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Nuclear Renewable Energy Integration: An Economic Case Study

Costs and environmental concerns associated with fossil fuels have encouraged researchers and eco-friendly organizations to seek an alternative energy source that can help satisfy this rising energy demand in an environmentally friendly and sustainable manner. The proposed work is driven by the need to harness the potential of a clean (nuclear) and inexhaustible renewable energy source, with enhanced reliability and resilience.

Piyush Sabharwall, Shannon Bragg-Sitton, Lauren Boldon and Seth Blumsack

I. Introduction

Electrical energy is a versatile form of energy that exhibits high efficiency and availability, and as a result is widely utilized with continually escalating needs worldwide. However, there are limits to the supply of natural resources that may be utilized to help meet these increasing needs. The Energy Information Agency (EIA) expects an additional 351 GW of electrical capacity to be installed during the period from 2013 to 2040 to meet the demands from all energy sectors (EIA, 2014). Costs and environmental concerns associated with fossil fuels have induced researchers and eco-friendly organizations to seek an alternative energy source that can help satisfy this rising energy demand in an

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environmentally friendly and sustainable manner.

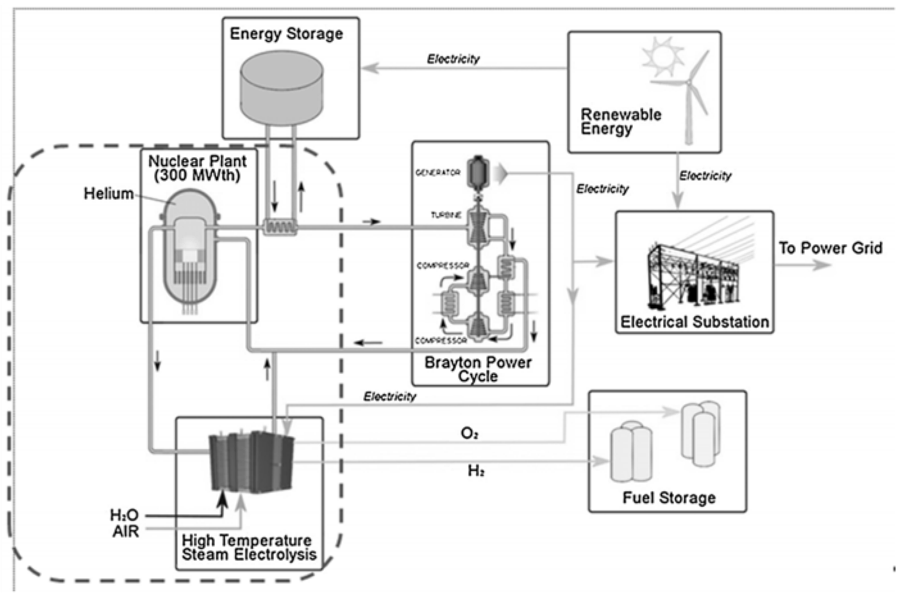

Figure 1: Schematic of a Possible Nuclear-Renewable Energy Integration System

Renewable and nuclear energy technologies are possible alternatives; however, the variability of renewable energy technologies can strain both the electrical grid and the market due to their intermittent nature. Currently, no combination of very-low-carbon generation technologies is available to precisely meet instantaneous electricity demand without substantial excess energy production or increases in cost (Energy Information Administration (EIA), 2014). Nuclear renewable energy integration (NREI) offers a new long-term approach (Bragg-Sitton et al., 2014a, 2014b; Ruth et al., 2014) toward sustainable energy generation. The NREI system may comprise a small modular reactors (SMRs) offering other distinct advantages, such as a reduction in the total capital costs, making them more economical over large commercial reactors; the ability to locate modules in sites where large reactors would be unsuitable or where aging or retiring coal or nuclear plants already exist; the ability to produce useful heat for industrial process heat applications; and finally, the ability to operate with improved safety and design feature (Rosner and Goldberg, 2011; Boldon and Sabharwall, 2014). The analysis detailed in this article is driven by the need to develop and harness the inherent potential of clean and inexhaustible energy sources, while simultaneously enhancing both the system reliability and resilience.

The proposed NREI system incorporates nuclear and wind energies in combination with high-temperature steam electrolysis (HTSE) to yield hydrogen. The nuclear component is represented by a small modular gas-cooled reactor, as shown in **Figure 1**. In the future, similar analyses could be carried out with solar as the renewable energy source or with another distinct type of reactor. The idea behind the NREI system in Figure 1 is that the baseload nuclear and variable wind generation would be sufficient to meet both electrical and thermal energy demands in an economic and sustainable manner, while the SMR piece would be useful in siting and deployment flexibility. Overall, the NREI would provide energy reliability and security with several significant advantages:

Reliable energy supply: Regions with prevalent renewable energy production suffer from variable power generation. An NREI system may help moderate these fluctuations with baseload production or by directing excess production to energy storage or process heat applications.

Thermal energy use: NREI has the potential to provide heat at varying temperatures based on reactor design for process heat applications, such as synthetic transportation fuel production.

Flexible operations: NREI may be operated to follow the load demand, such the nuclear portion operates at maximum capacity. As wind (or other renewable) energy becomes available, the nuclear output is redirected or split between electricity and heat generation. The heat may then be utilized for process heat applications.

Economic optimization: The flexibility in operation offers a unique opportunity to utilize the more lucrative output (either electricity or process heat), as electricity demand and prices vary over time.

Table 1: Nuclear and Wind Power Capital and O&M Costs.

Capital Costs	Nuclear: $4,637/kW (Du and Parsons, 2009; Shropshire et al., 2009)
	Wind: $2,155/kW (Tegen et al., 2010)
	HTSE: $87,614,000 per kg/sec H_2 (Bragg-Sitton et al., 2014c)
Variable O&M	Nuclear: $0.486/MWh (Du and Parsons, 2009; Shropshire et al., 2009)
Fixed O&M	Nuclear: $19,500,000 annual (Rothwell and Ganda, 2014)
	Wind: $34/kW annual (Tegen et al., 2010)
Direct Costs	$6M per kg/sec H_2 (Bragg-Sitton et al., 2014c)
Indirect Costs	$3.49M per kg/sec H_2 (Bragg-Sitton et al., 2014c)

II. Case Studies: Objective and Assumptions

In this study, three different cases will be analyzed. Case A analyzes the deployment of a small modular nuclear plant, Case B analyzes the combination of nuclear plant with renewable penetration (wind energy), and Case C analyzes Case B in conjunction with selling another energy commodity (hydrogen), produced using high-temperature steam electrolysis. Technical requirements and coupling challenges will not be addressed in this study. The main focus of this study will be to perform financial evaluation of the aforementioned three cases, respectively. For an NREI system deployed in a regulated market (i.e., the plant is built by a regulated electric utility), the cost is recovered from ratepayers (with public utility commission approval), whereas in a deregulated market, the same plant being built and deployed would need to recover its costs and earn profits by selling output into an electricity/energy commodity spot market. The NREI system will always have a threshold to overcome, irrespective of the market. In a deregulated market, the focus or the objective would be to make money, whereas in a regulated market, the system would need to be cost-justified compared to next best available alternative to provide the required type of service (e.g., baseload versus peaking power).

Table 1 displays the capital cost and variable and fixed operation and maintenance (O&M) costs for both wind and nuclear generation. Table 1 costs have been modified from the source to 2014 $, considering constant inflation rate of 3 percent.

A. Assumptions

This study analyzes the effects of coupling nuclear energy, wind generation, and hydrogen production in an effort to improve the economic feasibility of such systems. In the first case, a 750 MWth (300 MWe) nuclear power plant utilizing a 40 percent efficient supercritical Rankine power cycle and 90 percent capacity factor is considered. The time horizon for all the cases studied is 20 and 60 years with a fixed depreciation of 5 percent annually. The second case analyzed incorporates an additional 60 MWe of wind generation to the 300 MWe nuclear capacity. The marginal costs consist primarily of fuel costs, which are incorporated in the O&M costs. As a result, the marginal costs are considered negligible and not separately included. Hydrogen production through HTSE is added to the generation mix in the third case, such that 20 percent of the nuclear capacity is directed to hydrogen production, while the remaining 80 percent capacity and 100 percent wind capacity are utilized for electricity production. Table 2 provides a summary of the generation mix for the three cases. In this study, the PJM deregulated and the Mid-C market hubs were used to determine reasonable wholesale electricity prices. There is a market at the Mid-C, but the participants are primarily regulated utilities (and players in California and Canada) buying

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Table 2: Summary of Cases.

	Case A	Case B	Case C
Nuclear Generation	300 MWe	300 MWe	240 MWe
Wind Generation	–	60 MWe	60 MWe
Hydrogen Generation	–	–	150 MWth 39,939,210 kg*

* Value calculated using the 0.0329 MWh/kg conversion factor for atmospheric electrolysis (HES, 2015).

Table 3: Relevant Economic Data.

PJM Average Wholesale Electricity Price	\$54.38/MWh (EIA, 2015)
Mid-C Average Wholesale Electricity Price	\$42.42/MWh (EIA, 2015)
Hydrogen Sales Price (\$/kg)	\$2.50/kg (Bragg-Sitton et al., 2014c)
Nominal Discount Rate (same as WACC)	17.50%
Inflation Rate	3%
Depreciation Rate	5% (for 20 years and 60 years)
Corporate Tax Rate	37%

and selling surplus power on a bilateral basis. So the price at the Mid-C hub is still the product of a market, just a very different type of market than the PJM market. The annual weighted average electricity prices for 2001–2013 were obtained from the EIA database and then averaged to determine one rate for each market (EIA, 2015).

These averaged values are shown in **Table 3**, along with the values used for the depreciation, corporate tax, inflation, and discount rates and the hydrogen sales price. The discount rate represents the interest rate at which the present value of future dollars may be determined, and is significant in assessing investment feasibility through net present value (NPV). The discount factor was set equal to weighted average cost of capital (WACC), for assumed cost of debt of 15 percent, cost of equity of 20 percent and also assuming the system is 50 percent debt-financed and 50 percent equity-financed.

III. Quantitative Analysis

In this section, brief key financial terms with their significance are described, evaluated, and compared for different case studies.

Costs of equity and debt refer to a company's opportunity cost of investing in a particular project rather than in another investment with similar risk. The primary difference between debt and equity is the risk involved in borrowing. Equity borrowing is riskier than debt borrowing, as it necessitates leveraging assets to fund the investment (Shropshire et al., 2009). Assessing appropriate values for equity and debt in the nuclear industry is difficult due to large variations in risks as a result of construction and regulatory overruns and delays, which may translate into higher opportunity costs for equity and debt. In this economic model, the WACC is calculated and then used to determine the appropriate discount rate. The WACC is a value describing the percentage of capital that must be paid to the investors so they see the expected return on investments/assets. The equation to calculate WACC is as follows:

$$\begin{aligned}\text{WACC} = &(\text{Fraction financed by debt}) \times (\text{Cost of debt}) \\ &+ (\text{Fraction financed by equity}) \times (\text{Cost of equity})\end{aligned}$$

The total NPV is the sum of the present values of all annual cash flows, or the discounted value of all annual cash flows. It may be calculated from equation shown below, where CF_y represents the annual cash flow during year y and n is the total number of years including construction and operating lifetime.

$$\text{NPV} = \sum_{y=0}^{n} \frac{\text{CF}_y}{(1+d_r)^y}$$

The internal rate of return (IRR) is a project performance term that describes the return on investment over the project lifetime. It is determined by iterating until the NPV becomes zero at a discount rate equal to the

IRR. For a firm to pursue a project, the IRR should be greater than the WACC. The equation below details how the IRR is calculated.

$$\mathrm{NPV} = \sum_{y=0}^{n} \frac{\mathrm{CF}_y}{(1+\mathrm{IRR})^y} = 0$$

Both IRR and NPV are obtained for all the different case studies, positive value of NPV is taken as a favorable for the investors for investing in a project. IRR tells us how low the WACC would need to be for the project to break even. The larger the gap between IRR and WACC, the higher the profits and the return on initial investments. The LCOE represents the cost of energy production averaged over the lifetime of the plant, as shown in the following equation. In this case, the discounted cash flow includes capital, O&M, fuel, costs discounted at the real or nominal discount rate. The discounted annual energy represents the annual electricity production discounted at either the real or nominal discount rate.

$$\mathrm{LCOE} = \frac{\sum_{y=0}^{n} \text{Discounted Annual Cost Cash Flow}}{\sum_{y=0}^{n} \text{Discounted Annual Energy}}$$

For any investment in the energy projects, the revenue generated by the sale of the product needs to cover both the fixed and variable expenses incurred during normal operations; to repay the capital employed during the construction and decommissioning phases, including both overnight and financing charges; and to compensate the owners of the capital (both debt and equity investors) for the risk taken with the project. The electricity price that, in real dollars, covers all these charges is called "Levelized Cost of Electricity." (Perkowski, 2012).

The ultimate goal of this study is to financially compare different case studies and make the proposed NREI a sustainable, economically competitive, and feasible alternative energy option for the future.

A. Results and discussion

Table 4 displays a summary of the results for all three cases analyzed in both Mid-C and deregulated markets (PJM) and with 20-year and 60-year lifetimes. With the high capital cost of nuclear power at a discount rate of 17.55 percent, projects in Cases A, B, and C all end up having negative net present value for all markets and lifetimes (i.e., 20 and 60 years). Thus, the addition of wind for Case B and hydrogen generation for Case C is not substantial enough to drastically improve the costs. The LCOE is increased even further with the addition of HTSE system costs, but the resulting additional revenue drastically reduces the payback period. In all three cases, the 60-year lifetime results in a reduced LCOE, as the costs are levelized over a longer period of time. The Mid-C market happens to have a lower wholesale electricity price,

Table 4: Net Present Value, Levelized Cost of Electricity, and Payback Period for 20-Year and 60-Year Nuclear Hybrid Facilities in Both Mid-C and PJM (Deregulated Market).

	20-Year Lifetime		60-Year Lifetime	
	PJM	Mid-C	PJM	Mid-C
Case A				
NPV	($876,602,857)	($974,391,806)	($855,343,459)	($957,173,119)
LCOE	$115.91/MWh		$111.66/MWh	
IRR	3.03%	0.85%	6.59%	5.20%
Payback	15 years	19 years	15 years	19 years
Case B				
NPV	($901,060,079)	($1,020,579,905)	($875,468,502)	($999,926,974)
LCOE	$126.74/MWh		$122.09/MWh	
IRR	4.10%	1.79%	7.32%	5.79%
Payback	14 years	17 years	14 years	17 years
Case C				
NPV	($494,763,483)	($592,052,679)	($426,340,318)	($530,432,859)
LCOE	$142.90/MWh		$134.27/MWh	
IRR	9.62%	7.90%	11.76%	10.35%
Payback	9 years	10 years	9 years	10 years

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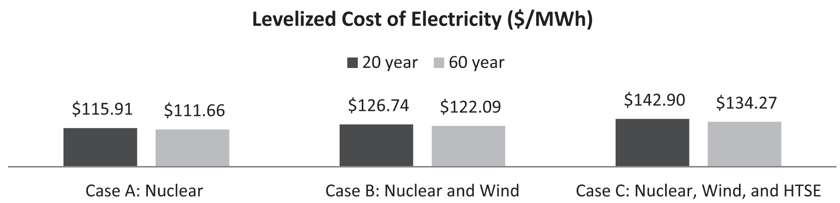

Figure 2: Levelized Cost of Electricity for the 20-Year and 60-Year Lifetimes

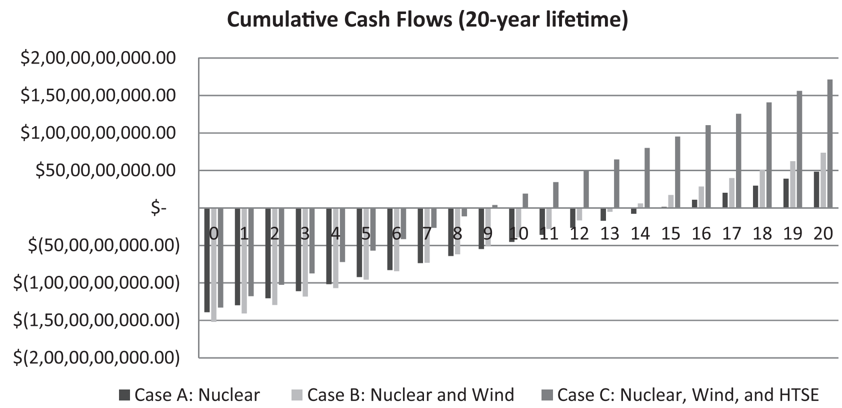

Figure 3: Cumulative Cash Flow for the 20-Year Lifetime Facility in the PJM Deregulated Market

resulting in a longer payback period and lower NPV for all cases. The LCOE for both the 20- and 60-year lifetimes are shown in Figure 2. The LCOE is independent of the market, because it only reflects the costs. The cumulative cash flows for all three cases in the PJM deregulated market are displayed in Figures 3 and 4 for the 20-year and 60-year lifetimes, respectively.

B. Sensitivity analysis

Sensitivity analysis is carried out to understand the financial viability of different cases that have been analyzed in this study.

1. *Effect of time horizon*

Sensitivity with different time horizon (i.e., for 20 and 60 years) for the proposed NREI system was carried out and the results with lower NPV and LCOE value for 60 years, as expected, were obtained and are shown in Figures 2–4.

2. *Effect of electricity market*

Sensitivity with different time horizon (i.e., for 20 and 60 years) and different energy market (i.e., Mid-C and PJM markets) was also investigated for the NREI system. The Mid-C market for all the cases had longer payback period and lower NPV, mainly due to lower wholesale electricity prices ($42/MWh) compared to deregulated market ($54/MWh) such as PJM.

3. *Effect of discount factor on NPV and LCOE on deregulated market*

Table 5 shows the reduction of the discount factor and the NPV increases for all the cases, as expected. Different discount factors were used to look into at what discount factor does each case being analyzed becomes economically attractive. Thus, for Case A and Case B NPV becomes positive at discount factor of 3 percent and 4 percent, respectively. For Case C, at a discount factor above 9.5 percent (~10 percent), the NPV becomes negative for 20 years and above

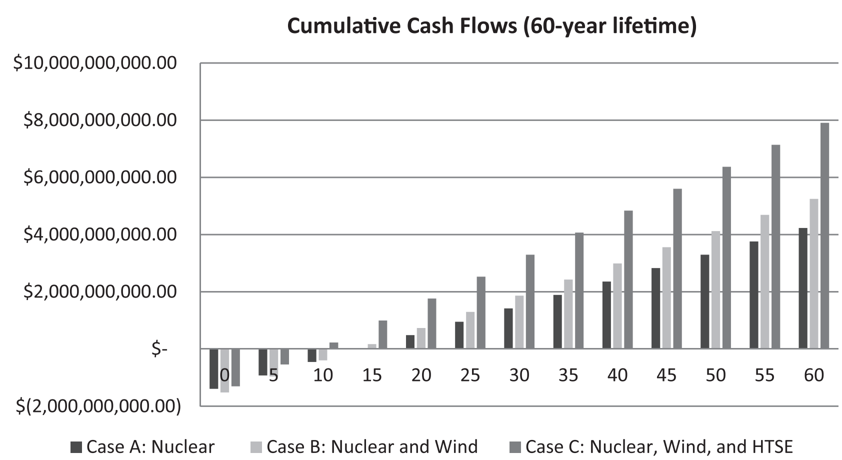

Figure 4: Cumulative Cash Flow for the 60-Year Lifetime Facility in the PJM Deregulated Market

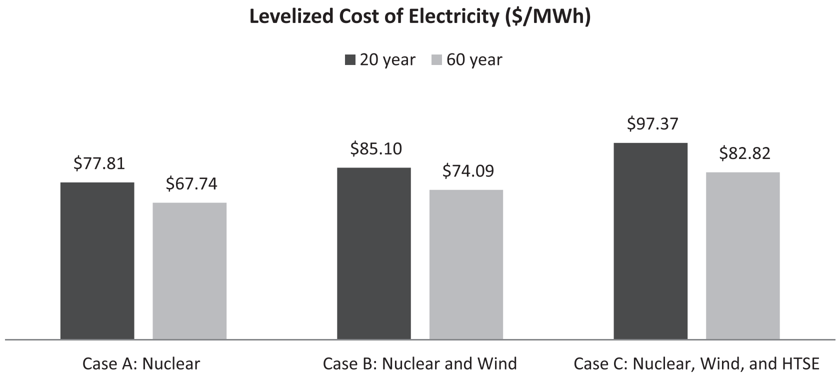

Figure 5: Levelized Cost of Electricity for the 20-Year and 60-Year Lifetimes

12 percent the NPV becomes negative for 60 years.

4. Change in depreciation for different length projects

In this sensitivity case, a discount factor of 10 percent is used for both 20 and 60-year time horizon, but different depreciation is utilized. A depreciation of 5 percent is used as an annual depreciation rate for 20 years and 2 percent depreciation is used for 60 years. This sensitivity analysis assumes a longer-term project has a slower depreciation rate. Table 6 summarizes the results for all three cases analyzed in both Mid-C and PJM markets and with 20-year and 60-year lifetimes considered. With the high capital cost of nuclear power at a discount rate of 10 percent, projects in Case A would not be pursued as the net present value because all markets and lifetimes is negative. The same is true with Case B because the addition of wind is not substantial enough to drastically improve the costs. It should be noted that a small reduction in the payback period is observed from the addition of wind to the facility and the NPV is reduced, despite the addition of costs shown in the LCOE. In Case C, the projects become feasible in all markets and lifetimes, as is shown by the positive NPV observed. The LCOE is increased even further with the addition of HTSE system costs, but the resulting additional revenue drastically reduces the payback period. In all three cases, the 60-year lifetime results in a reduced LCOE as the costs are levelized over a longer period of time, as shown in Figure 5. Furthermore, the 60-year lifetime actually produces a more-negative NPV for Cases A and B over the 20-year lifetime due to the effects of the lower depreciation rate resulting in higher annual taxes. In Case C, the additional revenue generated by HTSE actually offsets these depreciation losses resulting in a much higher NPV. The Mid-C

Table 5: Varying Discount Factors Affecting NPV and LCOE (Deregulated Market).

	Cost of Debt	Cost of Equity	Discount Factor	NPV ($)	LCOE ($/MWh)
Case A (20 Years)	4.00%	2.00%	3.00%	$3,860,837	48.26
	5.00%	10.00%	7.50%	($435,231,055)	66.42
	10.00%	10.00%	10.00%	($592,840,343)	77.81
Case B (20 Years)	4.00%	4.00%	4.00%	$13,541,447	56.89
	5.00%	10.00%	7.50%	($369,746,775)	72.65
	10.00%	10.00%	10.00%	($559,473,240)	85.10
Case C (20 Years)	5.00%	10.00%	7.50%	$221,584,371	83.76
	9.50%	9.50%	9.50%	$11,257,606	94.57
	10.00%	10.00%	10.00%	($34,216,011)	97.37
Case C (60 Years)	5.00%	10.00%	7.50%	$716,583,561	135.25
	10.00%	10.00%	10.00%	$226,557,223	94.63
	10.00%	15.00%	12.00%	$25,670,171	134.77

Table 6: Net Present Value, Levelized Cost of Electricity, and Payback Period for 20-Year and 60-Year Nuclear Hybrid Facilities in Both Mid-C and PJM Markets.

		20-Year Lifetime		60-Year Lifetime	
		PJM	Mid-C	PJM	Mid-C
Case A	NPV	($592,898,013)	($744,620,862)	($610,451,611)	($788,079,401)
	LCOE	$77.81/MWh		$67.74/MWh	
	Payback	15 years	19 years	18 years	23 years
Case B	NPV	($559,473,241)	($744,912,279)	($563,616,125)	($780,716,757)
	LCOE	$85.10/MWh		$74.09/MWh	
	Payback	14 years	17 years	16 years	21 years
Case C	NPV	($34,216,010)	($185,163,477)	$213,404,086	$31,829,012
	LCOE	$97.37/MWh		$82.82/MWh	
	Payback	9 years	10 years	9 years	10 years

market happens to have a lower wholesale electricity price, resulting in a longer payback period and lower NPV for all cases.

5. Change in hydrogen selling price for 60-year lifetime deregulated market

In this sensitivity analysis, the hydrogen-selling price per kg is varied from $2.50 to $7.50 to see the effect on NPV and payback period. With selling price of $5.50 the NPV for the NREI system becomes positive. When electricity demand is low, more thermal and electrical energy can be diverted for production of hydrogen and with increasing the output of hydrogen production at times when cost of electricity is low, we can reduce the production cost.

6. Effect of capacity payment for cases A, B, and C in PJM market

Capacity payments refer to the payment given to the power production facility to produce power (i.e., the plant gets paid whether it is operating or not). While calculating the capacity payment for nuclear, the capacity factor for the plant is taken as 1, but in the PJM market only 13 percent of wind-rated capacity is eligible for capacity payment (i.e., for 60 MW of wind capacity, the eligible capacity payment is based on $0.13 * 60 = 7.8$ MW). A capacity payment of $125/MW day is based on PJM market (PJM Capacity Market, 2014) and can vary depending on the market. With inclusion of capacity payment the NPV tends to become more favorable, but is still negative for the assumed discount rate of 17.50 percent. The payback period shifts by 1 year for both Case A and B and an increase in IRR is observed, as expected and shown in Table 7.

The analysis carried out in this study is not optimized and results may vary depending on assumptions and input values.

IV. Qualitative Discussion

If incentive programs such as subsidies, tax incentives (credits, deductions, and exemptions), loan guarantees, rebates, and grants are provided for NREI, the effort will promote growth of NREI in the energy sector and will encourage investors and utilities to pursue eco-friendly sustainable energy option, because the grants will make NREI option more economically attractive, by offsetting the capital cost of NREI system. Incentives and subsidies can affect LCOE in one of two basic ways (Du and Parsons, 2009): they can reduce the LCOE directly through tax credits or feed-in tariff-type structures, or they can reduce the WACC faced by the project developer (i.e., through loan guarantees or low/

Table 7: Case Comparison with and without Capacity Payment for PJM Deregulated Market.

	Payback Period	NPV	IRR (%)
With Capacity Payment			
Case A			
20 years	14	($829,286,113)	4
60 years	14	($806,071,552)	7.25
Case B			
20 years	13	($852,513,100)	4.97
60 years	13	($824,915,525)	7.92
Case C			
20 years	9	($453,007,012)	10.34
60 years	9	($385,641,723)	12.31
Without Capacity Payment			
Case A			
20 years	15	($876,602,857)	3.03
60 years	15	($855,343,459)	6.59
Case B			
20 years	14	($901,060,079)	4.1
60 years	14	($875,468,502)	7.32
Case C			
20 years	9	($494,763,483)	9.62
60 years	9	($426,340,318)	11.76

zero-interest loans). With incentives, as mentioned previously, the LCOE of the NREI would be very competitive with fossil and will be a move in the right direction to further achieve energy independence, and in a manner leading to a strong sustainable platform for the future. To increase renewable penetration goal by 2030, incentives would be needed to attract utilities to increase the energy production from renewable source. If \$23/MWh is provided as a tax incentive to utilize wind energy, for Case B 20-year time horizon, the net IRR% increase is about 28 percent and about 18 percent (if the incentive is given only for the first 10 years) compared to no incentive case. Similarly, for Case C 20-year time horizon, the increase in IRR is 15 percent and 12 percent (if the incentive is given only for first 10 years) compared to no incentive case. Further analysis with carbon tax should be carried out, as a comparison with fossil power plants. The added tax in pro-forma analysis could simply be taken as an increase in variable cost of operation. The objective of these incentives and carbon tax being enforced on CO_2 emission are few of the

Table 8: Summary of NREI Benefits and Drawbacks with Respect to Sustainability Measures.

Sustainability Measure	Benefits	Drawbacks
Economic	1. Flexibility to adapt to market changes. 2. Scalability to adapt to power or heat demand. 3. Could be designed for a wide range of applications. 4. Could use available existing infrastructure. 5. New market opportunities for nuclear energy. 6. Opportunity cost essentially zero for variable renewable and nuclear energies (i.e., the wind or solar energy and uranium would not be used for any other purpose). 7. Energy supply security reduces likelihood of price volatility.	1. New technology may have unknown limitations. 2. Initial understanding the proper licensing requirements by both the governing body and the integrated system owner will be a challenge. 3. Need for initial investment from the integrated system owner to prove feasibility and safety.

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Table 8 (*Continued*)

Sustainability Measure	Benefits	Drawbacks
Environment	1. Promotes environmental goals through reduction in emissions compared to current energy sources. 2. Process heat for industrial applications reduces greenhouse gas emissions, when compared to burning fossil fuels. 3. Consideration of low-risk, high-consequence events that pose significant health and environmental impacts have already been internalized for the nuclear industry.	1. Nuclear waste solution is still a concern for the public—recycle, storage for future use, or disposal in a repository. 2. Threads to local wildlife by wind mills.
Social (Political)	1. May be applicable to regions currently underserved by nuclear power or those lacking a large centralized electrical grid. 2. Improved energy security and independence. 3. Higher reliability and resilience than any of the components operating individually, to meet the peak demand. 4. Various energy sectors working together to promote eco-friendly practices. 5. Promotes clean environment while adapting new technologies for better efficiency and financial return.	1. Waste solution should follow the ethical aspects of sustainability and leave conditions at least as good as they are now for future generations. 2. Broader public involvement necessary for improved public perception.
Institutional Dimension	1. Opportunity to merge environmental goals and economics in the decision-making process. 2. Brings adaptability and flexibility to market changes. 3. Promotes and encourages industrial symbiosis.	1. Consistent government support is needed. 2. New modified policies that internalize air quality and take considerations like energy security into account will be required. 3. Determining which government agency would ultimately be responsible. 4. New standards required.

much-needed steps to encourage utilities toward a sustainable energy future.

Political and social considerations

Energy policy must dictate conditions for both energy consumers and suppliers that will safeguard energy security, including both resource availability and pricing (Koroneos et al., 2004). In terms of sustainability, there are many potential advantages and disadvantages that may be observed with the NREI system, as shown in **Table 8**.

V. Conclusions

NREI may operate with significant environmental advantages as a result of the incorporation of renewable and nuclear energy systems; it may also offer a method to more economically operate with heat being supplied to industrial process heat applications. NREI systems may be critical for stimulating renewable energy growth, promoting diversification of electricity production, coupling industrial process heat applications to energy production, and attaining a strong global sustainability platform. This study compares the economics of three cases: nuclear power plant, nuclear and wind-combined facility, and a nuclear-wind-hydrogen production facility, utilizing wholesale electricity prices and market conditions from the PJM deregulated and the Mid-C regulated market hubs. There is a market at the Mid-C, but the participants are primarily regulated utilities (and players in California and Canada) buying and selling surplus power on a bilateral basis. So the price at the Mid-C hub is still the product of a market, just a very different type of market than the PJM market. Sensitivity analysis is carried out to see the effect of discount rate, depreciation rate, energy market, and time horizon, by comparing NPV, IRR, LCOE, and payback period, respectively. The difference in NPV for both Mid-C and PJM (deregulated market) is due primarily to the lower prices in the Mid-C market, because that market is so hydro-based. Case C with nuclear, wind, and hydrogen if optimized (in terms of economic flexibility/adaptability) could lead to positive NPV with faster returns on investment, thus making NREI an economically attractive option for the future.■

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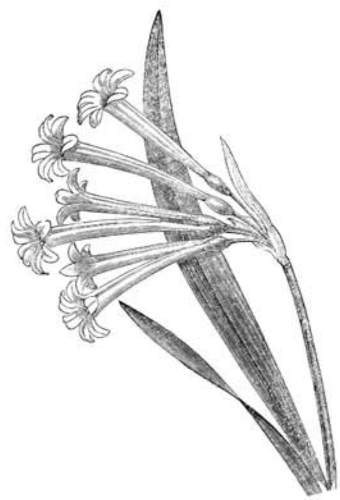

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