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Nuclear hydrogen: An assessment of product flexibility and market viability

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ABSTRACT

Nuclear energy has the potential to play an important role in the future energy system as a large-scale source of hydrogen without greenhouse gas emissions. Thus far, economic studies of nuclear hydrogen tend to focus on the levelized cost of hydrogen without accounting for the risks and uncertainties that potential investors would face. We present a financial model based on real options theory to assess the profitability of different nuclear hydrogen production technologies in evolving electricity and hydrogen markets. The model uses Monte Carlo simulations to represent uncertainty in future hydrogen and electricity prices. It computes the expected value and the distribution of discounted profits from nuclear hydrogen production plants. Moreover, the model quantifies the value of the option to switch between hydrogen and electricity production, depending on what is more profitable to sell. We use the model to analyze the market viability of four potential nuclear hydrogen technologies and conclude that flexibility in output product is likely to add significant economic value for an investor in nuclear hydrogen. This should be taken into account in the development phase of nuclear hydrogen technologies.

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1. Introduction

The US Department of Energy's (DOE's) Nuclear Hydrogen Initiative (NHI) is supporting system studies to better understand the potential role of nuclear energy in a hydrogen economy. This assessment includes identifying commercial hydrogen applications and their requirements, comparing the characteristics of nuclear hydrogen systems to those market requirements, evaluating nuclear hydrogen configuration options, and identifying the key drivers and thresholds for market viability of nuclear hydrogen options. In this paper, we present results from a profitability evaluation of different nuclear hydrogen technologies. Our focus is on how the flexibility to switch between hydrogen and electricity production can add economic value to a nuclear hydrogen plant.

The paper expands on previous work by moving beyond levelized cost calculations. Potential investors in nuclear hydrogen production will have to operate in a market environment that differs from the traditional regulated regime under which the nuclear industry formerly operated. While costs will remain an important decision variable, investment decisions are likely to be driven primarily by profit expectations and risk management considerations. Therefore, we are developing a financial model based on real options theory that analyzes profitability, risk, and uncertainty from an investor's perspective.

With current concerns about climate change the interest in nuclear energy is increasing in many parts of the world. There are obviously a number of policy concerns and considerations for nuclear energy technologies in general, ranging from waste management to proliferation. However, in this paper we limit our focus to the financial consequences of investments in nuclear hydrogen technologies. In order for nuclear energy to play a role in the future energy system, it is obviously important to develop technologies that are viable from potential investors' point of view.

The paper has the following structure. Section 2 discusses the potential role of nuclear hydrogen technologies in future hydrogen markets. Section 3 gives a brief introduction to real options theory. Section 4 describes the stochastic model we have developed for profitability analysis of nuclear hydrogen plants. In Section 5, we use the model to assess the profitability of four potential nuclear hydrogen technology configurations. Finally, in Section 6 we discuss the results of the analysis and provide conclusions and directions for future work.

2. Hydrogen markets and nuclear hydrogen technologies

If the transition to a hydrogen-based transportation system were to succeed, the US demand for hydrogen could substantially increase markets for large-scale production technologies such as nuclear power. Today's vehicle stock is projected to increase from 220 to 340 million vehicles to 2030 (DOE, 2006) and would, if entirely fueled by hydrogen, potentially consume about 77 million

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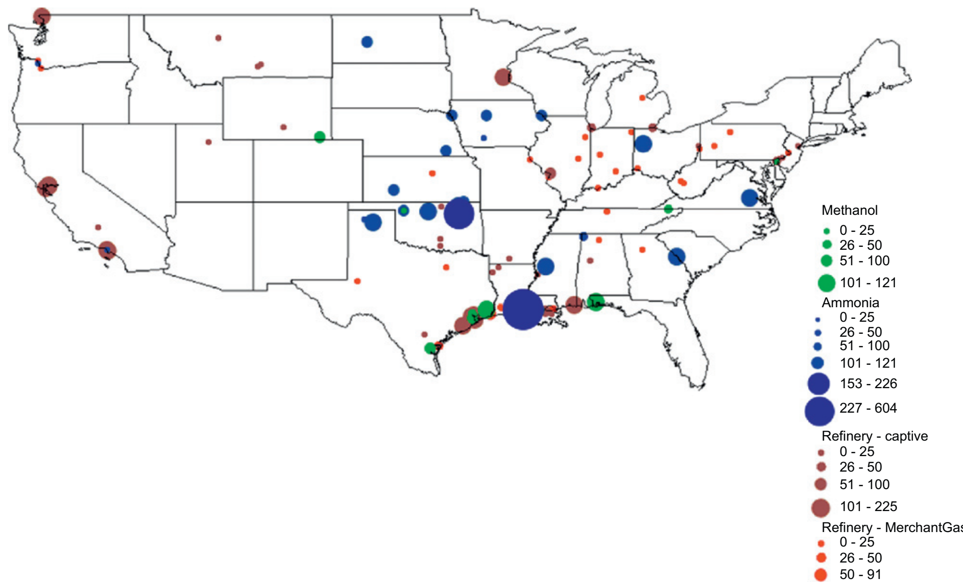

Fig. 1. Hydrogen consumption: location and quantity (1000 ton) for oil refining, ammonia and methanol production in 2003 (Yildiz et al., 2005).

metric tons of hydrogen. This is roughly 10 times today's US consumption of intentionally produced hydrogen (SRI, 2004). If the hydrogen were supplied solely by nuclear power, approximately 326 GWth would be needed, roughly doubling today's installed nuclear capacity.

While the potential for hydrogen, therefore, seems promising, this future market carries substantial risks and uncertainties that will affect how investors will try to enter it. Projected transportation demand for hydrogen is highly uncertain. And unlike today's captive, stationary H_2 demand, which is geographically contained in a limited number of locations (see Fig. 1), mobile H_2 demand may be dispersed across the country, often at low demand densities, eventually requiring a well-developed distribution system.

The current US hydrogen market is cornered (about 95%) by natural gas-based technologies. Large consumers, such as oil refiners, enter into 10–15 year purchase agreements with suppliers that either build their gas reformers on-site or across the fence. Opportunities for new market entrants in the captive stationary markets will be limited to any future incremental demand or as existing agreements expire. Nuclear hydrogen will compete directly with hydrogen from steam methane reforming (SMR) and other emerging technologies. Much will depend on the future price of natural gas relative to nuclear energy. At today's historically high gas prices, studies have shown that nuclear hydrogen is likely to be competitive with SMR (Penner, 2006).

Matching local or regional demand densities with unit output and ensuring a high utilization factor will be a challenge for nuclear hydrogen production facilities. Nuclear plant sizes typically vary from 300–600 to 2400 MWth. A 300 MWth unit can produce about 30,000 ton H_2/yr. The analysis of current hydrogen markets in Yildiz et al. (2005) showed about 60 locations in the US with demands above that level. Only five locations currently require hydrogen on a scale that would be produced from a 2400-MWth facility.

Several hydrogen production processes supported by advanced nuclear reactors could potentially contribute to the hydrogen supply in the evolving markets. The nuclear hydrogen processes can range from low-temperature electrolysis to high-temperature thermochemical water-splitting cycles. Table 1 presents an overview of the operating conditions for the most important nuclear hydrogen production technologies. A detailed description of technical and economical challenges for these technologies can be found in Yildiz et al. (2005) and in Yildiz and Kazimi (2006). Water electrolysis coupled to a light-water reactor (LWR) is the least energy efficient, but it is a well commercialized technology that does not emit any greenhouse gases (GHGs), and it can yield higher efficiencies if supported by advanced power conversion systems. It is the only currently available technology for producing hydrogen on a large scale without GHG release and without the burden of CO_2 capture and sequestration. The advanced hydrogen production technologies that require higher temperatures have the potential to provide higher efficiency and lower cost, but they are currently in the research and development (R&D) stage. Note that for the electrochemical technologies, the nuclear reactor provides electricity as input to the electrolysis. Thus, these plants lend themselves to co-production of electricity and hydrogen, or even switching between the two products depending on what is more profitable. In contrast, in the thermochemical plant designs the nuclear reactor mainly provides heat as input to the hydrogen production process. Consequently, co-production or product switching would require substantial additional investment for these technology configurations.

The goal of DOE's NHI[1] is to demonstrate cost efficient and large-scale production of nuclear hydrogen. Several of the advanced technologies are being investigated as candidates for this purpose. Until now, no consensus has been reached on the efficiencies and costs of these technologies. All candidate technologies, the leading ones being high-temperature steam electrolysis and the high-temperature sulfur-based thermochemical water-splitting cycles, have margins for improving their efficiencies and costs. Nevertheless, efficiency improvements may come at the price of higher complexity and capital cost. In this paper, we analyze the profitability of both electrochemical and thermochemical nuclear hydrogen technologies, using a stochastic profitability model that is outlined in Section 4. The model takes into account the value of product flexibility for technologies with the ability to switch output product.

[1] See http://www.ne.doe.gov/NHI/neNHI.html for more information on DOE's NHI.

Table 1
Overview of nuclear hydrogen production processes

Feature	Approach			
	Electrochemical		Thermochemical	
	Water electrolysis	High-temperature steam electrolysis	Steam-methane reforming	Thermochemical water splitting
Required temperature, °C	<100, at Patm	>500, at Patm	>700	>600–800, depending on cycle
Efficiency of hydrogen process, %	85–90	90–95 (at $T>800\,^{\circ}$C)	>60, depending on temperature	>40, depending on cycle and temperature
Energy efficiency conventional nuclear reactor, %	~27	~30	Not feasible	Not feasible
Energy efficiency advanced nuclear reactor, %	>40	>45, depending on power cycle and temperature	>60, depending on temperature	>40, depending on cycle and temperature
Advantage	Proven technology	High efficiency Can operate at intermediate temperatures No CO_2 emissions	Proven technology Reduces CO_2 emissions	Potential for high efficiency No CO_2 emissions
Disadvantage	Low efficiency	Requires development of durable, large-scale electrolysis units	CO_2 emissions Dependent on natural gas prices	Aggressive chemistry Requires very high temperature reactors Requires large-scale development

3. Real options theory

According to traditional finance theory, the net present value (NPV) is the best indicator for evaluating an investment project. The static form of the NPV rule states that a project should be undertaken as long as the sum of discounted cash flows from the project (i.e., the NPV) is positive; projects with a negative NPV should be rejected. It has become apparent, however, that traditional discounted cash flow techniques have severe shortcomings. The static assessment compares the value of investing today with not investing at all. In most cases, however, the decision maker can choose to defer making an investment and then to invest later if more favorable conditions emerge. Furthermore, the investor has the flexibility to make investment and operational decisions in the future, depending on how uncertainties unfold.

A new direction within investment theory emerged in the 1980s and 1990s that mitigated the shortcomings of static discounted cash flow techniques. The new approach, often referred to as real options theory, is based on a dynamic analysis of investment projects. Real options theory recognizes that an investment project can have several embedded properties that can be viewed as options. The most common options for investment projects are the option to defer an investment, the time to build option (for staged investments), the option to alter operating scale, the option to abandon a project, the option to switch inputs or outputs from a process, and different forms of growth options (e.g., R&D investments). In some projects, there are interacting effects among several of these options. In mathematical terms, real options valuation is based on a stochastic dynamic analysis. Compared with a simple static NPV evaluation of the cash flows from an investment, the real options paradigm adds two important analytical dimensions to the problem. First, a flexible and dynamic representation of future managerial operational and investment decisions is used. Second, important uncertain variables are represented as stochastic processes. Under certain assumptions about the underlying stochastic processes, the resulting mathematical models can be solved analytically. However, for complex investment problems with several sources of uncertainty, it is more common to use discrete mathematics or stochastic simulations to find the optimal investment strategy. The theoretical foundation for real options theory and its application to investment under uncertainty are covered in detail by Dixit and Pindyck (1994). A less theoretical description that focuses on real-world applications is given in Copeland and Antikarov (2003).

Real options theory is now frequently used for asset valuation and analysis of investments in energy-related industries. For instance, Schwartz and Smith (2000) developed a model for analyzing optimal decisions regarding the development of oil fields when future oil prices are uncertain. Deng et al. (2001) derived models for valuation of generation and transmission assets in electrical power systems. Botterud and Korpås (2007) analyzed the optimal timing of power generation investments in restructured electricity markets. Maribu and Fleten (2005) used Monte Carlo simulation to analyze the value of combined heat and power systems under uncertainty in electricity and natural gas prices. There are also several examples of real options models for nuclear power plants, for instance in Graber and Rothwell (2005) and Rothwell (2006). However, we are not aware of applications of real options theory for analyzing investments specifically in nuclear hydrogen production.

4. A stochastic profitability model

Our model for profitability assessment of nuclear hydrogen plants calculates the discounted profits from investing in a new nuclear hydrogen production facility. The plant can have either fixed or flexible output products. The model focuses on the value of the option to switch output product. Monte Carlo simulations are used to quantify the value of a plant's potential flexibility to switch between hydrogen and electricity production under uncertainty in hydrogen and electricity prices. A prior version of the model was first described in Botterud et al. (2007).

4.1. *Representation of hydrogen and electricity prices*

To represent the uncertainty in future hydrogen and electricity markets, we use stochastic variables for the future average annual electricity and hydrogen prices. In addition, we model intra-year variation in prices with deterministic price parameters, as described below.

For the hydrogen price, we model a monthly variation in price, assuming that the future hydrogen price will follow a seasonal pattern. The mathematical representation is below:

$$p^{h2}_{t,m} = PH2_t\, a^{h2}_m \tag{1}$$

where $p^{h2}_{t,m}$ is the hydrogen price year t, month m [\$/kg], $PH2_t$ the average hydrogen price, year t (stochastic variable) [\$/kg], a^{h2}_m the monthly price factor for hydrogen, month m. We do not expect a short-term (day/night) pattern in hydrogen prices, as some storage is likely for hydrogen as with natural gas today.

Electricity prices are known to exhibit a high degree of variability. Some of the variations are due to the seasonal and daily changes in load and are, therefore, fairly predictable. In order to represent the deterministic variation in electricity prices we use monthly price factors for electricity. In addition, within each month we define two sub-periods to represent peak- and off-peak prices. This is to model the daily cycle in electricity prices, with high prices during the day and low prices at night. The average annual electricity price, which is a stochastic variable, is multiplied by the two constant price factors to obtain the final peak- and off-peak prices for each month, as shown below:

$$p^{el}_{t,m,i} = PEL_t\, a^{el}_m b^{el}_{m,i} \tag{2}$$

where $p^{el}_{t,m,i}$ is the electricity price year t, month m, sub-period i ($i = 1$: peak, $i = 2$: off-peak) [\$/MWh], PEL_t the average electricity price, year t (stochastic variable) [\$/MWh], a^{el}_m the monthly price factor for electricity, month m, $b^{el}_{m,i}$ the sub-period price factor for electricity, month m, sub-period i.

The annual average hydrogen and electricity prices are stochastic variables and are represented as discrete Geometric Brownian Motion (GBM) processes using Eqs. (3) and (4):

$$PH2_{t+1} = PH2_t(1 + \alpha_{PH2} + \sigma_{PH2}\varepsilon_{PH2,t}) \tag{3}$$

$$PEL_{t+1} = PEL_t(1 + \alpha_{PEL} + \rho\sigma_{PEL}\varepsilon_{PH2,t} + \sqrt{1-\rho^2}\sigma_{PEL}\varepsilon_{EL,t}) \tag{4}$$

where σ_{PH2} is the hydrogen price volatility [%], α_{PH2} the hydrogen price growth rate [%], $\varepsilon_{PH2,t}$ the random variable for hydrogen price change, year t, normal dist. (0,1), σ_{PEL} the electricity price volatility [%], α_{PEL} the electricity price growth rate [%], $\varepsilon_{PEL,t}$ the random variable for electricity price change, year t, normal dist. (0,1), ρ the correlation between hydrogen and electricity price.

The GBM process is multiplicative. If the initial price is higher than zero, the future prices will also remain above zero. The simulated prices at a certain time period in the future will have a lognormal distribution, and the upper tail of the distribution tends to drift off to high levels owing to the multiplicative effect. The investment model also allows for using mean reversion processes for the average hydrogen and electricity prices. However, in the analysis presented in this paper, we only present results based on the GBM assumption.

In our analysis, we are mainly looking at new technologies that are not likely to be commercially available for a number of years into the future. Thus, it may be necessary to use subjective estimates of future market conditions as input parameters to the price models. Parameters for the electricity price model could also be estimated based on historical prices for electricity, or one could use a separate model to simulate electricity prices for future states of the system and use the simulated prices as input to the model. For the hydrogen price parameters, there are no large-scale transparent markets for hydrogen today. One could, however, use price data from other markets (e.g., gasoline or natural gas) as a proxy for future variations in the future hydrogen price.

4.2. Dispatch decision and profit calculations

The model has monthly prices for electricity and hydrogen. For electricity, there is also an off- and on-peak price within each month, as explained above. We assume that a decision for how to dispatch the plant takes place for each simulated month. Hence, a nuclear hydrogen plant with flexible plant output has three potential modes, φ, of operation within each month:

- $\varphi = 1$: Produce hydrogen only with no electricity generation;
- $\varphi = 2$: Produce electricity at constant output, possibly maintaining a fixed amount of hydrogen production at the same time; and
- $\varphi = 3$: Produce hydrogen at night when the electricity price is low, and produce electricity during the day when the electricity price is high.

We assume a switching cost in the third mode of operation, when there is a daily cycle of switching the hydrogen plant on and off. The switching cost is daily and includes the additional variable and maintenance costs due to one cycle of switching (i.e., shutting down the hydrogen plant and restarting it). When the plant is in the hydrogen (1) or electricity (2) mode of operation, there is no switching of operation within the month and, therefore, no switching cost. Note that we also assume that there is no switching cost in situations where the plant goes from electricity production to hydrogen production (or vice versa) between two months. Hence, the switching cost only applies to operating mode 3, that is, the daily switching cycle.

The objective for the plant operation within each month is to maximize the operational revenues (net of the switching costs) while staying within operational and contractual constraints. This can be expressed as shown in Eqs. (5)–(10). The objective function in Eq. (5) does not include fuel and operations and maintenance (O&M) costs, as these are assumed to be constant regardless of operating mode and are subtracted at an annual level, as explained below. The energy balance in Eq. (6) simply states that the sum of output from the flexible plant is constant, that is, all the available energy from the nuclear reactor is always fully utilized for hydrogen and/or electricity production. Planned and forced outages are represented by derating (i.e., reducing) the full production capacity with an availability factor, *af*, as shown in Eqs. (6)–(9). Eqs. (7)–(10) are upper and lower constraints on the amount of hydrogen and electricity production for the flexible plant.

$$RFLEX_{t,m} = \underset{q^{h2}_{t,m,i},q^{el}_{t,m,i},\varphi_{t,m}}{MAX}\left[\sum_{i=1}^{2}(q^{h2}_{t,m,i}p^{h2}_{t,m} + q^{el}_{t,m,i}p^{el}_{t,m,i}) - SC_{t,m}(\varphi_{t,m})days_m\right] \tag{5}$$

subject to

$$q^{h2}_{t,m,i}c + q^{el}_{t,m,i} = QEL\, af\,\frac{hrs_{m,i}}{8760} \tag{6}$$

$$q^{h2}_{t,m,i} \leqslant QH2\, af\,\frac{hrs_{m,i}}{8760} \tag{7}$$

$$q^{el}_{t,m,i} \leqslant QEL\, af\,\frac{hrs_{m,i}}{8760} \tag{8}$$

$$q^{h2}_{t,m,i} \geqslant q^{h2}_{min}\, QH2\, af\,\frac{hrs_{m,i}}{8760} \tag{9}$$

$$q^{el}_{t,m,i} \geqslant 0 \tag{10}$$

where $RFLEX_{t,m}$ is the revenue from flexible plant, year t, month m [M \$], $q^{h2}_{t,m,i}$ the hydrogen production, year t, month m, sub-period i ($i = 1, 2$) [kg], $q^{el}_{t,m,i}$ the electricity production, year t, month m, sub-period i ($i = 1, 2$) [MWh], $SC_{t,m}(\varphi_{t,m})$ the daily switching cost, year t, month m [M \$], $\varphi_{t,m}$ the operating mode, year t, month m, $\varphi_{t,m} \in \{1-el, 2-h2, 3-flex\}$, $QH2$ the annual hydrogen production at max output [kg/yr], QEL the annual electricity generation at max output [MWh/yr], q^{h2}_{min} the minimum fraction of hydrogen production for flexible plants [%], c the electricity-hydrogen production ratio for flexible plants [MWh/kg], af the plant availability factor [%], $days_m$ the no. of days in month m [days], $hrs_{m,i}$ the no. of hours in month m, sub-period i [h].

The minimum level of hydrogen production applies in all time periods for the flexible plant (q^{h2}_{min} in Eq. (9)). This means that the plant maintains a fixed lower level of hydrogen production also during periods with electricity generation. The minimum amount of hydrogen production could represent operational constraints. For example, it may be desirable to maintain a small amount of H_2 production to keep the hydrogen production system warm during periods of electricity generation. Alternatively, the minimum hydrogen production level could represent a firm delivery to hydrogen consumers, which requires a fixed lower amount of hydrogen production from the plant. This could be the case if the plant has only limited storage facilities for hydrogen.

The derivation of operating revenue presented above is for a plant with flexible output product. It is also possible to calculate the profitability of pure hydrogen (H2) and electricity (EL) plants using the same representation of hydrogen and electricity prices. For these single-output plants, the revenue in each month is equal to the production times the price, as shown in Eqs. (11) and (12). Naturally, no switching costs apply for these plants. The monthly production for the hydrogen and electricity plants is given by Eqs. (7) and (8), respectively (replacing the inequalities with equalities). A plant could also produce both hydrogen and electricity at fixed output levels, earning a combined revenue from both hydrogen and electricity sales.

$$RH2_{t,m} = p^{h2}_{t,m} \sum_{i=1}^{2} q^{h2}_{t,m,i} \tag{11}$$

$$REL_{t,m} = \sum_{i=1}^{2} q^{el}_{t,m,i} \cdot p^{el}_{t,m,i} \tag{12}$$

where $RH2_{t,m}$ is the revenue from a pure hydrogen plant, year t, month m [M \$] $REL_{t,m}$ the revenue from a pure electric power plant, year t, month m [M \$].

4.3. Cash flow analysis

Monthly revenues are aggregated to annual results, which in turn are discounted over the lifetime of the plant along with operating and investment costs. The total discounted profit for the plant, Π, is equal to the sum of annual free cash flows, FCF_t, and the salvage value at the end of the lifetime of the plant, SV, as shown in Eq. (13). Annual earnings before tax, EBT_t, and annual free cash flows, FCF_t, are calculated as shown in Eqs. (14) and (15). Note that we do not include decommissioning costs in the analysis. Since these costs occur at the end of the planning period they will have limited impact on the financial results due to the discounting factor. The magnitude and uncertainty of future decommissioning costs may still play a role for investors in nuclear hydrogen, but this aspect is not addressed in the model.

$$\Pi = \sum_{t=0}^{T} \frac{1}{(1+r)^t} FCF_t + \frac{1}{(1+r)^{T+1}} SV \tag{13}$$

$$EBT_t = R_t + (QEL^{out} - QEL^{in}) PEL_t - VOM_t - FOM_t - D_t \tag{14}$$

$$FCF_t = EBT_t(1 - tax) + D_t - WC_t - IC_t \tag{15}$$

where R_t is the annual plant revenue, year t (i.e., $R_t = \sum_{m=1}^{12} R_{t,m}$) [M \$], QEL^{out} the fixed annual electricity sales to grid [MWh/yr], QEL^{in} the annual external electricity input to H_2 process [MWh/yr], VOM_t the variable operating and maintenance cost, year t [M \$], FOM_t the fixed operating and maintenance cost, year t [M \$], D_t the depreciation, year t [M \$], WC_t the change in working capital, year t [M \$], IC_t the investment cost, year t [M \$], tax the tax rate, r the risk-adjusted real discount rate.

The annual plant revenue, R_t, in Eq. (14) is the sum of monthly revenues and could be equal to either $RFLEX_t$, $RH2_t$, or REL_t, depending on the type of plant being analyzed. The cost of external electricity input is included as a separate item in Eq. (14). This is relevant for nuclear hydrogen plant configurations that use the nuclear plant as a heat source only and require electricity from the grid as input to the hydrogen production process. The fixed electricity sales and external input, QEL^{out} and QEL^{in}, are assumed to be purchased for a price equal to the annual average electricity price, PEL_t. The annual fixed O&M costs, the depreciation, the change in working capital, the investment cost, and the salvage value are all deterministic parameters. All these parameters are assumed to be independent of the operating mode for flexible plant configurations. However, a switching cost is subtracted from the monthly operating revenues, as explained in Section 4.2, and is, therefore, reflected in the annual plant revenue.

We use a risk-adjusted interest rate for discounting of future cash flows in Eq. (13). Thus, we do not attempt to use contingent claims analysis or risk neutral valuation from real options theory in the financial assessment. This is because the technologies and markets that we are analyzing will only emerge in the distant future. Consequently, it is impossible to establish the replicating portfolios, which are required for the application of these methods, based on current market data.

4.4. Monte Carlo simulations

The stochastic profitability model is implemented in Microsoft Excel. We use @Risk to run Monte Carlo (MC) simulations for the nuclear plant cash flow analysis and profitability assessment. @Risk is an add-in to Excel for risk analysis and stochastic simulations (Palisade, 2004). In each iteration of the MC simulation, random numbers are drawn for the stochastic price variables, $\varepsilon_{H2,t}$ and $\varepsilon_{EL,t}$, in price Eqs. (3) and (4) for all future years, $t = 0,1,2, \ldots, T$. The number of MC iterations is specified in the @Risk interface. A fixed random number seed can also be defined, so that the same sequence of random simulations can be repeated. Thus, sampling errors are removed when comparing runs with different plant configurations.

4.5. Model results

In addition to calculating the discounted profit over the lifetime of the plant, the model can calculate additional financial indicators such as a plant's internal rate of return (IRR). Furthermore, for plant designs with flexible output product, the model calculates the amount of hydrogen and electricity production in each month. All the results are calculated for each iteration of the MC simulations of prices. Hence, the model produces probability distributions for all results, from which expected values, standard deviations, and other statistical metrics can easily be derived.

5. Financial analysis of nuclear hydrogen technologies

We now use the financial model outlined above to analyze profitability of four potential nuclear hydrogen technologies.

5.1. Technology characteristics

The four nuclear hydrogen technology configurations analyzed are listed in Table 2. The first plant configuration represents currently available plant designs and consists of a high-pressure, low-temperature water electrolysis process coupled to an advanced LWR. The other three technologies are at the R&D stage and are the main ones currently being considered within DOE's NHI program. For the two electrolysis-based technologies (HPE-ALWR and HTE-HTGR), the nuclear plant provides the required electricity, which is the main input to the hydrogen process. It is assumed that these two technologies have the capability of reducing the hydrogen production and instead selling electricity to the grid in periods when this is more profitable. Hence, they have hydrogen/electricity product flexibility. For the thermochemical SI-HTGR configuration, the nuclear plant provides the required heat, which is the main input to the hydrogen process: additional required electricity is purchased from the grid. Hence, this plant configuration is a dedicated hydrogen plant and does not have hydrogen/electricity product flexibility. In the hybrid HyS-HTGR design, two 600 MW nuclear reactors provide the required heat, whereas two additional 600 MW reactors provide electricity to the hydrogen process. Surplus electricity generation is sold to the grid at a constant rate. This plant is assumed to be operated at constant output levels of hydrogen and electricity. The cost and performance assumptions for all technologies are listed in Table 3 and are based on information from Technology Insights (TI), which estimate construction and operating costs based on information from potential nuclear hydrogen plant manufacturers.

There is, of course, substantial uncertainty in the cost and performance parameters used in the analysis, especially for the three nuclear hydrogen technologies that are still at the R&D stage. It is important to keep this uncertainty in mind when analyzing the financial analysis presented below, and the results should be interpreted accordingly.

Additional assumptions that are common for all technologies are:

- plant availability (af) 90%, tax rate (tax) 38.9%, real discount rate (r) 10%;
- a 3-year construction time and a 40-year lifetime, i.e. $T = 43$ years;
- $IC_{initial}$ is split between the three construction years with 25%, 40%, and 35%, respectively. Additional non-depreciable investment costs are $2M;
- annual unplanned replacement costs are 0.5% of the initial investment cost. In addition, there are some planned plant specific replacement costs;
- linear depreciation of capital costs over 20 years;
- the salvage value (SV) is 10% of the initial investment cost;
- working capital (WC_t) is 15% of the annual change in total operating costs.

For the two technologies with product flexibility (HPE-ALWR and HTE-HTGR), we can analyze the optimal dispatch decision as a function of electricity and hydrogen prices (Fig. 2). The dispatch decision depends on the amount of electricity required as input per unit of hydrogen output. Fig. 2 shows that the HPE-ALWR plant configuration is more likely to produce electricity than the HTE-HTGR plant. This is due to the higher electricity–hydrogen production ratio for the HPE-ALWR plant. The simple break-even chart in Fig. 2 does not take into account switching costs. Hence, the actual optimal dispatch within the monthly price sub-periods in the model may deviate from the dispatch regions in the figure.

5.2. Assumptions for hydrogen and electricity prices

We assume that most of the demand for hydrogen in the future will come from the transportation sector. To estimate the monthly

Table 2
Nuclear hydrogen technologies

Hydrogen production process	Nuclear reactor type	Product flexibility?
High-pressure water electrolysis (HPE)	Advanced light water reactor (ALWR)	Yes
High-temperature steam electrolysis (HTE)	High-temperature gas-cooled reactor (HTGR)	Yes
High-temperature sulfur-iodine cycle (SI)	High-temperature gas-cooled reactor (HTGR)	Pure hydrogen
Hybrid sulfur thermo-electro chemical cycle (HyS)	High-temperature gas-cooled reactor (HTGR)	Fixed hydrogen and electricity production

Table 3
Assumptions for nuclear hydrogen technologies (TI, 2006, 2007)

Parameter	HPE-ALWR	HTE-HTGR	SI-HTGR	HyS-HTGR	Unit
Nuclear total thermal capacity	3800	2400	2400	2400	MWt
Nuclear heat input to H_2 process	0	232	2400	1200	MWt
Nuclear el input to H_2 process	1350	1128	0	350	MWe
El input from grid (QEL^{in})	0	0	4.9	0	TWh/yr
Max. H_2 production ($QH2$)	221.0	241.1	283.4	158.2	M kg/yr
Max. el production (QEL)	10.6	8.89	–	–	TWh/yr
Fixed el generation (QEL^{out})	–	–	–	1.7	TWh/yr
Min. H_2 fraction ($q^{h2}_{\min}$)[a]	10	10	–	–	%
El-hydrogen production ratio (c)	0.0482	0.0369	–	–	MWh/kg
Switching cost ($SC_{t,m}(\varphi_{t,m} = flex)$)[a]	0.02	0.02	–	–	M $/day
Nuclear fuel cost	88.8	84.1	84.1	84.1	M $/yr
Other O&M cost	1.21	3.16	3.71	2.07	M $/yr
Total variable O&M (VOM_t)	90.0	87.2	87.8	86.1	M $/yr
Fixed O&M (FOM_t)	169.1	120.0	118.4	120.0	M $/yr
Inv. cost nuclear plant	1526	1731	1194	1463	M $
Inv. cost hydrogen process	675	1047	1519	496	M $
Total inv. cost ($IC_{initial}$)	2201	2778	2713	1959	M $

[a] Own assumptions.

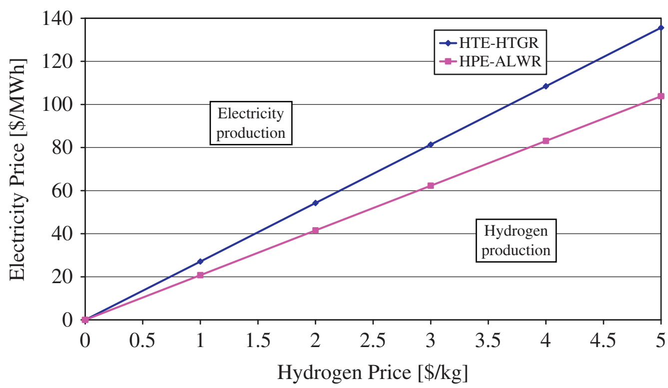

Fig. 2. Optimal dispatch regions for electricity and hydrogen production.

parameters in the price model for hydrogen, we, therefore, analyze historical prices for gasoline in the US for the last 20 years (1987–2006). The monthly variation in future hydrogen prices is assumed to follow the same seasonal pattern as the historical gasoline price data. Thus, the monthly price factors for hydrogen, a_m^{h2}, are calculated as the average relative monthly price factors for gasoline over the 20-year period. The resulting seasonality in hydrogen prices is illustrated in Fig. 3. The price tends to be higher in the summer because of more driving and increased demand for gasoline in the summer months.

We use historical price data from the PJM[2] electricity market to estimate the seasonal parameters in the electricity price model. In our analysis, we consider the aggregate hourly day-ahead prices for the entire PJM market.[3] In the electricity price model, we use two sub-period prices within each month, as explained in Section 4.1. We calculate the monthly price factors, a_m^{el}, and sub-period price factors, $b_{m,i}^{el}$, based on the historical PJM price data from the period 2003–2006, by first calculating the factors for each individual year and then taking the average of the calculated price factors over all years. For the high/low sub-period factors within each month, we assume that the periods with high and low prices each day are 16 h at daytime and 8 h at nighttime, respectively. Furthermore, we assume that a flexible plant in the switching mode of operation can time its switching decisions so that it produces hydrogen during the 8 h with the lowest average electricity price every night. Thus, the hydrogen production may not occur at exactly the same time every night, since the time period with lowest electricity prices may change slightly depending on the day of week, weather conditions and other factors. Fig. 3 shows that the overall price level on average is highest in July and August. The prices are low in spring and fall and higher in the winter months December–March. Thus, the seasonal price pattern is clearly different from the one assumed for hydrogen, although both have their highest prices in the summer time. The difference between the electricity prices during the day (high) and night (low) sub-periods is most distinct during the summer time. This means that the peak prices tend to be much higher in the summer time than in the rest of the year. This is because the peak loads in the system occur in the summer because of high air-conditioning demand. The monthly price parameters for both hydrogen and electricity are summarized in Table 4.

We also need to make assumptions about the annual average prices, which are stochastic variables in the model, as explained in Section 4.1. We assume average annual prices of $3/kg for hydrogen and $50/MWh for electricity. The price assumption for hydrogen is our subjective assessment of future hydrogen prices based on various estimates of production cost for hydrogen from different technologies (not only nuclear hydrogen). The electricity price of $50/MWh is close to what has been seen in the PJM electricity market over the last few years (Fig. 4). In fact, it is not unlikely that electricity prices will increase further if legislation limiting or taxing carbon emissions is introduced. In the analysis presented here, we assume that the average annual hydrogen and electricity prices follow the GBM stochastic processes. The variance in the GBM processes for hydrogen and electricity are based on our subjective assumptions with 12%/yr for both processes (i.e., $\sigma_{PH2} = \sigma_{PEL} = 0.12$). We assume no growth (i.e., $\alpha_{PH2} = \alpha_{PEL} = 0$) in the price processes, so the average price is the same throughout the simulation period. The correlation, ρ, between the hydrogen and electricity price is set to 0.5, assuming that there is some correlation between the two prices. Figs. 5 and 6 show the spread in the resulting simulated prices for electricity and hydrogen. The uncertainty range spreads out over time, owing to the multiplicative effect underlying the GBM process.

The results of the financial analysis will obviously depend heavily on the assumptions for electricity and hydrogen prices. A sensitivity analysis is, therefore, performed to investigate the relationship between the price assumptions and plant profitability.

5.3. *Comparison of levelized costs*

We first use the model to calculate the levelized cost for hydrogen, assuming that all the technologies are pure hydrogen plants. This is done iteratively by changing the annual average hydrogen price, which for this calculation is assumed to be deterministic, until the NPV of the project becomes zero. Table 5 shows that the two plants with electrolytic hydrogen processes (HPE-ALWR and HTE-HTGR) have about the same levelized production costs with current cost assumptions. For the two thermochemical technologies, the HyS-HTGR plant has a levelized cost in the same range as the two electrolytic processes, whereas the SI-HTGR has a considerably higher levelized cost. The lower levelized cost for the HyS-HTGR plant is partly due to a lower capital cost for the HyS compared with the SI hydrogen processing plant. More importantly, the HyS plant's fixed sales of surplus electricity for an assumed electricity price of $50/MWh contributes to lowering the unit cost for hydrogen for the HyS process. In contrast, the SI plant design relies on using a high amount of electricity from the grid (619 MW). Our assumption is that the plant purchases this electricity for the same price of $50/MWh, and this contributes to the significantly higher levelized hydrogen cost for the SI-HTGR plant configuration in this analysis.

5.4. *Profitability analysis*

We ran the stochastic profitability model for all four technologies. For the two flexible plant designs, we ran the model two times, both without and with the assumed electricity/hydrogen product flexibility. The main results from the profitability analysis are summarized in Table 6.

Table 6 shows that the two electrolytic technologies with product flexibility are the most attractive investment alternatives,

[2] PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves about 51 million people and is the largest electricity market in the US. PJM dispatches 164,905 MW of generating capacity over 56,250 miles of transmission lines.

[3] Note that the PJM market is based on so-called locational marginal pricing (LMP). That is, prices are calculated in each node of the grid taking into account transmission constraints and marginal losses. Power plants will in reality, therefore, receive a price that can be higher or lower than the aggregate PJM price, depending on their location in the network.

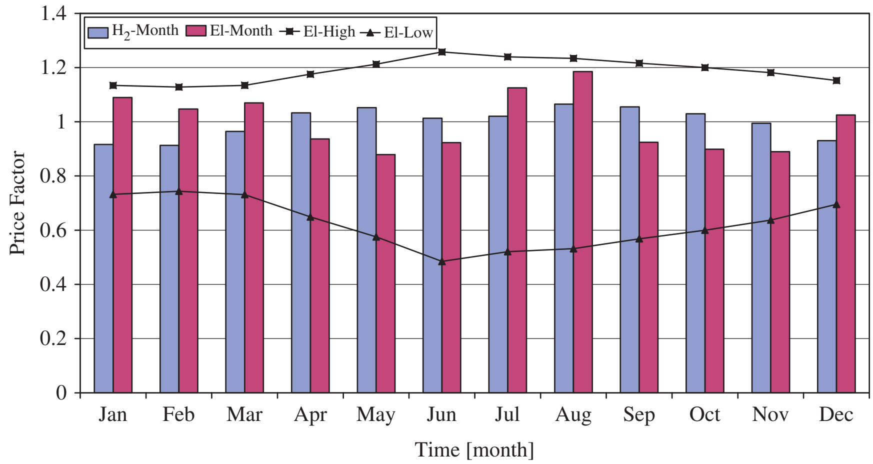

Fig. 3. Monthly price parameters for hydrogen and electricity.

Table 4
Monthly parameters in hydrogen and electricity price models

	Hydrogen	Electricity		
	Month	Month	Low	High
Jan	0.92	1.09	0.73	1.13
Feb	0.91	1.05	0.74	1.13
Mar	0.96	1.07	0.73	1.13
Apr	1.03	0.94	0.65	1.18
May	1.05	0.88	0.58	1.21
Jun	1.01	0.92	0.48	1.26
Jul	1.02	1.13	0.52	1.24
Aug	1.07	1.19	0.53	1.23
Sep	1.06	0.92	0.57	1.22
Oct	1.03	0.90	0.60	1.20
Nov	0.99	0.89	0.64	1.18
Dec	0.93	1.03	0.70	1.15

on the basis of expected profits under the current cost assumptions. The HTE-HTGR technology has the highest expected profit, whereas the conventional HPE-ALWR has the highest expected IRR. The reason for the higher IRR for the HPE-ALWR plant is that it has a lower investment cost than the HTE-HTGR design.[4] The SI-HTGR and HyS plants have considerably lower expected profits and IRRs. These plants do not have output flexibility and, therefore, cannot benefit from electricity sales during periods of high electricity prices. This is why the HyS-HTGR alternative has a much lower expected NPV and IRR than the flexible electrolytic technologies, even if the levelized cost is in the same range. Still, HyS-HTGR appears to be the more viable of the two thermochemical designs under current assumptions. This plant also has the lowest standard deviation in profits among the four plant designs.

To assess the value of flexibility we compare the expected profits for inflexible and flexible operations for the HPE-ALWR and HTE-HTGR plants. It is clear that both technologies benefit significantly from the ability to switch output product, as the expected option value of flexibility is $266 M and $212 M for the two plants, respectively (Table 7). This is despite the minimum hydrogen production level of 10% and the switching cost of $20,000/day, which applies to both technologies and contributes to reduce the value of flexibility. When looking at the expected hydrogen production from the two technologies, we see that the HPE-ALWR is likely to sell more electricity to the market than the HTE-HTGR plant (Table 6). This is due to the optimal dispatch schedules for the two plants, where electricity sales in relative terms are more profitable than hydrogen sales for the HPE-ALWR plant compared with the HTE-HTGR plant (see Fig. 2). Note that the hydrogen production in terms of percentage of maximum production is lower than the percentage of time in full hydrogen production mode. This is because of the minimum hydrogen production level of 10%, which forces the plant to continue producing hydrogen at a low level during time periods with electricity generation.

We run sensitivity analyses to analyze how the profitability of the plants depend on the assumed future price levels for electricity and hydrogen. Fig. 7 shows how the simulated expected profits for all plants change as a function of the mean in the stochastic process for electricity price. All other parameters are kept constant with the same values as in the analysis above. The two flexible hydrogen plants clearly benefit from an increasing electricity price level, since they can switch to more electricity production when it becomes more profitable to sell electricity. The option values of flexibility for the HPE-ALWR and HTE-HTGR plants, therefore, increase as a function of electricity price. Fig. 7 shows that the HPE-ALWR plant becomes the most profitable technology for high electricity price levels. The HyS-HTGR also benefits from a higher average electricity price, since it is selling its surplus electricity production to the electricity market. In contrast, the SI-HTGR plant's profit drops sharply with increasing electricity prices, since this plant configuration has to buy substantial amounts of electricity from the grid. Only at very low electricity price levels is the SI-HTGR plant competitive with the other technologies with current cost assumptions.

When performing the same type of sensitivity analysis for the mean hydrogen price (Fig. 8), we see that the SI-HTGR plant has the steepest increase in expected profits as a function of hydrogen price. However, the flexible electrolysis plants also increase their profits as a function of higher hydrogen prices, since the amount of hydrogen production goes up. In fact, the HPE-ALWR and HTE-HTGR plants are the most profitable technologies over the entire hydrogen price range in Fig. 8. Further investigation of the results reveals that the option value of product flexibility is highest for low hydrogen price levels. This is because electricity sales in relative terms become more profitable with a low hydrogen price.

[4] The underlying cost assumptions for the HPE-ALWR technology are not as recent as the ones used for the three other technologies. Thus, since the cost of some materials has increased, it may not be completely fair to compare the HPE-ALWR results with the other technologies.

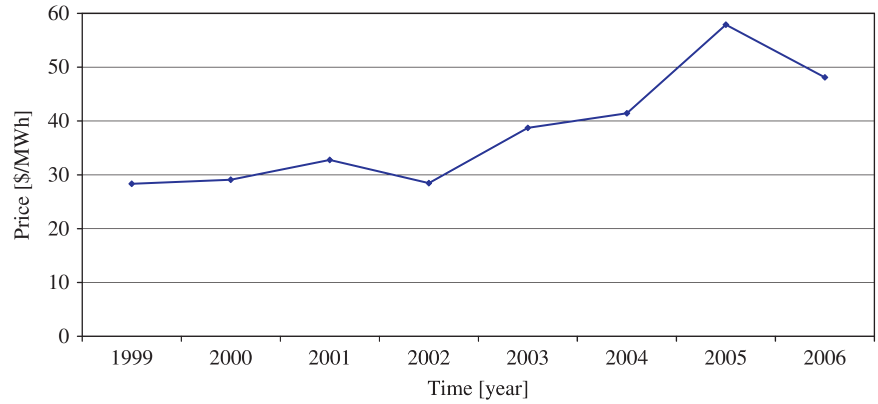

Fig. 4. Average annual prices in PJM electricity market, 1999–2006.

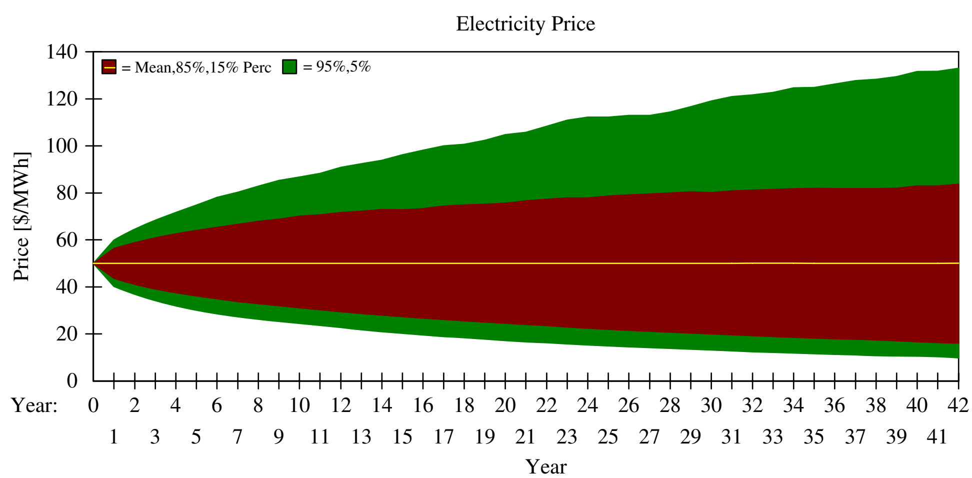

Fig. 5. Simulated probability distribution for electricity prices.

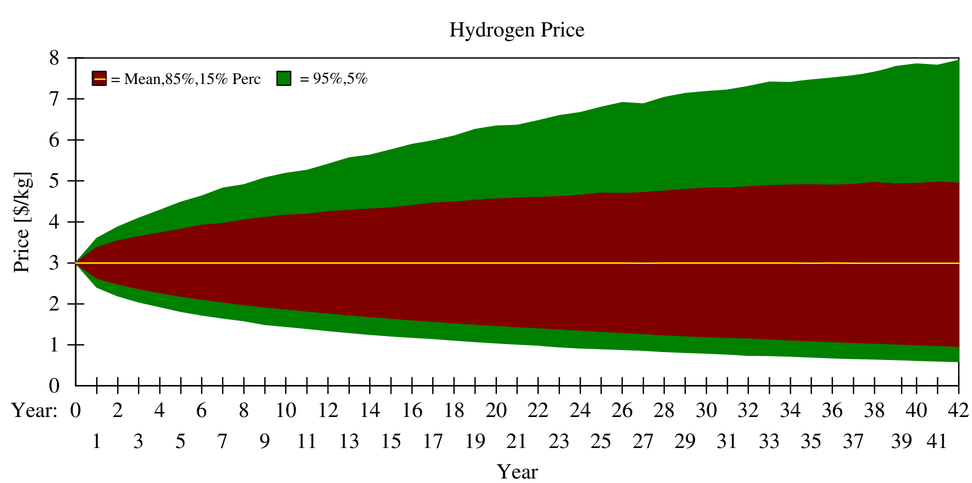

Fig. 6. Simulated probability distribution for hydrogen prices.

5.5. *Detailed results for the hte-htgr technology*

Let us look at the results in more detail for the HTE-HTGR plant configuration. Fig. 9 shows the simulated profit distributions for this plant for pure hydrogen production and flexible hydrogen/electricity production. When comparing the two simulated profit distributions, we see that operational flexibility decreases the downside of the profit distribution and increases the upside. Hence, the plant owner can clearly reduce exposure to economic risk by having the flexibility to switch output product. At the same time, the expected profit is considerably higher with flexibility.

Fig. 10 shows that the expected value of flexibility is relatively insensitive to the daily switching cost. In fact, there is only a small increase in the hydrogen production, from 82.2% to 83.9%, when varying the daily switching cost from $0/day to $100,000/day. In contrast, the constraint on minimum hydrogen production has a more significant impact on the results. The value of flexibility over the lifetime of the plant drops almost linearly to zero as the minimum hydrogen constraint approaches 100%, which is equivalent to no product flexibility.

Finally, we analyze how the option value of flexibility changes as a function of price uncertainty and correlation between hydrogen and electricity prices. Fig. 11 shows that the flexibility value generally increases as a function of uncertainty in both the hydrogen and electricity price. However, it is interesting to note that the flexibility value does not monotonically increase along both volatility dimensions. This is because it is the difference between the electricity and hydrogen price that generates the option value of flexibility. Since there is a correlation (assumed to be 0.5) between the two price processes, the highest volatility in the price difference does not necessarily occur for the highest values of individual price volatilities. Thus, the price correlation explains the shape of the flexibility value surface in Fig. 11. The effect of the hydrogen electricity price correlation is further analyzed in Fig. 12. The correlation has an important impact on the plant profitability and the value of product flexibility. Product flexibility is clearly an advantage with a low or even negative correlation between hydrogen and electricity prices. This is because with a low correlation, it is more likely that the electricity prices are high when hydrogen prices are low, and a flexible plant can take advantage of these situations by producing electricity instead of hydrogen. In contrast, if the correlation is high, this advantage disappears, since high electricity prices will only occur when hydrogen prices are also high. This is reflected in the amount of hydrogen production, which generally increases as a function of price correlation, although it levels off for high positive correlations.

6. Conclusions

Although the potential for hydrogen markets seems promising, substantial risks and uncertainties will affect the way in which investors will enter this market. Economic studies of nuclear hydrogen technologies have focused on levelized costs without accounting for these risks and uncertainties. The analysis presented in this paper is an important extension to the levelized hydrogen cost calculations and has attempted to identify and address some of the financial risks and opportunities associated with nuclear hydrogen production.

Table 5
Levelized cost for candidate technologies

Technology	Levelized cost ($/kg)
HPE-ALWR	2.98
HTE-HTGR	2.93
SI-HTGR	3.26
HyS-HTGR	2.97

Table 7
Expected option value of product flexibility

Technology	Option value of flexibility (M $)
HPE-ALWR	266
HTE-HTGR	212

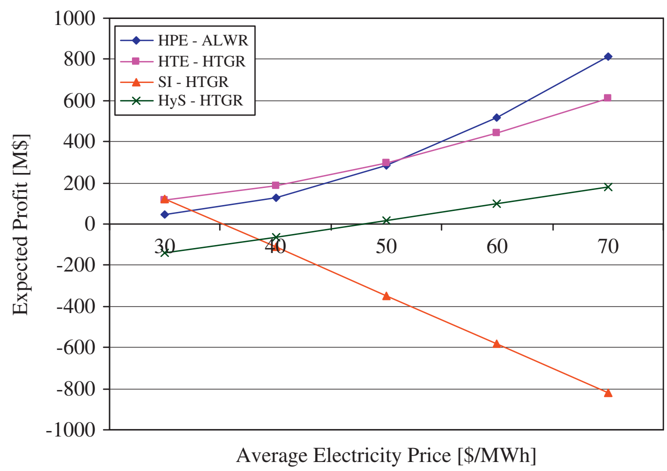

Fig. 7. Sensitivity analysis for average annual electricity price.

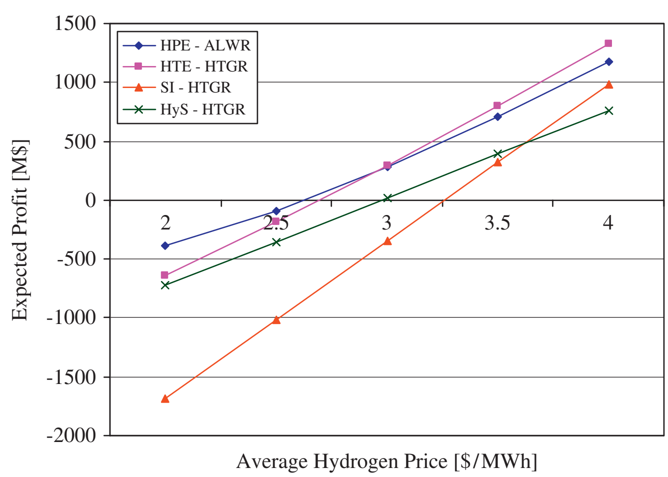

Fig. 8. Sensitivity analysis for average annual hydrogen price.

Table 6
Summary of results for nuclear hydrogen technologies

Technology	Product flexibility	Expected profit (M $)	Std. Dev. profit (M $)	Expected IRR (%)	Expected H_2 production	
					Prod. (%)	Time (%)
HPE-ALWR	No	17	1084	9.99	100.0	100.0
	Yes	283	1078	10.85	69.2	65.7
HTE-HTGR	No	83	1183	9.80	100.0	100.0
	Yes	295	1170	10.52	82.4	80.5
SI-HTGR	No	−348	1249	8.89	100.0	100.0
HyS-HTGR	No	19	841	9.72	100.0	100.0

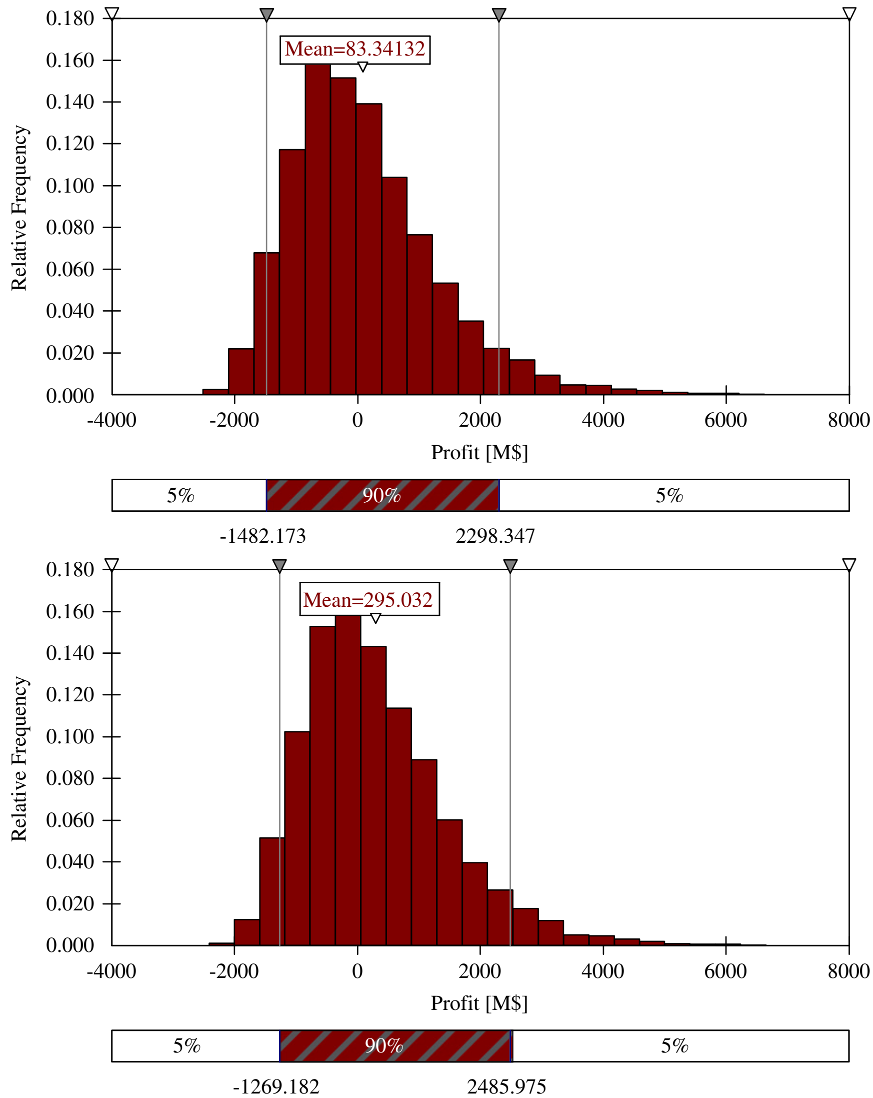

Fig. 9. Distribution of profit over lifetime of plant for an HTE-HTGR plant with inflexible (upper) and flexible (lower) plant operation.

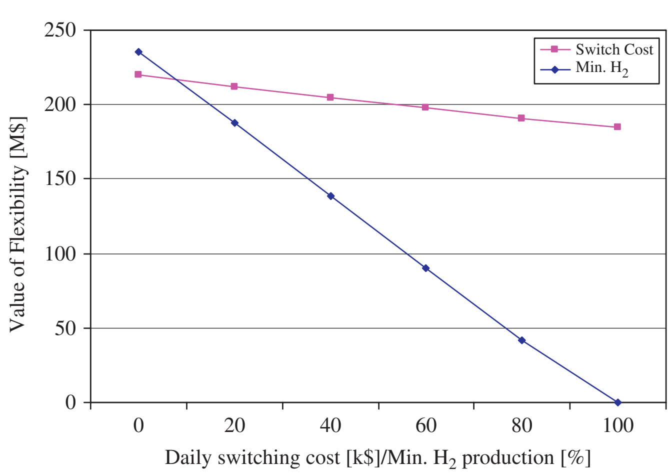

Fig. 10. Expected value of flexibility as function of daily switching cost and minimum hydrogen production.

Our model is based on real options theory and calculates the discounted profits from investing in a nuclear hydrogen facility. Monte Carlo simulations are used to represent uncertainty in hydrogen and electricity prices. The model computes both the expected value and the distribution of discounted profits from the plant. It also quantifies the value of the option to switch between hydrogen and electricity production while trying to maximize plant profits. The real options approach is ideal for analyzing the value of flexibility in future operational and investment decisions in uncertain and emerging energy markets.

We assessed the profitability of four nuclear hydrogen production technologies under uncertainty in hydrogen and electricity prices. Under the assumptions used, we conclude that investors will find significant value in the ability to switch plant output between electricity and hydrogen. Product flexibility increases the expected profits and lowers the financial risk from investing in nuclear hydrogen. There is obviously high uncertainty concerning the assumptions for the analysis in terms of performance, cost, and price parameters. The model results should, therefore, be interpreted as qualitative rather than quantitative.

The flexibility to quickly react to market signals brings technical challenges related to the durability of the components in the nuclear hydrogen plant. However, given the potential significant economic benefit from hydrogen/electricity product flexibility, we recommend that R&D should be aimed toward developing durable materials and advanced engineering designs

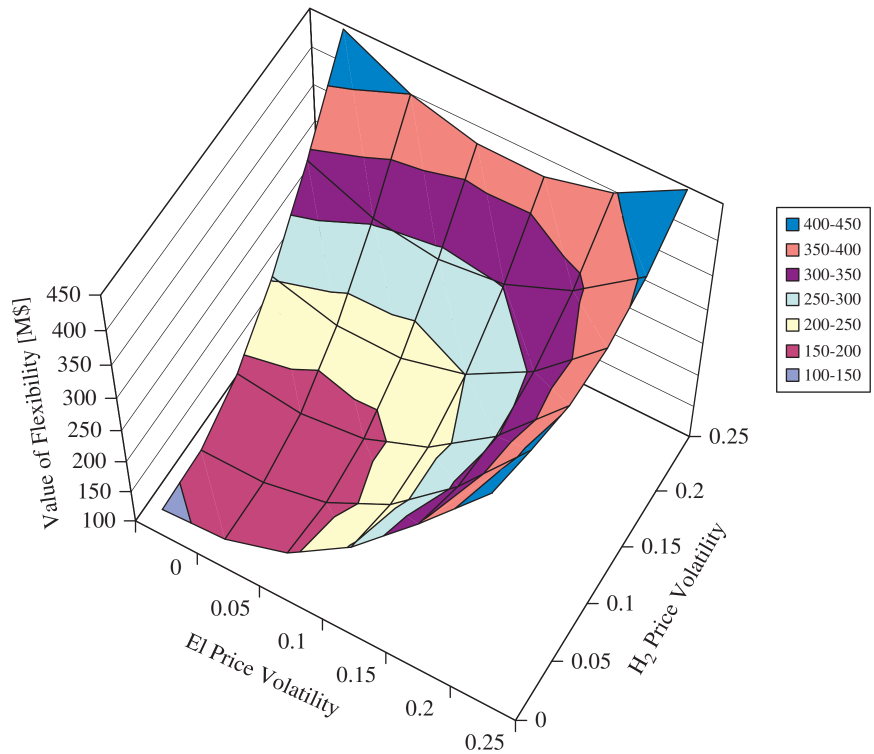

Fig. 11. Expected value of flexibility as function of price volatilities σ_{PH2} and σ_{PEL}.

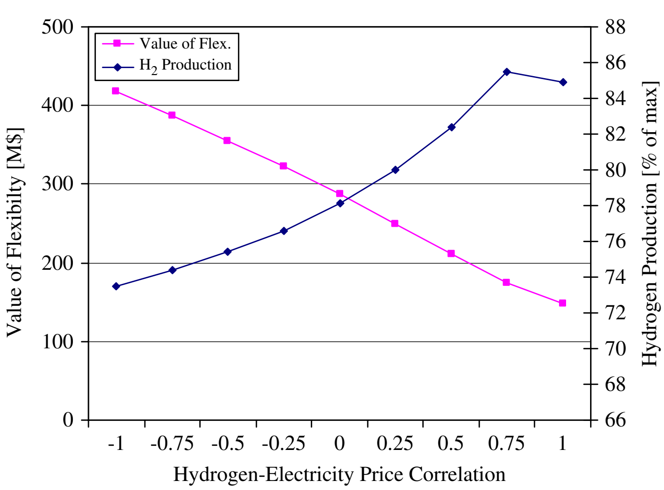

Fig. 12. Expected value of flexibility and hydrogen production level as a function of price correlation ρ (σ_{PH2} and σ_{PEL} are both fixed at 0.12).

that can enable this type of operation. Future plant owners should also carefully consider how much hydrogen production to sell on long-term contracts, at the expense of losing the value of the option to switch between electricity and hydrogen production. In the long run, if a substantial number of flexible nuclear hydrogen plants are built, it is likely that the correlation between hydrogen and electricity prices increases and also that the daily variation in electricity prices is reduced. Hence, the value of product flexibility is likely to be highest for the first nuclear hydrogen plants constructed.

Our ongoing work focuses on analyzing a wider range of hydrogen production technologies associated with an extension of the financial analysis framework presented here. We are addressing additional risks and options, such as the value of modular plant expansion (i.e., a modular increase in the hydrogen production capacity in a market with rising hydrogen demand), and contrast that with economies-of-scale of large-unit designs. We are also analyzing how hydrogen storage can contribute to more flexibility in plant operations and thereby possibly increase the investor's profits from investing in a nuclear hydrogen plant.

Finally, it is of course important to consider how the costs, risks, and opportunities of nuclear hydrogen compare to other energy technologies, such as energy efficiency measures, renewable energy technologies, and carbon capture and storage. Given the magnitude of the global energy challenges it is obvious that a number of different technologies will have to be developed and applied in order to meet future energy demand in a cost efficient, reliable, and environmentally responsible manner. Hydrogen and electricity production from nuclear energy can potentially play an important role.

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