REGIONAL MARKETS FOR FUTUREGEN PRODUCTS

Final Report

April 2005

Prepared for:

The West Virginia Development Office

Prepared by:
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MARSHALL UNIVERSITY
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EXECUTIVE SUMMARY

The proposed FutureGen facility is a demonstration plant whose primary purpose is to successfully separate carbon from coal, capture that carbon in the form of carbon dioxide and store it. In so doing, the facility will produce hydrogen. This hydrogen will be used to generate clean electricity and if produced in a pure form can be used for industrial purposes or in vehicles.

Due to its exploratory design, FutureGen must leverage both public and private resources to cover its construction and operating costs. Some of the key goals of this facility are associated with highly uncertain cost and performance characteristics; foremost among these is carbon sequestration. Operating characteristics assumed are thus informed estimates of what may be achieved.

In terms of daily operating costs, FutureGen is likely to require only a modest subsidy for electricity production if it achieves favorable reliability and consistent sales. This subsidy is estimated at about $735,000 per year (about one mill per kWh). Including fixed costs or the full cost of electricity in the evaluation increases the estimated subsidy to about $22 million per year (about 23 mills per kWh).

Diverting plant energy to production of pure hydrogen for use in vehicles will require a larger operating subsidy in the absence of a market for hydrogen during the demonstration. Diversion of five percent of energy output would produce about six tons of hydrogen a day, enough to fuel up to 30 vehicles a year. If maximized, FutureGen could produce up to 100 tons a day or more of pure hydrogen. However, at this level of production the required operating subsidy would be considerably large due to reduced electricity sales.

There is no question of demand for electricity produced from this facility if sited in West Virginia. Demand for electricity in the U.S. is growing and will continue to do so. The demand for hydrogen for vehicular or industrial use however is uncertain. Industrial users have real-time experience in use of hydrogen and that sector is currently the only significant producer and consumer of the gas. Demand for hydrogen by the transportation sector is subject to a number of factors that indicate it is still a fuel of the future. For distributed use in general, infrastructure cost and availability will remain prohibitive for some time.

The operating specifications for FutureGen are based on engineering estimates of what will be achieved as the facility establishes the capability to sequester carbon and to produce hydrogen. Until demonstration occurs, the actual characteristics of a facility of this type will not be known. FutureGen will be an important facility for promoting the growth of a hydrogen economy by contributing to experience in production of hydrogen. In a hydrogen economy the importance of a single FutureGen facility in that overall economy will be small. In the meantime, FutureGen can provide valuable information on the process of producing electricity with minimal to zero impact on air quality.

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INTRODUCTION

The massive quantities available for mining in the U.S. and an established infrastructure to deliver it cause coal to be the fuel with the greatest potential to satisfy domestic energy needs for the foreseeable future. Despite accelerated introduction of alternative energy technologies and breakthroughs in development of these technologies, coal will continue to play a large role in producing electricity and fueling industrial boilers. Coal reserves in West Virginia, and the quality of that coal, place the state in a prime position to continue its national role as a major supplier.

Coal also has the potential to be a source of liquid and gaseous fuel for transportation and industry. Hydrogen is one of those possible fuels. The following National Research Council statement is a strong indicator of the potential role of coal in hydrogen production.

> *"The United States has enough coal to make all of the hydrogen that the economy will need for more than 200 years."*[1]

This fact does come with a qualifier. Coal is an option best suited for large-scale hydrogen production. According to the Council:

> *"Coal is a viable option for making hydrogen in very large, centralized plants when the demand for hydrogen becomes large enough to support an associated very large distribution system."*[2]

FutureGen is a Presidential initiative for a project to demonstrate the capability to produce clean power and hydrogen from coal, while capturing and sequestering carbon dioxide. Announced in 2003, the project is defined to be a contributor to achievement of our nation's energy goals by burning hydrogen for power with near-zero emissions produced from an abundant domestic resource, and by contributing to hydrogen production capability.[3] The proposed plant will be a demonstration facility designed to establish the technical and economic feasibility of these processes. The public-private partnership that is FutureGen will be led by an industrial consortium of coal companies and utilities. It is this consortium that will make the construction and operating decisions for this facility, in cooperation with the U.S. Department of Energy.

Hydrogen is considered an ideal energy source not only because of its high heat content, but also because its combustion emits only heat and water. Hydrogen has the highest energy content per unit weight of any known fuel at 104 mmbtu/ton.[4] This heat

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[1] National Research Council, "The Hydrogen Economy: Opportunities, Cost, Barriers and R&D Needs," 2004, p. 93.

[2] Ibid.

[3] FutureGen Program Plan, U.S. Department of Energy, Office of Fossil Energy, March 2004.

[4] National Hydrogen Association FAQs, http://www.hydrogenus.com/h2-FAQ.asp, November 18, 2004.

content is four to five times that of coal. Hydrogen offers hope that our future energy needs can be met without emitting any pollutants, without relying on imported sources of energy, and ultimately without burning fossil fuels.

This paper describes a process for synthesizing hydrogen from coal and a potential magnitude of products that could result from that process. It lays a foundation for a wide-range of analyses of the potential impacts of siting FutureGen in the state of West Virginia.

Carbon Sequestration

West Virginia is an ideal site location for FutureGen due to the project's most prominently defined goal, that of carbon sequestration. Geologically, West Virginia may be the state that is best suited for underground storage of captured carbon. According to its program plan, FutureGen "will provide a unique real-world opportunity to prove the feasibility of large-scale carbon sequestration."[5] Carbon is currently an unregulated emission, but a strong multinational movement to curb its release has been evidenced in response to threats of climate change. As of this date, no consensus has been reached as to what level of carbon emissions is acceptable or how to achieve a reduced level of emissions. There is, however, little doubt that such reductions will be mandated at some point in the future.

The societal benefit of reducing carbon emissions and a decision to capture this benefit are factors that will distinguish the FutureGen facility from other clean coal power plants in operation today. But without a framework that defines the playing field for carbon emissions, it is highly unlikely that the private sector would undertake this project as it is currently envisioned.

"Emissions-free" electricity from coal would be a debut event in the U.S. and possibly the world. Not only would the FutureGen project demonstrate this, but it would also help meet growing demand for electricity, is a vital part of the U.S. economy. The Energy Information Administration has projected that by 2025 an additional 87 gigawatts (GW) of coal-fired power capacity will have been constructed to meet growth in demand for electricity.[6]

Hydrogen Production

Because hydrogen in a pure state does not occur in nature, it must be synthesized. The capability to produce hydrogen from coal exists with current technology, but at a considerable cost. The fact that U.S. industry has not yet meaningfully used this route for producing hydrogen suggests that it is not economical, and that the time when it can

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[5] FutureGen Program Plan, U.S. Department of Energy, Office of Fossil Energy, March 2004.

[6] Energy Information Administration, Annual Energy Outlook 2005, p. 88. This number was revised down from the EIA's 2004 projection of 112 GW.

compete with existing methods of production and other fuels has not yet arrived. This paper describes operating conditions under which coproduction of electricity and hydrogen from coal could be competitive with existing methods and fuels.

FutureGen is likely to begin operation in about 2015, and is expected to operate as a demonstration facility for three to five years. It could however have a life of up to 60 years, as is not uncommon for power plants. This life expectancy could carry its production capability well into the time period when hydrogen is hoped to impact our energy economy more substantially. As this paper aims to show, while producing pure hydrogen may not initially prove cost effective, and will require subsidization, the ability to increase production and decrease costs could be developed. This flexibility could be an important attribute of the facility. Until then, FutureGen can produce electricity with near-zero emissions with what could be considered a modest subsidy.

Plant Operation

The FutureGen facility is likely to be an Integrated Gasification Combined-Cycle (IGCC) electricity plant that produces a synthesis gas (syngas) derived from coal combined with a hydrogen production unit. Coal will not be burned as it is in ordinary steam turbine plants but will instead be gasified. The gasification occurs as coal is reacted with steam and oxygen at very high temperatures. The resulting syngas, which is about 33% hydrogen, is then partially cleaned of carbon and other impurities and sent to the hydrogen purification unit. Isolation of pure hydrogen from coal syngas is likely to require, at a minimum, the following additional units, which will operate on internally produced electricity:

1. CO shift unit (reacts CO and water to produce H_2 and CO_2)
2. CO_2 removal unit (sequestration)
3. Pressure swing adsorption (PSA) unit (a molecular sieve that further purifies the H_2 for industrial or transportation uses)

With the goal of total carbon sequestration all electricity produced at the facility will be produced post sequestration, and the source of power would be a combination of pure hydrogen and the tailgas from the PSA unit, which would have a hydrogen content of approximately 66%[7] (additional gas is CO). Units 1 and 2 will be used regardless of whether industrial or transportation fuel-grade hydrogen is produced in addition to electric power. If only power is produced, additional purification of the syngas may not be required because contrary to other hydrogen consuming industries such as fuel cells for transportation, which require pure hydrogen to operate, electricity production does not require pure hydrogen gas. The amount of CO shift and CO_2 removal will depend on the goals set for the FutureGen facility, which will be operated to meet that targeted level of removal.

[7] Conversation with David Gray of Mitretek, October 13, 2004. Actual hydrogen content of PSA tailgas will vary depending on the degree of CO shift. Multiple stages of shift would be required to convert all CO. With no production of pure hydrogen the syngas may have lower hydrogen content.

The additional steps required to fully separate hydrogen from the other elements found in the syngas produced from the gasification process are also not necessary for efficient production of electricity. This could provide electricity production with a substantial cost advantage over production of pure hydrogen.

This paper evaluates production of hydrogen and electricity as coproducts, and shows that in terms of operating costs electricity production is most viable. Synthesis of fuel-grade hydrogen is likely to require an operating subsidy in the absence of a market for the element in its purity. Although commercial demand for hydrogen for distributed use is nascent, regionally it is dependent on several factors that indicate it will not develop significantly by the time the FutureGen demonstration begins. Due to these conditions, this paper has evaluated the commercial use of hydrogen in established industrial processes as the most likely consumer of any hydrogen produced from FutureGen outside of a demonstration. It is up to the Administration and the Department of Energy to decide to what level they wish to support hydrogen produced at this facility for demonstration in vehicles.

The remainder of the current document is organized as follows – Section 2 provides a general description of methodologies. Section 3 provides the study team's scenario for electricity generation and hydrogen production. Sections 4 and 5 consider the possible expansion of use of hydrogen as a chemical feedstock and vehicle fuel. Finally, study conclusions and suggestions for additional research are provided in Section 6.

2. METHODOLOGY

A model FutureGen facility has been constructed to estimate a potential set of outputs. Electricity and hydrogen are treated as coproducts and projected supply is calculated as that which is achievable in terms of operating profits, which both include and exclude the capital investment. Electricity capacity is taken as specified from project literature.[8] Hydrogen capacity is based on current engineering analysis for comparable facilities.[9]

This analysis evaluates the production possibilities of such a facility as a base for assessing the impacts on regional markets for coal, electricity, producers of hydrogen-based chemicals and alternative fuels for transportation. Comparing the potential variable costs and revenues of this facility provides an evaluation of the production decision, or the dispatch decision for electricity generation, which is independent of fixed costs. Comparing total costs provides an estimate of the cost of electricity (COE), the industry standard for evaluating projects of this type.

It is recognized that the operation of FutureGen will provide additional research capabilities that contribute to greater efficiencies and operational proficiency for IGCCs as well as develop experience in sequestration and hydrogen production. Thus, the facility specifications are based on realistic observations of what is likely to be achieved while expanding this expertise. Assumptions used to construct this analysis are listed below, and are modeled in more detail in appendices A (total production costs) and B (operating costs only).

- *Coal consumption* – The 275 MW facility is assumed to have a base coal consumption of 1,173 tons per day based on the equation below. This corresponds with an annual electricity production of 963,600 MWh and zero production of pure hydrogen. It is assumed that the plant will operate at a 50 percent capacity factor, below the current state average for coal-fired power plants.[10] A 20% efficiency penalty is subtracted from this to account for steam required to support the water shift reaction in sequestration. Coal conversion efficiency is 40 percent, lower than the theoretical efficiency feasible for an IGCC but higher than what is often achieved by IGCCs in operation today.[11] Coal consumption is static for the range of pure hydrogen produced. Energy output is deducted accordingly. If an oversized gasifier was installed, consumption would rise based on the level of hydrogen production.

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[8] FutureGen Program Plan.

[9] Mitretek Technical Paper, "Hydrogen From Coal," D. Gray and G. Tomlinson, November 2001.

[10] Energy Information Administration, State Electricity Profiles 2002.

[11] Michael Mudd of American Electric Power and Frank Burke of Consolidated Energy recommended a 40% efficiency specification and a 50% C.F. in regards to plant output achievable during the demonstration period.

$$\text{Tons of coal per day} = \frac{(275\,MW)(50\%)(8760\,hours)(3{,}412\,btu/kWh)}{(40\%)(24\ \text{mmbtu/ton coal})(1000)(365\ \text{days})}$$

- *Hydrogen production* – The rate of hydrogen production is conservatively assumed to be 50,000 scf/ton coal, which falls in the lower range of potential production levels estimated for such a facility.[12] Production capability is approximately 100 tons per day with the plant as designed. Utilizing an oversized gasifier, capability could be as high as 400 tons/day (151 mmscf/day) in alignment with engineering estimates for an investment of this magnitude.[13]

- *Energy to hydrogen for sale* – Calculated as a simple percentage of total MWh produced. This energy diversion has been modeled in increments of five percentages points up to 40% of 963,600 MWh.

- *Hydrogen Power needs* - Hydrogen production itself is electricity intensive. Production of 153 mmscf/day of hydrogen could require about 126 MW of electric power.[14] Parasitic power requirements from other non-hydrogen specific units could also impact this estimate.[15] Instead of applying this parasitic power requirement, the 20% efficiency loss described above was applied to energy output. Parasitic power requirements from the gasifier and the air separation unit are already factored into the plant's base capability.[16]

- *Electricity production* – Power not used for hydrogen production is available for sale to the grid. As shown, production declines as production of fuel-grade hydrogen increases. In reality, the IGCC unit may not be able to achieve the assumed 50% level of reliability. Conversely, in the absence of reliability issues it is likely that plant operators would run the IGCC as much as possible in order to benefit from its very high efficiency.

- *Electricity Sales* – The wholesale price of electricity is assumed to be \$0.032/kWh (32 mills/kWh). Because electricity is a regulated industry in West Virginia, the sale price of electricity is very closely linked to the price of coal.[17] This rate was

[12] National Research Council, 2004, Table E-10. Estimated production potential ranges from about 27,000 to 131,000 scf hydrogen/ton coal.

[13] Mitretek, 2001.

[14] Mitretek Technical Paper, 2001.

[15] P. Chiesa, S. Consonni, T. Kreutz, and R. Williams. "Co-production of hydrogen, electricity and CO2 from coal with commercially ready technology. Part A: Performance and emissions. *International Journal of Hydrogen Energy*, 2004, p. 14. In this study, electric power for auxiliaries, including the air separation unit and the coal gasifier, are estimated to require one percent of input coal LHV.

[16] Michael Mudd, Corporate Technology Development, American Electric Power, March 15, 2005.

[17] This relationship was evaluated using cointegration analysis and elasticity estimates between both industrial and commercial electricity prices and coal prices. It is impossible to reject a hypothesis of unit

calculated based on observed prices for coal and wholesale power in the state and forecasted prices for coal.

- *O&M Costs* – A variable operating cost of $9/MWh is assumed.[18] Because energy output is modeled as constant for varying levels of fuel-grade hydrogen produced, this cost also does not vary. Operating costs may actually be lower for the IGCC portion of the facility than assumed here or higher for the hydrogen producing portion of the plant, which could contribute to cost non-linearity as production of fuel-grade hydrogen increases. Adding fixed operation and maintenance costs increases annual costs by about $78/KW.[19]

- *Coal Cost* – The delivered price of coal used is based on long-term projections and is modeled at $25/ton plus $7/ton for transport.[20]

- *CO_2 Disposal Costs* – Carbon dioxide is estimated to cost $8.18 per ton to dispose of.[21] This cost is lower than that assumed by other studies including that by the National Research Council[22].[23] The California Public Utilities Commission recently directed the state's largest electric utilities to include CO_2 costs between $8-25 per ton when evaluating the economics of future energy resource additions.[24] This cost is a crucial component of facility operation. If the actual cost is higher, electricity sales will have greater difficulty offsetting this cost and a larger operating subsidy may be required even in the absence of energy diversion for hydrogen production.

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elasticity between these two variables from 1990-2002. Thus, if coal prices vary, so too will electricity prices, in roughly the same proportion (though there will inevitably be lags to this effect).

[18] Electric Power Research Institute, "Cost Comparison IGCC and Advanced Coal," Roundtable on Deploying Advanced Clean Coal Plants, July 29, 2004.

[19] Ibid.

[20] The Energy Information Administration's 2005 Annual Energy Outlook forecasts average delivered coal prices to electric utilities to be $24.42/short ton in 2015. West Virginia prices to utilities are typically $5 to $6 above the national average.

[21] Timothy Lawrence Johnson, "Electricity Without Carbon Dioxide: Assessing the Role of Carbon Capture and Sequestration in U.S. Electric Markets," July 2002.

[22] National Research Council, 2004. This study estimates CO2 capture and disposal costs at $37/ton.

[23] T. Kreutz, R. Williams, S. Consonni and P. Chiesa. "Co-production of hydrogen, electricity and CO2 from coal with commercially ready technology. Part B: Economic analysis, *International Journal of Hydrogen Energy*, 2004, p. 12. This study estimates CO2 capture + disposal costs at $16.9/tonne to $23.6/tonne.

[24] As reported by The Carbon Sequestration Newsletter, National Energy Technology Laboratory, March 2005.

- *Operating Subsidy required* – The difference between total operating costs: Fixed O&M + Variable O&M (or just Variable) + coal costs + CO_2 disposal costs and electricity sales. With electricity production as the sole product, operating loss is $735,748 indicating a required subsidy of this amount. With diversion of five percent of energy produced the subsidy is $2,277,508, indicating a much higher financial loss. This amount will continue to rise as more energy is diverted to hydrogen. When including fixed costs in the subsidy the annual operating loss for electricity production is about $22 million and increases in increments of about $1.5 million a year for each five percent of energy diverted to hydrogen production. Appendices A and B show calculated subsidies for diversion of up to 40% of energy for pure hydrogen production.

- *Number of Hydrogen vehicles filled* – This assumes each vehicle travels 12,000 miles per year and achieves 65 mpg equivalent, thus consuming 185 kg of hydrogen each year.

- *Tons CO2 produced* – Calculated at 71 X 3.7 tons per 100 tons of coal.[25] The facility is likely to produce and sequester about 1.1 million tons of CO2 per year.

These assumptions are either consistent with the findings from the best available research or more conservative when estimates are drawn from less tested sources. It is important to keep in mind that we model the facility as commencing operation in 2015, so deviations from currently observed conditions in prices or costs are expected.

[25] This is consistent with the National Research Council's assumed carbon content of coal. "The Hydrogen Economy" pages 85 and 87.

3. POWER GENERATION FROM COAL-PRODUCED HYDROGEN

If electricity is the sole product of the FutureGen facility the cost of electricity will be about 5.5 cents/kWh, inclusive of capital repayment, thus requiring a subsidy of about 2.3 cents/kWh with a wholesale price of 3.2 cents/kWh. However, if pure hydrogen is produced a larger operating subsidy is likely to be required as it is assumed that no distributed commercial market for hydrogen will exist during demonstration.

FutureGen and the underlying IGCC equipment have the potential to be a highly efficient plant and would most likely be used as a base load plant because of relatively low dispatch costs. However, because of its demonstration status and the nature of employing an emerging technology, the reliability of this facility will be intermittent, and its efficiency will not initially be much better than ordinary steam turbines. Operation of FutureGen will contribute toward more advanced IGCC technology in a number of areas including improved feed systems, refractories and gas cooling and clean up.

The benefits of coproduction are illustrated by the following estimated break-even electricity prices and levels of production. Table 1 lists costs inclusive of capital costs while Table 2 looks only at daily production costs. The break-even price for electricity, or cost of electricity, is slightly lower than calculated in some studies [26] but comparable to others.[27] The hydrogen production levels shown here are less than half of facility capability. If more hydrogen were produced its break-even price would continue to fall.

Table 1. Sample Electricity and Hydrogen Outputs - Total Production Costs

Annual Electricity Output (MWh)	*Daily Hydrogen Output (Tons)*	*Break-Even Hydrogen Price ($/per mmbtu)*	*Break-Even Hydrogen Price ($/per Ton)*	*Break-Even Electricity Price ($/per KWh)*
963,600	0	--	--	0.055
915,420	6	100.15	10,458	0.058
867,240	12	53.33	5,569	0.061
819,060	19	37.72	3,939	0.065
770,880	25	29.92	3,124	0.069
722,700	31	25.24	2,635	0.073
674,520	37	22.11	2,309	0.079
626,340	44	19.89	2,076	0.085
578,160	50	18.21	1,902	0.092

[26] T. Kreutz et al, p. 8. This study estimates production costs for a facility that produces only electricity and captures CO2 to be between 6.05 cents/kWh and 6.77 cents/kWh, depending on the brand of generating equipment purchased and the method of syngas cooling employed.

[27] Timothy Lawrence Johnson, "Electricity Without Carbon Dioxide."

Table 2 shows that FutureGen facility may come close to breaking even in terms of daily costs and revenues if electricity is its sole product. With no pure hydrogen production, the plant could break even at a relatively low electricity price of 33 mills/kWh. With diversion of about five percent of plant energy output toward production of six tons of fuel grade hydrogen for industrial or transportation uses, the plant is likely to require an operating subsidy to recover costs of production, even without accounting for capital costs.

Table 2. Sample Electricity and Hydrogen Outputs - Operating Costs Only

Annual Electricity Output (MWh)	***Daily Hydrogen Output (Tons)***	***Break-Even Hydrogen Price ($/per mmbtu)***	***Break-Even Hydrogen Price ($/per Ton)***	***Break-Even Electricity Price ($/per KWh)***
963,600	0	--	--	0.033
915,420	6	9.61	1,004	0.034
867,240	12	8.06	842	0.036
819,060	19	7.54	788	0.039
770,880	25	7.28	761	0.041
722,700	31	7.13	744	0.044
674,520	37	7.03	734	0.047
626,340	44	6.95	726	0.050
578,160	50	6.90	720	0.055

Source: Study Team Calculations

In this model, as the quantity of hydrogen produced increases its break-even selling price decreases, indicating development of some economies of scale. It is likely that production efficiencies will emerge as hydrogen production increases, especially as operating experience develops, that would improve these economies. However, it is uncertain when a market for the larger quantities of hydrogen will exist at any price, or how long it will take to develop a proficiency in use of this technology.

The full models used to construct these two summary tables are attached as Appendixes A and B.

<u>The West Virginia Electricity Industry</u>

Evaluation of FutureGen as an electricity producer is similar to the process of siting a new power plant. Factors include the plant's contribution to meeting net internal demand and reserve margins required by the system operator, and the ability to obtain a power purchase agreement. American Electric Power (AEP), the largest producer and transmitter of electric power in the region, has stated that it will soon require additional capacity to meet its customer base and announced in 2004 that it is planning to build a new IGCC plant within its territory.[28] In early 2005, AEP announced three possible West Virginia locations for a new plant and said that the decision of where to build its first IGCC would be made in June of 2005.[29] This new plant will employ the same technology likely to be used in a FutureGen facility, but will not sequester carbon.

During the time period under consideration, it is possible that the status of utility regulation in West Virginia could change, which would impact prices. In a fully deregulated environment, retail electricity prices would be set competitively instead of being based on cost. The recently deregulated wholesale markets have already caused changes in regional electricity markets. Most new power capacity built in West Virginia since 1990 is natural gas-fired and located on the western side of the state.[30] These facilities operate on gas turbines designed to provide peak power production and dispatch to the peak-load hours of the day in response to the higher prices received at those hours. In the long-run, the FutureGen facility would not have to compete with these facilities as its potential efficiency will place it as a base-load plant in terms of its dispatch profile.

That fact that West Virginia has a regulated retail electricity market is a potential incentive for locating power plants in the state. Regulation ensures that the potential to experience stranded costs does not exist and is thus not a deterrent to investment. As long as retail markets are regulated, plant owners can be assured that lower-cost electricity producers will not entice away their customer base, leaving its facilities with diminished revenues that will not cover capital expenditures.

Existing West Virginia power plants are depicted in Figure 1. Appendix B lists the plants names by county, fuel type and generating capacity.

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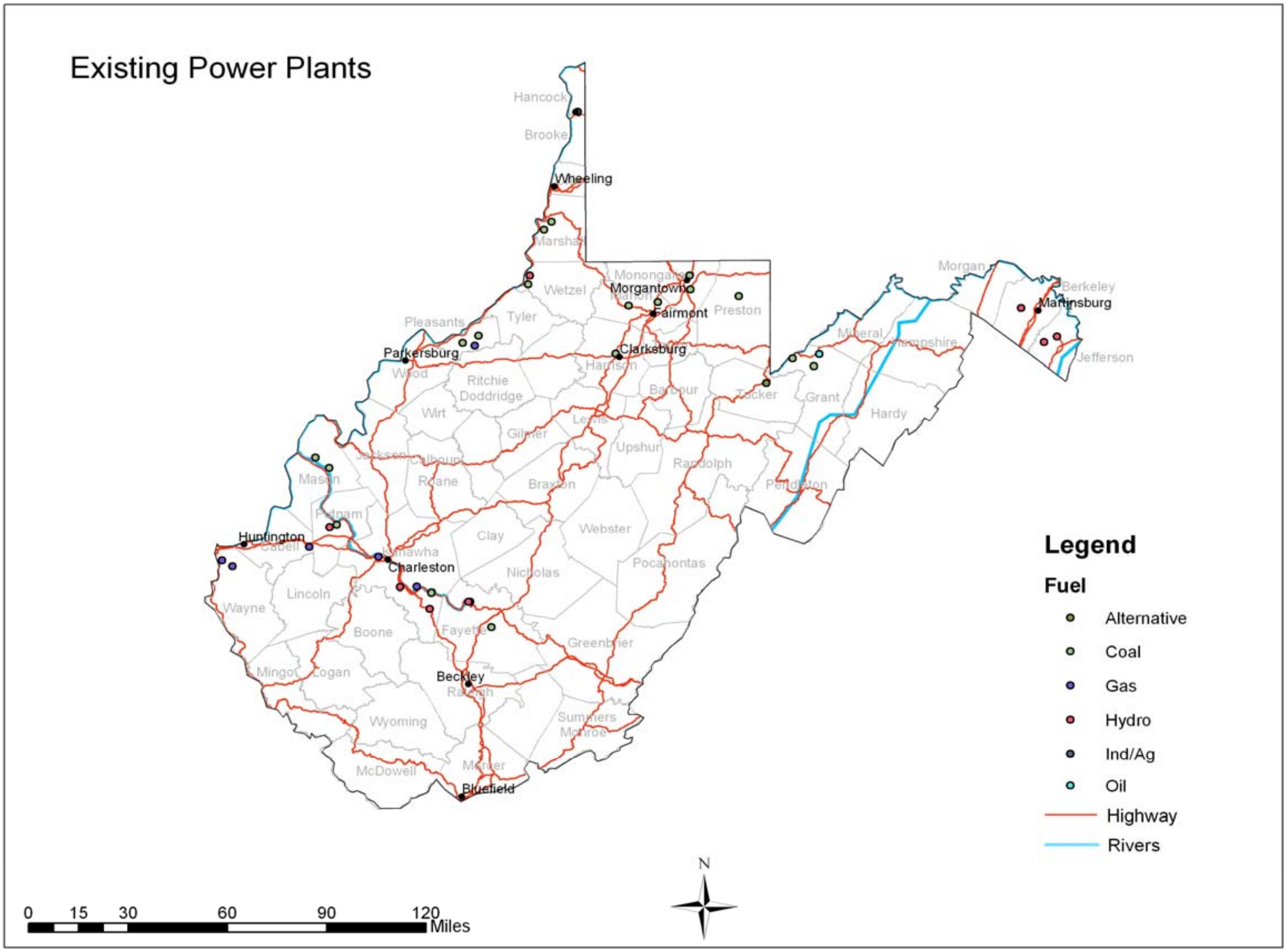
[28] http://www.aep.com/newsroom/, November 19, 2004.

[29] The State Journal (February 4, 2005), "State Makes Pitch for $1.6 Billion Clean-Coal Plant," p9.

[30] Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," 2004.

Figure 1. Existing Power Plants
(Source Data: Energy Information Administration, "Annual Electric Generator Report," 2004)



Electric Power Capacity

A FutureGen facility, with a power capacity of 275 MW, would increase the state's total power capacity by almost two percent. No coal-fired plants of this size have been built in the state since the early 1980s. Only three coal-fired plants have been built in West Virginia in the last 20 years, and all operate on waste coal. The Morgantown Energy Facility (50 MW) entered service in 1991 and the North Branch (74 MW) and Grant Town (80 MW) have been in service since 1992.[31] Another waste coal plant, the Western Greenbrier Co-Generating facility, is planned.[32] A recently permitted 600 MW plant in the Morgantown area will be the first built in the state since the early 1980s that is designed to operate on non-waste coal.

In 1993, West Virginia had the lowest coal-fired capacity utilization of any state in the surrounding area. As shown in Table 2 below, West Virginia now has a capacity utilization of about 72% for its coal fired plants, the highest of any in the area. This change is an indicator of the ability for West Virginia plants to take advantage of relatively low generation costs, and of new opportunities for independent power producers to own and market power in the recently deregulated wholesale markets, a condition that could also benefit FutureGen as a merchant plant. Continued and sustained increases in capacity utilization will increase competition in power generation and the need for more base-load plants.

Table 3. State Capacity Utilization Factors for Coal-Fired Generation Capacity[33]

	WV	PA	VA	OH	KY	MD
1993	**56%**	66%	66%	61%	66%	61%
1997	**69%**	70%	62%	63%	71%	67%
2002	**72%**	71%	71%	67%	67%	67%

Electricity Generation

The growing demand for electricity will ensure a market for power produced from FutureGen. West Virginia is in a unique position since 70% of electricity produced in the state is exported.[34] Power is sent to neighboring states both inside and outside the East Central Area Reliability Council (ECAR) in which West Virginia resides. Demand for power from WV-based plants is thus heavily subject to demand outside of the state.

The neighboring regions into which West Virginia exports power (See Figure 2) include the Southeastern Electric Reliability Council (SERC) and the Mid-Atlantic Area Council (MAAC). As shown in Figure 3, demand for electricity in the ECAR and MAAC

[31] Energy Information Administration, "Annual Electric Generator Report," 2004.

[32] National Energy Technology Laboratory, www.netl.doe.gov/publications/factsheets/project/Proj223.pdf

[33] Energy Information Administration, State Electricity Profiles 2002.

[34] Ibid.

regions is expected to grow by about 1.5 percent a year through 2025. Demand in the SERC region is expected to grow slightly faster. By the time the FutureGen facility comes online in about 2015, an additional 15-20% more electricity will be demanded in these regions, with the highest growth expected in the states of Georgia, Alabama and Louisiana.[35]

Figure 2. Connecting Electricity Reliability Regions[36]

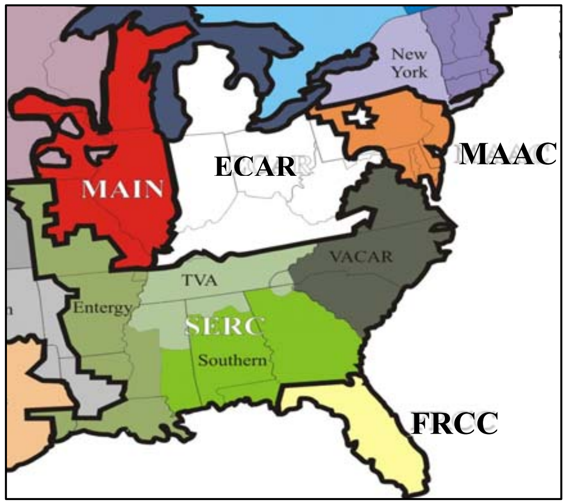
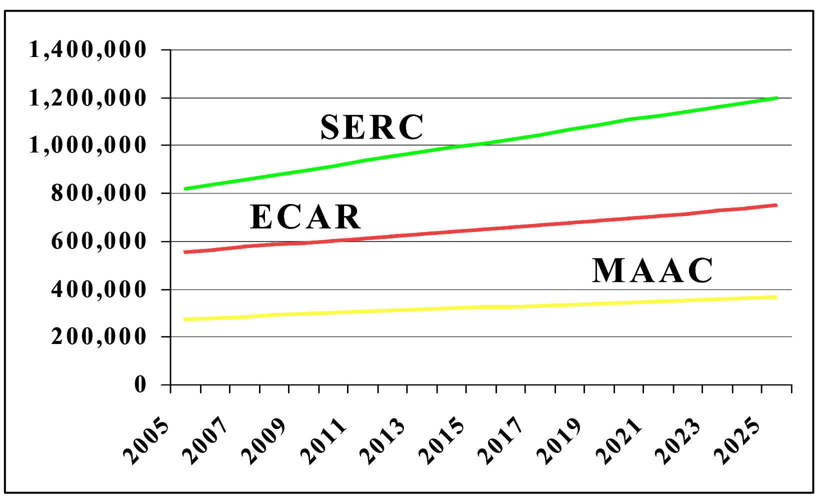


Figure 3. Forecasted Regional Electricity Demand (GWh)[37]



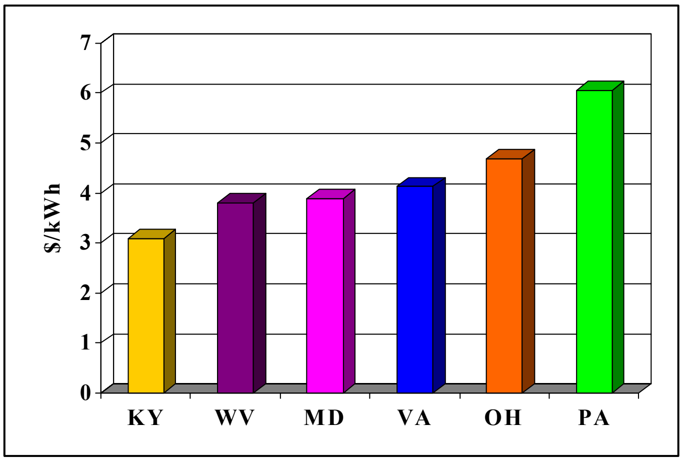
[35] North American Reliability Council, http://www.nerc.com, October 14, 2004.

[36] Ibid.

[37] Energy Information Administration, AEO2004 National Energy Modeling System.

As discussed, the sale price of electricity is an important determinant of the break-even prices for electricity and hydrogen produced from FutureGen. West Virginia has relatively low electricity generating costs compared to neighboring states. The following comparison of industrial electricity prices shows West Virginia prices very similar to those in Maryland and second to lowest in the region (see Figure 4). Low prices may negatively impact the ability to sell higher cost electricity into the local market, but positively impact the ability to sell into neighboring deregulated markets that have higher retail prices.

Figure 4. Industrial Electricity Prices for Selected States, 2002[38]



Both the MAAC and SERC regions are at least partly deregulated. West Virginia sells power into the deregulated retail markets in Ohio, Pennsylvania and Virginia. At present, there may be more opportunity for increased transmission into MAAC because of its ability to realize cost benefits from importing cheaper power and exporting its own more costly power to the Northeastern U.S. Conditions such as this, combined with the sales price of electricity will determine the demand for new plants and the decision to build FutureGen in West Virginia.

Hydrogen as a Peak Power Fuel

Hydrogen could potentially also be used as a substitute for natural gas in peak load plants operating on gas turbines. However, the costs of transporting the hydrogen to those facilities and storing it will further reduce its ability to compete with pipeline-transported natural gas.[39] At less than $5/mmbtu, hydrogen could be competitive as a substitute for natural gas as delivered natural gas prices to electric power generators are projected to be on average below $5/mmbtu through 2025.[40] Given the incremental costs of producing hydrogen this sort of transaction is not likely until the long-run.

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[38] Energy Information Administration, State Electricity Profiles 2002.

[39] The National Research Council estimates hydrogen dispensing and distribution costs to be greater than or equal to $5/mmbtu even assuming technological advancement in storage R&D. See p. 144 of "The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs."

[40] Energy Information Administration, Annual Energy Outlook 2004.

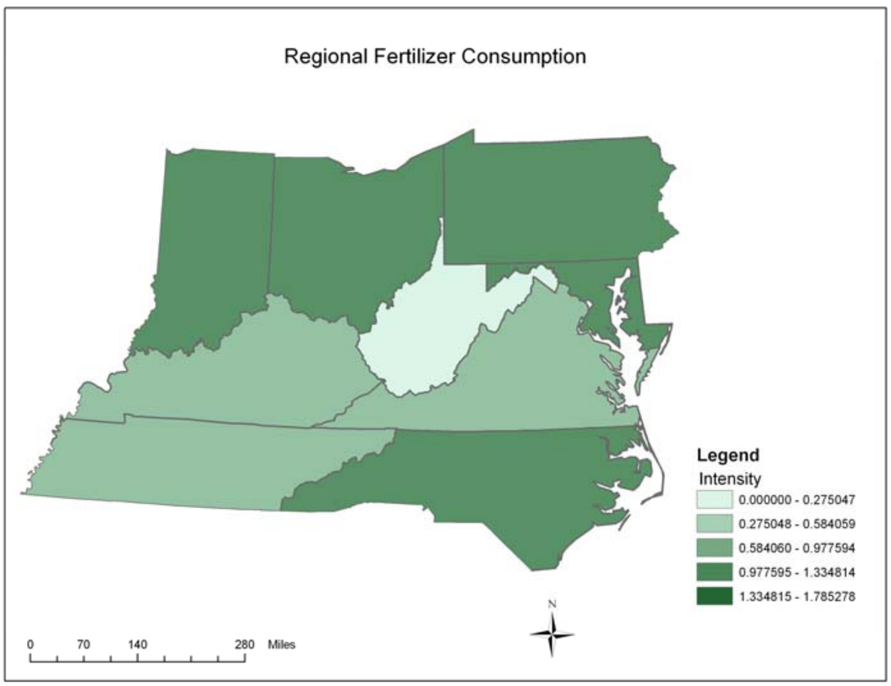
4. HYDROGEN AS A CHEMICAL FEEDSTOCK

Current and Potential Market Quantities

Hydrogen is used as a feedstock material within a variety of chemical manufacturing processes in the study region. In the vast majority of the cases it is manufactured on-site, often by an outside vendor. Nationally, between two-thirds and three-quarters of all hydrogen usage is in the manufacture of fertilizer materials.[41] Hydrogen is combined with nitrogen to yield anhydrous ammonia (NH_3), a basic material that can be applied directly as a fertilizer or converted to other forms of nitrogen fertilizer.

Overall fertilizer consumption intensity within the study region is depicted in Figure 6.[42] Intensity is measured as a fixed-effects parameter that ranks average fertilizer use per agricultural worker. This figure represents fertilizer intensity during the 1939 to 1996 time period, and shows that a WV-based FutureGen facility would be in good proximity to several states with relatively high intensities.

Figure 5. Regional Fertilizer Consumption



From a spatial perspective, regional usage of ammonia-based fertilizers or of hydrogen as a feedstock in other chemical manufacturing processes is largely ubiquitous.

41 National Hydrogen Association FAQs, http://www.hydrogenus.com/h2-FAQ.asp, November 22, 2004.

42 The study region is based on trucking distances of 225 miles from a hypothetical plant location at Parkersburg, West Virginia

The manufacture of anhydrous ammonia is concentrated in four locations in Pennsylania, Ohio, and Indiana that are also located at largely equidistant intervals within the region. Again, the direct production of hydrogen is generally on-site.[43]

There is little data describing the quantities of direct hydrogen usage within the study region. However, using transportation data from the Surface Transportation Board and the federal Office of Freight Management, the study team estimates that the regional usage of anhydrous ammonia, either in direct applications or as an intermediate fertilizer product, is approximately 560,000 tons per year.[44]

Currently, most anhydrous ammonia production uses natural gas as a feedstock. This has been true since the 1950s. Other feedstocks such as naphtha, oil and, ironically, gasified coal have also been used, with coal having been the primary feedstock for ammonia production prior to the 1940s. In 2003, natural gas was reported to account for 65 to 90% of nitrogen fertilizer production costs.[45] The fact that domestic natural gas prices have roughly tripled in the past five years has caused a decline in domestic nitrogen fertilizer production through both idling and closure of capacity.[46] This has pushed production to locations outside the U.S. where natural gas prices are more favorable and, in 2001, increased imports of nitrogen by about 43%.[47]

Pricing and Revenues from Hydrogen Sales

The estimates provided of daily hydrogen production quantities and associated per-unit production costs show volumes ranging between 6 and 50 tons per day and production costs ranging between $10,458 and $1,902 per ton respectively, inclusive of capital repayment. These levels were reported as Table 1 in Section 3 of this report, and only show the lower range of what is achievable by this facility.

At low to modest levels of FutureGen hydrogen production, up to about 12 tons, the break-even price for daily hydrogen output is more than current delivered natural gas. Even at higher levels of production and lower break-even prices, these prices may not offset the expected costs of transporting the hydrogen to a distributed fertilizer manufacturer. At a daily hydrogen output of six tons, the breakeven price for one ton of

[43] This phenomenon is directly attributable to the high cost of storing and transporting hydrogen.

[44] Rail movements were estimated directly through the Surface Transportation Board's confidential *Carload Waybill Sample* for 2001. Truck movements were based on a combination of the Waybill Sample and data from the Office of Freight Management's *Freight Analysis Framework*.

[45] The Star Phoenix, February 7, 2003, the Associated Press State & Local Wire, June 21, 2003 and the Western Farm Press, March 20, 2004 reported 65%, 80%, and 90% respectively.

[46] Gas Daily, October 13, 2003, citing the U.S. GAO. In 2001, record-high gas prices led to a 25% reduction in domestic fertilizer production.

[47] Foster Natural Gas Report, October 16, 2003.

hydrogen is also more than the cost of the natural gas necessary to manufacture one ton of anhydrous ammonia (33,500 c.f. at $7.00 per thousand cubic feet).[48] Accordingly, at these costs of production there is doubt that a single FutureGen facility could commercially dispose of hydrogen within the fertilizer market, which comprises the bulk of current hydrogen consumption in the region, in spite of its proximity to producing plants**.**

As noted, because hydrogen is extremely expensive to store or transport and because of uncertainties regarding the development of such an infrastructure, the current analysis assumes that any resulting hydrogen output would be used to produce a more manageable material at a facility co-located with the FutureGen operation. Given the probable downstream use in the production of fertilizer products, it is very conceivable that the hydrogen would be used on-site to produce anhydrous ammonia. In any case, an ammonia-based scenario is representative of what might be achievable.

In terms of weight, anhydrous ammonia production requires about one part hydrogen per five parts nitrogen.[49] In terms of regional consumption this is equivalent to about 112,000 tons of hydrogen per year. As a feedstock, natural gas provides both elements. It would, however, be possible to substitute hydrogen produced via a FutureGen facility for that produced from natural gas if the price of natural gas is sufficiently high to warrant this one-to-one substitution. Fixed nitrogen prices (in the form of ammonia) production levels and net import amounts are provided in Table 5, and show that using hydrogen produced at a FutureGen facility as an input would not be competitive at current prices.

The analysis to this point assumes the prices for hydrogen, natural gas, and anhydrous ammonia to be exogenous. At low levels of hydrogen production from a single FutureGen facility, this assumption would appear reasonable. For example, when directing 40% of facility energy output to hydrogen for sale (hydrogen output of 50 tons per day) the facility could replace a little more than three percent of regional anhydrous ammonia production, or 16% of its hydrogen content. It is, however, clear that higher levels of hydrogen production from a single FutureGen facility, or even low levels of production from multiple facilities, could yield a volume of hydrogen that is sufficiently large so as to affect the prices of downstream products.[50] Unfortunately, within the context of the current analysis, there is no ability to estimate the magnitude of these potential price effects.

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[48] See "Why Are Nitrogen Prices So High," Samuel Roberts Noble Foundation, Ardmore, OK, 2004.

[49] Actual ratio: 6 pounds H_2 + 28 pounds N = 34 pounds NH_3. SOURCE: Personal interview with Dr. Gary D. Anderson, Professor, Department of Chemistry, Marshall University, November 10, 2004.

[50] As previously noted, the facility as specified could produce up to 100 tons or more of pure hydrogen a day, or up to 400 tons a day using an oversized gasifier.

Table 5. Domestic Fixed Nitrogen (in the form of Ammonia) Production, Consumption, Prices and Import Quantities

Year	*Real Price (Per Ton $98)*	*Production (Millions of Tons)*	*Consumption (Millions of Tons)*	*Imports / Carry Over (Millions of Tons)*	*Percent Imports / Carry Over*
1950	69.8	1.2	1.2	0.0	0.0%
1951	72.5	1.3	1.3	0.0	0.0%
1952	73.4	1.5	1.5	0.0	0.0%
1953	78.8	1.7	1.7	0.0	0.0%
1954	78.8	2.0	2.0	0.0	0.0%
1955	77.0	2.4	2.4	0.0	0.0%
1956	68.0	2.5	2.5	0.0	0.0%
1957	76.1	2.8	2.7	-0.1	-3.7%
1958	76.1	2.9	2.8	-0.1	-3.6%
1959	77.9	3.4	3.3	-0.1	-3.0%
1960	83.4	3.6	3.5	-0.1	-2.9%
1961	83.4	3.9	3.8	-0.1	-2.6%
1962	83.4	4.3	4.3	0.0	0.0%
1963	83.4	5.0	4.9	-0.1	-2.0%
1964	83.4	5.7	5.7	0.0	0.0%
1965	83.4	6.6	6.6	0.0	0.0%
1966	83.4	7.9	8.0	0.1	1.3%
1967	76.1	9.1	8.2	-0.9	-11.0%
1968	68.9	9.0	8.9	-0.1	-1.1%
1969	45.3	9.5	9.2	-0.3	-3.3%
1970	51.7	10.3	9.9	-0.4	-4.0%
1971	50.7	10.9	10.7	-0.2	-1.9%
1972	54.4	11.3	11.2	-0.1	-0.9%
1973	70.2	11.3	11.5	0.2	1.7%
1974	156.0	11.7	11.6	-0.1	-0.9%
1975	168.0	12.2	11.9	-0.3	-2.5%
1976	168.0	12.5	12.5	0.0	0.0%
1977	118.0	13.2	13.4	0.2	1.5%
1978	74.3	12.8	13.8	1.0	7.2%
1979	118.0	13.9	14.9	1.0	6.7%
1980	111.0	14.7	16.0	1.3	8.1%
1981	120.0	14.2	14.9	0.7	4.7%
1982	106.0	11.8	12.8	1.0	7.8%
1983	161.0	10.2	12.4	2.2	17.7%
1984	131.0	12.5	14.4	1.9	13.2%
1985	150.0	12.9	14.0	1.1	7.9%
1986	65.2	10.8	12.4	1.6	12.9%
1987	94.7	12.0	13.8	1.8	13.0%
1988	133.0	12.5	14.7	2.2	15.0%
1989	78.8	12.3	14.9	2.6	17.4%
1990	106.0	12.7	14.9	2.2	14.8%
1991	106.0	12.8	14.8	2.0	13.5%
1992	139.0	13.4	14.6	1.2	8.2%
1993	131.0	12.6	15.0	2.4	16.0%
1994	235.0	13.3	16.4	3.1	18.9%
1995	197.0	13.0	15.3	2.3	15.0%
1996	217.0	13.4	16.2	2.8	17.3%
1997	118.0	13.3	16.4	3.1	18.9%
1998	88.9	13.8	14.1	0.3	2.1%
1999	98.9	12.9	16.3	3.4	20.9%
2000	209.0	11.8	14.9	3.1	20.8%
2001	183.0	9.5	13.5	4.0	29.6%
2002	151.0	10.8	15.2	4.4	28.9%

Source: US Geological Survey Publication 01-006, February 2004.

5. HYDROGEN FOR USE IN ALTERNATIVE FUEL VEHICLES

Demand for Alternative Fuel Vehicles

The application of hydrogen as a transportation fuel has been analyzed by a small number of scholars and by the National Research Council's Hydrogen Economy study.[51] There is little consensus among these analyses as to the timing and magnitude of the widespread use of alternative fuel vehicles (AFVs), and even less consensus regarding the use of hydrogen in AFVs. This is not surprising given the high degree of uncertainty regarding factors that influence demand for AFVs and on the relative cost of the new technologies. Furthermore, the rate of development of the necessary fueling network has enjoyed no significant empirical analysis. There is, however, considerable enthusiasm that these and related technologies may play an important role in both public and private transportation in the coming decades.

In order to analyze this potential we began with a model of AFV demand. The reduced form model we have adopted represents a considerable advance over existing aggregate estimates of AFV use in the U.S.[52] The study team modeled historical AFV use in each of the 48 conterminous states from 1997 through 2002 employing the EIA estimates of AFV utilization in each state. The study estimated the per capita adoption of these vehicles as a function of state and federal gasoline taxes, the proportion of each state's population in urban areas, the real per capita income in urban areas, the state level real price of natural gas, the real price of West Texas crude petroleum, the presence of state level tax incentives for the purchase of AFVs and a correction for spatial autocorrelation. The study modeled this in a time series cross sectional model with a fixed effects intercept for each state. The fixed effects intercept captures the non-time varying characteristics in each state. The results of this model appear in Table 6.

Table 6. The AFV Per Capita Model Results

Dependent Variable: AFVs Per Capita
Sample: 1997 2002
Total panel observations: 289

Variable	Coefficient	Std. Error	t-Statistic	Prob.
Real Federal and State Gas Tax	0.005864	0.000860	6.820099	0.0000
State share of Metropolitan Population	0.006033	0.003675	1.641800	0.1020
Metropolitan Incomes	7.16E-08	8.41E-09	8.519464	0.0000
Spatial Autocorrelation	0.764095	0.055057	13.87822	0.0000
Real State Natural Gas Prices	-2.96E-05	5.93E-06	-4.986696	0.0000
Real Oil Price	1.15E-05	1.80E-06	6.370342	0.0000
Tax Incentive Dummy	0.000133	3.21E-05	4.152926	0.0000

R-squared	0.930409	**Mean dependent var**	0.004423
Adjusted R-squared	0.913982	**S.D. dependent var**	0.004100
S.E. of regression	0.001202	**Sum squared resid**	0.000337
F-statistic	519.1875	**Durbin-Watson stat**	1.757362
Prob(F-statistic)	0.000000		

[51] National Research Council, "The Hydrogen Economy," Chapter 6.

[52] See Mokhtarian and Cao, 2003, and the Appendices for a review of these studies.

This model performs very well in its diagnostic tests, and explains an unusually large proportion of per capita AFV use. Importantly, gasoline taxes and prices are both positively correlated with AFV use, a finding that conforms to theory. Higher rates of population living in metropolitan areas and higher incomes in these regions are also strongly correlated with per capita AFV use. This is not surprising. Also, real natural gas prices in each state are negatively correlated with the adoption of AFVs. These findings are more extensive than the existing literature and explain more of the AFV levels in each state. We also find that there is a strong spatial component to AFV use, and that the rate in a state is highly correlated with the rates in adjoining states. Finally, we find a statistically strong correlation between state level tax incentives (typically rebates) for AFVs and the rate of adoption in states.

Since hydrogen-fueled vehicles currently represent a very small percentage of overall AFVs, and because hydrogen prices are a poor reflection of the cost of fuel cell vehicles or other hydrogen-fueled vehicles, we did not incorporate the price of hydrogen as a variable in this model. Also, since there are temporal correlations between hydrogen and natural gas and petroleum, statistical inaccuracies can arise from including too many of these variables in the model.

These results clearly portray the economic considerations surrounding the use of AFVs in recent years, and while the rate of adoption could change dramatically in the coming years, the possibility that AFVs will present themselves as a potential market for hydrogen during the early years of the FutureGen project is highly remote. This conclusion bears some quantification.

West Virginia's AFV tax incentives explain roughly 16.5 percent of the state's total AFVs, making this feature an important contributor to overall AFV use. However, this has resulted in roughly 175 additional AFVs operating in the State in 2002. Also, the approximate doubling of the real petroleum price that we have experienced since 2002 will have motivated roughly 40 consumers to purchase AFVs in the state.

There is considerably more research necessary regarding AFVs and the hydrogen economy. However, for the purpose of providing a market for hydrogen produced by the FutureGen plant, it is clear that, even assuming all new AFVs in the region are powered by hydrogen, demand from motorists in the Ohio River valley will not be sufficient to impact production decisions from a FutureGen facility well into its life-cycle.

FutureGen could, with a subsidy, produce enough fuel-grade hydrogen to power up to 30 vehicles per year or more. This assumes each vehicle will consume 185 kilograms of hydrogen in a year. Although demand for this type of fuel will not be commercial, as a source of fuel for demonstration of hydrogen vehicles this facility can produce an ample supply.

Status of Hydrogen-Fueled Vehicles

The supply of hydrogen-capable vehicles will have a large influence in establishing the demand for this type of AFV. Currently, polymer electrolyte membrane (PEM) fuel cells operating on hydrogen and hydrogen internal combustion engines (ICEs) both have the potential to power the next generation of AFVs. A potential commercialization date for both technologies is sometime in the 2012-2015 timeframe, depending on R&D success. Through its FreedomCAR & Fuels Partnership, the U.S. Department of Energy has set an aggressive R&D schedule through 2010, following which a commercialization decision can be made if technology goals are achieved.[53]

The operation of these vehicles to date is primarily through proprietary research and learning demonstrations with public and private partners. Consortia such as the California Fuel Partnership are coordinating performance testing of the technologies in vehicle systems. The vehicles tested in these demonstrations are one-of-a-kind and hand-built. They will be tested for a number of attributes including efficiency, durability, range and acceleration.

Until hydrogen-fueled AFVs can compete with current vehicles in terms of performance and costs, they will not impact the market for vehicles and thus the market for hydrogen. Both fuel cell and ICE technologies also require an established hydrogen storage and transport infrastructure in order to achieve significant market penetration. Hydrogen ICEs may have a long-term benefit over fuel cells due to their ability to power heavy-duty vehicles, a capability that is currently not viable for fuel cells. It is the sum of these things that will allow these vehicles to capture the transportation market.

[53] DOE Office of Hydrogen, Fuel Cells and Infrastructure Technology Multi-Year Research, Development, and Demonstration Plan, http://www.eere.energy.gov/hydrogenandfuelcells/fuel_cells.html.

6. CONCLUSIONS AND RECOMMENDED FUTURE RESEARCH

Study Findings

Of the three possible hydrogen products of a FutureGen facility, electricity is the most viable. If FutureGen operates at a 50% rate of availability and a 40% coal conversion efficiency, a modest subsidy may be all that is required. However, when a portion of power is diverted to produce pure hydrogen operating costs will begin to greatly exceed revenue from electricity sales and a larger subsidy will be required.

There is no question of the demand for electricity produced from this plant. The market for hydrogen, however, is uncertain. As a commercial plant, coproduction of electricity and hydrogen could greatly improve the economics of the FutureGen facility, especially prior to development of a full-scale hydrogen economy. Sale of electricity can offset the production costs of hydrogen while proficiency in its production is developed.

Hydrogen is used regionally as a feedstock in the manufacture of chemicals, where it is typically produced on-site. Once costs decline, to the extent that a FutureGen facility marginally increases overall hydrogen production, its outputs could be absorbed by existing markets and actually benefit regional production costs in most years. However, any savings from the substitution of hydrogen for natural gas within the fertilizer manufacturing process are likely to be dissolved after transport and storage costs are added, unless the hydrogen is used by a co-located manufacturer. Moreover, such a market substitutability may only economical if production increases to the levels associated with higher daily hydrogen outputs and if natural gas prices remain high.

Demand for hydrogen as a transportation fuel has not yet developed. At the national level, hydrogen fuel for transportation is still in the basic research stage of development in terms of fuel storage and the original equipment manufacturers can initiate commercialization no sooner than 2015. At the regional level, such a fuel may be less viable relative than at the national level due to below-average rates of adoption of AFVs.

The capture and disposal of carbon will add a significant cost, yet there are many potential benefits to undertaking such a facility. The operational experience of this plant will help lower the costs of hydrogen production from coal as well as electricity produced from IGCCs by improving the overall reliability of IGCCs and actual plant efficiencies. Continued refinement of IGCC technology would strengthen U.S. leadership in this emerging technology, which could increase exports of IGCC equipment and services.

Overall, demand for isolated hydrogen does not exist at the production quantities of which a coal-based plant is capable. When such a market does develop, coal can meet very large levels of demand. The production capability of a FutureGen plant would allow flexibility to increase its output of hydrogen in the event that market conditions spurred a fuel substitution and if the associated infrastructure developed rapidly.

Future Research

There are still many questions to be answered about how a FutureGen facility could operate. Multiple scenarios could be constructed based on sensitivity analyses that would provide more detailed indicators regarding the products of a FutureGen facility. These areas of analyses fall into several categories of analysis: regional, engineering, regulatory, market and fiscal policy. Engineering issues are many and could be combined with market and regulatory analyses to provide more robust simulations of the plant.

Regional Analysis:

1) An analysis examining the economic impacts of locating the FutureGen plant in West Virginia could estimate the macroeconomic impact of such a facility on the state. This would involve siting the plant and calculating potential impacts to the surrounding area in terms of employment and investment.

2) A nationwide location analysis could provide comparative results of regional variation in terms of current and expected demand for hydrogen products.

3) The adoption of new fuel technologies by consumers is highly dependent on distribution networks. The speed and regional formation of new fuel distribution networks will be a critical research issue for the adoption of alternative fueled vehicles for consumers and fleets.

Market Analysis:

1) On the industrial hydrogen side, a more in-depth analysis of the scale of the market for hydrogen for use in production of ammonia would provide details about how the higher levels of output would alter the regional market. This would entail looking more closely at the true substitutability of pure hydrogen for that produced by steam reforming natural gas as well as evaluating the option of co-locating an ammonia producer with FutureGen.

2) On the transportation side, an evaluation of co-producing Fischer-Tropsch diesel instead of hydrogen would provide a look at an alternative coal-based fuel that may be capable of serving the vehicle market earlier than could hydrogen. This would include an in-depth investigation of Fischer-Tropsch producing facilities and application to local infrastructure. Carbon sequestration would be considered part of the process here as well.

3) Co-production of peak power could also be added to this model, most likely as a long-term product following progress in hydrogen storage R&D.

Regulatory:

1) Under a traditional financing scheme and using current technology, FutureGen may need to sell its electricity at higher prices in order to produce hydrogen at costs competitive with natural gas. A more in-depth analysis of West Virginia's power market, including examination of the status of deregulation, could provide a better understanding of the potential impact of the FutureGen facility on the electricity market in West Virginia and surrounding regions. This would include an analysis of the transmission system and West Virginia's participation in regional powerpools. These conditions will strongly influence the rate at which electricity can be sold in 2015 and beyond and thus the viability of FutureGen.

2) A more full understanding of the external costs of carbon (including sequestered carbon) would better guide future regulatory policy in this area. This analysis would be tied in with the engineering reviews of the advantages of sequestering in West Virginia.

Fiscal Policy:

1) Federal policy covering the regulation of carbon emissions would have a major impact on FutureGen. A review of the status of those debates and application of policy recommendations to this setting would provide an indicator of how potential decisions would alter the carbon sequestration component of facility operations.

2) A complementary report on carbon regulation could include a review of other coal to hydrogen facilities in the world and the status of their sequestration projects, if any.

3) The potential use of more extensive state and federal fiscal policy to motivate alternative fueled vehicle use would be an important adjunct to the current analysis, and guide policy debate on future fuel choices.

4) State level incentives that motivate carbon sequestration and hydrogen production may also be considered as an important feature of the viability of non-demonstration plants.

Appendix A: Total Production Costs

Assumptions:	Coal $/Ton $	32.00	Electricity C.F.	0.5
	$/kWh $	0.032	Coal mmbtu/ton	24
Electricity Production Efficiency:			tons C/coal =	0.71
40%			CO2 Cost/ton	$8.18
IGCC Variable Operating Costs:		kg/yr H2/vehicle	185	
$ 9.000	$/MWh	H2 Prod Rate:	50,000	scf H2/ton coal
$ 20.26	per ton coal			

	All Electricity	5% H2	10% H2	15% H2	20% H2	25% H2	30% H2	35% H2	40% H2
tons/day coal	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173
mmscf/d H2	-	2	5	7	9	12	14	16	19
Tons H2/day	-	6	12	19	25	31	37	44	50
MW total cap	275	275	275	275	275	275	275	275	275
Percent of energy to H2 for sale	-	5%	10%	15%	20%	25%	30%	35%	40%
MWh reduction for H2 production	-	48,180	96,360	144,540	192,720	240,900	289,080	337,260	385,440
MWh (50% C.F with 20% energy loss)	963,600	915,420	867,240	819,060	770,880	722,700	674,520	626,340	578,160
Elec sales (annual)	$ 30,835,200	$ 29,293,440	$ 27,751,680	$ 26,209,920	$ 24,668,160	$ 23,126,400	$ 21,584,640	$ 20,042,880	$ 18,501,120
O&M ($9/MWh + $78/KW)	$ 30,122,400	$ 30,122,400	$ 30,122,400	$ 30,122,400	$ 30,122,400	$ 30,122,400	$ 30,122,400	$ 30,122,400	$ 30,122,400
Coal Cost (annual)	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180
CO2 Disposal Costs (100%)	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368
Total Operating Costs (annual)	$ 53,020,948	$ 53,020,948	$ 53,020,948	$ 53,020,948	$ 53,020,948	$ 53,020,948	$ 53,020,948	$ 53,020,948	$ 53,020,948
H2 Production Costs minus Elec Sales (annual)	$ 22,185,748	$ 23,727,508	$ 25,269,268	$ 26,811,028	$ 28,352,788	$ 29,894,548	$ 31,436,308	$ 32,978,068	$ 34,519,828
Break Even H2 sales P ($/mmbtu)	**NA**	**100.15**	**53.33**	**37.72**	**29.92**	**25.24**	**22.11**	**19.89**	**18.21**
Annual Operating Profit	$ (22,185,748)	$ (23,727,508)	$ (25,269,268)	$ (26,811,028)	$ (28,352,788)	$ (29,894,548)	$ (31,436,308)	$ (32,978,068)	$ (34,519,828)
Break Even H2 sales P ($/ton)	**NA**	**10,457.59**	**5,568.55**	**3,938.87**	**3,124.03**	**2,635.13**	**2,309.19**	**2,076.38**	**1,901.77**
Break Even Elec Price ($/kWh)	0.055	0.058	0.061	0.065	0.069	0.073	0.079	0.085	0.092
Annual Operating Subsidy Required	$ 22,185,748	$ 23,727,508	$ 25,269,268	$ 26,811,028	$ 28,352,788	$ 29,894,548	$ 31,436,308	$ 32,978,068	$ 34,519,828
# H2 vehicles filled (@ 65 mpg/12,000 mi/year)	-	30	61	91	122	152	183	213	244
Tons CO2 Produced	1,124,617	1,124,617	1,124,617	1,124,617	1,124,617	1,124,617	1,124,617	1,124,617	1,124,617
Hydrogen Tons	0	6	12	19	25	31	37	44	50

Appendix B: Operating Costs Only

Assumptions:	Coal $/Ton	$ 32.00	Electricity C.F.	0.5	
	$/kWh	$ 0.032	Coal mmbtu/ton	24	
Electricity Production Efficiency:			tons C/coal =	0.71	
40%			CO2 Cost/ton	$8.18	
IGCC Variable Operating Costs:		kg/yr H2/vehicle	185		
$	9.000 $/MWh	H2 Prod Rate:	50,000	scf H2/ton coal	
$	20.26 per ton coal				

	All Electricity	5% H2	10% H2	15% H2	20% H2	25% H2	30% H2	35% H2	40% H2
tons/day coal	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173	1,173
mmscf/d H2	-	2	5	7	9	12	14	16	19
Tons H2/day	-	6	12	19	25	31	37	44	50
MW total cap	275	275	275	275	275	275	275	275	275
Percent of energy to H2 for sale	-	5%	10%	15%	20%	25%	30%	35%	40%
MWh reduction for H2 production	-	48,180	96,360	144,540	192,720	240,900	289,080	337,260	385,440
MWh (50% C.F with 20% energy loss)	963,600	915,420	867,240	819,060	770,880	722,700	674,520	626,340	578,160
Elec sales (annual)	$ 30,835,200	$ 29,293,440	$ 27,751,680	$ 26,209,920	$ 24,668,160	$ 23,126,400	$ 21,584,640	$ 20,042,880	$ 18,501,120
VOM ($9/MWh)	$ 8,672,400	$ 8,672,400	$ 8,672,400	$ 8,672,400	$ 8,672,400	$ 8,672,400	$ 8,672,400	$ 8,672,400	$ 8,672,400
Coal Cost (annual)	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180	$ 13,699,180
CO2 Disposal Costs (100%)	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368	$ 9,199,368
Total Operating Costs (annual)	$ 31,570,948	$ 31,570,948	$ 31,570,948	$ 31,570,948	$ 31,570,948	$ 31,570,948	$ 31,570,948	$ 31,570,948	$ 31,570,948
H2 Production Costs minus Elec Sales (annual)	$ 735,748	$ 2,277,508	$ 3,819,268	$ 5,361,028	$ 6,902,788	$ 8,444,548	$ 9,986,308	$ 11,528,068	$ 13,069,828
Break Even H2 sales P ($/mmbtu)	**NA**	**9.61**	**8.06**	**7.54**	**7.28**	**7.13**	**7.03**	**6.95**	**6.90**
Annual Operating Profit	$ (735,748)	$ (2,277,508)	$ (3,819,268)	$ (5,361,028)	$ (6,902,788)	$ (8,444,548)	$ (9,986,308)	$ (11,528,068)	$ (13,069,828)
Break Even H2 sales P ($/ton)	**NA**	**1,003.78**	**841.65**	**787.60**	**760.58**	**744.36**	**733.56**	**725.84**	**720.04**
Break Even Elec Price ($/kWh)	0.033	0.034	0.036	0.039	0.041	0.044	0.047	0.050	0.055
Annual Operating Subsidy Required	$ 735,748	$ 2,277,508	$ 3,819,268	$ 5,361,028	$ 6,902,788	$ 8,444,548	$ 9,986,308	$ 11,528,068	$ 13,069,828
# H2 vehicles filled (@ 65 mpg/12,000 mi/year)	-	30	61	91	122	152	183	213	244
Tons CO2 Produced	1,124,617	1,124,617	1,124,617	1,124,617	1,124,617	1,124,617	1,124,617	1,124,617	1,124,617
Hydrogen Tons	0	6	12	19	25	31	37	44	50

Appendix C: Existing West Virginia Power Plants

Plant Name	*Fuel*	*Capacity (MW)*	*County*
Mountaineer Wind Energy Center	Wind	66	Tucker
Alloy Steam Station	Coal	37	Fayette
North Branch	Coal Gob	74	Grant
Mt Storm	Coal	1,569	Grant
Harrison Power Station	Coal	1,933	Harrison
Kanawha River	Coal	390	Kanawha
Grant Town Power Plant	Coal Gob	80	Marion
Rivesville	Coal	137	Marion
Mitchell	Coal	217	Marshall
Kammer	Coal	600	Marshall
PPG Natrium Plant	Coal	123	Marshall
Philip Sporn	Coal	1,020	Mason
Mountaineer	Coal Gob	1,300	Mason
Fort Martin Power Station	Coal	1,107	Monongalia
Morgantown Energy Facility	Coal	50	Monongalia
Willow Island	Coal	235	Pleasants
Pleasants Power Station	Coal	1,278	Pleasants
Albright	Coal	283	Preston
John E Amos	Coal	2,900	Putnam
Belle West Virginia Plant	Gas	2	Kanawha
Union Carbide South Charleston	Gas	6	Kanawha
Pleasants Energy LLC	Gas	292	Pleasants
Big Sandy Peaker Plant LLC	Gas	300	Wayne
Ceredo Generating Station	Gas	456	Wayne
Dam 5	Hydro	0.3	Berkeley
Hawks Nest Hydro	Hydro	97	Fayette
Glen Ferris Hydro	Hydro	4.4	Fayette
Millville	Hydro	0.8	Jefferson
Dam 4	Hydro	0.6	Jefferson
London	Hydro	13.8	Kanawha
Winfield	Hydro	16.4	Putnam
Marmet	Hydro	13.8	Kanawha
Covanta New Martinsville Energy	Hydro	31.6	Wetzel
Weirton Steel	Ind/Ag	95	Hancock
Mt Storm	Oil	12	Grant

Source: Energy Information Administration, “Annual Electric Generator Report,” 2004.

Appendix D: Cointegration of Energy Prices

Background

An understanding of the long-term relationship between the prices of energy sources is important in evaluating changes to consumption patterns. This is of special concern in an analysis in which inter-temporal substitution of energy sources comprises a concern regarding the fuel choice. It is also important in understanding the changes energy input costs play in the role of energy outputs. Here our concern, expressed in the assumptions in this market analysis, is the relationship between electricity and coal prices.

In the preceding analysis of electrical power generation and coal, we have employed a roughly 36 month lag between changes to the price of coal and resulting changes in electricity prices. This was the result of independent analysis presented in this appendix.

A Brief Review of Energy Relationships

Given the importance of energy prices to the economic performance of the United States it is unsurprising that a number of studies have advanced our understanding of the relationship between different fuels over time. One frequently cited study (Pindyck and Rotemberg, 1999) describes very long term mean reverting characteristics of fuel prices. His samples date from 1870 through the late 1990s. There are a number of additional models relating to long run prices using time series and structural models.

A relatively new approach has been to model the long-run relationship between prices as a cointegrating relationship. Cointegration modeling arose from Engle and Granger's [1987] observation of time series that that were non-stationary (or did not have a unit root). Non-stationary time series may be described as those which possess trends (or are not mean reverting). Examples of non-stationary time series are the nominal US GDP or population – both of which have tended to grow without reverting to a stationary mean. One observation provided by Engle and Granger [1987] is that a function combining two or more non-stationary time series may provide a third time series which is stationary. Under this condition it may be posited that the stationary time series generated through this process represents a condition of equilibrium. One timely example of this is that the relationship between coal and electricity prices might be a nearly constant value over time. The extension and application of Engle and Granger's work has seen considerable analysis in energy markets.

A financial study (Root and Lien; 2003) employs a threshold cointegration model, which suggests cointegration in prices for the same product in spot and future markets. Examples of cointegration studies of related products include a study of petroleum and refined product prices (Serlitis, 1994; and Girma and Paulson, 1994).

One criticism of pure cointegration analysis is that while a long term cointegration can be established, other factors (such as pure direction of causation) and a drifting spread may not be easily observed among the data. However, these models continue to be used to provide inference regarding long run prices. We do so here in a multi-step evaluation.

A Unit Root and Cointegration

In order for cointegration analysis to provide a useful tool the variables in question must not have a unit root. We test this relationship between coal and electricity prices obtained from the Energy Information Administration. We employ monthly prices for average electricity use (urban-nationwide) and coal prices for millions of BTUs. The electricity prices are from 1978 to the present, with coal dating from 1973. From these data we test for stationarity (or common unit root using three modestly different tests) and then for individual unit roots using the augmented Dickey-Fuller test. In all instances the rejection of a unit root (hence the presence of non-stationarity is suggested). Results appear in Table 1.

Table 1. Unit Root Tests of Logs of Electricity Prices and Coal Prices

Method	Statistic	Probability
Hadri Z-stat	7.15661	0
Heteroscedastic Consistent		
Z-stat	8.85759	0
Levin, Lin & Chu t	-5.65695	0
Individual Unit Root		
ADF Coal	-5.11142	0
ADF Elec	-3.8751	0

The ensuing step of analysis is to construct a Vector Autoregression which estimates individual values of the logarithm of monthly electricity and coal prices as lagged values of each and the cointegrating equation. In this model we employ the Akaike Information Criterion (AIC) to provide an estimate of the optimal lag length in this model. The minimization of the AIC yields the optimal lag length which we interpret as the duration at which the model best correlates past changes in each variable with present year changes in either coal or electricity prices.

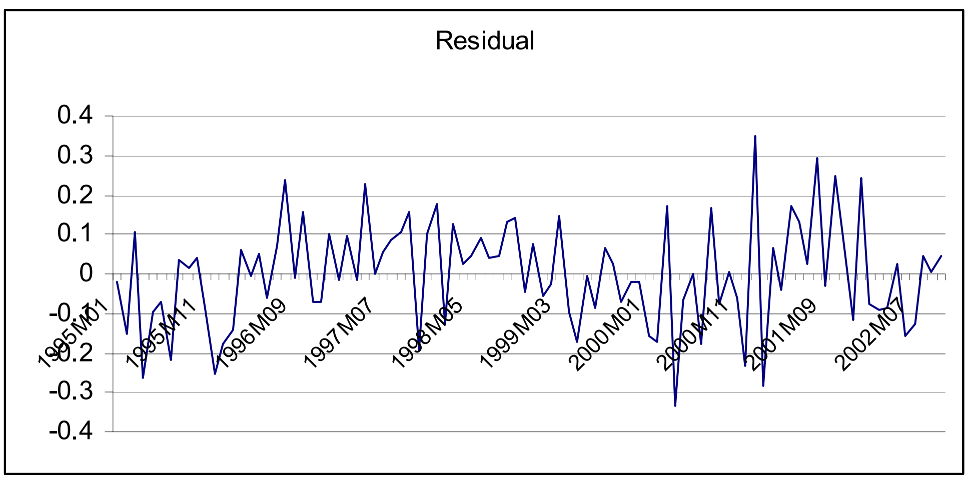
In this model, the lagged values of coal and electricity were tested on values from 2 to 48 months. The optimal range (lowest AIC) occurred between 24 and 48 months as illustrated by Table 2.

Table 2. AIC and Optimal Lag Lengths in VAR

	AIC	
Lags (months)	**coal**	**Electricity**
12	-6.41491	-5.43925
22	-6.41432	-5.42434
24	-6.40796	-5.4619
26	-6.44534	-5.45034
28	-6.41914	-5.48713
30	-6.42822	-5.44672
32	-6.47418	-5.43656
34	-6.49042	-5.44894
36	-6.49756	-5.41807
38	-6.46793	-5.40928
40	-6.46616	-5.38363
48	-6.49467	-5.39658

From these analyses we employ 36 months as an appropriate range of pricing impacts. Further, the magnitude of the price spread (as evidenced by the residual estimate) was mean reverting. See Figure 1.

Figure 1. Residual Estimate Electricity and Price Regression



Our final analysis was an elasticity estimate of electricity and coal prices. To perform this test we regressed a measure of electricity use (capacity index) on coal production and an autoregressive term. Employing a Wald test we were unable to reject unit elasticity.

From these results we believe that employing a nearly constant long term relationship between coal and electricity prices is a valid modeling assumption.

Appendix E: Alternative Fueled Vehicles – Regression Analysis

Background

Alternative Fueled Vehicles (AFVs) are widely viewed as one source of limiting carbon emissions, particularly in developed countries. Thus a continued interest in many aspects of AFVs has manifested itself in considerable research on their demand and environmental impacts.

For the purposes of this analysis it was necessary to evaluate the role AFVs may potentially play in the demand for hydrogen produced at the FutureGen facility. In order to perform this analysis we were drawn to models of aggregate demand for alternative fueled vehicles. In this appendix we next provide a review of the literature for AFVs. Since the findings of this analysis were presented in the report body, we will only briefly review them again.

Aggregate Studies of AFVs

Perhaps the dominant analysis of AFVs focuses on individual consumer choice characteristics, which then may be aggregated across regions. These studies are typically data intensive, but present fewer of the computational difficulties surrounding AFV analysis at the aggregate level.

The earliest studies of aggregate vehicle demand (Dyckman, 1965) evaluate the role income, prices, vehicle stocks and financial markets played in per capita car ownership in the United States. Most later studies owe something to this model specification, while extending the methods.

Virtually all studies employ some measure of aggregate economic activity. Studies which use incomes include Dyckman [1965], Tanner [1979], Train [1986], Manski [1990] Madre [1990], Dargay and Gately [1999], Chung and Lee [2002] and this study. With the exception of Chung and Lee [2002] each of these authors found a positive relationship between incomes and automobile ownership (measured in many different ways). Other studies employed either GNP or GDP as measures of aggregate economic activity. These include Han and Willumsen [1986], Button Ngoe and Hine[1993] and Abu-Eisheh [2001]. Each of these authors found positive impacts of this measure of aggregate economic activity on automobile ownership. Only this study examined AFVs directly.

Fiscal considerations also played a role in automobile studies. Khan and Willumsen [1986], directly employ import duties and ownership tax on a panel of developing countries. They found neither variable significant in explaining automobile ownership rates. Other studies included indexes of vehicle costs which may have included some tax and credit information (Tanner, 1979 and Abu-Eisheh, 2001). Panel models with country specific dummies also will include fiscal considerations in the fixed or random effects terms (Button, Ngoe and Hind, 1993). This study explicitly includes the sum of federal and state gas taxes, and tax incentives and is therefore the most extensive of the fiscal explanations of aggregate automobile consumption.

Population density or a proxy for this such as proportion of population in an urban setting also figured prominently in studies. Khan and Willumsen [1986]., Manski, 1980, Train, [1986] and Chung and Lee [2002] as well as this study employ a variable of this type. Only Khan and Willumsen found no positive statistical impact of population or its density on automobile demand.

Other important variables included automobile stocks (Dykman, 1965; Manski, 1980), average automobile price (Dyckman, 1965, Manski, 1980), and driving time, trips or distance (Train, 1980; Chung and Lee, 2002).

Among the more contemporary studies Abu-Eisheh [2001] estimated automobiles and number of drivers per household in the Palestinian Territories and included a dummy variable for political changes (Palestinian National Authority). And both this study and Chung and Lee [2002] considered the driving age population as an explanatory variable for automobile demand.

Prices were employed either in aggregate indices (Abu-Eisheh, 2001) or as part of driving cost (Tanner, 1979). The current study directly models automobile demand for AFV's as a function of both natural gas and oil prices. This is the first of the aggregate models to perform such a test.

The FutureGen Model

The data employed in this model were total AFV use by State from 1997 through 2002. The data were placed in a per capita basis using population data from the Regional Economic Information System which also yielded incomes data. The shares of metropolitan population were calculated from these data by the Center. The federal and state gas tax data were obtained from Hicks [2004] study of alternative highway finances and the tax incentive data from the Alternative Fueled Vehicles Data Center collection of state data. These were coded by the author.

An additional feature of this study is its treatment of spatial considerations. Spatial autocorrelation occurs when there are interactions across geography which influence the error term. The spatial autocorrelation term is constructed by weighting the dependent variable in adjoining areas by a spatial weights matrix. The model was constructed as:

Equation 1

$$
\begin{aligned}
&(AFV_i / Pop_i) = \\
&\quad \alpha_i + \beta_1(Tax_{Fed+State}) + \beta_2(UrbanPop_i / Pop_i) + \beta_3(UrbanIncome)) + \\
&\quad \beta_4(NatGas\,Price) + \beta_5(Oil\,Price) + \beta_5(AFVTAXINCENT) + \\
&\quad \delta(AFVC_i / PopC_i) + \varepsilon_i
\end{aligned}
$$

Where the per capita use of alternative fuel vehicles in state *i* in year *t* is a function of state level fixed effects (α), state and federal gasoline taxes, the share of each states' population in urban areas, the real urban income in each state, real natural gas prices, real petroleum prices, the presence of AFV tax incentives in each state, the spatial autocorrelation parameter, and the normally distributed error term.

This model was calibrated on data from 1997 through 2002 for the lower 48 conterminous states and the District of Columbia. The results (absent the fixed effect intercept for each state) appear in the following table.

Table 1. The AFV Per Capita Model Results
Dependent Variable: ?AFV/?POP
Sample: 1997 2002
Included observations: 6
Number of cross-sections used: 49
Total panel (unbalanced) observations: 289

Variable	Coefficient	Std. Error	t-Statistic	Prob.
(?GTR+FEDGASTAX)/GDPDEF	0.005864	0.000860	6.820099	0.0000
?METROPOP/?POP	0.006033	0.003675	1.641800	0.1020
?METROINC/GDPDEF	7.16E-08	8.41E-09	8.519464	0.0000
?AFVC/?POPC	0.764095	0.055057	13.87822	0.0000
?NGPRICE/GDPDEF	-2.96E-05	5.93E-06	-4.986696	0.0000
OILPRICE/GDPDEF	1.15E-05	1.80E-06	6.370342	0.0000
?AFVTAXINCENT	0.000133	3.21E-05	4.152926	0.0000
R-squared	**0.930409**	**Mean dependent var**		**0.004423**
Adjusted R-squared	**0.913982**	**S.D. dependent var**		**0.004100**
S.E. of regression	**0.001202**	**Sum squared resid**		**0.000337**
F-statistic	**519.1875**	**Durbin-Watson stat**		**1.757362**
Prob(F-statistic)	**0.000000**			

A brief interpretation of these results suggests that higher taxes, higher income, high rates of urban areas, oil prices and tax incentives all play a positive role in promoting AFV use per capita among the states. Natural gas prices reduce AFV rates.

These results are remarkably consistent with economic theory in an environment where data is scarce. There are important potential improvements in this model, to include measures of regional travel times, the availability of public transport and the appearance of networks for fuel distribution and additional types of incentives.

Perhaps the most useful short run application of this model is in its ability to provide policy simulation. Specific questions are, what levels of changes to exogenous variables (such as fuel prices) and which policy endogenous variables (such as tax incentives) may occur to make hydrogen as a fuel source for alternative fuel vehicles a significant transportation alternative.

As detailed in the text, our preliminary conclusion is that, given the very low use of Alternative Fuel Vehicles and hydrogen fuel cell vehicles specifically, the option for hydrogen as an alternative transportation source is sufficiently far enough in the future to make its role in FutureGen problematic.

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