APPENDIX L
REPLACEMENT ENERGY COSTS

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ABBREVIATIONS AND ACRONYMS

ABB	ASEA Brown Boveri
MWh	megawatt-hour
NRC	U.S. Nuclear Regulatory Commission
OMB	Office of Management and Budget
PJM	PJM Interconnection
REC	replacement energy costs

L.1 PURPOSE

This appendix provides guidance on how to apply the information in NUREG-2242, “Replacement Energy Cost Estimates for Nuclear Power Plants: 2020–2030”, issued June 2021, to estimate the replacement energy costs associated with regulatory actions that may result in the temporary or permanent loss of electrical power generation from a nuclear reactor. The term “replacement energy cost” refers to the change in wholesale power prices that would result when a reactor unit is taken offline. As discussed below, the two replacement energy cost attributes to be considered in a cost-benefit analysis are (1) the shutdown costs to install or implement mandated safety changes and (2) the present value of averted onsite costs due to changes in reactor accident frequencies. This appendix details methods and provides examples of how to quantify these two attributes using the information published in NUREG-2242.

L.2 OVERVIEW OF ESTIMATES

Replacement energy costs were estimated for the U.S. wholesale electricity market regions over the 2020 to 2030 period and reported in NUREG-2242. These cost estimates were developed using two different proprietary software packages: (1) ASEA Brown Boveri's (ABB's) PROMOD,[1] a production cost model that simulates electricity market operations, and (2) ICF's Integrated Planning Model for North America, which simulates long-term capacity expansion investment decisions for the wholesale electricity market. Together, these models forecast future market conditions and simulate the dispatching of generating units until the regional power demand is met.

As described in NUREG-2242, U.S. electricity markets were divided into eight regions based on U.S. Federal Energy Regulatory Commission planning regions. To estimate the replacement energy costs for each region, a reference case in which all operational nuclear power plants are available was compared to an alternative case, in which a nuclear unit in that region is taken offline. For the alternative case, the loss of electrical power from an operating nuclear unit results in the need for replacement power from another generating unit to meet energy demand. This demand is met by dispatching a generating unit in merit order, which may cause a shift in the market clearing price.[2] This change in market clearing price—the difference between reference and alternative cases—represents the estimated replacement energy cost in dollars per megawatt-hour ($/MWh) for that region.

NUREG-2242 provides estimates that capture potential seasonal variations in replacement energy costs within a simulation year along with annual variations in costs in future years due to a number of market forecast assumptions.[3] To account for the range of possible cost estimates, "most impact" and "least impact" units were also chosen for each region based on criteria such as size of the nuclear power plant, proximity to load centers, and location relative to congestion. Tables 3-1 through 3-5 of NUREG-2242 summarize the annual and seasonal replacement energy costs for each region; Appendix G, "Detailed Replacement Energy Costs: 2020–2030," tabulates detailed results for each year from 2020 to 2030 for each region. Appendix D, "Existing and Committed Nuclear Units," to NUREG-2242 lists the existing and committed nuclear generation units, their respective capacities, planned retirements, and model regions, all of this information is necessary for application of the replacement energy cost estimates. All replacement energy cost estimates in NUREG-2242 are presented in nominal dollars (NRC, 2021).

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[1] ABB divested this software to Hitachi ABB Power Grids in July 2020. Subsequently, this entity changed its name to Hitachi Energy in October 2021.

[2] "Market clearing price" refers to the price at which generation supply equals demand for the forecasted period and region. In a deregulated electricity market, as either supply or demand changes, generating units are dispatched in economic merit order, such that the least expensive units are chosen to meet energy demand and the wholesale energy price to be paid to all resources meeting demand is set by the most expensive unit dispatched. Thus, if a higher priced generator is dispatched to meet energy demand, the market clearing price increases.

[3] The modeling input assumptions are from publicly available data and reports from organizations such as the Energy Information Association, the U.S. Environmental Protection Agency, and the North American Electric Reliability Corporation. NUREG-2242 discusses these assumptions and data sources.

L.3 APPLICATION OF ESTIMATES

In addition to the replacement energy cost information provided in NUREG-2242, the analyst will predict the duration of the outage and the number of units affected by a regulatory action. This information will vary depending on the purpose and expected outcomes of the regulation being analyzed. In general, the analyst should assess the impact of long-term or permanent shutdowns using the annual replacement energy costs from NUREG-2242, Appendix G. For outages that are expected to be of short duration and for which the timing of a planned outage can be predicted, the analyst should use seasonal replacement energy costs, as they are more reflective of the season during which the unit is expected to be out of service.

The replacement energy cost estimates in NUREG-2242 are based on a snapshot of the current market conditions and forecasts available at the time the simulations were run. It is expected that the analyst will use the most current licensing and operating information available. This includes the remaining term of plant licenses, unit capacity factors, and plant-specific accident frequency estimates.

L.3.1 Industry Implementation and Operation Costs

Implementation of a proposed regulatory action may result in a short-term disruption while the nuclear plant makes the required safety enhancement. During such times, consumers purchase electricity from the next available source to replace the energy that the nuclear plant would normally provide, at a marginally higher production rate cost for the region. Similarly, routine and recurring activities required by the proposed action may necessitate periodic power outages that would result in recurring short-term replacement energy costs. The overall increased cost to consumers in the region can be computed as the product of the increase in the annual or seasonal replacement energy costs (in $/MWh) from NUREG-2242, Appendix G, the projected energy generation at the time of the outage in the region where the affected unit is located, and the estimated duration of the outage. Thus, the replacement energy costs for a planned shutdown of a single nuclear power plant is represented by the following equation:

$$\begin{gathered} Region\ Energy\ Generation \times Unit\ Outage\ Duration \\ \times Replacement\ Power\ Rates \end{gathered} \qquad \text{Equation 1}$$

where regional energy generation may be obtained from a power region’s load forecasts and replacement energy cost information may be obtained from NUREG-2242, Appendix G. Unit outage duration is estimated based on the complexity of the plant modification and industry data.

Example:

Estimate the range of replacement energy costs for a planned 1-day extension of a planned nuclear power unit outage occurring on April 15, 2023. The unit in this example is located in the PJM Interconnection (PJM) power region. Table G-5 of NUREG-2242 shows that the replacement energy cost estimates for PJM in spring 2023 are $0.55 per MWh and $0.12 per MWh for the most impact and least impact units, respectively. The April 2023 PJM monthly net energy forecast is 55,864 megawatts (PJM, 2020, Table E-2). The replacement energy costs are calculated as follows:

Forecast PJM April 15, 2023, daily load:

$$55{,}864\ MW \times 24\ \frac{hours}{day} = 1{,}340{,}736\ MWh\ per\ day$$

High daily replacement energy cost estimate:

$$1{,}340{,}736 \frac{MWh}{day} \times 0.55 \frac{\$}{MWh} = \$737{,}405\ per\ day$$

Low daily replacement energy cost estimate:

$$1{,}340{,}736\ \frac{MWh}{day} \times 0.12 \frac{\$}{MWh} = \$160{,}888\ per\ day$$

L.3.2 Averted Replacement Energy Costs for Reducing the Likelihood of a Severe Accident

If a proposed regulatory action is expected to reduce the likelihood of a severe accident, long-term replacement energy costs should be calculated as part of the onsite property costs attribute.[4] These risk-based costs reflect the expected loss due to an accident, the probability that such an accident could occur at any time over the remaining facility life, and the effects of discounting those potential future losses to the present value.

The averted replacement energy cost associated with a proposed regulatory action is calculated as the expected change in the probability of a severe accident due to a regulatory action multiplied by the integrated value of the loss of a representative unit in any year of a reactor's remaining operating life:

$$V_{RP} = N \times \Delta F \times U_{RP} \qquad \text{Equation 2}$$

where:

V_{RP} = total present value of expected averted replacement energy costs from a regulatory action

N = number of units affected by a regulatory action

ΔF = estimated change in accident frequency (events/unit-year)

U_{RP} = average integrated value associated with the loss of a representative unit that could occur in any year of a unit's remaining operating life

Thus, when the quantity U_{RP} is multiplied by the annual accident frequency ΔF, the result is the expected loss over the unit's life, discounted to the present value. Calculating U_{RP} requires that unit-specific lifetime costs for potential permanent shutdowns are calculated for each year following the implementation of a regulation. The stream of potential future costs following a

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[4] Regulatory actions that the analyst may encounter include addressing severe accident mitigation alternatives under the National Environmental Policy Act.

hypothetical permanent shutdown is calculated starting at the year in which the regulation is assumed to be implemented until the end of the unit's licensing term.

For each "accident year" (in which a permanent shutdown could occur), a stream of future replacement energy costs is calculated. Then the replacement energy cost estimates (in $/MWh) from NUREG-2242, Appendix G, are multiplied by the projected regional generation (in MWh). Thus, for any future year, i, following the loss of a unit, the annual replacement energy cost (*REC*) is represented by Equation 3:

$$REC_i = REC\ Rate_i \times DF_i \times Annual\ Generation \qquad \text{Equation 3}$$

where the annual generation term includes any projected energy growth.

The discount factor (*DF*) is computed using Equation 4:

$$DF = \frac{1}{(1+r)^n} \qquad \text{Equation 4}$$

where:

r = discount rate (e.g., 7 percent)
n = number of years that the cost is incurred

These costs are then summed over the unit's remaining licensing term to estimate the expected replacement energy costs that would be incurred if an accident happened in a given year. This same process is repeated for each successive accident year in which an accident could potentially occur, until the end of the unit's licensing term. Summing up the shutdown replacement energy costs for each future year of operation provides the integrated replacement energy costs, which are then divided by the remaining operation years under the licensing term to provide the average integrated replacement energy costs, U_{RP}, for Equation 2.

This process represents a double integration of cost streams because (1) loss of a unit in any given year would result in replacement energy costs for all remaining years of the reactor's licensing term, and (2) a reactor unit loss could occur in any remaining year of planned operation.

<u>Example</u>:

The following example illustrates how replacement energy costs would be computed and applied for a proposed future regulatory action beginning in 2023 that reduces the likelihood of a permanent shutdown of a nuclear power unit. All costs are discounted using a discount rate of 7 percent (OMB, 2003). The example project's costs are listed to 2045, the last year of the assumed unit's licensing term. The estimates in NUREG-2242 are computed until 2030, so the replacement energy costs for those years after 2030 are assumed to be the same as those for 2030.

PJM forecasts the 2023 annual generation for the PJM region to be 788,453,000 gigawatt-hours and projects an average net energy growth of 0.3 percent over the next 15 years (PJM, 2020). From NUREG-2242, Table G-5, the annual replacement energy costs in 2023 for the PJM model region are 0.74 and 0.19 for the most impact and least impact cases, respectively. For the most impact case, the annual replacement energy cost for the affected unit in 2023 is calculated as follows:

$$788{,}453{,}000\ MWh \times \$0.74\ /MWh = \$583{,}455{,}220$$

This estimate represents a single year of replacement energy costs. To calculate the replacement energy costs for a unit in permanent or long-term shutdown, this calculation is repeated for each future year of the unit’s expected remaining operating life and summed as shown in Table L-1.[5]

Table L-1 Projected Stream of Replacement Energy Costs for a Long-Term Shutdown

Year	Discount Factor	Energy Growth (0.3%/year)	Annual PJM REC ($/MWh)		Regional Annual REC[a] (2023 dollars)	
			Most Impact	Least Impact	Most Impact	Least Impact
2023	1	1.000	0.74	0.19	$583,455,220	$149,806,070
2024	0.934579	1.003	0.77	0.17	$569,093,585	$125,644,038
2025	0.873439	1.006	0.79	0.16	$547,314,825	$110,848,572
2026	0.816298	1.009	0.87	0.16	$564,997,503	$103,907,587
2027	0.762895	1.012	0.94	0.16	$572,232,190	$97,401,224
2028	0.712986	1.015	1.01	0.16	$576,345,571	$91,302,269
2029	0.666342	1.018	1.09	0.17	$583,049,249	$90,934,286
2030	0.622750	1.021	1.16	0.17	$581,639,492	$85,240,270
2031	0.582009	1.024	1.16	0.17	$545,219,075	$79,902,796
2032	0.543934	1.027	1.16	0.17	$511,079,189	$74,899,536
2033	0.508349	1.030	1.16	0.17	$479,077,034	$70,209,565
2034	0.475093	1.033	1.16	0.17	$449,078,753	$65,813,266
2035	0.444012	1.037	1.16	0.17	$420,958,868	$61,692,248
2036	0.414964	1.040	1.16	0.17	$394,599,762	$57,829,275
2037	0.387817	1.043	1.16	0.17	$369,891,178	$54,208,190
2038	0.362446	1.046	1.16	0.17	$346,729,768	$50,813,845
2039	0.338735	1.049	1.16	0.17	$325,018,652	$47,632,044
2040	0.316574	1.052	1.16	0.17	$304,667,017	$44,649,477
2041	0.295864	1.055	1.16	0.17	$285,589,736	$41,853,668
2042	0.276508	1.059	1.16	0.17	$267,707,014	$39,232,925
2043	0.258419	1.062	1.16	0.17	$250,944,052	$36,776,283
2044	0.241513	1.065	1.16	0.17	$235,230,733	$34,473,469
2045	0.225713	1.068	1.16	0.17	$220,501,332	$32,314,850
				Total	**$9,984,419,799**	**$1,647,385,755**

[a] This value is the product of the affected unit annual replacement energy cost, the discount factor, the energy growth, the annual REC rate, and the annual regional generation.

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[5] The analyst may truncate this analysis to a period less than the remaining license term if there is a technical basis for forecasting that the regional electricity production would recover in a shorter period of time.

From Table L-1, the total present value of replacement energy costs for a permanent loss of the example unit for a 23-year license term starting in 2023 ranges from approximately $1.65 billion to $9.98 billion based on a 7-percent discount rate. Because an accident could occur in any future year of unit operation, this calculation is performed on an annual basis through the final year of licensed operation. In effect, this cost estimate represents a double integration of cost streams because (1) a reactor loss in any given year would lead to replacement energy costs for all remaining years of planned operation, and (2) a reactor loss could occur with some small probability in any year of operation. Table L-2 shows the results from performing this estimate over the remaining operating life of the example unit (e.g., 2023–2045).

Table L-2 Integrated Value Associated with the Loss in Year 2023 of a Representative Unit that Could Occur in Any Year of a Unit's Remaining Operating Life

Accident Year	Years of Service Remaining	Cumulative Replacement Energy Costs (2023 million dollars)	
		Most Impact	Least Impact
2023	23	9,984	1,647
2024	22	9,401	1,498
2025	21	8,832	1,372
2026	20	8,285	1,261
2027	19	7,720	1,157
2028	18	7,147	1,060
2029	17	6,571	968
2030	16	5,988	878
2031	15	5,406	792
2032	14	4,861	712
2033	13	4,350	637
2034	12	3,871	567
2035	11	3,422	501
2036	10	3,001	440
2037	9	2,606	382
2038	8	2,236	328
2039	7	1,890	277
2040	6	1,565	229
2041	5	1,260	185
2042	4	974	143
2043	3	707	104
2044	2	456	67
2045	1	221	32
	Total	**100,753**	**15,238**

The cumulative replacement energy costs are \$100.8 billion and \$15.2 billion in 2023 dollar-years[6] for the most impact and least impact cases, respectively. These costs represent the range of expected values of U_{RP} in Equation 2 for the permanent shutdown of a nuclear power reactor unit licensed to operate until 2045 in the PJM region. This value is multiplied by ΔF (probability/reactor-year) to determine the value of averted costs of avoiding a reactor accident for this single reactor unit. For units that are not analyzed in NUREG-2242, Table 2-1, the arithmetic average of the most impact and least impact estimates should be used to compute the expected averted replacement energy costs. Thus, for this example, the average averted replacement energy cost is calculated, in billions of dollars (B), as follows:

$$\frac{\$100.8B + \$15.2B}{2} = \$58.0B$$

If a future regulatory action affecting the example unit is introduced in 2023 and is estimated to result in a decrease in the probability of a reactor unit loss of 1×10^{-6} per reactor-year, the present value of the average averted replacement energy costs for this reactor unit from Equation 2 is calculated as follows:

$$V_{RP} = (1 \times 10^{-6}) \times (\$58.0 \times 10^{9}) = \$58{,}000$$

This value represents the expected net present value (in 2023 dollars) of averted replacement energy costs from reducing the annual reactor accident probability by 1×10^{-6} per reactor-year at a single reactor unit from a future regulatory action implemented in 2023. The range of values, \$15,200 to \$100,800, may be used as lower and upper bounds on this estimate.

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[6] This estimate is given in dollar-years because that unit represents an integral of lifetime replacement energy costs summed over all potential years of reactor losses.

L.4 REFERENCES

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