TOPIC PAPER #11

HYDROGEN

On July 18, 2007, The National Petroleum Council (NPC) in approving its report, *Facing the Hard Truths about Energy,* also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the Task Groups and their Subgroups. These Topic Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached Topic Paper is one of 38 such working document used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix E of the final NPC report provides a complete list of the 38 Topic Papers and an abstract for each. The printed final report volume contains a CD that includes pdf files of all papers. These papers also can be viewed and downloaded from the report section of the NPC website (www.npc.org).

NATIONAL PETROLEUM COUNCIL

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Hydrogen — Supply and Demand Opportunities

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Introduction— In a search for alternatives to a hydrocarbon-based energy economy, hydrogen offers many opportunities (1). Transforming both supply and demand for energy, a Hydrogen Economy (H2E) is a family of advanced, cooperative technologies that need to be deployed in concert to realize their many strategic, environmental, efficiency and economic benefits. Hydrogen (H_2) used in fuel cells to make electricity is free of pollutants and carbon dioxide. To replace half of the light duty vehicle fleet in the U.S. by 2050, for instance, with electric drive hydrogen fuel cell vehicles would require dedicated domestic production of about 50 million tons per year (Mt/yr) of H_2 (3, 9) , compared to the 43 Mt/yr now used worldwide. This could result in eliminating over 2/3 of today's petroleum imports to the U.S., and a sizable share of U.S carbon emissions (1, 2).

On the way to widespread use, substantial technical and market barriers need to be overcome. Believing in the need for H_2 use on a large scale and its many business opportunities, industry and federal and state governments have made substantial public investments in major research, development and demonstration projects.

Where are the commercial opportunities? Early on with distributed and portable electricity generation, backup and auxiliary power, materials handling equipment, in fleets of buses, trucks and eventually light duty vehicles — passenger cars, SUVs, light pickup trucks. In the transportation sector, creating a H2E means eventually replacing large segments of a mature, reliable, and widely networked hydrocarbon infrastructure built on the advantages of the high energy density of gasoline. This has been enabled by over a century of engineering and market experience, which is turning to new challenges. There is already considerable technical experience with H_2 — nearly ¼ of the world's hydrogen is produced now in the U.S., used in petroleum refining and fertilizer manufacturing; in the metalworking, food and glass industries; and for research.

Domestic alternatives to imported petroleum need to be developed in ways that optimize their respective technical and regional supply benefits. Biomass and solar, coal and nuclear, wind and geothermal, energy efficiency and demand management — all will be critical resources. Technologies and systems capturing and storing carbon dioxide (CO_2) must be commercialized on a large scale.

An evolution to a H2E would be driven by strategic choices and enabled by large public and private investments. New H_2 production and distribution systems will be needed, coupled with services and products consumers expect and will freely purchase. And commercial H_2 systems must compete successfully with conventional systems throughout a transition to a H2E.

Observations

- As an energy carrier, H_2 can be manufactured from a wide variety of alternative domestic feedstocks and raw materials. Natural gas, coal, renewables, nuclear and direct solar energy could all become important sources of hydrogen supply. H_2 can be converted to electrical or mechanical energy while producing only water as a byproduct, with no associated emission of carbon dioxide (CO_2) and minimal air pollutants at the end use. And, a strong supply balancing effect derives from the better end use efficiencies promised by hydrogen and fuel cells, particularly in H_2/fuel cell powered cars, buses and trucks. For example, the Department of Energy and its industry partners foresee fuel economy for H_2 fuel cell vehicles improving to an achievable 70-80 miles/gallon of gasoline equivalent (1, 3, 9) by 2050. Without more rapidly advancing vehicle technologies, the fleet average for light duty vehicles in 2030 is expected to be 29.2 miles/ gallon (3).

- Coupled with robust energy demand growth of over 30% by 2030 (2, 3) and worldwide concern over greenhouse gas emissions, long term supply stability of conventional petroleum at reasonable prices becomes a greater concern as both demand rises and the rate of worldwide resource depletion increases. U.S. oil imports are expected to grow from 58% to over 62%. Between 2005 and 2030, the transportation sector in the U.S. is expected to emit 1/3 of all carbon dioxide. Light duty vehicle energy use between 2005 and 2030 is also expected to grow 40% (2), and accounts for 60% of U.S. transportation demand. These factors are encouraging intensive search for more abundant domestic fuel alternatives that are also more sustainable (1, 4).

- A serious U.S effort to solve R&D, long term supply and demand, and commercialization barriers — backed by the strategic policy guidance and public investments embodied in the Energy Policy Act of 2005 (EPAct 05) and new legislation in the 110th Congress — provides an important signal of intent to world markets and makes the Federal government a more reliable partner with industry in solving key problems (1, 3).

- Near term, bridge supply and demand technologies and systems are now providing key learning and market development transitions — portable, backup and auxiliary power; internal combustions engines (ICEs): blends with compressed natural gas, diesel and biofuels; materials handling equipment; and fleets of buses and delivery vans.

- At every stage of technology advancement and deployment, carefully designed incentives need to be offered by governments in concert with other tools, like a mixture of investment and production tax credits that cover installations and infrastructure as well as end uses, fuel supply, and alternative minimum tax reform. Several of these incentives are included in the EPAct 05, and new legislation in the 110th Congress expands on them. And they must endure for long enough that sustained market growth becomes less volatile and business decisions are not hobbled by excess uncertainty.

- Under favorable greenhouse gas policies, the International Energy Agency sees that some 30% of the world light duty vehicle demand — over 700 M vehicles — could be met by fuel cell vehicles by 2050, greatly diversifying the fuel mix and substantially stabilizing carbon emissions. The potential is high in OECD countries, India and China, where the shares of fuel cell vehicles by 2050 could be:

    - China ~ 60%
    - India ~ 42%
    - U.S. ~ 42%
    - Europe ~36-48%
    - Canada ~ 35%
    - Japan ~ 22%
    - Australia ~ 10%.

- Paying for imported oil leads to sizable direct offshore wealth transfers — the U.S. import bill has averaged over $200 billion/yr ($237 B in 2005) from 2003-2006, and with high prices widely expected over the long run, expected to be $300 B by 2030. At this magnitude, the oil import bill tends to distort domestic and world markets, and increases our negative trade balance — added to this are the indirect security and diplomacy costs borne by the Federal budget. Plus, volatile markets make planning and capitalizing future alternatives more difficult for both private and public investors (1, 3).

- As an example of the relative value of imported oil and domestic coal, by 2030 coal-to-hydrogen plants could supply about 15% of the light duty vehicle fuel needs in the U.S. — $ 2.5 billion (B) of coal could "back out" $25-$38 billion (B) in imported oil, or for every $1 B in coal, the U.S. could replace about $10-$15 B in oil. Of course, the capital intensive plants and infrastructure would need to be built to supplement and eventually replace components of the existing oil refining system, or become the next increment of supply infrastructure accommodating new growth in demand (1, 3, 9). This "exchange ratio" between substitutable feedstocks would improve with the evolution of both supply and demand technologies — they become more efficient, and wider deployment affords greater economies of scale.

- Another example is the relative value of biomass-to-H2 (1, 9): by 2050 biomass-to-hydrogen plants could provide about 24% of the H2 needed to supply 50% of the light duty vehicle fuel needs in the U.S., or about $3.3 billion (B) in biomass could back out $25-$38 billion (B) in imported oil. Thus for every $1 B in biomass, the U.S. could replace $7.6 B-$11.5 B in imported oil. Again, sizable supporting infrastructure would be needed.

- The potential markets in a mature H2E are very large (3). As one regional supply/demand study forecasts (9), replacing half the light duty vehicle fleet burning gasoline with domestically-produced hydrogen fuel cell vehicles by 2050 (or about 18% by 2030) means building and buying over 180 million (M) FC cars and light trucks, and supplying the hydrogen equivalent of over 130 billion (B) gallons of gasoline equivalent/yr from U.S. coal, nuclear and renewable sources. This would displace 8.2 million barrels/day of imported oil valued at over $425 M/day, or $155 B/yr that now simply drains out of the U.S economy. Over the life of the market transition to hydrogen, say 40 years, about $10 trillion worth of imported oil would be used if the U.S. continued its import dependence.

- Global air and greenhouse gas emissions could be substantially reduced with a H2E when deploying the full range of advanced stationary and mobile technologies. There is a large domestic market potential for home, commercial, industry and the transportation sector. One third of all U.S. carbon dioxide emissions come from the transportation sector, about the same as that from coal-fired powerplants — creating further market opportunities for U.S. products worldwide and increasing U.S. competitiveness.

- The U.S. is not alone in facing challenges to its energy future from under-diversified resources, potential supply volatility and environmental degradation. These are global conditions. While they may vary in direction and intensity, they affect both developed and developing nations. In addressing these conditions, national priorities vary. National motivation will matter as hydrogen moves into and penetrates the marketplace.

Reviewing Hydrogen Studies

It is useful to compare different views on how a hydrogen economy could evolve within the U.S. and identify what share natural gas, coal, biomass and nuclear power could have in this growth from 2015 through 2030 and beyond. Various market penetration forecasts and estimates have been made about the shares of alternative feedstocks in a H2E, but few use an integrated, systematic approach that attempts to balance supply and demand, make specific assumptions about evolution of technology and associated penetration rates, and estimate comparative costs of production.

To derive a range of estimates, the more significant analyses are selected here for comparison and review. It is also worth noting that the Energy Information Administration's (EIA's) very conservative analyses in both *Annual Energy Outlooks (*AEOs) 2006 and 2007 show no market penetration for hydrogen by 2030, yet considerable internal U.S. Department of Energy (DoE) analysis indicates otherwise. The largest single program, for instance, in DoE's Office of Energy Efficiency and Renewable Energy (EERE) funds RD&D on hydrogen and fuel cells ($1.2 B over 2004-2008). The EPAct 05 more than triples this through 2010.

Since a primary strategic driver for a H2E is displacement of oil imports for light duty vehicles, most H2 demand analyses focus on the transportation sector. Net U.S. petroleum imports (2, 3) in 2005 were 12.6 million barrels/day (Mb/d). The early release version of the Energy Information Administration's (EIA) *Annual Energy Outlook 2007* estimates in their Reference Case (2) that by 2030, U.S. net imports will be 16.4 Mb/d, a 30% increase. About 8.6 Mb were needed every day to fuel over 226 M light duty vehicles (LDVs) in 2005, while about 12.2 M b/d will be required by 2030, or about 60% of the total transportation sector demand of 20.2 Mb/d. The following graphs from *AEO 2007* show how these factors vary.

Figure 2. Delivered energy consumption by sector, 1980-2030 (quadrillion Btu)

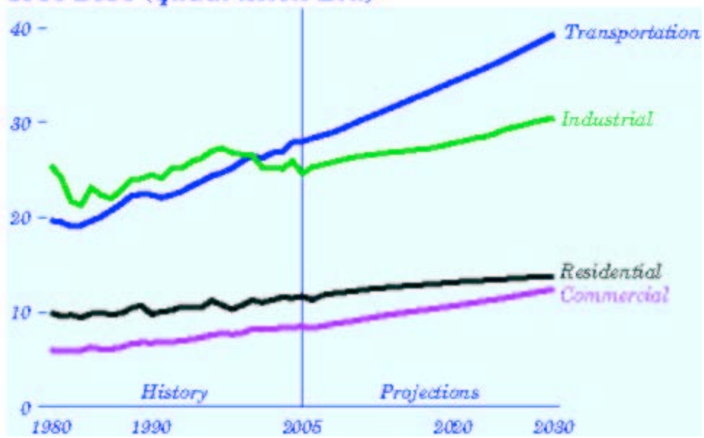


Figure 3. Energy consumption by fuel, 1980-2030 (quadrillion Btu)

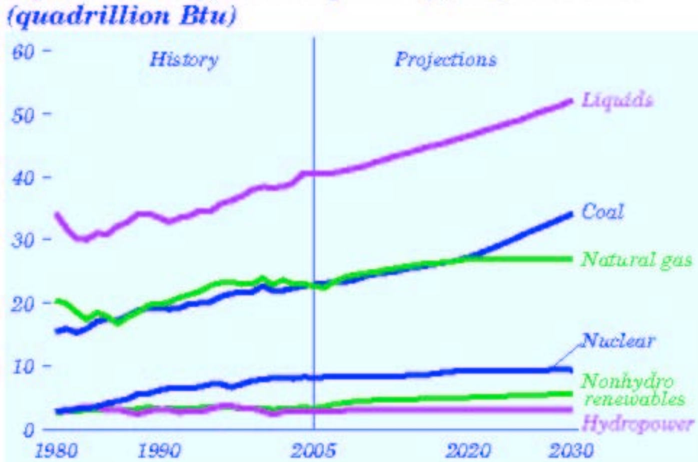
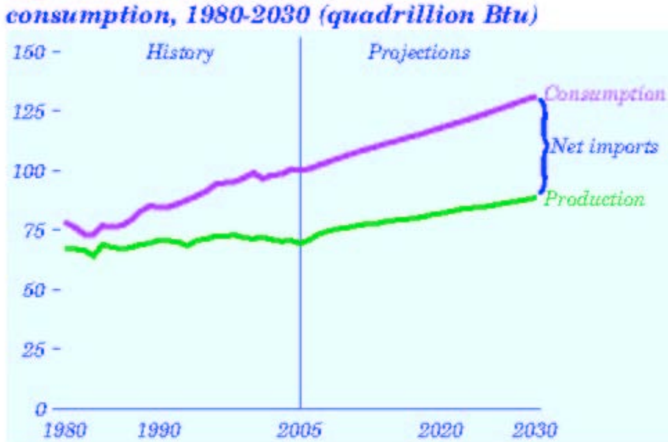


Figure 6. Total energy production and consumption, 1980-2030 (quadrillion Btu)

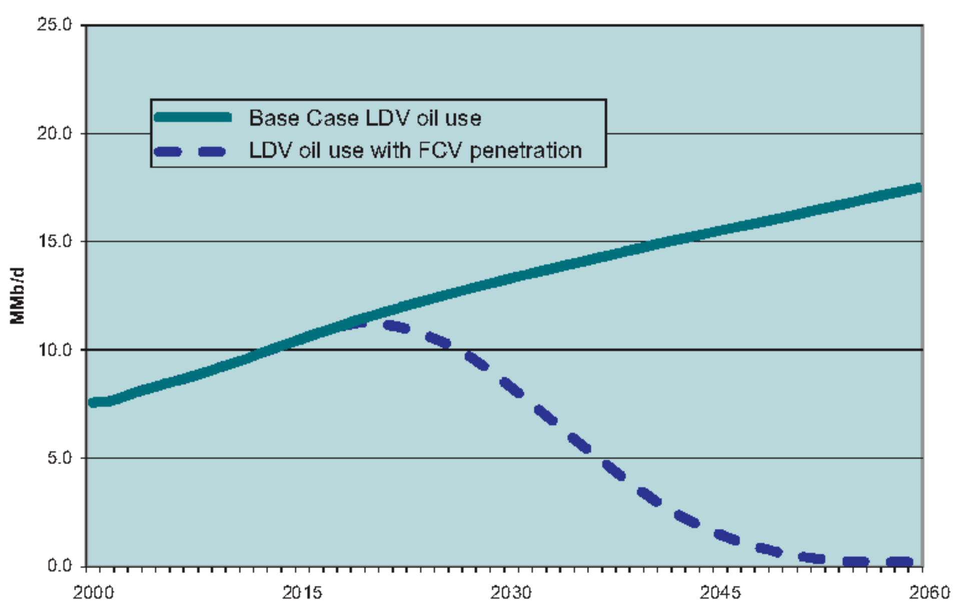


1. ***Hydrogen Posture Plan*** (DoE, February 2004)

The *Hydrogen Posture Plan* has the overall policy role of explaining the goals of the *President's Hydrogen Fuel Initiative* (HFI), which was announced in the State of the Union message in January 2003. It guides DoE's R&D programs and budget requests to the Congress.

In the attached charts from the *HPP*, a baseline scenario for LDVs shows petroleum use forecast out to 2060, compared to what would happen with steady replacement of conventional internal combustion engine (ICE) vehicles by fuel cell vehicles (FCVs). It is expected that these advanced FCVs will have more than twice current LDV efficiency. Assuming plausible, successively larger sales penetration rates for FCVs (4%/yr in 2018 and 100% by 2038) ☐ while solving substantial technical and marketing barriers — results in replacing about 75% of today's nearly 223 M LDVs with FCVs by 2040. The new vehicle fleet could eliminate all the 10.6 Mb/d of imports shown in the HPP (based on *AEO 2003*). More recent analysis by DOE anticipates that the LDV fleet expands to over 320 M by 2030, from 226 M in 2005.

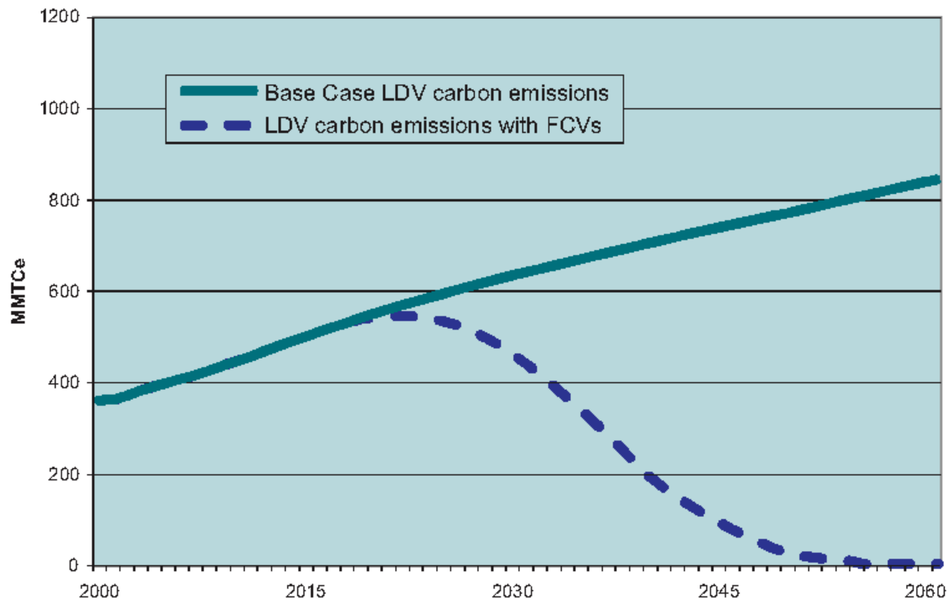
Figure 10. Oil Use by Light Duty Vehicles



By 2040, light-duty vehicle oil consumption may be reduced by over 11 million barrels per day using hydrogen fuel cell vehicles.[6]

This would have the effect of nearly subtracting the automobile out of the environmental equation at the demand end of the fuel cycle, lowering the transportation sector's expected 1500 M tons/year of carbon emissions by more than 1/3, or in excess of 500 Mt/y (some estimates go as high as 645 M t/yr) — assuming H2 production from a combination of natural gas and zero carbon production sources (1, 2, 5, 6, 7), including hydrogen from coal, with most of the carbon captured and stored (CCS). This shows a dramatic reduction in the LDV sector's carbon footprint, but it will take careful, strategic investment in deploying a particular mix of hydrogen production plants to achieve a net reduction of carbon throughout the various raw material-to-H2 fuel cycles — and particularly for coal, which creates a great deal of CO2 when gasified.

FIGURE 12. CARBON EMISSIONS WITH FUEL CELLS



By 2040, light-duty vehicle carbon emissions may be reduced by more than 500 million metric tons of carbon equivalent each year using hydrogen fuel cell vehicles.[8]

In a large body of analysis done by DoE (1) and the NAS, a principle strategic goal is to minimize carbon throughout the fuel cycle. This would be accomplished by utilizing the inherent efficiency gains from FCVs in concert with the best available techniques for gasifying coal, then capturing the carbon from CO2-rich synthesis gas and storing it in deep saline aquifers, in older, mature oil fields, or in other types of underground formations (e.g. basalts) where the CO2 can be safely stored.

In the *HPP*, to fuel 150 M advanced FCVs – about 3/4 of today's LDV fleet (or about 25 M homes with electricity) □ 40 M tons of H2 per year would need to be produced. Using the following chart, approximately 310 M t/y of coal would be needed to make ALL of the 40 M tons of H2, or about 7.8 M tons of coal for each M tons of H2 (5, 6, 7)**. As a consequence, satisfying 10% of transportation demand (15 M cars) and 10% of home/small business needs (2.5 M homes) would require about 62 M tons of new coal production by 2040.** Other alternative sources are shown in the following chart from the *HPP*.

Resource	Needed for Hydrogen[a]	Availability	Current Consumption	Consumption with Hydrogen Production (factor times current)	Construction/ Footprint Required
REFORMING AND/OR PARTIAL OXIDATION[b]					
Natural Gas	95 million tons/year	28 billion tons (technically recoverable as of 1/2000)	475 million tons/year	1.2	400 dedicated hydrogen plants (100 MMSCF of hydrogen per day)
Biomass	400-800 million tons/year	800 million tons/year of biomass residue and waste, plus 300 million tons/year of dedicated crops[c]	200 million tons/year (3 quads for heat, power & electricity)	2-4	400-600 dedicated hydrogen plants
Coal	310 million tons/year	126 billion tons (recoverable bituminous coal)	1100 million tons/year (all grades)	1.3	280 dedicated hydrogen plants
WATER ELECTROLYSIS[d]					
Wind	555 GW_e	3250 GW_e	4 GW_e	140	Available capacity of North Dakota (Class 3 and above)
Solar	740 GW_e	SW U.S.: 2,300 kWh/m^2-year	<1 GW_e	>740 times current	3750 sq. miles (approx. footprint of White Sands Missile Range, NM)
Nuclear	216 GW_e	n/a	98 GW_e	3.2	200 dedicated plants (1-1.2 GW_e)
THERMO-CHEMICAL					
Nuclear	300 GW_{th}	n/a	0 GW	n/a	125 dedicated plants (2.4 GW_{th})

H2 can also be used in stationary fuel cells, engines, and turbines to produce power and heat. EIA's base forecast for 2030 shows the need for an additional 48% increase in electric generating capacity. Increasing at an average rate of 1.6%/yr, 1720 B Kilowatt hours (kWh) will be needed by 2030. As an example, if 10 M tons of H2 were used to satisfy just 10% of this demand growth (172 B kWh), then over 20 M tons/yr of carbon dioxide emissions could be avoided — assuming the H2 is produced using renewables, nuclear, or fossil fuels with carbon capture and storage. Greater use of hydrogen electric technologies could result from replacing aging, inefficient and dirtier infrastructure, needs for more reliable premium power, and market deregulation.

*2. **The Hydrogen Economy: Opportunities, Costs, Barriers and R&D Needs*** (National Research Council, April 2004)

Still the most comprehensive look at a H2E yet published, this study offers many useful insights into the evolution of technologies, their economics, and the R&D effort required to get there. Although the NRC used EIA's *AEO 2003*, here *AEO 2007* is more appropriate. Figures 2, 3 and 4 from above show the latest U.S. demand and supply projections. Net petroleum imports are expected to serve 60% of demand in 2025, up from 58% in 2004. This grows to 62% by 2030.

Figs. 6.1 and 6-3 show NRC's "Optimistic" market scenario for the introduction of FCVs, contrasted with conventional and hybrid vehicles. This is one of the most aggressive current forecasts, where fully 40% of all vehicles in the U.S. are FCVs by 2030, and 100% by 2038. Similar to the above review of the DOE *Hydrogen Posture Plan,* where the total vehicle fleet in 2040 is about 355 M vehicles, **satisfying 10% of vehicle demand and 10% of household and small business distributed electricity generation from coal would require about 15 M tons of H2, or about 105 M tons of coal in 2040.**

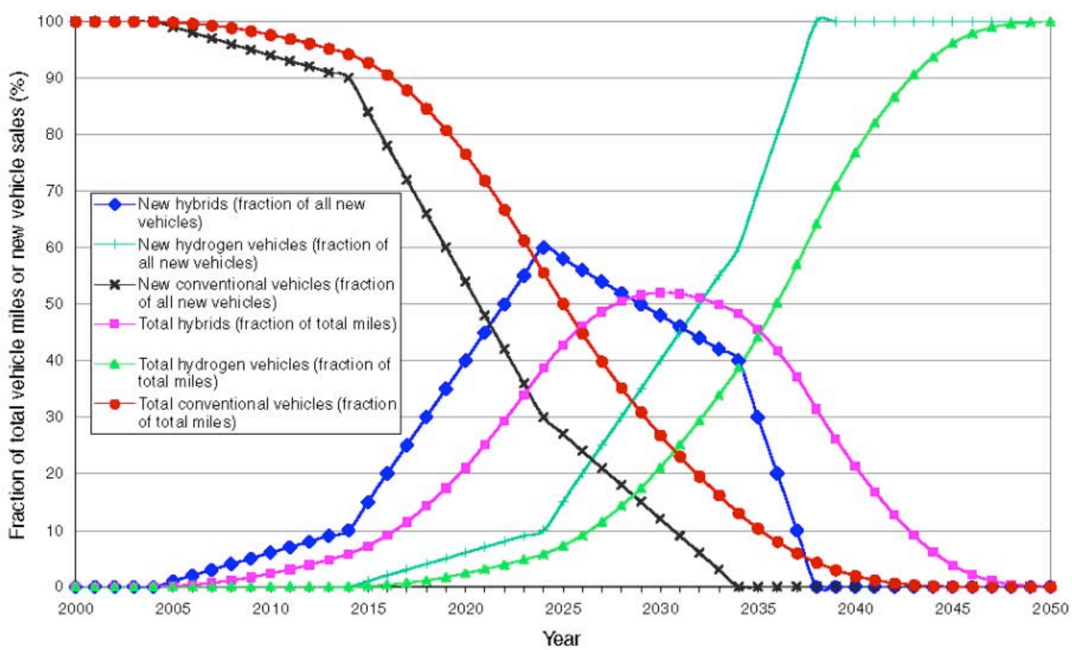


FIGURE 6-1 Demand in the optimistic vision created by the committee: postulated fraction of hydrogen, hybrid, and conventional vehicles, 2000–2050.

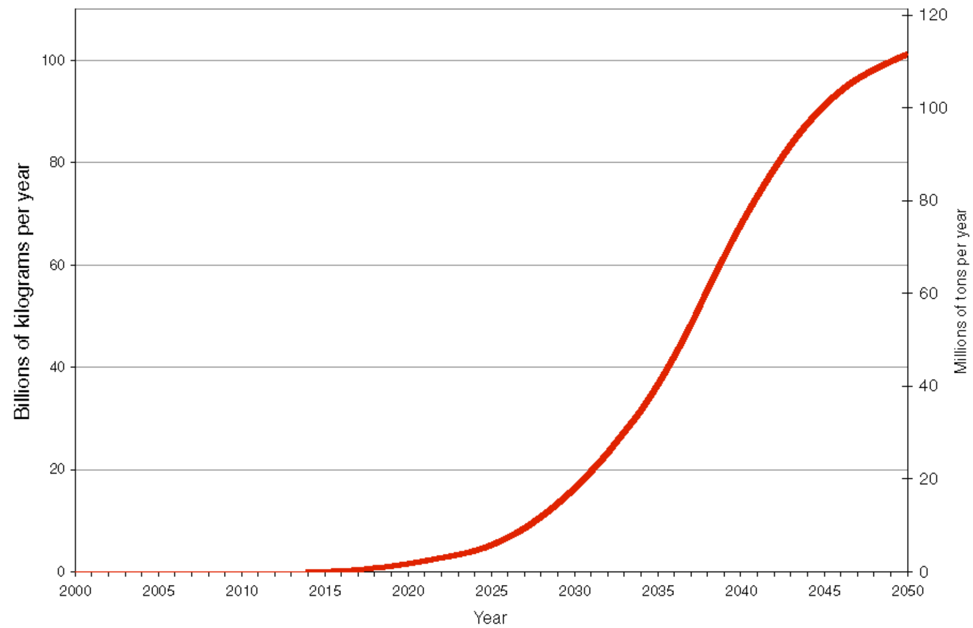
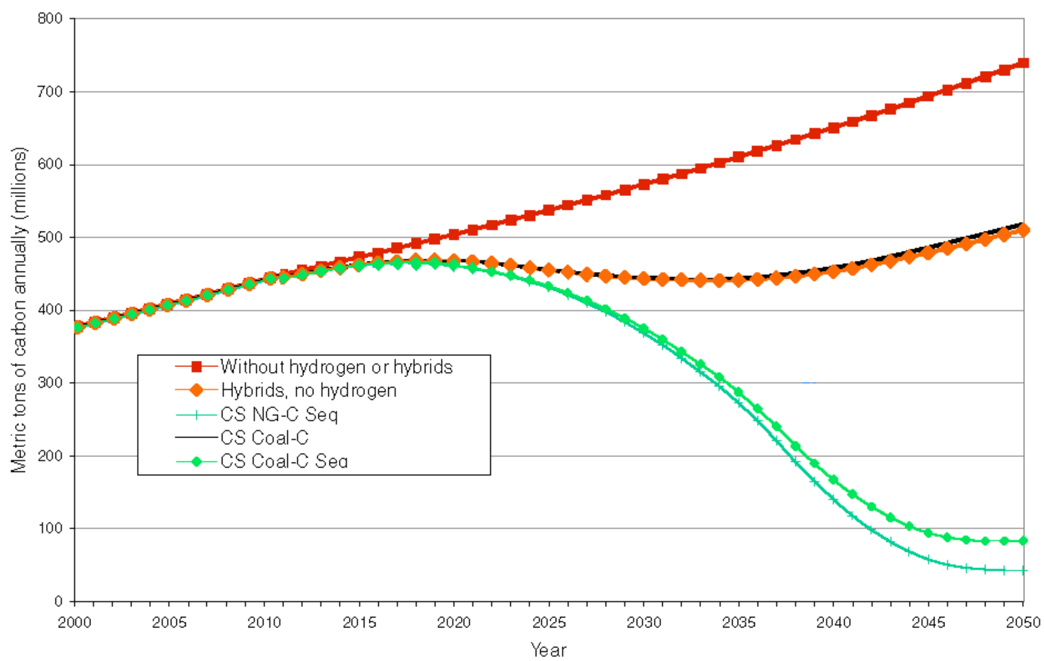


FIGURE 6-3 Light-duty vehicular use of hydrogen, 2000–2050, based on the optimistic vision of the committee.

The above conclusions on carbon emissions from DoE's *Hydrogen Posture Plan* are based on a variation of this NRC study. Depending on the particular technology used to make H2, carbon emissions are considerably lower for the "Optimistic" scenario — nearly 480 M tons less carbon is released than in the Business-as-Usual LDV case as shown in Figure 6.7, which depends on a mix of H2 from coal and natural gas, again depending upon very effective CCS. Several other curves in the NRC study show the effects of utilizing renewables and nuclear power.



At one extreme, the use of FCV powered by H_2 from coal without sequestration or of distributed electrolysis using electricity from powerplants on the grid (without additional carbon capture) would lead to no more reduction in CO_2 than merely transitioning to steadily evolving gasoline/diesel/biofuels hybrids. The fuel cycle is simply recarbonized, albeit with important gains in petroleum import reduction and overall energy systems efficiency from the use of FCVs. About 500-650 Mt/yr of carbon emissions could be avoided by 2040 with LDVs if CCS is used with all fossil fuel sources.

3. ***Coal-to-Hydrogen,*** Chapter 5 of the National Coal Council study, March 2006 (8)

DoE program planning and Federal R&D budgets have identified the Freedom Fuel and FreedomCAR initiatives as a means of transitioning to a H2E that could employ coal-fueled energy with CCS to power fuel cells. **The NCC study shows how a fleet of coal-to-H_2 plants could satisfy 10-20% of the nation's transportation energy needs for a fleet of FCVs. This would require about 70 -140 Mt/y of coal to make approximately 8.6 Mt/y of H_2**, depending upon the plant technology and coal feedstock chosen (3, 7, 8).

4. ***Hydrogen Demand, Production, and Cost by Region to 2050*** (Argonne National Laboratory*,* TA Engineering for DOE, August 2005) (9)

This is a detailed look at the possibilities for supply and demand for H_2 across several U.S. regions, balancing a wide variety of resource supply options from biomass and coal, to nuclear and wind. It develops a H2E across all regions of the U.S., and examines in detail the relative availability of feedstocks and the costs of producing and transporting H_2, primarily for the LDV fleet. Unlike the above analyses, it does not attempt to replace nearly all gasoline demand equivalent to petroleum imports, but instead seeks to evolve markets, interfuel competition, and infrastructure at a slower rate — eventually replacing 50% of LDV demand by 2050. As with the other studies, FCVs are assumed to be 2.5 times as efficient as ICEs, so gasoline is displaced at the end use at a much more rapid rate as each vehicle delivers similar vehicle miles traveled. The main focus of the study is a *Go Your Own Way* (GYOW) scenario, which accommodates evolving market growth in demand and supply infrastructure over the period 2010 to 2050.

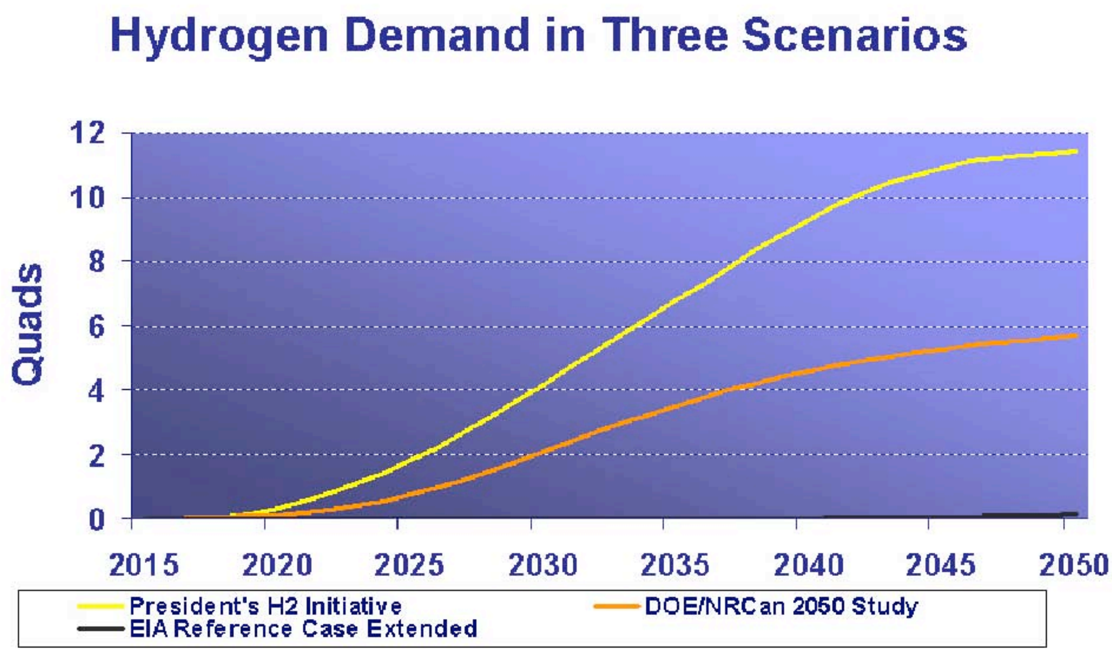


FIGURE 2.1 Total Demand of Three H_2 Scenarios, 2015–2050

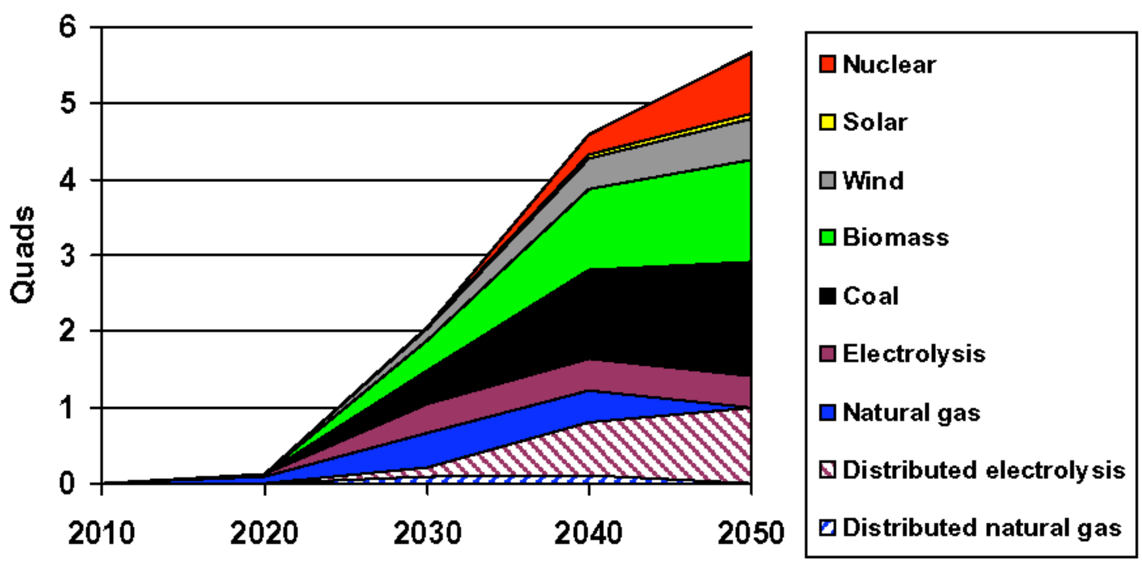


FIGURE 3.8 Resource Fuels Used to Produce H_2 in GYOW: United States

Figure 2.1 shows the three demand scenarios this study evaluates. The intermediate curve is the *Go Your Own Way* scenario, where 50% of U.S. LDV demand is satisfied by hydrogen.

TABLE 3.8 Final Estimate of H_2 Production in the United States for GYOW Scenario

	Distributed Production (Quads)		Centralized Production (Quads)							
Year	Distributed Natural Gas	Distributed Electrolysis	Electrolysis	Natural Gas	Coal	Biomass	Wind	Solar	Nuclear	Total
2010	0.00	0.00	0.000032	0.000073	0.000000	0.000000	0.000000	0.000000	0.000000	0.000105
2020	0.004	0.002	0.035	0.075	0.000	0.000	0.000	0.000	0.000	0.116
2030	0.085	0.132	0.396	0.438	0.437	0.396	0.150	0.018	0.014	2.065
2040	0.104	0.700	0.412	0.423	1.161	1.076	0.403	0.049	0.257	4.585
2050	0.000	0.996	0.412	0.000	1.501	1.354	0.535	0.063	0.812	5.673

	Distributed Production (%)		Centralized Production (%)							
Year	Distributed Natural Gas	Distributed Electrolysis	Electrolysis	Natural Gas	Coal	Biomass	Wind	Solar	Nuclear	Total
2010	0.0	0.0	30.0	69.8	0.0	0.1	0.1	0.0	0.0	100.0
2020	3.4	1.8	30.0	64.6	0.0	0.1	0.1	0.0	0.0	100.0
2030	4.1	6.4	19.2	21.2	21.1	19.2	7.2	0.9	0.7	100.0
2040	2.3	15.3	9.0	9.2	25.3	23.5	8.8	1.1	5.6	100.0
2050	0.0	17.6	7.3	0.0	26.5	23.9	9.4	1.1	14.3	100.0

By 2030, 2.1 quads (18.5 Mt H2) of H2 production replaces about 18% of U.S. gasoline demand in LDVs, and 5.7 quads in 2050 (50.8 Mt H2) ☐ or about 50% of LDV demand. Table 3.8 from the study shows the mix of feedstocks. For coal, large centralized H2 plants begin to be built between 2020 and 2030 and supply 21.1% (.437 quads, or 3.9 Mt H2) of the U.S. demand for H2 by 2030 and 26.4 % by 2050 (1.50 quads, or 13.4 Mt H2). This is well in excess of the 10% of H2 from coal estimated in the above two studies, amounting to 65 M tons of coal to make 3.9 Mt of H2 needed in 2030, and 108 tons of coal for 13.4 M tons of H2 in 2050.

Estimates of the carbon emissions from the *GYOW* scenario were not made, but the study assumes that each of the feedstock conversion processes utilizes the best available technology for capturing and storing carbon. Hence a mix of more advanced coal-H2 technologies is assumed in 2050, compared to 2030. H2 from coal, for example, is produced from an IGCC plant that coproduces H2 and electricity, then separates, captures, and stores the carbon dioxide stream.

5. ***Prospects for Hydrogen and Fuel Cells*** (Organization for Economic Cooperation and Development, International Energy Agency, December 2005)

The International Energy Agency has done a major energy technology analysis of prospects for FCVs around the world. This is both more ambitious and cautionary than the DoE and NAS studies cited above. Under the influence of several government incentive and regulatory initiatives, coupled with steady technology evolution and declining costs, an H2E emerges, the size of which is particularly sensitive to stronger carbon policies. Advanced internal combustion engine (ICE) powered vehicles, H2 hybrids, and H2 fuel supply systems will all play key roles in the transition to H2 as drive systems and controls become more highly developed and are mass produced in large quantities, while fuel supply systems for H2 are being developed and deployed. Since CO2 and climate are global challenges, the IEA study concludes that adopting these incentives only in the nations that are signatories to the Kyoto Protocol disproportionately limits demand for H2 FCVs worldwide.

As highlighted in the above studies, a key driver for H2 demand is the cost and availability of carbon capture and storage (CCS) for fossil-based fuel cycles. This reinforces the importance of the need to achieve success from the variety of technologies and feedstocks embedded in a H2E.

Higher oil prices help speed the advent of an H2E. This is affected by IEA's oil price assumptions (which seem somewhat low), and could considerably alter their conclusions: prices are assumed to be $30-$40/b over 2015-2050, versus a figure of $52-$59/b by 2030 in AEO 2007 (2).

Also, the relative energy efficiency of ICEs and FCVs strongly affects deployment . Again, IEA uses more conservative assumptions and lower FCV LDV deployment — 1.8 times advanced ICEs ☐ while DoE uses 2.3-2.9 times as technology improves, with Japan using a similar range. For example, a 60% higher operating efficiency for FCVs in model runs increases their market share by nearly 60%.

Nonetheless, a combination of some conservative oil price and efficiency assumptions and ambitious climate policies leads to the highest deployment of FCVs and the lowest net carbon emissions. International oil trade is reduced considerably in all scenarios. Some 30% of world LDV demand (over 700 M vehicles) is met by FCVs by 2050, greatly diversifying the fuel mix and helping to substantially stabilize carbon emissions. The potential for FCVs is high in OECD countries and China — where the shares of FCVs by 2050 are forecast to be:

- China ~ 60%
- India ~ 42%
- U.S. ~ 42%
- Europe ~ 36-48%
- Canada ~ 35%
- Japan ~ 22%
- Australia ~ 10%.

These scenarios are considerably affected by the variation in energy use intensity (joules/capita) and vehicle miles traveled, across regions. North American per capita oil use, for example, is 2.2 to 2.6 times higher than in Europe and the OECD Pacific regions.

It is unclear from the IEA study what H2 demand is forecast for LDVs, but this is estimated from AEO 2006 as 42% of 2030, or 4.8 quads (of H2) — equivalent to about 9 Mt of H2 (nearly today's production of H2 in the U.S.). This would translate into about 73 M tons of coal in 2050 to meet 42% of the LDV demand with H2.

2050 Summary: Coal to Hydrogen[i]			
	Hydrogen (Million Metric Tons)	**Demand Satisified**	**Coal (Million Metric Tons)**[iv]
DOE Hydrogen Posture Plan	7.9	10% LDV; 10% DG[ii]	62
National Academy of Science	15	10% LDV; 10% DG[ii]	105
National Coal Council	8.6	10-20% [iii]	70-140
Argonne National Laboratory	13.4	26% of 50% [iii]	108
International Energy Agency	9	25% of 42% [iii]	73

i Assumes advanced coal-to-hydrogen technologies with carbon capture and storage

ii LDV = Light Duty Vehicle fleet; DG = Distributed Generation in residential, commercial, and industrial sectors

iii % of the Light Duty Fleet

iv Differences in the amount of coal required to produce a unit of hydrogen are due to different plant designs, conversion efficiencies, and feedstocks

This table estimates the range of new coal production that would be needed — about *60-140* M tons — to satisfy 10%-20% of H2 demand for light duty vehicles and some distributed generation for homes and small businesses. For 2005, domestic U.S. production of coal is about 1050 M t/yr, which would need to expand by about 6%-13% to meet new H2 demand.

EIA shows that about 52% of today's electricity is generated from coal, and expects electricity demand to nearly double by 2050. If coal were to maintain its current market share through 2050, for example, "new" coal demand for H2 is likely to be only about 4%-7% of the forecast business-as-usual levels. This is a sizable quantity of coal, but should not critically test the capacity of U.S. mining and logistic infrastructure.

Nonetheless, it means that within about 15 years after 2050, the total amount of coal produced in the U.S. for hydrogen could be equivalent to what one year's production is now. This means an enormous market for fuels and about 180 M new FCVs on the roads, hundreds of new coal-H2 plants, and substantial regional expansion in mining activity — with its associated safety, reclamation and logistic impacts — plus millions of tons of carbon to successfully capture and store.

Why a Hydrogen Economy? — Besides the factors highlighted in the above section on ***Observations,*** here are several additional key benefits to the U.S. aggressively pursuing a hydrogen economy. A host of critical strategic variables arise from the opportunities that a hydrogen economy offers (1, 3, 4). These center on utilizing domestic resources, increasing energy efficiency gains, and reducing emissions, particularly of carbon dioxide.

- The U.S. faces strong economic and security vulnerabilities from its dependence upon imported oil and the lack of diversity in its energy sources, especially for transportation. Seeking an alternative strategy has high stakes, and coal, biomass and nuclear could be key components.

- As an energy carrier, H2 can be manufactured from a wide variety of alternative domestic feedstocks and raw materials. Natural gas, coal, renewables, nuclear and direct solar energy could all become important sources of hydrogen supply. And, a strong supply balancing effect derives from the better end use efficiencies promised by hydrogen and fuel cells, particularly in H2/fuel cell powered cars, buses and trucks. For example, the Department of Energy and its industry partners foresee fuel economy for H2 fuel cell vehicles improving to an achievable 75-85 miles/gallon of gasoline equivalent.

- H2 used in fuel cells creates more efficient and emissions-free electricity, which has a multiplicity of applications. The key to this is to employ low temperature chemical processes in end uses that avoid hydrocarbon combustion, which creates a rich stream of pollutants. For transportation and distributed power generation, H2 and fuel cells could replace many more carbon and energy intensive technologies.

- High oil prices, though painful to the U.S energy economy, begin to internalize the truer cost of world oil, and bring advanced technology alternatives closer — speeding evolution toward domestic commercialization.

- Advanced technologies manufactured at a transformational scale would enable building new and reengineered industries, creating new economic development possibilities.

- High geographic concentration of fuel and feedstock production invites systems vulnerability— for instance domestic supply disruptions arising from the Gulf of Mexico and Alaska. H2 made from domestic resources could considerably lower these risks by spreading production sites widely over the U.S. landscape.

- Fuel cell vehicles (FCV) offer important new design opportunities. They allow the vehicle platform, drive system, and passenger space to be entirely reengineered and purpose-built to take advantage of repackaging and relocating major subsystems. Fuel cell vehicles could employ advanced, lighter and stronger materials with conversion to all-electric drive and controls. General Motors, for instance, estimates that an advanced FCV would use less than 1/10 of the parts a conventional internal combustion engine vehicle does today.

- The likely magnitude of the oil import bill — over $ 1 trillion from 2003-2008 — indicates the size of the potential direct benefit pool for redirecting U.S. investments into higher technology solutions to energy security — a sizable drain on the U.S. that could purchase higher value at home.

- Changing to a H2E would require fundamental alteration in both supply and demand for energy, and must be accomplished in concert to avoid overbuilding supply capacity or stranding demand. A transformation to a H2E would eventually yield greater overall value to the U.S. economy. It's not just the costs of the fuel or its derivatives, but how we arrive at our next destination. We need to realize steadily lowering costs with improvements in the efficiency of production, and expanding markets to realize economies of scale, plus building and phasing those engineering and market bridges to ensure the evolution and deployment of steadily advancing technology.

- The U.S. is more vulnerable to supply disruptions of all sorts due to its poor fuel supply diversity. By displacing petroleum both in U.S. and world markets □ particularly in the transportation sector □ a hydrogen economy could eventually shrink U.S. imports and competitive pressures on prices, in turn dampening world price volatility much in the way an ecosystem provides its most advanced predators at the top of the food web multiple opportunities to survive and prosper in times of systems stress.

- The U.S. is not alone in facing challenges to its future security and prosperity from underdiversification of resources, supply volatility and environmental degradation. These are global conditions. While they may vary in direction and intensity, they affect both developed and developing nations.

International efforts In addressing these conditions, national priorities vary and national motivation will matter as hydrogen moves into and penetrates the marketplace. For example, the European Union places a high priority on environmental impacts of energy use. Already party to the Kyoto Protocol, the

European Union recently agreed to legally binding reductions in greenhouse gas emissions that go beyond the targets of the 1997 Kyoto Protocol. Over the next 13 years, they also agreed to increase the use of renewable energy to 20% of the Union's power needs over 1990 levels.

Germany and Spain now lead the U.S. in installed wind energy capacity with respectively 18,400 MW and 10,000 MW of installed capacity vs. 9,100 MW of installed capacity in the U.S. These European leaders are actively investigating the use of hydrogen storage to address the issue of the intermittency of the wind resource.

Japan has few indigenous energy resources and extremely high import dependency – oil accounts for 57% of its energy needs and 99.7% of the oil is imported. The world's fourth-largest producer of greenhouse gases, Japan has agreed to reduce its total greenhouse gas emissions by 6% under the Kyoto Protocol. These factors are driving the Japanese RD&D efforts in hydrogen.

Now the world's 11th largest economy, Korea ranks 10th in terms of energy consumption. It is 97% dependent on foreign imports for its energy resources, the fifth largest oil importer and the second largest importer of liquefied natural gas. The Korean government has announced a plan to replace 5% of the national energy consumption with new and renewable energy sources by 2012; the current percentage of such sources is under 2%. The plan identifies hydrogen and fuel cells as one of the ten key economic growth engines for the next decade.

At the 2005 Gleneagles Summit of the G-8, leaders called for a "clean, clever and competitive energy future," asking the International Energy Agency (IEA) and the World Bank to support this venture through closer cooperation with developing nations. The International Energy Agency Hydrogen Implementing Agreement (IEA HIA), which has been actively working to build its membership and expand its hydrogen RD&D portfolio for over 30 years, is contributing to this call to action by increasing its efforts to involve developing countries in its hydrogen research effort.

Both China and India are members of the International Partnership for a Hydrogen Economy, created under the leadership of former DOE Secretary Spencer Abraham in 2004 to promote advancement of the hydrogen economy.

A Future History for Hydrogen

Hydrogen production — H2 can be produced from a wide variety of sources including: natural gas and coal; water; renewables such as wind, solar or biomass; nuclear or solar heat-powered thermochemical reactions; and solar photolysis or biological methods.

Today, the U.S. H2 industry produces nearly 11 million tons per year (M t/yr) for use in petroleum refining, chemicals production, fertilizer manufacture, metals treating, and electrical applications. It primarily is manufactured from natural gas in process units largely integrated with petroleum refineries and is principally used for upgrading crude oil fractions for gasolines. More than 43 M t/yr of H2 are produced worldwide, with about 60% going into the manufacture of fertilizers. Petroleum refining consumes another 23%.

Hydrogen may be the most abundant element in the universe, but it does not exist on Earth naturally in large or concentrated amounts. Indirect production from water, fossil fuels, or biomass is necessary. Each production method has its own unique process efficiencies, byproducts, and emissions.

Nearly 95% of H2 made in the U.S. comes from steam reforming of methane using a catalytic process where natural gas or other light hydrocarbons are reacted with steam to produce a mixture of H2 and carbon dioxide (CO_2). High purity H2 is then separated from the mixture. This method is the most energy efficient commercial technology available today and the most cost effective for production of large and constant volumes of H2. Smaller reformers have been installed at filling stations and can be used to fuel fleets of municipal buses as demonstrations. Such reformers can take advantage of the widespread availability of the existing natural gas pipeline system in the U.S. Although most of the co-produced CO2 now is vented to the atmosphere because it has little commercial use, steam reforming produces a clean CO2 stream that could be readily captured and stored (sequestered) and thus prevented from entering the atmosphere.

Hydrogen also can be produced using electricity in electrolyzers to extract the H2 from water. At present, this method is not as efficient or cost effective as steam reforming of natural gas for large volumes, but can be successfully scaled to a wide range of facility sizes. This would allow H2 generation to be more widely distributed on the landscape — at virtually any location where electricity and water can be collocated. Electrolysis, moreover, enables electricity from renewables and nuclear power to be used extensively to manufacture H2. Thus local filling stations for fleets of vehicles, like buses, delivery vans, or personal vehicles can be built wherever the electricity distribution grid extends. The primary byproducts from H2 manufactured in this way are oxygen from the electrolyzer and CO2 for hydrocarbon combustion-based electricity generation (largely coal and natural gas).

For future, large scale production of H2, partial oxidation of hydrocarbon feedstocks in large gasifiers using coal, petroleum coke, heavy oils, and solid biomass can eventually become an attractive method of making H2. Unlike combustion, this involves a two-stage reaction of a fuel with a limited supply of oxygen, plus steam to produce a H_2 mixture with CO_2. The H_2 then can be separated and purified. The principal byproduct is CO_2 which, as mentioned earlier, can be readily captured and stored.

For H_2 to become a competitive product, significant technical strides will need to be made in achieving much greater efficiency and cost effectiveness, as well as perfecting the ability for byproduct carbon to be captured, stored, or utilized. Extensive public and private investments are being made to solve many of the technical problems accompanying the evolution of a H2E. Numerous financial incentives and federal research, development, and demonstration funding are included in the Energy Policy Act of 2005.

Building a Hydrogen Economy — a Cone into the Future

The transportation sector of the U.S. energy economy is almost completely dependent upon imported oil. Electric generating capacity, however, is largely based upon varied mixes of domestic resources, with considerable difference from region to region. Building a H2E in the U.S., with unique regional markets using a variety of domestic energy sources, might parallel the ways in which the electric power industry has evolved. Much like electricity, advanced hydrogen technologies employ a cleaner and more efficient energy carrier, achieving substantial efficiency gains in low carbon end use.

The U.S. has slowly improved the efficiency of its energy use over the years, and since the mid-1970s has pursued research and development on a range of alternatives to imported oil. Although private energy R&D has shrunk markedly since 1985, total Federal and state public investments have increased — highlighted by the *Energy Policy Act of 2005*, which provides for research, development, demonstration and commercialization of a wide range of energy alternatives. A rich and lively debate continues on how to implement effective policy and development strategies, and how much they should cost the government and consumer.

Key technical and cost challenges with H_2 remain to be solved, and the Federal government's intensive, cooperative research with industry over the past ten years has made considerable progress in identifying and solving these barriers, although it is unclear whether the pace or magnitude of the effort are sufficient. Aided by a package of Federal financial incentives, is the U.S. positioned to deploy a set of advanced energy conversion and utilization technologies for hydrogen at a commercial scale?

Widespread use of coal to make hydrogen, for instance, depends upon the ability to capture and store large quantities of carbon dioxide (CO_2). This could best be done by manufacturing hydrogen along with high conversion efficiency, Integrated Gasification Combined Cycle (IGCC) facilities, which are modified advanced technology electric power plants. CO_2 from an IGCC is more readily separated and stored when combined with a hydrogen plant, which necessitates separating a pure, controlled stream of CO_2. The added cost of carbon capture is relatively small. Without strong attention to the carbon management challenges, using coal would simply recarbonize the oil-to-gasoline fuel cycle, except with a cleaner end use.

The carbon footprint of the oil-to-vehicle use fuel cycle accounts for over 1/3 of all the emissions in the U.S, and ½ in California. Estimates vary, but with successful, and essential, carbon capture and storage at the production source of the hydrogen, the light duty vehicle's carbon budget could be halved or even eliminated by 2050. Some 500-650 M tons/yr come from light duty vehicles, leaving perhaps 20-26 B tons of carbon (over 40 transition years) in the balance depending upon how quickly hydrogen vehicles are deployed. Big gains in air quality would also result, especially in areas surrounding urban centers.

To replace our hydrocarbon infrastructure with domestically sourced hydrogen would be a formidable undertaking. Hundreds of feedstock conversion plants would need to be built in the U.S. About 4%-7% more coal would need to be mined, transported and converted to hydrogen to serve about 10%-20% of transportation demand.

Planning H2 supply — The following discussion reflects on what a team of investment planners might begin to think about as they consider when, where, what, and how to build H2 production plants as the demand for H2 begins to grow. This is especially difficult for a "pioneer" plant. The financial commitment is large and the technologies are not fully proven at the scale and level of system integration needed early in the deployment of advanced technologies. Government loan guarantees and tax incentives may be needed for both the supply and demand sides of the market. Through new authorities in the Energy Policy Act of 2005, the DoE and IRS are just now experimenting with new incentives. Several moderately complete plant simulation models are available, however they are mainly used for estimating financial performance rather than design. Several manufacturers are building major components, particularly gasifiers. The first projects could be underway by 2008-2010, and the "wedge" or "cone" into the future of this initial activity out to about 2025 is where this discussion is focused.

Early efforts — The beginnings of how a H2E might be built are already in place, and have been evolving for over 15 years. The Departments of Energy and Defense, plus numerous small and large industries, probably have invested over $2.5 B in the past 10 years for RD&D and demonstrations. Two major industry associations ☐ the National Hydrogen Association and the U.S. Fuel Cell Council ☐ represent over 200 large and small companies and research institutions across the U.S. and internationally.

In 2003, the President and the Secretary of Energy launched the *Hydrogen Fuel Initiative (HFI),* whose purpose is to make substantial public investments in higher risk RD&D with a goal of eventually commercializing advanced hydrogen and fuel technologies. Considerable systems analysis and planning have been done by DoE and a major commitment was made by the Federal government in the EPAct 05, which authorized over triple the resources for Federal RD&D (1, 4, 10) and expanded the Secretary of Energy's authorities to build more links to private industry and accelerate this family of advanced technologies toward commercialization (see Titles VII and VIII of the EPAct 05).

Stationary fuel cells are commercially available for backup and auxiliary power, as well as portable and micro cells for small electronics which are just now breaking into consumer and military markets. UTC Power, Plug Power and other firms have sold over 45 megawatts of installed stationary power, including several large H2FC backup systems for communications in South America and South Africa. There have been over $360 M in sales, and nearly 7100 employees involved in RD&D and manufacturing.

General Motors (GM) and Ballard Power Systems, for instance, believe that a cost and performance competitive FCV can be ready for mass production by 2011. GM intends to be the first manufacturer to sell a million vehicles. Many prototypes have been built by several manufacturers and DoE's "learning demonstrations" partner auto manufacturers, energy companies, and research institutions in multiyear systems demonstration projects that test integrated H2 supply and vehicles in different climates in the U.S. A good deal of experience is being gained with autos, buses and delivery vans and their associated fueling infrastructure.

Today, over 45 fuel cell products are being offered commercially by 13 different companies in portable, stationary, backup power, material handling and transportation applications. Forty-two fueling stations already are operating in the U.S., with 20 more planned over the next 2 years. Honda and GM are developing home systems. During 2007, GM will be deploying 100 fuel cell Chevrolet Equinox SUVs and has announced their purpose-built, next generation, all electronically controlled Sequel. BMW will be demonstrating and leasing dual-fuel (H2 and gasoline) Hydrogen 7 cars during 2007-8. DaimlerChrysler has over 100 FCVs in operation around the world. Honda has announced that they will have an FCV for lease in 2008. Several cities have 40 buses in revenue service and the Federal Transit Administration has launched a $43 M, multiyear program to demonstrate next generation H2FC buses with the goal of making them 10% of all U.S. bus purchases by 2015.

Bridges to the future — Much of this activity has great technical and economic learning benefits in shaping the evolution of H2 supply and fueling systems, the electric drive and electronic controls needed by FCVs, creation of purpose-built automotive platforms, application of high strength/lightweight materials, and the availability of competing technologies for both H2 supply and the kinds of vehicles and fuels coming to the market. **In the quest to begin to substitute H2 and FCVs for conventional petroleum-based fuels,**

alongside other alternatives like biofuels, hybrids and, coal-derived (and possibly oil shale-derived) liquids, markets and manufacturing supply chains are likely to be accommodating a much greater variety in vehicle and fuel options since autos began competing with the horse and buggy over a hundred years ago.

Market evolution—where will the H2E get built? The largest potential market for H2 is LDVs, where FCVs have the greatest strategic opportunity to produce national benefits on a large scale with respect to increasing the efficiency of the fleet, reducing oil imports, building new industries, and sharply reducing air emissions. With about 226 million LDVs registered in the U.S. in 2005, and about 17 million sold per year, it would take several years after a competitive vehicle was available for much of the existing fleet to be replaced. The size of the associated H2 supply infrastructure needs to keep pace with, but not outgrow, demand and build excess capacity, which would lead to stranded assets and market stagnation.

Much of the earlier discussion has focused on how 50% of the LDV fleet's gasoline demand could be replaced by H2 from a wide range of alternative feedstocks by 2030-2050, as well as some home and small business electricity demand. As the market penetration of FC grows, so does the whole market — and so does population, disposable personal income and total energy demand — leading to an expanding vehicle fleet estimated to be 285 M LDVs in 2020, 320 M in 2030, and 385 M in 2050. This is an enormous market and such expansion likely ensures that the auto and fuel industries remain the largest in North America for many years.

In the National Academy study's (1) 'Optimistic' FCV market penetration case, for instance (discussed above), it is assumed that competitive fuel cell vehicles enter the market in 2015 as part of the mix of hybrids and conventional internal combustion engine (ICE) powered vehicles. They estimate that 25% of the fleet would be replaced within 12 years, or by 2027.

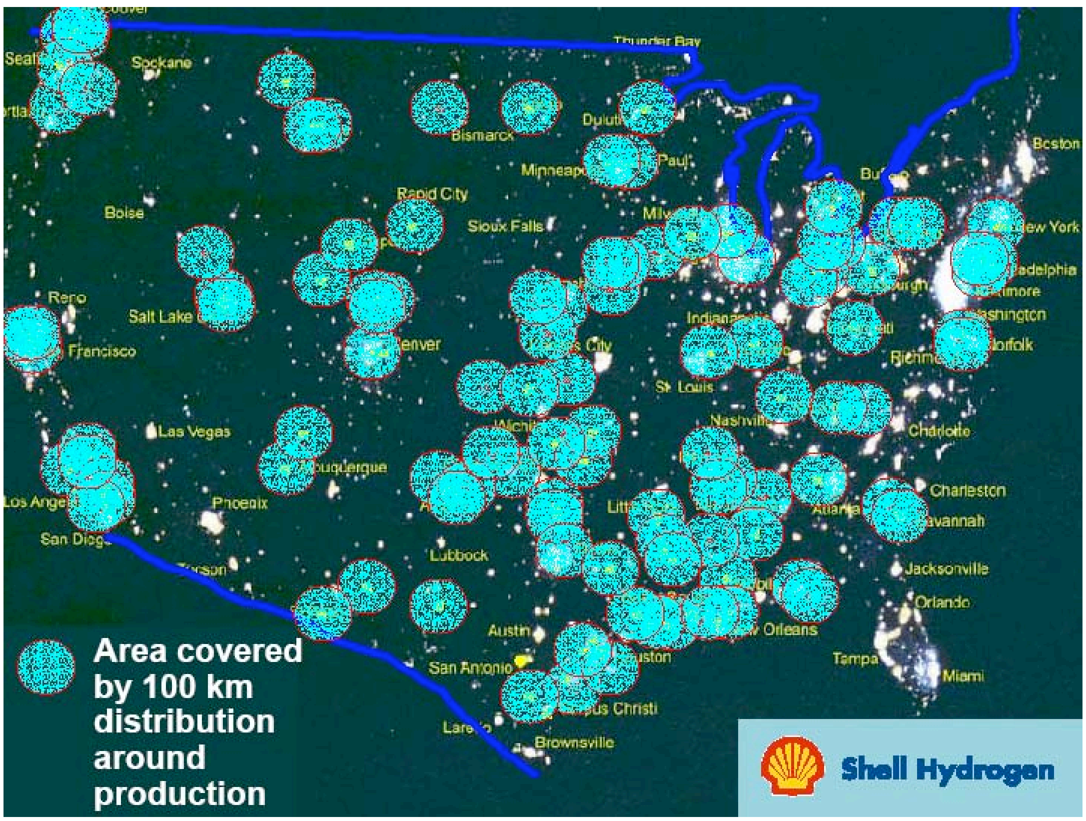
GM and others see that within 20 years the entire fleet could turn over with a superior group of products, which makes it possible to evolve hydrogen supply infrastructure along with vehicle production. In testimony before the Senate in July 2005, GM, Shell and Ballard all concurred that the U.S. could see a manufacturable fuel cell vehicle by 2010-2012 that would be competitive with other cars then available for sale (1). GM's urgent target is to validate a fuel cell propulsion system by 2010 that has the cost, durability, and performance of a mass-produced internal combustion system. These FCVs, as modeled in the ANL study (9), are very capable and highly efficient, obtaining 55.8 miles/gallon (mpg) in 2015, and reaching 80.3 mpg by 2050.

GM and others have estimated that a fueling station infrastructure for the first million vehicles could be created in the U.S. for $10-$15 billion. This would require making hydrogen available within two

miles for 70% of the U.S. population and connecting the 100 largest U.S. cities with a fueling station every 25 miles (1, 3). Others see broader deployment costing closer to $20 billion, not appreciably more than what the industry reportedly would spend each year to simply maintain its current gasoline supply system.

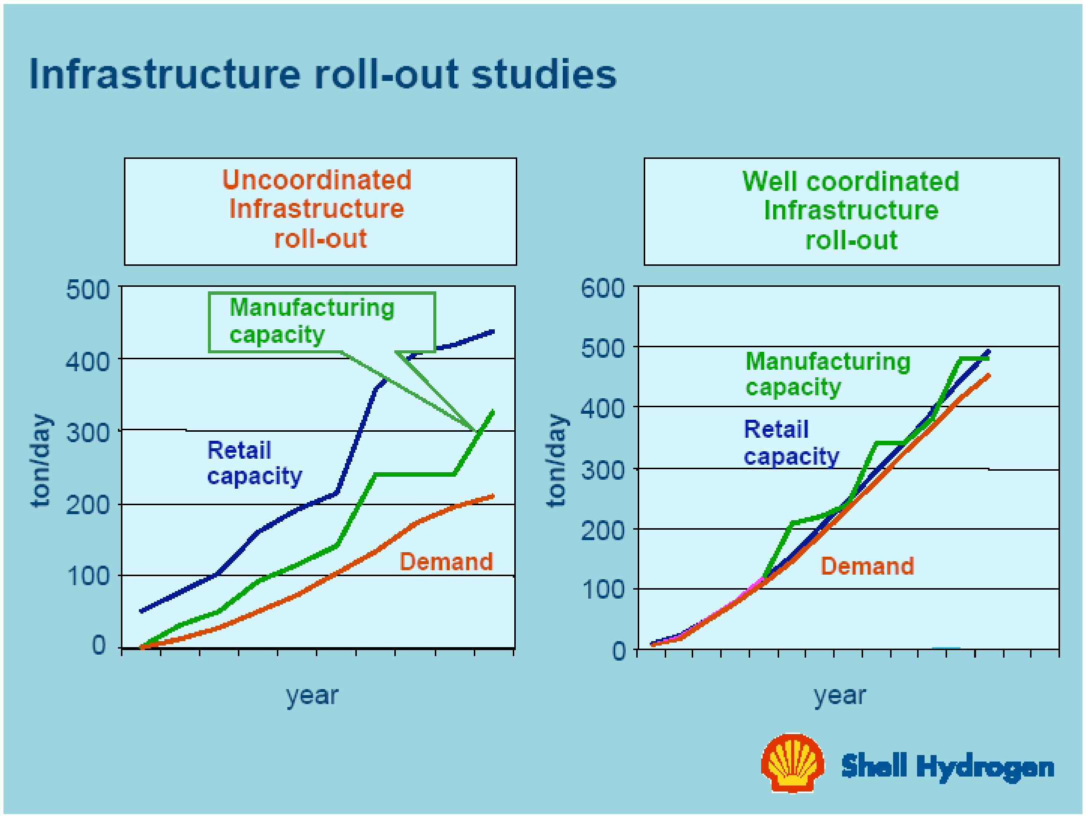
Substantial oil savings would result when 25% of the fleet is replaced, resulting in lessening peak refinery capacity needs as gasoline demand begins to shrink. Since much of the current industrial hydrogen production is utilized by oil refineries in making modern gasolines, some of that hydrogen could be freed up to become "merchant" hydrogen supply.

The following slides from Shell Hydrogen show the spatial array of industrial H2 production in the U.S.



The first shows a satellite picture of the U.S. at night overlaid by 100 km circles surrounding today's production sites for hydrogen — largely close to refineries. These also are major urban, higher density gasoline demand areas. There are over 100 of them, meaning that some 60% of the U.S. population already is within 100 km of a major source of hydrogen, today. These can be assumed to be locales where the introduction of hydrogen fuel cell vehicles and stationary fuel cell applications likely would be focused — starting with fleets of municipal and commercial buses and delivery vehicles, special purpose transportation (like forklift trucks), heavy trucks, and eventually evolving to fleets of cars and light trucks, and finally to LDVs for consumers. It is expected that stationary and portable fuel cells would lead these transitions in providing high quality, supplemental and distributed power to businesses and municipalities, and the early establishment of hydrogen supply networks.

Shell's next few slides discuss how a transition needs to be managed — in terms of key "Lighthouse" projects, those sized correctly and sufficiently smart to provide a beacon to lead the way to something larger. A critical component is the quality of public/private partnerships — something the EPAct 05 stresses. The coordination of "infrastructure rollout" is a critical aspect. If it is uncoordinated, excess retail and manufacturing capacity outruns demand and leads to high costs for hydrogen that further dampen demand and shrink profitability. "Smart beacons" see that there is an excellent match between the rates of demand and supply growth that optimizes investment in capacity and a more orderly and rapid transition, leading to more rapid and sustained growth in the H2E. Lighthouse Projects are the harbingers of commercial success. They are primary showcases for how well public and private institutions cooperate in establishing the climate for growth — whether it be in North America, Europe, or Asia.



Existing infrastructure and national markets — Much of the hydrogen produced in the early years likely will be from widely distributed sources, using electricity off the existing grid or natural gas from the existing pipeline system (1). These distribution networks are large and reliable, and they reach all urban areas. The combined electrical grid is connected everywhere. As the Hydrogen Utility Group suggests, "For decades, we have brought electrons to every home and business in the US; why not protons?" (11). The utilities' operations are well understood and key investments in the grid have largely been made. The smoothest early stages of the supply transition can be expected to be made in the same way.

Because hydrogen does not lend itself to worldwide transport in tankers like oil and liquefied natural gas, it will not be as internationally fungible as oil — leading to the emergence of largely domestic and regional markets {(1), Hinkle testimony and (9)}, **where value can be based largely on market fundamentals and cost of production and transportation, unhooked from global volatility.** This may induce market behavior absent national security or conflict premiums, helping to create more stable price regimes in domestic energy markets — a dampening effect which could yield large economic benefit by itself. This could also make government incentives — in investment, production and use tax credits, depreciation, loan guarantees, etc. ☐ more effective and predictable. As a result of a study called for in Section 1820 of the EPAct 05, *Overall Employment in a Hydrogen Economy,* DoE soon will complete an economic development analysis that looks at different transitions to varied forms of a hydrogen economy. This report will accompany other such work on market and technology transitions. It is expected that both new job growth and retention of existing jobs during such a transformation would center on the supply chain for new vehicles and somewhat altered refinery and utility operations producing hydrogen. In addition, there is likely to be considerable expansion in coal and renewable energy production — both in electricity and biofuels — in widely dispersed regions of the U.S. some distance from urban demand centers.

Domestic production of hydrogen could be the next wave of products for the energy industry. This may be where the growth of the H2E has the most business and economic potential for the coal, nuclear, renewable and energy industries. H2 supply likely will be an entirely domestic industry for many years beyond the major transformations in the vehicle fleet. This clearly favors domestic feedstocks — another key strategic goal (3, 4).

Depending upon how existing manufacturing capacity is converted and preserved in traditional areas, the automobile supply chain might have more inherent flexibility in locating new and old operations. The advanced fuel cell vehicle (FCV) could have only 1/10 as many moving parts as today's cars, SUVs, and pickups, and much of the rest of the vehicle would be different. Transformation could happen anywhere. True worldwide markets will evolve for components and vehicles, whose manufacturing capacity is more mobile than hydrogen production. It is a well-proven concept that technology can move around the globe more readily than a workforce, especially enabled by the ease of routinely transferring great quantities of information worldwide by electronic means.

Large export markets are expected to evolve for vehicles and components, and also for the technology surrounding hydrogen production and storage. Due to its particular appeal in improving the efficiency and shrinking the carbon footprint of conventional fuel cycles, hydrogen-related technologies will help create an even wider range of new export opportunities. International competition could prove to be fierce.

A H2 production scenario for the U.S. — As noted above, the U.S. has some of the basic infrastructure already in place that could be utilized in transitioning to a hydrogen economy. There are plants near oil refineries that manufacture hydrogen from natural gas and some byproduct plant fuel. The nationwide natural gas pipeline system and the electric power grid are key components. These are valuable and essential assets, but they will need to be adapted to new business models. Depending upon the highly varied and unique regional mix of generating capacity (coal, natural gas, hydroelectric, geothermal, nuclear, renewable), and how effectively they can grow, the relative production efficiencies and carbon footprint of the possible hydrogen fuel cycles will be quite different.

No single H2 or alternative fuel production strategy will work for the entire U.S. All feasible techniques and sources for making hydrogen likely will be needed to ultimately replace imported oil.

The ANL regional study cited above (9) is a balanced, multiyear supply and demand study that employs a wide variety of feedstocks to manufacture H2 and could be readily applied to answering questions about where, how rapidly and how large a H2E evolves — particularly the shares of different feedstocks in the mix. Table 3.8 indicates that centralized coal-to-H2 plants would begin to be built after 2020; the NCC study believes that this might occur sooner. Given the relative availability of many of the key components of an IGCC/H2 plant, centralized C-H2 production could begin as early as 2012-2015 if there is a will and need for them, and incentives are sufficient (3). This could happen most readily in those regions of the U.S. where the relative availability of coal allows relatively cheaper H2 to be manufactured — as in the Middle Atlantic (PA), East North Central (IL, OH), West North Central (ND), South Atlantic (VA), East South Central (KY), and Mountain (MT, WY) (9, 12) regions.

The ANL study (9) shows that as technology evolves and plants become more reliable, costs will move steadily downward between 2020 and 2050. Lower cost trends could start sooner and reach their steady state cost not in 2050, but earlier — perhaps 2040. This could be advanced by about 6-8 years (3).

Critical factors enabling this early deployment are, of course, related to whether the demand for large quantities of cheaper H2 begins to mature, also by 2010-2015. The ANL (9) conclusions on the ultimate levels of production for different regions and feedstocks are well-founded. They might occur sooner for coal in key regions.

Plant gate costs estimated by the ANL study (9) are somewhat higher than those portrayed in the technology appendix of the NHA/CEED study (3) — largely due to different groups of assumptions in the respective analyses. They tend to merge as more advanced plants are being built, and evolving technology, operational learning and economies of scale overtake earlier, costlier H2 production. By 2050, they are similar.

In the CEED study, plant gate costs of hydrogen from coal with carbon capture and storage vary from $.71/kg (approximately the energy content of a gallon of gasoline) to $1.79/kg (3). The ANL study (9) estimates that these costs would improve with technology evolution and market size from $3.30-$4.01/kg in 2010 to $1.50-$1.58/kg by 2050.

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-Mountain

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.79	0.56	0.51	1.13	4.99	Cryogenic Tanker Delivery
2020	1.60	0.32	4.59	0.91	7.42	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.40	0.28	2.18	0.72	4.58	Pipeline Delivery
2040	1.33	0.27	0.75	0.61	2.96	Pipeline Delivery
2050	1.27	0.25	0.67	0.44	2.63	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-Pacific

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.34	0.67	0.12	1.13	5.25	Cryogenic Tanker Delivery
2020	1.79	0.36	1.22	0.91	4.28	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.55	0.31	0.59	0.72	3.16	Pipeline Delivery
2040	1.45	0.29	0.20	0.61	2.55	Pipeline Delivery
2050	1.36	0.27	0.18	0.44	2.25	Pipeline Delivery

Coal-to-hydrogen production costs vary across regions that have a reasonable coal resource endowment. Those regions where coal needs to be transported farther are more expensive. But, overall delivered cost could be lower, as hydrogen, like any finished product has a higher value density when it has to travel a minimal distance to its final demand. For example, hydrogen made in the Mountain region is cheaper at the plant gate and more expensive in the Pacific — but total delivered cost in the Pacific overall is less than in the Mountain region. Both regions show a considerable drop across all the components of total cost delivered to market for production, CCS, delivery, and dispensing. In the Pacific, it drops from $5.25/ gasoline gallon equivalent (GGE) in 2010 to $2.25/GGE in 2050 (- 57%).

Siting - Another critical factor is siting. Compared to a conventional pulverized coal electric power plant, an IGCC/H2 facility offers substantial reduction in emissions, plus gains in output efficiency. A conventional coal power plant is unlikely to be sited in urban areas. But, with the integration of CCS in their design, IGCCs may be able to be sited in the city gate areas nearer concentrated urban transportation and electricity demand areas identified on the Shell refinery/H2 production map. Since there is also considerable experience in building and operating shorter (not interstate) hydrogen pipelines, collocation with higher density demand centers would greatly reduce the transportation cost — plus, IGCC/H2 plants could be readily built to satisfy refinery hydrogen demand as well as natural gas steam reforming plants — providing another bridge to the future of a hydrogen economy.

An Initial Deployment Scenario

Several long term visions for a hydrogen economy have been reviewed. What the analyses lack is a shorter term picture of what the first deployment steps might be. The ANL, NAS and NCC studies are useful in helping to examine the details of how the beginnings of a hydrogen economy would look. Federal incentive and R&D programs have helped establish some focus.

The government moved beyond R&DD to actively working on demonstrating this technology at a commercial scale when President Bush announced the FutureGen project in 2003, a public-private partnership to build a coal to hydrogen and electricity plant with carbon capture and storage. The project was originally budgeted for $1.2 billion, with substantial funds ($250 million) to be provided as a cost share by a coalition of coal producers and users, the FutureGen Alliance, which will participate in the construction and operation of the plant. FutureGen is currently in a site-selection phase with construction planned for 2009 and operations beginning in 2012.

From a legislative standpoint, the Energy Policy Act of 2005 (EPAct) was a landmark bill that intended to accelerate hydrogen and fuel cell technology. For coal, it contains a variety of projects and incentives for advanced coal plants, including provisions for cost-shared grants and contracts for clean coal projects, federally-backed loan guarantees for innovative technologies including gasification and hydrogen projects utilizing CCS, tax credits for clean coal, grants for universities to establish Centers of Excellence and expanded systems and learning demonstrations for hydrogen and FC applications. New legislation in the 110th Congress expands upon this.

As of July 2005 before the passage of EPAct 05, there were seventeen IGCC electricity generation projects planned in the United States. Since the passage of EPAct many more companies have announced proposals to build them. The DoE issued the first round of loan guarantees under Title XXVII of EPAct in August of 2006, making available $2 billion in loans for a wide range of innovative energy technologies. Preproposals were due December 31, 2006. The announcement appeared to stimulate broad interest in the energy community, but the design of the program has some offsetting defects (13) that may have actually limited the number of proposals submitted. The loans are designed to help reduce some of the investment risk for new energy technologies.

Added to the loan guarantees, Section 1307 of EPAct 05 authorized $1.65 billion in tax credits for clean coal projects: $800 million for IGCC projects producing electricity; $500 million for advanced coal electricity generation from non IGCC technologies; and $350 million for gasification projects other than electricity generation. On November 30, 2006, the Departments of Energy and Treasury announced the award of over $1 billion in Section 1307 tax credits to nine clean coal projects.

Among those awarded was the Carson Hydrogen Power, LLC project, a joint venture of BP and the Edison Mission Group. The project will be sited at BP's Carson petroleum refinery in Carson, California, and will gasify about 4500 tons per day of petroleum coke from the refinery to produce hydrogen — which will be directly burned in combined cycle gas turbines to generate 500 MW of electricity. Roughly 4 M t/yr of carbon dioxide captured during the process will be injected into mature oil fields nearby to enhance oil production.

This is a full scale commercial project utilizing a gasifier adaptable to coal as a feedstock. Although the Carson project produces no merchant hydrogen, it shares many similarities with what are the most congenial siting attributes.

First movers Each subsystem of a theoretical coal-to-hydrogen plant as described in the CEED report (3) has been tested commercially. Little experimental technology or few unproven processes are needed to build a plant today, but a completely integrated plant has yet to be constructed. Configurations are complex. The sophistication of control technology, mechanical safety, and engineering design that will be necessary to successfully bring a plant online is formidable. Due to the inherent operational risk, it is expected that first movers would be larger companies or consortia that have long experience with refining, electric power generation, gasification and hydrogen.

The first movers seem more likely to be integrated energy companies with large capital resources and technical experience, partnering perhaps with a gasifier company or an industrial gases firm familiar with manufacturing hydrogen for refinery or chemical uses. Coal-to-hydrogen plants produce several marketable byproducts. Slag, which can be sold for use in road-paving materials, will have a market regardless of location and it is cheap to transport. The sulfur market in the US was roughly $400 million in 2006, and is used in fertilizer production, refineries, batteries, detergents, and fungicides, often in the form of sulfuric acid — a major industrial raw material (3, 16). It is unknown how resilient these markets may be to saturation if coal-H2 were to be adopted on a large scale.

Product markets The most significant product is hydrogen, which has existing markets in the U.S., primarily at oil refineries where it is used for upgrading and refining petroleum into higher quality gasoline products — but also at ammonia and chemical plants, and in the food processing industries. These will be long term stable demand centers. And as the mix of heavier and higher sulfur crude oils continues to rise on world markets, more H2 will be needed in refining. Hydrogen will also have a growing portion of the transportation fuel market as automotive, bus and truck companies begin sales of H2 internal combustion engine and fuel cell vehicles, as discussed above.

Depending upon plant design, the most significant and valuable byproduct from coal-to-hydrogen processes is electricity. Electricity production is not a necessary output of the coal-to-hydrogen process, but a desirable design option that could improve plant economics and favor coproduction.

CO_2 is a necessary byproduct of manufacturing hydrogen. CO_2 is currently a waste product, vented into the atmosphere in a mixture of other flue gases by most coal-fired plants. However, CO_2 can have value as a working fluid when it is used for enhanced oil or coal-bed methane recovery (EOR). These processes inject captured CO_2 into mature oil fields or unrecoverable coal seams where coal cannot be economically recovered due to seam thickness or depth with present technology, to displace or mix with the oil and gas, allowing for increased recovery of hydrocarbon resources. Although it is a more expensive technique for effectively redeveloping oil reservoirs, it utilizes a waste product to recover as much as double the original production. There is considerable interest in this technique worldwide, which has largely been developed in the U.S. At current oil prices CO_2/EOR can be quite profitable for many fields that contain bypassed oil. DoE has invested in some CO_2 EOR R&D projects. The EPAct 05 has a pilot program to encourage use of CO_2 (often coproduced with natural gas) and combustion gases.

Nearby markets Financially successful plants are likely to be built at locations where there are stable existing markets for byproducts and potential growth markets for the high value products (17) (i.e. hydrogen and electricity). Existing petroleum refineries present possibilities — they would have steady hydrogen and power demands and associated infrastructure. They are likely to be owned and operated by a company having experience and familiarity with many aspects of complex chemical manufacturing processes. Many petroleum refineries are located near major urban centers that will provide the future demand for hydrogen and demand for other plant byproducts. This assumes that hydrogen from coal can be cost competitive with hydrogen from steam reformed methane, the traditional source of refinery hydrogen. At the average plant gate hydrogen cost of the current technology configurations examined by the CEED report (3), $1.15/kg, coal can be cost competitive when produced by large centralized plants.

As captured CO_2 will need to be stored permanently in safe geologic formations, nearby geologic resources will also play a role in the design and siting of plants. Captured CO_2 may be sequestered in EOR operations in older, mature oil fields to provide additional revenue. An example is the Dakota Gasification Project, which makes pipeline quality synthetic gas from lignite coal in North Dakota. The plant captures most of its CO_2 and sells and delivers it by pipeline 204 miles north to the largest geologic sequestration EOR project in the world at Weyburn, Saskatchewan. It has been particularly profitable, more than doubling the recovery of the original oil resources.

Few locations will meet all of those specifications, but several opportunities are apparent. Texas is already home to EOR operations, refineries, a population comfortable with energy technology, and cities of large enough size to grow sizable hydrogen demand. Both the Los Angeles and San Francisco Bay areas may be potential sites, but plants would need to be nearly emission-free. Rapidly growing areas like Phoenix and Denver offer possibilities. Florida, New York and South Carolina have active state hydrogen programs. Ohio (with an excellent hydrogen program) and Indiana have older oil fields, are close to coal reserves and urban demand centers. The Gary/Chicago/Milwaukee region are interesting, as is the Detroit/Toledo/Cleveland area — large markets, an interest in H2, and all Great Lake ports where bulk cargoes move easily, like coal, iron ore and limestone did when the Upper Midwest was a world center of steel and finished goods manufacturing. Again, the intersections of the Shell maps and the ANL study are suggestive.

California In California, the regulatory environment is somewhat different from other states, but many observers are watching how their ambitious policies may unfold. California recently passed a series of bills constraining emissions from power plants and automobiles in particular and greenhouse gas emissions in general. Assembly Bill 1493 directed the California Air Resources Board to develop regulations that would make the "maximum feasible and cost effective reduction of greenhouse gases (GHG) from motor vehicles beginning with model year 2009." Nearly ½ of all of the state's carbon emissions come from its transportation sector.

Senate Bill 1368 mandates that GHG emissions from new or upgraded power plants for baseload generation must be as low or lower than GHG emissions from new, combined-cycle natural gas power plants. Further, this bill applies not only to generators in California, but to any generator selling power into the state.

Assembly Bill 32 requires the California Air Resources Board to regulate to reduce GHG to 1990 levels by 2020 and 80% below 1990 levels by 2050. Reduction activities are scheduled to begin in 2012. Given this restrictive regulatory environment and the surging growth in electricity demand, the need and opportunity for a clean, low carbon emissions plant will be unparalleled. Although a careful analysis has not been done, the regulatory environment in California would make exploring the feasibility of an option to site an IGCC/H2 plant worthwhile.

An IGCC/coproduction hydrogen plant would compete with the growth of older-generation pulverized coal-fired power plants making electricity, and the use of steam methane reformation for hydrogen production without CCS (less CO2 is generated with natural gas, due to the chemistry and inherent efficiency of plant operations). There may be a significant market space for the products of a cleaner coal-to-hydrogen plant, but only with CCS. Coal-to-hydrogen coproduction plants could be able to compete with traditional power plants for electricity sales and methane steam reformation for hydrogen sales.

California is also incenting demand for hydrogen. Senate Bill 76 was signed in 2005, providing state funding to develop the California Hydrogen Highway system. The DoE learning demonstration program has helped build hydrogen stations in both Southern and Northern CA. The largest concentration of hydrogen stations in the U.S. is in CA where 23 hydrogen fueling stations are operational, with 14 more planned. California will likely be the first and one of the largest markets for hydrogen and FCVs, as it was for cleaner vehicles and more efficient foreign cars decades ago.

Argonne National Laboratory's regional analysis of hydrogen demand (9) forecasts that the contiguous Pacific region (California, Oregon, and Washington) will be consuming .81 quads of hydrogen by 2050 (14% of U.S. demand), of which 17.7% would come from coal. This amounts to 1.5 Mt/yr hydrogen from coal on the West Coast, or roughly 14 large (300 tons of hydrogen per day) coal-to-hydrogen plants (3).

Some localities in the Los Angeles area, with over half of the operational hydrogen fueling stations in California, are also geologically suitable for EOR utilization of CO2. California is the 4th largest domestic producer of oil, largely from the Central Valley region within 150 miles of Los Angeles (3). Declining production rates over many years (CA has been producing oil and gas since before 1900) highlights the opportunities for CO2 injection, but there are few CO2 sources within economically feasible distances at present. Consistently high oil prices and a market trading system for carbon could dramatically alter the economics, as the engineering challenges are well understood.

Additionally, there are several large refineries to provide hydrogen demand – California is the 3rd largest refiner in the U.S. with its 21 refineries located around San Francisco Bay, Los Angeles, and the Central Valley (3, 14). Further, siting in or near a refinery would allow cheap petroleum coke byproducts to be used as additional fuel that can be co-gasified with coal or biomass. Many of these factors will apply to any potential site, and a full systems analysis would be necessary to evaluate siting challenges and investment opportunities.

Coal may be cheap enough as a feedstock to transport to clean plants to satisfy CA demand, but the most rapidly growing component of delivered coal costs in recent years has been rail transportation — bottlenecks and car availability need to be solved. And, a synthetic, substitute methane/H2 mixture from coal gasification or renewables could be transported by pipeline more easily than hydrogen itself, with clean reforming nearer demand centers.

Going commercial Successful large scale demonstrations and small commercial projects carry strong messages for markets. Their visibility, the reach and expectations of the partners, quality of financing, the thoroughness of their analysis, their ability to solve technical problems and persevere, and profitability — all these factors could have a meaningful affect on how the rest of the industry looks at pioneering projects, and reflects on their own decisions about such investments. As an example, it is expected that potential gasification projects will have much in common with the Carson Hydrogen Project discussed above. Indeed, BP and the Edison Mission Group's investment and demonstration of the profitability of the project will further both technical comfort and confidence in the investor community. As noted in the discussion on vehicles and coal-H2 production, different types of demonstrations at both the supply and demand ends of the fuel cycle are essential. The future of H2 may depend upon early commercial successes.

Expect international competition in the marketplace. For example, Canada has a vibrant hydrogen and fuel cell program as well as an active early adoptors' program to stimulate the marketplace. The nascent Canadian hydrogen and fuel cell industry has been the beneficiary of considerable public and private sector investment. Already a leader in R&D, Canada may well be a successful "Early Mover" in the emerging hydrogen/fuel cell industry.

The Role of Public Investment

The U.S. has a robust and diverse private and public hydrogen RD&D program, and it is instructive to note other important international efforts. A key international program is the International Energy Agency Hydrogen Implementing Agreement (IEA HIA), the largest and longest-lived global collaboration in hydrogen. With 20 members[1], including the European Union, the IEA HIA (www.ieahia.org) has been engaged in innovative, longer-term, pre-competitive hydrogen RD&D since 1977. The U.S. was a founding IEA HIA member. With nine annexes (tasks) currently underway, the IEA has a 26 task portfolio of diversified hydrogen production and storage research complemented by analysis, economic and safety initiatives. It includes outreach in support of its RD&D activities. In addition, the IEA HIA recently prepared a report that examines the state of the art in hydrogen production and storage, detailing current, mid and long strategies. All IEA HIA nations have active hydrogen R&D programs of varying sizes and scope.

The European Union created a Hydrogen and Fuel Cell Platform in 2003. Hydrogen and fuel cell investment in R&D totaled 2.12 B € in the Sixth Framework Programme (2002-2006). As of 2004, 100 M €, matched 1:1 by public and private investment, was awarded for hydrogen and fuel cell research and demonstration needs. EU support for hydrogen and fuel cells has successively doubled over the last four frameworks. Energy is a key theme of the multi-year Seventh Framework Programme, which will be structured around the

[1] Australia, Canada, Denmark, European Commission, Finland, France, Germany, Iceland, Italy, Japan, Korea, Lithuania, the Netherlands, New Zealand, Norway, Spain, Sweden, Switzerland, United Kingdom, United States

hydrogen and fuel cell platform. At the regional level, a Nordic collaborative biohydrogen program with nine country participants began in 2004.

Japan has had robust hydrogen and fuel cell research efforts for many years. Its total 2006 hydrogen and fuel cell budget is 20.89 B ¥ (~$180,000,000).

Korea established a national hydrogen program in 2004. Its budgets for 2004 and 2005 were respectively, US $25.4 M and US$ 35. The total amount budgeted for the period 2006-2012 is US $760 M.

U. S. RD&D Government sponsored research on coal has been underway in the U.S. for over a century, and for three decades on hydrogen in transportation (15) (long before that in dirigibles, and as a propulsion fuel for aircraft and rockets). The strategic role of the federal government in coal research has mainly been a balanced effort in cooperation with a large and mature industry. **As private energy R&D has shrunk 75% between 1985 and 2005** (16)**, defining this approach has become a more dynamic process, moving with markets, legislation, technological advance and regulatory conditions.** DoE's Fossil Energy program (www.energy.gov) is responsible for nearly all of the federal RD&D on coal, carbon capture and storage, some hydrogen combustion and stationary fuel cells. Both DoE and the Department of Defense (DoD) pursue work on hydrogen and fuel cells (DoE's web site is www.hydrogen.energy.gov) . The federal RD&D mission is to carry out higher-risk and higher-value work that is intended to:

- accelerate the development of new energy technologies beyond the pace of market forces,
- expand the slate of beneficial energy options likely to be developed by the industry on its own, and
- encourage "breakthrough" technologies that achieve environmental, efficiency and cost goals well beyond private sector efforts.

Federal and industry R&D activities benefit current energy producers and strengthen the technical foundation for the next generation of advances, while providing sound data for future regulatory and policy decisions.

The more recent role of government in providing incentives to deploy advanced technologies has been suggested in preceding sections. Historically, government RD&D funding has been a well-accepted mission. Much has been done with prototypes and demonstration facilities, but less in aiding actual deployment of commercial scale coal-to-energy facilities or purchasing hydrogen energy conversion devices, for instance. Other countries with a tradition of greater government involvement in the product cycle have a more ambitious vision. The Energy Policy Act of 2005 (1, 3, 4) begins to settle some policy debates about the extent of the Federal reach toward commercialization. Whether the particular incentive instruments — like loan guarantees or tax credits — are well-designed or correctly administered has yet to be demonstrated, and much needs to be learned.

There are three fundamentally linked groups of technology applications that must gain momentum to make coal a clean and feasible option for the 21st century:

- IGCC and other very clean and efficient energy conversion methods
- Carbon capture and storage
- A sizable, growing demand for carbon-free electricity and hydrogen and their infrastructure.

To achieve eventual commercial success, Federal and state RD&D and regulatory programs must be designed in concert with tax and other financial incentives and the rollout of commercial scale enterprises. Current programs in DoE for coal and hydrogen generally reflect a more limited, traditional view of government's role in high risk RD&D undertakings in partnership with industry.

The Energy Policy Act of 2005 EPACT 05 has attempted to make a stronger bridge between the DoE RD&D programs and commercial deployment, and makes considerable strides in evolving links between government and industry — the following review highlights some key provisions.

Title IV—COAL

- ***Clean Coal Power Initiative*** — authorizes **$1.8 B** over nine years to assist projects with loans, grants and cooperative agreements that "…advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are in commercial service or have been demonstrated on a scale that (shows that) commercial service is viable…." At least 70% of the funds are to go to coal-based gasification technologies, including gasification combined cycle, fuel cells, coproduction, and others that produce a "…concentrated stream of carbon dioxide." There are several succeedingly more stringent emissions and efficiency milestones to be met by 2020. Performance requirements are also set for other types of non-gasification projects and existing coal-fired units. Financial performance and cost sharing criteria are also required.
- Specific projects are called out that are largely devoted to gasification, but Section 411. specifies an "Integrated Coal/Renewable Energy System": a project on low rank coal that "(1) is combined with wind and other renewable sources; (2) minimizes and offers the potential to sequester carbon dioxide emissions; and (3) provides a ready source of hydrogen for near-site fuel cell demonstrations."
- A ***Clean Coal Air Program*** authorizes **$2.5 B** in assistance for clean coal electric generating equipment that improves efficiency and emissions,

and includes "…systems integrating fuel cells with gasification or combustion units."

Title VII—VEHICLES and FUELS

- **Sec. 782. Federal and State Procurement of Fuel Cell Vehicles and Hydrogen Energy Systems**, intends an early adoption, market transition role for the federal government:
- "(1) to stimulate acceptance by the market of fuel cell vehicles and hydrogen energy systems; (2) to support development of technologies relating to fuel cell vehicles, public refueling stations, and hydrogen energy systems; and (3) to require the Federal government, which is the largest single user of energy in the United States, to adopt those technologies as soon as practicable after the technologies are developed, in conjunction with private industry partners."
- Mechanisms for sharing the cost of these products between the Secretary of Energy and other federal and state agencies are included.
- **Sec. 783. Federal Procurement of Stationary, Portable and Micro Fuel Cells** also provides a means of Federal purchase.
- **$450 M** is authorized for such purchases from Fiscal Year 2006 through 2010.

Title VIII—HYDROGEN

- This is the major title that includes most of the RD&D for hydrogen and fuel cells, including supply systems, vehicles, materials, demonstrations, basic science and codes and standards.
- **$3.28 B** is authorized for this Title, from FY 2006 through FY 2010. The source of this Title's language is largely S. 665, introduced in the Senate in March 2005, with a ten–year budget of $8 B
- The **SEC. 802. PURPOSES** are worth summarizing:
- "(1) to enable and promote comprehensive development, demonstration, and commercialization of hydrogen and fuel cell technology in partnership with industry;
- (2) to make critical public investments in building strong links to private industry, institutions of higher education, National Laboratories, and research institutions to expand innovation and industrial growth;
- (3) to build a mature hydrogen economy that creates fuel diversity in the massive transportation sector of the United States;
- (4) to sharply decrease the dependency of the United States on imported oil, eliminate most emissions from the transportation sector, and greatly enhance our energy security; and
- (5) to create, strengthen and protect a sustainable national energy economy."

Additional Provisions Other important provisions in EPAct 05 include:

- Grants, low interest loans and loan guarantees up to **$2 B** for industry to partner with Indian Tribes in Sec. 503, including projects that capture and store greenhouse gases
- Sec. 963 establishes a 10 year R&D program for capturing CO2 emissions from coal-fired power plants, both new and existing
- Investment tax credits in Sec. 1307 for clean coal and advanced generating, industrial gasification, and IGCC projects, amounting to **$1.6 B**
- Various tax credits for hydrogen and fuel cell equipment that expire in 2007, but legislation is pending to extend them — some out to 2015 to smooth market transitions and lend some stability
- **TITLE XVII—CLIMATE CHANGE** establishes a national strategy to promote the deployment, commercialization and export of greenhouse gas intensity (tons/$GDP) reducing technologies
- **TITLE XVII—INCENTIVES for INNOVATIVE TECHNOLOGIES** creates a unified, comprehensive loan guarantee program for encouraging a broad spectrum of clean, new technologies that avoid, reduce or sequester air pollutants or man-made greenhouse gases — a very wide range of projects are eligible, including IGCC, advanced coal gasification and hydrogen and fuel cell projects.
- Over 50 other sections of the EPAct 05 embrace in some way fuel cell buses, biofuels, energy efficiency, R&D, etc. where hydrogen and fuel cells relate in significant ways.

There are several factors driving the specific language in Titles VII and VIII, in addition to the "purposes" noted above, the Act was to:

- Provide long term stability in Federal law for the hydrogen and fuel cell programs authorized in 1990 and 1996, EPAct 05 is built on the President's Hydrogen Fuel Initiative (HIF) from 2003, which is a five year program with 2015 and 2020 goals — a program designed only through 2008 and funded year-by-year through the appropriations process that is inherently unstable over the long run, when industry partnerships need quite the opposite: reliability and staying power.

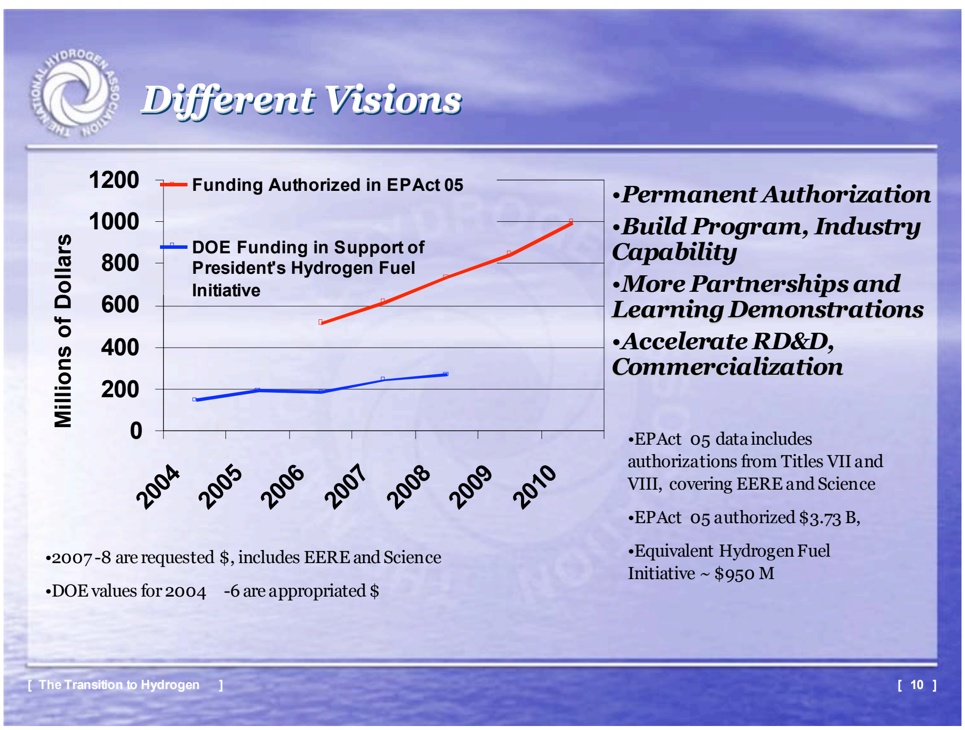
- The Federal government needs to become a more reliable partner with industry in its cofunded "learning demonstrations" — tests of integrated hydrogen supply and vehicle systems that validate technical concepts and help redesign these systems as well as refine the next stage of R&D.

- DoE needs more resources to accelerate and broaden its RD&D programs.

- Since the Federal government is the largest user of energy in the U.S., it is required to use its purchasing power as a transition to market for advanced hydrogen and fuel cell technologies — adopting these technologies early to replace older devices providing similar services — stationary, portable, and micro power from fuel cells, fork lift trucks, auxiliary power units and shuttle buses — then eventually to eventually buses, light duty and service vehicles.

In summary, EPACt 05 offers a wide range of actions for the DoE to take in addressing coal and hydrogen. Some very important policy guidance is laid out, although historically the Executive Branch does not always request in its annual budgets all the funding that is authorized by Congress. What the DOE views as being the most important under their overall budget constraints is being funded, although many of the above provisions are not. Some of this reflects budget deficit concerns, or policy disagreements with the Congress (a full budget and policy analysis is beyond the scope of this study).

Different Visions As an example, the following graph shows how differently the Administration and Congress view the hydrogen RD&D programs. "Different Visions" contrasts the President's HFI requested and appropriated funding levels with the authorized funding from Titles VII and VII of the EPAct 05 — which nearly quadruples the resources available to the Secretary, but the Administration has not requested funding at near these levels.



The lower curve on the graph shows a commitment to essential R&D, with some "learning demonstrations" and no transition to market, even though the Act is very clear on its purpose to drive toward commercialization. It is on the same funding track established in 2003. Replacing the President's HFI with a more ambitious program funded at four times its original level would create more valuable technology solutions more rapidly, and set hydrogen and fuel cell technologies well on their way to commercialization. R&D by itself does not accomplish this. The strategies represented in the two funding curves are very different. The Congress clearly feels that the upper curve would be more successful.

Although the President's Fiscal Year 2008 Budget Request announced on February 5, 2007, is at its highest level for hydrogen and fuel cells in the past five years, at $272.5 M, it only funds 36.8% of the EPAct's $739.5 M. This approach, which sidesteps Congressional guidance, will accomplish key R&D, but leaves the next administration to grapple with the policy and budget disconnects.

End Notes

1. A wide variety of reference sources were consulted for an overview of hydrogen's role in a hydrogen economy — including:

- *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs,* National Academy of Sciences, 2004 (NAS)
- *The Hydrogen Economy*, Jeremy Rifkin, Penguin, 2003
- *Hydrogen Posture Plan,* DoE, February 2004 (HPP)
- *Winning the Oil End Game,* Amory Lovins et al, Rocky Mountain Institute, 2004 (RMI)
- *National Hydrogen Energy Roadmap*, U.S. Department of Energy (DoE), November 2002 (H2ER)
- *Hydrogen from Coal Program,* Research, Development and Demonstration Program, DoE, 2006
- *Energy Policy Act of 2005, Public Law 109-58,* August, 2005 (including the long series of hearings and conferences held in 2002-2005 in the U.S. Congress on coal, R&D, hydrogen, climate and greenhouse gases, especially before the House Science and

Energy and Commerce Committees, and the Senate Energy and Natural Resources, and Environment and Public Works Committees)

- *Assessing Progress in Advanced Technologies for Vehicles and Fuels,* Jerome Hinkle, testimony before the Science Committee of the U.S. House of Representatives, June 2006

- *Coal: America's Energy Future*; Chapter 5, Coal to Hydrogen; National Coal Council, March 2006 (at the request of the Secretary of Energy)

- *Hydrogen Highlights: What's in the Energy Policy Act of 2005?* U.S. Senate, Hydrogen and Fuel Cell Caucus briefing: Jerome Hinkle, Office of Senator Byron Dorgan (Cochairman); Kathryn Clay, Energy and Natural Resources Committee; Steve Chalk, DoE ; Robert Rose, US Fuel Cell Council; Debbi Smith, National Hydrogen Association. Energy and Natural Resources Committee, September 15, 2005

- Numerous other briefings with Senate staff, industry and its associations: House Science Committee, 9/21/05; Senate Science and Technology Caucus 12/5/05; *Hydrogen Summit,* University of North Dakota, 11/15/05; New York Power Authority, 12/5/05; National Hydrogen Association international conference, Long Beach, CA, 3/13/06; Electric Drive Transportation Association international conference, 11/29/06; Hydrogen Technology Advisory Committee, DoE, 1/10/07; House Hydrogen and Fuel Cell Caucus, 1/29/07.

2. Energy Information Administration, *Annual Energy Outlook 2006,* 2007; *International Energy Annual 2006.* Extensive historical data and forecasts on coal are available from EIA at www.eia.doe.gov . Net petroleum imports represent the balance of all imported and exported crude oil and petroleum products (gasolines, jet fuel, heating oil, etc.).

3. *Coal to Hydrogen—Challenges and Opportunities:* a policy, economic and technology survey report done for the Center on Energy and Economic Development by the National Hydrogen Association, (forthcoming) February 2007.

4. *Hydrogen and Fuel Cell Technology Act of 2005, S. 665,* introduced in the U.S. Senate, March 2005 (original cosponsors were Senators Byron Dorgan, Lindsey Graham and Daniel Akaka), which served as the core of the hydrogen language for the Energy Policy Act of 2005, Public Law 109-58

5. In the *Hydrogen Posture Plan,* the DOE estimates of carbon emissions from throughout the hydrogen fuel production cycle assume a declining share coming from natural gas, with transition to effectively zero carbon sources by 2050. As building a hydrogen economy depends upon solving many technical and market challenges, capturing and storing or sequestering carbon from hydrocarbons and other reforming/gasification processes must also see considerable successful RD&D. In mid-January 2007 DoE issued an updated HPP, but the 2004 version makes the more useful points for our discussion.

6. *Well-to-wheels* analysis shows the energy flows throughout a particular fuel cycle from raw material/feedstock (eg, coal, biomass) through conversion to a fuel (gasoline or ethanol) or energy carrier (electricity or hydrogen) and utilization in a drive train (internal combustion engine, electric drive) to deliver motion. A large body of influential work has been done for DoE over 1991-2006 by teams of analysts at General Motors and Argonne National Laboratory (with BP, Shell and ExxonMobil) – see www.transportation.anl.gov . This analytical framework is also used to track the flow of carbon from different feedstocks, as well as the economics. Similar work on net energy flows and economics for synthetic fuels from coal and oil shale was done in 1976-78 for the Energy Research and Development Administration, *Synthetic Liquid Fuels Development: Assessment of Critical Factor,* ERDA 76-129/1-4, Stanford Research Institute, Hinkle, et al (1976-78).

   Amory Lovins (www.rmi.org), in his team's imaginative report *Winning the Oil End Game: Innovations for Profit, Jobs and Security* (2005) (www.oilendgame.com) also reminds us that only about 1.3% of the energy embodied in the fuel in an average ICE LDV actually is used to propel the payload — leaving considerable room for technical improvement, cost savings and shrinkage in the transportation sector's carbon footprint and fuel consumption.

7. Characteristic of advanced technologies, DoE appears to assume a rather high conversion efficiency and low impact for their average coal-to-hydrogen plants in the *HPP* scenarios — 7.8 tons of coal input for each ton of hydrogen output— thereby reducing feedstock cost and the amount of coal mined and transported, while shrinking the overall carbon footprint. In summarizing a review of coal-to-hydrogen plant configurations from a diverse body of literature in (3), coal-to-hydrogen ratios vary between 6.0 and 28.4, with an average of 11.9 for "off-the shelf" technologies and 9.3 for "future technologies". This is a function of many variables, including the evolution of the technology, energy content of the coal, inherent conversion efficiency, proportions of coproduced electricity and hydrogen, etc. DoE has likely chosen for the *HPP* a future technology IGCC plant with CCS, using a coal of around 12,000 BTU/lb and coproducing some electricity.

8. The National Coal Council, in an appendix *Economic Benefits of Coal Conversion Investments,* estimates that about 8.6 Mt/y of hydrogen are needed to satisfy about 10-20% of U.S. LDV demand by 2030. This amounts to about 1.21 Quads of energy in the form of hydrogen. When estimating the amount of coal needed, however, there may be some mistake in the calculation or a typographical error — the implicit conversion efficiency for coal-to-hydrogen from Figure 4.4 is 82%, far higher than the 50% in Table 4.2. From the individual plant specifications in Figure 4.4, we believe they intended to use a plant configuration like the 'Mitretek 2002 Configuration No. 9' ((3) — see the chapters on technology), which coproduces electricity and 153 Mmscfd H2/d, has a conversion efficiency of 56.5% and uses 6000 t/d (not 3014 t/d) of bituminous coal — resulting in 16.26 M t coal used for each 1 M t of hydrogen. Hence, 8.6 M tons of hydrogen would require not 70 Mt/y of coal as the NCC states, but 140 Mt.

9. *Hydrogen Demand, Production, and Cost by Region to 2050,* Center for Transportation Research, Argonne National Laboratory and TA Engineering for DoE, August 2005.

10. *President's Hydrogen Fuel Initiative*: announced in the State of the Union message of January 2003, it committed $1.2 B over Fiscal Years 2004-2008 to an expanded RD&D program in DOE.

11. *Hydrogen and Electric Utilities,* Hydrogen Utility Group: briefing for the U.S. Senate Hydrogen and Fuel Cell Caucus, February 12, 2006.

12. The ANL study team somewhat downplays the substantial lignite reserves in North Dakota and completely in Texas. Extensive analysis on gasification of these coals for hydrogen production has been done, and the plant configurations are in our technology chapter. Currently, the largest and oldest gasification plant in the world is in North Dakota, supplying pipeline quality synthetic natural gas commercially since 1982. It is also the source of the CO2 that is sold to the Encana miscible flood enhanced oil recovery (EOR) project at Weyburn, Saskatchewan — the world's largest geologic carbon sequestration project.

13. The DoE loan guarantee program is the first offered since the late 1970s, and entails a considerable learning effort by the government and industry. Without a Federal budget appropriation for the expected value of the contingent liability of the government to cover potential loan defaults, the applicant is to negotiate a prepayment of the loan subsidy cost as a cost of the loan. The loan application process does not specify a method for calculating this loan subsidy cost, nor does it indicate how or when the applications will be evaluated. Funding issues include managing the program and resolving the subsidy costs, hopefully settled in the 110th Congress. The first round of loan guarantees is much a work in progress, which should aid in preparing any succeeding rounds. Proposed language in

the Joint Resolution on the Fiscal Year 2007 Federal budget (1/29/07) will define detailed administrative and oversight mechanisms to remedy these shortcomings.

14. The super giant Elk Hills oil field west of Bakersfield, CA, is the 2nd largest oil field in CA and 4th in the lower 48 states, producing 43% of the natural gas from CA during 1999- 2005. Until 1998, it was owned by the Federal government and managed by the Office of Naval Petroleum and Oil Shale Reserves in DoE. In preparation for its sale at auction in 1997, an extensive upside development plan was done by the DoE and Bechtel Petroleum Operations, in conjunction with the investment banker, Credit Suisse/Petrie Parkman. Substantial tertiary EOR reserves were indicated if a cheap source of CO_2 were to be found. Breakeven costs were about $16-$18/b for CO_2 injection projects (without CO_2 costs), but oil was only about $12-$13/b at the time and such unproven reserves added no value to the sale price. The oil is still there. Unlike much natural gas in Wyoming, which is often coproduced with upwards of 80% naturally occurring CO_2 (piped northeast and south to EOR projects), Elk Hills gas averages about 5% CO, making the methane easier to separate and disposal costs minimal. There are no sizable combustion sources of cheap CO_2 within many miles of Elk Hills, which otherwise offers some interesting siting and EOR possibilities, as well as partially depleted reservoirs.

15. Federal authorizing language that launched exploratory work in hydrogen for transportation and distributed generation dates back to 1974. The first definitive hydrogen act was the *Spark M. Matsunaga Hydrogen Research, Development and Demonstration Act of 1990* (P.L. 101-566). Title VIII of the EPACt 05 is also named after Senator Matsunaga. Early efforts to explore hydrogen in automotive use were guided by the Alternative Automotive Power Systems Division of the U.S. Environmental Protection Agency in 1974 (eventually becoming the automotive program in DoE), while the National Aeronautics and Space Administration (NASA) sponsored the *Hydrogen Energy Systems Technology* study in 1975-6.

16. Private sector energy R&D has declined nearly 75% since 1985, when it peaked at $4 B ($2002). This is often explained by short run competitive forces that seek to drive costs out of the development and product cycles. See Kammen and Nemet, "Reversing the Incredible Shrinking Energy R&D Budget", in *Issues in Science and Technology*, Fall 2005, pp 84-88.

17. A new study on the life cycle environmental and cost aspects of different fossil feedstocks has been done for DoE's National Energy Technology Laboratory by Research and Development Solutions, LLC (forthcoming, March 2007). Several scenarios evaluate the "well-to-tank" portion of the fuel cycle, to compare the manufacture and delivery pathways of H_2 supplied to fueling stations located in generic urban areas. This work is a notable contribution to knowledge about life cycle effects, and should enable

more careful comparison of siting and regulatory challenges across various methods of making H2 from fossil sources, including natural gas and coal.

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18. Several people reviewed and commented on parts of this report:

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