

A Stochastic Multi-Firm Generation Expansion Model with Lifetime-Based Retirement and Market-Power Analysis

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Abstract

This paper introduces a two-level stochastic linear programming (LP) generation expansion planning (GEP) framework that actively incorporates the endogenous retirement of aging power plants, multi-firm competition, strict reserve-margin requirements, and ex-post assessments of market power. To address supply deficits under uncertain future demand, the Level 1 optimization model guarantees long-term system adequacy and minimizes structural market power, while respecting firm-specific investment budgets and the physical lifespans of existing generating units. By implementing a capacity penalty alongside a mandatory 15% peak demand reserve margin, the framework prevents unrealistic overbuilding and mathematically ensures overall grid reliability. Once the optimal capacity investments are identified, the Level 2 model simulates an economic dispatch program to derive competitive market-clearing prices and calculates the residual supply index (RSI) for each firm. A 30-year case study—featuring gas turbine, combined-cycle, and nuclear technologies managed by three competing firms—demonstrates the practical application of this framework. The results highlight a steady retirement of legacy plants matched by new investments, successfully sustaining the 15% reserve margin while keeping the RSI above 1.0 to prevent any firm from becoming a pivotal supplier. Ultimately, integrating plant lifecycles with structural competition metrics provides a highly robust GEP solution, offering regulators a practical tool to evaluate long-term resource adequacy and market concentration simultaneously.

Keywords

Generation Expansion Planning, Competition, Retirement, Stochastic Linear Programming, Market Power.

1. Introduction

The global transition of electric power systems is accelerating, driven by escalating electricity demand, the rapid integration of variable renewable energy resources, and the widespread retirement of aging thermal generation units. These compounding factors have fundamentally complicated long-term generation expansion planning (GEP) (Koltsaklis and Dagoumas 2018, Diewvilai and Audomvongseree 2021, Hemmati et al. 2013, Alizadeh and Jadid 2011). Today's grid planners must optimize not only for cost but also for profound uncertainty, resource adequacy, and evolving market structures. The motivation for this research stems from recent reliability assessments, which emphasize that system margins are tightening significantly as load growth outpaces capacity replacement. This underscores an urgent need for modern planning tools that treat uncertainty as a core variable rather than an afterthought (FERC 2025, NERC 2024). Furthermore, contemporary stochastic capacity expansion studies reveal that directly incorporating uncertainties—such as fluctuating demand, volatile fuel prices, and intermittent

renewable output—into optimization models yields materially different, and more robust, investment outcomes compared to traditional deterministic sensitivity analyses (Goteti et al. 2025, Mo et al. 1991).

Despite these advancements, a critical gap remains in existing planning methodologies: the disconnect between long-term physical resource adequacy and short-term market competitiveness. Traditional models often treat these as isolated challenges (NARUC 2012). However, adequacy and competition are intrinsically linked policy questions. A power system that is physically sufficient to meet demand may still be highly vulnerable to the market power of pivotal suppliers (Newbery 2008), while an economically competitive system might be inadequately planned for peak stress events (Hobbs et al. 2007). Furthermore, many existing GEP models fail to simultaneously integrate real-world operational constraints—such as endogenous generator retirements, the capital limitations of competing firms, and strict reserve margin mandates. There is a pressing need for a comprehensive framework that bridges the gap between physical capacity expansion and the subsequent economic realities of market power in liberalized electricity markets (Twomey 2005).

To address these challenges, this paper develops a novel, tractable two-level stochastic GEP framework that integrates several vital operational and economic features into a sequential optimization model. Specifically, the framework introduces four key practical elements:

- **Endogenous Retirement:** The model dynamically tracks the age and technical lifespan of existing units, naturally retiring capacity when it reaches the end of its viable life.
- **Multi-Firm Competition:** It simulates real-world market dynamics by allowing three distinct generation firms to make independent investment decisions, constrained by firm-specific capital budgets.
- **Robust Resource Adequacy:** It enforces a strict reserve-margin requirement of 15% above peak demand to guarantee system reliability under diverse demand scenarios, aligning with current industry standards (FERC 2025, NERC 2024).
- **Post-Expansion Market Power Evaluation:** After Level 1 investment decisions are finalized, the Level 2 model assesses post-expansion competitiveness by computing the residual supply index (RSI) and solving an economic dispatch problem to extract shadow prices. This identifies periods where supply is structurally tight, and market power is likely to emerge (CAISO 2025, ISO New England 2025, Hu et al. 2024, Kaszyński et al. 2023).

The primary objective of the Level 1 linear formulation is to guarantee long-term system adequacy while simultaneously minimizing expected structural market power across probabilistic demand scenarios, utilizing a minor penalty on new builds to prevent unrealistic over-capitalization. This structure is consistent with recent stochastic models that combine investment decisions with operational realism (Goteti et al. 2025, Diewvilai and Audomvongseree 2021, Liu et al. 2024). We demonstrate the model's efficacy through a 30-year case study featuring gas turbines, combined-cycle gas turbines, and nuclear power, illustrating how the capacity mix evolves under uncertainty and capital limits.

The contribution of this paper is therefore twofold. From a planning perspective, it provides a fully reproducible two-level stochastic GEP model where endogenous retirements, multi-firm budgets, reserve margins, and demand uncertainty interact dynamically within a sequential framework. From a market-design perspective, it establishes a vital link between long-term capacity investments and short-run competitive outcomes. By bridging the gap between physical adequacy and market competition, this framework serves as a practical, comprehensive tool for both system planners and market monitors.

2. Literature Review

Recent GEP research increasingly relies on stochastic programming because deterministic models are too restrictive when demand, renewable output, and fuel prices are uncertain. Goteti et al. (2025) present a stochastic capacity expansion model that integrates uncertainty in electricity demand, natural gas prices, and wind generation directly into the optimization, showing that the resulting plan can differ materially from a deterministic one. Their results also show that the model's solution is sensitive to whether the planner is risk-neutral or risk-averse, reinforcing the value of scenario-based planning for long-term capacity decisions (Zhang et al. 2025). In a similar direction, Liu et al. (2024) propose a multi-period capacity expansion scheme for regional integrated energy systems under multi-time-scale uncertainty and low-carbon retrofit decisions, while Tang et al. (2025) develop a synergistic low-carbon planning framework that couples coal plant retrofitting with carbon and green-certificate markets. Together, these

studies show that current GEP work is moving beyond simple least-cost models toward formulations that explicitly reflect uncertainty, decarbonization, and operational flexibility (Koltsaklis and Dagoumas 2018).

Operational detail has also become more prominent in recent planning models. Diewvilai and Audomvongseree (2021) show that generation expansion planning becomes more realistic when full-year hourly power balance constraints and technology-specific generation profiles are included. Their model demonstrates that multi-period planning can remain tractable even when operational constraints are made more explicit, and it also shows that scenario-based planning can be combined with detailed energy accounting. This is directly relevant to the present paper because the current model also uses an energy-balance representation to connect capacity availability with annual demand, while keeping the long-horizon formulation linear.

A second line of research focuses on competition among firms and the possibility of market power in liberalized power systems. Selçuklu and Elzein Elmahy (2022) formulate a generation expansion model that explicitly considers competition and market power, showing that strategic investment behavior can significantly influence both capacity expansion and prices. Their work is important because it demonstrates that generation planning cannot be treated as a purely technical problem once multiple firms with strategic incentives are introduced. The present paper follows this logic by representing several firms separately and by allowing budgets to constrain how aggressively each firm can expand.

Recent market-power studies also show that concentration ratios alone are not sufficient to capture the competitive structure of electricity markets (Kaszyński et al., 2023). Kaszyński et al. (2023) revisit the Polish power system and combine concentration measures with structural and behavioral indices, including the residual supply index and the Lerner index, to show how market power can persist even when the generation mixes change. Hu et al. (2024) similarly develop market-power detection and mitigation indicators for the spot electricity market, emphasizing that structural detection tools are needed to identify pivotal suppliers in uniform-price electricity markets. These studies support the use of RSI in the present model because RSI provides a simple but informative way to evaluate whether capacity additions and retirements alter the ability of a supplier to influence the market.

The RSI itself has a long methodological history, initially popularized by Sheffrin (2002), but it remains highly relevant in modern market monitoring. Swinand et al. (2010) show that the residual supply index is useful for analyzing market competition in electricity markets and that it can explain price-cost margins even when scarcity and other variables are considered. CAISO's recent market monitoring reports continue this tradition by using RSI-type indicators to flag structurally uncompetitive hours (CAISO 2025), while ISO New England's 2025 report interprets RSI values above 1.0 as evidence that the system can meet demand without the largest supplier, and values below 1.0 as evidence of pivotality (ISO New England 2025). This is the exact logic utilized in the present paper, where RSI is computed after expansion to determine whether any firm becomes pivotal under the resulting capacity mix.

A third strand of literature concerns the retirement of the existing generation and its implications for adequacy. NERC's 2024 Long-Term Reliability Assessment highlights the growing tension between demand growth, generator retirements, and capacity additions, noting that several areas face rising adequacy challenges as the fleet changes (NERC 2024). FERC's 2025 Summer Energy Market and Electric Reliability Assessment likewise states that when a region does not provide its own reference reserve margin, NERC assigns a 15% reserve margin, reinforcing the role of reserve-margin constraints in practical planning (FERC 2025). These reports justify the hard adequacy constraint used in the present model and show that reserve-margin rules remain an important planning benchmark in current reliability practice. At the modeling level, explicit retirement or lifetime accounting is increasingly recognized as essential. When retirements are modeled exogenously, the planning problem can miss the timing of capacity loss and the need for replacement investment. The current paper addresses this issue by treating retirement endogenously through age and lifetime tracking, consistent with the broader trend in recent low-carbon expansion studies (Liu et al. 2024, Tang et al. 2025).

While literature has made substantial progress in each of these three areas, the strands remain fragmented. Stochastic expansion models often stop at capacity planning and do not evaluate market structure after the buildout. Market-power studies typically analyze the market ex-post and do not endogenize investment and retirement over a multi-decade horizon. Reliability studies, meanwhile, usually focus on reserve margins and adequacy without linking those constraints to firm-level competition. The present paper is positioned to fill this gap by integrating

probabilistic demand, endogenous retirement, multi-firm competition, reserve-margin adequacy, and ex-post RSI-based market-power assessment into a single stochastic GEP architecture that remains computationally manageable while producing actionable outputs that are meaningful for planners, regulators, and market monitors.

3. Methodology

The methodology employs a two-level stochastic generation expansion planning (GEP) framework over a 30-year planning horizon with annual time steps. It models three generation companies (GENCOS) indexed by c and three technologies: gas turbine (GT), combined-cycle gas turbine (CCGT), and nuclear power indexed by g . The set of planning years is $y = \{1 \dots 30\}$. To account for uncertainty in demand and fuel costs, the model uses three scenarios ($s1, s2, s3$) with probabilities 0.4, 0.4, and 0.2, respectively. Each scenario defines annual peak demand and annual energy demand. To visually summarize this process, Figure 1 outlines the two-level architecture of the proposed framework, which sequentially integrates stochastic capacity investment to minimize market power (Level 1), followed by an operational dispatch and post-expansion market assessment (Level 2).

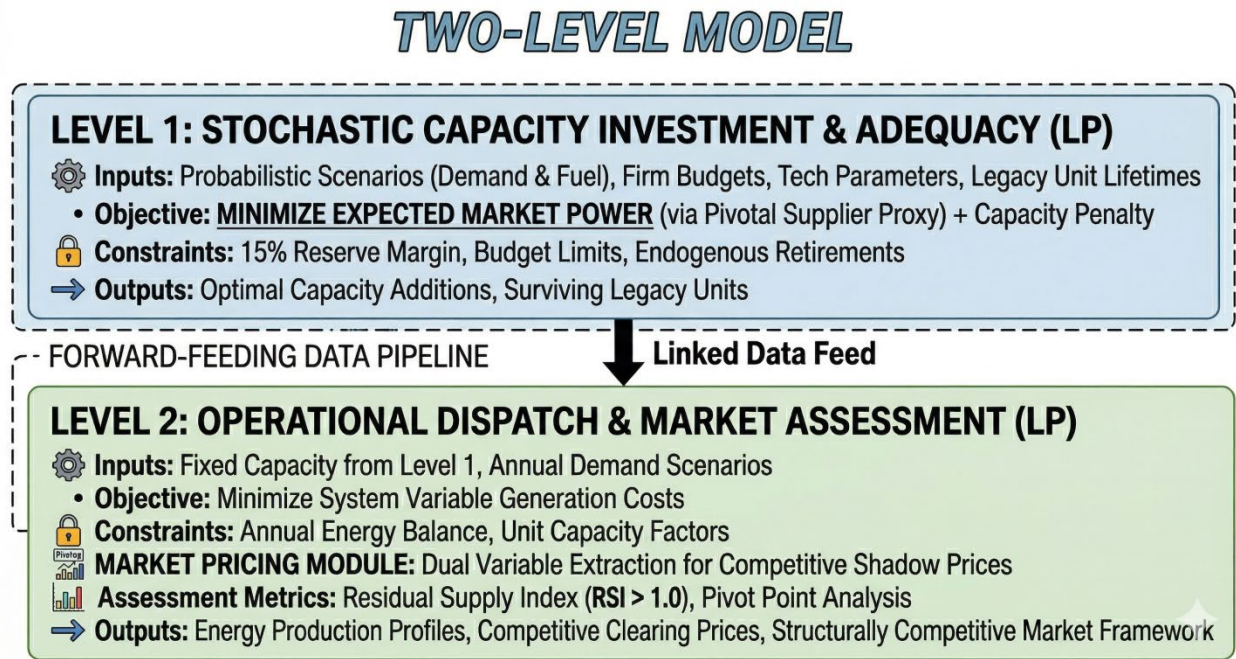


Figure 1. The two-level proposed stochastic generation expansion planning framework.

3.1. Model Architecture

To accurately capture the economic and physical complexities of liberalized electricity markets, the proposed GEP model is structured as a two-level sequential linear programming (LP) framework. This architectural division is both mathematically and practically necessary to decouple long-term capital investment risks from short-term operational market behaviors.

If long-term capacity investment costs, expected adequacy penalties, and short-term daily energy dispatch were mathematically compressed into a single, flat objective function, the dual variables (shadow prices) of the energy balance equations would become heavily distorted by capital expenditures. By separating the model into two distinct sequential levels, the framework maintains strict continuous LP domains, which is a fundamental requirement for preserving duality theory.

Decision Variables

The model relies on several key decision variables:

- Investment:** $S_{y,c,g}$ (MW) represents new capacity built in year y by firm c using technology g .
- Availability:** $Av_{y,c,g}$ (MW) represents the available capacity, which accounts for surviving existing units, cumulative new builds, and unit retirements.

- **Production:** $P_{y,c,g,s}$ (MWh) measures the annual energy produced by firm c using technology g in scenario s .
- **Structural Market Power:** $Sh_{y,c,s}$ (MW) calculates the residual load (system peak demand minus rivals' capacity) to quantify the grid's reliance on a single firm. It serves as a direct measure of pivotal supplier risk and market power exposure.

3.2. Mathematical Formulation

3.2.1 Level 1: Stochastic Capacity Investment and Adequacy

The initial level represents the long-term planning horizon. It determines the optimal continuous capacity expansion and calculates the total available capacity across the 30-year timeframe, evaluating generation firms c and technologies g under stochastic demand scenarios s .

Level 1 Objective Function

The primary objective of the **Level 1 Investment LP** is to guarantee long-term system adequacy while simultaneously minimizing expected structural market power across all probabilistic futures. A minor penalty factor (ϵ) is applied to new capacity builds to discourage unrealistic over-capitalization and enforce disciplined investment behavior:

$$\min \sum_y \sum_c \sum_s p_s Sh_{y,c,s} + \epsilon \sum_{y,c,g} S_{y,c,g}$$

Where p_s represents the probability of scenario s occurring, $Sh_{y,c,s}$ acts as a direct mathematical proxy for structural market power (representing the pivotal supplier dependency, or the unmet peak demand if firm c were to withhold its assets strategically), and $S_{y,c,g}$ is the newly built continuous capacity.

Level 1 Constraints

The following physical and financial realities strictly bind the investment phase:

- **Reserve Margin and Adequacy:** To ensure system reliability, the total available capacity must exceed peak demand by a 15% reserve margin in every year and scenario.

$$\sum_{c,g} Av_{y,c,g} \geq (1 + 0.15) PeakDemand_{y,s}$$

- **Energy Balance and Production:** Annual production must equal the annual demand for each scenario. Additionally, a technology's output is constrained by its availability and capacity factor (CF_g).

$$P_{y,c,g,s} \leq 8760 CF_g \cdot Av_{y,c,g}$$

- **Budget Constraints:** The cumulative investment for any firm (IC_g) cannot exceed its allocated budget (B_c).

$$\sum_{y,g} IC_g S_{y,c,g} \leq B_c$$

- **Structural Market Power Definition:** To eliminate monopolistic vulnerabilities, the model calculates the system's reliance on each firm. The variable $Sh_{y,c,s}$ quantifies this market power by measuring the residual unmet peak demand if a specific firm c were to withhold its entire portfolio:

$$Sh_{y,c,s} \geq PeakDemand_{y,s} - \sum_{j \neq c} Av_{y,j,g}$$

- **Retirement Dynamics:** The model tracks surviving capacity. Existing units remain active if their current age plus the planning year is below their technical lifetime, while new builds are retired once they reach their lifetime limit (LT_g).

$$Av_{y,c,g} = ExCap_{c,g} ExAlive_{y,c,g} + \sum_{t \leq y} S_{t,c,g} - \sum_{t \leq y-LT_g} S_{t,c,g}$$

Here $ExCap_{c,g}$ is the existing capacity for firm c and technology g , and $ExAlive_{y,c,g}$ is an indicator that equals one if the existing unit g is alive in year y and zero otherwise.

3.2.2 Level 2: Operational Dispatch and Market Assessment

To obtain energy prices, the model solves an economic dispatch linear program for each planning year and scenario to minimize total variable generation costs. The mathematical formulation is defined as follows:

Level 2 Objective Function:

The objective is a pure economic dispatch designed to minimize total system variable generation costs:

$$\min \sum_g VarCost_{g,s} G_g$$

Level 2 Constraints

The following short-term operational rules bind the dispatch and assessment:

Energy Balance Constraint:

$$\sum_g G_g = AnnualDemand_{y,s}$$

Generation Capacity Limits:

$$0 \leq G_g \leq 8760 CF_g \cdot \sum_c Av_{y,c,g}$$

Where:

- G_g is the continuous decision variable representing the actual annual electrical energy dispatched by generation technology g .
- $VarCost_{g,s}$ is the input parameter representing the variable generation cost (such as fuel and operational expenses) for technology g under scenario s .

The dual variable associated with the energy balance constraint yields the competitive market energy price. This post-dispatch step ensures that capacity expansion decisions are evaluated under competitive pricing.

Market-Power Assessment (Level 2): Finally, to assess post-expansion competitiveness across the demand scenarios, the RSI is calculated for each firm using the fixed capacities.

$$RSI_{y,c,s} = \frac{\sum_j Av_{y,c,g}}{PeakDemand_{y,s}}$$

An RSI below 1.0 indicates a firm is a pivotal supplier capable of exercising monopolistic market power, whereas an RSI above 1.0 means rival capacity alone can satisfy peak demand.

Computational Implementation: The proposed stochastic generation expansion planning model is formulated as a large-scale Linear Programming (LP) problem and solved utilizing MATLAB's *linprog* optimization algorithm.

4. Data

To demonstrate the practical applicability of the proposed methodology, a comprehensive case study is conducted over a 30-year planning horizon. The modeled power system comprises three competing generation companies (GENCOs) and features three distinct generation technologies: gas turbine (GT), combined-cycle gas turbine (CCGT), and nuclear power.

Technology Parameters

The technical and economic parameters for these technologies, adapted from the primary analysis document, are detailed in Table 1. This technological mix is designed to represent a realistic balance of baseload and peaking options. Specifically, gas turbines require low initial investment but incur high variable costs and have relatively short technical lifetimes of 20 years. In contrast, nuclear units demand significant capital expenditure but benefit from highly competitive marginal operating costs and longer 30-year lifespans.

Table 1. Technical and economic parameters of generation technologies

Technology	Investment Cost (k\$/MW)	Var. Cost s1 (\$/MWh)	Var. Cost s2 (\$/MWh)	Var. Cost s3 (\$/MWh)	Capacity Factor	Lifetime (years)	Existing Capacity (MW)	Existing Age (years)
Gas Turbine	867	45	50	40	0.4	20	300	8

(GT)								
Combined-cycle (CCGT)	1176	28	32	24	0.6	25	400	12
Nuclear	7777	10	12	8	0.9	30	500	18

Demand Scenarios and Reliability Metrics

Uncertainty regarding future load growth and fuel costs is captured through a discrete set of three scenarios. The system's peak demand originates at a base of 3,000 MW and is projected to increase linearly over the planning horizon. The specific characteristics of these scenarios—representing high, base, and low growth trajectories—along with their assigned probabilistic weights and annual peak growth rates, are outlined in Table 2.

Table 2. Demand scenarios and peak growth rates

Scenario	Probability	Peak Growth (MW/year)	Description
s1 (medium)	0.4	60	Base case
s2 (high)	0.4	90	High growth and high fuel cost
s3 (low)	0.2	20	Low growth and low fuel cost

To determine the total annual energy requirements for the dispatch model, the peak demand in each scenario is multiplied by a constant system load factor of 0.6. Furthermore, system reliability is rigorously guaranteed by enforcing a mandatory reserve margin, requiring available capacity to remain at least 15% above the peak demand.

Investment Budgets and Optimization Parameters

To ensure realistic market dynamics and simulate constrained capital access, each firm is restricted by a firm-specific investment budget. These budgets are broadly scaled to reflect the firms' existing market footprints, with total capital limits set at \$4 billion for Firm 1, \$6 billion for Firm 2, and \$8 billion for Firm 3. Finally, to prevent mathematically degenerate solutions and actively penalize economically inefficient overbuilding, a regularization penalty coefficient of 0.01 is applied to all new capacity addition variables within the computational model's objective function.

5. Results and Discussion

The computational model successfully converged to yield an optimal, non-anticipatory capacity expansion and retirement strategy across the 30-year planning horizon. The results demonstrate how strict capital constraints, endogenous unit lifespans, and stochastic demand uncertainties interact to dictate the structural evolution and economic competitiveness of the power system.

5.1. System Adequacy and the Cost of Robustness

The stochastic optimization framework rigorously maintained system adequacy across all future uncertainties (**Figure 2a–c**). Throughout the planning horizon, the total available capacity successfully exceeded the peak demand plus the mandatory 15% reserve margin in every scenario, effectively preventing any structural shortages. However, because the stochastic approach computes a single investment schedule designed to be robust against all probable futures, capacity expansion was fundamentally driven by the most extreme, binding constraint—the aggressive high-growth trajectory (Scenario 2, **Figure 2b**). Consequently, in scenarios where actual demand growth was moderate (Scenario 1, **Figure 2a**) or low (Scenario 3, **Figure 2c**), the robust investment plan inherently yielded a substantial capacity surplus. This highlights the primary economic trade-off inherent in risk-averse stochastic planning: guaranteeing absolute reliability against high-growth risks inevitably necessitates capital over-procurement if lower-growth realities materialize.

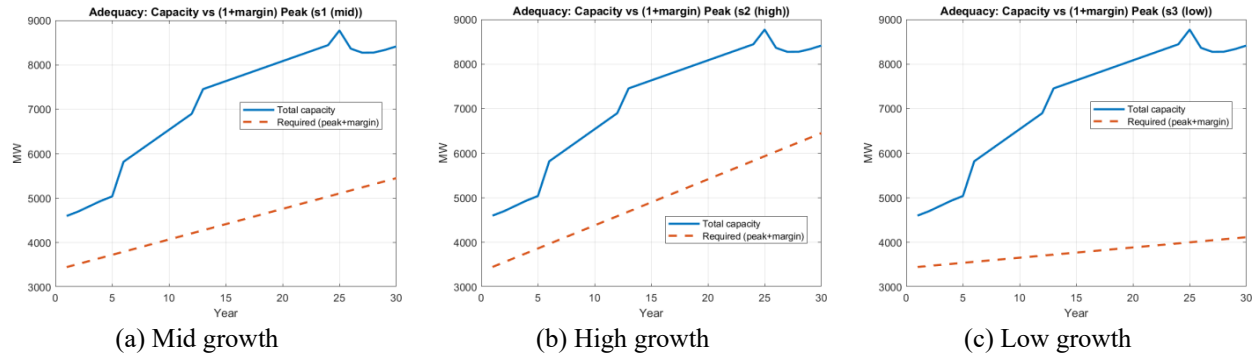


Figure 2. System adequacy and total capacity expansion versus required peak demand margin across three stochastic scenarios: (a) Mid growth, (b) High growth, and (c) Low growth.

5.2. Fleet Turnover and Technological Transition

The expansion trajectory was characterized by discrete, aggressive investment phases rather than smooth, linear growth. This stepped behavior was driven by an endogenous "retirement cliff" midway through the planning horizon (Figure 3), during which the majority of the system's legacy assets simultaneously reached the end of their technical lifespans. This mass retirement event forced a profound structural transition in the overall technology mix (Figure 4).

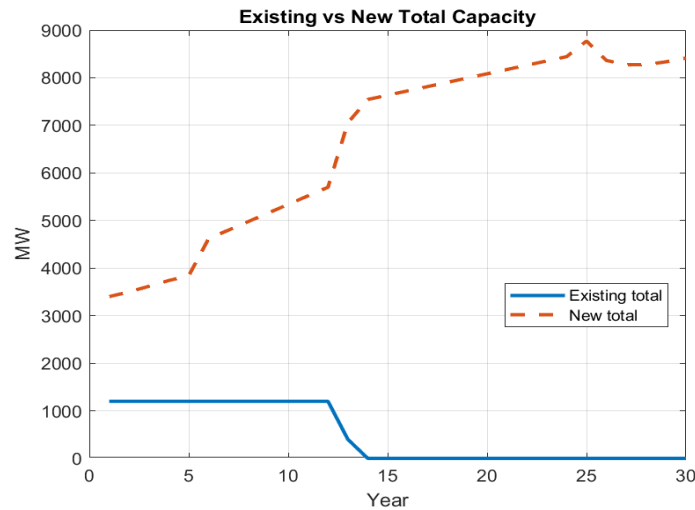


Figure 3. Endogenous retirement dynamics demonstrating the complete turnover of legacy existing capacity versus newly built total capacity over the 30-year horizon.

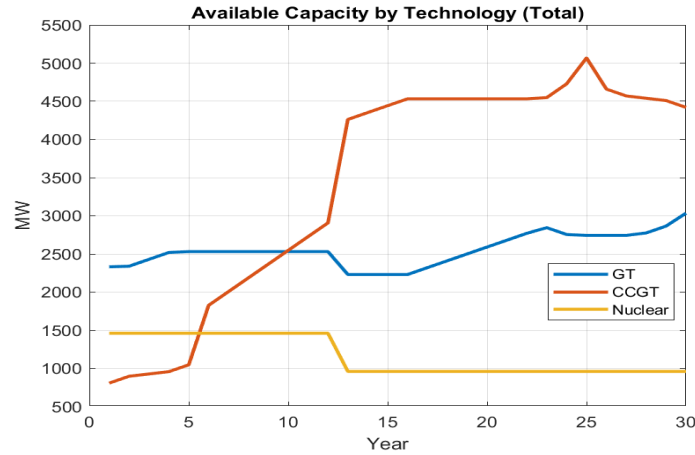


Figure 4. Evolution of total available system capacity disaggregated by generation technology.

Notably, the prohibitive capital costs associated with new nuclear technology, when strictly bounded by the generation companies' investment budgets, created a long-term "nuclear freeze" (Figure 5c); retiring nuclear baseload capacity was not replaced in kind. Instead, Combined-Cycle Gas Turbines (CCGT) emerged as the optimal replacement technology. CCGT capacity was aggressively scaled (Figure 5a) to absorb the bulk energy provision and serve as the system's new baseload and mid-merit workhorse. Conversely, while Gas Turbines (GT) saw significant capacity additions in the latter half of the horizon (Figure 5b), operational dispatch data (Figure 6a–c) revealed their energy output remained near zero. GTs were deployed almost exclusively as low-capital reliability assets to satisfy the escalating 15% reserve margin, as their high variable operating costs priced them entirely out of competitive energy dispatch.

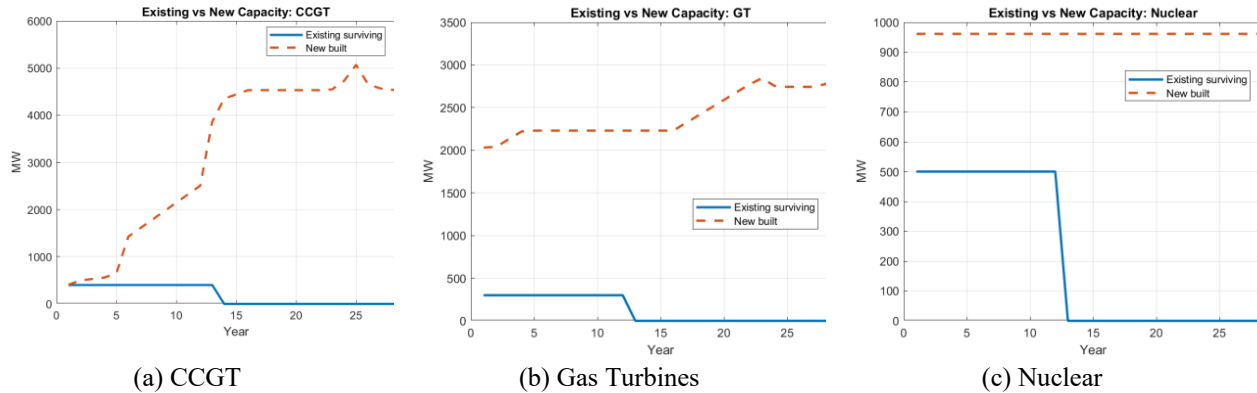


Figure 5. Comparison of existing surviving capacity versus newly built capacity by specific technology: (a) CCGT, (b) Gas Turbines, and (c) Nuclear.

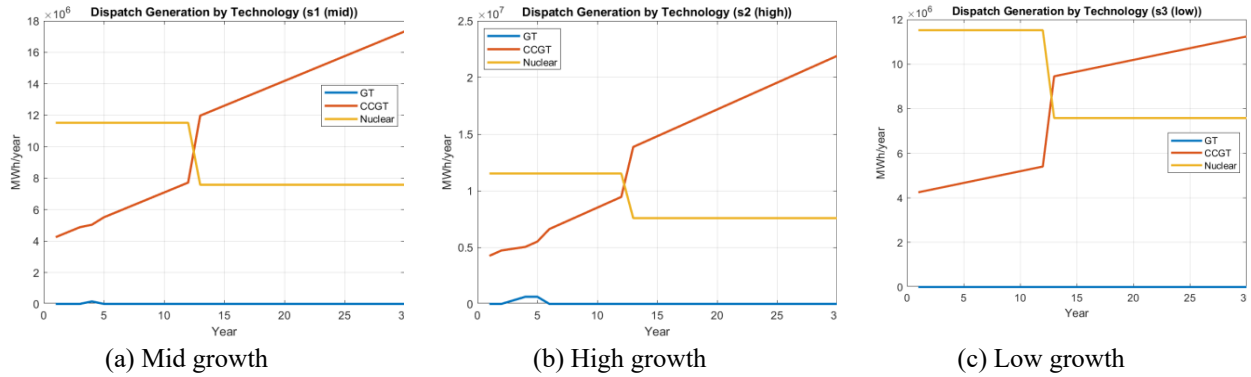


Figure 6. Operational energy dispatch by technology across three demand scenarios: (a) mid growth, (b) high growth, and (c) low growth, illustrating the transition of baseload provision from nuclear to CCGT.

5.3. Market Equilibrium and Structural Competitiveness

The physical shifts in the capacity mix directly influenced market economics and firm-level competition. Following the retirement of the legacy nuclear fleet, CCGT established the long-term marginal clearing price for the system across all scenarios (Figure 7). Market prices remained highly stable, perfectly reflecting CCGT variable operating costs, with brief, transient price spikes occurring only when temporary capacity deficits forced expensive GTs into the dispatch merit order during the early transition phase.

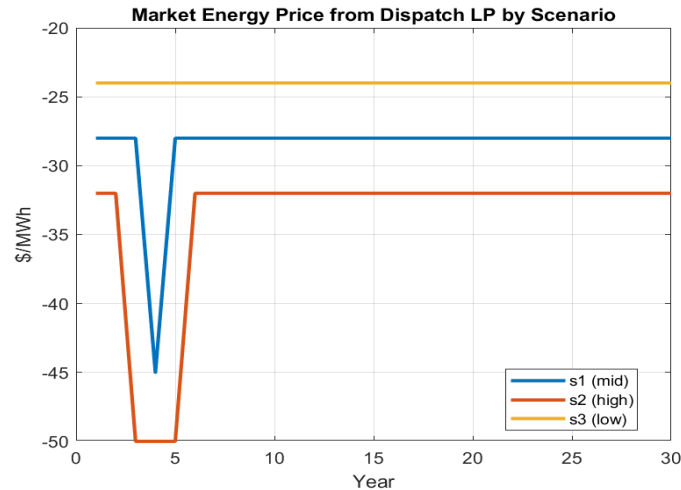


Figure 7. Competitive market energy clearing prices derived from the operational dispatch dual variables across all three stochastic scenarios.

Finally, an assessment of the Residual Supply Index (RSI) confirmed the complex impact of demand uncertainty on structural market power (Figure 8a–c). In the mid- and low-growth scenarios, the capacity surplus effectively ensured that no single firm became a pivotal supplier, fostering a highly competitive market structure ($RSI > 1.0$, Figure 8a, 8c). However, in the binding high-growth scenario, the lack of structural slack drove the RSI dangerously close to the 1.0 threshold (Figure 8b). This demonstrates that while the strict reserve margin constraint guarantees physical reliability against worst-case demand, it simultaneously creates a tight market equilibrium under those same high-growth conditions, leaving the system highly vulnerable to pivotal supplier market power.

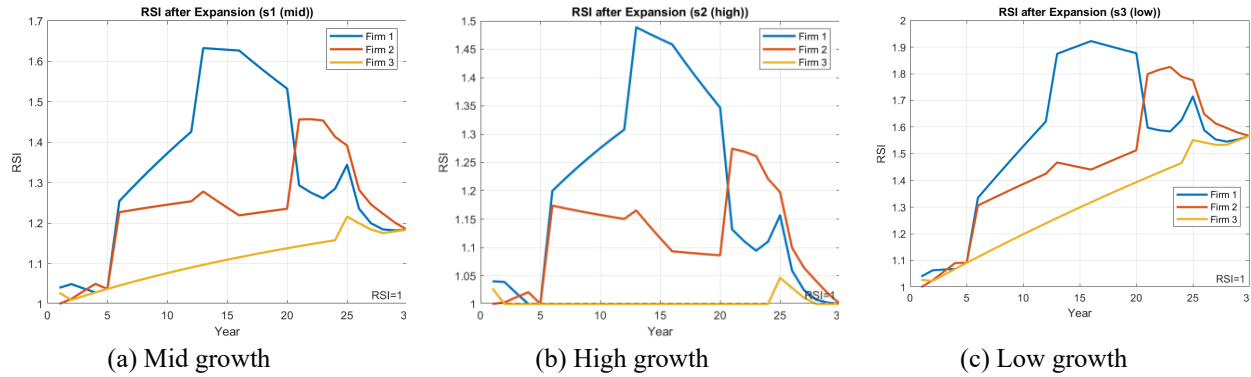


Figure 8. Post-expansion Residual Supply Index (RSI) evaluation for the three generation companies across (a) mid, (b) high, and (c) low growth scenarios, assessing structural market competitiveness.

6. Conclusion

This paper presented a novel two-level sequential stochastic linear programming (LP) framework for Generation Expansion Planning (GEP), explicitly incorporating endogenous legacy asset retirements, strict firm-level capital budgets, and mandatory reserve margin constraints. Crucially, by actively minimizing structural market power during the investment phase and evaluating post-expansion economics, the model successfully illuminated the complex physical and economic trade-offs inherent in long-term power system planning under uncertainty.

Several critical insights emerged from the computational results:

- **The Economic Cost of Robustness:** The strict enforcement of a 15% reserve margin across all stochastic scenarios guaranteed absolute system adequacy. However, because the most severe high-growth trajectory mathematically bound the non-anticipatory investment decisions, the system naturally exhibited a massive capacity surplus when moderate or low-growth realities materialized. This highlights a fundamental tension in risk-averse capacity planning: guaranteeing physical reliability against worst-case uncertainties inherently necessitates significant capital over-procurement.
- **Capital Constraints and Technological Transition:** The simulation demonstrated a profound structural turnover of the generation fleet, triggered by an endogenous "retirement cliff" of legacy assets. Crucially, the combination of prohibitive specific investment costs and strict firm budgets created a long-term "nuclear freeze." Retiring nuclear baseload capacity was fundamentally replaced by Combined-Cycle Gas Turbines (CCGT), which emerged as the optimal economic compromise to serve as the system's primary energy provider.
- **The Bifurcation of Capacity and Energy Assets:** The results revealed a distinct decoupling of physical capacity expansion and operational energy dispatch. While Gas Turbines (GT) saw aggressive capacity additions, their operational dispatch remained near zero. GTs were deployed exclusively as low-capital reliability assets to cheaply satisfy mandatory reserve margins, whereas CCGTs dictated the long-term marginal clearing price of the competitive energy market.
- **Vulnerabilities in Market Competitiveness:** Post-expansion Residual Supply Index (RSI) evaluations confirmed that while capacity surpluses in low-growth futures naturally foster structural competitiveness, high-growth futures eliminate market slack. Under tight supply-demand conditions, generation firms converged dangerously close to becoming pivotal suppliers, indicating that strict reliability constraints alone are insufficient to prevent the emergence of monopolistic market power during periods of aggressive load expansion.

Ultimately, this study demonstrates that while traditional reliability mandates successfully guarantee system adequacy, they heavily penalize capital-intensive baseload technologies like nuclear power and leave energy markets vulnerable to tight structural margins. By integrating stochastic capacity investment with active market power minimization, this two-level framework provides a vital tool for designing grids that are both physically resilient and structurally competitive. Future research should explore the integration of carbon pricing mechanisms,

flexible demand-side response, and dynamic budget constraints further to refine the economic realities of the energy transition.

Acknowledgment

This study was funded by the Scientific and Technological Research Council of Türkiye (TUBITAK) ARDEB 1001 Grant No: 225M497.

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