THE DEPARTMENT OF ENERGY'S GRID RESILIENCE PRICING PROPOSAL: A COST ANALYSIS

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The Department of Energy proposed out-of-market subsidies for power plants with a 90-day on-site supply of fuel. Conservative readings of this proposal suggest it could cost customers $311 million-$10.6 billion. More than 80 percent of the increased costs customers would pay to subsidize coal would go to just five companies, and nearly 90 percent of the costs to subsidize nuclear would go to just five or fewer companies.

Note: This report was updated on October 25th, 2017 to fix an error identified with estimates for nuclear plants.[1]

INTRODUCTION

On September 28, 2017, the US Department of Energy (DOE) issued a Notice of Proposed Rulemaking (NOPR), proposing significant changes to the nation's wholesale markets for electricity. The NOPR directs the Federal Energy Regulatory Commission (FERC) to develop new tariffs to compensate unregulated units with a 90-day on-site supply of fuel for their "operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment."[2] The full text of the memo makes clear that the rule is intended to apply to coal and nuclear facilities, which it mentions as having firm on-site fuel.

The proposal marks a significant departure from for the way unregulated units make money in organized markets today. It would allow plant owners to recover their non-variable costs directly through a tariff, whereas these costs have historically been recovered through energy and capacity markets. The proposal would impose significant costs on electricity customers, requiring them to pay the full costs of power plants that are too expensive to compete against cheaper alternatives in the market. The ambiguous language of the NOPR also opens the door to higher

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[1] The earlier version can be accessed online at: http://energyinnovation.org/wp-content/uploads/2017/10/20171021_Resilience-NOPR-Cost-Research-Note-ARCHIVE.pdf

[2] Grid Resiliency Pricing Rule, FERC Docket RM18-1-000, https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14708757

cost readings where consumers could be forced to not only cover coal and nuclear plants' operating costs, but also ensure their profitability.

SCENARIOS EXAMINED

We evaluated four different ways in which the NOPR could be implemented, since the proposal lacks detail about exactly which costs would be covered and how it would be implemented. Each reading only counts the regions covered by the NOPR (which applies only to regions with capacity and energy markets): PJM, ISO-NE, NYISO, and MISO.[3] We assume the NOPR would cover non-regulated non-CHP coal and nuclear units in those regions. We evaluate costs at the unit (not facility) level, using 2015 as a "typical year."[4] Reading 1 is the most conservative reading of the NOPR, and each reading that follows analyzes incrementally more costs that could be covered by the NOPR as it is written.

READING 1: UPLIFT FOR CASH FLOW NEGATIVE UNITS

In the first way of reading the rule, we evaluate the cash flow of individual units at energy and capacity market prices and unit capacity factors in 2015. Units that have negative net cash flows (energy and capacity market revenue less the sum of: fuel, variable and fixed operations and maintenance, and annual capital expenditures) receive out-of-market payments that increase their cash flow, bringing their net revenue up to zero. These payments are referred to as "uplift payments." This reading is the most conservative of the four we evaluated.

READING 2: RECOVERY OF CAPITAL AND FIXED O&M COSTS, AFTER MARKET REVENUE

The second reading includes the costs compensated by the first reading, as well as capital recovery plus a rate of return on remaining undepreciated capital and future ongoing capital expenditures. Like Reading 1, this reading only considers units that are cash flow negative after accounting for market revenues. Units receive out-of-market compensation for variable and fixed operations and maintenance (O&M), undepreciated past and ongoing capital expenditures with a guaranteed rate of return, making them whole on net revenue.

READING 3: RECOVERY OF UNCOMPENSATED CAPITAL AND FIXED O&M COSTS, IN ADDITION TO MARKET REVENUE

The third reading is the same as Reading 2, except that market revenues are not netted out. In other words, customers pay units all of their fixed O&M and full recovery of undepreciated past

[3] The NOPR applies to "Commission-approved independent system operators or regional transmission organizations with energy and capacity markets and a tariff that contains a day-ahead and a real-time market or the functional equivalent." The scope would definitely cover PJM, NYISO, and ISO-NE. It is less clear if it would cover MISO, which has a voluntary capacity market, but MISO is included in this analysis.

[4] For more information, see attached Appendix.

capital expenditures and ongoing capital expenditures, at a guaranteed rate of return, on top of energy and capacity market revenues, to all units (not just cash flow negative ones).

READING 4: RECOVERY OF UNCOMPENSATED CAPITAL AND FIXED O&M COSTS IN ADDITION TO MARKET REVENUE, PLUS UNECONOMIC DISPATCH COSTS DUE TO INCREASED OUTPUT

The fourth reading goes one step further than Reading 3 by assuming not only full recovery of capital and fixed O&M, but also considering that coal units, which would be paid their full operating costs outside of the market under the NOPR, increase generation up to their maximum potential output (i.e., equivalent availability factor). Nuclear units typically already dispatch at their maximum output, because their marginal costs are usually lower than the market price and they are not typically responsive to market prices, and therefore do not increase output under this reading. However, there are many hours in which coal units would dispatch even though the market price would be below their variable operating costs, since those variable costs would be paid for outside of the market by customers. This would result in units with higher marginal costs effectively setting the market clearing price in many hours (since customers would pay the difference between the market price and their operating costs), resulting in higher overall electricity costs for customers (beyond the costs of fixed O&M and capital recovery, which customers would be paying separately outside the market).

COST TO CUSTOMERS

The cost to customers of the NOPR would differ significantly based on how many costs the proposal is assumed to cover. Reading 1, which is the most conservative, results in increased costs of $0.3 billion per year. A little more than half of the increase goes to nuclear plants. The costs cover the handful of plants that are operating at a loss under today's market conditions.[5] The total cost of this reading could be even larger in the future, as wholesale market prices in 2016 were even lower than those in 2015.

Table 1: Annual Increase in Customer Costs from NOPR

	Coal	Nuclear	Total
Reading 1	$0.1 billion	$0.2 billion	$0.3 billion
Reading 2	$0.3 billion	$0.3 billion	$0.7 billion
Reading 3	$3.4 billion	$7.1 billion	$10.4 billion
Reading 4	$3.5 billion	$7.1 billion	$10.6 billion

In Reading 2, customer costs increase by $0.7 billion per year. As in Reading 1, this is due to energy and capacity market revenue shortfalls at some plants, especially when incorporating a rate of return on capital investments.

[5] Some of these plants would be eligible for credit programs, such as the ZEC programs in Illinois and New York, which may decrease the cost of the NOPR.

In Reading 3, costs increase significantly, growing to $10.4 billion per year, as generators earn market revenues in addition to revenues covering their fixed O&M and capital costs.

The incremental costs for coal in Reading 4 are due to increased output from coal generators during times in which their generating costs are higher than the marginal price of electricity. As customers would be forced to pay generators their full generating cost, this results in higher electricity costs of roughly $200 million per year. Nuclear plants are assumed to be dispatching at their full potential in all readings, so there is no cost increase in Reading 4.

COSTS BY REGION

Customers in PJM would see the largest increase in costs, up to $7.3 billion per year. ISO-NE would see the smallest increase, with up to $700 million in added costs per year.

Table 2: Annual Increase in Customer Costs by Region

Coal					
	PJM	**ISO-NE**	**MISO**	**NYISO**	**Total**
Reading 1	<$0.1 billion	<$0.1 billion	$0.1 billion	<$0.1 billion	$0.1 billion
Reading 2	<$0.1 billion	<$0.1 billion	$0.3 billion	<$0.1 billion	$0.3 billion
Reading 3	$2.6 billion	<$0.1 billion	$0.6 billion	$0.1 billion	$3.4 billion
Reading 4	$2.7 billion	<$0.1 billion	$0.7 billion	$0.1 billion	$3.5 billion
Nuclear					
	PJM	**ISO-NE**	**MISO**	**NYISO**	**Total**
Reading 1	<$0.1 billion	<$0.1 billion	$0.2 billion	<$0.1 billion	$0.2 billion
Reading 2	<$0.1 billion	<$0.1 billion	$0.3 billion	<$0.1 billion	$0.3 billion
Reading 3/4	$4.6 billion	$0.6 billion	$0.8 billion	$1 billion	$7.1 billion
Total					
	PJM	**ISO-NE**	**MISO**	**NYISO**	**Total**
Reading 1	<$0.1 billion	<$0.1 billion	$0.3 billion	<$0.1 billion	$0.3 billion
Reading 2	<$0.1 billion	<$0.1 billion	$0.6 billion	$0.1 billion	$0.7 billion
Reading 3	$7.2 billion	$0.7 billion	$1.5 billion	$1.1 billion	$10.4 billion
Reading 4	$7.3 billion	$0.7 billion	$1.6 billion	$1.1 billion	$10.6 billion

The incremental costs could significantly increase market and customer costs. For example, an increase of $7.3 billion per year in costs in PJM would be an increase of more than 17% of total costs (total billing in PJM in 2015 was $42.63 billion[6]). Spreading the incremental costs evenly over the 65 million people served by PJM[7] results in an increase of $112 per person per year (though this probably is not how costs would be passed through).

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[6] Monitoring Analytics, *PJM State of the Market Report – 2015*, 2016, Table 1-1, available online at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2-sec1.pdf

[7] PJM – At a Glance, 2017, available online at: https://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/pjm-at-a-glance.ashx

PAYMENTS BY COMPANY

Just a handful of companies stand to benefit significantly from the NOPR. NRG would be one of the biggest beneficiaries of the NOPR's resulting subsidies for coal units, with increased revenue between $40 million and $1.2 billion per year. FirstEnergy and Dynegy would also stand to benefit significantly, with potential additional revenue of up to $500 million per year. Under all four readings, more than 80% of the coal subsidies paid by customers under DOE's proposal would go to just five companies.

Table 3: Annual NOPR Payments to Coal Units by Company[8]

Reading 1		Reading 2		Reading 3		Reading 4	
Company	**Subsidy**	**Company**	**Subsidy**	**Company**	**Subsidy**	**Company**	**Subsidy**
American Municipal Power	$0.1 billion	Dynegy Energy	$0.2 billion	NRG	$1.2 billion	NRG	$1.2 billion
NRG	<$0.1 billion	NRG	$0.1 billion	FirstEnergy	$0.5 billion	Dynegy Energy	$0.5 billion
Dynegy Energy	<$0.1 billion	American Municipal Power	$0.1 billion	Dynegy Energy	$0.5 billion	FirstEnergy	$0.5 billion
AGC Division of APG Inc.	<$0.1 billion	AGC Division of APG Inc.	<$0.1 billion	American Electric Power	$0.4 billion	American Electric Power	$0.4 billion
PPL	<$0.1 billion	The Blackstone Group	<$0.1 billion	Talen Energy	$0.3 billion	Talen Energy	$0.3 billion
All others	<$0.1 billion	All others	<$0.1 billion	All others	$0.6 billion	All others	$0.6 billion
Total	**$0.1 billion**	**Total**	**$0.3 billion**	**Total**	**$3.4 billion**	**Total**	**$3.5 billion**

The group of owners benefitting from the increased payments to nuclear generators is even smaller. Exelon stands to benefit the most across all readings, with increased revenue of $0.1 billion to $3.6 billion per year. Entergy, PSEG, FirstEnergy, and NextEra could all see significant increases in revenue as well, approaching $1 billion per year for some owners. Under all four readings, more than 89% of the nuclear subsidies paid by customers under DOE's proposal would go to just five companies.

[8] Individual values may not sum to the total due to rounding.

Table 4: Annual NOPR Payments to Nuclear Units by Company[9]

Reading 1		Reading 2		Reading 3/4	
Company	**Subsidy**	**Company**	**Subsidy**	**Company**	**Subsidy**
NextEra	$0.1 billion	NextEra	$0.2 billion	Exelon	$3.6 billion
Entergy	$0.1 billion	Entergy	$0.1 billion	Entergy	$1 billion
Exelon	<$0.1 billion	Exelon	<$0.1 billion	PSEG	$0.6 billion
PSEG	<$0.1 billion	PSEG	<$0.1 billion	NextEra	$0.5 billion
				FirstEnergy	$0.5 billion
				Other	$0.4 billion
Total	**$0.2 billion**	**Total**	**$0.3 billion**	**Total**	**$7.1 billion**

Ultimately, the net impact on plant owners depends on the total impact to all assets, including those benefitting from the rule as well as those that could be impacted negatively.

ADDITIONAL CONSIDERATIONS

The four readings analyzed represent a range of potential ways in which the DoE NOPR could be implemented. There are additional readings, which we have not analyzed here, but which could result in significantly higher costs. For example, the NOPR could result in recently retired plants coming out of retirement. This could result in an additional two to four gigawatts of coal capacity coming back into the system, with associated capital addition costs of $113 million to $228 million per year.

These cost estimates are also likely conservative because we assume all units clear regional capacity markets without additional out-of-market payments and that all units receive energy revenues during the highest share of hours without additional out-of-market payments. In reality, some units have not cleared in recent capacity auctions. Hourly generating data also reveals that units do not always dispatch during the highest share of hours aligned with their capacity factors. Similarly, the NOPR would very likely change overall market clearing prices for energy and capacity, likely decreasing both by encouraging uneconomic to remain online. This would further drive up the costs of the rule. Therefore, we likely overstate baseline energy and capacity market revenue and understate additional revenue necessary to make currently-uneconomic units whole. Similarly, we do not look at the incremental variable and fixed O&M costs that would be necessary for coal units to continue operating and comply with environmental regulations. Many units now contemplating retirement would require significant environmental retrofits that could significantly increase their operating costs. Further, while costs represented here are annual, they could continue in perpetuity, since generators would now have no reason to retire.

[9] Individual values may not sum to the total due to rounding.

Omitting plants scheduled for retirement would reduce the cost of capital additions by approximately 30%. However, if plants are truly eligible to receive full cost recovery, it is likely they would stay in the market. Therefore, we do not remove plants scheduled for retirements from our analysis.

It also is not clear what other ways power plants might respond to the incentives offered by the NOPR. Right now, coal plants have on average 70 days of fuel on site; would they now have an incentive to store more coal, increasing O&M costs? Would natural gas units find a way to store on-site gas or oil to meet the 90-day fuel requirement? Do hydro plants qualify under the rule if they have an ample reservoir? These uncertainties could add significantly to the costs estimated here.

CONCLUSION

The Department of Energy's Grid Resilience NOPR could significantly alter the structure of the nation's wholesale markets. By requiring customers to pay for revenue shortfalls at coal and nuclear plants, many of which are not profitable given cheaper options available in the market today, the NOPR will significantly increase costs for customers.

Under our most conservative reading, we find incremental costs for customers totaling $311 million per year. More likely readings of the NOPR could result in significantly higher costs, approaching $10.6 billion or more, per year. These costs are unnecessary; markets are operating today as intended, with record low prices, and no reliability concerns. A mere 0.00007% of outages since 2012 have been caused by fuel supply emergencies[10] – this NOPR is aiming to solve a problem we do not have. Many markets have already implemented changes aimed at improving reliability in the wake of the Polar Vortex, making the NOPR even more unnecessary. If implemented as outlined, the NOPR would result in a subsidy from customers to a small handful of companies, without demonstrably making the grid any more reliable or resilient.

[10] Houser, Larsen, and Masters. *The Real Electricity Reliability Crisis*. 2017. Available online at: http://rhg.com/notes/the-real-electricity-reliability-crisis

APPENDIX: METHODOLOGY

PLANT LIST

This analysis is based on publicly available data published by the U.S. Energy Information Administration (EIA Form 861 and EIA Form 923), the Federal Energy Regulatory Commission (FERC Form 1), and the National Energy Model System (NEMS). The dataset lists unregulated "Conventional Steam Coal" and "Nuclear" power plants currently operating in ISO-NE, MISO, NYISO, and PJM that have a nameplate capacity of over 10MWs, generated electricity in the year 2016, and do not list natural gas as their "Planned Energy Source." We have ignored combined heat and power (CHP) plants since their primary function is not power generation.

OPERATING COSTS

Coal plants' fuel costs represent state averages when there were no fuel receipts associated to a particular plant reported to the EIA. Nuclear plants' fuel costs represent a national average calculated from data reported in the FERC Form 1 if plant-specific fuel costs were not reported to the EIA. For both technologies, variable and fixed O&M are based on the 2015 NEMS (adjusted for inflation) or estimated based on the plant's technology. Capacity factors were calculated using EIA's forms for the coal units and FERC Form 1 for the nuclear units.

ENERGY AND CAPACITY MARKET REVENUE

Hourly system-wide energy market locational marginal prices for PJM, MISO, ISO-NE, and NYISO are used to calculate energy market revenues. Average system prices are used rather than nodal prices given the very short timeline to submit comments on the NOPR.

2015 is used as a proxy for future years' revenues. 2015 represents a roughly average year with a price duration curve between 2014 and 2016 across markets. Given the nature of the data, using annual averages for hourly data is not appropriate.

Capacity market revenue is based on regional weighted average capacity market prices for the 2014/2015 and 2015/2016 delivery years.

Unit specific revenue was calculated by assuming units dispatched during the highest priced hours that correspond with their capacity factors. For example, a unit with a 60% capacity factor is assumed to dispatch during the 5,256 hours with the highest market prices. This approach likely overstates energy market revenue, but ignores uplift and ancillary service revenue.

Capacity revenue was calculated by taking the weighted average annual capacity price and multiplying it by the summer capacity for each unit. This approach likely overstates capacity revenues, as some coal and nuclear units have not been selected in recent capacity auctions, but ignores locational differences in capacity prices.

CAPITAL ADDITIONS

Annual capital additions are calculated using data from the U.S. Energy Information Administration's NEMS model documentation. The Electricity Market Module[11] includes annual capital additions – which are distinct from fixed O&M – of $17/kW for coal plants and $23/kW for nuclear plants. Additionally, there is an extra charge of $7/kW for coal plants over 30 years old and $35/kW for nuclear plants over 30 years old, meant to reflect "capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to mitigate the effects of aging."[12]

In the baseline and Reading 1, capital additions are only calculated on an annual basis, i.e. each year there are incremental capital costs. Readings 2, 3, and 4 incorporate return on undepreciated capital as well as future capital cost recovery.

To calculate undepreciated capital recovery, we estimate the remaining return on past investment using revenue requirement calculations from Synapse's Coal Asset Valuation Tool (CAVT), tab D3_CRF. We use the annual return on investment calculated by Synapse to calculate the remaining return on past investments, tracking capital additions in each year for the past 20 years. We do the same calculation separately for plants that passed a lifetime of 30 years within the past 20 years.

Future costs grow every year, as the previous years' capital additions are returned and new capital additions are added. This value continues to grow for 20 years until capital additions reach an equilibrium point, where past investments are fully depreciated and paid for and new additions are added at the same rate each year. To capture this growth, we forecast capital additions (and returns on those additions) 20 years forward. We take the net present value of these returns, discounted at the inflation rate, and divide by 20 to get the average annual cost to customers of capital additions. In the short-run, this value overstates costs to customers, but in the long-run it understates the costs, for the reasons discussed above under Additional Considerations.

ESTIMATING INCREASED ENERGY COSTS IN READINGS 4

To estimate the costs of increased coal dispatch in Reading 4, we first assumed each unit dispatches at a fleet-wide equivalent availability factor of 83.3%[13] covering the highest priced 83.3% of hours. We then looked at hours within that set in which each unit's production costs exceeded the 2015 energy price, and took the difference between the two and multiplied by the unit's capacity, to find the net increase in production costs from increased generation. This

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[11] EIA, *Assumptions to the Annual Energy Outlook 2017,* "Chapter 8. Electricity Market Module." 2017. Available online at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf

[12] Id.

[13] Generation Consulting Services, *Reliability Analysis of Power Plant Unit Outage Problems*. 2013. Available online at: http://famos.scientech.us/PDFs/2013_Symposium/Reliability_Analysis_of_Power_Plants_Curley.pdf

approach clearly provides only a very rough estimate of additional costs and does not account for interactions between units and market clearing prices. However, it does provide at least a rough estimate of the magnitude of potential energy cost increases.