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Compressorless Hydrogen Transmission Pipelines Deliver Large-scale Stranded Renewable Energy at Competitive Cost

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ABSTRACT:

We assume a transmission-constrained world, where large new windplants and other renewables must pay all transmission costs for delivering their energy to distant markets. We modeled a 1,000 MW (1 GW) (nameplate) windplant in the large wind resource of the North America Great Plains, delivering exclusively hydrogen fuel, via a new gaseous hydrogen (GH2) pipeline, to an urban market at least 300 km distant. All renewable electric energy output would be converted, at the source, to hydrogen, via 100 bar output electrolyzers, directly feeding the GH2 transmission pipeline without costly compressor stations at inlet or at midline. The new GH2 pipeline is an alternative to new electric transmission lines. We investigate whether the pipeline would provide valuable energy storage. We present a simple model by which we estimate the cost of wind-source hydrogen fuel delivered to the distant city gate in year 2010, at GW scale. Ammonia, synthetic hydrocarbons, and other substances may also be attractive renewable-source energy carriers, storage media, and fuels; they are not considered in this paper.

KEYWORDS: pipeline, renewable, stranded, compressor, storage

INTRODUCTION

See our more complete paper.[1] We assume a large, nascent market for renewable-source hydrogen fuel in a carbon-constrained world, for transportation fuel and potentially for distributed generation of retail-value electricity on the customer's side of the meter. Large-scale GH2 pipeline transmission may offer important technical and economic advantages and synergies vis-à-vis electric transmission: [2]

1. "Firming" the output energy of renewable generation assets with energy storage adds value;
2. Pipeline capacity factor (CF) may be improved by synergistic sharing with diverse renewable GH2 sources in the same geographic area, complementing wind's time-variability;
3. Underground location of the GH2 transmission pipeline may be more socially acceptable and be more secure from natural and human threats;
4. The oxygen byproduct of electrolytic production of hydrogen from wind-source, and other renewable-source, electricity may be sold to adjacent biomass and coal gasification plants;
5. Sharing power electronics and controls between wind generation and electrolysis systems saves substantial capital, O&M, and energy conversion loss costs; removing requirements to deliver grid-quality electricity will slightly improve wind generation COE; [3]

Design and construction of large, long-distance, high pressure gaseous hydrogen pipelines and conventional natural gas (NG) transmission lines are similar. Four technological aspects differentiate a GH2 line from an NG line and will need to be addressed for the concept to be attractive to industry:

1. The volumetric energy density of hydrogen is one-third that of methane;
2. High pipeline utilization, CF, is critical for economic feasibility;
3. Hydrogen embrittlement of pipeline steel must be prevented and controlled;

4. Compression is very costly in capital, O&M, and energy.

Most analyses show that pipelining GH2 costs approximately 1.3 to 1.8 times more, per unit energy-distance, than NG, because of these four factors; ammonia, as an energy carrier, costs less than NG.

Pipelines are very expensive to design and construct and must have high utilization to justify the initial capital cost. They must have a large, relatively continuous, source of product. In the NG industry, underground storage at the upstream and / or downstream ends of pipeline systems provide high pipeline CF. A GH2 pipeline with wind generation as the sole source of energy would be severely handicapped by the wind turbines' low CF (about 40%) and time-varying production, on hourly to seasonal time scales. Wind energy would have to be complemented with storage and other electricity or hydrogen generation at the upstream end of the pipeline in order to provide consistent energy to the pipeline, high pipeline CF, to "smooth", and perhaps to "firm", the supply of GH2 fuel to markets.

The industrial gas companies' success and safety in operating thousands of km of GH2 pipelines worldwide is encouraging, but these are relatively short, small-diameter, and operating at low and constant pressure: not subject to the technical demands of renewables-hydrogen service (RHS), nor to the economic challenge of delivering low-volumetric-energy-density GH2 over hundreds or thousands of km to compete with other hydrogen sources at the destination. The time-varying output of windplants and other renewables will cause large, frequent pressure fluctuations in GH2 pipelines, which induces and exacerbates hydrogen embrittlement.

The materials challenges of GH2 transmission pipelines may result in new materials or hybrids, with reduction in GH2-capable pipeline system costs to equal or below that of today's NG pipelines.

METHOD

We modeled the technical and economic performance of a large 1,000 MW and 2,000 MW nameplate capacity windplant delivering its entire output as GH2 fuel, by pipeline, to a distant urban market. First, we modeled pipeline performance, using hydraulic models standard in the NG pipeline industry, and assuming no compressors in the system, either at source or at midline, to find:

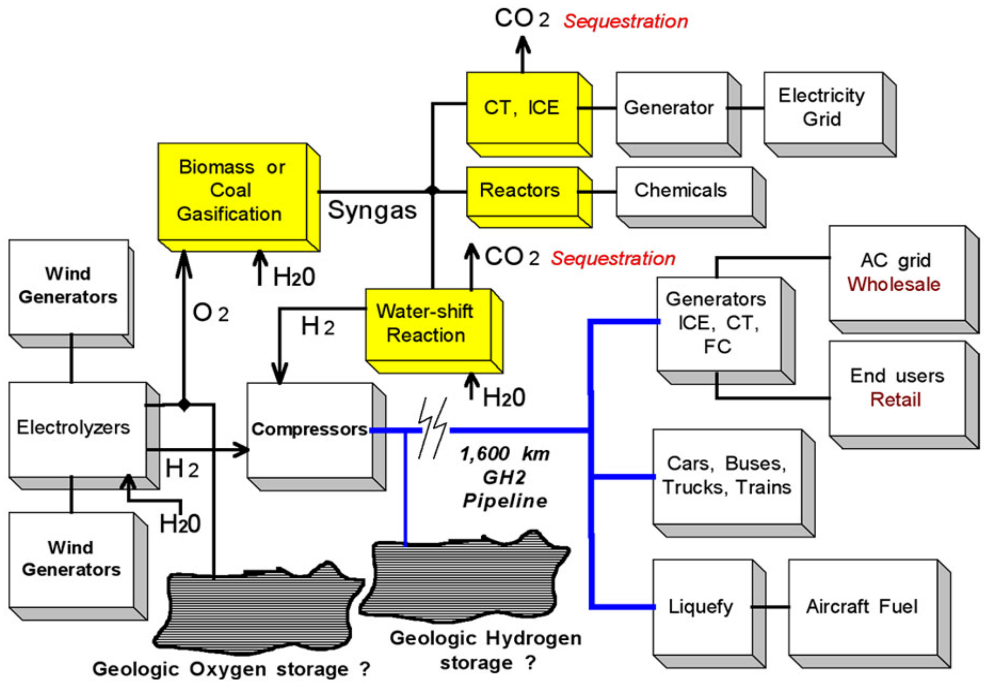
1. Pipeline transmission capacity;
2. Pipeline energy storage capacity, assuming "packing" the pipeline to 100 bar, "unpacking" to 30 bar (for an adequate delivery pressure for distribution at the distant urban market);
3. Dynamic energy storage behavior, as windplant output varies with time;
4. Optimization of system capital components capacity: wind generators, electrolyzers, pipeline.

Based on the pipeline modeling, we chose 20" diameter and 100 bar maximum allowable operating pressure (MAOP) as amenable to modern pipeline design practice and economy-of-scale.

We estimated system capital cost savings from optimizing wind generator power electronics to supply low voltage DC to the electrolyzers, rather than high quality AC to the grid, thus eliminating the "transformer-rectifier" component of electrolysis systems, and a small amount of wind generator power electronics (PE) and controls cost.

We surveyed manufacturers of wind generators, electrolyzers, and compressors, to obtain expected performance and capital costs in year 2010, with costs expressed in year 2005 $US.
Table 1 estimates year 2010 technology and capital component costs and technology goals, from industry consensus and from USDOE: [4]

1. Wind generators in a large, dense windplant will offer significant economy-of-scale in manufacture and installation. Technology improvements, shared power electronics (PE), and freedom from electricity grid delivery will reduce total installed capital cost (TICC) to $800 / kW. We add $30 / kW for PE specialized for low voltage direct current (DC) electrolyzer drive.
2. Electrolyzers with 100 bar output capability, at MW scale, will be available. Less the transformer-rectifier-controls subsystem, in a large-volume order, TICC will be $330 / kW.
   The 800 km long, 20" diameter, GH2 pipeline will be built of materials that control H2 embrittlement, at no cost premium over NG pipeline construction at the same diameter and pressure. For example, TICC for the 36" diameter, 3,200 km long Alliance Pipeline, North America's newest large NG pipeline system, was $25 per inch diameter per meter length. [5] We assume $30 / inch diam / m length, to account for higher current steel prices and lower economy-of-scale for a shorter pipeline length than Alliance Pipeline.



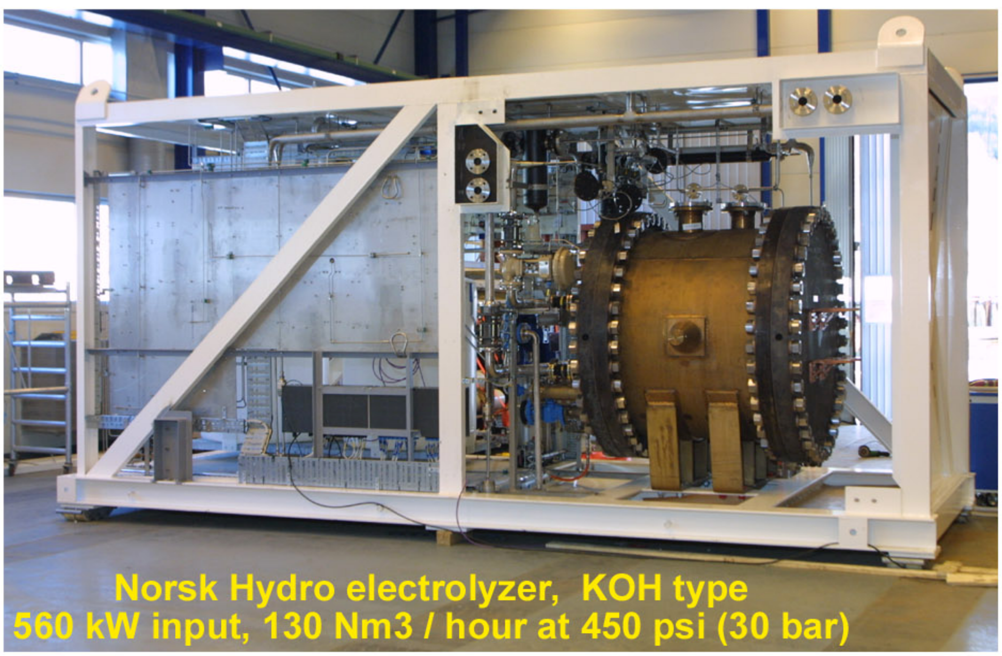


FIGURE 1. (Above) System Diagram, with potential "value adding" features of byproduct oxygen sale to adjacent gasification plants, improved pipeline CF, and seasonal-scale geologic storage of GH2.
(Below) Norsk Hydro electrolyzer system, liquid potassium hydroxide (KOH) type, without gas cleanup equipment. 560 kWe input, 4.2 – 4.3 kWh per Nm3 output, at 30 bar, 130 Nm3 / hour.

TABLE 1: Capital costs: 1,000 MW Windplant, Electrolyzers, 20" Pipeline 800 km long

	TICC $ / kW in Year 2010	**Total (million 2005 $US)**
Windplant	$ 800	$ 800
Power electronics incremental cost	$ 30	$ 30
Electrolyzers: 100 bar output	$ 330	$ 330
Pipeline: 20", 800 km long	$ 30 / inch diam / m length	$ 464
TICC (total installed capital cost)		**$ 1,624**

We calculated cost of energy (COE) at the end-of-pipe at a distant urban market, considering a range of capital recovery factors (CRF), shown in Table 2 and Figure 3. We used a simple Capital Recovery Factor (CRF) model by which we estimate the untaxed cost of renewable-source hydrogen fuel delivered at wholesale to the distant city gate, from calculated cost per unit energy-distance for the assumed 20" diameter GH2 pipeline transmission system. We chose 15% as a good compromise for this paper's analysis, for year 2010 technology and year 2005 $US costs.

TABLE 2: Unsubsidized Cost of Wind-source GH2 Fuel Delivered at End-of-pipe at Distant City Gate, as a Function of CRF and Pipeline Length. Assumes: Unsubsidized (no US federal PTC, or other); no "value adders" in byproduct oxygen sales or carbon emissions offset credits or payments.

PIPELINE LENGTH	320 km	480 km	800 km	1,600km
	Cost / kg	**Cost / kg**	**Cost / kg**	**Cost / kg**
@ CRF = 12%	$2.19	$2.34	$2.64	$3.38
@ CRF = 15%	$2.72	$2.91	$3.28	$4.21
@ CRF = 18%	$3.26	$3.48	$3.93	$5.04
@ CRF = 21%	$3.75	$4.01	$4.53	$5.82

We also modeled system economics, to find the optimum capacity ratio among windplant, electrolyzers, and pipeline. Figure 4.

We also modeled this system, in Figure 3, to include "value-adding" features which reduce the cost of GH2 fuel delivered at end-of-pipe at the distant urban market:

1. Byproduct oxygen (O_2) sale to adjacent gasification plants for dry biomass, and perhaps for coal (assuming carbon capture and sequestration);
2. US federal production tax credit (PTC), $0.019 / kWh in year 2005;
3. Estimated future carbon-emission offset payment or credit of $0.01 / kWh;
4. Improved pipeline CF via "packing" storage.

We recognized several possibilities for system energy storage, upstream or downstream, although we did not consider or model them:

1. Hydrogen storage in underground geologic structures;
2. Hydroelectric reservoirs, but only if large electricity grid capacity is available and connected.

We report expertise on the critical problem of hydrogen embrittlement of pipeline steel, which will be exacerbated in "renewables-hydrogen service" (RHS) where the time-varying output of renewable sources like windpower and radiant solar, will cause frequent, large excursions in pipeline pressure.

Finally, we address GH2 transmission's potential contribution to "firming" the time-varying output of windplants, increasing its value. We also suggest several topics for further research and analysis.

RESULTS: PIPELINE CAPACITY

Table 3 and Figure 2 show results of modeling pipeline transmission and storage capacity using hydraulic equations standard in NG pipeline design practice, assuming:

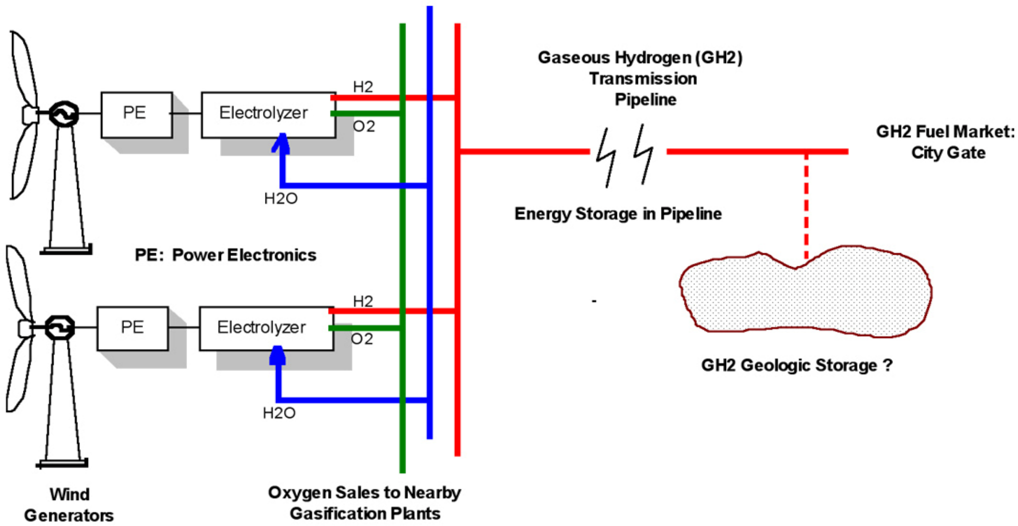
1. 100 % GH2 product;
2. 100 bar input, 30 bar output pressures;
3. Capacity: fully turbulent flow achieved;
4. Storage capacity: "pack" and "unpack" pipeline from 100 bar to 30 bar;
5. Pipeline lengths of 320, 500, 800, and 1,600 km;
6. 20" and 36" nominal diameter (inside diameter).

RESULTS: SYSTEM CAPACITY

A 1,000 MW windplant produces about 6 x 10^6 Nm3 / day of GH2 at full output; about 2.5 x 10^6 Nm3 / day at 40% average CF. The continuous capacity of an 800 km long, 20" diameter, GH2 pipeline is ~ 12 x 10^6 Nm3 / day (1,200 tons / day), without compressors. It could deliver wind-source GH2 fuel 800 km by pipeline for an unsubsidized price of ~$3.30 / kg, assuming;

1. Estimated year 2010 technology and costs, expressed in year 2005 $US;
2. All wind energy is converted to GH2 and delivered via a 20" diameter pipeline at 100 bar inlet pressure and 30 bar delivery pressure, at the distant urban market;
3. No compressors, at pipeline inlet or at midline;
4. Capital Recovery Factor (CRF) of 15%;

5. Average pipeline CF of about 15%;
6. For a given diameter and pressure, GH2 pipelines can be built for the same capital cost as for natural gas (NG), although serious line pipe materials challenges must be met.



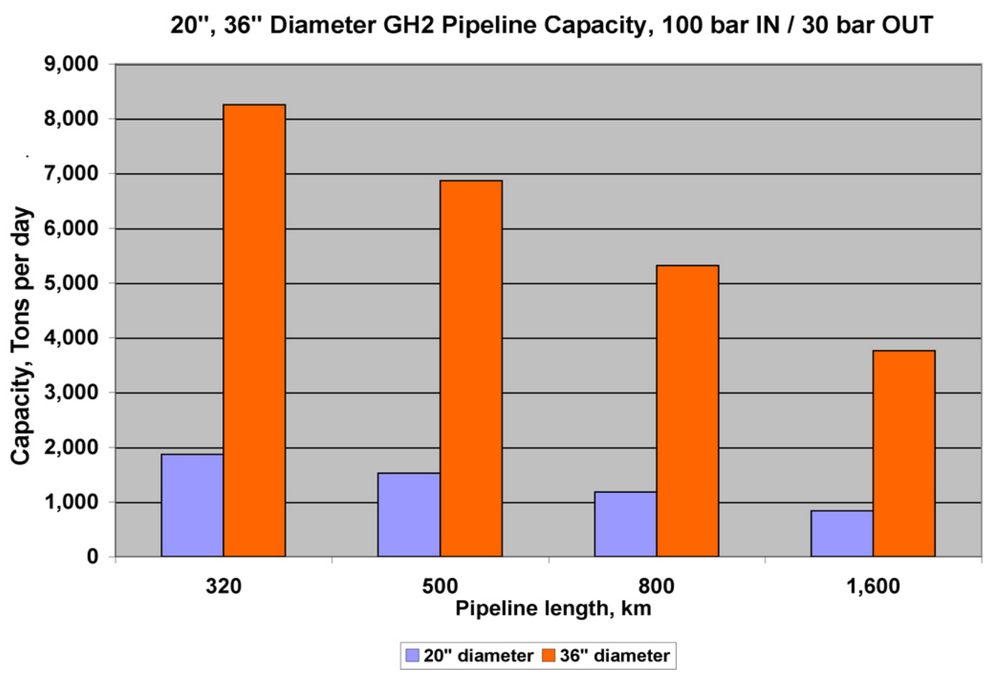


FIGURE 2. (Above) System Diagram. All wind energy is converted to GH2 for transmission; no electricity is delivered to the grid. Windplant infrastructure is primarily piping, with a small supply of electricity distributed only for controls. (Below) Gaseous hydrogen (GH2) pipeline capacity as function of diameter and length, tons per day, assuming pressure drop from friction loss from 100 bar input at source to 30 bar output at city-gate delivery.

Given the low pipeline CF in this 1,000 MW scenario, the 20” pipeline would need to serve considerable additional windplant generating capacity, > 2,000 MW, to approach full CF. In a mature wind-GH2 system, many nodes of production, storage, and utilization may be distributed along the transmission pipeline. These nodes are much less complex and costly than the substations required for delivering energy to and from electricity transmission lines.

TABLE 3: GH2 Pipeline Transmission and Storage Capacity, Without Inlet or Midline Compression.

Distance, km	Inside Diameter inches	Capacity GW	Capacity MMscfd	Capacity Million Nm3 / day	Capacity Tons per day	Storage Capacity MMscf	Storage Capacity Tons
320	20	2.8	702	18.1	1,869	141	374
320	36	12.3	3,100	80.1	8,253	450	1,199
480	20	2.3	573	14.8	1,526	211	562
480	36	10.2	2,580	66.7	6,869	675	1,798
800	20	1.8	444	11.5	1,182	352	936
800	36	7.9	1,998	51.7	5,319	1,126	2,997
1,600	20	1.2	313	8.1	833	703	1,872
1,600	36	5.6	1,413	36.5	3,762	2,251	5,994

RESULTS: COST OF ENERGY (COE) AT END-OF-PIPE

We analyzed three "value-added" cases as well as the "unsubsidized" case, for both 1 GW and 2 GW windplants, because Table 3 shows that the 20" pipeline has continuous transmission capacity of ~1.8 GW at 100 bar inlet, 30 bar delivery pressure, at 800 km length. Tables 2 and 3 and Figure 3 show that a 2 GW windplant improves pipeline CF, and thus lowers delivered COE, vis-à-vis a 1 GW windplant. The delivered cost of energy (COE) through an 800 km, 20" pipeline would be reduced to about $1.50 / kg by the sum of these value-adding steps:

1. US federal production tax credit (PTC), $.019 / kWh in year 2005;
2. Byproduct oxygen (O_2) sales to adjacent dry biomass (and perhaps coal) gasification plants @ $20 / ton of O_2;
3. Future carbon-emissions-offset credits or REC's, estimated at $0.01 / kWh;
4. Increase windplant to 2,000 MW (nameplate).

HIGH-PRESSURE-OUTPUT ELECTROLYZERS

We assume high-pressure-output electrolyzers will be available at attractive capital and O+M cost, as in Figure 1. Technologies may include proton exchange membrane (PEM), alkaline (KOH), high temperature ceramic, or a combination thereof. We assume they will directly feed the pipeline at 100 bar. Energy conversion efficiency is about 72-85%, declining with power, for a MW-scale KOH electrolyzer, the only technology presently available at MW scale. PEM electrolyzers are now available at > 100 bar output, at ~10 kW scale; they may not economically scale to MW. KOH electrolyzers are now available at 30 bar output; 100 bar output will require an R+D effort and incremental capital cost, primarily for a stronger stack containment vessel and for materials choice.

GH2 COMPRESSION

We have completely eliminated compressors, both at input and midline, from the system modeled in this paper, because:

1. Hydraulic modeling of the pipeline for the assumed 1,000 MW (1 GW) windplant shows that midline compressors are not needed, for an accepted pressure drop from 100 bar to 30 bar;
2. 100 bar output electrolyzers should be feasible, and available, by year 2010, especially if a market seems promising; the electrolyzers will directly feed the pipeline at 100 bar;
3. GW-scale compressors are not readily available for GH2; some technologies will be difficult to scale to GW;
4. GW-scale compressors will be costly in capital, O&M, and operating energy—a large cost burden on the system.

The economic cost of GH2 compression, in this compressorless system, is the incremental cost of building the electrolyzer system capable of 100 bar output, vis-à-vis low pressure electrolyzer output. Pressurizing the H_2O feed water to 100 bar costs very little.
Hydrogen compression is a difficult problem at GW scale. Since GH2 has one-third the energy of NG, by volume (13 MJ *vs* 40 MJ per Nm3), compressor power and energy are greater for pipelining GH2 than for NG. Several compressor technologies are candidates for GH2 at GW scale, but few mechanical compressors of such size are available now, for GH2; therefore, we cannot estimate costs for them. Technological breakthroughs and development are needed in this field, for transmission pipelining of GH2 from sources other than electricity: biomass, solar thermal, photobiological, etc. are inherently low-pressure sources. Most compressor research today is focused on low-volume, high-pressure (300 – 700 bar) service for vehicle fueling.

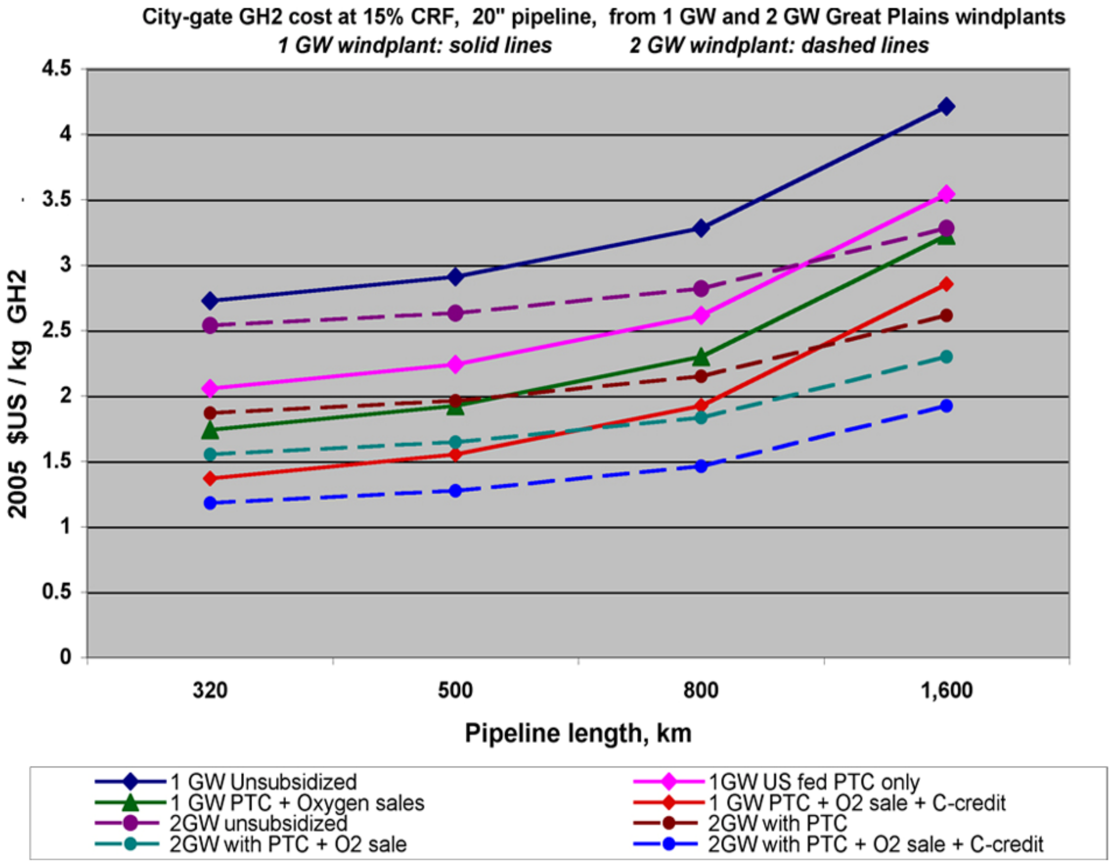


FIGURE 3. Cost of GH2 Fuel Delivered to City-gate market. Unsubsidized and four “value-added” cases are shown for both 1,000 MW (1 GW) and 2,000 MW (2 GW) (nameplate) windplant size.

Large diameter cross-country NG pipelines use centrifugal compressors driven by either large electric motors or by gas turbines. The stations are in the 10,000 – 30,000 kW range and often consist of a single compression package. Hydrogen is much more difficult to compress than NG due to its low specific gravity. In our model, compressing hydrogen from 30 bar to 100 bar would require up to 60 stages of centrifugal compression, while the same NG compression would need 4 or 5 stages. This large number of required GH2 centrifugal compression stages eliminates usual NG compression technology. Various reciprocating compressors may be used for GH2, but the large volumes and pressures we assume in this paper require equipment of such complexity and size that it becomes difficult to consider. Therefore, we have modeled our system entirely without compression, to take full advantage of high-pressure-output electrolyzers feeding the pipeline input.

SHARED POWER ELECTRONICS

Replacing the transformer-rectifier subsystem of the electrolyzer with power electronics (PE) and controls shared with the wind generator will save ~ 10% in electrolyzer system capital cost and ~ 3% in energy conversion loss. Modern wind generators pass 100% of their output power through PE which provides variable-speed operation, low voltage ride through (LVRT) (electricity grid fault tolerance and recovery), and power conditioning to deliver grid-quality AC. PE topology includes an internal DC bus which, with PE redesign, would feed the electrolyzer, or several of them in series.

This DC bus voltage is typically 800-1,000 VDC, while MW-scale electrolyzers typically operate at 200 VDC. This impedance-mismatch problem might be solved by connecting several electrolyzers in series, although this presents electrical isolation and safety problems.

PE is 10-15% of wind generator capital cost. Since the system in Figures 1 and 2 delivers no energy to the grid, the inverter section of the PE is eliminated, for a small saving in wind generator capital and O&M cost. The distribution-voltage transformer and underground wiring are also eliminated, replaced with piping for H_2O feedstock, H_2 and O_2, and a small AC electricity supply for controls.

MATERIALS CHALLENGE: HYDROGEN EMBRITTLEMENT (HE)

See Section 3.7 of our more complete paper for a detailed discussion of HE fracture mechanics [1]. Hydrogen gas can compromise the structural integrity of high-pressure containment or delivery systems. [6] In particular, the interaction between hydrogen gas and surface flaws can promote failure of pressurized steel structures. [7] Hydrogen interacts with material at the tip of a flaw and can cause embrittlement by one of several well-established mechanisms. [6, 8] The high stresses at the flaw tip coupled with the presence of embrittled material facilitate propagation of the flaw. The design of hydrogen gas containment or delivery systems must consider the presence of flaws in the structure.

Although hydrogen embrittlement can operate in steel exposed to high-pressure gas, flaw-tolerant structures can be designed through the application of fracture mechanics. Flaws in pipelines can result from handling, corrosion, metallurgical defects, or welding. [6, 9] These flaws can be located on the interior and exterior surfaces of the pipeline. Hydrogen-assisted flaw propagation is sensitive to material- and environment-dependent fracture mechanics properties.

Fracture Mechanics Methodologies

Pipeline wall stresses generated from either static pressure or pressure cycling can cause hydrogen-assisted flaw propagation. The fracture mechanics property relevant to static pressure loading is K_{IH}, which is a material- and environment-dependent value of the stress-intensity factor. The fracture mechanics property used for pressure cycling, or fatigue loading, is the crack growth increment per cycle *vs* stress-intensity factor range, $(da/dN)_H$ *vs* ΔK. This relationship also depends on material and environmental variables.

Hydrogen embrittlement of high-pressure pipelines can be accommodated through the application of fracture mechanics. The critical design parameters are the maximum allowable flaw depth under static pressure loading and the number of cycles required to grow a small flaw under cyclic pressure loading to the maximum allowable flaw depth. Fatigue loading must be considered when the pipeline is subjected to pressure cycling, particularly since flaws can propagate under lower applied K levels compared to static loading. Fatigue analysis predicts the growth of a small postulated flaw, e.g., existing flaw depth equal to 5% of the wall thickness, as a function of the number of loading cycles.

SYSTEM OPTIMIZATION

At GW scale, if operating from a single AC or DC bus, KOH-type electrolyzers can most economically be arranged in "star" modules, sharing electrolyte circulation and gas cleanup piping. A proposed 265 MW electrolyzer plant used a configuration of four "star" modules of individual electrolyzers; the plant contains 96 electrolyzers, each with 230 cells @ ~1.5 volts DC in series; current is 6,000 A, 2.76 MWe input per electrolyzer. However, a wind generator array may not provide a single electricity bus; shared PE and piping may require a MW-scale electrolyzer at every wind generator, as in Figure 2. This paper does not attempt this topology optimization.

COMPONENT CAPACITY: SYSTEM OPTIMIZATION SIMULATION

Figures 4 and 5. Using a year-long data set of actual hourly output of a northern Great Plains windplant, we modeled the system of wind generators, electrolyzers, and pipeline to estimate:

1. Smoothing of delivered GH2 provided by pipeline storage;
2. Optimum ratio of component capacity for minimum cost of delivered GH2.

Optimum electrolyzer capacity is difficult to estimate, because of the stochastic nature of the wind energy resource. Electrolyzers may be operated above their rated capacity at an energy conversion efficiency penalty, but at reduced duty cycle to avoid overheating the electrolyzer system. We have applied this operating range limit to our model, which requires the electrolyzers to operate above nominal rating ~ 10% of the time:

- Minimum 360 kW 82.9 % efficiency
- Nominal 1,200 kW 75.8 % efficiency
- Maximum 1,620 kW 73.3 % efficiency

However, if much of the operating time above nominal capacity is at high duty cycle, the electrolyzers may overheat, forcing more curtailment of wind generation than we have assumed. Empirical data from pilot plants like the proposed IRHTDF pilot plant will be necessary to guide more valid and accurate modeling of the wind generator-electrolyzer subsystem [18].

With the above electrolyzer rating assumptions, the electrolyzers become relatively more expensive than the wind generators, so the economic optimum undersizes them relative to the maximum wind capacity, to increase their utilization factor, or capacity factor (CF).

Windplant capacity is about 125% of electrolyzer and pipeline capacity at optimum, in Figure 4. This "wastes" some wind energy, by curtailing wind generation to avoid overheating the electrolyzers and overpressurizing the pipeline, but increases utilization (CF) of electrolyzers and pipeline.
For windplant-to-electricity transmission, Cavallo has proposed system optimization to enhance transmission CF and increase firmness of supply by "oversizing" the windplant and by using compressed air energy storage (CAES). [10, 11]

ENERGY STORAGE AS GH2

As demand for hydrogen grows, demand for hydrogen storage capacity will grow, to:

1. Allow producers to meet peak demand levels in excess of production capacity. For example, large amounts of NG is produced (mined) and stored, primarily underground, during the summer months for use in the winter, when demand is higher. With the storage capacity, the NG mining industry does not have to maintain mining capacity equal to peak winter NG demand. This lowers costs significantly. Seasonal fluctuations in the price of NG provide producers with the incentive to develop storage capacity, because storage allows them to sell more of their NG during peak periods, when prices are higher.
2. Increase the utilization rate (i.e., CF) of expensive pipeline and other delivery infrastructure. As with NG, storage capacity at the upstream end of a pipeline will result in higher pipeline utilization than a scenario without storage. Financing capital-intensive infrastructure is far more likely when potential investors project a high utilization rate.

GH2 STORAGE IN PIPELINE

A long pipeline could provide a significant amount of storage capacity. Table 4 shows storage capacity in an 800-km-long pipeline would range from 10 GWh (a 20" pipeline operating between 40 and 20 bar) to 107 GWh (a 36" pipeline operating between 100 and 30 bar).

The throughput of the pipeline drops substantially when used as a storage vessel. For NG, pipeline storage is economical only when used to cover for short compression equipment outages.

GH2 STORAGE IN WIND GENERATOR TOWERS

US Department of Energy National Renewable Energy Laboratory (NREL) has investigated this potential.[12] Because tower storage would be at much lower pressure (15 - 30 bar) than required for pipeline transmission, the cost of required pipeline input compression may defeat this value.

GH2 STORAGE IN END-USER DEVICES

Distribution pipelines, ground vehicle and aircraft fuel tanks, equipment for distributed generation (DG) of electricity, and peak-shaving reversible fuel cells may provide significant aggregate distributed GH2 storage. This would reduce peak demand and "smooth" windplant output, but it would not completely "firm" the windplant output, because pipeline storage is relatively small.

GH2 STORAGE IN GEOLOGIC FORMATIONS

Low-cost, seasonal-scale, storage is needed for renewable-source GH2, as it is for NG. Solution-mined salt caverns are GH2-tight to > 100 bar, but these formations are rare; most are man-made. The US stores helium beneath an aquifer in Texas. Similar aquifers may be abundant and GH2-tight. In Tees County, UK, >1,000 tons of GH2 is stored in several solution-mined salt caverns, for industrial use. [13] The ChevronPhillips GH2 cavern in Texas has stored ~ 2,500 tons of GH2 for over twenty years. [14] This resource needs exploration and assessment, given the potential to firm, and render dispatchable, large, indigenous, clean energy sources of inherently time-varying output.

MARKETS AND FIRMING FOR WIND-GENERATED GH2 FUEL

The most attractive markets for wind-generated hydrogen in the near term are the traditional industrial and commercial markets, given the higher value of hydrogen in these markets than in commodity energy markets. Typically, hydrogen is produced by large steam methane reformers (SMR), which can generate hydrogen at no less than 50-60% higher than the cost of the natural gas feedstock.

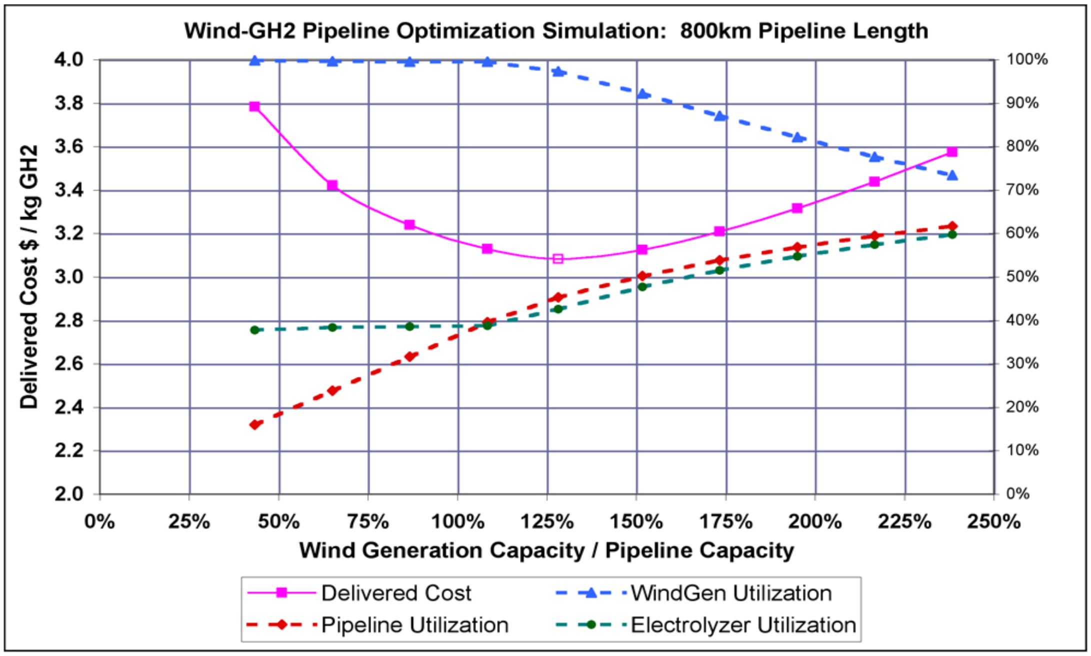


FIGURE 4. Wind - hydrogen pipeline system optimization simulation: unsubsidized, 800 km long GH2 transmission pipeline. Wind generators, electrolyzers, and 800 km transmission pipeline system. Minimum cost point is where the maximum wind capacity slightly exceeds the maximum pipeline capacity, "wasting" some wind energy but increasing the utilization of the electrolyzers and pipeline.

TABLE 4: Energy Storage as Compressed GH2 in the Pipeline
*Energy Storage, Days: Number of days of storage of 1,000 MW windplant output @ 40% CF (9.6 GWh / day)

Length km	Inside Diam inches	Volume Cubic Meters	Inlet Press bar	Delivery Press bar	Energy Storage Nm3 x 10^6	Energy Storage MMscf	Energy Storage Tons	Energy Storage GWh	Energy Storage Days *
800	20	146,338	100	30	10	352	936	33	3.5
800	36	468,605	100	30	32	1,126	2,997	107	11.2
800	20	146,338	40	20	3	105	281	10	1.0
800	36	468,605	40	20	10	338	899	32	3.3
1600	20	292,675	100	30	20	703	1,872	67	7.0
1600	36	937,209	100	30	64	2,251	5,994	214	22.3
1600	20	292,675	40	20	6	211	562	20	2.1
1600	36	937,209	40	20	19	675	1,798	64	6.7

The storage capacity shown in Table 4 could benefit the wind plant by allowing it to sell more energy on a “firm” basis than if the energy were transmitted via electricity lines. “Firm” refers to contract terms under which the seller guarantees delivery of the energy (and must procure energy in the market if he cannot generate it). Buyers pay more for firm energy than for non-firm energy.

Because pipeline developers will seek to maximize throughput (minimizing needed storage), and because other hydrogen producers using the line would make storage unreliable for wind generators, we believe there is likely to be little storage value in a hydrogen pipeline dedicated to windplants. More work could be done to test this hypothesis, enabled by empirical data from the proposed IRHTDF pilot plant [18]. The pipeline would need to maximize its utilization rate by receiving hydrogen from diverse other producers in order to be economically attractive. The production from these other facilities would reduce the pipeline storage available to the wind generators. Further, the activities of the other hydrogen producers using the pipeline would make storage highly uncertain for wind generators, without inherent seasonal synergy. Wind generators would not be able to count on the storage capacity, making firm contracts for hydrogen sales risky.

As seen in Figure 5, the energy storage in the pipeline would smooth the output of the windplant somewhat, but hydrogen delivered from the pipeline at the city gate would still be quite variable. Typically, a variable supply of any energy product is less valuable than a firm supply, as evidenced by lower priced "interruptible" gas and electricity tariffs. The owner of the windplant-electrolyzer-pipeline project would have two options for firming the hydrogen: storage and firming purchases.

Hydrogen storage could occur anywhere along the pipeline path. Storage options include:

1. Underground storage – using suitable underground reservoirs, hydrogen can be stored in volumes up to ~ 3,000 tons.
2. Liquid storage – typically used for the storage and distribution of large volumes of hydrogen today, where pipelines are not available. Liquid production systems are typically sized for 10^5 - 10^6 Nm3 per day, with a liquid trailer delivering approximately 3 – 6 x 10^4 Nm3.
3. Hydrogen tube trailer storage – typically used for delivery of lower volumes of hydrogen to industrial and commercial customers. Typically, tube trailers operate at up to 150 bar with volumes of 3 – 6 x 10^3 Nm3.

In addition to large-scale storage as part of the pipeline project, the pipeline company could target customers with storage capacity. Large tanks at transportation fueling facilities (like the underground tanks used at gas stations today) represent one option for customer-site storage.

In a firming strategy based on spot purchases, the windplant-electrolyzer-pipeline company would purchase from other suppliers the hydrogen necessary to provide firm service. If the company had hydrogen tank trucks and could take the gas directly from production plants, it might pay a wholesale price. If it took the gas from another company's distribution system, it would pay something closer to a retail price. As long as the hydrogen could be purchased at a price equal to or below the retail price of hydrogen, the pipeline company would not lose money using this firming strategy. However, if the company could be caught short during a period of extremely high wholesale prices, using spot purchases as a firming strategy would be more risky.

Thus, the key question in evaluating purchases as a firming strategy is: what is the annual profile of wholesale hydrogen prices at the city gate? If the profile is relatively flat, purchases could be a less costly firming strategy than storage. If the price profile were highly variable, purchases would be more risky and storage may be the lower-cost option. Because NG demand is heavily driven by space heating, spot market gas prices are higher during the winter than the summer, and they can be extremely high in the coldest periods of the winter. [15] A much smaller portion of hydrogen would probably be used for space heating than is currently the case with NG, because transportation is expected to be a major hydrogen demand driver. In other words, strong hydrogen demand from the transportation sector might well prevent heating and cooling demand from causing seasonal swings in spot market prices. However, if NG becomes the main fuel input for hydrogen production, spot market hydrogen prices might follow the seasonal variations of NG prices.

Thus, without functioning hydrogen markets to observe, it is difficult to predict how risky a firming strategy based on spot purchases would be. However, with projections of annual hydrogen prices and the cost of storage, it would be a simple matter to determine the lower-cost firming strategy. Additional large-scale sources of hydrogen generation might include:

1. Coal gasification, with carbon capture and sequestration (CCS);
2. Electrolysis, ideally from hydroelectric, concentrating solar power (CSP), or nuclear-source electricity, for near-zero C-emissions;
3. Thermal, from solar radiation or nuclear;
4. Photovoltaic, photochemical and photobiological, and biomass.

For the use of the wind-generated hydrogen supply in commodity energy markets, the most obvious source of supply firming is the use of NG / hydrogen blends. Hydrogen can be mixed directly into the NG supply, either in the NG transmission system or into NG storage, resulting in a lower-btu, cleaner-burning fuel. The European Commission (EC) is now studying this blended fuel strategy via the "NaturalHY" project, conducted by Gasunie Research, The Netherlands. [16, 17]

Typically, NG consuming devices can accept up to 10% hydrogen by volume, often with efficiency or emissions improvements. Provided material compatibility of the transmission and distribution system is adequate, the concentration of hydrogen can be increased over time as hydrogen supply increases. If the concentration of hydrogen does not increase more than 10-15% over the life of the burner tip appliances, new hardware can be introduced to accept higher concentrations of hydrogen, in parallel with the change in fuel concentration. Such a scenario can avoid the onerous task of maintaining a parallel fuel infrastructure for hydrogen or introducing large scale fuel switching over a short period of time.

CONCLUSIONS

COST: Figure 3. With various "value-adders", wind-source GH2 may be delivered to distant markets, 320 to 1,600 km distant, at an untaxed wholesale energy unit cost apparently competitive with, at year 2005 market prices:

- hydrogen fuel made from NG by SMR;
- gasoline made from crude oil.

SMOOTHING: Figure 5. Pipeline energy storage smooths windplant output variations at time scales of minutes to days, but is probably inadequate to "firm" windpower to command full wholesale market price at the city gate. However, low-cost, seasonal-scale, geologic storage of GH2 could theoretically firm wind energy, adding significant strategic and market value. Such storage remains technically unexplored and unproven in the Great Plains, beyond the Texas Gulf Coast region.

MARKETS: Our research for this paper will not adequately inform the energy industry about future hydrogen markets (particularly the annual price profile) to be able to say anything quantitative about firming the supply. There is a quantifiable difference between the prices of firm and non-firm NG today, but the annual price profile of hydrogen may be quite different from today's NG price profile. The remaining challenge is determining whether storage or spot purchases is the lower-cost firming option for wind-source GH2 fuel.

HYDROGEN EMBRITTLEMENT (HE): Line pipe and system component materials must be tested, selected, and other measures taken, to control the critical phenomenon of hydrogen embrittlement (HE) of steel, *aka* hydrogen corrosion cracking (HCC) and stress corrosion cracking (SCC).

COMPRESSORS: Assuming that 100 bar output electrolyzers feed the GH2 pipeline directly, no compressors are needed in the system, for a large saving in capital, energy, and other O&M costs.

CAPACITY: For the 20" diameter, 100 bar, GH2 pipeline assumed here, optimum windplant capacity, for minimum cost of GH2 fuel delivered to the city gate, is ~1.5 GW (for a 1,600 km pipeline) to ~3.5 GW (for a 320 km pipeline).

SIMULATION: To better understand the economics of the windfarm-electrolyzer-pipeline system, we performed several simulation analyses using hourly wind data. A sample of these results is shown in Figure 4. Based on the relative costs of these three system components, the most economical design point appears to be to size the electrolyzer units to match the maximum pipeline capacity and then to slightly oversize the wind generation, by 20-35%, which wastes some wind generation but increases the overall utilization factor of the system.

IRHTDF; IPHE: This paper may support building a pilot-scale hydrogen pipeline system, optimized for bringing large-scale, diverse, stranded, renewable energy sources to distant markets as hydrogen gas, as an International Partnership for the Hydrogen Economy (IPHE) project: the International Renewable Hydrogen Transmission Demonstration Facility (IRHTDF). [18] This paper's analysis is applicable to large, diverse, stranded, renewable energy resources worldwide.

Perhaps all new NG pipelines, worldwide, could be built capable of future renewables-hydrogen service (RHS), characterized by pressure-fluctuation fatigue, at little or no incremental capital cost, if:

1. Fracture mechanics tests in hydrogen prove suitable line pipe material(s);
2. The IRHTDF results are promising.

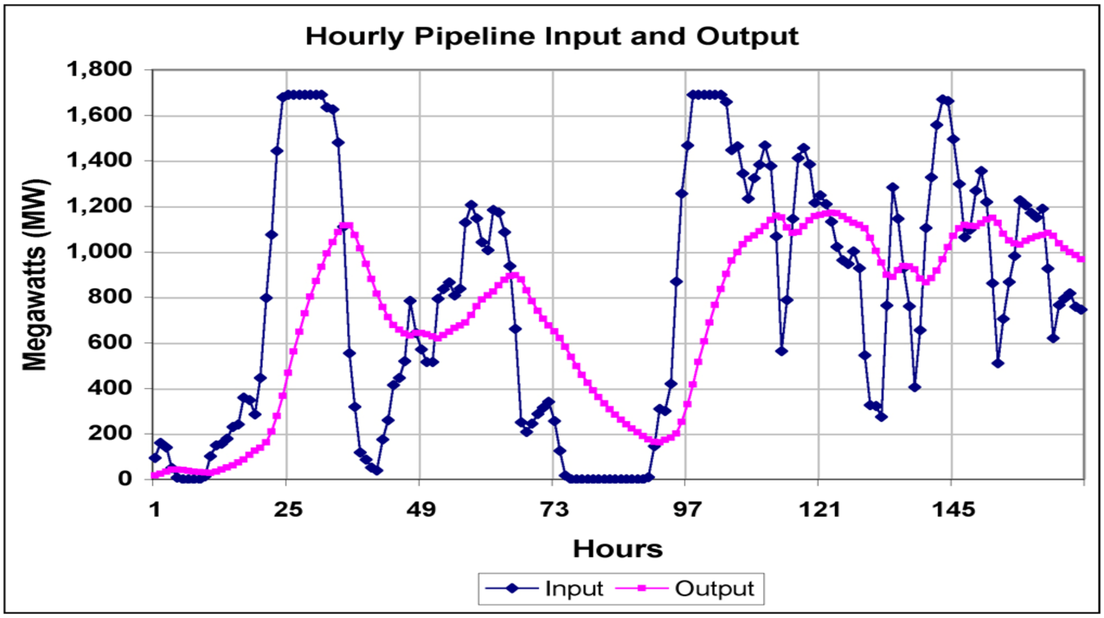
Pipeline RHS-capability would be an important strategy for building the infrastructure for a future "hydrogen sector" of a carbon-emissions-free, global energy economy, based largely on renewables.

RECOMMENDED FURTHER STUDY

See our more complete paper for details. [1]

1. Linepipe materials testing
2. System optimization
3. Firming value of storage, especially large-scale geologic storage, perhaps synergistic with nuclear hydrogen generation [19]
4. Electrolyzer duty cycle and overload tolerance

5. Sharing power electronics and controls between wind generator and electrolyzer
6. Preliminary planning for an International Renewable Hydrogen Transmission Demonstration Facility (IRHTDF), as a project for the IPHE (International Partnership for the Hydrogen Economy).[18, 20]



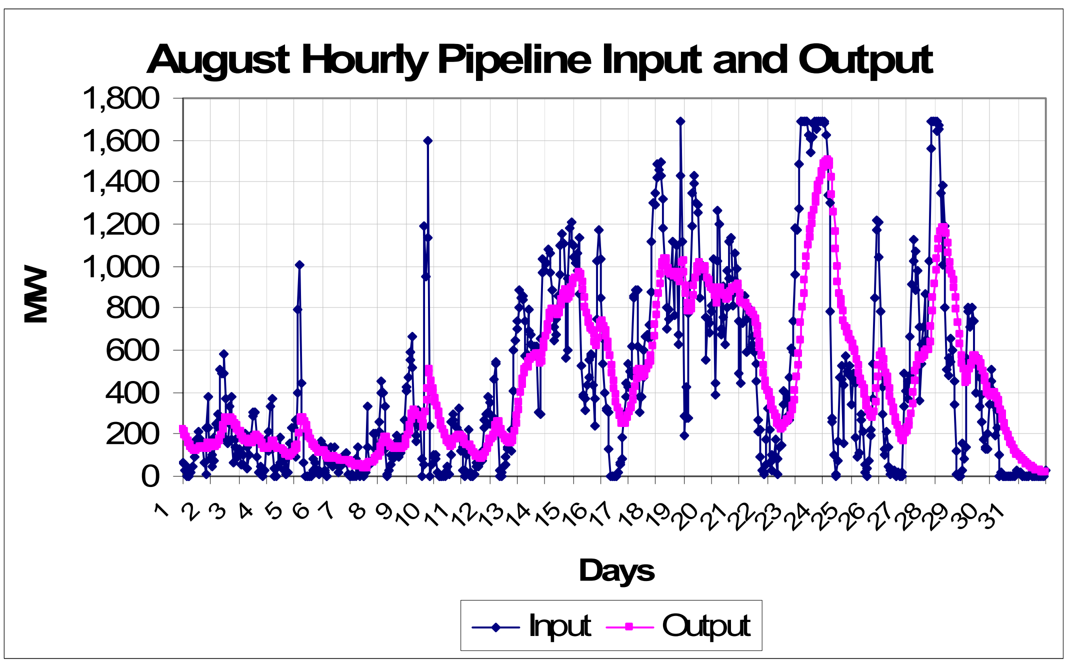


FIGURE 5: GH2 delivery "smoothing" from energy storage in an 800 km pipeline. Above: first week of September, modeled from actual hourly output of a northern Great Plains, North America, windplant. Below: month of August, the least-windy month. Pipeline transit time lag is about 20 hours, smoothing some of the hourly and shorter period wind generation variations. Note apparent input limitation at 1,700 MW by electrolyzer capacity, resulting in a small amount of lost wind energy via curtailed generation, and in greater long-term pipeline utilization factor, or capacity factor (CF).

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