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2018 TECHNICAL UPDATE

Economic Value of Increased Operational Flexibility for Fossil-Fired Generation Assets



Economic Value of Increased Operational Flexibility for Fossil-Fired Generation Assets

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3002013735
Technical Update, April 2018

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Acknowledgments

The Electric Power Research Institute (EPRI) prepared this report.

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This report describes research sponsored by EPRI.

The author would like to thank Adam Diamant, Michael Caravaggio, Nidhi Santen, and David Young for their suggestions. Any remaining errors are solely the responsibility of the author.

This publication is a corporate document that should be cited in the literature in the following manner:

Economic Value of Increased Operational Flexibility for Fossil-Fired Generation Assets.
EPRI, Palo Alto, CA: 2018.
3002013735.

Abstract

Flexibility is increasingly important in power sector planning, especially as low natural gas prices and proliferating renewables increase net load variability and cycling for grid-connected assets. This report explores how enhanced flexibility through lower minimum load levels (also called "turndown" limits) for coal- and natural-gas-fired power plants can impact operations and profitability. Using soft-linked capacity planning and unit commitment models, this research examines the economic value of this flexibility and variation across different regions, generation asset types, and market environments (e.g., level of renewable deployment).

Model results suggest that lower minimum loads are most valuable for mid-merit units with intermediate capacity factors, policy conditions that rearrange the merit order (e.g., carbon pricing), regions and scenarios without seasonal layup of assets, and units that are more flexible than generators with otherwise similar characteristics. Lower minimum loads increase operating hours and net revenues, and decrease startups and long-run maintenance costs. The scenarios in this analysis show that plant flexibility affects operations more than annual profitability. For many plants, the modest changes in net revenues as a fraction of net revenues with higher minimums mean that the focus will likely be on making operational changes to increase flexibility rather than capital investments. Additionally, this analysis quantifies how revenues from ancillary services markets can boost the value of lower minimum loads, especially for efficient natural gas units, but total market size and depth are uncertain.

Keywords
Flexible operations
Resource planning
Economic dispatch
Minimum load
Renewable integration

Deliverable Number: 3002013735

Product Type: Technical Update

Product Title: Economic Value of Increased Operational Flexibility for Fossil-Fired Generation Assets

PRIMARY AUDIENCE: Utilities, technology developers, policy-makers, researchers, and other stakeholders who want to understand the potential value and impacts of flexible operations.

SECONDARY AUDIENCE: Other electric sector stakeholders who want to understand drivers, barriers, and impacts of system flexibility.

KEY RESEARCH QUESTION

Flexibility is increasingly important in power sector planning, especially as low natural gas prices and proliferating renewables increase net load variability and cycling for grid-connected assets. This report explores how enhanced flexibility through lower minimum load levels for coal- and natural-gas-fired power plants can impact operations and profitability.

RESEARCH OVERVIEW

The Electric Power Research Institute's (EPRI's) U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model is used to examine the economic value of this flexibility and variation across different regions, generation asset types, and market environments (e.g., level of renewable deployment).

KEY FINDINGS

- Model results suggest that lower minimum loads are most valuable for mid-merit units with intermediate capacity factors, policy conditions that rearrange the merit order (e.g., carbon pricing), regions and scenarios without seasonal layup of assets, and units that are more flexible than generators with otherwise similar characteristics.
- Lower minimum loads increase operating hours, increase net revenues, and decrease startups and long-run maintenance costs.
- For the scenarios, regions, and assumptions investigated in this analysis, plant flexibility affects operations more than annual profitability. For many plants, the modest changes in net revenues as a fraction of net revenues with higher minimums mean that the focus will likely be on making operational changes to increase flexibility, rather than on capital investments.
- The analysis quantifies how revenues from ancillary services markets can boost the value of lower minimum loads, especially for efficient natural gas units, but total market size and depth are uncertain.

WHY THIS MATTERS

From the perspective of an individual asset owner, power plant operational flexibility (in this analysis, through reducing a generator's minimum load) has the potential to reduce energy market losses, mitigate wear-and-tear costs, and increase reserve range. From a system perspective, flexibility is useful for increasing reliability, lowering system costs, and integrating renewables.

HOW TO APPLY RESULTS

Understanding the value and impacts of flexible operations is important for fossil-fueled generators like coal- and natural-gas-fired power plants as evolving markets change their operational profiles. This report offers insights for a range of stakeholders who want to understand the potential value and impacts of flexible operations. Some results can be applied directly, while others require additional region- and asset-specific scenario analysis. The report also highlights future research and data needs, including better ranges of cycling cost estimates across different operational conditions.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- Readers of this report may be interested in EPRI's Program 178 Project Set B (*Integrated Portfolio Planning and Market Analysis*), which helps members understand resource planning issues and improved methods for integrated generation, transmission, and distribution planning and fuels management. Contact Adam Diamant at adiamant@epri.com for additional information.
- Users of this report may be interested in EPRI's Program 201 Project Set C (*Emerging Technologies Analysis: Drivers & Impacts*), which conducts analysis for its members and the public to understand policy and market drivers for emerging technologies, including energy storage, renewables, nuclear, and carbon capture. Contact John Bistline at jbistline@epri.com for additional information.

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PROGRAM: Project Set 178(b)

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Section 1: Introduction

Flexible Operations in the Electric Power Sector

Flexibility is increasingly a buzzword in the electric power sector, especially as low natural gas prices and proliferating renewables increase net load variability and cycling for grid-connected assets (Wiser, et al., 2017). From the perspective of an individual asset owner, power plant operational flexibility could be important for minimizing short- and long-run costs and for maximizing revenues. From a system perspective, flexibility is useful for increasing reliability, lowering system costs, and integrating renewables.

Understanding the value and impacts of flexible operations is important for fossil-fueled generators like coal- and natural-gas-fired power plants as evolving markets change their operational profiles. Units that historically operated close to their maximum available outputs are now being used in more flexible operating modes that entail greater cycling, lower utilization, and increasing relative costs of generation (especially as fixed costs are spread across fewer hours of output).

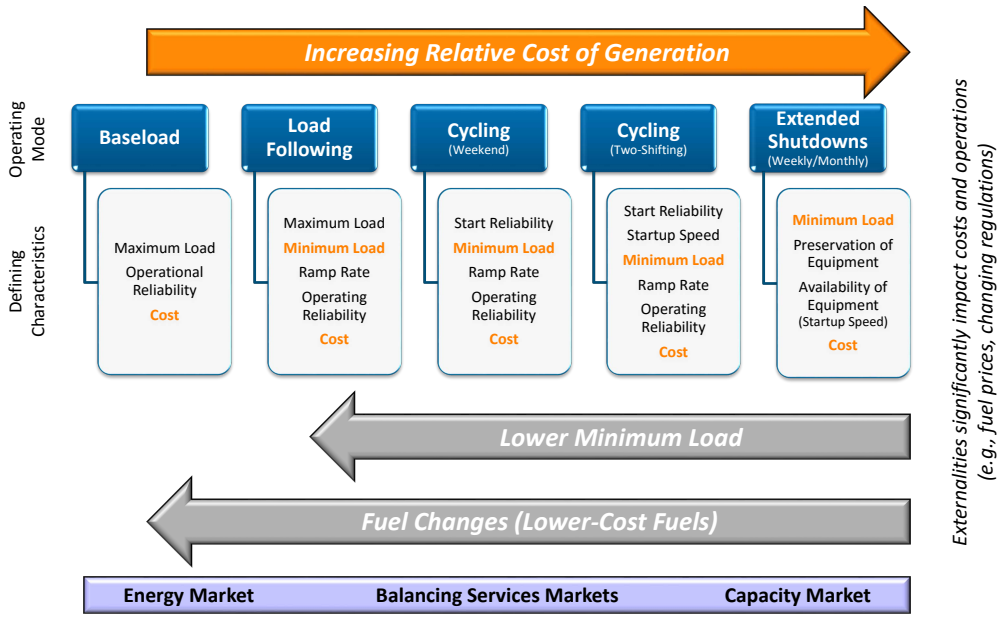


Figure 1-1
Spectrum of flexible operations (from EPRI's Mission Profile Working Group)

There is a broad spectrum of operating modes under the heading of "flexible operations," each with different implications for the cost and value of flexibility. Moving from operating modes on the left of Figure 1-1 (e.g., baseload and load following) to the right (e.g., extended shutdowns), flexible operations entail increasing costs per unit of generated electricity. Lowering minimum stable loads or changing relative fuel costs could allow a generating unit to move from the right toward operating regimes on the left side of the spectrum, which means that revenues for that unit would come more from energy and balancing services markets rather than capacity markets.

The potential value of dispatchable and flexible generation assets on the grid may grow as the share of non-dispatchable resources increases. Existing studies on the value of flexibility typically focus on system-level impacts and indicate that flexible assets lower power system costs, decrease renewable curtailment, increase system reliability, and help to meet other policy goals like greenhouse gas emissions reductions (Bistline, 2017; Denholm, 2016; Cochran, et al., 2014; Bouffard, 2011; IEA, 2011). Power system flexibility provided by generation, load, transmission, and storage can also reduce the rate of variable renewable energy value decline (Wiser, et al., 2017). However, the literature is less developed for assessing the value of flexibility from the perspective of an individual asset owner or operator, which is the focus of this paper.

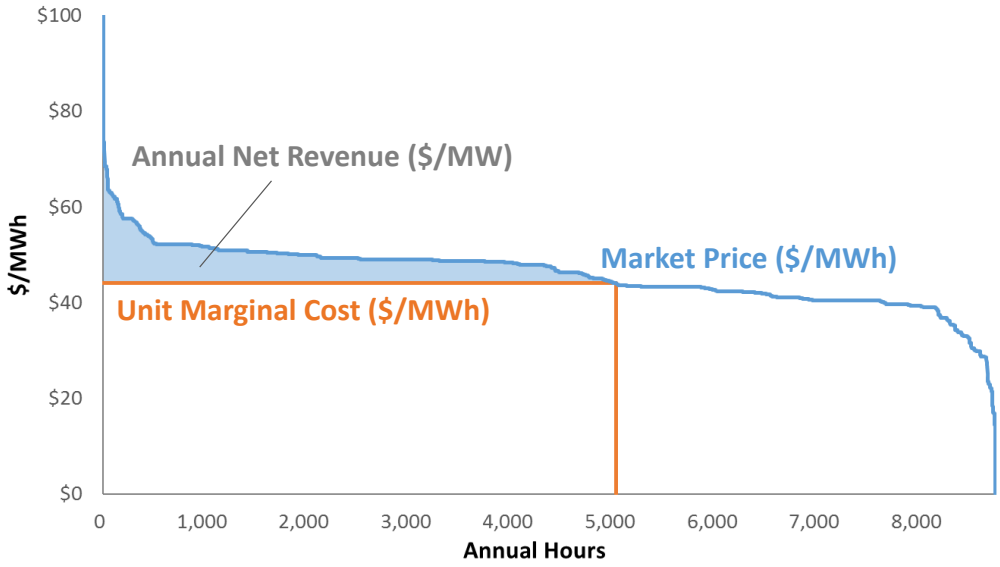


Figure 1-2
Example of wholesale electricity price duration curve (hourly values are sorted from highest to lowest)

Unit operations are driven by net revenues for power plants and their commitment-related costs and constraints. Figure 1-2 provides an example of a price duration curve, which sorts hourly market-clearing electricity prices (vertical axis) from their highest to lowest values across all annual hours (horizontal axis). For this illustration, a hypothetical natural gas combined cycle (NGCC) unit with marginal costs of about $45/MWh would operate almost 5,000 hours with a

positive spark spread (i.e., when market revenues from electricity sales exceed the short-run marginal costs of operations including fuel costs). The plant's dispatch and annual capacity factor also depend on a broader range of factors, including chronology and unit-commitment costs (e.g., startup costs) and constraints (e.g., minimum stable load), as shown in Figure 1-3.

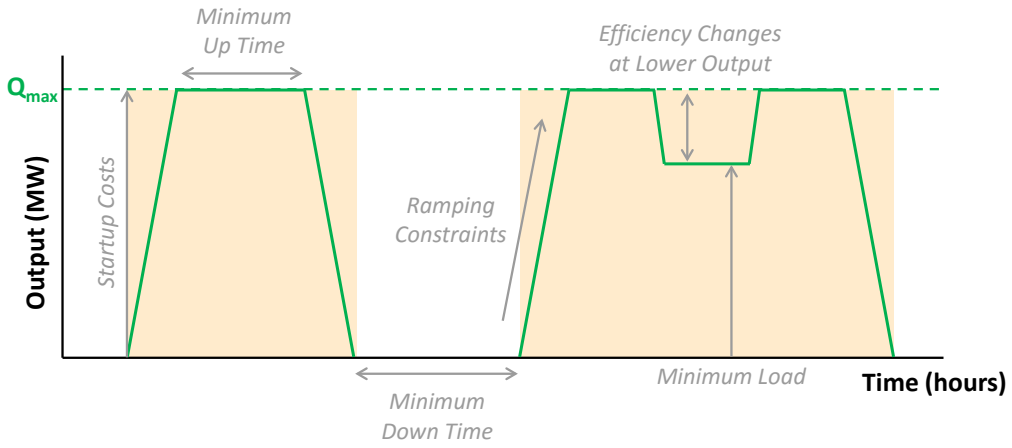


Figure 1-3
Examples of unit commitment costs and constraints

Figure 1-3 illustrates unit-commitment-related costs and constraints that can impact operational decisions for power plants. The figure shows output over time for a hypothetical dispatchable unit with maximum capacity Q_{max}. The unit incurs startup costs when it is dispatched (and the magnitude of these costs depends on its offline time) and shutdown costs when its output drops to zero. Minimum up and down times dictate the required duration a unit must be committed before its output can be adjusted. Ramping constraints dictate the maximum rate of change in the unit's output. Minimum load levels, which are discussed in the next subsection, are the lowest safe and reliable operating mode where a unit can operate. At these lower output levels, the unit's efficiency decreases, which increases normalized production costs and emissions intensities.

Value of Lower Minimum Loads

During hours when wholesale power prices are low and operating margins for plants are negative (i.e., when the short-run marginal costs of operations exceed revenues), a plant can either ramp down to its minimum stable operating load (or "turndown level") or shut down. Minimum load is the lowest safe and reliable operating mode without supplementary firing that complies with environmental regulations. There are three primary value prospects of minimum load operations:

- Running at minimum generation mitigates short-run costs of startup and shutdown while minimizing monetary losses during hours with negative margins.

- If a unit is online with upward flexibility to adjust its output, then it also can respond to quick residual load changes, provide grid services, and receive revenues in ancillary services markets.
- Avoiding long-run costs from cycling-induced wear-and-tear (e.g., fatigue damage, corrosion fatigue, steam turbine impacts) helps plant competitiveness. A key strategy to avoid shutdowns is to reduce turndown levels. One difficulty is that wear-and-tear costs are highly uncertain, since many plants have not been cycled until recently and determining these costs are complex due to latency (i.e., multi-year time lagging) and dependence on the plant's operations and maintenance (O&M) history.

These benefits must be weighed against higher heat rates, emissions, and marginal production costs at minimum load levels. Optimal operational strategies depend on the magnitudes and duration of price changes, characteristics of individual units (e.g., minimum generation levels), and other region- and unit-specific considerations, as shown in the mathematical example in Appendix A.

To demonstrate the value of lower minimums, the next three figures show weekly operations and revenues for a hypothetical NGCC plant in California with three different system mixes.[1] For a counterfactual scenario with 0 GW installed solar (Figure 1-4), if there were no unit commitment constraints, this plant would always be on when the blue line (top panel) is above the horizontal axis and off when it is below. The bottom panel illustrates how this unit is essentially running in a "baseload" mode, and revenue fluctuations (bottom panel) are due solely to diurnal wholesale price variations during the early-evening peak.

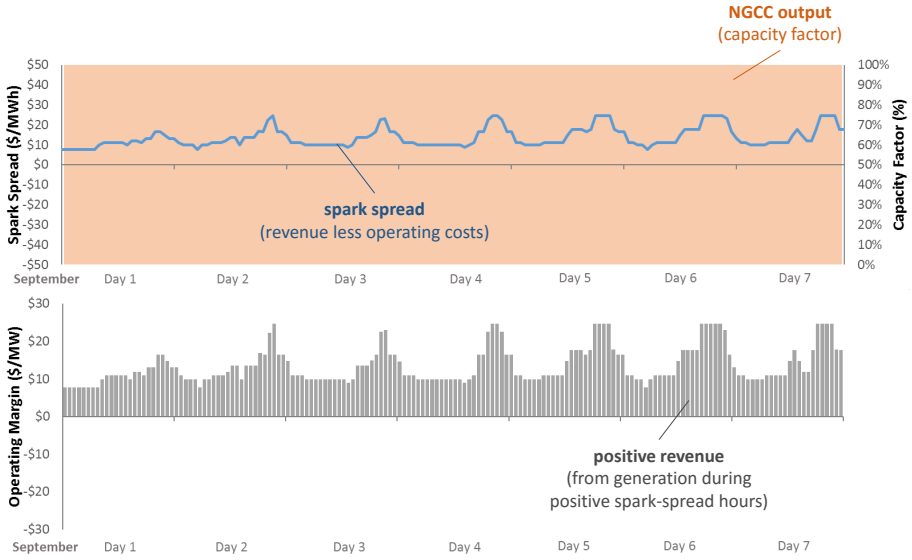


Figure 1-4
Example NGCC operations (top panel) and operating margin (bottom panel) in California with 0 GW solar

[1] These examples are based on the analysis in Bistline (2017).

With 40 GW of installed solar (Figure 1-5), the plant's operating mode changes due to the deluge of midday solar generation, which suppresses wholesale electricity prices. These dynamics causes spark spreads to go negative for a few hours each day, which means that this NGCC unit will ramp down to its minimum load to avoid incurring shutdown costs.

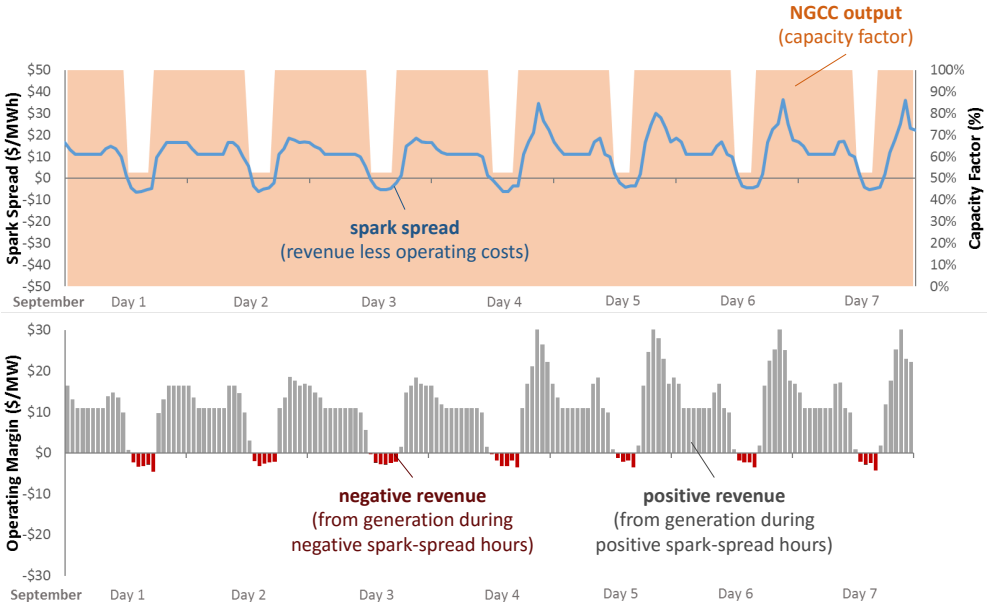


Figure 1-5
Example NGCC operations (top panel) and operating margin (bottom panel) in California with 40 GW solar

With 100 GW of installed solar (Figure 1-5), this same NGCC unit is likely to operate as a "two-shifter" (i.e., turning on and off once per day). Whether a unit turns off completely at night or ramps down to its minimum load depends on its flexibility attributes (e.g., startup cost) and price changes.

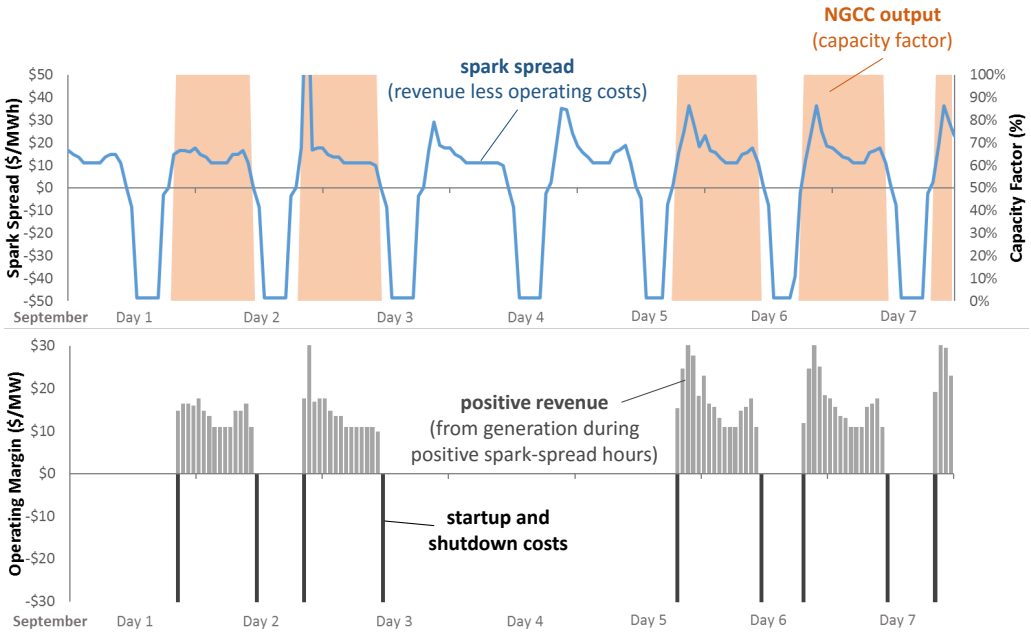


Figure 1-6
Example NGCC operations (top panel) and operating margin (bottom panel) in California with 100 GW solar

A takeaway from the past three slides is that there is a "sweet spot" for valuing increased flexible operations. Lower minimum loads would not be valuable in the first or third scenarios (since minimum turndown operations are not economically profitable) but would be valuable in the second case (i.e., the 40 GW solar example).

Research Questions

In light of these potential benefits, generators that can increase flexibility through lower turndown levels (or through higher efficiencies at low loads and faster cycling) can better respond to changing conditions and potential profit from market volatility. The focus on part-loaded synchronized generators and their minimum stable generation limits in this analysis is driven by previous literature indicating that constraints associated with these parameters are likely binding more frequently and have greater impacts than ramp rates, efficiency changes at reduced output, or other flexibility-related parameters (Denholm, et al., 2018; Hentschel, 2016; Ma, et al., 2013; EPRI, 2013a).

Existing power plants can reduce minimum loads through a range of operational measures with strategic modifications, including proactive inspections, training programs, forced cooling, monitoring economizer inlet headers, layup procedures, pressure part management, and boiler operating procedures (EPRI,

2014; EPRI, 2013b).[2] Some changes require minimal effort and expenditures (e.g., configuration changes, modifications to operator checklists), while other larger capital changes (e.g., economizer water bypass installation, new feedwater controls) entail costs ranging from $100,000 to millions of dollars (EPRI, 2014).

This analysis focuses on how enhanced operational flexibility through lower minimum loads can change the operations and profitability of individual coal and natural gas power plants. Using soft-linked capacity planning and unit commitment models, this paper assesses the variation in the economic value of this flexibility across different regions, asset types, and market environments (e.g., level of renewable deployment). Additionally, uncertainty about the long-run wear-and-tear costs from cycling is incorporated into the analysis through parametric sensitivities on startup costs to understand possible net revenue implications for electricity market participants.

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[2] For additional information about EPRI research on flexible operations, see the "Enabling Flexible Operations of the Generation Fleet" website: http://genstrategy.epri.com/enabling-flexible-operations-of-the-generation-fleet/

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Section 2: Model Overview

Modeling Framework

The analysis in subsequent sections uses the U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) modeling framework to evaluate regional capacity planning and unit-level dispatch decisions.
US-REGEN is a detailed capacity planning and dispatch model of the electric sector that simultaneously determines investment and operational decisions. This version of the model is solved as an intertemporal optimization through 2050 with five-year time steps. Joint variability in load, wind, and solar is captured through the selection of so-called "representative hours" (Blanford, et al., 2018).

In determining optimal resource mixes given scenario-specific assumptions, the dynamic version of US-REGEN optimizes generation across all 15 model regions simultaneously and dispatches aggregated capacity blocks across these segments.

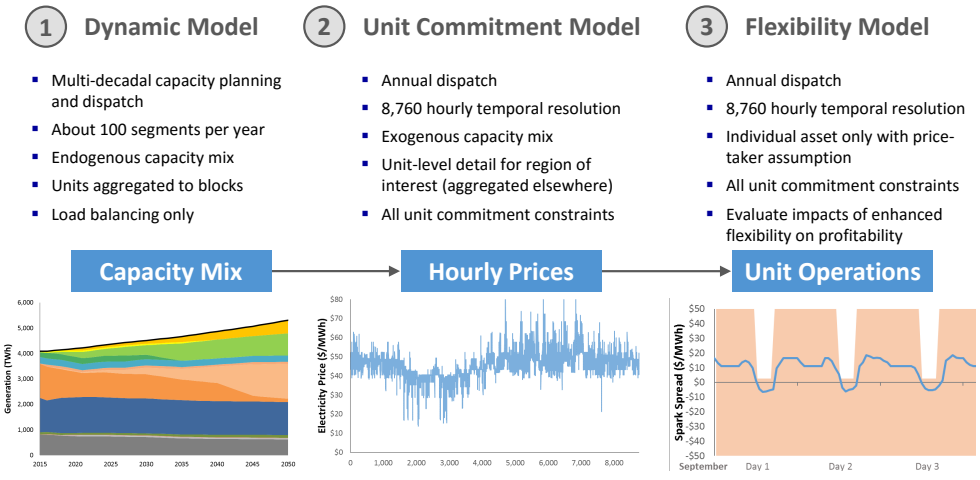


Figure 2-1
Analysis approach summary using the US-REGEN modeling framework

As shown in Figure 2-1, the capacity mix from the dynamic model is then used in a soft-linked unit-commitment model with annual dispatch, hourly temporal resolution, unit-level detail, and more detailed representations of operational constraints and costs like minimum load levels and startup costs (EPRI, 2015). The unit-commitment model assumes perfectly competitive markets with

centralized commitment and dispatch scheduling. Hourly prices are then used in a reduced-form flexibility model that captures a single unit's self-commitment and dispatch decisions with a price-taker assumption (i.e., optimizing operations against a fixed price vector). Modeling self-commitment decisions for an individual asset can evaluate impacts of enhanced flexibility while remaining relatively compact and allowing a greater range of unit-level sensitivities to be conducted.

The analysis assumes the perspective of a representative firm with a focus on changes in revenues net of production costs. Market-clearing electricity prices from the dynamic and unit commitment versions of US-REGEN are the Lagrange multipliers on the load balance constraint. The analysis assumes competitive electricity markets to understand the basic principles of the equilibrium value of enhanced flexibility (specifically, low turndown operations). Note that these models do not explicitly incorporate uncertainty about load or renewables forecasts, which can increase demand for flexible operations especially at shorter timescales.

US-REGEN has been used to investigate a range of power sector and energy questions including studies of renewable integration and impacts of flexible operations on the U.S. generation fleet (Blanford, et al., 2018; Bistline, 2017; James, et al., 2015). Additional detail about the US-REGEN model structure and assumptions can be found in the model documentation (EPRI, 2017; EPRI, 2015).

Data and Assumptions

Startup and shutdown costs for coal and gas units come from Intertek (NREL, 2012). These costs differ by start type (e.g., cold versus hot starts), technology, and cost category (e.g., O&M, fuel, and others). Given the uncertainty associated with the impact of a startups on wear-and-tear costs, this analysis uses 25th and 75th percentile values from Intertek to represent "Low" and "High" values in sensitivity analyses. Note that Intertek considers these "lower bound costs" and does not publish higher values, which means that the outputs of this analysis should be interpreted as lower bounds as well. These calculations focus on a single year only and do not account for the possibility (or costs) associated with early retirements. Additionally, more startups are correlated with higher equivalent forced outage rates, which are not included in the analysis.

The value of flexibility is linked to how minimum loads can be reduced from their initial ("High") to final ("Low") levels. These values were selected to be representative of general values that, in practice, depend on many plant-specific characteristics. "High" and "Low" minimum loads are assumed to be 50 and 20 percent of maximum output, respectively. The same values are selected for all three asset types (i.e., coal, new natural gas combined cycle, and existing natural gas combined cycle) to enable comparable experiments across asset types. The analysis quantifies the value of increased flexibility by comparing net revenues with and without lower minimum loads but does not incorporate the costs associated with implementing these lower minimums (EPRI, 2014). These

constraints and costs do not vary based environment controls configurations across specific units. All three assets are assumed to have capacities of 500 MW.

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Section 3: Scenarios

A range of scenarios is used to examine the value of lower minimum loads across different regions, policies, and technology types. The analysis focuses on four regions in 2035: California, Texas, Mountain-North, and South-Atlantic. Regional definitions are shown in Figure 3-1.

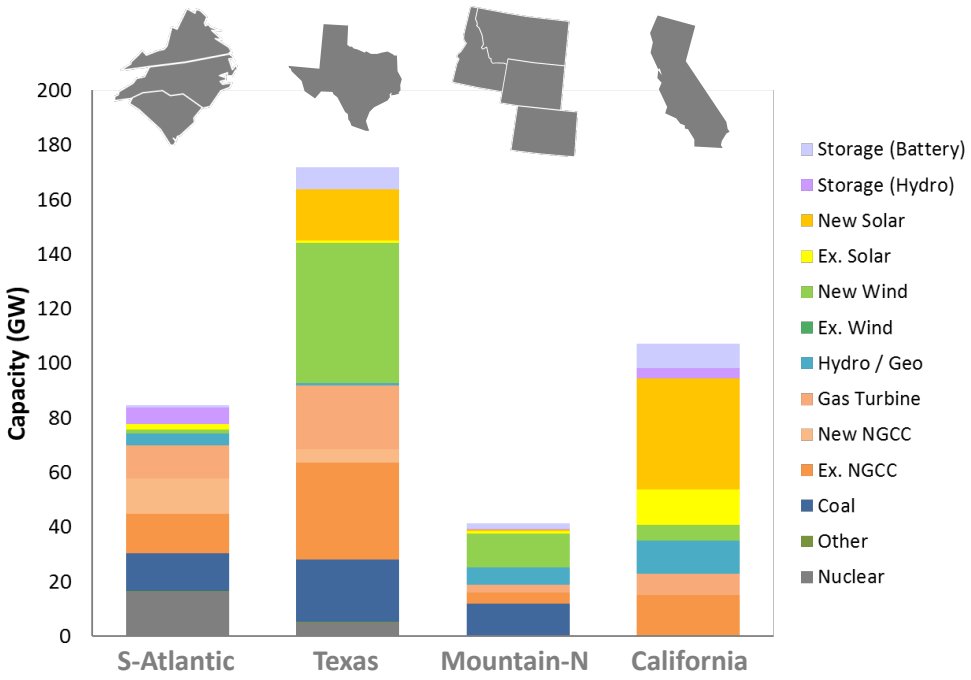


Figure 3-1
Capacity by technology under reference policy conditions across regions in 2035

Regional grid sizes and compositions vary significantly without policy interventions (Figure 3-1). The economic competitiveness of wind is strong in Texas and Mountain-N even without policy support. These capacity mixes translate into unit dispatch and flexible operations through price signals, which are outputs of the unit commitment model and represent the short-run marginal cost of the last dispatched unit. Note that there are changes in other model regions under these scenarios, which are not shown in Figure 3-1 (US-REGEN captures all regions in the Lower 48 states).

Five alternate scenarios offer different potential revenue profiles for units exposed to wholesale market prices:

1. **Reference:** This scenario assumes on-the-books state and federal policies and incentives only.
2. **Tax:** This scenario assumes a \$16/t-CO_2 tax in 2035, a stringency roughly similar to Clean Power Plan estimates (Bistline, et al., 2017). Different assumptions about policy stringency, timing, and implementation may alter model outputs and the economic incentives for flexibility.
3. **50% RPS (Wind):** This renewable mandate assumes that half of in-region demand must be met with either onshore or offshore wind generation technologies.
4. **50% RPS (Solar):** This renewable mandate assumes that half of in-region demand must be met with solar generation technologies.
5. **50% RPS (Both):** This renewable mandate assumes that half of in-region demand must be met with even shares of wind and solar generation technologies.

For each region and scenario, the analysis examines changes in operations and revenues for three asset types: existing coal units, new natural gas combined cycle (NGCC) units, and existing NGCC units. Parametric sensitivities for minimum loads and startup costs are conducted.

References

- Bistline, J.E., Niemeyer, V., Young, D. (2017). *Understanding Clean Power Plan Choices in Kansas: Options and Uncertainties*, EPRI Technical Report #3002009492 (EPRI, Palo Alto, CA).

Section 4: Results

Changes in Commitment and Dispatch with Lower Minimum Loads

Figure 4-1 illustrates the annual operating profile of new NGCC units in all four study regions with lower minimum loads with the capacity mixes shown in Figure 3-1. These examples show the output (on the vertical axis, as a percentage of its maximum available capacity) for each hour of the year (on the horizontal axis) in the reference scenario. For the S-Atlantic region, the unit is online for all hours of the year but oscillates between minimum and maximum output depending on the wholesale electricity price. This generation pattern is qualitatively similar in Texas, though the unit turns off completely in the springtime when load is low and wind output is high. For the Mountain-N region, the unit is in-the-money for nearly three-quarters of the year, but the high-wind and low-load conditions in the springtime lead to seasonal layup. For California, high solar output in the springtime similarly keeps the unit offline for consecutive months.

Extended shutdowns impact the potential value of flexibility for plants, as chronic periods of low prices drive fewer opportunities for increased operating ranges to change operational decisions. Later sections will demonstrate that regions with seasonal layups in the reference scenario have lower changes in profitability from lowering minimum generation levels. However, these differences become less significant under the high renewable mandate cases due to the prevalence of longer layup periods across regions.

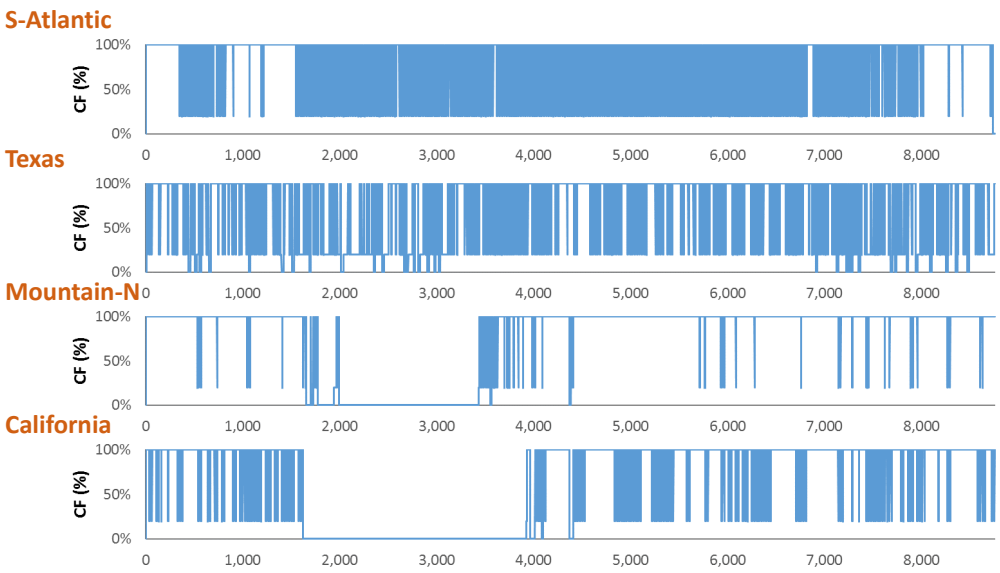


Figure 4-1
Annual commitment and dispatch (% maximum capacity) of a new NGCC unit with lower minimum load under reference policy conditions across the four study regions

Operational changes from lower minimum generation levels vary across scenarios, as Figure 4-2 demonstrates for a new NGCC unit in Texas. Each bar shows the number of annual operating hours (left vertical axis) spent at full load (blue) and at minimum generation (gray). The total number of annual starts (right vertical axis) is shown in the black circles. Values are shown for the high minimum generation level (i.e., with a minimum generation level of 50% of maximum output) and low level (20%).

Lower minimums lead to more annual operating hours, fewer starts, and increased time at minimum generation levels across all scenarios. For instance, under a reference policy environment, lowering the NGCC unit's minimum generation level implies that online hours will increase from 6,500 to over 8,000 (with roughly a third of those hours at its minimum load level) and that annual startups decrease from 40 to near zero. Note that the lowest capacity factors occur under the renewable mandate scenarios, though lower minimum loads decrease the variance of total online hours across scenarios.

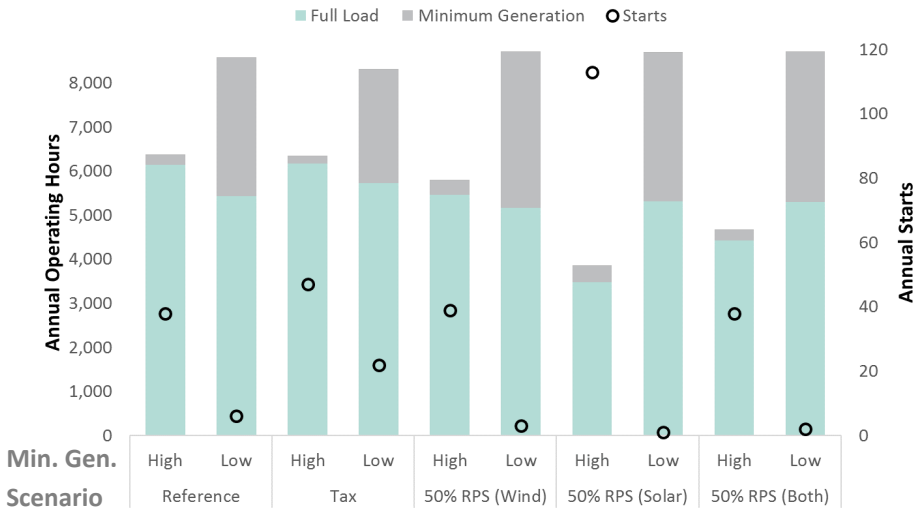


Figure 4-2
Changes in annual operating hours at full load and minimum generation for a new NGCC unit in Texas across scenarios

Comparing across all regions, policy scenarios, and asset classes, Figure 4-3 shows changes in operating hours with lower minimum loads relative to the operating hours at higher minimum loads. Each point represents a separate combination of regions, scenarios, and technology types. This figure shows how mid-merit (i.e., intermediate capacity factor) units experience the largest increase from lower minimum loads. Units with between 2,000 and 6,000 annual operating hours generally have greater changes in operating hours with lower minimum loads, which is correlated with higher net revenues (Figure 4-4). High capacity factor units already have higher operating margins, which means that enhancing flexibility-related characteristics (e.g., minimum loads) does not materially impact operations or profitability. Low capacity factor units do not benefit enough from lower minimums at the margin to change operations significantly.

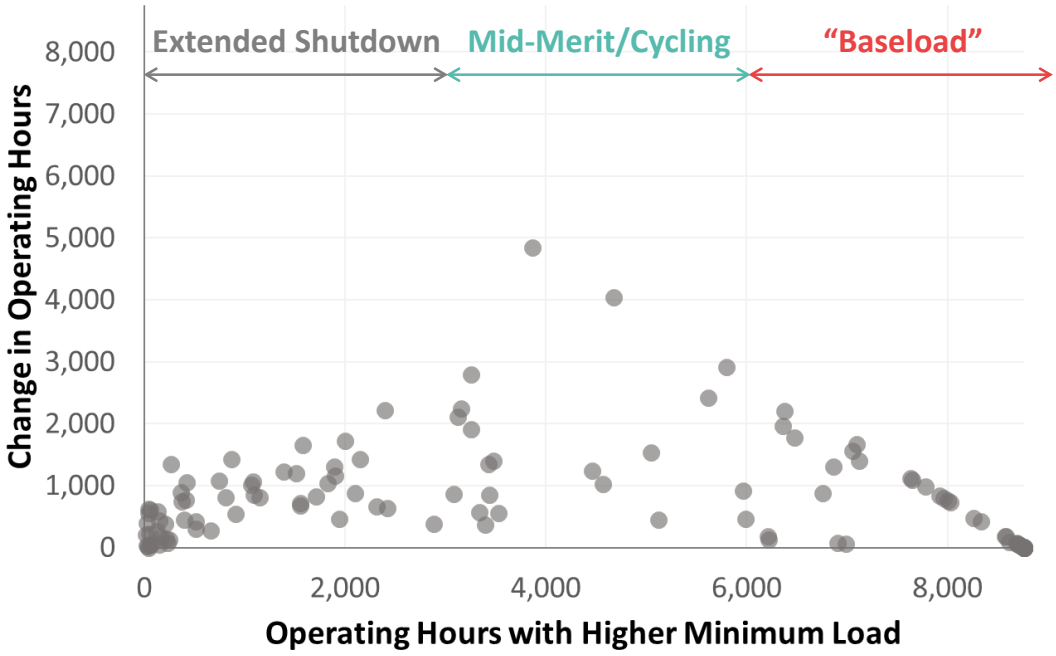


Figure 4-3
Changes in operating hours with lower minimums relative to the operating hours at higher minimums in all regions, scenarios, and asset classes

Although operating at lower minimum loads increases a unit's heat rate (and consequently its emissions intensity), these changes are modest due to the limited time and generation at minimum load operations under many conditions. Overall, total emissions change more than the emissions intensity with lower minimum loads, but both are likely to increase only slightly for the scenarios considered in this analysis.

Changes in Net Revenues with Lower Minimums

Figure 4-4 compares changes in net revenue (i.e., revenues received by a unit less operating costs) and increases in operating hours across all regions, policy scenarios, and asset classes with lower minimum generation levels. Higher startup costs are shown in yellow, and lower startup costs are shown in green.

There is a low positive correlation between increased operating hours and net revenues from lower minimums. In other words, as lower minimum loads increase the number of hours a unit spends online, there is an increase in that unit's net revenues.

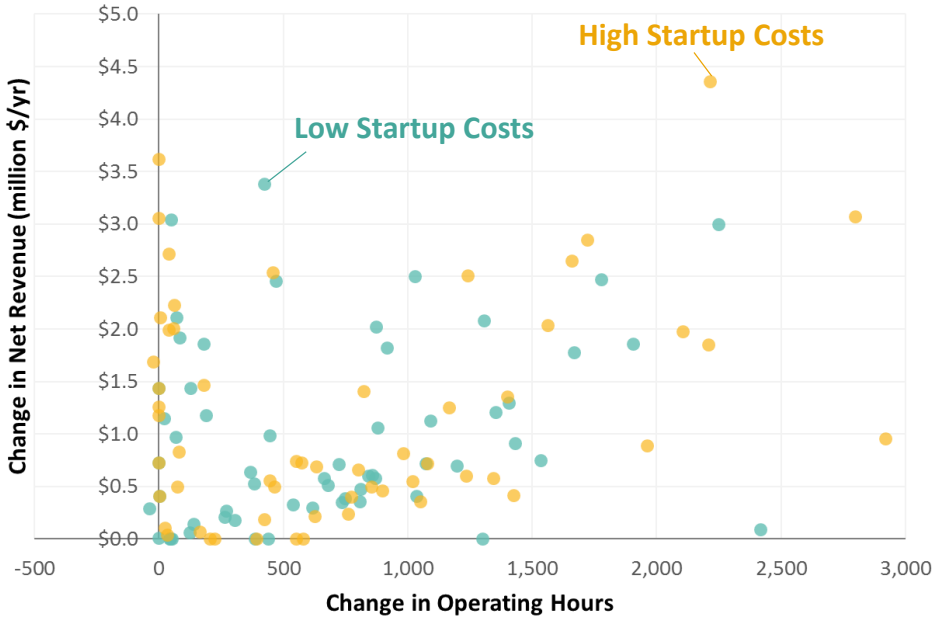


Figure 4-4
Changes in net revenues and operating hours with lower minimums in all regions, scenarios, and asset classes

Revenues from lower minimum generation levels vary across scenarios, as Figure 4-5 demonstrates for a new NGCC unit in Texas. Values are shown for the high minimum generation level (i.e., 50% of maximum output) and low level (20%). Under scenarios where lower minimum generation changes the operating profile, total annual operating margins do not change as much as dispatch, as increases in revenue are roughly offset by higher costs and startups are a small fraction of total operating costs.

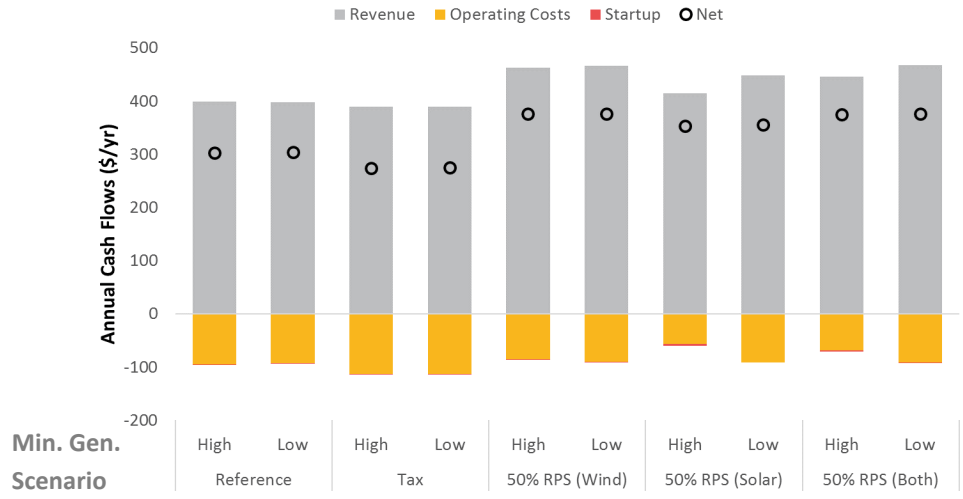


Figure 4-5
Changes in annual operating revenue for a new NGCC unit in Texas across scenarios

To quantify the value of increased operational flexibility, Figure 4-6 shows changes in net revenues with lower minimum loads. Individual points in the scatter plot represent values for specific regions and assets, and values are separated by policy scenario and startup costs across the horizontal axis. For example, lower minimum loads in the reference case lead to an increase in median annual revenues of about $1 million. In the CO_2 tax scenario, where the carbon price is reflected in dispatch offers and rearranges the merit order based on the carbon intensity of output, lower minimums could increase median annual revenues by almost $2 million. Variation within a scenario indicates that decreased minimum operating loads can lead to larger changes for units under certain policy and regional conditions. For example, one unit shown in the reference policy scenario could increase annual net revenues by almost $4.5 million, even though the median outcome is over 75 percent lower.

Figure 4-6 indicates that lower minimum loads can alter net revenues even for units in grids without significant variable renewable deployment. Lower minimum generation levels are most valuable (on average) under a CO_2 tax scenario, especially as more coal units switch to mid-merit dispatch (as shown in Figure 4-7). Depending on the policy stringency and timing, carbon pricing alters retirement and dispatch decisions for generators. The $16/t-$CO_2$ tax scenario investigated in this paper is not high enough to induce retirements for all coal capacity, but the tax increases dispatch costs for coal plants and consequently increases the frequency of cycling and hours with negative operating margins, which significantly increases the value of lower minimum generation levels for these units. Net profitability impacts are similar across the three 50% RPS scenarios, and higher renewable deployment (especially during seasons with lower load and higher renewable output) induces seasonal layups, which lower the value of flexibility.

Note that the relative value of lower minimums depends on changes in net revenues compared to baseline net revenues with higher minimums. Although operational changes are more significant in absolute terms, differences in net revenues are small in relative terms for many units but may be more significant for lower-profitability assets that are barely covering fixed costs. Under scenarios where lower minimums alter dispatch, net revenues generally do not change as much owing to differences in revenues being roughly offset by cost changes. Additionally, startups are a small fraction of total operating costs for many units, which means that avoiding these events through lower turndown operations may not markedly change profitability.

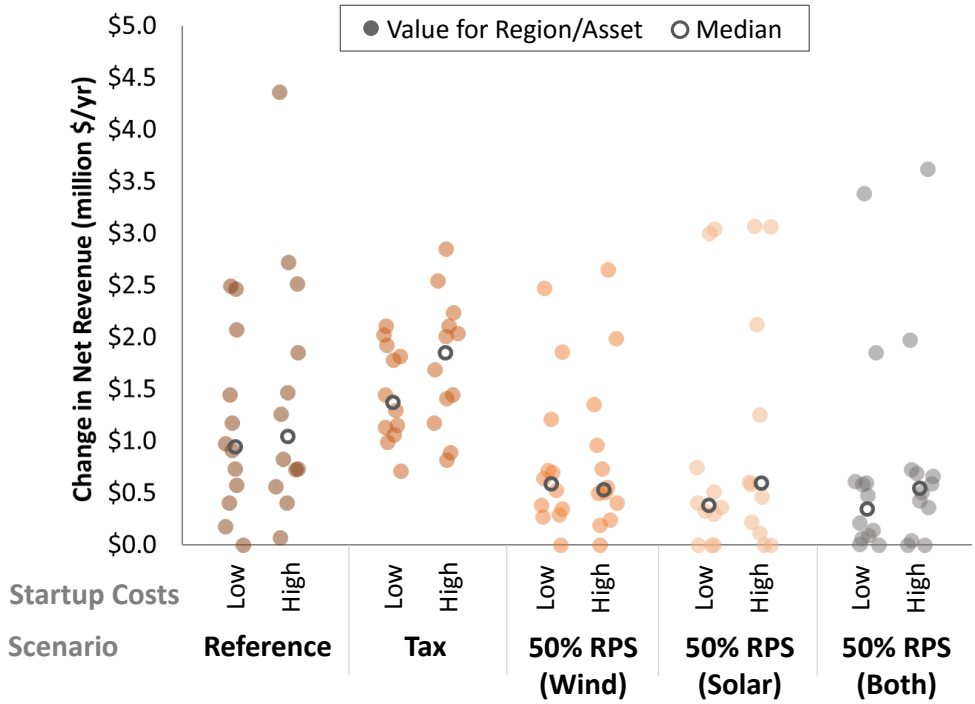


Figure 4-6
Changes in net revenue with lower minimums for different scenarios and startup costs (horizontal axis) for specific regions and assets (dots)

Figure 4-7 shows changes in net revenue sorted by three asset types: existing coal, new NGCC, and existing NGCC. Lower minimum load levels are more valuable for new NGCC units than the existing NGCC units, since new NGCC units have lower heat rates (i.e., higher efficiencies and lower short-run marginal costs) are closer to mid-merit for the regions and scenarios examined here. Capacity factors are lower for existing NGCC units due to their higher dispatch costs. Wider coal variation reflects different dispatch patterns across regions and scenarios due to different fleet capacity mixes, resources, policies, and transmission. As mentioned earlier, changes in net revenue with lower minimums are often higher under regions and circumstances without seasonal layups.

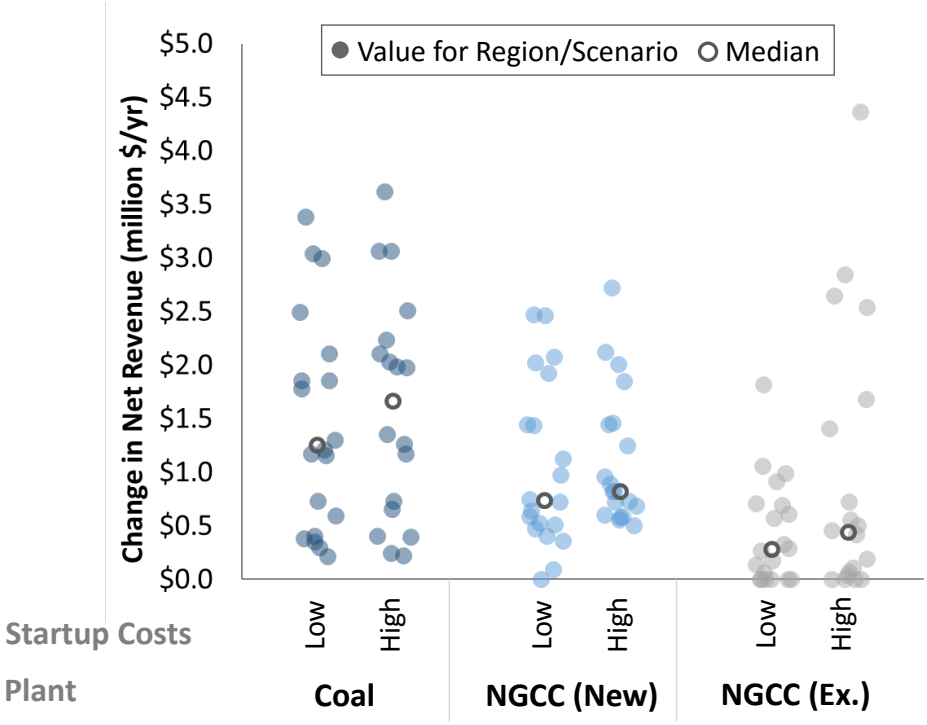


Figure 4-7
Changes in net revenue with lower minimums for different assets and startup costs (horizontal axis) for specific regions and scenarios (dots)

Another consistent finding shown in Figure 4-6 and Figure 4-7 is that lower minimum generation levels are typically more valuable when startup costs are higher but only by a modest amount. Higher startup costs have countervailing effects when minimum generation is lower. On one hand, when a unit is already online, it may spend more hours at these minimum generation levels to avoid costly startups. On the other hand, when a unit is offline, the higher opportunity cost of commitment may prevent startups.

Sensitivity to Ancillary Services Revenues

Analyses in previous sections assume that net revenues account only for power sales (i.e., in energy and capacity markets), but another benefit of staying online at minimum generation levels is the ability to participate in reserve markets if such markets exist. Figure 4-8 demonstrates the changes in net revenue with lower minimum loads across different assumed levels of spinning reserve prices (in $/MW-h terms). Reserve prices are exogenously assumed and are not the result of a system optimization to determine likely market-clearing prices in individual hours depending on the capacity mix, especially since such estimates are uncertain and highly dependent on specific scenario assumptions.

Overall, Figure 4-8 suggests that ancillary services revenues can increase the value of enhanced operational flexibility, especially if value stacking is possible (i.e., if revenues from reserve provision are incremental to energy and capacity market revenues). NGCC units benefit most from reserve revenues due to higher number of hours at minimum generation when they have capacity headroom.

Broadly, ancillary services revenues can boost the economics of flexible operations, but these markets are uncertain and potentially thin (Ela and Tuohy, 2016).

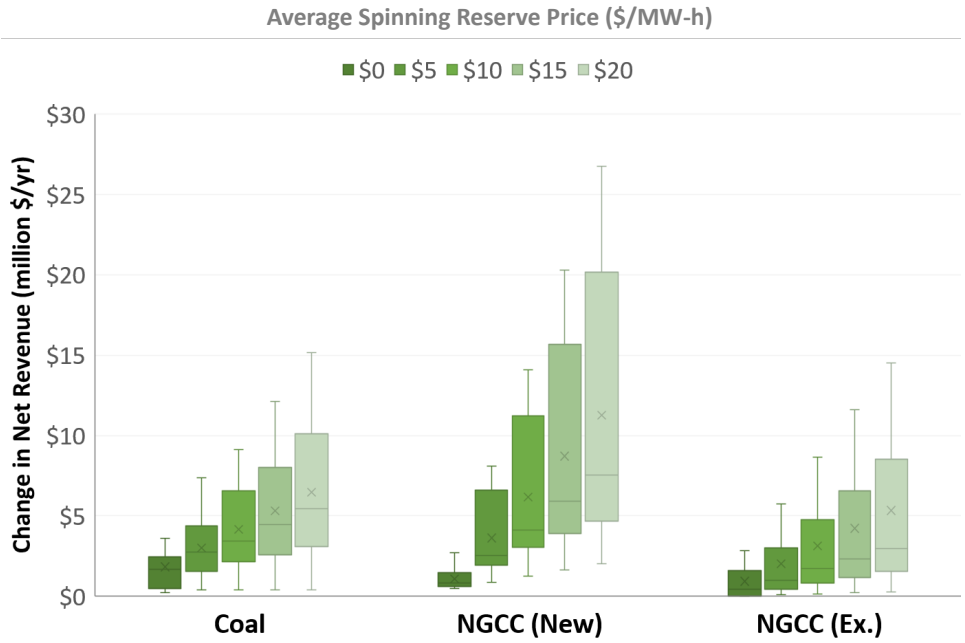


Figure 4-8
Changes in net revenue with lower minimums for different assets across different spinning reserve price assumptions

An implication is that system forecast errors likely become more important to track for asset owners and system operators over time. Forecast errors impact reserve needs and prices and also are essential for determining least-cost commitment schedules for plant operators, especially if startups are costly. Better understanding diurnal and seasonal uncertainty in load, renewables, and other time-series forecasts will likely become more important over time as wind and solar deployment increase and end-use electrification changes load shapes.

References

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Section 5: Conclusions

Flexibility (in this analysis, through reducing a generator's minimum load) has the potential to reduce energy market losses, mitigate wear-and-tear costs, and increase its reserve range. This report examines the economic value of this flexibility and variation across different regions, generation asset types, and market environments using US-REGEN's soft-linked capacity planning and unit commitment models. Examining changes in net revenue across scenarios, model results suggest that lower minimum loads are most valuable when policies rearrange the merit order, mid-merit units are considered, regions/scenarios do not force seasonal layup, and units are more flexible than other comparable generators. Ancillary services revenues may increase the value of enhanced operational flexibility, but the market outlook and depth for reserve provision are uncertain.

Expected market returns for coal- and natural gas-fired generators are shaped by future market and policy conditions for many regions, and for many sensitivities investigated in this analysis, operational characteristics are a second-order driver of profitability. Flexibility can allow assets to adapt to bearish markets, and the analysis in this paper indicates that preparations for flexible operations may increase net revenues across many possible futures. Significant variable renewable energy deployment may decrease on/off cycling by increasing the frequency and duration of extended shutdowns, and these shutdowns and seasonal layups ultimately decrease the likelihood that lower minimums will improve net revenues.

Ultimately, the modest changes in net revenues from increased operating ranges for many units and scenarios suggest that interventions that primarily require changes in operational practices instead of capital investments are more likely to be economic. Enhanced plant flexibility impacts operational profiles more than annual margins under many circumstances. Given the extensive literature referenced in Section 1 indicating the system value of flexibility, the results of this analysis raise questions about possible discrepancies between the public value of system flexibility and the incentives for generators to provide such flexibility. Further research is required to quantify this possible gap and, if it is substantial, to identify market reforms and remuneration required to manage such externalities.

This analysis only examined changes in minimum load for a single unit at a time. However, if all similar units in a region are able to decrease their minimum generation levels, then the value of this flexibility would be lower for any single unit. Future work should examine wider range of cycling costs, both in terms of

costs of output adjustments (and not just startups) and across a wider sensitivity range informed by observed experience. Since damage mechanisms from cycling may give rise to "lumpy" costs, future work should also use a wider range of cost estimates associated with startups and cycling and incorporate changes in non-cost parameters (e.g., outage rates) as part of a value of flexibility analysis.

Appendix A: Analytical Model

This section presents a simplified analytical model to provide intuition for the results in later sections. These calculations also motivate the use of more detailed numerical models, which are discussed in Section 2.

A stylized economic unit commitment and dispatch problem for a day-ahead electricity market can be formulated as follows. Based on the notation from O'Neill, et al. (2005) and Hogan and Ring (2003), let:

q_{it}	output of unit i in time t
$C_i(q_{it})$	bid-based convex cost function for i
S_i	startup cost for i
z_{it}	integer commitment variable for i
$q_{min,max}$	minimum and maximum output for i
d_t	total demand in time t

For an individual hour *t*, consider the single-period simplification of the system operator's cost-minimization problem without transmission constraints, system losses, fixed demand, and security commitments:

$$\min_{q_{it},\, z_{it}} \sum_i C_i(q_{it}) + \sum_i S_i\, z_{it}$$

$$\text{s.t. } \sum_i q_{it} = d_t,$$

$$q_{it} \geq z_{it} q_{min} \quad \forall i,$$

$$q_{it} \leq z_{it} q_{max} \quad \forall i,$$

$$z_{it} \in \{0,1\} \quad \forall i.$$

The unit commitment problem determines an operating schedule for each plant that minimizes total operating costs (including fuel, operations, maintenance, and startup costs) subject to operational and system constraints. The constraints represent market-clearing, operating constraints for minimum and maximum

load (given binary state variables z_{it} for unit *i* in period *t*), and integrality constraints, respectively.

Suppose we have shadow prices for the four varieties of constraints in the optimization problem above (p_t, λ_{it}, θ_{it}, ρ_{it}) for a well-behaved problem with suitable $C'_i(q_{it}) = dC_i(q_{it})/dq_{it}$. The first-order conditions become:

$$p_t = C'_i(q_{it}) - \lambda_{it} + \theta_{it} \quad \forall i,$$

$$\rho_{it} = S_i + \lambda_{it} q_{min} - \theta_{it} q_{max} \quad \forall i,$$

$$\lambda_{it} \geq 0, \theta_{it} \geq 0 \quad \forall i.$$

The market-clearing wholesale power price p_t is the same for all generators in the market in time *t*, but ρ_{it} is generator-specific. Note that this stylized example assumes that a unit's startup cost S_i is not a function of its downtime, which is relaxed in the numerical model in later sections to account for different costs of hot and cold starts.

The decentralized self-commitment problem for each generator has a similar optimization structure, but the objective function is framed from a unit's profit-maximization perspective (instead of a cost-minimizing one):

$$\max_{q_{it},\, z_{it}} \pi_{it} = p_t q_{it} + \rho_{it} z_{it} - C_i(q_{it}) - S_i z_{it}$$

$$\text{s.t. } q_{it} \geq z_{it} q_{min},$$

$$q_{it} \leq z_{it} q_{max},$$

$$z_{it} \in \{0,1\}.$$

where π_{it} is the profit of generator *i* in period *t*. Assuming a piecewise linear generator cost function $C_i(\cdot)$, the optimal solution to the decentralized problem is (q^*_{it}, z^*_{it}), and profits for all generators are exactly zero, per a Walrasian competitive equilibrium with non-convexities associated with the integer formulation described in O'Neill, et al. (2005).

Thus far, the exposition in this section has focused on a single-period model, but the optimization problem from an individual unit's perspective becomes considerably more complicated when quasi-fixed costs and intertemporal dependencies are considered simultaneously. In particular, startup and shutdown costs may lead a generator to remain online during low wholesale price hours and accept operational losses in order to profit from higher prices in later periods. These intertemporal constraints on production decisions and costs in the dynamic optimization problem can increase the computational complexity of commitment decisions. Ede, et al. (2000) demonstrate how a strategy for cycling and operations in a multi-period game can be determined through backward induction. For instance, consider the two-period case $t \in \{1,2\}$, where *t=1* is a

low-demand, low-price period and *t=2* is a high-demand, high-price period. Generator *i* in Period 1 determines possible Period 2 payoffs:

$$\pi_{i2} = p_2 q_{i2} - C_i(q_{i2}) - \min[S_i, C_i(q_{i1}) - p_1 q_{i1}]$$

where the rightmost term is the debt from Period 1. Assuming perfect foresight, the optimal first-stage strategy depends on whether it would be profitable to run during the low-price period (*t=1*), even though the unit would incur losses, in anticipation of higher aggregate profits across all periods. Note that there are different optimal strategies for generators depending on their initial commitment states. If a unit is already committed, it will stay online in Period 1 if the operating losses are less than or equal to the payoff if the unit were to go offline and incur S_i during the high-price *t=2*.

It can be shown (Ede, et al., 2000) that the optimal bidding strategy for $q_{it} > q_{min}$ is to stay online when:

$$p_1 \geq C_i(q_{min}) - \frac{S_i}{q_{min}}$$

In other words, generator *i* should stay online if negative operating margins from Period 1 are less than the normalized startup costs. This equation illustrates how a unit's profitability and commitment strategy depend on unit-specific characteristics and flexibility attributes like q_{min} (i.e., the unit's minimum load limit), S_i (i.e., the unit's startup costs), and $C_i(q_{min})$ (i.e., production costs, which are a function of the output-dependent heat rate). In particular, lowering the unit's minimum load level (q_{min}) increases the range of p_1 where the profit-maximizing strategy is to remain online. Also, higher startup costs increase a unit's incentive to maintain continuous dispatch if already committed (ceteris paribus).

Ultimately, the two conditions where lower minimum loads increase net revenue are periods when a unit is currently running at minimum load to avoid startup costs and when a unit is offline but could be online at minimum load in order to capture high-price hours later in the horizon that it would otherwise miss. As the analysis in later sections will show, the economic value of this flexibility depends on the frequency of these conditions and differences in net revenues, which depend critically on characteristics of the system (e.g., market prices) and characteristics of the generator (e.g., turndown levels and startup costs).

The calculations in this section underscore the complexity of unit commitment and dispatch decisions even in a simplified setting with a limited number of periods. The main sections of the report describe more sophisticated numerical models that can incorporate more realistic and detailed decisions.

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