

An Analysis of Replacement Energy Costs Associated with Nuclear Power Plant Outages in South Korea

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1. Introduction

Because nuclear power has low variable operating costs and supplies a substantial share of South Korea's electricity, the loss of nuclear generating capacity requires replacement generation from costlier resources and can raise overall system costs. The magnitude of this impact depends on system demand, reserve availability, the generation mix, and other operating conditions, and therefore requires a system-specific economic assessment. This study therefore examines whether changes in nuclear generating availability are associated with short-run movements in the system marginal price (SMP) and uses the Posy2[1] power-system optimization model to evaluate the system-cost consequences of planned and unplanned nuclear outages in South Korea.

2. Research Scope and Methods

Previous studies have assessed the economic effects of nuclear outages through two complementary approaches: scenario-based system-cost modeling and empirical price analysis. VanKuiken et al. [2] estimated replacement energy costs using probabilistic production-cost simulations comparing otherwise equivalent cases with and without nuclear-unit availability. NUREG-2242 [3] applied a similar matched-case design using the PROMOD dispatch model and the Integrated Planning Model, defining replacement energy cost as the difference in production costs between matched reference and outage cases. Lundin [4], by contrast, used hourly regression analysis to estimate day-ahead price responses to unplanned nuclear outages.

Building on both approaches, the present study employs a two-stage assessment: a descriptive event-based analysis, and a scenario-based system-cost analysis using Posy2 [1, 5]. Posy2 is a power-system optimization model developed by the OECD Nuclear Energy Agency; it evaluates least-cost system configurations and operations under specified demand, technology, and operational constraints. The two stages are complementary: the descriptive analysis examines observable SMP movements, whereas the Posy2 analysis estimates system-cost effects that may not be reflected in SMP.

For the descriptive analysis, records of changes in available nuclear generating capacity during 2024–2025

were compiled from the Open Nuclear Power Plant Operating Information portal and the Operational Performance Information System for Nuclear Power Plants (OPIS) [6]. We supplemented and verified missing or unclear records through direct consultation with the responsible personnel. Hourly SMP values for the corresponding period were obtained separately from the Electric Power Statistics Information System (EPSIS) operated by the Korea Power Exchange [7].

The dataset comprised 17,544 matched hourly observations of available nuclear generating capacity and SMP during 2024–2025. In South Korea, SMP is the hourly electricity-market price determined by the marginal cost of the highest-cost generator selected in the day-ahead price-setting schedule to meet forecast demand. A reduction in available nuclear capacity was expected to require replacement generation from higher-variable-cost resources, such as LNG-fired generation, and could therefore be accompanied by an increase in SMP.

An event hour, H_0 , was defined as an hour in which available nuclear capacity changed because of a planned shutdown, an unplanned shutdown, or a unit restart. For each event, the capacity change (in MW) and the corresponding SMP change (in KRW/kWh) were calculated as

$$\Delta Capacity = Capacity_{H-6} - Capacity_{H_0} \quad (1)$$

$$\Delta SMP = SMP_{H_0} - SMP_{H+6} \quad (2)$$

The different comparison intervals reflect the distinct roles of the two variables. Because H_0 denotes the hour of a nuclear-capacity-change event, $\Delta Capacity$ captures the capacity change associated with the event by comparing availability at $H-6$ with availability at H_0 , whereas ΔSMP captures the subsequent market-price movement from H_0 to $H+6$. Both differences are defined as the earlier value minus the later value, so a decrease is positive and an increase is negative. Under this sign convention, the hypothesized response of an SMP increase following a reduction in nuclear availability appears as a negative relationship between $\Delta Capacity$ and ΔSMP . These paired changes were plotted to examine their descriptive association. This analysis does not establish a causal relationship.

For the scenario stage, Posy2 was calibrated to the South Korean electricity system to quantify changes in total system cost under alternative nuclear-availability assumptions.

Four nuclear-availability scenarios were evaluated for the 2024 South Korean electricity system under otherwise identical assumptions. The Actual-Outage Case uses the observed planned and unplanned outage histories. The Planned-Outage-Only Case keeps the observed planned outage history but removes unplanned outages. The No-Outage Benchmark assumes continuous nuclear availability throughout the year, as an idealized reference. The Median-Overhaul Case is identical to the Planned-Outage-Only Case, except that each overhaul — the periodic planned refueling-and-maintenance outage of a unit — is capped at its type-specific historical median duration [8]. The difference between the Actual-Outage Case and the Planned-Outage-Only Case is interpreted as the modeled system cost of unplanned outages. In the same way, Planned-Outage-Only minus No-Outage gives the cost of planned outages; Actual-Outage minus No-Outage gives the cost of all outages; and Planned-Outage-Only minus Median-Overhaul gives the cost of overhaul extensions beyond historical norms.

3. Results of the Descriptive Event-Based Analysis

Among the 17,544 hourly observations collected for 2024–2025, 84 events involving changes in available nuclear generating capacity were identified. Table I presents four selected planned and unplanned nuclear outages.

Table 1. Selected Examples of Planned and Unplanned Nuclear Unit Outages, 2024–2025

Nuclear Unit	Outage Type	Outage Period	
		Start	Return
Saeul 2 (1,400 MW)	Planned	24/03/11 10:00	24/05/03 7:00
Shin-Wolsong 2 (1,000 MW)	Unplanned	24/05/18 12:35	24/06/08 13:34
Hanbit 4 (1,000 MW)	Planned	24/04/21 7:00	24/06/07 18:43
Hanul 6 (1,000 MW)	Unplanned	24/10/28 8:20	24/10/30 18:20

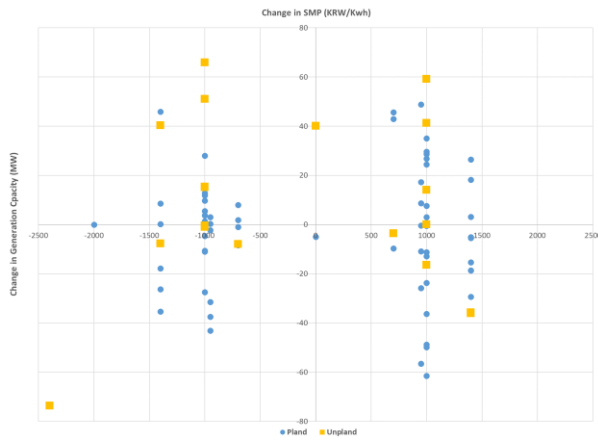


Fig. 1. Scatter plot of nuclear-capacity changes and corresponding six-hour SMP changes, 2024–2025

Of the 84 identified capacity-change events, 19 were associated with unplanned shutdowns or subsequent returns to service. Figure 1 presents a scatter plot of Δ Capacity on the horizontal axis and Δ SMP on the vertical axis for all identified events. Unplanned-outage-related events, including subsequent returns to service, are distinguished by yellow square markers.

The R^2 values were 0.000079, 0.000038, and 0.000354 for all events, planned-outage-related events, and unplanned-outage-related events, respectively, indicating negligible bivariate linear explanatory power for the relationship between nuclear-capacity changes and the corresponding H0-to-H+6 SMP changes. To examine system-cost consequences that may not be observable through the descriptive SMP comparison, the subsequent POSY2 analysis assesses system-wide redispatch and the resulting changes in total system cost.

4. Posy2 Modeling Results

The Posy2 analysis used actual hourly records of available nuclear generating capacity in 2024, reflecting capacity changes resulting from planned and unplanned outages (Fig. 2). Because SMP reflects broader supply-and-demand conditions rather than nuclear availability alone, the Posy2 analysis evaluates outage-related costs that may not be observable through SMP movements by quantifying system-wide redispatch and changes in total system cost.

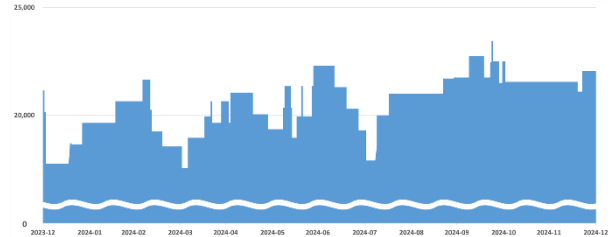


Fig. 2. Hourly available nuclear generating capacity in the Actual-Outage Case, South Korea, 2024

All cases share the 2024 hourly demand, the fixed generating capacities, fuel prices, and renewable generation profiles; only the hourly nuclear availability differs, so the cost differences isolate the dispatch-level effect of the outages. Unavailability that is not an outage, such as the license-renewal gaps of Kori 2 and Kori 3, the pre-commercial period of Shin-Hanul 2, and a grid-requested stop of Hanul 3, is retained unchanged in every case, including the No-Outage Benchmark. In the Actual-Outage Case, the modeled nuclear generation is 179.6 TWh, 3.7–6.1% below published 2024 totals of roughly 187–192 TWh, which vary with the source and the fleet accounting basis [7]. The gap lies in the availability record's conventions rather than in the dispatch model, whose nuclear output matches the energy ceiling of the record to within 0.01%. The record counts a unit as available only when it is capable of full rated output, so hours of post-outage power ascension count as fully unavailable, and the pre-commercial test generation of Shin-Hanul 2 (about 3.2 TWh) is excluded although published totals may include it. Because every

case applies the same convention, this level gap does not carry over one-for-one into the cost differences between cases. Without the observed availability calendar, the same model overproduces nuclear generation by roughly 10%, so imposing the calendar is essential for a credible baseline.

Table II summarizes the four cases. Removing the nine unplanned outages of 2024 lowers total system cost only modestly, well under one percent, whereas the planned-outage effect is an order of magnitude larger. All outages together appreciably raise total system cost and power-sector CO₂ emissions relative to the No-Outage Benchmark. Because the benchmark is an idealized reference, the all-outage difference is an upper bound. The pairwise differences isolate the two components: unplanned outages cost 0.21 B US\$ (Actual-Outage minus Planned-Outage-Only), and overhaul extensions beyond historical norms cost 1.07 B US\$ (Planned-Outage-Only minus Median-Overhaul); part of the latter may be operationally recoverable, whereas extensions driven by regulatory findings are not. The lost nuclear generation is replaced chiefly by LNG combined-cycle and coal generation, with small contributions from pumped-storage hydro and demand response.

Table II: Posy2 results by nuclear-availability case, South Korea, 2024

Case	Nuclear (TWh)	CO ₂ (Mt)	System cost (B US\$)	Δ cost (B US\$)
No-Outage Benchmark	217.0	179.0	51.25	—
Median-Overhaul	192.9	192.0	53.51	2.26
Planned-Outage-Only	182.1	197.9	54.58	3.33
Actual-Outage	179.6	199.4	54.79	3.54

Note: Δ cost is the increase relative to the No-Outage Benchmark, an idealized reference, so it is an upper bound.

The Median-Overhaul Case caps each overhaul at the median duration of overhauls started in 2012–2016 (68.1 days for PWRs and 41.1 days for CANDU units, computed from the KHNP planned-maintenance history [8]), shortening 12 of the 21 overhaul windows in the 2024 calendar. This window is the most recent five-year span before fleet-wide overhaul durations lengthened; annual medians have exceeded 70 days in every completed year since 2017 [8].

5. Discussion

The descriptive event-based analysis does not control for other determinants of SMP, including electricity demand, weather conditions, renewable generation, fuel prices, reserve availability, and outages of other generators. The small number of unplanned-outage-

related events limits statistical power, and the simple linear specification cannot capture nonlinear or condition-dependent effects. Because the SMP is determined through day-ahead scheduling in the Korean cost-based pool, prices within the same-day six-hour window can respond to an unplanned trip only to a limited extent. The near-zero R² values therefore should not be interpreted as evidence that nuclear outages have no economic consequences.

The Posy2 scenario comparisons price nuclear outages at the marginal cost of the resources that actually replace the lost generation. The implied replacement cost per lost megawatt-hour, 3.54 B US\$ over 37.4 TWh, or about 95 US\$/MWh, is close to the variable cost of LNG combined-cycle generation in the model (about 104 US\$/MWh), the marginal replacement resource in most hours; it sits slightly below that cost because coal, at roughly half of it, supplies part of the replacement. A different approach multiplies curtailed generation by an electricity price. Estimates of that kind differ from this measure by construction and vary several-fold with the choice of price; the system-cost difference reported here reflects the actual redispatch. The unplanned-outage effect is far smaller than the planned-outage effect because the unavailable energy is correspondingly smaller. About one-third of the planned-outage effect (1.07 of 3.33 B US\$) stems from overhauls running longer than the 2012–2016 median durations (Planned-Outage-Only minus Median-Overhaul in Table II).

The cost and emissions consequences warrant separate emphasis. The modeled effect of unplanned outages on system cost is small, 0.21 B US\$, or less than 0.5% of total system cost, but the replacement generation emitted about 0.55 t CO₂ per lost megawatt-hour, adding 1.5 Mt CO₂ for unplanned outages and 20.4 Mt CO₂ for all outages in 2024. Because Posy2 dispatches generation at a near-zero internal carbon price, consistent with Korea's cost-based pool, these emissions are not reflected in the reported cost differences. At any positive carbon valuation, they therefore represent an additional social cost. The CO₂ column in Table II should consequently be weighed alongside the cost column, rather than interpreted as already embedded in it.

Three qualifications apply to the Posy2 estimates. First, because the availability record counts power-ascension hours as fully unavailable (Section 4), the 2.5 TWh of lost energy attributed to unplanned outages, and hence their modeled cost, is overstated. Second, the seasonal caps on coal generation under the winter fine-dust management policy [9] bind in January–March, precisely when the 2024 calendar removes the most nuclear capacity. Replacement in those months is therefore priced against gas and demand response rather than coal. Essentially all demand-response dispatch in the outage cases arises under these caps, and most of it is economic demand reduction rather than unserved energy priced at the value of lost load. Third, the model prices energy replacement only. It excludes the reserve, balancing, and start-up effects of a sudden trip, and

because capacities are fixed, it captures no capacity-related costs. These omissions bias the unplanned-outage estimate downward, whereas the first qualification biases it upward, so the net direction is undetermined. The No-Outage Benchmark is likewise an idealized bound, since sustained operation without refueling outages is not physically achievable.

6. Conclusions

This study assessed the economic consequences of nuclear power plant outages in South Korea through a descriptive event-based price analysis and a Posy2 scenario analysis. The descriptive analysis found no meaningful short-run association between nuclear capacity changes and SMP, an expected result in a day-ahead cost-based pool. The scenario comparisons show that the 2024 outages raised total system cost by up to 3.54 B US\$ relative to an idealized no-outage benchmark. Planned outages account for most of this cost, about one-third of their effect stems from overhauls exceeding the 2012–2016 median durations, and unplanned outages contribute 0.21 B US\$. Because the model prices energy replacement only, these estimates exclude the reserve, balancing, and start-up costs of sudden trips. Refining the availability record and pricing these excluded effects remain future work.

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