Reliability and Emission Impacts of Stationary Engine-Backed Demand Response in Regional Power Markets

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1. INTRODUCTION

Unlike most consumer products, electricity cannot yet be economically stored to any significant scale. As a result, power systems must balance the generation and consumption of electricity on a near-instantaneous basis, with far-reaching implications for power system reliability and economics. In this context, the recent growth in the penetration of Demand Response (DR) resources has the potential to increase consumers' control over energy costs, assist with system contingencies, and moderate market pricing for power generation. However, as is the case with any emerging technology or new market design, it is important to objectively assess these trends to ensure energy market and system operations are capturing the range of potential benefits while avoiding unwanted, unintended consequences.

Demand resources are typically viewed as a reduction in annual consumption of energy, an opportunity to suddenly reduce demand on the system in limited instances within a year, or both. But like power generation resources, DR comes in different flavors. Demand resources can consist of one-time investments that continuously reduce energy consumption, or they may be available to reduce demand in any hour based on market pricing, or only episodically as load curtailment.

Episodic and price-responsive demand resources, in turn, can be based on technologies to moderate or curtail actual customer loads (e.g., air conditioner or water heater control devices), or can be based on the availability of back-up, supplemental, or emergency generation that is on-site. This on-site generation (often powered by diesel fuel) can be activated to allow continued consumption and uninterrupted site operations, but reduces load drawn from the bulk power system. In these cases, the "load reduction" is not tied to absolute reductions in energy use; instead it relies on the use of behind-the-meter generation that simply displaces electricity that otherwise would be provided by the grid.

Price-responsive demand bidding into all market hours as an energy market resource has a vastly different potential impact on pricing and system dispatch than temporally-limited interruptible load that serves primarily as a capacity market resource; and DR that derives from changes in actual customer consumption levels and patterns has a very different impact on power system emissions than DR programs that involve only the periodic dispatch of behind-the-meter generation that is otherwise used only for back-up or emergency situations.

The U.S. Environmental Protection Agency (EPA) has issued a Notice of Proposed Rulemaking to amend the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (Stationary Engines, or RICE) under Section 112 of the Clean Air Act

(Proposed Rule).[1] In part, the Proposed Rule would include a limited temporary allowance for existing stationary area source engines to be used for peak shaving and non-emergency DR, and would substantially increase the hours that Stationary Engines may be used for so-called "emergency DR," without requiring those units to install emission controls.[2] EPA has proposed to waive otherwise-applicable emissions control requirements for Stationary Engines used for "emergency DR," as well as non-emergency DR and peak shaving, because allegedly, (1) such RICE-backed DR is needed to help power system operators protect the reliability of interconnected power grids, and (2) the emission impacts associated with RICE operation for this purpose are insignificant due to the limited operation of such units.[3]

Neither is true.

To understand the reliability and emission impacts of RICE-backed DR resources, one must consider their role in the broader context of reliability planning, wholesale capacity markets, and real-time dispatch. Focusing only on the limited and targeted operation of Stationary Engines for DR fails to consider the full scope of reliability mandates and practices, and ignores the impact such engines have in the emissions associated with continuous power system operations.

This report investigates the role of RICE-backed DR in the broader context. First, power system reliability – and the role of RICE-backed DR in capacity markets – is described and analyzed. Next, a power system dispatch analysis is used to estimate the level of power system emissions (1) with the amount of RICE-backed DR currently in place and estimated to occur over the next several capacity market cycles; and (2) with various portions of these resources replaced with alternative market resources, holding everything else the same. This report describes the dispatch model approach, assumptions, scenarios, and results.

The results run counter to the assumptions relied upon by EPA in the rulemaking document and counter to the view that DR, in every instance, provides economic and/or environmental benefits. Those benefits, in reality, are contingent upon the type of DR resource and the manner in which it is integrated into the market. As is more fully described below, a not-insignificant percentage of the recent growth of DR is

[1] U.S. Environmental Protection Agency, *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines,* Proposed Rule. Federal Register 77, no. 110 (June 7, 2012): 33812-33857 ("Proposed Rule").
[2] Proposed Rule, p. 33812.
[3] Proposed Rule, p. 33817-33819.

based on the use of behind-the-meter generation, despite the fact that DR is generally considered to be a form of market-based energy conservation.[4,5]

In contrast to EPA's assumptions, I find the following:

- RICE-backed DR capacity resources simply displace other capacity resources that would contribute equally – if not more – to power system reliability than these DR resources; and
- the successful participation of RICE-backed DR in regional capacity markets *increases* generation from coal and other fossil-fuel resources, and *increases* emissions of carbon dioxide (CO_2), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and mercury (Hg), relative to the same capacity needs being met by alternative market resources.

Importantly, the results in this Report flow entirely from the emission impacts of system dispatch outcomes under various capacity scenarios; they do not include any direct or specific emission impacts or health outcomes associated with emissions from the RICE units themselves. Any such impacts may be considered additive to the impacts summarized in this Report.

Demand response has played – and going forward can and should play – an important role in improving the efficiency of wholesale electricity market operations and diversifying the resources relied upon to meet power system needs. However, a fundamental tenet underlying the development of successful competitive wholesale power markets is the existence of a level playing field across competing resource types. This is particularly important when considering regulatory waivers or allowances that favor one resource over competitive alternatives. EPA's proposed amendment puts a thumb on the scale of market competition – ultimately to the detriment of electricity consumers – in favor of RICE-backed DR at the expense of competing alternatives. This analysis shows that there is neither an environmental- nor reliability-based justification for doing so.

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[4] The Federal Energy Regulatory Commission (FERC) defines demand response as a "reduction in the consumption of electric energy," implying that DR should involve an absolute reduction in power use. FERC, *Demand Response Compensation in Organized Wholesale Energy Markets* Order No. 745, March 15, 2011, footnote 2.

[5] The California Public Utilities Commission (CPUC) notes "… we have consistently stated that demand response programs that rely on using back-up generation were contradictory to our vision for demand response…" CPUC, *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations*, Rulemaking 09-10-032, October 10, 2011, p. 26.

2. DEMAND RESPONSE CAPACITY, RELIABILITY, AND COMPETITIVE WHOLESALE MARKETS

Proponents of granting RICE-backed DR the exceptions from emissions control requirements included in EPA's Proposed Rule often cite the role of emergency DR in maintaining power system reliability. Yet there is no reason to single out DR from a reliability perspective – whether or not backed by stationary engines. DR's role in reliability is the end result of coordinated capacity planning procedures and market outcomes; outcomes that ensure reliability with or without DR resources. This section provides background on capacity resources, and discusses the role of DR vis-à-vis alternatives.

The History and Purpose of Reliability Obligations

The purpose of capacity markets and capacity obligations is straightforward: make sure there are sufficient capacity resources available to serve the forecast electric load consistent with established reliability criteria. Prior to the restructuring of the electric industry, utilities were required (and still are in states that have not restructured) to plan for, and build or purchase, sufficient capacity to meet the needs of all current and future customers within franchised service territories. These obligations were enforced by state regulators, and over time (in particular after the November 1965 blackout in the Northeast) utilities in many regions formed voluntary reliability councils to coordinate system operations and take steps to improve the reliability of interconnected power systems.[6] These voluntary reliability councils became more tightly organized in many regions, coordinated reliability planning and operations, collaborated on best-practices, and developed reliability standards and guidelines used by individual system operators and utilities.

Through restructuring, many of these voluntary organizations transformed into the Independent System Operators (ISO) and Regional Transmission Organizations (RTO) that are in place today. Today's ISO/RTOs vary by geography, membership, responsibilities, and market constructs, but have evolved (to varying degrees) over the past decade and a half into fully independent organizations that are empowered by the Federal Energy Regulatory Commission (FERC) to preserve reliability through system planning,

[6] A portion of electricity demand has always been met by municipal electric companies, cooperatives, and federal power authorities. While these entities operate under different authorities and regulatory settings, they follow the same practices as investor-owned utilities with respect to approaches to reliability planning, system reserve requirements, and coordination and cooperation with neighboring electrical systems consistent with regional reliability council standards and guidelines.

maintenance coordination, real-time system operating procedures, and the design and administration of capacity markets or requirements to ensure sufficient generating capacity.[7]

Throughout this evolution, preserving power system reliability has been the most fundamental obligation and goal of the ISO/RTOs; they now hold primary responsibility for the design, monitoring and administration of planning processes and capacity markets to maintain reliability. The Energy Policy Act of 2005 (1) made reliability a mandatory legal obligation within the jurisdiction of FERC, (2) created an Electric Reliability Organization (ERO), subject to FERC oversight, to develop and administer reliability standards (ultimately, the North American Electric Reliability Corporation (NERC) – an outgrowth of the voluntary utility organization that preceded it – was designated as the ERO); and (3) most importantly, made compliance by regional entities (in essence the ISO/RTOs, or individual transmission owners or operators where ISO/RTOs do not exist) mandatory, with failure subject to enforcement and potentially significant financial penalties.

Compliance with the now-mandatory NERC reliability standards – which affect many elements of planning, operations, and market design – is taken very seriously by the ISO/RTOs. In organized ISO/RTO regions, reliability planning accounts for the contributions of all existing resources, and, in several of the major ISO/RTOs, capacity markets are the primary vehicle for ensuring that sufficient resources are added over time to meet resource adequacy criteria. In such markets, such as the Reliability Pricing Model (RPM) in the PJM Interconnection (PJM) RTO region, DR's contribution to system reliability stems from successfully competing in capacity markets and, in turn, is effectively counted as a supply resource when planning for future capacity needs.

The Role of DR versus Alternatives in Capacity Markets

Capacity markets are designed to meet a region's resource adequacy needs.[8] To determine the quantity to procure in a capacity auction, regions typically conduct analyses to determine the level of resources required to meet a specific reliability criterion – namely, that the "loss-of-load-expectation" (LOLE) for a system not exceed one occurrence in ten years. This LOLE analysis evaluates the probability of loss of

[7] ISO/RTOs also typically have responsibility to administer open transmission access; and design, monitor and administer comprehensive markets for energy and ancillary services.

[8] A region meets its resource adequacy needs if the total of amount of installed capacity (megawatts) is sufficient to meet its load obligations throughout the year, including an adequate margin of reserves for contingency purposes. Capacity resources are then used to produce the actual energy (megawatt-hours) required to meet system demand on a real-time basis.

load in consideration of forecast uncertainty, resource availability and performance, and planned (scheduled and maintenance) outages.[9]

Because it serves as the basis for the quantity of incremental resources to be procured in capacity markets, LOLE analysis specifically presumes or incorporates the availability of all existing resources – demand and supply – as well as operator actions that may be taken to avoid loss of load. This includes all resources that are currently operating - e.g., generating resources and demand resources – as well as emergency resources and actions, voltage reductions, conservation appeals, etc. In addition, since the assessment is forward looking – typically covering a ten-year forecast horizon – the analysis includes resources that have cleared capacity markets, or are otherwise assured of being in operation in the forecast year in question. Consequently, the relationship between reliability need and capacity resources is in effect a zero-sum game.

This is fundamentally important when considering the reliability value of the RICE-backed DR at issue in the present rulemaking – namely, <u>there is no special value</u>. The reliability criterion will be met, with or without such resources. If it is not economic for the owner of a stationary engine to make the necessary investments to comply with the new emission standards, and it withdraws from the DR program, reliability is not compromised. Instead, the LOLE analysis would reflect the absence of the associated DR resource, and *the capacity market would be administered to procure additional resources to maintain the same level of reliability*. The absence of one resource cannot lead to a violation of the reliability criterion – instead, it necessarily leads to an increase in the quantity of resources procured in annual or incremental capacity auctions to meet the criterion.

Taken to its logical conclusion, the argument that EPA applies to stationary engines that back emergency DR resources could equally be applied to any large natural gas, oil, or coal resource that currently exists on the system. [10] Such resources are vitally important to maintaining system reliability throughout the year (particularly under emergency conditions) and are similarly accounted for in the LOLE analysis.[11]

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[9] See, e.g., the description of Resource Adequacy in *PJM Manual 18: PJM Capacity Market*, Revision 15, Effective Date June 28, 2012, p. 7.

[10] As PJM Independent Market Monitor Dr. Joseph Bowring indicated at the July 10, 2012 Public Hearing: "The demand side product generally in PJM capacity markets, DR, is also referred to as "emergency DR," but that name is actually a misnomer… saying the demand response, or DR, is an emergency-only resource is like saying a gas-fired combined cycle is an emergency-only resource. Both are forms of capacity. Both need to function in order to provide reliability, and neither is an emergency resource in any meaningful sense of that word." *Transcript of Hearing of the Environmental Protection Agency in the Matter of the Proposed Rule for National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Internal Combustion Engines*, EPA Docket No. EPA-HQ-OAR-2008-0708, July 10, 2012 ("Hearing Transcript") at 116-117.

[11] While it is true that "emergency DR" resources may only be called on only a limited number of times per year, that does not diminish the equivalent reliability value of other supply resources. When emergency DR programs are activated, all available resources on the system are typically committed and dispatched near their maximum possible operating levels, and the value of the emergency DR resource is no more than

Simply put, if it is too costly for an old coal unit to install compliance retrofits, the right answer is to let it retire, and be replaced with a cleaner generation resource that can serve the same reliability need. The same is true for stationary engines that back DR resources. The wrong answer – in either case – is to grant a waiver from emission compliance requirements on the basis that such capacity is needed for reliability.[12]

Finally, the fact that RICE-backed DR resources are only called upon in emergency circumstances – e.g., when a system operator has or is about to institute voltage reductions – should not be interpreted as ascribing any greater reliability value to these resources. To the contrary, if anything it may be an indication that the range or operating characteristics of such resources is limited relative to competing alternatives, to the extent that additional attributes of resources are not factored into the capacity market pricing mechanism.[13]

In all capacity markets, all MWs are effectively treated as equal in the auction mechanism: a MW from a fast-start, fast-ramping resource that is available every hour of the year is no more valuable than a MW from a resource that has limited operational hours, has very slow ramping capability, no automatic generation control (AGC) capability, very long start-up times, or extended minimum run or minimum down times. In short, in current capacity market designs, no value is placed on fuel type, technology type, or resource flexibility. Those attributes may be valued (from a financial perspective) through existing energy, reserve or ancillary market constructs, but the only performance requirement placed on a *capacity* resource is that the level of capacity sold by a resource owner in the market has to be an accurate representation of the facility's capability under peak load conditions. Resources clear (are selected by) the auction based almost exclusively on price; the auction does not differentiate among capacity resources based on any type of resource-specific reliability criteria.

Yet, as regions of the country continue to add greater and greater levels of variable renewable resources, these other characteristics – flexibility, ramping, automatic generation control (AGC), etc. – will become more and more important from the perspective of system operational reliability. In this context, certain

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the value of a traditional generation resource – whether existing or new – that is able to and would provide the same quantity of capacity at that time.

[12] There may be limited but appropriate exceptions to this rule. In some regions, certain generating units may be important for the support of local transmission system security needs (e.g., voltage, stability), and requests to retire such capacity may be temporarily rejected by the system operator pending the commercial operation of generation alternatives, and/or the completion of transmission system upgrades that eliminate the local reliability needs. However, this circumstance typically does *not* hold with respect to any of the behind-the-meter resources that back DR in regional markets.

[13] Rather than an indication of unique reliability status, the limited-use special condition for DR resources likely derives from the development of market rules that view DR as energy conservation, or an interruption to customer operations (rather than behind-the-meter generation), that should be minimized.

RICE-backed “emergency DR” resources simply cannot provide the same level of reliability value as alternative generating resources that are available to operate year-round, and that can provide system operators with the enhanced flexibility needed to accommodate increasing levels of variable renewable resources.

Nevertheless, demand response can be a valuable resource in wholesale electricity markets; it has played – and going forward can and should play – an important role in improving market efficiency and diversifying the resources relied upon to meet power system needs. The more options available to system operators to respond to power system conditions and the more pressure on the demand side to control price spikes, the better. But a careful review of the role of various resources in meeting the resource adequacy criterion that is the objective of capacity markets reveals that RICE-backed DR should not be ascribed any more reliability value than alternative resources against which it competes. It simply is not appropriate to conclude that RICE-backed DR resources are uniquely needed for reliability or have enhanced reliability attributes; rather, they simply provide a reliability service that could and would be equally met by alternative resources.

Implications for Competition and Market Efficiency

In power system planning, procurement, and operations, reliability is not optional. Nevertheless, reliability is not the only purpose of regional wholesale electricity markets in regions (such as PJM) that rely on them. Wholesale market competition and the incentives that markets provide to improve generating efficiency and reduce underlying costs are critically important to minimize the cost of electricity for ultimate consumers. The fundamental condition of fair competition and a level playing field is, in turn, critically important to the success of competitive markets. Discriminatory actions that provide one resource or resource type a competitive advantage relative to others can distort market outcomes to the detriment of market efficiency, and increase costs to consumers.

Wholesale electricity markets remain relatively new. While not perfect, the markets established across the U.S. have continuously improved since their inception a couple decades ago, from the perspectives of competitiveness, fairness, reduction in barriers to entry, and price outcomes. However, that does not mean that all existing competitors in wholesale market face a perfectly-level playing field. Various policies complicate the competitive landscape – including local or state fuel, tax, or development subsidies; application of fuel-specific incentives or opportunities for long-term contracting/financing support; and a host of state, regional or federal public energy policies that provide explicit or implicit preferences for one form of generation over another.

Capacity markets in particular have been challenged by programs and initiatives that diminish the ability of markets to replicate perfectly competitive conditions. Against this background, it is particularly important to avoid creating new discriminatory subsidies or uneven regulatory requirements across competing supply- and demand-side technologies, unless there are legitimate and compelling environmental or other public policy justifications for doing so.

As discussed above, the basic structure of reliability planning analyses, and their connection to capacity procurements, ensures that reliability will be met with *or without* RICE-backed DR resources in regional markets; consequently, there is no reliability-based justification for discriminatory application of emission control requirements. The next section reviews the second policy issue in question – the impact of RICE-backed DR on power system emissions of key pollutants.

3. THE EMISSION IMPACTS OF STATIONARY ENGINE-BACKED DEMAND RESPONSE AS A CAPACITY RESOURCE

Introduction

From an emissions perspective, there is an important and overlooked aspect of the difference between capacity and energy markets. As discussed in the previous section, capacity markets are designed to procure sufficient capacity resources to meet power system needs. The quantitative objective is the total amount of system capacity adequate to satisfy any forecast level of electrical demand, subject to the reliability criterion of a LOLE of no more than once in ten years. In essence, the quantity procured (in combination with existing resources) must be enough to meet operational requirements in all hours, including the hour of system peak load.

However, actual system load (real-time customer demand) is met via the energy and other daily markets. Once procured and operational, a capacity resource is either required to or may choose to participate in energy and ancillary service (e.g., reserves) markets not just at the time of system peak – or in emergency situations – but in every hour of the year.[14] While from a reliability perspective the focus on peak loads is appropriate for purposes of procuring adequate capacity resources, what matters from the standpoint of evaluating overall electric system emissions is how those resources actually operate in practice on a day-

[14] Notably, emergency DR resources are the exception, required only to be available for a certain number of "calls," and/or for a maximum number of hours per year.

to-day basis, compared to competing alternatives. Consequently, in considering the potential emission impact of a resource, it is not sufficient to focus only on the actual emissions from that particular resource; rather, a more complete evaluation must consider the impact of the operation of that resource on total system emissions. While a comparison of the emissions impacts associated with actual dispatch of each resource would show that emissions from the aggregated RICE-backed emergency DR resource are significantly greater in pounds per megawatt-hour (MWh) of criteria pollutants, greenhouse gases (GHG) and hazardous air pollutants, that comparison would only evaluate one side of the story; a more pronounced and important emissions impact can be observed when a comparison is made of the impact that such resources would have on overall electric system emissions throughout the rest of the year, not just when the RICE-backed "emergency" DR resources are actually dispatched.

Consider, for example, the different potential impacts on system emissions of two new, competing capacity resources with equal total capacity value: (1) an aggregation of RICE-backed "emergency" DR, and (2) a similarly-sized natural gas combined-cycle (NGCC) plant. In capacity markets, one or the other could be chosen to meet an identified capacity need. On peak, when needed the most, each resource will – and is expected to – contribute equally to meeting load and preserving power system reliability.

Yet how each would operate throughout the year is different. The RICE-backed DR resource would be called upon rarely, if at all, depending on system conditions and specific ISO/RTO rules; most DR is called upon only during peak conditions. The NGCC plant would also be called upon to operate in those hours, but additionally would operate, at various levels of output, for a significant percentage of the remaining hours of the year.[15] Holding everything else equal, these two scenarios lead to very different system emissions.

In the first case, the RICE-backed DR resources only directly affect emissions in a handful of hours during the year, when and if they are called upon. If the capacity need was filled with the NGCC resource *instead of* the DR resource, there are two differences in the emissions profile. The first is the difference in emissions associated with the operation of the NGCC resource compared to emissions associated with operation of the RICE-backed DR resource in those hours when the DR resource would have been called upon. As noted, while these impacts may be important, they are not the focus of this analysis.

[15] This assumes that the NGCC plant has variable operating costs low enough to often be economically dispatched throughout the year – in other words, the resource is frequently inframarginal in energy markets. For the newest, most efficient NGCC plants that are proposed for development in competitive markets in PJM, this is typically the case.

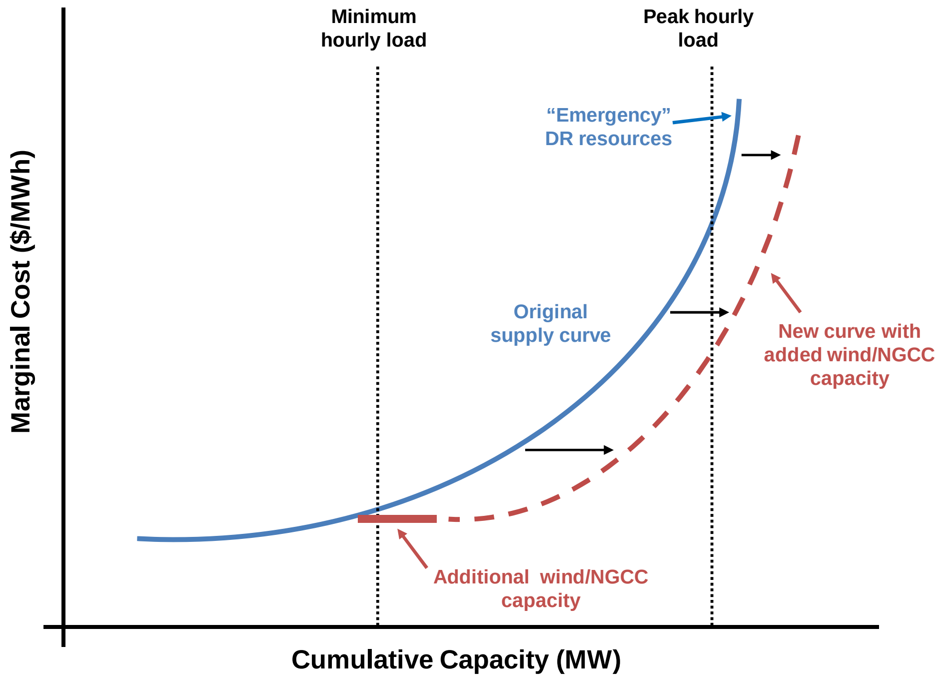
But the second is potentially far more important. The DR resource does not directly affect system emissions in any other hours of the year. In contrast, the NGCC resource is likely to operate in many – if not most – hours of the year because of the economic value the NGCC resource provides in the context of the regional energy market. In every hour that it operates, it will displace emissions from generation that otherwise would have been needed, on the margin. In some hours, this could be a lower-emitting resource, meaning that overall system emissions are increased. In other hours, this operation of the NGCC resource could displace a higher-emitting resource, meaning overall system emissions are decreased.[16] Thus, while the DR resource may not have a direct impact on system-wide air emissions (assuming it is not actually dispatched), its participation in the regional energy and capacity markets can – and does – have a potentially measurable indirect impact on regional air emission due to this displacement effect.

In contrast to the DR resource, the NGCC resource fundamentally changes the supply curve for the region, altering system dispatch in many hours, in ways that have implications for system emissions. The addition of inframarginal capacity (such as wind or efficient NGCC capacity) low on the supply curve will change which unit operates on the margin in many hours; in contrast, DR resources are effectively at the "top" of the supply curve and rarely, if ever, change the dispatch of units on the margin (see Figure 1). In each hour that the additional wind or NGCC capacity operates, it is likely to push the operation of some other unit off the margin.

The impact on emissions of these very different dispatch outcomes between RICE-backed DR and alternative capacity resources may be estimated by simulating the dispatch of the power system under these two scenarios. The sections that follow contain a description of the analytic method used to do this, a summary of the results with respect to differences in emissions of CO_2, NO_x, SO_2, and Hg, and a discussion of the implications of the analysis.

[16] In this Report, I will refer to this effect as increasing or decreasing emissions. However, for pollutants that are controlled under an existing emission cap and trade program across all states in the region in question (in the case of the analysis in this report, SO_2 and NO_x), the level of actual emissions would presumably be unchanged over time, subject to the cap. In this case, what changes are the complexity and/or cost of meeting the compliance obligations associated with the emissions cap. For pollutants not covered by an emission cap and trade program across the all states in the region in question (in the case of the analysis in this report, CO_2 and Hg), emissions may be assumed to actually increase or decrease by the estimated quantities. In the current context, an important exception to the rule that emission caps put a ceiling on power sector emissions of a given pollutant is the fact that the emissions of small, behind-the-meter resources are generally not included in cap programs. Thus, the operation of RICE-backed DR may, in many states, represent absolute increases in emissions even for those pollutants subject to emission caps.

Figure 1



Analytic Method

In order to assess the potential magnitude of this effect, I simulated the dispatch of the PJM power system over a 10-year period (2016 – 2025) associated with various scenarios that reflect differences in different capacity market outcomes.[17] The purpose of the analysis was to evaluate system dispatch with and without postulated quantities of RICE-backed DR, in order to assess the potential emissions impact associated with participation of these resources in capacity markets, relative to alternative capacity market outcomes. Consequently, the scenarios differ in the assumed levels of DR relative to capacity market alternatives.

Identifying the specific levels of RICE-backed DR to assume for the analysis is frustrated by a lack of clear, public data on the extent to which DR resources are associated with back-up generation units. That is, it is not possible to identify specifically what portion of existing (or future) DR capacity is or would be

[17] I chose PJM because is the largest centrally-organized wholesale electricity market with a forward capacity market in the Eastern Interconnection, and has the largest contribution to capacity needs from DR resources.

backed by RICE.[18] This is largely due to the fact that the specific location, source, type (e.g., backed by RICE or not), or economics of most of the DR in the PJM capacity market is not available.

There is, however, significant evidence that the extent of RICE-backed DR is substantial. For example:

- Of the RTOs that provide for the participation of DR as a capacity resource, MISO has perhaps the most explicit and complete reporting of the source of DR capability. The 2011 State of the Markets Report for MISO notes that, in 2010, 5,077 MW out of a total of 8,663 MW – or *nearly 60 percent* - of DR capability was comprised of behind-the-meter generation.[19] While the quantity of behind-the-meter DR declines in 2011 (to approximately 3,001 MW), most or all of the difference transferred into PJM's service territory – see below.
- While PJM DR owners essentially do not need to describe their method for achieving load reduction levels in advance, PJM began surveying participants about the make-up of their demand resources. Fifteen percent reported using backup generation. However, providers of DR were allowed to select an 'other' category to the extent they preferred to keep the source of DR confidential. This 'other' category contains 65 percent of all demand response resources, and likely includes both RICE-backed DR and other sources.[20] Thus, at least 15 percent, but theoretically as much as 80 percent, of the DR currently operating in PJM may be based on behind-the-meter generation.
- In a report issued earlier this month, Northeast States for Coordinated Air Use Management (NESCAUM) provides data suggesting that *at least* twenty percent of New England's DR and ten percent of New York's DR is associated with back-up generation.[21]
- DR provider EnergyConnect estimates that as much as 30 percent of demand response is sourced from emergency generators.[22]
- Finally, the transition of First Energy (FE) subsidiaries into the PJM control region provides an indication of how significant the overall level of DR in PJM may be. Prior to 2011, FE's subsidiaries were split between MISO and PJM. As of June 1, 2011, their assets were consolidated into the PJM region. American Transmission Systems, Inc. (ATSI), a subsidiary of

[18] Since it is not possible to know the extent or type of back-up generation behind DR resources, it is also not possible to assess what portion of these resources would not participate in DR programs but for a waiver of NESHAP RICE requirements.
[19] Potomac Economics, *2011 State of the Market Report for the MISO Electricity Markets*, June 2012, ("MISO 2011 SOM") p. 54, refer to Table 3.
[20] Northeast States for Coordinated Air Use Management, *Air Quality, Electricity, and Back-up Stationary Diesel Engines in the Northeast*. August 1, 2012, p. 23.
[21] Ibid, p. 14.
[22] Hearing Transcript at 101.

First Energy, located in Northern Ohio, was transferred from MISO to PJM.[23] Between 2010 and 2011, MISO lost 2,076 MW of Demand Response that was specifically identified as behind-the-meter generation with an additional loss of 286 MW of Load Modifying Resources.[24] According to the 2011 MISO State of the Market Report, this reduction "is largely due to the departure of First Energy in June 2011."[25] This magnitude of generation-backed DR that exited MISO from the ATSI service territory is closely aligned with the 2,038.5 MW of DR offered into the 2012 Base Residual Auction in PJM for the ATSI Zone for the 2015/2016 delivery year (1,763.7 MW cleared), indicating that in at least one of PJM's load zones, the vast majority of DR is likely to be backed by RICE-based or other on-site generation.[26]

While all of this evidence suggests that potentially significant quantities of DR are backed by RICE units, the lack of hard data makes it difficult to pinpoint the actual quantity, requiring that the dispatch analysis cover a range of potential outcomes. Consequently, based on consideration of the data summarized above, I conducted the dispatch simulation under a number of different potential scenarios – from one that assumes displacement with market alternatives of just ten percent of DR to one that assumes no more than fifty percent of DR. In other words, the analysis addresses outcomes related to replacing from 10 percent to 50 percent of existing and expected DR with other capacity resources. This relatively wide range is roughly consistent with the range of minimum and maximum behind-the-meter contributions to DR in the eastern RTOs, and should be sufficient to represent the potential range of emission impacts associated with the participation of RICE-backed DR in capacity markets.

The simulated dispatch analysis (SDA) approximates the dispatch of generating resources in PJM to meet the electrical load requirements in every hour of each year in the modeling period under the different scenarios. To do so, it identifies the total megawatt-hours (MWh) of generating units and the marginal generating unit operating on the system in each hour, as well as emissions of CO_2, NO_x, SO_2, and Hg (where applicable). System-wide totals of pollutant emissions are calculated, and are compared across scenarios. The modeling period is set for the ten-year period 2016 – 2025, to correspond with the start of

[23] Press Release from Ellen Raines, News Media Contact, American Transmission Systems, Inc., *ATSI Signs Agreement to Join PJM* (December 18, 2009).
[24] MISO 2011 SOM, p. 54, refer to table 3.
[25] Ibid, p. 54.
[26] The 2015/2016 auction is the most recent auction in PJM in which ATSI participated. PJM, *2015/2016 RPM Base Residual Auction Results*, PJM Document #699093, p. 8, table 3A.

the first calendar year associated with the most recent PJM forward capacity market Base Residual Auction (BRA).[27]

Specific elements of the SDA model for the **Base Case** include the following: [28]

1. **Peak Load and Annual Energy Requirements:** Electrical load requirements are based on actual historical hourly load in the PJM region in 2011. PJM forecast load growth rates are then used to forecast peak load and hourly energy requirements for each year of the modeling period. Average transmission and distribution system losses are estimated based on average PJM loss factors and added to forecast hourly metered loads for the purposes of system dispatch simulation.
2. **Existing Capacity Resources:** Capacity resource information is from SNL Financial for the PJM region. Capacity information includes plant-level data on fuel, technology type, heat rates, total variable cost and historical performance. NERC Generation Availability Data System (GADS) data for PJM are used to model scheduled, maintenance and forced outages for each capacity resource, based on technology- and size-average factors in GADS (this data is also used for new resource additions; see below). Wind, solar and hydro resources are derated based on reported capacity factors in the PJM 2011 State of the Markets Report. Emission data for CO_2, NO_x, and SO_2 are from SNL Financial, based on EPA-reported historical plant monitoring results. Mercury emissions are based on data collected in the EPA Mercury and Air Toxics Standards rulemaking docket.
3. **Resource Addition/Attrition:** Additions and retirements are based on data from SNL Financial, and are added to/removed from the existing capacity resources. Only known additions and retirements are applied, which include units either "under construction" or "in advanced development" according to SNL Financial, and reported retirements. In addition, it is assumed that approximately 15,000 MW of DR exists in 2016 (consistent with the DR resources that cleared in the most recent BRA), and that in each year beyond 2016, an additional 1,000 MW of demand resources is added to the system. Beyond this point, generic capacity is added in MW quantities if and as needed to ensure that PJM continues to meet a reserve margin of 15.4 percent; the resources added are in rough proportion to development interests currently represented in the

[27] The Delivery Year of the most recent BRA is June 2015 through May 2016.
[28] This section summarizes the model used for simulating system dispatch, the scenarios analyzed and compared, the basic assumptions applied, and the output of model analyses. The Appendix contains a more detailed description of model inputs, forecasts, and assumptions.

PJM interconnection queue (approximately two-thirds natural gas-fired, and one-third wind generation).[29]

4. **Fuel Prices:** Resource variable costs are increased over time consistent with forecasts of fuel prices through the end of the modeling period. The natural gas price forecast is based on NYMEX futures contracts out to December 2018 (when liquidity dries up), and then grows to 2025 using delivered prices to electric generators from the EIA 2012 Annual Energy Outlook. Coal and oil price forecasts are based on annual regional growth rates for delivered prices to electric sector consumers from the EIA 2012 Annual Energy Outlook.

With these inputs, SDA is used to approximate the differences in total system emissions and generation by fuel source between the Base Case and four different system capacity scenarios, which are identical in every respect to the Base Case, with the following exceptions:

1. **Scenario 1:** *Fifty percent* of the DR in the Base Case is removed, and replaced with generation resources roughly in proportion to existing supply development interests represented in the PJM interconnection queue (approximately two-thirds natural gas-fired, and one-third wind generation).
2. **Scenario 2:** *Twenty five percent* of the DR in the Base Case is removed, and replaced with generation resources roughly in proportion to existing supply development interests represented in the PJM interconnection queue (approximately two-thirds natural gas-fired, and one-third wind generation).
3. **Scenario 3:** *Ten percent* of the DR in the Base Case is removed, and replaced with generation resources roughly in proportion to existing supply development interests represented in the PJM interconnection queue (approximately two-thirds natural gas-fired, and one-third wind generation).
4. **Scenario 4:** *Fifty percent* of the DR in the Base Case is removed, and replaced with generation resources assumed to all be fueled by natural gas. This scenario's capacity mix is the least plausible given development interests, and because it is highly unlikely that, in the absence of RICE-backed emergency DR's participation in the capacity market, new wind generating

[29] The proportion of PJM interconnection queue capacity by fuel source can differ significantly depending on the expected delivery date of the proposed projects. While current queue capacity has a higher level of contribution from renewable (primarily wind) resources than I assume in the analysis, in later years the proportion of such resources drops off relative to natural gas-fired resources. For the purposes of simplicity and consistency, I chose to apply the two-thirds natural gas, one-third wind across all years and all Scenarios (except Scenario 4, which assumes all natural gas replacement).

resources would not be utilized to meet some portion of the regional capacity needs. However, I analyzed this scenario in order to demonstrate that the observed reduction in overall electric system emissions is not due solely to addition of renewable generating resources (which have no emissions), but rather includes displacement of higher-emitting resources (including older, less-efficient gas units, as well as coal and oil resources) that are currently operating at the margins of the supply curve by new, low-emission natural gas capacity.

Results of the Emission Analysis

The results of the SDA analysis are at first glance counterintuitive. It is often assumed that avoiding the construction of new generating capacity through the implementation of DR would represent a decrease in emissions of key air pollutants, all else equal. This analysis shows that in consideration of the vastly different roles that RICE-backed DR and alternative *capacity* resources play in wholesale *energy* markets, this assumption is not necessarily valid – and at the current time appears to be incorrect, at least in PJM.[30]

Table 1

Total Emissions by Pollutant
Basecase v. Scenarios
2016-2025

Emissions Type	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CO_2 (tons)				
Basecase	5,436,229,964	5,436,229,964	5,436,229,964	5,436,229,964
Scenario	5,164,699,995	5,282,565,009	5,353,962,599	5,331,908,036
Difference	-271,529,969	-153,664,956	-82,267,366	-104,321,928
SO_2 (tons)				
Basecase	10,613,586	10,613,586	10,613,586	10,613,586
Scenario	10,162,603	10,355,393	10,477,845	10,324,894
Difference	-450,982	-258,193	-135,740	-288,692
NO_x (tons)				
Basecase	4,962,285	4,962,285	4,962,285	4,962,285
Scenario	4,722,205	4,820,156	4,883,505	4,794,032
Difference	-240,080	-142,129	-78,779	-168,253
Hg (tons)				
Basecase	36.86	36.86	36.86	36.86
Scenario	35.30	35.97	36.40	35.87
Difference	-1.56	-0.89	-0.46	-0.98

Notes:
[1] Values shown represent the difference between scenario case and base case. A negative value indicates a decrease in emissions in the Scenario, relative to the Basecase.
[2] Scenario 1 reduces DR contributions by 50%; Scenario 2 by 25%; Scenario 3 by 10% and Scenario 4 by 50%, and replaces the DR with market alternatives.

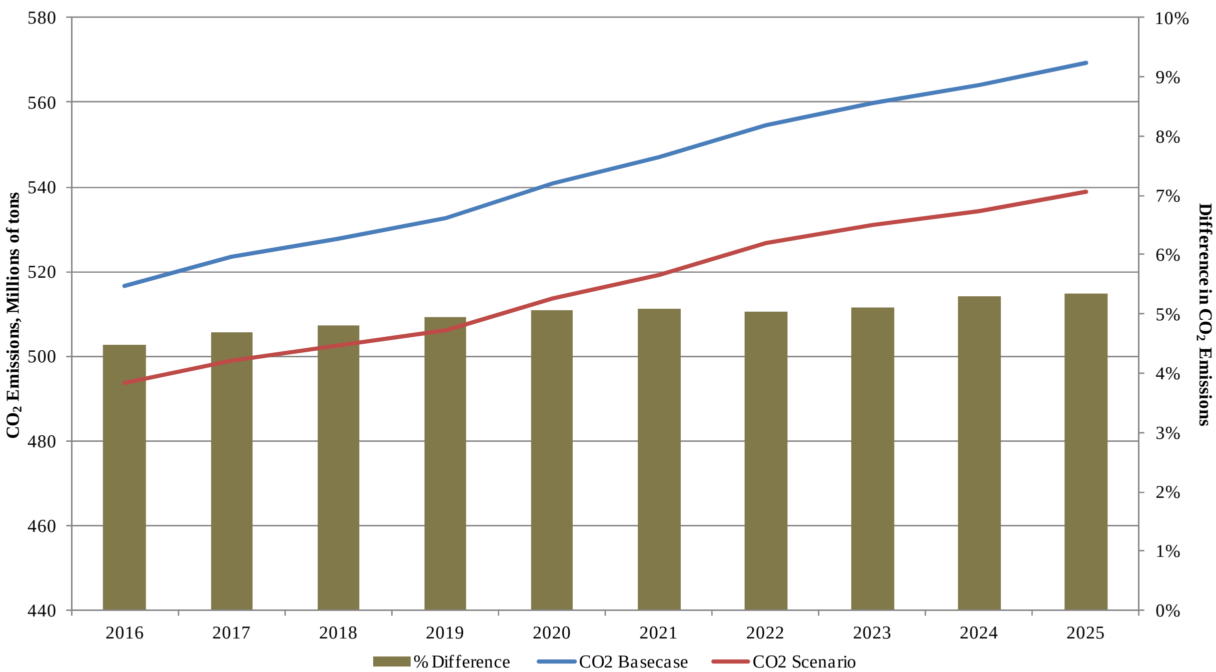
[30] The analysis is conducted only for PJM. However, since the results are driven by market structures, fuel mixes, and relative fuel price conditions that exist across many of the country's power regions, the conclusions may hold in other regions as well.

In all scenarios with reduced DR penetration, the system-wide emissions of all pollutants are lower than the Base Case emissions. See Table 1, which presents the total emission results across the modeling period for each Scenario, and Figure 2, which shows emission reductions for CO_2 on an annual basis for Scenario 1.[31] Specifically:

- The decrease in emissions of CO_2 across the scenarios, relative to the Base Case, range from 82 million tons (Scenario 3) to 272 million tons (Scenario 1) over the modeling period. Average annual emission reductions in Scenario 1 are 27 million tons of CO_2, representing a reduction of approximately 5 percent.
- The decrease in emissions of Hg across the scenarios, relative to the Base Case, range from 0.5 tons (Scenario 3) to 1.6 tons (Scenario 1) over the modeling period. Average annual emission reductions in Scenario 1 are 0.2 tons of Hg, representing a reduction of approximately 4.2 percent.

Figure 2

Total Emissions
CO_2, Basecase v. Scenario 1
2016-2025



Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 50% reduction in DR relative to the base case, replaced by natural gas and wind capacity. Natural gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.

[31] Additional charts and data representing the (similar) results for all Scenarios, and all pollutants, are presented in the Appendix.

- The decrease in emissions of NO_x across the scenarios, relative to the Base Case, range from 79 thousand tons (Scenario 3) to 240 thousand tons (Scenario 1) over the modeling period. Average annual emission reductions in Scenario 1 are 24 thousand tons of NO_x, representing a reduction of approximately 4.8 percent.[32]
- The decrease in emissions of SO_2 across the scenarios, relative to the Base Case, range from 136 thousand tons (Scenario 3) to 451 thousand tons (Scenario 1) over the modeling period. Average annual emission reductions in Scenario 1 are 45 thousand tons of SO_2, representing a reduction of approximately 4.3 percent.[33]

In short, the analysis demonstrates that it is inappropriate to assume that the emission impacts of granting a waiver to RICE-backed DR are de minimis, especially when considering the interaction of energy and capacity markets. Waiving otherwise applicable environmental requirements for RICE-backed DR to participate in the competitive energy and capacity markets would effectively provide a financial subsidy for those resources, further enhancing their ability to underbid and inhibit the development of new generation facilities that could provide substantial environmental benefits to the region.

The reduction in emissions is driven primarily by a displacement of energy production at older, less-efficient fossil-fuel resources with the combination of output from new, efficient and inframarginal natural gas-fired and wind-powered generation (Scenarios 1-3), or all natural gas-fired generation (Scenario 4). Since in the Base Case the DR resources (that are replaced in the Scenarios) rarely operate, this displacement effect does not occur, resulting in higher emissions system-wide, and on an annual basis, than in any of the Scenarios.

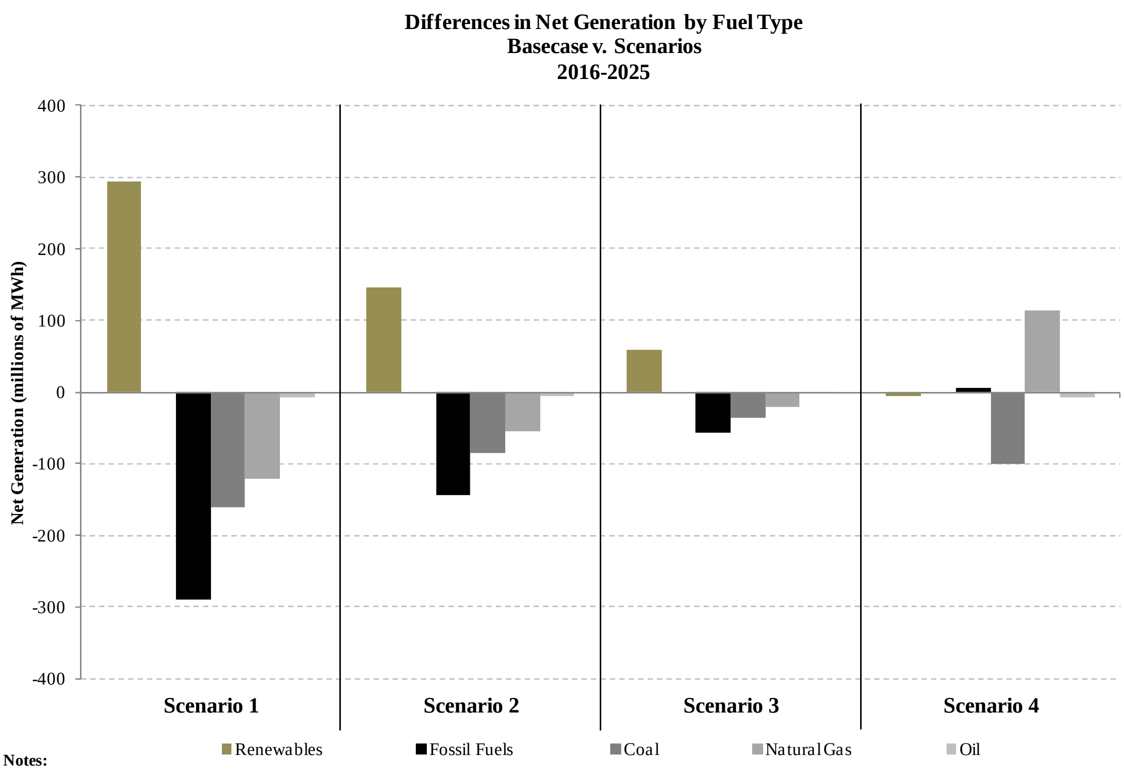
As can be seen in Figure 3, there is actually a net *decrease* in total generation from fossil-fuel resources across Scenarios 1-3, even though DR is being replaced in part by new natural gas generation. Only in Scenario 4 is there a net increase in production from fossil-fired resources. Specifically, the effect of increased generation from the new natural gas-fired capacity, net of reductions in less-efficient gas-fired resources that are displaced in all Scenarios, is an increase in overall production from natural gas capacity. However, this net increase is overshadowed by the substantial decrease in production from

[32] As noted earlier, since emissions of NO_x are subject to a cap and trade mechanism, it may be assumed that, over time, emissions will equal the cap on an annual average basis. Consequently, the "decrease" in emissions of NO_x shown here is more accurately representative of a change in the cost or difficulty of compliance with the cap on NO_x emissions.
[33] As noted earlier, since emissions of SO_2 are subject to a cap and trade mechanism, it may be assumed that, over time, emissions will equal the cap on an annual average basis. Consequently, the "decrease" in emissions of SO_2 shown here is more accurately representative of a change in the cost or difficulty of compliance with the cap on SO_2 emissions.

system coal and oil-fired resources, and less-efficient natural gas resources, leading again to substantial net reductions in emissions of all pollutants.[34]

Finally, when the replacement resources that would be added (but for the RICE-backed DR) are dispatched, the impact is to reduce the dispatch of less efficient, more expensive generation further up the supply curve. In most hours, this leads to lower marginal prices in the energy market – prices that are paid by all purchasers of power within PJM. The analysis conducted for this Report confirms that the net effect of this outcome is significantly lower dispatch prices in PJM, and substantially lower payments for energy across every year of the model results, for every Scenario.

Figure 3



Notes:
[1] Values shown represent the difference between scenario case and base case. Fossil Fuels value reflects the sum of Coal, Natural Gas, and Oil values.
[2] Scenario 1 reduces DR contributions by 50%; Scenario 2 by 25%; Scenario 3 by 10% and Scenario 4 by 50%.
[3] In Scenarios 1-3, the reduced DR is replaced with a mix of 2/3 natural gas, 1/3 wind capacity. In Scenario 4, the DR is replaced with 100 percent natural gas capacity.
[4] Renewables include biomass, solar, hydro, and wind.
[5] Only significant changes are shown. Changes in other fuels are either zero (e.g., nuclear) or small (e.g., biomass, other non-renewable). See table for breakdown of changes by fuel type.

[34] Specific changes in generation from all sources, across all Scenarios (relative to the Base Case), are presented in the Appendix.

In other words, reliance on DR as a capacity resource affects not only power system emissions, but energy prices for consumers as well. This is because the same mechanism applies in both cases: To the extent a MW of DR capacity displaces an opportunity to install a MW of new renewable or NGCC generation, the market fails to realize the emissions benefit associated with having that MW of new generation participate as an energy resource and displace emissions from more polluting resources. The *reason* this occurs is because the new MW of NGCC or wind has lower fuel costs, is more energy efficient, and/or has other attributes that allow it to economically displace more polluting and less efficient resources that otherwise would operate.

DR providers assert that DR results in system-wide cost savings.[35] This is because, to the extent that the lowest-cost DR clears the capacity market, it can place downward pressure on capacity prices. However, consumers ultimately experience the combined effect of capacity and energy costs, and energy costs typically comprise a significant portion of a consumer's total energy bill. Therefore, it is not appropriate to focus on only potential DR-related cost savings in capacity market prices; in order to assess whether DR positively or negatively affects consumer energy payments, one must determine the net effect of potential capacity and energy cost impacts.[36]

Additional Considerations

It is important to keep in mind the limitations of modeling exercises such as this one. This is by necessity a simplified representation of electricity market outcomes, with a number of uncertainties and assumptions that may cause the results to be over- or under-stated, relative to what would actually happen. Key variabilities and uncertainties include load, generation, and fuel price forecasts; the lack of nodal or zonal representations of load and generation (masking the potential influence of transmission interface constraints on results); the implicit assumption of perfect information and perfect competition with no variation in resource owner bidding behavior, and market bids based on variable costs; and the existence of variations in industry structure across the region that, in reality, can affect resource commitment and dispatch (e.g., through self-scheduling of resources). Finally, as noted, while the range of potential uneconomic RICE-backed DR is based on a review of available information, much of that

[35] See, for example, testimony of Bruce Campbell on behalf of EnergyConnect (Hearing Transcript at 102).
[36] I do not report on the magnitude of energy market cost reductions here because the focus of this review was on generation and emission impacts in the context of a pending EPA rulemaking, and because the cost picture would be incomplete without calculation of changes in costs that derive from capacity market outcomes, which was not modeled in the SDA.

information includes significant uncertainty; it is difficult at this time to assess where the actual results lie within in the range used for the Scenarios in this analysis.

Finally, the analysis in this report is exclusively focused on the *system-wide* emission impacts of competing scenarios of capacity resource integration, focused on RICE-backed DR and existing interconnection queue resource types. It does not review what the *resource-specific* emission impact is of displacing the actual generation of diesel generation in DR resources with queue-based wind or natural-gas fired generation, in those hours when the DR programs are activated. Nor is any effort made to assess the potential correlation between operation of Stationary Engines and days when air quality violations occur, or other factors that could increase or decrease the public health implications of differences in emission outcomes. The recent Report issued by NESCAUM raises significant questions about the specific impacts associated with RICE-backed DR emissions; to the extent such impacts arise, they would be additive to the impacts discussed in this report.

4. CONCLUSIONS

EPA is proposing a special waiver/allowance under the RICE NESHAP rules for Stationary Engines that are used as DR resources that participate in wholesale markets for capacity in the electric sector, on the bases that (1) such resources are needed to maintain reliability under stressed electric system conditions, and (2) the emission impacts of such a waiver are de minimis, since the DR resources are only called upon in very limited circumstances, for few hours per year.

In this Report, I review EPA's justifications on reliability and environmental grounds, and find that both come up short. Specifically, RICE-backed DR is not uniquely needed to preserve power system reliability – it simply displaces other capacity resources that would contribute equally, if not more, to power system reliability than these DR resources. Second, the successful participation of RICE-backed DR in regional capacity markets likely *increases* emissions of CO_2, NO_x, SO_2, and mercury, relative to the same capacity needs being met by alternative market resources. This is due to the fact that RICE-backed DR may prevent or delay the development of new cleaner generating resources which would displace less efficient, higher emitting fossil-fueled resources currently operating at the margin of the supply curve throughout the year. Importantly, it is this displacement effect that is often cited as a key driver of the economic retirement of the power system's least-efficient, highest-emitting resources. Unfortunately, the increasing penetration of RICE-backed DR is inhibiting the market's ability to achieve this.

The conclusion based on this analysis is not that DR should be prevented from participating in wholesale electricity markets – various forms of economic DR can and do provide benefits to system operations, market efficiency, and consumer costs. Rather, the analysis simply tests EPA's assumptions regarding any reliability and environmental justification for granting a *special* exemption for Stationary Engines to participate in wholesale electricity markets through DR programs without installing emissions controls.

It is an important question because of the scope of the current level of DR participation in the market, and because such special treatment of one class of supply resources – RICE-backed "emergency" DR vis-à-vis cleaner resources currently in the interconnection queue – creates inequities in the competitive wholesale markets for electric generating capacity – inequities that compromise competitive outcomes, decrease the efficiency of power system operations, and increase electricity costs for all consumers. In order for such a waiver to be justified, there should be strong and unambiguous environmental, reliability or other public policy benefits.

In this case, based on my review and analysis I conclude that there is no plausible reliability justification and that the environmental impacts are headed in the wrong direction. Waiving otherwise-applicable environmental compliance requirements for RICE-backed DR facilitates capacity market outcomes that result in significant increases in emissions of key pollutants, with no commensurate increase in power system reliability.

5. APPENDIX: MODEL ASSUMPTIONS AND RESULTS

This appendix provides a summary of the method and sources used to develop the supply curve dispatch model developed by Analysis Group and used for the analysis presented in the main body of the report, and presents scenario results in detail.

Base Case

Supply Curves

The 2011 supply curve was downloaded from SNL Financial for the PJM region. This supply curve includes plant level information on fuel and technology types, heat rates, total variable costs, and capacity factors.

For some units, plant level information in the supply curve is incomplete (a very small number of units, representing less than one percent of total regional capacity); for such units, data is obtained from preliminary EIA data or historical data. If no data are available from any source, the unit is excluded from the supply curve.

Wind and solar capacity is derated in all hours based on the capacity factors reported for 2011 in the PJM State of the Market report. Hydro capacity is also derated using the same source, but is given full capacity credit for the reserve margin calculations discussed in the next section.

Adjustments for unit availability are also made. GADS data for PJM from the PJM 2011 Reserve Requirement study are used based on fuel and technology type, with planned outages assigned during the shoulder months. Forced outages are spread over the full year.

SNL data was used to develop fuel/technology type fuel cost ratios, which were applied to total variable costs. For example, all coal units had a fuel cost ratio applied to develop what portion of total variable costs were attributable to fuel costs for coal plants in the PJM region. These fuel costs were then adjusted for fuel forecasts developed by Analysis Group (described in the following sections).

For the first forecast year (2016), DR resources were assumed to be equal to the DR resources that cleared in the most recent BRA. In subsequent years, it is assumed that 1,000 MW of new DR is added to this base amount in each year.

Unit Additions and Retirements

Once the current form of the supply curve is finalized, future additions and retirements are taken into account. These are based on data from SNL, and are applied to the supply curve data. Only known additions are added, which include units either “under construction” or in “advanced development” according to SNL; and only those retirements that have been reported by the plant owner as of July 2012 are accounted for. The vast majority of both known additions and known retirements occur between 2012 and 2015. Additions are included in the model using costs, heat rates, and capacity factors for recently installed and operating plants of the same technology, and are added as average size plants compared to recent installations or new plants in the interconnection queue. Retirements are for specific units.

The net effect of known additions and retirements, and the potential need for capacity beyond that, is evaluated to determine the quantity of generation to be added in later years of the forecast period. A test is performed to determine whether the changing supply and demand conditions assumed using the SNL data would result in a breach of the reserve margin; a reserve margin of 15.4% is used for this calculation, based on the most recent PJM Reserve Requirement study. When that condition is violated, additional generic capacity is added to ensure that reserve margins are met. For this purpose, the model applies a mix of 2/3 combined cycle gas and 1/3 wind capacity sufficient to meet the capacity requirements of the region.

Demand Forecast

The SDA model includes a forecast for load in every hour of the modeling period (2016 – 2025). The forecast begins with historical hourly load for 2011, adjusted to account for the integration of the ATSI system into PJM. This hourly load is grown based on peak demand forecasts published by PJM, including the most recent load report from the PJM and any updates issued. The peak demand forecast is used to calculate an annual growth percentage that is applied to all hours of the 2011 demand curve to grow it forward. Transmission line losses are accounted for by adjusting forecast metered demand by eight and a half percent, based on reported loss factors in the PJM footprint.

Fuel Prices

Fuel price forecasts are used to grow the fuel cost portion of total variable costs for the plants in the supply curve for future years. Fuel price forecasts for natural gas, coal, and oil are based on several sources.

Natural Gas – Natural gas price forecasts are based on NYMEX futures contracts through December 2018. These futures are for the Henry Hub. After December 2018, liquidity in trading dries up in NYMEX contracts, so monthly prices are grown at the annual regional growth rates for delivered prices to electric sector consumers from the EIA 2012 Annual Energy Outlook. A basis differential is added to the Henry Hub forecast prices, representing the three-year historical basis differential between Henry Hub and the average of the Columbia, Algonquin NJ-PA, and TETCO M-3 hubs.

Coal – Coal price forecasts are based on annual regional growth rates for delivered prices to electric sector consumers from the EIA 2012 Annual Energy Outlook. These growth rates are applied to the calculated coal fuel costs from the SNL Financial supply curve values.

Oil – Oil price forecasts are based on annual regional growth rates for delivered prices to electric sector consumers from the EIA 2012 Annual Energy Outlook 2012. These growth rates are applied to the calculated oil fuel costs from the SNL Financial supply curve values.

Emissions

Plant-level 2011 CO_2, SO_2, and NO_x emission totals, as well as annual net generation totals, were obtained from SNL Financial. 2010 mercury emissions were obtained from the EPA Mercury and Air Toxics Standards rulemaking docket. EPA's mercury total is reported for each individual boiler unit, so EPA totals were aggregated by EIA site ID in order to correlate them to SNL's plant-level data. These data were combined to yield the respective plant-specific emission rate for that pollutant. Fuel and technology type average rates were used for plants that did not have a valid plant-specific emission rate.[37] All emissions from solar, water, wind, and nuclear plants were taken to be zero.

[37] This occurred either because the plant's emissions were not in SNL or was reported as zero, or the plant's operating capacity was less than 25 MW and thus it was exempt from the Continuous Emissions Monitoring System reporting requirements. If a plant reported some pollutants and not others, then plant-specific rates were used for those pollutants and category averages for the others.

Scenarios

Four separate Scenarios were run, which are all identical in every respect to the Base Case, with the following exceptions:

1. **Scenario 1:** *Fifty percent* of the DR in the Base Case is removed, and replaced with generation resources roughly in proportion to existing supply development interests represented in the PJM interconnection queue (approximately two-thirds natural gas-fired, and one-third wind generation).
2. **Scenario 2:** *Twenty five percent* of the DR in the Base Case is removed, and replaced with generation resources roughly in proportion to existing supply development interests represented in the PJM interconnection queue (approximately two-thirds natural gas-fired, and one-third wind generation).
3. **Scenario 3:** *Ten percent* of the DR in the Base Case is removed, and replaced with generation resources roughly in proportion to existing supply development interests represented in the PJM interconnection queue (approximately two-thirds natural gas-fired, and one-third wind generation).
4. **Scenario 4:** *Fifty percent* of the DR in the Base Case is removed, and replaced with generation resources assumed to all be fueled by natural gas.

Results

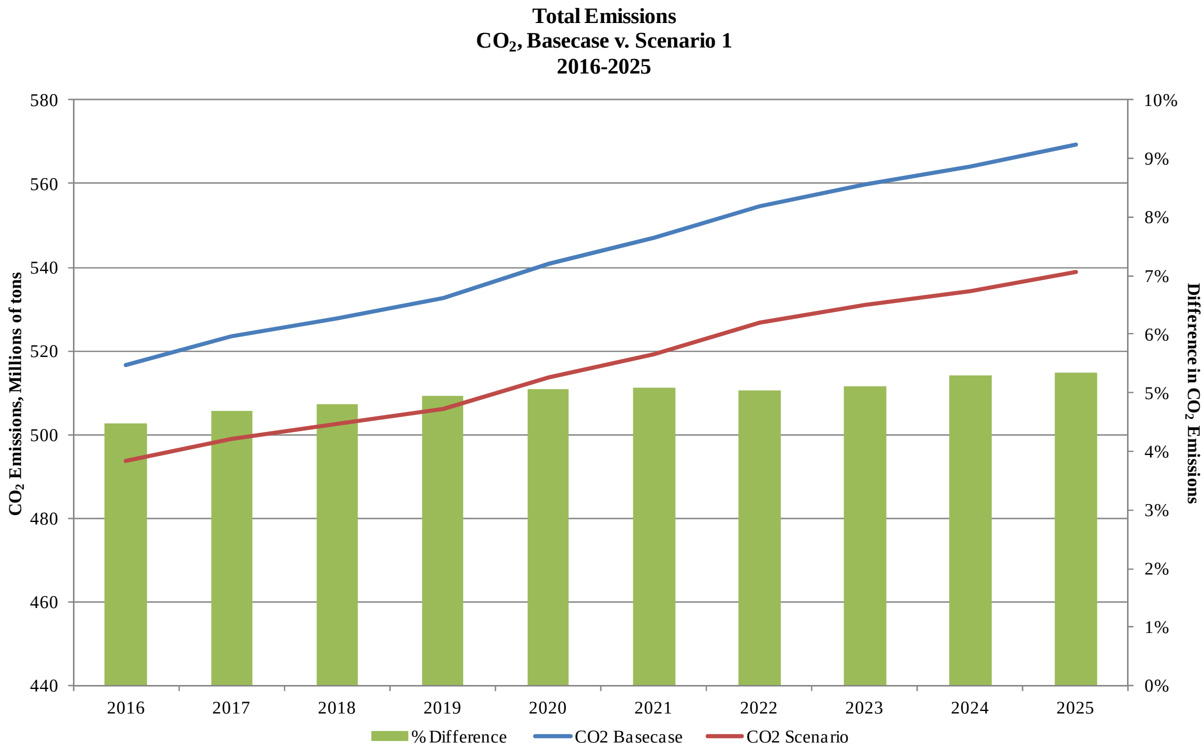
i. Generation Changes Across All Scenarios

Total Generation by Fuel Type
Basecase v. Scenarios
2016-2025

Fuel Type	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Biomass				
Basecase	71,251,452	71,251,452	71,251,452	71,251,452
Scenario	64,991,863	67,650,415	69,658,518	65,682,831
Difference	-6,259,588	-3,601,036	-1,592,933	-5,568,621
% Difference	-8.8%	-5.1%	-2.2%	-7.8%
Coal				
Basecase	4,271,855,448	4,271,855,448	4,271,855,448	4,271,855,448
Scenario	4,110,408,335	4,186,772,445	4,236,787,060	4,170,821,387
Difference	-161,447,113	-85,083,003	-35,068,388	-101,034,061
% Difference	-3.8%	-2.0%	-0.8%	-2.4%
Gas				
Basecase	1,400,467,656	1,400,467,656	1,400,467,656	1,400,467,656
Scenario	1,279,315,523	1,345,920,192	1,380,304,813	1,514,813,093
Difference	-121,152,132	-54,547,464	-20,162,843	114,345,437
% Difference	-8.7%	-3.9%	-1.4%	8.2%
Nuclear				
Basecase	2,721,027,862	2,721,027,862	2,721,027,862	2,721,027,862
Scenario	2,721,027,862	2,721,027,862	2,721,027,862	2,721,027,862
Difference	0	0	0	0
% Difference	0.0%	0.0%	0.0%	0.0%
Oil				
Basecase	12,576,664	12,576,664	12,576,664	12,576,664
Scenario	4,570,284	7,680,241	10,368,770	4,686,100
Difference	-8,006,380	-4,896,423	-2,207,894	-7,890,564
% Difference	-63.7%	-38.9%	-17.6%	-62.7%
Other Nonrenewables				
Basecase	17,587,795	17,587,795	17,587,795	17,587,795
Scenario	16,289,980	16,817,629	17,239,122	16,350,851
Difference	-1,297,816	-770,166	-348,674	-1,236,945
% Difference	-7.4%	-4.4%	-2.0%	-7.0%
Solar				
Basecase	3,375,599	3,375,599	3,375,599	3,375,599
Scenario	3,375,599	3,375,599	3,375,599	3,375,599
Difference	0	0	0	0
% Difference	0.0%	0.0%	0.0%	0.0%
Water				
Basecase	155,994,702	155,994,702	155,994,702	155,994,702
Scenario	155,994,702	155,994,702	155,994,702	155,994,702
Difference	0	0	0	0
% Difference	0.0%	0.0%	0.0%	0.0%
Wind				
Basecase	283,207,713	283,207,713	283,207,713	283,207,713
Scenario	582,507,713	432,857,713	343,067,713	283,207,713
Difference	299,300,000	149,650,000	59,860,000	0
% Difference	105.7%	52.8%	21.1%	0.0%

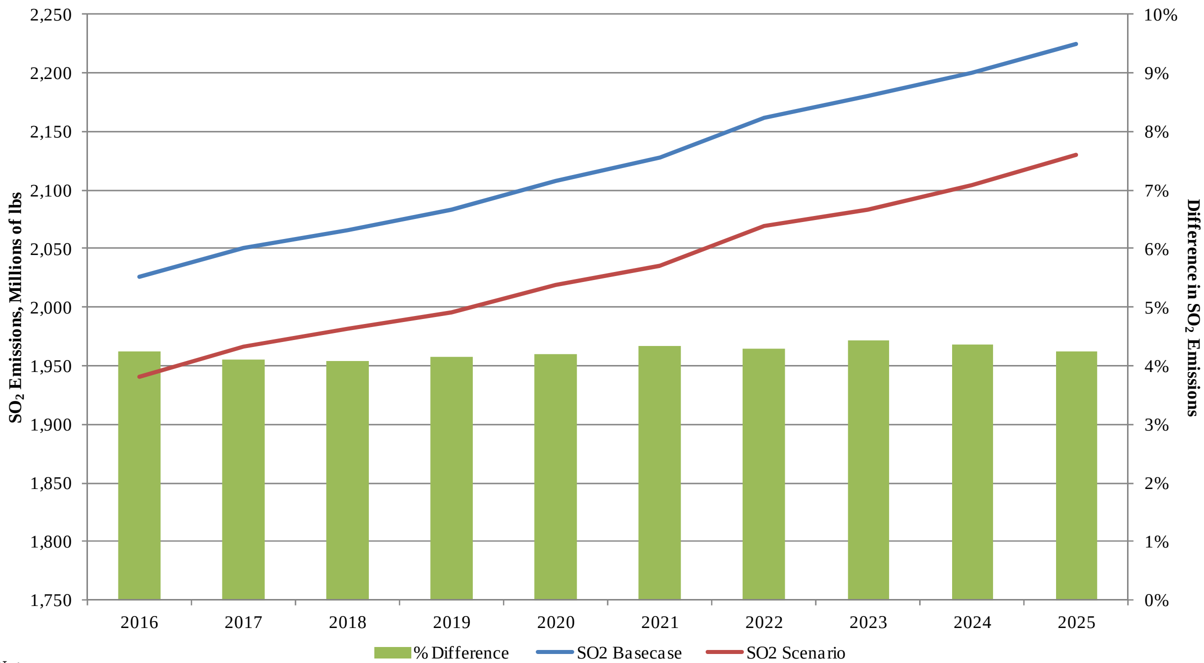
Notes:
[1] Values shown represent the difference between scenario case and base case.
[2] Scenario 1 reduces DR contributions by 50%; Scenario 2 by 25%; Scenario 3 by 10% and Scenario 4 by 50%, but with all capacity replacements with gas combined cycle units.

ii. Scenario 1

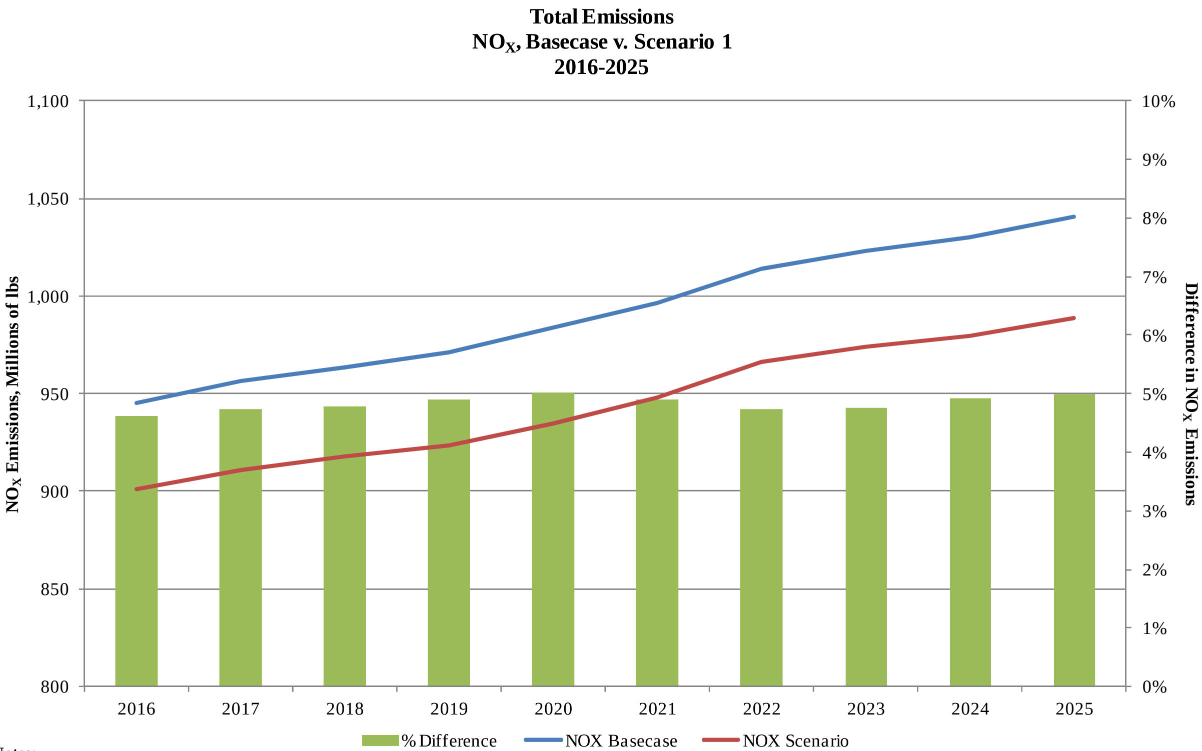


Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 50% reduction in DR relative to the base case, where 500MW of DR, and 500MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.

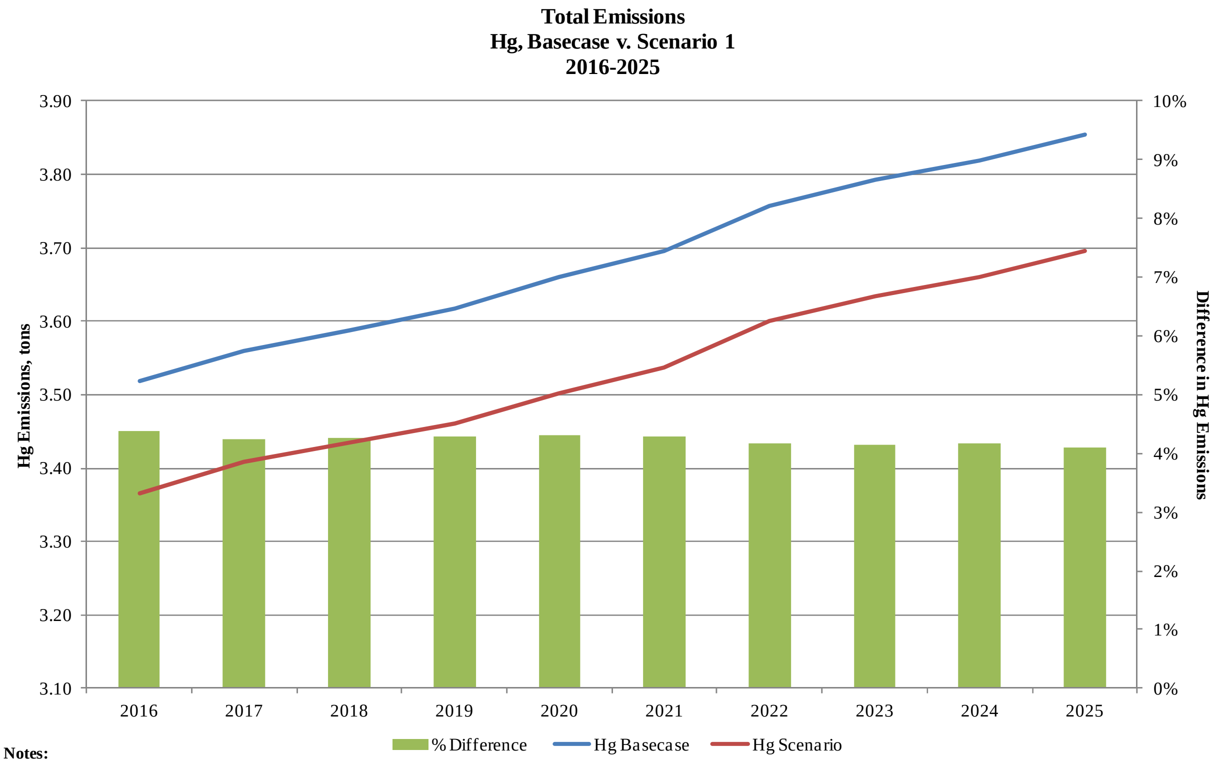
Total Emissions
SO_2, Basecase v. Scenario 1
2016-2025



Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 50% reduction in DR relative to the base case, where 500MW of DR, and 500MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.



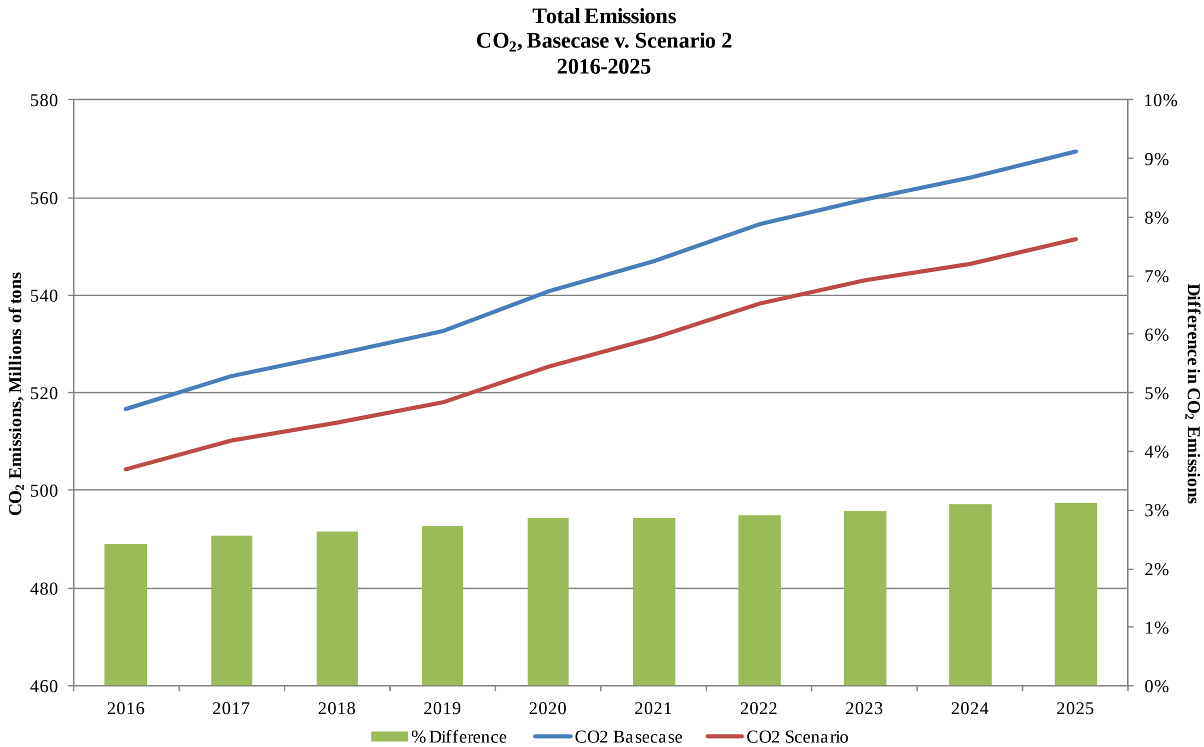
Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 50% reduction in DR relative to the base case, where 500MW of DR, and 500MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.



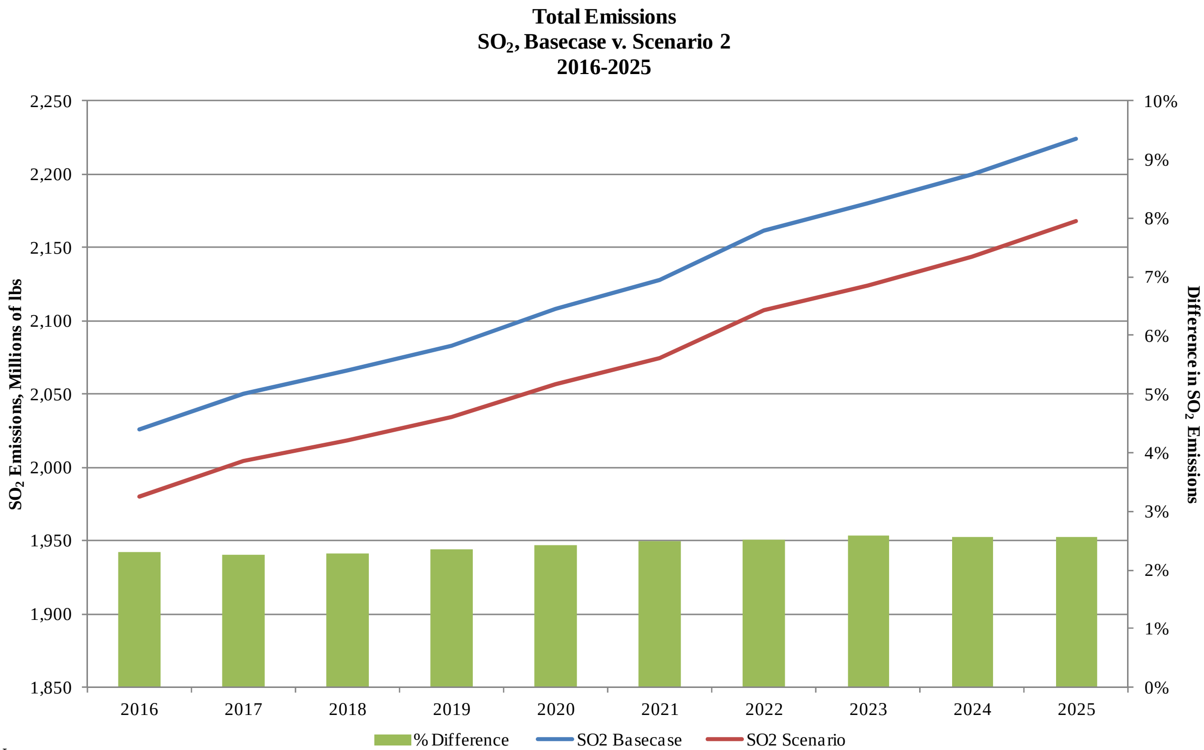
Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 50% reduction in DR relative to the base case, where 500MW of DR, and 500MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.

Sources:
[1] SNL Financial.
[2] EIA Data.

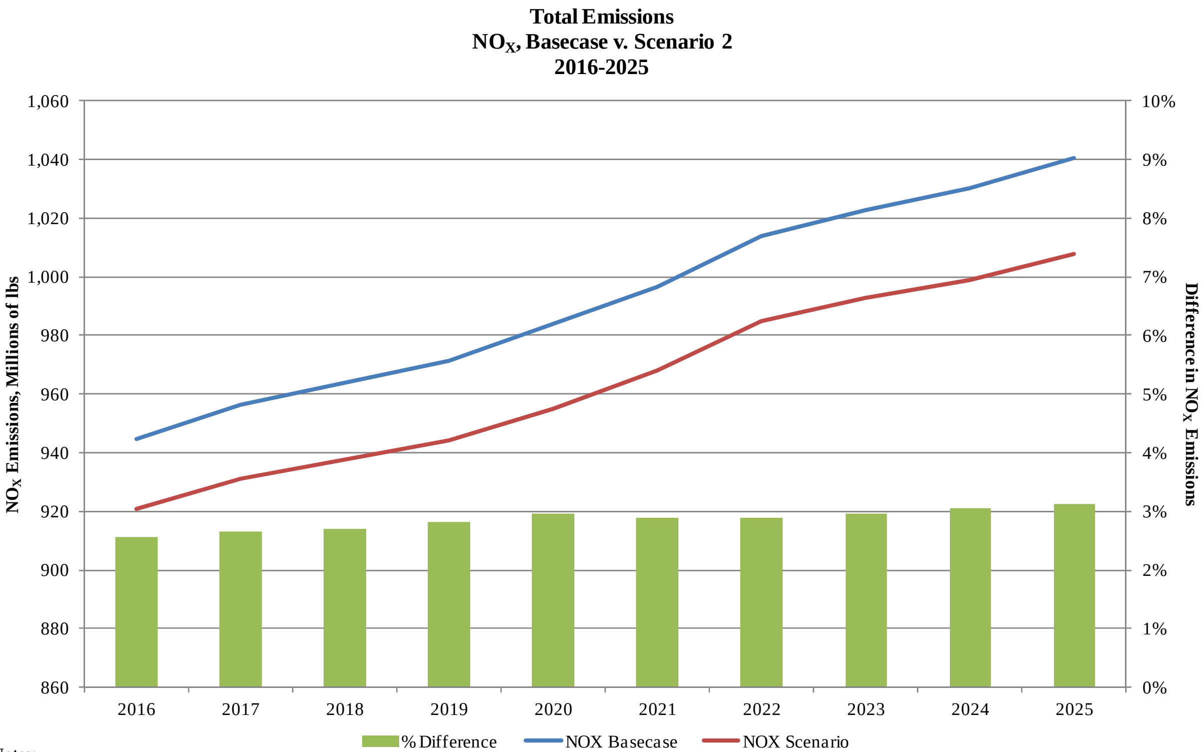
iii. Scenario 2



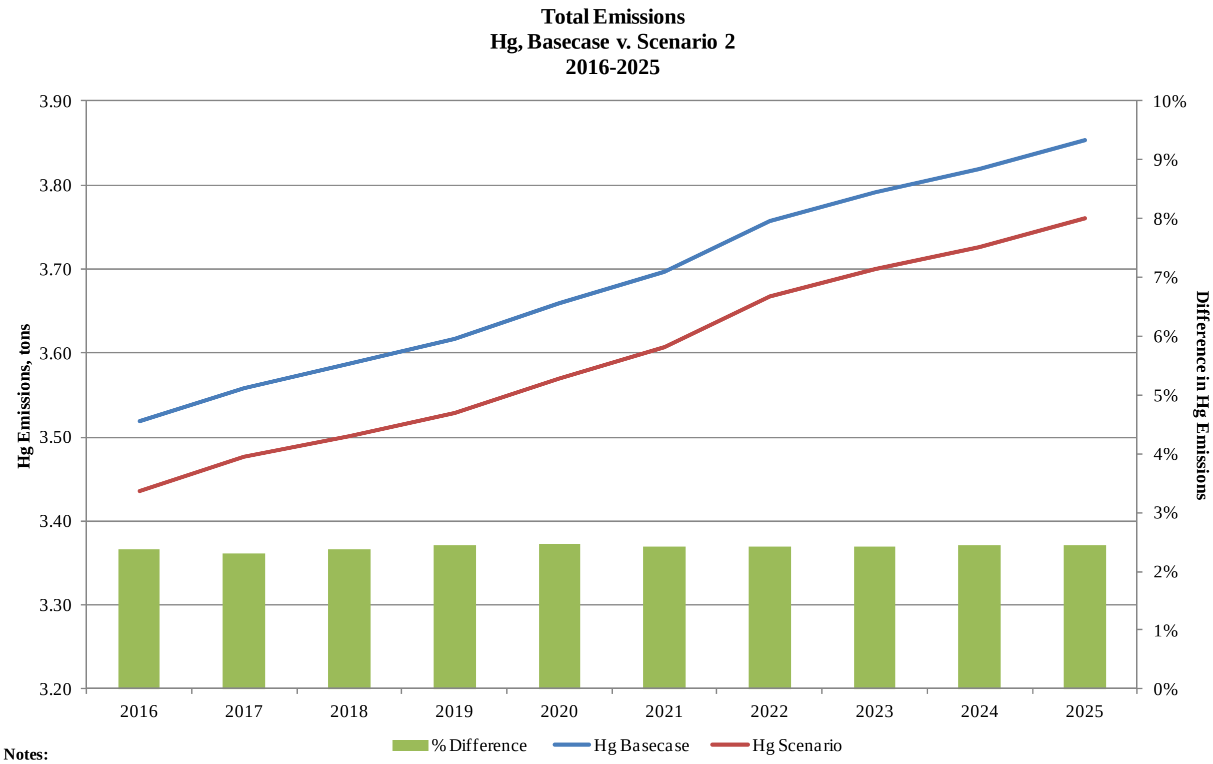
Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 25% reduction in DR relative to the base case, where 750MW of DR, and 250MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.



Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 25% reduction in DR relative to the base case, where 750MW of DR, and 250MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.

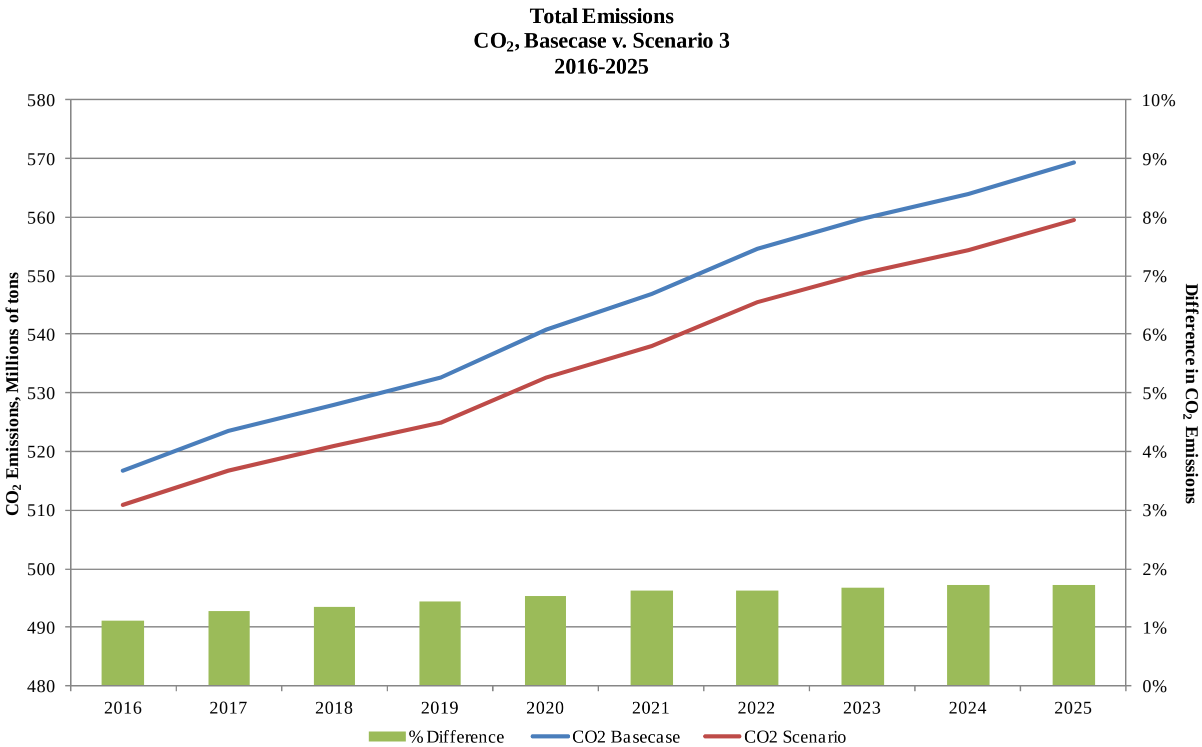


Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 25% reduction in DR relative to the base case, where 750MW of DR, and 250MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.

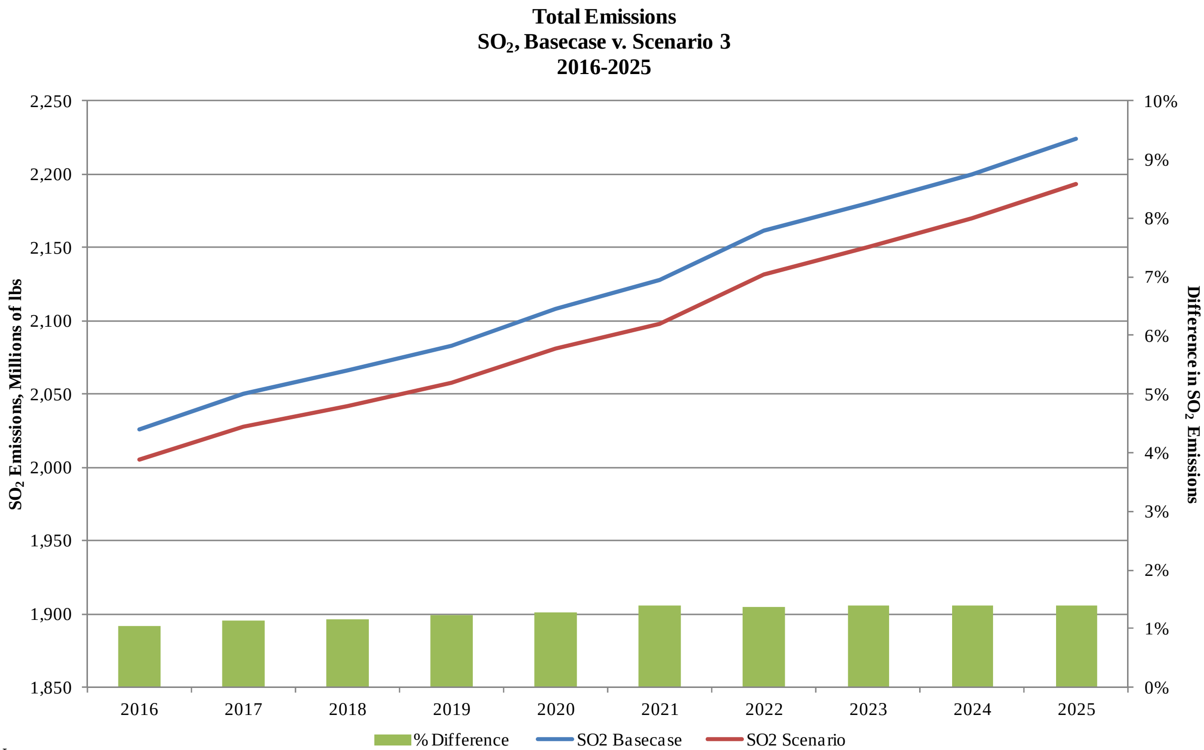


Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 25% reduction in DR relative to the base case, where 750MW of DR, and 250MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.

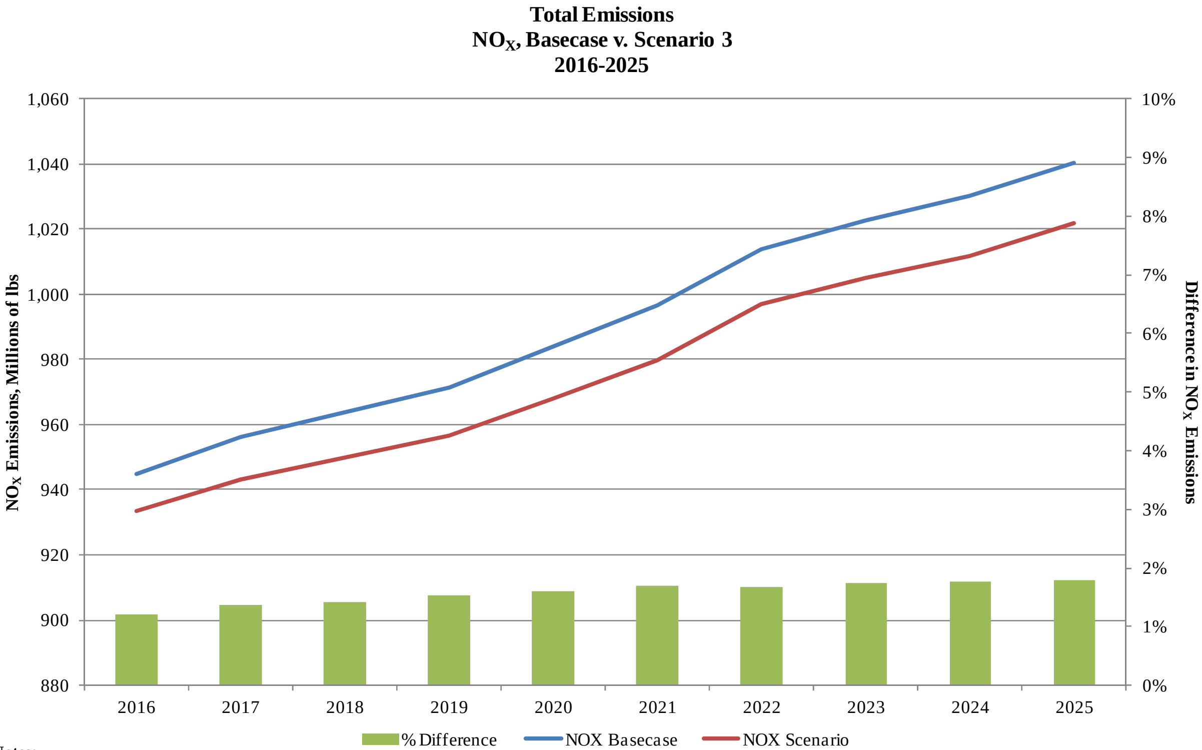
iv. Scenario 3



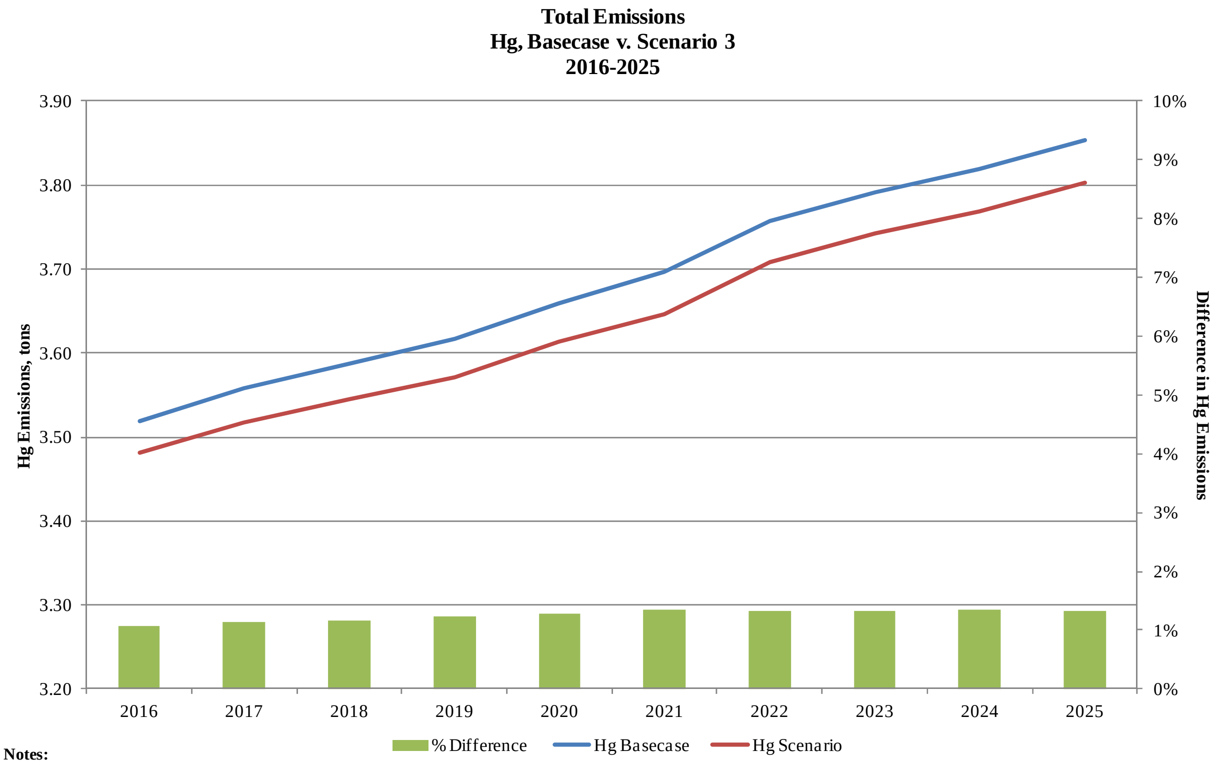
Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 10% reduction in DR relative to the base case, where 900MW of DR, and 100MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.



Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 10% reduction in DR relative to the base case, where 900MW of DR, and 100MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.

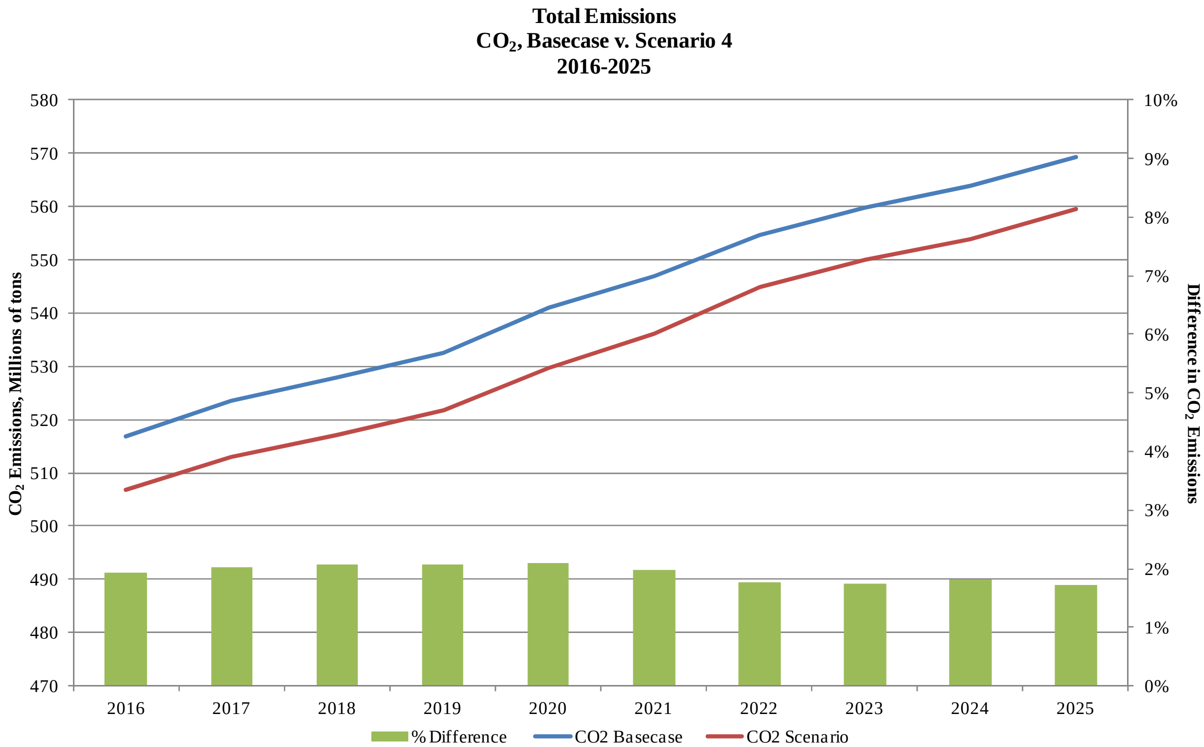


Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 10% reduction in DR relative to the base case, where 900MW of DR, and 100MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.

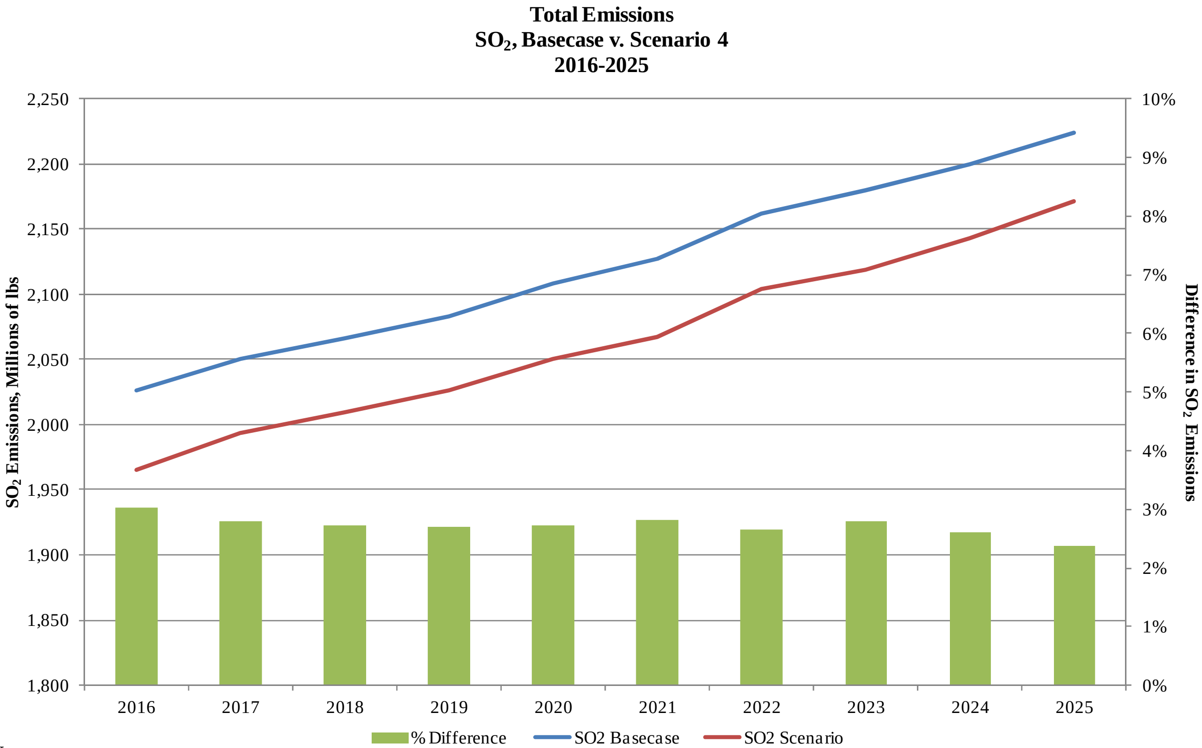


Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 10% reduction in DR relative to the base case, where 900MW of DR, and 100MW of gas combined cycle and wind units are added per year from 2016-2025, where gas and wind are apportioned in a 2/3 and 1/3 ratio respectively.
Sources:
[1] SNL Financial.
[2] EIA Data.

v. Scenario 4

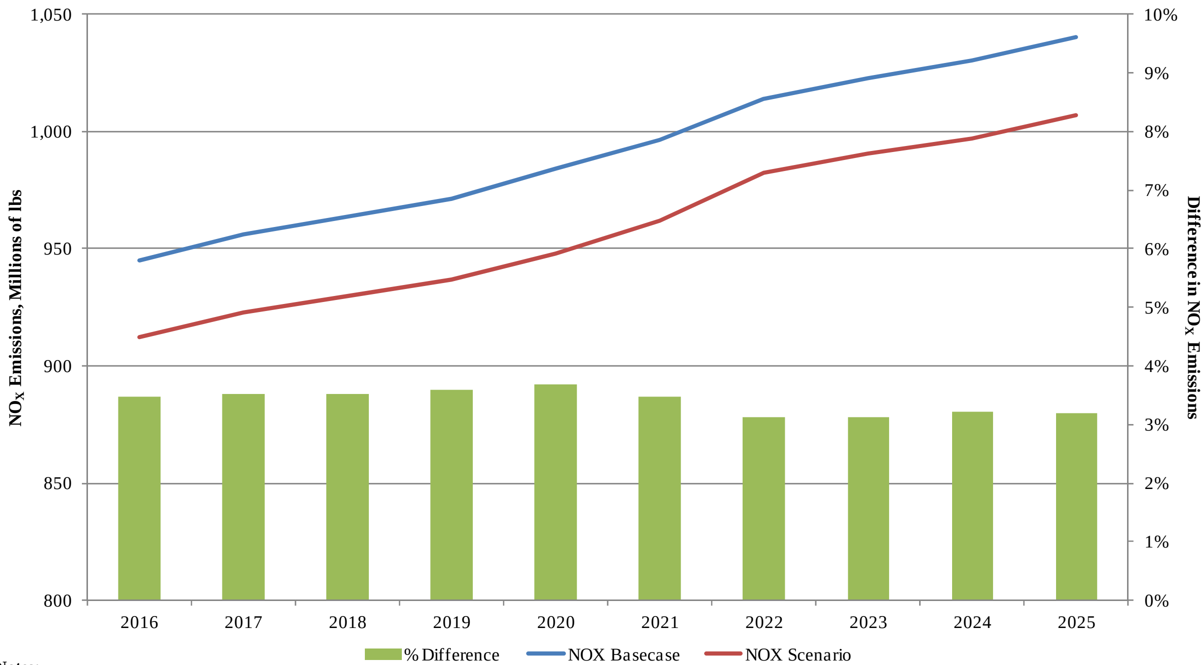


Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 50% reduction in DR relative to the base case, where 500MW of DR, and 500MW of gas combined cycle units are added per year from 2016-2025.
Sources:
[1] SNL Financial.
[2] EIA Data.

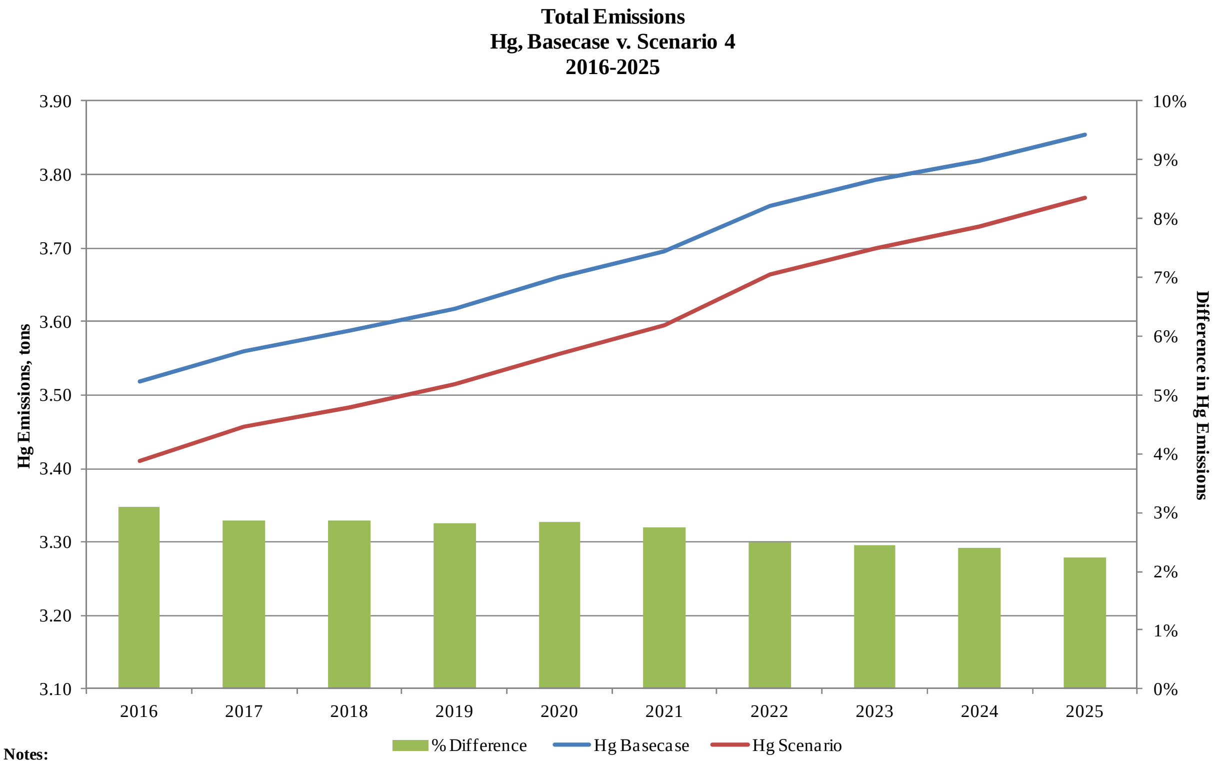


Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 50% reduction in DR relative to the base case, where 500MW of DR, and 500MW of gas combined cycle units are added per year from 2016-2025.
Sources:
[1] SNL Financial.
[2] EIA Data.

Total Emissions
NO_X, Basecase v. Scenario 4
2016-2025



Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 50% reduction in DR relative to the base case, where 500MW of DR, and 500MW of gas combined cycle units are added per year from 2016-2025.
Sources:
[1] SNL Financial.
[2] EIA Data.



Notes:
[1] The base case represents an addition of 1000MW of DR per year from 2016-2025.
[2] The scenario case represents a 50% reduction in DR relative to the base case, where 500MW of DR, and 500MW of gas combined cycle units are added per year from 2016-2025.
Sources:
[1] SNL Financial.
[2] EIA Data.