Analysis of Hydrogen Export Potential

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National Renewable Energy Laboratory
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DOE Hydrogen Program
2022 Annual Merit Review and Peer Evaluation Meeting

Project ID: SA177

Project Goal: Assess Hydrogen Export Opportunity and Potential to Leverage Existing Liquefied Natural Gas (LNG) Infrastructure

Vision

Understand hydrogen export potential, competitiveness of transport paths, access to cheap, clean electricity and how, if at all, existing LNG facilities could be leveraged

What

- Quantify export market potential and competitiveness of multiple transport paths
- Quantify hydrogen technical potential and access to cheap, clean electricity near LNG facilities
- Understand and quantify what cost or time savings may be achieved from leveraging existing LNG infrastructure, if any

How

- Assess existing literature, public announcements, previously conducted DOE research and other publicly available technical reports
- Leverage NREL past resource assessment work, NREL's U.S. Utility Rate Database (USURDB) and EPA's eGRID data
- Interview industry exports in cryogenic technologies and derive approximate cost estimates

Why

- To understand if such opportunities exist and if so, how to leverage infrastructure to economically scale exports

Overview: Analysis of Hydrogen Export Potential

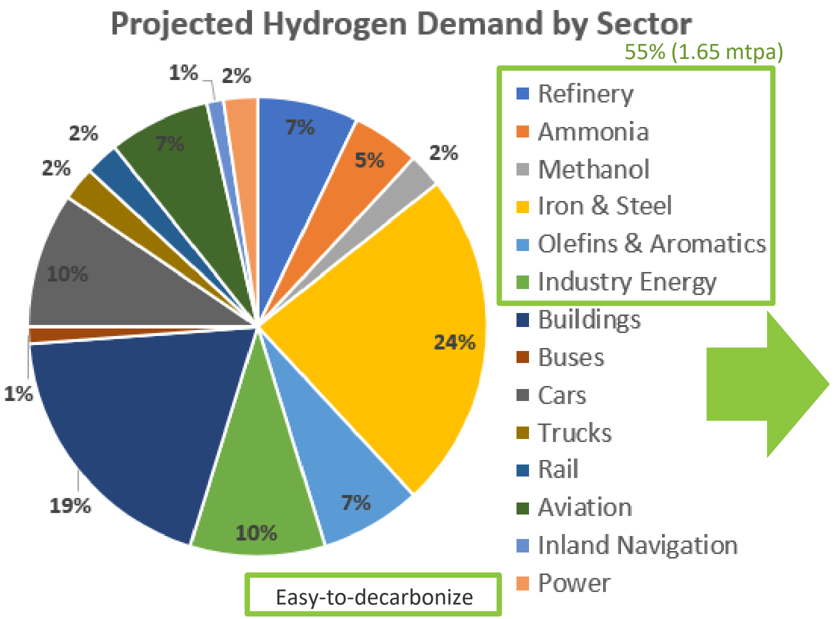
Timeline	Partners
Start: May 2021 End: April 2022 90% complete* *As of April 25th, 2022	***National Labs*** NREL - Mark Chung, PI Argonne National Lab – Ed Frank Argonne National Lab – Amgad Elgowainy Argonne National Lab – Krishna Reddi
Budget	
Total project budget: $175k • DOE Share: $175k • DOE funds spent*: $30.4k *as of ~03/01/2022	

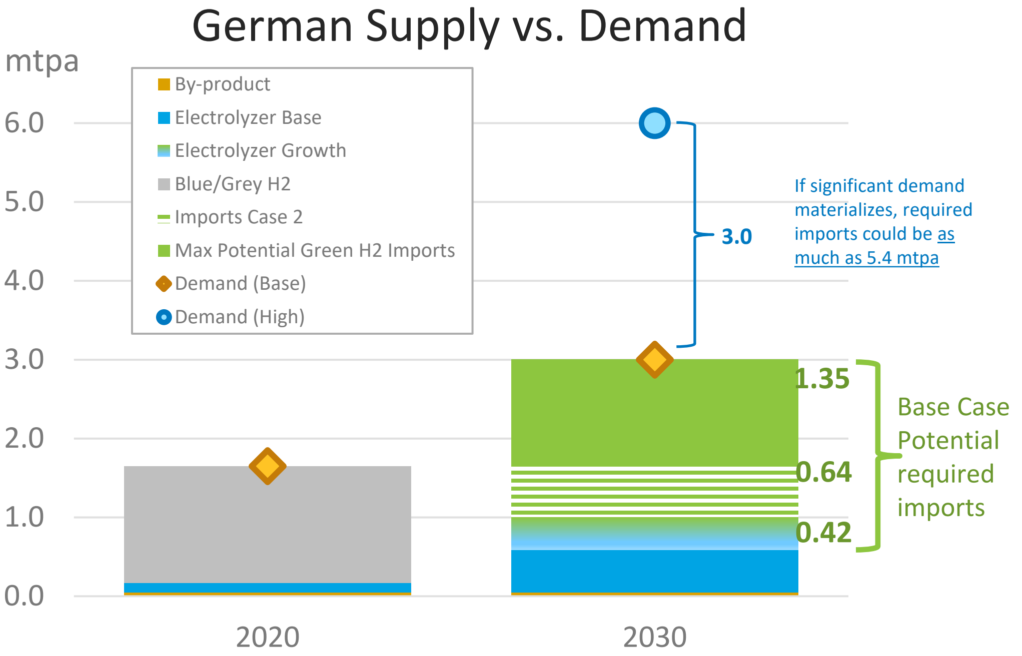
Approach (1/1): Analysis of Hydrogen Export Potential

Task Description	Status	Lab	Challenges / Barriers
Quantify potential export market size	Complete	NREL	High uncertainty without deeper analysis
Quantify and compare cost competitiveness of hydrogen export paths	Complete	NREL	None
Quantify hydrogen production technical potential within 200-mile radius of existing LNG export terminals	Complete	NREL	None
Identify access to clean, cheap electricity within a 200-mile radius of LNG export terminals	In Progress	NREL	Difficult to know with certainty the emissions from grid electricity
Understand and quantify what cost or time savings may be achieved from leveraging existing LNG infrastructure, if any	Complete	ANL	Existing literature is sparse. Rely primarily of expert interviews.

Accomplishments and Progress (1/10):
Quantifying German Import Potential

Base case and High case: Max potential green hydrogen imports by 2030 could be **2.41 mtpa**, assuming base case demand growth and only 5 GW of electrolyzer capacity installed. Should significant demand materialize, required imports could reach **5.4 mtpa.** Low case suggests 1.08 mtpa of required imports.





Source: Opportunities for Hydrogen Energy Technologies Considering the National Energy & Climate Plans, German National Hydrogen Strategy

Accomplishments and Progress (2/10):
Quantifying International Import Potential

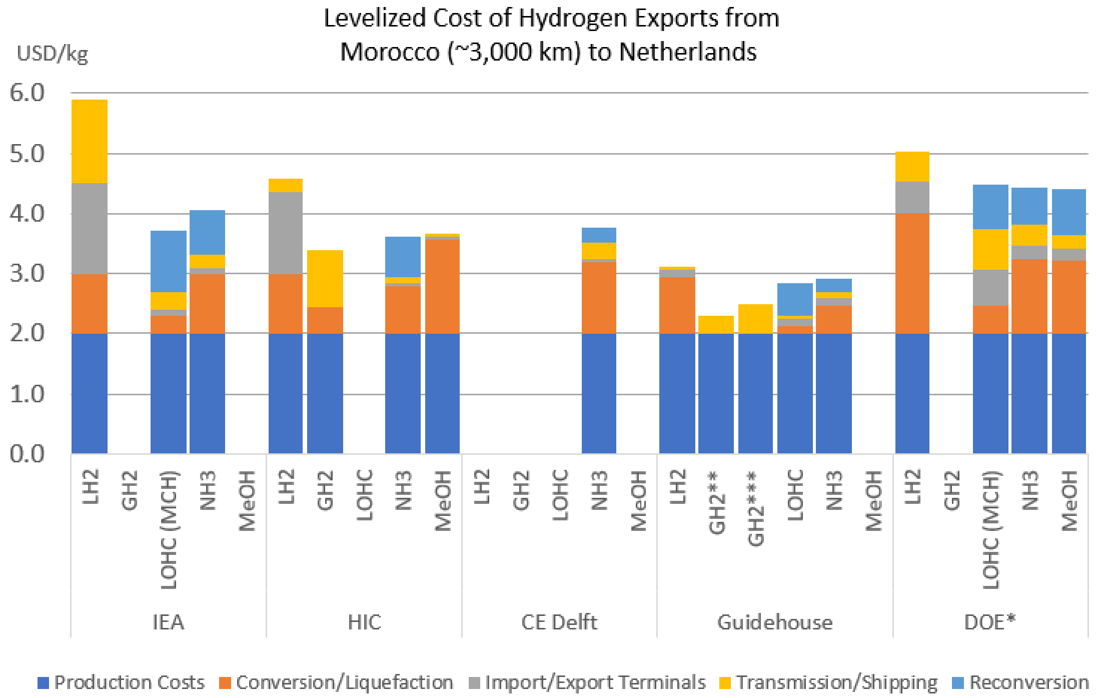
International export market potential could reach 40+ mtpa by 2050

- EU to import **19 mtpa by 2035** to support energy and feedstock transition. This quantity is far beyond limits of what existing infrastructure can handle. – Hydrogen Import Coalition
- EU to import **30 mtpa by 2050**, half of potential demand. – World Energy Council Report
- Korea to import **2 mtpa by 2030** – Korea's Ministry of Trade, Industry and Energy
- Japan will require **5-10 mtpa** imported hydrogen by 2050 – Ministry of Energy Trade and Industry
  - Developing LH2 capabilities with Australia. Trying to demonstrate LH2 supply chain in the 2020's for commercial deployment in 2030's. Also looking to research MCH and ammonia as alternative pathways.
  - Large LNG importers are likely to be large hydrogen importers. Japan imported 85 MM tons of LNG in 2016.

Sources: METI Basic Hydrogen Strategy 2017, METI Basic Hydrogen Strategy slides, Australia National Hydrogen Strategy, S&P Global Insights – South Korea Hydrogen, Clean Energy Wire Article, World Energy Council paper, S&P Global Insights – European Hydrogen, World Energy Council Report, Hydrogen Import Coalition Report

Accomplishments and Progress (3/10):
Transport Cost Comparison

DOE cost estimates of LH2 transport in range of third-party estimates. All studies concur LH2 for export is the most expensive transport pathway, but cost estimates vary widely.



Acronyms Defined:

- LOHC = Liquid organic hydrogen carrier (dibenzyl toluene), except DOE which used MCH
- MCH = Methylcyclohexane
- NH3 = Ammonia
- MeOH = Methanol
- GH2 = Gaseous hydrogen via pipeline
- LH2 = Liquid hydrogen via ocean tanker

Sources: NREL Research; Ahluwalia, 2021; Elgowainy, 2021; International Energy Agency, Hydrogen Import Coalition, CE Delft, Guidehouse

* DOE estimates are based on research done as of May 2021.

** Green hydrogen from Morocco via new build 48’’ pipeline

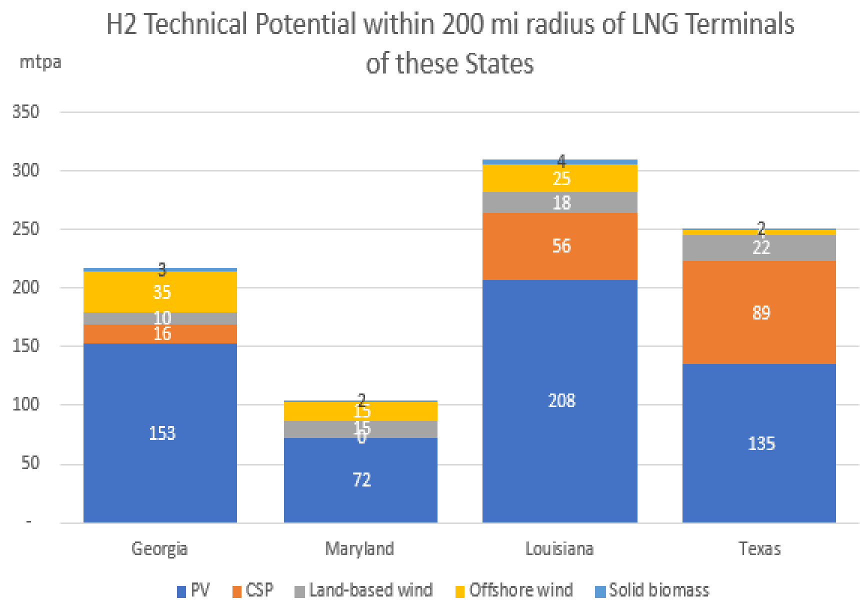
*** Green hydrogen from Seville, Spain to Hamburg, Germany via new 48’’ pipeline

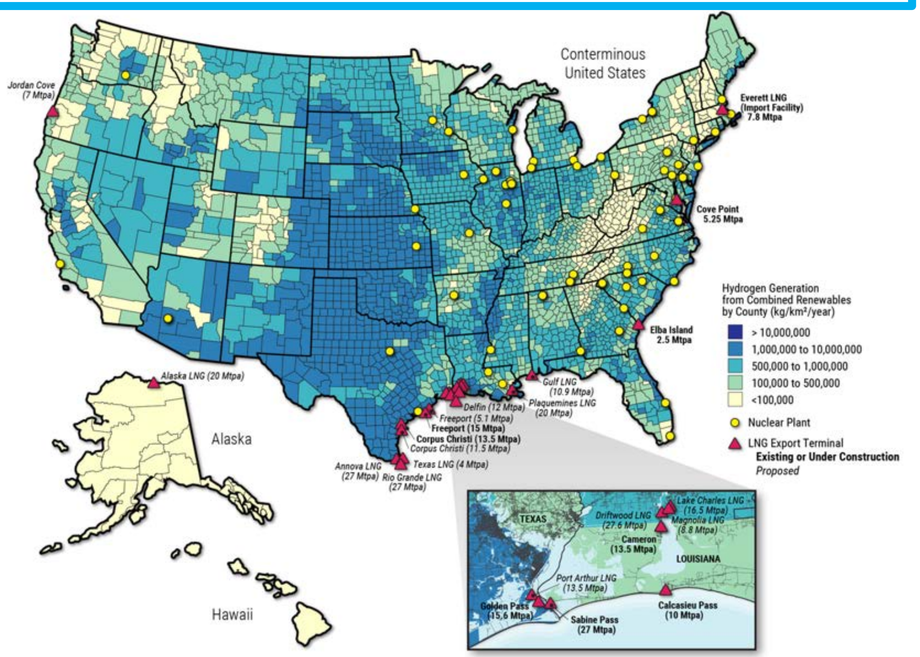
Assumes production cost of 2 USD/kg for comparison purposes

Accomplishments and Progress (4/10):

U.S. Technical Potential

Hydrogen production technical potential amounts to ~885 mpta, but how can existing LNG infrastructure benefit large-scale hydrogen exports?





Note: Technical production potential differs from economic potential as it does not include economic or market constraints.
Resource Assessment for Hydrogen Production, Connelly et al. 2020

Accomplishments and Progress (5/10):
Can existing LNG Export Terminals be Leveraged?

BACKGROUND

- US decarbonization plans call for developing hydrogen export capacity
- The US is the world's largest LNG exporter
- Historically, the US deployed the largest H2 liquefaction plants (individually and total fleet capacity).

BARRIER

- Hydrogen liquefaction is expensive and energy intensive

PROJECT OBJECTIVE

- Determine whether US NG liquefaction plants and terminals can be leveraged to reduce hydrogen liquefaction cost

PROJECT APPROACH

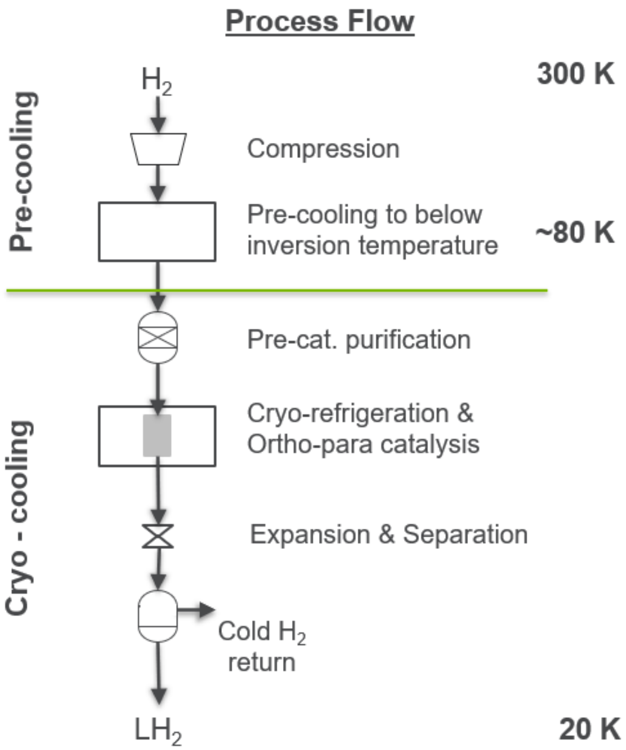
- Literature search for prior analysis
- High level assessment calculations

Accomplishments and Progress (6/10):
Can existing LNG Export Terminals be Leveraged?

TECHNICAL BACKGROUND

- H_2 liquefaction comprises two steps
  - Pre-cooling to below the inversion temp.
  - Cryo-cooling to liquefaction
- Existing H_2 liquefiers use LN2 for pre-cooling
  - Achieve pre-cooled temp. of ~80-90K
- LNG refrigeration almost reaches H_2 inversion temperature

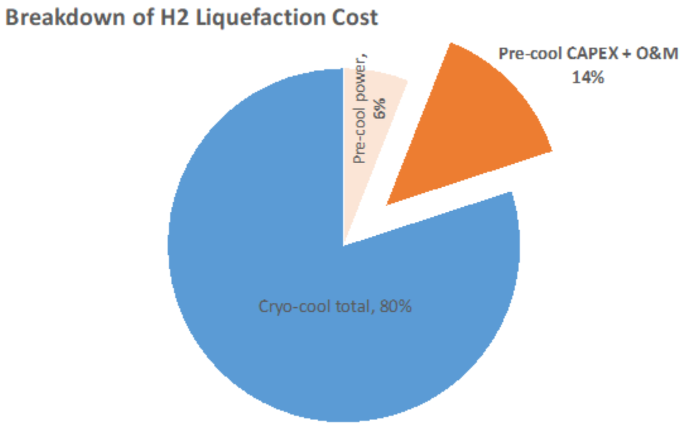
LNG facilities can only contribute to the pre-cooling portion of the hydrogen liquefaction process



Accomplishments and Progress (7/10):
Can existing LNG Export Terminals be Leveraged?

H2 LIQUEFIER COST

- CAPEX and O&M are almost entirely from compressors used for liquefaction
- Used compressor power as a surrogate to estimate shares of liquefaction cost arising from pre-cooling vs. cryo- cooling



Only ~14% of the liquefaction cost is a *candidate* for cost savings from leveraging an LNG facility

NREL Argonne

Accomplishments and Progress (8/10):
Can existing LNG Export Terminals be Leveraged?

WHAT PORTION OF THE 14% MIGHT ACTUALLY BE AVOIDED?

- From discussions with LNG engineers and analysts:
  - Offtake agreements cover LNG facility lifetime
  - LNG plants primarily operate at capacity
  - Small variability in operations, except for planned/unplanned maintenance events or sudden shift in market dynamics (i.e., COVID resulting in a sudden sharp, but brief reduction in exports)
  - Most LNG export capacity is relatively new: Many years of capital annuity remain
- Therefore:
  - ∴ Small or no marginal opportunity
  - ∴ Economic value of cooling exergy should be close to as-built
  - ∴ Heat integration opportunities unlikely

…What do these mean?

Accomplishments and Progress (9/10):
Can existing LNG Export Terminals be Leveraged?

SAVINGS OPPORTUNITIES NOT APPARENT

- Small or no marginal opportunity:
  - If there were idle periods or excess capacity, the operator might see a business value arising from offering capacity at a discount
  - LNG plants operate at capacity and low variability; hence, no marginal opportunity
- Economic value of cooling exergy should be close to as-built:
  - Facilities are relatively new and small depreciation has occurred
  - Thus, if LNG equipment were repurposed for H_2 liquefaction, the original LNG cost calculations would need to be satisfied for a new business case to be made
  - The hydrogen liquefaction would see small saving in equipment CAPEX contributions to the H_2 liquefaction cost compared to simply acquiring new equipment. OPEX may be higher for lack of optimization.
- Heat integration opportunities unlikely:
  - H_2 liquefaction needs the coldest temperatures, but LNG plants will already be utilizing such high-exergy streams in its existing heat integration

Significant cost savings unlikely

Accomplishments and Progress (10/10):
Can existing LNG Export Terminals be Leveraged?

FINAL THOUGHTS

- Perhaps opportunity for savings in *time to market?*
    - Use idle import terminals and abandoned LNG export projects to reduce permitting time?
- Savings from site development?
    - Note that LNG storage is not suitable for LH2 nor are LNG transfer lines, with both lack vacuum jacketing
    - New storage, transfer, ship loading, and probably electrical utilities all seem likely

LNG industry investments might be best engaged and most rapidly applied by shipping LNG as the H_2 carrier and making blue hydrogen at the destination

- For countries dependent upon LNG imports, NG liquefaction is a sunk cost
    - Partial pre-cooling against LNG at the import regasifier is a savings
- LNG ocean transport less costly than LH2 transport?
- Available storage sites will be required for CO_2 sequestration at destination

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Argonne NATIONAL LABORATORY

Collaboration and Coordination

- **U.S. DOE National Laboratories**
  - NREL: Project Lead
  - ANL: Assessing whether there are advantages to hydrogen liquefaction that could be provided by existing LNG export terminals
- **Expert interviews**
  - In-depth interviews with process engineers skilled in designing, building, and deploying commercial cryogenic technologies

Proposed Future Work

- **Planned tasks for FY22**
  - None at this point. Awaiting further guidance from HFTO.
- **Proposed future tasks**
  - Deeper dive into global import potential with country-by-country supply/demand analysis and hydrogen breakeven economics to competing fuels.
  - Quantify on a country-by-country basis the levelized cost of hydrogen from renewable resources.
  - Quantify economics of larger-scale exports (including terminals, transport, hydrogen conversion/gasification) to better understand costs at scale.

Remaining Challenges and Barriers

- Difficulty in pinpointing emissions to electricity from the grid makes identifying low-cost, clean grid electricity highly uncertain.
- Due to uncertainty and ambiguity on clean, low-cost grid electricity, this portion of the analysis has been put on hold until further guidance from HFTO on direction of this work.

Summary

- The size of the hydrogen export market could reach **40+ mtpa by 2050**
- The **most expensive mode** of transport overseas is in liquefied form with costs across liquefied and carrier form **ranging widely**.
- The technical potential for U.S. hydrogen production within 200 miles of existing LNG export terminals is significant at ~885 mtpa, but access to clean, low-cost electricity as well as economic and market constraints will limit access to cheap, low-cost production.
- Significant cost savings from utilizing LNG heat integration systems for liquefied hydrogen **seems highly unlikely**.
- However, **time savings could be realized** from utilizing idled terminals or failed projects if time from permit application and approvals can be saved.

Thank You

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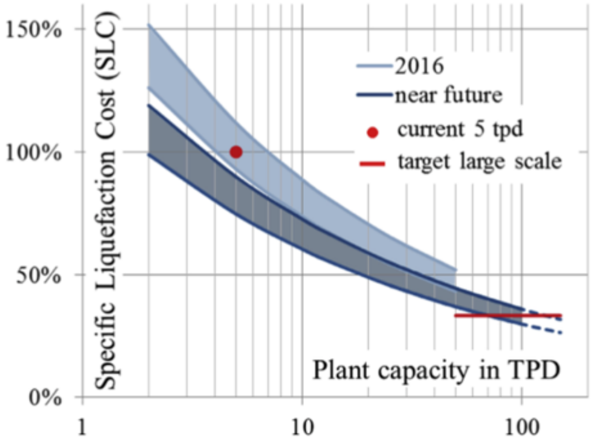
Technical Backup and Additional Information

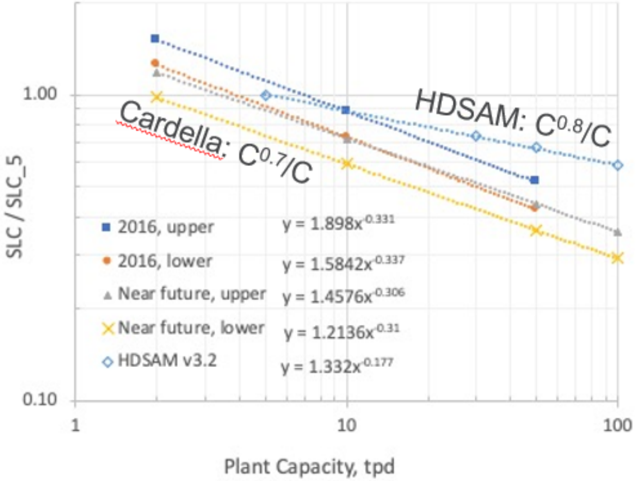
Accomplishments and Progress (Backup):
Liquefaction Cost

MODIFIED HDSAM LIQUEFIER COST EXPONENT



Cardella, U., Decker, L. and Klein, H., 2017. Roadmap to economically viable hydrogen liquefaction. *International Journal of Hydrogen Energy*, *42*(19), pp.13329-13338.

SLC = Cost/Capacity = C^e/C,
C=Capacity, e=scaling exponent



Specific liquefaction costs from Cardella 2017c and from HDSAM. The ordinate is the SLC divided by the reference 5 tpd SLC. Note that Cardella 2017c uses an unspecified value for SLC_5 while the HDSAM SLC values were divided by the HDSAM 5 tpd SLC. Thus, the two datasets do not share a common normalization and only the scaling behavior can be compared.

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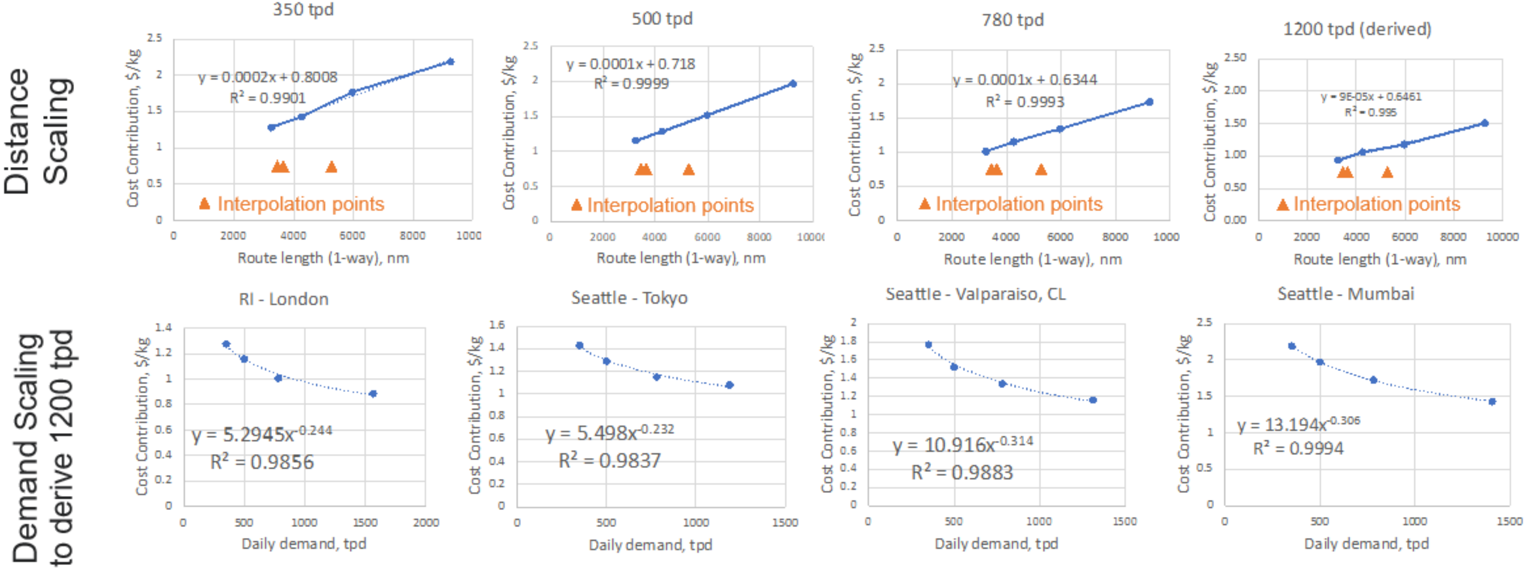
Accomplishments and Progress (Backup):

Liquefaction Cost

INTERPOLATION OF ST001 DATA



Route	1-way, nm	350 tpd	500 tpd	780 tpd	1200 tpd
Anchorage-> Tokyo	3643	$1.40	$1.20	$1.10	$1.00
Texas-> Hamburg	5264	$1.60	$1.40	$1.30	$1.10
Providence-> Hamburg	3441	$1.30	$1.20	$1.00	$1.00

Accomplishments and Progress (Backup):

Liquefaction Cost

UPDATED PIPELINE TRANSMISSION COSTS

- Krishna Reddi

	Pipeline Cost Transmission Cost [$/kg]				
Great Plains		**Market Demand [tpd]**			
	Transmission Distance [km]	350 tpd	500 tpd	780 tpd	1200 tpd
	50	$ 0.013	$ 0.012	$ 0.010	$ 0.007
	100	$ 0.034	$ 0.029	$ 0.022	$ 0.017
New England		Market Demand [tpd]			
	Transmission Distance [km]	50 tpd	500 tpd	780 tpd	1200 tpd
	50	$ 0.29	$ 0.27	$ 0.22	$ 0.17
	100	$ 0.71	$ 0.62	$ 0.49	$ 0.38
Pacific Northwest		Market Demand [tpd]			
	Transmission Distance [km]	350 tpd	500 tpd	780 tpd	1200 tpd
	50	$ 0.026	$ 0.023	$ 0.018	$ 0.014
	100	$ 0.063	$ 0.054	$ 0.041	$ 0.031
California		Market Demand [tpd]			
	Transmission Distance [km]	350 tpd	500 tpd	780 tpd	1200 tpd
	50	$ 0.13	$ 0.12	$ 0.096	$ 0.076
	100	$ 0.33	$ 0.29	$ 0.23	$ 0.18
Southwest		Market Demand [tpd]			
	Transmission Distance [km]	350 tpd	500 tpd	780 tpd	1200 tpd
	50	$ 0.13	$ 0.12	$ 0.096	$ 0.076
	100	$ 0.33	$ 0.29	$ 0.23	$ 0.18

- **Cost difference drivers:**
  - Terrain, which affects labor costs
  - Right of way costs

No pipeline data for Alaska

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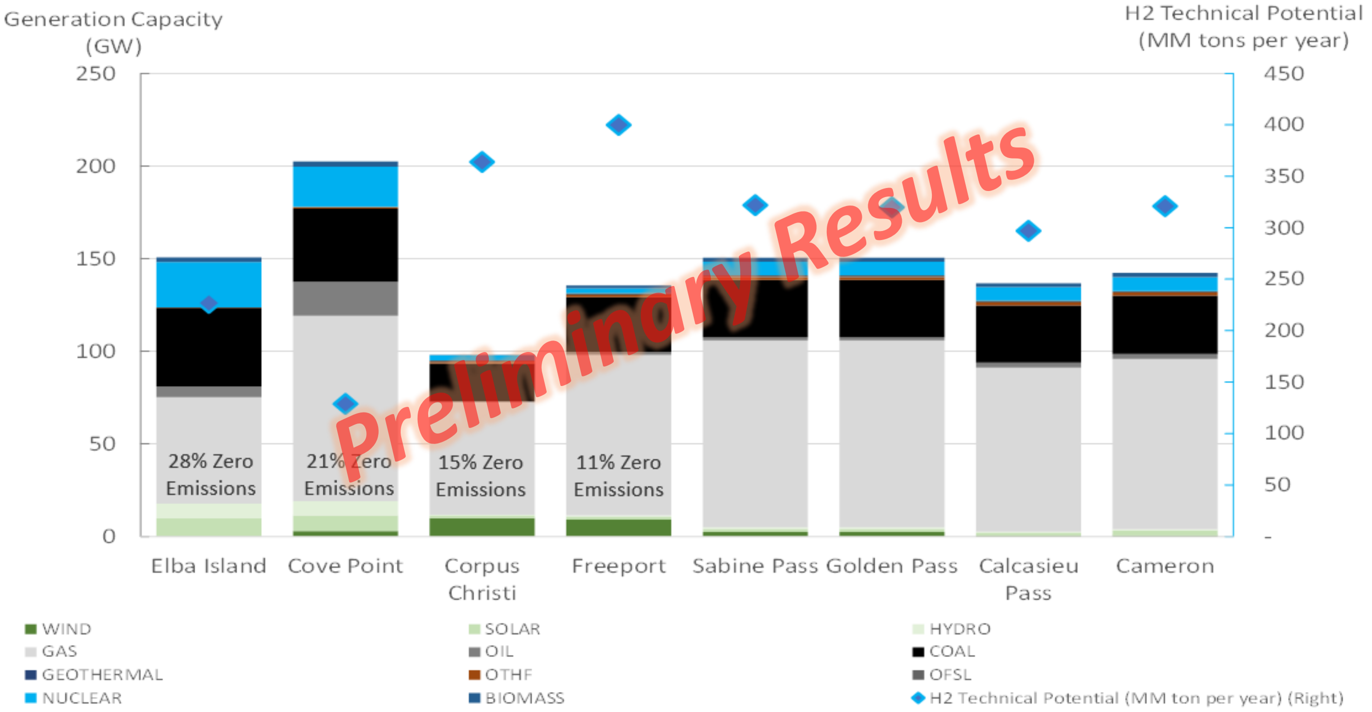
Accomplishments and Progress (Backup):
Affordable, Clean Grid Electricity



Note: OTHF = Other waste heat, OFSL = Other fossil fuel.
Data source: NREL analysis, EPA's eGRID data. "Zero Emissions" = electricity production from solar, wind, hydro, and nuclear

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Accomplishments and Progress (Backup):

Affordable, Clean Grid Electricity

	LNG_Terminal	count	mean	std	min	25%	50%	75%	max
0	Calcasieu Pass	199.0	0.018285	0.019920	0.000510	0.003890	0.010150	0.025450	0.094700
1	Cameron	199.0	0.018285	0.019920	0.000510	0.003890	0.010150	0.025450	0.094700
2	Corpus Christi	130.0	0.016532	0.020760	0.000510	0.003890	0.005100	0.023070	0.094700
3	Cove Point	360.0	0.048991	0.031719	0.000065	0.023600	0.044567	0.063825	0.169600
4	Elba Island	161.0	0.058370	0.024273	0.017120	0.044230	0.054650	0.068393	0.181667
5	Everett	507.0	0.054810	0.034514	0.002610	0.027315	0.049087	0.075710	0.182699
6	Freeport	157.0	0.018041	0.021643	0.000510	0.003890	0.010130	0.023560	0.094700
7	Golden Pass	195.0	0.018307	0.020949	0.000510	0.003890	0.009560	0.024600	0.094700
8	Lake Charles LNG	199.0	0.018285	0.019920	0.000510	0.003890	0.010150	0.025450	0.094700
9	Plaquemines LNG	126.0	0.017042	0.017596	0.001560	0.003890	0.008585	0.025775	0.081000
10	Port Arthur LNG	146.0	0.018488	0.021570	0.000510	0.003890	0.009500	0.024600	0.094700
11	Sabine Pass	195.0	0.018307	0.020949	0.000510	0.003890	0.009560	0.024600	0.094700

East Coast Terminals

Preliminary Results

Gulf coast terminals benefit from relatively cheaper energy TOU charge compared to east coast terminals

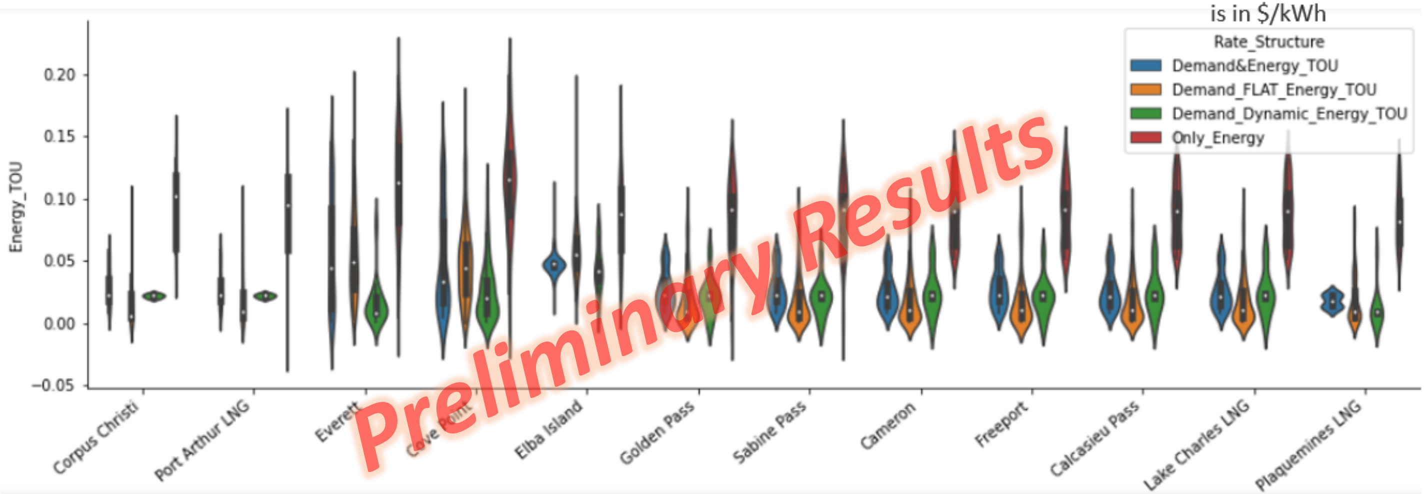
Note: Units in $/kWh. These statistics represent values calculated over all tariffs in proximity to these LNG terminals

Accomplishments and Progress (Backup):

Affordable, Clean Grid Electricity

Energy Time of Usage charges by LNG Terminal by Rate Structure

Energy TOU rate is in $/kWh



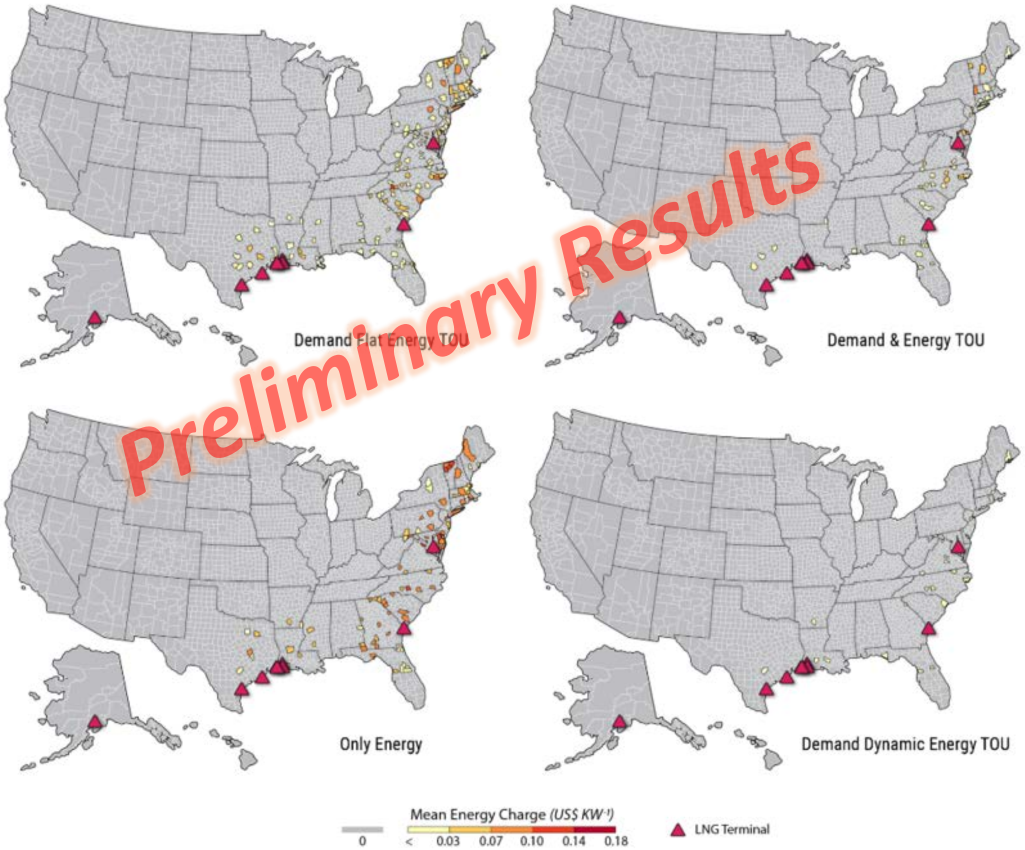
The majority of the rates fell under "Demand_FLAT_Energy_TOU" meaning there was a flat demand charge with a TOU energy charge.

Tariff Type	Count
Demand&Energy_TOU	758
Demand_Dynamic_Energy_TOU	231
Demand_FLAT_Energy_TOU	2574
Only_Energy	655

Tariff Definitions:

- Demand&Energy_TOU: Both the demand charge and energy charge of TOU (Time of Usage).
- Demand_Dynamic_Energy_TOU: The demand charge had both a flat and TOU tariff. Energy charge is TOU.
- Demand_FLAT_Energy_TOU: The demand charge is flat (non-zero) and energy charge is TOU.
- Only_Energy: Demand charge is zero. Only an energy TOU charge.

Accomplishments and Progress (Backup):
Affordable, Clean Grid Electricity



Accomplishments and Progress (Backup):
Affordable, Clean Grid Electricity

- A typical tariff consists of two components for charge:
  - (1) A Demand charge and an (2) Energy charge.
  - **Demand charges** refer to the maximum demand that occurs during a billing period (in $/kW), where as **Energy charges** are associated with the quantity of energy used during a single interval (in $/kWh).

Tariff Structure	No. Tariffs	Energy Charge ($/kWh)	Demand Charge ($/kW)
Demand_TOU_Energy_TOU	758	Depends on time electricity used	Depends on time electricity used
Demand_No_Energy_TOU	655	Depends on time electricity used	No demand charge
Demand_FLAT_Energy_TOU	2574	Depends on time electricity used	Demand charge flat
Demand_Dynamic_Energy_TOU	231	Depends on time electricity used	Consists of a flat and TOU charge

Total Monthly Electricity Bill = Demand_Charge * Peak_kW_level + Energy_Charge * Consumption_kWh

Total Monthly Electricity Bill = $8/kW * 100 kW + $0.04/kWh * 72,000 kWh = $800 + $2,880 = **$3,680**
A business who uses 100 kW an hour over the course of a month for every hour

Total Monthly Electricity Bill = $8/kW * 100 kW + $0.04/kWh * 36,000 kWh = $800 + $1,440 = **$2,240**
A business who uses 100 kW an hour half the day over the course a month