Electricity Generation Capacity Planning with Nuclear, Renewables, and Batteries: Defining Pathways to Energy Security and Decarbonization

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ABSTRACT

Our study presents a capacity planning approach to assess the impact of integrating nuclear energy systems on techno-economics and CO_2 emissions. While the U.S. Environmental Protection Agency (EPA) has imposed strict rules and standards to reduce pollution from fossil fuel fired power plants, energy security and reliability are pervasive issues in the light of climate crisis. Issues related to sustainability need to be addressed. The complexity of the problem at the interface of climate change and energy security poses major challenges for utility companies and electric grid operators in providing cost-effective and reliable electricity to their customers.

The main goal of our study is to better understand the integration of nuclear, renewables, and battery storage units with the help of a model utility system. To this end, this study utilizes a daily load curve from a model utility system to demonstrate electricity generation capacity planning and portfolio selection. It investigates three possible capacity planning scenarios: *Scenario I* comprised of coal, nuclear, and natural gas units; *Scenario II* comprised of nuclear and natural gas units; and *Scenario III* comprised of nuclear, natural gas, renewable, and battery energy storage units. Using U.S. Energy Information Administration data, the impact of capacity planning scenarios on techno-economic elements such as plant performance factors, economics, reliability, and CO_2 emissions are examined. The results indicate a significant variation in performance factors, the levelized cost of electricity (LCOE), and CO_2 emissions while the reliability remains the same across all three scenarios. With nuclear energy, renewables, and battery energy stor-

age replacing coal, a significant reduction of CO_2 emissions of 99% is observed. In summary, this study provides a framework to study the techno-economic complexity of electricity generation capacity planning with nuclear energy, renewables, and battery storage units.

INTRODUCTION

Most recently, there has been an ongoing debate pertaining to the commissioning of nuclear power plants to produce carbon-free electricity in the United States. U.S. EPA standards have imposed strict regulations to reduce pollution from fossil-fuel fired power plants leading to the decommissioning of numerous coal-fired power plants across the U.S. [1]. It has become critical to find alternatives to produce base load electricity to enhance the stability of electric grids. The International Energy Agency (IEA) defines energy security as the uninterrupted availability of energy sources at an affordable price with intricate relationships to national security and natural resources [2]. However, the quest to decarbonize energy infrastructure and produce affordable, clean, and reliable electricity poses a collective challenge for industries and nation states.

While natural gas (NG) plants produce less CO_2/kWh of electricity generated than those using coal or oil, they are more suited for producing power for intermediate and peak loads in conjunction with renewable energy systems. The rapid emergence of artificial intelligence (AI) data centers, electric vehicle (EV) charging infrastructure, and requirements for achieving net-zero greenhouse gas emissions (GHG) goals are straining local power grids. There are numerous safety concerns in the minds of the public and policy makers after nuclear disasters at the Chernobyl plant in Ukraine, Japan's Fukushima Daichi plant, and the incident at the Three-Mile Island plant in the U.S. [3]. Despite concerns about nuclear waste disposal, the climate crisis has prompted many to reconsider nuclear energy as a viable option for producing electricity [4]. Given this complex situation, the U.S. government has issued official statements supporting generation of electricity using nuclear energy [5].

A historical analysis of the U.S. portfolio of energy resources since 2008 shows that the energy mix used for electrical generation has evolved over the last 16 years. Data obtained from the Lawrence Livermore National Laboratory (LLNL) energy flow charts are reproduced in Table 1 and Figure 1 [6]. Using the 2008 base year, coal usage declined by 55.8% from 22.4 to 9.9 quads* while NG usage increased from by 40.1% from 23.4 to 33.4 quads by 2022. We see substantial development of operating wind and solar farms over the period increasing by 677% and 1,977% respectively. While hydropower production declined by 5.7%, biomass usage has surged by 28.1% with the use of wood pellets in many retired coal-fired power plants and smaller biomass plants [7]. Although nuclear power production has declined by 4.7%, from 8.5 to 8.1 quads due to plant closures, it has the potential to reemerge as a viable option for producing electricity without the threat of increasing GHG emissions.

The reassessment of nuclear energy to meet the climate goals involves both technical, operational, management and financial challenges.† A recent survey conducted by Parker et al. indicated numerous

Table 1. Changes in energy use by resource.

Energy resources	*2008 (quads)*	*2022 (quads)*	*% Change*
Coal	22.42	9.91	-55.8%
Natural Gas	23.84	33.40	40.1%
Nuclear	8.45	8.05	-4.7%
Hydro	2.45	2.31	-5.7%
Biomass	3.81	4.88	28.1%
Wind	0.51	3.89	662.8%
Solar	0.09	1.87	1,977.8%
Geothermal	0.35	0.21	-40.0%
Petroleum	37.13	35.80	-3.6%

*1 quadrillion Btu = 293 x 10^9 kWh of electricity.

†A new nuclear power plant, the first in the U.S. in over 30 years, is now operating in Waynesboro, Georgia. Plant Vogtle units 3 and 4 have a capacity of 1,100 MW each and are expected to generate more than 17 million MW hours of electricity, enough to power an estimated 1.6 million average American homes. These were commissioned after 2022. The plants hold the distinction of producing the most expensive electricity of any plant of any type ever constructed [8,9,20].

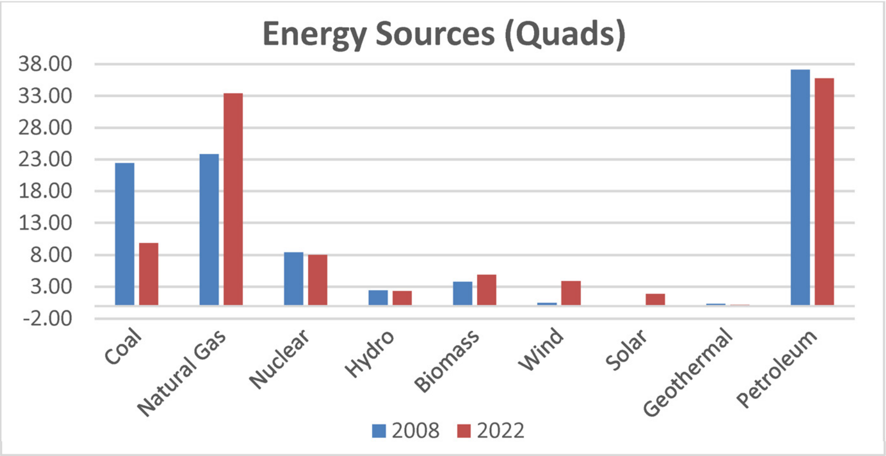

Figure 1. U.S. energy portfolio mix from 2008 to 2022.

such opportunities and policy challenges facing the electric power industry [10]. Our conceptual study, a sequel to an earlier study, addresses this complex issue by examining the impacts of nuclear integration along with renewables and battery storage units [11]. It further considers their impacts on CO_2 emissions, plant performance factors, economics, and grid reliability.

The study begins with the assessment of a daily load curve data (see Appendix A, Figure A1 and Table A1) for a modeled electric utility company with 17 conventional power generation systems [12]. The operating and dispatch schedules are provided in Appendix A, Table A2. Using the conventional power system shown in Appendix A, Table A3, three possible scenarios are considered (see Appendix A, Tables A4-A6). Appendix A, Table A7 provides the approximate reliability factor data.The cost data for the coal, nuclear, natural gas, renewables, and battery energy storage units were obtained from the U.S. Department of Energy (DoE) and the Energy Information Administration (see Appendix A, Table A8) [13]. The energy resources used for the three selected scenarios are summarized in Table 2.

This study presents three capacity planning scenarios:

- *Scenario I* comprised of coal, nuclear, and natural gas units.
- *Scenario II* comprised of nuclear and natural gas units.

- *Scenario III* comprised of nuclear, natural gas, renewable, and battery storage units.

Table 2. Three possible scenarios.

Scenario I	*Scenario II*	*Scenario III*	
Coal	Nuclear	Nuclear	
Nuclear			
Natural Gas	Natural Gas	Natural Gas	Solar PV
			Wind onshore
			Wind offshore
			Battery storage

With the addition of renewable and battery units in *Scenario III*, the capacity factor is reduced which indicates excess reserve capacity. The levelized cost of electricity (LCOE) increases significantly while grid reliability remains the same. The results indicate that *Scenario I* using coal-fired units produces 30 million metric tons of CO_2 per year. *Scenario II* with nuclear units instead of six coal coal-fired units produces much lower CO_2 emissions of 350,000 tons per year, a 98.8% reduction from Scenario I. Using renewable energy resources and battery energy storage complement the NG-fired plants and further reduces CO_2 emissions to about 245,000 metric tons in *Scenario III*. The three scenarios demonstrate the fact that nuclear energy provides an effective pathway to achieving decarbonization and climate goals while maintaining energy security due to higher generation capacity.

METHODOLOGY

The methodology for this analysis involves an initial assessment of *Scenario I* followed by the nuclear-based *Scenario II*, and subsequently *Scenario III* with a mix of nuclear, renewables, and battery energy storage units. The performance, economics, reliability, and CO_2 emissions are evaluated for each of the three scenarios. We next investigate four key elements that are important for the techno-economic evaluation of power grids: performance, economics, reliability, and CO_2 emissions.

Performance

The study begins with the assessment of a daily load curve data depicted in Appendix A, Figure A1 and Tables A1 and A2. This data models a mid-sized utility company operating 17 conventional power generation units to meet consumer electricity demand. Using the Appendix A, Table A1 data, we can calculate the plant performance parameters: daily electricity generation (*DEG*), average load (*AL*), load factor (*LF*), capacity factor (*CF*), and reserve factor (*RF*) in Equations 1-5 as follows [14]:

$$DEG = \sum \text{Load}\,(i) * \Delta t\,(i) \tag{1}$$
$$\text{Average load}\,(AL) = DEG/24 \text{ hours} \tag{2}$$
$$\text{Load factor}\,(LF) = \text{Average load/Peak load} \tag{3}$$
$$\text{Capacity factor}\,(CF) = \text{Average load/Rated capacity} \tag{4}$$
$$\text{Reserve factor}\,(RF) = \text{Load factor/Capacity factor} \tag{5}$$

Sample calculations for *Scenario I* are provided for the convenience of the reader. Using the data from Appendix A, Tables A1 and A2, we have the following metrics:

$$DEG = [(3{,}888 \text{ MW x 1 hour}) + (3{,}696 \text{ MW x 1 hour}) + \ldots + (4{,}800 \text{ MW x 1 hour}) = 119{,}232 \text{ MWh}$$
$$\text{Average load}\,(AL) = 119{,}232 \text{ MWh}/24 \text{ hours} = 4{,}968 \text{ MW}$$
$$\text{Load factor}\,(LF) = 4{,}968 \text{ MW}/6{,}000 \text{ MW} = 0.83$$
$$\text{Capacity factor}\,(CF) = 4{,}968 \text{ MW}/6{,}825 \text{ MW} = 0.73$$
$$\text{Reserve factor}\,(RF) = 0.83/0.73 = 1.14$$

If the rated capacity of the plant is equal to the peak load, then the capacity factor and load factor would be equal. The difference between the load factor and capacity factor is an indication of the reserve capacity represented by the reserve factor. The difference between the operating capacity and the load at different hours is the spinning reserve (see Appendix A, Figure A1). This is the buffer capacity that can be switched on immediately to match supply with demand when an increase in demand and/or supply disruption occurs.

Coal-fired plants are replaced by nuclear plants for *Scenario II* (see Appendix A, Table A5). The capacities of the nuclear units are assumed to be the same as that of coal units to maintain the same capacity factors. Renewable energy resources and battery storage capabilities are integrated to create *Scenario III* as shown in Table 2. With a capacity factor of 0.3, the renewable resource capacities are determined to match that of natural gas. This is because NG-fired units act as back up for solar and wind along with the batteries. The total capacity of 24 battery storage units is assumed to be equal to that of the NG-fired units (50 MW x 24 = 1,200 MW) matching the NG electrical generation capacity of 1,175 MW.

Economics

It is important to assess the economic performance of an electric utility system. For this analysis, we procedures to calculate the variables capital cost (*CCOST*), operating and maintenance cost (*OMCOST*), fuel cost (*FCOST*), annualized cost (*ACOST*), and the levelized cost of electricity (*LCOE*) are provided in Equations 5-10 as follows:

$$CCOST = \sum \text{[Rated capacity unit } (i) \text{ x Capital cost unit } (i)] \quad (6)$$
$$OMCOST = \sum \text{[Rated capacity unit } (i) \text{ x O\&M cost unit } (i) \text{]} \quad (7)$$
$$FCOST = \sum \text{[Generation unit } (i) \text{ x Fuel cost unit } (i) \text{]} \quad (8)$$
$$ACOST = CCOST \text{ x } [I \text{ x } (1+\mathrm{I})^N/(1+\mathrm{I})^N\text{-}1)] \quad (9)$$
$$LCOE = (ACOST + OMCOST + FCOST)/DEG \quad (10)$$

The interest rate (*I*) and the length of the project (*N*) were assumed to be 7% and 20 years for the sake of the analysis. Daily electric generation (*DEG*) is the average daily power output in kWh. The detailed cost data was selected from the EIA (see Appendix A, Table A8) and is presented for the generation units used in this study (see Appendix A, Tables A4-A6). The operations and maintenance (O&M) costs were obtained by multiplying the unit O&M cost with their unit rated capacities. However, the fuel costs incurred by the fossil fuel power systems depend on the power generated by each unit. The *LCOE* in units of $/kWh is calculated using Equation 10.

Reliability

The objective of a reliability analysis is to derive suitable measures, criteria, and indices of reliable and dependable performance based on component outage data and system configuration [15]. For this study, reliability is defined as the probability that the system functions to generate full power [P(S)]. In other words, the performance measure of reliability is 1 when 100% of the demand is met, and 0 otherwise.

We assume that the energy system consists of several power blocks, where each block consists of one or more units. We let $P(B_d)$

denote the probability that Block d operates successfully. The reliability factors for different blocks ($P(B_d)$, $d = 1, 2, 3,...$) are approximated based on historic data and the availability of the fuel source for units in Block d [15-16].

For the case when the energy system consists of k power blocks and power is needed from each of these to meet the entire demand, then the reliability is a multiplication function of the probability of each functioning k energy block. This is equivalent to a series with k blocks in series.

$$P(S) = P(B_1) \times P(B_2) \times P(B_3) \times \ldots \times P(B_k), \quad (11)$$

For the case when the system consists of k blocks and power is need from any one of these to meet the entire demand, then…

$$P(S) = 1 - [1-P(B_1)] \times [1-P(B_2)] \times \ldots \times [1-P(B_k)] \quad (12)$$

This is equivalent to a parallel system with k blocks in parallel [15-16].

For this study the reliability assessment is performed for configurations including both series and series subsystems connected in parallel. These configurations approximately represent the physical arrangement of generation units. The reliability assessment for the following three scenarios is outlined in Appendix A, Tables A4-A6:

- *Scenario I* with coal, nuclear, and natural gas (17 units).
- *Scenario II* with nuclear and natural gas (17 units).
- *Scenario III* with nuclear, natural gas, renewables, and battery energy storage (61 units).

The individual power generation units are combined into seven blocks: coal, nuclear, natural gas, solar PV, onshore wind, offshore wind, and battery energy storage (see Appendix A, Table A7). For instance, the coal block is comprised of six plants each with multiple boilers, steam turbines, condensers, and pumps to ensure that they meet the electric demand when operational. The same is true with the nuclear block that is comprised of six nuclear plants each with multiple reactors to ensure smooth operation during shutdown for refueling and maintenance. This same logic applies for the remaining blocks including NG, solar, onshore wind, offshore wind, and battery energy storage. The approximate operational reliabilities are presented in Appendix A, Table A7. These reliability numbers are intended to reflect actual values but are used for benchmarking the scenarios in this study. We assume the configurations in Figures 2 to 4 meet the demand by using different blocks.

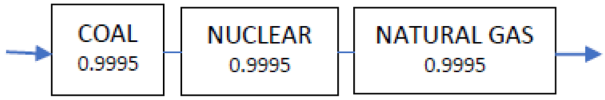

Figure 2.
Reliability configuration of Scenario I with coal + nuclear + natural gas.

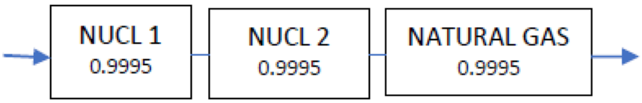

Figure 3.
Reliability configuration of Scenario II with nuclear + natural gas without coal.

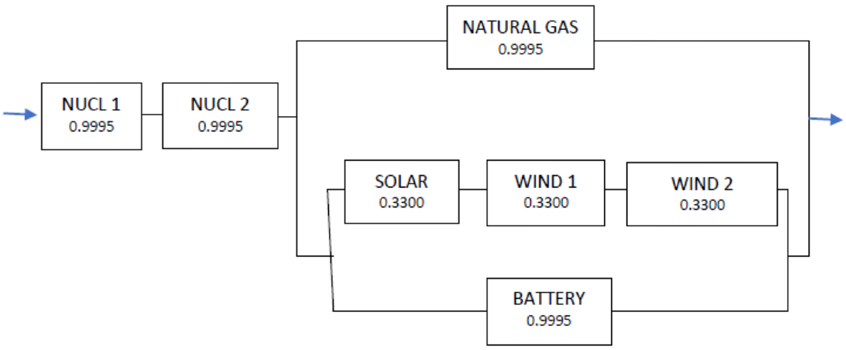

Figure 4.
Reliability configuration of Scenario III with nuclear + natural gas + renewables + battery energy storage without coal.

CO_2 Emissions

With these configurations, we assume that *Scenario III* with both nuclear and renewables along with battery energy storage reduces CO_2 emissions by about 50% from *Scenario II*; the overall capacity factor and reserve capacity of the system are increased. It is assumed that renewables will produce adequate electricity to offset the electricity produced by NG by approximately 30%. With addition of batteries, it is assumed that renewables will provide an additional 20% of the electricity—for a total of 50% of the electricity that would have been produced by NG-fired units in *Scenario II*. This is designed to reduce the CO_2 emissions of *Scenario II* by 50% which achieves potential decarbonization goals.

RESULTS AND DISCUSSION

In this section, we analyze the variables related to performance, economics, reliability, and CO_2 emissions for three scenarios starting with the coal-based scenario. The cost data for conventional, renewable, and battery energy storage systems are provided in Appendix A, Tables A3-A6 which are adopted from U.S. EIA Appendix A, Tables A8. *Scenario II* involves a utility generation system with nuclear units replacing all 6 coal units. For *Scenario III* we integrated three widely used renewable systems (solar PV, onshore wind, offshore wind, and battery energy storage units) in equal portions for the sake of demonstration. It is expected that the capacity of the NG-fired units totals 1,175 MW (750 MW + 425 MW) is used as the basis to select the rated capacities of renewable energy systems for *Scenario III*. In doing so, the renewable systems and NG-fired units are coupled to complement each other with the objective of producing carbon-free electricity. We assume a hypothetical situation in which *Scenario III* produces electricity using nuclear power and renewable resources supported by battery storage which provides near-zero CO_2 emissions.

This means that an individual electric load of 391.33 MW (1,175 MW/3 = 391.33 MW) will be met by each one the three renewable energy systems. Capacity factors used to evaluate the needed capacities for installation of the renewable energy systems are based on actual projects (27.8% from the Fowler Ridge Wind Farm and 30.2% from the Blythe Mesa Solar PV Project) [16-18]. On average, the capacity factor of 0.30 was chosen for the selection and sizing of solar PV, onshore wind, and offshore wind units whose rated capacities and data are obtained from U.S. DOE Appendix A, Table A8. The needed capacities of the solar and wind are selected as follows:

$(\text{Rated capacity})_{\text{Solar PV}}$ = Average load/Capacity factor = 391.33 MW/0.30 = 1,304 MW

$(\text{Rated capacity})_{\text{Wind Onshore}}$ = Average load/Capacity factor = 391.33 MW/0.30 = 1,304 MW

$(\text{Rated capacity})_{\text{Wind Offshore}}$ = Average load/Capacity factor = 391.33 MW/0.30 = 1,304 MW

Based on these estimates, we required at least 1,350 MW of rated capacities of solar PV, onshore wind, and offshore wind to complement NG (see Appendix A, Table A6). The selected battery storage units are assumed to meet the electric demand equal to the capacity of the NG-fired units which is 1,175 MW. We selected 24 50 MW battery storage units to meet the 1,175 MW demand (24 x 50 MW = 1,200 MW) that otherwise would have been met by the NG units. The idea behind the selection of renewable energy systems is to match the capacity of NG units. By doing so, the NG units would act as back-up for the renewables while meeting intermediate and peak loads. In *Scenario III* with utility system III, we assumed that renewables along with supplemental battery energy storage would meet the load of 1,175 MW thus reducing the CO_2 emissions to near-zero.

Appendix A, Tables A4-A6 represent three configurations starting with a total of 17 units for conventional systems, 17 units with nuclear systems, and 61 units with renewable energy systems plus battery storage. Appendix A, Table A7 provides estimates of operational reliability factors of units in both conventional and hybrid systems. These reliability factors are adjusted based on the availability of fuel source. The results and discussion including performance analysis, economic evaluation, reliability assessment, and CO_2 emissions of three configurations are presented in Figures 5 through 13.

Performance Analysis

The daily electricity generation (*DEG*), average load (*AL*), and the load factor (*LF*) remain the same for all three scenarios because the electric demand is the same. The capacity factor (*CF*) measures the utilization of the plant capacity. A plant with a capacity factor of 100% can produce electricity continuously at its rated capacity. The capacity factors vary

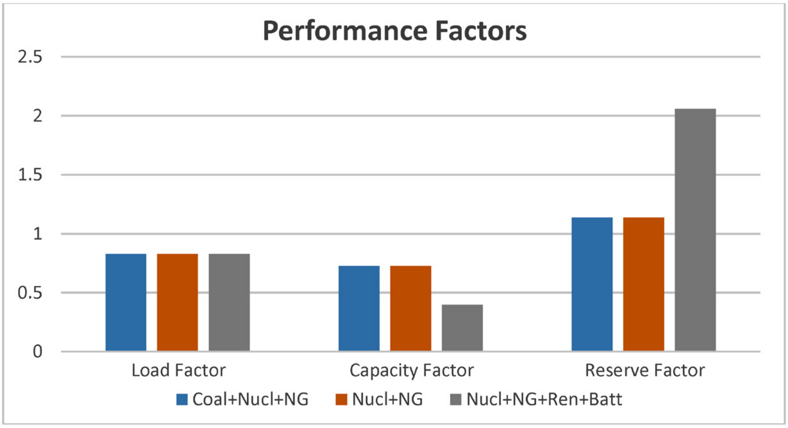

Figure 5. Overview of performance factors.

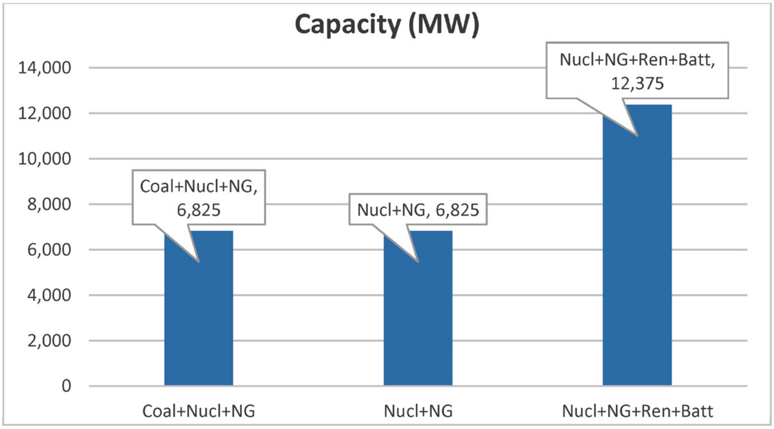

Figure 6. Increase in rated capacity.

with increases in rated capacity. Reserve factor (*RF*) is a measure of buffer capacity that exceeds peak demand; *RF* increases with the addition of renewable energy and battery energy storage system capacities resulting in increased reserve capacity (see Figure 5). The overall increase in capacity and number of assets is shown in Figures 6 and 7 respectively.

Economic Evaluation

The capital cost of the alternatives increases with the addition of generation assets (see Figure 8). The *LCOE* is calculated based on the interest rate of 7% and project life of 20 years for our system-level

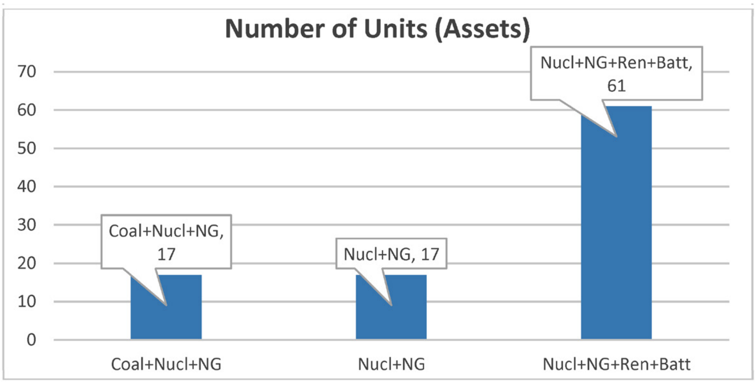

Figure 7. Increase in number of assets (units).

study. However, this warrants detailed analysis of the *LCOE* for different interest rates and project lengths. The *LCOE* increases from \$0.08/kWh to \$0.11/kWh to \$0.15/kWh as shown in Figure 9. For an average monthly residential electricity consumption of 1,000 kWh, the monthly cost increases from \$82 to \$111 to \$153 per month as shown in Figure 10.

Reliability Assessment

Using the operational reliability factors in Appendix A, Table A7, the results of the reliability assessments are estimated and shown in Figures 11 and 12. The equipment reliability factor of 0.9995 was assumed for all units. Note that the value of 0.9995 implies a reasonable unplanned downtime of about 4 hours annually [(1.0 – .9995) x 8,760 = 4.38 hours/year]. The operational reliability of renewable energy systems is much lower than the fossil-fuel and nuclear plants due to the intermittent generation of solar and wind resources.

The results show that the reliability of the coal-based *Scenario I* is 0.9985 (99.85%). This implies that the likelihood of a conventional power system generating power is 99.85% and the expected power outage is time 13.13 hours [= (1-0.9985) x 8,760 hours] annually. With nuclear power replacing coal, the reliability in *Scenario II* remains the same at 0.9985 with the power outage time of 13.13 hours. In *Scenario III*, the addition of renewable energy systems and battery energy storage units increases the operational reliability of the entire system to 0.9989 (99.89%) while the expected power outage time drops to 8.76 hours annually.

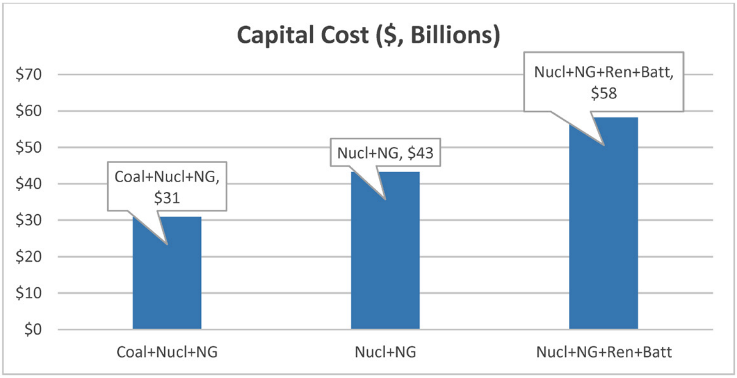

Figure 8. Capital costs (billion $s).

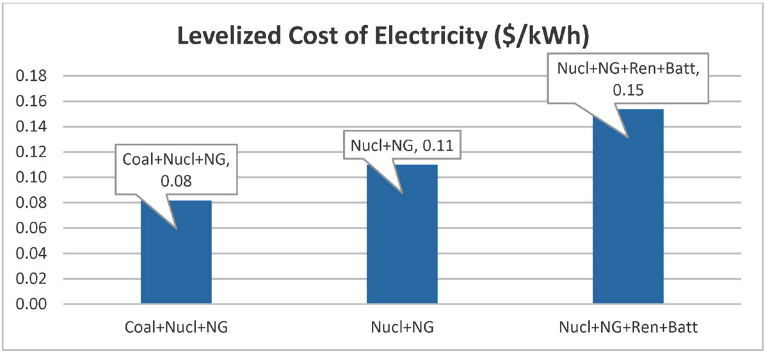

Figure 9. Levelized cost of electricity (I = 7%; N = 20 years).

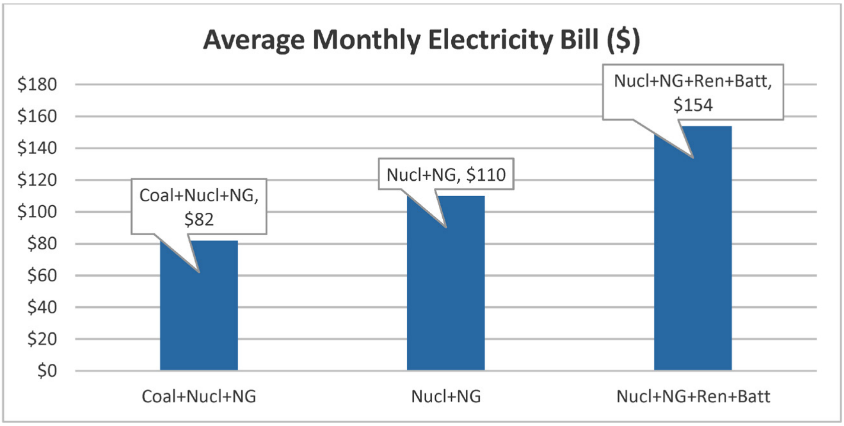

Figure 10. Average monthly home electricity bill ($).

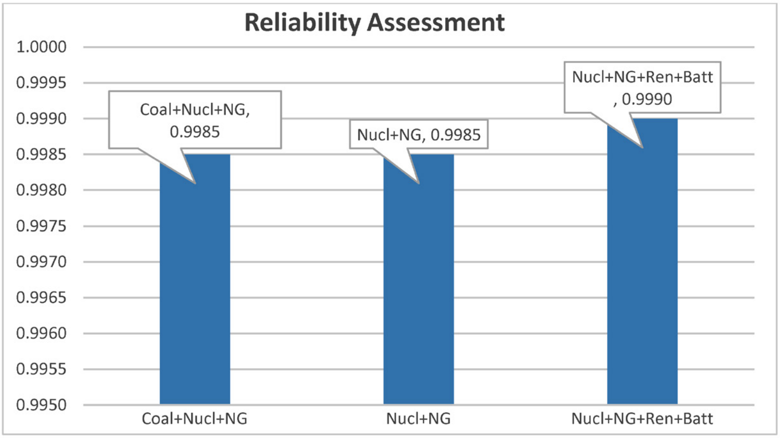

Figure 11. Reliability factors of three scenarios.

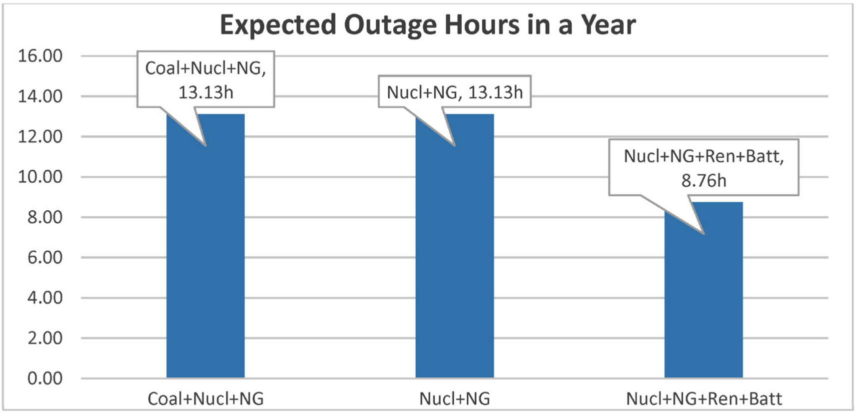

Figure 12. Expected annual outage hours for three scenarios.

CO_2 Emissions

Using the U.S. EIA standards of 2.30 lbs./kWh for coal and 0.97 lbs./kWh for natural gas, we calculated the CO_2 emissions for three scenarios (see Table 3) [19]. With the integration of nuclear energy systems in *Scenario II* for producing base load electricity, CO_2 emissions can be reduced by 98.8% from 30.3 million metric tons of CO_2/year to approximately .35 metric tons/year (see Figure 13). Replacing coal with nuclear energy contributes to this significant decline in CO_2 emissions. With the integration of renewable energy systems and battery energy storage in *Scenario III*, CO_2 emissions are expected to decrease by about

50% to approximately 174,615 metric tons annually.

It is assumed that renewables will produce enough electricity to approximately offset the electricity produced by natural gas by 30%. With the addition of battery energy storage, it is assumed that renewables will provide another 20% of the needed electricity, a total of 50% of the electricity that would have been produced by the natural gas units in *Scenario II*. This reduces the CO_2 emissions of *Scenario II* by 50% leading to the potential of meeting or exceeding possible decarbonization goals. This is a probabilistic scenario that requires further investigation with real-time data obtained from a demonstration project for verification.

CONCLUSION

The main goal of our study was to better understand the integration of nuclear, renewables, and battery energy storage units with the help of a model utility system. To achieve this objective, this study involved assessing a conceptual utility system comprised of 17 conventional power generation units. The impact of three possible scenarios: *Scenario I* with coal, nuclear, and natural gas units; *Scenario II* with nuclear and natural gas units; and *Scenario III* with nuclear, natural gas, solar PV, onshore wind, offshore wind, and battery storage was examined.

It is clear from the results that the overall system capacity, the capital cost, levelized cost of electricity, and average monthly electricity costs increase significantly with the integration of nuclear, renewable energy systems, and batteries in *Scenario III*. The reliability of the system does not change significantly since nuclear units replacing coal have similar reliability factors along with natural gas units. Replacing coal units with nuclear leads to a 99% reduction in CO_2 emissions as evidenced in *Scenario II*. Furthermore, the addition of renewable energy systems and battery storage units in *Scenario III* leads to further reductions in CO_2 emissions provided the renewables and natural gas units complement each other to meet at least 50% of the intermediate and peak demands.

Achieving sustainable development goals involve trade-offs. Nuclear energy along with renewables and battery energy storage can provide viable options for achieving decarbonization goals within the energy security framework but challenges remain. Utility-scale nuclear energy projects

Systems	*CO_2 (lbs./kWh)*	*Daily Generation (MWh)*	*CO_2 million metric tons per year*		
			Scenario I	*Scenario II*	*Scenario III*
Coal	2.3	78,658	29,960,704	0	0
Natural Gas	0.97	2174	349,231	349,231	174,615
Nuclear	0	38,400	0	0	0
Solar PV	0	0	0	0	0
Wind Onshore	0	0	0	0	0
Wind Offshore	0	0	0	0	0
TOTAL		119,232	30,309,935	349,231	174,615

Table 3. Annual CO_2 production in metric tons for three scenarios.

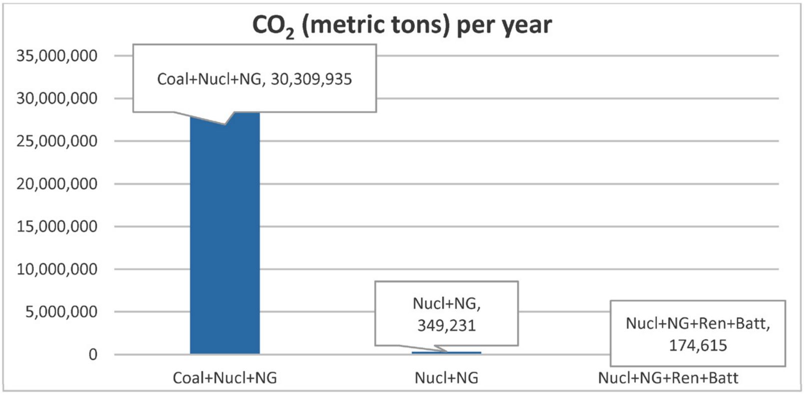

Figure 13. Impact of nuclear energy on CO_2 emissions.

carry associated financial risks which are mitigated when construction and financing costs are predictable—which is rarely the case [20]. There are challenges in implementing these solutions. Optimizing the potential electrical generation from the installation of a solar photovoltaic (PV) system provide intermittent generation because the production of electricity from a solar PV array varies due to factors such as the site location, weather conditions and orientation [21]. Electrical generation from wind power systems add to intermittency and require management. Utility-scale battery energy storage systems are declining in cost; many electric utilities see them as viable for their operations. The challenges associated with variable forms of generation are being met and we are seeing technological advancements which are overcoming their barriers.

Acknowledgements

The authors thank Professor Eckhard Groll and Professor James Jones from Purdue University School of Mechanical Engineering for supporting this research project.

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APPENDIX A

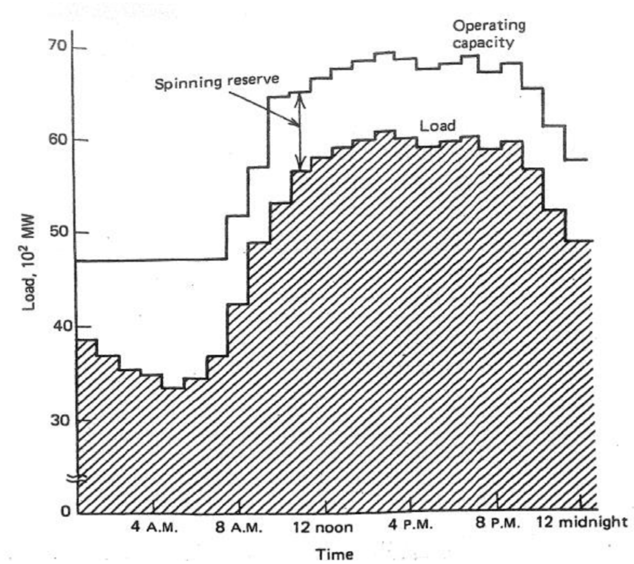

Figure A1. Daily load curve of a mid-sized U.S. city [12].

Table A1. Daily electricity load data on an hourly basis.

	1	*2*	*3*	*4*	*5*	*6*
Load (MW)	3,888	3,696	3,552	3,504	3,360	3,456
Hours	*13*	*14*	*15*	*16*	*17*	*18*
Load (MW)	5,856	5,904	6,000	5,904	5,808	5,856

7	*8*	*9*	*10*	*11*	*12*
3,696	4,224	4,848	5,280	5,616	5,760
19	*20*	*21*	*22*	*23*	*24*
5,904	5,760	5,856	5,568	5,136	4,800

Table A2. Daily operating schedule of the utility system.

Utility System Load Distribution in a 24-Hour Period

				Unit Number																
		Capacity in	Spinning	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
	Load	Operation	Reserve																	
Hours	(MW)	(MW)	(MW)	Load Distribution (MW)																
0100	3888	4700	812	483	513	574	719			800	800									
0200	3696	4700	1004	416	450	534	696			800	800									
0300	3552	4700	1148	341	418	508	685			800	800									
0400	3504	4700	1196	312	410	500	682			800	800									
0500	3360	4700	1340	240	382	472	665			800	800									
0600	3456	4700	1244	283	402	492	678			800	800									
0700	3696	4700	1004	416	450	534	696			800	800									
0800	4224	5150	926	566	568	624	749		117	800	800									
0900	4848	5650	802	687	664	695	800	63	339	800	800									
1000	5280	6400	1120	737	711	742	800	303	388	800	800	s	s							
1100	5616	6450	834	800	750	750	800	466	450	800	800	s	s							s
1200	5760	6575	815	800	750	750	800	500	450	800	800	s	110				s		s	s
1300	5856	6675	819	800	750	750	800	500	450	800	800	s	206			s	s	s	s	s
1400	5904	6750	846	800	750	750	800	500	450	800	800	s	254	s		s	s	s	s	s
1500	6000	6825	825	800	750	750	800	500	450	800	800	77	273	s	s	s	s	s	s	s
1600	5904	6750	846	800	750	750	800	500	450	800	800	s	254	s		s	s	s	s	s
1700	5808	6625	817	800	750	750	800	500	450	800	800	s	158				s	s	s	s
1800	5856	6675	819	800	750	750	800	500	450	800	800	s	206			s	s	s	s	s
1900	5904	6750	846	800	750	750	800	500	450	800	800	s	254	s		s	s	s	s	s
2000	5760	6575	815	800	750	750	800	500	450	800	800	s	110				s	s	s	s
2100	5856	6675	819	800	750	750	800	500	450	800	800	s	206			s	s	s	s	s
2200	5568	6400	832	800	750	750	800	418	450	800	800	s	s							
2300	5136	6000	864	716	692	722	800	239	376	800	800		s							
2400	4800	5650	850	680	658	689	800	50	323	800	800									

Note: "s" denotes the spinning reserve.

Table A3.
Cost data for conventional power generation units of the utility system.

Unit number	*Unit name*	*Fuel type (*)*	*Daily generation (MWh)*	*Rated capacity (MW)*	*Capital cost ($/kW)*	*O&M cost ($/kW-year)*	*Fuel cost ($/MWh)*
1	Fbase1	C	15,417	800	$4,507	$45.68	$5.06
2	Fbase2	C	15,318	750	$4,507	$45.68	$5.06
3	Fbase3	C	16,080	750	$4,507	$45.68	$5.06
4	Fbase4	C	18,361	800	$4,507	$45.68	$5.06
5	Fcycle1	C	6,539	500	$4,507	$45.68	$5.06
6	Fcycle2	C	6,943	450	$4,507	$45.68	$5.06
7	Nuclear1	N	19,200	800	$7,406	$136.91	$2.67
8	Nuclear2	N	19,200	800	$7,406	$136.91	$2.67
9	Ccycle1	G	77	400	$1,176	$13.73	$2.10
10	Ccycle2	G	2,031	350	$1,176	$13.73	$2.10
11	Gas1	G	10	75	$867	$7.88	$5.06
12	Gas2	G	10	75	$867	$7.88	$5.06
13	Gas3	G	10	50	$867	$7.88	$5.06
14	Gas4	G	10	75	$867	$7.88	$5.06
15	Gas5	G	10	50	$867	$7.88	$5.06
16	Gas6	G	10	50	$867	$7.88	$5.06
17	Gas7	G	6	50	$867	$7.88	$5.06
Total			119,232	6,825			
*C = Coal; N = Nuclear; G = Natural Gas							
Source: https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf.							

Table A4.
Scenario I using coal, nuclear, and natural gas.

Systems	*Quantity*	*Installed capacity (MW)*	*Capital cost ($/kW)*	*O&M cost ($/kW-year)*	*Fuel cost ($/MWh)*	*Daily generation (MWh)*
Coal (1-4)	4	3,100	$4,507	$45.68	$5.06	119,232
Coal cycle (5-6)	2	950	$4,507	$45.68	$5.06	
Nuclear (7-8)	2	1,600	$7,406	$136.91	$2.67	
Natural Gas cycle (9-10)	2	750	$1,176	$13.73	$2.10	
Gas turbine (11-17)	7	425	$867	$7.88	$5.06	
Total	17	6,825				119,232

Table A5. Scenario II using nuclear and natural gas.

Systems	*Quantity*	*Installed capacity (MW)*	*Capital cost ($/kW)*	*O&M cost ($/kW-yr.)*	*Fuel cost ($/MWh)*	*Daily generation (MWh)*
LWR (1-4)	4	3,100	$7,406	$136.91	$2.67	119,232
SMR (5-6)	2	950	$7,590	$106.92	$3.38	
LWR (7-8)	2	1,600	$7,406	$136.91	$2.67	
Natural Gas cycle (9-10)	2	750	$1,176	$13.73	$2.10	
Gas turbine (11-17)	7	425	$867	$7.88	$5.06	
Total	17	6,825				119,232

Abbreviations: LWR → Light Water Reactor
SMR → Small Modular Reactor

Table A6. Scenario III using nuclear, natural gas, renewables, and battery storage.

Systems	*Quantity*	*Installed capacity (MW)*	*Capital cost ($/kW)*	*O&M cost ($/kW-year)*	*Fuel cost ($/MWh)*	*Daily generation (MWh)*
LWR (1-4)	4	3,100	$7,406	$136.91	$2.67	119,232
SMR (5-6)	2	950	$7,590	$106.92	$3.38	
Nuclear (7-8)	2	1,600	$7,406	$136.91	$2.67	
Natural Gas Cycle (9-10)	2	750	$1,176	$13.73	$2.10	
Gas Turbine (11-17)	7	425	$867	$7.88	$5.06	
Solar PV (18-27)	9	1,350	$1,448	$17.16	$0.00	
Wind Onshore (28-34)	7	1,400	$2,098	$29.64	$0.00	
Wind Offshore (35-37)	4	1,600	$5,338	$123.81	$0.00	
Battery Storage (38-61)	24	1,200	$1,270	$45.78	$0.00	
Total	61	12,375				119,232

Table A7. Approximate reliability factors of power generation units.

Blocks	*Equipment reliability factor*	*Fuel availability*	*Operational reliability*
Coal	0.9995	1.0000	0.9995
Nuclear	0.9995	1.0000	0.9995
Natural Gas	0.9995	1.0000	0.9995
Wind onshore	0.9995	0.3000	0.3000
Wind offshore	0.9995	0.3000	0.3000
Solar PV	0.9995	0.3000	0.3000
Battery	0.9995	1.0000	0.9995

Table A8. 2023 cost estimates of coal, nuclear, natural gas, renewables, and battery storage units [13].

Technology	First available year[a]	Size (MW)	Lead time (years)	Base overnight cost[b] (2022$/kW)	Techno-logical optimism factor[c]	Total overnight cost[d,e] (2022$/kW)	Variable O&M[f] (2022$/MWh)	Fixed O&M (2022$/kWy)	Heat rate[g] (Btu/kWh)
Ultra-supercritical coal (USC)	2026	650	4	$4,507	1.00	$4,507	$5.06	$45.68	8,638
USC with 30% carbon capture and sequestration (CCS)	2026	650	4	$5,577	1.01	$5,633	$7.97	$61.11	9,751
USC with 90% CCS	2026	650	4	$7,176	1.02	$7,319	$12.35	$67.02	12,507
Combined-cycle—single-shaft	2025	418	3	$1,330	1.00	$1,330	$2.87	$15.87	6,431
Combined-cycle—multi-shaft	2025	1,083	3	$1,176	1.00	$1,176	$2.10	$13.73	6,370
Combined-cycle with 90% CCS	2025	377	3	$3,019	1.04	$3,140	$6.57	$31.06	7,124
Internal combustion engine	2024	21	2	$2,240	1.00	$2,240	$6.40	$39.57	8,295
Combustion turbine—aeroderivative[h]	2024	105	2	$1,428	1.00	$1,428	$5.29	$18.35	9,124
Combustion turbine—industrial frame	2024	237	2	$867	1.00	$867	$5.06	$7.88	9,905
Fuel cells	2025	10	3	$6,771	1.08	$7,291	$0.66	$34.65	6,469
Nuclear—light water reactor	2028	2,156	6	$7,406	1.05	$7,777	$2.67	$136.91	10,447
Nuclear—small modular reactor	2028	600	6	$7,590	1.10	$8,349	$3.38	$106.92	10,447
Distributed generation—base	2025	2	3	$1,915	1.00	$1,915	$9.69	$21.79	8,912
Distributed generation—peak	2024	1	2	$2,300	1.00	$2,300	$9.69	$21.79	9,894
Battery storage	2023	50	1	$1,270	1.00	$1,270	$0.00	$45.76	NA
Biomass	2026	50	4	$4,996	1.00	$4,998	$5.44	$141.50	13,500
Geothermal[i,j]	2026	50	4	$3,403	1.00	$3,403	$1.31	$153.98	8,881
Conventional hydropower[j]	2026	100	4	$3,421	1.00	$3,421	$1.57	$47.06	NA
Wind[e]	2025	200	3	$2,098	1.00	$2,098	$0.00	$29.64	NA
Wind offshore[i]	2026	400	4	$5,338	1.25	$6,672	$0.00	$123.81	NA
Solar thermal[i]	2025	115	3	$8,732	1.00	$8,732	$0.00	$96.10	NA
Solar photovoltaic (PV) with tracking[e,i,k]	2024	150	2	$1,448	1.00	$1,448	$0.00	$17.16	NA
Solar PV with storage[i,k]	2024	150	2	$1,808	1.00	$1,808	$0.00	$32.42	NA

Data source: Sargent & Lundy, Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, December 2019; Hydroelectric: Oak Ridge National Lab, An Assessment of Energy Potential at Non-Powered Dams in the United States, 2012, and Idaho National Engineering and Environmental Laboratory, Estimation of Economic Parameters of U.S. Hydropower Resources, 2003; Geothermal: National Renewable Energy Laboratory, Updated U.S. Geothermal Supply Curve, 2010.

Note: MW=megawatt, kW=kilowatt, MWh=megawatthour, kWy=kilowattyear, kWh=kilowatthour; Btu=British thermal unit

[a] The first year that a new unit could become operational.

[b] Base cost includes project contingency costs.