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Deployment of Fuel Cell Electric Buses in Transit Agencies: Hydrogen Demand Allocation and Preferable Hydrogen Infrastructure Rollout Scenarios

THESIS

submitted in partial satisfaction of the requirements
for the degree of

MASTER OF SCIENCE

in Environmental Engineering

by

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DEDICATION

To my parents,

Jorge and Idania,

to my grandmother, Argelia, and to each one of my brothers,

for their love, support and sacrifice.

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NOMENCLATURE

APEP	Advanced Power and Energy Program
BEB	Battery Electric Bus
CA	California
CNG	Compressed Natural Gas
D&D	Distribution and Dispensing
DGE	Diesel Gallons Equivalent
FCEB	Fuel Cell Electric Bus
GHG	Green House Gas
GIS	Geographic Information Systems
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
GWP	Global Warming Potential
H_2	Hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied petroleum gas
OCTA	Orange County Transportation Authority
PCA	Preferred Combination Assessment

PP	Power Plant
Rnwb	Renewable
SC	Scenarios
SMR	Steam Methane Reformation
WTT	Well to Tank
WTW	Well To Wheels
WWTP	Waste Water Treatment Plants

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ABSTRACT OF THE THESIS

Deployment of Fuel Cell Electric Buses in Transit Agencies:

Allocation of Hydrogen Demand and Rollout of Preferable Infrastructure Scenarios

By

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Master of Science in Engineering with concentration in Environmental Engineering

University of California, Irvine, 2016

Professor Scott Samuelsen, Chair

Initiatives to improve air quality in urban areas and to mitigate climate change through the reduction of greenhouse gas emissions have resulted in new mandates and legislation to implement zero emissions vehicles (ZEV). While several studies have focused on fueling infrastructure for light-duty fuel cell electric vehicles, there is a lack of knowledge regarding the nature of hydrogen supply chains for fuel cell electric buses. This thesis presents an analysis of hydrogen infrastructures to guide policymakers and transit agencies in the identification of preferable scenarios for the deployment of hydrogen fuel cell electric buses.

Based on research for light-duty vehicles conducted at the Advanced Power and Energy Program in the University of California, Irvine, two novel computer-based tools were developed to design and analyze environmentally sensitive hydrogen fueling infrastructure that addresses the wide range of requirements faced by transit agencies in the deployment of fuel cell buses. The first tool provides spatially-resolved allocation of hydrogen demand and identifies feedstocks for hydrogen production. The second tool provides a systematic

evaluation of hydrogen supply chain scenarios through the analysis of well-to-wheel energy and water demand, and the emission of greenhouse gases and criteria pollutants. In addition, this evaluation includes a detailed analysis of the space requirements and operations modifications for the placement of hydrogen fueling infrastructure at transit agencies.

The tools were used to establish hydrogen fueling infrastructures scenarios at three levels of deployment: national, state and county. At the national level, the spatial allocation of hydrogen demand and potential environmental benefits of different hydrogen scenarios were developed for transit agencies in the U.S. At the state level, the hydrogen demand allocation and spatial rollout of possible feedstock sources were established for the state of California. At the local level, preferable hydrogen scenarios were developed for a large transit agency (the Orange County Transportation Authority) along with the quantification of emissions and resources and cost projections of hydrogen distribution pathways.

CHAPTER 1. Introduction

This thesis presents an analysis of hydrogen infrastructures to guide policymakers and transit agencies in the identification of preferable scenarios for the deployment of hydrogen fuel cell electric buses. Two novel computer-based tools were developed to design and analyze environmentally sensitive hydrogen fueling infrastructure that addresses the wide range of requirements faced by transit agencies when deploying FCEB.

1.1. Goal

The goal of this thesis is to develop viable pathways for the deployment of hydrogen fueling infrastructure to support the adoption of fuel cell electric buses in transit agencies.

1.2. Objectives

To meet the goal of this research, the following objectives were met:

1. <u>Spatially and Temporally Resolved Hydrogen Demand Allocation Tool</u>. Develop a hydrogen demand allocation tool - spatially and temporally resolved- to support the strategic deployment of hydrogen fuel cell electric buses.

2. <u>Hydrogen Supply Chain Infrastructure Tool</u>. Develop a hydrogen supply chain infrastructure tool to analyze the emission of greenhouse gas and criteria pollutant, and energy and water demand in order to establish preferable hydrogen scenarios.

3. <u>Use of a Large Transit Agency as Test and Evaluation Platform</u>. Select a large scale transit agency as test and evaluation platform for the application of the hydrogen demand allocation tool and he hydrogen supply chain infrastructure tool.

CHAPTER 2. Background

2.1. Air Quality in Urban Areas

Over 131.8 million people—42 percent in the U.S.—live where pollution levels are dangerous to breathe [1]. Throughout the world, urban air pollution is a leading cause of respiratory illnesses in children and responsible for millions of premature deaths [2].

In the state of California more than 9,000 deaths per year are associated with urban air pollution [3]. Combustion of fossil fuels for energy production and transportation is the principal source of criteria pollutant emissions. While air quality has improved significantly over time as a result of increasingly stringent regulations on stationary and mobile source emissions; it still ranks amongst the worst in the United States with respect to ozone and particulate matter. According to the American Lung Association's ratings for the 10 most-air-polluted cities in the United States, six California cities are among the worst for ozone, worst for year-round particulate pollution, and worst for short-term particulate pollution [4].

Through California's proactive policies and air pollution regulations, criteria pollutants from motor vehicles have been reduced with remarkable success (particularly passenger vehicles) over the last five decades. However, transportation-related criteria pollutants remain a principal contributor to the still severe air pollution problem. This is largely because California's vehicle population and total "vehicle miles traveled" continue to increase [5]. Therefore, the reduction of emissions from the transportation sector is required to improve the air quality in urban areas.

2.2. Greenhouse gas emissions as forcing factor for alternate transportation in California

In 2013, total greenhouse gas (GHG) emissions for the state of California were almost 460 million metric tons of CO2 equivalents (MMTCO2e), an overall decrease of 7% since peak levels in 2004 [6]. Overall, trends in the inventory demonstrate that the carbon intensity of California's economy (the amount of carbon pollution per million dollars of GDP) is declining; representing a 23% decline since the 2001 peak. These trends reflect California's progress toward the goal set by the Global Warming Solutions Act of 2006 (AB 32) to reduce the State's GHG emissions to 1990 levels by 2020.

The transportation sector remains the largest source of GHG emissions in the state, accounting for 37% of the inventory. Figure 1 show the GHG emission by sector, evidencing the large portion of contribution that the transportation sector accounts for in the overall emissions in California.

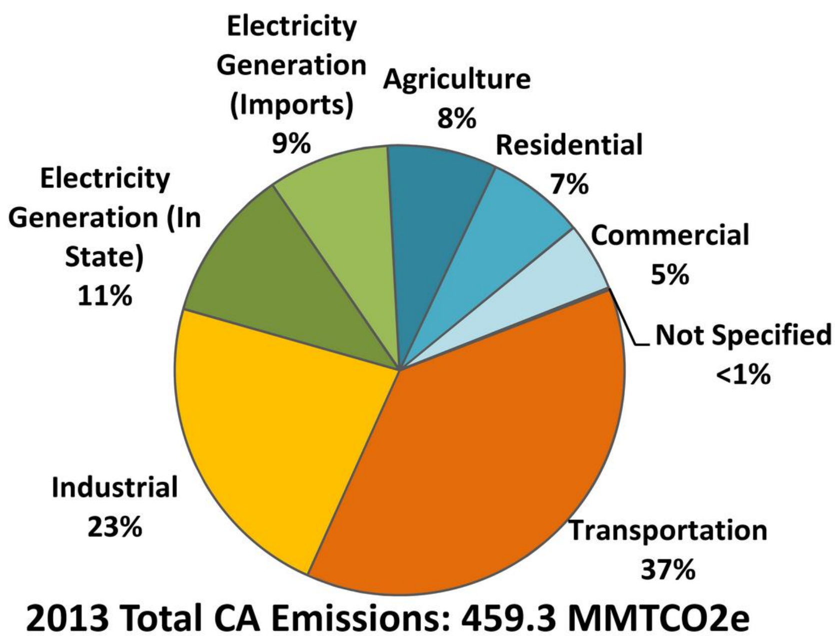


Figure 1: Total Greenhouse gases emissions by sector for California [6]

Emissions in Figure 2 are organized by the categories in the AB 32 Scoping Plan and use global warming potentials (GWPs) from the Intergovernmental Panel on Climate Change (IPCC) [7]. Note that the GHG emissions from transportation sector are above 160 million metric tons of CO2 equivalents, and the emissions from transportation sources increased through 2007, but then declined through 2012. While in-state transportation GHG emissions shows a slight increase of 1% in 2013, emissions from this sector are 11% lower than peak levels in 2007 [8].

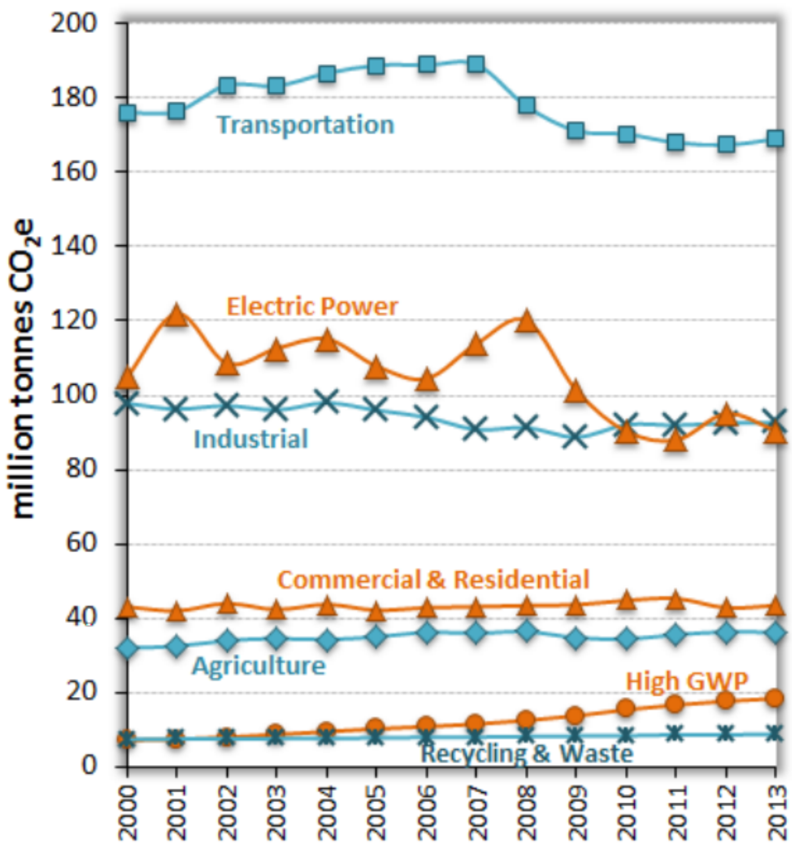


Figure 2: California GHG emissions by category 2000-2013 [8]

The majority of emissions in the transportation sector are from on-road vehicles, which consist of light-duty vehicles (cars, motorcycles, and light-duty trucks) and heavy-duty vehicles (heavy-duty trucks, buses, and motorhomes). As shown in Figure 3, the emissions of heavy duty vehicles were more than 30 million metric tons of CO2 equivalents (MMTCO2e) in 2013.

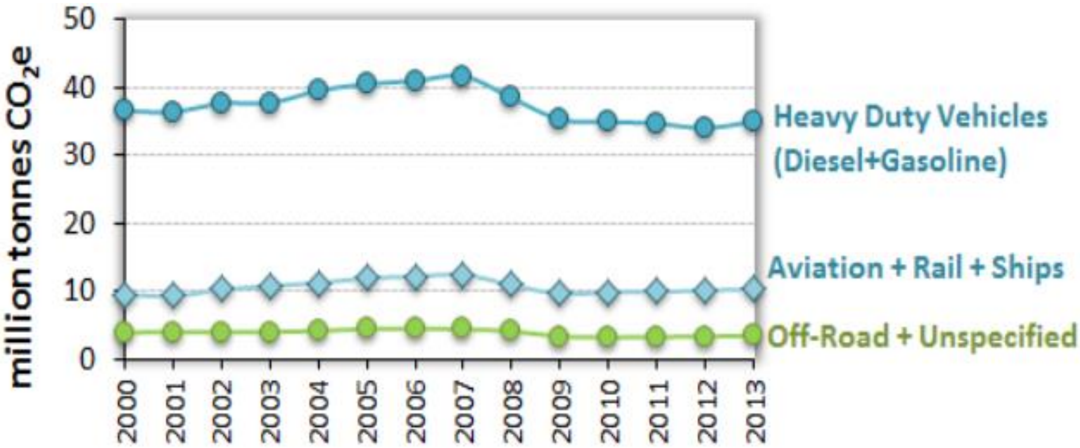


Figure 3: GHG emissions from transportation sector [8]

Emissions increased in 2013, largely driven by the increase in heavy-duty vehicles, specifically diesel vehicles. Emissions from diesel vehicles track the same trends as the sales in diesel fuel as presented in Figure 4.

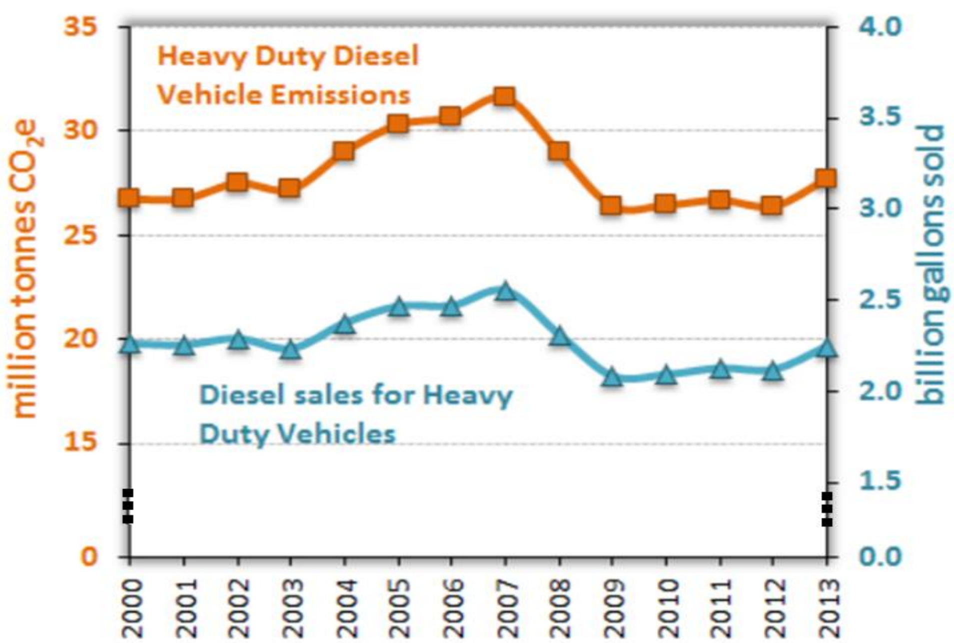


Figure 4: Trends of emissions and sales for heavy duty diesel vehicles [8]

While the largest category contributing to the GHG emission are light-duty vehicles (accounting for approximately 71% of transportation emissions in 2013), the increasing trend for heavy-duty vehicles call attention to more proactive efforts in adopting cleaner technologies for heavy-duty vehicles. Overall, a transition to cleaner technologies is required to reach the goals and timeline of the legislated GHG and urban air quality requirements established for California.

2.3. Background in Legislation

California has been a leader in pollution and greenhouse gas (GHG) emissions reductions for decades. In 2005 Governor Schwarzenegger enacted Executive order S-3-05 which set into motion three GHG emission goals for the state of California in the near and long term. These goals are to 1) bring GHG emission to 2000 levels by 2010, 2) achieve 1990 levels by 2020, and 3) establish levels of GHG emissions by 2050 that are equivalent to an 80% reduction below those recorded in 1990. These goals have been affirmed in part by Assembly Bill 32 (AB 32), the Global Warming Solutions Act, which sets by law the second objective of reducing GHG emissions to 1990 levels by 2020 [9].

Other legislation, such as Senate Bill 1078, establishes the Renewable Portfolio Standard (RPS), or renewable energy penetration goals for the state. These goals are delineated in Senate Bill 1078 and are updated by Senate Bill 2, with an aim to have a penetration of 20% by 2013, 25% by 2016 and 33% by 2020 [10]. These high penetration objectives, along with future increased load from the electrification of the transportation sector, will have complex and dynamic interactions with the electrical grid. These complex interactions and concurrent complementary technology utilization strategies play a key role in energy utilization and price regulation [11], [12]. Therefore, to fully leverage these high renewable penetration rates, a sector wide, California specific approach must be taken when analyzing the future of California's energy system and build out of complementary infrastructure [13].

To meet the schedule and reduction targets, a substantial effort has been focused on the transportation sector to accelerate fleet modernization, and increase the penetration of clean engine technologies and cleaner fuels. Part of this effort is an "Advanced Clean Transit" initiative from the California Air Resource Board that requires an implementation level of Zero Emission Buses (ZEBs) into transit agencies [14], [15]. However, no holistic analysis has been conducted to compare the environmental impacts of the overall fuel supply chain needed for the deployment of ZEBs. This type of analysis is essential to (1) maximize the emission reduction while minimizing resource consumption in the supply chain, e.g., energy and water, and (2) establish a criterion that can identify the most effective combination of ZEB technologies based on the characteristics and limitations of the transit agency.

2.4. Overview of Hydrogen Supply Chain

Hydrogen is an energy carrier that can be used in fuel cells to generate electric power using an electrochemical reaction rather than combustion, producing only water and heat as byproducts. Fuel cells are emerging to power vehicles, power homes and office buildings, and potentially power locomotives and ships.

The focus of this thesis is the use of hydrogen in zero emission fuel cell electric buses with the hypothesis that the strategic planning of the hydrogen supply chain will provide benefits beyond the elimination of tailpipe emissions. Hydrogen provides a paradigm shift from the current fossil-based fuels due to (1) the great variety in renewable technologies for the production of hydrogen, and (2) the flexibility to incorporate renewable technologies along the supply chain. The main components of the hydrogen supply chain are presented in Table 1.

Table 1: Technology components of the hydrogen supply chain [16]

Categories of Hydrogen Technologies	Specific technology to be studied
Production of Hydrogen	Steam reforming Electrolyser Biological systems Gasification Thermo-chemical water splitting Photo-electrochemical systems
Storage of Hydrogen	Compressed Liquid Materials based / absorption Chemical
Transport of Hydrogen	Pipelines Road –rail tankers (g or l) Ships
Transport applications / primary drives	Fuel cell Combustion engine Electric / hybrid drives On board production

In addition to the generation technologies described above, hydrogen can be produced from a series of renewable sources that are transitioning to commercialization (Figure 5). Hydrogen can also be produced either centralized or distributed (local to the point of use). As a result, the hydrogen supply chain for fuel cell electric buses (FCEBs) has a myriad of options that can be interrogated to establish scenarios that best fit the unique characteristics presented by each transit agency.

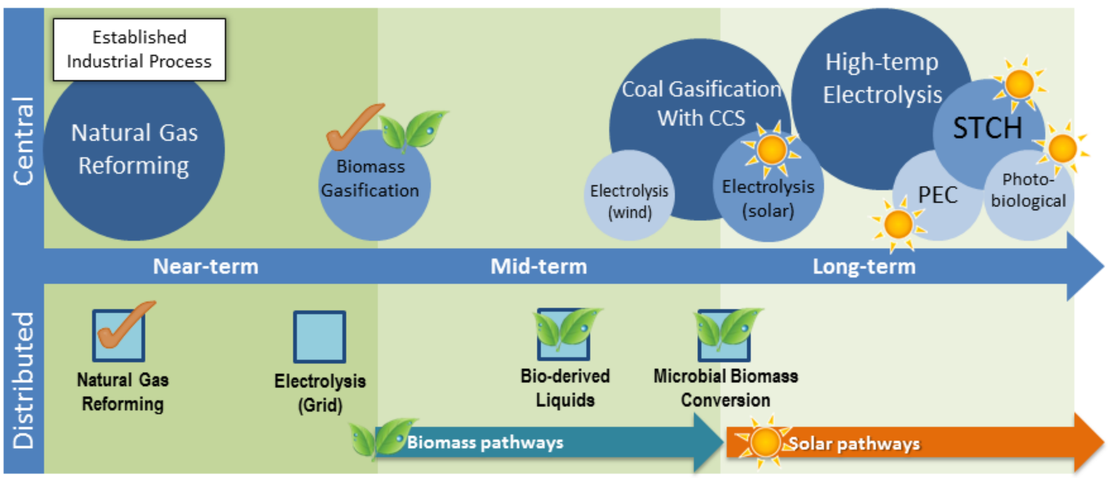


Figure 5: Hydrogen generation technologies [17]

More than 95% of current hydrogen generation in the world relies on some fossil fuel as the feedstock, specifically from natural gas. The United States is rich and abundant in natural gas (Figure 4) having an estimated 2552 trillion cubic feet (827 trillion cubic feet is in the form of shale gas) (EIA 2010). As a result, the generation of hydrogen from natural gas has the potential to reduce dependency on foreign oil since 87% of the natural gas used in the U.S. is produced domestically (Figure 6).

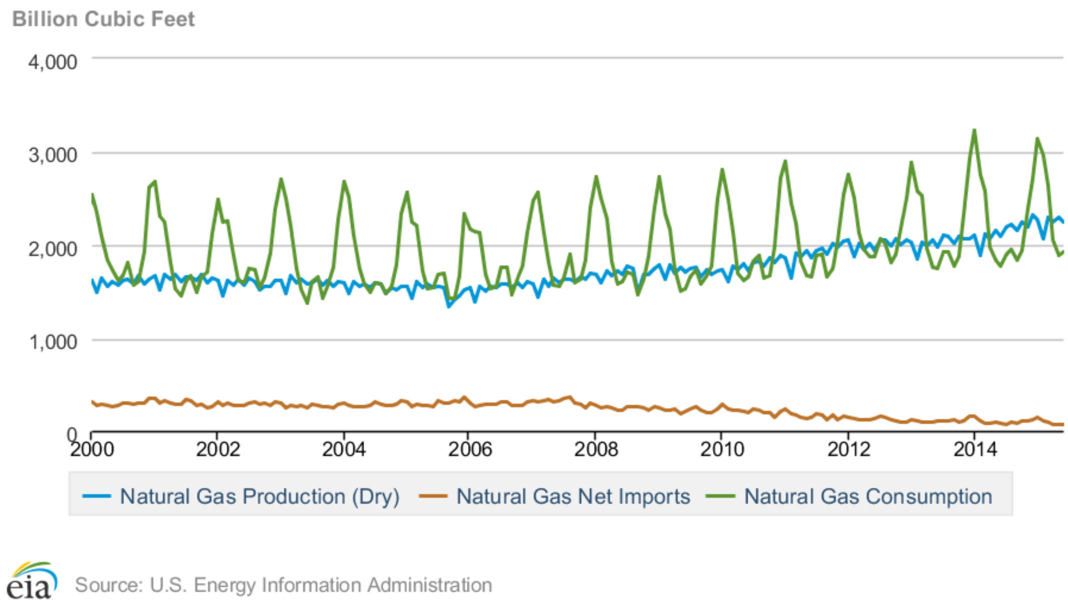


Figure 6: Natural gas consumption, production, and net imports in the U.S. [18]

The two technologies commercially available to produce hydrogen with a low environmental impact are steam methane reformation (SMR) and electrolysis. For both technologies, the production of renewable hydrogen is available with the use of feedstocks like biogas for the SMR and renewable electricity to power the electrolysis.

Steam Methane Reformation (SMR)

Today, most of the hydrogen in the world is generated by steam methane reforming (SMR) of natural gas. SMR of natural gas is the most cost effective and efficient of all commercial reformation technologies with a low environmental impact. Efficiencies for centralized natural gas operated SMR plants range from 76 – 81% [19].

Reformation operations currently take place mostly on a centralized scale. An example of non-centralized (i.e., "distributed") hydrogen generation is the SunLine Transit station in Thousand Palms, California. It is likely that more distributed reformation will be introduced into the emerging hydrogen infrastructure since it can take advantage of the existing natural gas infrastructure for feedstock delivery to produce hydrogen on site. Some companies, such as HyRadix, H_2Gen, and Ztek are working on commercializing integrated reformer systems that generate, compress, and dispense hydrogen into vehicles [20].

Electrolysis

Electrolysis is a common method of generating hydrogen from water. An electrolyzer uses an electric current to split water into its two parts: hydrogen and oxygen. The source of the electricity dictates the cost of the process, estimated to be 58% of the price at the pump in one study [21].

Using renewable electricity to power an electrolyzer is an environmentally friendly method of generating hydrogen. Large-scale solar or wind farms can be used for centralized generation of hydrogen by electrolysis and potentially result in more extensive utilization of renewable energy resources by utilizing electricity that would be otherwise curtailed [22]. The installation cost of a hydrogen pipeline is 1/3 that of an electrical transmission line that moves the same amount of energy [20]. Hydrogen pipelines are also safer than overhead transmission lines, require less maintenance, and are aesthetically preferred.

Electrolysis using the electrical power grid comes at a higher environmental cost. Some studies even show that generating hydrogen from grid electrolysis to fuel automobiles yields a net increase of greenhouse gas emissions compared to today's conventional vehicles [23]. There are some advantages associated with grid electrolysis, but it is only worthwhile to consider it on a distributed scale, and not in a centralized facility. On a distributed scale, grid electrolysis produces no on-site emissions, and since hydrogen generation is occurring at the dispensing station, no transportation of the fuel is necessary. In addition, emissions from trucks are omitted that would otherwise be moving the fuel. Electrolysis requires an incoming feedstock of only water and electricity making it simple to integrate with the existing infrastructure.

2.5. Previous Hydrogen Infrastructure Models, Methods and Approaches

Results from past research are available for (1) sizing and estimating costs for different hydrogen supply chain components, and (2) conducting life cycle analysis of different hydrogen supply chains. Most of these models and approaches, however, are specific to light-duty vehicles and do not incorporate the capability to address characteristics that are unique to transit agencies (e.g., return-to-base refueling methodology and small-forecourt scale). Below is a description of the models that served as the foundation for the development of the comprehensive tools developed and utilized in this thesis.

Alternative Fuel Life-Cycle Environmental and Economic Transportation (AFLEET)

The AFLEET tool allows stakeholders to estimate life-cycle petroleum use, life-cycle greenhouse gas emissions, vehicle operation air pollutant emissions, and costs of ownership for light-duty vehicles (LDVs) and heavy-duty vehicles (HDVs). The AFLEET tool provides three calculation methods. The first option is the Simple Payback Calculator that examines acquisition and annual operating costs to calculate a simple payback for purchasing new alternative fuel vehicles as compared to its conventional counterpart, as well as average annual petroleum use, GHGs, and air pollutant emissions. The second option is the Total Cost of Ownership (TCO) Calculator that evaluates the net present value of operating and fixed costs over the years of planned ownership of a new vehicle, as well as lifetime petroleum use, GHGs, and air pollutant emissions. Finally, the Fleet Energy and Emissions Footprint Calculator estimates the annual petroleum use, GHGs, and air pollutant emissions of existing and new vehicles, taking into consideration that older vehicles typically have higher air pollutant emission rates than newer ones [24].

The AFLEET tool does not allow a customization of the alternative fuel supply chain. To overcome this, AFLEET was incorporated into GREET to have this flexibility. The result, however, is limited to LDVs and not directly applicable to the present thesis.

The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Tool (GREET)

The GREET tool calculates the emissions (CO_2, CH_4, and N_2O) as well as other criteria pollutants that result from transportation life cycles; in particular life cycles of electricity, transportation fuels, and vehicle components. For this tool each stage of a life cycle (end use, transportation, distribution and production) is represented as a stationary or transportation process. At each process step, emissions can be emitted in several ways: (1) combustion of process fuels that provide head and energy for the process, and (2) leakage which is usually associated with storage and transportation of volatile fuels [25]. In GREET, transportation-related activities are simulated using input parameters such as transportation modes, transportation distances, and energy use intensities for various transportation modes.

Figure 7 below presents the flow of the calculations in the GREET tool. To account for energy inputs to a process, the tool specifies a list of resources, associated amounts, and leaking rates if any. To account for process emissions, GREET uses a set of emission factors for each of the criteria pollutants. Each resource used in a process can be allocated to one or more technologies. GREET combines the entire life cycle processes into pathways.

GREET accounts for all of the resources and technologies used in a pathway and then combines them to calculate the energy demand and emissions associated with each pathway. Each pathway has a single main product. The calculated energy demand and emissions of a pathway are used as upstream values for the corresponding product when it is used as an input to any process within the tool. Iterative calculations are used to resolve the circular references [25].

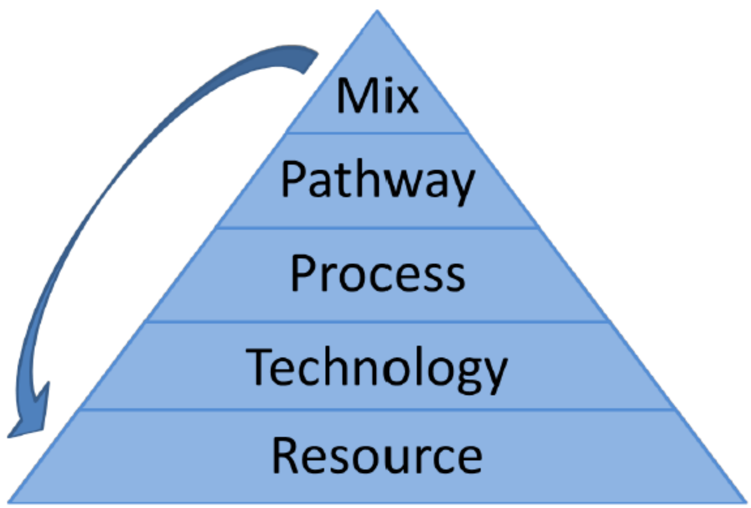


Figure 7: GREET Pyramid [26]

Department of Energy Hydrogen Analysis tool (DOE H_2A)

The H2A tool is a standardized approach and set of assumptions for estimating the well to tank costs of hydrogen production and delivery technologies (and the resulting cost of hydrogen) [27]. H2A only provides a quantification of greenhouse gases on a well-to-wheels basis and does not provide an analysis on criteria pollutants nor does it have the capability to directly compare the designed hydrogen supply chain with a base case to weight the environmental or economic benefit of the transition from old technologies.

H2A Production Tool

Figure 8 shows the set of hydrogen production and delivery technologies that are considered in H2A. The analyses include various options for central production of hydrogen (in large plants) and for forecourt production (in distributed production facilities).

Figure 8 shows the basic architecture for the H2A Tool Analysis tools. The tool is Microsoft Excel-based with multiple tabs. Each has the same feedstock and utility prices in addition to physical property data tabs.

Exhibit 3

Technologies to Be Characterized by the H2A Project

Central Production of Hydrogen (Central is defined as >50,000 kg/day of hydrogen. The production cost will stop at 300 psi hydrogen with minimal storage for production purposes only.)

- Coal Gasification: Hydrogen Production
- Coal Gasification: Hydrogen and Electricity Production
- Natural Gas Hydrogen Production
- Biomass Gasification Hydrogen Production
- Next Generation Nuclear Energy High Temperature Sulfur-Iodine Thermochemical Hydrogen Production
- Next Generation Nuclear Energy High Temperature Steam Electrolysis Hydrogen Production
- Current Nuclear Energy Using Standard Electrolysis Hydrogen Production
- Wind Electrolysis Hydrogen Production
- Wind Electrolysis Hydrogen and Electricity Production

Forecourt Production of Hydrogen (The sizes of the facilities are 100 and 1500 kg/day.)

- Natural Gas Reforming
- Electrolysis
- Reforming of Ethanol: Sourced from fermentation from corn grain or from cellulosic biomass (to be posted at a later date)
- Reforming of Methanol: Sourced from biomass gasification or from fossil fuels (to be posted at a later date)

Delivery

- Pathways: Gaseous hydrogen by pipelines, gaseous hydrogen by truck tube trailers, and cryogenic hydrogen by truck
- Components Model including; Pipelines, compressors, truck tube trailers, cryogenic liquid trucks, liquefaction, gaseous tube storage, geologic storage, gaseous hydrogen terminals, liquid hydrogen terminals
- Scenario Model: Geographic-specific scenarios for a complete delivery infrastructure

Figure 8: Scope of the Hydrogen Analysis Project (H2A) [27]

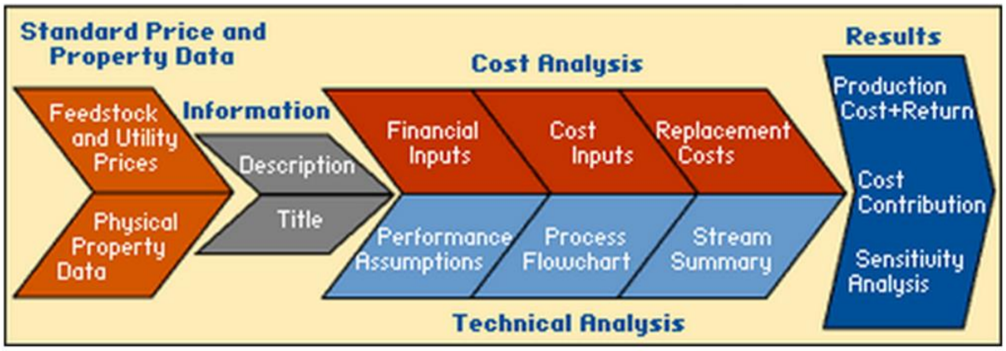


Figure 9: Components of Cost Analysis in H2A [27]

H2A Delivery Components Tool

This tool works in a similar manner to the H2A Production Tool but with three sub-models: Delivery Carriers Components, Delivery Scenarios Analysis, and Refueling Station Analysis. All models follow the H2A approach with regard to economic parameters and tool layouts.

The results for this tool are the cost contribution of each delivery component to the cost of hydrogen in terms of $/kg. The cost analysis is built based on the Capital Recovery Factor (CRF) method rather than a rigorous Discounted Cash Flow method. Although the CRF method is not quite as rigorous, the results are comparable when the same economic parameters are used [27], [28].

Preferred Combination Assessment (PCA) tool

The Preferred Combination Assessment (PCA) tool is a tool designed by the Advanced Power and Energy Program at UCI, designed to analyze the impacts of possible hydrogen supply chains[29]. The PCA tool determines the well to wheels (WTW) impacts associated with the extraction of the feedstock and the variety of pathways for generation, distribution, and utilization of hydrogen.

The purpose of the PCA tool is to determine the GHG and criteria pollutant emission levels and associated resources consumed (e.g., water, electricity, natural gas, and diesel fuel) for the hydrogen supply chain scenarios selected for study. This tool has played a key role in a much larger organizational effort coined Spatially and Temporally Resolved Energy and Environment Tool or STREET [30]. The overall layout and flow of STREET can be visualized in Figure 10.

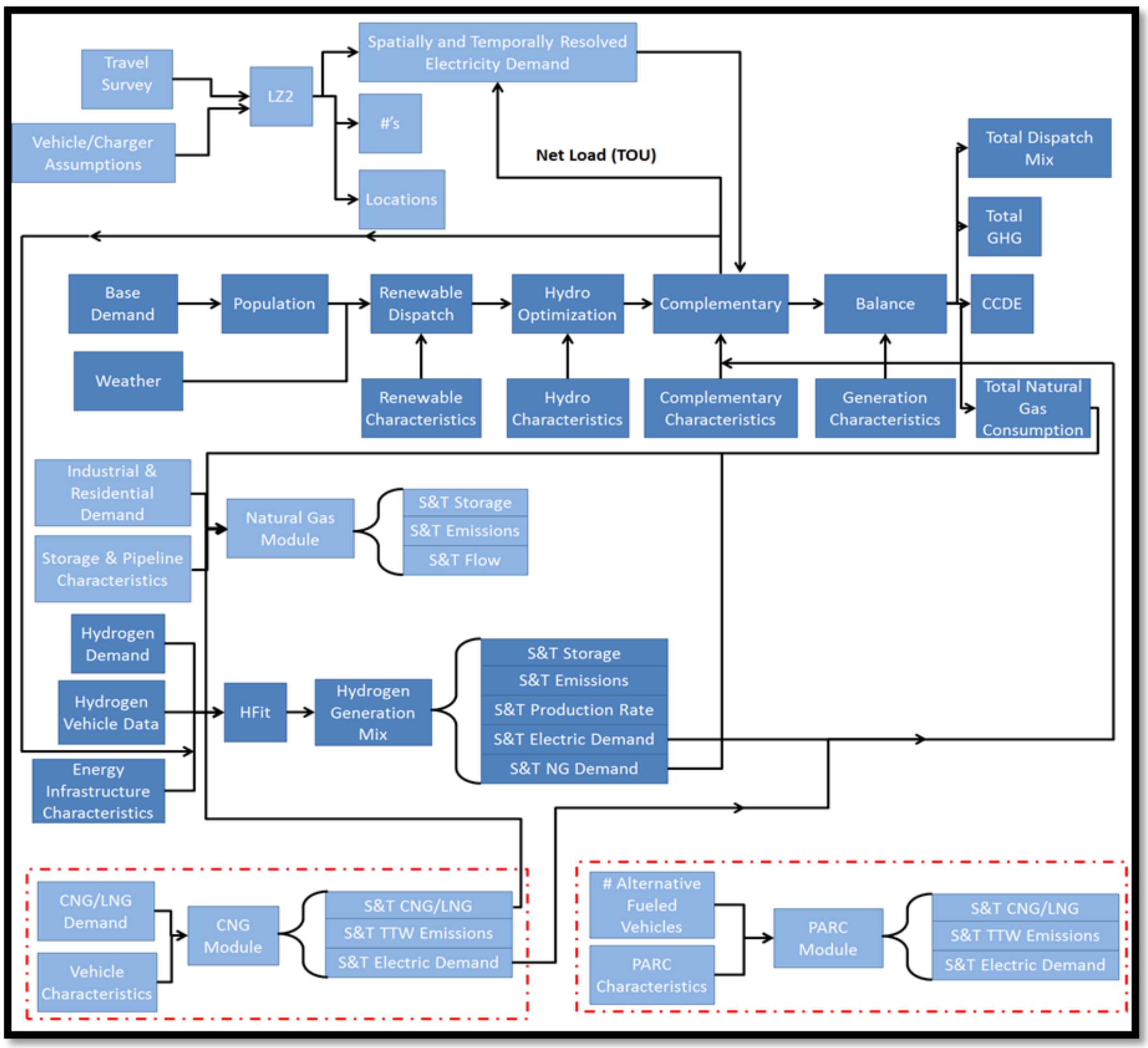


Figure 10: Schematic of modeling platform known as STREET [30]

STREET is a suite of models that are capable of interacting in order to explore the impacts that various changes will have on the overall energy system. STREET focuses on optimal hydrogen refueling station placement from a spatially and temporally resolved perspective. Based on the station placement, STREET has been utilized to determine the emissions and air quality impacts that hydrogen demand would have in localized geographic regions such as southern California [31]. Both the STREET and PCA models have been decisive tools in the preliminary stages of the troll-out strategy for hydrogen infrastructure in California for light-duty vehicles [31]. In the current thesis, the PCA tool is expanded to address hydrogen infrastructure for fueling fuel cell electric buses.

2.6. Current status of FCEB technology and its future market penetration rate in the U.S.

Zero emission passenger cars are entering the market and several demonstrations across the United States and all over the world have validated the technology of hydrogen and electric buses. While battery electric buses are being purchased for demonstration purposes, the technology does not have the range to support the high percentage of long routes typical of a transit district and requires unusually long times for recharging. Hydrogen fuel cell electric buses, in contrast, have the range to serve the long routes and refueling times comparable to today's bus fleet. As a result, for transit agencies looking to implement Zero Emission Vehicles, fuel cell electric buses are an attractive option because of (1) the similar range and refueling times typical of conventional buses, (2) better fuel economy, and (3) virtually zero emission of criteria pollutants. Fuel cell technologies for transit buses have the additional benefits:

- Reduced dependence on foreign oil

- Quiet, smooth rides for customers
- Creation of green technology jobs
- Technologies for better-performing, more-efficient hybrid and electric buses
- Demonstration of the value of fuel cell technology to a larger, heavy-duty vehicle market.

The Department of Energy (DOE) and the National Renewable Energy Laboratory (NREL) have been evaluating alternative fuel transit buses with the Federal Transit Administration (FTA) since the early 1990s. In 1996, the DOE and NREL completed an evaluation of transit buses at eight transit agencies that included six different alternative fuels. As part of this alternative fuel transit bus evaluation, NREL and Battelle (NREL's subcontractor for this effort) developed a customized data collection and evaluation protocol. Since the 1996 study of alternative fuels in transit, NREL has completed additional evaluations of natural gas and hybrid propulsion transit buses as well as several evaluations of alternative fuel and advanced propulsion truck applications.

NREL's first evaluation of fuel cell transit buses was in 2000 working with SunLine Transit Agency in the Palm Springs, California. In 2006, the FTA created the National Fuel Cell Bus Program (NFCBP), a cooperative research, development, and demonstration program created to advance commercialization of fuel cell electric buses [32]. The NFCBP requires an equal cost share by project teams for each federal dollar invested, bringing the size of the program to more than $150 million through FY2011. The FTA Office of Research, Demonstration and Innovation funds FCEB research and demonstrations projects, including:

- Purchase of and improvements for FCEBs
- Implementation and demonstration of FCEBs in transit operations, including hydrogen fueling infrastructure
- Modifications and improvements of facilities (e.g., maintenance, indoor storage, fueling) to support FCEB operations
- Independent analysis and evaluation of transit agency implementation and demonstration of FCEBs and related infrastructure improvements.

Out of this funding and initiative a yearly report prepared by the National Renewable Energy Laboratory (NREL) where it catalogs fuel cell electric bus research projects in the United States and describes their impact on commercialization of fuel cell power systems and electric propulsion for transit buses in general. NREL publishes individual reports on each demonstration that focus on the results and experiences for that specific project. The annual status report combines results from all of those FCEB demonstrations, tracks the progress of the FCEB industry toward meeting technical targets (as shown in Table 2), documents the lessons learned, and discusses the path forward for commercial viability of fuel cell technology for transit buses. Its intent is to inform FTA and DOE decision makers who direct research and funding; state and local government agencies that fund new propulsion technology transit buses; and interested transit agencies and industry manufacturers.

DOE and FTA have established performance, cost, and durability targets for FCEBs. These targets, established with industry input, include interim targets for 2016 and ultimate targets for commercialization. FCEB technology continues to show progress toward meeting technical targets for increasing reliability and durability as well as reducing costs.

Table 2: Summary of FCEB Performance Compared to DOE/FTA Targets [33]

	Units	Current Status[a] (Range)	2016 Target[1]	Ultimate Target[1]
Bus lifetime	years/miles	2.5–5 / 49,296–151,000[b]	12/500,000	12/500,000
Power plant lifetime[c]	hours	5,557–17,211[b,d,e]	18,000	25,000
Bus availability	%	45–72	85	90
Fuel fills[f]	per day	1	1 (<10 min)	1 (<10 min)
Bus cost[g]	$	2,000,000	1,000,000	600,000
Power plant cost[c,g]	$	N/A[h]	450,000	200,000
Hydrogen storage cost	$	N/A[h]	75,000	50,000
Roadcall frequency (bus/fuel cell system)	miles between roadcalls	1,408–6,363 / 10,406–37,471	3,500/ 15,000	4,000/ 20,000
Operation time	hours per day/days per week	7–19 / 5–7	20/7	20/7
Scheduled and unscheduled maintenance cost[i]	$/mile	N/A[j]	0.75	0.40
Range	miles	145–294[k]	300	300
Fuel economy	miles per gallon diesel equivalent	4.32–7.26	8	8

[a] The summary of results in this report represents a snapshot from the included demonstrations: data generally from August 2013–July 2014 with the exception of BC Transit, which covers April 2013 through March 2014.
[b] Accumulated totals for existing fleet through July 2014; these buses have not reached end of life.
[c] For the DOE/FTA targets, the power plant is defined as the fuel cell system and the battery system. The fuel cell system includes supporting subsystems such as the air, fuel, coolant, and control subsystems. Power electronics, electric drive, and hydrogen storage tanks are excluded.
[d] The status for power plant hours is for the fuel cell system only; battery lifetime hours were not available.
[e] The highest-hour power plant was transferred from an older-generation bus that had accumulated more than 6,000 hours prior to transfer.
[f] Multiple sequential fuel fills should be possible without an increase in fill time.
[g] Cost targets are projected to a production volume of 400 systems per year. This production volume is assumed for analysis purposes only and does not represent an anticipated level of sales.
[h] Capital costs for subsystems are not currently reported by the manufacturers.
[i] Excludes mid-life overhaul of power plant.
[j] Maintenance costs are not available for this report. See individual project reports on the NREL website.
[k] Based on fuel economy and 95% tank capacity.

The FCEBs continue to show higher fuel economy compared to the baseline buses in similar service. FTA's performance target for FCEB fuel economy is 8 miles per diesel gallon equivalent (mi/DGE), which is approximately two times higher than that of typical conventional diesel buses. Actual data from the FCEBs included in the 2014 report showed fuel economy ranging from 1.67 to 1.85 times higher than that of diesel baseline buses and 2.17 times higher than that of compressed natural gas baseline buses [33]. Fuel economy for the FCEBs ranged from 4.3 mi/DGE up to 7.3 mi/DGE and averaged 6.25 mi/DGE.

At this point in the development, FCEBs are not commercial products. According to NREL, FCEB current design is considered to be around technology readiness level (TRL) of 7 (Figure 11).

The current costs for FCEB technology—both capital and operating costs—are still higher than that of conventional diesel technology. This is expected considering diesel is a very mature technology (TRL 9).

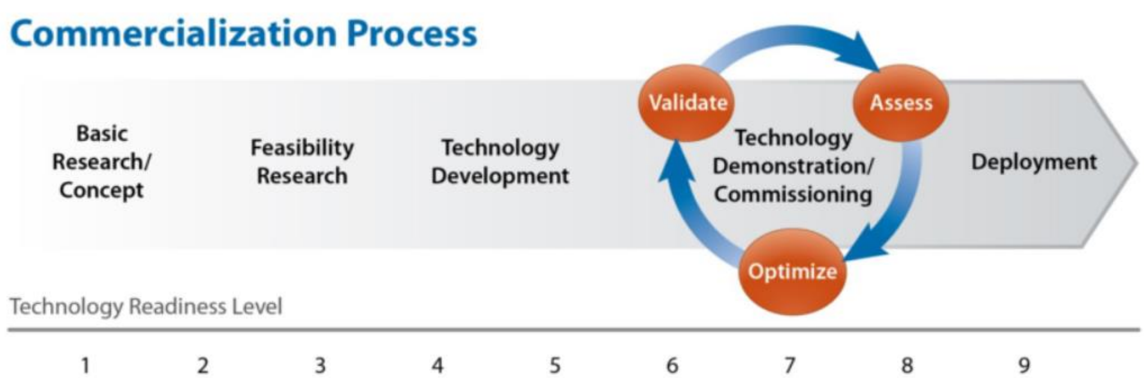


Figure 11: Graphic representation of the commercialization process developed for FCEBs [33]

While FCEB performance continues to improve, challenges must be overcome to move the technology to a commercial product. For example, the industry continues to have problems with companies leaving the market through restructuring or bankruptcy. This makes conducting long- term demonstrations a challenge when the partners no longer provide technical support or produce replacement parts. Other challenges include the following:

- Integration and optimization of components like the fuel cell stack and battery systems
- Parts availability for replacement of FCEBs
- The weight of FCEBs compared to conventional diesel buses (almost 3,000lb heavier)
- The transition of knowledge from the manufacturers to the transit staff.
- The cost of buses and infrastructure is decreasing incrementally and large quantity purchases are required to realize substantial cost reductions.
- Production, delivery, and dispensing of the hydrogen fuel

2.7. Literature Contribution

The literature regarding hydrogen as a transportation fuel focuses on light duty vehicles, and most of the literature for fuel cell electric buses (FCEB) consists of demonstration reports [33], [34][35]. The journal papers that address FCEBs applied to transit agencies focus on the economic aspects or on the modeling of refueling infrastructure without considering deployment constraints due to space availability or logistic modifications [36], [37]. The goal and objectives of this thesis study aim to address these major voids in the literature associated with future fuel cell electric bus transportation systems.

CHAPTER 3. Approach

The goal of this thesis is to develop viable pathways for the deployment of hydrogen fueling infrastructure to support the deployment of fuel cell electric buses in transit agencies. To achieve this goal, the following tasks were addressed.

Task 1: Spatially and Temporally Resolved Hydrogen Demand Allocation Tool

This task is aimed to developing a tool, Hydrogen Allocation Tool (H_2AT), to estimate the hydrogen demand of fixed-route buses at transit agencies with the following characteristics:

- Spatial allocation of hydrogen to analyze current and future hydrogen demand scenarios.
- Temporal resolution that can estimate the hydrogen demand over time considering aspects like penetration rate of fuel cell electric buses, expansion of miles for their routes, increase fleet size, and improvements on bus technology that impact the fuel economy.

A geographic information system (GIS) will be utilized for the spatial allocation of all the transit agencies in a desired region. To complete this task, the fleet specifications for each transit agency are required (such as number of buses, total miles per day traveled and spatial location of each fleet-base). For the hydrogen equivalent calculations, a code is required which allows modifications to default values to obtain more accurate and personalized values. The outputs to this tool will then be utilized to establish the most efficient number of hydrogen fueling stations, as well as, their spatial allocation.

To demonstrate the capabilities of H_2AT, the spatial and temporal demand of hydrogen will be calculated for all the transit agencies in the United States with a close look to agencies in the state of California.

Task 2: Hydrogen Supply Chain Infrastructure Tool

This task is dedicated to creating a tool, the Hydrogen Characterization and Analysis Tool (H_2CAT), which can characterize different hydrogen supply chain scenarios and analyze how each scenario influences greenhouse gases and criteria pollutant emissions, as well as energy and water consumption. For any desired supply chain, the output is the quantification of resources utilization, the emissions of GHG and criteria pollutants, and efficiencies.

In this task the spatial and temporal hydrogen demand allocation will be obtained as input from Task 1. Then, a library of processes will be created with specifications of efficiency, emission factors, and feedstock utilization that allow the selection of a technologies mix for production, distribution and dispensing of hydrogen, and the selection of the feedstock-mix. The library of processes includes the emission analysis and energy-demand and water consumption of each technology on a well-to-wheels basis.

Task 3: Use of a Large Transit Agency as Test and Evaluation Platform

The purpose of this task is to identify preferred hydrogen infrastructures that can enable the deployment of fuel cell electric buses in a major public transit agency. To do so, a selection criterion must first be created to categorize and evaluate different transit agencies and then determine the ideal agency to use in the task.

In Task 3, the tools developed in Tasks 1 and 2 will be utilized and applied to the operational constraints of a specific large transit agency, which becomes a test platform for the purpose of this thesis. Task 3 is designed to characterize different hydrogen supply chains that will satisfy the fuel demand of the test-platform, with an especial emphasis on the analysis and comparison of centralized versus distributed generation. After this, preferred roll-out scenarios will be selected based on resource consumption, emission analysis, feasibility of implementation and infrastructure requirements for the transit agency.

Finally, the assessment of the FCEBs deployment will be compared to the conventional buses in current use by the transit agency.

CHAPTER 4. Hydrogen Allocation Tool – H_2AT

The current need to reduce greenhouse gas emissions and to improve air quality through reduction of criteria pollutants in urban areas has put into consideration guidelines that mandate transit agencies to incorporate a percentage of zero emission buses into their fleet [14]. It is important to have a spatial view of different adoption scenarios of hydrogen fuel cell buses in the future in order to analyze the use of resources across a region, as well as the impacts related to the resource demand (e.g., water, natural gas, biogas and renewable energy-sources like wind and solar). For such a purpose, the H_2AT tool was developed utilizing a geographic information system (GIS) that allows identifying the specific location where hydrogen is needed and the magnitude of such demand.

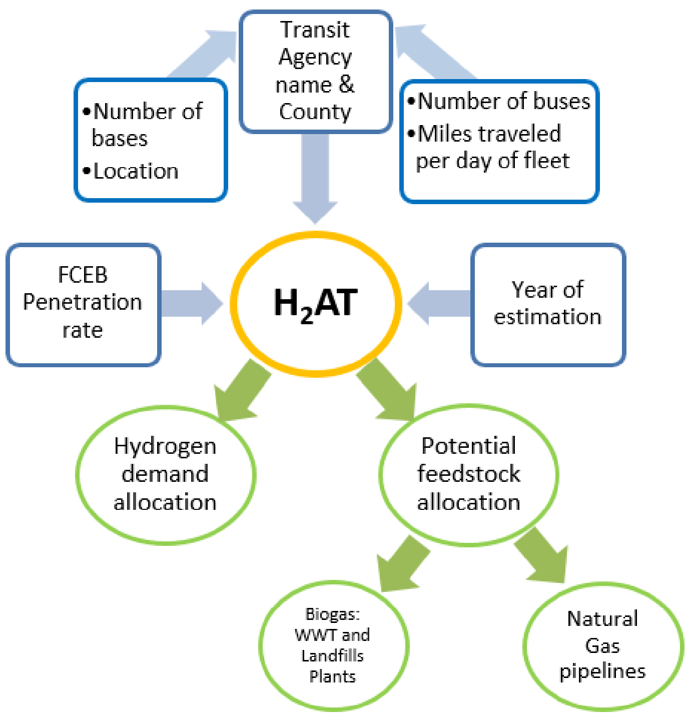


Figure 12: Hydrogen Allocation Tool – H_2AT

Figure 12 illustrates the inputs and outputs of the tool. A feature of this tool is that allows varying the penetration rate of FCEBs in the transit fleet, which allows a large portfolio for different deployment stages. Accordingly, the tool allows changes in the year of estimation that is directly related to the level of performance of the buses. For future years, it can be assumed that a better fuel economy can be achieved to reduce the hydrogen demand or increase miles covered.

By inputting the name and county of the transit agency to H_2AT, an internal transit-library finds the latitude-altitude and fleet specifications of the transit service-bases (fleet size, type of fuel, fuel consumption). The transit-library was incorporated to the tool from selected resources of the National Transit Database [38] and from the Fare Summary of the California Transit Association [39] which includes data for the fuel consumption of 2009 to 2013. This information is only for the transit agency as a whole and does not allow identifying the fuel utilization per base, which is needed in order to conduct the spatial analysis of hydrogen demand and possible distributed generation locations that will be explored in the next chapter.

Inputs and assumptions

The inputs required by H_2AT are marked with blue boxes in Figure 12. The user needs to set these parameters in order to have a spatial analysis of the hydrogen demand. The inputs are:

- Transit Agency name & County
- Number of bases
- Location of bases

- Number of buses per base
- Daily miles traveled at each base
- Year of estimation
- FCEB penetration proportion
- Available foot-print at each base

With the daily miles traveled per base, the tool can have a direct conversion to the daily hydrogen consumed by the fleet at each base using the equation below, where the set fuel economy of the hydrogen fuel cell electric buses is 6.50 mi/kg [33]. The hydrogen fuel consumption will improve accordingly to the year of estimation due to assumptions in the improvement of the technology.

Equation 1: Hydrogen demand calculation from daily miles of fleet

$$Daily\ H_2 = \left(\frac{miles\ fleet}{day}\right) * \left(\frac{kg\ H_2}{6.50mi}\right) = {}^{kg\ H_2}/_{day}$$

The above inputs are the ideal information that the tool needs to start the calculations. However, not all transit agencies manage their internal information in the same way and this can create difficulties in obtaining the required information. Because of this, the internal library of the tool contains information, such as fuel type and fuel utilization, that can be used to derive the required inputs. The information required for the calculation is (1) the name and county of the transit agency, and (2) number and location of bases. The tool makes the following assumptions in order to calculate the spatial hydrogen demand at the transit agency:

- Equal distribution of the total number of buses among all the fleet-bases (i.e., equal hydrogen demand distribution among all the bases).
- The fuel economy of the bus fleet (Table 3), required to calculate the daily miles traveled by the fleet (Equation 2) using the type of fuel and fuel consumption per transit agency provided by the Library.

Equation 2: Hydrogen demand calculation from fuel consumption

$$Daily\ Miles\ of\ fleet = \left(\frac{fuel\ consumption}{year}\right) * \left(\frac{mi}{fuel\ economy}\right) * \frac{year}{service\ days} = \frac{miles}{day}$$

Table 3: Fuel economy of different bus technologies

Type of Bus	Fuel Economy		Fuel economy in diesel gallon equivalents	
Battery Charging	2.67	KWh/mile [40]	13.87	mi/DGE
Diesel fuel	4.07	miles/gallon [41]	4.07	mi/DGE
Bio-diesel	3.99	miles/gallon [42]	3.84	mi/DGE
Gasoline (vans)	10.00	miles/gallon [43]	8.77	mi/DGE
Liquefied petroleum gas (LPG)	1.77	miles/DGE [44]	1.77	mi/DGE
Liquefied natural gas (LNG)	1.62	miles/DGE [45]	1.62	mi/DGE
Compressed natural gas (CNG)	2.39	miles/DGE [45]	2.39	mi/DGE
Hydrogen	6.50	miles/Kg [33]	7.36	mi/DGE

The outputs from the tool are the green ovals in Figure 12, including the spatial allocation of hydrogen demand. The hydrogen demand calculation was discussed above and the spatial representation is achieved utilizing a Geographic Information System (GIS) platform called ArcMap10. This output shows a map of the county or city with the exact location of where hydrogen is required, represented by dots that are proportional in size to the quantity of hydrogen.

Additional output of the tool is the spatial allocation of possible feedstock locations, including the natural gas pipeline network, natural gas stations, landfills and wastewater treatment plants with biogas production estimations. The output includes a GIS map (spatial representation) with the location of nearby feedstock locations and an analysis of the distance in miles of the transit agency bases to the feedstocks (if the location of the bases is provided by the user).

The spatial allocation of feedstock is especially important to inform decision making when selecting the hydrogen generation method. For example, if a landfill with biogas production is available at a distance of 10mi from the main transit agency base, the utilization of SMR with biogas becomes more viable than having SMR with natural gas when the closest natural gas pipeline is located 60mi from the base.

4.1. H_2AT Tool Capabilities Demonstration: Hydrogen Demand Spatially and Temporally Resolved for Public Buses in the United States

In order to demonstrate the capabilities of H_2AT, this section presents the hydrogen demand allocation for all the transit agencies in the United States with a closer look to the results of California, and explains the manner by which the tool is used.

The first step is to establish the location of transit agencies across the United States. The exact location of all the transit agencies was obtained utilizing the National Transit Data (NTD) [38]. From the NTD, the number and type of buses at each agency and the fuel utilization per agency can be obtained. Additional details regarding the size of the fleet can also be obtained from the 2012 Fare Summary report of the California Transit Association[39].

4.1.1. Spatially Resolved Hydrogen Demand of Transit Agencies in the USA

Utilizing ArcMap10, the spatial allocation of all the transit agencies in the United States is possible using the library created for the tool. An example is presented in Figure 13.

The exact address of any desire transit agency can be accessed along with the type of buses, number of buses, mode of operation and year fuel consumption (for each type of fuel used in the agency). Figure 13 shows all the transit agencies in the United States which includes:

1. Independent public agency or authority for transit service
2. Subsidiary unit of a transit agency
3. State, city, county or local government deportment of transit
4. MPO, COG or other planning agency
5. Publicly owned corporation
6. Private-non-profit corporation
7. Private provider reporting on behalf of a public entity

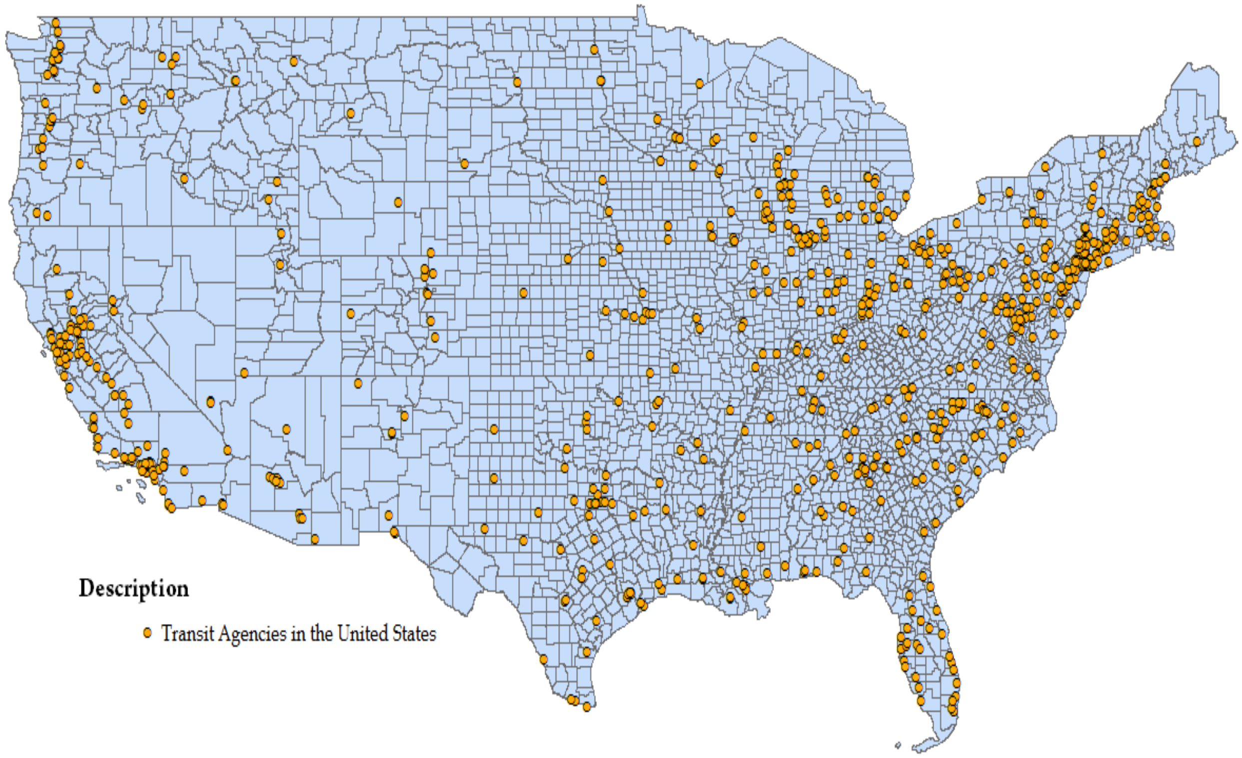


Figure 13: Spatial Allocation of Transit Agencies in the United States

Similarly, the tool can spatially represent the hydrogen demand on a daily or yearly basis. To this point, the location of where the hydrogen demand is needed is the main transit agency location. A detailed allocation of hydrogen can be represented when the exact location of the bases is provided by the user, and thereby identify the cities, counties and states that could have large demand of hydrogen. As a result, H_2AT provides information of value to (1) investors regarding large scale hydrogen production, and (2) to policy makers since the information can prioritize investments in states where the demand of hydrogen is large. The spatial allocation of hydrogen for the United States is presented in Figure 14.

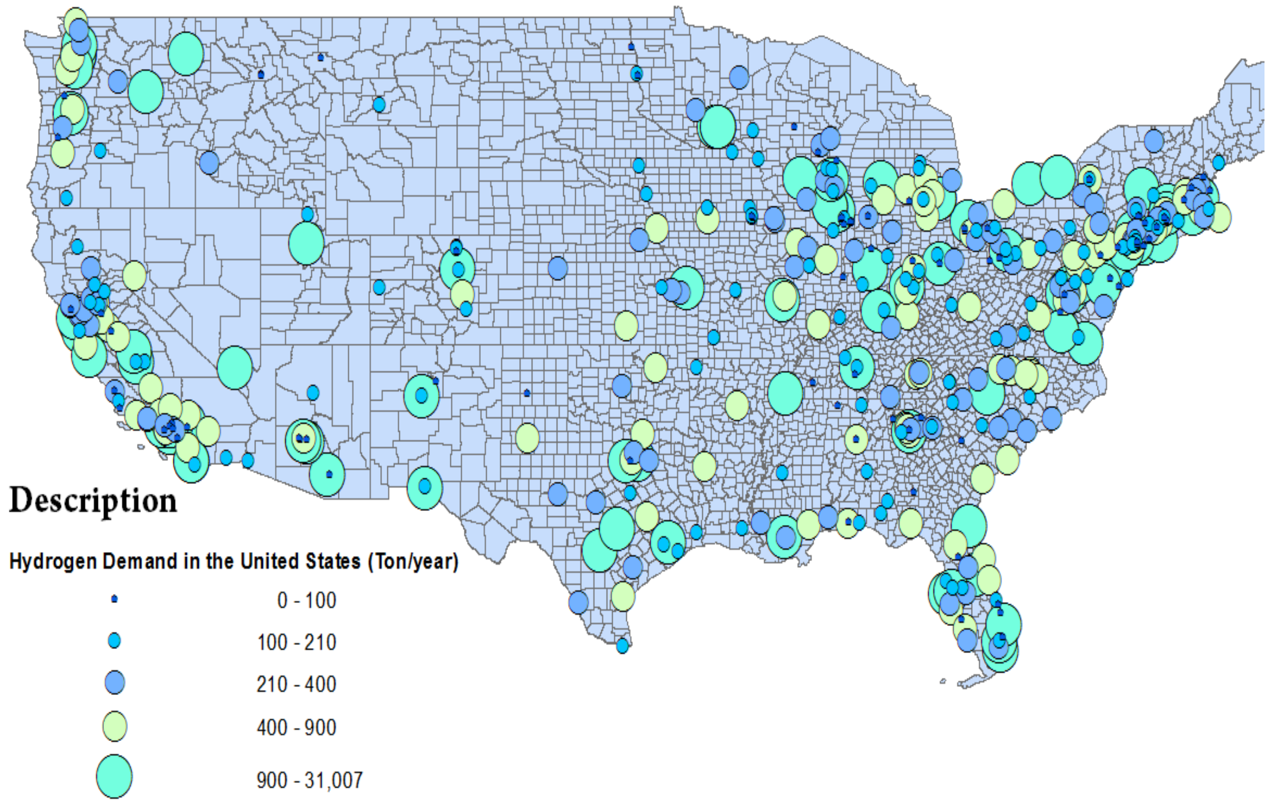


Figure 14: Spatially resolved yearly hydrogen demand in the United States, includes transit agencies utilizing fixed-route buses as well as commute buses, demand response vehicles, rapid buses and vanpools.

Figure 14 shows the hydrogen demand only for transit agencies that have directly operated (DO) vehicles and that have purchased transportation vehicles (PT). The vehicles that were considered as feasible replacement to hydrogen technologies were only Non-Rail Modes, specifically the following:

- Transit Buses (MB)
- Commute buses (CB)[1]
- Demand response vehicles (DR)

[1] CB: Fixed-route bus systems that are primarily connecting outlying areas with a central city through bus service that operates with at least five miles of continuous closed-door service. This service may operate motor-coaches (aka over-the-road buses)

- Public Buses (PB)[2]
- Rapid buses (RB)
- Vanpools (VP)

The following figures show a close up view of the regions and states where the hydrogen concentration is high (New York, California, and Florida). A more detailed analysis of the hydrogen demand for other states can also be performed from the outputs of the tool.

[2] PB: Passenger vans or small buses operating with fixed routes but no fixed schedules

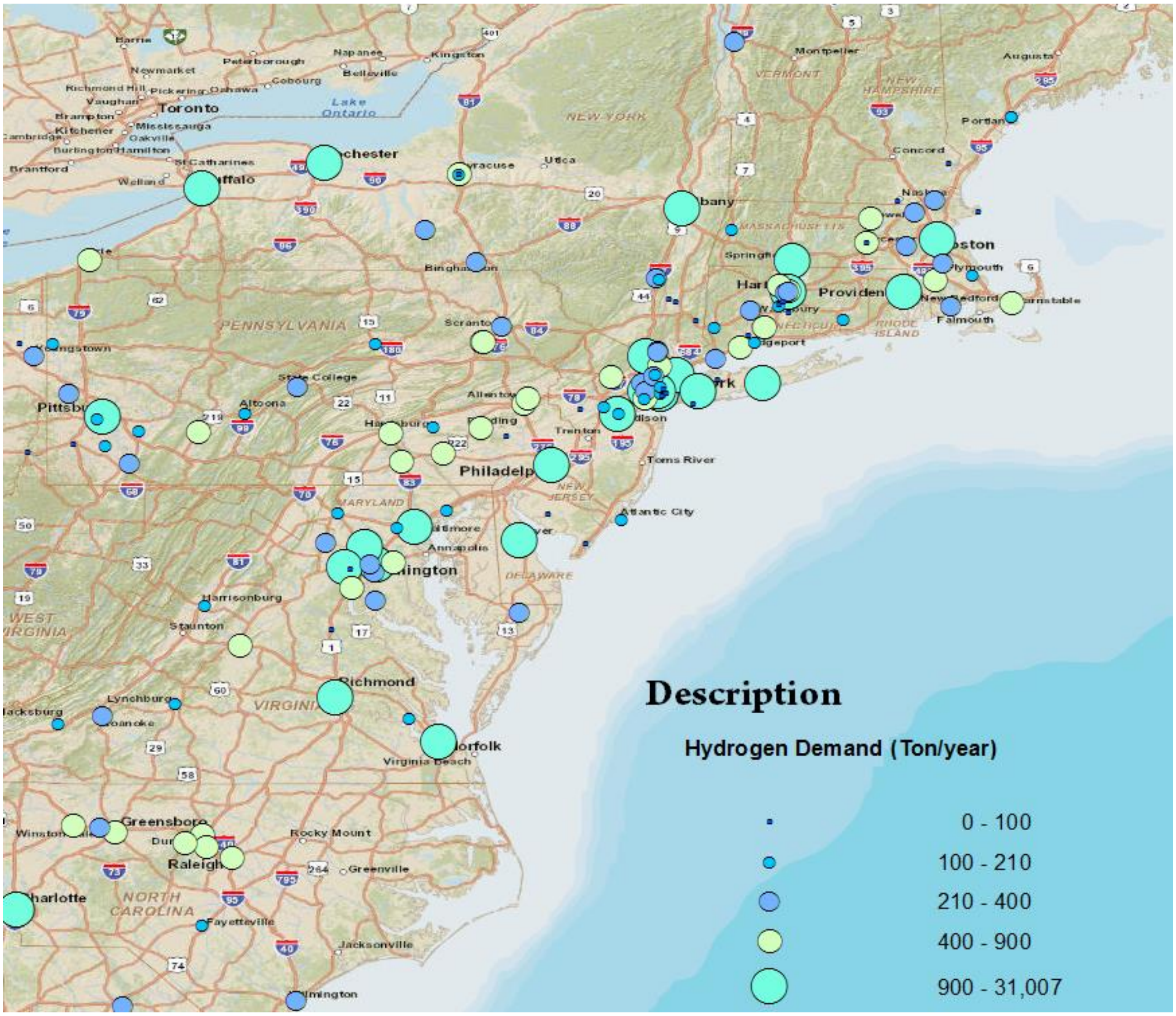


Figure 15: Spatial allocation of hydrogen demand for transit agencies in the East Coast of the U.S, zoom-in from figure 3.

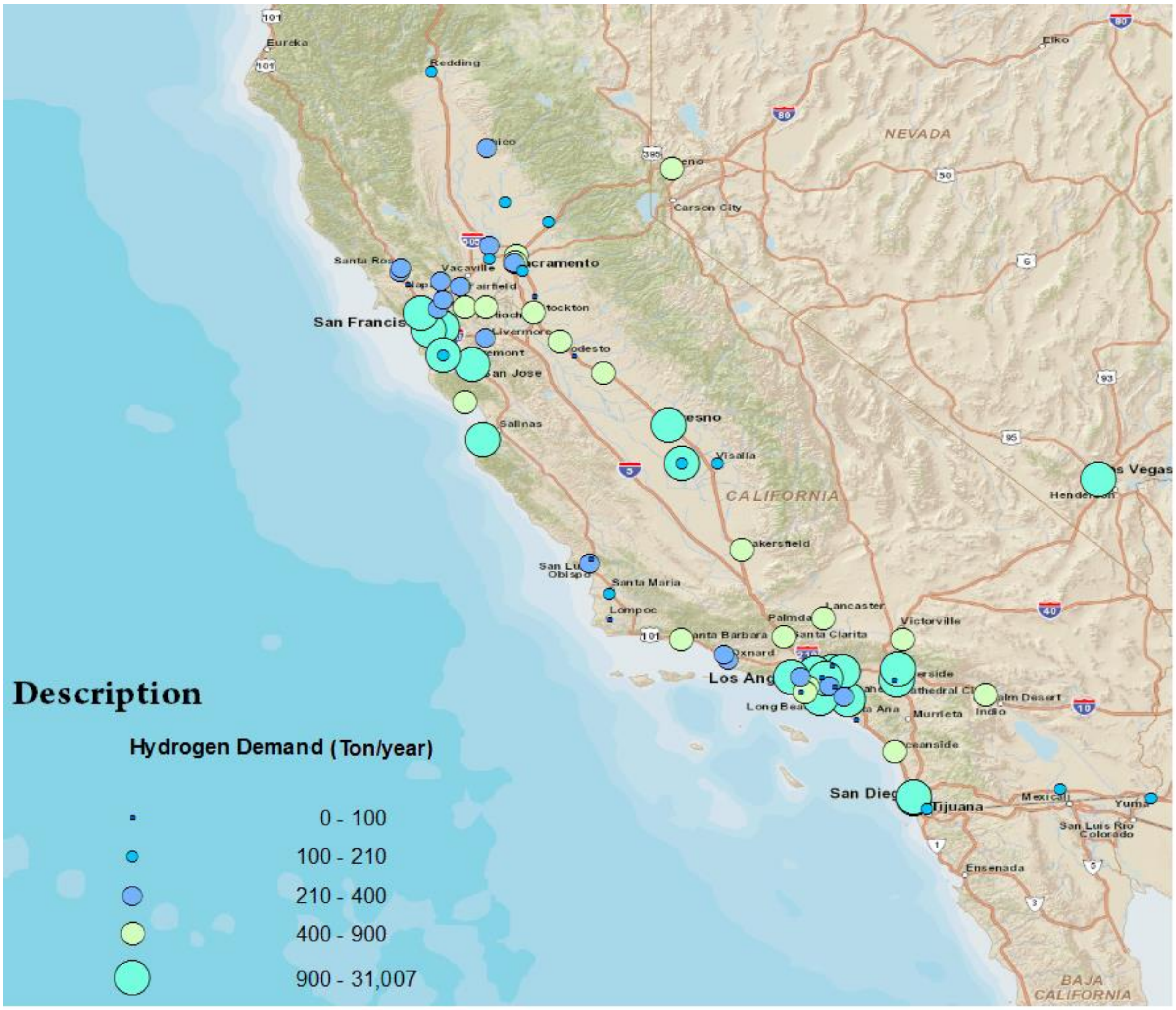


Figure 16: Spatial allocation of hydrogen for transit agencies in the state of California and Nevada, zoom-in from figure 3.

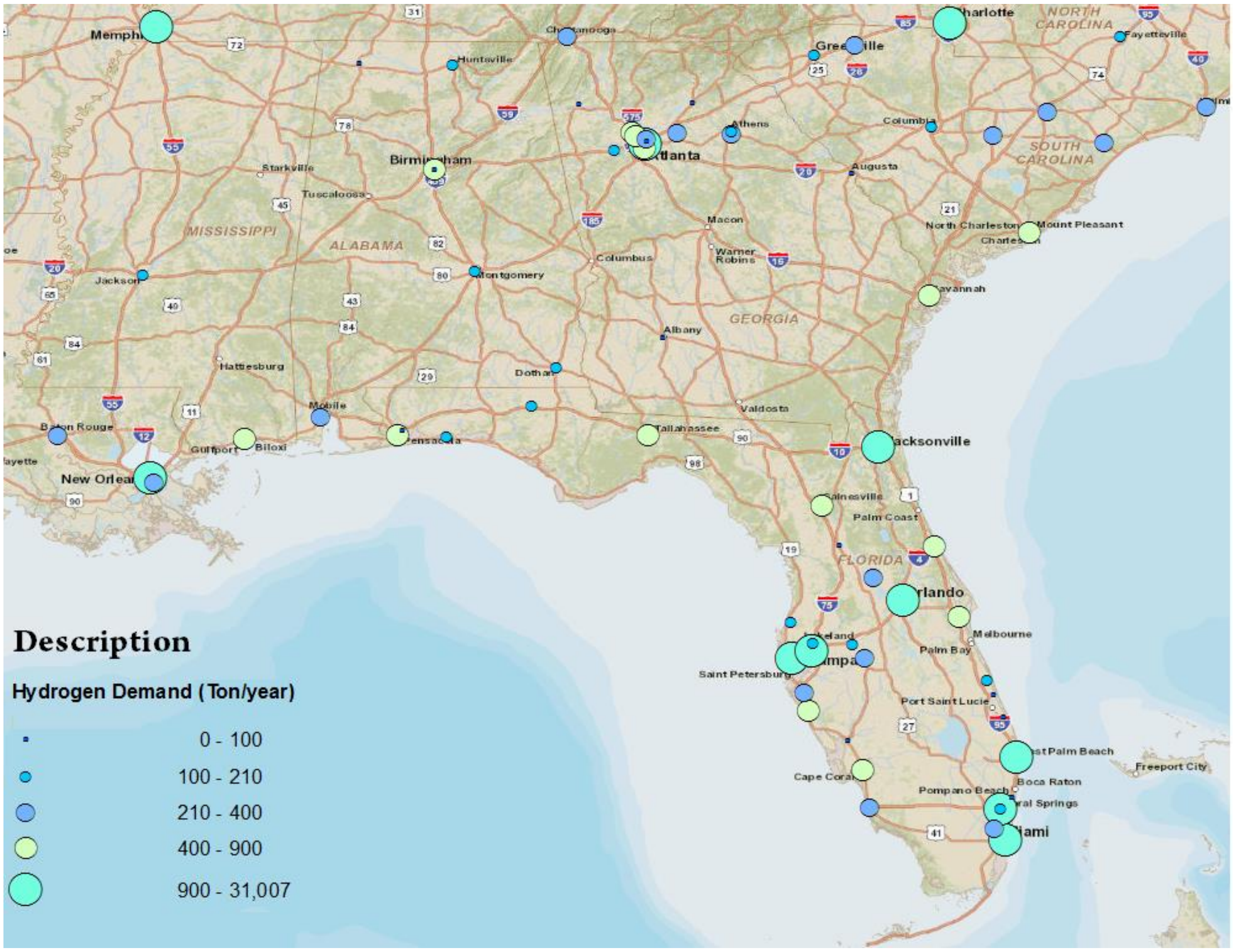


Figure 17: Spatial allocation of hydrogen demand for transit agencies in the southeastern U.S., zoom-in from figure 3.

The tool provides the year fuel consumption for each transit agency and, using Equation 2 in combination with the information from Table 3, the hydrogen demand can be calculated for the year 2013.

The outputs of the tool include the hydrogen demand per state and per transit agency. The results are presented in the tables below and include the ratio of the state hydrogen demand with respect to the total demand of all the agencies in the country; it also includes a ratio of the transit agency's hydrogen demand with respect to the total demand of its state and with respect to the total US demand. The assumptions made for the results showed in

Table 4 include 1) all the vehicles listed in Section 4.1.1 are substituted with fuel cell electric vehicles 2) the traveled miles by each transit agency remain the same 3) the assumed fuel economy of each vehicle type is presented in table 3.

Table 4: Hydrogen demand for transit agencies in the United States for the year 2013

State	H_2 Demand (Ton/year)	Percentage of H_2 demand for the country
California	85,520	18.07%
New York	52,190	11.03%
Florida	32,027	6.77%
Texas	31,551	6.67%
Pennsylvania	26,221	5.54%
Illinois	24,877	5.26%
New Jersey	24,010	5.07%
Washington	20,685	4.37%
Massachusetts	13,259	2.80%
Maryland	12,005	2.54%
Washington DC	11,704	2.47%
Ohio	11,332	2.39%
Minnesota	10,582	2.24%
Colorado	9,662	2.04%
Arizona	9,585	2.02%
Michigan	9,509	2.01%
Virginia	8,891	1.88%
Georgia	7,539	1.59%
North Carolina	6,802	1.44%
Nevada	6,778	1.43%
Missouri	5,830	1.23%
Wisconsin	5,747	1.21%
Tennessee	5,406	1.14%
Oregon	5,352	1.13%
	⋮	
Total	473,373	100%

The total amount of hydrogen required to replace conventional bus technologies with fuel cells electric buses in all of the transit agencies in the United States is 473,372ton/year. This represents 18% of the hydrogen production capacity from all of the refineries in the country which, according to the EIA, is 2.6 million tons of hydrogen per year [46].

From Figure 14 and from outputs of the tool (The outputs of the tool include the hydrogen demand per state and per transit agency. The results are presented in the tables below and include the ratio of the state hydrogen demand with respect to the total demand of all the agencies in the country; it also includes a ratio of the transit agency's hydrogen demand with respect to the total demand of its state and with respect to the total US demand. The assumptions made for the results showed in Table 4 include 1) all the vehicles listed in Section 4.1.1 are substituted with fuel cell electric vehicles 2) the traveled miles by each transit agency remain the same 3) the assumed fuel economy of each vehicle type is presented in table 3.

Table 4, the state with the largest hydrogen demand is California with 85,520 metric tons of H_2 per year. This represents the 18% of the total potential hydrogen demand of all the transit agencies in the country. The second largest state in its H_2 demand is New York with 52,190tons/year, representing 11% of the total demand in the country.

The H_2AT tool can also estimate the hydrogen demand per transit agency. Table 5 presents the analysis for the top 15 transit agencies in the United States with the highest hydrogen demand.

The two largest transit agencies based on fuel consumption are the MTA New York City Transit and Los Angeles County Metropolitan Transportation Authority (Metro). The MTA could have a potential H_2 demand of 31,000 tons of hydrogen per year (representing 59% of the demand in the state and an overall 6.55% of the demand in the country). LA Metro could have a potential demand of over 17,000 hydrogen tons per year, representing 20% of the demand in the state and 3.70% of the required hydrogen in the country.

Table 5: Top fifteen transit agencies with the highest hydrogen demand in the US

Transit Agency	City	State	H_2 Demand (Ton/year)	Percentage of H_2 demand in the state	Percentage of H_2 demand in the country
MTA New York City Transit	New York	NY	31,007	59%	6.55%
Los Angeles County Metropolitan Transportation Authority: Metro	Los Angeles	CA	17,508	20%	3.70%
New Jersey Transit Corporation	Newark	NJ	16,591	69%	3.50%
Southeastern Pennsylvania Transportation Authority	Philadelphia	PA	12,233	47%	2.58%
Chicago Transit Authority	Chicago	IL	11,792	47%	2.49%
Washington Metropolitan Area Transit Authority	Washington	DC	11,704	100%	2.47%
Metropolitan Transit Authority of Harris County, Texas	Houston	TX	10,362	33%	2.19%
King County Department of Transportation - Metro Transit Division	Seattle	WA	8,996	43%	1.90%
Maryland Transit Administration	Baltimore	MD	8,649	72%	1.83%
Miami-Dade Transit	Miami	FL	8,409	26%	1.78%
Denver Regional Transportation District	Denver	CO	8,284	86%	1.75%
Massachusetts Bay Transportation Authority	Boston	MA	8,277	62%	1.75%
MTA Bus Company	New York	NY	7,342	14%	1.55%
Orange County Transportation Authority	Orange	CA	6,375	7%	1.35%
Port Authority of Allegheny County	Pittsburgh	PA	6,252	24%	1.32%

4.1.2. California Hydrogen Demand and Feedstocks Allocation

H_2AT allows for the specific allocation and quantification of the hydrogen demand for transit agencies. Additionally, the tool has the capability of allocating and quantifying possible feedstocks to produce the hydrogen. The feedstocks library includes:

- Natural gas for SMR
- Biogas from wastewater treatment plants (WWTP) for SMR units
- Biogas from landfills for SMR units
- Refineries with current on-site hydrogen production.

The tool provides the spatial allocation and the proximity of such feedstocks to the transit agencies. In the sections bellow, each feedstock allocation and source is descried, in addition to presenting the proximity results of the locations. Only the state of California was used as the region to demonstrate this tool capability in order to have more area resolution of the results and due to lack of information regarding the feedstock source for other states.

California Natural Gas Spatial Allocation and Vicinity to Transit Agencies

Data of all major natural gas transmission pipelines were sourced from the California Energy Commission [47], and do not include gas gathering or gas distribution systems (pipes connecting to homes). Figure 18 shows a map with the crossover of transit agencies that have a hydrogen demand with the pipeline infrastructure in the state.

This spatial allocation shows that over 58% of all the transit agencies in the state of California have an existing natural gas pipeline connection to their facilities. This is of importance since such transit agencies will only need a moderate infrastructure adjustment in order to produce hydrogen on-site using SMR. Additionally, the results show that only 5% of the transit agencies do not have a natural gas pipeline within 15mi.

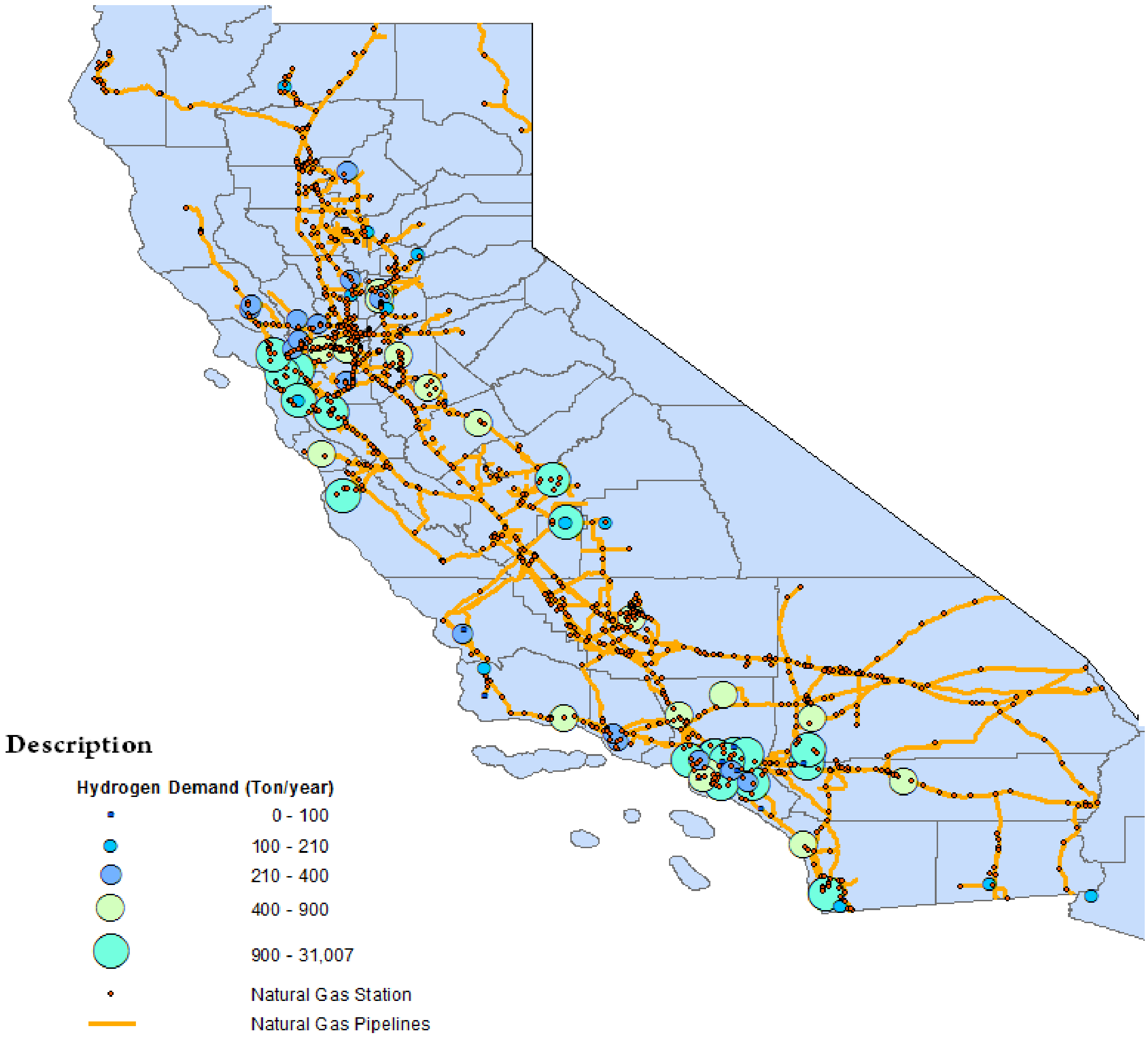


Figure 18: Transits agencies hydrogen demand and vicinity to Natural Gas pipelines and stations in the state of California

California WWTP spatial allocation and vicinity to transit agencies

The Advanced Power and Energy Program (APEP) at the University of California Irvine is conducting extensive research to identify the potential biogas from wastewater treatment plants (WWTP) and landfills in the state. The biogas from both sources is a key feedstock for the production of renewable hydrogen and of main interest for future hydrogen supply infrastructures.

Data of all major WWTP and of their potential to generate biogas are available [48]. Figure 19 identifies wastewater treatment plants that could supply transit agencies with bio-hydrogen.

This spatial allocation shows that only 5 of the transit agencies in the state of California do not have a potential source of bio-hydrogen within 20 miles.

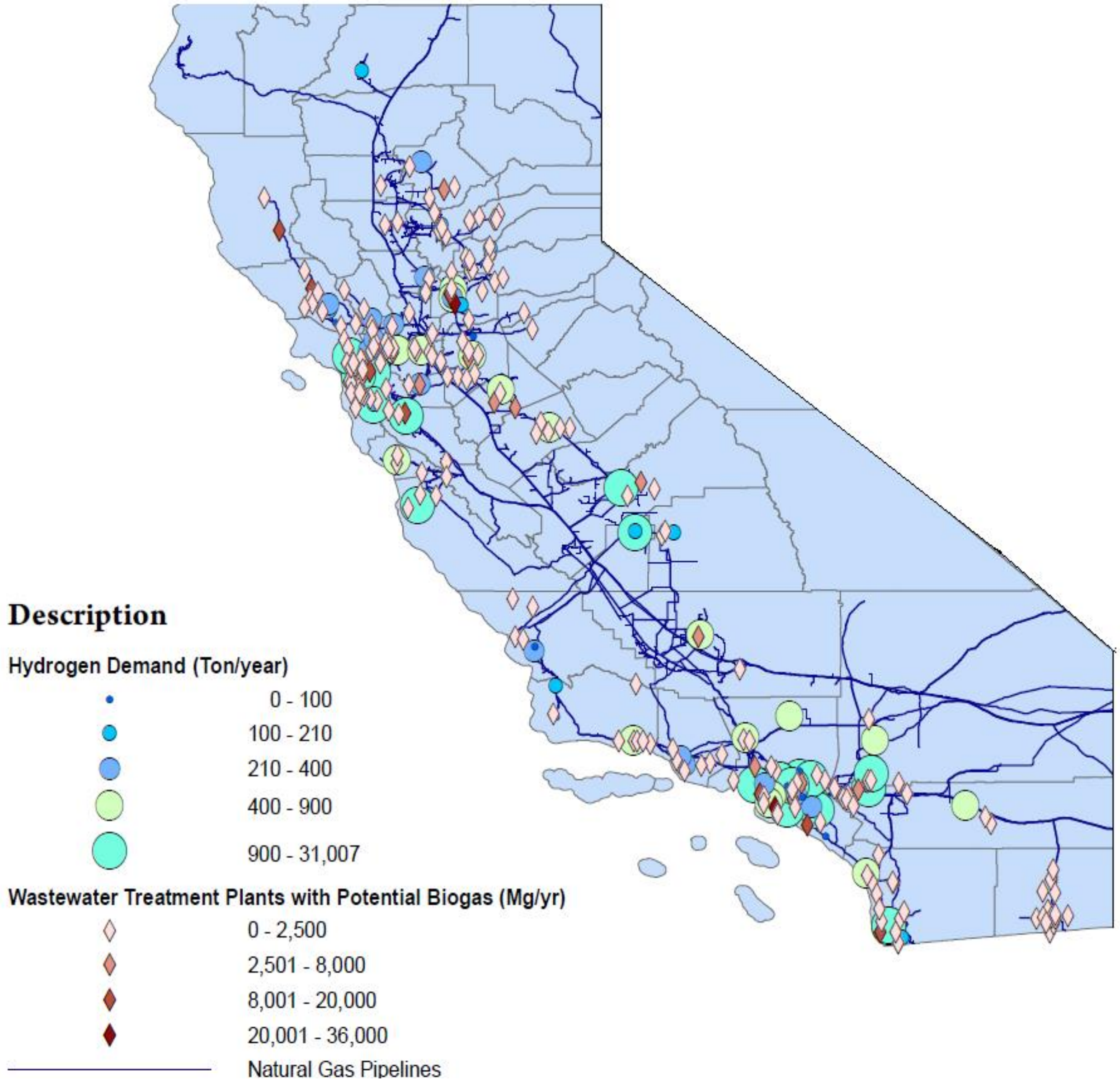


Figure 19: Transits agencies hydrogen demand and vicinity to Wastewater Treatment Plants (WWTP) with its biogas production capacity in the state of California

California landfills Spatial Allocation and Vicinity to Transit Agencies

Similar to the analysis of biogas from WWTP and, the data to support the analyses [48], Figure 20 shows a map with the crossover of transit agencies that have a hydrogen demand with the potential biogas from landfills.

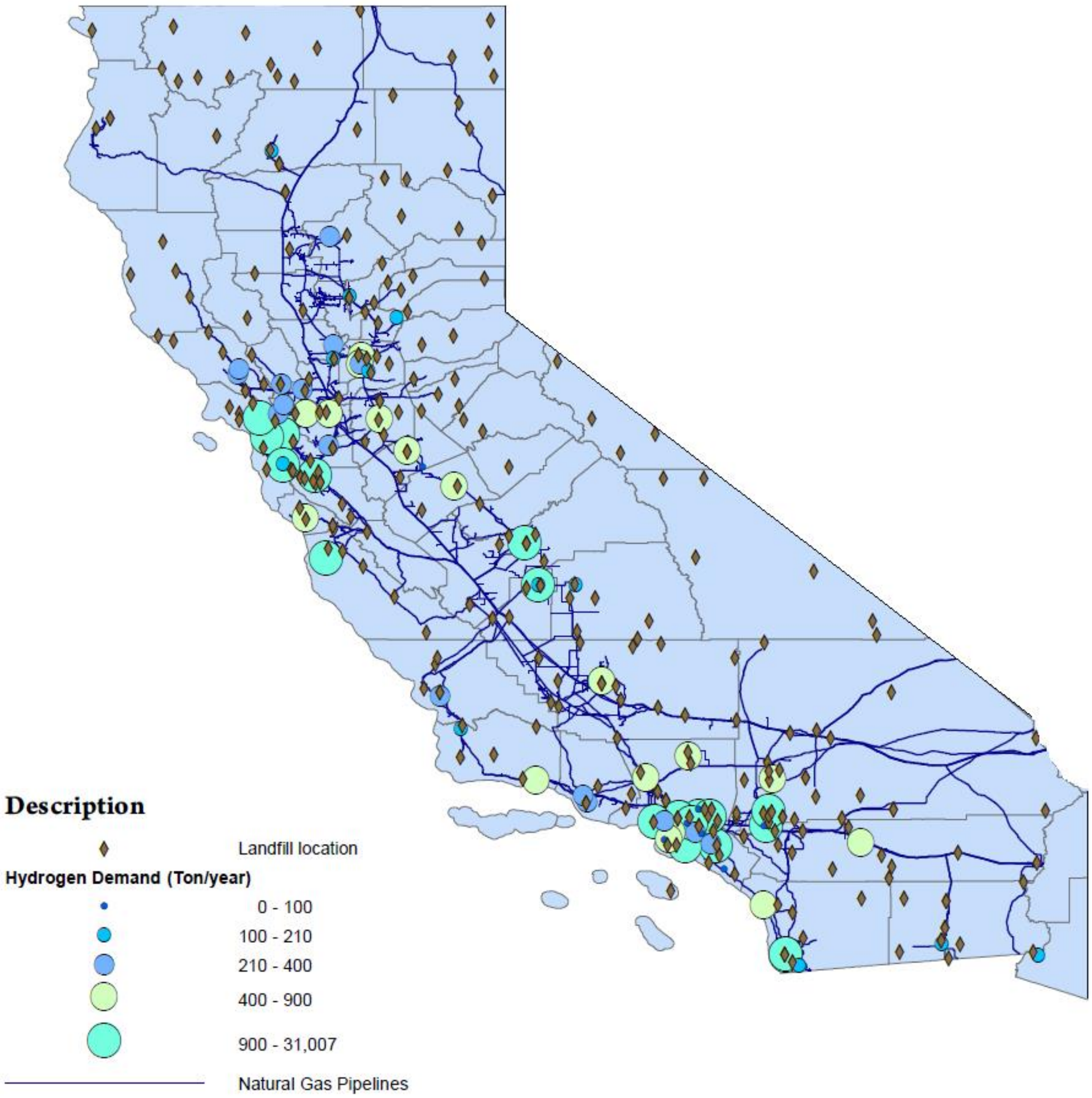


Figure 20: Transits agencies hydrogen demand and vicinity to Landfills with capacity to produce biogas in the state of California

Biogas from WWTP and landfills can be injected into the natural gas pipeline from which transit agencies can contract for the "directed biogas." As presented in Figure 18, the existing pipeline infrastructure provides great accessibility to transit agencies and this can be used to the advantage of biogas injection.

Both WWTP and landfills location could represent a solution to space constraints that transit agencies often experience. WWTP and landfills could use as semi-centralized hydrogen generation site to then use either pipelines or tube trucks to deliver the hydrogen.

California refineries Spatial Allocation and Vicinity to Transit Agencies

The state of California has a large hydrogen production associated with petroleum refineries. In 2014, California generated 35% of total national production [49]. Refineries represent, as a result, a central source of hydrogen for transit agencies that can be distributed using either pipelines or tube trucks (either gas or liquid hydrogen).

Figure 21 shows the location and hydrogen production capacity of refineries in the state of California. Most of the generation is central to three main areas in the state and only 12% of the transit agencies are in a radius of 40 miles from a refinery. This represents a constraint for some of the transit agencies to use existing hydrogen generation facilities. However, most of these refineries are already operating at top capacity and a study is required to determine the percentage of the hydrogen demand from nearby transit agencies that the refineries are capable to satisfy.

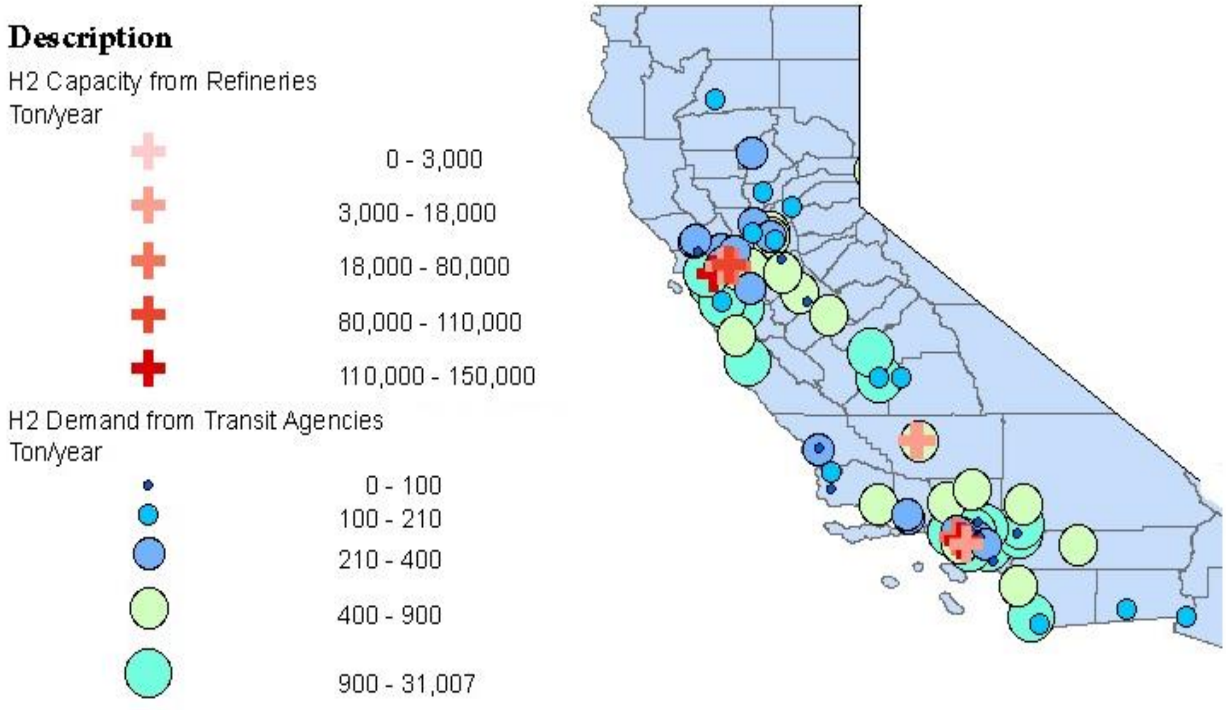


Figure 21: Transits agencies hydrogen demand and vicinity to refineries in the state of California

4.2. Summary

The Hydrogen Allocation Tool (H_2AT) was developed to estimate the hydrogen demand based on specific inputs including the current fuel demand at the transit agency. H_2AT allows identifying the specific location where hydrogen is needed and the magnitude of such demand. Additionally, H_2AT provides the spatial allocation of possible feedstock locations, including natural gas pipeline network, natural gas stations, landfills and wastewater treatment plants with biogas production estimations; as well as existing refineries with hydrogen production. The output includes a GIS map (spatially resolved) with the location of nearby feedstock location and an analysis of the distance in miles of the transit agency bases to the feedstocks.

Using the National Transit Data (NTD) [38] to establish the fuel demand and the exact location of all the transit agencies in California, the capabilities of H_2AT were utilized to establish (1) the hydrogen demand allocation for all the transit agencies in the United States and (2) the hydrogen potential from different feedstock sources at California was completed. The results show that:

- The adoption of fuel cell electric buses by all transit districts in the United States would create a demand for hydrogen of almost 500,000 hydrogen tons per year in the United States, representing 18% of the national hydrogen production capacity.
- New York, California, and Florida have the highest hydrogen demand for fuel cell electric buses. The two largest transit agencies based on fuel consumption are MTA New York City Transit and Los Angeles County Metropolitan Transportation Authority (Metro).
- Most of the transit agencies in California have nearby natural gas pipeline infrastructure to support on-site hydrogen production via SMR and only 5 of the transit agencies in California do not have a potential source of bio-hydrogen within a 20 mile range.

CHAPTER 5. Hydrogen Characterization and Analysis Tool–H_2CAT

The Hydrogen Scenarios Characterization and Analysis Tool (H_2CAT) has the capacity to analyze hydrogen supply chain scenarios for public transit agencies with large fleet sizes and it was developed using as a base the Preferred Combination Assessment (PCA) tool, developed by the UCI Advanced Power and Energy Program [29]. PCA can determine the well-to-wheels (WTW) impacts associated with the generation, distribution, and utilization of hydrogen for light duty vehicles.. It's important to note than all the output analysis that the tool provides (GHGs, criteria pollutants, energy and water) are on a WTW basis and do not consider the full life cycle analysis of the equipment (e.g., SMR, electrolysis, gas turbines) or the buses.

5.1. Tool Modifications

The principal changes in the PCA tool made in this thesis work to create the H_2CAT were (1) an adjustment to the sizes of the hydrogen supply chain technologies to meet the demands associated with a transit agency, (2) creating a new library with emissions factors appropriate for heavy duty vehicles, (3)adding a battery electric plug-in bus supply chain so that different scenarios can be created and utilized for comparison and analysis, (4) the available foot-print for the distributed generation technologies to be deployed at the transit base, and (5) an additional emissions output to measure the global warming potential (GWP).

The Global Warming Potential (GWP) is an index that compares the ability of one mass unit of a particular gas to affect global warming relative to carbon dioxide [7][50]. The GWP for greenhouse gases can be calculated using the following equation.

Equation 3: Global Warming Potential for Green House Gases

$$GWP = (CO_2\ emissions) + (CH_4\ emissions) \times 21 + (N_2O\ emissions) \times 310$$

Figure 22 and Figure 23 show the schematic of the PCA tool and H_2CAT respectively, reflecting the modifications made to the original PCA. Details regarding the modifications are presented along the description of the following sections.

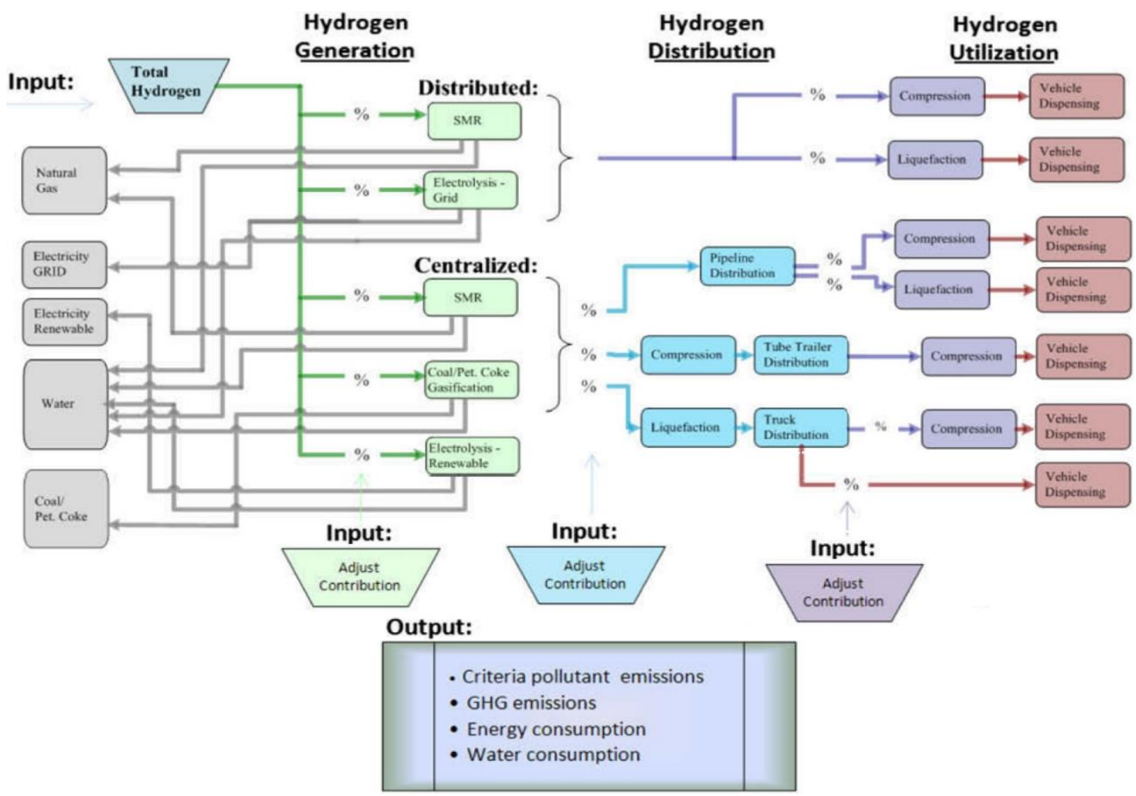


Figure 22: Simplified schematic of the PCA tool[20]

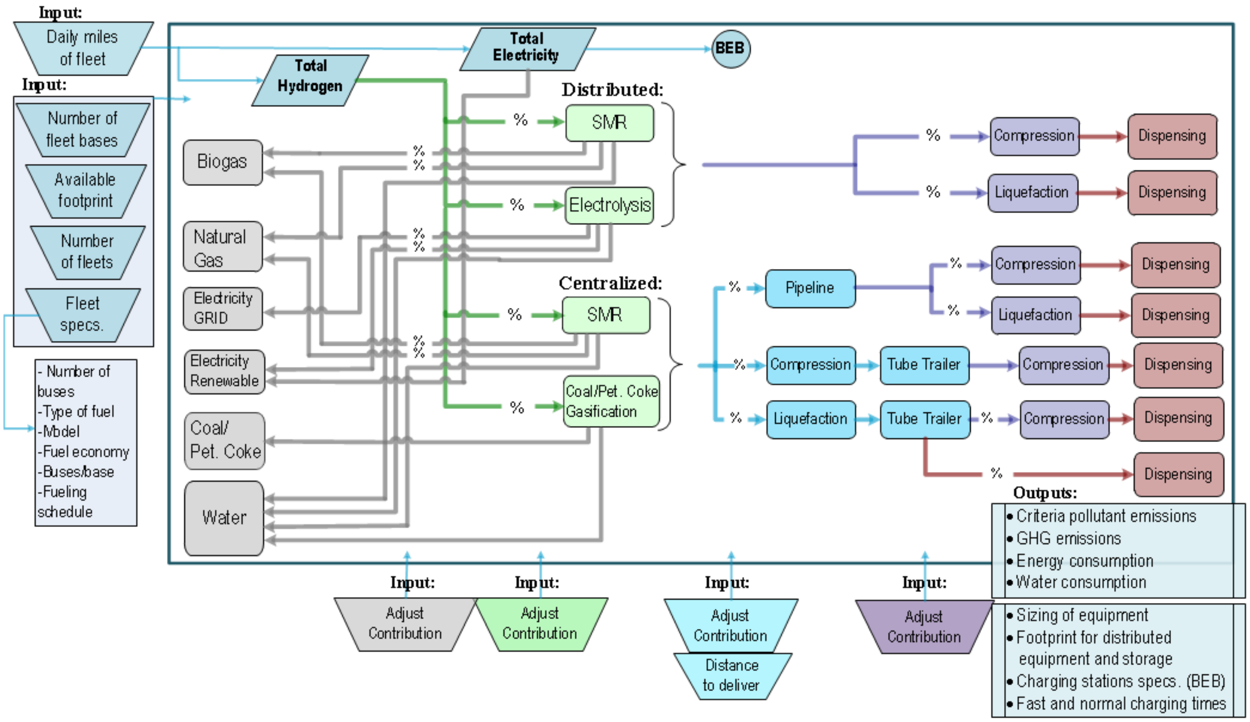


Figure 23: Modified PCA tool for Transit Buses – H_2CAT

5.2. Tool Inputs

H_2CAT aims to be a tool that informs transit agencies decisions regarding the transition to a zero emission fleet. Specifically, the tool aims to establish a preferable hydrogen supply chain for the deployment of fuel cell electric buses. For this, H_2CAT requires as a first input the daily hydrogen demand required by the transit agency.

Input: Hydrogen Demand

The hydrogen demand input is obtained utilizing H_2AT. If H_2AT is not utilized to estimate the hydrogen demand, the basic information needed by H_2CAT is the daily millage traveled by the transit buses that will be on service (i.e., total daily miles traveled per fleet). From this information, the following equation is used to obtain the required input:

Equation 4: Calculation of hydrogen demand from daily traveled miles per fleet

$$H_2 Demand = (mi_{fleet}) * \left(\frac{1}{FE_{H_2}}\right) = {kg\ of\ H_2}/{day}$$

Where:

mi_{fleet} = traveled miles for the fleet in a day

$FE_{H_2} = hydrogen\ fuel\ economy\ (miles/kg)$

The hydrogen fuel economy for the FCEBs is set in the tool to be 6.43 mi/kg (7.26 mi/DGE[3]), which is the value that has been reported by NREL regarding the current demonstration projects across the United States [33].

However, to have a spatial resolution of the hydrogen demand among the fleet bases, additional information is required regarding the distributed generation options for the supply chain. This additional information is described in Chapter 4 and includes the following inputs:

- Number of bases and locations
- Number of buses per base
- Miles traveled per bus at each base or fuel consumption per base
- Available foot-print at each base

H_2CAT integrates a variety of technologies and pathways for the supply chain of hydrogen and has the capability to adjust the contribution of each technology, creating

[3] Diesel Gallon Equivalent

different supply chain combinations to then generate a well-to-wheels (WTW) analysis for each desired configuration. From this, a second input for the tool is the selection of the percentage-of-contribution for each technology of the supply chain.

Input: Percentage of contribution for generation technologies

The first selection is for the type of generation. The user can adjust the percentage of hydrogen produced between 0 to 100% from a centralized location to distributed generation.

For the portion of hydrogen set to be centralized-produced, the user then can set the contribution for each generation technology. The centralized generation technologies include steam methane reformation (SMR) and coal/pet coke gasification, so the user can set a percentage between 0 and 100% for one of them and assign the rest to the other. In a similar matter, the user can set the percentage of contribution for the distributed hydrogen technologies; which includes SMR and electrolysis.

Table 6 presents the options available for the hydrogen generation technologies.

Table 6: Hydrogen generation technologies available at H_2CAT

Centralize Hydrogen Generation	Distributed Hydrogen Generation
Steam Methane Reformation –SMR Coal Gasification Pet Coke Gasification	Steam Methane Reformation –SMR Electrolysis

One of the additions made to the tool is the capacity of selecting the percentage of contribution of the type of feedstock for the following technologies:

- Steam methane reformation: the user can set a mix of natural gas and biogas. Additionally, the user can set its own mix of biogas by selecting percentage of contribution between landfill biogas and wastewater treatment biogas.
- Electrolysis: the tool can select the electricity to be generated using the current California grid or can select a grid mix with higher penetration of renewable sources like wind and solar.

Table 7 shows the options of feedstock that are available for each generation technology for the tool.

Table 7: Feedstock options for hydrogen generation technologies

Centralized and/or Distributed Hydrogen Generation	Main feedstock
SMR	Natural gas Biogas from wastewater treatment plants Biogas from landfills
Electrolysis	Electricity from the CA grid Electricity from Renewable sources (wind or solar)
Gasification	Coal Pet Coke

For example, a user can set the hydrogen generation to be produced at a centralized location utilizing SMR that uses only biogas from wastewater treatment plants (WWT), as shown in Figure 24.

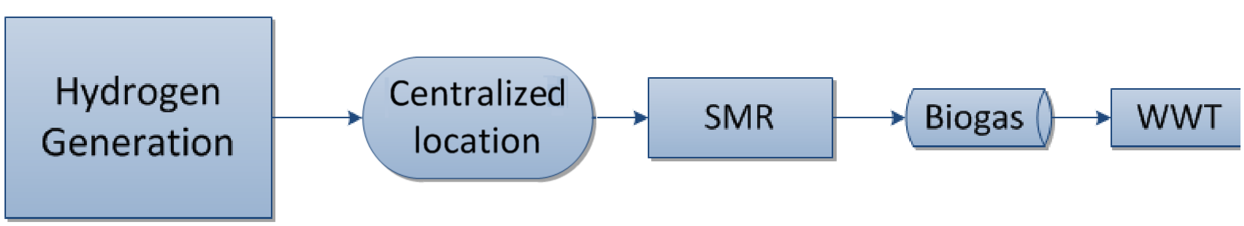


Figure 24: Example of possible setting for the percentage of contribution in H_2CAT

In a more complex example, the user can set percentage of contribution for different generation technologies and simultaneously set different percentages of feedstock to be utilized and including the source of the feedstock, as presented in Figure 25.

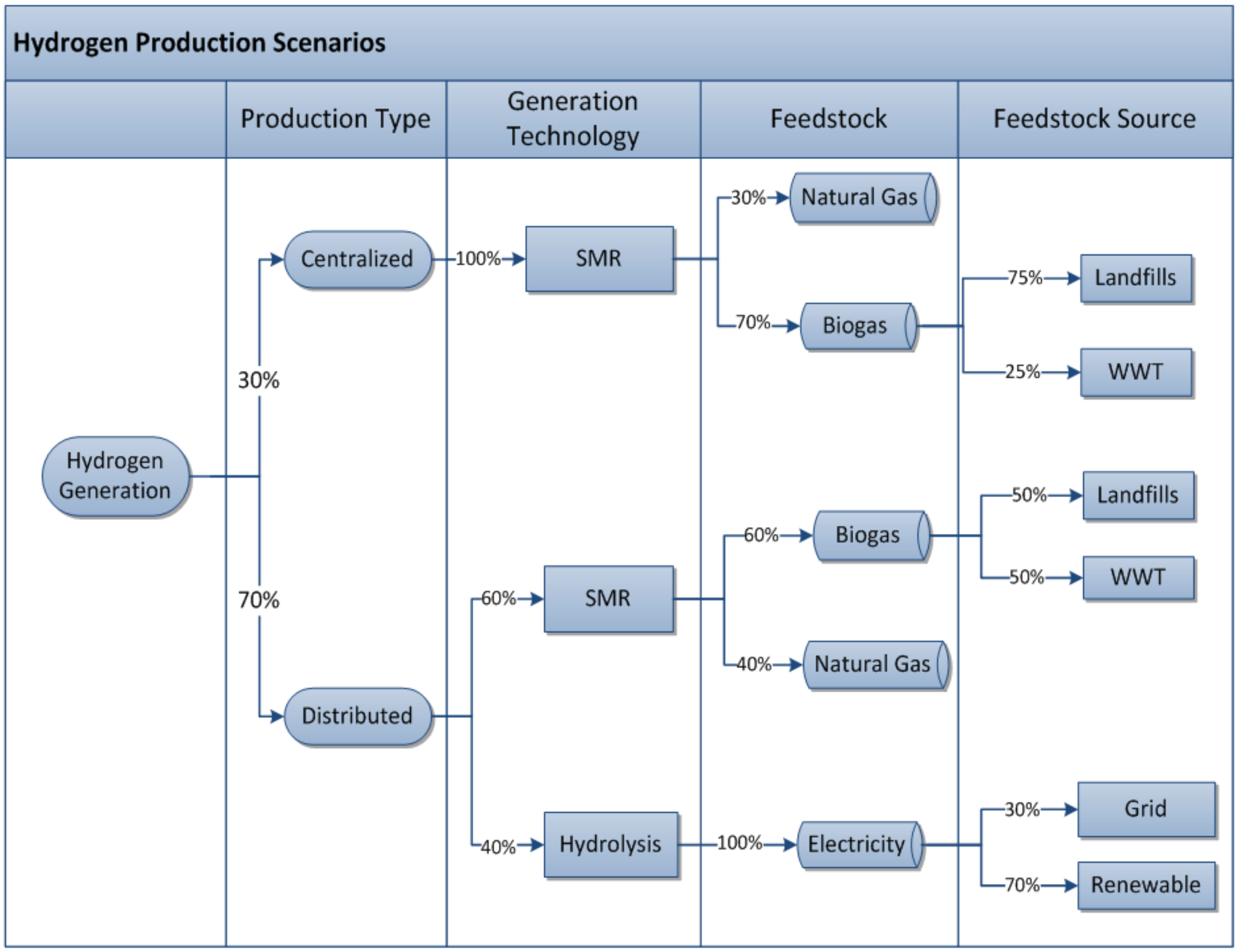


Figure 25: Example, percentages of contribution for generation tech. and feedstock in H_2CAT

After characterizing the generation technologies for the supply chain, it's necessary then to characterize the hydrogen distribution methodology for the transit agencies from the centralized generation locations.

Input: Percentage of contribution for distribution pathways

If any centralized hydrogen generation is set for the supply chain, it is required to define how that hydrogen will be delivered to the bus bases.

Similar to selecting the percentage of contributions for the hydrogen generation technologies, the percentage for the different methods of hydrogen delivery can be adjusted in the tool. The tool can be set to one of the following methods or a combination of both:

- Compressed hydrogen trucks
- Hydrogen delivery by pipeline
- Liquefied hydrogen trucks

Table 8 shows in summary the distribution pathways and type of fuel that are utilized in each option.

Table 8: Distribution pathways that can be selected from H_2CAT

Distribution pathways	Main feedstock
Pipeline	Electricity for compression into pipeline
Liquid tube-truck	Diesel
Compressed gas tube-truck	Diesel

An example of how these percentages of contributions can be set is presented in Figure 26.

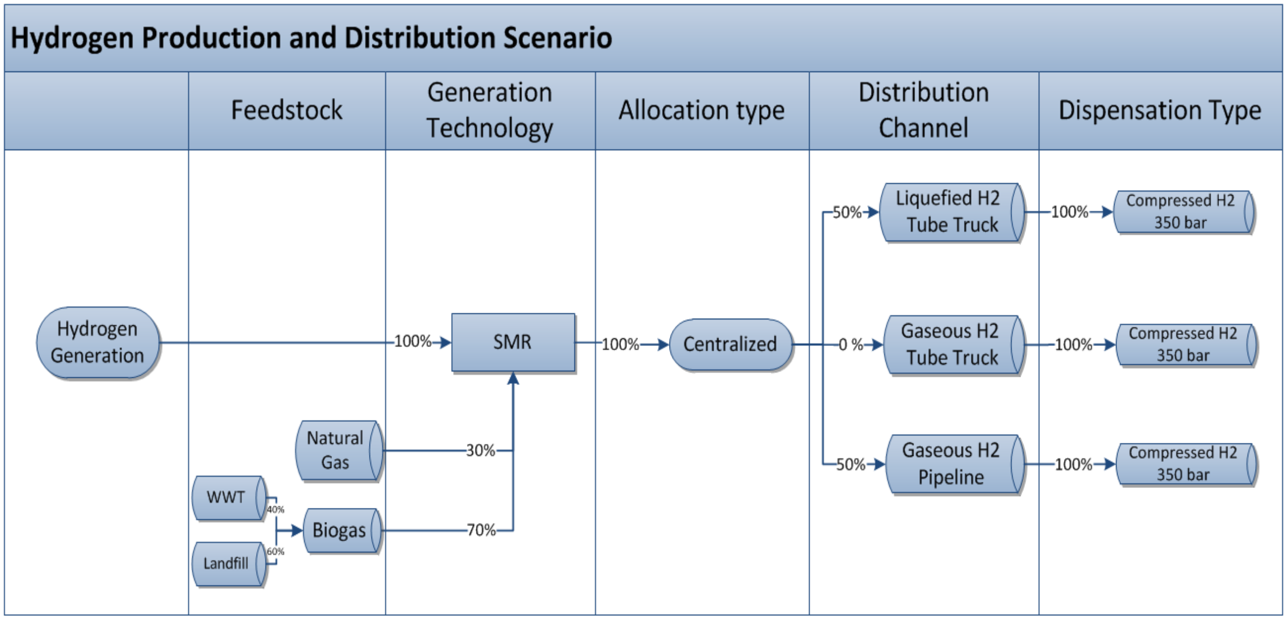


Figure 26: Example, percentages of contribution for distribution pathways

Figure 26 is an example of one of the many hydrogen supply chains that the tool can analyze. SMR is the type of generation technology utilized, and the feedstock is a portion of biogas from a wastewater treatment plant and another portion of biogas from landfills. For this example, the distribution channels that are used are 50% tube trucks transporting liquefied hydrogen and 50% gaseous hydrogen coming through pipelines. For all the current hydrogen fuel cell buses planned to be commercialized, the refueling requirement is compressed gas Hydrogen at 350 bar (approx. 5,000 psi). As a result, the only distribution modality in the tool is 350 bars.

For the purposes of this tool, the storage type depends directly on the distribution channel (e.g., if hydrogen is delivered as a liquid in a tub-truck, then the utilized storage on site will also be liquid hydrogen). For any portion of hydrogen produced on-site (either SMR or electrolysis), the storage assumed is compressed gaseous hydrogen.

An additional feature added to the PCA tool is the analysis of space availability. This is of special importance because, even though transit agencies have large square feet depots, often times the space is already strategically assigned and represents as a result a major limitation for expanding the fleet size and even more for when installing new equipment. Having this in mind, the feature assigned to the tool allows identifying possible space for required equipment like compressors, storage tanks and generation units (SMR and/or Electrolyzers). To do so, is necessary to provide the certain inputs, which are described below. More detail about the execution of this feature can be found in Chapter 5.

Input: available space of transit agency's bases

In order for the tool to identify where possible equipment can be physically allocated, the tool determines the available space using two principles: (1) any space utilized at the base for storage, dispensers and compressors will be available once the replacement of the fleet takes place; and (2) available space that the transit district identifies over and above the space utilized for storage.

The tool matches the available space with the space required for SMR or electrolyzer units, compressors, dispensers, hydrogen storage as liquid or gas, and clearance required to comply with safety standards. The tool output compares available space with the required space, and generates suggestions for the allocation of such equipment. From this, it can be determined if the space available at the base would be a determinant to the deployment of fuel cell buses and possible stationary hydrogen generation at the transit agency.

The inputs that the tool utilizes are the following:

- Total square feet of each fleet base
- Current space assigned for natural gas compressors – ideally the length, width and total area in feet and square feet, respectively.
- Assigned space for dispensers – also length, width and total area.
- Assigned space for storage tanks – number of tanks, tank capacity, total area and specification if the tanks are underground.
- Potential space for additional equipment – square feet of space that has been identified as potential location for additional equipment or storage.

All the inputs described until this juncture allows the design of different hydrogen supply chain scenarios using H_2 CAT, for later analysis. In order to provide perspective and objectivity to such analysis, it is necessary to have a comparison point. To do so, the tool also allows for the design of the supply chain currently utilized by the transit agency (i.e., the tool designs the base case scenario, using another set of inputs, that reflects the current service of the transit agency).

Input: current supply chain technologies of the transit agency

The tool designs the "base case" to determine the emissions, energy demand, and water consumption of the current transit agency system. The base case includes information about the production and extraction process of the fuel utilized as well as the distribution and dispensing methodologies.

While the following inputs are required for H_2AT, they are repeated in this section since is essential to have such information for a comparison of the transit agency's supply chain scenario with the hydrogen scenarios:

- Fleet specifications
  - Type of buses (LNC, CNG, biodiesel or diesel) and quantity of each type
  - Daily fuel consumption for each fuel type (LNC, CNG, biodiesel, diesel)
  - Distribution method for each fuel type (tube truck or pipeline)
    - If tube trucks are utilize to deliver the fuel, then is required to have the delivery distance
  - Available time for the refueling of the buses (hours per day) and usual start time.

By giving such inputs to the tool, the base case scenario can be analyzed by the tool and then used to compare to any desired hydrogen infrastructure supply chain scenario. Figure 27 shows how the tool represents the inputs.

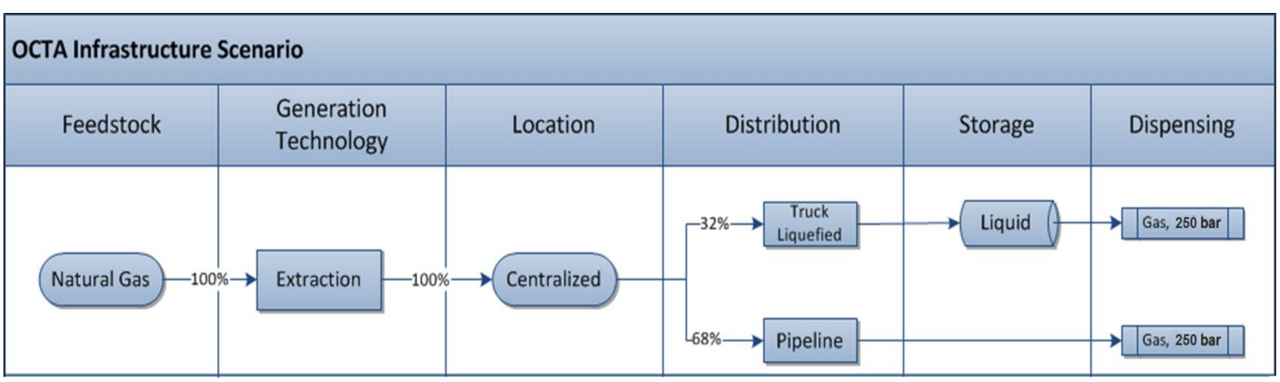


Figure 27: H_2CAT design of base case scenario after inputs from the user.

5.3. Tool Execution

This section of the chapter gives a detailed explanation of how the tool is coded, and describes the calculations and the assumptions made to generate the outputs. The first subsections describe how the necessary emissions factors to run the tool were selected; and explain how the inputs are used in the calculations for the benefit analysis that the tool allows.

The emissions and resource consumption for the hydrogen supply chain are calculated on a Well-To-Wheels (WTW) basis. As a result, emissions factors are assigned for each process along the supply chain. Examples include emissions factors for extraction, transport, and conversion of feedstock, transport of the fuel, on-site emissions during dispensing; and the emissions related to tailpipe emissions of the buses if any.

5.3.1. Feedstock Options

The main purpose of this section is to show how the quantification for the energy demand, water consumption, and emissions associated with the extraction and generation of feedstocks set in the H_2CAT tool. The emissions related to the use of the feedstocks are described in the following section under hydrogen generation technologies and tailpipe emissions for the baseline scenario.

The emission factors included in the tool are established for criteria pollutants (volatile organic compounds, carbon monoxide, oxides of nitrogen, oxides of sulfur, total particulate matter) and GHGs (carbon dioxide and methane) [29].

Electricity

The emissions and resources utilized for the generation of electricity can be adjusted for the U.S. average mix or any specific state, depending of which region is being analyzed for the deployment of fuel cell buses. In this case, the generation mix is directed to California. In particular, the 2013 California energy generation mix is utilized with an average efficiency of 52% [51], [52] (Figure 28).

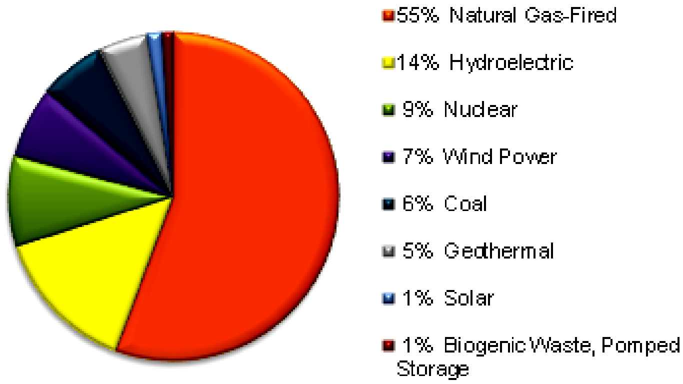


Figure 28: California non-distributed electric power industry generation [53].

Using GREET [26], the emissions associated with the generation of 1 KWh of electricity in the state of California encompass the emissions generated by each technology in proportion to the percentage of contribution presented in Figure 28. Table 9 contains the emissions released to the environment for each 1KWh of electricity that is used, which includes emissions generated during extraction of each feedstock and during the corresponding electricity generation processes (well-to-tank).

Table 9: Emission factors for 1 KWh of electricity using the California grid mix*

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
Electricity (CA grid)	0.046	0.206	0.320	0.273	0.033	0.049	352.13	0.947	0.002	g/kWh$_e$

* Values based on GREET [26]

The 2014 resources needed to generate 1KWh of electricity with the California grid mix was also obtained from GREET [26] with adjustments for the generation of biogas and biomass based on a literature review [54], [55]. Table 10 shows this feedstock/resource utilization that was set for the tool.

Table 10: Resources utilized for the generation of electricity with the CA grid mix

	Natural Gas	**Renewable Electricity** (in kwh)	**Coal**	**Biomass**	**Crude Oil**	**Others** (in kwh)	
Electricity (CA grid)	0.1003	0.0105	0.0303	0.0066	0.0007	0.4439	**kg/kWh$_e$**

The California grid mix includes 14% of hydropower. Water withdrawals refers to water that has to be available for the generation process but is not necessary consumed since it can be returned to the source of origin. The addition of water withdrawals and water consumption is the water that has to be available in the region for the scenarios process that include feedstock extraction and generation processes (Table 11) [56].

Table 11: Water withdrawal and consumption per 1KWh using the CA grid

	Water withdrawals	Water consumption	Total Water	
Electricity (CA grid mix)	3.388	0.187	3.575	gal/KWh_e

Biogas and Biomethane

As mentioned before, one of the modifications made to the PCA is the selection of directed biogas from wastewater treatment plants and/or landfills as feedstock for hydrogen production when using SMR.

The generation and cleanup processes depend on the origin of the directed biogas and impacts, as a result, the overall well-to-wheel analysis. Table 12 shows needed resources to produce the biogas [57] and cleanup the biogas [58] from both sources.

Table 12: Resource utilization for the production of biogas

	Generation capacity		Clean up requirements	
Biogas from Landfills	0.10	Kg biogas/kg MSW	0.34	KWh_e/kg Biogas
Biogas from WWTP	0.0003	Kg biogas/gal WW	0.38	KWh_e/kg Biogas

The emissions and resources associated with the generation of the directed biogas are not included in the well-to-wheel analysis since these emissions will otherwise occurred in a wastewater treatment plant and in a landfill [54]. However, the emissions related to the cleanup of the biogas for pipeline injection are included [59]. In contrast, the on-site emissions related to the use of the SMR units at distributed or centralized locations when using directed biogas are neglected in the WTW analysis since these emissions are released when utilizing the biogas for other purposes such as internal combustion engines, fuel cells [54], gas turbines, boilers, flaring, or other BACT[4] engines. A comparison between the emissions of BACT engines and fuel cell units can be found in the appendix.

The only emissions considered in the tool when using directed biogas are emissions related to the electricity use for any of the processes, namely .the emissions associated with electricity used for the cleanup of the biogas or for running the controls of the SMR units (Table 13). The electricity demand for the cleanup process of biogas is set to 0.34KWh of electricity per kilogram of biogas processed, a value obtained from data collected during the demonstration of Tri-Generation at OCSD conducted by the NFCRC [58].

Table 13: Emission factors for the generation of Biomethane

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
Landfill biogas	0.02	0.07	0.11	0.09	0.01	0.02	119.73	0.32	0.001	g/kg Biogas
WWT biogas	0.02	0.08	0.12	0.10	0.01	0.02	133.81	0.36	0.001	g/kg Biogas

The efficiency of separating biomethane from biogas has been estimated to be 87%, which includes a membrane efficiency of 90% and a small share of input biogas being combusted in the thermal oxidizer to reduce emissions [60]–[62]. Therefore, the biomethane potential is 87% of the total methane available in the original biogas, as shown in Equation 5 [63]. The methane content in the biogas was assumed to be 60% [64].

[4] Best Available Control Technology (BACT) [114].

Equation 5: Biomethane potential

$$Biomethane = 87\% * (methane\ content\ in\ biogas)$$

When using directed biogas, the price assumed for the tool is $8 per MMBTU. This price assumes a 20% reduction of the current average gas price in the open market of conditioned biomethane for pipeline standards, which was reported by SoCalGas [65].

Diesel

Diesel is considered a feedstock for the tool since is the fuel utilized for the tube-trailer that delivers fuel (H_2, LNG or diesel) to the transit agency base. Diesel can also be the fuel utilized in the transit buses or other fleet vehicles in the transit agency.

The production of diesel often times represents a major portion of the emissions released to the environment for the transportation sector and the accuracy of the emission factors per gallon of diesel produced is critical for an objective comparison versus zero emission technologies.

Table 14 presents the emissions that are released to the environment for the production of one gallon of diesel [53]. These emission factors are for a well-to-product process including primary and secondary emissions, which contains the extraction of all the necessary feedstock, the generation processes itself, and the necessary refinery. These emissions do not reflect the pollutants released during the distribution of the diesel nor tailpipe emissions from when buses utilize the diesel. An example of the primary and secondary resources that are utilized for the production of diesel is presented in Table 15.

Table 14: Well-to-Product emission factors for the production of diesel fuel

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
Diesel (low sulfur)	1.115	1.812	5.854	3.406	0.434	0.560	1,436	17.56	0.018	gram/gal diesel

Table 15: Well-to-Product resources utilized per gallon of Diesel fuel produced

		Secondary			Primary
Water Withdrawals (gallons)	**Water Consumption (gallons)**	**Natural Gas (kg)**	**Coal (kg)**	**Biomass (kg)**	**Crude Oil (kg)**
1.411	5.004	0.314	0.067	0.001	3.002

Liquefied Natural Gas (LNG)

Similar to diesel, LNG can be utilized as the fuel to power transit buses or other fleet types in the transit agency. The primary and secondary emissions utilized in H_2CAT for the production of LNG are presented in Table 16 [53], [66], [67]. These emission factors do not include the emissions associated with the distribution of the fuel to the transit agency since such emissions are included in the distribution and dispensing pathway section.

Table 16: Well-to-Production emissions per gallon of liquefied natural gas (LNG)

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
LNG	0.542	1.214	1.472	1.057	0.067	0.078	885.844	10.679	0.004	gram/gal LNG

Compressed Natural Gas (CNG)

The primary and secondary emissions utilized in H_2CAT for the production of CNG are presented in Table 17. Standard conditions were utilized to estimate the factors in kg of CNG.

The emission factors in Table 17 include the compression of natural gas to 250bar which usually occurs on-site. These emission factors, however, do not reflect the emissions from injection of the natural gas into the pipeline, since such emissions are included in the distribution section. Information from Table 15, Table 16 and Table 17 were obtained from GREET 2014 and adapted according to literature review [68]–[72].

Table 17: Well-to-Product emissions per kg of compressed natural gas (CNG)

	VOCs	**CO**	**NO_x**	**SO_x**	**PM2.5**	**PM10**	**CO_2**	**CH_4**	**N_2O**	
CNG	0.275	0.446	0.584	0.537	0.020	0.024	228.301	4.569	0.0015	gram/kg of CNG

5.3.2. Hydrogen Generation Technologies

For each hydrogen generation technology included in the tool, emission factors are established for criteria pollutants (volatile organic compounds, carbon monoxide, oxides of nitrogen, oxides of sulfur, total particulate matter) and GHGs (carbon dioxide and methane) [29]. Energy demand and water consumption factors are also established for each technology [73], [74]. These factors serve as parameters in the tool such that emissions and energy consumption outputs can be produced. The tool does not include the impacts associated with the manufacturing and decommissioning of the equipment.

Steam Methane Reformation (SMR)

As discussed in the Chapter 2, SMR is one of the most common processes to generate hydrogen. The process itself has primary and secondary emissions and the efficiency of the process depends largely in the scale of the plant, centralized units having higher efficiency than distributed units.

One hydrogen generation option for a deployment scenario is the use of natural gas as a feedstock in a SMR unit. The emissions associated with the production of hydrogen via SMR and natural gas are presented in Table 18. Included are the on-site emissions, the secondary emissions associated with the production of the electricity that is used during the process, and secondary emissions associated with the extraction and distribution of natural gas [19], [71], [75].

Table 18: Emission factors for the generation of H_2 via SMR

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
SMR centralized	1.28	3.78	5.25	2.49	1.36	1.41	4,230	21.68	0.017	gram/ kg H_2
SMR distributed	1.42	3.78	5.84	2.77	1.52	1.57	4,700	22.98	0.019	gram/ kg H_2

The water consumption and withdrawal for this generation process is presented in Table 19. The values showed in the table are the result of literature review converted to the appropriate units [19], [53], [73].

Table 19: Water utilization for the production of hydrogen using SMR and natural gas

	Water withdrawals	Water consumption	Total Water	
Centralized SMR	6.95	1.44	8.39	gal/kgH_2
Distributed SMR	8.15	1.66	9.81	gal/kgH_2

As explained in the previous section, the on-site emissions related to the use of the SMR units at distributed or centralized locations when using biogas are neglected in the WTW analysis since these emissions are equal or even less to emissions released to the environment when utilizing the biogas for other purposes

The only emissions considered for hydrogen generation in the tool when using biogas in SMR units are emissions related to the electricity use. The electricity used to power a SMR unit is 0.57 KWh of electricity per kilogram of hydrogen. The emission factors for this process are presented in Table 20. The water withdrawal and consumption is correlated to the electricity use during the cleanup. In addition, 7.78gal/kg of hydrogen is used during the process [19], [53], [73]. The water requirement for SMR units when using biogas and natural gas is presented in Table 21.

Table 20: Emission factors for the generation of H_2 via SMR with Biogas

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
SMR-biogas centralized	0.02	0.10	0.15	0.13	0.02	0.02	169.90	0.46	0.001	gram/ kg H_2
SMR-biogas distributed	0.03	0.12	0.18	0.16	0.02	0.03	199.88	0.54	0.001	gram/ kg H_2

Table 21: Water utilization for the production of hydrogen using Biogas SMR

	Water withdrawals	Water consumption	Total Water	
SMR Centralized				gal/kgH_2
Natural gas	6.95	1.44	8.39	
Landfills	12.04	1.69	13.73	
Wastewater	12.70	1.73	14.43	
SMR Distributed				gal/kgH_2
Natural Gas	8.15	1.66	9.81	
Landfills	13.98	1.98	15.97	
Wastewater	14.74	2.03	16.77	

Electrolysis

Chapter 2 describes the key aspects of electrolysis, a technology that can be selected to generate hydrogen for the deployment of fuel cell electric buses (FCEBs). In the tool, the supply chain scenarios can select the electrolysis process to be powered from the California grid mix, from a higher renewable penetration in the CA grid, or totally from renewable sources.

The emissions associated with the electrolysis process will depend on the efficiency of the process and the source of electricity. Due to the efficiency of scale, distributed electrolysis generates more emissions than centralized electrolysis (Table 22 and Table 23). Distributed electrolysis was set to have an operational capacity factor of 85% and the centralized process to 97% [76].

Table 22: Emissions for the generation of hydrogen via Distributed Electrolysis

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
Electrolysis with CA grid	2.23	9.97	15.54	13.49	1.60	2.37	17,078	45.93	0.1002	gram/kg H_2
Electrolysis Renewables	0.023	0.103	0.160	0.136	0.016	0.024	176	0.472	0.0010	gram/kg H_2

Table 23: Emissions for the generation of hydrogen via Centralized Electrolysis

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
Electrolysis with CA grid	2.01	8.97	13.98	12.14	1.44	2.13	15,370	41.34	0.09	gram/kg H_2
Electrolysis Renewables	0.06	0.25	0.39	0.33	0.04	0.06	432	1.16	0.003	gram/kg H_2

The emissions associated with the electrolysis powered by renewable sources in Table 22 and Table 23 are generated by the electricity employed to supply and distribute the water. In the state of California, the average energy intensity of each element in the water cycle was investigated by The California Energy Commission. The energy requirement to supply and distribute the water in California is around 7,950KWh per mega gallon delivered [77]. Producing 1 kg of hydrogen requires 2.95 gallons of water as feedstock [76], [78], [79]; 1kg of hydrogen requires around 58 gallons of water for cooling when using distributed electrolysis, and 147 gallons of water for cooling when the process is centralized [80].

Table 24 presents the water withdrawal and consumption for this process in distributed and centralized scale of electrolysis, in addition to a summary of the electricity from the grid or from renewable sources used in each type or process.

Table 24: Water and electricity consumption for the process of electrolysis

	Water withdrawals	Water consumption	Total Water		Electricity CA grid	Renewable Electricity	
Distributed Electrolysis							
Grid	222.37	13.39	235.76	gal/ kgH_2	48.5	0	KWh/ kgH_2
Renewables	59.71	3.04	62.75	gal/ kgH_2	0.5	48.5	KWh/ kgH_2
Centralized Electrolysis							
Grid	291.65	12.09	303.74	gal/ kgH_2	42.68		KWh/ kgH_2
Renewables	148.71	2.97	151.68	gal/ kgH_2	1.23	39.92	KWh/ kgH_2

[76], [78], [79]

Coal and Pet Coke Gasification

A large portion of the hydrogen produced in the U.S. can be generated via coal and pet coke gasification. These are options available to select in the tool at a centralized scale. The emissions in a well-to-product basis were obtained from GREET. Table 25 and Table 26 present the emissions for both process and the water requirements, respectively.

Table 25: Well-to-product emissions for Coal and Pet Coke Gasification

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
Coal Gasification	2.07	1.31	2.68	3.34	0.35	1.99	20,395	33.08	2.07	gram/ kg H_2
Pet Coke Gasification	1.92	4.52	8.92	8.01	0.83	1.13	24,155	40.82	1.92	gram/ kg H_2

*Values adapted from GREET [26]

Table 26: Water withdrawal and utilization for Coal and Pet Coke Gasification

	Water withdrawals	Water consumption	Total Water	
Coal Gasification	7.56	0.62	8.18	gal/kgH_2
Pet Coke Gasification	18.28	7.56	25.84	gal/kgH_2

*Values adapted from GREET [26] and [77], [80].

5.3.3. Distribution and Dispensing Pathways

When centralized hydrogen production is part of the design of any hydrogen infrastructure scenario, a user can select among the different delivery methods including gaseous tube trailers, liquid hydrogen by truck, or gas pipelines. Since hydrogen buses are designed to fill at 350bar, this is a set pressure for the dispensing process.

The selection of the distribution channel has a major impact on the overall environmental benefit of the hydrogen supply chain. Therefore, the accurate accountability of emissions and technology efficiency selected for the distribution channel is essential. The assumptions and consideration for all the distribution channels and dispensing are presented in this section.

Compressed gas trucks

The first assumption for this distribution channel is the capacity of the tube trucks, set in the tool to be 650 kg of gaseous hydrogen per truck at 250 bar [81][82].

The compression of the hydrogen is energy intense. For the tool, the electricity demand was set to 2.5 KWh/kg of H_2 to compress into truck (250bar) plus 3.03 KWh/kg to use the dispenser and on-site storage [82], [83].

The fuel economy of the truck is set to 5.5 mpg powered by diesel fuel. The fuel consumption depends on the miles traveled to deliver the hydrogen which is an input set by the user. The tool assumes a diesel consumption of 0.00062 gal/KgH_2*mile[30]. Once the fuel consumption is determined internally by the tool, the emissions for the diesel truck are calculated using Table 27 [84].

Table 27: Tailpipe emission factors of diesel tube trucks used to deliver H_2

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
Truck tailpipe	12.76	59.51	114.45	1.04	2.32	9.28	9,992	0.08	0.12	g/ gal diesel

Cryogenic Liquid truck

Similar to the compressed gas truck, the cryogenic liquid hydrogen delivery method is defined with the certain assumptions. The truck capacity is set to 4,500 kg of liquid hydrogen per tube truck and an electricity demand of 8.27 KWh to liquefied and set into truck per kilogram of hydrogen in addition to 2.50 KWh/kg of hydrogen for on-site storage and dispensing of the fuel.

The fuel economy of the truck is set to 5.5 mpg powered by diesel fuel. The tool assumes a diesel consumption of 0.000047 gal/KgH_2*mile [30]. The emissions for the diesel truck are calculated using Table 27 [84], which are the same emission factors used for gas tube trucks. Note that the use of diesel is less per kilogram of hydrogen for cryogenic liquid hydrogen since more hydrogen can be distributed per truck.

Gas Pipeline

One of the less energy intensive distribution pathways is distribution of gaseous hydrogen via pipeline. The pathway assumes compression to 70 bars and injection of the hydrogen at the centralized generation location and compression at the refueling station will compress the hydrogen from the pipeline pressure of 70 bars to the dispensing pressure of 350 bars.

The electricity needed to inject into the pipeline is 0.0044 KWh/kgH_2*mile at 70 bars. The electricity needed to dispense the hydrogen at 350 bars into the buses is assumed to be 3.03 KWh/kgH_2.

Distributed generation storage and dispensing

The following assumptions were set for the tool when distributed generation is part of the hydrogen supply scenario mix. For the portion of hydrogen that is distributed generated, the tool assumes that only 60% of the total on-site demand is storage and that the reaming is produced as a continuous process during the refueling times. This allows a reduction in storage footprint.

For the tool it was set an electricity requirement of 4.30 KWh/kgH_2, which includes the compression into storage and the dispensing to 350 bars.

Summary of Distribution and Dispensing Pathways

Table 28 summarizes the parameters set for the tool. Note that the different supply chains that the user can build can contain a combination of all the distribution pathways.

Table 28: Summary of parameters for the tool of hydrogen distribution pathways*

	Gas truck	Liquid Truck	Pipeline	Distributed Generation	
Compression into trailer	2.50	-	-	-	KWh/ kgH_2
Compression into pipeline	-	-	0.00044	-	KWh/ kgH_2*mile
Compression for dispensing (350bar) and storage	3.03	2.50	3.03	4.30	KWh/ kgH_2
Liquefaction	-	8.27	-	-	KWh/ kgH_2
Truck diesel consumption	0.00062	0.000047	-	-	Gal Diesel/ kgH_2*mile

*Values adapted from [26], [37], [82]

5.3.4. Tailpipe Emissions of Base Cases

In order to set a baseline of comparison and reflect the current greenhouse gases and criteria pollutant emissions, the tailpipe emissions of different bus technologies is set for the tool. Most of the emissions factors are obtained from literature review or from the DOE's tool AFLEET [53], [66], [67], [85]–[87]. Some of these emissions factors are reflected as grams per mile but some others are reported as grams per gallon of fuel. For the latter, the fuel economy of the buses needs to be defined. The fuel economy can largely vary due to several factors such as average drive speed, topography of city, climate and year of the buses. For this reason, the fuel economy of the current fleet can be adjusted by the user in order to reflect a realistic base line.

The bus technologies that were considered in the tool are:

- Diesel buses
- Biodiesel (B20 from soybeans)
- Compressed Natural Gas (CNG)
- Liquefied Natural Gas (LNG)

For the different fuels, the quantity of fuel is expressed in diesel gallons equivalent (DGE). Table 29 and Table 30 present the tailpipe emissions and fuel economy of the different transit bus technologies. The emissions from the extraction of the feedstocks and actual production of the fuels are presented in Table 14 through Table 17.The emissions of distributing the fuels applies to the pathways described in section 5.3.3.

Table 29: Tailpipe emissions and fuel economy of baseline buses for U.S. average

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	N_2O	CO_2	CH_4		Fuel Economy	
CNG	1.99	30.08	4.49	0.06	0.042	0.075	0.24	2,630	2.34	g/kg CNG	2.39	mi/DGE of CNG
LNG	2.32	21.06	1.22	0.06	0.049	0.087	0.28	4,536	0.99	g/gal LNG	1.62	mi/gal LNG
Diesel	6.01	38.23	38.68	0.02	0.119	0.124	0.92	9,352	7.02	g/gal Diesel	4.59	mi/gal Diesel
B20	6.89	13.59	9.06	0.02	0.104	0.108	0.92	9,211	2.72	g/gal B20	4.53	mi/gal B20
LPG	2.67	24.22	1.40	0.07	0.056	0.101	0.33	5,216	1.14	g/gal LPG	1.77	mi/gal LPG
Electric Bus	-	-	-	-	-	-	-	-	-		2.67	KWh/ mi
H_2 Bus	-	-	-	-	-	-	-	-	-		6.50	mi/kg

Table 30: Tailpipe emissions and fuel economy of baseline buses for California

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	N_2O	CO_2	CH_4		Fuel Economy	
CNG	0.94	17.39	3.65	0.06	0.0415	0.0748	0.19	2,060	2.34	g/kg CNG	3.18	mi/DGE of CNG
LNG	2.32	21.06	1.22	0.06	0.0486	0.0875	0.28	4,536	0.99	g/gal LNG	1.62	mi/gal LNG
Diesel	2.31	14.47	32.68	0.02	2.8728	2.9597	0.76	7,702	5.78	g/gal Diesel	3.78	mi/gal Diesel
B20	6.89	13.59	9.06	0.02	2.4993	2.5750	0.76	9,211	2.72	g/gal B20	4.53	mi/gal B20
Electric Bus	-	-	-	-	-	-	-	-	-		2.67	KWh/mi
H_2 Bus	-	-	-	-	-	-	-	-	-		6.50	mi/kg

The fuel economies for CNG, LNG and diesel were obtained from the FLEET tool and different reports of transit agencies [66], [67], [69] in combination with baseline comparisons used for the Hydrogen Fuel Cell Bus Program demonstration funded by the DOE [33] and emissions from EMFAC, a tool from the California Air Resources Board [88]. The biodiesel fuel efficiency in transit buses was also obtained from research reports and current transit agencies performance reports [89], [90].

The difference between factor emissions for U.S. average and California are mainly the technology year assumed for the buses. California has had more proactive legislation to remove old buses from the road and to promote cleaner CNG and diesel technologies.

Currently, transit agencies utilize the pipeline infrastructure in combination with on-site compression as the delivery pathway when using CNG. Section 5.3.3 includes the emissions of extraction and compression to generate CNG as a fuel for the buses, but the distribution and injection of the natural gas into the pipeline was considered separately to have more accurate estimation since these emissions depend on the miles traveled by the natural gas to its final point of use. Therefore, the emissions for the injection and distribution of natural gas are specified in Table 31.

Table 31: On-site emissions to inject and distribute natural gas into the pipeline network*

	VOCs	CO	NO_x	SO_x	PM2.5	PM10	CO_2	CH_4	N_2O	
Emissions of natural gas pipeline injection	2.73	8.85	14.00	0.00476	0.0177	0.0177	1000	37,100	0.00162	$x10^{-4}$ g/ kgNG*mi

*Values adapted from [59], [91], [92]

5.3.5. Analysis of Space Availability

The footprint requirements for distributed hydrogen conversion and storage space are important factors that could potentially limit the deployment of FCEBs in transit agencies. The PCA tool was modified with a capability to estimate the footprint for both the conversion and storage in the tool.

Recall that the tool determines the available space using two principles. First, any space utilized at the base for storage, dispensers and compressors will be available once the replacement of the fleet takes place. And second, the identification of available space specified by the user.

The tool matches the available space with the space required for SMR or electrolyzer units, compressors, dispensers, hydrogen storage as liquid or gas and it includes the clearance needed to comply with safety standards. The footprint is calculated based on specs from currently available equipment that have been validated or are currently used in demonstration projects [34], [76], [78], [93]–[95].

The output that the tool provides is the comparison of available space with required space and generates suggestion for the allocation of such equipment (e.g., locating storage tanks where the old compressors were placed). From the output, an assessment can be made if space availability at the bases would pose a restriction for the deployment of fuel cell buses and possible stationary hydrogen generation at the transit agency.

5.4. Cost Analysis Module

An additional module of H_2CAT is the cost analysis to inform the decision-making process by adding information about economic delivery pathway and estimations about the total cost of hydrogen. This section contains a brief description of the methodology used for this module and Chapter 8 presents results generated for three scenarios of deployment for OCTA using this module.

Figure 29 describes what the is considered in the cost analysis and it shows that to this point is designed to only evaluate the capital cost and price per kilogram variation of four distribution pathways:

1. Liquid Truck
2. Gas Truck
3. Pipeline
4. Distributed generation

For distribution from a centralized location, the module assumes a levelized production cost of hydrogen of $3.42 per kilogram. This assumption was made considering centralized SMR units with natural gas as the feedstock and it was obtained using the H2A Production Analysis Tool from the Department of Energy[84].

The price of feedstock, cost per truck, and additional cost assumptions regarding the station and dispensing were adjusted based on literature review and data from other transit agencies with current hydrogen buses demonstrations. Table 32 presents these assumptions and the correspondent reference.

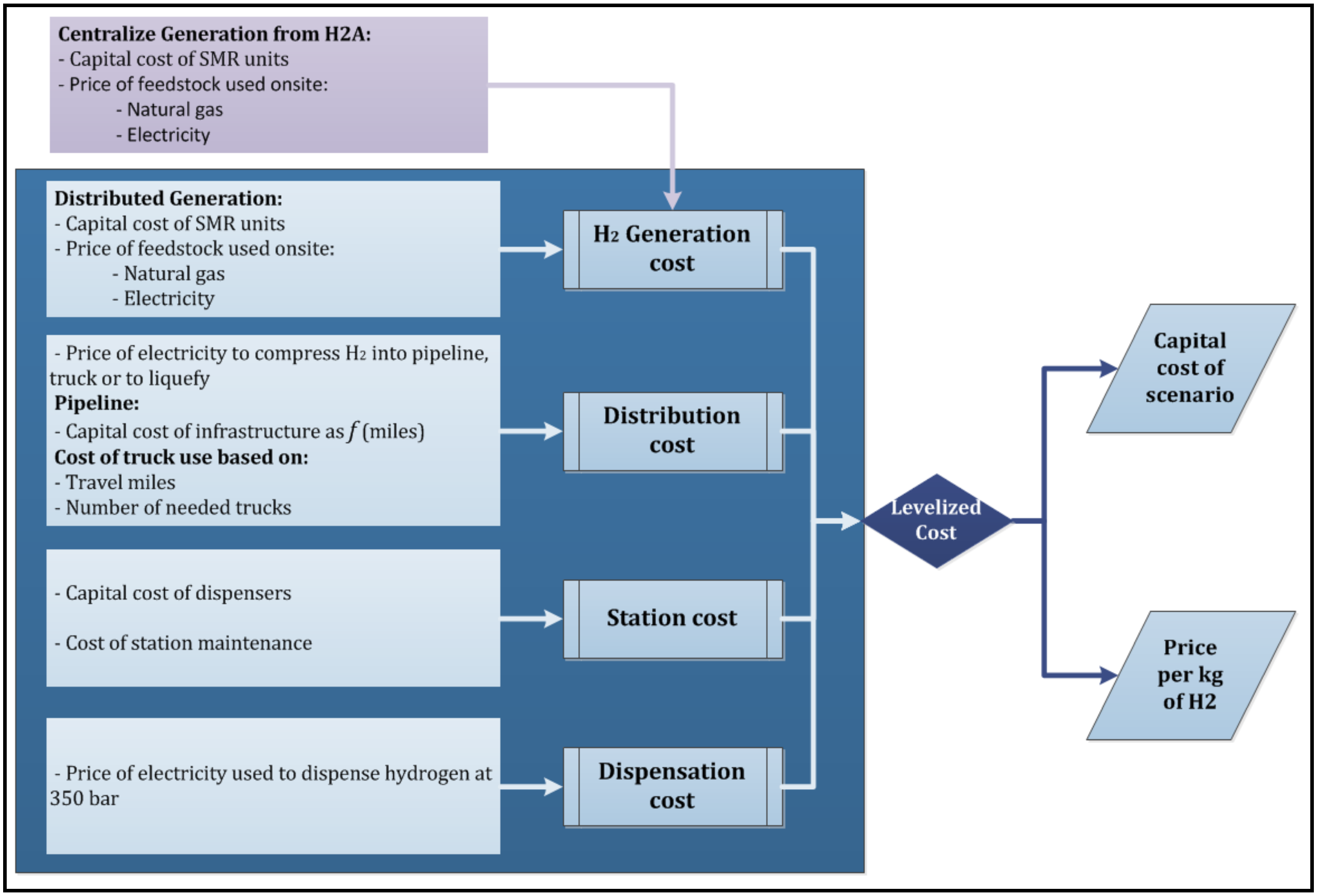


Figure 29: Considerations of H_2CAT Cost-Analysis module

Table 32: Variables for hydrogen stations and distribution pathways

Detail	Units		Reference
Cost of electricity	0.118	$/KWh	[96]
Well-to-product cost of Hydrogen	3.42	$/kg of H_2	[84]
Liquid Hydrogen			
Liquid truck capacity	4,500	Kg of H_2/truck	[82]
Cost of liquefaction equipment	1.03	$/kg of H_2	[61]
Cost of travel	4	$/mile traveled per truck	[82]
Electricity requirement for liquefaction	8.27	KWh/kg of H_2	[37]
Gaseous Hydrogen			
Electricity req. to compress into truck	2.5	KWh/kg of H_2	[82]
Gas truck capacity	650	Kg of H_2/truck	[82], [84]
Cost of travel	4	$/mile traveled per truck	[82]
Pipeline			
Capital cost of infrastructure	358,507	$/mi	[82], [84]
Electricity req. to compress into pipeline	0.50	KWh/kg of H_2	[20], [97]
Distributed generated Hydrogen			
Capital Cost of SMR units	2,862,300	$/unit	[82], [98]
Storage capacity	3,000	kg of H_2	[99]
Natural gas req.	0.172	MMBTU/kg of H_2	[71]
Cost of natural gas	7.5	$/MMBTU	[82]
Electricity req. for storage	2.27	KWh/kg of H_2	[20]
Dispensing details			
Electricity req. for dispensing at 350bar	3.03	KWh/kg of H_2	[20], [97]
Station details			
Capital cost of station			
Maintenance cost	142,000	$/year	[100]

Capital Cost

is a regression that is designed to adjust the capital cost of light duty vehicles hydrogen stations to the predicted cost for large fleet stations. The data upon which the equation was established were obtained from several reports of stations cost, cost of bus stations from demonstration projects, and H2A delivery [34], [37], [82], [84], [97], [98]. The capital costs that this equation considers include storage, compressors, dispensers, and investment in infrastructure to comply with safety requirements. The required inputs for the tool are:

- Travel miles for trucks
- Travel length of pipeline
- Well-to-product cost of hydrogen can be adjusted
- Number of Hydrogen fuel cell buses

Equation 6: Capital cost of hydrogen stations as a function of daily demand and number of dispensers

$$Station\ CC = 101{,}849 * (kg/day)^{0.5516} + (Number\ of\ Dispensers) * 26{,}880$$

Price per Kilogram of hydrogen

levelized capital With the defined variables from Table 32 and the above inputs, the tool can calculate the levelized capital cost based on the present value of the capital cost for a period of 12 years with an 8% debt rate (Table 33) The cost, in addition to other fixed costs and variant costs presented in Table 34 are used to calculate the breakeven for the hydrogen price.

Table 33: Financial assumptions for levelized hydrogen cost

Financial Assumptions	
8%	Debt rate
312	Days in a year
12	years to pay back
6.5	Fuel economy mi/kg

Table 34: Fixed and variant cost used for breakeven cost of hydrogen

Fixed Cost	Variant Cost
Levelized C.C. of the station per year	Cost of Transportation per kilogram of hydrogen transported
Maintenance cost of H_2 station per year	Production of hydrogen (well-to-wheels price)
	Cost of electricity for compression into storage and dispensing

The economic analysis is limited to scenarios with centralized and distributed generation via SMR and natural gas. The flexibility of the tool allows the incorporation of the capital cost for other equipment like electrolysis, and a variety of supply chain technology mixes.

5.5. Summary

The Hydrogen Characterization and Analysis Tool (H_2CAT) can characterize different hydrogen supply chain scenarios and analyze how each scenario influences greenhouse gases and criteria pollutant emissions, as well as energy demand and water consumption.

H_2CAT obtains as input the spatial and temporal hydrogen demand allocation from H_2AT. Then, a library of processes is created with specifications of efficiency, emission factors, and feedstock utilization that allow a selection mix of technologies for production, distribution, and dispensing of hydrogen, and the selection of the feedstock-mix. The library of processes includes emissions, energy demand, and water consumption of each technology on a well-to-wheels basis.

The hydrogen production technologies considered are coal/pet coke gasification, steam methane reformation, and water electrolysis where the two last have the options to be a centralized process or a distributed process. For steam methane reformation, three different feedstocks can be utilized: pure natural gas, biogas, or a mixture of the two. The feedstock mix can be set by the user to create different hydrogen supply chain scenarios. For electrolysis, either the grid or re-directed renewable energy can be used to power the process, or a fixed mixture of the two sources.

The hydrogen distribution method can be set to be pipeline, liquid tube trucks, compressed gas tube trucks, or a combination. .

In summary, a characterization and analysis tool was created that provides as outputs for any desired supply chain the quantification of resources utilization, emissions analysis, efficiencies, and costs of supply chain scenarios specified by the user.

CHAPTER 6. Potential environmental benefits of hydrogen for all transit agencies of the US

6.1. Exercise to demonstrate the capabilities of H_2CAT

The objective of this exercise is to demonstrate the capabilities of the Hydrogen Characterization Analysis Tool (H_2CAT) by creating three different hydrogen infrastructure scenarios that could be used to supply hydrogen fuel to all the transit agencies in the United States. The exercise analyzes the feedstock extraction and fuel generation supply chain processes, and uses the Hydrogen Allocation Tool (H_2AT) to obtain the current fuel demand from the U.S. transit agencies and uses the information as an input for the analysis.

6.2. Fuel consumption of non-rail vehicles in U.S. transit agencies

Based on the library created for H_2AT, information on the fuel type and fuel consumption is available for all the transit agencies in the United States. With this information, the tool can quantify the emissions and resource utilization for the production of the fuel currently used to support transit buses in the U.S. Additionally, this information can be compared to the emissions associated with the production of the equivalent hydrogen using different generation technologies.

From H_2AT, the total amount of fuel consumed by the transit agencies in the United States for the year 2013 is obtained as an input. The tool also has in its library fuel consumed for the years 2009 to 2013. The year 2013 was selected since was the most recent data. While the fuel library includes all types of vehicles and transit agencies, this example adopts the fuel used by transit agencies that have directly operated (DO) vehicles and purchased transportation vehicles (PT). The vehicles considered were Non-Rail Modes, specifically the following:

- Transit Buses (MB)
- Commute buses (CB)[5]
- Demand response vehicles (DR)
- Public Buses (PB)[6]
- Rapid buses (RB)
- Vanpools (VP)

By specifying vehicle types, the tool generates Table 35, which shows the total amount of fuel consumed by the transit agencies in the United States for the year 2013. Table 35 also presents the total amount of gigajoules consumed for each fuel type (based on low heating value). The total amount of energy consumed by the transit agencies in 2013 was over 94 million of gigajoules. The major fuel type utilized in 2013 was diesel with over 400 million gallons for that year; this represents 58% of the total energy consumed.

[5] CB: Fixed-route bus systems that are primarily connecting outlying areas with a central city through bus service that operates with at least five miles of continuous closed-door service. This service may operate motor-coaches (aka over-the-road buses)

[6] PB: Passenger vans or small buses operating with fixed routes but no fixed schedules

Table 35: Total 2013 fuel consumed by non-rail vehicles in U.S. transit agencies

	Gal/year		GJ/year (LHV)
Diesel fuel	401,471,549	57.82%	54.41E+06
CNG[7]	131,841,525	20.28%	19.08E+06
Gasoline[8]	81,944,929	10.67%	10.04E+06
Bio-diesel	64,351,234	9.18%	8.63E+06
LNG	17,014,964	1.43%	1.34E+06
LPG[9]	6,607,270	0.63%	5.92E+05
Total		**100%**	**94.1E+06**

6.3. Baseline emissions: well-to-product and tailpipe emissions of transit agencies in the U.S.

Once the base case fuel demand and fuel type have been established from H_2AT, then H2CAT can be used to calculate the emissions associated with feedstock extraction and fuel generation processes, as well as the tailpipe emissions. For this exercise, the processes of generation are considered and any emissions from distribution and dispensing are neglected since not enough information is available that describes the current distribution channels associated with each individual transit agency. An example for a complete hydrogen supply chain analysis is demonstrated in the following chapter.

The emissions from feedstock extraction and fuel conversion processes are calculated by the tool according to the methodology described in Chapter 5. The emission factors are a reflection of the average fuel production process across the United States and not specific for each state.

[7] CNG fuel utilization in diesel gallon equivalent (DGE)
[8] Gasoline used in Vans for vanpool services
[9] Liquefied petroleum gas

The tailpipe emission factors were also obtained under the methodology described in Chapter 5. The emission factors for diesel vehicles were obtained from EMFAC [88], using the average for the emissions by diesel buses (no school buses considered) released between 2005 and 2013.

Table 36 shows the total base-line emissions that are released to the environment in order to produce and used traditional fuel by the transit agencies for the year of 2013. During that period, all the vehicles operated by the transit agencies released over 6 million tons of carbon dioxide and more than 26 thousand tons of carbon monoxide; in addition to over 21 and 14 thousand tons of nitrogen oxides and methane (CH_4) respectively.

Table 36: H_2CAT results for well-to-product and tailpipe emissions released to the environment by transit agencies in the United States for 2013 year period.

	Ton/year								
	CO_2	**CO**	**NO_x**	**CH_4**	**VOCs**	**SO_x**	**N_2O**	**PM_{10}**	**$PM_{2.5}$**
Diesel	4,331,236	16,078	17,877	9,872	2,862	1,375	376	275	222
CNG	1,157,028	5,795	2,056	2,057	915	242	99	40	25
B20	666,697	991	960	1,079	515	220	60	43	35
Gasoline	402,280	3,168	379	892	149	169	11	42	30
LNG	92,252	379	46	199	49	19	5	3	2
LPG	131,821	340	52	103	24	16	2	3	2
Total emissions	**6,781,315**	**26,750**	**21,369**	**14,201**	**4,513**	**2,041**	**553**	**406**	**315**

Figure 30 presents the source of emission for each type of criteria pollutant and greenhouse gas (e.g., more than 60% of the total VOC emitted is due the use of diesel, 20% is due to CNG, 11% due to the use of biodiesel and so on)..

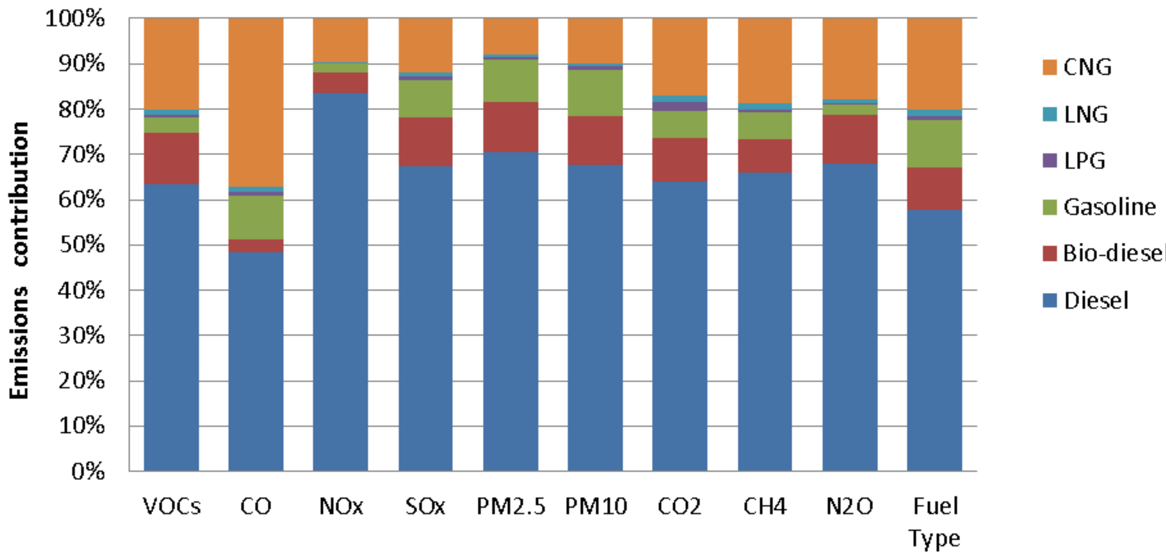


Figure 30: Contribution from fuel type to the total greenhouse gases and criteria pollutants emitted to the environment by transit agencies

6.4. Hydrogen Infrastructure Scenarios to Supply Transit Agencies in the U.S.

With the total emissions for a base case scenario H_2CAT has the capability to compare the environmental benefits associated with replacing petroleum-based fuels with hydrogen in all the transit agencies of the United States or for any specified region/state/county/city.

Since the base case emissions do not include distribution processes, the emissions for the hydrogen infrastructure scenarios also neglects emissions from distribution paths.

The first output of the tool is the total hydrogen demand, presented in Table 4. The total amount of hydrogen required to replace old vehicle technologies with fuel cells over all the transit agencies in the United States is 473,372 tons/year.

From the hydrogen demand, the tool can build hydrogen infrastructure scenarios and calculate the emissions associated with the generation of hydrogen, including the extraction of feedstocks (well-to-product). This result can then be compared to the total emissions released from well-to-product and the tailpipe of current utilized fuels.

For the purpose of this exercise, three hydrogen generation technologies are considered: (1) steam methane reformation (SMR) from natural gas, (2) SMR with biogas, and (3) electrolysis using renewable electricity. Using these three generation technologies, several scenarios can be design and used to compare the level of benefits that can be accomplished from transitioning to hydrogen technologies. The three scenarios considered in this exercise are:

1. **Scenario 1 (SC1): SMR with 67% of the hydrogen produced from natural gas and 33% from biogas.**

   This scenario is selected as the most immediately available. Large centralized SMR plants are installed and functional around the United States, operating on natural gas as the feedstock, to produce hydrogen for refineries and industry. For refueling, California legislation requires that 33% of the hydrogen dispensed needs to be produced from renewable sources [101]. The renewable portion for these scenarios is satisfied by using directed biogas as the feedstock for the SMR.

2. **Scenario 2 (SC2): SMR with 20% of the hydrogen produced from natural gas and 80% from biogas**.

   This scenario considers a larger portion of renewable hydrogen that can be produced by using directed biogas at the centralized steam methane reformation facility.

3. **Scenario 3 (SC3): Electrolysis using the grid to produce 20% of the hydrogen and renewable energy sources to generate the other 80%**.

While hydrogen generation from large plants using electrolysis is not yet viable, projects have been introduced overseas that have large electrolysis projects under construction or already running [102]. The portion of renewables selected for this scenario is 80% to match the goal that some states (e.g., Hawaii) plan to achieve by 2045 [103] as the percentage of renewable integration into the grid.

Assumptions

One of the assumptions for this exercise was the grid mix used to supply electricity for Scenario 3. Of the 20% supplied by non-renewables, 40% is generated by natural gas plants, and 20% is generated by coal power plants (a total of 4% coal power contribution to the grid mix). Even with this small contribution of coal, coal substantially impacts the overall emissions. As a result of this observation, a sensitivity analysis was performed in the following sections in order to demonstrate the importance in reducing coal use for power generation.

For all the scenarios using SMR to produce hydrogen, it is assumed that carbon dioxide is sequestered.

In the following sections, additional scenarios are developed and analyzed to explore the following conditions:

- California Grid (CAG): these scenarios explore the ideal penetration of renewables into the California grid that is needed to equal the environmental benefits of biogas utilization for hydrogen production.

- Distribution Pathway (DP): scenarios designed to individually explore the environmental impact of each distribution pathway in the hydrogen supply chain.

- Renewable Hydrogen (RH): These combinations of scenarios show the environmental benefits of only renewable pathways to produce hydrogen.

- OCTA Preferred Scenarios (PS): Scenarios created specifically for the Orange County Transportation Authority (OCTA) to identify the preferable supply chain of hydrogen. These scenarios are created based on the analysis and conclusions of the previous scenarios.

- Cost Module (CM): Scenarios designed to evaluate how the distribution pathways impact the cost of hydrogen.

Table 36 provides a summary and description of each scenario as a guide for following the analyses in the chapters to follow.

Table 36: Description of established scenarios

Thesis section	Scenario name	Scenario Acronym	Description: Generation Mix	Description: Distribution Mix
6.4 Hydrogen Infrastructure Scenarios to Supply Transit Agencies in the U.S.	U.S. Scenarios	**SC1**	SMR: 67% NG, 33% biogas	Undefined
		SC2	SMR: 20% NG, 80% biogas	Undefined
		SC3	Electrolysis: 20% Grid, 80% Rnw*.	Undefined
7.4 Defining preferable components of the hydrogen supply chain				
7.4.2 SMR vs Electrolysis: ideal renewable penetration of California grid to power electrolysis	California Grid	**CAG1**	SMR: 67% NG, 33% biogas	Pipeline (40min)
		CAG2	Electrolysis: 17% Grid, 83% Rnw.	Pipeline (40min)
		CAG3	Electrolysis: 100% Grid	Pipeline (40min)
7.4.3 Minimizing emissions from distribution pathway	Distribution Pathway	**DP1**	SMR: 67% NG, 33% biogas	Pipeline (40min)
		DP2	SMR: 67% NG, 33% biogas	50% pipeline, 50% liquid H_2
		DP3	SMR: 67% NG, 33% biogas	100% liquid H_2
7.4.4 Renewable hydrogen scenarios	Renewable Hydrogen	**RH1**	SMR: 100% biogas	Pipeline (40min)
		RH2	Electrolysis: 100% renewables	Pipeline (40min)
		RH3	50% SMR-biogas; 50% Electrolysis Rnw	Pipeline (40min)
7.5 Preferable hydrogen infrastructure scenarios for OCTA	OCTA Preferable Scenarios	**PS1**	SMR: 67% NG, 33% biogas	Pipeline (40min)
		PS2	67% SMR-NG, 33% Electrolysis Rnw	67% Distributed, 33% liquid H_2
		PS3	40% SMR-NG Electrolysis: 40% Grid and 20% Rnw.	Distributed
Chapter 8 Cost Analysis Module for Hydrogen Infrastructure	Cost Module	**CM1**	SMR: 67% NG, 33% biogas	Liquid H_2
		CM2	SMR: 67% NG, 33% biogas	Gas H2
		CM3	SMR: 67% NG, 33% biogas	Pipeline
		CM4	SMR: 67% NG, 33% biogas	Distributed

*Rnw. = Renewable Energy

6.5. Results

The results for the emissions of the above described scenarios in comparison to the current emissions generated to produce and use (tailpipe) the conventional fuels in transit agencies are presented in Table 37.

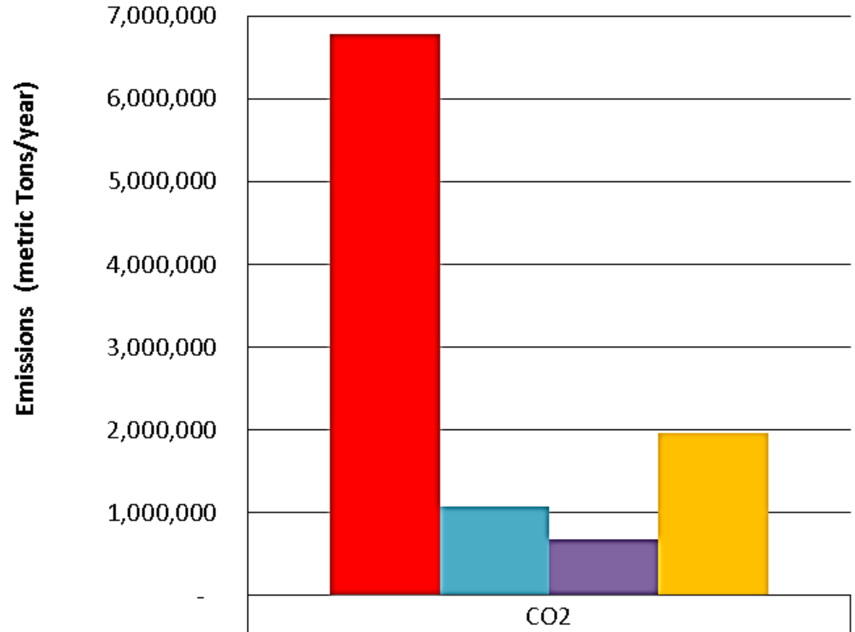
Table 37: Emissions offset from different hydrogen generation scenarios to replace conventional fuels from transit agencies in the United States in comparison to the well-to-product and tailpipe emissions*

	2013 Emissions from Transit Agencies	SC1	SC2	SC3
	Tons/year			
GWP[10]	7,251,000	(5,912,434)	(6,476,965)	(5,189,808)
CO_2	6,781,315	(5,705,378)	(6,100,989)	(4,817,940)
CO	26,750	(24,943)	(26,109)	(25,970)
CH_4	14,201	(1,790)	(9,835)	(9,825)
NO_x	21,369	(17,706)	(19,845)	(19,204)
VOCs	4,513	(4,090)	(4,350)	(4,286)
SO_x	2,041	5	(513)	1,584
N_2O	553	(547)	(547)	(534)
PM_{10}	406	(204)	(237)	33
$PM_{2.5}$	315	(163)	(205)	(49)

* Emissions from distribution of fuel are neglected for all the scenarios

Scenario 2 (SMR with 20% natural gas and 80% biogas)show the potential to remove six million metric tons of carbon dioxide (CO_2) per year, a 90% emissions reduction. The other two hydrogen scenarios also represent significant CO2 reductions: Scenario 1 with only 33% renewables using SMR yields 84% reductions and Scenario 3 that assumes electrolysis reduces CO_2 emissions by 70%. The reduction on CO_2 emissions from each hydrogen scenario is presented in Figure 31.

[10] GWP = global warming potential, more information in section 5.1



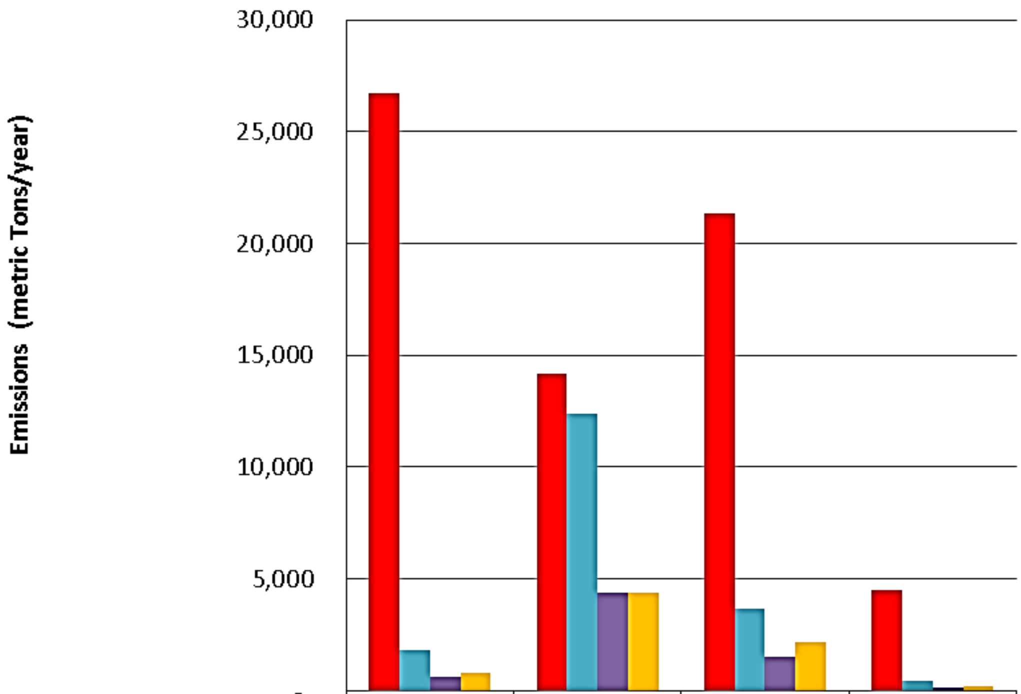
	CO2
Emissions from Transit Agencies in the US	6,781,315
SC1	1,075,937
SC2	680,325
SC3	1,963,375

Figure 31: Possible Carbon Dioxide emissions reduction from three different hydrogen production scenarios to replace conventional fuels in the US transit agencies

For carbon monoxide (CO), all the hydrogen scenarios present similar offset emission, over 25 thousand metric tons per year fewer emissions released to the environment which is more than a 93% reduction (Figure 32). Offset of methane (CH_4) emissions is more beneficial if a larger portion of renewable is in the mix. If steam methane reformation with natural gas is used as the main hydrogen generation technology, only around two thousand metric tons per year (13% reduction) are no longer released to the environment, versus almost 26 thousand metric tons that can be offset with the other two scenarios (69% reduction). For nitrogen oxides (NO_x), the same tendency as with methane is observed:

Scenario 1 leads to the less emissions reduction (83%), Scenario 2 reduces NOx emissions by 93%, and Scenario 3 results in a reduction in emissions of 90%.

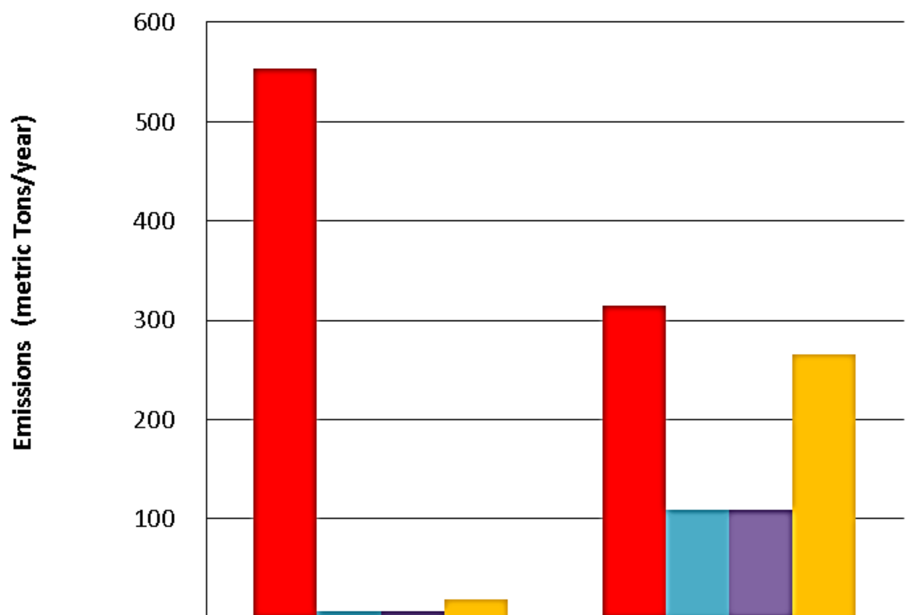
For volatile organic compounds (VOCs), the three scenarios show a reduction in emissions greater than 91%.



	CO	CH4	NOx	VOCs
Emissions from Transit Agencies in the US	26,750	14,201	21,369	4,513
SC1	1,807	12,411	3,663	423
SC2	642	4,366	1,524	163
SC3	780	4,376	2,165	227

Figure 32: Possible CO, CH_4, NO_x and VOCs emissions reduction from three different hydrogen production scenarios to replace conventional fuels in the US transit agencies

Nitrous Oxide (N_2O) emissions are almost completely eliminated with the adoption of any of the hydrogen scenarios (Figure 33). Reductions greater than 96% are achieved, preventing 553 metric tons from being released to the environment. For the emissions of particulate matter (PM2.5), the benefits between hydrogen scenarios vary. The scenario with more biogas to power the SMR units (Scenario 2) reduces emissions 65%, taking out of the environment more than 200 metric tons per year. If only 33% of the hydrogen is produced from biogas (Scenario 1) then the emissions reductions drops to 52% (163 metric tons/year). Finally, for the scenario where electrolysis is used with 20% electricity from the grid, almost the same amount of PM2.5 is emitted (only a 3% reduction), the largest emission of PM2.5 (Scenario 3) is directly linked to the use of coal for the generation of electricity.

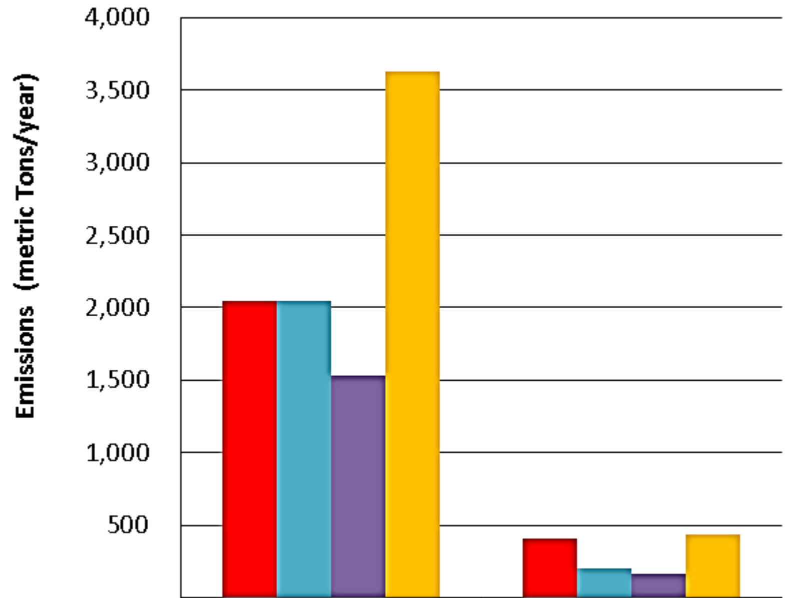


	N2O	PM2.5
Emissions from Transit Agencies in the US	553	315
SC1	7	110
SC2	7	110
SC3	19	266

Figure 33: Possible N_2O and PM2.5 emissions reduction from three different hydrogen production scenarios to replace conventional fuels in the US transit agencies

For the emissions of sulfur oxide (SOx), the reduction (25%) is the largest for Scenario 2 (Figure 34). This is also the case for PM10 emissions, where Scenario 2 achieves almost a

60% reduction in the emissions. For Scenario 1 where only 33% is renewable hydrogen via SMR, the SOx emissions are equal to the base case scenario. The PM10 emissions for this scenario offer a 50% reduction compared to the current emission of the U.S. transit agencies.

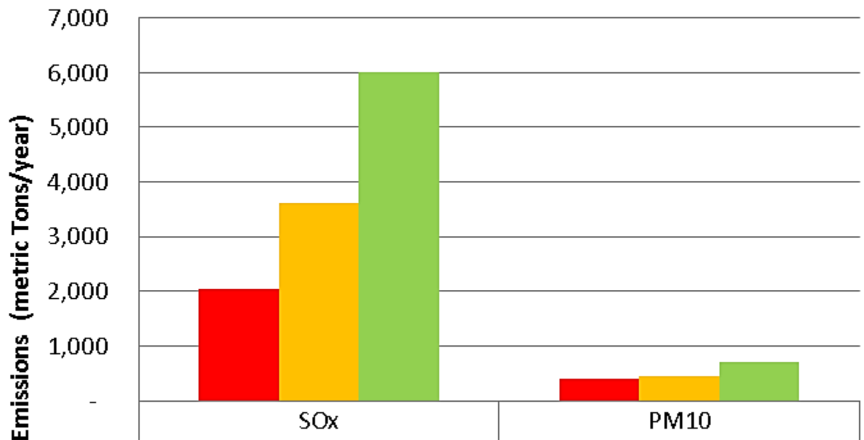


	SOx	PM10
Emissions from Transit Agencies in the US	2,041	406
SC1	2,047	202
SC2	1,528	169
SC3	3,625	439

Figure 34: SO_x and PM10 emissions from different hydrogen scenarios in comparison to the 2013 well-to-product and tailpipe emissions from US transit agencies

For Scenario 3, the emission of SOx exceeds the current emissions by 78% or 3,625 tons/year. This is attributed to the 4% contribution to the grid mix from coal. For this same coal source, Figure 34 also shows an increase of 25% in PM10 emissions for Scenario 3.

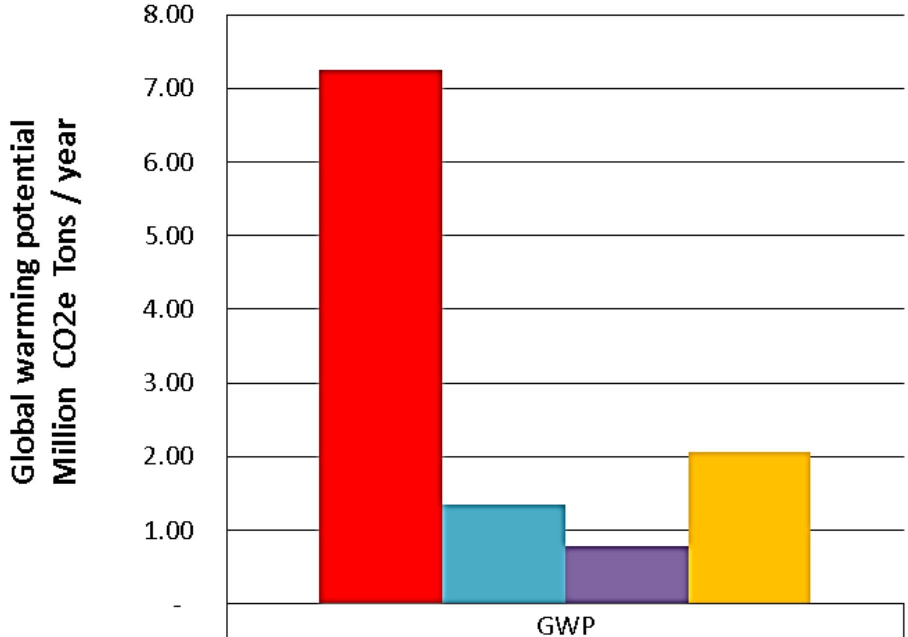
In order to explore the impact that coal plants have in SOx and PM10 emissions, a sensitivity analysis was conducted. The results are presented in Figure 35 where a new scenario, shown in green, is comprised of a total of 80% renewable penetration by electrolysis and twice the coal contribution (8%). The SOx emissions increase to over six thousand tons/year and, the PM10 emissions increase 76% from the baseline.



	SOx	PM10
Emissions from Transit Agencies in the US	2,041	406
H2 from Electro: Grid (4% coal) - 20% and Rnw 80%	3,625	439
H2 from Electro: Grid (8% coal) - 20% and Rnw - 80%	6,009	712

Figure 35: Sensitivity analysis of coal power plants contribution to the grid for hydrogen scenarios with generation via electrolysis.

By comparing the hydrogen infrastructure scenarios from a global warming potential perspective (an index that compares the ability of one mass unit of a particular gas to affect global warming relative to carbon dioxide), a broad comparison can be made. Figure 36 shows metric tons of CO_2 equivalent per year for the three hydrogen scenarios. As presented in the figure, the global warming potential that producing and using conventional fuels in the U.S. transit agencies is more than seven million metric tons of equivalent CO_2 per year. Replacing conventional fuels with Scenario 1 (hydrogen generated via steam methane reformation with a large portion of biogas) could result in a 90% reduction of greenhouse gases. For Scenario 2 (33% renewable hydrogen via SMR) results is an 82% reduction in greenhouse gas emission. Scenario 3 is the lowest GHG emissions reduction (72%).



	GWP
Emissions from Transit Agencies in the US	7.25
SC1	1.34
SC2	0.77
SC3	2.06

Figure 36: Global Warming Potential for different hydrogen infrastructure scenarios to supply U.S. transit agencies

6.6. Summary

- The total amount of energy associated with the fuel consumed in 2013 by the transit agencies that operate fixed routes was over 94 million of Gigajoules. The major fuel type was diesel with over 400 million gallons.
- The well-to-product and tailpipe emissions generated by transit agencies in a year average around 7.25 million tons of CO_2 equivalents.
- The total amount of hydrogen required to replace conventional-fuel buses with fuel cell buses in U.S. transit agencies is almost five hundred thousand hydrogen tons per year.
- If hydrogen is used to replace conventional fuels in buses at each US transit agency, a reduction of 90% in greenhouse gas emissions can be achieved by using biogas to produce 80% of the hydrogen via steam methane reformation.
- Using a grid mix of 80% renewable electricity can result in an increase of almost 80% in the SOx emissions when 4% of the power for the non-renewable grid portion comes from coal plants.

CHAPTER 7. Preferred Hydrogen Scenarios for a Transit Agency

H_2AT and H_2CAT are tools to assist transit agencies in evaluating options for transitioning to zero emissions fleets through a detailed analysis of greenhouse gas and criteria pollutant emissions, energy demand and water energy consumption, and the associated economics. This chapter is dedicated to demonstrate the application of the tools to a large size transit agency. The Orange County Transportation Authority (OCTA) was selected to serve as a test platform for demonstration of the tools. This chapter contains (1) a detailed characterization of OCTA's fleet and daily operations and (2) the development of preferable scenarios to deploy hydrogen fuel cell electric buses (FCEBs) at the OCTA. The cost analysis module, integrated into H_2CAT, is presented in Chapter 8.

7.1. Orange County Transportation Authority as the Large Scale Transit Agency

Following the size classification of transit agencies used by the University of California Transportation Center [104], OCTA is classified as a large transit agency with more than 20 million unlinked passenger trips. A medium-sized transit agency would serve between 10 and 20 million unlinked passenger trips and smaller agencies would be serving fewer than 10 million unlinked passenger trips within large metro areas as well as in smaller cities and rural areas.

In addition to the size classification, OCTA was selected as a test-platform for two main reasons: (1) OCTA successfully transitioned from diesel to natural gas buses and therefore have experience with refueling compressed gas (CNG) and cryogenic storage/refueling (LNG) in addition to experience implementing security measures to handle gaseous fuels and maintenance of the buses, and (2) UCI is in the OCTA service area which supported a close collaboration relationship including visits to their main fleet bases, and meetings to exchange information and communicate the challenges and opportunities that a transit agency faces in the deployment of hydrogen fuel cell electric buses.

The first step in using the tools is to obtain a detailed knowledge of the transit agency's current fleet. The internal library of the Hydrogen Allocation Tool (H_2AT) provides the basic information like the fuel utilization and fuel type consumed by OCTA, but to have a detailed emission inventory of the transit agency, additional information is needed. The detailed characterization of OCTA is presented in this section in addition to identifying nearby resources that can be part of future hydrogen supply chains.

Current fuel supply chain of OCTA and predicted hydrogen demand

A relationship with the Orange County Transportation Authority (OCTA) was established in October 2014 during which a principal contact was established for the OCTA. Subsequent to this meeting, an in-depth understanding was established regarding the operational specifications of OCTA, including details about the fleet, the fuel consumption, and the refueling methodology. The tables below summarize some of the information that characterizes this large transit agency.

Table 38: Fuel utilization for OCTA

	# buses	Gallons per month	Therms per month	miles per gallons
Diesel	12	20,943	-	3.78
LNG	206	443,877	-	1.62
CNG	350	-	740,940	2.73
TOTAL	**568**	**464,820**	**740,940**	**-**

OCTA has four bases to handle the maintenance and refueling for the bus fleet. The table below shows the number and types of buses assigned to each base.

Table 39: Detailed fleet characterization of Orange County Transportation Authority

	# LNG buses	# CNG buses	# Diesel buses	# buses per base	Portion of buses at each base
Base 1	138	11	0	149	27%
Base 2	16	167	12	195	34%
Base 3	0	172	0	172	30%
Base 4	52	0	0	52	9%
TOTAL	**206**	**350**	**12**	**568**	**100%**

The information from Table 38 and Table 39 is required as input for H_2AT to calculate the hydrogen demand and to estimate the demand of hydrogen among the four bases. The hydrogen demand, presented in Table 40, is calculated assuming an efficiency of 6.5 kg of hydrogen per mile for the FCEBs and 26 days of full service per month at OCTA.

Table 40: Hydrogen utilization for OCTA

	Kg/ week day	Kg/ month	Kg/ Year
Base 1	3,856	100,260	1,203,123
Base 2	5,047	131,213	1,574,556
Base 3	4,451	115,737	1,388,839
Base 4	1,346	34,990	419,882
TOTAL	**14,700**	**382,200**	**4,586,400**

The information about the current methodologies for distribution, storage and refueling of CNG and LNG is a required input for H_2CAT since it allows a detailed estimation of the emissions and resources used for each process of their current supply chain. Table 41 details this information.

Table 41: Detail of refueling process at OCTA

Daily fuel demand	33,807 GGE of natural gas
Distribution	CNG – pipeline (68% of base total fuel) LNG – tube truck (32% of base total fuel)
Storage	CNG – no storage LNG – underground liquid tanks
Dispensing	Gas – pressure at 250 bar Liquid – standard state (25°C, 1 bar)
Compressors	8 compressors
Refueling Schedule	After 6pm to 4am

7.2. OCTA well-to-wheels emissions as the baseline

An accurate description of the current supply chain used for the fuel consumed at OCTA, in combination with their fuel demand, allows for the quantification of greenhouse gas and criteria pollutant emissions as well as a description of the resources used to produce and distribute the fuel. The results are presented in Table 42 and Figure 37.

The average emissions released to the environment by the daily operations of OCTA serve as the basis for the baseline scenario.

Figure 37 presents the daily emissions during the processes of production, distribution and dispensing, and the tailpipe emissions that result from using the fuel. The emissions are presented for the following compounds: NOx, VOCs, PM2.5, PM10, CO, N_2O, CH_4 and CO_2 equivalent based on the global warming potential (GWP) of the last three. As presented in the graphs, the tailpipe emissions are the dominant source of contamination in comparison to the other processes. Activities related to the production, distribution and use of the fuel to run fixed routes releases 256 metric tons of equivalent CO_2; 59 daily kilograms of SOx; almost 360 daily kilograms of NOx and nearly 1.5 thousand kilograms of CO.

Table 42: Daily Well-to-Wheels Criteria Pollutant and Greenhouse Gas Emissions of OCTA calculated with H_2CAT

	VOCs (kg/day)	CO (kg/day)	NOx (kg/day)	SOx (kg/day)	PM2.5 (kg/day)	PM10 (kg/day)	GHG (CO_2e ton/day)
Production	28	49	66	54	2,827	3	40
Distribution and Dispensing	3	12	20	0.11	0.31	1	6
Tailpipe	94	1,364	272	5	7	10	210
Total	**124**	**1,424**	**359**	**59**	**10**	**14**	**256**

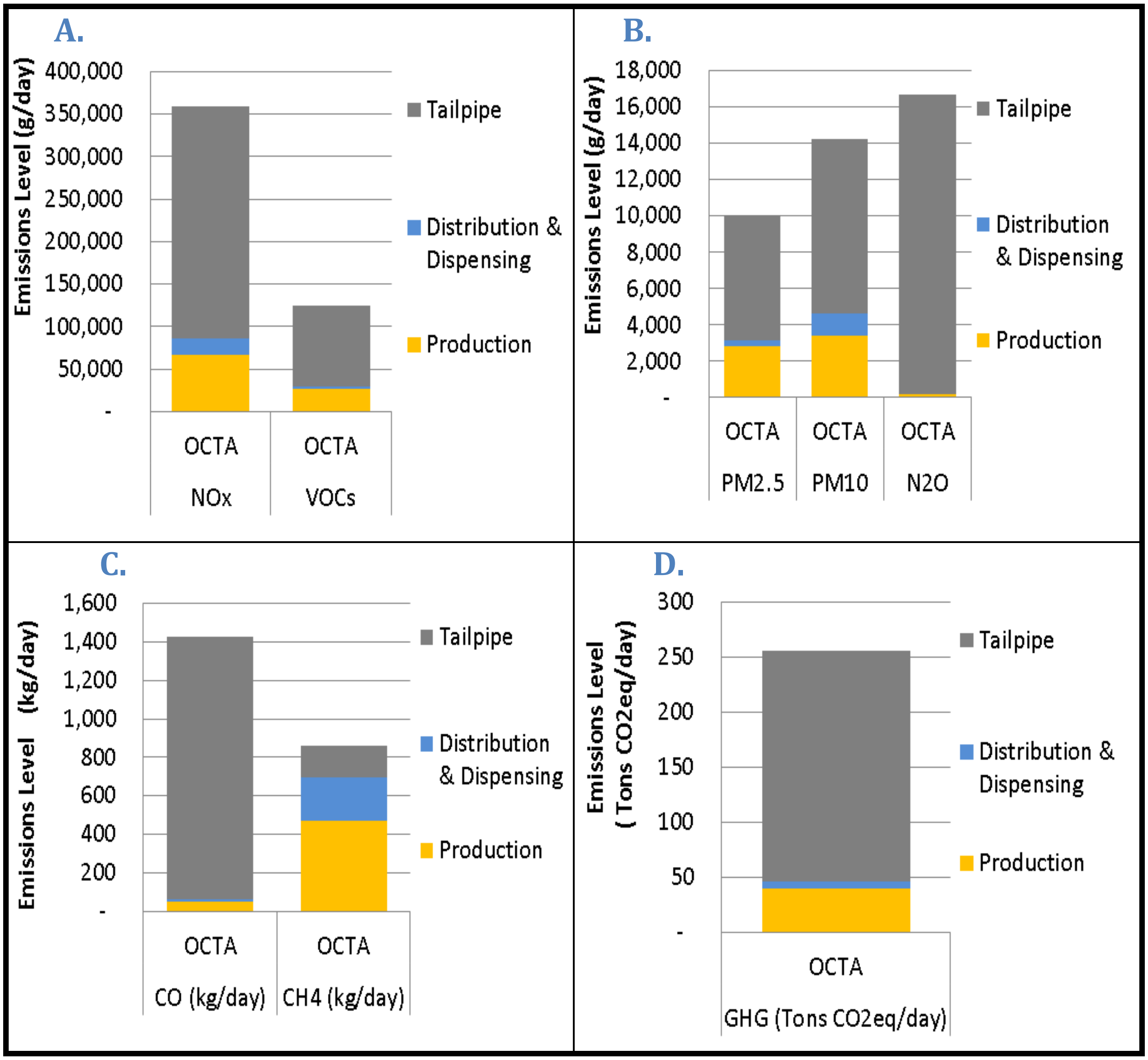


Figure 37: Well-to-Wheels greenhouse gas and criteria pollutant emissions of OCTA

Figure 38 shows the graphical description of the resources used on a daily basis by OCTA. The resources include electricity supplied by the California grid, natural gas, water withdrawal and water consumption; as well as biomass, crude oil and coal used to generate electricity and supply the California grid.

Figure 38-A shows the consumption of electricity is categorized according to the process during which is used, i.e. quantification of electricity used during the conversion of the fuel

(Production of CNG, LNG and diesel) and electricity used for the process of distribution and dispensing (D&D) of the fuel. In total over 50 thousand KWh of electricity are used daily in the supply chain of the fuels used by OCTA.

Figure 38-B illustrates the quantity of natural gas used daily by OCTA. The orange bar referrers to all the natural gas directly used in the supply chain, i.e. the amount of fuel used as CNG and LNG in addition to losses occur during the D&D and resources used for the feedstock extraction. The grey bar shows the natural gas that is used in power plants to generate electricity in proportion to the 55% of contribution of fired natural gas plants that form the California grid mix (indirect use). Almost 100 thousand kilograms of natural gas are used daily directly or indirectly by OCTA. These outputs are calculated using the methodology described for H_2CAT.

A similar quantification of emissions was made for biomass, crude oil and coal, although all these resources are only indirectly consumed to daily generate the 55 thousand KWh of electricity from the California grid (Figure 38-C).

Figure 38-D shows the quantification of water consumption and water withdrawal that occurs directly and indirectly from the consumption of fuel at OCTA. Water withdrawal is defined as the water used in any process but recirculated (sent back to the source), while water consumption is the resource converted and no longer available. Both types of resources show the water availability that the region needs to have for either direct or indirect processes. Over 250 thousand gallons of water are required in the region for electricity generation, mostly due to hydroelectric and geothermal power generation.

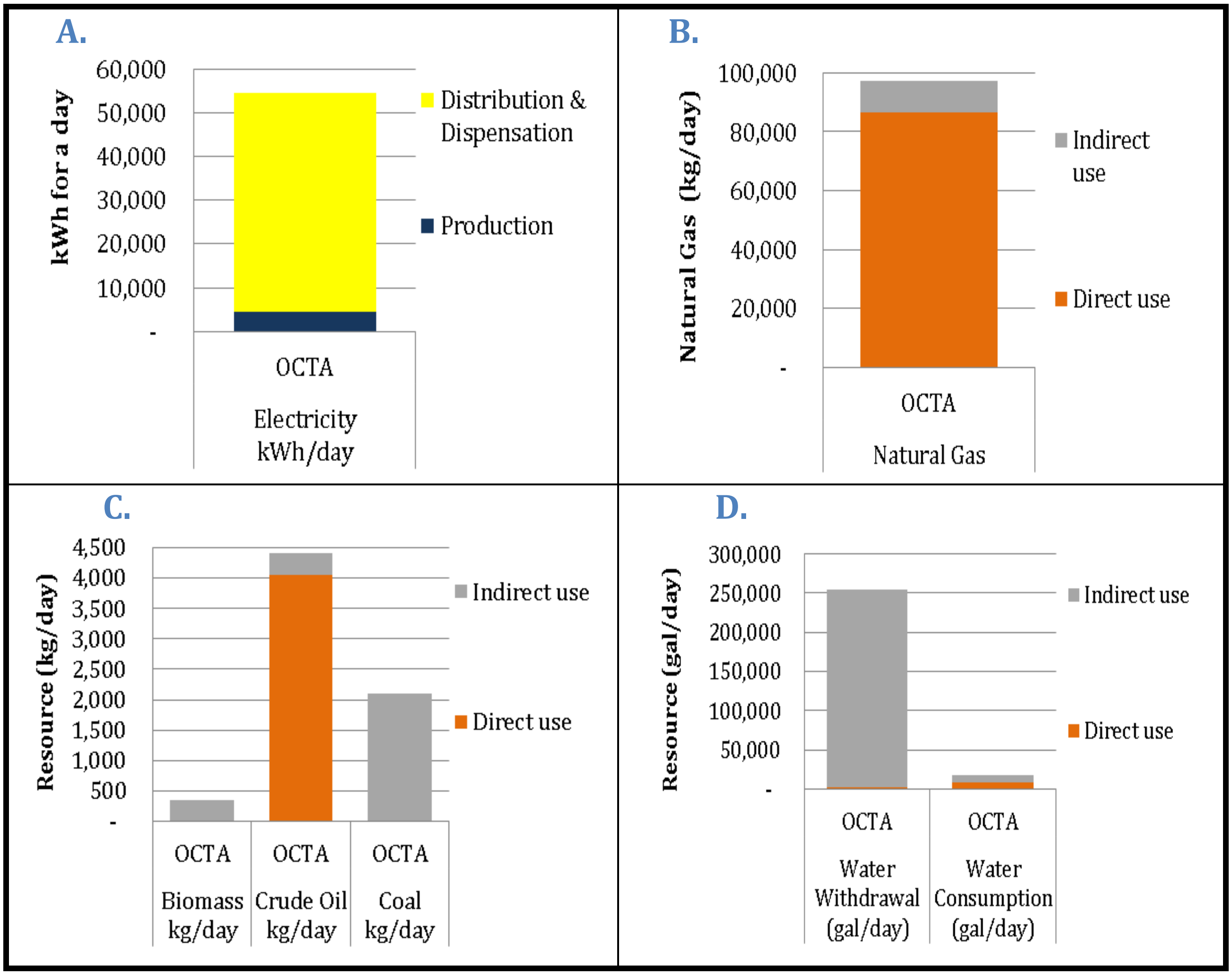


Figure 38: Quantification of feedstocks used in the supply chain of fuel for OCTA on a Well-to-Wheels basis

7.3. Roll-out of hydrogen stations for OCTA

After quantifying the emissions and resources associated with the activities of OCTA and with the hydrogen projected demand to replace petroleum-based fuels, the next step is to determine the number of hydrogen fueling stations and their ideal location. To assess the most efficient number of fueling stations, the first step is to spatially allocate the current base location of the transit agency using ArcMap 10, a Geographic Information System, and following the methodology described for H_2AT in Chapter 4. Figure 39 shoes the spatial allocation of the four main OCTA fleet bases.

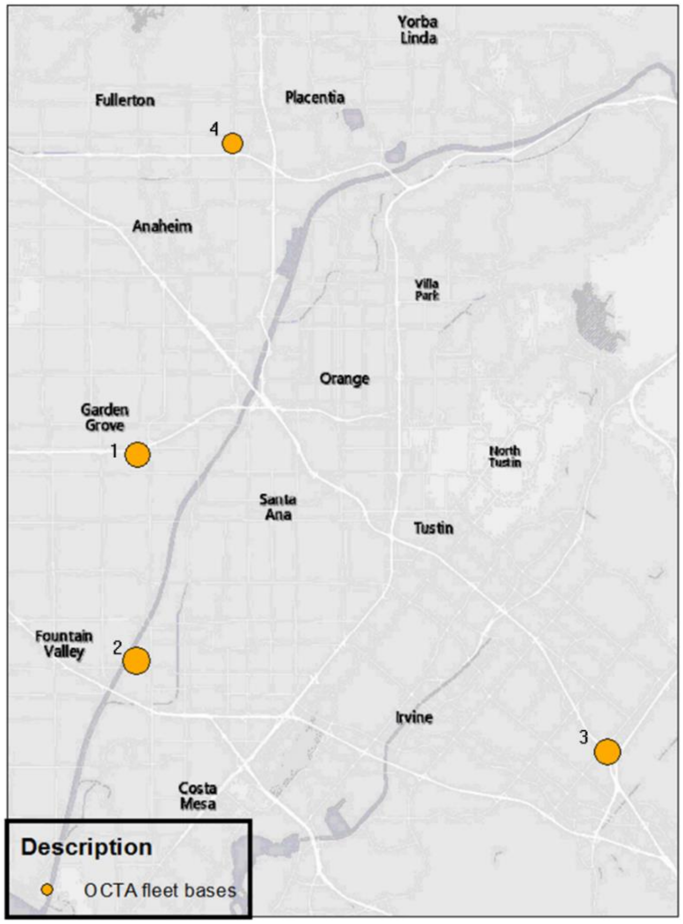
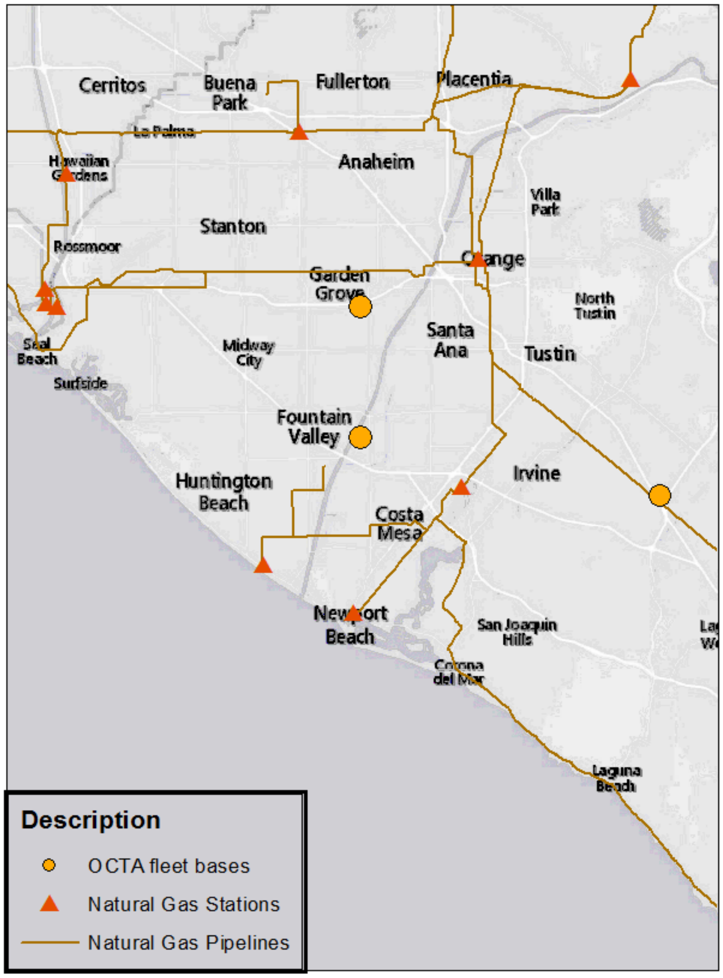


Figure 39: Spatial allocation of OCTA bases

H_2AT then evaluates the proximity of the fleet bases to natural gas pipeline distribution systems (Figure 40) for the following reasons:

- Immediate access to a natural gas pipeline will more easily allow large onsite hydrogen generation via natural gas steam reformation.
- Natural gas pipelines can serve as corridors for future hydrogen pipelines.



*only showing pipelines with a diameter bigger than one inch.

Figure 40: Spatial allocation of OCTA and Natural Gas infrastructure

A third step is the evaluation of the proximity of the maintenance/fueling bases to current hydrogen production facilities. This analysis estimates the length of hydrogen pipeline and/or the distance that tube trailers would travel to deliver the hydrogen. Hydrogen, generated at refineries for the production of gasoline, can be trucked or delivered by pipeline to the OCTA. As a result, the identification of nearby refineries is important in determining possible hydrogen sources. Figure 41 shows the spatial allocation of the refineries in reference to the fleet bases.

The location of f wastewater treatment plants and landfills that have a large potential for hydrogen production from the biogas are also located. This is of special relevance because it represents a renewable source for hydrogen production and provides estimated distances for pipelines and/or route distances for tube trucks. Figure 42 presents this spatial allocation.

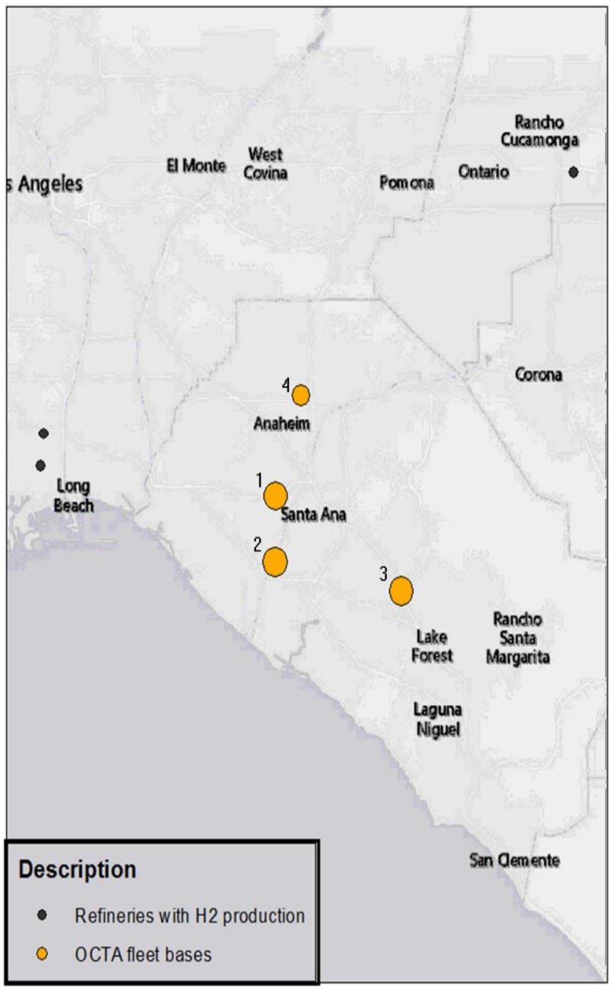


Figure 41: Spatial allocation of OCTA and nearby refineries

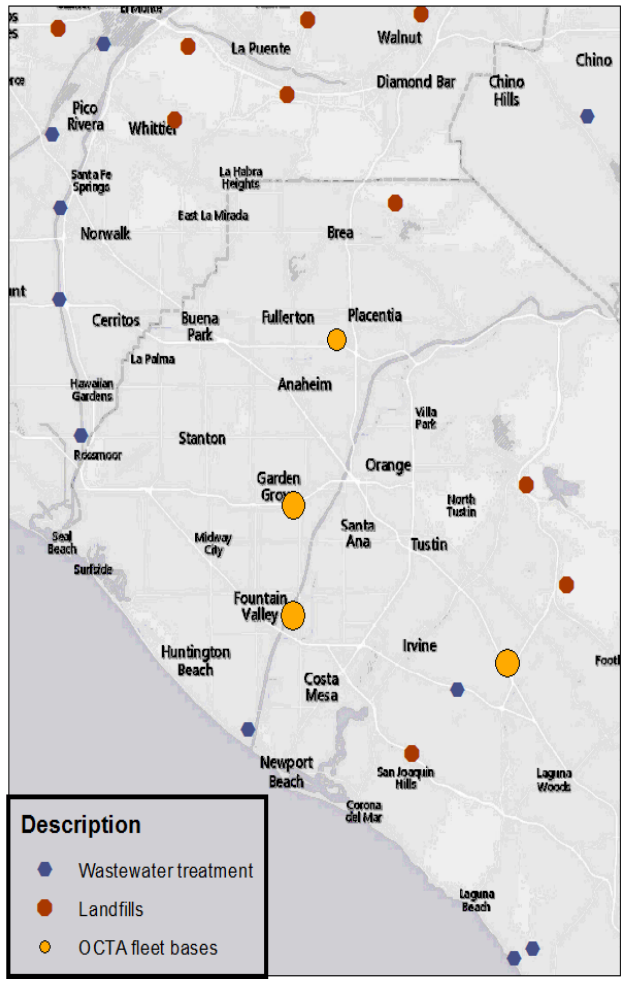


Figure 42: Spatial allocation of OCTA and nearby WWT and Landfills

Finally, once H_2AT has identified all the nearby hydrogen sources and potential feedstock locations, the ideal location for the hydrogen fueling stations is established considering the following criteria:

- Evaluation of all the fleet bases' location and the number of buses per base
- Shorter distance between bases and:
    - Natural gas pipelines
    - Existing refineries
    - Wastewater treatment with biogas potential that exceeds the amount of feedstock needed to satisfy the hydrogen demand of the transit agency
    - Landfills with biogas potential that exceeds the feedstock needed for transit agency's hydrogen demand.
- Possible bus reassignment from small to larger bases.

The same type of analysis can applied to any desired transit agency when the input information is available. Based on the described procedure, bases 1, 2 and 3 are more accessible to refineries and biogas sources than Base 4. Additionally, from a generation viewpoint, a low hydrogen demand has higher investment cost resulting in higher cost per kilogram of hydrogen. Therefore, Base 1 with only 52 buses would have a substantial higher hydrogen price than the other bases. The recommendation that can result from the tool is to reassign the buses from Base 4 to Base 1. The results of the reassigned buses and hydrogen demand are shown in Table 43.

Table 43: OCTA fleet reassignment and total hydrogen demand

	# buses per base	Portion of buses at each base	H_2 Kg/ day
Base 1	201	36%	5,200
Base 2	195	34%	5,050
Base 3	172	30%	4,450
TOTAL	**568**	**100%**	**14,700**

Table 43 summarizes the locations for the roll-out red of hydrogen for OCTA, which can also be presented spatially as shown in Figure 43.

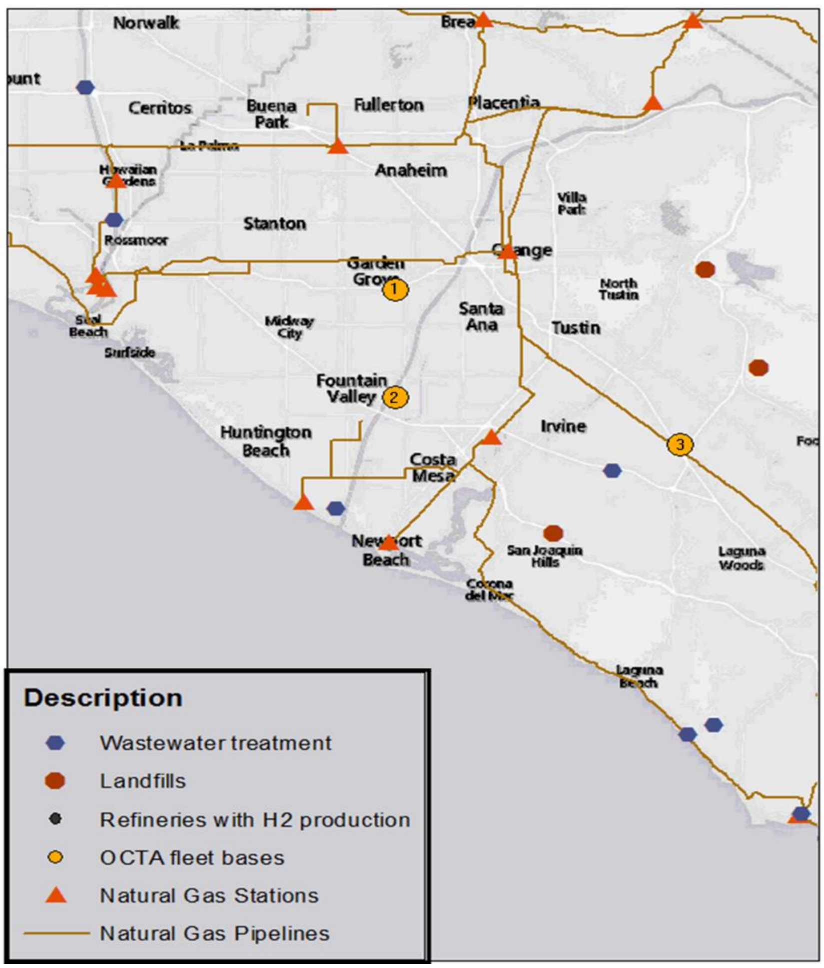


Figure 43: Roll-out red of hydrogen fueling stations for OCTA

This analysis-methodology also identified the following best-case scenario length of hydrogen pipelines going from the locations that have the capacity to satisfy the agency's fuel demand to the three major bases (Table 44).

Table 44: Possible hydrogen pipeline scenarios for OCTA bases

Hydrogen Generation Location	Generation type	Covered bases	Minimum pipeline length (Miles)	Maximum pipeline length (Miles)
El Tesoro / Air Products, Wilmington	Centralized SMR from refinery	**1, 2, 3**	52	58
El Tesoro / Air Products, Wilmington	Centralized SMR from refinery	**1, 2, 4**	34	38
Orange County Sanitary District	Centralized SMR with biogas from WWT	1, 2, 3	26	32
Frank R. Bowerman SLF	Centralized SMR with biogas from Landfill	1, 2, 3	24	30
OCTA, Base 1	Distributed Generation from one base to the others	1, 2, 3	18	24

Similarly to Table 44, the analysis-methodology can generate the traveled distance of tube trucks needed deliver hydrogen from sources (e.g., refineries or other centralized hydrogen plant) to the three transit agency bases. This distance is calculated assuming the most common route using freeways and main streets in the state of California. Table 45 shows the distance from selected origins.

Table 45: Possible hydrogen truck delivery scenarios for OCTA bases

Hydrogen Generation Location	Type of hydrogen	Generation type	Covered bases	Travel distance (Miles)
El Tesoro / Air Products, Wilmington	Gas	Centralized SMR from refinery	1, 2, 3	**42**
Praxair Ontario	Liquid	Centralized SMR	1, 2, 3	**44**
Sacramento	Liquid	Centralized SMR from refinery	1, 2, 3	**434**

Results from Table 44 and Table 45 can be explored and used as additional criteria to create different supply chain scenarios of hydrogen for OCTA, or other transit agencies.

7.3.1. Assessment of space available at OCTA

The main objective of this analysis is to categorize the space available at each base that can be used to accommodate equipment of possible supply chain scenarios. For example, if a future scenario encompasses distributed generation with electrolyzers at each base, the base must have enough available space to accommodate the electrolyzer, hydrogen storage tanks, compressors and possible additional dispensers. The space availability is of special importance to transit agencies and will be a consideration in decision making when moving forward with zero emission bus technologies. The available space information can be an input for the tool but, if this is not available, it is possible to obtain the foot-print measurement of the current equipment that would be displaced (i.e., space of compressors, dispensers and liquid-storage). An example of this type of measurement is shown in Figure 44.

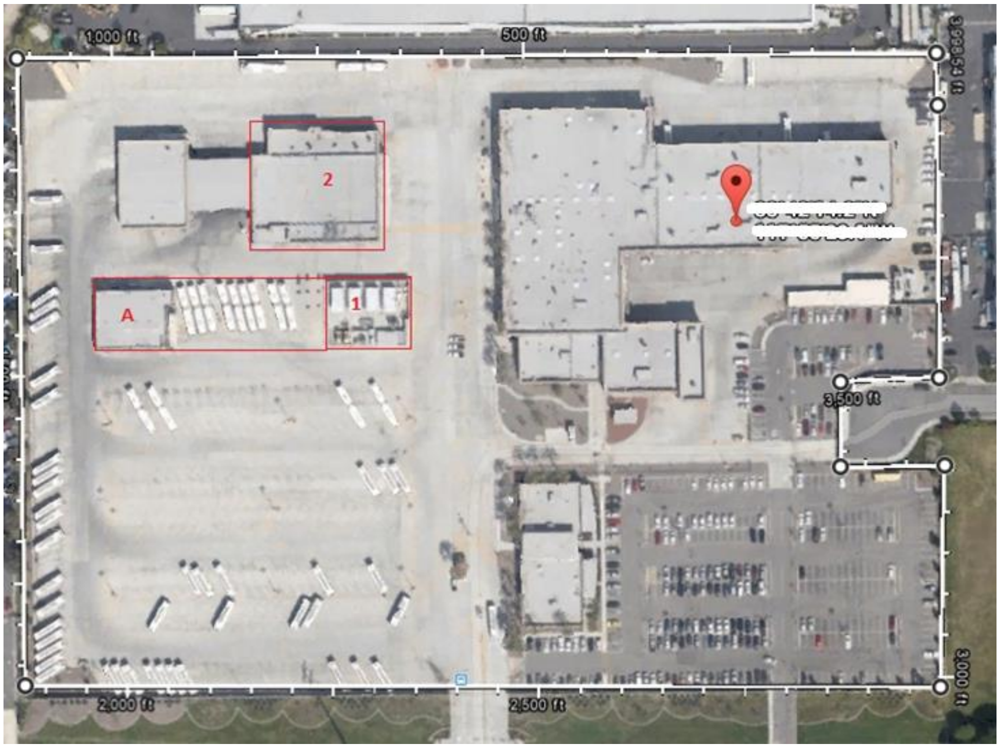


Figure 44: Footprint measurement of OCTA base 2

In Table 46, space measurements are presented for areas ("Available Sections") at Bases 1, 2, and 3 that are available (listed in order of priority relative to other Base needs) for new equipment.

Table 46: OCTA space requirements

	Compressors space (ft^2)	Dispenser space (ft^2)	Available sections A	Available sections B (ft^2)	Available sections C	Liquid Storage (ft^2)
Base 1	5,935	5,778	14,016	8,900	4,232	6,255
Base 2	6,450	4,248	12,472	6,828	5,851	3,671
Base 3	8,441	22,217	15,228	-	-	3,535

*A = space with low priority for other activities at the base and so on for B and C

For example, a section of the base with low priority for fleet activities would be current bus parking that is designated for out of service buses. This type of space could be reassigned to other bases or relocated among other sections in the same base.

Based on the hydrogen demand of 14,700 kg/day, H_2CAT establishes that a maximum of either (1) three SMR units of 3.5MW LHV, (2) four electrolyzers of 4MW or (3) the combination of these units would be enough to satisfy the hydrogen demand with on-site generation. Based on industrial description available for each of these units, it was possible to identify the required space for on-site generation and for the hydrogen storage [19], [95].

In Table 47, results of the foot-print required for supplying the hydrogen from either distributed SMR units or electrolyzers at each base are presented. For all the bases, the available space is more than the space required for storage and for distributed generation equipment (either SMR or electrolysis).

Table 47: Space requirements for distributed generation of hydrogen using SMR or electrolyzers

	Fleet Proportion	Compressors space ft^2	Dispensers space ft^2	Available sections ft^2			Liquid Storage ft^2	SMR+ ft^2	Electro++ ft^2	Storage ft^2
Base 1	46%	5,935	5,778	14,016	8,900	4,232	6,255	3,500	7,125	4,664
Base 2	28%	6,450	4,248	12,472	6,828	5,851	3,671	3,500	7,125	2,738
Base 3	26%	8,441	22,217	15,228	-	-	3,535	3,500	-	2,636

+ 2,550 kg H2/day (3.5 MW, H_2 LHV)

++ 2,800 kg H2/day (4 MW, H_2 LHV)

7.4. Defining preferable components of the hydrogen supply chain

This section analyzes some of the individual hydrogen supply chain components in order to determine which of such components has more impact in the well-to-wheels emissions. In the following section the results from this analysis is used to consider the different mix and match to find preferable supply chains.

7.4.1. Hydrogen scenarios constraints

From the space assessment it was determined that only 3 out of the 4 current OCTA bases have the potential to transition to hydrogen fueling stations due to the hydrogen demand magnitude and for their proximity to hydrogen sources like refineries, wastewater treatment plants and landfills.

The three selected bases reveal potential for several hydrogen infrastructure scenarios based on their spatial distribution:

- A centralized hydrogen scenario with production from the nearest refinery would require a pipeline length of 38 miles or a one-way travel distance of 42 miles for delivery of gaseous hydrogen using tube trucks.
- A pipeline length of 18 miles would interconnect the three OCTA fleet bases.
- A centralized production of liquid hydrogen requires a maximum one way travel distance of 434 miles to supply all three bases if the hydrogen travels from Sacramento.
- A centralized hydrogen production at the nearest wastewater facility and from a landfill would require a pipeline length of 26 and 24 miles, respectively.

- The space available at each of the selected hydrogen fueling locations is sufficient to accommodate distributed generation equipment. The current space used for dispensers and storage would be sufficient to accommodate the equivalent equipment to supply hydrogen.

With these considerations, H_2CAT allows the design and analysis of diverse hydrogen supply chains from the different components (Figure 23).

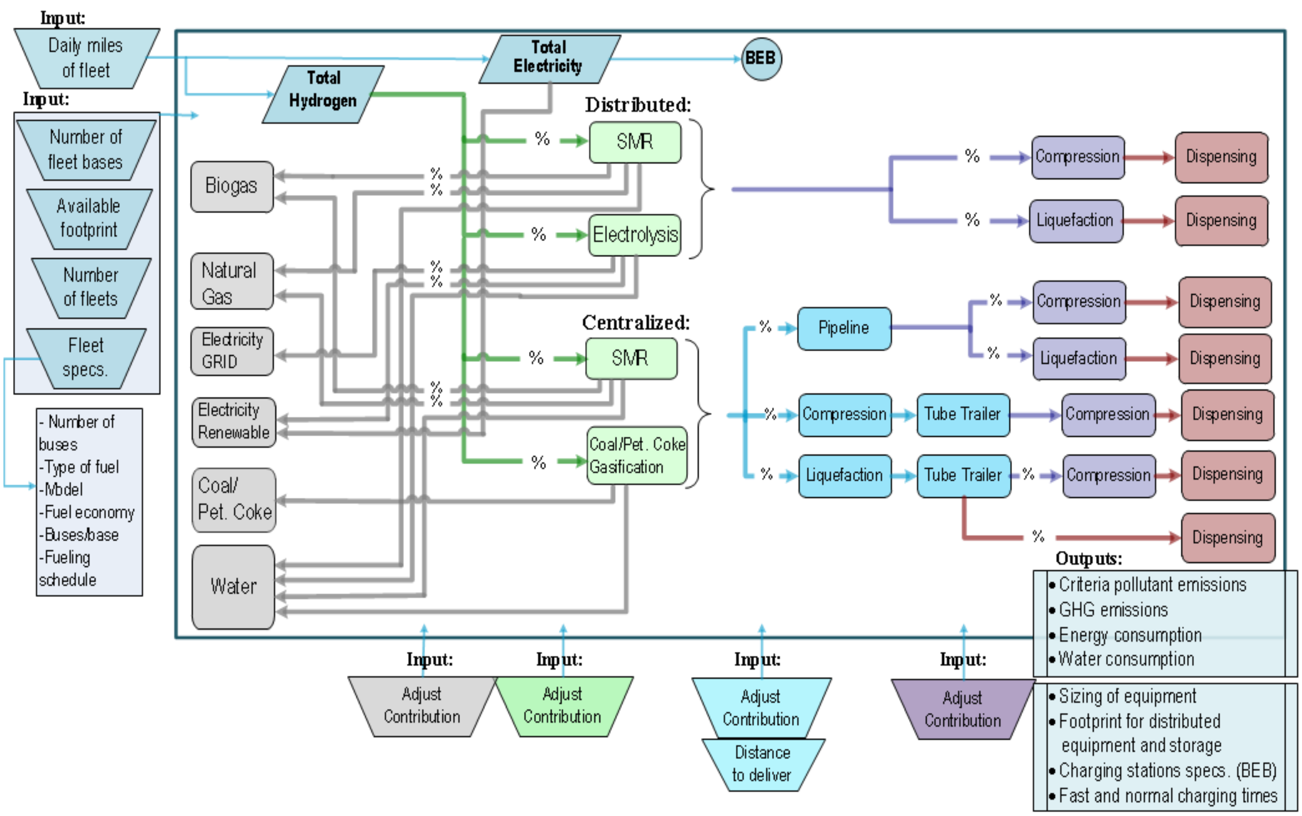


Figure 23: Modified PCA tool for Transit Buses – H_2CAT

Each individual component of the hydrogen supply chain can be combined in their contribution percentages to generate hundreds of hydrogen infrastructure options. In order to find preferable scenarios, some of the hydrogen supply chain components were individually analyzed and later combined into complete hydrogen infrastructure options. Additionally, the following constraints were set for the selection of scenarios:

- 33% of the hydrogen needs to be sourced from renewable sources (by California law)
- The process to produce hydrogen needs to release 30 percent fewer greenhouse gas emissions (GHG) as compared to the current fuel used by the transit agency on a well-to-wheel basis

From previous research, producing hydrogen from pet coke and coal gasification, even with carbon capture and sequestration (CCS), shows less emissions offset than hydrogen produced from natural gas using SMR [62] [63]. As a result, these generation technologies were not considered as components for OCTA hydrogen supply chain scenarios.

The main generation technologies considered were (1) steam methane reformation, and (2) electrolysis. These technologies can be combined with a differing percentage of contribution to produce the hydrogen, and differing percentage of contribution from various feedstocks including natural gas or biogas for the SMR, and regular grid power or renewable electricity to power the electrolyzer.

A higher contribution of renewable feedstock will generate fewer emissions but will also increase the cost of hydrogen. Based on the 33% renewable hydrogen constraint, the tool first compares which generation technology releases less emissions, and then the tool finds the penetration level of renewables that the California grid needs to reach to reduced emissions when electrolysis is compared to other generation pathways.

7.4.2. SMR vs Electrolysis: ideal renewable penetration of California grid to power electrolysis

Some private initiatives in the United States are trying to eliminate the use of natural gas as a transition fuel to cleaner technologies. However the early electrification of a specific process can be more harmful from an environment perspective if the grid mix still relies on coal or other fossil fuels to generate electricity during the transition process [106]. This is the case for hydrogen generation using grid powered electrolysis in comparison to steam methane reformation using natural gas in 2016.

To demonstrate which feedstock and generation technology is preferable to use as a transition to full renewable hydrogen production, H_2CAT is used to compare three hydrogen scenarios for OCTA using the constraints described above and adopting the same distribution channel path for all the scenarios. Since the purpose is to identify the percentage of renewable penetration for the California grid that will equal the emissions of using SMR, these scenarios are named California Grid (CAG) scenarios.

- Scenario 1 (CAG1): 33% renewable hydrogen generated from landfill biogas and 67% from natural gas using steam methane reformation (SMR). Distributed by pipeline from a central refinery with less than 40mi pipeline interconnection.
- Scenario 2 (CAG2): 83% hydrogen from renewable sources to power electrolysis and 17% from electricity of the California grid also for electrolysis. The current California grid has a 38% renewable penetration [51], therefore the 17% of the hydrogen generated from the grid adds an extra 6.5% renewable hydrogen for a total of 90% green hydrogen. Distributed by pipeline from a central facility with less than 40mi pipeline interconnection.

- OCTA Scenario 3 (CAG3): 100% hydrogen from electrolysis powered by electricity from the California grid, for a total of 38% renewable hydrogen. Distributed by pipeline from a central facility with less than 40mi pipeline interconnection.

The technology mix for the generation technologies in scenario CAG2 is the result of H_2CAT finding the optimal renewable penetration to the California grid to minimize criteria pollutants and GHGs to the same level compared to scenario CAG1.

Figure 45 presents how the three scenarios with very different portions of renewable hydrogen can release similar emissions quantities. In the set of figures, graph A and B characterize the supply chain for each scenario. In Figure 45- A, the emissions baseline (Scenario 0) from OCTA is presented.

Figure 45- B describes all the scenarios evaluated that use pipeline as the distribution pathway from the centralized hydrogen production facility.

Figure 45- C and D provide the emissions associated with each scenario from a well-to-wheels basis. For the two scenarios, the particulate matter and the equivalent CO_2 metric tons are comparable even when 90% of the hydrogen is coming from renewable sources for scenario CAG2, almost three times more renewable hydrogen than for scenario CAG1.

The large amount of emissions from scenario CAG2 is due to producing electricity using the grid even when the electricity from the grid used to produce hydrogen is only 20% of the total required electricity (121,172 KWh per day).

As shown in Figure 45, the grid requires a 90% renewables penetration in order to be beneficial using grid powered electrolysis over SMR with only 33% renewable hydrogen in order to satisfy the hydrogen demand at OCTA. Additionally, Figure 45-D shows that with the current California grid mix, using the grid to produce hydrogen (scenario CAG3) will generate 74% more CO_2 equivalent than using natural gas and biogas as feedstock for SMR units (scenario CAG1). During the transition to a full renewable grid, using natural gas to produce hydrogen through SMR provides more benefits than using the grid to produce hydrogen through electrolyzers.

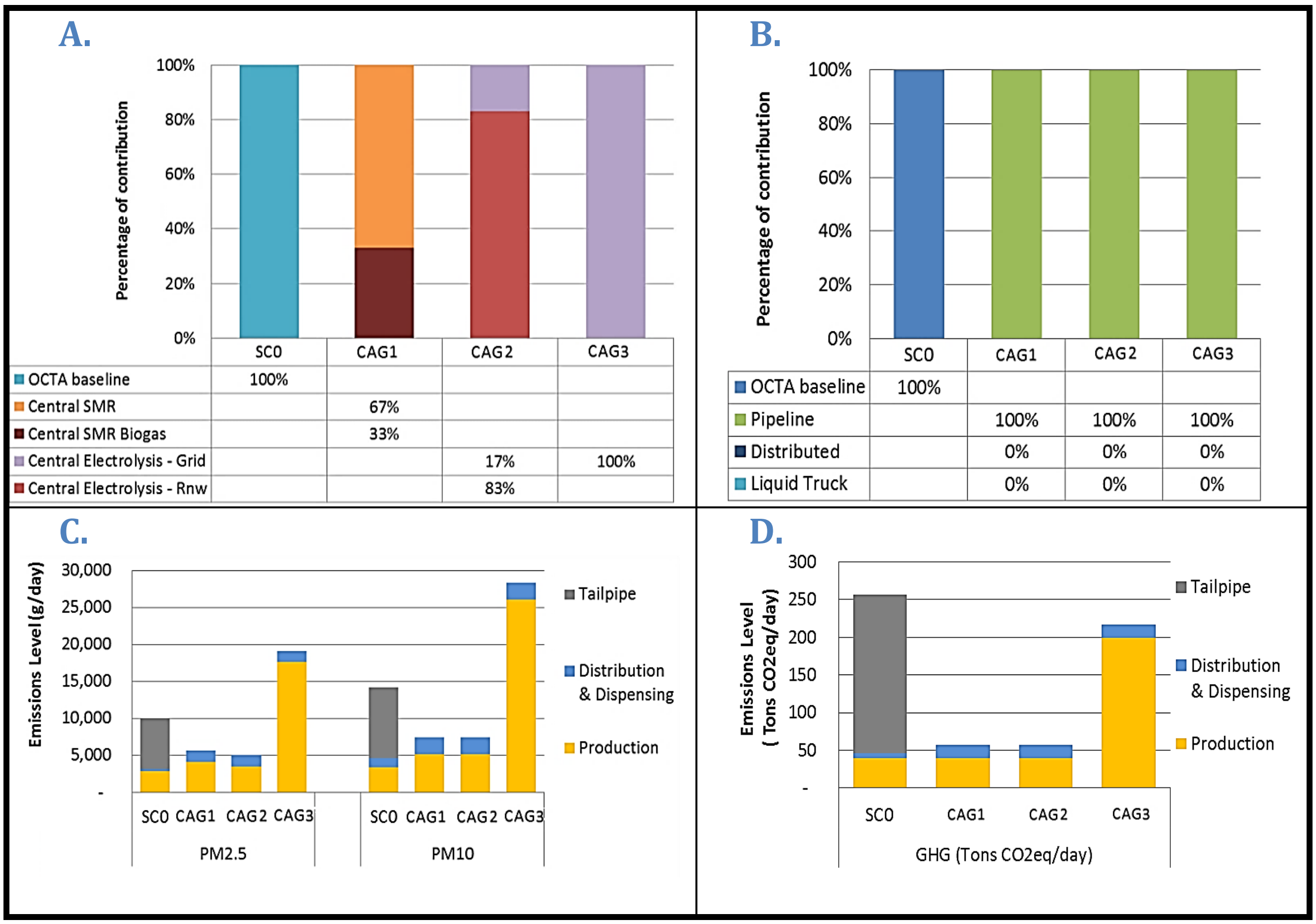


Figure 45: Hydrogen scenarios with comparable emissions for Centralized SMR (CAG1: 33% renewable H_2) and Centralized electrolysis (CAG2: 90% renewable H_2) in comparison to 100% grid-powered electrolysis (CAG3: 38% renewable H_2).

Figure 46 shows the water withdrawal and water consumption associated directly and indirectly activities at OCTA in comparison to the other three hydrogen scenarios.

Figure 46-A shows that only CAG1 increases water withdrawal (11% from the baseline), while CAG2 and CAG3 would create an increase of 87% and 94%, respectively. For all the hydrogen scenarios, there is an increase in the water consumption with respect to the baseline with CAG1 with less increment. A large portion of the increase associated with CAG3 is due to the water withdrawal and consumed in indirect activities while generating electricity from hydroelectric and geothermal power plants (grey bars in figures). The water requirement can be mitigated by having a larger penetration of renewable electricity from solar and wind sources into the California grid. The water for indirect use (grey bar) in CAG2 is the water used to generate electricity through the grid that is needed to distribute the water for direct use to a centralized electrolysis plant.

The water directly used for CAG2 and CAG3 (orange bars) is directly associated with the water needed for the electrolysis process of 2.97 gal/kg of hydrogen for a centralized process [76].

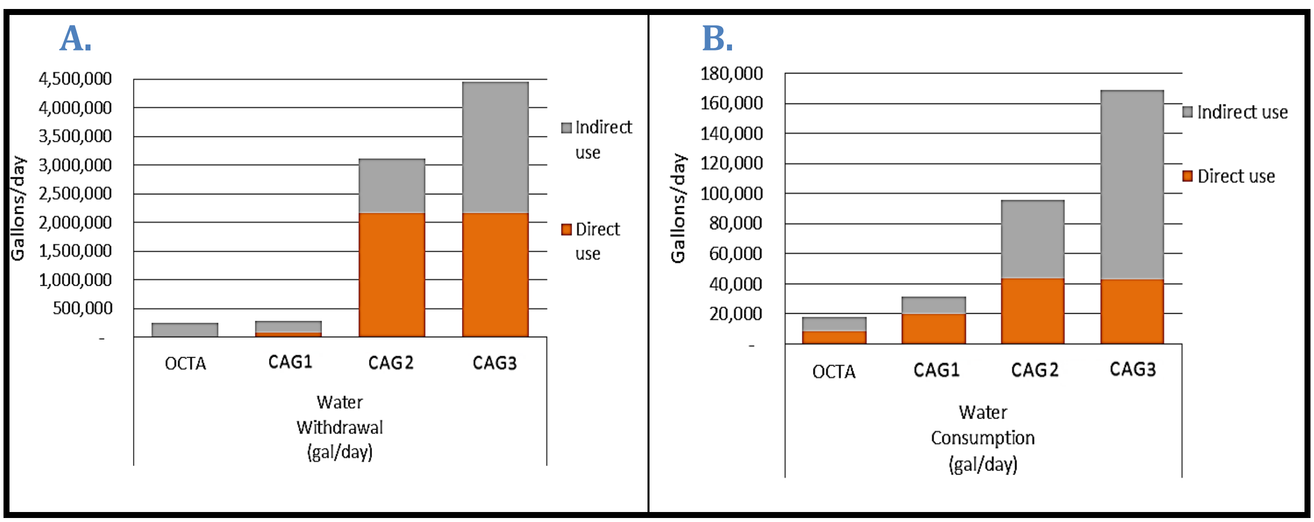


Figure 46: Water withdrawal and consumption for Centralized SMR (CAG1: 33% renewable H_2), Centralized electrolysis (CAG2: 90% renewable H_2) and 100% grid-powered electrolysis (CAG3: 38% renewable H_2).

7.4.3. Minimizing emissions from distribution pathway

Previous papers have demonstrated that the use of pipelines is the ideal pathway to deliver hydrogen for dense areas with large hydrogen demand [107]. To demonstrate that the hydrogen demand at OCTA allows for a maximization of environmental benefits, the factors that were found as most important in determining hydrogen transmission and distribution costs in the Yang C. study [107] were applied to develop the following three hydrogen scenarios for OCTA. The selected scenarios have the same generation technology but vary in the distribution pathway (DP) in order to identify the distribution technology that minimizes emissions for the activities at OCTA.

- Scenario 1(DP1): 33% renewable hydrogen generated from landfill biogas and 67% from natural gas using steam methane reformation (SMR). Distribution by pipeline from a central refinery with less than 40mi pipeline interconnection.
- Scenario 2 (DP2): Same production technology mix and for the delivery pathway 50% is delivered via pipeline with 50% with liquid trucks.
- Scenario 3 (DP3): 33% renewable hydrogen generated from landfill biogas and 67% from natural gas using steam methane reformation (SMR) but 100% of the hydrogen is delivered using liquid trucks.

Distribution of hydrogen as a gas using tube trucks was not considered as a pathway since it would require more than 3 tube trucks per day coming in and out of the fleet to supply 35 buses, which represents only 6% of OCTA's fleet. (See the following chapter for more detail about this type of calculation.)

Figure 47 shows the emissions for the OCTA scenarios compared to the OCTA baseline.

Figures-A and B show a description of the scenarios supply chain. Since the three scenarios have the same generation technology mix, the production emissions (yellow bars of graphs) will all be the same and the variant will only be the blue bar or distribution and dispensing bar. Tailpipe emissions refer (grey bar) to the emissions exhausted from the buses when they are in service. Note that emissions are not generated when using hydrogen buses.

For all the criteria pollutants (NOx, VOCs, PM, N_2O and CO), except for SOx, the three scenarios reduce emissions in comparison with the baseline. The higher the percentage of hydrogen that is delivered by liquid trucks, the higher the emissions in the case of SOx, an increase occurs due to the portion of electricity that is generated from coal plants and tailpipe emissions from the trucks that are used to deliver the hydrogen. The lowest impact is from the conveyance of hydrogen in dedicated pipelines (Figure 47-H).

Based on these results, the next chapter establishes the optimal number of buses that are needed to justify an investment in a dedicated pipeline over liquid trucks for the distribution pathway. .

Note, should cleaner vehicles be used to deliver hydrogen, a large portion of the tuck emissions would be eliminated. The liquefaction of hydrogen requires a high demand of electricity which, if generated from the current grid-mix, would result in a higher level of emissions in contrast to the pipeline conveyance of hydrogen.

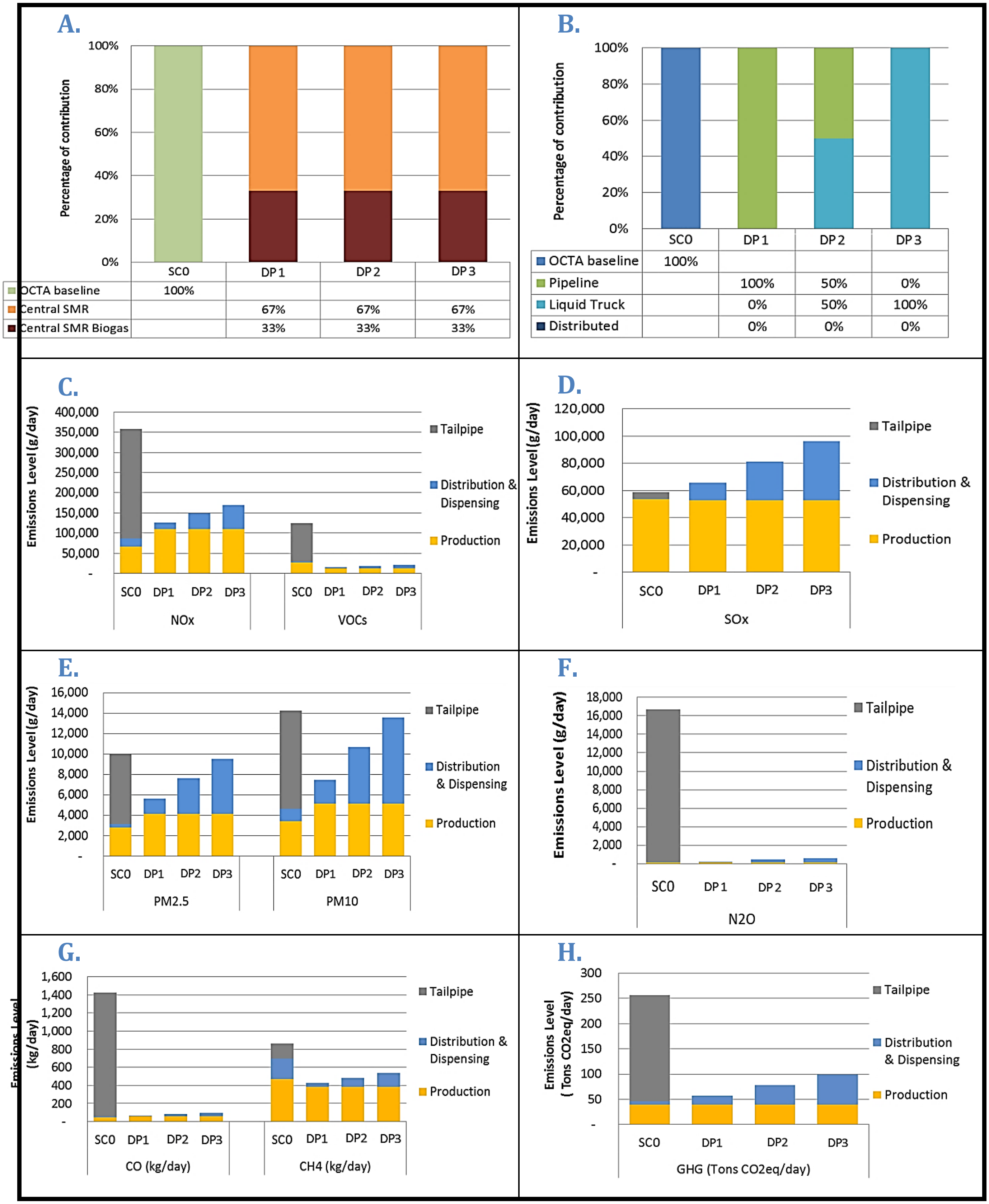


Figure 47: Analysis of emissions associated with different distribution pathways for centralized SMR hydrogen production scenario

7.4.4. Renewable hydrogen scenarios

Now that it is determined that pipeline distribution pathways are preferable and that at least 90% renewable hydrogen from electrolysis is needed to have comparable emissions to the use of SMR (with 33% hydrogen from biogas), the last step to identify preferable hydrogen scenarios in order to determine which source of renewable hydrogen that provides the best environmental benefits. To do so, three new scenarios with different types of renewable sources were designed and compared. Renewable hydrogen (RH) from electrolysis was compared to hydrogen produced from landfill biogas and the same distribution pathway was assigned to the 3 scenarios to normalize emission from distribution and dispensing:

- Scenario 1 (RH1): 100% renewable hydrogen generated from landfill biogas using steam methane reformation (SMR). Distributed by pipeline from a central refinery with less than 40mi pipeline interconnection.
- Scenario 2 (RH2): 100% renewable hydrogen generated from electrolysis by using either solar panels or wind turbines. Distributed by pipeline from a central plant with less than 40mi pipeline interconnection.
- Scenario 3 (RH3): 50% renewable hydrogen generated from SMR with biogas and 50% from renewable electrolysis. Distributed by pipeline from a central plant with less than 40mi pipeline interconnection.

Figure 48 from C to G shows how criteria pollutants are reduced in comparison to the current emissions. SOx emissions are of particular interest since, in the other scenarios, these emissions increase with respect to the baseline. The main reduction is associated with the offset of SOx emissions that occur naturally when biogas is produced and because there are not SOx emissions associated with electricity from solar or wind.

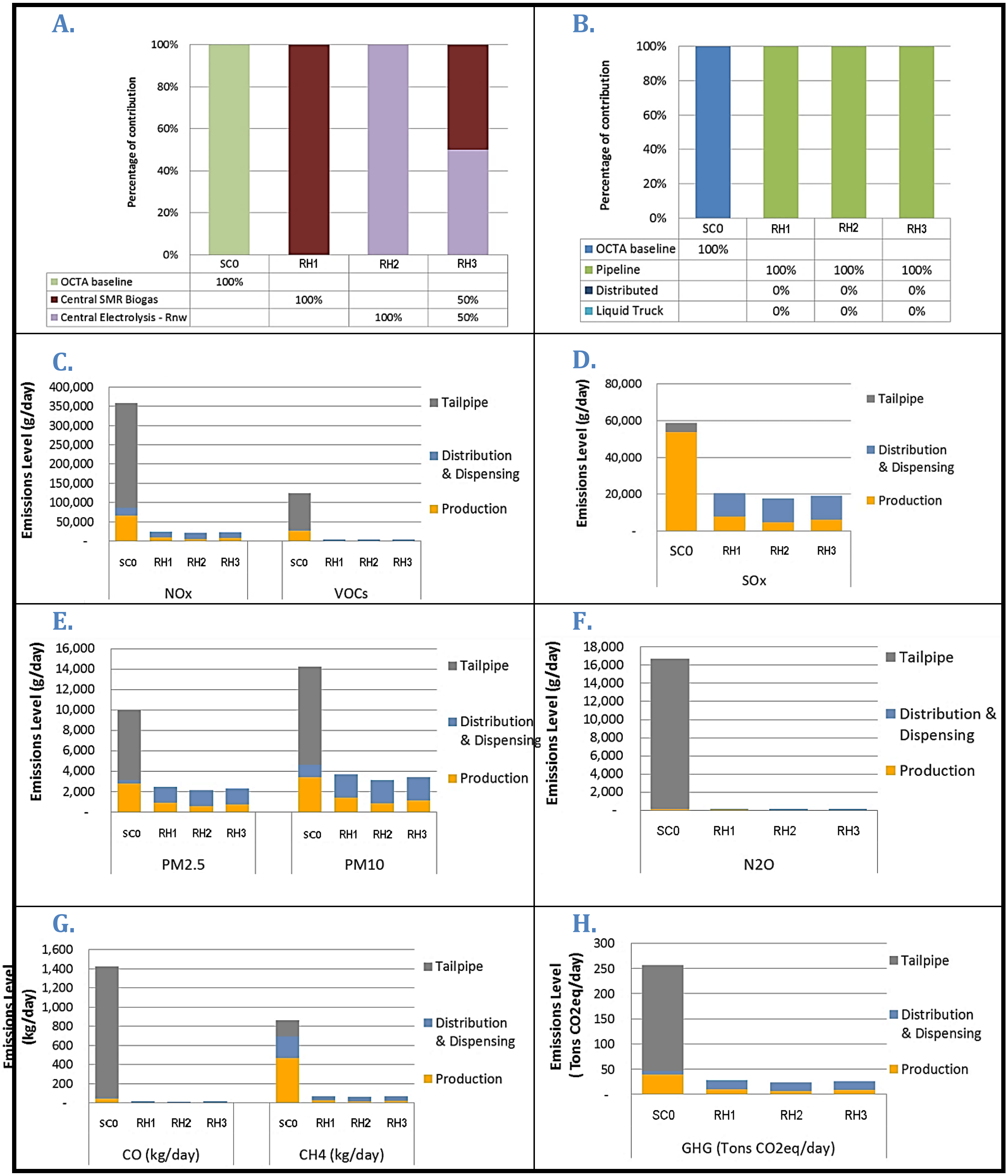


Figure 48: Hydrogen infrastructure scenarios with different sources of renewable hydrogen; RH1 Renewable biogas, RH2 Renewable electricity, RH3 50-50% of the last two.

From the emissions of criteria pollutants, producing 100% of the hydrogen from biogas with SMR is equivalent to produce the hydrogen using a mix of 50% renewable electrolysis and 50% biogas. This represents an opportunity to minimize cost since capital cost of SMR is significantly lower than from electrolysis [79], [82].

When analyzing the GHG emission of renewable hydrogen scenarios from Figure 48, all the scenarios reduce emissions by 89% or more with respect to the baseline. The technology that minimizes emissions the most is RH2, H_2 produced 100% from renewable electrolysis, but only by a 15% difference with respect to RH1 and an 8% with respect to RH3 (Figure 49)

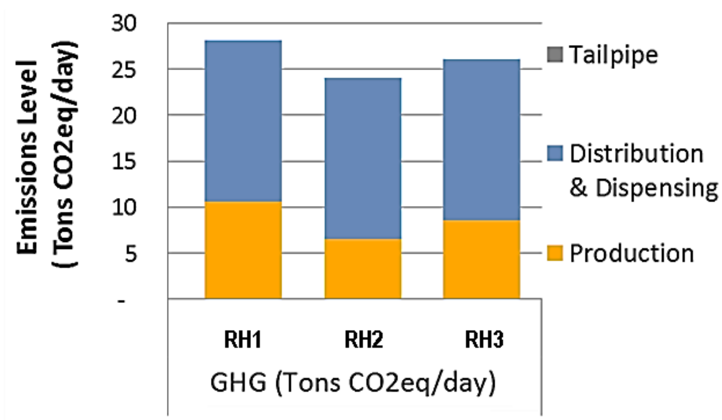


Figure 49: Close-up of Figure 48-H without base case scenario

The capital cost of renewable electricity and electrolysis is considerably higher than other hydrogen generation technologies [91], but it is a desired pathway for hydrogen generation due to their overall emissions mitigation. This analysis shows that the mix of renewable electrolysis with biogas SMR only has 8% difference in its GHG emissions, suggesting that potential reductions on capital cost can be reached by having equal environmental benefit by combining the two renewable pathways.

7.5. Preferable hydrogen infrastructure scenarios for OCTA

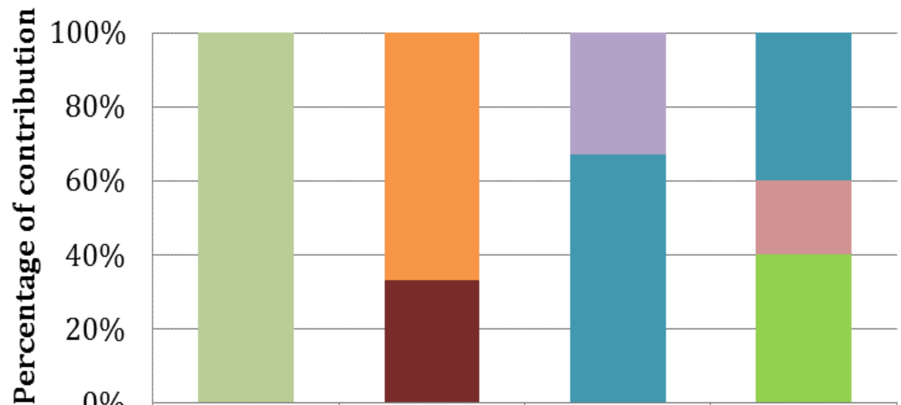
After individually analyzing components from the hydrogen supply chain and considering the previously described constraints, three scenarios were designed as the preferable hydrogen infrastructure options for OCTA. H_2CAT was then used to analyze the emissions and resources consumed by such scenarios.

The preferable scenarios (PS) for OCTA hydrogen infrastructure are:

1. Scenario 1 (PS1): Steam methane reformation used to generate 33% renewable hydrogen from landfill biogas and 67% hydrogen from natural gas. Distribution using pipelines from a centralized location that would require a pipeline length of less than 40 miles.
2. Scenario 2 (PS2): 33% renewable hydrogen generated from centralized electrolysis using either solar or wind electricity and 67% of the hydrogen produced from a distributed SMR unit with natural gas as the feedstock. From the centralized electrolysis plant the hydrogen is transported to the bases as a liquid using tube trucks, assuming a trip of 150 miles.
3. Scenario 3 (PS3): A full distributed scenario with 40% of the hydrogen generated from SMR with natural gas, 20% from electrolysis powered by solar/wind electricity and 40% using grid powered electrolysis. The scenario has a total of 35% renewable H_2.

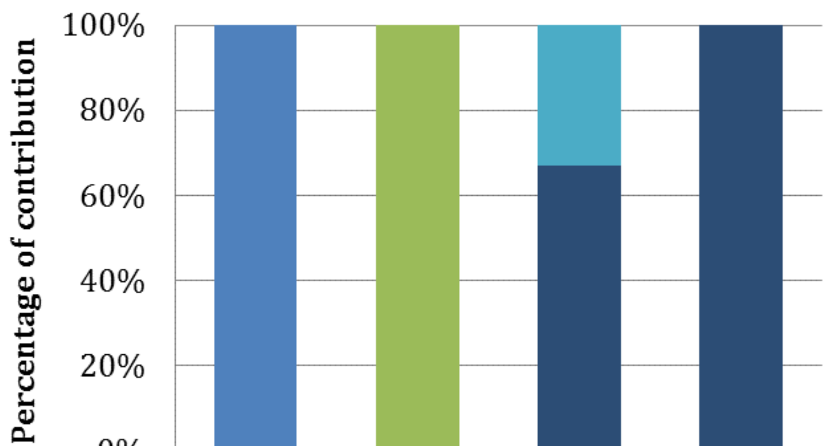
Figure 50 shows a graphical description of the generation technology mix and distribution pathways for each hydrogen scenario.

A.



	OCTA	PS1	PS2	PS3
OCTA baseline	100%			
Central SMR		67%		
Central SMR Biogas		33%		
Central Electrolysis - Rnw			33%	
Distributed SMR			67%	40%
Distributed Electrolysis- Rnw				20%
Distributed Electrolysis- Grid				40%

B.



	OCTA	PS1	PS2	PS3
OCTA baseline	100%			
Pipeline		100%	0%	0%
Liquid Truck		0%	33%	0%
Distributed		0%	67%	100%

Figure 50: Characterization of preferable hydrogen infrastructure scenarios for OCTA

The selection of distributed hydrogen generation for the scenarios was based on both the available footprint at each base and current available electrolyzer specifications. One of currently available multi-megawatt electrolyzers has a max capacity of 2,800kg/day (4MW assuming low heating values - LHV) [108]. H_2CAT iterates to suggest the appropriate number of equipment given the available footprint, the iterations resulted that the OCTA bases can accommodate two 4 MW electrolyzers (H_2 LHV).

For PS2, distributed natural gas SMR accounts for 67% of the total hydrogen. The sizing of the on-site SMR equipment is calculated similarly. One of the largest distributed SMR units tested has a max capacity of 2,550 kg/day of hydrogen. The tool results suggested that three units better utilizes the available space at the OCTA bases.

For the on-site generated hydrogen (PS3), 35% is produced on-demand during fueling hours and the remaining is assumed to be storage at high pressure tanks (420 bars) to establish a power to gas energy storage system [22], [78], [109].

Directed biogas for the scenarios is purified bio-methane (methane/natural gas developed from waste water treatment plants for this scenario) that is assumed to be inject into the natural gas pipeline from the provider's location so that OCTA can take credit for such biogas.

For this study, the nearby waste water treatment plants (WWTP) and landfills were evaluated as possible directed biogas producers in Chapter 5. The first step was to determine the potential biogas that can be produced at each plant; this was accomplished utilizing a research tool being developed at the Advanced Power and Energy Program, UCI [110]. This tool is able to allocate the potential biogas and the proximity of the generation location to existing natural gas pipelines. The biogas needed as feedstock for one day of the OCTA hydrogen demand represents 35% of the biogas production at the Hyperion WWTP, which is located approximately 50 miles from the fleet bases.

For the scenarios considered, the results are presented from a well to wheel (WTW) analysis for:

- Criteria Pollutant Emissions.
- Greenhouse Gas Emissions.
- Water Consumption.
- Electrical Energy Consumption.
- Natural Gas Consumption.
- And Energy efficiency per mile basis.

7.5.1. Analysis of well-to-wheels emissions

When analyzing for the emission of criteria pollutants, each of the three scenarios results in a significant reduction in the emission of NOx and VOCs. Referring to Figure 51, PS1 yields the maximum in NOx and VOCs reduction with 65% and 88% emissions offset, respectively. PS3 results in the least emissions reduction due to emissions associated with the centralized SMR of natural gas; still this scenario reduces emission in comparison to the baseline by 54% for NOx and 82% for VOCs.

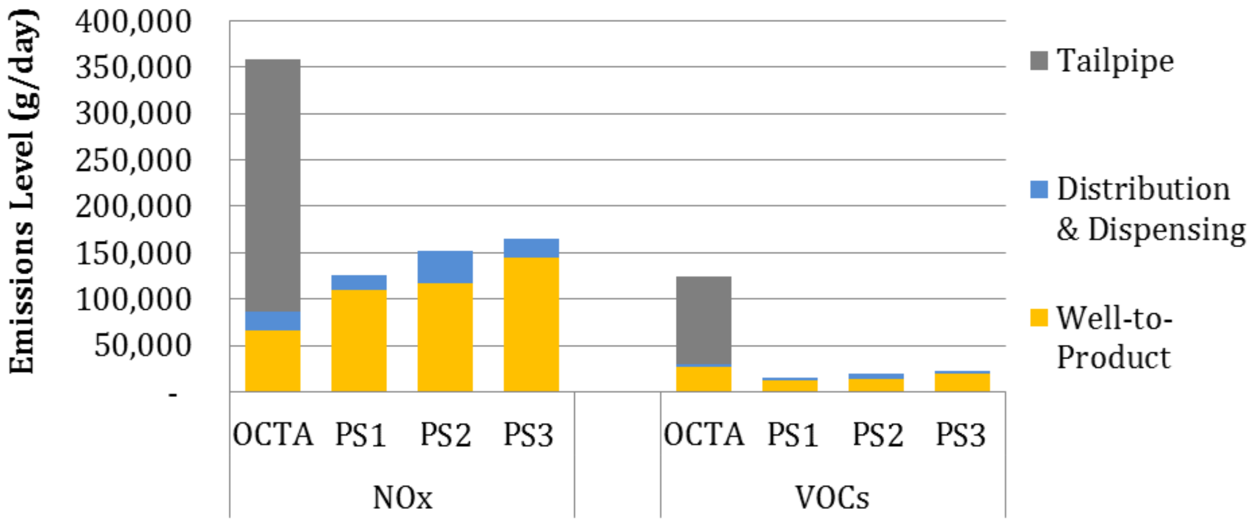


Figure 51: Well-to-Wheels NOx and VOCs emissions for preferable hydrogen scenarios

The WTW particulate matter emissions (PM2.5) for the base case, shown in Figure 52, are the major source is tailpipe emissions with 82% originating from using natural gas as fuel and 18% from diesel.

PS1 and PS2 present significant reductions of PM2.5, with most of the emissions generated in the hydrogen production process. Centralized SMR generates 74% of the total PM2.5 emission in PS2. PS3 resulted in an increase of PM2.5 with respect to the base line, mostly due to the production process from the supply chain. The indirect emissions from using the grid to power both the electrolysis and operations of the SMR units represent 83% of the total PM2.5 emissions for such scenario.

In Figure 52, the tendency for the hydrogen scenarios is the same for PM10, with PS3 resulting in an increase of this criteria pollutant. For PS1 and PS2, the major sources of PM10 emissions are associated with natural gas SMR plants (63% and 79%, respectively). For PS2, the impact from hydrogen distribution by diesel powered trucks is evident in the blue bar for PM2.5 and PM10, impacted also for the liquefaction process of that 33% portion that is generated from a centralized location. Noteworthy, these emissions emanate from centralized locations and further control measures could be applied more readily than in the control of tailpipe emissions. Secondly, distribution by clean trucks (e.g., fuel cell powered trucks) would substantially mitigate the emission of PM10.

Note that diesel as a fuel accounts for a high portion of PM10 tailpipe emissions in the baseline scenario (labelled as OCTA) even when diesel buses are only 5% of the bus fleet (from the 68% that tailpipe emission represent, 40% are due to diesel).

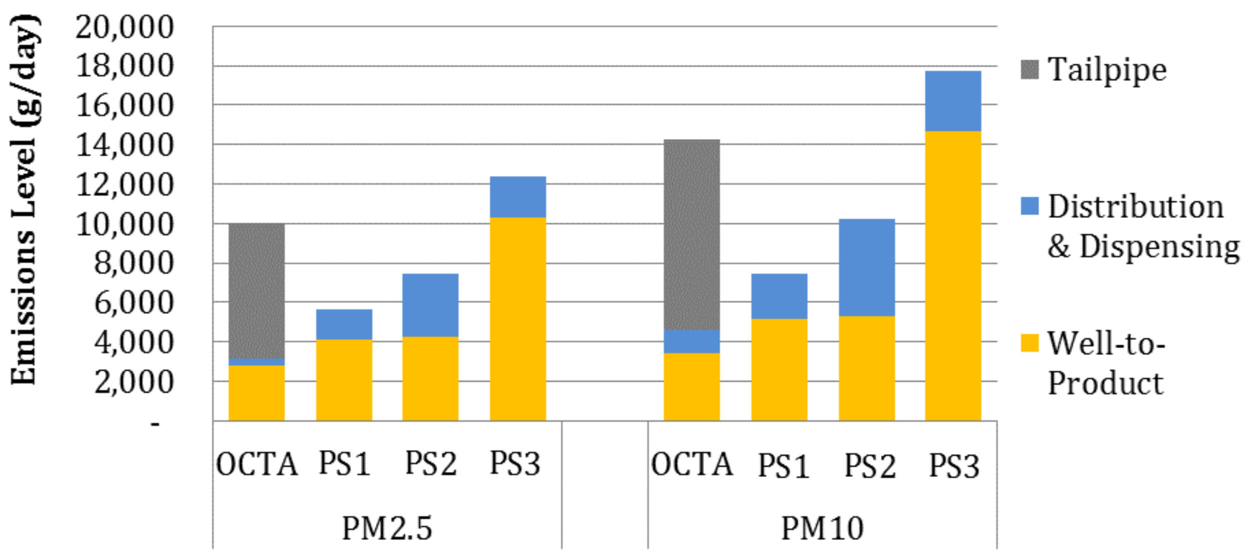


Figure 52: Well-to-Wheels particulate matter emission of preferable hydrogen scenarios

In Figure 53, all the scenarios show a large reduction in N_2O emissions when compared to the base case (OCTA): 99% emissions reduction with PS1, 98% reduction with PS2 and 96% offset of emissions with PS3. The opportunity to reduce such a large quantity of emissions is due to offset of tailpipe emissions from the baseline. The tailpipe emissions for OCTA were calculated for buses newer than 2008 but not more than 2010. As a result, the offset of N_2O emissions can be lower if newer buses are used for the base comparison.

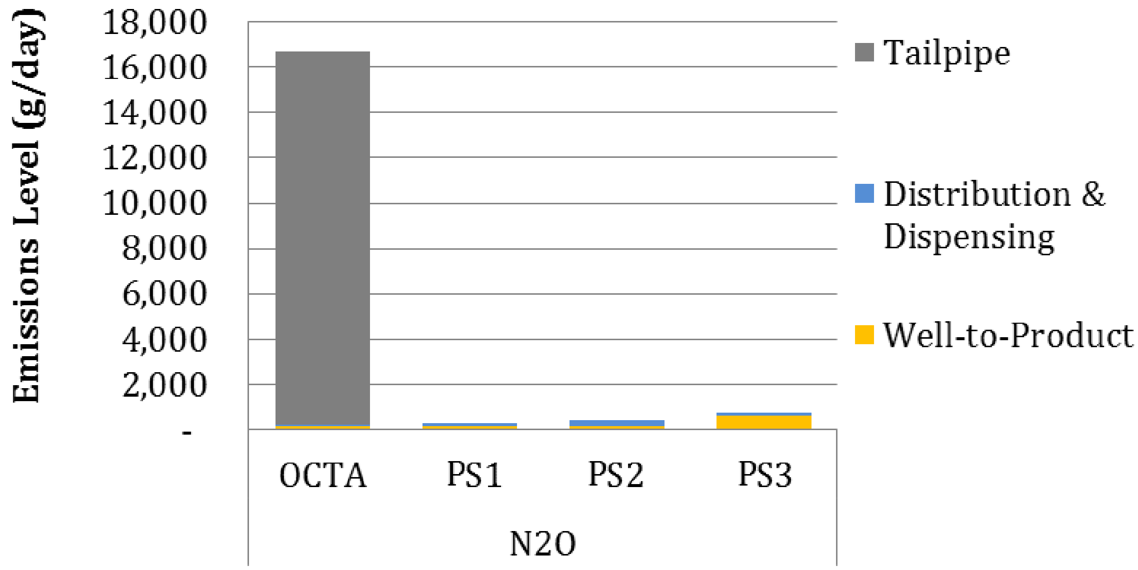


Figure 53: Well-to-Wheels N_2O emission of preferable hydrogen scenarios for OCTA

Figure 54 presents the WTW carbon monoxide emissions for hydrogen scenarios with all resulting in reductions of 93% or more associated with the offset of tailpipe emission from CNG, LNG and diesel buses.

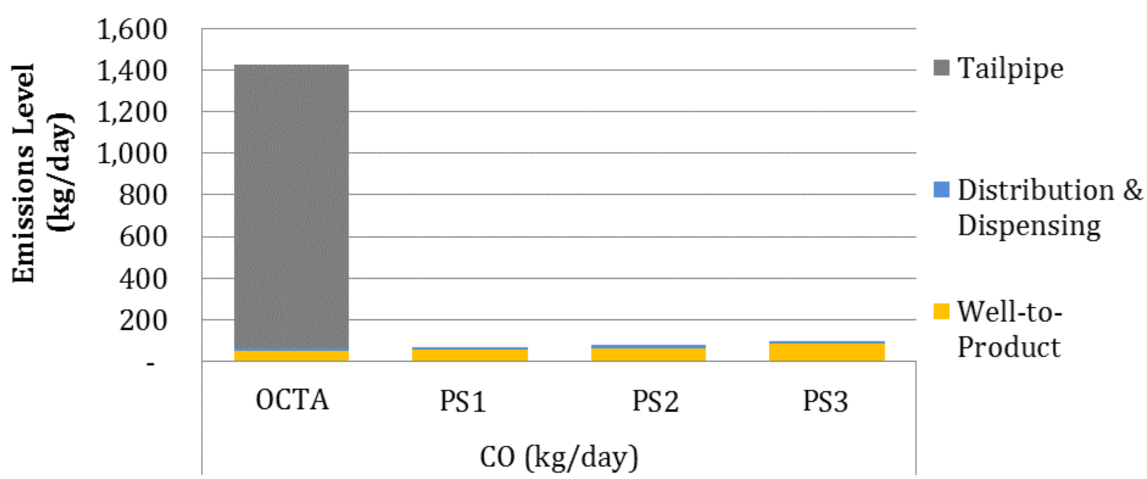


Figure 54: Well-to-Wheels CO emissions of preferable hydrogen scenarios for OCTA

Well to wheels SOx emissions, illustrated in Figure 55. PS1 (which encompasses the generation of hydrogen using 33% centralized SMR with biogas 67% from natural gas), presents the only reduction (9% less SOx emissions compared to the base case scenario).

The other two scenarios show an increase in the SOx emission associated with an increase in electricity from the grid. The electricity consumption for each scenario is presented in Figure 56 and correlates with levels of SOx emissions. In PS2, the increase of 16% in SOx emissions results from using the grid to liquefy the hydrogen so it can be transported form the renewable electrolysis centralized facility (red bars in Figure 56). For PS3, the increase in SOx emissions is almost 85% with the major source of emissions attributed to the use of grid electricity to power the distributed electrolysis (blue bars in Figure 56).

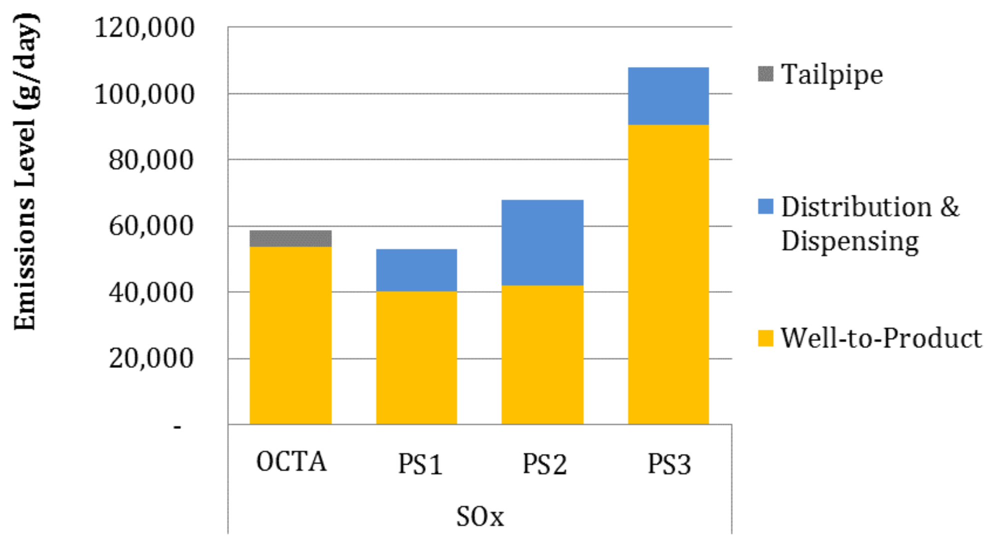


Figure 55: Well-to-Wheels SOx emissions of OCTA and preferable hydrogen scenarios

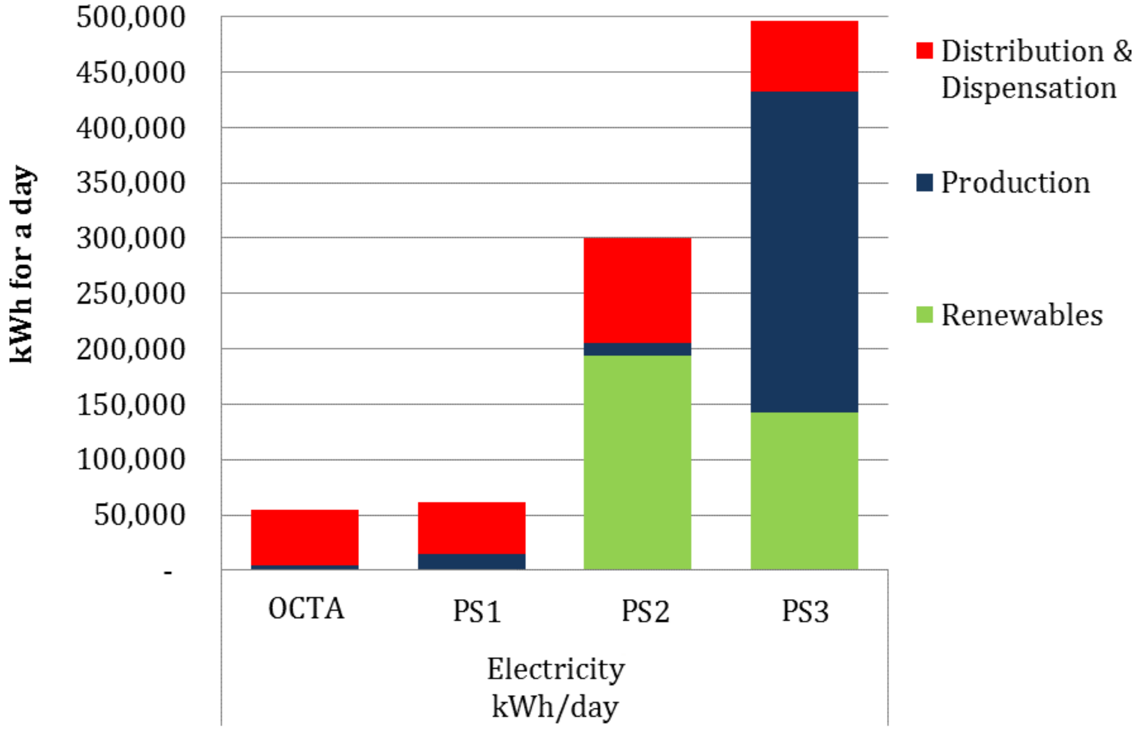


Figure 56: Electricity use during the hydrogen supply chain for the preferable OCTA scenarios.

For the three FCEB scenarios, the levels of criteria pollutant emissions can be decreased by emission control on centralized and distributed SMR units by (1) transporting all the hydrogen with pipeline or fuel cell trucks, (2) using distributed generation of electricity from stationary fuel cells; and (3) generating hydrogen from Tri-Generation plants powered by natural gas and/or biogas (e.g., waste water treatment plants, land-fills, food processing plants) [111]. Increasing the contribution of electrolysis from renewable sources to produce hydrogen will also reduce emissions. While this technology remains more expensive than other technologies [37], this pathway has the capability of adapting to the variability of renewable wind and solar resources (i.e., hydrogen production and storage can occur when solar and/or wind resources would otherwise be curtailed and this could represent economic benefits) [12][26][33].

Well-to-Wheels Greenhouse gases (GHG)

The WTW GHG emissions are shown in Figure 57. The major GHG reduction is associated with PS1 with 78% less than the base case. PS2 and PS3 have a 70% and 47% reduction, respectively.

For PS3, even when grid-powered electrolysis only produces 40% of the total hydrogen, almost 85% of the well-to-product emissions (yellow bar) are emissions released to the environment during the production of electricity by the CA grid. Once again, this shows how direct use of natural gas to generate hydrogen has environmental benefit over early electrification when not enough renewables are integrated in the electric grid.

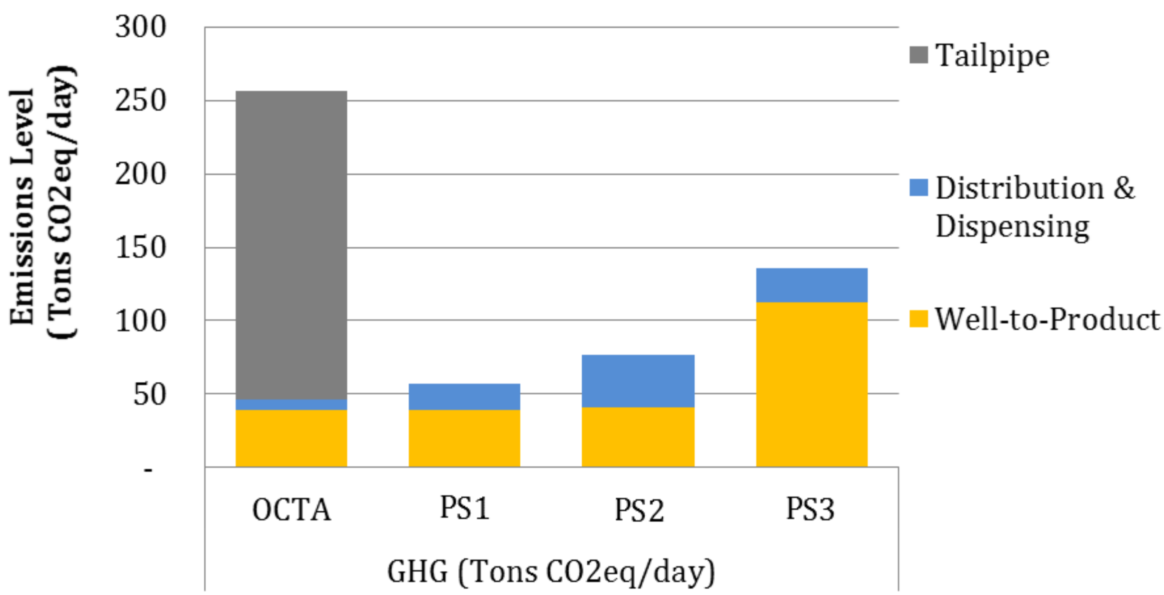


Figure 57: Well-to-Wheels greenhouse gas emissions for OCTA and hydrogen scenarios

7.5.2. Analysis of resource utilization

The H_2CAT tool has the capability of quantify the resources used in the hydrogen supply chain. The quantification can be per process (i.e., resources used during production, distribution, dispensing, etc.) or differentiated between direct or indirect use. For example, resources used on-site to produce hydrogen from SMR using natural gas would be classified as direct used while the feedstock (like natural gas, coal, biomass, etc.) used to generate the electricity used to liquefy the hydrogen would be classified as resources from indirect use.

WTW use of natural gas

There is a common misconception that the production of hydrogen increases the need for natural gas, sifting the dependency from one fossil fuel to another. However, as demonstrated by Figure 58, hydrogen production for the three scenarios reduces by almost half the net use of natural gas. Furthermore, by increasing dependency on the electric grid the net consumption on natural gas increases with respect to other hydrogen generation technologies. The net use of natural gas in PS3 is 54,791kg/day and for PS1 is 52,096kg/day, even when for PS1 67% of the hydrogen is produced directly from SMR.

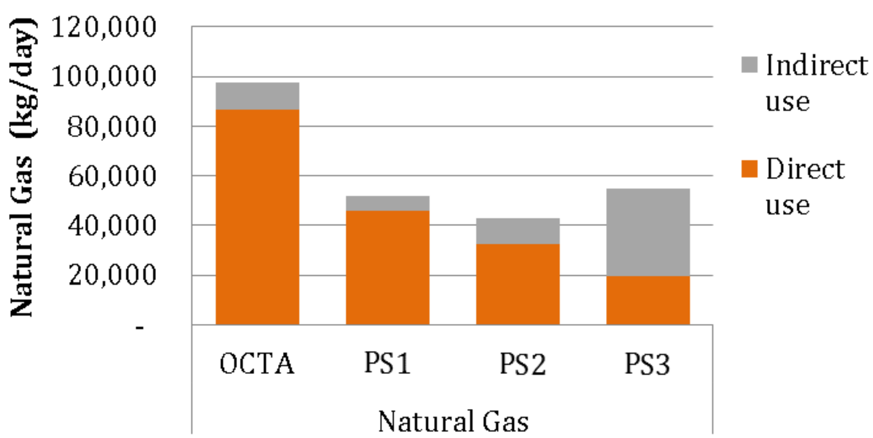


Figure 58: Consumption of natural gas for direct and indirect used

WTW water utilization

Water demand is important to take into consideration for any future ZEB's application, particularly for the state of California where water resource constraints have been an issue historically. The increase with respect form the baseline for water consumption and water withdrawal is presented in Table 48 and Figure 59.

For direct processes, the amount of water required for electrolysis is about 30% less of that required for hydrogen generation from SMR. However, the amount of water utilized during the supply chain (mostly conversion process) of the three FCEB scenarios (PS1 to PS3) reflects the same proportion of water used (color orange on Figure 59-A), which is consumed during the conversion processes.

The California grid produces 14% of electricity from hydroelectric power plants (PP) and 6% from coal plants, both have a major water withdrawal associated with the power generation: 2.63 gallons of water are withdrawal from hydroelectric PP for each KWh that is consumed for the California electric grid and 0.037 gallons from coal plants. The specific water withdrawal that takes place for electricity generation (indirect use) for each scenario is shown by the grey bar at Figure 59-B. In this graph, PS3 has a higher withdrawal in comparison with the other scenario and to the baseline, reflecting that the scenarios with higher use of electricity from the grid have greater water withdrawal. The electricity used from the grid is presented for each scenario in Figure 56.

Table 48: Water consumption and withdrawal for OCTA and preferable hydrogen scenarios

		Direct Use	Indirect Use	Total	Increase from baseline
Water Consumption (gal/day)	OCTA	8,572	9,380	**17,952**	
	PS1	19,749	11,420	**31,169**	x 2
	PS2	29,743	19,814	**49,558**	x 3
	PS3	35,426	66,024	**101,450**	x 6
Water Withdrawal (gal/day)	OCTA	1,904	252,222	**254,126**	
	PS1	78,995	206,912	**285,907**	equal
	PS2	774,397	358,990	**1,133,388**	x 4
	PS3	548,157	1,196,193	**1,744,350**	x 7

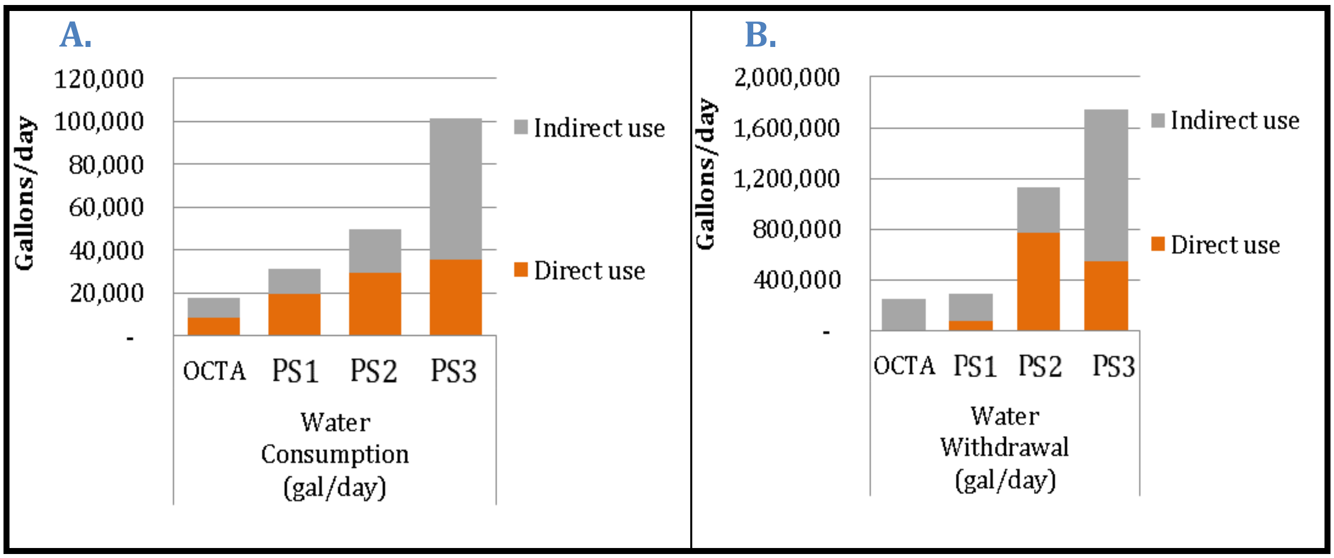


Figure 59: Well-to-Pump water consumption and withdrawals for OCTA and H_2 scenarios

Table 49: Daily electricity consumption for OCTA and for hydrogen scenarios

	Electricity use per process (KWh/day)			
	Production	**D&D**	**Total**	**Increase from baseline**
OCTA	4,427	50,160	**54,587**	
PS1	14,132	46,940	**61,072**	Equal
PS2	11,374	94,585	**105,959**	x 2
PS3	289,857	63,210	**353,067**	x 6

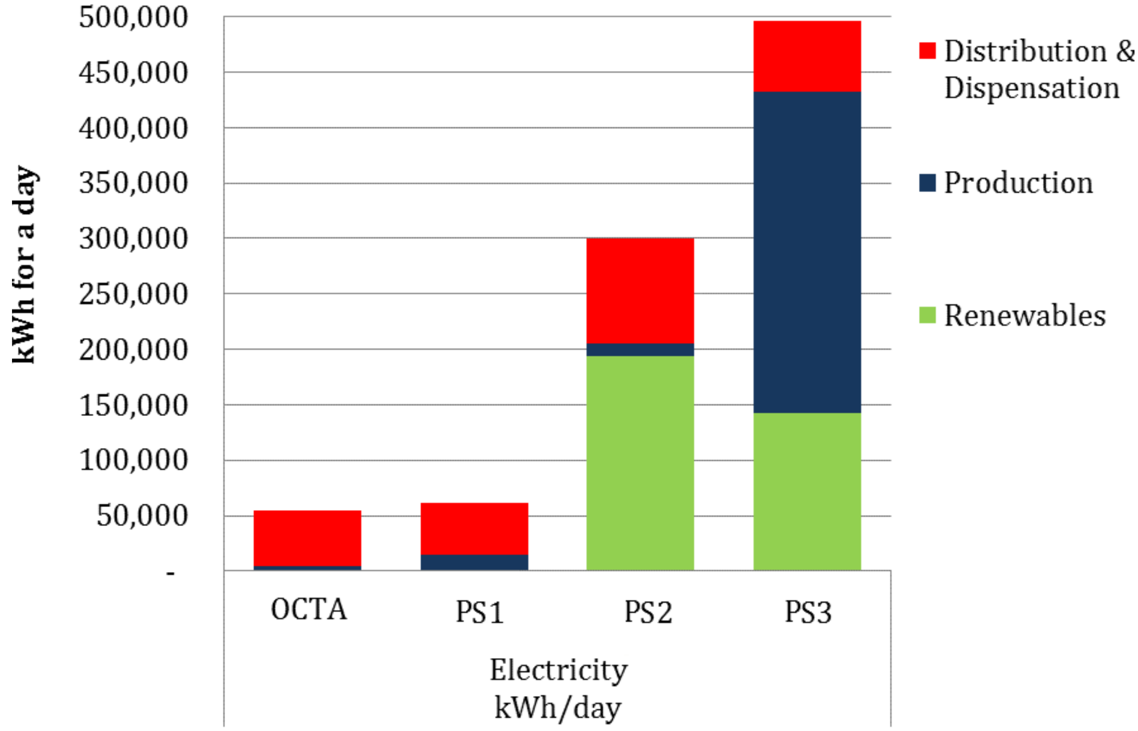


Figure 60: Electricity use during the hydrogen supply chain for the preferable scenarios

Other resources used for power generation (indirect use)

For consumption of biomass and coal, the trends are similar to the results for water. Scenarios with a higher use of electricity from the grid increase the use of resources fossil resources. Figure 61 shows how the increase in these biomass and coal correlates with the higher use of grid electricity from Figure 56 and

Table 49. PS2 uses twice the electricity than the current demand at OCTA, resulting in twice as much biomass and coal use. PS3 uses six times more electricity than the baseline which results in seven times more biomass consumption and five times more coal.

The use of crude oil will be reduce by more than 94% for any of the hydrogen scenarios due to the replacement of diesel used by 28 buses at OCTA by hydrogen.

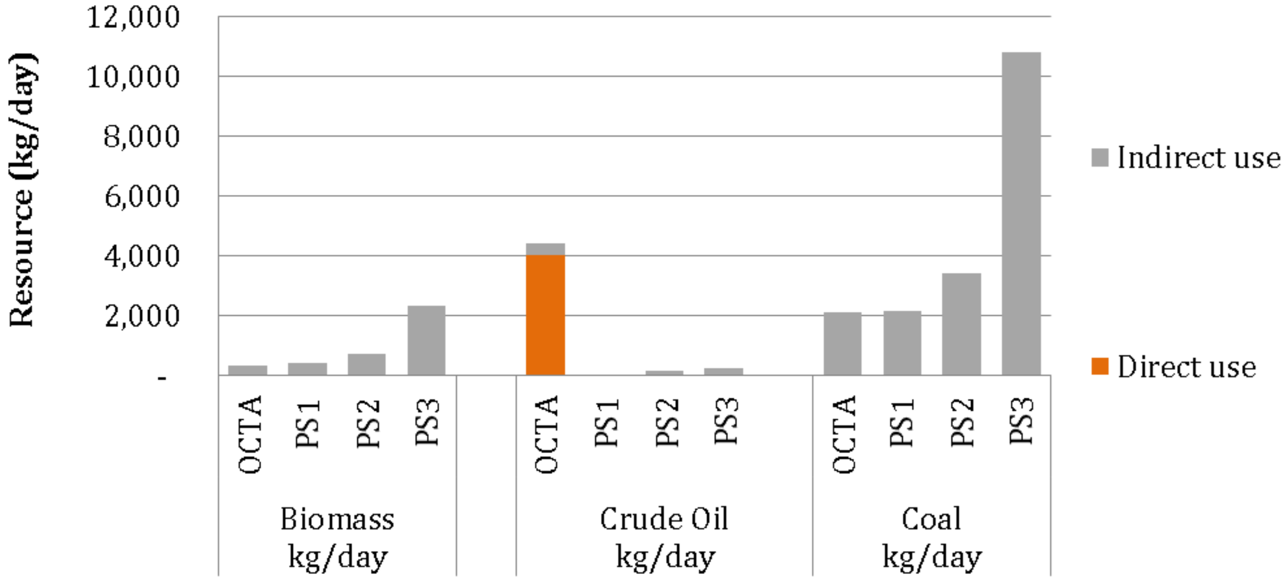


Figure 61: Well-to-Pump biomass, crude oil and coal use for OCTA and hydrogen scenarios.

WTW energy consumption

The total energy consumption on a well-to-wheels basis was analyzed using low heating values and measured in mega Jules per mile, the results are presented on Figure 62.

The fuel efficiency of the bus technology or tank-to-wheels energy (light blue color on Figure 62) contributes to an overall more efficient energy utilization per mile for the hydrogen scenarios. PS1 uses less energy to operate per mile and is 44% more efficient than the current WTW energy consumption of OCTA, mostly due to lower electricity use for the production and distribution.

The green color represents energy used in the generation and distribution of hydrogen. PS3 has the most energy intense process to convert the same amount of hydrogen that the other hydrogen scenarios have. The large amount or resources that are used in scenario three are converted to electricity under the efficiency assumed for the California grid of 52% [56].

Even when the conversion to fuel is more energy intensive for all the hydrogen scenarios (when compared to the energy intensity of generating and distributing CNG, LNG and diesel for OCTA), the high efficiency of the FCEBs allows for the hydrogen scenarios to use less energy (LHV) per mile traveled.

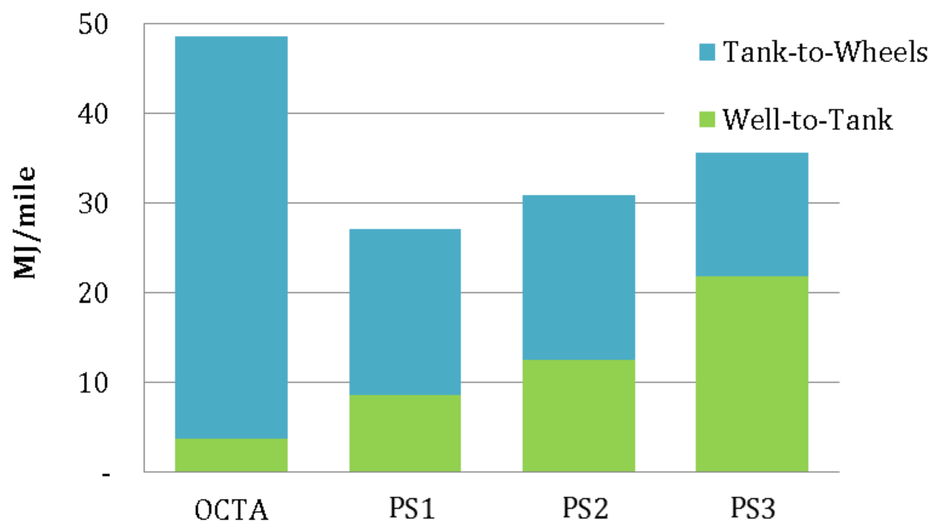


Figure 62: Well-to-Wheels energy consumption for OCTA and hydrogen scenarios

7.6 Cost Analysis Module for Hydrogen Infrastructure

The capabilities of HAT and H_2CAT have been explained and demonstrated previous chapters, starting with applications to a national level, then for the State of California, and lastly for an specific transit agency. Both tools generate outputs that establish the environmental impact of different hydrogen infrastructure and deployment-feasibility in term of feedstocks availability. An additional module of H_2CAT is the cost analysis that help complements the decision making by adding information about the most economic delivery pathway and estimations about the total cost of hydrogen.

The cost analysis module of H_2CAT is designed to evaluate the capital cost and price per kilogram variation for different distribution pathways: Truck (liquid and gas), pipeline, and distributed generation via SMR.

This chapter presents results for four deployment hydrogen infrastructure scenarios at OCTA when using the Analysis Cost Module with the purpose to find the most economic distribution pathway when considering SMR from natural gas as the generation technology.

7.7. Cost Scenarios Description

The tool evaluates hydrogen infrastructures with generation from SMR with natural gas and biogas. Therefore, the purpose of designing different scenarios is to analyze the impact on the distribution methodology. Figure 63 shows the design of the four analyzed scenarios; the generation technology is constant even for the distributed scenario.

- Scenario 1 for cost module (CM1): Steam methane reformation (SMR) used to generate 33% renewable hydrogen from landfill biogas and 67% hydrogen from natural gas. Distributed using **liquid hydrogen trucks** from a centralized location that with a travel length of 35 miles.

- Scenario 2 for cost module (CM2): SMR used to generate 33% renewable hydrogen from landfill biogas and 67% hydrogen from natural gas. Distributed using **gas hydrogen trucks** from a centralized location that with a travel length of 35 miles.
- Scenario 3 for cost module (CM3): 33% renewable hydrogen from landfill biogas and 67% hydrogen from natural gas generated through centralized SMR from. Distributed using **pipelines** from a centralized location that would require a pipeline length of 35 miles.
- Scenario 4 for cost module (CM4): Distributed SMR used to generate 33% renewable hydrogen from landfill biogas and 67% hydrogen from natural gas.

The travel length of the delivery trucks and of the pipeline infrastructure were chosen based on the results previously discussed in CHAPTER 7, which resulted from using H_2AT to identify nearby resources for potential centralized generation facilities.

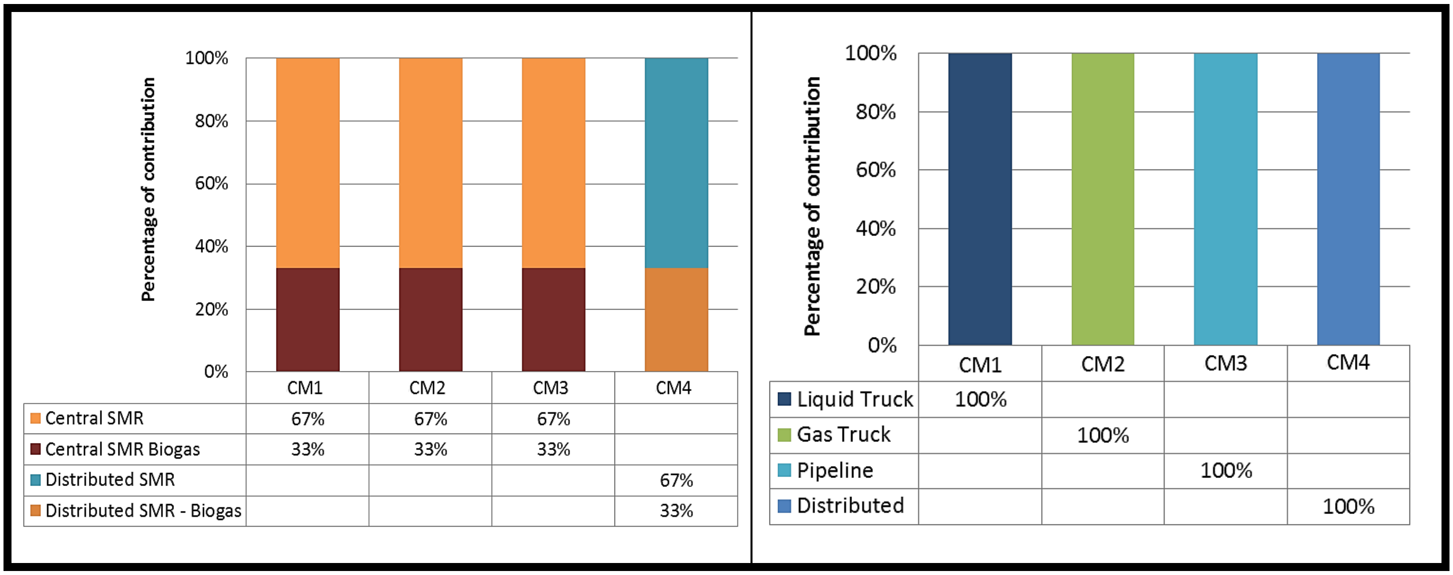


Figure 63: Hydrogen scenarios for the economic analysis

7.8. Capital cost and cost per kilogram of hydrogen

The methodology used for this module is described in Section 5.4 along with the made assumptions and their reference. In this section the tool is used to analyze different scenarios the inputs presented in Table 50 and based on the variables defined in Table 32.

Table 50: Inputs for Analysis Cost module

Financial assumptions	
8%	Debt rate
312	Days in a year
12	years to pay back
Operational assumptions	
250	miles per day for one bus
6.5	Fuel economy mi/kg
Delivery assumptions	
35	miles travel (one-way)
35	miles of pipeline
3.42	\$/kg of H_2 well-to-product price

Table 32: Variables for hydrogen stations and distribution pathways

Detail	Units		Reference
Cost of electricity	0.118	\$/KWh	[96]
Well-to-product cost of Hydrogen	3.42	\$/kg of H_2	[84]
Liquid Hydrogen			
Liquid truck capacity	4,500	Kg of H_2/truck	[82]
Cost of liquefaction equipment	1.03	\$/kg of H_2	[61]
Cost of travel	4	\$/mile traveled per truck	[82]
Electricity requirement for liquefaction	8.27	KWh/kg of H_2	[37]
Gaseous Hydrogen			
Electricity req. to compress into truck	2.5	KWh/kg of H_2	[82]
Gas truck capacity	650	Kg of H_2/truck	[82], [84]
Cost of travel	4	\$/mile traveled per truck	[82]
Pipeline			
Capital cost of infrastructure	358,507	\$/mi	[82], [84]
Electricity req. to compress into pipeline	0.50	KWh/kg of H_2	[20], [97]
Distributed generated Hydrogen			
Capital Cost of SMR units	2,862,300	\$/unit	[82], [98]
Storage capacity	3,000	kg of H_2	[99]
Natural gas req.	0.172	MMBTU/kg of H_2	[71]
Cost of natural gas	7.5	\$/MMBTU	[82]
Electricity req. for storage	2.27	KWh/kg of H_2	[20]
Dispensing details			
Electricity req. for dispensing at 350bar	3.03	KWh/kg of H_2	[20], [97]
Station details			
Capital cost of station	Equation 7		
Maintenance cost	142,000	\$/year	[100]

Equation 7: Capital cost of hydrogen stations as a function of daily demand and number of dispensers

$$Station\ CC = 101{,}849 * (kg/day)^{0.5516} + (Number\ of\ Dispensers) * 26{,}880$$

7.8.1. Liquid vs gas delivery trucks

Specific diagram with the components description of scenario CM1 and CM2 are presented in Figure 64 and Figure 65, respectively, to illustrate the comparison that will be made for distribution using liquid trucks against gas trucks.

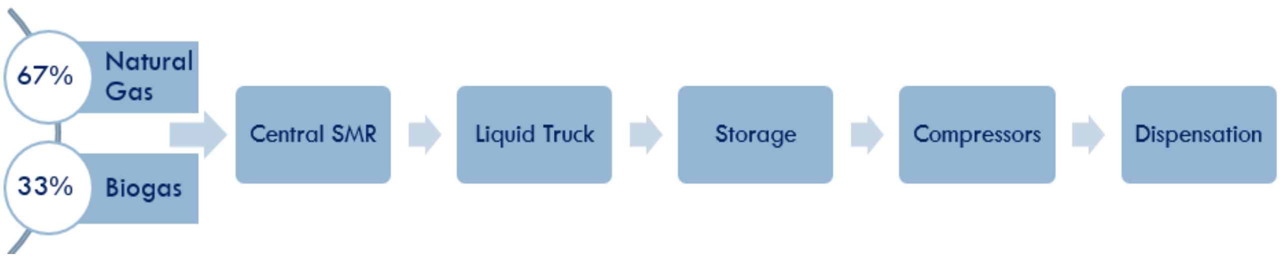


Figure 64: Components of liquid truck delivery hydrogen scenario (CM1)

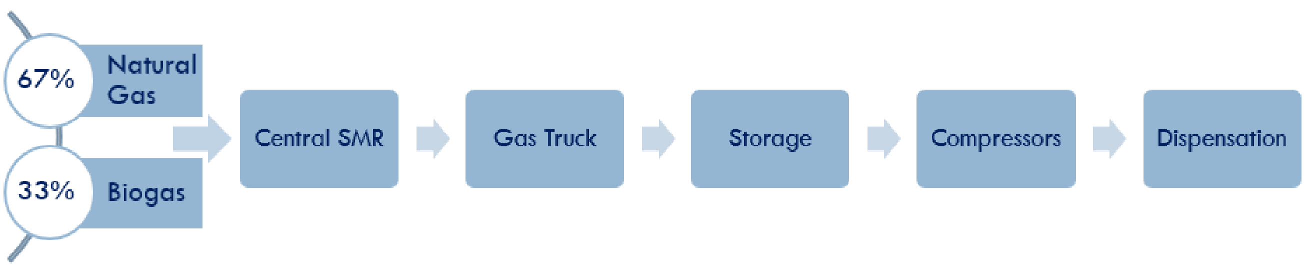


Figure 65: Components of gaseous truck delivery hydrogen scenario (CM2)

Capital Cost

The cost analysis module allows the capital cost calculation for the two scenarios by applying, a projection from the cost tendency of different light duty vehicle hydrogen stations. The capital cost here calculated considers:

- Storage
- Compressors
- Dispensers
- Investment of infrastructure to comply with safety requirements
- Vaporizers

The capital cost for CM1 and CM2 is presented in Figure 66 and Figure 67 as a function of the number of buses that can be filled by the station. The more buses are filled, the more capacity the station will have and the more expensive it will be. The important aspect of these graphs is t to identify the lower investment cost between the two scenarios.

The capital cost is presented as a function of the filled buses to help identify the capital cost for different penetration percentage of hydrogen buses into the fleet of OCTA. This information can be used by OCTA to have an estimate of the investment that will be needed to deploy certain number of buses into their fleets and by legislators to consider the appropriate funding incentives. Figure 66 and Figure 67 show that for 300 buses to be filled by a hydrogen station an initial capital cost of $21.4 million would be require for liquid hydrogen delivery and $18 million for gas hydrogen delivery.

When hydrogen is deliver as a liquid, the hydrogen first is vaporized and compressed by the main compressor to 54MPa and stored in storage tubes, when the bus is filled the hydrogen is cascaded directly from the 54MPa storage tubes to the bus tank. For hydrogen delivered as gas there is no need for vaporizers and this is one of the reason why the capital cost for a station that gets hydrogen deliver as a gas is lower than for when it's delivery as a liquid.

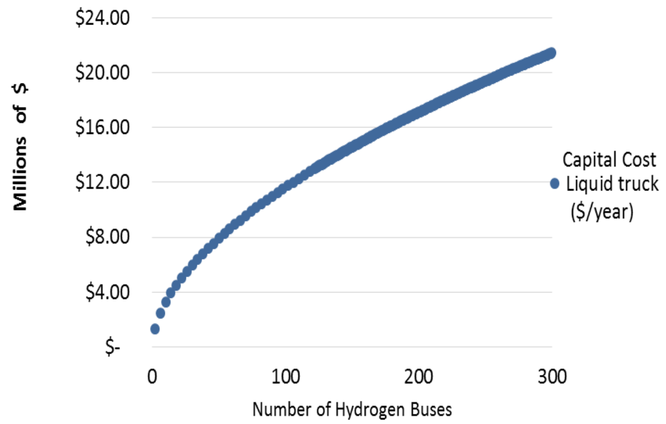


Figure 66: Capital cost of distribution via liquid trucks

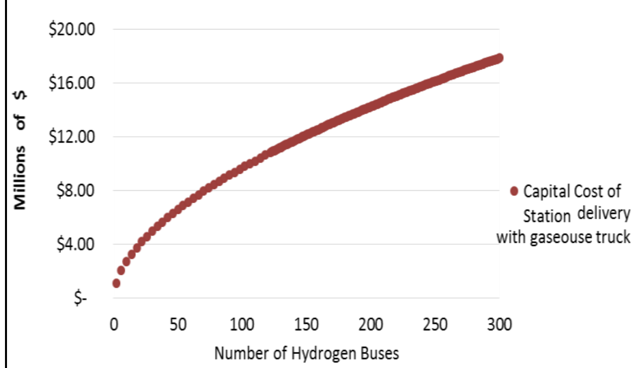


Figure 67: Capital cost of distribution via gaseous trucks

The hydrogen demand for 300 buses assuming an average of 250 daily miles is of 11,500kg of hydrogen per day. For this demand and based on the current market equipment specification, six dispensers will be require to fill 300 buses in a period time of 6 to 8 hours. To storage gas hydrogen at 3,190psi it would be require four sets of eight vessels (8 x 40' ABS skids [99]) with a total area of 1,100 ft^2.

Price per kilogram of hydrogen

One of the outputs of the H_2CAT Analysis Cost module is the price per kilogram of hydrogen calculated according to the methodology described in Section 5.4. The price per kilogram for CM1 that considers centralized SMR and distribution with liquid trucks is presented in Figure 68 and it reflects the well-to-pump price of hydrogen that complies with the 33% renewable hydrogen requirement that some states are implementing. The price of hydrogen can be lower than \$7.00 per kilogram of hydrogen when more than 150 buses are deployed at OCTA and as low as \$6.65 per kilogram of hydrogen when 300 buses or more are deployed.

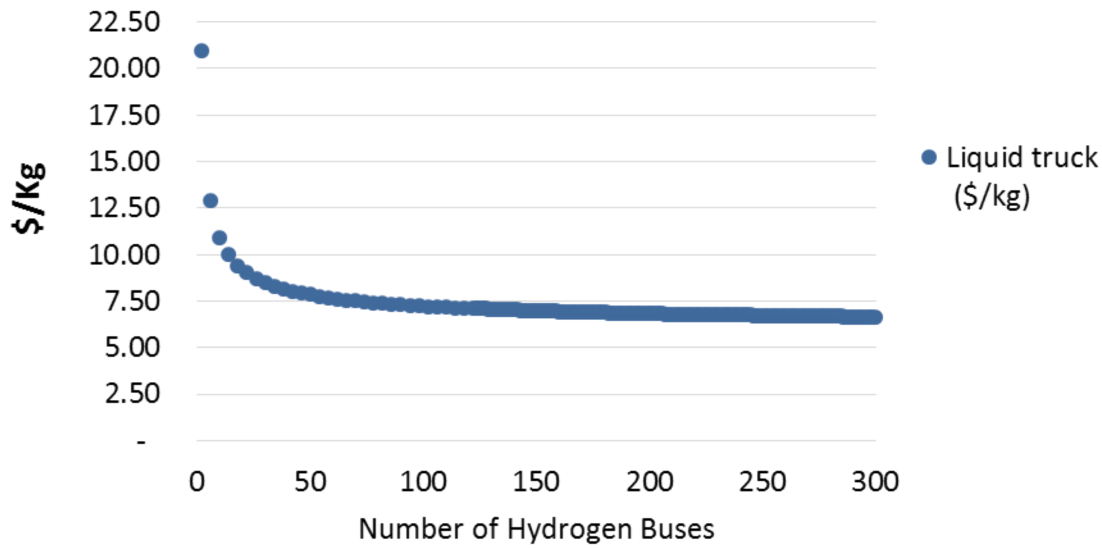


Figure 68: Cost per kilogram of H_2 from central SMR and distribution via liquid trucks

The price per kilogram for scenario CM2 (centralized SMR and distribution with gas trucks) is presented in Figure 69. The price of hydrogen can be lower than \$5.20 per kilogram of hydrogen when more than 150 buses are deployed at OCTA and as low as \$5.00 per kilogram of hydrogen when 300 buses or more are deployed.

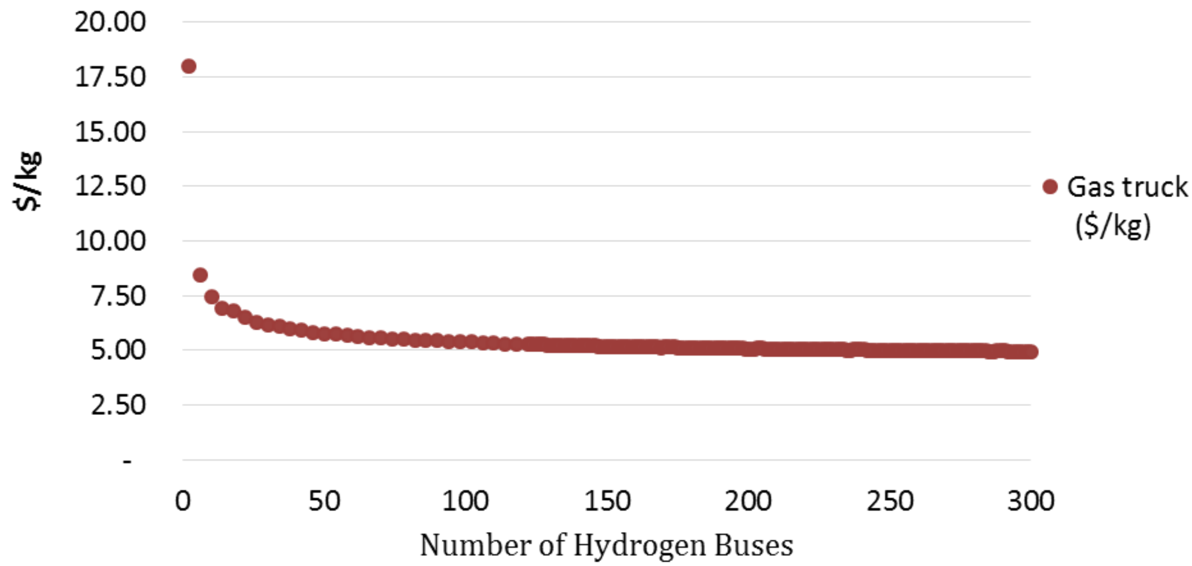


Figure 69: Cost per kilogram of H_2 from central SMR and distribution via gas trucks

Even when the capital cost of gas delivery trucks is lower than for liquid delivery, the feasibility of the gas distribution pathway has its limitations. One of the outputs of the tool is the number of trucks that will be required for the delivery of hydrogen, for both gas and liquid. Figure 70 compares the hydrogen price for both pathways and shows the number of gas tube trucks that will be required to deliver the hydrogen in function of the number of buses that are deployed at OCTA. From this figure, the gas tube trucks are shown to be not feasible since, to supply the demand of 300 buses, 18 tube trucks per day will be needed to supply the 3 bases. From the current logistics and space available at OCTA, delivery using only compressed hydrogen is cheaper but not feasible when more than 3 tube trucks need to arrive per day, which occurs when 35 hydrogen buses are in service.

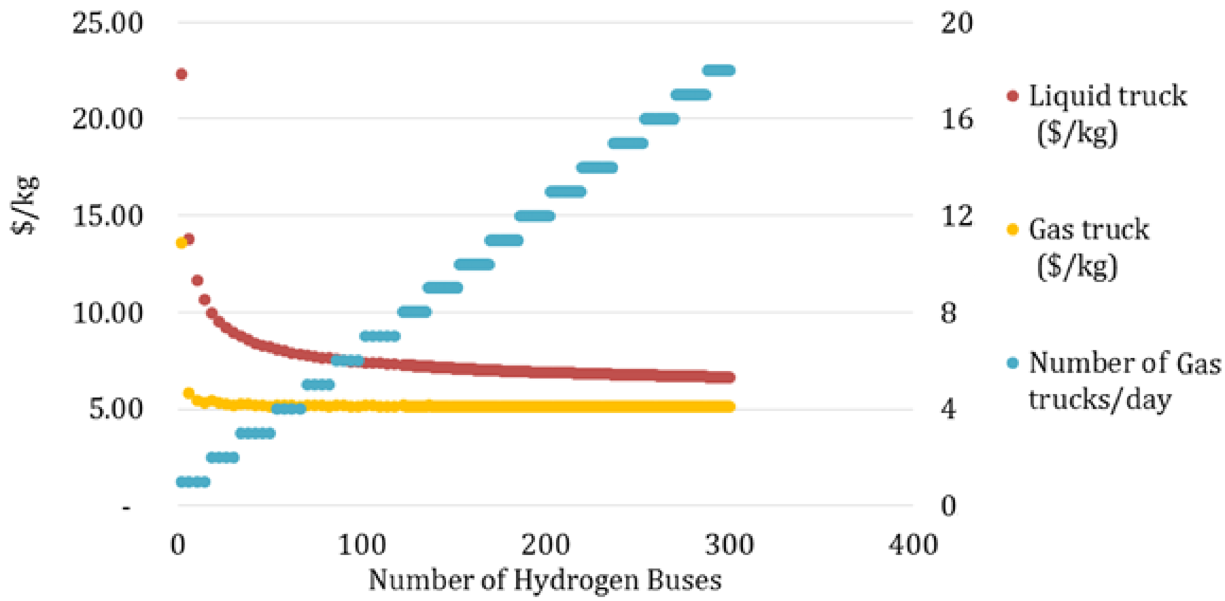


Figure 70: Comparison of liquid truck and gas truck distribution pathways for centralized SMR generation scenario

7.8.2. Pipeline vs distributed generation

Specific diagrams with the components description of scenario CM3 and CM4, pipeline distribution and distributed generation respectively, are presented in Figure 71 and Figure 72.

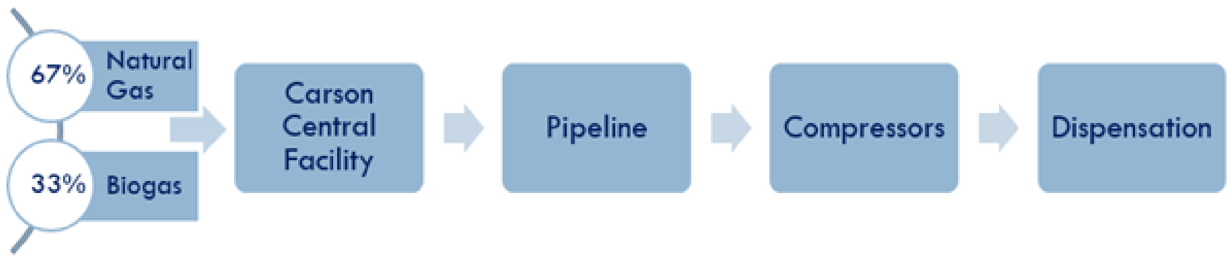


Figure 71: Components of pipeline delivery hydrogen scenario

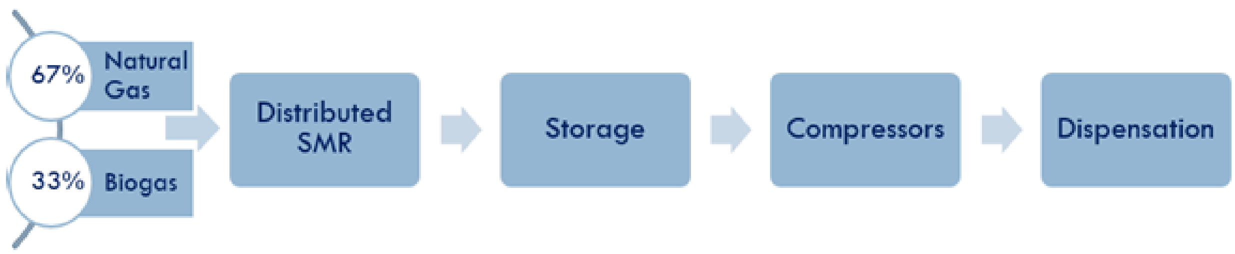


Figure 72: Components distributed generation hydrogen scenario

Similar to the comparison between liquid and gas truck delivery, this comparison includes the initial capital cost and the total price of hydrogen per kilogram. The tool took the same inputs and the same financial assumptions describe in Section 8.1.

The suggested infrastructure for the pipeline (red) was obtained from using H_2AT to identify the nearby resources. With the outputs from H_2AT and ArcGIS, the spatial allocation of the preferable refinery and layout of suggested pipeline infrastructure were obtained (Figure 73). The outputs from H_2AT utilized the current layout of natural gas pipelines to generate the 35 miles of hydrogen pipelines needed to interconnect a refinery in Carson with the three main bases at OCTA.

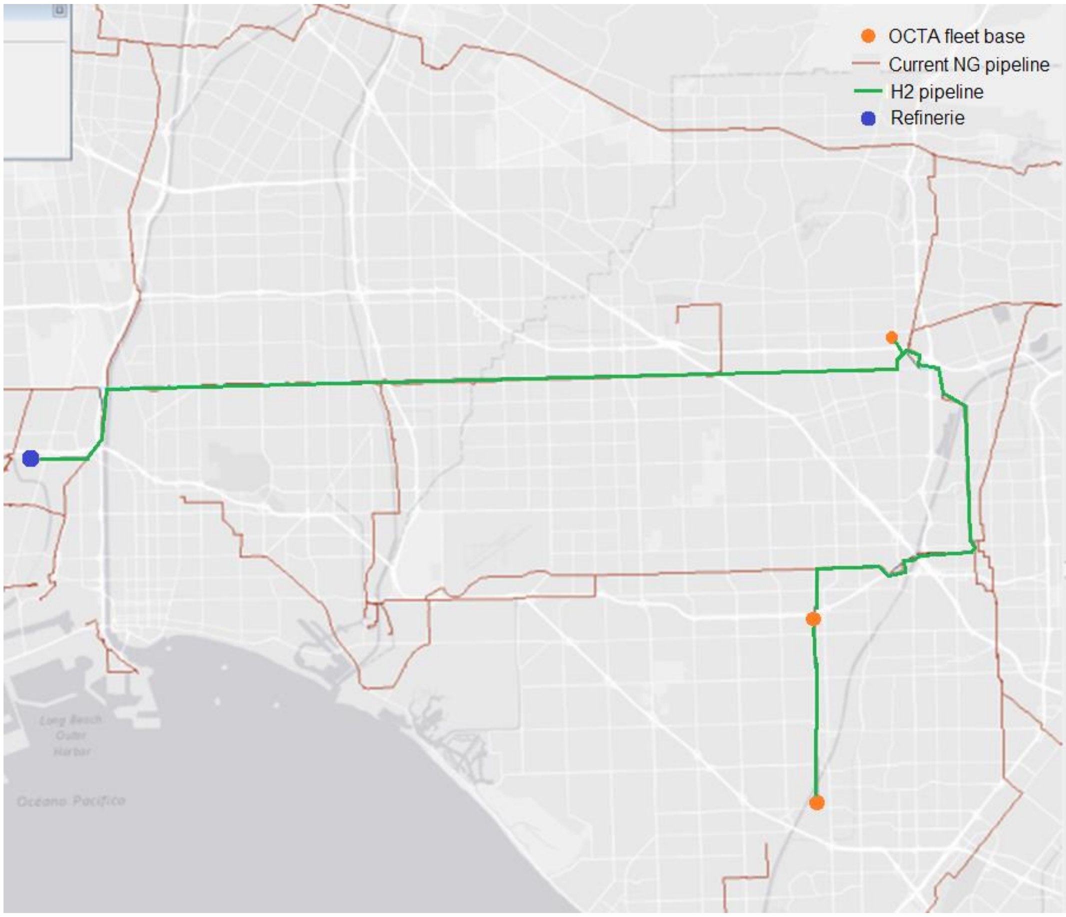


Figure 73: Spatial allocation of suggested pipeline between Carson refinery and OCTA bases

Capital Cost

The capital cost for the scenario with pipeline as the distribution pathway (CM3) has a similar trend line to the capital cost of the tube truck scenarios, namely increasing in a linear tendency after reaching a capacity to serve 100 buses. The capital cost for the pipeline scenario is presented in Figure 74 and includes the cost of:

- Pipeline infrastructure investment
- Dispensers

- Compressors
- Investment of infrastructure to comply with safety requirements

It considers storage only for emergency which price is almost irrelevant in comparison to the other considerations.

The capital cost for the pipeline infrastructure is $10.8 million and it remains independent on the hydrogen demand (buses in service). When the capital cost for the other equipment is added for 300 buses to be filled at a hydrogen station that receives the fuel via pipeline, Figure 74 shows that an initial capital cost of $18 million is needed. The capital cost is lower than for the tube truck scenarios because the storage equipment is almost eliminated as well as the vaporizers.

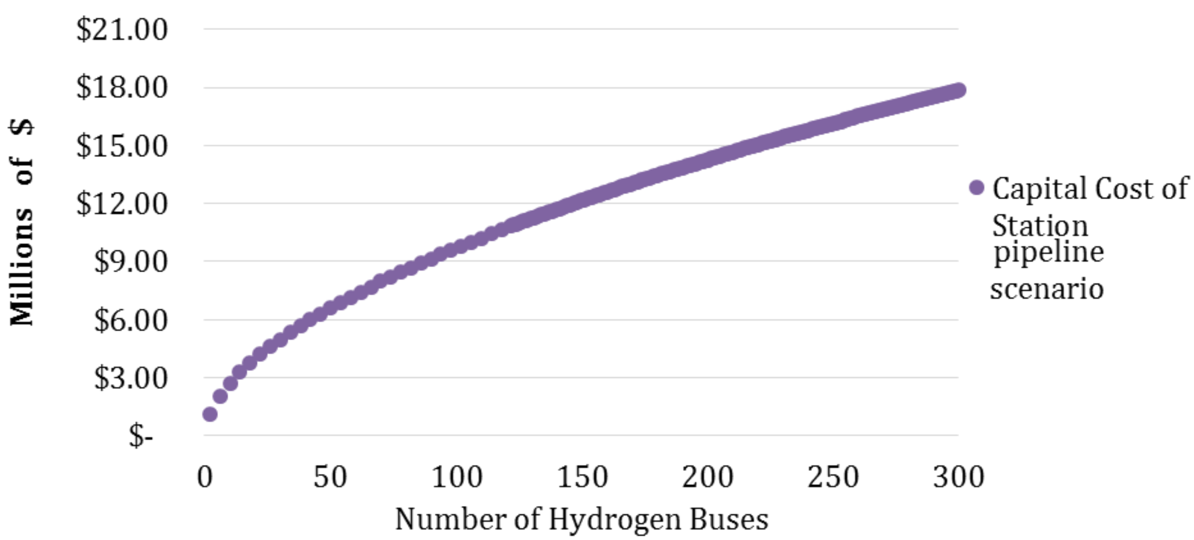


Figure 74: Capital cost of distribution via hydrogen pipelines.

The capital cost for the scenario with distributed generation using SMR units (CM4) has a different tendency than the other scenarios. Unlike the other distribution pathways, the capital cost is continuous until a new SMR unit or more storage vessels need to be added because of the hydrogen demand scales up. This trend is presented in Figure 76 and includes capital cost of:

- Storage vessels
- SMR units
- Compressors
- Dispensers
- Investment of infrastructure to comply with safety requirements

Figure 76 shows that the capital cost can be as high as $50 million for stations that could accommodate the hydrogen demand of 300 FCEB. The capital cost is significantly higher with respect to the other scenarios because it includes the production cost and not just the station itself. The cost of production is levelized in the other scenarios in the well-to-product price of $3.50 per kilogram of hydrogen. Therefore this should not be a point of comparison between the other scenarios; the comparison can be made with respect to the total price of hydrogen per kilogram. But even when the total price per kilogram will be fair point of comparison, the capital cost for this scenario is of importance because it represent an initial investment that the transit agency will need to make in addition to the investment for the refueling station for the deployment of the buses instead of paying the levelized cost of production to third party.

Figure 76 figure is also of special importance because it can be used as a planning tool by transit agencies. The intervals of hydrogen buses for each section where the capital cost becomes discontinuous can be used as the ideal number of new acquisitions to expand the fleet when upgrading the hydrogen production capacity at the bases.

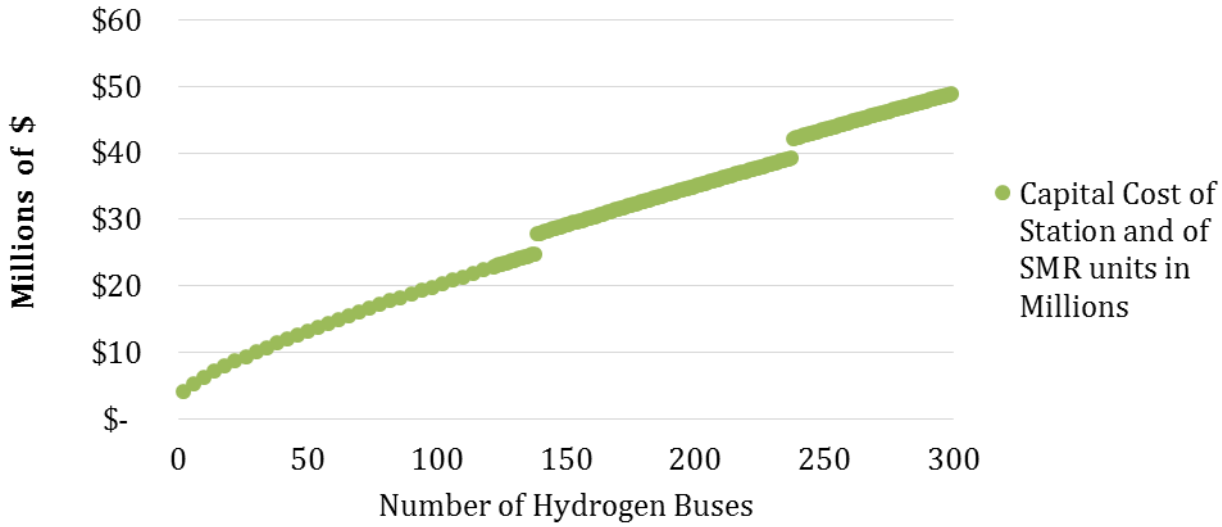


Figure 75: Capital cost of hydrogen from distributed SMR with natural gas and biogas

Cost per kilogram of hydrogen

Under the same criteria than for the tube truck delivery scenarios the total cost of hydrogen per kilogram was estimated for the pipeline and the distributed generation scenarios. The fixed cost were the same for both and the additional variable cost added was the price of natural gas an biogas for the distributed scenario.

Figure 76 shows the price of hydrogen as function of the hydrogen demand (buses deployed). If this scenario were to be implemented at OCTA when they have less than 50 buses then the price for hydrogen would not be lower than $10. Therefore, investing in pipeline infrastructure is not recommended for a period of 12 years, unless more than 50 buses are to be deployed.

A positive aspect about this scenario is that the cost of hydrogen can be as low as $4.96 per kilogram if more than 300 buses are deployed at OCTA.

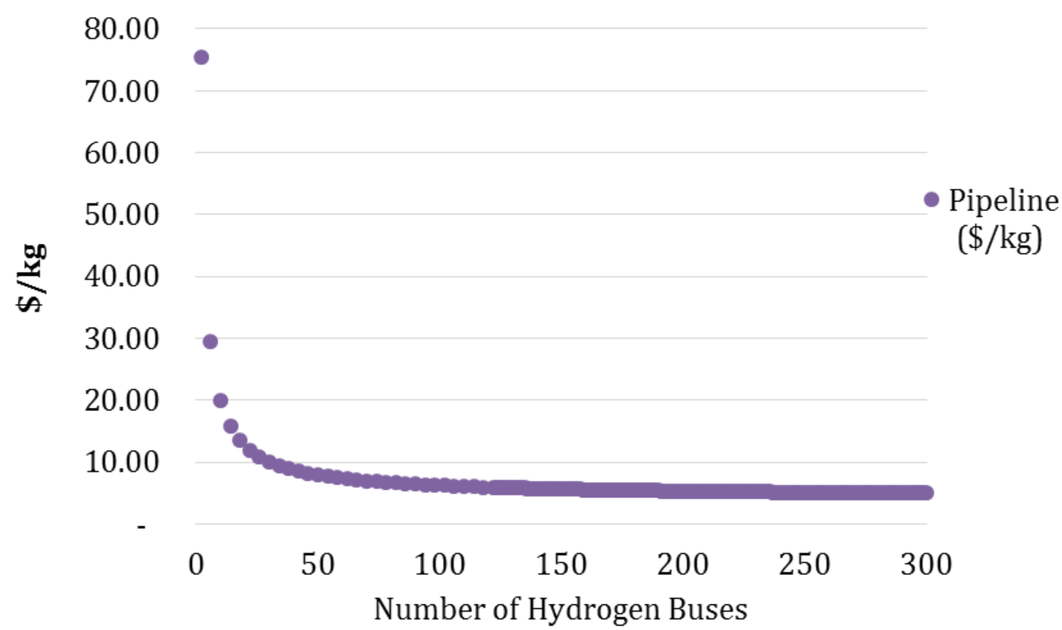


Figure 76: Cost per kilogram of hydrogen from central SMR and distribution via pipeline

For the distributed SMR scenario the price per kilogram of hydrogen is dependent on the feedstock prices of the directed biogas from wastewater treatment plants and of the price of the natural gas. But unlike the other scenario, is independent from third parties that could control the well-to-product price of the hydrogen.

Figure 77 shows the total price of hydrogen by kilogram. Similar to the pipeline scenario the price of hydrogen is really high if less than 50 FCEB are deployed with the difference that the higher price for this scenario is $37 per kilogram in comparison to $75 for the pipeline case.

The hydrogen price for the distributed generate SMR can be as low as $3.87 if more than 300 are deployed at OCTA.

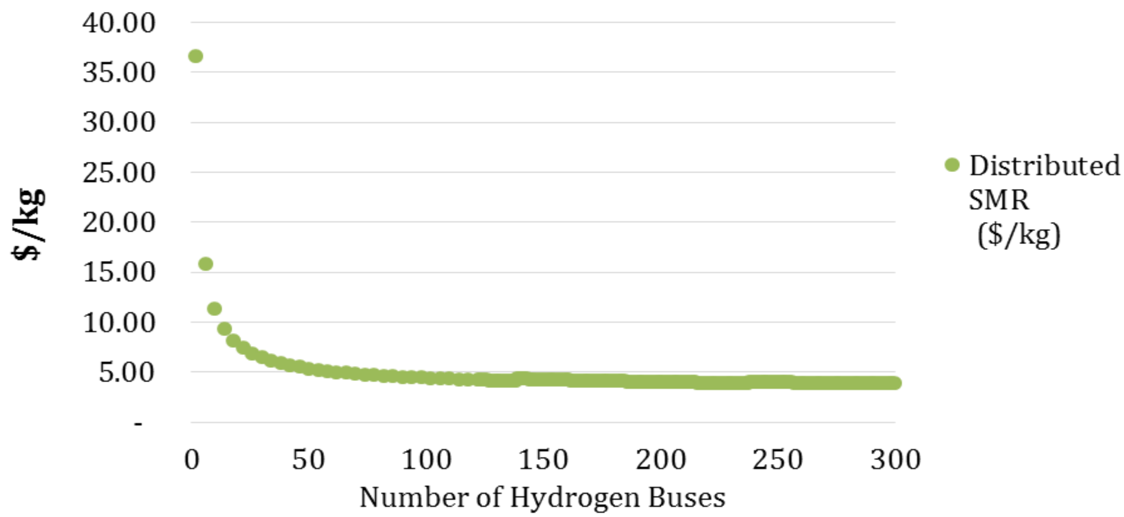


Figure 77: Cost per kilogram of hydrogen from distributed generation via SMR

As established in the section above, the distribution pathway involving gas delivery trucks presents restrictions on the number of trucks that can be managed by the bases at OCTA, therefore is not included as a viable scenario for full FCEB deployment.

Figure 78 shows the price per hydrogen for three scenarios: 1) delivery by liquid trucks 2) pipeline infrastructure and 3) distributed generation via SMR units. The on-site generation scenario is the pathway with lower total price of hydrogen but also the one with higher investment. It can also be inferred that when 25 or more FCEBs are in service, pipeline infrastructures is preferable over liquid trucks.

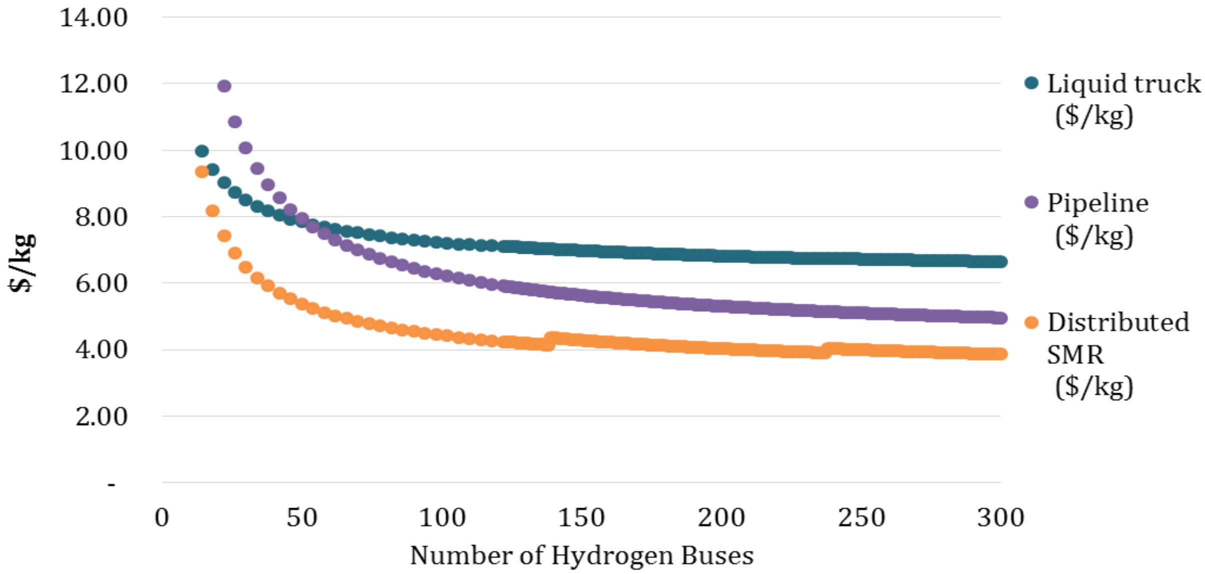


Figure 78: Cost per kilogram of hydrogen for three different distribution methodologies

7.9. Summary

The H_2AT and H_2CAT were utilized to analyze the environmental implications of hydrogen supply chains for a large size transit agency like Orange County Transportation Authority in order to: 1) examine H_2AT as a hydrogen allocation tool, 2) exercise the H_2CAT in a case study to find preferable hydrogen infrastructure, and 3) examine the robustness and resolution of the analysis results.

Several components of a hydrogen supply chain were analyzed individually and without variation of other components to identify their environmental benefits. From this analysis, the following conclusions can be made:

- Hydrogen generation from renewable sources does not necessarily translate into environmental benefits. If higher penetration of renewable electricity is used but it also increase demand of electricity from other sources (like coal or fired natural gas) the benefits from using H_2 are minimized. The grid needs to reach a 90% renewables penetration when using 4% coal in order to be beneficial using grid powered electrolysis over the use of SMR with only 33% renewable hydrogen to satisfy the hydrogen demand at OCTA.
- A mix between renewable generation pathways for hydrogen can lead to capital cost reductions by maintaining the maximum environmental benefit when renewable electrolysis is combined with biogas SMR.
- With the use of H_2AT it was confirmed that 44 miles of pipelines are sufficient to distribute hydrogen from identified potential central hydrogen generation facilities. It

was also confirmed that pipelines are the preferable distribution pathway to minimize criteria pollutants and greenhouse gases.

From identifying the preferable individual components of a hydrogen supply chain, three hydrogen infrastructure scenarios were analyzed for deployment at OCTA (refer to Figure 50 for details) with the following findings:

- Hydrogen production for the three scenarios could reduce by almost half the net use of natural gas.
- Producing 40% of the OCTA hydrogen demand with distributed electrolysis powered by the grid increases the electricity consumption in a factor of six, resulting in a doubling of SOx emissions.
- By replacing fossil-based fuels at OCTA with any of the recommended hydrogen infrastructures, WTW reductions in GHG emission between 47% to a max of 78% would result.
- The reductions in WTW energy consumed per mile when deploying any of the preferable hydrogen scenarios for OCTA vary between 17% and 44%.
- For hydrogen produced from electrolyzers that are powered from a grid with 90% renewables penetration, but with 4% of the electricity still sourced from coal plants (current coal contribution in the California grid mix), the emissions would be the same as if the hydrogen were produced from SMR with the minimum requirement of 33% renewable hydrogen.
- Distribution of hydrogen as gas with tube trucks has restrictions on the number of trucks that can be managed by the bases at OCTA for the fuel delivery. Based on the

current logistics and space available at OCTA, hydrogen gas delivery is not feasible when more than 9 tube trucks need to arrive per day at the bases (hydrogen demand for 35 hydrogen buses).

- When 25 or more FCEBs are in service, pipeline infrastructures are preferable over liquid trucks.
- Distributed generated hydrogen has potential to reduce hydrogen price to less than $4 per kilogram when at least 300 FCEBs are deployed, however the initial investment for this scenario is almost three times higher than for pipeline pathway.
- Piped hydrogen is an attractive scenario due to reduce space requirements at the bases and projected hydrogen prices of $4.97 per kilogram for 300 FCEBs.
- Investing in pipeline infrastructure is not recommended for a period of 12 years, unless more than 50 buses are to be deployed.

CHAPTER 8. Conclusions and Recommendations

8.1. Conclusions

Hydrogen infrastructure and spatial allocation of feedstock must be established for the deployment of fuel cell electric buses

Developing supply chains for new fuel technologies presents a challenge where engineering meets real-world practical constraints. For transit agencies looking to transition to hydrogen fleets in order to lower emissions and increase overall process efficiency, the hydrogen infrastructure must be established. Practical challenges include space limitations, cost of investment, final cost of fuel, and the proximity to new feedstocks.

Three states in the US are especially attractive to enable the hydrogen fuel cell bus market

The adoption of light-duty hydrogen vehicles into the market faces the 'chicken and egg' dilemma: hydrogen vehicles cannot be deployed to the market because of inadequate infrastructure; on the other hand the limited number of hydrogen vehicles on the roads makes it economically unappealing to build the required supply infrastructure. Transit agencies looking to adopt fuel cell electric buses as replacement of fossil-based fuels could create a demand for hydrogen of almost 500,000 hydrogen tons per year. This would propel reductions of over 90% of the 7.25 million tons of CO_2 equivalent when biogas is used as 80% of the feedstock for SMR generation. This demand can create the economic incentive for investment in distribution infrastructure as well as new centralized hydrogen generation plants resulting in lower prices of hydrogen due to economies of scale. Additionally, distributed generation of hydrogen at transit agencies will increase hydrogen availability in main urban areas while creating a niche market for on-site electrolysis and

SMR units. The spatial allocation of hydrogen demand shown in this thesis with the use of the Hydrogen Allocation Tool (H_2AT) allowed for the identification of three states (CA, NY and FL) as preferable initial adopters due to their large volume of hydrogen demand.

Natural gas provides a viable transition technology towards a 100% renewable grid

The Hydrogen Characterization and Analysis Tool (H_2CAT) was used to simulate the overall emissions and resource consumption of different hydrogen supply chain scenarios to supply the hydrogen demand of Orange County Transportation Authority. The results revealed that the use of natural gas to produce hydrogen via SMR with 33% renewables produces less criteria pollutants and greenhouse gas than grid powered electrolysis unless there is a reduction in the 4% coal contribution to the California grid or a renewable penetration rate higher than 90%.

The Hydrogen Characterization and Analysis Tool (H_2CAT): an investment evaluation tool to maximize environmental benefits in the deployment of hydrogen buses for transit agencies

Combining the results from H_2AT with the capabilities of H_2CAT will allow transit agencies to evaluate the environmental and economic benefit of different hydrogen supply chain configurations. This was demonstrated in a case study by finding the preferable hydrogen supply chain configuration for Orange County Transportation Authority; the recommended configurations are: 1) centralized hydrogen generation from SMR with 67% from natural gas and 33% from biogas, 2) pipeline as distribution pathway with a max of 35 miles 3) dispensing in three of the main bases at 350 bar. This configuration will reduce the WTW greenhouse gas emissions by 78%, improve energy consumption per mile by 44%, and minimize the impact in water consumption while achieving prices of hydrogen as low as $5 per kilogram of hydrogen.

8.2. Recommendations

Recommendations for future work are associated with determining how to optimize the selection of hydrogen supply chain infrastructures. This thesis' work presents tools for the analysis of scenarios and develops several criteria to identify preferable scenarios taking into consideration constraints of transit agencies; however this constraints and analysis outputs can be integrated in a multi-objective optimization method. The result would be a comprehensive assessment of resources and environmental impacts. Specifically, the optimization could integrate aspects like cost, route length of fixed routes, greenhouse gas emissions, criteria pollutants, resources utilization, and infrastructure constraints to ensure a balanced deployment of FCEBs into fleets.

The work in this thesis has primarily focused on well-to-wheel emissions and resources analysis. However, the scope of the tools can be expanded to Life Cycle Analysis (LCA) for hydrogen supply chains and even for other zero emission technologies like plug-in electric buses and on-route charging buses. The idea is to identify the optimal mix of technologies for the transit agency's fleet while minimizing emissions and total cost of operation.

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APPENDIX A: Emissions of BACT engines and Fuel Cell Units

Table A: Emissions from landfill gas use for bio-power production [54]

Process	Harvest	Conversion
Description	LFG recovery	LFG combustion
Equipment	Electric blower	BACT Engine
Energy type	Electricity	
Energy Use	9,262	
Energy Units	Btu/MMBtu	
Direct Emissions		
Units		lbs per MMBtu of gas recovered
VOC		0.2224
CO		0.6939
NO_X		0.1660
PM_{10}		0.0136
$PM_{2.5}$		0.0136
SO_X		0.0068
CH_4		1.1133
N_2O		0.0022
CO_2		143.6914
Indirect Emissions		
Units	lbs per MMBtu of gas recovered	
Description	Electricity for blower	
VOC	0.0003	
CO	0.0020	
NO_X	0.0033	
PM_{10}	0.0019	
$PM_{2.5}$	0.0006	
SO_X	0.0004	
CH_4	0.0045	
N_2O	0.0000	
CO_2	2.5496	

Table A.1: Performance and emissions comparison between a biogas engine and a fuel cell [54]

	Engine	Fuel Cell	ARB limits
Efficiency	0.34	0.47	
Emissions (lb/MWh)			
VOC	2.23	--	0.02
CO	6.96	--	0.10
NO_X	1.67	0.01	0.07
SO_2	0.07	0.0001	
PM_{10}	0.14	0.00002	
CO_2	1441	940	

APPENDIX B: Runs for Cost Analysis Module

Table B: Example of capital cost calculation for hydrogen stations (liquid hydrogen station)*

Number of Hydrogen Buses	Hydrogen kg/year	# of Dispensers	Number of liquid trucks needed per day	Capital Cost of Station dispensing liquid Hydrogen
2	24,000	1.0	1.0	$ 1,108,333
30	360,000	1.0	1.0	$ 4,936,307
50	600,000	1.0	1.0	$ 6,542,955
70	840,000	2.0	1.0	$ 7,904,194
90	1,080,000	2.0	1.0	$ 9,075,498
110	1,320,000	2.0	2.0	$ 10,134,625
130	1,560,000	3.0	2.0	$ 11,137,166
150	1,800,000	3.0	2.0	$ 12,047,483
170	2,040,000	4.0	2.0	$ 12,931,663
190	2,280,000	4.0	2.0	$ 13,744,788
210	2,520,000	4.0	3.0	$ 14,520,342
230	2,760,000	5.0	3.0	$ 15,290,295
250	3,000,000	5.0	3.0	$ 16,004,908
270	3,240,000	6.0	3.0	$ 16,721,189
280	3,360,000	6.0	3.0	$ 17,057,287
290	3,480,000	6.0	3.0	$ 17,388,043
300	3,600,000	6.0	3.0	$ 17,713,724

*Calculations based on assumptions from Section 5.4

APPENDIX C: Storage Specifications and Space Requirements

Table C: Space and capacity assumptions for on-site hydrogen storage

On-Site Storage of Hydrogen							
Tank Capacity (SCF)	**H2 Storage Conditions**	**Capacity (Kg)**	**Tube type**	**Long (Ft)**	**Wide (Ft)**	**High (Ft)**	**Area (ft^2)**
118,442	Gas @ 2,640psi / 70F	**2,712**	3AAX	40.00	8.17	8.50	327
31,725	Gas @ 2,640psi / 70F	**726**	22 cylinder	20.00	8.00	8.50	160
43,261	Gas @ 2,640psi / 70F	**990**	30 Cylinder	21.00	8.00	8.50	168
51,913	Gas @ 2,640psi / 70F	**1,188**	36 tube trailer	24.00	8.00	8.50	192
54,797	Gas @ 2,640psi / 70F	**1,254**	38 tube trailer	24.00	8.00	8.50	192
57,681	Gas @ 2,640psi / 70F	**1,321**	40 tube trailer	24.00	8.00	8.50	192
111,610	Gas @ 2,640psi / 70F	**2,555**	49 tube trailer	32.00	8.00	8.50	256
85,903	Gas @ 2,640psi / 70F	**1,967**	60 tube trailer	44.00	8.00	8.50	352
77,870	Gas @ 2,640psi / 70F	**1,783**	54 tube trailer	26.00	8.50	6.50	221
131,060	Gas @ 3,190psi / 70F	**3,000**	8 tube 40' ABS skid	36.00	8.00	4.00	288

Source [99], [112], [113]