The Cost of Preventing Baseload Retirements

A PRELIMINARY EXAMINATION OF THE DOE MEMORANDUM

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Notice

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I. Introduction and Summary

The Trump Administration has responded to continued retirements of coal and nuclear units by proposing policies intended to prevent any further retirements of the traditional "baseload" fleet, under the premise that such retirements impair grid reliability, "resilience" and, more recently, national security. The first attempt at imposing a policy designed to deter retirements occurred when the U.S. Department of Energy (DOE) proposed a rule for Federal Energy Regulatory Commission (FERC) consideration in October 2017. That proposal, which would have required cost-of-service based payments to merchant coal and nuclear plants in certain Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) regions, was unanimously rejected by the FERC in January 2018. The FERC decided instead to examine the premise of grid resilience in greater depth at a regional level.

The second major policy attempt was described in a May 31, 2018 article by *Bloomberg Energy,* which revealed a draft memorandum ("Draft Memo") by the DOE that outlined a proposal to prevent retirement of certain generation plants ("Subject Generation Facilities" or SGFs) that might, according to the DOE, affect grid resilience in all regions of the U.S. (*i.e.*, not only RTOs).[1] Although the Draft Memo did not disclose the identity of the SGFs, or describe specific implementation mechanisms, the stated intent was to prevent any retirements of "fuel secure" generating capacity (primarily coal and nuclear units) in the near term. The policy would require system operators and load-serving entities to purchase energy and/or capacity from designated SGF plants for a period of two years. The day after the release of this Draft Memo, President Trump directed the Secretary of Energy to "prepare immediate steps" to stop coal and nuclear plants from retiring.[2]

This Report discusses some of the policy design issues that the Draft Memo raises and presents a range of illustrative estimates of the potential direct cost of implementing a program of mandated purchases to prevent or deter coal and nuclear retirements. In this preliminary analysis, we do not assess the extent of likely negative impact on competitive markets nor address the magnitude, if any, of potential benefits.

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[1] "Trump Prepares Lifeline for Money-Losing Coal Plants," *Bloomberg*, May 31, 2018, posted at https://www.bloomberg.com/news/articles/2018-06-01/trump-said-to-grant-lifeline-to-money-losing-coal-power-plants-jhv94ghl

[2] "Trump Orders Perry to Stop Coal, Nuclear Retirements," *Utility Dive*, posted at https://www.utilitydive.com/news/trump-orders-perry-to-stop-coal-nuclear-retirements/524805/

Our observations and key conclusions are as follows:

1. Current and likely future wholesale market conditions will continue to add pressure on some coal and nuclear plants to retire even if a financial support mechanism is put in place.
2. The Draft Memo described in broad and general terms the intent and high-level structure of the proposed policy. Two primary design elements were not articulated: how the Government might select the SGFs for inclusion into the program, and what financial mechanisms would be employed to deter the retirement of those plants. Decisions regarding both of these elements will have conflicting impacts on policy attributes such as administrative feasibility, effectiveness, and cost.
3. Without additional information regarding how the DOE might select SGFs or what decision criteria might determine eligibility, we assume that the policy will apply to all coal and nuclear plants currently operating in the U.S. that are located in 44 states.[3]
4. We examined two approaches DOE may consider to provide additional support to coal and nuclear plants, based on a preliminary reading of the Draft Memo. We first estimate the impacts of a policy that would give all coal and nuclear plants an out-of-market annual payment of $50 per kilowatt of capacity (which is roughly the average operating shortfall for plants that operate at a deficit) if they continue to operate. Assuming that the entire current fleet of coal (235.8 GW) and nuclear (99.1 GW) would continue to operate and receive such a capacity payment of $50/kW-year, that would imply a direct cost of $16.7 billion dollars per year in the form of out-of-market payments via contracts or other mechanisms.
5. We also examine a less expansive and less uniform approach that would attempt to tailor out-of-market payments to exactly cover estimated operating shortfalls. If such a policy were extended to all coal and nuclear plants that we estimate currently experience operating shortfalls (plants with a total capacity between 226.6 GW and 297.4 GW) the policy cost would be between $9.7 and $17.2 billion per year. The range of impacts arises from the use of different cost data to identify plants with operating shortfalls and to estimate the size of shortfalls. Annual payments would be in the range of $43 - $58/kW, but would apply only to those units that we calculate would otherwise experience negative earnings. Because these estimates rely on an idealized ability of the DOE to identify plants that are currently experiencing shortfalls and to sculpt a payment scheme to precisely compensate for the shortfall, the cost estimates represent a lower bound of adopting such an approach.

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3 States without coal or nuclear units include Alaska, Hawaii, Idaho, Maine, Rhode Island and Vermont. It is also possible that DOE may include oil-fired and dual-fuel units with adequate storage into the list of SGFs, since the Draft Memo included these plants in the category of "fuel-secure" plants.

6. If the Administration adopts a financial support formula that includes a return on invested capital, as it proposed last year, this would substantially increase the amount of out-of-market payments. We conservatively estimate that cost-of-service recovery (including embedded capital) could at least double the policy cost to between $20 and $35 billion per year.

The magnitude and range of these estimates indicate the significant impact of yet-to-be determined policy design parameters and the uncertainty of the scope and impact of those choices on cost. These estimates also do not account for any distortionary effects on the operation of competitive wholesale markets, or the long-run implications of re-regulating a substantial portion of the generation fleet. Arresting the retirement of uneconomic generating assets in the current market environment will likely prove quite costly.

II. Administration Policy to Address Coal and Nuclear Retirement and Reliability

One of the prominent themes of the Trump presidential campaign was to bring back coal, which had suffered significant losses in production and employment that the candidate attributed to environmental rules.[4] While the Administration has moved to repeal or rescind a variety of environmental rules finalized or proposed during the prior administration, the primary driver of the current challenges for coal plants are flat power demands combined with low natural gas and wholesale power prices, not environmental rules.[5] These market conditions are expected to persist along with new announcements of coal and nuclear retirements. While regional grid authorities, reliability organizations and integrated electricity companies have indicated that these pending retirements do not threaten the reliable provision of electric power, the Administration has taken a different view.

4 "President Obama has done everything he can to kill the coal industry"…. "Regulations that shut down hundreds of coal-fired power plants and block the construction of new ones"… "We're going to save the coal industry and other industries threatened by Hillary Clinton's extremist agenda." Candidate Trump's energy speech in Bismarck North Dakota found at http://blog.4president.org/2016/2016/05/donald-j-trump-formal-policy-address-on-energy-at-the-williston-basin-petroleum-conference-in-bismar.html

5 The environmental rule that most directly influenced coal unit retirements, the Mercury and Air Toxics Standards (MATS), had a compliance date of 2015. Between 2010 and 2015 about 42 GW of coal units retired; since currently operating coal units must comply with MATS the current retirement pressures arise through market conditions.

A. The September 2017 DOE Notice of Proposed Rulemaking

On April 14, 2017, Secretary of Energy Rick Perry issued a memorandum instructing DOE staff to examine electricity markets and reliability. The subsequent report was issued on August 23, 2017 (hereafter the "DOE Staff Report") and covered a substantial range of electricity market topics, including resilience and fuel security. The DOE Staff Report also noted that the growing significance of natural gas-fired capacity meant that electric system reliability—and potentially resilience—may depend on the uninterrupted availability of natural gas supplies, but did not appear to prioritize this topic.[6] Nevertheless, DOE issued a Notice of Proposed Rulemaking (NOPR) the following month that instructed the Federal Energy Regulatory Commission (FERC) to expeditiously consider a rule to prevent retirement of solid fuel generating units in certain Regional Transmission Organization (RTO) and Independent System Operator (ISO) regions. The NOPR was based almost exclusively on the perceived threat to grid reliability and resilience arising from the retirement of "fuel secure" coal and nuclear capacity and rising dependence on natural gas generation.

The policy outlined in the DOE NOPR was designed to deter merchant coal and nuclear plant retirements by giving additional payments to plants with extensive (*i.e.*, 90 days) on-site fuel inventories through changes in RTO/ISO tariffs that would mimic traditional cost of service arrangements. These payments would, in turn, have been recovered through charges paid by load-serving entities (LSEs) who purchase wholesale power. The proposed rule raised a host of issues and induced supportive comments from some coal and nuclear interests, and antipathy from nearly everyone else. In particular, the cost of the rule (between $4 and $11 billion per year)[7] appeared much higher than any potential value for the DOE's vaguely-defined concept of resilience, along with concerns that the rule would undermine competitive wholesale market operations as well as raise legal issues of compatibility with the Federal Power Act. The NOPR was rejected in a unanimous vote by the FERC in January 2018, and simultaneously FERC initiated a new proceeding (Docket No. AD18-7-000) to evaluate the resilience of the bulk power system in RTO/ISO regions.

By March 2018, FERC had received numerous comments from ISOs/RTOs in Docket AD18-7-000, answering a set of questions FERC posed regarding the resilience of the bulk power system. The responses share some common themes, such as the need for cybersecurity and robust

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6 *Staff Report to the Secretary on Electricity Markets and Reliability*, U.S. DOE, August 2017, found at: https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

7 *Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule*, Metin Celebi, Judy Chang, Marc Chupka, Sam Newell, Ira Shavel, October 23, 2017, posted at http://files.brattle.com/files/11635_evaluation_of_the_does_proposed_grid_resiliency_pricing_rule.pdf

transmission planning. However, each RTO/ISO emphasized specific regional concerns, accounting for differences in existing infrastructure (*e.g.*, generation mix and reliance on imported fuel) and differences in the nature of threats (*e.g.*, types of severe weather, earthquakes, or fuel supply disruptions). RTOs/ISOs also expressed different views regarding meaningful distinctions between reliability (as traditionally understood as resource adequacy and operational reliability) and the emerging understanding of resilience. Some emphasized potential reforms in market design and pricing as a way to ensure robustness by shaping fuel and generation choices to avoid disruption. Others emphasized the concept of disaster preparedness and establishing procedures to react resourcefully to minimize damage and rapidly recover from outages. Additional comments from stakeholders echoed earlier comments in the DOE NOPR Docket.

B. Current Policy Deliberations and the Draft Memorandum

After the FERC rejected the DOE NOPR, coal suppliers along with coal and nuclear generation interests continued to press the issue of resilience to provide the basis and rationale for significant market interventions. For example, FirstEnergy Solutions (FES) filed a request under Section 202(c) of the Federal Power Act and Section 301(b) of the DOE Organization Act to declare an emergency in PJM that would require the DOE to arrange contracts and provide compensation to coal and nuclear plants to keep them operating. This request expanded on precedent, as the 202(c) authority has typically been used to target specific plants to preserve local reliability on a temporary basis. In addition, discussions emerged about using the Defense Production Act of 1950 to mandate contracts between coal and nuclear plant owners and RTOs for baseload output under the rationale that U.S. national security is threatened by unaddressed reliability or resilience risks.

These speculations and rumors culminated in a draft DOE memorandum ("Draft Memo") released by *Bloomberg* on May 31, 2018 that revealed DOE's potential plans to use its powers under Section 202(c) of the Federal Power Act <u>and</u> the Defense Production Act of 1950 to prevent early retirement of certain generation plants.[8] Two paragraphs on page 3 of the Draft Memo describe the outlines of the policy:

> To promote the national defense and maximize domestic energy supplies, federal action is necessary to stop the further premature retirements of fuel-secure generation capacity while DOE, in collaboration with other federal agencies, the States, and private industry, further evaluates national security needs and additional measures to safeguard the Nation's electric grid and natural gas pipeline infrastructure from current threats. To that end, as described below, it is

[8] "Trump Prepares Lifeline for Money-Losing Coal Plants," *Bloomberg*, May 31, 2018, posted at https://www.bloomberg.com/news/articles/2018-06-01/trump-said-to-grant-lifeline-to-money-losing-coal-power-plants-jhv94ghl.

> necessary and appropriate for the Department to: (1) issue orders pursuant to its authority under the Defense Production Act of 1950 (DPA) and the Federal Power Act (FPA) to temporarily delay retirements of fuel-secure electric generation resources, while we (2) continue our analysis of, and take prompt action to address, the comprehensive resilience needs of our electric generation system, including specific actions to support defense critical energy infrastructure in the event of attack.
>
> The Department is exercising its DPA and FPA authority by directing System Operators (as defined in the Directive), for a period of twenty-four (24) months, to purchase or arrange the purchase of electric energy or electric generation capacity from a designated list of Subject Generation Facilities (SGFs) sufficient to forestall any further actions toward retirement, decommissioning, or deactivation of such facilities during the pendency of DOE's Order. DOE also is directing SGFs outside of the RTO/ISO territories to continue generation and delivery of electric energy according to their existing or recent contractual arrangements with Load-Serving Entities. DOE's Order establishes a Strategic Electric Generation Reserve (SEGR) to promote the national defense and maximize domestic energy supplies. This prudent stop-gap measure will allow the Department further to address the Nation's grid security challenges while the Order remains in force.

The lack of detail suggests that many policy parameters remain undecided at this point. The plan apparently would require system operators and load-serving entities to purchase energy and/or capacity from "Subject Generation Facilities" (SGFs) for a period of two years, but that is the extent of the policy described. We believe that there are two key aspects that will determine in large part the impact of the program. The first involves the universe of plants to which the Order applies, and the second is the implementation mechanism(s) of the Order.

1. Defining Subject Generation Facilities

If the proposal outlined in the Draft Memo is implemented, this Order could expand the scope of affected coal and nuclear plants compared with the previous DOE NOPR (merchant units in certain RTO regions with 90-days of fuel supply on-site) to conceivably include any coal and nuclear plant in every region, including non-RTO regions. In addition, some oil-fired and dual-fuel units might also qualify as SGFs based on the discussion of resources with secure on-site fuel supply. However, nothing is currently known about how DOE might define the SGF units or establish criteria for inclusion. This might include, for example, whether units have to announce a pending retirement; whether they have to demonstrate that they are losing money (or calculate how much they are losing); whether units can self-nominate; whether the list is a one-time designation or the number of SGFs could change over time. All of these choices will affect the cost and efficacy of the program.

While we can only speculate about the ultimate list of SGFs, it is important to understand the fundamental tension between a one-time, immutable list chosen by the DOE and a list that might grow as a result of changing conditions or a self-nomination procedure. Assuming that the

DOE applies some selectivity to a one-time static list of SGFs, the criteria used could require a great deal of information and/or judgment and the payments might not be effective at preventing all units from retiring. For example, a one-time list of SGFs could include only those units that have announced a pending retirement, which would target some obvious candidates for support. If those units do not retire, however, then other units who do not receive financial support but also may be losing money (and expected that other plants' retirements might improve market conditions) might retire instead—leading to out-of-market payments but nevertheless ending up with retirements anyway. But if unit owners could qualify for payments (perhaps by demonstrating current impairment or the announcement of an intent to retire) then the list of units (and attendant costs) could grow substantially—and potentially create a similar displacement phenomenon whereby SGFs do not retire but force others into retirement or encourage enlistment in the list of SGFs. In these cases, the degree of financial support from the policy will also determine the incentives for enlisting in the program.[9]

Determining a mechanism for including units on the list of favored SGFs is not a trivial exercise, unless the list includes all plants (a universal approach) or the selection is entirely arbitrary. An example of a universal approach was in the DOE NOPR, through which all coal and nuclear plants (located in certain RTOs/ISOs and with a 90-day supply of fuel) were eligible for payments sufficient to cover their cost of service (including a return on invested capital). Between these extremes lies some methodology or criteria that determine inclusion, presumably based on a unit's likelihood to retire or the impact its retirement might have on regional reliability or resilience. Composing a list of SGFs in this fashion would involve a substantive analysis in order to be credible.

2. Defining the Financial Support Mechanism

Regardless of the SGFs, the implementation of the financial support required to keep units from retiring poses another set of tradeoffs and tensions. One very tractable, but not particularly cost-effective approach would be to require a payment for all plants scaled to the generating capacity—*e.g.*, a uniform capacity payment denominated in dollars per kilowatt-year. Thus, a $10/kW-year payment would provide $2 million per year for a 200 MW unit and $5 million for a 500 MW unit. This would improve the economics of all units, but only prevent some from retirement, as $10/kW-year might not be large enough to assist a unit that loses $50/kW over the year, and would represent a windfall to a currently profitable unit. While simple to compute and entirely predictable in overall cost, a uniform capacity payment would not be effective at preventing all retirements unless it were very high—in which case it would also be extremely expensive and provide assistance in excess of need for many units.

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9 We describe the financial support obtained through mandatory contracts as "payments" or "costs" of the program. We do not presuppose any specific mechanism in using this terminology, except to recognize that (1) the Order would involve some financial compensation (beyond revenues obtained in the market) and (2) some entity other than the recipient unit owner would have to provide that compensation, *e.g.*, ratepayers, non-effected unit owners, or taxpayers.

To limit costs, a policy that financially supports generating units that otherwise might retire in the near term could supplement market revenues just enough to cover going-forward costs. That would provide sufficient support to continue operations, but no more. The precedent for such an arrangement is "reliability-must-run" (RMR) contracts, which are short-run arrangements that are used infrequently to ensure local grid reliability when a specific generator retirement might compromise reliability, at least until an alternative solution is identified and implemented. This is a unit-specific, temporary contract; its duration typically is contingent on external events (*e.g.*, the time it takes to implement the necessary reliability project). The problem with this precedent is that most RMR contracts are negotiated between a unit owner and RTO/ISO or else result from the decisions in a contested, evidence-based proceeding. Either way, setting the amount and structure of the financial support needed to prevent retirement takes time, effort and information to which the government does not typically have access.

Alternatively, the Order could mandate a generic level of support that would ensure continued operation of all units, without a formal proceeding. In order to assure effectiveness at attaining the objective of preventing retirements or actions to further retirement, however, the level of support would be generous by design. For example, the DOE NOPR included a return on invested capital in the financial support, a subsidy beyond the amount necessary to cover going-forward costs and forestall retirement. Prior investments are sunk and have no bearing on marginal decisions such as incurring going-forward costs vs. retirement for merchant plants. For plants owned by rate regulated entities, regulators determine whether and how much prior investment can be recovered.

The form of such payment would also affect the costs. In RTO regions, a capacity payment (augmenting an organized capacity market where such markets operate) could suffice to retain capacity, but the DOE order could, as a matter of policy, dictate an energy payment to keep certain plants operating at desired levels. The costs of either policy would depend on how the payments were structured, and the impact on customers in the short run and long run would depend on how the payments are furnished from market participants and any impact on prices in the short and long run.

In non-RTO regions, the memo implies that the SGFs would continue generating and delivering energy (the memo is silent on capacity in these regions) "according to their existing or recent contractual arrangements with Load-Serving Entities." This language is somewhat ambiguous, but seems to suggest that the DOE would order LSEs to continue contracts (or reinstate recently expired contracts) with specific generators even if they otherwise would economically terminate or renegotiate terms to conform to current market conditions. Vertically integrated utilities would presumably receive compensation in lieu of potentially retiring their own SGFs (potentially creating conflict with State regulators who find the retirement in the interest of the company and its ratepayers). Depending on the legal relationships, the government may have to provide direct compensation if the current or recent contracts were insufficiently remunerative to SGFs to prevent retirement or if State regulators do not approve retail rates to cover the cost of maintaining an unviable generating unit.

Other aspects of designing the support mechanism might prove problematic, in part because payments designed to induce (or compensate for mandated) continued operation will dull the incentive to mitigate risks or minimize costs. Owners of generating units that are nearing retirement often reduce their expenditures on operating and maintenance (O&M) because they do not expect long-run returns on sustained performance. These might be deemed "actions toward retirement, decommissioning, or deactivation of such facilities during the pendency of DOE's Order" that the order would presumably counteract—but that would require additional support to maintain O&M expenditures at higher levels that would sustain operation over the long run. Finally, the support for selected SGFs could reduce wholesale prices compared to what they otherwise might be, meaning that other plants could become further impaired and retire. It is likely that many generating units currently are not receiving enough revenue to cover going-forward costs, but have not decided or announced a retirement in the hope that market conditions (including prices rising due to other plant retirements) would permit continued operation. Because some markets will adjust to coal and nuclear retirements with higher capacity payments, for example, these additional revenues help surviving units stay in the market.[10] Thus payments to selected SGFs that simply encourage different plants to retire would not be effective at preserving existing capacity levels.

III. Analyzing Potential Implementation of the Draft Memorandum Policy

The policy outlined in the Draft Memo focuses on preventing coal and nuclear retirements, presuming that compensation for plants that otherwise would (or might) retire could arise from market and/or contractual arrangements.[11] To understand how various potential compensation mechanisms might work, we first undertake an assessment of current operating economics of U.S. coal and nuclear plants. Because we rely on publicly available data rather than proprietary unit-level information, our assessment is only approximate.

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10 For example, the most recent capacity auction in PJM resulted in RTO capacity prices increasing to $140/MW-day (from $77/MW-day in the previous auction) in part due to about 7 GW of less nuclear capacity clearing than the previous auction. See "2021-2022 Base Residual Auction Results," PJM Interconnection, May 23, 2018, posted at http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.

11 Because legal issues could arise under a policy of compulsory operation that does not provide adequate compensation for plants continuing to operate while losing money, we assume that the policy would involve out-of-market compensation.

A. Subject Generation Facilities

The Draft Memorandum identifies the "fuel-secure" generation resources as "nuclear and coal-fired power plants, as well as oil-fired and dual-fuel units with adequate storage'" but does not define the list of "Subject Generation Facilities" ("SGFs") that would receive compensation in return for delaying their retirement. In this analysis we focus on coal and nuclear plants, since the stated purpose of the proposed program is to deter the retirement of "fuel-secure" generation resources and we do not know how DOE might define "adequate storage" for the purpose of eligibility.

Figure 1 below shows the composition of the potentially eligible generation plants by type and region. We estimate approximately 334.9 GW of operating plants might be eligible under the proposal in the Draft Memo, i.e., the entire existing coal and nuclear fleet for which we have sufficient data to analyze. This fleet consists of 235.8 GW of coal-fired plants and 99.1 GW of nuclear plants, with two-thirds (67%) of this capacity located in RTO regions.[12] Only six states had neither a coal nor nuclear plant in this database: Alaska, Hawaii, Idaho, Maine, Rhode Island and Vermont.

Figure 1
Eligible Coal and Nuclear Generation Capacity (GW)

	RTO	Non-RTO	**Total**
Coal	160.1	75.7	235.8
Nuclear	65.2	34.0	99.1
Total	**225.2**	**109.7**	**334.9**

Sources and Notes: Using summer capacities in the "Generating Unit Capacity" dataset from ABB, Inc. Velocity Suite (2018).

Our primary unit-level metric is the annual operating surplus or shortfall, which we define as annual revenue received less annual cost incurred. We estimate this metric using calendar year 2017 data, which is a reasonable proxy for the next 2-3 years, since projections for natural gas prices and load growth suggest that market conditions are likely to stay fairly stable over that timeframe. The Appendix has details regarding the data and methodology we used to compute operating surplus/shortfall.

12 The entire generating unit dataset had an additional 298 coal-fired units that totaled 11.7 GW (average of 39 MW per unit). No generation was recorded for these units in the dataset, and most cost information was missing as well. Since we could not determine if these units actually generated electricity but did not report, or did not generate, we excluded them from our data and analyses.

B. 2017 Market Revenues

For units operating in RTO regions, we assume that the market-based revenues are limited to the sale of energy (at day-ahead energy prices at each plant's location) and the sale of capacity (in regional capacity auctions). We do not estimate any revenues from providing ancillary services. For units operating in non-RTO regions, there was no public information available for the market revenues. Therefore, we assume that these units received market revenues at the system lambdas (i.e., marginal cost of energy) reported by the electric utilities in the balancing areas where the units are located. It should be noted that system lambda does not produces actual cash revenues for units, but expresses the hourly value of the unit's output in terms of avoiding the incremental cost of a more expensive source of generation. This provides a proxy for market value of energy where price data is not available, but will not convey information about capacity or ancillary services value. Thus, lambda-derived prices probably understate somewhat the value of retaining regulated generation in non-RTO markets. While regulated units are not exposed directly to market prices, state commissions and the utilities themselves often view the viability of generating units in terms of market revenue.

C. 2017 Going-Forward Costs

We estimate the annual cost of keeping a generating unit available for operation and the cost of providing energy, sometimes called "going-forward" or avoidable costs because these costs are necessary to keep the unit operating and could be avoided through retirement. The annual operating and fuel expenses include the cost incurred for fuel used for generation and for materials, equipment and labor used in that year to operate, maintain, and repair the generation plant. To estimate annual operating and fuel costs, we relied on various public data sources to develop an estimated cost range in 2017 for potentially-eligible coal and nuclear plants. The Appendix provides a more detailed description of our approach and data sources use to estimate each of these cost components.

D. 2017 Operating Margin Outcomes

We estimated 2017 operating margins or earnings for all coal and nuclear units where we had sufficient data by subtracting going-forward costs from revenues.[13] We performed this calculation with four different scenarios of costs and used the highest and lowest overall cost cases (corresponding to the lowest and highest realization of average operating margins) to derive ranges of outcomes. After deriving the operating margin surplus or shortfall for 2017, we divided that amount by the unit capacity to obtain the unit operating margins in terms of $/kW-year. This normalization enables comparisons between units of different sizes, and provides a metric

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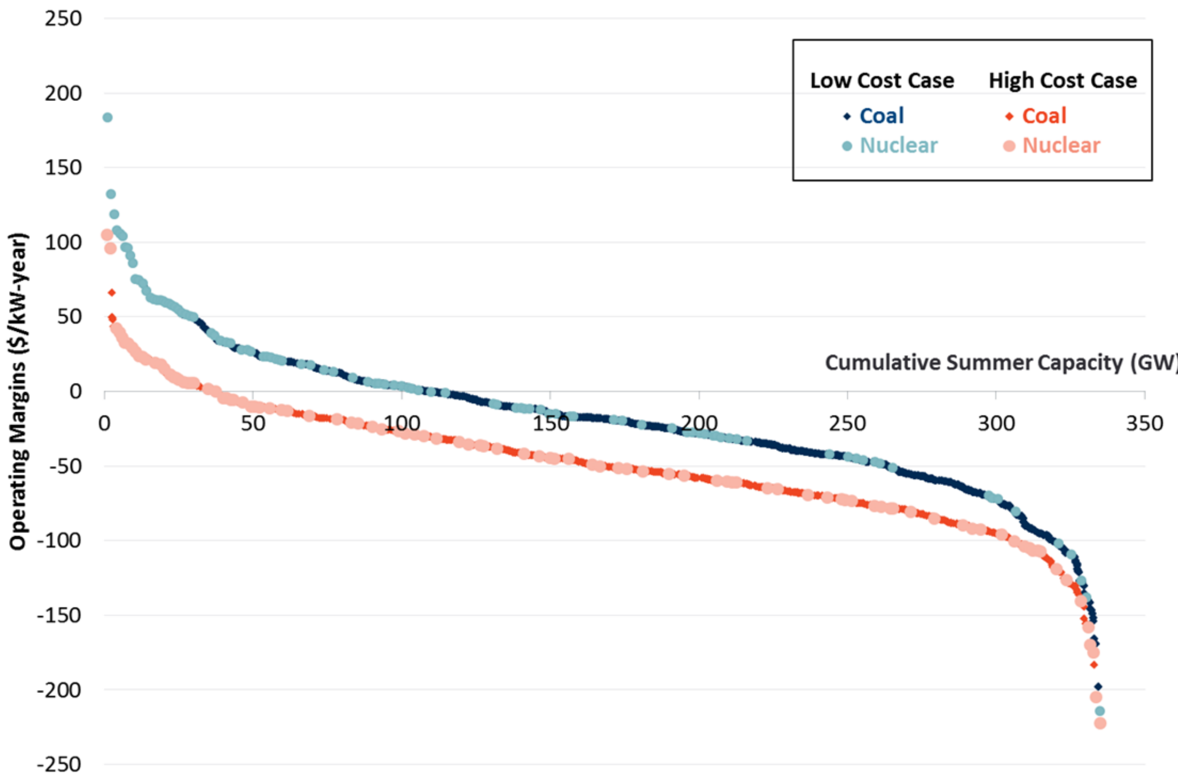
13 Operating margins would be similar to the accounting term Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) for merchant units.

that corresponds to retirement vulnerability. We then ranked the units in terms of highest surplus to largest deficit, and arrayed them as dots corresponding to cumulative capacity on Figure 2 for two cost cases: The case with the lowest costs and highest average operating margins (and thus the higher set of dots), and the case with the highest costs and lowest average margins (the lower set of dots).

Figure 2
Unit Operating Margins in 2017



On Figure 2, the height of each dot represents the units' operating margin, while the position on the dot along the horizontal axis represents the capacity of each unit, which cumulatively reaches about 335 GW. This representation shows how individual units performed, as well as how various segments of the fleet fared in 2017. The lower cost scenario depicts the coal and nuclear fleet as operating at a shortfall on average, with approximately one third of capacity operating at a surplus (108 GW), and two thirds operating at a deficit. Most of the capacity operating at a deficit experienced a deficit below $50/kW-year, with only about 16.7 GW operating at a deficit greater than $100/kW-year. For plants operating at a deficit, the capacity-weighted average deficit was $43/kW-year.

The higher cost scenario paints a much bleaker picture, with only about 38 GW (or 11%) of the fleet operating in positive territory and more of the fleet experiencing greater losses, which average approximately $58/kW-year. Not all capacity operating at an apparent earning shortfall in the short run would necessarily retire, but over time we would expect chronic operating margin deficits to encourage economic retirement, especially for merchant plants. And of course, some units currently operating at a profit might retire as a function of age/condition. The analysis shows how the overall fleet fares under current market conditions, and which types of units tend to perform better than others. In this case, large nuclear units appear to be generally more profitable than most coal units, which tend to have negative operating margins. The analysis also shows the uncertainty arising from using different cost data, so that a policy designed to target units that experience operating shortfalls and/or compensate for shortfalls will have very uncertain costs owing to the uncertainty in unit-specific cost information, some of which remains proprietary and not generally visible to policymakers.

IV. The Cost of Deterring Retirements

The draft memorandum proposes that DOE issue orders to temporarily prevent retirements of "fuel-secure" electricity generation resources through purchases of energy and/or capacity from such resources. The draft memorandum did not specify how DOE might select the SGFs or how they might determine the level of compensation to such resources in order to prevent their retirement.

A. Designating Subject Generation Facilities

There are myriad ways to select affected plants under various policies. These range from applying a single selection criterion to include all relevant plants to conducting extensive analysis of each unit to determine if the proposed policy should apply. As an example of the former, DOE could designate all coal and nuclear plants as SGFs. This is similar to how the DOE NOPR proposal operated (within specific RTOs) as it would have applied to all plants that could demonstrate a 90-day on-site fuel supply, which, depending on how that would be measured, could have included all coal and nuclear plants within the RTO. DOE could adopt a similar approach implementing the Draft Memorandum and extend SGF status to all coal and nuclear facilities in the US.

Less expansive approaches could involve formulating criteria to designate plants based on the analysis of unit-specific data. Not knowing at this point how the Administration plans to approach this task, we have analyzed an option that would apply to all coal and nuclear plants as well as an option that would provide additional payments only to units that experience (or demonstrate that they are experiencing) operating shortfalls.

B. Uniform Capacity Payment

The first approach we examine is to give each coal and nuclear unit a uniform capacity payment, i.e., an annual payment scaled to the size of each unit, provided it continues to remain operable. Recall from the discussion of Figure 2 that the average earning shortfall for units that experience negative operating margins is between \$43/kW-year and \$58/kW-year. To illustrate the impacts of a uniform capacity payment approach, we use a \$50/kW payment. Under a \$50/kW compensation approach, a 100 MW unit would receive $5 million per year, while a 500 MW unit would receive $25 million per year. Figure 3 below shows the total payments to coal and nuclear units if each unit receives an additional $50/kW-year, which would total $16.7 billion annually.

Figure 3
Out-of-Market Revenues Received and Direct Cost of a $50/kW-year Payment
($ Billions per Year)

	RTO	Non-RTO	**Total**
Coal	8.0	3.8	11.8
Nuclear	3.3	1.7	5.0
Total	**11.3**	**5.5**	**16.7**

Despite the costs, however, this policy might have limited impact on stopping or deferring actual retirements regardless of the level of SGF payments. That is due to the presence of units that a) currently are experiencing operating surpluses that do not require subsidy to encourage their continued operation and b) are experiencing annual shortfalls well in excess of $50/kW, and might retire regardless of the capacity payment. Figure 2 shows how a $50/kW-year payment would affect various segments of the fleet under the two cases examined in Figure 1. Recall that there were between 38 GW (High Cost Case) and 108 GW (Low Cost Case) of capacity that were already experiencing an operating margin surplus, to which the $50/kW would be added. The $50/kW payment would elevate roughly 154 GW from deficit to surplus under the Low Cost Case and about 128 GW from deficit to surplus under the High Cost Case. Because this analysis does not account for myriad factors that might influence a retirement decision, we do not represent this as the estimated effect of the payments on deterring retirements. However, it may be indicative of the range of units that could be influenced under the policy. Of course, a substantial fraction of the capacity would still experience an operating deficit with the $50/kW payment—about 72 GW in the Low Cost Case and 170 GW in the High Cost Case.

C. Payment Designed to Offset Operating Shortfalls

The second policy option we examined tailors payments to target operating shortfalls, i.e., to compensate resources for which going-forward fuel and operating costs exceed the revenues they obtain in wholesale power markets. In this section, we estimate the potential size of out-of-market payments that would have to be made to eligible generators under the draft memorandum. Our estimates are indicative, focusing on the payments that eligible generators would have received in 2017, had the rule been in place then.

Our cost estimates assume that DOE would be able to calculate unit-specific payments exactly equal to the shortfalls in covering going-forward fuel and operating costs with the revenues in wholesale power markets. Therefore, we assume that each of the eligible generation plants would receive revenues just sufficient to cover the generation plant's fixed and variable operating costs, offset by revenues received from selling energy and capacity in the wholesale markets. We assume that the compensation would not affect how the plants are bid into the wholesale energy markets or capacity markets relative to how they bid in 2017.

We assume that the subsidy given to plants exactly equals the annual operating loss as measured by 2017 revenues minus 2017 going-forward costs. We estimate the net cost of annual out-of-market payments under this approach would range from $9.7 billion per year under the Low Cost Case assumptions to $17.2 billion per year under the High Cost Case assumptions. These figures do not include any estimate for return on invested capital, as such was proposed in the 2017 DOE NOPR, which would substantially increase estimates. Figure 4 below shows the components of these estimates, broken out by coal and nuclear units and regulated and merchant types. As discussed further in the Appendix, the range of payments is due to variation in data sources used to estimate going-forward cost.

Figure 4
Summary of Revenue Shortfall for U.S. Coal and Nuclear Plants by Scenario

	Low Cost Case	High Cost Case
Revenue Shortfalls (excluding units with positive net revenues)		
Coal		
RTO	-4.0	-7.4
Non-RTO	-4.1	-5.4
Total Coal ($ Billion)	**-8.1**	**-12.8**
Nuclear		
RTO	-1.0	-2.8
Non-RTO	-0.6	-1.6
Total Nuclear ($ Billion)	**-1.6**	**-4.4**
Total Gap ($ Billion)	**-9.7**	**-17.2**
Capacity with Revenue Shortfall (GW)		
Coal		
RTO	120.1	154.2
Non-RTO	65.3	69.5
Total Coal (GW)	**185.4**	**223.7**
Nuclear		
RTO	26.7	44.9
Non-RTO	14.6	28.8
Total Nuclear (GW)	**41.2**	**73.7**
Total Capacity (GW)	**226.6**	**297.4**
Unit Earnings ($/kW-year)		
Coal		
RTO	-33.7	-47.7
Non-RTO	-62.5	-77.8
Total Coal	-43.8	-57.0
Nuclear		
RTO	-38.8	-63.0
Non-RTO	-40.0	-55.0
Total Nuclear	-39.3	-59.9
Total ($/kW-year)	**-43.0**	**-57.7**

In the Low Cost Case, units totaling 226.6 GW earn market revenues less than their going-forward cost (68% of overall capacity of 334.9 GW). For those units, the estimated annual out-of-market payment is $9.7 billion, which translates into an average payment of $43/kW-year. In the High Cost Case, a case where higher costs implied more capacity would experience operating deficits, about 297.4 GW would receive payments (89% percent of the overall capacity). The estimated annual cost of the out-of-market payment would be $17.2 billion, this translates into $58/kW-year on average for the affected coal and nuclear units. These results arise from an idealized set of assumptions where DOE would be able to obtain the necessary information from unit owners to 1) identify which plants would receive payments and 2) compute the precise amount of payments required to compensate for earning shortfalls. The range of operating costs we use—which lead to significant differences in the number of units involved and the overall size of the payments—illustrate one dimension of the challenge involved. If DOE were to pursue such a policy, we expect that overall costs would be much higher than the estimates presented here, unless some unit-by-unit analysis were pursued with much more information that is publicly available.

D. Potential Costs of Alternative Implementation Choices

The above estimates assume a very specific version of financial support for coal and nuclear units, namely that such support (1) would be given only to units that exhibit a shortfall in operating margins and (2) the level of support would precisely equal that shortfall. Thus, these figures represent a very conservative estimate of potential policy cost where actual program costs could be much higher depending on how the policy is defined and implemented. To illustrate the magnitude of cost impacts from alternative implementation choices, we note that the DOE NOPR policy included a return on prior investment to the support offered to merchant coal and nuclear units in certain RTOs. When we analyzed the cost of that program in our October 2017 study, we found that expanding support to include return on prior investment raised estimated costs by roughly two to four times the amount compared to a policy based on support for operating margin deficits alone. [14]

Estimating the amount by which costs would increase under a policy that included compensation for embedded capital cost recovery in addition to operating margin shortfalls would require detailed analysis. We can impute some of the likely magnitudes from the October 2017 analysis of the DOE NOPR under reasonable assumptions regarding the representativeness of the units covered in that study. However, different assumptions and methods would produce alternative cost estimates, ranging from two to almost five times the $10 to $17 billion per year figures noted above. Thus, we conclude that the impact of including returns on previously invested capital would likely at least double the cost estimate to roughly $20 to $35 billion per year in out-of-market payments to plant owners across the U.S.

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[14] This is seen in the bottom row of Table 7, page 63 of *Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule.* In the low cost case, compensating operating deficits only would cost $0.8 billion per year, but including return on prior investment would cost $3.7 billion per year. Likewise, the cost in the high cost case would rise from $4.7 billion to $11.2 billion. In that study, the cost increase arises from two sources: an expanded list of units to which support is given (as the selection criteria was whether operating income covered entire cost-of-service, including capital recovery) and the higher amount of support given to plants in order to cover the deficit in cost-of-service recovery.

Appendix: Estimated Cost of Proposed Policy

This appendix provides the details supporting the calculation of coal and nuclear plant 2017 earnings, and direct policy costs that take the form of out-of-market payments to plants which experience an operating shortfall (market revenues below overall expenditure) exactly equal to the operating shortfall. Below we describe the details of our assumptions and calculations of the ranges of the cost estimates, covering the estimations of (i) Operating and Fuel Costs, (ii) Offsetting Market Revenues from the energy and capacity markets, (iii) the overall Out-of-Market Payments to the potentially eligible generating units, and (iv) additional operational information relating to the coal and nuclear fleet.

A. Going-forward Cost for Coal and Nuclear Units

Going-forward costs include fuel costs, variable operation and maintenance (VOM) costs, fixed O&M (FOM) costs, and ongoing capital expenditures (CapEx) in 2017. Since there is no single complete database that provides unit-specific cost data for all of these components, we reviewed several sources of information to develop a range of estimates for unit-specific annual operating and fuel costs.

- **ABB, Inc.:** contains estimated unit-specific information on fuel costs, VOM costs and FOM costs in 2017.[15] The ABB, Inc. dataset does not include estimates for ongoing CapEx.
- **U.S. Environmental Protection Agency (EPA):** contains unit-specific estimates of VOM and FOM costs for nuclear units, and estimated VOM and FOM costs for coal units based on age, size, and installed emissions control equipment.16 The EPA data does not include estimates for fuel costs and ongoing CapEx.
- **U.S. Energy Information Administration (EIA):** contains estimated ongoing CapEx for a typical coal unit and a typical nuclear unit.[17]

15 ABB, Inc. Velocity Suite (2017).

16 *Documentation for EPA Base Case v.6 Using the Integrated Planning Model*, EPA, May 2018, Tables 4-8, 4-9, and 4-47. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/epa_platform_v6_documentation_-_chapter_4.pdf, and https://www.epa.gov/sites/production/files/2018-05/table_4-47_characteristics_of_existing_nuclear_units_in_epa_platform_v6.xlsx.

17 *Assumptions to the Annual Energy Outlook 2018*, EIA, April 2018, Electricity Market Module, page 13: https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

- Nuclear Energy Institute (NEI): contains average costs of fuel, operating and ongoing CapEx in 2016 for the nuclear fleet.
- Idaho National Laboratory (INL): contains estimated generating costs for nuclear units based on size (less than 800 MW or greater than 2,000 MW) and number of units (single unit or multiple units).18

We estimate the operating and fuel costs in 2017 for each unit under the following four Cost Cases. These Cases differ by the sources of data for various cost estimates:

- Case 1: ABB, Inc. fuel and O&M costs, and EIA ongoing CapEx
- Case 2: ABB, Inc. fuel, EPA O&M and EIA ongoing CapEx
- Case 3: For nuclear units, NEI data for operating costs and ongoing CapEx; for coal units, ABB, Inc. fuel costs, EPA O&M and EIA CapEx
- Case 4: For nuclear units, Idaho Lab operating costs; for coal units, ABB, Inc. fuel, EPA O&M and EIA CapEx

The table below summarizes the estimated average operating and fuel costs for coal and nuclear units by component under each cost case.

Figure A-1
Operating and Fuel Costs for Coal and Nuclear Units
Using Four Alternative Cost Cases

	Alternative Cost Cases			
	1	**2**	**3**	**4**
Coal Average Operating and Fuel Costs ($/MWh)				
Fuel Costs	22.30	22.30	22.30	22.30
VOM	1.56	4.91	4.91	4.91
FOM	7.14	8.51	8.51	8.51
Ongoing CapEx	4.97	4.97	4.97	4.97
Total	**35.97**	**40.69**	**40.69**	**40.69**
Nuclear Average Operating and Fuel Costs ($/MWh)				
Fuel Costs	4.62	4.62	6.91	34.28*
VOM	3.44	0.09	0.00	0.00
FOM	13.72	20.86	20.97	0.00
Ongoing CapEx	6.86	6.86	6.93	0.00
Total	**28.63**	**32.42**	**34.81**	**34.28**

*Operating costs for Case 4 is the sum of fuel costs, O&M, and ongoing CapEx as it appears in INL's generating cost assumptions.

18 https://nuclear-economics.com/2017-09-market-challenges-for-nuclear-fleet-essai-study/

The largest component of the operating and fuel costs on a per MWh basis is the fuel costs for coal units and fixed O&M (FOM) costs for nuclear units. The table also shows a wide range of estimated costs for coal plants based on unit-specific information provided by various data sources. Table A-1 also shows which alternative has the highest and lowest overall cost. Looking at both coal and nuclear average costs, we see that Case 1 is lowest in both, so we label this case the Low Cost Case. Among alternative Cases 2, 3 and 4, we see that coal cost are identical (and higher than Case 1) while nuclear costs are highest in Case 3, so we label Case 3 as the High Cost Case.

B. Offsetting Market Revenues

We estimate the market revenues for the coal and nuclear units as the sum of energy and capacity revenues in the wholesale power markets in 2017. For the units in RTO regions, we estimate the energy market revenues for each generating unit based on the unit-specific information compiled by ABB, Inc. for the day-ahead market revenues in 2017. For capacity revenues, while historical market-clearing prices for the RTO capacity market auctions are publicly available, historical capacity revenues are not. Some of the existing generating capacities did not clear in all past capacity auctions. As an estimate that err on the side of higher market-based capacity payments, we assume that all of the potentially eligible units would have cleared in the capacity market for 2017 and would have received the full capacity revenues based on the market-clearing prices in the zone they are located. For the units in non-RTO regions, there was no public information available for the market revenues. Therefore, we assume that these units received market revenues at the 2017 system lambdas (i.e., marginal cost of energy) reported by the electric utilities in the balancing areas the units are located.

The table below summarizes our estimates for the wholesale market revenues for coal and nuclear units in 2017. Wholesale market revenues were similar on average between coal and nuclear units, and revenues were slightly higher in RTO regions compared to the units in non-RTO regions. On average, wholesale market revenues for coal units in 2017 were $29.7/MWh ($30.4/MWh for units in RTO regions and $28.2/MWh for units in non-RTO regions). For nuclear units, wholesale market revenues were $29.8/MWh ($30.7/MWh in RTO regions and $28.2 in non-RTO regions).

Figure A-2
Wholesale Market Revenues for Coal and Nuclear Units
All currently operating units

	$/MWh		
	RTO	Non-RTO	Total
Coal			
Energy	26.8	28.2	27.2
Capacity	5.1	NA	5.1
Total Coal ($/MWh)	**30.4**	**28.2**	**29.7**
Nuclear			
Energy	26.8	27.9	27.2
Capacity	5.1	NA	5.1
Total Nuclear ($/MWh)	**31.2**	**27.9**	**30.1**
Total Revenue ($/MWh)	**30.7**	**28.1**	**29.8**

Note: Calculations for capacity use the portion of generation tied to units with capacity revenues.

C. Estimated Coal and Nuclear Generating Unit Earnings Under Alternative Cost Assumptions

The table below provides the operating and fuel costs and market revenues for coal and nuclear units under the four alternative cost cases.

Figure A-3
Summary of Revenues and Costs for U.S. Coal and Nuclear Plants
All currently operating units

	Alternative Cost Cases			
	1	**2**	**3**	**4**
Revenues (Energy + Capacity)				
Coal				
RTO	23.7	23.7	23.7	23.7
Non-RTO	10.2	10.2	10.2	10.2
Total Coal ($ Billion)	**33.9**	**33.9**	**33.9**	**33.9**
Nuclear				
RTO	16.3	16.3	16.3	16.3
Non-RTO	7.6	7.6	7.6	7.6
Total Nuclear ($ Billion)	**24.0**	**24.0**	**24.0**	**24.0**
Total Revenue ($ Billion)	**57.9**	**57.9**	**57.9**	**57.9**
Costs (Operating + Fuel)				
Coal				
RTO	27.1	31.0	31.0	31.0
Non-RTO	14.0	15.5	15.5	15.5
Total Coal ($ Billion)	**41.1**	**46.5**	**46.5**	**46.5**
Nuclear				
RTO	15.3	17.0	18.6	18.2
Non-RTO	7.5	8.8	9.2	9.1
Total Nuclear ($ Billion)	**22.8**	**25.8**	**27.7**	**27.3**
Total Cost ($ Billion)	**63.9**	**72.3**	**74.2**	**73.8**

The table below shows the total revenue shortfalls and surpluses across all coal and nuclear units. Under Cost Case 1 (the Low Cost Case), units with negative operating margins had a total revenue shortfall of $9.7 billion while units with positive operating margins had a total revenue surplus of $3.7 billion. For the full fleet of coal and nuclear units, this results in $6.0 billion of net revenue shortfall in 2017, or a shortfall of $29.39/kW-year on average. Under Cost Case 3 (the High Cost Case), the fleet of coal and nuclear units incurred a net revenue shortfall of $16.4 billion in 2017, or a shortfall of $53.78/kW-year.

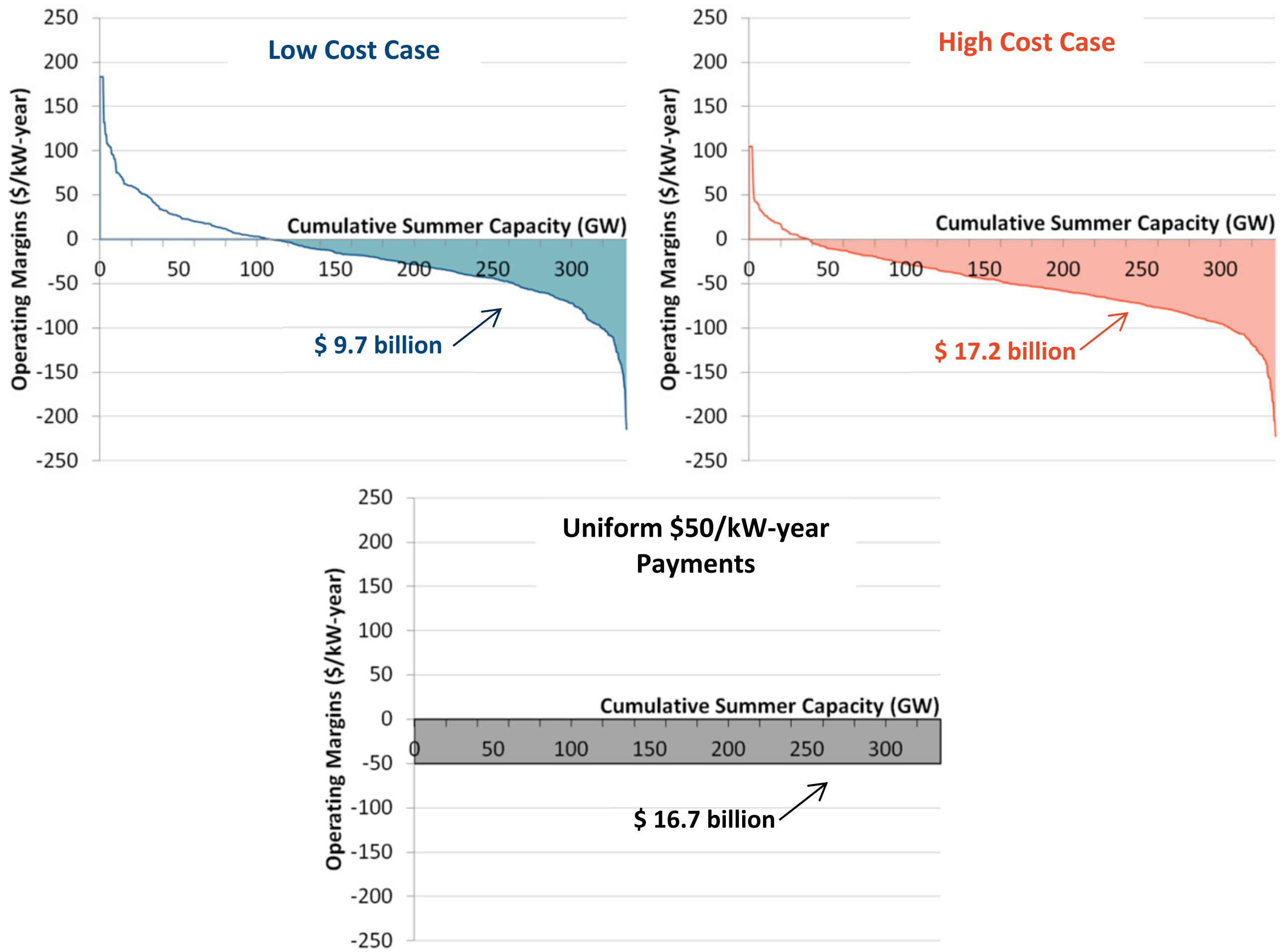
Figure A-4
Summary of Revenue Shortfalls and Surpluses for U.S. Coal and Nuclear Plants

	Alternative Cost Cases			
	1	2	3	4
Revenue Shortfall ($ Billions)	-9.7	-15.6	-17.2	-16.8
Revenue Surplus ($ Billions)	3.7	1.1	0.8	0.9
Total Net Revenue ($ Billions)	-6.0	-14.5	-16.4	-15.9
Capacity-Weighted Average Unit Earnings ($/kW-year)	-29.39	-51.04	-53.78	-53.45

D. Estimated Out-of-Market Payments: Low and High Cost Estimates

We assume that the policy would provide out-of-market payments to compensate exactly for operating shortfalls under each scenario, and we provide the lower and upper bounds of the direct policy cost under the Low Cost Case and the High Cost Case. Figure below is a graphic depiction of our approach to estimate the total out-of-market payments to units with revenue shortfalls under three scenarios. The first two scenarios reflect unit-specific determination of payments to units with revenue shortfalls under low and high cost cases, and the third scenario reflects a uniform payment of $50/kW-year to all units regardless of whether the unit incurs a revenue shortfall. In each case, the out-of-market payments are shown as the shaded areas that represent the payments only to the units having revenue shortfall in the first two scenarios, and the $50/kW-year uniform payment to all units in the third scenario.

Figure A-5
Summary of Estimated Out-of-Market Payments



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