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Can the Modular Helium Reactor Compete in the Hydrogen Economy

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ABSTRACT

In today's energy economy, hydrogen is primarily used in the petroleum refining and petrochemical industries. The dominant technology for generating hydrogen is Steam Methane Reforming (SMR), which uses natural gas as both feedstock and fuel. In the much-discussed future hydrogen economy, hydrogen could become a major carrier of energy for distributed use, such as in fuel-cell vehicles. This paper compares the cost of hydrogen production using natural gas and SMR technology with the cost of nuclear-powered hydrogen production using a Modular Helium Reactor (MHR). A time series model of natural gas prices is estimated and used to simulate the cost of hydrogen from SMR to 2030: it is never above $11.80/GJ or $12.45/million BTU (in 2001 dollars). A cost engineering model of the General Atomics' MHR shows a range of hydrogen production costs, none of which are below $11.80/GJ. For the MHR to be competitive in the pipeline hydrogen market, there must be an increase of 50-100% in the price of natural gas.

Keywords: hydrogen markets, hydrogen economics, nuclear power economics

JEL classification number: Q41

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1. Today's Hydrogen Economy

Some predict that hydrogen will replace other energy carriers, particularly gasoline in the transportation sector and fossil-fueled electricity production. But in today's hydrogen economy, hydrogen is used primarily in the petroleum refining and petrochemical industries (93% in the U.S. in 2003). According to the Chemical Market Reporter (2003, p.43): "More hydrogen plants are being constructed because of the demand growth from the refinery sector, which uses hydrogen to upgrade fuels to meet mandates for low-sulfur gasoline and diesel, as well as for processing higher-sulfur crude."

There are two sectors of the hydrogen production industry: (1) "captive capacity" owned by downstream users of the hydrogen, e.g., oil refiners, and (2) "merchant capacity," where producers compete for business. Ignoring the "cryogenic liquid" market (e.g., rocket fuel) that accounts for 7% of the merchant market, the total U.S. merchant hydrogen gas capacity is about 1,500 million (M) standard cubic feet (SCF)/day, or about 42 million cubic meters (Mm^3). Most of this merchant production capacity (92%) is located in three states: Texas with 560M SCF/day, Louisiana with 440M SCF/day, and California with 380M SCF/day. See Chemical Market Reporter (2001, 2003). Regarding the size of the captive capacity, the Chemical Market Reporter (2003, p. 43) writes, "Another 3 billion SCF per day of captive hydrogen capacity exists at 145 locations in the US." Therefore, the U.S. has a total capacity of approximately 4,500 M SCF/day, or about 127 Mm^3.

Throughout this decade, demand for hydrogen should continue to grow: "Although aggregate hydrogen consumption is growing 4 percent annually, growth in the merchant hydrogen business is significantly higher, perhaps 10 percent." (Chemical Market Reporter, 2003, p. 43) With one-third of the market growing at 10% and the total market growing at 4%, the captive market is growing at approximately 1%. If the merchant market grows 10% annually, merchant capacity will equal captured capacity by 2010. This implies adding 100M – 200M SCF/day (3-5 Mm^3) of capacity each year, much of it with100M SCF (2.83 Mm^3)/day plants.

Figure 1 represents a model of the hydrogen economy (now being developed in association with the Economic Modeling Working Group of the Generation IV International Forum). It's primary purpose is to determine demand for central station (i.e., pipeline) and distributed hydrogen (e.g., with electrolysis) as hydrogen fuel-cell vehicles compete with hybrid/internal combustion engines.

Energy is delivered to the hydrogen sector through natural gas or electricity. The prices of natural gas and coal are functions of an exogenous oil price. The cost of hydrogen production is described with cost-engineering models. The prices of distributed electricity, distributed gasoline, and distributed hydrogen are determined in endogenous markets. The demand for vehicle type in the transportation sector is a function of fuel cost and vehicle investment. The model calculates probability distributions for prices and quantities of pipeline and distributed hydrogen to 2030.

Figure 1 points to the possibility of generating pipeline hydrogen with nuclear power. Generating hydrogen with nuclear power has been discussed for decades. Recently, the U.S. House of Representatives passed the H.R. 6 Energy Policy Act of 2005. Section 651 of the Act addresses Hydrogen Production Programs, authorizing $1,320 million for the Advanced Reactor Hydrogen Cogeneration Project:

> "The project shall consist of the research, development, design, construction, and operation of a *hydrogen production cogeneration* research facility that, relative to the current commercial reactors, enhances safety features, reduces waste production, enhances thermal efficiencies, increases proliferation resistance, and has the potential for improved economics and physical security in reactor siting. . . The overall project, which may involve demonstration of selected project objectives in a partner nation, *must*

> *demonstrate both electricity and hydrogen production*. . . The Secretary [of Energy] shall select technologies and develop the project to provide initial testing of *either hydrogen production or electricity generation by 2011*. (*emphasis added*)

The present paper forecasts the cost of hydrogen produced (1) with Steam Methane Reforming with natural gas, and (2) with the leading nuclear power technology for hydrogen production: the Modular Helium Reactor (MHR). SMR and MHR could compete in the centralized production of hydrogen, where all production is sold via pipeline. Section 2 presents a model of the average cost of hydrogen with Steam Methane Reforming as a function of the price of natural gas. Section 3 develops time-series models of the prices of oil, natural gas, and hydrogen. It shows that the cost of hydrogen is unlikely to exceed \$11.80/GJ (or \$12.45/M Btu) for many months during the next 25 years without substantial increases in the price of natural gas (e.g., after the imposition of carbon taxes). Section 4 analyzes cost estimates for the Modular Helium Reactor. After making adjustments following international standards, the cost of hydrogen using the Sulfur-Iodine process is greater than \$11.80/GJ in all sensitivity scenarios. More development must be done before the Sulfur-Iodine process can be demonstrated at a prototype scale, e.g., of 50,000 tonnes of hydrogen per year.

2. The Cost of Hydrogen from Steam Methane Reforming

Most of the hydrogen today is produced with Steam Methane Reforming (SMR) by chemically reacting natural gas and steam at high temperature, see Padro and Putsche (1999, p. 2). As described in Crosbie and Chapin (2003, p. 4):

> "The conventional process occurs in a chemical reactor at temperatures of about 800-900°C. When fueled with fossil fuels it is the most economical method of producing hydrogen today [Padro and Putsche, 1999]. The heat is generally supplied by burning an excess of the methane. This results in a loss of both the reactant, and some of the product hydrogen. Typical thermal efficiencies for steam reforming are about 70% [Padro and Putsche, 1999]."

This means that the cost of producing hydrogen depends on the price of natural gas. This can be seen in Padro and Putsche's discussion of scale economies in SMR. Table 1 is a reproduction of their Table 2 and Figure 2 is a reproduction of their Figure 1. By using their information, an average cost curve can be estimated with Ordinary Least Squares, see Table 2:

$$AC_t = \$2.049 + 1.218\, P^{NGAS}{}_t + \$1.569\,(1/\,SIZE\,)\ , \tag{1}$$

where AC_t is the average cost of hydrogen production in mid-1998 dollars per GJ, $P^{NGAS}{}_t$ is the price of natural gas in $/GJ (which is nearly equal to dollars per million BTU), and (1/ *SIZE*) is the inverse of the facility capacity in Mm^3. (This technique can lead to a lower estimation than with a bottom-up model of SMR cost with a new plant.) Average Cost can be graphed as a function of facility size and the price of natural gas, as in Figure 3. Assuming a facility of 2.83 Mm^3, the average cost of hydrogen would be $\$2.603 + 1.218 \cdot P^{NGAS}{}_t$. For example, if $P^{NGAS}{}_t$ were $6/GJ, the average cost of hydrogen would be about $9.90/GJ in 1998 dollars, or $10.60/GJ in 2001 dollars (using the U.S. GDP implicit price deflator).

Using average cost curves (representing long-run marginal cost curves), a supply schedule for the U.S. merchant hydrogen market can be constructed from this estimate of cost (assuming all merchant plants use SMR technology). See Figure 5, where "demand lines" have been added to show the intersection of historical demand with historical supply. Notice that in each year, consumption is near the upturn in the average cost curve, putting cost pressure on the price of hydrogen. The Chemical Market Reporter (2003) observes and predicts,

> "Hydrogen has remained strong despite the weakened economy in recent years and this situation should prevail regardless of when the economy turns around. The industrial gas majors, Air Products, Praxair, Air Liquide, and BOC, have all raised their prices for hydrogen, based on the strong demand. This pricing trend is expected to continue."

It appears that the demand for hydrogen in the petroleum and petrochemical sector will continue to grow. Although it is difficult to predict how long the merchant hydrogen market will grow at 10% per year, it is likely that all new pipeline hydrogen production capacity can be fully employed as long as it can compete with an average cost of $8-12/GJ, which depends on the price of natural gas. The next section forecasts natural gas prices in Texas and California as econometric functions of crude oil prices.

3. Forecasting Oil and Natural Gas Prices

To forecast the cost of hydrogen production using natural gas with SMR, I propose two first-order autoregressive functions (see Rothwell 2004, based on Rothwell 2002):

$$P^{OIL}_{t} = \beta_1 + \beta_2 P^{OIL}_{t-1} + \varepsilon^{OIL}_{t}, \quad (2)$$

$$P^{NGAS}_{t} = \beta'_1 + \beta'_2 P^{OIL}_{t-1} + \beta'_3 P^{NGAS}_{t-1} + \varepsilon^{NGAS}_{t}, \quad (3)$$

Figure 5 presents the data to estimate these models. Table 3 presents estimates of Equations (2) and (3) for the West Texas Intermediate Crude Oil Spot Price (representing the world oil price) from http://www.eia.doe.gov/oil_gas/petroleum/info_glance/prices.html and City Gate Natural Gas Prices in Texas http://tonto.eia.doe.gov/dnav/ng/hist/n3050tx3m.htm and California, http://tonto.eia.doe.gov/dnav/ng/hist/n3050ca3m.htm. One can conclude that the price of oil leads both natural gas prices and that the price of oil does not follow changes in either price of natural gas. (Oil prices do not follow other energy prices, see Rothwell, 2004.)

To use these estimates in forecasting, they must be stationary, i.e., the mean and variance must be stationary over time. One can test for stationarity in crude oil prices and in Texas and California natural gas prices by considering the Dickey-Fuller (1979) procedures:

$$\Delta P^{J}_{t} = \delta_1 P^{J}_{t-1} + \varepsilon^{J}_{t}, \quad (4a)$$

$$\Delta P^{J}_{t} = \delta_0 + \delta_1 P^{J}_{t-1} + \varepsilon^{J}_{t}, \quad (4b)$$

$$\Delta P^{J}_{t} = \delta_0 + \delta_1 P^{J}_{t-1} + \delta_2\ time + \varepsilon^{J}_{t}, \quad (4c)$$

where $\Delta P^J_t = P^J_t - P^J_{t-1}$ is the first difference of the monthly price, J indexes the form of energy (here oil or natural gas), and *time* is a time trend. The null hypothesis is if $\delta_1 = 0 = 1 - \rho$, then P^J_t is non-stationary (where ρ is the correlation between P^J_t and P^J_{t-1}). The alternative hypothesis is that $\delta_1 < 0$ (that P^J_t is stationary), where a one-tailed test is appropriate (if $\delta_1 > 0$, the series can explode). If δ_0 is significant in Equations (4b) and (4c), then P^J_t is increasing or decreasing ("drifting"). If δ_2 is significant in Equation (4c), then P^J_t is changing with time (e.g., "drifting around a trend"). The regression results are presented in Table 4. Using standard significance levels, one can conclude for the purposes here that oil and natural gas prices are stationary.

Given these results, I propose the following forecasting model (based on Table 3, Row 2) for oil prices after January 1, 2000 (here, 0.044 = 0.030 + 0.014):

$$P^{OIL}_t = 0.044 + 0.917\, P^{OIL}_{t-1} + e^{OIL}_t \tag{5}$$

where e^{OIL}_t are normally distributed residuals with a mean of zero and standard error of 0.0325 (The choice of January 2000 is arbitrary; other dates give similar results.)

Further, I propose the following forecasting equations for natural gas prices (based on Table 3, Rows 6 and 8):

Texas: $$P^{TX\text{-}NGAS}_t = 0.015 + 0.203\, P^{OIL}_{t-1} + 0.737\, P^{TX\text{-}NGAS}_{t-1} + e^{TX\text{-}NGAS}_t \quad \text{and} \tag{6a}$$

California: $$P^{CA\text{-}NGAS}_t = -0.016 + 0.238\, P^{OIL}_{t-1} + 0.768\, P^{CA\text{-}NGAS}_{t-1} + e^{CA\text{-}NGAS}_t\,, \tag{6b}$$

where $e^{K\text{-}NGAS}_t$ are normally distributed residuals with means of zero and standard errors of 0.048 for Texas and 0.066 for California. Figure 6 presents one Monte Carlo simulation of the forecast.

These natural gas prices can be substituted into Equation (1) to forecast the price of pipeline hydrogen over the next 25 years, assuming no structural changes in oil and natural gas markets. Figure 7 presents one forecast of the average cost of hydrogen production in Texas and

California using SMR (this is only one of many possible simulations). The mean price for hydrogen is \$8/GJ in both Texas and California. The price is never over \$12/GJ.

4. Estimating Cost of Hydrogen from a Modular Helium Reactor

Crosbie and Chapin (2003) estimated the cost of nuclear-produced hydrogen with technologies using energy from a Modular Helium Reactor (MHR). A promising long-term technology for producing hydrogen with high-temperature nuclear heat is the Sulfur-Iodine (S-I) technology. Brown et al. (2002) claim the cost of hydrogen could be as low as \$10/GJ, which is in the mid-range of the estimates by Schultz and General Atomics (2002).

However, estimating costs for future nuclear power technologies must adhere to a set of internationally agreed upon standards. A set of standards based on International Atomic Energy Agency bid evaluation process has been developed by the Economic Modeling Working Group (EMWG) of the Generation IV International Forum (GIF): *Cost Estimating Guidelines for Energy Systems* (2004). These *Guidelines* specify a comprehensive set of cost estimating assumptions, such as the cost of capital and costs for each stage of the nuclear fuel cycle.

To recreate these "Nth-of-a-Kind" (i.e., after at least 8,000 MW of commercial capacity has been installed, following GIF *Guidelines*) estimates of Schultz and General Atomics (2002) and other General Atomics documents (see discussion in Appendix G of EMWG, 2004). Table 5 presents the non-capital "Input Data" spreadsheet following the EMWG *Guidelines* to estimate nuclear power generation cost. Table 6 presents the "Capital" spreadsheet. See discussion in EMWG (2004).

The General Atomics' MHR for hydrogen production with the S-I process is designated as the (Process Heat) PH-MHR. Its estimated efficiency is 42%, operating at the same outlet temperature as the GT-MHR (850º C). Table 7 compares the annualized and levelized costs of production for the PH-MHR with the GT-MHR.

Most of the non-capital input data for the PH-MHR are the same as those for the GT-MHR. The "electricity-equivalent" size of the 4-unit plant has been adjusted to reflect the lower efficiency of the PH-MHR: a 2400 MWt plant operating at 42% efficiency would have an electric-equivalent rating of 1008 MWe. The chemical facility was optimized for a heat source of 2857 MWt. Given the 4-module MHR is only 2400 MWt, the hydrogen facility size is reduced by 16%. Fuel costs are the same for the PH-MHR as the GT-MHR. However, because of the lower electric-equivalent output, fuel costs per MWh-equivalent are higher for the PH-MHR.

Regarding reactor operating costs, "Assuming the O&M costs scale as the capital cost, the O&M cost is $23,400,000 per year for the PH-MHR" (Brown et al. 2003, p. 3-37). This cost has been converted to an all-staff equivalent of 293 persons. Also, the annual chemical plant O&M costs are $48.775M from Brown et al. (2003), Table 3-16, plus water costs of $1.805M.

Equipment costs must be adjusted to account for hydrogen production: The cost of the Intermediate Heat Exchanger ($56M), Primary Circulator ($33M), IMX Circulator ($22M), and Reactor-Process Ducting ($38.07M) were added to 84% of the "Fixed Capital Investment," i.e., $571.531M x 0.84 = $480.086M. This total, $629.156M, replaces the cost of the turbine-generator in Account 23 in Columns 3 and 4 of Table 6. The other difference between Column 3 and Column 4 is the additional IDC on the chemical plant, equal to $79M (times 84%). Also, the initial chemical inventory (primarily iodine) is equal to $114.802M x 0.84 = $96.434M. (Although there is an implicit assumption that all iodine inventory is recycled in the S-I process, as in Brown et al., 2003, Werkoff, 2003, questions whether this is a reasonable assumption.)

Two additional changes are made to the calculations in Brown et al. (2003) for PH-MHR. First, the contingency rate is increased to 15% and applied to both the reactor and chemical plant. Although contingency appears to have been added to the "Fixed Capital Investment" in Table 13-3 in Brown et al. (2003) under the item "Contingency and Fee," the contingency *and* fee are equal to 18% of the "Total Bare Module Cost with Adders." This "fee" is nearly equal to the indirect rate for reactor construction (17.3%). Therefore, contingency is only 0.7%, if indirect costs are equal to those for the reactor. Given that the Sulfur-Iodine process has not been proven at the prototype's scale, a 15% contingency is less than what EPRI TAG Guidelines would suggest. (The contingency could be doubled to 30% given the state of S-I technology; see Rothwell 2005a.) Second, the IDC rate is increased to 10% and applied to all capital costs, including the chemical plant, initial chemical inventory, and first fuel core.

Table 7 presents the results of these calculations. The annual production of 201,982 tonnes of hydrogen per year is from Brown et al. (2003), Table 3-16. The cost of hydrogen is $12.58/GJ under the Brown et al. (2003) assumptions, with a fixed charge rate (FCR) of 10.5%. With the cost of the first fuel core and a FCR of 10.23% the cost is $11.86/GJ (column 4 in Table 7). With the GIF *Guideline* adjustments, the cost of hydrogen increases to $15.11/GJ, which is between the values of $13.90/GJ for a FCR of 12.5% and $16.50/GJ for a FCR of 16.5% in Brown et al. (2003). A reasonable range of a state-of-the-art MHR with the S-I technology is $12-$16/GJ.

This range of nuclear-produced hydrogen is added to Figure 7. The cost of nuclear hydrogen is greater than the cost of hydrogen from Steam Methane Reforming in all but one period: December 2000 to June 2001, i.e., during the California energy crisis, and in the price simulation during one month, May 2023.

5. Application

The next stage of development of the Modular Helium Reactor is the building of a dual-unit MHR with one unit generating electricity and the other unit generating hydrogen. The cost of the prototype can be estimated with the values in Tables 5-7, noting these are "Nth-of-a-Kind" (NOAK) costs. Following the GIF *Guidelines*, the prototype will cost at least $1,009M equal to one quarter of the Total Capitalized Cost for the GT-MHR ($444M, from Table 6, Col. 2) plus one quarter of the Total Capitalized Cost for the PH-MHR ($565M from Table 6, Col. 4). However, the first unit of any set costs more than the remaining units. These units could be 25% more costly than one quarter of a four-unit plant. This would increase the costs to $1,260M.

Assuming a decline in cost of 6% with each doubling of total MHR capacity and NOAK costs equal to cost at 8,000 MW, there are three doublings to 28 units with a total of 8,008 MW. So, total "First-of-a-Kind" (FOAK) costs could be at least 19% (=1.06^3) higher, or about $1,500M. Also, FOAK engineering and certification costs could be as much as $300M. The total cost for an electricity **and** hydrogen production facility could be $1,800M. Instead, the project should focus on the GT-MHR and start the hydrogen facility in 2011, once electricity and revenue are being generated. It is too early to assume the cost of hydrogen from the MHR/S-I will decline with learning-by-doing. For MHR technology to be competitive with Steam Methane Reforming, i.e., to achieve a minimum commercial deployment of 8,000 MW, either one of the following conditions must be satisfied: (1) an increase of 50-100% in the price of natural gas, or (2) a decline in the cost of MHR with S-I technology of 33-50%.

Figure 1: A Model of the Hydrogen Economy

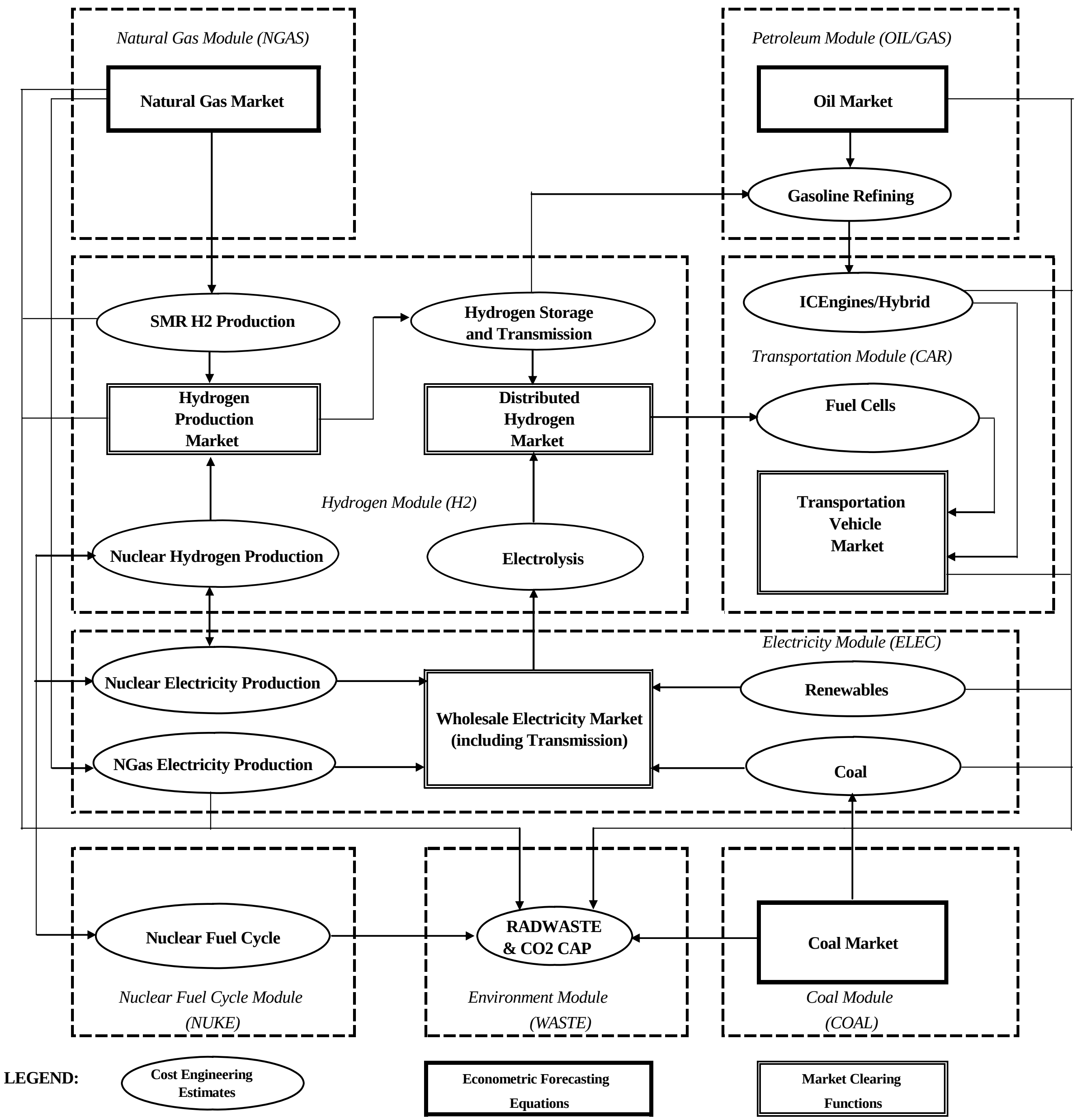
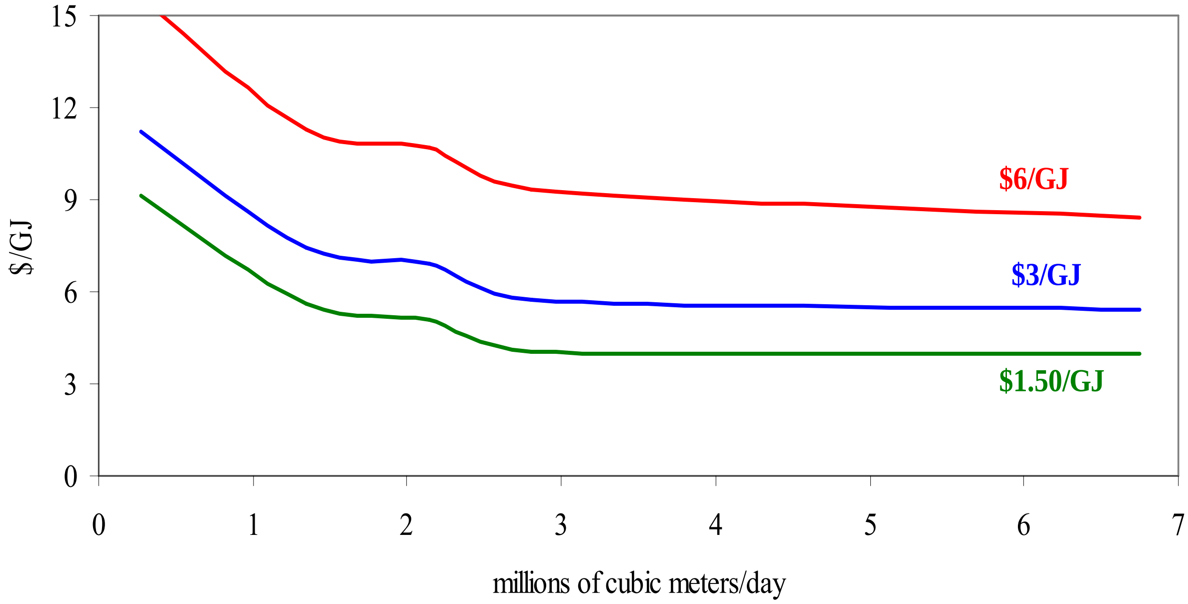
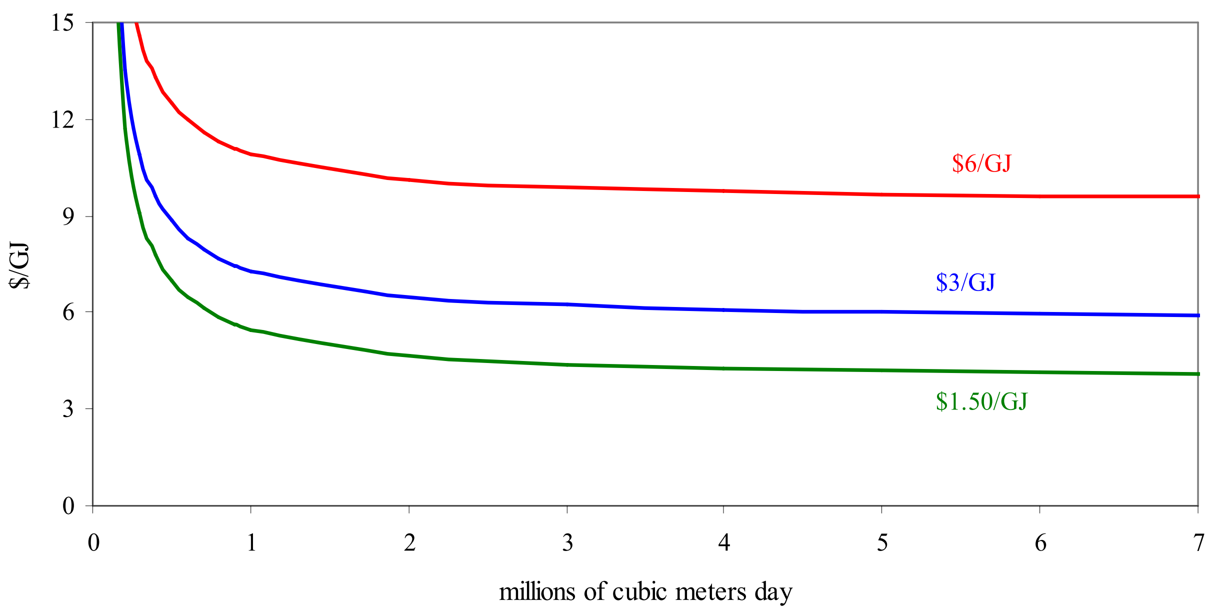


Figure 2: Scale Economies in SMR Production of Hydrogen



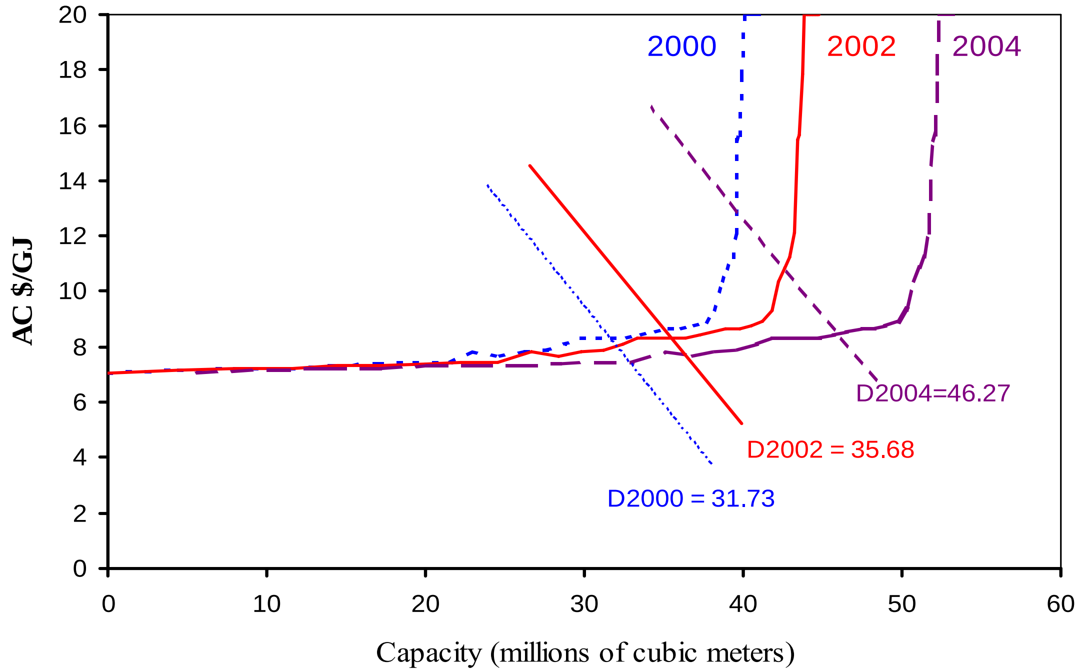
Source: Padro and Putsche (1999, p. 3).

Figure 3: Estimated Average Cost in SMR Production of Hydrogen



Source: Parameter values from Table 2.

Figure 4: U.S. Merchant Hydrogen Market (2000, 2002, 2004)



Source: Plant capacities available in Chemical Market Reporter (2001 and 2003). Calculations assume the price of natural gas is $4/GJ in all years.

Figure 5: Natural Gas Prices in California and Texas, 1989-2004

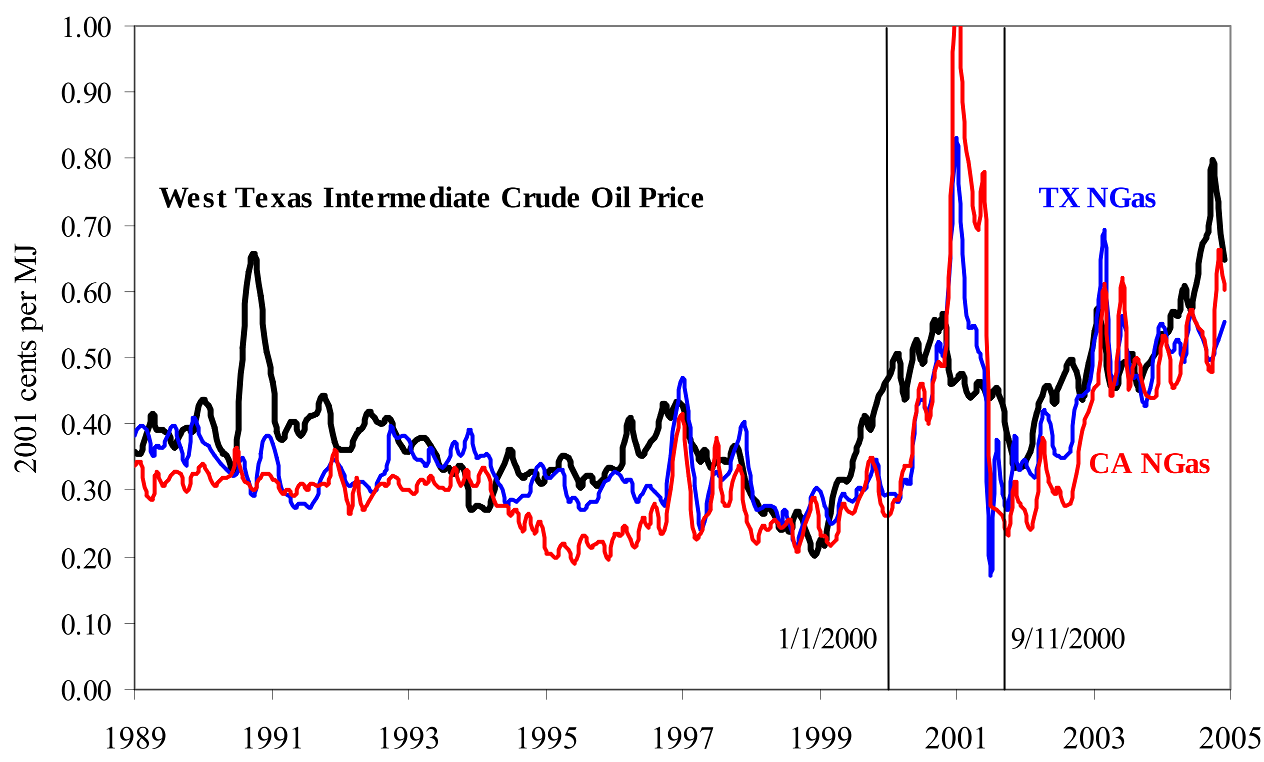


Figure 6: Projected Energy Prices for Texas and California, 2005-2030

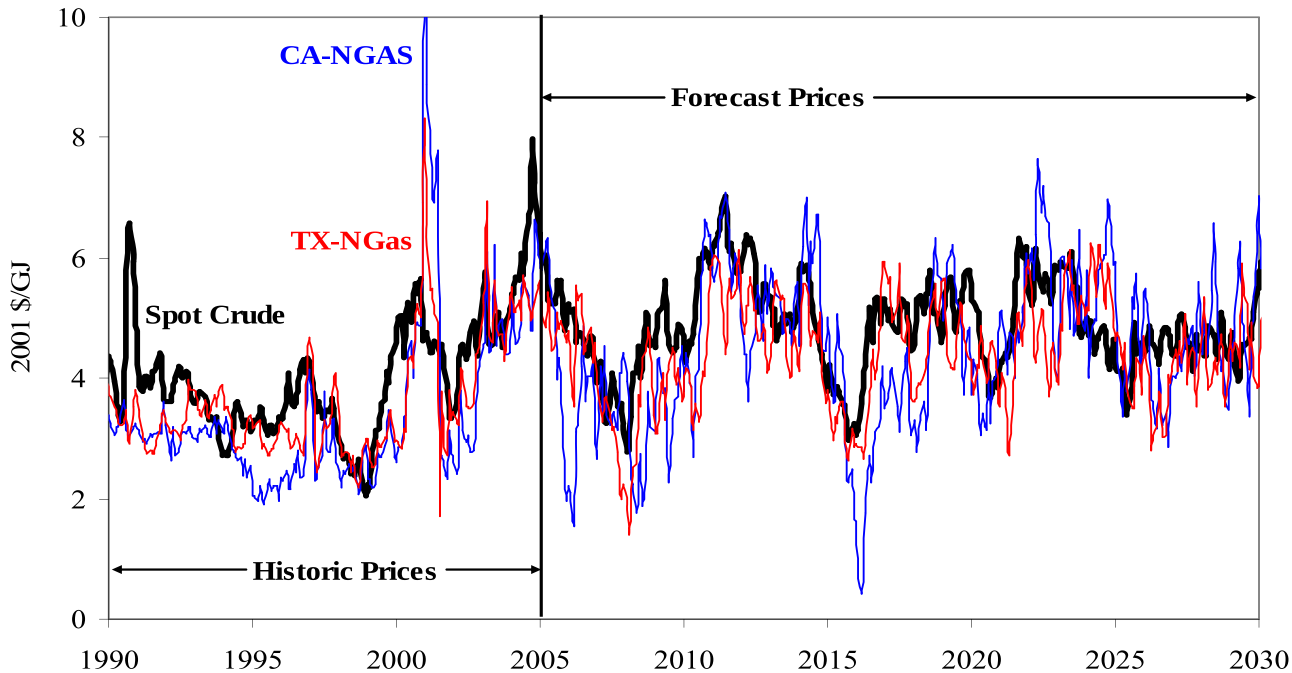


Figure 7: Projected Hydrogen Costs for Texas and California

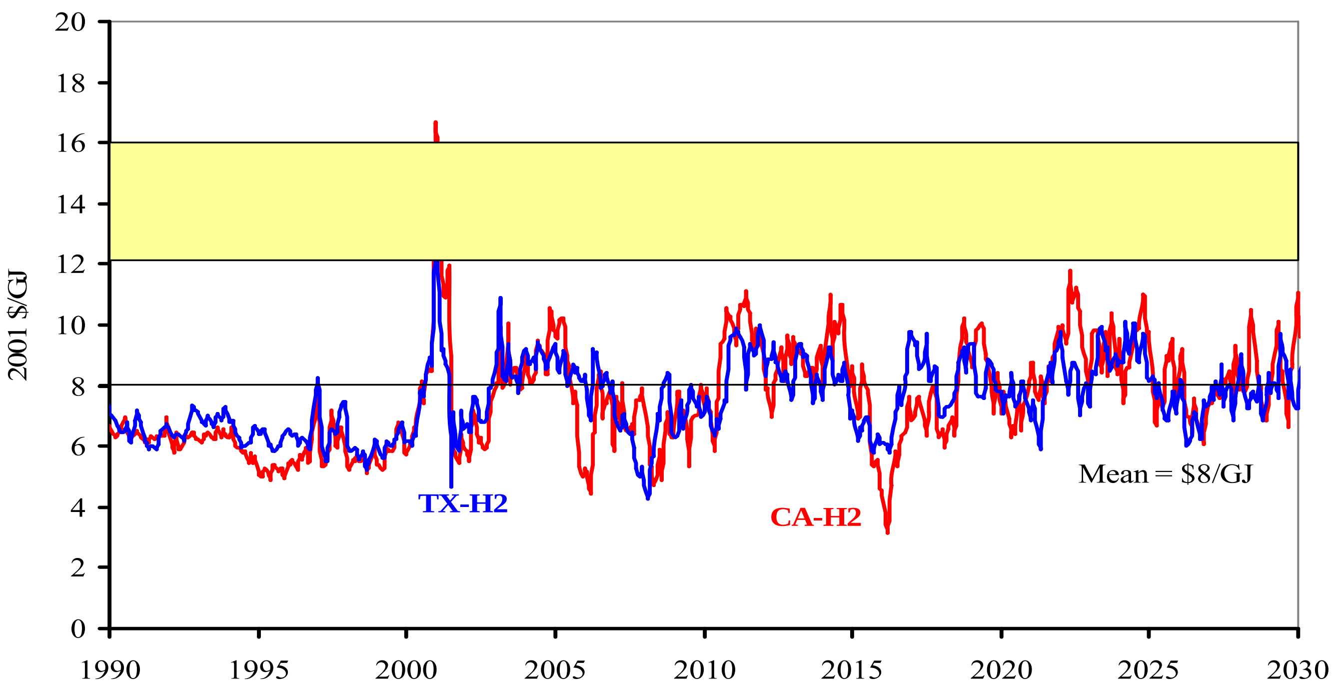


Table 1: Summary of SMR Costs

Facility Size million scf/d (million Nm3/d)	Reference	Specific Total Capital Investment ($/GJ)	Hydrogen Cost ($/GJ)
Small Facilities			
10 (0.27)	Leiby (1994)	27.46	11.22
Large Facilities			
47 (1.34)	Leiby (1994)	14.74	7.46
75 (2.14)	Leiby (1994)	12.61	6.90
100 (2.80)	Kirk-Othmer (1991)	9.01	6.26
238 (6.75)	Foster-Wheeler (1996)	10.00	5.44

Source: Padro and Putsche, 1999, p. 2. The price of natural gas was assumed to be $2.96/GJ by Padro and Putsche. (The cost estimate for Padro and Putsche's largest plant, 900 M SCF, was ignored because it was ten times larger than any single unit in the US.)

Table 2: OLS Model of SMR Scale Economies

OLS Statistics	
Adjusted R Square	0.96
Standard Error	0.65

	df	*SS*	*MS*	*F*
Regression	2	142.84	71.42	171.30
Residual	12	5.00	0.42	
Total	14	147.84		

	Estimate	*SError*	*t Stat*	*P-value*
Intercept	2.049	0.378	5.426	0.000
Price of Natural Gas	1.218	0.089	13.693	0.000
1/Size (Mm3)	1.569	0.126	12.454	0.000

Price of Natural Gas is assumed to be $1.50/GJ, $3.00/GJ, and $6.00/GJ by Padro and Putsche (1999, p. 3), and (*1/Size*) is the inverse of the SMR facility size (Mm^3).

Table 3. Granger Causality Tests: Crude Oil Spot Price, Texas City Gate Natural Gas, and Californian City Gate Natural Gas, 1989-2004

	Depend Variable	df	R2	RSS	C	Independ Variable	Est Value	t Stat	Independ Variable	Est Value	t Stat	F test
1	Oil(t)	189	89	0.20	0.018	Oil(t-1)	0.959	39.65				
2	Oil(t)	188	90	0.20	0.030	Oil(t-1)	0.917	29.22	Time>2000	0.014	**2.09**	**4.359**
3	Oil(t)	188	89	0.20	0.017	Oil(t-1)	0.955	31.03	TX-NGas(t-1)	0.008	0.25	0.062
4	Oil(t)	188	89	0.20	0.017	Oil(t-1)	0.948	32.41	CA-NGas(t-1)	0.015	0.67	0.455
5	TX-NGas(t)	189	73	0.48	0.050	TX-NGas(t-1)	0.865	22.77				
6	TX-NGas(t)	188	76	0.43	0.015	TX-NGas(t-1)	0.737	16.07	Oil(t-1)	0.203	**4.54**	**20.586**
7	CA-NGas(t)	189	74	0.89	0.046	CA-NGas(t-1)	0.867	23.00			.	
8	CA-NGas(t)	188	76	0.82	-0.016	CA-NGas(t-1)	0.768	17.54	Oil(t-1)	0.238	**4.04**	**16.333**

Table 4. Dickey-Fuller Tests: Texas and Californian Energy Prices, 1989-2004

	Depend Variable	df	R2	RSS	C	Std Error	Independ Variable	Est Value	Std Error	Independ Variable	Est Value	Std Error
1	Oil(d1)	190	0	0.2067			Oil(t-1)	0.0012	0.0058			
2	Oil(d1)	189	1	0.2033	0.0178	0.0100	Oil(t-1)	-0.0406	0.0242			
3	Oil(d1)	188	3	0.2007	0.0172	0.0100	Oil(t-1)	-0.0562	0.0262	Time	0.0009	0.0006
4	TX-NGas(d1)	190	0	0.5076			TX-NGas(t-1)	-0.0064	0.0099			
5	TX-NGas(d1)	189	6	0.4766	**0.0501**	0.0143	TX-NGas(t-1)	**-0.1353**	0.0380			
6	TX-NGas(d1)	188	9	0.4628	**0.0496**	0.0141	TX-NGas(t-1)	**-0.1792**	0.0419	Time	**0.0021**	0.0009
7	CA-NGas(d1)	190	0	0.9442			CA-NGas(t-1)	-0.0139	0.0141			
8	CA-NGas(d1)	189	6	0.8905	**0.0462**	0.0137	CA-NGas(t-1)	**-0.1326**	0.0377			
9	CA-NGas(d1)	188	8	0.8685	**0.0384**	0.0140	CA-NGas(t-1)	**-0.1704**	0.0412	Time	**0.0026**	0.0012

Note: Standard Errors of variables with high t-statistics are in bold.

Table 5: Non-Capital Cost Input Data for 4-unit GT-MHR and PH-MHR

	units		
Design Data			
Plant technology (reactor type)	type	GT-MHRx4	PH-MHRx4
Reactor Net Capacity (thermal)	MWt	2400	2400
Reactor Net Capacity (electric)	MWe	1145	1008
Reactor Capacity factor	%	90%	90%
Contingency Rate	%	5%	5%
Contingency Rate **(adjustment)**	%	**15%**	**15%**
Plant economic life	years	40	40
Years to construct	years	5	5
EMWG Non-fuel Data		0	0
Real discount rate for IDC & amortization	%	10.00%	10.00%
Estimated D&D cost	$M	$0	$0
Estimated D&D cost **(adjustment)**	$M	**$263**	**$204**
Fuel Data from Designer		0	0
U-235 enrichment level (1st core ave)	% U-235	15.5%	15.5%
U-235 enrichment level (reload ave)	% U-235	15.5%	15.5%
Heavy metal mass of fuel assembly	grams	5.88	5.88
Fuel Assemblies in Full Core	thousands	3,060	3,060
Fuel Assemblies per Reload	thousands	1,530	1,530
Average time between refuelings	years	1.5	1.5
EMWG Fuel Cycle Data		0	0
Enrichment plant tails assay	%U-235	0.30%	0.30%
Enrichment level of feed	%U-235	0.71%	0.71%
Cost of uranium ore in $/lb	$/lbU3O8	$12	$12
Cost of uranium ore in $/kg	$/kgU	$31	$31
Cost of U3O8 to UF6 conversion	$/kgU	$6	$6
Cost of Enrichment	$/SWU	$100	$100
Cost of Fabrication	$/kgHM	$5,756	$5,756
Cost of once-through waste disposal	$/MWh	$1	$1
Non-Fuel Operational Recurring Costs		0	0
On-site Staff count	person/yr	376	293
On-site Staffing Cost, including benefits	$/person	$80,000	$80,000
Annual chemical plant O&M costs	$M/yr	$0	$50.581

Table 6: Capital Cost for a General Atomics 4-unit GT-MHR and PH-MHR

		Col. 1	Col. 2	Col. 3	Col. 4
GIF Code of Accounts	MHRx4	**GT**	**GT adjusted**	**PH**	**PH adjusted**
	Description	**Cost ($M)**	**Cost ($M)**	**Cost ($M)**	**Cost ($M)**
10 series	Capitalized Pre-construction Costs	0	0	0	0
20 series	Capitalized Direct Costs (subtotal)	789	789	1,190	1,190
21	Buildings, Structures, & Improvements on Site	132	132	132	132
22	Reactor Plant equipment	443	443	254	254
23	***T/G or (HX-H2 equipment+Chemical plant)***	***91***	***91***	***629***	***629***
24	Electrical equipment	62	62	50	50
25	Water intake and heat rejection plant	33	33	0	0
26	Miscellaneous plant equipment	28	28	28	28
27	Special materials (including chemicals)	0	0	96	96
30 series	Capitalized Support Services (Subtotal)	137	137	106	106
31	Design Services at A/E Offices (home office)	25	25	20	20
35	Construction supervision at plant site (field)	28	28	22	22
36	Field indirect costs (rentals, temp facil, etc)	83	83	64	64
40 series	Owners' capital investment costs (Acct 46)	138	138	107	107
50 series	First Fuel Load or First Core (Acct 56)	180	180	180	180
	Total Contingency (Accts 29+39+49+59)	53	187	41	237
60 Series	Financing: Interest during Construction (Acct 62)	129	345	167	439
	Total Capitalized Cost w/o First Core	$1,245	$1,594	$1,611	$2,079
	Specific Cost ($/kw)	**$1,088**	**$1,393**	**$1,599**	**$2,063**
	Total Capitalized Cost plus First Core	$1,426	$1,775	$1,792	$2,260
	Specific Cost ($/kw)	**$1,245**	**$1,550**	**$1,777**	**$2,242**

Table 7: Annualized and Levelized Cost for General Atomics 4-unit MHR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
Case:	**GT-MHRx4**	**GT-MHRx4** adjusted	**PH-MHRx4** CFR=10.5%	**PH-MHRx4** w/First Core CFR=10.23%	**PH-MHRx4** adjusted CFR=10.23%
Annualized Cost in $M/yr					
Capital Cost incl Financing	145.785	181.469	169.197	151.450	231.067
Operations Cost	30.110	30.110	73.981	73.981	73.981
Fuel Cycle Cost	66.834	66.834	66.834	66.834	66.834
D&D Cost	0.000	0.593	0.000	0.000	0.443
Totals	**$242.729**	**$279.006**	**$310.013**	**$292.265**	**$372.325**
Mills/kwh or $/MWh			Electricity Equivalents		
Capital Cost incl Financing	16.15	20.10	21.29	19.06	29.08
Operations Cost	3.34	3.34	9.31	9.31	9.31
Fuel Cycle Cost	7.40	7.40	8.27	8.27	8.27
D&D Cost	0.00	0.07	0.00	0.00	0.06
Totals	**$26.89**	**$30.91**	**38.87**	**36.64**	**46.71**

Annual Production of H2 in kMt			201.982	201.982	201.982
Cost of H2 in $/kg			**$1.53**	**$1.45**	**$1.84**
Cost of H2 in $/GJ			**$12.58**	**$11.86**	**$15.11**

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