System Evaluation and Economic Analysis of a HTGR Powered High-Temperature Electrolysis Hydrogen Production Plant

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Abstract − *A design for a commercial-scale high-temperature electrolysis (HTE) plant for hydrogen production has been developed. The HTE plant is powered by a high-temperature gas-cooled reactor (HTGR) whose configuration and operating conditions are based on the latest design parameters planned for the Next Generation Nuclear Plant (NGNP). The current HTGR reference design specifies a reactor power of 600 MW$_t$, with a primary system pressure of 7.0 MPa, and reactor inlet and outlet fluid temperatures of 322°C and 750°C, respectively. The power conversion unit will be a Rankine steam cycle with a power conversion efficiency of 40%. The reference hydrogen production plant operates at a system pressure of 5.0 MPa, and utilizes a steam-sweep system to remove the excess oxygen that is evolved on the anode (oxygen) side of the electrolyzer. The overall system thermal-to-hydrogen production efficiency (based on the higher heating value of the produced hydrogen) is 40.4% at a hydrogen production rate of 1.75 kg/s and an oxygen production rate of 13.8 kg/s. An economic analysis of this plant was performed with realistic financial and cost estimating assumptions. The results of the economic analysis demonstrated that the HTE hydrogen production plant driven by a high-temperature helium-cooled nuclear power plant can deliver hydrogen at a cost of $3.67/kg of hydrogen assuming an internal rate of return, IRR, of 12% and a debt to equity ratio of 80%/20%. A second analysis shows that if the power cycle efficiency increases to 44.4%, the hydrogen production efficiency increases to 42.8% and the hydrogen and oxygen production rates are 1.85 kg/s and 14.6 kg/s respectively. At the higher power cycle efficiency and an IRR of 12% the cost of hydrogen production is $3.50/kg.*

I. INTRODUCTION

Hydrogen is used in many industrial processes such as hydrogenation of crude oil, ammonia production, and synthetic fuel generation. The most common process to produce hydrogen is through steam/methane reforming. Steam/methane reforming however emits carbon dioxide, a greenhouse gas, and is cost driven by natural gas prices. High-temperature electrolysis, HTE, combined with a high temperature reactor, HTR, can produce hydrogen with little or no carbon dioxide emissions and have no dependency on natural gas.

A study has been prepared as part of the Next Generation Nuclear Plant (NGNP) Project to evaluate integration of high-temperature gas-cooled reactor (HTGR) technology with conventional chemical processes [1]. The NGNP Project is being conducted under U.S. Department of Energy (DOE) direction to meet a national strategic need identified in the *National Energy Policy* to promote reliance on safe, clean, economic nuclear energy and to establish a greenhouse-gas-free technology for the production of hydrogen. The NGNP represents an integration of high-temperature reactor technology with advanced hydrogen, electricity, and process heat production capabilities, thereby meeting the mission need identified by DOE. The strategic goal of the NGNP Project is to broaden the environmental and economic benefits of nuclear energy in the U.S.

economy by demonstrating its applicability to market sectors not being served by light water reactors.

In 2009, an independent review team considered three hydrogen production technologies to be combined with a next generation nuclear plant [2]. Those technologies included the sulfur iodine (SI) process, the hybrid sulfur (HyS) process and the high-temperature electrolysis (HTE) process. The review team recommended the HTE process as the first choice for the NGNP Project, with HyS as the second option. The purpose of this paper is to present the process modeling and economic results from producing hydrogen from high-temperature steam electrolysis combined with a high-temperature gas reactor. These results are used in other process models developed under the NGNP program where HTGR-integrated hydrogen may be integrated with industrial processes.

II. PROCESS DESCRIPTION

A steam Rankine power cycle was evaluated as part of the development of the HTE hydrogen production process. The power cycle was assumed to be powered by an HTGR whose configuration and operating conditions are based on the latest design parameters planned for the Next Generation Nuclear Plant (NGNP). The current HTGR reference design specifies a reactor power of 600 MWth with a primary system pressure of 7.0 MPa and reactor inlet and outlet fluid temperatures of 322 and 750°C, respectively. Using these reactor operating conditions, the power cycle was optimized using Hyprotech's HYSYS.Plant process analysis software [3] to maximize power cycle efficiency prior to coupling the power cycle to the HTE hydrogen production process.

The following assumptions were made for this analysis:

- The minimum approach temperature for most of the heat exchangers is 50°C.

- The high temperature recuperating heat exchangers in the high temperature electrolysis process have minimum approach temperatures of 20°C because they have relatively smaller temperature differences between the inlet and outlet conditions.

- The primary and secondary helium loops and the HTE loop have heat exchanger pressure drops equal to 2% of the average pressure in the loops.

- The power cycle components have 2% pressures drops based on inlet pressures, except for the steam generator and the reheater of the Rankine cycle, which have a 10% pressure drop.

- The primary and secondary circulators have adiabatic efficiencies of 90%.

- The hydrogen recirculator and all pumps have adiabatic efficiencies of 75%.

II.A. Power Cycle

The Rankine steam cycle assumed for this analysis is a standard configuration with three turbines and seven feedwater heaters. The inlet pressure and temperature into the high pressure turbine is 24 MPa and 593°C. The pressure in the condenser is 1 psia. The Rankine high pressure turbine, intermediate pressure turbine, and low pressure turbine have adiabatic efficiencies of 85, 90, and 80%, respectively.

II.A. HTE Process Model

Figure 1 is a process model of the HTE process coupled with the Rankine Steam cycle. The design for the HTE hydrogen production process operates at a system pressure of 5 MPa and uses a steam sweep system to remove oxygen from the anode side of the electrolyzer. Thus, the oxygen product gas, which represents a valuable commodity, can be recovered by condensing the steam and recovering the dry oxygen product gas for later sale.

The HTGR (depicted on the left side of the process flow sheet in Figure 1) provides both electricity and process heat to drive the HTE process. The Rankine steam cycle used to produce electricity to drive the electrolysis process is modeled in a sub-flow sheet designated by the letter "T" on the left side of the process flow sheet in Figure 1. An AC to DC power conversion efficiency of 96% was assumed for supplying DC power to the electrolyzer.

Process heat from the HTGR (which represents only about 10% of the total reactor power) is transferred from the primary loop through an IHX to an intermediate helium loop, and then to the two steam generators (SG1 and SG2) shown in Figure 1. The use of the intermediate loop between the reactor primary system and the HTE process was included in the design as an added barrier to minimize the potential for tritium migration from the primary system, and potential tritium contamination of the HTE product hydrogen.
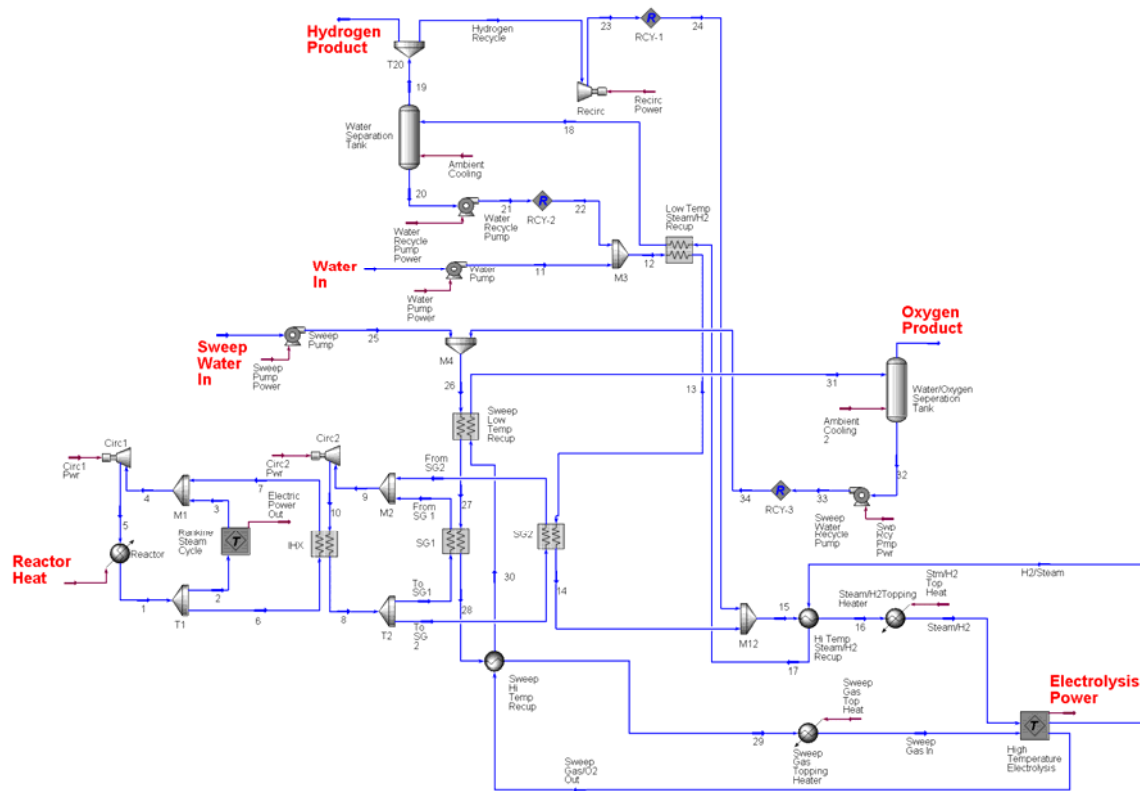
Fig. 1: Process flow diagram of combined HTR and HTE.

Feed water for the HTE process (Water In) is raised to the system operating pressure of 5 MPa by a pump, where it is then mixed with recycled water condensed from the hydrogen product water separation tank. The water stream is then partially vaporized in the recuperator (Low Temp Steam/H2 Recup) which recovers heat from the post-electrolysis process. The low quality feed stream then enters a steam generator (SG2) where the remaining water is vaporized and the steam is heated to approximately 100°C below the electrolysis operating temperature of 800°C. Downstream of the steam generator, at M12, the steam is mixed with recycled hydrogen product gas. A fraction of the product gas is recycled in this way in order to assure that reducing conditions are maintained on the steam/hydrogen electrode. The resulting steam and hydrogen mixture (approximately 10% hydrogen) then passes through a second post-electrolysis process recuperator and a gas-fired heater to raise its temperature to the desired electrolysis operating temperature of 800°C.

The process stream then enters the electrolyzer, where oxygen is electrolytically removed from the steam, producing hydrogen and oxygen. The custom electrolyzer module developed at INL for direct incorporation into the HYSYS process analysis code is described in more detail further in this paper.

Downstream of the electrolyzer, the hydrogen-rich product stream (approximately 70 mol% hydrogen) passes back through the two post-electrolysis recuperators where the product stream is cooled and, as described earlier, the recovered heat is used to heat the inlet process stream to near the desired electrolysis process temperature. The product stream is then further cooled at the water separation tank, where the majority of any residual steam is condensed and separated, yielding the dry hydrogen product. The cooled product stream is split at T20 and a small fraction of the product gas is recycled into the inlet process stream as discussed previously. A recirculating blower is required to repressurize the hydrogen recycle stream to the upstream pressure at M12.

A steam sweep system is used to remove the excess oxygen that is evolved on the anode side of the electrolyzer. In the steam sweep system, the inlet water (Sweep Water In) is raised to the system operating pressure by the sweep pump, and then mixed with condensed water recirculated back from the water/oxygen separation tank at M4. The recirculation of condensed water from the oxygen product stream significantly reduces the net amount of water needed to operate the steam sweep system. After leaving the M4 mixer, the sweep water passes through a recuperator (Sweep Low Temp Recup),

where recovered heat from the sweep system heats and vaporizes the feed water. The superheated steam then passes through steam generator (SG1), where it is superheated to approximately 100°C below the electrolysis operating temperature of 800°C. The steam then passes through a second sweep system recuperator (Sweep Hi Temp Recup) and a gas fired heater where the sweep steam is raised to 800°C before entering the electrolyzer stack.

After removing the excess oxygen from the anode of the electrolyzer, the steam/oxygen mixture (50% oxygen) then passes through the two previously discussed steam sweep system recuperators, where excess heat is recovered and the post-electrolysis steam-oxygen mixture is cooled. The resulting high quality steam-oxygen mixture is then further cooled in the water/oxygen separation tank, where the majority of the water is condensed and recirculated back to be combined with the sweep water feed at M4. The relatively dry oxygen product leaving the water/oxygen separation tank at high pressure (4.9 MPa) is then available for immediate use or storage for later use.

II.C. Electrolysis Module

The electrolyzer model process flow diagram is shown in Figure 2. The process inlet flow, consisting of steam and hydrogen passes through a conversion reactor where the steam is split into hydrogen and oxygen. The conversion reactor uses a stoichiometric equation for the splitting of water. Based upon the utilization, a specified percentage of the steam is converted. HYSYS calculates the heat of reaction for this conversion, which is shown as the "Electrolysis Heating" energy stream in Figure 2. The hydrogen, oxygen, and steam enter a component splitter labeled Electrodes. The oxygen is split from the other components and exits at the anode stream. The sweep gas mixes with the anode stream and exits as the "Sweep Gas/O2 Out" stream. An embedded spreadsheet is used to calculate the Nernst potential, operating voltage, current and electrolysis power [4, 5, 6]. In this base case, the boundary conditions are isothermal and adiabatic, which is referred as the thermal neutral point.
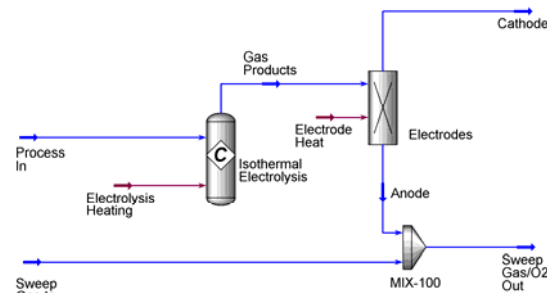

Fig. 2: Process flow diagram of electrolysis module.

III. PROCESS MODEL RESULTS

Two parametric cases were run with this process model, the base case assumed a 50°C minimum approach on most of the heat exchangers, and the second case assumed a 25°C minimum approach temperature. Table 1 summarizes the primary results of the study.

The hydrogen production efficiency is calculated for both cases. The hydrogen production efficiency is defined as the thermal value of the hydrogen product divided by the sum of thermal values of the feed streams, process heat in, and thermal equivalent of the electric power. The efficiency is basically the thermal value of the hydrogen output divided by the thermal value of the input. For the steam reforming case, the hydrogen production efficiency is the higher heating value of the hydrogen divided by the sum of the higher heating value of the natural gas and the thermal energy equivalent of the electrical power input. The thermal value of the electricity is found by the electrical power divided by the efficiency of the power cycle.

		HX Minimum Approach Temperature	
		50°C	25°C
Input	Electricity (MWe)	216	239
	Nuclear Process Heat (MWt)	61.1	62.5
	Process Topping Heat (MWt)	3.45	3.15
	Water (lpm)	8690	8220
	Natural Gas (m³/min)	17.4	15.3
Output	Power Cycle Efficiency	40.0%	44.4%
	Hydrogen Production Efficiency	40.4%	42.8%
	Hydrogen Product (kg/s)	1.75	1.85
	Oxygen Product (kg/s)	13.8	14.6
	Carbon Dioxide Emissions (m³/min)	17.4	15.3

Table 1: Results of nuclear-integrated HTE.

Most of the cooling water comsumption shown in Table 1 (88%) is used to cool the condenser of the power cycle for the nuclear integrated cases. The natural gas usage and carbon dioxide emissions shown in Table 1 come from burning natural gas for the topping heat. At reactor outlet temperatures higher than 825°C, the topping heat is no longer needed.

As the minimum approach temperature on the heat exchanger is reduced, the power cycle efficiency increases producing more electricity for a given thermal input. As the available electricity production increases, more hydrogen is produced in the electrolysis cells. The topping heat is reduced because the steam generators can provide a higher

temperature from the reactor outlet. Each of these factors contributes to increase the hydrogen production.

IV. ECONOMIC ANALYSIS

The economic viability of nuclear assisted hydrogen production was assessed using standard economic evaluation methods. The economics were evaluated for a Rankine steam cycle combined with a HTGR. The total capital investment (TCI), based on the total equipment costs, along with the variable and fixed operating costs were first calculated. The present worth of the annual cash flows (after taxes) is then calculated for the TCI, as well as the TCI at -30% of the HTGR cost, with the debt-to-equity ratios of 80% to 20%.

The estimates of capital costs and operating and maintenance costs assumed the nuclear plant was an "n^{th} of a kind", (NOAK). In other words, the estimates were based on the costs expected after the HTGR technology is integrated into an industrial application more than 10 times. The economic modeling calculations were based on two capital cost scenarios: a current best estimate of $2,000/$kW_{th}$ and a target of $1,400/$kW_{th}$, where kW_{th} is the thermal rating of the plant. In comparison, light water nuclear reactor costs are approximately $1,250/$kW_{th}$. Based on the two capital cost scenarios for HTGR technology, the nominal capital cost for a 600 MW_{th} HTGR would be $1.2 billion; the target capital cost would be $840 million.

The capital costs and operation and maintenance information for the Rankine steam cycle is based on the DOE National Energy Technology Laboratory (NETL) report, *Cost and Performance Baseline for Fossil Energy Plant* [7]. It was assumed that the pulverized coal Rankine steam cycle developed in this report would be similar to the power cycle developed for a high-temperature gas-cooled reactor (HTGR). The costs from this report are 2006 dollars. The analysis is performed using 2009 dollars; therefore, the Chemical Engineering Plant Cost Index (CEPCI) was used to adjust the costs to 2009 dollars. The cost was also adjusted using the six-tenths factor rule using the power output as the capacity variables.

The capital installed costs for the HTSE process are based on a report by Harvego et al. [8] which assumes hydrogen production from a 600 MWt high-temperature gas reactor with an outlet temperature of 900°C. At that temperature, the power cycle efficiency is 53% with a corresponding hydrogen production rate of 2.4 kg/sec. For the current cases, the power cycle efficiencies are 40% and 44% with a hydrogen production flow rates of 1.75 kg/s and 1.85 kg/sec. The hydrogen production system in the Harvego report used air as the sweep gas, whereas this analysis used steam for the sweep gas. Heat exchanger costs in the HTSE process were adjusted in this analysis to account for the different sizes. Air sweep compressor costs (including intercoolers) were removed and a water pump for the steam sweep was added. The same installed cost factors found in the Harvego report were used to adjust the cost of the equipment. The costs from the Harvego report are 2005 costs; therefore CEPCI was used to adjust the costs to 2009 dollars. Uninstalled costs are the basic cost of the equipment from the manufacturer. Installed costs are the uninstalled costs plus the additional materials and labor needed to place and install the equipment.

In the Harvego report, the cost of the electrolysis cells is $200/kWe, based on the power into the cells. This was derived from a 2007 goal of the Solid State Energy Conversion Alliance (SECA) for solid oxide fuel cells. The goal was set to $400/kWe for the fuel cells, but because solid oxide electrolysis cells run at twice the voltage for the same current density, the electrolysis cells are half the cost. At a recent SECA conference, the goal for solid oxide fuel cells has changed to $175/kWe, which when halved for SOEC comes to $87.5/kWe [9]. Consulting with HTE experts, a NOAK goal of $100/kWe was used for this study [10, 11].

The installed capital costs of the HTSE process without reactor and power cycle costs is $63.2 million for the base case and $66.4 million for the case with a power cycle efficiency of 44%. The breakdown of these costs is very similar for both cases. Figure 3 shows the breakdown of the 44% case.
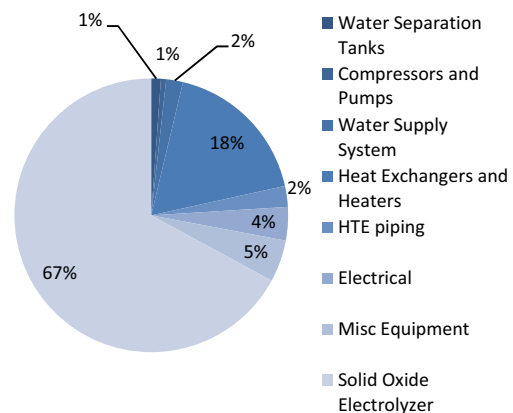

Fig. 3: Installed capital costs of HTSE without reactor and power cycle costs.

The total capital investment (TCI) of the HTE connected to a 600 MWt HTGR are calculated by multiplying the installed power cycle and HTE costs with a 10% engineering fee and a 18% contingency fee. The reactor cost already includes

these fees. The HTE TCI also includes cooling towers and support capital like water, piping, instrument and controls, electrical systems and building and structures. The TCI for the nuclear reactor for both cases is $1.025 billion. The TCI for the power cycle and the HTE process are $172 million, and $109 million for the 40% power cycle case and $184 million, and $116 million for the 44 % power cycle case. The total TCI are $1.308 billion and $1.324 billion for the 40% and 44% power cycle cases respectively. The HTE process makes up 8 to 9% of the total TCI. If one assumes a -30% TCI for the reactor cost, the total TCI costs are $1.000 billion and $1.017 billion for the 40% and 44% power cycle cases.

Yearly revenues were estimated for low, average, and high prices for hydrogen, see Tables 2 and 3.

	Price ($/kg)	Generated (kg/s)	Annual Revenue ($M)
Oxygen	0.0459	13.8	$18.4
Hydrogen-Low	1.00	1.75	$50.8
Hydrogen-Avg.	3.00	1.75	$152
Hydrogen-High	5.00	1.75	$253
Combined Annual Revenue, low			**$69.2**
Combined Annual Revenue, average			**$170.4**
Combined Annual Revenue, high			**$271.4**

Table 2: Annual revenues for 40% power cycle case.

	Price ($/kg)	Generated (kg/s)	Annual Revenue ($M)
Oxygen	0.0459	14.6	$19.4
Hydrogen-Low	1.00	1.85	$53.7
Hydrogen-Avg.	3.00	1.85	$161
Hydrogen-High	5.00	1.85	$269
Combined Annual Revenue, low			**$73.1**
Combined Annual Revenue, average			**$180.4**
Combined Annual Revenue, high			**$288.4**

Table 3: Annual revenues for 44% power cycle case.

Manufacturing cost is the sum of direct and indirect manufacturing costs. Direct manufacturing costs for this project include the cost of raw materials, utilities, and operating labor and maintenance. Indirect manufacturing costs include estimates for the cost of overhead and insurance and taxes.

The expected duration of the electrolysis cells for NOAK is 8 years. Assuming that one-eighth of the cells are replaced every year, and based on the $100/kWe cost of the cells, the yearly replacement cost are $2,714,310 and $2,872,250 for the 40% and 44% power cycle cases respectively.

Labor costs are assumed to be 1.15% of the total capital investment. Maintenance costs were assumed to be 3% of the total capital investment.[13] The power cycle and HTSE were not included in the TCI for operation and maintenance costs, as they were calculated separately. Taxes and insurance were assumed to be 1.5% of the total capital investment, excluding the HTGR, an overhead of 65% of the labor and maintenance costs was assumed, and royalties were assumed to be 1% of the coal or natural gas cost [12]. Availability of the nuclear plant was assumed to be 92%.

To assess the economics of the HTSE case, several economic indicators were calculated. The IRR for low, average, and high hydrogen selling prices was calculated. In addition, the fuel price necessary for a return of 10% was calculated. The following assumptions were made for the economic analyses:

- The plant startup year is year 5
- A construction period of five years for the nuclear plant that begins in year 0
  - It is assumed that all reactors come online at the same time
  - Percent capital invested for the HTGR is 20% per year
- Plant startup time is one year
  - Operating costs are 85% of the total value during startup
  - Revenues are 60% of the total value during startup
- The analysis period for the economic evaluation assumes an economic life of 30 years, excluding construction time (the model is built to accommodate up to 40 years)
- An inflation rate of 2.5% is assumed
- Debt-to-equity ratios of 80%/20% are calculated as this would be most consistent for an NOAK plant
  - The interest rate on debt is assumed to be 8%
  - The repayment term on the loan is assumed to be 15 years
- The effective income tax rate is 38.9%
  - State tax is 6%
  - Federal tax is 35%

- Modified Accelerated Cost-Recovery System (MACRS) depreciation is assumed [13, 14, 15].

To assess the IRR and present worth (PW) of each scenario, it is necessary to calculate the after tax cash flow (ATCF). To calculate the ATCF it is necessary to first calculate the revenues (R_k), cash outflows (E_k), sum of all noncash, or book, costs such as depreciation (d_k), net income before taxes (NIBT), the effective income tax rate (t), and the income taxes (T_k), for each year (k). The taxable income is revenue minus the sum of all cash outflow and noncash costs. Therefore the income taxes per year are defined as follows:

$$T_k = t\left(R_k - E_k - d_k\right) \qquad \text{(eq. 1)}$$

Depreciation for the economic calculations was calculated using a standard MACRS depreciation method with a property class of 15 years. Depreciation was assumed for the total capital investment over the five year construction schedule, including inflation.

The ATCF is then the sum of the before tax cash flow (BTCF) minus the income taxes owed. Note that the expenditures for capital are not taxed but are included in the BTCF each year there is a capital expenditure (C_k); this includes the equity capital and the debt principle. The BTCF is defined as follows:

$$BTCF_k = R_k - E_k - C_k \qquad \text{(eq. 2)}$$

The ATCF can then be defined as:

$$ATCF_k = BTCF_k - T_k \qquad \text{(eq. 3)}$$

The IRR method is the most widely used rate of return method for performing engineering economic analyses. This method solves for the interest rate that equates the equivalent worth of an alternative's cash inflows to the equivalent worth of cash outflows (after tax cash flow), i.e., the interest rate at which the PW is zero. The resulting interest is the IRR (i'). For the project to be economically viable, the calculated IRR must be greater than the desired minimum annual rate of return (MARR).

$$PW(i'\%) = \sum_{k=0}^{N} ATCF_k\left(1 + i'\right)^{-k} = 0 \qquad \text{(eq. 4)}$$

IRR calculations were performed for an 80%/20% debt-to-equity ratio and for -30% TCI for the HTGR at low, average, and high prices. In addition, the price of hydrogen necessary for an IRR of 12% and a PW of zero was calculated for each case at each debt-to-equity ratio. The IRR and hydrogen price required (for an IRR of 12%) was

solved for using the Goal Seek function in Excel. Table 4 and 5 show the results of this analysis for both cases.

	TCI -30% HTGR		TCI	
	IRR	$/kg	IRR	$/kg
	$1,000,417,985		*$1,307,917,985*	
	-1.43	$1.00	-3.10	$1.00
HTE	12.52	$3.00	9.21	$3.00
	21.65	$5.00	16.88	$5.00
	12.00	$2.90	12.00	$3.67

Table 4: IRR results for 80%/20% debt-to-equity ratio for 40% power cycle case.

	TCI -30% HTGR		TCI	
	IRR	$/kg	IRR	$/kg
	$1,016,751,979		*$1,324,251,979*	
	-0.78	$1.00	-2.48	$1.00
HTE	13.25	$3.00	9.86	$3.00
	22.59	$5.00	17.72	$5.00
	12.00	$2.77	12.00	$3.50

Table 5: IRR results for 80%/20% debt-to-equity ratio for 44% power cycle case.

V. CONCLUSIONS

An analysis was performed for the production of hydrogen using nuclear-integrated high temperature electrolysis. A 600 MWt high temperature gas reactor with a 750°C outlet temperature can produce 1.75 to 1.85 kg/s of hydrogen and 13.8 to 14.6 kg/s of oxygen. At an IRR of 12% and a debt-to-equity ratio of 80%/20%, the cost of hydrogen production is $3.50/kg to $3.67of hydrogen produced.

The current method of hydrogen production is through the steam/methane reform process (SMR). The price of SMR produced hydrogen is linked closely with the cost of the natural gas feed. Based on a natural gas price of $5.40, (the average price in 2009), the price of hydrogen production for SMR is $1.75 [16, 17]. Although the cost of hydrogen production is less, the SMR process releases greenhouse gases.

At higher reactor outlet temperatures, the power cycle efficiency increases which directly increases the hydrogen production efficiency. At reactor outlet temperatures of 900°C, the power cycle efficiency can exceed 50%. At these higher temperatures it is hoped that the cost of hydrogen production will be more like the cost of SMR production.

Finally, if the cost of the reactor can be reduced, the cost of hydrogen production via HTE improves greatly. At the -30% HTR TCI, the cost of hydrogen production is $2.77/kg to $2.90/kg of hydrogen.

VI. ACKNOWLEDGEMENTS

VII. COPYRIGHT STATEMENT

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