California Environmental Protection Agency
Air Resources Board

Detailed GREET Pathway for Liquid Hydrogen from North American Natural Gas

Stationary Source Division
Release Date: July 18, 2008
Version 1.0

The Staff of the Air Resources Board developed this preliminary draft version as part of the Low Carbon Fuel Standard Regulatory Process

The ARB acknowledges contributions from the California Energy Commission, TIAX LLC and Life Cycle Associates LLC during the development of this document.

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These comments will be compiled, reviewed, and posted to the LCFS website in a timely manner.

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SUMMARY

CA-GREET Model Pathway for Liquid Hydrogen Produced From North American Natural Gas

A Well-To-Tank (WTT) life cycle analysis of a fuel (or blending component of fuel) pathway includes all steps from feedstock production to final finished product. Tank-To-Wheel (TTW) analysis includes actual combustion of fuel in a motor vehicle for motive power. WTT and TTW analysis are combined together to provide a total Well-To-Wheel (WTW) analysis.

A life cycle analysis model called the **G**reenhouse gases, **R**egulated **E**missions, and **E**nergy use in **T**ransportation (GREET)[1] developed by Argonne National Laboratory has been used to estimate the energy use and Greenhouse Gas (GHG) emissions and consequent GHG emissions generated during the entire process of liquid hydrogen production and its use in a fuel cell vehicle. The model however, was modified by TIAX under contract to the California Energy Commission during the AB 1007 process[2]. Changes were restricted to mostly input factors (electricity generation factors, transportation distances, etc.) with no changes in methodology inherent in the original GREET model. This California-modified GREET model formed the basis for all the fuel pathways published by staff before July 2008. Starting July 1, 2008, staff with assistance from Life Cycle Associates, has developed a new version of the CA-GREET model. This CA-GREET v1.8b model uses the current version of the GREET model published by Argonne National Laboratory (v 1.8b). Necessary changes have been made to incorporate CA specific factors into the Argonne GREET v1.8b model. A draft version of the new CA-GREET v1.8b model is expected to be made available for download from the Low Carbon Fuel Standard website in early August (http://www.arb.ca.gov/fuels/lcfs/lcfs.htm).

The values shown in this document are from the draft CA-GREET v1.8b model and are preliminary draft values at this time. Staff is in the process of evaluating them to assess areas where revisions may be necessary. The areas that staff may revise include emission factors, energy intensity factors, percent fuel shares, transport modes and their shares, etc.

This document first details the WTT energy and inputs required to produce liquid hydrogen starting with the recovery, processing, and transport of North American Natural Gas (NA-NG) as feedstock to hydrogen plants in California (section 1), production of gaseous hydrogen (section 2), hydrogen liquefaction (section 3), and finally, distribution and storage (section 4) for use in California. The electricity mix assumed is the *California marginal mix* (NG combined cycle plants plus the non-combustion renewables to satisfy the Renewable Portfolio Standard). WTT greenhouse gas emissions are also calculated based on the energy results above. The TTW part includes the use of liquid hydrogen in a fuel cell vehicle.

[1] http://www.transportation.anl.gov/software/GREET/
[2] http://www.energy.ca.gov/ab1007/

Several general descriptions and clarification of terminology used throughout this document are:

- GREET employs a recursive methodology to calculate energy consumption and emissions. To calculate WTT energy and emissions, the values being calculated are often utilized in the calculation. For example, crude oil is used as a process fuel to recover crude oil. The total crude oil recovery energy consumption includes the direct crude oil consumption AND the energy associated with crude recovery (which is the value being calculated).

- Btu/mmBtu is the energy input necessary in Btu to produce one million Btu of a finished (or intermediate) product. This description is used consistently in GREET for all energy calculations. There are 1055 mmBTU per 1 MJ.

- gCO_2e/MJ provides the total greenhouse gas emissions on a CO_2 equivalent basis per unit of energy (MJ) for a given fuel. Methane (CH_4) and nitrous oxide (N_2O) are converted to a CO_2 equivalent basis using IPCC global warming potential values and included in the total.

- GREET assumes that VOC and CO are converted to CO_2 in the atmosphere and includes these pollutants in the total CO_2 value using ratios of their molecular weights.

- Process Efficiency for any step in GREET is defined as:
  Efficiency = energy output / (energy output + energy consumed)

- Note that rounding of values has not been performed in several tables in this document. This is to allow stakeholders executing runs with the GREET model to compare actual output values from the CA-modified model with values in this document.

Figure 1 shows the discrete components that form the liquid hydrogen from NA-NG pathway.

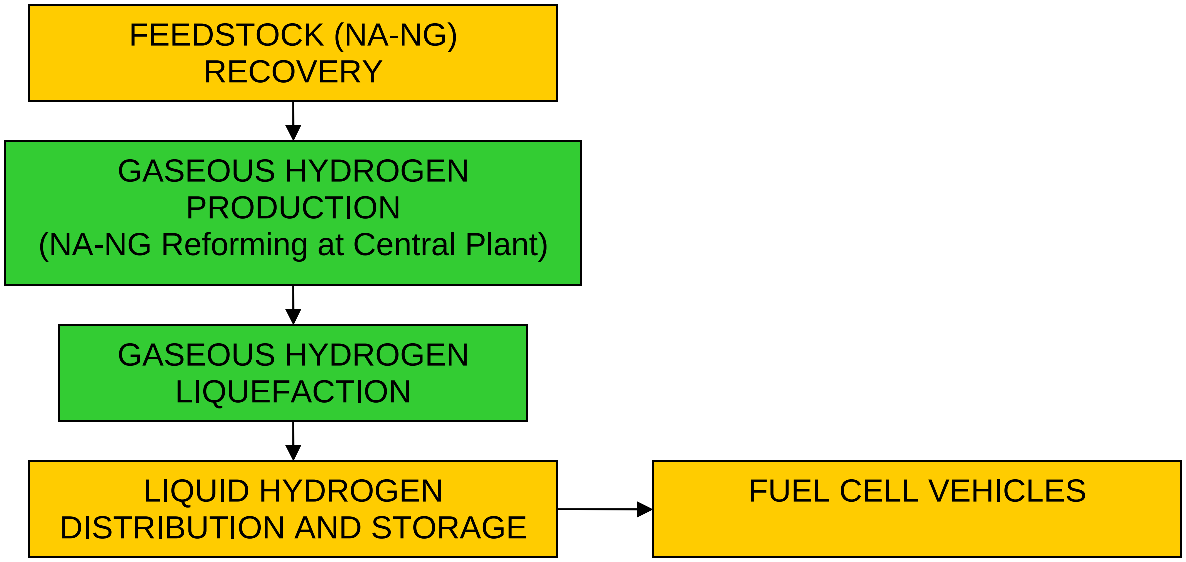

Figure 1. Discrete Components of the Liquid Hydrogen Pathway

Table A provides a summary of the results for this hydrogen pathway. The WTW analysis for hydrogen results in 2,724,418 Btu of energy required to produce 1 (one) mmBtu of available fuel energy. From a GHG perspective, 153.1 g CO_2e/MJ of greenhouse gas emissions are generated during the production and use of hydrogen in a fuel cell vehicle. *Note that this pathway assumes North American natural gas as feedstock.*

Table A. Summary of Energy Consumption and GHG Emissions for Liquid Hydrogen

	Energy Required (Btu/mmBtu)	**% Energy Contribution**	**GHG Emissions (gCO_2e/MJ)**	**%Emissions Contribution**
Well to Tank				
Feedstock	73,323	3%	8.1	5%
Hydrogen Production	430,522	16%	80.9	53%
Hydrogen Liquefaction	1,211,397	44%	63.6	42%
Distribution and Storage	9,176	0%	0.55	0%
Total (WTT)	**1,724,418**	**63%**	**153.1**	**100%**
Tank to Wheel				
Carbon/Energy in Fuel	1,000,000	37%	0	0
Vehicle CH_4 and N_2O			**0**	0
Total WTW	**2,724,418**	**100%**	**153.1**	**100%**

Note: percentages may not add to 100 due to rounding

Figure 2 depicts the relative contribution of each discrete component of this pathway to the total energy use and total GHG emissions. From an energy viewpoint, the hydrogen liquefaction step (44%) and energy in fuel (37%) comprise the bulk of the energy contributions to the WTW pathway. From a GHG emissions perspective, hydrogen production (53%) and liquefaction (42%) dominate the GHG contributions to this pathway.

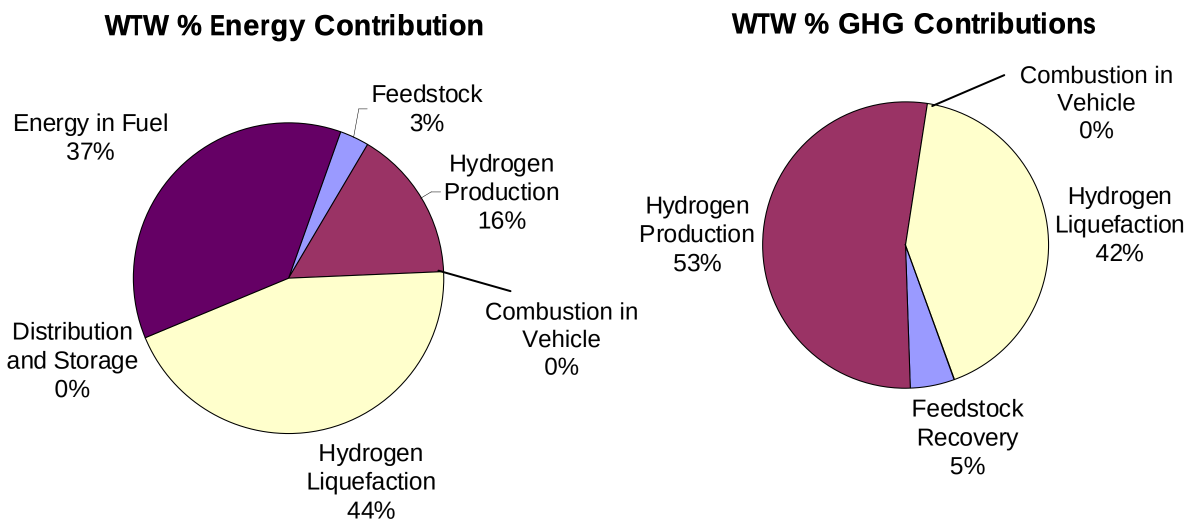

Figure 2. Energy and GHG Contributions of the Liquid Hydrogen Pathway

The following sections provide summaries of each of the WTW components of this pathway. Expanded details are provided in Appendix A. A table of all input values and assumptions is provided in Appendix B. For detailed calculations regarding the energy use and emissions associated with recovery, processing and transport of the feedstock used here (Natural Gas) please refer to a companion document "Detailed California-Modified GREET Pathway for Compressed Natural Gas (CNG) from North American Natural Gas", (referred to as CNG document in sections to follow). For detailed calculations regarding electricity used here as an energy source, please refer to another companion document "Detailed California-Modified GREET Pathway for Electricity" (referred to as Electricity document in sections to follow). The electricity document was generated for average electricity but the use in this document has considered only a marginal electricity mix. Modifications will be necessary to adjust for the different resource mixes in the average and marginal cases of electricity generation. Both the companion documents are available on the Low Carbon Fuel Standard website.

Feedstock Recovery, Processing and Transport

Tables B and C provide a summary of the energy consumption and associated GHG emissions from recovery, processing and transport of the feedstock (North American Natural Gas) to the hydrogen plant. Calculation details are provided in Appendix A.

Table B. Total Energy Consumption for Feedstock Recovery, Processing and Transport to the Hydrogen Plant

Fuel Type	Btu/mmBtu
Natural Gas Recovery	31,206
Natural Gas Processing	31,469
Natural Gas T&D	10,648
Total	**73,323**

Table C. Total GHG Emissions from Feedstock Recovery, Processing and Transport to the Hydrogen Plant, g/mmBtu

	*CO_2	CH_4	N_2O	GHG $gCO_2e/mmBtu$	GHG gCO_2e/MJ
Natural Gas Recovery	1,710.043	77.267	0.028	3,495.385	3.313
Natural Gas Processing	3,029.579	33.065	0.028	3,798.398	3.600
Natural Gas T&D	547.484	29.391	0.015	1,227.949	1.164
Total	**5,287.1**	**139**	**0.1**	**8,521.7**	**8.1**

* Includes contribution from CO and VOC

Gaseous Hydrogen Production

Tables D and E provide a summary of the energy consumption and associated GHG emissions from hydrogen production. Natural gas has two applications in the hydrogen pathway. It is both a process fuel (i.e. it provides energy to the system) and a feedstock (i.e. the origin of the hydrogen). Calculation details are provided in Appendix A.

Table D. Total Energy Consumption by Fuel Type for Gaseous Hydrogen Production

Fuel Type	Btu/mmBtu
Natural Gas (Process Fuel)	256,210
Electricity	1,608
Natural Gas (Feedstock)	172,704
Total	**430,522**

Table E. Total GHG Emissions from Gaseous Hydrogen Production, g/mmBtu

	*CO_2	CH_4	N_2O	GHG $gCO_2e/mmBtu$	GHG gCO_2e/MJ
Natural Gas (Process Fuel)	15,160.53	33.44	0.092	15,957.034	15.12
Electricity	84.25	0.190	0.002	89.24	0.08
Natural Gas (Feedstock)	68,738.15	22.36	0.011	69,255.84	65.64
Total	**83,982.9**	**56**	**0.1**	**85,302.1**	**80.9**

* Includes contribution from CO and VOC

Hydrogen Liquefaction

Tables F and G provide the energy consumption and associated GHG emissions from liquefaction of the gaseous hydrogen. Calculation details are provided in Appendix A.

Table F. Total Energy Consumption for the Liquefaction Step

Fuel Type	Btu/mmBtu
Electricity	1,208,346
Feedstock Loss	3,051
Total Energy	**1,211,397**

Table G. Total GHG Emissions from the Liquefaction Step, g/mmBtu

	*CO_2	CH_4	N_2O	GHG $gCO_2e/mmBtu$	GHG gCO_2e/MJ
Electricity	63,320.3	142.9	1.6	67,073	**63.6**

* Includes contribution from CO and VOC

Liquid Hydrogen Distribution and Storage

Tables H and I summarize energy consumption and GHG emissions from liquid hydrogen distribution and storage. Calculation details are provided in Appendix A.

Table H. Energy Use for Liquid Hydrogen Distribution and Storage

Fuel Type	Btu/mmBtu
Distribution Truck Energy	7,299
Distribution Feedstock Loss	60
Storage Feedstock Loss	1,816
Total Energy	**9,176**

Table I. GHG Emissions from Liquid Hydrogen Distribution, g/mmBtu

	*CO_2	CH_4	N_2O	GHG $gCO_2e/mmBtu$	GHG gCO_2e/MJ
Distribution Truck	563.1	0.63	0.01	581.6	**0.55**

* Includes contributions from VOC and CO.

Vehicle N_2O and CH_4

Since Fuel Cell vehicles are assumed to generate no emissions, all CO2, CO, VOC, CH_4 and N_2O emissions are assumed to be zero. The details are shown in Table J.

Table J. Energy Use and GHG Emissions From Hydrogen, g/mmBtu

	*CO_2	CH_4	N_2O	GHG $gCO_2e/mmBtu$	GHG gCO_2e/MJ
Fuel Cell Vehicles	0	0	0	0	**0**

* Includes contributions from VOC and CO.

APPENDIX A

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SECTION 1: FEEDSTOCK RECOVERY, PROCESSING AND TRANSPORT TO THE HYDROGEN PLANT

1.1 Energy and Emissions for Feedstock Recovery, Processing and Transport

This hydrogen pathway assumes that North American natural gas is used as the feedstock. For a detailed description of North American Natural gas recovery, processing and transport please refer to the CNG pathway document released earlier.

The energy and emissions for natural gas recovery, processing and transport are multiplied by the hydrogen pathway loss factors (L1, L2, and L3) which are described in sections 3.1 and 4.1. These are the losses associated with boil-off of the liquid hydrogen at the central plant, during transport, and from storage tanks at the hydrogen fueling station, respectively. Table 1.1 provides the energy consumption associated with the feedstock while Table 1.2 provides the GHG emissions.

Table 1.1 Energy Consumption for Feedstock Recovery, Processing and Transport, Btu/mmBtu

Process*	Total Energy Use*	Energy Use with Loss Factors Applied
Natural Gas Recovery	31,053	31,206
Natural Gas Processing	31,315	31,469
Natural Gas Transport	10,596	10,648
Total	**72,963**	**73,323**

Note: * See CNG pathways document released April 2008 for more details. Loss Factor = $L_1 * L_2 * L_3$ = 1.0005. (See sections 1.3 and 1.4)

Above results are shown in the example calculation below:
For Natural Gas Recovery: 31,053 (Btu/mmBtu)*1.005 = 31,206 Btu/mmBtu

Table 1.2 GHG Emissions From Feedstock Recovery, Processing and Transport, g/mmBtu

Process	CH_4	N_2O	CO_2*	GHG, gCO_2e/mmBtu	GHG, gCO_2e/MJ
Natural Gas Recovery	77.3	0.03	1,710	3,495.4	3.3
Natural Gas Processing	33.1	0.03	3,029.6	3,798.4	3.6
Natural Gas Transport	29.4	0.015	547.5	1,227.95	1.12
Total	139.7	0.07	5,287.1	8,521.7	8.1

* Includes contributions from VOC and CO. CH_4 and N_2O also are converted to CO_2e. Hydrogen pathway loss factors applied to all values. See CNG fuel pathways released April 2008 for details calculations

SECTION 2: GASEOUS HYDROGEN PRODUCTION

2.1 Energy Use for Gaseous Hydrogen Production

Once the natural gas is at the hydrogen plant, gaseous hydrogen is produced through steam reforming. There are three key assumptions made to calculate direct energy consumption for natural gas recovery:

- Process efficiency (71.5%, GREET Default)
- Fuel shares (split of total energy consumed by fuel type, GREET Default)
- Percent of the total natural gas that is utilized as a feedstock (83% of the natural gas consumed becomes hydrogen; the balance is used as a process fuel.)

The assumed process efficiency of 71.5% means that 0.715 Btu of hydrogen are produced from each Btu of direct energy consumed. The efficiency assumption is coupled with an assumed split of fuels used in natural gas recovery to arrive at direct energy use by fuel to produce hydrogen. The results of this calculation are provided in Table 2.1.

Table 2.1 Calculation of Direct Energy Consumption to Produce Gaseous Hydrogen

Process Fuel Type	**Fuel Shares**	**Relationship of Production Efficiency and Fuel Shares**	**Direct Energy Consumption, Btu/mmBtu**
Natural Gas (Process + Feedstock)	99.8%	$(10^6)(1/\ 71.5\% - 1)(99.8\%)$	397,804
Electricity	0.2%	$(10^6)(1/71.5\% - 1)(0.2\%)$	797
Total Direct Energy Consumption for Hydrogen Production			**398,601**

Once the total natural gas consumption is determined it must be split into two parts: process fuel and feedstock. The baseline assumption is that 83% of the natural gas goes to hydrogen (feedstock) while 17% is used as a process fuel. The amount of natural gas utilized as a process fuel is calculated as follows:

Natural Gas (Process Fuel) = (10^6/production efficiency – electricity) * 17%
= (10^6/0.715 – 797) * 17% = 237,627 Btu/mmBtu

Natural Gas (Feedstock) = Total Natural Gas Use – Process Natural Gas
= 397,804 – 237,627 = 160,178 Btu/mmBtu

The values provided in Table 2.1 are *direct* energy consumption for the hydrogen production step. This is not the *total* energy required however, since GREET accounts for the “upstream” energy associated with each of the fuels utilized to recover natural gas. For example, 797 Btu of electricity are required to produce each mmBtu of hydrogen. The total energy associated with the 797 Btu of electricity includes the energy to recover the feedstocks and the losses associated with electric power plant efficiency and transmission.

Table 2.2 demonstrates how the direct energy values shown in Table 2.1 are utilized to calculate total energy required to produce hydrogen. Table 2.3 provides details on the values used in Table 2.2.

Table 2.2 Calculation of Total Energy Consumption from Direct Energy Consumption for Hydrogen Production

Fuel Type	Formula	Btu/mmBtu
Natural Gas (Process Fuel)	(A + A*(B + C + D) /10^6) * L1 * L2 * L3	256,210
Electricity	(E *(F + G)/ 10^6) * L1 * L2 * L3	1,608
Natural Gas (Feedstock)	(H + H*(B + C + D) /10^6) * L1 * L2 * L3	172,704
Total energy for hydrogen production		**430,522**

Table 2.3 Values Used to Calculate Total Energy Use from Direct Energy Use

Variable	Description
A	237,627 Btu of process NG fuel used per mmBtu hydrogen produced. (see discussion below Table 2.1)
B	Total energy to recover NG is 31,007 Btu/mmBtu NG. (See CNG document)
C	31,315 Btu are used to process 1 mmBtu NG. (See CNG document)
D	10,596 Btu are used to transport 1 mmBtu NG to the hydrogen plant. (See CNG document)
E	797 Btu of direct electricity used to recover 1 mmBtu NG. (see Table 2.1)
F	120,830 Btu of energy used to recover and transport sufficient feedstock to generate 1 mmBtu electricity. (See Electricity document but modified for marginal production)
G	1,886,091 Btu used to produce 1 mmBtu electricity. (See Electricity document but modified for marginal production)
H	160,178 Btu of feedstock NG used per mmBtu hydrogen produced. (see discussion below Table 2.1)
L1	1.003 loss factor for hydrogen storage at plant after liquefaction, a GREET calculation. (See section 3.1)
L2	1.0001 loss factor for liquid hydrogen transport, a GREET calculation. (See section 4.1)
L3	1.002 loss factor for liquid hydrogen storage, a GREET calculation. (See section 4.1)

2.2 GHG Emissions from Gaseous Hydrogen Production

The emission calculation methodology is analogous to the energy calculations. First the direct emissions are calculated and then the upstream emissions (due to recovery and processing of each direct fuel used) are added. To calculate the direct emissions, direct energy by fuel type (here only natural gas) is multiplied by the technology share (% fired in turbine, boiler, engine etc) and then multiplied by the appropriate emission factor. Emissions of CO_2, N_2O and CH_4 due to combustion are quantified. In addition, emissions of VOC and CO are quantified and assumed to convert to CO_2 in the atmosphere. The conversions are calculated as follows:

CO (g/mmBtu) * 44 gCO_2/gmole / 28 gCO/gmole * 0.43 gC/gCO
VOC (g/mmBtu) * 44 gCO_2/gmole / 12 gC/gmole * 0.85 gC/gVOC

In this case, the only process fuel with direct emissions is natural gas and it is assumed (GREET Default) to be fully combusted in an industrial/utility boiler. Table 2.4 provides the emission factors utilized. For a description of the modified emission factors, please refer to Tables 5.1 through 5.4 in the AB1007 “Well-to-Tank” Report.

Table 2.4 Natural Gas Fired Utility Boiler Emission Factors, g/mmBtu

GHG	Emission Factor, g/mmBtu	Notes
VOC	0	Assume offsets required (new plant)
CO	8.5	BACT. GREET value is 16.42
CH_4	1.13	AP-42 (GREET value is 1.10)
N_2O	0.315	AP-42 (GREET value is 1.1)
CO_2	58,215	GREET Default

The direct emissions from hydrogen production are based on the direct energy use (237,627 Btu/mmBtu – the process natural gas not the feedstock natural gas, see Section 2.1). Multiplying the direct energy by the emission factors in Table 2.4 yields the direct emissions provided in Table 2.5. Note that there are no direct emissions from direct electricity use. For the portion of the natural gas that becomes feedstock, the carbon ultimately goes to CO_2 and this value is shown.

The natural gas feedstock CO_2 emissions are calculated by determining the CO_2 potential (all carbon to CO_2) due to the total natural gas input (process + feedstock) and subtracting the carbon emissions of the natural gas process share:

CO_2 Potential = (Process NG + Feedstock NG + 1,000,000) x NG density / NG LHV x NG Carbon content x ratio of molecular weights

= 1,397,804 Btu/mmBtu x 20.4 g/scf / 930 Btu/scf x 0.724 gC/gNG x 44/12

= 81,396 g CO_2/mmBtu

Therefore, the CO_2 potential emissions associated with the feedstock natural gas are the total less the process and is given by:

Feedstock CO_2 Potential = 81,396 – 13,837 = 67,559 g CO_2/mmBtu

Table 2.5 Direct Emissions from Hydrogen Production, g/mmBtu

	VOC	CO	CH_4	N_2O	CO_2	CO_2*	GHG	GHG gCO_2e/MJ
Natural Gas Process	0	2.02	0.269	0.075	13,833	13,837	13,865	13.1
Electricity	0	0	0	0	0	0	0	0
Natural Gas Feedstock	0	0	0	0	67,559	67,559	67,559	64.1
Total Direct	**0**	**2.02**	**0.27**	**0.075**	**81,392**	**81,395**	**81,424**	**77.2**

* Includes contributions from VOC and CO. CH_4 and N_2O also are converted to CO_2e.

Table 2.5 above provides direct emissions. Similar to total energy, the total emissions include direct emissions plus the emissions associated with recovery and processing/refining the fuels used to produce hydrogen. Table 2.6 illustrates the calculation methodology for upstream CO_2 emissions for hydrogen production. Similar calculations are performed for the other pollutants. Table 2.7 provides the values used in Table 2.6.

Table 2.6 Calculation of Upstream CO_2 emissions from Direct CO_2 Emissions for Hydrogen Production

Fuel Type	Formula	g/mmBtu
Natural Gas (Process)	$A*(B+C+D)/10^6$	1,241
Electricity	$E (F + G)/ 10^6$	83.8
Natural Gas (Feedstock)	$H*(B+C+D)/10^6$	836.5
Total		**2,161**

Table 2.8 summarizes the upstream emissions for each GHG contributor. The direct and indirect emissions are summed and presented in Table 2.9. Finally, three loss factors are applied (please refer to Table 2.3) and the overall results are presented in Table 2.10.

Table 2.7 Values Used to Calculate Upstream CO_2 Emissions for Hydrogen Production

Variable	Description
A	237,627 Btu of direct NG fuel used per mmBtu hydrogen produced
B	1,685 g CO2/mm Btu NG for NG recovery
C	2,998 g CO2/mmBtu NG for NG processing (1,761 + 1,237)
D	540 g CO2/mmBtu NG for NG transport to the hydrogen plant
E	797 Btu of direct electricity used per mmBtu of hydrogen produced
F	8,773 g/mmBtu CO_2 to produce & transport feedstocks for electricity
G	96,314 g CO_2 to produce 1 mmBtu electricity
H	160,178 Btu of NG use as feedstock per mmBtu hydrogen produced

Table 2.8 Upstream GHG Emissions (emissions associated with recovery & production of direct fuels used) for Hydrogen Production, g/mmBtu

	VOC	CO	CH_4	N_2O	CO_2
Natural Gas (Process)	1.66	2.13	33	0.017	1,241.1
Electricity	0.009	0.02	0.2	0.002	83.8
Natural Gas (Feedstock)	1.12	1.44	22.25	0.011	836.6
Total Indirect	**2.8**	**3.6**	**55.4**	**0.03**	**2,161.4**

Note: See table 2.6 for detail calculations

Table 2.9 Direct plus Upstream GHG Emissions for Hydrogen Production, g/mmBtu

	VOC	CO	CH_4	N_2O	CO_2
Natural Gas (Process)	1.66	4.15	33.28	0.092	15,074.5
Electricity	0.009	0.023	0.2	0.002	84
Natural Gas (Feedstock)	1.12	1.435	22.25	0.011	68,395.3
Total	**2.8**	**5.6**	**55.7**	**0.1**	**83,554**

Note: Table 2.5 results plus Table 2.8 results

Table 2.10 Total GHG Emissions for Hydrogen Production, g/mmBtu

	CO_2*	CH_4	N_2O	GHG gCO_2e/mmBtu	GHG gCO_2e/MJ
Natural Gas (Process)	15,160	33.4	0.1	15,957	15.1
Electricity	84	0.2	0.002	89	0.1
Natural Gas (Feedstock)	68,738	22.4	0.01	69,255	65.6
Total	**83,983**	**56**	**0.1**	**85,302**	**81**

* Includes contributions from VOC and CO. CH_4 and N_2O also are converted to CO_2e.

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SECTION 3: HYDROGEN LIQUEFACTION

3.1 Energy Use for Hydrogen Liquefaction

The next step in the hydrogen pathway is liquefaction. The methodology to calculate direct and total energy for liquefaction is the same as that to calculate direct and total energy for hydrogen production. The key assumptions are:

- Process efficiency (62.5%, GREET Default)
- Fuel shares (100% electricity, GREET Default)
- Hydrogen boil off (utilized to calculate liquefaction loss factor)

The electricity mix assumed is the California marginal mix (NG combined cycle plants plus the non-combustion renewables to satisfy the Renewable Portfolio Standard).

Table 3.1 illustrates how direct energy consumption is calculated based on process efficiency and fuel shares.

Table 3.1 Calculation of Direct Energy Consumption for Hydrogen Liquefaction from Assumed Values for Efficiency and Fuel Shares

Process Fuel Type	Fuel Shares	Relationship of Efficiency (0.625) and Fuel Shares	Direct Energy Consumption, Btu/mmBtu
Electricity	100%	$(10^6)(1/0.625 – 1)(1)$	600,962
Feedstock Loss	n/a	See discussion below	3,046
Direct Energy Consumption for Hydrogen Liquefaction			**604,007**

The feedstock loss is the energy associated with "boil off" losses of stored liquid hydrogen at the production plant. The quantity of hydrogen loss is calculated as follows:

$$H_2 \text{ loss (g/mmBtu)} = \frac{(0.3\%/\text{day} \times 5 \text{ days} / 30{,}500 \text{ Btu/gal} \times 268 \text{ g/gal} \times 10^6) \times (1\text{-}80\%)}{(1 – 0.3\%/\text{day} \times 5 \text{ days})}$$

$$= 26.762 \text{ g/mmBtu}$$

As can be seen, an 80% boil-off recovery is assumed. The energy associated with this loss is calculated as follows:

$$\text{Feedstock Loss (Btu/mmBtu)} = 26.762 \text{ g/mmBtu} / 268 \text{ g/gal} \times 30{,}500 \text{ Btu/gal}$$

$$= 3{,}046 \text{ Btu/mmBtu}$$

Note: An error has been found in the loss factor calculations in CA-GREET version developed as part of the AB 1007 analysis. The error overestimates the loss factors due to boil-off of liquid hydrogen because it does not include the boil-off recovery rates (80% assumed here). The AB1007 values for this pathway are therefore overestimated. This error has been corrected in GREET1.8b and has been corrected here.

The loss factor associated with storage of liquid hydrogen at the plant (L1 in Table 2. 3) is based on this boil-off value. The loss factor is calculated as follows:

Loss Factor L1 = 1 + 26.762 g/mmBtu / 268 g/gal * 30,500 Btu/gal / 10^6 Btu/mmBtu
= 1.003

The values provided in Table 3. 1 are direct energy consumption per Btu for the hydrogen liquefaction step. This is not the total energy required however, since GREET accounts for the "upstream" energy associated with each of the fuels utilized to recover natural gas. Table 3.2 demonstrates how the direct energy consumption values shown in Table 3.1 and values in Table 3.3 are utilized to calculate total energy required to liquefy hydrogen.

Table 3.2 Calculation of Total Energy Use from Direct Energy Use for Hydrogen Liquefaction

Fuel Type	Formula	Btu/mmBtu
Electricity	A*(B + C)/ 10^6 * L2 * L3	1,208,346
Feedstock Loss	D * L2 * L3	3,051
Total Energy Consumption for Hydrogen Liquefaction		**1,211,397**

Table 3.3 Values Used to Calculate Total Energy Consumption from Direct Energy Consumption for Hydrogen Liquefaction

Variable	Description
A	600,962 Btu of direct electricity used to liquefy 1 mmBtu hydrogen.
B	120,830 Btu of energy used to recover and transport sufficient feedstock to generate 1 mmBtu electricity.
C	1,886,091 Btu used to produce 1 mmBtu electricity.
D	3,046 Btu hydrogen loss per mmBtu hydrogen produced
L2	1.0001 loss factor for liquid hydrogen transport, a GREET calculation. (See section 4.1)
L3	1.002 loss factor for liquid hydrogen storage, a GREET calculation (See section 4.1)

3.2 GHG Emissions from Hydrogen Liquefaction

Because the only process fuel utilized in hydrogen liquefaction is electricity, there are no direct emissions for this step. Table 3.4 provides the upstream CO_2 emission calculations and Table 3.5 provides the values used in the terms of Table 3.4. Table 3.6 provides the upstream emissions for each GHG contributor. Table 3.7 combines the upstream and direct GHG emissions, converts VOC and CH_4 to CO_2, and applies loss factors L2 and L3 (see Table 3.3).

Table 3.4 Calculation of Upstream CO_2 Emissions for Hydrogen Liquefaction

Fuel Type	Formula	g/mmBtu
Electricity	$A*(B + C)/ 10^6$	63,152.7

Table 3.5 Values Used to Calculate Upstream CO_2 Emissions for Liquefaction

Variable	Description
A	600,962 Btu of direct electricity used to liquefy 1 mmBtu hydrogen.
B	8,773 g/mmBtu CO_2 to produce & transport feedstock for electricity production
C	96,314 g CO_2 to produce 1 mmBtu electricity.

Table 3.6 Upstream GHG Emissions (emissions associated with recovery & production of direct fuels used) for Hydrogen Liquefaction, g/mmBtu

	VOC	CO	CH_4	N_2O	CO_2
Electricity	6.9	17.3	142.7	1.6	63,158

Note: See example calculation of CO_2 in Table 3.4

Table 3.7 Total GHG Emissions for Hydrogen Liquefaction, g/mmBtu

	CH_4	N_2O	CO_2*	GHG g CO_2e/mmBtu	GHG gCO_2e/MJ
Electricity	142.7	1.6	63,271	67,073	63.6

* Includes contributions from VOC and CO. CH_4 and N_2O also are converted to CO_2e.

SECTION 4: HYDROGEN DISTRIBUTION AND STORAGE

4.1 Energy Use for Liquid Hydrogen Distribution and Storage

The final step in this hydrogen pathway is delivery by truck and storage at the fueling station. For the delivery component, it is assumed that liquid hydrogen is delivered by heavy duty diesel trucks over a distance of 50 miles directly to retail stations (no intermediate stops at fuel terminals). In addition to truck fuel consumption, there are energy losses associated with hydrogen boil off from the truck. At the retail station, there are no emissions, but there is an energy loss associated with boil-off from storage tanks. Table 4.1 illustrates the energy consumption calculations while Table 4.2 provides the values utilized in the formulas.

Table 4.1. Liquid Hydrogen Distribution and Storage Energy Calculations

Parameter	**Units**	**Formula**	**Value**
Truck Energy Intensity	Btu/ton-mile	(Diesel LHV, Btu/gal) / (truck fuel economy, mi/gal) / (payload, tons)	6,423
Truck Energy Use	Btu/mmBtu	(Liquid H_2 density, g/gal) / (Liquid H_2 LHV, Btu/gal) * (10^6 Btu/mmBtu) / (454 g/lb) / (2000 lb/ton) * (roundtrip miles) * (energy intensity) * (1+WTT diesel energy)	7,299
Truck Feedstock Loss	Btu/mmBtu	((Transit time, days) * (Boil-off rate, %/day)) / (1 – (transit time) * (Boil-off rate)) * 10^6 Btu/mmBtu * (1 – recovery rate)	60
Storage Loss	Btu/mmBtu	((Storage time, days) * (Boil-off rate, %/day)) / (1 – (storage time) * (Boil-off rate)) * 10^6 Btu/mmBtu * (1 – recovery rate)	1,816
Total Distribution and Storage Energy	Btu/mmBtu	Truck Energy + Distribution Loss + Storage Loss	**9,176**

Table 4.2. Values Used to Calculate Distribution and Storage Energy Use

	Units	Value	Comments
Diesel LHV	Btu/gal	128,450	GREET Default
Truck Fuel Economy	Mi/gal	5	GREET Default
Truck Liquid H_2 Payload	Tons	4	GREET Default
Liquid H_2 Density	g/gal	268	GREET Default
Liquid H2 LHV	Btu/gal	30,500	GREET Default
Distance (roundtrip)	Miles	100	GREET Default
WTT diesel energy	Btu/Btu	0.174	GREET Calculation
Truck Transit Time	Days	0.1	GREET Default
Truck Boil-off rate	%/day	0.3%	GREET Default
Truck Boil-off Recovery	%	80%	GREET Default
Storage Time	Days	3	GREET Default
Storage Boil-off rate	%/day	0.3%	GREET Default
Storage Boil-off recovery	%	80%	GREET Default

Two of the loss factors utilized throughout the pathway are quantified at this step: the distribution loss factor L2 and the storage loss factor L3. Similar to the calculation of L1 described in Section 3, L2 and L3 are based on the evaporative hydrogen losses (boil-off). The loss factor is calculated as follows:

Loss factor = 1 + (storage days * loss rate, %/day) /(1 – days * loss rate, %/day) * (1 – recovery rate).

L2 = 1 + (0.1 * 0.3%) / (1 – 0.1 * 0.3%) * (1 – 80%) = 1.0001

L3 = 1 + (3 * 0.3%) / (1 – 3 * 0.3%) * (1 – 80%) = 1.002

4.2 GHG Emissions from Hydrogen Distribution and Storage

The GHG emissions from the distribution and storage consist entirely of emissions from the diesel truck over the 100 mile roundtrip distance. Table 4.3 provides the heavy duty truck emission factors utilized. These VOC and CO emission factors are based on EMFAC2007. The CH_4 and N_2O values are from the Climate Action Registry Reporting Protocol, and the CO_2 value is calculated from fuel composition subtracting out the VOC, CO and methane carbon.

Table 4.3 Heavy Duty Diesel Truck Emission Factors

Pollutant	g/mi	g/mmBtu diesel
VOC	1.2	45.7
CO	4.2	162.1
CH_4	0.03	1.29
N_2O	0.05	2
CO_2	1,998.6	77,798

Note: The g/mi values are converted to a g/mmBtu diesel basis by multiplying by miles/gal, dividing by diesel LHV in Btu/gal and multiplying by one million.
e.g.: for VOC (1.2 g/mi) x (5 miles/gal) / (128,450 Btu/gal) * 10^6 = 45.7 g/mmBtu

Table 4.4 illustrates the equations utilized to calculate distribution emissions and Table 4.5 provides the values used in the equations. Total GHG emissions are provided in Table 4.6 (VOC and CO are converted to CO_2 and a composite CO_2 equivalent value is provided).

Table 4.4 Calculation of Distribution Emissions

Parameter	Formula	Value
Transport Energy Btu diesel/Btu Liquid H_2	(Liquid H_2 Density, g/gal) / Liquid H_2 LHV, Btu/gal) / 454 g/lb / 2000 lb/ton * (Energy Intensity, Btu/ton-mile) * (Roundtrip miles)	0.00622
VOC, g/mmBtu	Transport Energy * (Direct Emission factor + WTT Diesel Emission) of VOC	0.33
CO, g/mmBtu	Transport Energy * (Direct Emission factor + WTT Diesel Emission) of CO	1.09
CH_4, g/mmBtu	Transport Energy * (Direct Emission factor + WTT Diesel Emission) of CH_4	0.6
N_2O, g/mmBtu	Transport Energy * (Direct Emission factor + WTT Diesel Emission) of N_2O	0.013
CO_2, g/mmBtu	Transport Energy * (Direct Emission factor + WTT Diesel Emission) of CO_2	560

Table 4.5 Values Used to Calculate Distribution Emissions

Parameter	Units	Value	Comments
Liquid H_2 Density	g/gal	268	Assumed Value
Liquid H_2 LHV	Btu/gal	30,500	Assumed Value
Energy Intensity	Btu/ton-mile	6,423	See Table 4.1
Roundtrip miles	Miles	100	Assumed Value
WTT Diesel VOC	g/mmBtu	7.62	Calculated Value
WTT Diesel CO	g/mmBtu	12.89	Calculated Value
WTT Diesel CH_4	g/mmBtu	100.42	Calculated Value
WTT Diesel N_2O	g/mmBtu	0.27	Calculated Value
WTT Diesel CO_2	g/mmBtu	12,357	Calculated Value

Example calculation for CO_2 emission: 0.00622 Btu diesel/ Btu Liquid H_2* (77,798 g/mmBtu + 12,357 g/mmBtu) = 560 g/mmBtu (as shown in Table 4.4)

Table 4.6 Total GHG Emissions from Liquid Hydrogen Distribution, g/mmBtu

	CH_4	N_2O	CO_2*	GHG g CO_2e/mmBtu	GHG g CO_2e/MJ
Truck Emissions	0.6	0.013	563.1	581.6	0.55

* Includes contributions from VOC and CO. CH_4 and N_2O also are converted to CO_2e.

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SECTION 5: GHG EMISSIONS FROM VEHICLE

If hydrogen is utilized in a fuel cell vehicle, it is assumed that there are no vehicle CO_2, CO, VOC, CH_4 and N_2O emissions. Hence for this pathway, there are no GHG emissions from the TTW portion of the analysis. All emissions are from the WTT part of the analysis.

APPENDIX B

LIQUID HYDROGEN PATHWAY INPUT VALUES

Scenario: Liquid Hydrogen from North American Natural Gas using California Electricity Marginal Mix

Parameters	Units	Values	Note
GHG Equivalent			
CO_2		1	GREET Default
CH_4		23	GREET Default
N_2O		296	GREET Default
VOC		3.1	GREET Default
CO		1.6	GREET Default
Gaseous Hydrogen Production			
Process Efficiency		71.5%	GREET Default
Percent of Natural gas as feedstock (Balance used as process fuel)		83%	GREET Default
Process Fuel Shares			
Residual Oil		0%	GREET Default
Conventional Diesel		0%	GREET Default
Conventional Gasoline		0%	GREET Default
Natural Gas		99.8%	GREET Default
Electricity		0.2%	GREET Default
Natural Gas Equipment Shares			
Industrial Boiler		100%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	58,215	GREET Default
Liquefaction			
Process Efficiency		62.5%	GREET Default
Fuel Shares			
Conventional Diesel		0%	GREET Default
Natural Gas		0%	GREET Default
Electricity		100%	GREET Default
Boil Off Losses			
Loss Rate	%/day	0.3%	GREET Default
Number of Days Stored	Days	5	GREET Default
Recovery Rate		80%	GREET Default
Liquid Hydrogen Transport			
Heavy Duty Truck		100%	GREET Default
Miles		50	GREET Default
Boil Off Losses			
Loss Rate	%/day	0.3%	GREET Default
Number of Days Stored	Days	0.1	GREET Default
Recovery Rate		80%	GREET Default
Liquid Hydrogen Storage at Refueling Station			
Boil Off Losses			
Loss Rate	%/day	0.3%	GREET Default
Number of Days Stored	Days	3	GREET Default
Recovery Rate		80%	GREET Default