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# Running the world on renewables: Hydrogen transmission pipelines and firming geologic storage

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## SUMMARY

On every continent, diverse renewable resources could supply all humanity's future energy needs. Earth's richest renewable energy resources—large in geographic extent, high intensity—are usually stranded: far from end-users without gathering and transmission systems. The output of most renewables varies greatly, at time scales of seconds to seasons: the energy capture assets thus operate at inherently low capacity factor (CF), and energy delivery is not 'firm'. New electric transmission systems dedicated to renewables will suffer the same low CF and represent substantial stranded capital assets.

At gigawatt (GW) scale, renewable-source electricity could be converted to hydrogen and oxygen, *via* high-pressure-output electrolyzers. Hydrogen would be pipelined to load centers for use as vehicle fuel, retail-value combined-heat-and-power generation on the customers' side of meters, ammonia production, and refinery feedstock. Great Plains, U.S.A. wind energy alone, if fully harvested and pipelined to markets, could supply all U.S.A. energy. About 15 000 new, large, solution-mined Great Plains salt caverns could economically store enough energy as compressed hydrogen to 'firm' this wind power at annual scale, at an incremental capital cost to the generation–transmission system of 5–10%. Worldwide, firming in geologic formations adds great market and strategic value to diverse, stranded, and abundant renewables. Copyright © 2008 John Wiley & Sons, Ltd.

KEY WORDS: hydrogen; geologic storage; firming; stranded; renewable; pipeline; salt cavern

## 1. INTRODUCTION

We report the results of several studies of the technical and economic feasibility of large-scale renewables-hydrogen systems [1–4]. Windplants are the lowest-cost renewable energy sources. The largest and richest wind resources in North America, with high average annual wind speed, are stranded in the 12 Great Plains, U.S.A. (Great Plains) states: extant electric transmission capacity is insignificant relative to the resource potential.

The costs reported herein were developed in 2004–05, but are now 30–70 per cent higher because of:

1. Rapid increases in worldwide material, energy, and construction costs;

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2. A worldwide shortage of wind turbines, which has caused production inefficiencies and a sellers' market, thus high turbine prices;
3. Decline in value of the \$US vis-a-vis other major world currencies

Great Plains wind energy alone, if fully harvested and converted to hydrogen, 'firmed' in $\sim$ 15 000 new storage salt caverns and pipelined to markets, could supply the entire energy consumption of the U.S.A. Annual-scale firming adds $\sim$ 5–10% incremental capital cost to the generation–transmission system.

At gigawatt (GW = 1000 MW) scale, renewable-source electricity can be converted to gaseous hydrogen (GH2) and oxygen, *via* high-pressure-output electrolyzers, and pipelined to load centers for use as vehicle fuel, combined-heat-and-power (CHP) generation on the retail side of the customers' meters, ammonia production, and petroleum refinery feedstock. New, large, man-made, solution-mined salt caverns in the Great Plains, and probably elsewhere in the world, can economically store enough energy as compressed hydrogen gas to 'firm' renewables at annual scale. This adds great market and strategic value to diverse, stranded, rich, renewable resources, rendering them dispatchable. Figures 10–13 show salt cavern storage. Natural geologic formations, such as deep aquifers and depleted natural gas (NG) reservoirs, may also provide GH2-tight storage. This is a worldwide opportunity.

The energy output of most renewables varies greatly at time scales of seconds to seasons: the energy capture assets thus operate at inherently low capacity factor (CF); energy delivery to end-users is not 'firm'. Few candidate strategies can economically firm renewables at annual scale. New electric transmission systems, or fractions thereof, dedicated to renewables, will suffer the same low CF as the renewable generators, and represent substantial stranded capital assets, which increases the cost of delivered renewable-source energy.

We assume a transmission-constrained world, where large new windplants, for example, must pay all transmission costs for delivering their energy to distant markets. Increasing the capacity of extant electricity transmission corridors is an attractive immediate strategy. Large, new, electric transmission systems will be difficult to site and permit, may be difficult to finance, and provide no energy storage for the inherently time-varying output of renewable sources. Building new underground pipelines has historically been easier and faster than new electric transmission lines.

We assume a large nascent market for renewable-source hydrogen fuel in today's carbon-constrained world for transportation fuel and potentially for distributed generation (DG) of CHP. We assume that distributors will buy all the GH2 fuel from the transmission pipeline at the city gate. GH2 pipeline transmission and geologic storage may offer important technical and economic advantages and synergies *vis-à-vis* electricity transmission, at large scale [4]:

1. Adding value to wind generation assets by 'firming' their energy output with energy storage.
2. Sharing power electronics (PE) between wind generation and electrolysis systems might save substantial capital, O&M, and energy conversion loss cost; removing requirements to deliver grid-quality electricity will improve wind generation cost of energy (COE) slightly [5].
3. Locating GH2 transmission pipelines underground may be more socially acceptable and more secure from natural and human threats.
4. Selling the oxygen byproduct of electrolytic production of hydrogen from wind-source electricity to adjacent biomass and coal gasification plants could add significant revenue, lowering COE.
5. Improving pipeline CF if geologic storage is available at the renewable resources.
6. Improving pipeline CF by synergistic sharing with diverse renewable GH2 sources in the same geographic area, complementing wind's time variability.

'Firm' refers to contract terms under which the seller guarantees delivery of the energy (and must procure energy in the market if seller cannot generate it). 'Firm' usually means available at any time of the year. Buyers pay more for firm energy than for non-firm energy. Storage capacity could benefit the wind, or other renewables, plant by allowing it to sell more 'firm' energy than if the energy were transmitted *via* power lines.



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Consider GH2 pipeline *versus* electricity for wind energy transmission 300 km for a 4000 MW (nameplate) windplant; at 40% CF typical for the Great Plains, the windplant will produce $\sim 14$ Terawatt-hours (TWh = billion kWh) of electricity per year. The complete 20-in (0.5 m) diameter pipeline system will have an estimated capital cost of $US 210 million, at $US 35 per inch diameter per meter length. Pipeline annual O&M costs are low, unless frequent 'pigging' inspection is required. A new 300 km electric transmission line, dedicated to the windplant, with 4000 MW capacity, capable of capturing all wind-generated energy with zero or small curtailment, would probably be an HVDC system with the following estimated capital costs:

- Converter stations @ $150 kW$^{-1}$ per station pair: $645 M.
- Overhead transmission line, 600 kv bipole @ $2 M km$^{-1}$, 300 km long: $600 M.
- Total capital cost: $1245 M.

HVDC transmission losses are $\sim$ 0.6% per converter station plus $\sim$ 0.4% per 100 km of line = 2.4% total; $\sim$ $33 M year$^{-1}$ on 14 TWh @ $50 MWh$^{-1}$. The dedicated electric transmission line will operate at $\sim$ 40% CF, the same as the windplant, presenting a substantial stranded capital asset. Electricity transmission can provide no affordable seasonal-scale firming energy storage. A VRB-ESS (vanadium redox battery energy storage system) was recently sold by Canada's VRB Power Systems for $3.6 M; rated 1.5 MW, 12 MWh. Annual-scale firming of the energy of a 4000 MW windplant would require $\sim$ 105 000 of these VRB-ESS plants, or their equivalent. However, 300 km is rather short for an HVDC system, where allocating converter stations cost per km is a large cost component; HVAC transmission would cost less.

The industrial gas companies' success and safety in operating thousands of km of GH2 pipelines worldwide is encouraging, but these are relatively short, with a 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 will cause large, frequent pressure fluctuations in GH2 pipelines in RHS unless firming storage is installed at the sources. These pressure cycles induce and exacerbate hydrogen embrittlement (HE): Section 3.6.

Design and construction of large, long-distance, high-pressure GH2 pipelines and conventional NG transmission lines are similar. Four technological aspects differentiate a GH2 line from an NG line and will need to be addressed if this concept is to be attractive to industry; most analyses show that pipelining GH2 costs approximately 30–80% times more than pipelining NG because of the following reasons:

1. The volumetric energy density of hydrogen is one-third that of methane.
2. Pipeline utilization: CF would be low without geologic storage at the sources.
3. HE of pipeline steel must be prevented and controlled: Section 3.6.
4. GH2 compression is very costly in capital, O&M, and energy.

The materials challenges of GH2 transmission pipelines may result in new materials or hybrids, with reduction in GH2-capable pipeline system costs to that of today's NG pipelines: Section 3.6.

Other attractive transmission and firming storage schemes for large-scale renewable-source hydrogen include the following conversions to:

1. Anhydrous ammonia ($NH_3$), transmission and storage as liquid in pipelines and refrigerated above-ground tanks of 30–60 000 metric tons (Mt) each.
2. Fischer–Tropsch liquids (FTL's), transmission and storage in pipelines and tanks.
3. Magnesium hydride, aluminum–gallium, and several other chemical forms.

As an alternative to the GH2 scheme for windplant-to-electricity transmission, Cavalho has proposed system optimization to enhance electricity transmission CF and increase firmness of supply by 'oversizing' the windplant and by using compressed air energy storage (CAES) [6, 7]. This scheme requires significant NG fuel for efficient



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recovery of the energy stored as compressed air, and some windplant output curtailment.

## 2. METHOD

We surveyed manufacturers of wind generators, electrolyzers, and compressors to obtain expected performance and capital costs in year 2020, with costs expressed as $US in year 2005. Table I estimates year 2020 technology and capital component costs from industry consensus and USDOE goals [8].

We surveyed engineers, geologists, and constructors in the U.S.A. solution mining salt cavern industry [9].

We modeled the technical and economic performance of a large 4000 MW (4 GW) nameplate capacity windplant delivering its entire output as GH2 fuel, by pipeline, to an urban 'city-gate' market 300 km away; Figures 1–3 [10]. Such a large generation and transmission system would achieve full economy of scale.

We considered two modeling options; see Table III:

1. Firming geologic storage at the 4 GW windplant, requiring GH2 pipeline capacity of ~ 1.6 GW. In this case, the 20-in pipeline could be 800 km long.
2. No firming storage at the 4 GW windplant; pipeline 'packing' and downstream firming storage would allow a 300 km 20-in pipeline.

We chose the latter, to be conservative.

First, we modeled pipeline performance, using hydraulic models standard in the gas pipeline industry, and assuming no compressors in the

Table I. Capital costs: 4000 MW windplant, electrolyzers, and 20 in (~ 0.5 m) pipeline 300 km long.

| | TICC*\$ kW$^{-1}$ in Year 2020 | Total (million 2005 \$US) |
|---|---|---|
| Windplant | \$800 | \$3200 |
| Windplant power electronics incremental cost | \$30 | \$120 |
| Electrolyzers: 100 bar output, KOH type | \$330 | \$1320 |
| Pipeline: 20 in, 300 km long | \$35 in$^{-1}$ diam m$^{-1}$ length | \$210 |
| *TICC (total installed capital cost, 2005 \$US) | | \$4850 |

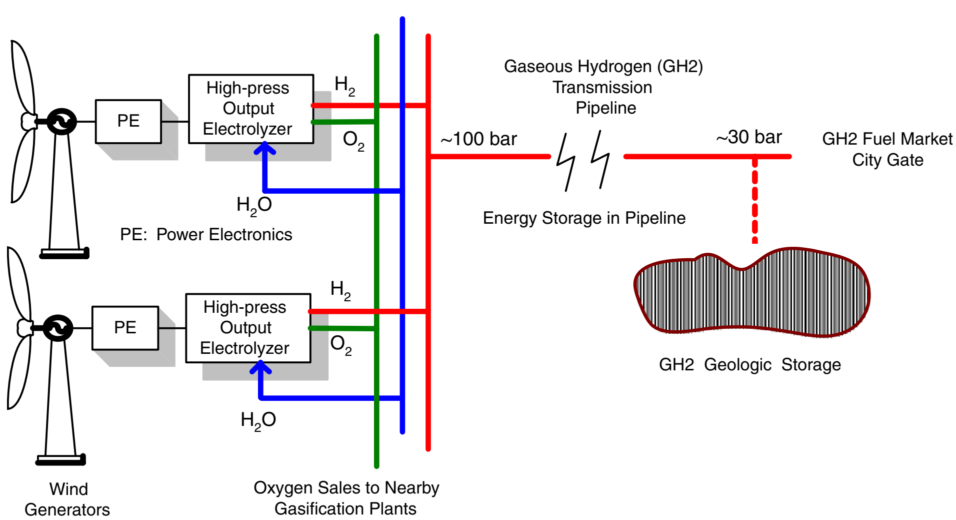


Figure 1. System diagram: topology options. All wind energy is converted to GH2 for transmission; no electricity is delivered to the grid. Windplant infrastructure is primarily piping, with a small supply of electricity distributed only for controls. Byproduct oxygen cannot be pipelined far, to biomass or coal gasification plants, at competitive cost.



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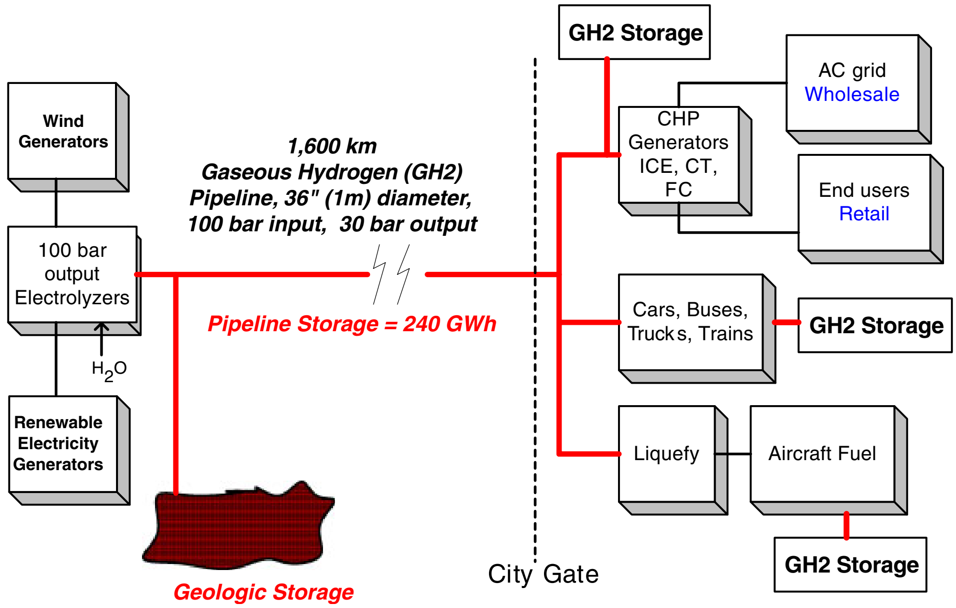


Figure 2. System diagram. One hundred bar output electrolyzers directly feed the pipeline without compressors. Gaseous hydrogen (GH2) delivery to the city-gate market is at ~ 30 bar, after pipeline friction losses: a good pressure for urban distribution; a tradeoff for eliminating compressors. Pipeline and end-user storage provides renewable-source smoothing, but not annual-scale firming which can only be accomplished in geologic storage, probably salt caverns.

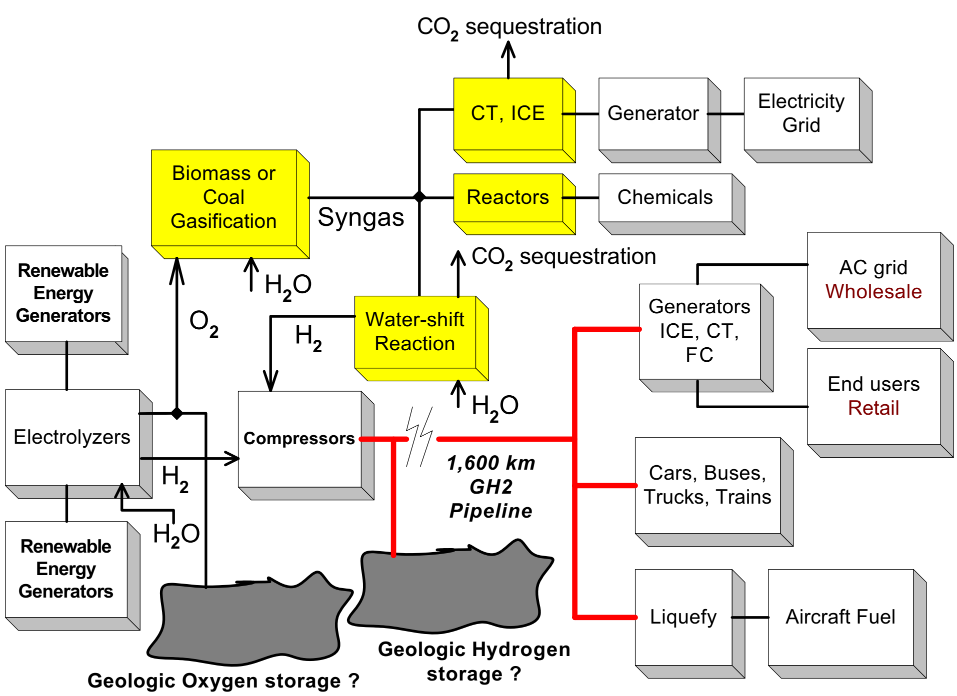


Figure 3. System diagram, with potential 'value-adding' features of byproduct oxygen sale to adjacent gasification plants, improved pipeline CF, and seasonal-scale geologic storage of GH2 at the source, which would allow transmission pipeline length up to 1600 km. High-pressure-output electrolyzers would eliminate compressors.



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Table II. Unsubsidized cost of wind-source GH2 fuel delivered at end of pipe at distant city gate, as a function of CRF and pipeline length, in 2005 $US.

| Pipeline length | 320 km (Cost $kg^{-1}$) | 480 km (Cost $kg^{-1}$) | 800 km (Cost $kg^{-1}$) | 1600 km (Cost $kg^{-1}$) |
|---|---|---|---|---|
| At CRF = 12% | $2.19 | $2.34 | $2.64 | $3.38 |
| At CRF = 15% | $2.72 | $2.91 | $3.28 | $4.21 |
| At CRF = 18% | $3.26 | $3.48 | $3.93 | $5.04 |
| At CRF = 21% | $3.75 | $4.01 | $4.53 | $5.82 |

Assumes: Unsubsidized (no US federal production tax credit (PTC), or other); no 'value adders' in byproduct oxygen sales or carbon emissions offset credits or payments.

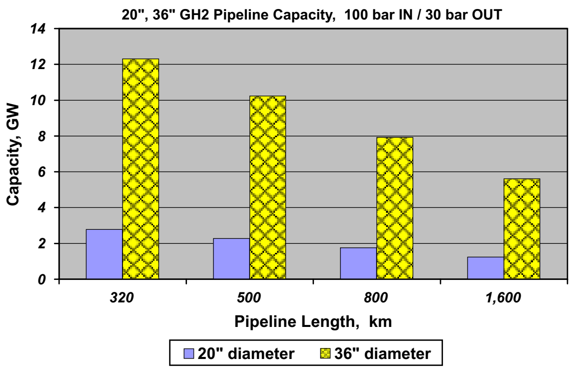


Figure 4. Eight hundred km long GH2 pipeline capacity as a function of diameter and length: GW.

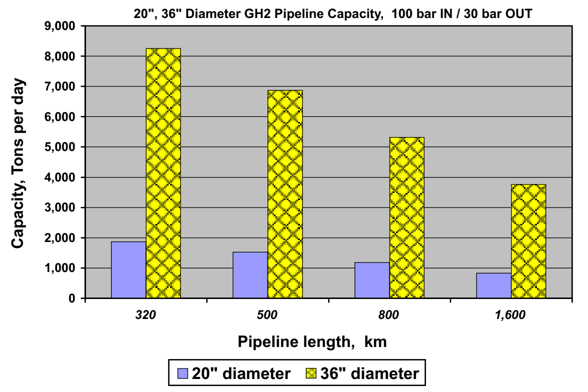


Figure 5. GH2 pipeline capacity as a function of diameter and length: metric tons (Mt) per day.

system, either at source or at midline, to find the following:

1. Pipeline transmission capacity.
2. Pipeline energy storage capacity, assuming 'packing' the pipeline to 100 bar, 'unpacking' to 30 bar, for adequate delivery pressure for distribution at the distant urban market.
3. Dynamic energy storage behavior as windplant output varies with time.

Second, for this large-scale windplant in the Great Plains, we used a simple capital recovery factor (CRF) model to calculate average annual wholesale, untaxed cost of energy (COE) for GH2 fuel in $US 2005, at the end of pipe at a distant urban market, considering a range of CRF: Table II and Figure 6 [11]. For expected year 2020 technology and year 2005 $US costs, we assumed the following:

- No electric energy is delivered to the grid; all is converted to GH2 for the pipeline.
- Others will buy the end-of-pipe wholesale GH2 fuel for urban distribution.
- For a given diameter and pressure, GH2 pipelines can be built for the same capital cost as for NG, although serious line pipe material challenges must be met: Section 3.6.
- Total installed capital costs in Table I.
- Wind generator CF = 40%.
- CRF = 12–21%; a good compromise for this analysis is 15%, as shown in Figure 6.
- Potential added value from byproduct oxygen sale, U.S.A. federal production tax credit (PTC), and renewable energy certificates (RECs).

Third, we modeled system economics to find the optimum nameplate capacity ratios among windplant, electrolyzers, and pipeline, as shown in Figure 8.

We estimated system capital cost savings from optimizing wind generator power electronics (PE) to supply low voltage DC to the electrolyzers, rather

Table III. GH2 pipeline transmission and storage capacity, without inlet or midline compression.

| Length (km) | Length (miles) | Nominal diameter (in) | Capacity (GW) | Capacity (MMscfd) | Capacity million (N m$^3$ day$^{-1}$) | Capacity (tons per day) | Storage capacity (MMscf) | Storage capacity (ton) |
|---|---|---|---|---|---|---|---|---|
| 320 | 200 | 20 | 2.8 | 702 | 18.1 | 1869 | 141 | 374 |
| 320 | 200 | 36 | 12.3 | 3100 | 80.1 | 8253 | 450 | 1199 |
| 480 | 300 | 20 | 2.3 | 573 | 14.8 | 1526 | 211 | 562 |
| 480 | 300 | 36 | 10.2 | 2580 | 66.7 | 6869 | 675 | 1798 |
| 800 | 500 | 20 | 1.8 | 444 | 11.5 | 1182 | 352 | 936 |
| 800 | 500 | 36 | 7.9 | 1998 | 51.7 | 5319 | 1126 | 2997 |
| 1600 | 1000 | 20 | 1.2 | 313 | 8.1 | 833 | 703 | 1872 |
| 1600 | 1000 | 36 | 5.6 | 1413 | 36.5 | 3762 | 2251 | 5994 |

Table IV. Energy storage as compressed GH2 in pipeline.

| Length (km) | Nominal diam (in) | Volume, cubic (meters) | Inlet press (bar) | Delivery press (bar) | Energy storage (N m$^3$ × 10$^6$) | Energy storage (MMscf) | Energy storage (ton) | 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 | 1126 | 2997 | 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 | 1872 | 67 | 7.0 |
| 1600 | 36 | 937 209 | 100 | 30 | 64 | 2251 | 5994 | 214 | 22.3 |
| 1600 | 20 | 292 675 | 40 | 20 | 6 | 211 | 562 | 20 | 2.1 |
| 1600 | 36 | 937 209 | 40 | 20 | 19 | 675 | 1798 | 64 | 6.7 |

*Energy storage, Days: number of days of storage of 1000 MW windplant output at 40% CF (9.6 GWh day$^{-1}$).

than high-quality AC to the grid, thus eliminating the 'transformer–rectifier' component of electrolysis systems and the inverter section of PE.

Based on these pipeline modeling results in Figures 4, 5, and 8, and Tables III and IV, we chose 20 in diameter and 100 bar maximum allowable operating pressure (MAOP) as follows:

- Amenable to modern pipeline design practice and economy of scale.
- Adequate for a 4000 MW windplant 300 km from the city-gate market, without firming storage.
- Capable of 800 km transmission if firming storage is installed at the windplant (or other renewable sources).

We also modeled this system to include 'value-adding' features that reduce the cost of GH2 fuel delivered at end of pipe at the distant urban market. Figures 3 and 6.

1. US federal PTC: \$0.019 kWh$^{-1}$ in year 2005.
2. Byproduct oxygen sale to adjacent gasification plants for dry biomass, and perhaps for coal (assuming carbon capture and sequestration (CCS)): Figures 1 and 3.
3. Estimated future carbon-emission offset payment or REC of \$0.01 kWh$^{-1}$.

Finally, we estimate the cost and potential contribution of GH2 pipeline transmission and geologic storage for 'smoothing' (Figure 9) and 'firming' the time-varying output of windplants, increasing its value. We calculate the quantity of energy storage required for annual-scale firming of Great Plains wind. We also suggest several topics for further research and analysis: Section 5.



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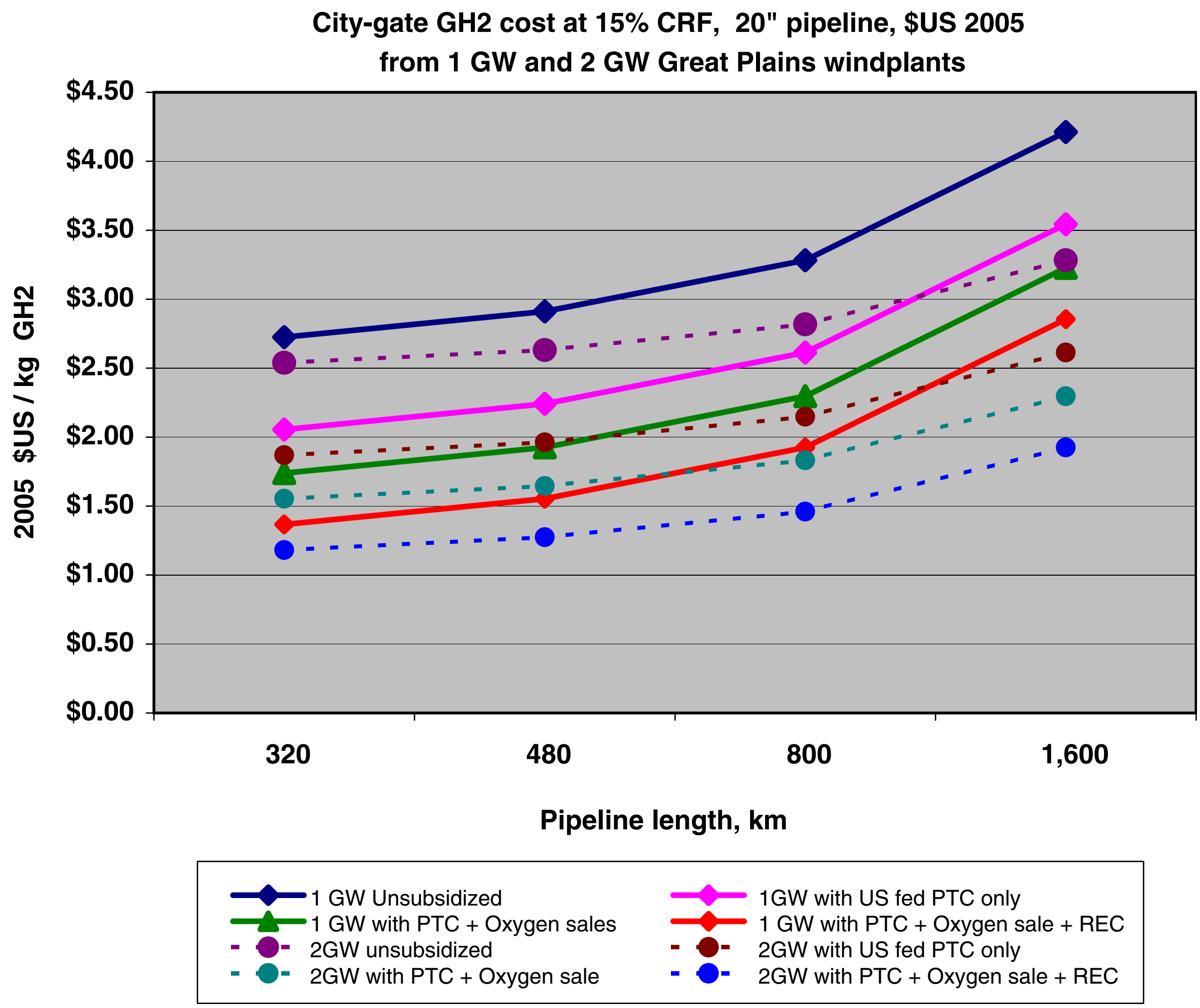


Figure 6. Unsubsidized and four 'value-added' cases are shown for both 1 GW (solid lines) and 2 GW (dashed lines) windplant sizes. Cost per kg GH2 would be about the same for 2 GW and 4 GW windplants.

## 3. RESULTS

### *3.1. System and pipeline capacity*

A 4000 MW windplant produces about $20 \times 10^6$ N m$^3$ day$^{-1}$ of GH2 at full output; $8 \times 10^6$ N m$^3$ day$^{-1}$ at 40% average CF. The continuous capacity of a 300 km long, 20 in diameter, GH2 pipeline is $\sim 18 \times 10^6$ N m$^3$ day$^{-1}$, without compressors. It could deliver wind-source GH2 fuel 300 km by pipeline for an unsubsidized price of $\sim$ \$3.30 kg$^{-1}$, assuming the following:

1. Estimated year 2020 technology and costs, expressed in year 2005 $US.
2. All wind energy is converted to GH2 and delivered *via* 20 in 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. CRF of 15%.

Results of modeling pipeline transmission and storage capacity, using hydraulic equations standard in pipeline design practice, are shown in

Table III and Figures 4 and 5. This assumes the following:

1. Hundred per cent GH2.
2. Hundred bar input, 30 bar output pressures.
3. Capacity: fully turbulent flow achieved.
4. Storage capacity: 'unpack' the pipeline from 100 to 30 bar.
5. Pipeline lengths of 320, 480, 800, and 1600 km.
6. Twenty and 36 in (0.5 and 1 m) nominal industry-standard pipeline diameters.

In a mature renewables–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 accessing electricity transmission lines. Synergistic harvest of diverse renewable energy resources will improve pipeline CF and reduce geologic storage required for firming.

### 3.2. COE at end-of-pipeline

Table II and Figure 6. Based on results in Table III and Figures 4 and 5, we analyzed three 'value-added' cases as well as the 'unsubsidized' case, for both 1 and 2 GW windplants. Per-unit-capacity capital costs would be about the same for 4 GW and 2 GW plants, assuming that both achieve full economy of scale in asset manufacturing and installation. Table III shows that the 20 in pipeline has continuous transmission capacity of $\sim 2.8$ GW ($\sim 18 \times 10^6$ N m$^3$ day$^{-1}$) at 100 bar inlet, 30 bar delivery pressure, at 300 km length: adequate for a 4 GW windplant assuming 'smoothing' storage in the pipeline and downstream firming storage, or with firming storage at the windplant; Figure 9.

### 3.3. GH2 compression

We have completely eliminated compressors from the system modeled in this paper, for the following reasons:

1. Hydraulic modeling of the pipeline for the assumed 1 GW windplant shows that midline compressors are not needed if we accept pipeline friction losses from 100 to 30 bar; pipeline friction losses are smaller for GH2 than for NG.
2. Hundred bar output electrolyzers should be feasible, and perhaps available, by year 2020, especially if a market seems promising; the electrolyzers will directly feed the pipeline at 100 bar.
3. 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 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, compressor power and energy are greater for pipelining GH2 than for NG. Centrifugal compressors are impractical for low-molecular-weight GH2. Large reciprocating compressors, up to 12 000 kW electric motor drive, are available from Dresser-Rand: model HHE-VL is used for GH2 and for NG. Technological breakthroughs and development are needed in this field, for transmission pipelining of GH2 from sources other than electricity; biomass, solar thermal, etc. are inherently low-pressure sources. Most compressor research today is focused on low-volume, high-pressure (300–700 bar) service for vehicle fueling.

Therefore, we have modeled our system entirely without compression, to take full advantage of high-pressure-output electrolyzers directly feeding the pipeline input.

### 3.4. High-pressure-output electrolyzers

We assume that high-pressure-output electrolyzers will be available at attractive capital and O&M cost; technologies may include proton exchange membrane (PEM), alkaline (KOH), high-temperature ceramic, or a combination thereof. We assume that they will directly feed the pipeline at 100 bar. PEM electrolyzers are now available at $> 100$ bar output, at $\sim 10$ kW scale; they may not economically scale to MW. KOH is the only technology presently available at MW scale, at 30 bar output; Figure 7. An R&D program and accepting an incremental capital cost, primarily for a stronger



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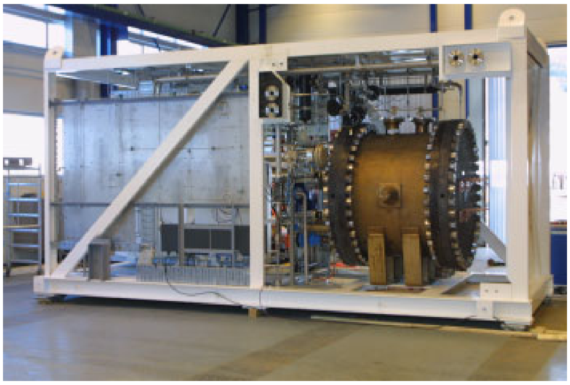

Figure 7. Hydro Hydrogen Systems high-pressure electrolyzer system, KOH type, without gas cleanup equipment. Input is 560 kWe, 4.2–4.3 kWh per N $m^3$ output, at 30 bar, 130 N $m^3$ $h^{-1}$.

stack containment vessel and for more durable stack materials, will be required to achieve 100 bar output.

### 3.5. Shared PE

Figure 1. Replacing the transformer–rectifier subsystem of the electrolyzer with PE shared with the wind generator will save $\sim 5\%$ in electrolyzer system capital cost and $\sim 2\%$ 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 electrolyzers in series or series–parallel arrays.

This wind generator DC bus voltage is typically 800–1000 VDC, while MW-scale electrolyzers typically operate at 200 VDC. This impedance–mismatch problem might be solved by connecting several electrolyzers in series, and in series-parallel, although this presents electrical isolation and safety problems.

PE is 10–15% of wind generator capital cost. Since the system in Figure 1 delivers no energy to the grid, the inverter section of the PE is eliminated for a small, but significant 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.

### 3.6. Materials challenge: hydrogen embrittlement

Hydrogen gas can compromise the structural integrity of high-pressure containment or delivery systems [12]. In particular, the interaction between hydrogen gas and surface flaws can promote failure of pressurized steel structures [13]. Hydrogen interacts with material at the tip of a flaw and can cause embrittlement by one of several well-established mechanisms [14]. 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 HE 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 [15]. 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.

HE 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. Several approaches can be followed to maximize the allowable flaw depth. One approach is to maximize $K_{IH}$. This can be accomplished through materials selection (e.g. materials with lower yield strength) or possibly by altering the gas composition (e.g. adding small amounts of oxygen to the hydrogen). Another approach is to increase the wall thickness or lower the wall stress. Similar considerations apply to fatigue loading; in this case, favorable properties are achieved by decreasing $(\mathrm{d}a/\mathrm{d}N)_{\mathrm{H}}$ as a function of $\Delta K$.



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### 3.7. System optimization

*3.7.1. Topology*. At GW scale, if operating from a single AC or DC bus, KOH-type electrolyzers might most economically be arranged in series, series–parallel, or 'star' modules, sharing electrolyte circulation and gas cleanup piping. 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 1. This paper does not attempt this topology optimization.

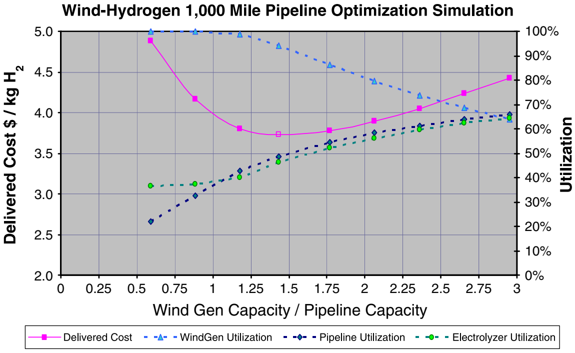


Figure 8. Wind-Hydrogen Pipeline System Optimization Simulation: wind generators, electrolyzers, and 1600 km GH2 pipeline, unsubsidized. Minimum cost per delivered kg GH2 is where the nameplate wind capacity exceeds the maximum pipeline capacity by ~35%. This 'wastes' a small amount of wind energy but increases the CF of electolyzers and pipeline.

*3.7.2. Component capacity: system optimization simulation*. Using a confidential 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 the following:

- Optimum ratio of component capacity for minimum cost of delivered GH2; Figure 8.
- Smoothing of delivered GH2 provided by pipeline storage; Figure 9.

The 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.

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 International Renewable Hydrogen Transmission

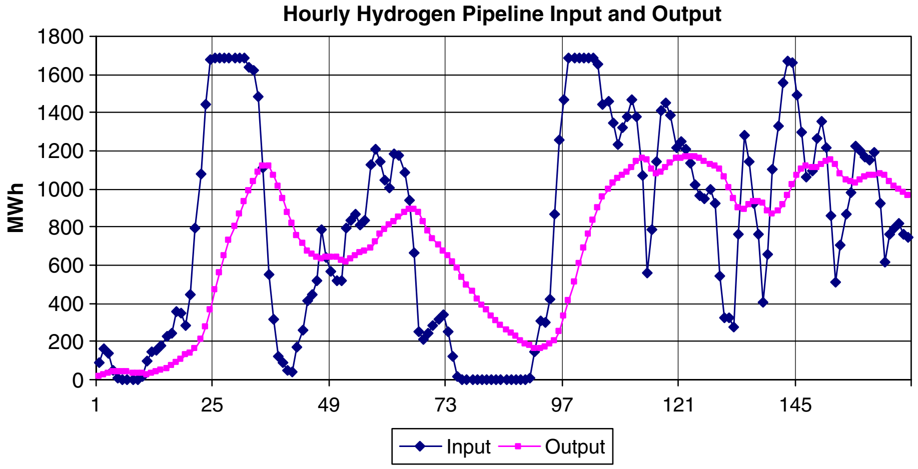


Figure 9. Eight hundred km pipeline, first week of September, actual Great Plains windplant operation. The lag effect and pipeline transit time is about 22 h. This smooths some of the hourly and shorter period wind generation variations. Input is limited at 1700 MW by pipeline and electrolyzer capacity, which results in some lost wind energy *via* curtailed generation, but which results in greater long-term pipeline utilization rate, capacity factor (CF).



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Demonstration Facility (IRHTDF) (Sections 4 and 5.6) will be necessary to guide more valid and accurate modeling and optimization of the wind generator–electrolyzer subsystem.

Figure 8. With the above electrolyzer rating assumptions, the electrolyzers become relatively more expensive than the wind generators; hence, the economic optimum undersizes them relative to the maximum wind capacity to increase their CF. Windplant capacity slightly exceeds pipeline capacity at optimum. This 'wastes' a small amount of wind energy by curtailing wind generation to avoid overheating the electrolyzers and overpressurizing the pipeline, but increases CF of electrolyzers and pipeline.

### *3.8. Energy storage as GH2*

Hydrogen storage can be anywhere along the pipeline path, or anywhere in the entire system from production to end use; Figures 1–3. 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 are produced (mined) and stored 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. This may also apply to renewable-source GH2, to some extent.
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.

*3.8.1. GH2 storage in pipeline*. A long pipeline could provide a significant amount of storage capacity. Table IV shows that storage capacity in an 800-km-long pipeline would range from 10 GWh (a 20 in pipeline operating between 20 and 40 bar) to 107 GWh (a 36 in (1 m) pipeline operating between 30 and 100 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.

*3.8.2. GH2 storage in wind generator towers*. National Renewable Energy Laboratory (NREL) has investigated this potential [16]. 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.

*3.8.3. GH2 storage in end-user devices*. Figure 2. Ground vehicle and aircraft fuel tanks, equipment for DG of electricity, and peak-shaving reversible fuel cells may provide significant aggregate distributed GH2 storage. This would reduce peak demand, but it would not help firm the wind farm output, because pipeline and end-user storage is relatively small.

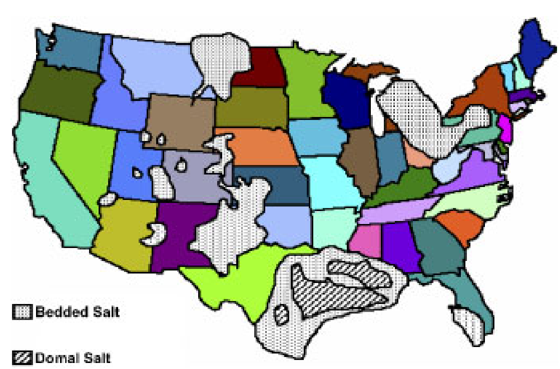


Figure 10. Large underground dry salt formations that may be suitable for solution mining to create large GH2 storage caverns. 'Domal' salt, best for hosting large, high-pressure, solution-mined caverns, is restricted to near the Gulf of Mexico coast, both onshore and offshore.



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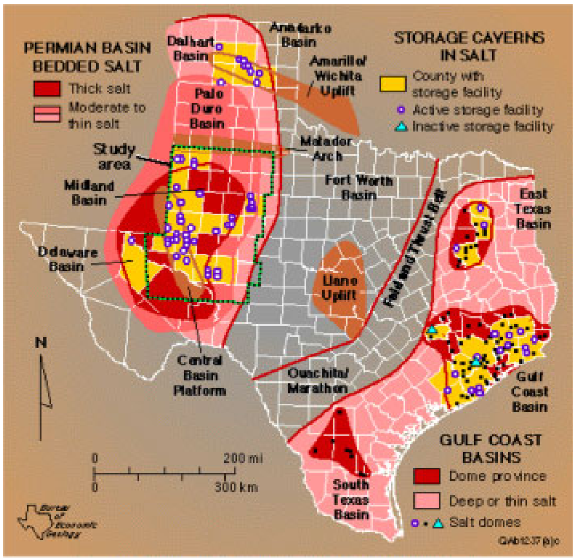


Figure 11. Extant storage caverns in 'domal' and 'bedded' salt in Texas. 'Domal' salt deposits are generally thicker, deeper, and more homogeneous than 'bedded'.

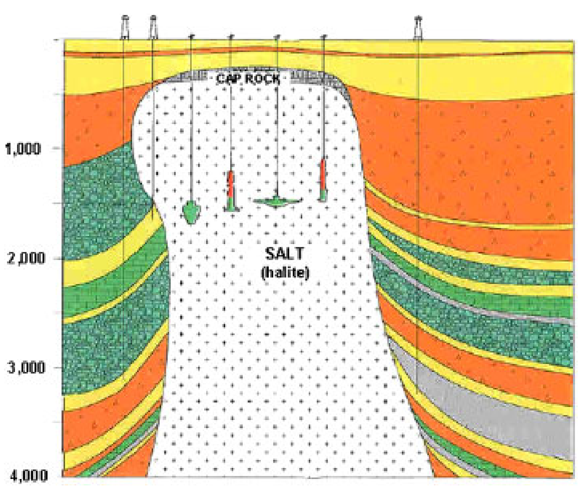


Figure 12. Solution mined storage salt caverns in 'domal' salt typical of the Gulf of Mexico coast, U.S.A. Depth below ground level, meters. Oil and natural gas wells are in adjacent formations.

*3.8.4. GH2 storage in geologic formations.* Figures 10–13. Low-cost, annual-scale, storage is needed for renewable-source GH2, as it is for NG. Man-made solution-mined salt caverns are GH2

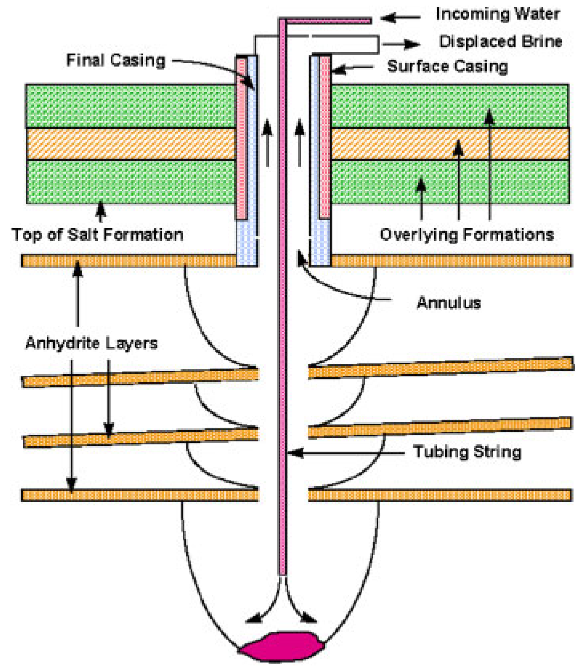


Figure 13. Solution mining of storage salt caverns in 'bedded' salt typical of the Great Plains, north of the Gulf of Mexico coast. Excavating caverns in 'bedded' salt is riskier than in 'domal' salt because of potential leakage through non-salt (halite) strata.

tight to > 150 bar and are the lowest-cost method of large-scale GH2 storage. Storage caverns may be constructed in both 'domal' and 'bedded' salt. No GH2 storage caverns have been attempted in bedded salt, where leakage loss through non-salt strata may be excessive and unacceptable.

In Tees County, U.K., > 1000 tons of GH2 is stored in several solution-mined salt caverns, for industrial use [17]. The 'ChevronPhillips Clemens Terminal' cavern has been in service for > 20 years, storing ~ 2500 net tons of GH2 at up to 150 bar.

The U.S. stores helium beneath an aquifer in Texas. Similar aquifers may be abundant and GH2 tight. This resource needs exploration and assessment, as suggested in Section 5.4.

Consider the quantity of GH2 storage required to 'firm' the output of a 4000 MW windplant which produces ~ 14 TWh in an average year. Using the numbers from 'Seasonal Variability of Wind Electric Potential in the United States,' [18]

Table V. Capital costs: 4000 MW windplant, electrolyzers, 20 in (~0.5 m) pipeline 300 km long, and high-pressure GH2 cavern storage for annual-scale firming. Cavern storage is a small cost component.

| | TICC* $\$kW^{-1}$ in Year 2020 | Total (million 2004–5 $US) |
|---|---|---|
| Windplant | $800 | $3200 |
| Windplant power electronics incremental cost | $30 | $120 |
| Electrolyzers: 100 bar output, KOH type | $330 | $1320 |
| Pipeline: 20 in, 300 km long | $35 $in^{-1}$ diam $m^{-1}$ length | $210 |
| Subtotal, from Table I | | $4850 |
| Add: 14 storage caverns @ $20 M each | | $280 |
| *TICC (total installed capital cost) | | $5130 |
| Incremental capital cost of storage caverns = $280/$4850 = 5.8 % | | |

Table III, for 'North Central', normalized, yields the following 'seasonality factors':

Spring 1.17 Autumn 0.93

Summer 0.69 Winter 1.23

We find that expected average seasonal energy production would be (14 TWh/4) = (3.5 TWh) $\times$ seasonality factor, above:

$$\text{Winter} = 3.5 \times 1.20 = 4.20 \text{ TWh}$$

$$\text{Spring} = 3.5 \times 1.17 = 4.10 \text{ TWh}$$

$$\text{Summer} = 3.5 \times 0.69 = 2.42 \text{ TWh}$$

$$\text{Autumn} = 3.5 \times 0.93 = 3.26 \text{ TWh}$$

The biggest difference between seasons is between Winter and Summer: $4.20 - 2.42 = 1.78$ TWh. If all windplant energy is converted to GH2 for export, at the 80% efficiency typical of large-scale electrolyzers, this is apparently 1.42 TWh of GH2 storage needed. However, the biggest difference between *adjacent*, *sequential seasons* is between Spring and Summer: $4.10 - 2.42 = 1.68$ TWh. If all windplant energy is converted to GH2 for export, at 80% electrolyzer efficiency, apparently 1.34 TWh of GH2 storage is needed. The latter case is more relevant.

A 1600 km 36 in diameter GH2 pipeline, packed to 65 bar and unpacked to 30 bar, stores ~ 120 000 MWh = 0.12 TWh. Packed to 130 bar, unpacked to 65 bar, it would store twice as much = 0.24 TWh. GH2 transmission pipelines are likely to operate at 100–150 bar maximum input pressure, with city-gate delivery at ~ 30 bar. Assume, for this analysis, 0.12 TWh of pipeline storage.

Thus, the geologic storage needed to seasonally 'firm' 4000 MW (nameplate) of Great Plains wind, over the maximum average seasonal variation, is $1.34 - 0.12 = 1.22$ TWh =~ 36 000 Mt of GH2.

The 'ChevronPhillips Clemens Terminal' GH2 storage cavern (near Freeport, TX) characteristics are as follows [19]:

- Age is 20 years.
- Physical volume is 580 000 $m^3$.
- 'Useable capacity' is 2500 Mt of GH2; total capacity is 5300 Mt.
- Maximum pressure (MAOP) is 150 bar.
- Estimated excavation capital cost is $US 2005 5–10M.
- Leakage rate unknown; probably very small.
- O&M cost is unquantified; probably small; some periodic and preventive maintenance (PM) required.

Praxair has constructed a similar GH2 storage cavern nearby, in the same salt dome. It will begin service in 2007. Praxair reports that it cost more to construct than the ConocoPhillips estimate, above [20]. Several solution-mining industry contacts estimated cavern construction at $US 10–15 M. Therefore, we have conservatively estimated new cavern construction at $US 15 M, plus the cost of GH2 'cushion gas', in Table V.

Thus, 36 000 MT/2500 MT = 14 caverns are required @ $20 million capital cost each ($15 million construction + $5 million for 'cushion gas') = $280 million, to 'firm' 4000 MW (nameplate) of Great Plains wind: a small fraction of total generation–transmission system cost. Cavern useable capacity might be slightly larger for renewable energy transmission service, if pipeline pressure is designed to vary from 100–150 bar input to 30 bar delivery at city-gate end of pipeline, and if the cavern can endure the lower pressure.

Tables I and V. Adding $280 million in firming cavern storage to Table I presents a $\sim 6\%$ incremental capital cost to the complete generation–transmission-storage system.

Totally harvesting the wind energy of the 12 Great Plains states, on about half the land area of these states, would require $\sim$ 3 million MW (nameplate) of wind generation, and would produce $\sim$ 10 000 TWh per year, which is the present entire energy consumption of the U.S.A., from all sources [21]. With $\sim$ 14 caverns per 4000 MW, or $\sim$ 4 caverns per 1000 MW, about 15 000 caverns like the 'ChevronPhillips Clemens Terminal' cavern would be needed to firm all Great Plains wind. This storage requirement would probably be reduced by synergistic harvest and transmission of GH2 from diverse Great Plains renewables, especially wind and radiant solar, as proposed in the IRHTDF concept; Sections 4 and 5.6.

### 3.9. *Markets and firming for wind-generated GH2 fuel*

Because pipeline developers will seek to maximize throughput (minimizing needed storage) and 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 IRHTDF pilot plant; Sections 4 and 5.6. The pipeline would need to maximize its utilization rate by receiving hydrogen from 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.

As shown in Figure 9, 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-pipeline project would have two options for firming the hydrogen: storage and firming purchases.

In a firming strategy based on spot purchases, the windplant-pipeline company would purchase from other suppliers the hydrogen necessary to provide firm service. 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.

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. Market purchases are a particularly poor strategy for firming NG supply, because supply interruptions are most likely to occur precisely when spot prices are high. The windplant-pipeline company would probably not face a correlation between low production periods and high hydrogen prices. A much smaller portion of hydrogen would probably be used for space heating than is currently the case with NG, because transportation fuel is expected to be a major hydrogen demand driver. 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 having 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 simple to determine the lower-cost firming strategy.

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-energy, cleaner-burning fuel. Typically, NG consuming devices can accept up to 10% hydrogen by volume, often with efficiency or emissions improvements; pipeline HE is apparently not a problem. Provided the 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 could avoid the cost of maintaining a parallel fuel infrastructure for hydrogen or introducing large-scale fuel switching over a short period of time.

The EC is now studying this blended fuel strategy *via* the 'NaturalHY' project, conducted by Gasunie Research, Netherlands [22, 23].

## 4. CONCLUSIONS

Figure 6. With various 'value-adders', wind-source GH2 may be delivered to distant markets, 300–1600 km distant, at an untaxed wholesale energy unit cost apparently competitive with:

- Hydrogen fuel made from NG by steam methane reforming (SMR).
- Gasoline, at 2007 price.

'Firming' this renewable energy at annual scale costs little, if suitable geology for storage in salt caverns or other geologic formations is available, as in the Gulf Coast and Great Plains. This opportunity exists, for diverse stranded renewables, worldwide. Thus, with enough GH2 transmission pipelines and storage caverns, the world can run on renewables.

Figure 9. Pipeline energy storage smooths windplant output variations at time scales of minutes to days, but is inadequate to 'firm' wind power to command full wholesale market price at the city gate. However, low-cost, annual-scale, geologic storage of GH2 could theoretically firm wind energy, adding significant value. Such renewable energy storage remains unexplored and unproven in the Great Plains.

Solution mining of storage caverns in salt formations is a mature industry. Large-scale, low-cost GH2 storage has been proven in 'domal' salt but not in 'bedded' salt formations.

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.

Line pipe materials must be tested and selected, and other measures taken, to control the critical phenomenon of HE of steel.

Figure 8. To better understand the economics of the windfarm–electrolyzer–pipeline system, we performed several simulation analyses using actual hourly wind data. On the basis of 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, which wastes a small amount of wind generation but increases the overall CF of the system.

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. A remaining challenge is determining whether storage or spot purchases is the lower-cost firming option for wind-source GH2 fuel, in a mature 'hydrogen sector' of a continental energy economy.

This paper may support building a pilot-scale hydrogen pipeline system, optimized for bringing large-scale, diverse, stranded, renewable energy



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sources to distant markets as hydrogen gas, as an International Partnership for the Hydrogen Economy (IPHE) project: the IRHTDF [24]. 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) at little or no incremental capital cost, if:

- Fracture mechanics tests in hydrogen prove suitable line pipe material(s) at small incremental capital cost.
- The IRHTDF pilot plant results are promising.

Pipeline RHS capability would be an important strategy for building the infrastructure for a 'hydrogen sector' of a carbon-emissions-free, global energy economy.

## 5. RECOMMENDED FURTHER STUDY

### *5.1. Linepipe material testing*

Composite reinforced line pipe (CRLP)$^{TM}$ and X-42 or X-65 'sour service' grade are candidates for RHS. Testing these materials for accelerated fatigue life, in pressure cycling over a 2:1 range, is needed to establish 'fitness of purpose' for large-scale (high-pressure, large-diameter) GH2 transmission pipelines for the severe cyclic loading of RHS, and consequently also 'fitness of purpose' for less-demanding use in GH2 pipelines from new nuclear and coal gasification plants. TransCanada Pipelines proposed CRLP$^{TM}$ for hydrogen transmission at the ASME International Pipeline Conference (IPC04), Calgary, 4–8 October 2004 [25].

### *5.2. System optimization*

System optimization of capital cost components depends on dynamic fluid mechanics of the pipeline with time-varying input from the wind generator–electrolyzer subsystems. This is now poorly understood; modeling improvement may depend on empirical data from the operation of a pilot plant like the proposed IRHTDF.

### *5.3. 'Firming value'*

Assess and estimate economic value of firming windplant output *via* strategies discussed in Sections 3.9 and 5.2, above.

### *5.4. Geologic storage*

Verify GH2 storage feasibility in bedded salt geology. Low-cost, large-scale, geologic storage of GH2 in formations other than solution-mined salt caverns, which are man-made, relatively rare, and limited in size, would be very valuable to the wind energy industry, and to other renewables. Smoothing windplant output at seasonal scale, to deliver a firm, dispatchable energy supply, would greatly increase the usefulness and value of wind-generated energy. Specifically:

(a) Geologists should prospect for subterranean formations, for salt caverns or other storage, capable of containing GH2 at $> 100$ bar, with an acceptable annual loss rate; calculate what reservoir (formation) volume and projected surface land area is required, for 1 GW and for 10 GW scales; estimate total U.S.A. storage potential.
(b) Extend the prospecting in (a) worldwide.
(c) Construct a tall, small-diameter test cavern by solution mining in deep and thick bedded salt; test for leakage when pressurized with GH2.

### *5.5. Electrolyzer integration, duty cycle, and overload tolerance*

We need to optimize the windplant-to-electrolyzer nameplate capacity ratio. Electrolyzer systems need to be optimized for handling heat rejection from short-duration overloads, driven by the stochastic nature of the wind resource. We need to know the incremental capital cost of increased heat rejection capability, as a function of duty cycle and ambient temperature. Families of curves might be useful. Both time and frequency domain data on wind generator output may be essential. Then, we can optimize for an amount of wind generation curtailment to best match the overload capability of electrolyzer systems; Figure 8. In real systems, the individual electrolyzers'



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control systems, and probably PE, would be integrated with the wind generators' control systems, so that at a high-temperature limit, the electrolyzer forces a reduction (curtailment) of wind generation output.

### 5.6. International Renewable Hydrogen Transmission Demonstration Facility (IRHTDF)

Begin feasibility, preliminary engineering, and cost estimation for this pilot-scale facility proposed as a project for the International Partnership for the Hydrogen Economy (IPHE) [1,26]. It will yield empirical operational data enabling refinement of the analyses in this paper.

### 5.7. Electrolysis feed water required

Calculate the quantity of required electrolysis feed fresh water for large-scale export of stranded renewables from each candidate geographic region. Investigate supply options, including pipeline transmission of feed water from GH2 pipeline destination to source, in the same trench.

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