GULF ENERGY CATALYST

DS Industry

Applications of Green H2 in Industry

Gulf Energy Catalyst

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Texas LCI-H2 at a Glance

- Texas is already the center of gravity of US hydrogen
  - About 3.6 million tonnes per year (MTA), roughly one-third of US output, from about 48 Gulf Coast plants
  - Today's supply is predominantly conventional (gray) hydrogen for refining and ammonia, the baseline LCI-H2 must displace

- Three routes to low-carbon-intensity hydrogen are advancing together
  - Natural gas reforming with CCS (SMR capture roughly 70–95%, ATR up to about 98%)
  - Electrolysis powered by Texas wind and solar
  - Recovery of hydrogen-rich off-gas from refineries and crackers, a Gulf Coast strength

- The HyVelocity Gulf Coast Hub anchors the build-out
  - Up to $1.2 billion DOE award;
  - Combines SMR/ATR with CCS, electrolysis, salt caverns, pipelines and demand programs
  - Hub CI target of 2 kg CO2e/kg H2 or lower, versus the 4 kg ceiling for the 45V tax credit

- Why this story travels
  - Like other port-industrial clusters (Bilbao), the USGC is anchored by refining, chemicals and steel
  - This presentation follows the value chain (upstream, midstream, downstream), then closes on project economics, off-take friction and regulatory alignment

Texas Enjoys Many Advantages In Scaling Hydrogen Production

General



Proximity to demand favorable to driving early adoption



Welcoming environment for infrastructure development



Existing hydrogen capacity and expertise



Environmental justice impact



Concentration of academic and industry-driven innovation



Highly skilled workforce

Production capacity & cost



Access to low-cost renewable energy capacity



Access to CO_2 storage locations



Access to low-cost natural gas

Transportation & storage



Largest network of hydrogen pipelines in the US



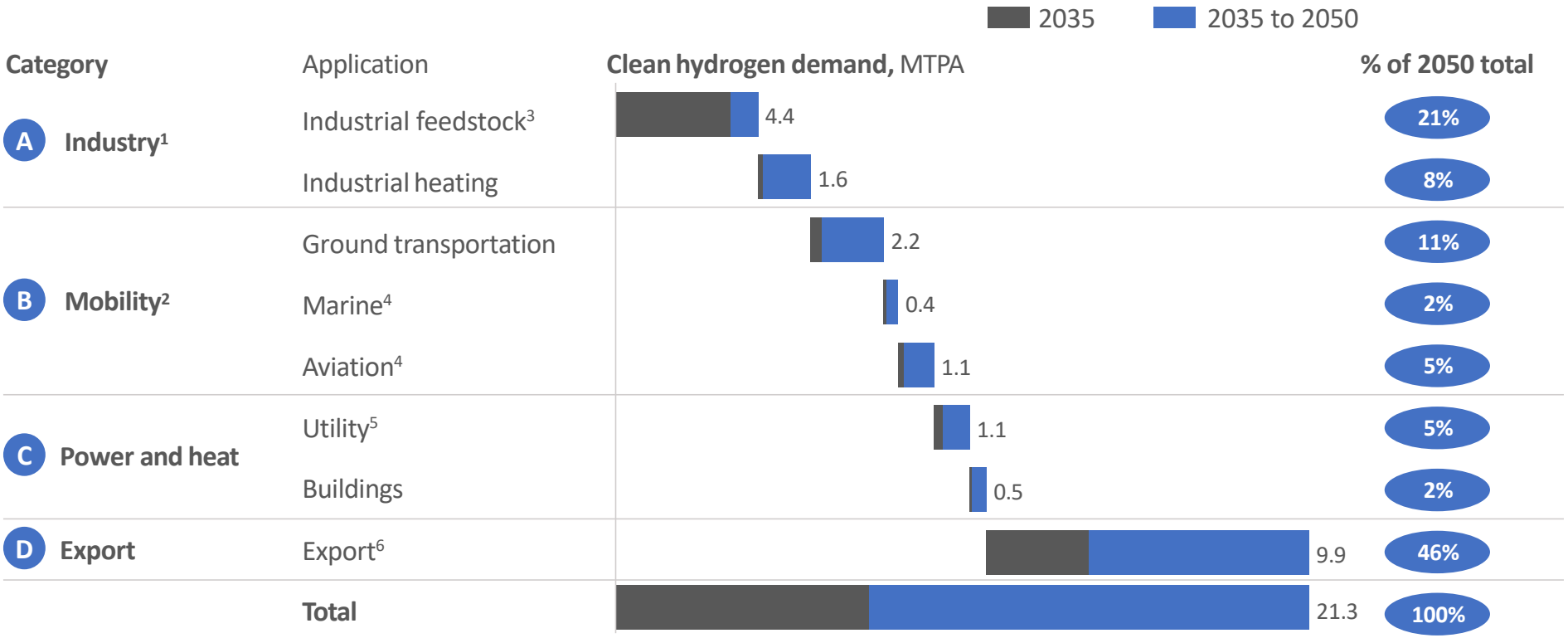
Access to geologic formations for seasonal storage

What Makes TX Unique in H2FC – Growing Upstream Capacity

- Unrivaled infrastructure already in the ground
  - About 900–1,000+ miles of dedicated hydrogen pipeline, over half (~56%) of the US network
  - Three salt-cavern hydrogen sites (Clemens, Moss Bluff, Spindletop) holding roughly 11,000–14,500 tonnes; three of the four operating hydrogen caverns worldwide
  - Refining capacity of about 5.9 million bbl/d (~31% of US) and more than 42% of US petrochemical capacity in the Houston area, next to deepwater ports
- Resource diversity: low-cost gas plus massive renewables
  - Low-cost Gulf Coast and Permian gas supports SMR/ATR with CCS at scale
  - ERCOT has about 40 GW of wind, about 40 GW of solar and about 21 GW of storage (mid-2026), supporting low-cost electrolysis
  - Renewables are in the west and demand and ports are in the east, so moving molecules and electrons across the state is the design challenge
- The additive transition model
  - Strategy framed as "energy addition," not asset replacement; hydrogen scales alongside oil and gas
  - Reuses midstream skills, rights-of-way, workforce and CO2-storage know-how
- Factors supporting new upstream capacity
  - Industrial feedstock and heat demand could reach about 6 MTA by 2050
  - Blue hydrogen could add up to about 1 trillion cubic feet per year of new Texas gas demand by 2050
  - Established ecosystem of engineering firms, Houston capital markets and universities, in a state that favors incentives over mandates

Potential U.S. Gulf Coast clean hydrogen demand

Industrial applications and export could drive most of the demand, with mobility and industrial heating to follow



1. Sizing includes Gulf Coast (Texas and Louisiana); 2. Sizing includes Texas; marine only includes Port of Houston; 3. Includes refining, petrochemicals, ammonia, iron, steel, and cement; 4. Includes synthetic fuels and hydrogen propulsion for Texas; 5. Includes natural gas power generation and energy storage; 6. Represents hydrogen and hydrogen-based fuels (e.g., for aviation and marine) produced in Texas and consumed elsewhere

Upstream Policy: 45V, 45Q, Hub Funding and Methane Accounting

- Federal support has narrowed and tilted toward blue hydrogen
  - 45V pays $0.60–$3.00/kg for 10 years (CI ≤4 kg CO2e/kg), but construction must now begin before 1 January 2028 (previously 2033)
  - 45Q ($85/t stored for 12 years) was largely left intact, favoring hydrogen with CCS
  - Long waits for final 45V rules had real costs; Plug Power paused a Panhandle project pending clarity
- Hub funding moved from commitment to uncertainty
  - HyVelocity's award was signed in late 2024, with only a small first tranche (about $22 million) released
  - The hub appeared on DOE's leaked termination lists in October 2025 and was reportedly "retained" in April 2026, though progress remains unclear
  - Lesson: policy timing shapes investment decisions as much as technology cost
- Texas-level enablers
  - The Railroad Commission took over Class VI CO2-well permitting from EPA (effective 15 December 2025), giving one state path for CO2 storage
  - Gulf Coast saline formations offer on the order of 1 trillion tonnes of CO2 storage capacity
- Methane accounting is the next lever for LCI-H2 value
  - 45V well-to-gate CI relies on default GREET upstream methane values; the rules do NOT credit facility-specific certified gas data or methane EACs
  - Combined with CCS, up to about 56% lower lifecycle CI for fossil-derived ammonia



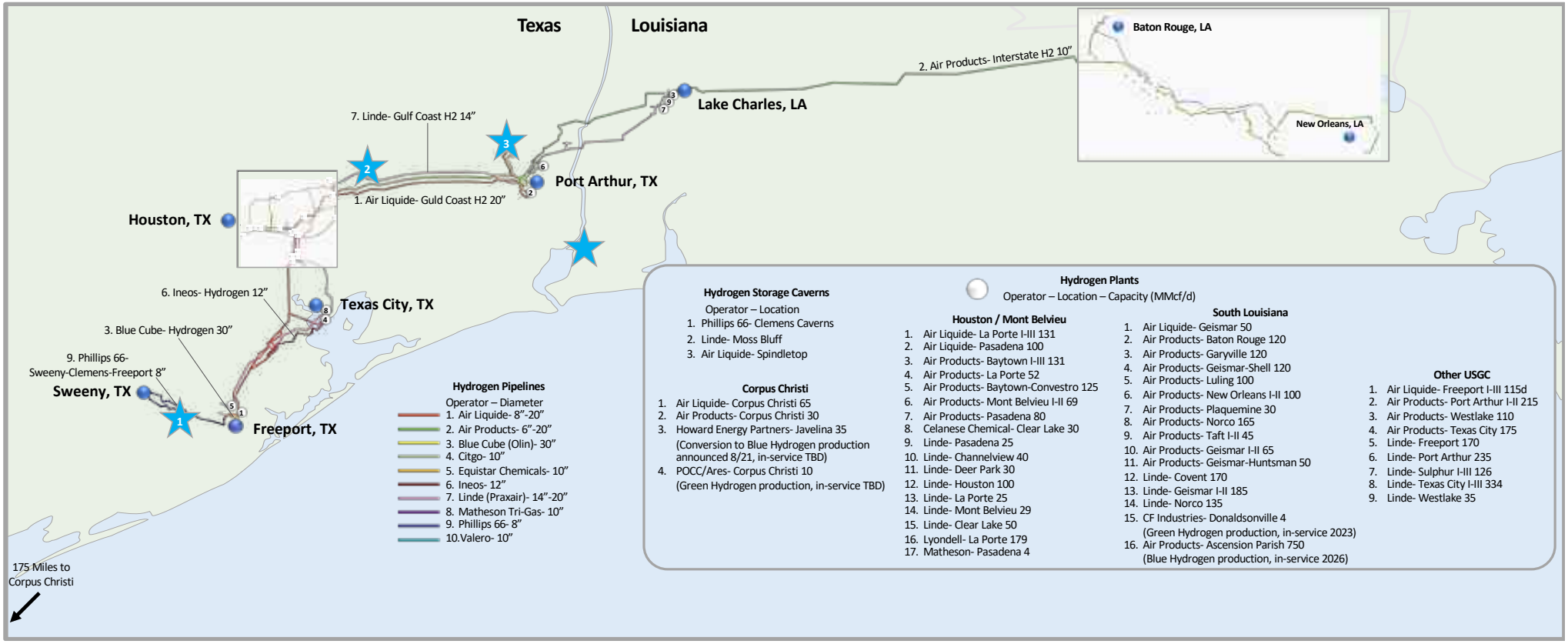
Midstream: Pipelines, Storage and Logistics Pricing

- The Texas pipeline network is deep but narrow
  - Serves Gulf Coast refineries and ammonia plants, mostly through private, bilateral "bundled" supply-plus-transport contracts rather than open access
  - Existing lines serve limited geographies (East Texas and South Louisiana); reaching West Texas renewables, interstate markets and export terminals requires expansion

- Logistics pricing: cheap where pipes exist, opaque where they don't
  - Retrofitted, well-utilized pipelines can move hydrogen for under $0.1/kg over about 500 km; transmission runs about $0.10–0.25/kg per 1,000 km
  - Trucking is limited by payload (liquid ~4 t/load; tube trailers ~0.5–1 t/load); shipped carriers (ammonia, LH2, LOHC) were modeled at roughly $2–3/kg by 2030
  - No transparent price index or spot market exists, which limits investor confidence

- Gas quality decides whether a shared network works
  - Three pipeline classes: pure/reagent grade (up to 99.999% purity), fuel grade (~95% purity, up to 5,000× more impurities) and blended natural gas/hydrogen
  - Common quality standards (e.g., CGA G-5.3) are needed for multiple industries to share one system
  - Retrofits need due diligence: embrittlement, lower operating pressures and hydrogen-capable leak detection

U.S. Gulf Coast Hydrogen Infrastructure



Source: RBN Energy

System Reliability and Feedstock Security

- Refiners buy reliability and purity, not just molecules
  - Hydro-treating and hydro-cracking have no viable alternative to hydrogen, so supply interruptions are costly
  - Uptime comes from network design: multiple producers, pipeline interconnection and storage, rather than standalone on-site units

- Salt caverns hedge intermittency and price volatility
  - Caverns can absorb electrolyzer output when renewables are abundant and supply users during shortfalls, with high injectivity and discharge rates

- Grid reliability is part of hydrogen supply security
  - ATR/POX blue hydrogen needs reliable low-cost power and gas
  - Council priorities: winterization, PUCT–ERCOT coordination and treating grid reliability as a complement to renewables
  - Storage and rapid battery growth (about 21 GW) help absorb ERCOT's demand growth

- Takeaway for other regions
  - Texas pairs variable renewable hydrogen with base-load SMR/ATR+CCS and geologic storage

TX Regulatory Model: Fast Siting, Common Carrier, Mass Balancing

- Development velocity: no state siting permit
  - Across all pipeline types, Texas built more than 15,000 miles in 2011–2016 with over 99% of tracts acquired voluntarily
  - Not permit-free: notification to the Commission for lines over one mile (30–60 days before construction), a T-4 operating registration, TCEQ air permits and ERCOT interconnection

- Common-carrier status is the trade for eminent domain
  - Hydrogen pipelines serving the public for hire can register as common carriers: they publish an RRC tariff and carry without discrimination
  - HB 2847 (2023) confirmed Commission authority over safety and rates for intrastate hydrogen pipelines and underground storage

- Common carriage can enable mass balancing for e-fuels
  - E-methanol and synthetic fuels need large, continuous clean hydrogen plus captured CO2
    - Ørsted's Star e-Methanol targets about 160 t/day of hydrogen
    - HIF Matagorda had planed about 1.8 GW of electrolysis
  - Producers in distant resource zones inject into a shared network; coastal e-fuel plants off-take equivalent mass-balanced volumes at the port, avoiding dedicated point-to-point pipelines
  - Caveat: most Texas hydrogen pipelines today are private and bilateral, so the model depends on more common-carrier registrations and clear accounting rules

Fed Gap: Loper Bright, FERC vs. STB and “Texas Contradiction”

- Removed safety net of agency deference
  - The Supreme Court's June 2024 ruling overturned Chevron; courts now read statutes independently
  - Agency "institutional knowledge" counts for less, so jurisdictional claims over hydrogen pipelines are easier to challenge; expect substantial litigation and possible project delays
- No agency clearly manages interstate hydrogen pipeline rates
  - FERC has the rate-setting expertise, but pure hydrogen contains no hydrocarbons; FERC declined jurisdiction over ammonia pipelines, and neither FERC nor the STB has asserted authority over hydrogen
  - The STB has explicit catch-all authority over non-oil, non-gas commodities (ICCTA), and GAO, DOT and CRS have read it as covering hydrogen, yet it has not acted and may lack the manpower and appetite
  - Only the Natural Gas Act gives federal siting and eminent domain; the other routes leave siting to the states
- The Texas contradiction
  - Texas offers a fast, hands-off intrastate model, yet no hydrogen-specific pipeline rules had been issued as of the Council's December 2024 report
  - The Council recommended keeping the current framework with targeted clarifications
  - Interstate ambitions (West Texas to other states, exports) depend on federal clarity that has not arrived
  - A Texas House committee was charged in April 2026 with reviewing the Council's recommendations for statutory changes
- **Lesson**: a fast state model does not remove interstate regulatory risk; long waits, as with 45V, can stall a midstream market

Downstream Anchors: Refining, Chemicals and Steel

- Refining and chemicals set the baseline demand
  - Replace gray hydrogen in refinery hydro-treating and hydro-cracking and in ammonia and methanol synthesis, a like-for-like molecule swap
  - New pull from renewable diesel, sustainable aviation fuel and pyrolysis-oil upgrading

- Steel and heavy industry: DRI without interrupting continuous production
  - DRI runs on natural gas today; hydrogen blends of about 30% are considered feasible without significantly altering process
  - Texas has advanced direct-reduction capacity (Corpus Christi HBI plant), but steel is a small demand driver (about 0.2 Mt/yr by 2050)
  - Continuous operation raises premium on supply and buffer storage

- Feedstock conversion barriers
  - Fuel-switching uses need new burners, piping, compressors or turbines, plus permit amendments
  - Retrofit costs and downtime risks

- What industrial buyers evaluate
  - Delivered cost of hydrogen (DCOH): production plus transport, storage and conversion
  - System reliability, product purity and the cost of adapting existing plants

Downstream Growth: e-Fuels and Hydrogen Derivatives

- Immediate anchor off-takes
  - Petroleum refineries, Gulf Coast ammonia plants and e-methanol for maritime shipping
  - Industry and export are expected to drive most demand coming online by 2035

- e-Methanol projects illustrate the opportunity and the risk
  - Texas has co-located hydrogen and CO2 infrastructure, which the Council expects to make it a leader in e-fuels such as e-SAF

- Ammonia is the most mature derivative
  - Existing world-scale ammonia industry; blue ammonia projects such as Beaumont (about 1.1 Mt/yr) build on it
  - Nitrogen from air-separation units at blue hydrogen plants is a low-cost co-product that makes synthesis natural
  - Europe is building ammonia import terminals that can convert back to hydrogen, and a Texas–Northwest Europe hydrogen corridor has been discussed

- The economics hinge on inputs
  - CO2 is an added feedstock cost for methanol and other e-fuels, so sourcing it is a key design choice
  - Shipping-fuel demand signals (long-term methanol offtakes starting in 2026) are what make these plants financeable

Project Economics, Off-Take Friction and Lessons for LCI-H2 Elsewhere

- Economics are set by delivered cost, reliability and conversion cost
  - 2022 modeling targeted about $1.50/kg (gas-based) and $2/kg (electrolysis) production costs by 2030, with transport and storage adding cents to tens of cents per kg on existing assets
  - In practice, blue hydrogen has carried a premium of roughly one-third over gray

- Off-take friction is the binding constraint
  - ExxonMobil paused its $7 billion Baytown blue hydrogen project in late 2025, citing insufficient buyers
  - Bilateral contracts and no price index leave buyers and lenders without a benchmark
  - Anchor first where the swap is simplest (refining, ammonia)

- Regulatory alignment sets the pace
  - Texas offers fast siting, a single regulator for pipelines and storage, and CO2-storage permitting authority

- Lessons other industrial clusters can borrow
  - Build on existing pipelines, caverns and ports and add capacity rather than replace assets
  - Pair variable renewables with firm supply and storage, and certify methane and carbon intensity early
  - Push for common-carrier and mass-balance accounting so shared networks can serve many users

