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Date of Hearing: 9/29/2015

Case No. 14-1297-EL-SSO

PUCO Case Caption: In the Matter of the Application of Ohio Edison, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.	Case No. 14-1297-EL-SSO

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PROCEEDINGS

before Mr. Gregory Price, Ms. Mandy Chiles, and Ms. Megan Addison, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 10:00 a.m. on Tuesday, September 29, 2015.

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VOLUME XX

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December 1, 2014

EPA Docket Center, U.S. EPA
Docket ID No. EPA-HQ-OAR-2013-0602
U.S. Environmental Protection Agency
Mail code: 28221T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Sir or Madam:

Re: Docket ID No. EPA-HQ-OAR-2013-0602
FirstEnergy Corp. Comments on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

Please find enclosed FirstEnergy's comments on EPA's proposed "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units."

If you should have any questions, please contact Ms. Michele Somerday at (330) 761-4128 or email at msomerday@firstenergycorp.com, or Mr. Michael Jirousek at (330) 384-5744, or email at mjjirousek@firstenergycorp.com.

Sincerely,

Raymond L. Evans

rle/mls
Enclosure
By e-mail: a-and-r-docket@epa.gov

EXHIBIT
IGS 8

PENGAD 800-631-6989

FirstEnergy Corp. Comments on EPA's proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

INTRODUCTION

FirstEnergy Corp. (FE) is a diversified energy company dedicated to safety, reliability and operational excellence. Its 10 electric distribution companies form one of the nation's largest investor-owned electric systems, serving customers in Ohio, Pennsylvania, New Jersey, West Virginia, Maryland and New York. Its generation subsidiaries currently control nearly 18,000 megawatts of capacity from a diversified mix of scrubbed coal, non-emitting nuclear, natural gas, hydro and other renewables. The majority of our generation is merchant.

FE has already achieved significant reductions of CO_2 emissions. As a company, we expect to achieve a 25% reduction below 2005 levels by 2015. Even so, it is unclear if the company will get credit under the Clean Power Plan (CPP) for any of these reductions even though the EPA press statements emphasized that the rule's goal is to reduce power sector emissions 30% below 2005 levels by 2030.

In 2009, the President announced his goal of a 17% reduction below 2005 levels by 2020. The power industry is on track to meet its share of that target. Over the long term, we see dramatic long term emission reductions in our sector very much in line with the President's 2050 goals given the average retirement age of a coal plant, the transformative shift to gas due to the enormous domestic resource now economically recoverable, MATS and other proposed EPA rules. Given these facts, we question the need for the current structure of the proposed rule.

The nation's electric system has been developed and maintained on the core principles of reliability and affordability. The current emissions trajectory of the electric generation sector would suggest that reliability and affordability can come with significant reductions in emissions. However, the proposed Clean Power Plan puts no emphasis on either affordability or reliability and, in fact, deemphasizes and, depending upon implementation, punishes both. For example, existing nuclear power is the most reliable, affordable and emission free source of electricity today, yet the proposal does not appropriately recognize any of these attributes and actually devalues it in comparison to other generation that is less reliable, less affordable and relies on quick response backup power that comes with CO_2 emissions. It is crucial to maintain diversity within our generation fleet going forward in order to hedge against potential price increases and supply disruptions for any particular fuel. From a reliability perspective, it is essential that base load generation (coal and nuclear) remain a feasible and cost-effective source of generation to meet existing and future energy needs.

In structuring this rule, EPA doesn't appear to have fully vetted issues with regard to the broader system that will be impacted by this rule, such as; transmission capability of both electricity and natural gas; general infrastructure upgrades; energy storage; and even the contribution of fuel diversity to reliability and affordability of the system, to name a short few. Virtually all of these broader system issues fall under the jurisdiction of FERC and/or state utility regulatory commissions. Given the complexities of the broader system which EPA does not have jurisdiction over, we believe that prior to EPA approval of any state implementation plan, FERC (and/or the relevant regional transmission organization (RTO)) should first certify that the plan will not adversely impact the broader energy system or degrade reliability. Because the system interconnects multiple states, the reliability impact in one state cascades to an entire region, so it is vital that FERC/RTO play a role in fully understanding the impact of each individual plan and be responsible for certifying its impact before EPA approves and a state implements its plan.

FE is also concerned that the Best System of Emission Reduction (BSER) has been developed without consideration to how electricity market structures are not monolithic throughout the states. Economic decisions with regard to investment in a unit or other infrastructure will vary dramatically depending upon whether those occur in a regulated market or in a competitive merchant market. For example (and further discussed in Block #1 comments), economic tolerance for investment in heat rate improvements differs significantly depending upon whether that investment is subject to a regulated rate of return from a state public utility commission (PUC) or whether the return is totally dependent upon market pricing. While EPA has developed state specific BSER emission rates, it does not take into account the differing market dynamics in each state. As noted above, a heat rate that may be economically achievable in a "regulated" state may not be achievable in a "competitive" state. To ensure fairness and accuracy, EPA should reconstruct BSER calculations based on the differing market dynamics in each state. Setting an accurate state specific rate requires such attention to detail.

And lastly as a general comment, FE believes that the rule is faulty in that while EPA relied on the fact the electric system is an inter-connected system and thus requires an interdependent approach laid out in the proposal, EPA then developed specific BSER building blocks as independent silos without calculating their interconnectivity. FE will address this more specifically in the comments below.

SPECIFIC

FE appreciates the opportunity to further comment on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (EGU). These comments focus on four key areas of concern:

1) Nuclear
2) Best System of Emission Reduction
3) Maximum State Flexibility
4) Clean Air Act Authority

Nuclear

In its development of the state goals through application of BSER, EPA assumed the license renewal of all existing nuclear units up to a final life span of 60 years. The license renewal process is an extremely thorough, multi-year endeavor and, as with any permitting process, the outcome is certainly not predetermined. NRC cannot commit that it will approve any application prior to the end of the exhaustive public process. To do so would be inconsistent with the law and overall good government. EPA cannot and should not presume a licensing outcome that is currently unknown. EPA's final 111(d) rule should exclude nuclear units whose license expires prior to 2030 from its calculation of BSER. Consistent with EPA's treatment of new nuclear plants, any unit whose license expires prior to 2030, and receives a license renewal approval after 2012 should be considered a "new" nuclear unit for the purpose of compliance.

Also with regard to the treatment of nuclear, EPA determined that 5.8% of all existing nuclear units, regardless of location, are at risk of economic shutdown. At risk nuclear plants vary state to state, largely dependent upon whether they operate as a merchant unit or a unit regulated by a PUC. As a result, EPA improperly represented at risk nuclear capacity in setting the standards for states that have existing nuclear capacity, by applying a uniform 5.8% in each state regardless of whether a specific unit in a state is at risk for an early closure.

Best System of Emission Reduction

EPA's interpretation of BSER includes actions that are outside of its jurisdiction and legal enforceability (i.e., "outside the fence measures"). In fact, no federal agency has statutory authority to require or enforce the emission reductions contemplated in Building Blocks #3 or #4 (with the possible exception of the NRC authority to regulate nuclear generation). Building Block #1 is the only block that EPA has authority to regulate. The Clean Air Act does not grant EPA authority over Building Blocks #2, #3, and #4, which were used to develop and establish state compliance goals. These Building Blocks are primarily the domain of the state and/or Regional Transmission Organizations as granted by FERC or the Nuclear Regulatory Commission (NRC). The Clean Air Act (CAA) does not provide EPA authority to implement or enforce such energy system programs, nor can a state provide authority to EPA (for programs which do not currently exist)[1] by including certain compliance methods (such as renewable energy standards or energy efficiency requirements) in a State plan ultimately approved by EPA. EPA, similarly, lacks authority to fully utilize the building blocks that are the basis of its own proposal to develop and enforce a federal implementation plan, if it becomes necessary.

EPA has a statutory obligation to ensure that BSER is adequately demonstrated and to show that the state emission rate goals are achievable, particularly in light of the interconnected nature of the power system. EPA should ensure that the state emission rate goals in any final rule reflect: (1) an evaluation of the four BSER Building Blocks to properly reflect the interrelationships of the various options and potential for impact on power grid reliability and affordability and (2) appropriate assumptions and conclusions about the level of reductions achievable by each Building Block. Specifically, Building Blocks #1 and #2 are diametrically opposed; therefore, both should not be included in the BSER calculation.

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[1] Gina McCarthy, Administrator U.S. Environmental Protection Agency responses to questions in a U.S. Senate Committee on Environment and Public Works, July 23, 2014, hearing entitled, "Oversight Hearing: EPA's Proposed Carbon Pollution Standards for Existing Power Plants."

In regard to Building Block #2, increasing the utilization of natural gas combined cycle (NGCC) units will displace coal-fired EGU output and coal-fired EGU heat rates will actually increase as a result, increasing their CO_2 emission rate.[2] Coal-fired EGUs are designed to be most efficient when operated in a steady state at their full load capacity. Increases to the NGCC fleet capacity factor will necessarily relegate coal-fired EGUs to load following service resulting in more time operating at unstable and generally lower loads where they are less efficient. Load following service will also lead to an increase in the number of startups and shutdowns experienced by the coal-fired fleet. Coal-fired unit startups are lengthy and inefficient operating regimes that will further increase coal-fired EGU heat rates and CO_2 emissions.

In addition, efficiency is poor for low generation levels (a connected plant that is operating at zero MW output still has to supply station loads) and increases with the level of generation, but at some optimum level it begins to diminish[3]. Most power plants are designed so that the optimum level is close to the rated output.

When capital investments (i.e. heat rate improvements) are made in merchant markets, investors carefully consider whether the forward looking revenues will cover the costs of the investment. Given the uncertainties that Building Block #2 introduces into how coal units will be dispatched, it is unlikely that investors relying on the market for recovery of investments will choose to invest in these improvements. This dynamic does not exist for regulated generators and points out how this proposed rule exacerbates the inequity between regulated and restructured states.

Similarly, EPA has also overlooked the negative impact on gas-fired EGU efficiency with respect to load following units. Under Building Block #2 of the Proposed Guidelines, EPA would require states to redispatch generation from coal-fired EGUs to NGCC units, which will result in more coal-fired EGUs being dispatched as load-following units as well as higher heat rate simple cycle combustion turbines. This raises a concern that there may not be sufficient load following generation capable of meeting the load following needs of transmission grids,

[2] Most power plants are designed such that when the unit operates at its designed capacity, efficiency is also optimized. Therefore, reduction of coal-fired units' output, because of increased utilization of NGCC, will result in degradation of the effective heat rate of coal-fired EGUs. The result will be an increase in the rate of carbon dioxide emissions from coal-fired EGUs that see their output dispatched to lower than optimal levels, which is counter to the goal of the proposed rule.
[3] Source: http://home.eng.iastate.edu/~jdm/ee553/CostCurves.pdf

such as PJM, as NGCC units typically follow load at an order of magnitude faster than coal-fired generating plants. A greater utilization of natural gas, oil peaking, or addition of new natural gas peaking units would have higher heat rates than NGCC plants and some baseload coal plants. Reliance on peaking units to fill the traditional load following mission could result in an increase in CO_2 emissions that is again contrary to the intent of the proposed rule.

EPA rejected natural gas co-firing or conversion at coal-fired steam EGUs in calculating BSER stating that "...other approaches could reduce CO_2 emissions from existing EGUs at lower cost" and "...EPA has not proposed at this time to include this option in the BSER and has not incorporated implementation of the option into proposed state goals." EPA solicits comment on whether this option should be considered part of BSER (Fed. Reg. 34876).

FirstEnergy agrees that natural gas co-firing or conversion of coal-fired steam EGUs should not be considered in determining the BSER due to the impacts on EGU performance and the availability and delivery of natural gas supplies.

Natural gas combustion will result in higher tube metal temperatures in the furnace and convection pass than is seen with coal combustion. A unit derate, typically 85%[4] of maximum continuous rating, may be needed to keep heat transfer surfaces within the range of temperatures for which they are designed and avoid modification or upgrade of materials. Redesign and replacement of furnace tubing and components such as superheaters, reheaters and other components would be needed to continue to achieve maximum continuous rating.

The availability of natural gas supply and delivery to EGUs is critical to reliable operation. Unlike coal, natural gas cannot be stored on site, so any interruption in supply results in immediate shutdown. The extreme colder than normal conditions, termed the polar vortex, experienced by many regions of North America in January, 2014, as well as the Southwest Cold Weather event of February, 2011[5], exposed the various challenges with fuel supply and delivery

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[4] Technical Assessment Guide (TAG®)-Power Generation and Storage Technology Options: 2012 Topics. EPRI, Palo Alto, CA: 2013. 1024063

[5] Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations, Staffs of FERC & NERC, 2011

related to increased reliance of the power industry on natural gas, according to NERC. High demand for natural gas exceeded the delivery capacity of the gas transportation system and resulted in curtailment of fuel delivery to some power plants. The lack of natural gas fuel supply resulted in extremely high market pricing for electricity and the threat of rolling blackouts for certain regions.

In the proposed rule, EPA states that it does not propose to find that carbon capture and storage (CCS) is a component of BSER for CO_2 emissions from existing fossil fuel-fired EGUs. EPA solicits "comment on all aspects of applying CCS to existing fossil fuel-fired EGUs (in either full or partial configurations)". (Fed. Reg. at 34876). FirstEnergy agrees CCS should not be a component of BSER for CO_2 emissions from existing fossil fuel-fired EGUs. Partial CCS has not been adequately demonstrated at full scale for existing units, is not technically feasible and cannot be implemented at costs that are reasonable.

Building Block #1

Building Block #1 assumes that all affected units can achieve a 6% heat rate improvement (HRI). FE believes that the methods used to establish the 6% HRI are flawed and set an unrealistic target.

Heat rate degradation is a normal occurrence in steam plants that results from normal aging of plant equipment and systems and can be exacerbated by changes in operational duty cycles such as increased start-ups, shut-downs, operation at other than steady state load and run time at lower-than-rated capacity. Degradation also occurs when new systems that draw large amounts of auxiliary power, such as environmental controls, are added to a plant. Changes in coal supply to meet environmental requirements can also degrade heat rate due to changes in fuel quality. Most of these types of degradation are not economically recoverable.

The proposed rule includes 4% HRI related to maintenance and operating practices that is based on an unsubstantiated statistical analysis. Serious flaws in that statistical analysis include several coal-fired units listed with gross efficiencies over 42% which is impossible; while others are listed with heat rates under 20% – very unlikely. Another serious flaw is EPA's assumption that 30% of the heat rate variance from the top decile is associated with controllable operating and maintenance practices that would be cost effective to perform. EPA fails to consider that what may be cost effective in a state with regulated markets with a guaranteed rate of return on investments may not be "cost-effective" in states with competitive markets where market prices determine what is "cost-effective." EPA only adjusted the data for ambient temperature and capacity factor, however, there are many factors other than maintenance and operating practices that likely contributed to heat rate variability on the units in the dataset. These include, among others, heat rate improvement projects (that results in a double impact because they are included as potential operating practice heat rate improvements when, in fact, they are heat rate improvement opportunities that have already been completed); capacity factor changes within the EPA bands; fuel switching; and additions of environmental controls. FirstEnergy is not aware of any work EPA performed to 1) validate their statistical approach and variability of the data set, 2) validate the assumption that 30% of the heat rate variability is due to operation and maintenance practices, or 3) evaluate that such practices, are cost effective – both in a competitive and regulated market structure. The proposed rule's use of a 4% HRI for maintenance and operating practices is significantly overstated which results in a BSER that is unachievable.

EPA relies on the Sargent and Lundy (S&L) report prepared for EPA in 2009 to justify an additional 2% HRI from future plant modifications. A cursory review of the S&L report shows that it outlines a group of upgrades that have been known and practiced by the industry for years. S&L specifically stated in their report that "[t]he primary intent of the study was to focus on methods that have been successfully implemented by the utility industry." Since utilities have already completed the actions that S&L includes in the study at many EGUs or have already determined them to be inapplicable to their EGUs, the additional 2% HRI is unachievable and should be removed from Building Block #1.[6]

FE's analysis concludes a total heat rate improvement up to 1.5% from current operating parameters is the maximum attainable at an economically justifiable cost for a merchant unit. An

[6] Additionally, from the report: "S&L cautions that the costs presented herein are not indicative of those that may be expected for a specific facility due to variables such as equipment, material, and labor market conditions and site specifications." And further that, "The costs should not be used as a basis for project budgeting or financing purposes." Regardless of the specific statements by S&L to the contrary, EPA still used the S&L costs as a basis for the cost of compliance. The report characterizes the costs as "order of magnitude". There is a substantial difference between $20/ton and $200/ton of CO_2 which is beyond the cost of a new NGCC plant.

S&L case study found a 4% heat rate improvement, including both maintenance and uprate projects, was possible. However, over half of the heat rate improvements were due to an entire turbine steam path replacement. Only a 1.7% heat rate improvement could be achieved without that turbine steam path replacement which many plants have already performed. The second S&L case study found a 1.2% HRI and included a number of improvements the utility had already performed – reinforcing the point that plants are already performing many of the heat rate improvements S&L described in the normal course of business. In addition, the proposed rule's assumptions ignore that any heat rate improvement recovered through maintenance or heat rate improvement projects will deteriorate between maintenance outages (that is how it became recoverable in the first place). In addition, heat rate improvements attained against the 2012 base year will be significantly offset by reduced coal plant capacity factors associated with EPA's Building Block #2 that shifts dispatch from coal-fired units to NGCC units and future additions of pollution control devices that utilize station power.

FE agrees with EPA's findings that total potential CO_2 reductions achievable through heat rate improvements at non coal-fired units are small compared to the potential at coal-fired units and should not be used in the setting of BSER. (Fed. Reg. 34877)

In general, current market power prices in competitive markets do not support making many of these capital investments, such as a number of heat rate improvements, and could lead to further shut downs of coal plants beyond EPA's assumptions. In the regulated markets, additional costs, if approved by the state PUC, will be passed on to the customer through higher prices.

Any final rule that relies on heat rate improvements must expressly provide that those changes do not trigger NSR or NSPS requirements. The looming threat and cost of NSR will further reduce the economic tolerance in the decision making process. In addition, NSR would also introduce further time delay that could impede the ability of a state to meet compliance deadlines.

Building Block #2

Building Block #2 assumes the ability to shift generation from coal-fired plants to NGCC plants, thereby raising the average NGCC plant capacity factor to 70%. This shifting of generation will reduce the average efficiency of the coal-fired units. EPA has shown a strong relationship between lower capacity factors and lower coal plant efficiency. Therefore, one of the impacts of Building Block #2 will be to offset some of the efficiency improvement efforts taken by coal-fired plants to meet Building Block #1, thereby making Building Block #1 even harder to achieve. This reinforces the necessity to analyze BSER Building Blocks in an integrated manner rather than individually.

FE operates in the PJM Interconnection RTO which recorded the following NGCC capacity factors: 2010 – 28.8%, 2011 – 46.8%[7], 2012 – 60.4%, 2013 – 51.6%[8], and January – June 2014 – 49.4%[9]. In PJM, capacity factors for NGCC have never approached 70%. In fact, when natural gas prices were volatile from 2000 through 2008, NGCC capacity factors were typically well below 20%. While NGCC capacity factors were their highest in 2012, that year was characterized by milder than normal weather, reduced economic activity, and natural gas prices that reached low levels of $2/mmbtu not experienced in over a decade. This combination of factors resulted in NGCC capacity factors that were an anomaly that year.

EEI analysis indicates that the average utilization rate of NGCC capacity in 2012 was 46 percent. Only 10 percent of these units operated at *annual* utilization rates of 70% or higher and 19% of these units operated at utilization rates of at least 70% over the summer season. So, while a 70% utilization rate may be "technically" feasible, it is unrealistic based on operational experience. EPA appears to have based its proposed increase in utilization rate on analysis of only 10% of the NGCC fleet.

Since 2012, natural gas prices have rebounded and have remained around $4/mmbtu. For NGCC capacity factors to reach the 70% range, natural gas prices would need to return to record low levels for NGCC units to be economically dispatched in RTO markets such as PJM. Therefore, from an economic dispatch perspective, EPA's assumed 70% NGCC utilization rate for BSER is unrealistic and based on faulty assumptions and expectations.

[7] Monitoring Analytics 2011 State of the Market Report for PJM, page 111
[8] Monitoring Analytics 2013 State of the Market Report for PJM, page 188
[9] Monitoring Analytics 2014 Quarterly State of the Market Report for PJM, page 181

EPA's assumed 70% utilization rate for all NGCC units ignores permit conditions that may create regulatory restrictions or artificial barriers to full operation, often referred to as "synthetic minor" permits. Permits can impose limits on emissions, fuel consumption, or hours of operation for regulatory reasons or for ease of permitting. NGCC units may not be able legally to maintain a 70% capacity factor or be able to maintain a high enough capacity factor to help bring the state's average capacity factor to a 70% level. This legal impediment combined with the physical inability of some plants to operate at a 70% capacity factor is a fatal flaw in Building Block #2.

The assumption that existing pipeline infrastructure can support increased NGCC capacity nationwide also seems to ignore regional disparities as well as the realities of pipeline markets. The electric power sector competes for pipeline services with two other major natural gas consumers: local gas distribution companies serving residential and commercial sectors and industrial consumers. Gas pipelines are very highly subscribed. FE's recent survey of pipelines within PJM determined that Texas Eastern is fully subscribed and Tennessee Gas is unable to offer "No-Notice" service due to lack of available storage.

Congestion in the electric transmission system does not necessarily coincide with congestion in the natural gas transmission system. Ongoing changes in gas-electric coordination and direct gas consumption should be factored into determining "reasonable" levels of NGCC utilization. In fact, recent experience has shown that gas supplies may not be available for NGCC generation in shoulder months due to the need to replenish storage or in winter months when pre-empted by local distribution companies. While the existing natural gas pipeline infrastructure was able to support 2012 peak utilization, this may not be sufficient evidence that a 70% utilization rate will be achievable for every state's existing NGCC fleet in the future.

Operating NGCCs at 70% capacity will be the equivalent of adding 5,200 MW of generation into the system on an average basis. An assumed heat rate of 8,000-9,000 BTU/kWh equates to an increase in gas usage of approximately 1 BCF/day, or 365 BCF/year not including any new combined cycle generation or a 6% increase in Marcellus shale gas production. The infrastructure to move this additional gas is currently not constructed and most construction projects are centered on getting gas out of the system not delivery to generation facilities that run at reduced capacity factors. In fact, PJM reported that over 9,000 MW of gas generation capacity was offline due to "Confirmed Gas Curtailments" this past January. This equates to roughly 17% of all gas generating capacity (natural-gas fired generators accounted for 47% of the unavailable MW).[10] FirstEnergy was forced to switch units that historically ran on natural gas to oil due to the inability of Columbia Gas to supply the units with natural gas on a firm or intermittent basis.

PJM recently discovered that NGCC units have been "chronically curtailed" over the past six winters stating that they are currently working on "gas-related contingencies" which would include switching to oil during significant weather related curtailment events.[11]

Another study prepared by the staffs at FERC and NERC[12] investigated cold weather events in the southwest in 2011 concluded that at least 12% of the electrical outages attributed to weather events were actually "occasioned by natural gas curtailments to gas-fired generators and difficulties in fuel switching." The authors point out that in some states the priority of curtailments places the needs of residential and other human needs above those of gas-fired EGUs. In other words, natural gas-fired generators, including NGCC, will be curtailed before residential customers and other human services.

Natural gas curtailments cast further doubt on the viability of a 70% capacity factor for NGCC units assumed in Building Block #2.

NGCC unit capacity factor can only be increased by a market mechanism that forces NGCC units to offer generation into RTO markets so that they will be dispatched at the proposed rule's desired 70% rate. Such a mechanism does not currently exist and there has been no indication from federal and state regulators that any such mechanism is even being considered. If implemented, NGCC units would likely be offered as "must-run", which effectively is a $0 offer. Must-run offers are uneconomic and well below the NGCC marginal costs. The unintended consequence of mandating NGCC units as must-run units to meet policy objectives would be a

[10] PJM's May 8 "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events."
[11] Winter Generation Outage Analysis, PJM Planning Committee, June 5, 2014
[12] Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011. Causes and Recommendations, Staffs at FERC and NERC, August 2011

shifting of the supply curve and thus artificially depressing market prices (LMPs) for all resources.

The Independent Market Monitor (IMM) for PJM has stated that depressing market prices leads to premature and uneconomic retirements. Coal and nuclear units are already under stress. The IMM estimates that 14,597 MW of capacity are at risk of retirement in addition to the 24,933 MW that are currently planning to retire.[13] The risk of further retirements will only be increased by additional price suppression due to policy decisions made in any final carbon rules.

PJM analysis concludes that it would likely not be able to meet the winter peak requirement if comparable generator outages that occurred in January 2014 were to occur in the winter of 2015/2016 coupled with extremely cold temperatures and expected coal plant retirements.[14]

If market conditions continue to be depressed, generation resources on the margin that are forced to decide between investments to maintain viability or retirement, will choose retirement. This will further exacerbate reliability concerns and the volatility of consumer cost.

As far as transmission constraints are concerned, FE offers the following comments from EPRI:

> *"The changes in the utilization of the various generating plants driven by this proposal could have a significant impact on transmission reliability due to potential large changes in power flows across the system and retirement of generation that contributes to transmission system voltage and frequency performance. The change in generation will almost certainly require development of new transmission to ensure operational reliability, but scheduling outages of existing facilities will be difficult if simultaneous upgrades across many systems are needed such that time lines for commissioning of new transmission facilities may be delayed. To understand the full reliability, economic, and financial impacts of the proposed rule, detailed transmission reliability evaluations should be conducted."*[15]

[13] Monitoring Analytics, 2013 State of the Market Report for PJM, page 1
[14] PJM Capacity Performance, PJM Staff Proposal, August 20, 2014, page 4
[15] EPRI Docket ID No. EPA-HQ-OAR-2013-0602

Shifting from market-based dispatch of generation to regulatory driven mandates will result in market distortions and have unintended consequences. The market operates on the principle of ensuring reliability and affordability, and any changes to system operations that ignore those principles will by definition degrade reliability and/or affordability. According to an IHS Energy report "The Value of US Power Supply Diversity," economic and reliability affects will be felt if the power supply is arbitrarily changed.

> *"If the US power sector moved from its current diverse generation mix to the less diverse generating mix, power price impacts would reduce US GDP by nearly $200 billion, lead to roughly one million fewer jobs, and reduce the typical household's annual disposable income by around $2,100. These negative economic impacts are similar to an economic downturn. Additional potential negative impacts arise from reducing power supply diversity by accelerating the retirement of existing power plants before it is economic to do so. For example, a transition to the reduced diversity case within one decade would divert around $730 billion of capital from more productive applications in the economy. The size of the economic impact from accelerating power plant turnover and reducing supply diversity depends on the deviation from the pace of change dictated by the underlying economics".*[16]

In addition, operating NGCC units to a certain capacity factor is currently highly dependent on the price of natural gas. Economics are what dictate the capacity factors of electric generators. However, it appears that EPA disregarded the role of economic dispatch and its impact on capacity factors by utilizing a 70% NGCC unit capacity factor in BSER. Economic dispatch is what ensures consumers will pay the most affordable rates for electricity. To prioritize capacity factor over economic dispatch would require changing the current dispatch regime and thus eliminate affordability as a top priority. Thus, consumers will end up paying more for electricity than they currently do. We do not believe that is in the interest of our customers.

Finally, mandating baseload operation of NGCC units (at 70% CF) eliminates the availability of those NGCC units to load follow, serve peak power needs during ramps and on extreme demand

[16] IHS Energy, The Value of US Power Supply Diversity, July 2014, page 6

days, and back up intermittent generation. This is especially important since this proposed rule's Building Block #3 relies on significant increases in intermittent renewable energy, which is typically backed up by natural gas generation. Continued displacement of coal and nuclear baseload resources by historically peaking units, such as NGCC, will result in a shortage of capacity during peak periods, threatening future reliability.

Building Block #3

EPA must correct numerous faulty assumptions in Building Block #3 and re-calculate state target rates prior to finalization of this rule.

For example, EPA state emission rates in the East Central Region must be re-calculated due to the passage of SB310 in Ohio just prior to the publication of EPA's proposed 111(d) rule. Ohio SB310 amended energy efficiency and alternative energy resource mandates (including renewable mandates) by imposing a two-year pause on energy efficiency, peak demand reduction and renewable energy resource requirements. It also eliminated both the renewable energy resource in-state requirements and the advanced energy resource requirements, thereby reducing the former alternative energy resource mandate by half. Due to the timing of Ohio SB 310, EPA did not reflect the impact of this new state law in the BSER Building Block #3 calculations for the East Central Region. EPA must recalculate state goals within the region based on Ohio's SB310.

Ohio SB310 states that "because the energy mandates in current law may be unrealistic and unattainable, it is the intent of the General Assembly to review all energy resources as part of its efforts to address energy pricing issues. Therefore, it is the intent of the General Assembly to enact legislation in the future, after taking into account the recommendations of the Energy Mandates Study Committee that will reduce the mandates in sections 4928.64 and 4928.66 of the Revised Code and provide greater transparency to electric customers on the costs of future energy mandates, if there are to be any." Therefore, EPA's final 111(d) rule should provide a mechanism for re-calculating state target rates following future Ohio legislation based on the recommendations of the Energy Mandates Study Committee.

In developing the target renewable energy generation levels, the EPA calculated a hypothetical RES requirement for each region by averaging the RES requirement of each state that currently has an RES requirement within the region. EPA recognizes state expertise in developing renewable energy goals, thus justifying the use of these goals in calculating BSER goals. The GHG Abatement Measures Technical Support Document states:

> *"These state goals and requirements have been developed and implemented with technical assistance from state-level regulatory agencies and utility commissions such that they reflect expert assessments of RE technical and economic potential that can be cost-effectively developed for that state's electricity consumer"*

However, EPA chose to exclude that same expertise by the state of West Virginia simply because after an exhaustive vetting and legislative process, the state determined that it could not support a mandatory renewable energy goal. It was the state's informed decision, developed and implemented with technical assistance from state-level regulatory agencies, the utility commission, and interested public and private parties, no different from any other state that EPA used in the calculation of a region's renewable potential. By excluding states like West Virginia that have determined their renewable mandate to be zero, whether through affirmative action or through a decision not to act on a legislative mandate, EPA disregards its own technical justification document. EPA cannot and should not pick only those states that have concluded a specific outcome after study. EPA should accept all states' "expert assessment of RE technical and economic potential that can be cost-effectively developed for the state's electricity consumer" regardless of what conclusion that expertise leads to. To cherry pick a few states in order to produce a certain outcome undermines the credibility of EPA's technical support for this proposal. Either all states are experts or all states are not. EPA should recalculate the target renewable energy generation levels under Building Block #3 by including every state in the calculation, incorporating states such as West Virginia as a zero since it imposes no renewable energy mandate.

EPA's approach is also flawed as it does not distinguish between renewable energy that is generated within the state versus renewable energy imported from a neighboring state. For example, Washington, DC has a renewable target of 20%, yet it is difficult to imagine 20% of

Washington, DC electricity being generated by allowed renewable energy within the District's borders. Washington, DC recognized as much when it allowed for RECs to be procured outside the District's borders, but within PJM. And yet, for the purposes of EPA's proposed rule, it is assumed that Washington, DC has the potential to achieve a 20% renewable energy requirement. Renewable energy that is generated within the state is what is most representative of the capabilities within the state. Thus, to accurately reflect each state's renewable potential, EPA's approach should only be based on in-state renewable sources of generation. EPA should recalculate state emission rate targets based solely on verifiable in-state renewable sources of generation.

EPA's approach is further flawed as it gives equal weight to each state in the region, as opposed to a weighted average to factor in the different sizes and populations of the various states in the regions that impact electric consumption and generation. For example, Washington, DC is given the same weight as Ohio or Pennsylvania whose electric consumption each is 12 to 15 times as large as Washington, DC and hundreds of times larger in terms of electric generation.

EPA's approach also ignores its own GHG Abatement Measures Technical Support Document that provides: "[s]tates *within each region exhibit similar profiles of RE potential or have similar levels of renewable resources.*" Clearly landlocked states do NOT "*exhibit similar profiles of RE potential or have similar levels of renewable resources*" as states with off-shore capability. Including New Jersey and Maryland in the same region as West Virginia ignores the obvious regional differences. For example, Maryland has created a "*mechanism to incentivize the development of up to 500 megawatts (MW) of offshore wind capacity, at least ten nautical miles off of Maryland's coast*" (state of MD website). However, landlocked states like West Virginia have zero capacity to develop or offer incentives for large scale off-shore renewable projects. EPA's Technical Support Document states that the "*Northeast region has strong resources off-shore*" but has placed states with strong off-shore renewable energy capability (i.e. New Jersey, Maryland and Virginia) in the same region as landlocked states who have zero off-shore resources. EPA must reconfigure the regions in its proposed rule and recalculate BSER.

EPA's approach also assumes that renewable programs are emission reduction programs, but the vast majority include alternative compliance methods or "safety valves" that do not result in emission reductions. In fact, environmental groups have consistently opposed the use of safety-valves under the logic that it reduces investment in renewable energy and allows for emissions that would otherwise not occur without such a mechanism. However, EPA assumes, for the purpose of setting BSER that a state will achieve its entire renewable requirement through the procurement of allowed renewable energy and actually achieve the emission reduction used to calculate BSER goals for individual states. This approach is simply not accurate and results in artificial inflation of renewable energy assumptions and thus emission reduction assumptions. EPA must recalculate BSER in a manner that reflects the true emissions impact of all state renewable energy requirements including calculating the impact of each safety-valve mechanism (or alternative compliance mechanism). Additionally, within the notice of data availability (NODA) the EPA requests feedback on ways that state-level RE targets could be set based on regional potential for renewable energy. EPA relied on historic RE development from the top 16 states. This approach overstates the RE development rate by relying only on data from those states that have been most successful in developing their renewable generation. Historic RE development should be based on the experience of all states.

With regard to the nuclear portion of BSER in Building Block #3, please refer to our previous comments.

Building Block #4

The proposed rule assumes a 1.5% annual Energy Efficiency (EE) gain that is not reasonable. EPA acknowledges that the projected cumulative EE savings rate are well above the average savings that most states have actually achieved of 0.58% in 2012. EPA concluded that three states (AZ, ME, VT) have already achieved the highest level of performance, more than 1.5% annual incremental retail sales savings. However, EPA failed to explain why AZ, ME, and VT were successful and how that success can be uniformly duplicated in every other state. EPA further assumes each state currently below the 1.5% annual savings rate can increase its incremental savings levels by 0.2% per year. Therefore, EPA assumed that states would start ramping up EE programs in 2017 in order to reach the target annual EE savings rate no later than 2025.

The proposed rule's assumptions of 1.5% rate and the 0.20% per year pace of improvement are too aggressive and unrealistic. In the Greenhouse Gas Technical Support Document (GHG TSD)[17], the 1.5% value is the highest value of the studies referenced. Based on EPRI's most recent study, a value of 0.5-0.6% per year is achievable, only about one third of the 1.5% value used.[18] Of the studies referenced, the EPRI study is the more realistic because it is based on a "bottom up" engineering approach as opposed to the "top down" policy approach performed by American Council for an Energy-Efficient Economy (ACEEE). The 1.5% annual incremental savings has only been achieved by three states. Market potential is highly dependent on maturity of EERS in each state, saturation levels of various programs and technologies, existing level of state building code standards and what is qualified in each state. The pace of incremental EE savings slows over time as codes and standards increase and typically, the largest gains are made earliest in the life of EE programs. As an illustration of this point, in the baseline year 2012 savings values largely were influenced by lighting programs. Widespread adoption of increasing EISA standards (EISA 2008) have effectively and significantly reduced what can be counted towards lighting savings. As efficient lighting programs and other technologies saturate consumer opportunities, there is a diminishing level of potential. The EPRI Study[19] reports potential using a baseline that includes current codes and standards in place at the time the study was done. The 0.5 - 0.6% incremental annual potential reported from this study will be reduced by future stricter federal and state standards and local building codes requirements for efficiency.

Projection of the top three states achievements to remaining states is unrealistic and will result in unachievable and uneconomic goals. It is not appropriate for the EPA to use the experience of 3 out of 50 states to determine a one-size-fits-all nationwide annual incremental savings rate for all EE programs in all states. Furthermore, the sustainability of past achievements is not guaranteed going forward, particularly over a long time horizon through 2030. Recently, one of those top three state's utility commission, the Arizona Corporation Commission, issued a request for informal comment on modifying its current rules on energy efficiency to eliminate Arizona's aggressive goals of 22% by 2020 and instead incorporates energy efficiency requirements as part

[17] Greenhouse Gas Technical Support Document at 5-24
[18] EPRI Report 1025477, "U.S. Energy Efficiency Potential Through 2035"
[19] Ibid

of a biannual integrated resource planning process.[20] The proposed changes also include a focus of cost effectiveness on ratepayer impacts.[21] Arizona Commissioner Gary Pierce was quoted as saying that

> *"The rules were set up, and it was pretty easy at first to capture all the low-hanging fruit, but as we started reaching, these companies, because they are under an order to reach certain levels of energy efficiency, they were looking for stuff and trying to plug it in no matter what the costs."*[22]

This not only highlights that the performance of a limited group of states is not appropriate for all states, but that the level of savings achieved or projected to be achieved is not necessarily achievable and shouldn't be assumed going forward as the high cost to achieve such level of savings is increasing and causing reconsideration of such requirements due to ratepayer impacts.

Also, Ohio was listed as one of the eleven states that are projected to achieve 2.0% or more by 2020. But recent legislation modified the Ohio targets with the purpose of further study by the state to ensure that energy efficiency and renewable energy levels are realistic and beneficial to ratepayers.

> *"It is the intent of the General Assembly to ensure that customers in Ohio have access to affordable energy. It is the intent of the General Assembly to incorporate as many forms of inexpensive, reliable energy sources in the state of Ohio as possible. It is also the intent of the General Assembly to get a better understanding of how energy mandates impact jobs and the economy in Ohio and to minimize government mandates. Because the energy mandates in current law may be unrealistic and unattainable, it is the intent of the General Assembly to review all energy resources as part of its efforts to address energy pricing issues. Therefore, it is the intent of the General Assembly to enact legislation in the future, after taking into account the recommendations of the Energy Mandates Study Committee, that will reduce the mandates in sections 4928.64 and 4928.66 of the Revised*

[20] Arizona Corporation Commission, Utilities Division Docket No. E-00000XX-13-0214, November 4, 2014, at R14-2-2404, Energy Efficiency Goal
[21] Ibid at R14-2-2411, Cost-effectiveness.
[22] Arizona Daily Star, November 8, 2014, "State Regulators Mull Scrapping Energy Savings Goals"

Code and provide greater transparency to electric customers on the costs of future energy mandates, if there are to be any."[23]

Additionally, Ohio's legislation creates an opportunity for large customers to opt out of participating in utility energy efficiency programs.[24] FirstEnergy estimates that the potential volume of customers electing to opt out of efficiency programs will be over a third of its total sales volume.

A Market Potential Study that was performed for the FirstEnergy Ohio Companies' Energy Efficiency and Peak Demand Reduction Filing[25] reports that the achievable potential for the Companies' territories are in fact less than the current state targets for both the base case and high case. For the years 2017 through 2026, the average annual incremental savings for the base case for Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company respectively are approximately 0.5%, 0.6% and 0.4%. For the high case, those values are 0.7%, 0.7% and 0.5%.

Furthermore, in referencing the Pennsylvania 2012 Potential Study[26] the GHG TSD[27] references a value of 2.9% as annual incremental achievement. This is incorrect. Table 1-3 and 1-4 from this Study show program potential of cumulative values for the periods of 2013 – 2016 and 2013-2018 of 2.3% and 3.7%, respectively. On an incremental basis this would be approximately 0.75% per year (before considering effects of degradation). This is significantly lower than EPA's assumption of 2.9%/year. The Pennsylvania value was the highest in the range of potential studies quoted (see GHG TSD, at Appendix 5-1) used to support EPA's assumed 1.5% incremental EE savings.

In addition, rebound effects of EE measures should be considered, particularly in conjunction with a mass based BSER scenario. More efficient use of energy results in (as stated in GHG TSD at 5-29) "[a]n improvement in energy efficiency would effectively reduce the cost of a

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[23] *Ohio Senate Bill 310, effective September 12, 2014, Section 3 page 34.*
[24] Ibid, Section 4928.6611, page 31 and Section 8, page 37.
[25] Market Potential Study Energy Savings and Demand Reduction for Ohio Edison, Toledo Edison and the Illuminating Company, June 22, 2012, Public Utilities Commission of Ohio Case 12-2190-EL-POR et al. (See Tables 1-1 through 1-9.)
[26] Electric Energy Efficiency Potential for Pennsylvania, Final Report, May 10, 2012, Prepared for Pennsylvania PUC
[27] Ibid, Appendix 5-1, Table 1

service or production input, potentially boosting its demand or production output thus increasing energy use." This creates additional growth in demand and energy. Although good for the economy, this additional demand and energy usage makes a state goal more difficult to achieve.

EPA requested comment on alternative approaches and/or data sources for evaluating costs associated with the implementation of state demand-side energy efficiency policies (Fed. Reg. 34875). In determining the role of demand side energy efficiency programs as a Building Block for carbon reduction, cost assumptions should take into consideration that there are correlations to cost regarding both the level of savings as a percent of sales as well as varying levels of maturity of state EERS. The EPA assumed first-year net costs of $275/MWh (2011$)[28] based on the 2009 ACEEE national review of data on EE programs costs.[29] This study relied on outdated data from a period of 2001 to 2009 across fourteen states. During this pre-EISA era, low cost efficient lighting represented a third or more of total savings. For the purposes of Building Block #4, the time period in consideration for achievement of EE savings is 2017 through 2030. Four major factors will contribute to higher costs in that future time period than have been observed in the last two decades: 1) increasing saturation levels from programs in place for multiple decades, 2) increasing federal and state standards and local building codes which will effectively make each marginal kWh savings more and more costly to achieve; 3) diminishing opportunities for marginal kWh savings from new technologies and 4) increasing costs associated with new technologies. These factors should be taken into consideration when forecasting costs, particularly, so far out into the future. To further illustrate this point, the references given in the GHG TSD[30] point to additional growing "greenfield" states that have started programs. These lower costs represent low hanging fruit that will be harvested during the first implementation cycle and are not representative of savings beyond 2020. For example, after 2020, the baseline for most general service lamps is effectively the CFL. LEDs will never realize the savings as CFLs did in the residential sector because EISA has effectively saturated lighting end uses with CFLs and because of the code change in 2020. The incremental savings of LEDs compared to CFLs is a fraction of that for CFLs compared to incandescent lighting and

[28] GHG TSD, pages 5-50

[29] Though not referenced in the GHG TSD, presumably the document referenced is the ACEEE report *"Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved through Utility-Sector Energy Efficiency Programs,"* Fredrich, Eldridge, York, Witte and Kushier, September 2009

[30] GHG TSD, pages 5-51 first paragraph

at a significantly higher cost per kilowatt hour of savings. While the EPA has included cost escalators of 20% to 40%,[31] cost escalators alone do not explicitly account for each of these four factors.

The EPA's analysis also makes assumptions for participant incremental measure costs to arrive at total costs of energy efficiency programs. As stated in the GHG TSD[32]:

> *"....while program costs are relatively known and consistently reported by the program administrator, participant costs require significant effort to estimate, and are less consistently estimated and reported. The ratio between program and participant costs will vary significantly from one program to the next within a utility's portfolio."*

There are correlations between participant cost versus program cost and overall levelized cost, and it is not apparent that these are accounted for by the EPA. For example, a program with high costs will have a lower ratio of participant costs to programs costs, and conversely a program with low costs will have a higher ratio. These factors introduce variation from state-to-state and to assume a 1:1 ratio for all states could cause significant over or under forecasts.
EPA invited comments on all aspects of its goal computation procedure (Fed. Reg. 34895-34897). In EPA's calculation of the contribution of demand side energy efficiency, the degradation assumption used in developing targets is based on 20 years, while measure life is based on 10 years –which overstates the potential (see 5-36 GHG TSD). Contrary to EPA claims, this is not conservative (see GHG TSD 5-38) and results in higher values achievable than would be calculated if 10 year degradation was assumed in lieu of 20 years. The final rule's BSER should be recalculated using 10-year degradation assumptions.

EPA requests comment on Efficiency Measurement and Verification (EM&V) protocols for energy efficiency (Fed. Reg. 34921). With regard to EM&V protocols, FE supports the following approach:

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[31] GHG TSD, pages 5-53
[32] GHG TSD, pages 5-51

- States should be granted the flexibility to determine the protocols for the measurement and verification of demand side energy efficiency programs
- No new EM&V protocols which would create undue administrative burden and increases the cost of energy efficiency
- Assumptions used by EPA (regarding 2012 achievements for EE) to develop state BSER goals were based on existing state evaluation methods, therefore compliance EM&V should be consistent with this methodology
- Consideration of what can count:
    - States should decide what can count towards energy efficiency. For example, in Ohio, the legislation has specific language that allows CHPs and efficiency improvements resulting from transmission and distribution investments to count towards its energy efficiency mandates.
    - Energy efficiency should be counted on a gross versus net basis that takes "free ridership" into consideration.[33]
    - Any savings from changing federal, state standards, and local building codes should be explicitly supported with protocols defined by EPA or "given" to States as credits against their obligations.
    - Credits for energy efficiency should not be limited to established programs as long as savings can be measured and verified within accepted protocols.

EPA requests comment on the treatment of export/import power (Fed. Reg. 34922). States should have ultimate flexibility during implementation, including determining how to treat export/import power. For energy efficiency savings, states should be able to take credit for 100% of savings regardless of whether they are a net importer or exporter of power. Typically these programs are funded by state ratepayers or taxpayers, and therefore, the state should receive credit for the reductions regardless of where the generation is offset.

EPA requests comments on different approaches for providing crediting or administrative adjustment of CO_2 emission rates (Fed. Reg. 34919). In regards to the value of a credit or

[33] A free-rider is someone who would have installed an energy-efficiency measure without any program incentives based on the energy savings, but receives a financial incentive or rebate anyway. Free ridership is very dynamic and changes overtime. Regardless of free ridership, resulting energy savings are real savings whether or not they can count towards an individual state's statutory compliance purposes and regardless of why they occur.

adjustment resulting from energy efficiency, whatever methodology is selected for planning and compliance purposes should be consistent with how the BSER was calculated to ensure that BSER is realistic and achievable.

As noted above, achieving the aggressive targets for non-emitting sources is unrealistic. Combining the unreasonableness of meeting those targets with the limited opportunity for heat rate improvements and redispatch in Building Blocks #1 and #2, results in serious consequences both in the short-term and long-term. In their comments, EPRI has determined that any shortfalls within Building Blocks #3 or #4 would require decreases in fossil generation. EPRI's "fossil leverage factor" highlights that the algebra of the compliance equation results in a multiplier effect. Essentially, they were able to identify that 1 MWhr shortfall of nonemitting resources must be made up by more than a factor of 2 MWhrs of fossil generation in 20 states across the United States. For example in West Virginia, for every 1 MWhr of Building Block #3 or #4 that is not achieved, 5.17 MWhrs of fossil generation must compensate for the lack of the zero emission delivery in 2030. Building Blocks #3 or #4 unrealistic assumption will force additional decreases in fossil generation, raising serious concerns regarding reliability, planning and compliance. This leverage factor is significantly increased if nonemitting resources are not met by the 2020 interim goal. Again, taking West Virginia as an example, for every 1 MWhr of Building Block #3 or #4 that is not achieved, 23.35 MWhrs of fossil generation must compensate for the lack of the zero emission delivery in 2020. This "fossil leverage factor" underscores the reason why the interim goals must be set aside.

EPA also contends that some stakeholders' believe that the state goals fail to reflect the full potential, under the BSER, for incremental RE and EE to replace fossil steam generation. By adding incremental RE and EE generation, this action actually avoids emissions and does not decrease emissions. Therefore, to subtract equivalent fossil generation from the BSER would be erroneous.

Maximum State Flexibility

CAA section 111(d) require states, not EPA, to set standards of performance for sources. Not only do states have the authority to set the standards, but they also have the authority to determine how the sources within each state will meet those standards. Therefore, states should have ultimate flexibility in building their state programs and determining what activities can be included for compliance. These activities include, but are not limited to, the following areas:

- A state should have authorization to deem that a current state program qualifies as BSER for that state
- The states should have sole discretion on how to reach the 2030 compliance target including timing, glide path, interim targets, etc..., without any requirements from EPA during that interim period
- Enforcement of a state plan should be the sole responsibility of the state
- States should have the discretion to include new Section 111(b) affected NGCC units in their compliance plans
- States should have the ability to control what activities count towards compliance and when these activities can count towards compliance including, but is not limited to, plant retirements, treatment of nuclear and hydro, energy efficiency measures, renewable energy, and new 111(b) NGCC units
- States should have the ability to count any emission reductions that occur after the baseline year including retirement of fossil-fired generation
- States should have sole authority over whether or not the state uses a mass-based or rate-based approach towards compliance and how that translation is calculated
- States should have definitive oversight and control over any multi-state approach or plan

The CAA gives states authority over implementation under section 111(d). This rule should not impede on state's power to carry out that authority.

<u>Clean Air Act Authority</u>

EPA's authority under section 111(d) is limited to issuing "emission guidelines" addressing factors relevant to the states' implementation of the BSER that has been adequately demonstrated to reduce CO_2 emissions at a source (inside the fence).

Section 111(d) specifically directs EPA to establish a procedure for states to submit plans establishing performance standards for existing sources. States possess considerable discretion and flexibility under the Act in developing standards of performance based on EPA's emission guidelines. To the extent EPA's guidelines are based on replacing equipment to improve the efficiency of the generating unit, EPA should clearly exempt such activities from being considered a "modification" for purposes of NSR permitting, particularly in light of EPA's Office of Enforcement and Compliance Assurance's previous focus on these type of projects in their enforcement cases. These projects have also been the target of third party citizen suits contending they represent violations of the NSR rules.

Duplicative regulation under Sections 111(b) and 111(d) is not permitted by the CAA. EPA cannot regulate the same source under both CAA Section 111(b) and CAA Section 111(d). An EGU regulated under CAA Section 111(b) because it is a "new source"—which modified and reconstructed sources are defined to be— cannot simultaneously be subject to regulation under CAA Section 111(d) as an existing source and vice versa. Modified or reconstructed sources that were previously subject to a state plan under CAA Section 111(d) cannot be required to continue to be covered by CAA Section 111(d), although states do have discretion to keep those sources in their CAA Section 111(d) plans if the states choose to do so.

Similarly, EPA is prohibited from regulating pollutants under Section 111(d) from a source category already regulated under Section 112 of the CAA.

Other

EPA has yet to make available all the documentation the public needs to assess whether the proposed rule is reasonable, including 21 of the 25 IPM modeling runs EPA relies on to argue that the Building Blocks are achievable.

Review of the limited modeling results leaves many questions, for example, regarding the appropriateness of how energy efficiency is represented in the model (both characteristics and cost), the appropriateness of modeled transmission investment, and the treatment of any "remaining plant balance" associated with modeled retiring plants. Further, it is not clear from the limited modeling results presented, how the Building Blocks are integrated into the cases.

IPM's assumption that a 100% load factor (full reductions in all hours of each year) for EE resources is unreasonable. For example, an energy efficiency program involving residential light bulbs only generated reductions when the lights are normally on, likely something far less than

100% of the time. Or, consider a residential refrigerator EE program that results in savings only when the old refrigerator was normally running (i.e. more efficient operation, fewer hours of each day) again, far less than 100% of the time. Examples similarly continue in the industrial sector with HVAC programs with less than 100% load factor and even industrial lighting and/or motors which would only approach 100% load factor results in the most efficient 24/7 manufacturing facilities.

It is not clear from the limited results and documentation provided by EPA whether the assumed $44B cost for EE is consistent with "one for one" programs with less than a 100% load factor (in which case the modeling assumptions are not appropriate) or alternately, the $44B cost assumption may be understating the spend necessary to accomplish this magnitude of energy reductions.

Rural Cooperatives and Municipal facilities should be subject to the same requirements as electric generating units under this rule. Especially in deregulated markets where they would operation at a competitive advantage, as compared to units subject to the proposed rule. Any longer-term capacity planning strategies advantage could be misconstrued as market distortion.

Conclusion

Having an electric system that is reliable and affordable is paramount to individual families, manufacturing, the service industries, economic security and prosperity, and the overall well-being of this nation. The current emissions trajectory of the utility industry would suggest that reliability and affordability can come with significant CO_2 emission reductions from the existing fleet, similar to what EPA's projects will result from this rule, without the negative consequences of this proposal. As such we question the need for such a radical retransformation of the electric system based on building blocks that do not place the utmost value on reliability or affordability. We recognize the difficulty of EPA's task of using the Clean Air Act to effectively and economically regulate GHGs. We agree with statements from many political leaders and leaders of EPA that the Clean Air Act is not adequately designed to effectively regulate GHGs, so we caution EPA to be careful in using an inappropriate tool where the results of doing so often come with negative consequences. Even so, we submit these comments as a means of providing additional technical support and identifying areas where EPA's calculations can be made more accurate. We thank you for the opportunity to comment and engage in this process.

FE is an active member of the Utility Air Regulatory Group (UARG), Edison Electric Institute (EEI), Utility Solid Waste Activities Group (USWAG), Midwest Ozone Group (MOG), and the Electric Power Research Institute (EPRI) and incorporates their comments herein by reference.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Regulatory Impact Analysis for the Clean Power Plan Final Rule

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Regulatory Impact Analysis for the Clean Power Plan Final Rule

U.S. Environmental Protection Agency
Office of Air and Radiation
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Table of Contents

Executive Summary

This Regulatory Impact Analysis (RIA) discusses potential benefits, costs, and economic impacts of the Final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (herein referred to as "final emission guidelines" or the "Clean Power Plan Final Rule").

ES.1 Background and Context

The emission of greenhouse gases (GHGs) threatens Americans' health and welfare by leading to long-lasting changes in our climate. Carbon dioxide (CO_2) is the primary greenhouse gas pollutant, accounting for roughly three-quarters of global greenhouse gas emissions in 2010 and 82 percent of U.S. greenhouse gas emissions in 2013. Fossil fuel-fired electric generating units (EGUs) are by far the largest emitters of GHGs, primarily in the form of CO_2, among stationary sources in the U.S.

In this action, the Environmental Protection Agency (EPA) is establishing final emission guidelines for states to follow in developing plans to reduce greenhouse gas emissions from existing fossil fuel-fired EGUs. Specifically, the EPA is establishing: 1) CO_2 emission performance rates representing the best system of emission reduction (BSER) for two subcategories of existing fossil fuel-fired EGUs – fossil fuel-fired electric utility steam generating units and stationary combustion turbines, 2) state-specific CO_2 goals reflecting the CO_2 emission performance rates, and 3) guidelines for the development, submittal and implementation of state plans that establish emission standards or other measures to implement the CO^2 emission performance rates, which may be accomplished by meeting the state goals. This final rule will continue progress already underway in the U.S. to reduce CO_2 emissions from the utility power sector.

ES.2 Summary of Clean Power Plan Final Rule

Under CAA section 111(d), states must establish standards of performance that reflect the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER) that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impacts and energy requirements, the Administrator determines has been adequately demonstrated. The EPA has determined that the BSER is the combination of emission rate improvements and limitations on overall emissions at affected EGUs that can be accomplished through any combination of one or more measures from the following three sets of measures or building blocks:

1. Improving heat rate at affected coal-fired steam EGUs.
2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for reduced generation from higher-emitting affected steam generating units.
3. Substituting increased generation from new zero-emitting generating capacity for reduced generation from affected fossil fuel-fired generating units.

Specifically, the EPA is establishing CO_2 emission performance rates for two subcategories of existing fossil fuel-fired EGUs, fossil fuel-fired electric steam generating units and stationary combustion turbines. The rates are intended to represent CO_2 emission rates achievable by 2030 after a 2022-2029 interim period on an output-weighted-average basis collectively by all affected EGUs. The interim and final emission performance rates are presented in the following table:

Table ES-1. Emission Performance Rates (Adjusted Output-Weighted-Average Pounds of CO_2 Per Net MWh from All Affected Fossil Fuel-Fired EGUs)

Subcategory	Interim Rate	Final Rate
Fossil Fuel-Fired Electric Steam Generating Units	1,534	1,305
Stationary Combustion Turbines	832	771

Also, states with one or more affected EGUs will be required to develop and implement plans that set emission standards for affected EGU. These emission standards may incorporate the subcategory-specific CO_2 emission performance rates set by the EPA or, in the alternative, may be set at levels that ensure that the state's affected EGUs, individually, in aggregate, or in combination with other measures undertaken by the state achieve the equivalent of the interim and final CO_2 emission performance rates between 2022 and 2029 and by 2030, respectively.

EPA derived statewide rate-based CO_2 emissions performance goals as a weighted average of the uniform rate goals with weights based on baseline generation for the two types of units (fossil steam and stationary combustion turbine) in the state. This blended rate reflects the collective emission rate a state may expect to achieve when its baseline fleet of likely affected EGUs continues to operate at baseline levels while meeting its subcategory-specific emission performance rates reflecting the BSER.

The Clean Power Plan Final Rule also establishes an 8-year interim compliance period that begins in 2022 with a glide path for meeting interim CO_2 emission performance rates separated into three steps: 2022-2024, 2025-2027, and 2028-2029. This results in interim and final statewide goal values unique to each state's historical blend of fossil steam and NGCC generation. Chapter 3 presents finalized state rate-based CO_2 emissions performance goals.

The EPA is also establishing mass-based statewide CO_2 emission performance goals for each state, which are also presented in Chapter 3. For more detail on the methodology that translates CO_2 emission performance rates to mass-based CO_2 performance goes, please refer to the preamble of the Clean Power Plan Final Rule and the U.S. EPA's CO_2 Emission Performance Rate and Goal Computation Technical Support Document for Final Rule, which is available in the docket.[1]

Given the flexibilities afforded states in complying with the emission guidelines, the benefits, cost and economic impacts reported in this RIA are not definitive estimates. Rather, the impact estimates are instead illustrative of approaches that states may take.

ES.3 Illustrative Plan Approaches Examined in RIA

In the final emission guidelines, the EPA has translated the source category-specific CO_2 emission performance rates into state-level rate-based and mass-based CO_2 goals in order to maximize the range of choices that states will have in developing their plans. Because of the range of choices available to states and the lack of *a priori* knowledge about the specific choices states will make in response to the final goals, this RIA presents two scenarios designed to achieve these goals, which we term the "rate-based" illustrative plan approach and the "mass-based" illustrative plan approach.

In this final rule, states may use trading or other multi-unit compliance approaches and technologies or strategies that are not explicitly mentioned in any of the three building blocks as

[1] U.S. EPA. 2015. Technical Support Document (TSD) the Final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. CO_2 Emission Performance Rate and Goal Computation.

part of their overall plans, as long as they achieve the required emission reductions from affected fossil fuel-fired EGUs. In addition, the final rule provides additional options to allow individual EGUs to use creditable out-of-state reductions to achieve required CO_2 reductions, without the need for up-front interstate agreements.

The modelled implementation plan approaches reflect states and affected EGUs pursuing building block strategies such as heat rate improvements, shifting generation to less CO_2 – intensive generation, and increased deployment of renewable energy, which are more completely described in Chapter 3. However, the modelled strategies are not limited to the technologies and measures included in the BSER. While the final rule no longer includes demand-side energy efficiency potential as part of BSER, the rule does allow such potential to be used for compliance. These scenarios include a representation of demand-side energy efficiency compliance potential because energy efficiency is a highly cost-effective means for reducing CO_2 from the power sector, and it is reasonable to assume that a regulatory requirement to reduce CO_2 emissions will motivate parties to pursue all highly cost-effective means for making emission reductions accordingly, regardless of what particular emission reduction measures were assumed in determining the level of that regulatory requirement. In the rate-based approach, energy efficiency activities are modeled as being used by EGUs as a low-cost method of demonstrating compliance with their rate-based emissions standards. In the mass-based approach, energy efficiency activities are assumed to be adopted by states to lower demand, which in turn reduces the cost of achieving the mass limitations.

Alternative compliance approaches other than those modelled are also possible, which may have different levels and distributions of emissions and electricity generation as well as costs. While IPM finds a least cost way to achieve the state goals implemented through the rate-based or mass-based emissions constraints imposed in the illustrative plan approaches, individual states or multi-state regional groups may develop alternate approaches to achieve their state goals.

It is very important to note that the differences between the analytical results for the rate-based and mass-based illustrative plan approaches presented in this RIA may not be indicative of likely differences between the approaches if implemented by states and affected EGUs in response to the final guidelines. Rather, the two sets of analyses are intended to illustrate two contrasting, stylized implementation approaches to accomplish the emission performance rates finalized in the Clean Power Plan Final Rule. In other words, if one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances.

To present a complete picture of costs and benefits of the final emission guidelines, this RIA presents results for the analysis years 2020, 2025, and 2030. While 2020 is before the first year of the interim compliance period (2022), the EPA expects states and affected EGUs to perform voluntary activities that will facilitate compliance with interim and final goals. These pre-compliance period activities might include investments in renewable energy or demand-side energy efficiency projects, for example, that produce emissions reductions in the compliance period. Activities might also include preparatory investments in transmission capacity or monitoring, reporting, and recordkeeping systems. As a result, there are likely to be benefits and costs in 2020, so these are reported in the illustrative analysis of this RIA. Meanwhile, cost and benefits are estimated in this RIA for 2025, which is intended to represent a central period of the interim compliance time-frame as states and tribes are on glide paths toward fully meeting the final CO_2 emission performance goals. Lastly, the RIA presents costs and benefits for 2030, when the emission performance goals are fully achieved.

ES.4 Emissions Reductions

Table ES-2 shows the emission reductions associated with the modelled rate-based illustrative plan approach.

Table ES-2. Climate and Air Pollutant Emission Reductions for the Rate-Based Illustrative Plan Approach[1]

	CO_2 (million short tons)	SO_2 (thousand short tons)	Annual NO_X (thousand short tons)
2020 Rate-Based Approach			
Base Case	2,155	1,311	1,333
Final Guidelines	2,085	1,297	1,282
Emissions Change	-69	-14	-50
2025 Rate-Based Approach			
Base Case	2,165	1,275	1,302
Final Guidelines	1,933	1,097	1,138
Emissions Change	-232	-178	-165
2030 Rate-Based Approach			
Base Case	2,227	1,314	1,293
Final Guidelines	1,812	996	1,011
Emission Change	-415	-318	-282

Source: Integrated Planning Model, 2015. Emissions change may not sum due to rounding.
[1] CO_2 emission reductions are used to estimate the climate benefits of the guidelines. SO_2, and NO_X reductions are relevant for estimating air quality health co-benefits of the final guidelines. The final guidelines are also expected to achieve reductions in directly emitted $PM_{2.5}$, which we were not able to estimate for this RIA.

In 2020, the EPA estimates that CO_2 emissions will be reduced by 69 million short tons under the rate-based scenario compared to base case levels. In 2025, the EPA estimates that CO_2 emissions will be reduced by 232 million short tons under the rate-based approach compared to base case levels. CO_2 emission reductions increase to 415 million short tons annually in 2030 when compared to the base case emissions. Table ES-2 also shows emission reductions for criteria air pollutants (in short tons).[2]

[2] The final guidelines are also expected to achieve reductions in directly emitted $PM_{2.5}$, which we were not able to estimate for this RIA. However, the SO_2 and NO_X reductions account for the large majority of the anticipated health co-benefits. Based on analyses for the proposed rule which included benefits from reductions in directly emitted $PM_{2.5}$, those benefits accounted for less than 10 percent of total monetized health co-benefits.

Table ES-3 shows the emission reductions associated with the modeled mass-based illustrative plan approach.

Table ES-3. Climate and Air Pollutant Emission Reductions for the Mass-Based Illustrative Plan Appproach[1]

	CO_2 (million short tons)	SO_2 (thousand short tons)	Annual NO_X (thousand short tons)
2020 Mass-Based Approach			
Base Case	2,155	1,311	1,333
Final Guidelines	2,073	1,257	1,272
Emissions Change	-82	-54	-60
2025 Mass-Based Approach			
Base Case	2,165	1,275	1,302
Final Guidelines	1,901	1,090	1,100
Emissions Change	-264	-185	-203
2030 Mass-Based Approach			
Base Case	2,227	1,314	1,293
Final Guidelines	1,814	1,034	1,015
Emission Change	-413	-280	-278

Source: Integrated Planning Model, 2015. Emissions change may not sum due to rounding.
[1] CO_2 emission reductions are used to estimate the climate benefits of the guidelines. SO_2, and NO_X reductions are relevant for estimating air quality health co-benefits of the final guidelines. The final guidelines are also expected to achieve reductions in directly emitted $PM_{2.5}$, which we were not able to estimate for this RIA.

In 2020, the EPA estimates that CO_2 emissions will be reduced by 82 million short tons under the mass-based approach compared to base case levels. In 2025, the EPA estimates that CO_2 emissions will be reduced by 264 million short tons under the mass-based approach compared to base case levels. CO_2 emission reductions increase to 413 million short tons annually in 2030 when compared to the base case emissions. Table ES-3 also shows emission reductions for criteria air pollutants (in short tons).

Table ES-4 presents CO_2 emission reductions relative to 2005.

Table ES-4. Projected CO_2 Emission Reductions, Relative to 2005

	CO_2 Emissions (million short tons)	CO_2 Emissions: Change from 2005 (million short tons)			CO_2 Emissions Reductions: Percent Change from 2005		
	2005	2020	2025	2030	2020	2025	2030
Base Case	2,683	-528	-518	-456	-20%	-19%	-17%
Rate-based	-	-598	-750	-871	-22%	-28%	-32%
Mass-based	-	-610	-782	-869	-23%	-29%	-32%

Source: Integrated Planning Model, 2015.

In 2020, the EPA estimates that CO_2 emissions will be reduced by 598 million short tons (22 percent) under the rate-based approach compared to 2005 levels. In 2025, the EPA estimates that CO_2 emissions will be reduced by 750 million short tons (28 percent) under the rate-based approach compared to 2005 levels. Under the rate-based approach, CO_2 emission reductions increase to 871 million short tons (32 percent) in 2030 when compared to 2005 levels.

Under the mass-based approach in 2020, the EPA estimates that CO_2 emissions will be reduced by 610 million short tons (23 percent) under the rate-based approach compared to 2005 levels. In 2025, the EPA estimates that CO_2 emissions will be reduced by 782 million short tons (29 percent) under the mass-based approach compared to 2005 levels. Under the mass-based approach, CO_2 emission reductions increase to 869 million short tons (32 percent) in 2030 when compared to 2005 levels.

ES.5 Costs

The compliance cost estimates for this final action are represented in this analysis as the change in electric power generation costs between the base case and illustrative plan approach policy cases, including the cost of demand-side energy efficiency measures and costs associated with monitoring, reporting, and recordkeeping requirements (MR&R). In the rate-based approach, energy efficiency activities are modeled as being used by EGUs as a low-cost method of demonstrating compliance with their rate-based emissions standards. In the mass-based approach, energy efficiency activities are assumed to be adopted by states to lower demand, which in turn reduces the cost of achieving the mass limitations. The level of energy efficiency measures is determined outside of IPM and is assumed to be the same in the two illustrative plan approaches. The compliance assumptions, and therefore the projected "compliance costs" set forth in this analysis, are illustrative in nature and do not represent the full suite of compliance flexibilities states may ultimately pursue.

The annual incremental cost is the projected additional cost of complying with the final rule in the year analyzed and includes the net change in the annualized cost of capital investment in new generating sources and heat rate improvements at coal-fired steam generating units, the change in the ongoing costs of operating pollution controls, shifts between or amongst various fuels, demand-side energy efficiency measures, and other actions associated with compliance. The total compliance cost estimates presented here include the costs associated with monitoring, reporting, and recordkeeping.[3] The costs for both illustrative plan approaches are reflected in Table ES-5 below and discussed more extensively in Chapter 3 of this RIA. All dollar estimates are in 2011 dollars.

The EPA estimates the annual incremental compliance cost for the rate-based approach for final emission guidelines to be $2.5 billion in 2020, $1.0 billion in 2025 and $8.4 billion in 2030, including the costs associated with monitoring, reporting, and recordkeeping.[4] The EPA estimates the annual incremental compliance cost for the mass-based approach for final emission guidelines to be $1.4 billion in 2020, $3.0 billion in 2025 and $5.1 billion in 2030, including the costs associated with monitoring, reporting, and recordkeeping.

Table ES-5. Compliance Costs for the Illustrative Rate-Based and Mass-Based Plan Approaches

	Incremental Cost from Base Case (billions of 2011$)	
	Rate-based Approach	**Mass-based Approach**
2020	$2.5	$1.4
2025	$1.0	$3.0
2030	$8.4	$5.1

Source: Integrated Planning Model, 2015, with post-processing to account for exogenous demand-side management energy efficiency costs and monitoring, reporting, and recordkeeping costs. See Chapter 3 of this RIA for more details.

[3] These costs are estimated outside of the IPM modelling framework as IPM only models the contiguous U.S. and does not incorporate monitoring, reporting, and recordkeeping requirements specific to the Clean Power Plan Final Rules.

[4] The MR&R costs estimates are $67 million in 2020, $16 million in 2025 and $16 million in 2030 and are assumed to be the same for both rate-based and mass-based illustrative plan approaches. Note the MR&R costs in 2020 are related to facilities setting up net energy output monitoring and upgrading data acquisition systems.

The costs reported in Table ES-5 represent the estimated incremental electric utility generating costs changes from the base case plus the estimates of demand-side energy efficiency program costs (which are paid by electric utilities), demand-side energy efficiency participant costs (which are paid by electric utility consumers), and MR&R costs. For example, in 2030, under the rate-based approach, the incremental electric utility generating costs decline by about $18.0 billion from the base case. MR&R requirements in 2030 are estimated at $16.0 million, and demand-side energy efficiency costs in 2030 are estimated to be $26.3 billion, split equally between program and participants using a 3 percent discount rate (see Chapter 3 of this RIA for more details on these estimates). These cost estimates sum to the $8.4 billion shown in Table ES-3 and represent the total costs of the rate-based illustrative plan approach in 2030. The same approach applies in each year of analysis for the rate-based and the mass-based illustrative plan approaches.

The compliance costs reported in Table ES-5 are not social costs. These costs represent the estimated expenditures incurred by EGUs and states to comply with the BSER goals for the Clean Power Plan Final Rule. These compliance cost estimates are compared to estimates of social benefits to derive net benefits of the final emission guidelines, which are presented later in this Executive Summary. For a more extensive discussion of social costs and benefits, see Chapter 3 and Chapter 4, respectively, of this RIA.

ES.6 Monetized Climate Benefits and Health Co-benefits

Implementing the final emission guidelines is expected to reduce emissions of CO_2 and have ancillary emission reductions (i.e., co-benefits) of SO_2, NO_2, and directly emitted $PM_{2.5}$, which would lead to lower ambient concentrations of $PM_{2.5}$ and ozone. The climate benefits estimates have been calculated using the estimated values of marginal climate impacts presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866 (May 2013, Revised July 2015)*, henceforth denoted as the current SC-CO_2 TSD.[5] Also, the range of combined benefits reflects

[5] Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and

different concentration-response functions for the air quality health co-benefits, but it does not capture the full range of uncertainty inherent in the health co-benefits estimates. Furthermore, we were unable to quantify or monetize all of the climate benefits and health and environmental co-benefits associated with the final emission guidelines, including reducing exposure to SO_2, NO_X, and hazardous air pollutants (e.g., mercury), as well as ecosystem effects and visibility improvement. The omission of these endpoints from the monetized results should not imply that the impacts are small or unimportant. Table ES-6 provides the list of the quantified and unquantified health and environmental benefits in this analysis.

Department of Treasury (May 2013, Revised July 2015). Available at: <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf> Accessed 7/11/2015.

Table ES-6. Quantified and Unquantified Benefits

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Environment				
Reduced climate effects	Global climate impacts from CO_2	—[1]	✓	SC-CO_2 TSD
	Climate impacts from ozone and black carbon (directly emitted PM)	—	—	Ozone ISA, PM ISA[2]
	Other climate impacts (e.g., other GHGs such as methane, aerosols, other impacts)	—	—	IPCC[2]
Improved Human Health (co-benefits)				
Reduced incidence of premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	✓	✓	PM ISA
	Infant mortality (age <1)	✓	✓	PM ISA
Reduced incidence of morbidity from exposure to $PM_{2.5}$	Non-fatal heart attacks (age > 18)	✓	✓	PM ISA
	Hospital admissions—respiratory (all ages)	✓	✓	PM ISA
	Hospital admissions—cardiovascular (age >20)	✓	✓	PM ISA
	Emergency room visits for asthma (all ages)	✓	✓	PM ISA
	Acute bronchitis (age 8-12)	✓	✓	PM ISA
	Lower respiratory symptoms (age 7-14)	✓	✓	PM ISA
	Upper respiratory symptoms (asthmatics age 9-11)	✓	✓	PM ISA
	Asthma exacerbation (asthmatics age 6-18)	✓	✓	PM ISA
	Lost work days (age 18-65)	✓	✓	PM ISA
	Minor restricted-activity days (age 18-65)	✓	✓	PM ISA
	Chronic Bronchitis (age >26)	—	—	PM ISA[2]
	Emergency room visits for cardiovascular effects (all ages)	—	—	PM ISA[2]
	Strokes and cerebrovascular disease (age 50-79)	—	—	PM ISA[2]
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[3]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[3]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc)	—	—	PM ISA[3,4]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[3,4]
Reduced incidence of mortality from exposure to ozone	Premature mortality based on short-term study estimates (all ages)	✓	✓	Ozone ISA
	Premature mortality based on long-term study estimates (age 30–99)	—	—	Ozone ISA[2]
Reduced incidence of morbidity from exposure to ozone	Hospital admissions—respiratory causes (age > 65)	✓	✓	Ozone ISA
	Hospital admissions—respiratory causes (age <2)	✓	✓	Ozone ISA
	Emergency department visits for asthma (all ages)	✓	✓	Ozone ISA
	Minor restricted-activity days (age 18–65)	✓	✓	Ozone ISA
	School absence days (age 5–17)	✓	✓	Ozone ISA
	Decreased outdoor worker productivity (age 18–65)	—	—	Ozone ISA[2]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[3]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[3]
	Reproductive and developmental effects	—	—	Ozone ISA[3,4]

Table ES-6. Continued

Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions (all ages)	—	—	NO_2 ISA[2]
	Chronic lung disease hospital admissions (age > 65)	—	—	NO_2 ISA[2]
	Respiratory emergency department visits (all ages)	—	—	NO_2 ISA[2]
	Asthma exacerbation (asthmatics age 4–18)	—	—	NO_2 ISA[2]
	Acute respiratory symptoms (age 7–14)	—	—	NO_2 ISA[2]
	Premature mortality	—	—	NO_2 ISA[2,3,4]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO_2 ISA[3,4]
Reduced incidence of morbidity from exposure to SO_2	Respiratory hospital admissions (age > 65)	—	—	SO_2 ISA[2]
	Asthma emergency department visits (all ages)	—	—	SO_2 ISA[2]
	Asthma exacerbation (asthmatics age 4–12)	—	—	SO_2 ISA[2]
	Acute respiratory symptoms (age 7–14)	—	—	SO_2 ISA[2]
	Premature mortality	—	—	SO_2 ISA[2,3,4]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	SO_2 ISA[2,3]
Reduced incidence of morbidity from exposure to methylmercury	Neurologic effects—IQ loss	—	—	IRIS; NRC, 2000[2]
	Other neurologic effects (e.g., developmental delays, memory, behavior)	—	—	IRIS; NRC, 2000[3]
	Cardiovascular effects	—	—	IRIS; NRC, 2000[3,4]
	Genotoxic, immunologic, and other toxic effects	—	—	IRIS; NRC, 2000[3,4]
Improved Environment (co-benefits)				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[2]
	Visibility in residential areas	—	—	PM ISA[2]
Reduced effects on materials	Household soiling	—	—	PM ISA[2,3]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[3]
Reduced PM deposition (metals and organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[3]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[2]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[2]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[2]
	Damage to urban ornamental plants	—	—	Ozone ISA[3]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[2]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[3]
	Other non-use effects			Ozone ISA[3]
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[3]
Reduced effects from acid deposition	Recreational fishing	—	—	NO_x SO_x ISA[2]
	Tree mortality and decline	—	—	NO_x SO_x ISA[3]
	Commercial fishing and forestry effects	—	—	NO_x SO_x ISA[3]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO_x SO_x ISA[3]
	Other non-use effects			NO_x SO_x ISA[3]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO_x SO_x ISA[3]

Table ES-6. Continued

Reduced effects from nutrient enrichment	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[3]
	Coastal eutrophication	—	—	NO_x SO_x ISA[3]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[3]
	Other non-use effects			NO_x SO_x ISA[3]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NO_x SO_x ISA[3]
Reduced vegetation effects from exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NO_x SO_x ISA[3]
	Injury to vegetation from NO_x exposure	—	—	NO_x SO_x ISA[3]
Reduced ecosystem effects from exposure to methylmercury	Effects on fish, birds, and mammals (e.g., reproductive effects)	—	—	Mercury Study RTC[3]
	Commercial, subsistence and recreational fishing	—	—	Mercury Study RTC[2]

[1] The global climate and related impacts of CO_2 emissions changes, such as sea level rise, are estimated within each integrated assessment model as part of the calculation of the SC-CO_2. The resulting monetized damages, which are relevant for conducting the benefit-cost analysis, are used in this RIA to estimate the welfare effects of quantified changes in CO_2 emissions.

[2] We assess these co-benefits qualitatively due to data and resource limitations for this analysis.

[3] We assess these co-benefits qualitatively because we do not have sufficient confidence in available data or methods.

[4] We assess these co-benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

ES.6.1 Estimating Global Climate Benefits

We estimate the global social benefits of CO_2 emission reductions expected from this rulemaking using the SC-CO_2 estimates presented in the current SC-CO_2 TSD. We refer to these estimates, which were developed by the U.S. government, as "SC-CO_2 estimates" for the remainder of this document. The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (i.e., benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions).

The SC-CO_2 estimates used in this analysis have been developed over many years, using the best science available, and with input from the public. The EPA and other federal agencies have considered the extensive public comments on ways to improve $SC\text{-}CO_2$ estimation received via the notice and comment period that was part of numerous rulemakings. In addition, OMB's Office of Information and Regulatory Affairs recently issued a response to the public comments it sought through a separate comment period on the approach used to develop the $SC\text{-}CO_2$ estimates.[6]

An interagency working group (IWG) that included the EPA and other executive branch entities used three integrated assessment models (IAMs) to develop $SC\text{-}CO_2$ estimates and recommended four global values for use in regulatory analyses. The $SC\text{-}CO_2$ estimates represent global measures because of the distinctive nature of the climate change problem. Emissions of greenhouse gases contribute to damages around the world, even when they are released in the United States, and the world's economies are now highly interconnected. Therefore, the $SC\text{-}CO_2$ estimates incorporate the worldwide damages caused by carbon dioxide emissions in order to reflect the global nature of the problem, and we expect other governments to consider the global consequences of their greenhouse gas emissions when setting their own domestic policies. See RIA Chapter 4 for more discussion.

The IWG first released the estimates in February 2010 and updated them in 2013 using new versions of each IAM. The $SC\text{-}CO_2$ values was estimated using three integrated assessment models (DICE, FUND, and PAGE)[7], which the IWG harmonized across three key inputs: the probability distribution for equilibrium climate sensitivity; five scenarios for economic, population, and emissions growth; and three constant discount rates. The 2010 $SC\text{-}CO_2$ Technical Support Document (2010 $SC\text{-}CO_2$ TSD) provides a complete discussion of the methodology and the current $SC\text{-}CO_2$ TSD[8] presents and discusses the updated estimates. The four $SC\text{-}CO_2$ estimates are as follows: \$12, \$40, \$60, and \$120 per short ton of CO_2 emissions in the year 2020 (2011\$), and each estimate increases over time.[9] These $SC\text{-}CO_2$ estimates are

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[6] See https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf

[7] The full models names are as follows: Dynamic Integrated Climate and Economy (DICE); Climate Framework for Uncertainty, Negotiation, and Distribution (FUND); and Policy Analysis of the Greenhouse Gas Effect (PAGE).

[8] The IWG published the updated TSD in 2013, then issued two minor corrections to it in July 2015.

[9] The 2010 and 2013 TSDs present $SC\text{-}CO_2$ in 2007\$ per metric ton. The estimates were adjusted to (1) short tons for using conversion factor 0.90718474 and (2) 2011\$ using GDP Implicit Price Deflator, http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf.

associated with different discount rates. The first three estimates are the model average at 5 percent discount rate, 3 percent, and 2.5 percent, respectively, and the fourth estimate is the 95th percentile at 3 percent.

The 2010 SC-CO_2 TSD noted a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently integrated assessment models do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. In particular, the IPCC Fourth Assessment Report concluded that "It is very likely that [SC-CO_2 estimates] underestimate the damage costs because they cannot include many non-quantifiable impacts." Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 emission reductions to inform the benefit-cost analysis.

In addition, after careful evaluation of the full range of comments submitted to OMB's Office of Information and Regulatory Affairs, the IWG continues to recommend the use of these SC-CO_2 estimates in regulatory impact analysis. With the release of the response to comments, the IWG announced plans to obtain expert independent advice from the National Academies of Sciences, Engineering, and Medicine (Academies) to ensure that the SC-CO_2 estimates continue to reflect the best available scientific and economic information on climate change.[10] The Academies process will be informed by the public comments received and focus on the technical merits and challenges of potential approaches to improving the SC-CO_2 estimates in future updates.

ES 6.2 Estimating Air Quality Health Co-Benefits

The final emission guidelines would reduce emissions of precursor pollutants (e.g., SO_2, NO_X, and directly emitted particles), which in turn would lower ambient concentrations of $PM_{2.5}$

[10] See <https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions>.

and ozone. This co-benefits analysis quantifies the monetized benefits associated with the reduced exposure to these two pollutants.[11] Unlike the global SC-CO_2 estimates, the air quality health co-benefits are only estimated for the contiguous U.S. The estimates of monetized $PM_{2.5}$ co-benefits include avoided premature deaths (derived from effect coefficients in two cohort studies [Krewski *et al.* 2009 and Lepeule *et al.* 2012] for adults and one for infants [Woodruff *et al.* 1997]), as well as avoided morbidity effects for ten non-fatal endpoints ranging in severity from lower respiratory symptoms to heart attacks (U.S. EPA, 2012). The estimates of monetized ozone co-benefits include avoided premature deaths (derived from the range of effect coefficients represented by two short-term epidemiology studies [Bell *et al.* (2004) and Levy *et al.* (2005)]), as well as avoided morbidity effects for five non-fatal endpoints ranging in severity from school absence days to hospital admissions (U.S. EPA, 2008, 2011).

We use a "benefit-per-ton" approach to estimate the $PM_{2.5}$ and ozone co-benefits in this RIA. Benefit-per-ton approaches apply an average benefit per ton derived from modeling of benefits of specific air quality scenarios to estimates of emissions reductions for scenarios where no air quality modeling is available. The benefit-per-ton approach we use in this RIA relies on estimates of human health responses to exposure to PM and ozone obtained from the peer-reviewed scientific literature. These estimates are used in conjunction with population data, baseline health information, air quality data and economic valuation information to conduct health impact and economic benefits assessments.

Specifically, in this analysis, we multiplied the benefit-per-ton estimates by the corresponding emission reductions that were generated from air quality modeling of the proposed Clean Power Plan. Similar to the co-benefits analysis conducted for the RIA for this rule at proposal, we generated regional benefit-per-ton estimates by aggregating the impacts in BenMAP[12] to the region (i.e., East, West, and California) rather than aggregating to the nation. To calculate the co-benefits for the final emission guidelines, we then multiplied the regional

[11] We did not estimate the co-benefits associated with reducing direct exposure to SO_2 and NO_X. For this RIA, we did not estimate changes in emissions of directly emitted particles. As a result, quantified $PM_{2.5}$ related benefits are underestimated by a relatively small amount. In the proposal RIA, the benefits from reductions in directly emitted $PM_{2.5}$ were less than 10 percent of total monetized health co-benefits across all scenarios and years.

[12] BenMAP is a computer program developed by the EPA that calculates the number and economic value of air pollution-related deaths and illnesses. The software incorporates a database that includes many of the concentration-response relationships, population files, and health and economic data needed to quantify these impacts.

benefit-per-ton estimates for the EGU sector by the corresponding emission reductions. All benefit-per-ton estimates reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions in this rulemaking, and thus they may not reflect the local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location.

Our estimate of the monetized co-benefits is based on the EPA's interpretation of the best available scientific literature (U.S. EPA, 2009) and methods and supported by the EPA's Science Advisory Board and the NAS (NRC, 2002). Below are key assumptions underlying the estimates for $PM_{2.5}$-related premature mortality, which accounts for 98 percent of the monetized $PM_{2.5}$ health co-benefits:

1. We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because $PM_{2.5}$ varies considerably in composition across sources, but the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. The PM ISA concluded that "many constituents of $PM_{2.5}$ can be linked with multiple health effects, and the evidence is not yet sufficient to allow differentiation of those constituents or sources that are more closely related to specific outcomes" (U.S. EPA, 2009b).

2. We assume that the health impact function for fine particles is log-linear without a threshold in this analysis. Thus, the estimates include health co-benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both areas that do not meet the National Ambient Air Quality Standard for fine particles and those areas that are in attainment, down to the lowest modeled concentrations.

3. We assume that there is a "cessation" lag between the change in PM exposures and the total realization of changes in mortality effects. Specifically, we assume that some of the incidences of premature mortality related to $PM_{2.5}$ exposures occur in a distributed fashion over the 20 years following exposure based on the advice of the SAB-HES (U.S. EPA-SAB, 2004c), which affects the valuation of mortality co-benefits at different discount rates.

Every benefits analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. In addition, given the flexibilities afforded states in complying with the emission guidelines, the co-benefits estimated presented in this RIA are not definitive estimates, but are instead illustrative of approaches that states may take. Despite these uncertainties, we believe this analysis provides a reasonable indication of the expected health co-benefits of the air quality emission reductions for the final emission guidelines under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates.

ES 6.3 Combined Benefits Estimates

The EPA has evaluated the range of potential impacts by combining all four SC-CO_2 values with health co-benefits values at the 3 percent and 7 percent discount rates. Different discount rates are applied to SC-CO_2 than to the health co-benefit estimates; because CO_2 emissions are long-lived and subsequent damages occur over many years. Moreover, several discount rates are applied to SC-CO_2 because the literature shows that the estimate of SC-CO_2 is sensitive to assumptions about discount rate and because no consensus exists on the appropriate rate to use in an intergenerational context. The U.S. government centered its attention on the average SC-CO_2 at a 3 percent discount rate but emphasized the importance of considering all four SC-CO_2 estimates. Table ES-7 (rate-based illustrative plan approach) and Table ES-8 (mass-based illustrative plan approach) provide the combined climate benefits and health co-benefits for the Clean Power Plan Final Rule estimated for 2020, 2025, and 2030 for each discount rate combination. All dollar estimates are in 2011 dollars.

Table ES-7. Combined Estimates of Climate Benefits and Health Co-Benefits for Rate-Based Approach (billions of 2011$)*

SC-CO_2 Discount Rate and Statistic**	Climate Benefits Only	Climate Benefits plus Health Co-benefits (Discount Rate Applied to Health Co-benefits)					
		3%			7%		
In 2020	69	million short tons CO_2					
5%	$0.80	$1.5	to	$2.6	$1.4	to	$2.5
3%	$2.8	$3.5	to	$4.6	$3.5	to	$4.5
2.5%	$4.1	$4.9	to	$6.0	$4.8	to	$5.9
3% (95th percentile)	$8.2	$8.9	to	$10	$8.9	to	$9.9
In 2025	232	million short tons CO_2					
5%	$3.1	$11	to	$21	$9.9	to	$19
3%	$10	$18	to	$28	$17	to	$26
2.5%	$15	$23	to	$33	$22	to	$31
3% (95th percentile)	$31	$38	to	$49	$38	to	$47
In 2030	415	million short tons CO_2					
5%	$6.4	$21	to	$40	$19	to	$37
3%	$20	$34	to	$54	$33	to	$51
2.5%	$29	$43	to	$63	$42	to	$60
3% (95th percentile)	$61	$75	to	$95	$74	to	$92

*All benefit estimates are rounded to two significant figures. Climate benefits are based on reductions in CO_2 emissions. Co-benefits are based on regional benefit-per-ton estimates. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski *et al.* (2009) with Bell *et al.* (2004) to Lepeule *et al.* (2012) with Levy *et al.* (2005)). The monetized health co-benefits do not include reduced health effects from reductions in directly emitted $PM_{2.5}$, direct exposure to NO_X, SO_2, and HAP; ecosystem effects; or visibility impairment. See Chapter 4 for more information about these estimates and for more information regarding the uncertainty in these estimates.

**Unless otherwise specified, it is the model average.

Table ES-8. Combined Estimates of Climate Benefits and Health Co-benefits for Mass-Based Approach (billions of 2011$)*

SC-CO_2 Discount Rate and Statistic**	Climate Benefits Only	Climate Benefits plus Health Co-benefits (Discount Rate Applied to Health Co-benefits)					
		3%			7%		
In 2020	82	million short tons CO_2					
5%	$0.94	$2.9	to	$5.7	$2.8	to	$5.3
3%	$3.3	$5.3	to	$8.1	$5.1	to	$7.7
2.5%	$4.9	$6.9	to	$9.7	$6.7	to	$9.3
3% (95th percentile)	$9.7	$12	to	$14	$11	to	$14
In 2025	264	million short tons CO_2					
5%	$3.6	$11	to	$21	$10	to	$19
3%	$12	$19	to	$29	$18	to	$27
2.5%	$17	$24	to	$35	$24	to	$33
3% (95th percentile)	$35	$42	to	$52	$42	to	$51
In 2030	413	million short tons CO_2					
5%	$6.4	$18	to	$34	$17	to	$32
3%	$20	$32	to	$48	$31	to	$46
2.5%	$29	$41	to	$57	$40	to	$55
3% (95th percentile)	$60	$72	to	$89	$71	to	$86

*All benefit estimates are rounded to two significant figures. Climate benefits are based on reductions in CO_2 emissions. Co-benefits are based on regional benefit-per-ton estimates. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski *et al.* (2009) with Bell *et al.* (2004) to Lepeule *et al.* (2012) with Levy *et al.* (2005)). The monetized health co-benefits do not include reduced health effects from reductions in directly emitted $PM_{2.5}$, direct exposure to NO_X, SO_2, and HAP; ecosystem effects; or visibility impairment. See Chapter 4 for more information about these estimates and for more information regarding the uncertainty in these estimates.
**Unless otherwise specified, it is the model average.

ES.7 Net Benefits

Table ES-9 and ES-10 provide the estimates of the climate benefits, health co-benefits, compliance costs and net benefits of the final emission guidelines for rate-based and mass-based approaches, respectively. There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified benefits also include climate benefits from reducing emissions of non-CO_2 greenhouse gases and co-benefits from reducing exposure to SO_2, NO_X, and hazardous air pollutants (e.g., mercury), as well as ecosystem effects and visibility impairment. Upon considering these limitations and uncertainties, it remains clear that the benefits of this final rule are substantial and far outweigh the costs.

Table ES-9. Monetized Benefits, Compliance Costs, and Net Benefits Under the Rate-based Illustrative Plan Approach (billions of 2011$) [a]

	Rate-Based Approach					
	2020		2025		2030	
Climate Benefits [b]						
5% discount rate	$0.80		$3.1		$6.4	
3% discount rate	$2.8		$10		$20	
2.5% discount rate	$4.1		$15		$29	
95th percentile at 3% discount rate	$8.2		$31		$61	
	Air Quality Co-benefits Discount Rate					
	3%	7%	3%	7%	3%	7%
Air Quality Health Co-benefits [c]	$0.70 to $1.8	$0.64 to $1.7	$7.4 to $18	$6.7 to $16	$14 to $34	$13 to $31
Compliance Costs [d]	$2.5		$1.0		$8.4	
Net Benefits [e]	$1.0 to $2.1	$1.0 to $2.0	$17 to $27	$16 to $25	$26 to $45	$25 to $43
Non-Monetized Benefits	Non-monetized climate benefits Reductions in exposure to ambient NO_2 and SO_2 Reductions in mercury deposition Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury Visibility impairment					

[a] All are rounded to two significant figures, so figures may not sum.
[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC-CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC-CO_2 estimated for a 3 percent discount rate, however we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC-CO_2 estimates are year-specific and increase over time.
[c] The air quality health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Estimates in the table are presented for three analytical years with air quality co-benefits calculated using two discount rates. The estimates of co-benefits are annual estimates in each of the analytical years, reflecting discounting of mortality benefits over the cessation lag between changes in $PM_{2.5}$ concentrations and changes in risks of premature death (see RIA Chapter 4 for more details), and discounting of morbidity benefits due to the multiple years of costs associated with some illnesses. The estimates are not the present value of the benefits of the rule over the full compliance period.
[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final emission guidelines and a discount rate of approximately 5 percent. This estimate also includes monitoring, recordkeeping, and reporting costs and demand-side energy efficiency program and participant costs.
[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

Table ES-10. Monetized Benefits, Compliance Costs, and Net Benefits under the Mass-based Illustrative Plan Approach (billions of 2011$) [a]

	Mass-Based Approach					
	2020		2025		2030	
Climate Benefits [b]						
5% discount rate	$0.94		$3.6		$6.4	
3% discount rate	$3.3		$12		$20	
2.5% discount rate	$4.9		$17		$29	
95th percentile at 3% discount rate	$9.7		$35		$60	
	Air Quality Co-benefits Discount Rate					
	3%	7%	3%	7%	3%	7%
Air Quality Health Co-benefits [c]	$2.0 to $4.8	$1.8 to $4.4	$7.1 to $17	$6.5 to $16	$12 to $28	$11 to $26
Compliance Costs [d]	$1.4		$3.0		$5.1	
Net Benefits [e]	$3.9 to $6.7	$3.7 to $6.3	$16 to $26	$15 to $24	$26 to $43	$25 to $40
Non-Monetized Benefits	Non-monetized climate benefits Reductions in exposure to ambient NO_2 and SO_2 Reductions in mercury deposition Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury Visibility improvement					

[a] All are rounded to two significant figures, so figures may not sum.
[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC-CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC-CO_2 estimated for a 3 percent discount rate, however we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95[th] percentile at 3 percent). The SC-CO_2 estimates are year-specific and increase over time.
[c] The air quality health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of, SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Estimates in the table are presented for three analytical years with air quality co-benefits calculated using two discount rates. The estimates of co-benefits are annual estimates in each of the analytical years, reflecting discounting of mortality benefits over the cessation lag between changes in PM2.5 concentrations and changes in risks of premature death (see RIA Chapter 4 for more details), and discounting of morbidity benefits due to the multiple years of costs associated with some illnesses. The estimates are not the present value of the benefits of the rule over the full compliance period.
[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final emission guidelines and a discount rate of approximately 5 percent. This estimate also includes monitoring, recordkeeping, and reporting costs and demand-side energy efficiency program and participant costs.
[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

ES.8 Economic Impacts

The final emission guidelines have important energy market implications. Table ES-11 presents a variety of important energy market impacts for 2020, 2025, and 2030 for both the rate-based and mass-based illustrative plan approaches.

Table ES-11. Summary Table of Important Energy Market Impacts (Percent Change from Base Case)

	Rate-Based			Mass-Based		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
Retail electricity prices	3%	1%	1%	3%	2%	0%
Price of coal at minemouth	-1%	-5%	-4%	-1%	-5%	-3%
Coal production for power sector use	-5%	-14%	-25%	-7%	-17%	-24%
Price of natural gas delivered to power sector	5%	-8%	2%	4%	-3%	-2%
Natural gas use for electricity generation	3%	-1%	-1%	5%	0%	-4%

Energy market impacts from the guidelines are discussed more extensively in Chapter 3 of this RIA.

Additionally, changes in supply or demand for electricity, natural gas, and coal can impact markets for goods and services produced by sectors that use these energy inputs in the production process or that supply those sectors. Changes in cost of production may result in changes in price and/or quantity produced by these sectors and these market changes may affect the profitability of firms and the economic welfare of their consumers. The EPA recognizes that these final emission guidelines provide flexibility, and states implementing the guidelines may choose to mitigate impacts to some markets outside the EGU sector. Similarly, demand for new generation or energy efficiency, for example, can result in changes in production and profitability for firms that supply those goods and services.

ES.9 Employment Impacts

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, "our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science" (Executive Order 13563, 2011). Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, we typically conduct employment analyses. During the current economic recovery, employment impacts are of particular concern and questions may arise about their existence and magnitude.

Given the wide range of approaches that may be used to meet the requirements of the Clean Power Plan Final Rule, quantifying the associated employment impacts is difficult. The EPA's illustrative employment analysis includes an estimate of projected employment impacts associated with these guidelines for the utility power sector, coal and natural gas production, and demand-side energy efficiency activities. These projections are derived, in part, from the detailed model of the utility power sector used for this regulatory analysis, and U.S government data on employment and labor productivity.

In the electricity, coal, and natural gas sectors, the EPA estimates that these guidelines could result in a net decrease of approximately 25,000 job-years in 2025 for the final guidelines under the rate-based illustrative plan approach and approximately 26,000 job-years in 2025 under the mass-based approach. For 2030 the estimates of the net decrease in job-years is 30,900 under the rate-based plan, and 33,700 under the mass-based plan. The Agency is also offering an illustrative calculation of potential employment effects due to demand-side energy efficiency programs. Employment impacts from demand-side energy efficiency programs in 2030 could range from approximately 52,000 to 83,000 jobs under the final guidelines. More detail about these analyses can be found in Chapter 6 of this RIA.

ES.10 References

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CHAPTER 3: COST, EMISSIONS, ECONOMIC, AND ENERGY IMPACTS

3.1 Introduction

This chapter reports the compliance cost, emissions, economic, and energy impact analysis performed for the Clean Power Plan Final Rule. EPA used the Integrated Planning Model (IPM), developed by ICF International, to conduct most of the analysis discussed in this Chapter. IPM is a dynamic linear programming model that can be used to examine air pollution control policies for CO_2, SO_2, NO_X, Hg, HCl, and other air pollutants throughout the contiguous United States for the entire power system. The IPM electricity demand projections are based on projections from the Energy Information Administration (EIA), adjusted for demand-side energy efficiency measures that can be reasonably anticipated to occur under the Clean Power Plan.

3.2 Overview

This chapter of the RIA presents illustrative analyses of the final rule by making assumptions about the possible approaches that States might pursue as they develop their state plans. Over the last decade, EPA has conducted extensive analyses of regulatory actions affecting the power sector. These efforts support the Agency's understanding of key variables that influence the effects of a policy and provide the framework for how the Agency estimates the costs and benefits associated with its actions.

3.3 Power Sector Modelling Framework

The Integrated Planning Model (IPM), developed by ICF Consulting, is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system. EPA used IPM to project likely future electricity market conditions with and without the Clean Power Plan Final Rule. Additional demand side energy efficiency measures that may be adopted in response to the regulation, and the resulting changes to future demand projections, are also accounted for in the analyses. The level of demand side energy efficiency-driven reductions in electricity demand, and their associated costs, are reported in section 3.7.

IPM is a multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. EPA has used IPM for over two decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emission impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[56]

The model incorporates a detailed representation of the fossil-fuel supply system that is used to forecast equilibrium fuel prices. The model includes an endogenous representation of the North American natural gas supply system through a natural gas module that reflects a partial supply/demand equilibrium of the North American gas market accounting for varying levels of potential power sector and non-power sector gas demand and corresponding gas production and price levels.[57] This module consists of 118 supply, demand, and storage nodes and 15 liquefied natural gas re-gasification facility locations that are tied together by a series of linkages (i.e., pipelines) that represent the North American natural gas transmission and distribution network.

IPM also endogenously models the partial equilibrium of coal supply and EGU coal demand levels throughout the contiguous U.S., taking into account assumed non-power sector demand and imports/exports. IPM reflects 36 coal supply regions, 14 coal grades, and the coal transport network, which consists of over four thousand linkages representing rail, barge, and truck and conveyer linkages. The coal supply curves in IPM were developed during a thorough bottom-up, mine-by-mine approach that depicts the coal choices and associated supply costs that power plants would face if selecting that coal over the modeling time horizon. The IPM

[56] Detailed information and documentation of EPA's Base Case using IPM (v5.15), including all the underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: http://www.epa.gov/powersectormodeling

[57] See Chapter 10 of EPA's Base Case using IPM (v5.154) documentation, available at: http://www.epa.gov/powersectormodeling

documentation outlines the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 36 coal regions' supply curves.[58]

The costs presented in this RIA include both the IPM-projected annualized estimates of private compliance costs as well as the estimated costs incurred by utilities and ratepayers to achieve demand-side energy efficiency improvements. The IPM-projected annualized estimates of private compliance costs provided in this analysis are meant to show the increase in production (generating) costs to the power sector in response to the final rule.

To estimate these annualized costs, EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital.[59] It is important to note that there is no single CRF factor applied in the model; rather, the CRF varies across technologies in the model in order to better simulate power sector decisionmaking.

While the CRF is used to annualize costs within IPM, a discount rate is used to estimate the net present value of the intertemporal flow of the annualized capital and operating costs. The optimization model then identifies power sector investment decisions that minimize the net present value of all costs over the full planning horizon while satisfying a wide range of demand, capacity, reliability, emissions, and other constraints. As explained in Chapter 8 of the IPM documentation, the discount rate is derived as a weighted average cost of capital that is a function of capital structure, post-tax cost of debt, and post-tax cost of equity. While the detailed formulation of this rate is presented in the IPM documentation, the rate estimated and used in the current analysis is 4.77 percent. It is important to note that this discount rate is selected for the purposes of best simulating power sector behavior, and not for the purposes of discounting social costs or benefits.

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[58] See Chapter 9 of EPA's Base Case using IPM (v5.15) documentation, available at: http://www.epa.gov/powersectormodeling

[59] See Chapter 8 of EPA's Base Case using IPM (v5.15) documentation, available at: http://www.epa.gov/powersectormodeling.

EPA has used IPM extensively over the past two decades to analyze options for reducing power sector emissions. Previously, the model has been used to forecast the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule, Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), and the proposed Carbon Pollution Standards for New Power Plants. Recently IPM has also been used to estimate the air pollution reductions and power sector impacts of water and waste regulations affecting EGUs, including Cooling Water Intakes (316(b)) Rule, Disposal of Coal Combustion Residuals from Electric Utilities (CCR) and Steam Electric Effluent Limitation Guidelines (ELG).

The model and EPA's input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly-detailed review of key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts. For example, in the late 1990s, the Science Advisory Board reviewed IPM as part of the CAA Amendments Section 812 prospective studies that are periodically conducted. The model has also undergone considerable interagency scrutiny when it was used to conduct over a dozen legislative analyses (performed at Congressional request) over the past decade. The Agency has also used the model in a number of comparative modeling exercises sponsored by Stanford University's Energy Modeling Forum over the past 15 years. IPM has also been employed by states (e.g., for RGGI, the Western Regional Air Partnership, Ozone Transport Assessment Group), other Federal and state agencies, environmental groups, and industry.

3.4 Recent Updates to EPA's Base Case using IPM (v.5.15)

The "Base Case" for this analysis is a business-as-usual scenario that would be expected under market and regulatory conditions in the absence of this rule. As such, the IPM base case represents the baseline for this RIA. EPA frequently updates the IPM base case to reflect the latest available electricity demand forecasts as well as expected costs and availability of new and existing generating resources, fuels, emissions control technologies, and regulatory requirements.

EPA's IPM modeling platform used to analyze this final rule (v.5.15) incorporates updates to the version of the model used to analyze the impacts of the proposed rule (v.5.13). These updates are primarily routine calibrations with the Energy Information Agency's (EIA) Annual Energy Outlook (AEO), including updating the electric demand forecast consistent with the AEO 2015 and an update to natural gas supply. Additional updates, based on the most up-to-date information and/or public comments received by the EPA, include unit-level specifications (e.g., pollution control configurations), planned power plant construction and closures, and updated cost and performance for onshore wind and utility-scale solar technologies. This IPM modeling platform incorporates federal and most state laws and regulations whose provisions were either in effect or enacted and clearly delineated in March 2015. This update also includes two non-air federal rules affecting EGUs: Cooling Water Intakes (316(b)) Rule and Combustion Residuals from Electric Utilities (CCR). Additionally, all new capacity projected by the model is compliant with Clean Air Act 111(b) standards, including the final standards of performance for GHG emissions from new sources. For a detailed account of all updates made to the v.5.15 modeling platform, see the Incremental Documentation for EPA Base Case v.5.15 Using IPM.[60]

EPA also updated the National Electric Energy Data System (NEEDS). This database contains the unit-level data that is used to construct the "model" plants that represent existing and committed units in EPA modeling applications of IPM. NEEDS includes detailed information on each individual EGU, including geographic, operating, air emissions, and other data on every generating units in the contiguous U.S.[61]

3.5 State Goals in this Final Rule

In this final rule, the EPA is establishing CO_2 emission performance rates for two categories of existing fossil fuel-fired EGUs, fossil fuel-fired electric utility steam generating units and stationary combustion turbines. The EPA has translated the source category-specific CO_2 emission performance rates into state-level rate-based and mass-based CO_2 goals in order to expand the range of choices that states have in developing their plans. Due to the range of choices available to states, and the lack of *a priori* knowledge about the specific choices states

[60] Available at: http://www.epa.gov/powersectormodeling/

[61] The NEEDS database can be found on the EPA's website for the Base Case using IPM (v5.15), <http://www.epa.gov/powersectormodeling >.

will make in response to the final goals, this RIA presents two scenarios designed to achieve these goals, which we term the "rate-based" illustrative plan approach and the "mass-based" illustrative plan approach. Table 3-1 presents the rate-based and mass-based state goals.

Table 3-1. Statewide CO_2 Emission Performance Goals, Rate-based and Mass-based

	Rate-Based (Adjusted Output-Weighted-Average Pounds of CO_2 Per Net MWh From All Affected Fossil Fuel-Fired EGUs)		Mass-Based (Adjusted Output-Weighted-Average Short Tons of CO_2 From All Affected Fossil Fuel-Fired EGUs)	
State	**Interim Goal**	**Final Goal**	**Interim Goal**	**Final Goal**
Alabama	1,157	1,018	62,210,288	56,880,474
Arkansas	1,304	1,130	33,683,258	30,322,632
Arizona	1,173	1,031	33,061,997	30,170,750
California	907	828	51,027,075	48,410,120
Colorado	1,362	1,174	33,387,883	29,900,397
Connecticut	852	786	7,237,865	6,941,523
Delaware	1,023	916	5,062,869	4,711,825
Florida	1,026	919	112,984,729	105,094,704
Lands of the Fort Mojave Tribe	832	771	611,103	588,519
Georgia	1,198	1,049	50,926,084	46,346,846
Iowa	1,505	1,283	28,254,411	25,018,136
Idaho	832	771	1,550,142	1,492,856
Illinois	1,456	1,245	74,800,876	66,477,157
Indiana	1,451	1,242	85,617,065	76,113,835
Kansas	1,519	1,293	24,859,333	21,990,826
Kentucky	1,509	1,286	71,312,802	63,126,121
Louisiana	1,293	1,121	39,310,314	35,427,023
Massachusetts	902	824	12,747,677	12,104,747
Maryland	1,510	1,287	16,209,396	14,347,628
Maine	842	779	2,158,184	2,073,942
Michigan	1,355	1,169	53,057,150	47,544,064
Minnesota	1,414	1,213	25,433,592	22,678,368
Missouri	1,490	1,272	62,569,433	55,462,884
Mississippi	1,061	945	27,338,313	25,304,337
Montana	1,534	1,305	12,791,330	11,303,107
Lands of the Navajo Nation	1,534	1,305	24,557,793	21,700,587
North Carolina	1,311	1,136	56,986,025	51,266,234
North Dakota	1,534	1,305	23,632,821	20,883,232
Nebraska	1,522	1,296	20,661,516	18,272,739
New Hampshire	947	858	4,243,492	3,997,579
New Jersey	885	812	17,426,381	16,599,745
New Mexico	1,325	1,146	13,815,561	12,412,602

State	Rate-Based (Adjusted Output-Weighted-Average Pounds of CO_2 Per Net MWh From All Affected Fossil Fuel-Fired EGUs)		Mass-Based (Adjusted Output-Weighted-Average Short Tons of CO_2 From All Affected Fossil Fuel-Fired EGUs)	
	Interim Goal	Final Goal	Interim Goal	Final Goal
Nevada	942	855	14,344,092	13,523,584
New York	1,025	918	33,595,329	31,257,429
Ohio	1,383	1,190	82,526,513	73,769,806
Oklahoma	1,223	1,068	44,610,332	40,488,199
Oregon	964	871	8,643,164	8,118,654
Pennsylvania	1,258	1,095	99,330,827	89,822,308
Rhode Island	832	771	3,657,385	3,522,225
South Carolina	1,338	1,156	28,969,623	25,998,968
South Dakota	1,352	1,167	3,948,950	3,539,481
Tennessee	1,411	1,211	31,784,860	28,348,396
Texas	1,188	1,042	208,090,841	189,588,842
Lands of the Uintah and Ouray Reservation	1,534	1,305	2,561,445	2,263,431
Utah	1,368	1,179	26,566,380	23,778,193
Virginia	1,047	934	29,580,072	27,433,111
Washington	1,111	983	11,679,707	10,739,172
Wisconsin	1,364	1,176	31,258,356	27,986,988
West Virginia	1,534	1,305	58,083,089	51,325,342
Wyoming	1,526	1,299	35,780,052	31,634,412

3.6 Illustrative Plan Approaches Analyzed

To estimate the costs, benefits, and economic and energy market impacts of implementing the CPP guidelines, the EPA modeled two illustrative plan approaches, each at the state level, based on a rate-based approach and a mass-based approach. The rate-based plan approach requires affected sources in each state to achieve a single average emissions rate in each period as represented by the statewide goals. The mass-based plan approach requires affected sources in each state to limit their aggregate emissions not to exceed the mass goal for that state. The two plan types in these illustrative analyses represent two types of plans that are available to the states.

In each of these scenarios, affected EGUs include:

- Existing fossil steam boilers with nameplate capacity greater than 25 MW
- Existing NGCC units with nameplate capacity greater than 25 MW

In the rate-based scenario, generation (or avoided generation) from these additional sources represented in the model is counted toward meeting state goals:

- All renewable capacity (hydro, solar PV, wind, geothermal) that comes online after 2012
- Under-construction nuclear[62]
- Demand-side energy efficiency in addition to levels implicit in base case electricity demand.

In the rate-based illustrative plan approach analyzed in this RIA, the affected EGUs within each state are required to achieve an average emissions rate that is less than or equal to the state goals for each state. In order meet the goal for each state, the affected sources in this scenario have the ability to do one or both of the following:

1) generate in amounts within that state such that the average emissions rate is achieved, and/or
2) include in the average emissions rate calculation new renewable generation or demand-side energy efficiency located outside of the state but within each of the illustrative Interconnection-based regions shown in Figure 3-1 below.[63]

[62] Includes three nuclear facilities at which construction has already commenced: Watts Barr (TN), Vogtle (GA), and Summer (SC)

[63] In this illustrative scenario, energy efficiency/renewable energy procurement is limited to within one of the three illustrative regions. Since the interconnections do not always follow state borders, certain states that fall into more than one region were grouped in regions where there was a majority of geographic territory (area) or generation. Depending on the elements of their respective state's plan, sources in states that have adopted certain rate-based plans may be able to procure energy efficiency/renewable energy from states outside of these illustrative regions. See the preamble for discussion.

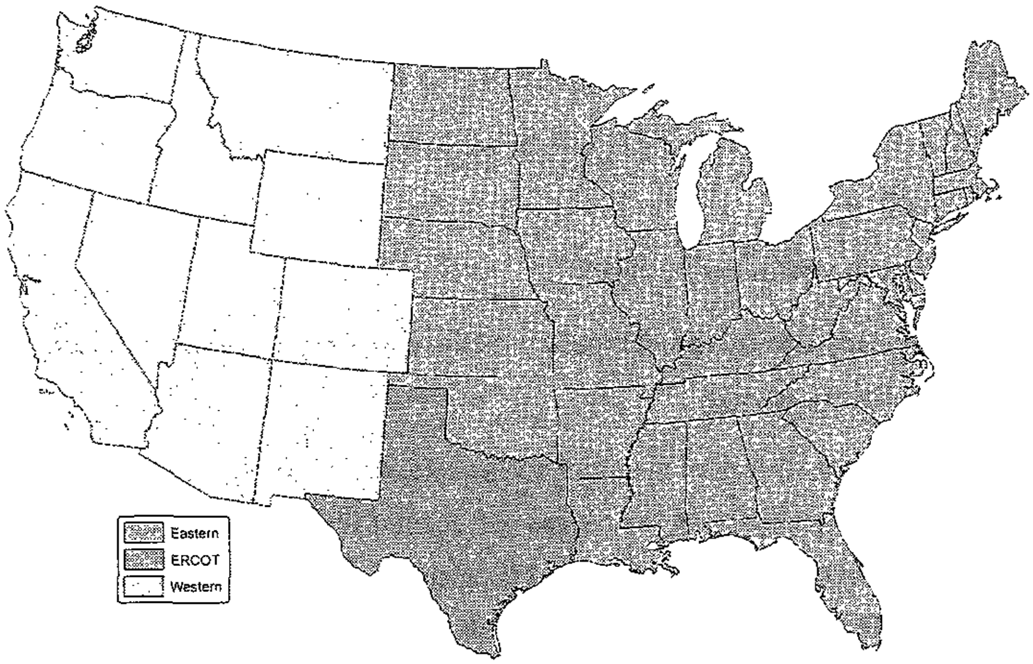

Figure 3-1. Illustrative Regions for Demand-Side Energy Efficiency/Renewable Energy Procurement Used in this Analysis

This rate-based implementation plan approach enables some sources to emit at emission rates higher than their applicable state goal, as long as there is either corresponding generation coming from affected sources in that state that emit at a lower rate and/or generation (or avoided generation) from energy efficiency/renewable energy (which is procured from within the illustrative regions, including within the source's state). In this illustrative analysis affected EGUs may not procure emission reductions from (e.g., by averaging their emissions with) affected EGUs located in other states (which may also have different emission performance standards) in order to demonstrate compliance. Furthermore in this rate-based scenario, specific generation (or avoided generation) from energy efficiency/renewable energy procurement may only be used once for compliance toward a state goal; in other words, while emitting sources in all states may avail themselves of qualifying energy efficiency/renewable energy across the illustrative region, no particular energy efficiency/renewable energy MWh can be claimed by more than one emitter as part of reaching a state goal.

Each illustrative plan approach assumes identical levels of demand-side energy efficiency megawatt-hour (MWh) demand reductions and associated costs, which are specified exogenously and consistent with the energy efficiency plan scenario performance levels described in section 3.7. Details of the implementation of the demand reduction are reported in the following section.

The mass-based scenario presented in this chapter includes a 5 percent set-aside of allowances that would be allocated to recognize deployment of new renewable capacity, which is represented by lowering the capital cost of new renewable capacity in a compliance period by the estimated value of the allowances in the set-aside in that period. The value of the set-aside is estimated in each model run year (i.e., simulated year in IPM) as the total allowances in the set-asides of each state in the contiguous U.S. multiplied by the projected average allowance price over the contiguous U.S. for that year. This total value is then assumed to apply evenly to all new renewable capacity.

Each of the two illustrative plan approaches assumes that sources within each state comply with the applicable state goals without exchanging a compliance instrument (ERC or allowance) with sources in any other state. However, in the rate-based scenario, sources are allowed to procure renewable energy or demand-side energy efficiency beyond their own state in order to adjust their effective emission rate, which is consistent with the conditions for rate-based implementation in any state that are described in section VIII of the preamble.[64] For example, while the final rule enables states to achieve their mass goals with the flexibility of interstate trading, this RIA presents analysis is an illustrative plan approach that assumes that each state achieves its goal independently. Cooperation between the states that allows for trading across states would provide EGUs with additional low cost abatement opportunities and would therefore lower the overall cost of compliance across the affected states. While the illustrative plan approaches assume particular plan types that may limit compliance options available to affected EGUs, the equilibrium effects on generation, emissions, etc., in a particular state that are forecast in these analyses depend on the behavior of generators in neighboring states in response to the regulation.

The full array of estimates for the benefits, costs, and economic impacts of this action are presented for both the illustrative rate-based and mass-based plan approaches. These illustrative plan approaches are designed to reflect, to the extent possible, the scope and nature of the CPP

[64] In this modeling scenario, sources were only able to procure such RE and EE within the same interconnection-based region, while the rule does not impose a regional limitation to such claims in rate-based compliance.

guidelines. However, there is considerable uncertainty with regard to the regulatory form and precise measures that states will adopt to meet the requirements, since there are considerable flexibilities afforded to the states in developing state plans. Nonetheless, the analysis of the benefits, costs, and relevant impacts of the rule attempts to encapsulate some of those flexibilities in order to inform states and stakeholders of the potential overall impacts of the CPP.

It is also important to note that the analysis does not specify any particular CO_2 reduction measure to occur, with the exception of the level of demand-side energy efficiency assumed to be adopted in response to the CPP. In other words, aside from investments in energy efficiency, the analysis allows the power system the flexibility to respond to average emissions rate or mass constraints on affected sources in the illustrative scenarios to achieve the goals in the most cost-effective manner determined by IPM, as specified below. Additionally, there are other zero-emitting alternatives to replacing fossil generation beyond the renewable generation technologies that are part of building block 3 and the energy efficiency measures that were analyzed in these scenarios. For instance, while costs would be different, the impact of distributed zero-emitting generation such as residential and commercial solar would displace fossil generation in the same way that demand side energy efficiency would.

While IPM produces a cost-minimizing solution to achieve the state goals imposed in the illustrative scenarios, there may be yet lower-cost approaches that the states may adopt to achieve their state goals inasmuch as states and sources take advantage of emission reduction opportunities in practice, and flexibilities afforded under the final rule, that are not represented in this analysis and would yield different cost and emissions outcomes.

As previously noted, the power sector modeling and analysis presented in this chapter is intended to be illustrative in nature, and reflects the EPA's best assessment of likely impacts of the CPP under a range of approaches that states may adopt. The modeling is designed to reflect the rule's requirements, including the timing, applicability to sources, and flexibilities across the power system as accurately as possible to represent the nature and scope of the CPP. The analysis is a reasonable expectation of the incremental effects of the rule, and is consistent with past EPA analyses of power sector regulatory requirements. The EPA has separately analyzed and considered the cost of implementing the emission reduction measures in BSER, which do not rely on energy efficiency measures. For this analysis, see section V.A.4.d. of the preamble to this final rule.

For the CPP, the analysis and projections for the year 2025 reflect the impacts across the power system of complying with the interim goals, and the analysis and projections for 2030 reflect the impacts of complying with the final goals. In addition to the 2025 and 2030 projections, modeling results and projections are also shown for 2020. There is no regulatory requirement reflected in the 2020 run-year in IPM, consistent with the final rule. These years reflect the basic run-year structure in IPM, as configured by EPA.

Although the analysis of the CPP does not include estimates of the costs and benefits of the CPP across each year of the rule in a year-by-year manner, the EPA has reflected the structure of the rule, including the interim and the final state goals of the CPP, in a manner that is consistent with the regulatory requirements. This is also consistent with past practice, including analysis of the Clean Air Interstate Rule, the Cross State Air Pollution Rule, the NO_X SIP Call, the Acid Rain Program, National Ambient Air Quality Standards, and state rules. These past regulatory and legislative efforts included modeling and analysis in a similar manner, where select analytic years reflected projections of policy impacts for rules that include multi-year compliance periods.

3.7 Demand-Side Energy Efficiency

3.7.1 Demand-Side Energy Efficiency Improvements (Electricity Demand Reductions)[65]

While the final rule no longer includes demand-side energy efficiency potential as part of BSER, the rule does allow such potential to be used for compliance. These scenarios include a representation of demand-side energy efficiency compliance potential because energy efficiency is a highly cost-effective means for reducing CO_2 from the power sector, and it is reasonable to assume that a regulatory requirement to reduce CO_2 emissions will motivate parties to pursue all highly cost-effective means for making emission reductions accordingly, regardless of what particular emission reduction measures were assumed in determining the level of that regulatory requirement. The EPA has included in our illustrative plan scenarios (both rate- and mass-based)

[65] For a more detailed discussion of the demand-side energy efficiency demand reductions and their associated costs, refer to U.S. EPA. 2015. Technical Support Document (TSD) the Final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Demand-Side Energy Efficiency.

a level of demand reduction that could be achieved, and the associated costs incurred, through implementation of demand-side energy efficiency measures. This "demand-side energy efficiency plan scenario" represents a level of performance that has already been demonstrated or is required by policies (e.g., energy efficiency resource standards) of leading energy efficiency implementing states, and is consistent with a demonstrated or required annual pace of performance improvement over time. The resulting levels of demand reduction are consistent with recent studies of achievable demand reduction potential conducted throughout the U.S. For these reasons, the demand-side energy efficiency plan scenario represents a reasonable assumption about the level of demand-side energy efficiency investments that may be encouraged in response to the final CPP.

For the illustrative demand-side energy efficiency plan scenario, electricity demand reductions for each state for each year are developed by ramping up from a historical basis[66] to a target annual incremental demand reduction rate of 1.0 percent of electricity demand over a period of years starting in 2020, and maintaining that rate throughout the modeling horizon.[67] Nineteen leading states either have achieved, or have established requirements that will lead them to achieve, this rate of incremental electricity demand reduction on an annual basis. Based on historic performance and existing state requirements, for each state the pace of improvement from the state's historical incremental demand reduction rate is set at 0.2 percent per year, beginning in 2020, until the target rate of 1.0 percent is achieved. States already at or above the 1.0 percent target rate are assumed to achieve a 1.0 percent rate beginning in 2020 and sustain that rate thereafter.[68] The incremental demand reduction rate for each state, for each year, is used to derive cumulative annual electricity demand reductions based upon information about the average life of energy efficiency measures and the distribution of measure lives across energy

[66] The historical basis of the percentage of reduced electricity consumption differs for each state and is drawn from the data reported in Energy Information Administration (EIA) Form 861, 2013, available at http://www.eia.gov/electricity/data/eia861/.

[67] The incremental demand reduction percentage is applied to the previous year's electricity demand for the state.

[68] This assumption may result in underestimating electricity demand reductions in these states in the illustrative plan scenarios.

efficiency programs.[69] The cumulative annual electricity demand reduction derived using this methodology is used to adjust base case electricity demand levels in the illustrative plan approach modeling.

To reflect the implementation of the illustrative energy efficiency plan scenario in modeling, the IPM base case electricity demand was adjusted exogenously to reflect the estimated future-year demand reductions calculated as described above. State-level demand reductions were scaled up to account for transmission losses and applied to base case generation demand in each model year to derive adjusted demand for each state, reflecting the energy efficiency plan scenario energy reductions. The demand adjustments were applied proportionally across all segments (peak and non-peak) of the load duration curve.[70] To reflect the adjusted state-level demand within IPM model regions that cross state borders, energy reductions from a bisected state were distributed between the applicable IPM model regions using a distribution approach based on reported sales in 2013 as a proxy for the distribution of energy efficiency investment opportunities.

Table 3-2 summarizes the results of the illustrative demand-side energy efficiency plan scenario at the national level.

Table 3-2. Demand-Side Energy Efficiency Plan Scenario: Net Cumulative Demand Reductions [Contiguous U.S.] (GWh and as Percent of BAU Sales)

	2020	2025	2030
Net Cumulative Demand Reduction (GWh)	23,150	194,126	327,092
Net Cumulative Demand Reduction as Percent of BAU Sales	0.59%	4.81%	7.83%

Source: U.S. EPA. 2015. Technical Support Document (TSD) for the Final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Demand-Side Energy Efficiency.

[69] The average life of demand-side energy efficiency measures used is 10.2 years. This average is represented using a four-tier distribution of measure lives ranging from 6.5 to 21.2 years. This approach is based on 2015 analysis by Lawrence Berkeley National Laboratory and is discussed in detail in section 8.2.6 of the Demand-Side Energy Efficiency TSD.

[70] Details and reasoning for this assumption are included in U.S. EPA. 2015. Technical Support Document (TSD) for the Final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Demand-Side Energy Efficiency.

3.7.2 Demand-Side Energy Efficiency Costs[71]

Total costs of achieving the demand-side energy efficiency plan scenario for each year were calculated exogenous to the power sector modeling. The power system cost impacts resulting from the illustrative plan approach analyses were captured within IPM and include the effects of reduced demand levels driven by the energy efficiency scenario discussed above. The integration of the exogenously calculated demand-side energy efficiency scenario costs with the power system cost impacts of the illustrative plan approaches are discussed in section 3.9.2. In addition to the demand reduction results, the demand-side energy efficiency costs were based upon an estimate of the total first-year cost of saved energy (i.e., reduced demand), the average life of the demand-side energy efficiency measures, the distribution of those measure lives, and cost factors as greater levels of demand reductions are achieved. The total first-year cost of saved energy accounts for both the costs of the demand-side energy efficiency programs, known as the program costs, and the additional cost to electricity consumers participating in the program (e.g., purchasing a more energy efficient technology), known as the participant costs.

To calculate total annualized demand-side energy efficiency costs, first-year costs for each year for each state were levelized (at 3 percent and 7 percent discount rates) over the estimated distribution of measure lives and the results summed for each year for each state. For example, the 2025 estimate of annualized energy efficiency cost includes levelized value of first-year costs for energy efficiency investments made in 2020 through 2025. The annualized costs rise in each analysis year as additional first-year costs are incurred. The annualized cost results are summarized below in Table 3-3. The total levelized cost of saved energy was calculated based upon the same inputs and using a 3 percent discount rate resulted in national average values of 9.2 cents per kWh in 2020, 8.6 cents per kWh in 2025, and 8.1 cents per kWh in 2030.

Table 3-3. Annualized Cost of Demand-Side Energy Efficiency Plan Scenario (at discount rates of 3 percent and 7 percent, billions 2011$)

Discount Rate	2020	2025	2030
at 3 percent	2.1	16.7	26.3
at 7 percent	2.6	20.6	32.5

Source: U.S. EPA. 2015. Technical Support Document (TSD) the Final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Demand-Side Energy Efficiency.

[71] For a more detailed discussion of the demand-side energy efficiency cost analysis, refer to the Demand-Side Energy Efficiency TSD.

The funding for demand-side energy efficiency programs (to cover program costs) is typically collected through a standard per kWh surcharge to the ratepayer; the regional retail price impacts analyzed from this RIA's illustrative plan approaches assumes the recovery of these program costs through the following procedure.[72] For each state, the first-year energy efficiency program costs are calculated for each year. These costs were distributed between the applicable IPM regions using an approach based on reported sales in 2012 as a proxy for the distribution of energy efficiency investment opportunities. These regionalized energy efficiency program costs were then incorporated into the regional retail price calculation as discussed in section 3.9.9.[73] The U.S. EPA's_Demand-Side Energy Efficiency Technical Support Document (U.S. EPA 2015) provides complete details on the calculations of annualized costs and first-year costs as well as comprehensive results (by state, by year) for the illustrative demand-side energy efficiency plan scenario.

3.8 Monitoring, Reporting, and Recordkeeping Costs

EPA projected monitoring, reporting and recordkeeping costs for both state entities and affected EGUs for the compliance years 2020, 2025, and 2030. In calculating the costs for state entities, EPA estimated personnel costs to oversee compliance, and review and report annually to EPA on program progress relative to meeting the state's reduction goal. To calculate the national costs, EPA estimated that 47 states and 1,028 facilities would be affected.

The EPA estimated that the majority of the cost to EGUs would be in calculating net energy output, which is needed whether the state plan utilizes a rate-based or a mass-based limit. Since the majority of EGUs do have some energy usage meters or other equipment available to them, EPA believes a new system for calculating net energy output is not needed. Under the final guidelines, states are required to use monitoring and reporting requirements for their affected EGUs to ensure that the sources are meeting the appropriate CO_2 emission performance rates or emission goals.

[72] The full retail price analysis method is discussed in section 3.7.9 of this chapter.

[73] The effect on equilibrium supply and demand of electricity due to changing retail rates to fund energy efficiency programs is not captured in the IPM modeling.

The EPA has made it a priority to streamline reporting and monitoring requirements. In this rule, the EPA is making implementation as efficient as possible for both the states and the affected EGUs by allowing state plans to utilize the current monitoring and recordkeeping requirements and pathways that have already been well established in other EPA rulemakings. For example, under the Acid Rain Program's continuous emissions monitoring, 40 CFR Part 75, the EPA has established requirements for the majority of the EGUs that would be affected by a 111(d) state plan to monitor CO_2 emissions and report that data using the Emissions Collection and Monitoring Plan System (ECMPS). Additionally since the CO_2 hourly data is already reported to the EPA's ECMPS there is no additional burden associated with the reporting of that data. Since the ECMPS pathway is already in place, the EPA will allow for states to utilize the ECMPS system to facilitate the data reporting of the additional net energy output data required under the emission guidelines. However, because the Acid Rain Program does not require net energy output to be reported, there is some additional burden (Shown in Table 3-4) in updating an affected EGUs monitoring system to be able to report the associated net energy output of an affected EGU.

The EPA estimates that it would take three working months for a technician to retrofit any existing energy meters to meet the requirements set in the state plan. Additionally EPA believes that 50 hours will be needed for each EGU operator to read the rule and understand how the facility will comply with the rule, based on an average reading rate of 100 words per minute and a projected rule word count of 300,000 words.[74] Also, after all modifications are made at a facility to measure net energy output, each EGU's Data Acquisition System (DAS) would need to be upgraded to supply the rate-based emissions value to either the state or EPA's Emissions Collection and Monitoring Plan System (ECMPS). Note the costs to develop net energy output monitoring and to upgrade each facility's DAS system are one-time costs incurred in 2020. Recordkeeping and reporting costs substantially decrease for the period 2021-2030. The projected costs for 2020, 2025, and 2030 are summarized below.

[74] According to one source, the average person can proofread at about 200 words per minute on paper and 180 words per minute on a monitor. (Source: Ziefle, M. 1988. "Effects of Display Resolution on Visual Performance." *Human Factors* 40(4):554-68). Due to the highly technical nature of the rule requirements in subpart UUUU, a more conservative estimate of 100 words per minute was used to determine the burden estimate for reading and understanding rule requirements.

In calculating the cost for states to comply, EPA estimates that each state will rely on the equivalent of two full time staff to oversee program implementation, assess progress, develop possible contingency measures, perform state plan revisions and host the subsequent public meetings if revisions are indeed needed, download data from the ECMPS for their annual reporting and develop their annual EPA report. The burden estimate was based on an analysis of similar tasks performed under the Regional Haze Program, whereby states were required to develop their list of eligible sources, draft implementation plans, revise initial drafts, identify baseline controls, identify data gaps, identify initial strategies, conduct various reviews, and manage their programs. A total estimate of 78,000 hours of labor performed by seven states over a three-year period resulted in 3,714 hours per year, per entity. Due to the nature of this final rule whereby we believe the air office and the energy office will both be involved in performing the above-mentioned tasks, we rounded up to the equivalent of two full time staff, which totaled 4,160 hours per year.[75] Table 3-4 shows estimates of the annual state and industry respondent burden and costs of reporting and recordkeeping for 2020, 2025 and 2030.

Table 3-4. Years 2020, 2025 and 2030: Summary of State and Industry Annual Respondent Burden and Cost of Reporting and Recordkeeping Requirements (2011$)

Nationwide Totals	Total Annual Labor Burden (Hours)	Total Annual Labor Costs	Total Annualized Capital Costs	Total Annual O&M Costs	Total Annual-ized Costs	Total Annual Respondent Costs
State						
Year 2020	195,520	13,838,429	0	34,545	34,545	13,872,974
Year 2025	208,320	14,744,381	0	23,500	23,500	14,767,881
Year 2030	208,320	14,744,381	0	23,500	23,500	14,767,881
Industry						
Year 2020	581,848	49,959,446	0	1,532,000	1,532,500	51,491,446
Year 2025	0	0	0	0	0	0
Year 2030	0	0	0	0	0	0
Total						
Year 2020	777,368	63,797,875	0	1,566,545	1,566,545	65,364,420
Year 2025	208,320	14,744,381	0	23,500	23,500	14,767,881
Year 2030	208,320	14,744,381	0	23,500	23,500	14,767,881

[75] Renewal of the ICR for the Regional Haze Rule, Section 6(a) Tables 1 through 4 based on 7 states' burden. EPA-HQ-OAR-2003-0162-0001.

3.9 Projected Power Sector Impacts

The following sections present projected impacts from the two illustrative scenarios described above. The tables present impacts from 2020 (prior to the initial compliance year), 2025 (representative of the interim compliance period), and 2030 (representative of the final compliance period). The narrative focuses on results during the initial and final compliance periods.

3.9.1 Projected Emissions

Under the rate-based approach, EPA projects annual CO_2 reductions of 3 percent below the base case in 2020, 11 percent below the base case in 2025, and 19 percent below base case projections in 2030 (reaching 28 percent to 32 percent below 2005 emissions[76] in 2025 and 2030, respectively). For the mass-based approach, EPA projects annual CO_2 reductions of 4 percent below the base case in 2020, 12 percent below the base case in 2025 and 19 percent below base case projections in 2030 (reaching 29 percent to 32 percent below 2005 emissions[77] in 2025 and 2030, respectively).[78]

Table 3-5. Projected CO_2 Emission Impacts, Relative to Base Case

	CO_2 Emissions (million short tons)			CO_2 Emissions: Change from Base Case (million short tons)			CO_2 Emissions: Percent Change from Base Case		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Base Case	2,155	2,165	2,227						
Rate-based	2,085	1,933	1,812	-69	-232	-415	-3%	-11%	-19%
Mass-based	2,073	1,901	1,814	-81	-265	-413	-4%	-12%	-19%

Source: Integrated Planning Model run by EPA, 2015

[76] For purposes of these calculations, EPA has used historical CO_2 emissions from eGRID for 2005, which reports EGU emissions as 2,683 million short tons in the contiguous U.S.

[77] For purposes of these calculations, EPA has used historical CO_2 emissions from eGRID for 2005, which reports EGU emissions as 2,683 million short tons in the contiguous U.S.

[78] EPA also analyzed a mass-based scenario without any set-asides using IPM, which produced a 2030 emission reduction estimate of 31 percent, relative to 2005 levels (approximately a 1 percent erosion of emission reductions due to leakage to new sources of emissions, relative to both the mass-based scenario that includes the RE set-aside, and the rate-based scenario. This equates to approximately 24 million short tons of CO_2.). The scenario can be found in the docket for the final rule, and is called "Mass-based without set-aside."

Table 3-6. Projected CO_2 Emission Impacts, Relative to 2005

	CO_2 Emissions (million short tons)	CO_2 Emissions: Change from 2005 (million short tons)			CO_2 Emissions: Percent Change from 2005		
	2005	2020	2025	2030	2020	2025	2030
Base Case	2,683	-528	-518	-456	-20%	-19%	-17%
Rate-based	-	-598	-750	-871	-22%	-28%	-32%
Mass-based	-	-610	-782	-869	-23%	-29%	-32%

Source: Integrated Planning Model run by EPA, 2015

Under the rate-based illustrative plan approach, EPA projects a 14 percent reduction of SO_2, 13 percent reduction of NO_X, and a 11 percent reduction of mercury in 2025, and a 24 percent reduction of SO_2, 22 percent reduction of NO_X, and a 17 percent reduction of mercury in 2030. Under the mass-based illustrative plan approach, EPA projects a 15 percent reduction of SO_2, 16 percent reduction of NO_X, and a 12 percent reduction of mercury in 2025, and a 24 percent reduction of SO_2, 22 percent reduction of NO_X, and a 16 percent reduction of mercury in 2030. The projected non-CO_2 reductions are summarized below in Table 3-7.

Table 3-7. Projected Non-CO_2 Emission Impacts, 2020-2030

	Base Case	Rate-based	Mass-based	Rate-based	Mass-based
2020					
SO_2 (thousand short tons)	1,311	1,297	1,257	-1.0%	-4.1%
NO_X (thousand short tons)	1,333	1,282	1,272	-3.8%	-4.5%
Hg (short tons)	6.6	6.4	6.4	-2.8%	-3.3%
2025					
SO_2 (thousand short tons)	1,275	1,097	1,090	-14.0%	-14.5%
NO_X (thousand short tons)	1,302	1,138	1,100	-12.6%	-15.6%
Hg (short tons)	6.6	5.9	5.8	-10.8%	-12.2%
2030					
SO_2 (thousand short tons)	1,314	996	1,034	-24.2%	-21.3%
NO_X (thousand short tons)	1,293	1,011	1,015	-21.8%	-21.5%
Hg (short tons)	6.8	5.6	5.8	-17.2%	-15.6%

Source: Integrated Planning Model run by EPA, 2015. For this RIA, we did not estimate changes in emissions of directly emitted particles ($PM_{2.5}$).

While the EPA has not quantified the climate impacts of non-CO_2 emissions changes or CO_2 emissions changes outside the electricity sector for the final emissions guidelines, the Agency has analyzed the potential changes in upstream methane emissions from the natural gas and coal production sectors that may result from the illustrative approaches examined in this

RIA. The EPA assessed whether the net change in upstream methane emissions from natural gas and coal production is likely to be positive or negative. The EPA also assessed the potential magnitude of changes relative to CO_2 emissions reductions anticipated at power plants. This assessment included CO_2 emissions from the flaring of methane, but did not evaluate potential changes in other combustion-related CO_2 emissions, such as emissions associated with drilling, mining, processing, and transportation in the natural gas and coal production sectors. This analysis found that the net upstream methane emissions from natural gas systems and coal mines and CO_2 emissions from flaring of methane will likely decrease under the final emissions guidelines. Furthermore, the changes in upstream methane emissions are small relative to the changes in direct CO_2 emissions from power plants. The projections include voluntary and regulatory activities to reduce emissions from coal mining and natural gas and oil systems, including the 2012 Oil and Natural Gas NSPS. In addition, the EPA plans to issue a proposed rule later this summer that would build on its 2012 Oil and Gas NSPS. When these standards are finalized and implemented, they would further reduce projected emissions from natural gas and oil systems. The technical details supporting this analysis can be found in the Appendix to this chapter.

3.9.2 Projected Compliance Costs

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the base case and illustrative CPP scenarios, including the cost of demand-side energy efficiency programs and measures and monitoring, reporting, and recordkeeping (MR&R) costs. The system costs reflect the least cost power system outcome in which the sector employs all the flexibilities assumed in the modeling, as discussed above, and pursues the most cost-effective emission reduction opportunities in order to meet the rate- and mass-based goals, as represented in the illustrative plan scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to meet demand projections while complying with state goals, including the total demand-side energy efficiency costs.[79] The compliance costs for the final emissions guidelines for EGUs in the contiguous U.S.

[79] The compliance costs also capture the effect of changes in equilibrium fuel prices on the expenditures of the electricity sector to serve demand.

states is forecast using IPM. The cost of demand-side energy efficiency programs assumed in the IPM *analysis are reported in section* 3.7.2.

EPA projects that the annual compliance cost of the rate-based illustrative plan scenario are $2.4 billion in 2020, $1.1 billion in 2025, and $8.5 billion in 2030 (Table 3-8). The annual compliance cost of the mass-based illustrative plan approach are estimated to be $1.4 billion in 2020, $3.0 billion in 2025, and $5.1 billion in 2030. The different patterns of incremental cost in each of these scenarios over 2020-2030 are consistent with the differences in the projected pattern of gas use and price in these scenarios. consistent with the differences in the projected pattern of gas use and price in these scenarios. The annual compliance cost is the projected additional cost of complying with the rule in the year analyzed and reflects the net difference in the sum of the annualized cost of capital investment in new generating sources and heat rate improvements at coal steam facilities,[80] the change in the ongoing costs of operating pollution controls, the change in expenditures on various fuels (inclusive of changes in the price of these fuels), demand-side energy efficiency measures, and other actions associated with compliance. Relative to the base case, we expect a decrease in the total cost to generate sufficient supply for demand, which, together with the costs of demand-side energy efficiency measures, we project will result in net cost estimates of $8.4 billion in 2030 for the rate-based scenario and $5.1 billion for the mass-based scenario.

Table 3-8. Annualized Compliance Costs Including Monitoring, Reporting and Recordkeeping Costs Requirements (billions of 2011$)

	2020	2025	2030
Rate-based	$2.5	$1.0	$8.4
Mass-based	$1.4	$3.0	$5.1

Source: Integrated Planning Model run by EPA, 2015, with post-processing to account for exogenous demand-side energy efficiency costs and monitoring, reporting, and recordkeeping costs.

In order to contextualize EPA's projection of the additional costs in 2030 across the two illustrative plan approaches evaluated in this RIA, it is useful to compare these incremental cost estimates to total projected power sector expenditures. The power sector is expected in the base case to expend over $201 billion in 2030 to generate, transmit, and distribute electricity to end-use consumers. In 2014, according to EIA, the power sector generated $389 billion in revenue

[80] See Chapter 2 of the GHG Mitigation Measures TSD and EPA's Base Case using IPM (v5.15) documentation, available at: http://www.epa.gov/powersectormodeling

from retail sales of electricity. For context, the projected costs of compliance with the final rule amount to a 4 percent increase in the cost of meeting electricity demand, while securing public health and welfare benefits that are several times greater (as described in Chapters 4 and 8).

The following example uses projected results for the year 2030 to illustrate how different components of estimated expenditures are combined to form the full compliance costs presented in Table 3-8. In Table 3-9, we present the IPM modeling results for the two illustrative plan scenarios in 2030 (as well as 2020 and 2025). The results show that annualized expenditures required to supply enough electricity to meet demand decline by $18 billion (rate) and $21 billion (mass) from the base case in 2030. This incremental decline is a net outcome of two simultaneous effects that move in opposite directions. First, imposing the CO_2 constraints represented by each illustrative plan scenario on electric generators would, other things equal, result in an incremental increase in expenditures to supply any given level of electricity. However, once electricity demand is reduced to reflect demand-side energy efficiency improvements, there is a substantial reduction in the expenditures needed to supply a correspondingly lower amount of electricity demand.

Table 3-9. Total Power Sector Generating Costs (IPM) (billions 2011$)

	2020	2025	2030
Base Case	$166.5	$178.3	$201.3
Rate-based	$166.8	$162.6	$183.3
Mass-based	$165.7	$164.6	$180.1

Source: Integrated Planning Model run by EPA, 2015

In order to reflect the full compliance cost attributable to the CPP scenarios, it is necessary to include the annualized expenditures needed to secure the demand-side energy efficiency improvements. As described in section 3.7.2, EPA has estimated these energy efficiency-related expenditures to be $26.3 billion in 2030 (using a 3 percent discount rate). The energy efficiency-related expenditures include costs incurred by parties administering energy efficiency programs and costs incurred by participants in those programs. As a result, this analysis finds the cost of the rate-based and mass-based illustrative plan approaches in 2030 to be $8.4 billion and $5.1 billion, respectively.

3.9.3 Projected Compliance Actions for Emissions Reductions

Heat Rate Improvements (HRI): EPA analysis assumes that the existing coal steam electric generating fleet has, on average, the ability to improve operating efficiency (i.e., reduce the average net heat rate, or the Btu of fuel energy needed to produce one kWh of net electricity output). All else held constant, an HRI allows the EGU to generate the same amount of electricity using less fuel. The decrease in required fossil fuel results in a lower output-based CO_2 emissions rate (lbs/MWh), as well as a lower variable cost of electricity generation. In the modeling conducted for these illustrative plan approaches, coal boilers have the choice to improve heat rates by 4.3 percent in the eastern illustrative compliance region, 2.1 percent in the western illustrative compliance region, and 2.3 percent in Texas, all at a capital cost of $100 per kW.[81] The option for heat rate improvement is only made available in the illustrative plan approaches during the compliance period, in response to the final rule.

The majority of existing coal boilers are projected to adopt the aforementioned heat rate improvements. Of the 183 GW of coal projected to operate in 2030, EPA projects that 99 GW of existing coal steam capacity (greater than 25 MW) will improve operating efficiency (i.e., reduce the average net heat rate) under the rate-based approach by 2030. Under the mass-based approach, EPA projects that 88 GW of the 174 GW of coal projected to operate in 2030 will improve operating efficiency by 2030.

Generation Shifting: Another approach for reducing the average emission rate from existing units is to shift some generation from more CO_2-intensive generation to less CO_2-intensive generation. Compared to the base case, existing coal steam capacity is, on average, projected to operate at a lower capacity factor for both illustrative plan approaches. Under the illustrative rate-based plan approach, the average 2030 capacity factor is 69 percent, and under the mass-based approach, the average capacity factor for existing coal steam is 75 percent. Existing natural gas combined cycle units, which are less carbon-intensive than coal steam capacity on an output basis, operate at noticeably higher capacity factor under both illustrative plan approaches, on average. The utilization of existing natural gas combined cycle capacity is lower than the BSER level of 75 percent[82] on an annual average basis in these illustrative plan approaches, reflecting the fact that,

[81] The option for heat rate improvement is only made available in the illustrative plan scenarios, and is not available in the base case. For an explanation of the regional differences in average ability to improve heat rates, see GHG Mitigation Measures TSD.

[82] See preamble section V.D.

in practice, the most cost-effective CO_2 reduction strategies to meet each state's goal may not require that each building block be achieved in entirety. See Table 3-10.

Table 3-10. Projected Capacity Factor of Existing Coal Steam and Natural Gas Combined Cycle Capacity

	Existing Coal Steam			Existing Natural Gas Combined Cycle		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
Base Case	77%	76%	79%	54%	56%	51%
Rate-based	78%	75%	69%	56%	60%	61%
Mass-based	78%	75%	75%	56%	58%	54%

Source: Integrated Planning Model run by EPA, 2015

Demand-Side Energy Efficiency: Another approach for reducing emissions from affected EGUs is to consider reductions in demand attributable to demand-side energy efficiency measures as discussed in section 3.7. In the illustrative plan approaches presented in this RIA, each state is credited for total demand-side energy efficiency implemented in, or procured by, that state, consistent in aggregate with the state-by-state demand reductions that are represented by the demand-side energy efficiency scenario discussed in section 3.7.1.

Deployment of Cleaner Generating Technologies: Another key opportunity to reduce emissions from existing sources is to build more lower- or zero-emitting generating resources, in particular renewable energy. These sources of electricity, including wind and solar, can displace higher emitting existing sources, may be procured for compliance with the state goals in the rate-based illustrative scenario, and are further incentivized as a generation option in the mass-based illustrative scenario as they are not subject to the mass-based constraint and may receive the renewable set-aside. Increased deployment results in CO_2 reductions in both rate-based and mass-based approaches. See sections below discussing projected impacts on generation mix and capacity.

3.9.4 Projected Generation Mix

Table 3-11 and Figure 3-2 show the generation mix in the base case and under the two illustrative plan approaches. In both scenarios, total generation declines relative to the base case as a result of the reduction in total demand attributable to the demand-side energy efficiency applied in the illustrative scenarios, by 5 percent in 2025 and 8 percent in 2030.

Under the rate-based scenario, coal-fired generation is projected to decline 12 percent in 2025, and natural-gas-fired generation from existing combined cycle capacity is projected to increase 5 percent relative to the base case. The coal-fired fleet in 2030 generates 23 percent less than in the base case, while natural-gas-fired generation from existing combined cycles increases 18 percent relative to the base case. Gas-fired generation from new combined cycle capacity decreases in 2025 and 2030, consistent with the decrease in new capacity (see section 3.9.6). Relative to the base case, generation from non-hydro renewables decreases 1 percent in 2025 and increases 9 percent in 2030.

Similarly, under the mass-based scenario, coal-fired generation is projected to decline 15 percent in 2025, and natural-gas-fired generation from existing combined cycle capacity is projected to increase 2 percent relative to the base case. The coal-fired fleet in 2030 generates 22 percent less than in the base case, while natural-gas-fired generation from existing combined cycles increases 5 percent relative to the base case. Gas-fired generation from new combined cycle capacity decreases 8 percent and 36 percent relative to the base case in 2025 and 2030, respectively. Relative to the base case, generation from non-hydro renewables decreases 3 percent in 2025 and increases 8 percent in 2030.

The results presented in these illustrative compliance scenarios suggest that existing nuclear generation could be slightly more competitive under a mass-based implementation than under a rate-based implementation, because the former tends to create more wholesale price support for those generators. These scenarios do not include potential approaches that states can take to incentivize zero-carbon baseload power.

Table 3-11. Generation Mix (thousand GWh)

	Base Case	Rate-based	Mass-based	Rate-based	Mass-based
2020					
Coal	1,462	1,391	1,374	-5%	-6%
NG Combined Cycle (existing)	1,111	1,126	1,132	1%	2%
NG Combined Cycle (new)	33	53	69	61%	111%
Combustion Turbine	15	20	17	39%	14%
Oil/Gas Steam	51	51	50	0%	-1%
Non-Hydro Renewables	393	399	385	2%	-2%
Hydro	310	311	310	0%	0%
Nuclear	798	792	804	-1%	1%
Other	18	18	18	0%	0%
Total	4,190	4,160	4,159	-1%	-1%
2025					
Coal	1,428	1,256	1,217	-12%	-15%
NG Combined Cycle (existing)	1,152	1,206	1,179	5%	2%
NG Combined Cycle (new)	113	53	104	-53%	-8%
Combustion Turbine	23	30	34	31%	46%
Oil/Gas Steam	39	21	19	-46%	-52%
Non-Hydro Renewables	417	414	404	-1%	-3%
Hydro	340	340	340	0%	0%
Nuclear	799	791	804	-1%	1%
Other	17	17	18	0%	0%
Total	4,328	4,128	4,118	-5%	-5%
2030					
Coal	1,466	1,131	1,144	-23%	-22%
NG Combined Cycle (existing)	1,042	1,230	1,090	18%	5%
NG Combined Cycle (new)	324	100	207	-69%	-36%
Combustion Turbine	22	27	32	21%	46%
Oil/Gas Steam	22	11	11	-52%	-53%
Non-Hydro Renewables	450	488	485	9%	8%
Hydro	340	341	340	0%	0%
Nuclear	783	777	785	-1%	0%
Other	17	17	17	0%	0%
Total	4,467	4,122	4,110	-8%	-8%

Note: "Other" mostly includes generation from MSW and fuel cells. Source: Integrated Planning Model run by EPA, 2015

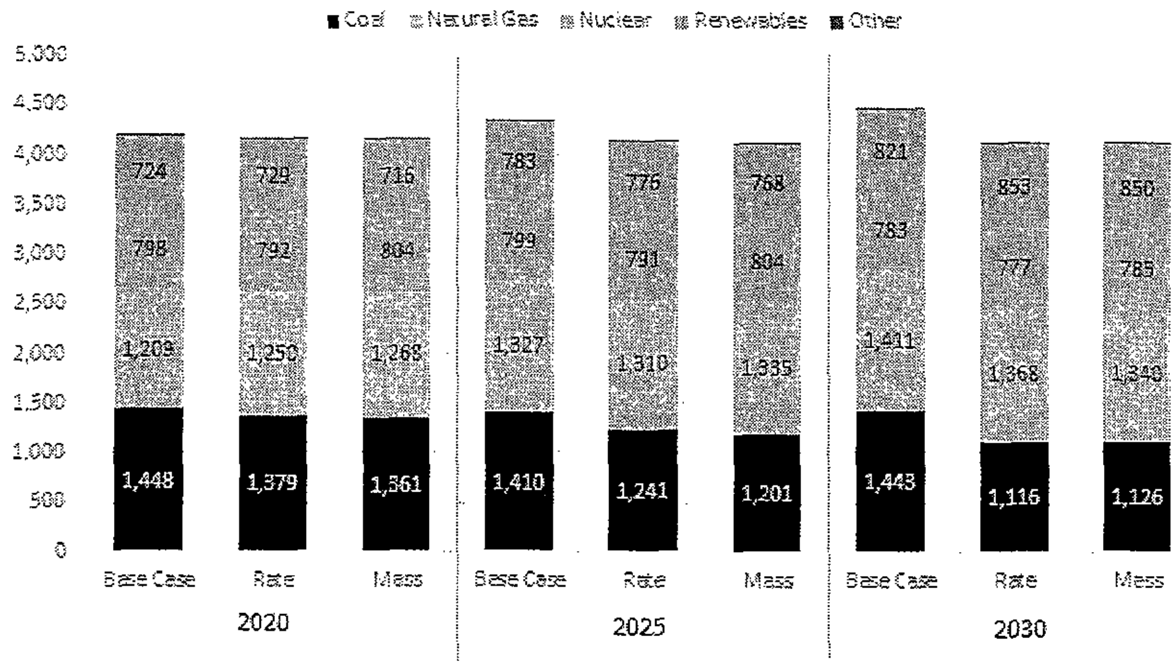

Figure 3-2 Generation Mix (thousand GWh)

Source: Integrated Planning Model run by EPA, 2015

Under both the rate-based and mass-based approaches, the projected rate of change in coal-fired generation is consistent with recent historical declines in coal-fired generation. Additionally, under both of these approaches, the trends for all other types will remain consistent with what their trends would be in the absence of this rule. Specifically, natural-gas fired generation and renewables would be expected to increase without this rule, and both are expected to increase under this rule, with renewables increasing at a somewhat greater rate than in the absence of this rule; and nuclear, oil-fired, and other types of generation are expected to be little impacted by this rule generation mix is consistent with recent declines in coal-fired generation and increases in gas-fired generation. See Figures 3-3, 3-4, and 3-5.

Figure 3-3. Nationwide Generation: Historical (1990-2014) and Base Case Projections (2020, 2025, 2030)

Sources: Historic data (i.e., 1990-2014): U.S. Energy Information Administration, June 2015 Monthly Energy Review, Table 7.2a Electricity Net Generation: Total (All Sectors), Available at <http://www.eia.gov/totalenergy/data/monthly/>. Projected data (i.e., 2020, 2025, 2030): Integrated Planning Model, 2015. Notes: Historic and projected data include generation from the power, industrial, and commercial sectors. Historic data from U.S. EIA reflects all cogeneration, while projections from the Integrated Planning Model reflect net cogeneration.

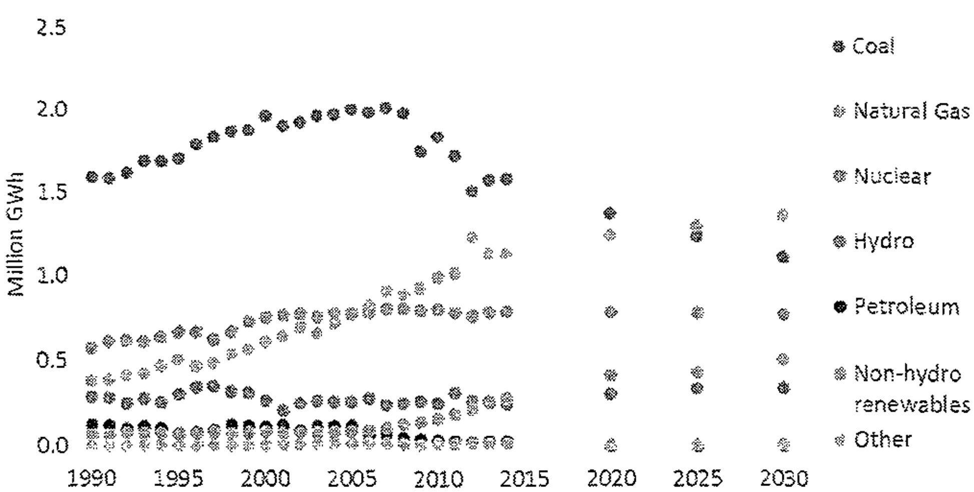

Figure 3-4. Nationwide Generation: Historical (1990-2014) and Rate-Based Illustrative Plan Approach Projections (2020, 2025, 2030)

Sources: Historic data (i.e., 1990-2014): U.S. Energy Information Administration, June 2015 Monthly Energy Review, Table 7.2a Electricity Net Generation: Total (All Sectors), Available at <http://www.eia.gov/totalenergy/data/monthly/>. Projected data (i.e., 2020, 2025, 2030): Integrated Planning Model, 2015. Notes: Historic and projected data include generation from the power, industrial, and commercial sectors. Historic data from U.S. EIA reflects all cogeneration, while projections from the Integrated Planning Model reflect net cogeneration.

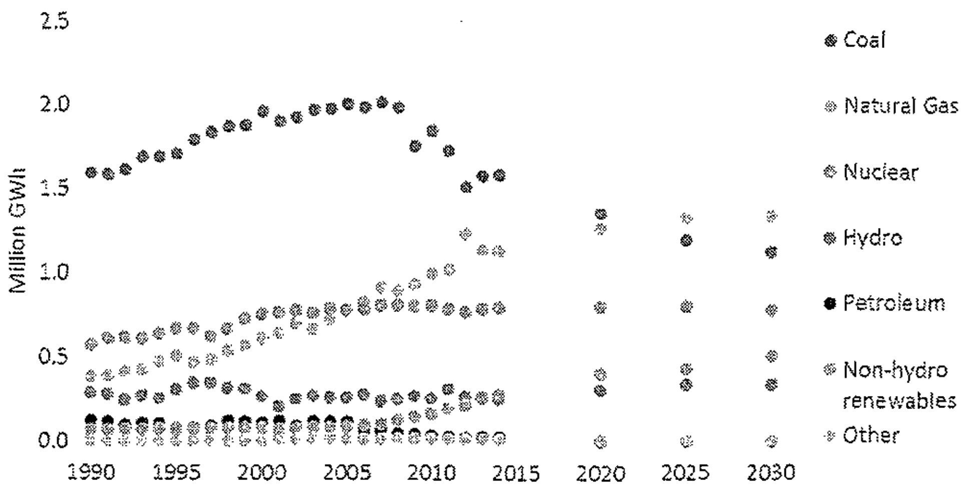

Figure 3-5. Nationwide Generation: Historical (1990-2014) and Mass-Based Illustrative Plan Approach Projections (2020, 2025, 2030)

Sources: Historic data (i.e., 1990-2014): U.S. Energy Information Administration, June 2015 Monthly Energy Review, Table 7.2a Electricity Net Generation: Total (All Sectors), Available at <http://www.eia.gov/totalenergy/data/monthly/>. Projected data (i.e., 2020, 2025, 2030): Integrated Planning Model, 2015. Notes: Historic and projected data include generation from the power, industrial, and commercial sectors. Historic data from U.S. EIA reflects all cogeneration, while projections from the Integrated Planning Model reflect net cogeneration.

3.9.5 Projected Incremental Retirements

Relative to the base case, about 23 GW of additional coal-fired capacity is projected to be uneconomic to maintain by 2025 under the rate-based illustrative scenario, increasing to 27 GW in 2030 (about 11-13 percent respectively of all coal-fired capacity projected to be in service in the base case). Under the mass-based scenario, about 29 GW of additional coal-fired capacity is projected to be uneconomic to maintain by 2025, increasing to 38 GW by 2030 (about 14-19 percent respectively of all coal-fired capacity projected to be in service in the base case). Capacity changes from the base case are shown in Table 3-12.[83]

[83] EPA examined the implications of the illustrative plan scenarios for concerns about regional resource adequacy and the potential for concerns about reliability. This examination can be found in U.S. EPA. 2015. Technical Support Document (TSD) the Final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Resource Adequacy and Reliability Analysis.

Table 3-12. Total Generation Capacity by 2020-2030 (GW)

	Base Case	Rate-based	Mass-based	Rate-based	Mass-based
2020					
Coal	208	195	193	-6%	-7%
NG Combined Cycle (existing)	233	231	232	-1%	0%
NG Combined Cycle (new)	4	7	9	62%	113%
Combustion Turbine	141	137	137	-3%	-3%
Oil/Gas Steam	88	81	80	-8%	-9%
Non-Hydro Renewables	130	132	128	1%	-2%
Hydro	106	106	106	0%	0%
Nuclear	100	100	101	-1%	1%
Other	5	5	5	0%	0%
Total	1,016	994	992	-2%	-2%
2025					
Coal	208	187	181	-10%	-13%
NG Combined Cycle (existing)	233	231	232	-1%	0%
NG Combined Cycle (new)	15	7	14	-52%	-9%
Combustion Turbine	143	138	137	-4%	-4%
Oil/Gas Steam	82	71	69	-14%	-16%
Non-Hydro Renewables	139	137	134	-1%	-3%
Hydro	112	112	112	0%	0%
Nuclear	100	99	101	-1%	1%
Other	5	5	5	0%	0%
Total	1,037	988	985	-5%	-5%
2030					
Coal	207	183	174	-11%	-16%
NG Combined Cycle (existing)	233	231	232	-1%	0%
NG Combined Cycle (new)	44	14	27	-68%	-38%
Combustion Turbine	147	138	136	-6%	-7%
Oil/Gas Steam	82	70	67	-15%	-18%
Non-Hydro Renewables	154	174	171	13%	11%
Hydro	112	112	112	0%	0%
Nuclear	99	98	99	-1%	0%
Other	5	5	5	0%	0%
Total	1,082	1,025	1,024	-5%	-5%

Source: Integrated Planning Model run by EPA, 2015

3.9.6 Projected Capacity Additions

Due largely to the electricity demand reduction attributable to the demand-side energy efficiency improvements applied in the illustrative scenarios, the EPA projects less new natural gas combined cycle capacity built under the rate-based scenario than is built in the base case over the period covered by the rule. While this new NGCC capacity cannot be directly counted towards the average emissions rate used for compliance in the rate-based approach, it can displace some generation from covered sources and thus indirectly lower the average emissions rate from covered sources. Conversely, the EPA projects an overall increase in new renewable capacity. New non-hydro renewables are able to contribute their generation to the average emissions rate in each state or region.

Under the rate-based illustrative scenario, new natural gas combined cycle capacity is projected to decrease by 8 GW in 2025 and 30 GW in 2030 (52 percent and 68 percent decrease relative to the base case). New renewable capacity is projected to decrease by about 2 GW (3 percent decrease) below the base case in 2025, and increase by 20 GW (27 percent increase) by 2030.

Under the mass-based illustrative scenario, new natural gas combined cycle capacity is projected to decrease by 1 GW in 2025 and decrease by 17 GW in 2030 (a 9 percent and 38 percent decrease relative to the base case). New renewable capacity is projected to decrease 4 GW (7 percent) relative to the base case in 2025, and increase 18 GW (24 percent increase) by 2030.

Table 3-13. Projected Capacity Additions, Gas (GW)

	Cumulative Capacity Additions: Gas Combined Cycle			Incremental Cumulative Capacity Additions: Gas Combined Cycle		
	2020	2025	2030	2020	2025	2030
Base Case	4.4	14.9	44.0			
Rate-based	7.1	7.1	13.9	2.7	-7.8	-30.1
Mass-based	9.3	13.6	27.2	4.9	-1.3	-16.8

Source: Integrated Planning Model run by EPA, 2015

Table 3-14. Projected Capacity Additions, Renewable (GW)

	Cumulative Capacity Additions: Renewables			Incremental Cumulative Capacity Additions: Renewables		
	2020	2025	2030	2020	2025	2030
Base Case	39.1	59.1	74.1			
Rate-based	40.5	57.4	94.4	1.4	-1.8	20.2
Mass-based	36.7	54.9	91.9	-2.4	-4.2	17.8

Source: Integrated Planning Model run by EPA, 2015

3.9.7 Projected Coal Production and Natural Gas Use for the Electric Power Sector

Coal production is projected to decrease in 2025 and beyond in the illustrative scenarios due to (1) improved heat rates (generating efficiency) at existing coal units, (2) electricity demand reduction attributable to demand-side energy efficiency improvements, and (3) a shift in generation from coal to less-carbon intensive generation. As shown in Table 3-15, the largest decrease in coal production is projected to occur in the western region.

Table 3-15. Coal Production for the Electric Power Sector, 2025

	Coal Production (million short tons)			Percent Change from Base Case	
	Base Case	Rate-based	Mass-based	Rate-based	Mass-based
Appalachia	92	71	69	-23%	-25%
Interior	250	242	236	-3%	-6%
West	379	306	293	-19%	-23%
Waste Coal	6	6	6	0%	0%
Imports	1	1	1	-37%	-14%
Total	729	626	606	-14%	-17%

Source: Integrated Planning Model run by EPA, 2015

Power sector natural gas use is projected to decrease by about 1 percent in 2025 and 2030 under the rate-based illustrative plan scenario. In the mass-based scenario, power sector natural gas use is projected to decrease by 4.5 percent in 2030. These trends are consistent with the change in generation mix described above in Section 3.9.4.

Table 3-16. Power Sector Gas Use

	Power Sector Gas Use (TCF)			Percent Change in Power Sector Gas Use		
	2020	2025	2030	2020	2025	2030
Base Case	8.62	9.38	9.72			
Rate-based	8.91	9.28	9.59	3.4%	-1.0%	-1.3%
Mass-based	9.02	9.39	9.28	4.6%	0.2%	-4.5%

Source: Integrated Planning Model run by EPA, 2015

3.9.8 Projected Fuel Price, Market, and Infrastructure Impacts

The impacts of the two illustrative plan scenarios on coal and natural gas prices before shipment are shown below in Table 3-17 and Table 3-18 and are attributable to the changes in overall power sector demand for each fuel due to the final guidelines. Coal demand decreases by 2030, resulting in a decrease in the price of coal delivered to the electric power sector. In 2030, gas demand and price decrease below the base case projections, due to the cumulative impact of demand-side energy efficiency improvements and the consequent reduced overall electricity demand.

IPM modeling of natural gas prices uses both short- and long-term price signals to balance supply and demand for the fuel across the modeled time horizon. As such, it should be understood that the pattern of IPM natural gas price projections over time is not a forecast of natural gas prices incurred by end-use consumers at any particular point in time. The natural gas market in the United States has historically experienced some degree of price volatility from year to year, between seasons within a year, and during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). These short-term price signals are fundamental for allowing the market to successfully align immediate supply and demand needs. However, end-use consumers are typically shielded from experiencing these rapid fluctuations in natural gas prices by retail rate regulation and by hedging through longer-term fuel supply contracts by the power sector. IPM assumes these longer-term price arrangements take place "outside of the model" and on top of the "real-time" shorter-term price variation necessary to align supply and demand. Therefore, the model's natural gas price projections should not be mistaken for traditionally experienced consumer price impacts related to natural gas, but a reflection of expected average price changes over the period represented by the modeling horizon.

There are very small changes to natural gas pipeline infrastructure needs over time, in response to the illustrative plan scenarios. These changes, compared to historical deployment of new infrastructure, are very modest. In both the rate-based and mass-based scenarios, pipeline capacity construction through 2020 is projected to increase by less than two percent beyond base case projections. By 2030, however, the total cumulative pipeline capacity construction built is projected to decrease compared to the base case, consistent with the projected decrease in total demand and natural gas use. The projected increase in pipeline capacity in the near term is largely the result of building pipeline capacity a few years earlier than projected in the base case.

Table 3-17. Projected Average Minemouth and Delivered Coal Prices (2011$/MMBtu)

	Minemouth			Delivered - Electric Power Sector		
	2020	2025	2030	2020	2025	2030
Base Case	1.55	1.67	1.79	2.38	2.50	2.68
Rate-based	1.54	1.58	1.73	2.34	2.35	2.46
Mass-based	1.54	1.59	1.73	2.35	2.40	2.55
Rate-based	-0.8%	-5.0%	-3.8%	-1.7%	-6.2%	-8.0%
Mass-based	-0.7%	-4.7%	-3.2%	-1.6%	-4.3%	-4.6%

Source: Integrated Planning Model run by EPA, 2015

Table 3-18. Projected Average Henry Hub (spot) and Delivered Natural Gas Prices (2011$/MMBtu)

	Henry Hub			Delivered - Electric Power Sector		
	2020	2025	2030	2020	2025	2030
Base Case	5.20	5.12	6.01	5.25	5.17	5.98
Rate-based	5.48	4.73	6.21	5.53	4.77	6.13
Mass-based	5.40	4.97	5.92	5.45	5.00	5.86
Rate-based	5.4%	-7.5%	3.3%	5.3%	-7.7%	2.5%
Mass-based	3.9%	-3.0%	-1.4%	3.8%	-3.2%	-2.1%

Source: Integrated Planning Model run by EPA, 2015

3.9.9 Projected Retail Electricity Prices

EPA's analysis of the illustrative rate-based plan scenario shows an increase in the national average (contiguous U.S.) retail electricity price of less than one percent in both 2025 and 2030, compared to the modeled base case price estimate in those years. Under the illustrative mass-based plan scenario, EPA projects an increase in the national average (contiguous U.S.) retail electricity price of 2 percent in 2025 and 0.01 percent in 2030.

Retail electricity prices embody generation, transmission, distribution, taxes, and demand-side energy efficiency costs. IPM modeling projects changes in regional wholesale power prices and capacity payments related to imposition of the represented CPP scenarios that are combined with EIA regional transmission and distribution costs to calculate changes to regional retail prices using the Retail Price Model (RPM).[84] As described in Section 3.7.2, the funding for demand-side energy efficiency (to cover program costs) is typically collected through a standard per kWh surcharge to the ratepayer and the regional retail price impacts presented here assume that these costs are recovered by utilities in retail rates. This is an approximation, since not every utility will pass through the entirety of demand-side energy efficiency costs. For example, a distribution only utility may generate reductions from demand-side energy efficiency, sell the associated reduction in generation to affected EGUs (which in turn use them to demonstrate compliance), and then account for this revenue in rate determination. Furthermore, this analysis assumes that ratepayers in the state producing zero-emitting generation (or avoided generation) bear the costs of such production. However, in practice, if such generation is claimed by an affected source in another state, part of the cost of that generation may ultimately be borne by ratepayers in the claiming state rather than the state in which that zero-emitting generation was located. There are many factors influencing the estimated retail electricity price impacts, namely projected changes in generation mix, fuel prices, and development of new generating capacity. These projected changes vary regionally under each illustrative plan scenario in response to the goals under the two scenarios. The projected changes also vary depending upon retail electricity market structure (e.g., cost-of-service vs. competitive). In the mass-based approach, treatment of allowance allocations will also have an impact on retail electricity prices. In competitive regions, this RIA assumes that allowances are freely allocated to generators who then keep 100% of the freely allocated allowance value without passing this value through to ratepayers in the form of lower retail electricity prices. To the extent that implementing authorities choose to require this allowance value to be passed through to ratepayers (such as by allocating allowances to load-serving entities who could be subject to such a requirement), retail prices would be lower than those shown here.

[84] See documentation available at: http://www.epa.gov/powersectormodeling/

Table 3-19. 2020 Projected Contiguous U.S. and Regional Retail Electricity Prices (cents/kWh)

	2020 Projected Retail Price (cents/kWh)			Percent Change from Base Case	
	Base Case	Rate-based	Mass-based	Rate-based	Mass-based
ERCT	9.7	9.9	9.9	2.5%	2.1%
FRCC	10.5	10.7	10.7	2.0%	1.6%
MROE	9.9	10.3	10.3	4.2%	3.8%
MROW	8.7	9.0	9.0	2.8%	2.3%
NEWE	13.3	14.0	14.0	5.1%	5.5%
NYCW	17.4	18.3	18.3	5.0%	5.3%
NYLI	14.4	15.1	15.1	4.6%	5.1%
NYUP	12.4	13.1	13.1	5.4%	5.3%
RFCE	11.1	11.8	11.8	6.1%	6.1%
RFCM	10.4	10.9	10.9	4.3%	4.3%
RFCW	9.4	9.8	9.8	5.1%	4.8%
SRDA	8.6	8.8	8.7	2.1%	1.7%
SRGW	8.6	9.0	9.0	4.1%	4.8%
SRSE	10.0	10.1	10.1	0.9%	0.5%
SRCE	8.0	8.1	8.1	1.1%	0.8%
SRVC	9.8	9.9	9.9	1.5%	1.2%
SPNO	9.9	9.9	9.9	-0.8%	-0.9%
SPSO	7.9	8.1	8.1	3.2%	2.4%
AZNM	10.9	11.2	11.2	2.1%	2.1%
CAMX	14.3	14.8	14.7	3.3%	3.0%
NWPP	6.9	7.1	7.1	3.2%	2.9%
RMPA	8.7	9.0	8.9	3.1%	2.9%
Contiguous U.S.	10.0	10.3	10.3	3.2%	3.0%

Note: regions pictured on Figure 3-6.

Table 3-20. 2025 Projected Contiguous U.S. and Regional Retail Electricity Prices (cents/kWh)

	2025 Projected Retail Price (cents/kWh)			Percent Change from Base Case	
	Base Case	Rate-based	Mass-based	Rate-based	Mass-based
ERCT	10.7	11.1	10.9	3.8%	1.5%
FRCC	10.2	10.2	10.3	-0.2%	1.0%
MROE	9.7	10.0	10.0	2.4%	2.6%
MROW	8.7	9.0	9.0	2.5%	3.1%
NEWE	12.6	12.4	12.7	-1.3%	0.5%
NYCW	17.0	16.9	16.9	-0.5%	-0.5%
NYLI	14.0	13.7	13.7	-2.2%	-1.7%
NYUP	11.8	11.7	11.7	-0.8%	-1.3%
RFCE	10.3	10.2	10.5	-0.2%	2.1%
RFCM	10.4	10.4	10.6	0.5%	1.9%
RFCW	9.8	9.7	10.1	-1.4%	2.4%
SRDA	8.6	8.6	8.7	0.0%	1.4%
SRGW	9.1	9.0	9.3	-0.9%	2.5%
SRSE	9.6	9.7	9.8	1.4%	2.1%
SRCE	7.8	8.0	8.0	2.6%	3.0%
SRVC	9.3	9.5	9.6	1.7%	2.4%
SPNO	9.8	10.0	10.2	2.9%	4.3%
SPSO	8.1	8.3	8.4	2.7%	4.4%
AZNM	10.7	10.9	10.9	2.2%	1.8%
CAMX	13.2	13.3	13.5	0.8%	2.4%
NWPP	6.8	6.9	7.0	2.1%	2.7%
RMPA	8.6	8.7	8.9	2.0%	4.3%
Contiguous U.S.	9.9	9.9	10.1	0.9%	2.0%

Note: regions pictured on Figure 3-6.

Table 3-21. **2030 Projected Contiguous U.S. and Regional Retail Electricity Prices (cents/kWh)**

	2030 Projected Retail Price (cents/kWh)			Percent Change from Base Case	
	Base Case	Rate-based	Mass-based	Rate-based	Mass-based
ERCT	11.6	11.4	11.3	-1.4%	-2.5%
FRCC	10.3	10.8	10.5	4.6%	2.3%
MROE	9.7	10.3	10.3	5.9%	6.3%
MROW	8.9	9.1	9.1	2.7%	2.8%
NEWE	14.3	13.6	13.4	-5.4%	-6.9%
NYCW	19.2	18.2	18.0	-5.2%	-6.4%
NYLI	16.3	14.8	14.6	-9.0%	-10.1%
NYUP	13.6	12.7	12.5	-7.0%	-8.4%
RFCE	11.3	10.7	10.6	-5.6%	-6.5%
RFCM	10.5	10.8	10.7	3.4%	1.7%
RFCW	10.4	10.5	10.5	1.2%	0.7%
SRDA	9.0	9.3	9.2	3.5%	1.9%
SRGW	9.7	9.6	9.7	-0.6%	0.4%
SRSE	9.8	10.2	10.0	3.9%	2.1%
SRCE	7.8	8.1	8.0	4.3%	3.3%
SRVC	9.3	9.6	9.5	3.2%	2.0%
SPNO	9.5	9.8	10.1	2.7%	5.8%
SPSO	8.7	9.0	8.9	3.9%	2.0%
AZNM	10.9	11.2	11.1	2.3%	2.0%
CAMX	13.5	13.6	13.7	1.1%	1.4%
NWPP	6.9	7.0	7.1	2.2%	2.6%
RMPA	8.9	9.0	9.3	0.7%	3.5%
Contiguous U.S.	10.3	10.4	10.3	0.8%	0.01%

Note: regions pictured on Figure 3-6.

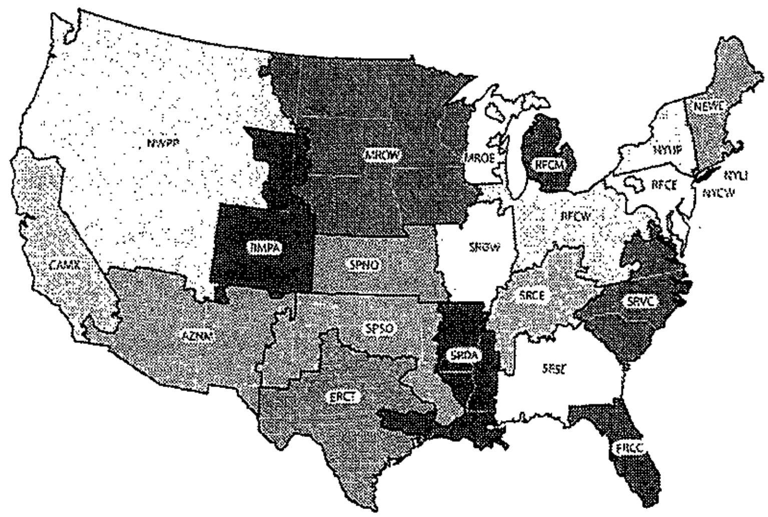

Figure 3-6. Electricity Market Module Regions

Source: EIA (http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf)

3.9.10 Projected Electricity Bill Impacts

The electricity price changes addressed in section 3.9.9 combine with the significant reductions in electricity demand applied in the illustrative approaches to affect average electricity bills. The estimated changes to average bills are summarized in Table 3-22, and are subject to the same caveats described in section 3.9.9. Under the illustrative rate-based plan scenario, EPA estimates an average monthly bill increase of 2.7 percent in 2020 and an average bill decrease of 3.8 percent in 2025 and 7 percent in 2030. Under the mass-based scenario, EPA estimates an average bill increase of 2.4 percent in 2020 and an average bill decrease of 2.7 percent in 2025 and 7.7 percent in 2030. These reduced electricity bills reflect the combined effects of changes in both average retail rates (driven by compliance approaches taken to achieve the state goals) and lower electricity demand (driven by demand-side energy efficiency).

Table 3-22. Projected Changes in Average Electricity Bills

	2020	2025	2030
Rate-based	2.7%	-3.8%	-7.0%
Mass-based	2.4%	-2.7%	-7.7%

3.10 Adoption of a Mix of State Plan Approaches

The impact of the EGs on the marginal cost of generating electricity may differ for affected EGUs if a state adopts a rate-based or a mass-based plan. Analysts have observed, in the context of the proposed EG, that the different production incentives for rate and mass-based plans may encourage greater generation by the affected EGUs in the rate-based state. This is because the rate-based approach may yield lower marginal costs of electricity generation than the mass-based approach for some otherwise similar EGUs. In a rate-based program, affected EGUs may emit more if they generate more, whereas in a mass-based approach, if an affected EGU generates more it must incur the full cost of increasing its emissions. Some analysts have suggested that this implies that if a state with a rate-based plan shares an electricity market with another state that adopted a mass-based plan, then total CO_2 emissions may be higher than if both states adopted the same form of implementation (e.g. Burtraw et al., 2015; Bushnell et al., 2014). In each case, both states would still be able to demonstrate that their affected EGUs are in compliance, such that the state is achieving its state goal (or the uniform rates).

While these analyses identify how emissions and costs may be influenced by the variation in the types of plans that states adopt, they have not raised concerns about the ability of the electricity system to provide reliable and affordable electricity when EGUs face different regulatory incentives. The EPA believes that differences in state plans, along with differences in incentives from those plans, will not detrimentally affect the operation of electricity markets because EGUs in the same market are often subject to different regulatory incentives. For example, the time-differentiated pattern of renewable portfolio standard (RPS) adoption, their varying stringency and form, and the operation of their associated renewable energy credit (REC) markets, across the U.S. demonstrates how interconnected electricity markets are able to function successfully, even with differential regulatory incentives across states. RPS are adopted at the state level and are required of load-serving entities (LSEs). In some states, LSEs and the owners of most of the fossil generation are one and the same. In other states, LSEs own no generation (either fossil or renewable), and in some states and markets, one LSE may own generation, while another may not. Furthermore, RPS requirements for LSEs serving load in multiple states will influence the behavior of all EGUs operating the electricity market. Even with this non-uniform regulatory environment, electricity has been delivered affordably and reliably while at the same time, the use of renewable energy has increased dramatically.

In the context of preexisting programs, evidence suggests that the effect of differential regulatory structures on emissions is relatively modest. For example, Schennach (2000) finds that in the early years of the Title IV cap and trade program, the increase in SO_2 emissions of

Phase II units, which historically were subject to emission rate performance standards, offset the decrease in SO_2 emissions by Phase I units in by about 5%. The EPA's prospective analysis of the benefits and costs of the Cross-State Air Pollution Rule, which used IPM, forecast only a small increase in SO_2 emissions from plants that were not subject to the rule (U.S.EPA 2011). The Regional Greenhouse Gas Initiative (RGGI) produces an annual report monitoring the trends in on CO2 emissions from electricity generation in the region and imports from outside of the region. To date, RGGI's monitoring effort has not identified any significant change in CO_2 emissions or the CO_2 emission rate from non-RGGI electric generation serving load in the RGGI region (e.g., RGGI 2014). The effect on the relative costs of production across similar sources affected by different regulatory approaches will, in part, depend on the relative stringency of the different regulatory approaches, and the emission rate of the EGUs that represent the marginal source of electricity supply in the long-run.

In practice, determining the direction and magnitude of the effect of variation in state plan type on sector wide emissions, relative to the two illustrative plan scenarios evaluated in this RIA, would be difficult. At the outset there is a lack of information as to what design features states might adopt in their plans and in turn what patterns of spatial and plan variation would be most appropriate to consider. Determining the change in sectoral costs and emissions for the situation in which subsets of states adopt different types of plans would require many additional assumptions regarding which states adopt which plan types and the specific features of those plans. The effect on the relative costs of generation across states will be sensitive to these analytical choices, and therefore so will the estimated results regarding the direction and magnitude of state plan variation on aggregate sectoral costs and emissions.

The mere existence of variation among the design of state plans would not be sufficient to conclude that there will be a notable change in emissions relative to a case with less variation. The ultimate impact of the variation will depend upon the specific plan approaches, such as the way mass-based states allocate allowances, the state's goals, as well as the states' existing generating fleets, the transmission grid, spatial variation in future electricity demand, and the degree of ERC and allowance trading available within the system, amongst other variables.

There are other features of the requirements of state plans in this final rulemaking that would influence the scope of emissions changes that may result from states adopting a mix of mass and rate-based plans. For example, this final rulemaking also requires that states adopting mass-based plans include a method for addressing leakage to new fossil-fired generation. These approaches are described in the preamble for this final rule. If states adopt programs to address leakage within their state, those programs may lead to reduced generation by EGUs in neighboring rate-based states (relative to the scenario where those plans were not in place). For example, as shown in Burtraw et al. (2015) and Demailly and Quirion (2006), as well as other related studies, output-based allocation to sources covered by a mass requirement would lead to reduced production by sources subject to rate-based (or no) regulation.

3.11 Limitations of Analysis

EPA's modeling is based on expert judgment of various input assumptions for variables whose outcomes are in fact uncertain. As a general matter, the Agency reviews the best available information from engineering studies of air pollution controls, the ability to improve operating efficiency, and new capacity construction costs to support a reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory actions.

The costs presented in this RIA include both the IPM-projected annualized estimates of private compliance costs as well as the estimated costs incurred by utilities and program participants to achieve demand-side energy efficiency improvements. The demand-side energy efficiency costs are developed based on a review of energy efficiency data and studies, and expert judgment. The EPA recognizes that significant variation exists in these analyses reflecting data and methodological limitations. The method used for estimating the demand-side energy efficiency costs is discussed in more detail in the Demand-Side Energy Efficiency Technical Support Document (TSD). The evaluation, measurement and verification (EM&V) of demand-side energy efficiency is addressed in the section VIII, State Plans, of the preamble for the final rule.

The base case electricity demand in IPM v.5.15 is calibrated to reference case demand in AEO 2015. AEO 2015 demand may reflect, to some extent, a continuation of the impacts of state demand-side energy efficiency policies but does not explicitly represent the most significant existing state policies in this area (e.g., energy efficiency resource standards). To some degree, the implicit representation of state policies in the EPA's base case alters the impacts assessment, but the direction and magnitude of change is not known with certainty. This issue is discussed in the Demand-Side Energy Efficiency TSD.

Cost estimates for the final emission guidelines are based on rigorous power sector modeling using ICF's Integrated Planning Model.[85] IPM assumes "perfect foresight" of market conditions over the time horizon modeled; to the extent that utilities and/or energy regulators misjudge future conditions affecting the economics of pollution control, costs may be understated as well.

One important element of the final CPP is the flexibility afforded to states as they develop requirements for their existing emitting sources. Each state has discretion on how to best achieve the standards of performance and/or state goals. As such, states can apply requirements to sources that achieve greater reductions than required during the interim period, and use those earlier reductions in the final period (i.e., banking of reductions).

In the analysis and modeling for the RIA, such flexibilities were not explicitly modeled in the compliance scenarios. Doing so would require additional assumptions about the specific opportunities states may choose to adopt in their plans, including the form of the standard that states apply, the manner in which it is applied, and the economic signal that such a mechanism provides to sources over time, such that sources would have an incentive to make greater reductions earlier. As previously stated, the analysis in the RIA is intended to be illustrative to inform the broad impacts of the rule across the power sector, and not intended to forecast the specific approaches that individual states might choose, and how sources might prefer to achieve the emission reductions to reflect each state plan in response to particular policy signals or requirements. Not representing banking of earlier reductions into the final period captures this uncertainty that there is inadequate and incomplete information at this time regarding state plans in the analytic approach.

The analysis does not fully reflect the potential under the final rule for recognition of pre-compliance emission reduction measures. Under the final rule, states implementing a rate-based plan can recognize eligible emission reduction measures, including RE and demand-side energy

[85] Full documentation for IPM can be found at <http:// http://www.epa.gov/powersectormodeling>.

efficiency, implemented after 2012 for the emission reductions those measures provide during the interim and final performance periods (see preamble Sec. VIII.K.1). In the analysis, this treatment is appropriately applied in the compliance period to generation from renewable capacity built after 2012. However, demand-side EE is limited to recognition of impacts occurring in the compliance period that result from investments in demand-side EE that are assumed to begin after 2019 (as represented in the illustrative demand-side EE plan scenario). Additionally, under the final rule, states will have the opportunity to recognize certain RE and demand-side EE measures implemented after the effective date of the rule for the emission reductions they provide in 2020-2021 through the Clean Energy Incentive Program (see preamble Sec. VIII.B.2). By committing to recognize these actions in 2020-2021, states will have access to a capped pool of additional rate-based ERCs and mass-based allowances, based on their plan type. The Clean Energy Incentive Program is not reflected in this analysis.

The illustrative mass-based implementation scenario presented in this chapter includes an RE set-aside, which is only one component of a potential approach to address leakage to new sources. Please see section VIII of the preamble for a description of how states must show that they are addressing leakage under mass-based implementation.

3.12 Social Costs

As discussed in the EPA Guidelines for Preparing Economic Analyses, social costs are the total economic burden of a regulatory action. This burden is the sum of all opportunity costs incurred due to the regulatory action, where an opportunity cost is the value lost to society of any goods and services that will not be produced and consumed as a result of reallocating some resources towards pollution mitigation. Estimates of social costs may be compared to the social benefits expected as a result of a regulation to assess its net impact on society. The social costs of a regulatory action will not necessarily be equivalent to the expenditures associated with compliance. Nonetheless, here we use compliance costs as a proxy for social costs. This section provides a qualitative discussion of the relationship between social costs and compliance cost estimates presented in this chapter.

The cost estimates for the illustrative plan scenarios presented in this chapter are the sum of expenditures on demand-side energy efficiency and the change in expenditures required by the electricity sector to comply with the final emission guidelines. These two components are estimated separately. The expenditures required to achieve the assumed demand reductions through demand-side energy efficiency programs are estimated using historical data, analysis, and expert judgment. The change in the expenditures required by the electricity sector to meet demand and maintain compliance are estimated by IPM and reflect both the reduction in electricity production costs due to the reduction in demand caused by the demand-side energy efficiency measures and the increase in electricity production costs required to achieve the additional emission reductions necessary to comply with the state goals.

As described in section 3.7.1, the illustrative plan approaches assume that, in achieving their goals, demand-side energy efficiency measures are adopted which lead to demand reductions in each year represented by the illustrative energy efficiency plan scenario. The estimated expenditures required to achieve those demand reductions through demand-side energy efficiency are presented in this chapter and detailed in the Demand-Side Energy Efficiency TSD. The social cost of achieving these energy savings comes in the form of increased expenditures on technologies and/or services that are required to lower electricity consumption beyond the business as usual. Under the assumption of complete and well-functioning markets, the expenditures required to reduce electricity consumption on the margin will represent society's opportunity cost of the resources required to produce the energy savings.

Due to the flexibility held by states in implementing their compliance with the final standards these energy efficiency expenditures may be borne by end-users through direct participant expenditures or electricity rate increases, or by producers through reductions in their profits. While the allocation of these expenditures between consumers and producers is important for understanding the distributional impact of potential compliance strategies, it does not necessarily affect the opportunity cost required for the production of the energy savings from a social perspective. However, specific design elements of demand-side energy efficiency measures included to address distributional outcomes may have an effect on the economic efficiency of the programs and therefore the social cost.

Another reason the expenditures associated with demand-side energy efficiency may differ from social costs is due to differences in the services provided by more energy efficient technologies and services adopted under the program relative to the baseline. For example, if under the program end-users adopted more energy efficient products which were associated with quality or service attributes deemed less desirable, then there would be an additional welfare loss that should be accounted for in social costs but is not necessarily captured in the measure of expenditures. However, there is an analogous possibility that in some cases the quality of services, outside of the energy savings, provided by the more energy efficient products and practices are deemed more desirable by some end-users. For example, weatherization of buildings to reduced electricity demand associated with cooling will likely have a significant impact on natural gas use associated with heating. In either case, these real welfare impacts are not fully captured by end-use energy efficiency expenditure estimates.

The fact that such quality and service differences may exist in reality but may not be reflected in the price difference between more and less energy efficient products is one potential hypothesis for the energy paradox. The energy paradox is the observation that end-users do not always purchase products that are more energy efficient when the additional cost is less than the reduction in the net present value of expected electricity expenditures achieved by those products.[86] Such circumstances are present in the analysis presented in this chapter, whereby in some regions the base case and illustrative approaches suggest that cost of reducing demand through energy efficiency programs is less than the retail electricity price. In addition to heterogeneity in product services and consumer preferences, there are other explanations for the energy paradox, falling both within and outside the neoclassical rational expectations paradigm that is used in benefit/cost analysis. The Demand-Side Energy Efficiency TSD discusses the energy paradox and provides additional hypothesis for why consumers may not make energy efficiency investments that ostensibly seem to be in their own interest. The TSD discussion also provides details on how the presence of additional market failures can lead to levels of energy efficiency investment that may be too low from society's perspective even if that is not the case for the end-user. In such cases there is the potential for properly designed energy efficiency programs to address the source of under-investment, such as principal-agent problems where there is a disconnect between those making the purchase decision regarding energy efficient investments and energy use and those that would receive the benefits associated with reduced energy use through lower electricity bills.

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[86] An analogous situation is present when some EGUs have assumed to have the ability to make heat rate improvements at a capital cost that is less than the anticipated fuel expenditure savings.

The other component of compliance cost reported in this chapter is the change in resource cost (i.e., expenditures) required by the electricity sector to fulfill the remaining demand while making additional CO_2 emissions reductions necessary to comply with the state goals. Included in the estimate of these compliance costs, estimated using IPM, are the cost reductions associated with the reduction in required electricity generation due to the demand reductions from demand-side energy efficiency measures and improvements in heat rate. By shifting the demand curve for electricity, demand-side energy efficiency reduces the production cost in the sector. The resource cost estimates from IPM therefore account for the increased cost of providing electricity, including changes in fuel prices associated with changes in their demand, while EGUs comply with their regulatory obligations (net of the reduction in their production costs due to lower demand resulting from demand-side energy efficiency measures).

3.13 References

Burtraw, Dallas, Karen Palmer, Sophie Pan, and Anthony Paul. 2015. A Proximate Mirror: Greenhouse Gas Rules and Strategic Behavior under the U.S. Clean Air Act. Resources for the Future Discussion Paper 15-02. March 2015.

Bushnell, James B., Stephen P. Holland, Jonathan E. Hughes, Christopher R. Knittel. 2015. Strategic Policy Choice in State-Level Regulation: The EPA's Clean Power Plan. National Bureau of Economic Research Working Paper No. w21259. June, 2015.

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U.S. EPA. 2010. EPA Guidelines for Preparing Economic Analyses Available at: <http://yosemite.epa.gov/ee/epa/eed.nsf/webpages/guidelines.htm>. Accessed 7/11/2015.

U.S. EPA. 2015. Technical Support Document (TSD) the Final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Demand-Side Energy Efficiency.

U.S. EPA. 2015. Technical Support Document (TSD) the Final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Resource Adequacy and Reliability Analysis.

RESA Set 3
Witness: Santino L. Fanelli
As to Objections: Carrie M. Dunn

Case No. 14-1297-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and
The Toledo Edison Company for Authority to Provide for a Standard Service Offer
Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan

RESPONSES TO REQUEST

RESA Set 3-INT-14 Have the Companies conducted any analysis on the cost to residential customers if the transmission upgrades occur as referenced at line 8, page 4 of Gavin Cunningham's written direct testimony?

Response: Objection. This request is overbroad and seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the objections, no.

EXHIBIT
PENGAD 800-631-6989
SC 66

Environmental Disclosure Information

As part of Ohio's Electric Choice program, the Public Utilities Commission of Ohio (PUCO) requires local utilities and suppliers to identify the sources they use to make electricity and the byproducts of that process. Inside you'll find this environmental information for Ohio Edison, The Illuminating Company and Toledo Edison.

For more information on Ohio's Electric Choice program, please call our toll-free customer choice information line: 1-800-225-0444.

EXHIBIT

PENGAD 800-631-6989

OCC

2

FirstEnergy

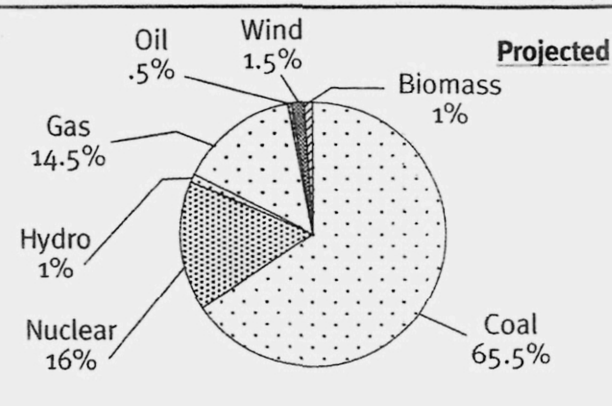
Environmental Disclosure – Quarterly Comparison

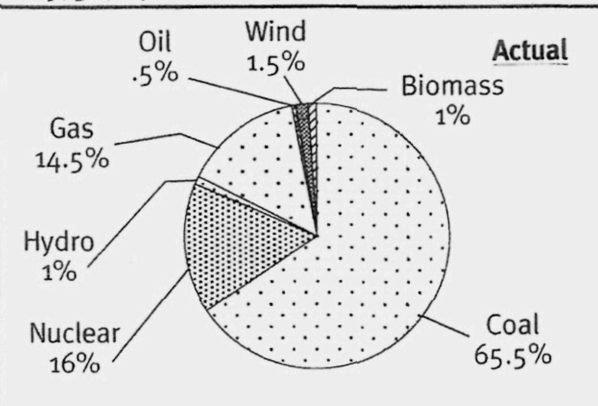
Ohio Edison, The Illuminating Company and Toledo Edison

Projected Data for the 2014 Calendar Year

Actual Data for the Period 01/01/14 to 09/30/14

Generation Resource Mix
A comparison between the sources of generation projected to be used to generate this product and the actual resources used during this period.

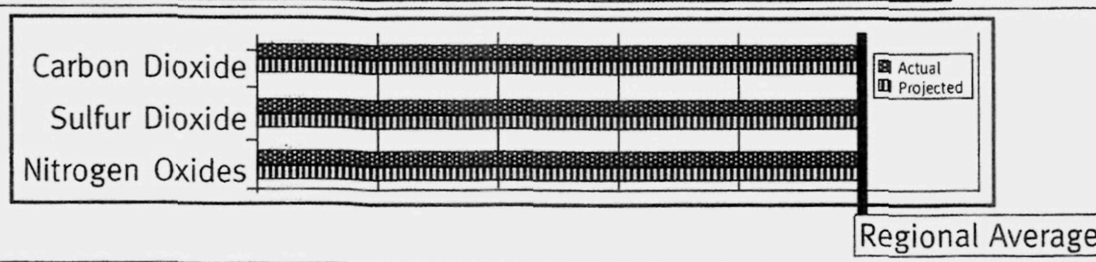




Environmental Characteristics
A description of the characteristics associated with each possible generation resource.

Biomass Power	Air Emissions and Solid Waste
Coal Power	Air Emissions and Solid Waste
Hydro Power	Wildlife Impacts
Natural Gas Power	Air Emissions and Solid Waste
Nuclear Power	Radioactive Waste
Oil Power	Air Emissions and Solid Waste
Other Sources	Unknown Impacts
Solar Power	No Significant Impacts
Unknown Purchased Resources	Unknown Impacts
Wind Power	Wildlife Impacts

Air Emissions
A comparison between the air emissions related to this product and the regional average air emissions.



Radioactive Waste
Radioactive waste associated with the product.

Type:	Projected Quantity:	Actual Quantity:	
High-Level Radioactive Waste	NA	NA	Lbs./1,000 kWh
Low-Level Radioactive Waste	NA	NA	Ft^3/1,000 kWh

Renewable Energy Credits: FirstEnergy Utility Companies purchase renewable energy credits (RECs) as a means of complying with the renewable energy resource benchmark under the state's alternative energy portfolio standard requirements. The requirement for 2014 is 2.5% renewable, including 0.12% solar. With in-depth analysis, the environmental characteristics of any form of electric generation will reveal benefits as well as costs. For further information, contact your local electric utility (Ohio Edison, The Illuminating Company or Toledo Edison) at www.firstenergycorp.com/environment, or call 1-800-225-0444.

FirstEnergy

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COMM6531-12-14-AP-AP

Environmental Disclosure Information

As part of Ohio's Electric Choice program, the Public Utilities Commission of Ohio (PUCO) requires local utilities and suppliers to identify the sources they use to make electricity and the byproducts of that process. Inside you'll find this environmental information for Ohio Edison, The Illuminating Company and Toledo Edison.

For more information on Ohio's Electric Choice program, please call our toll-free customer choice information line: 1-800-225-0444.

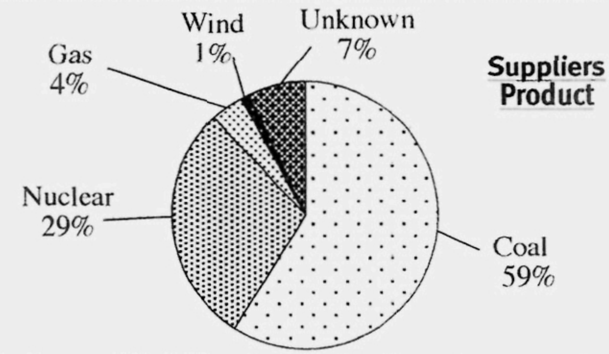
FirstEnergy®

Environmental Disclosure Information

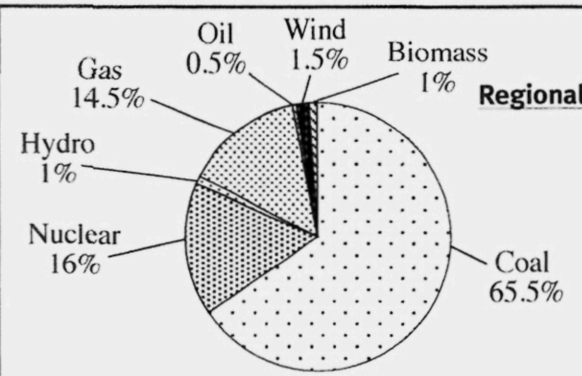
Ohio Edison, The Illuminating Company and Toledo Edison

Projected Data for the 2014 Calendar Year

Generation Resource Mix
Compares the sources of generation used to produce this product and the historic regional average supply mix.



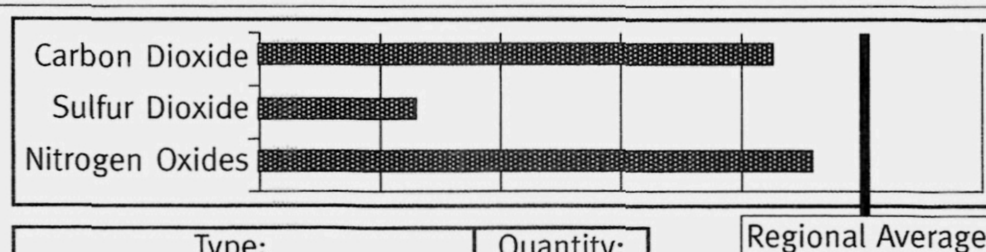
FirstEnergy Ohio Utility Company's will purchase a total of 297,138 Renewable Energy and Solar Renewable Energy Credits (REC and SREC) to meet year 2014 compliance obligations.



Environmental Characteristics
A description of the characteristics associated with each possible generation resource.

Biomass Power	Air Emissions and Solid Waste
Coal Power	Air Emissions and Solid Waste
Hydro Power	Wildlife Impacts
Natural Gas Power	Air Emissions and Solid Waste
Nuclear Power	Radioactive Waste
Oil Power	Air Emissions and Solid Waste
Other Sources	Unknown Impacts
Solar Power	No Significant Impacts
Unknown Purchased Resources	Unknown Impacts
Wind Power	Wildlife Impacts

Air Emissions
Compares the air emissions related to this product and the regional average air emissions.



Radioactive Waste
Radioactive waste associated with the product.

Type:	Quantity:	
High-Level Radioactive Waste	0.0027	Lbs./1,000 kWh
Low-Level Radioactive Waste	0.0008	Ft^3/1,000 kWh

Note: The generation of this product involves the use of 7% projected Unknown Purchased Resources. The air emissions and radioactive waste associated with these unknown resources are not included in these charts.

Renewable Energy Credits: FirstEnergy Ohio Utility Companies purchase Renewable Energy and Solar Renewable Energy Credits (REC and SREC) as a means of complying with the renewable energy resource benchmark under the state's alternative energy portfolio standard requirements. The requirement for 2014 is 2.5% renewable, including 0.12% solar. With in-depth analysis, the environmental characteristics of any form of electric generation will reveal benefits as well as costs. For further information, contact your local electric utility (Ohio Edison, The Illuminating Company or Toledo Edison) at www.firstenergycorp.com/environment, or call 1-800-225-0444.

FirstEnergy

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COMM3133-01-14-AP-AP

Environmental Disclosure Information

As part of Ohio's Electric Choice program, the Public Utilities Commission of Ohio (PUCO) requires local utilities and suppliers to identify the sources they use to make electricity and the byproducts of that process. Inside you'll find this environmental information for Ohio Edison, The Illuminating Company and Toledo Edison.

For more information on Ohio's Electric Choice program, please call our toll-free customer choice information line: 1-800-225-0444.

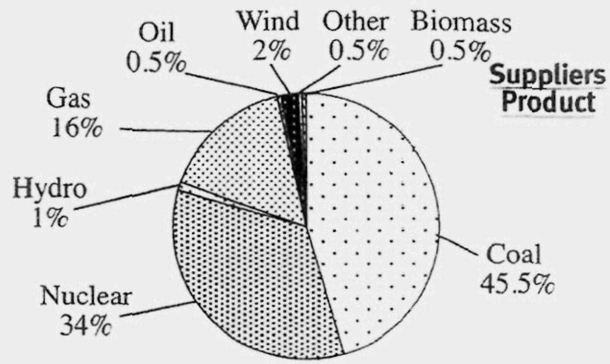
FirstEnergy

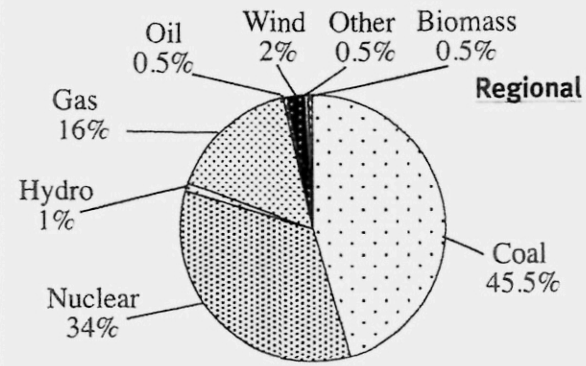
Environmental Disclosure Information

Ohio Edison, The Illuminating Company and Toledo Edison

Projected Data for the 2015 Calendar Year

Generation Resource Mix
A comparison between the sources of generation used to produce this product and the historic regional average supply mix.

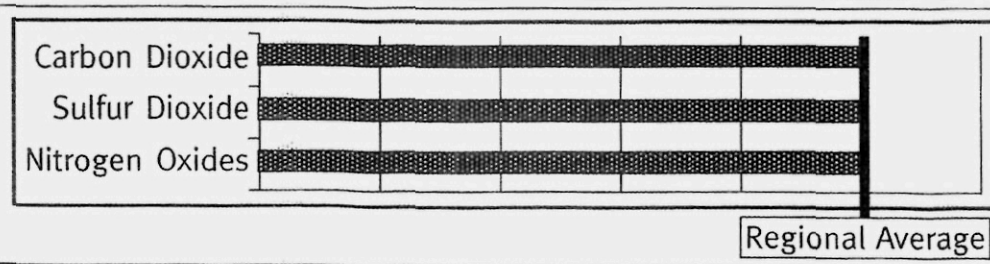




Environmental Characteristics
A description of the characteristics associated with each possible generation resource.

Biomass Power	Air Emissions and Solid Waste
Coal Power	Air Emissions and Solid Waste
Hydro Power	Wildlife Impacts
Natural Gas Power	Air Emissions and Solid Waste
Nuclear Power	Radioactive Waste
Oil Power	Air Emissions and Solid Waste
Other Sources	Unknown Impacts
Solar Power	No Significant Impacts
Unknown Purchased Resources	Unknown Impacts
Wind Power	Wildlife Impacts

Air Emissions
A comparison between the air emissions related to this product and the regional average air emissions.



Radioactive Waste
Radioactive waste associated with the product.

Type:	Quantity:	
High-Level Radioactive Waste	NA	Lbs./1,000 kWh
Low-Level Radioactive Waste	NA	Ft^3/1,000 kWh

Renewable Energy Credits: FirstEnergy Ohio Utility Companies purchase Renewable Energy and Solar Renewable Energy Credits (REC and SREC) as a means of complying with the renewable energy resource benchmark under the state's alternative energy portfolio standard requirements. The requirement for 2015 is 2.5% renewable, including 0.12% solar. With in-depth analysis, the environmental characteristics of any form of electric generation will reveal benefits as well as costs. For further information, contact your local electric utility (Ohio Edison, The Illuminating Company or Toledo Edison) at www.firstenergycorp.com/environment, or call 1-800-225-0444.

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COMM6557-01-15-AP-AP

IEU Set 3
Witness: Santino L. Fanelli
As to Objections: Carrie M. Dunn

Case No. 14-1297-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan

RESPONSES TO REQUEST

IEU Set 3 – INT-3 Identify any documents that illustrate the typical bill impacts by rate schedule if the Stipulation is accepted by the Commission.

Response: Objection. The request is vague and ambiguous and seeks information not in the Companies' possession. Subject to and without waiving the foregoing objections, please see IEU Set 3-INT-3 Attachment 1, IEU Set 3-INT-3 Attachment 2, and IEU Set 3-INT Attachment 3 for estimated typical bill impacts associated with the Stipulation to non-shopping customers of the Companies, by rate schedule, for each year of ESP IV.

PENGAD 800-631-6989 EXHIBIT OCC 16

IEU Set 3-INT-3 Attachment 1

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - Standard (Rate RS)						
1	0	250	$ 35.63	$ 36.45	$ 0.81	2.3%
2	0	500	$ 67.11	$ 68.74	$ 1.62	2.4%
3	0	750	$ 98.59	$ 101.02	$ 2.44	2.5%
4	0	1,000	$ 130.07	$ 133.31	$ 3.25	2.5%
5	0	1,250	$ 161.54	$ 165.60	$ 4.06	2.5%
6	0	1,500	$ 193.02	$ 197.89	$ 4.87	2.5%
7	0	2,000	$ 255.97	$ 262.47	$ 6.49	2.5%
8	0	2,500	$ 318.70	$ 326.81	$ 8.12	2.5%
9	0	3,000	$ 381.42	$ 391.16	$ 9.74	2.6%
10	0	3,500	$ 444.14	$ 455.51	$ 11.36	2.6%
11	0	4,000	$ 506.87	$ 519.86	$ 12.99	2.6%
12	0	4,500	$ 569.59	$ 584.20	$ 14.61	2.6%
13	0	5,000	$ 632.31	$ 648.55	$ 16.24	2.6%
14	0	5,500	$ 695.04	$ 712.90	$ 17.86	2.6%
15	0	6,000	$ 757.76	$ 777.24	$ 19.48	2.6%
16	0	6,500	$ 820.48	$ 841.59	$ 21.11	2.6%
17	0	7,000	$ 883.21	$ 905.94	$ 22.73	2.6%
18	0	7,500	$ 945.93	$ 970.28	$ 24.35	2.6%
19	0	8,000	$ 1,008.65	$ 1,034.63	$ 25.98	2.6%
20	0	8,500	$ 1,071.38	$ 1,098.98	$ 27.60	2.6%
21	0	9,000	$ 1,134.10	$ 1,163.32	$ 29.22	2.6%
22	0	9,500	$ 1,196.82	$ 1,227.67	$ 30.85	2.6%
23	0	10,000	$ 1,259.55	$ 1,292.02	$ 32.47	2.6%
24	0	10,500	$ 1,322.27	$ 1,356.36	$ 34.09	2.6%
25	0	11,000	$ 1,384.99	$ 1,420.71	$ 35.72	2.6%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Electric Heating						
1	0	250	$ 34.00	$ 35.36	$ 1.36	4.0%
2	0	500	$ 63.84	$ 66.57	$ 2.73	4.3%
3	0	750	$ 86.93	$ 91.02	$ 4.09	4.7%
4	0	1,000	$ 110.02	$ 115.48	$ 5.46	5.0%
5	0	1,250	$ 133.12	$ 139.94	$ 6.82	5.1%
6	0	1,500	$ 156.21	$ 164.39	$ 8.18	5.2%
7	0	2,000	$ 202.39	$ 213.30	$ 10.91	5.4%
8	0	2,500	$ 248.34	$ 261.98	$ 13.64	5.5%
9	0	3,000	$ 294.30	$ 310.66	$ 16.37	5.6%
10	0	3,500	$ 340.25	$ 359.34	$ 19.09	5.6%
11	0	4,000	$ 386.20	$ 408.02	$ 21.82	5.7%
12	0	4,500	$ 432.15	$ 456.70	$ 24.55	5.7%
13	0	5,000	$ 478.11	$ 505.38	$ 27.28	5.7%
14	0	5,500	$ 524.06	$ 554.06	$ 30.01	5.7%
15	0	6,000	$ 570.01	$ 602.74	$ 32.73	5.7%
16	0	6,500	$ 615.96	$ 651.42	$ 35.46	5.8%
17	0	7,000	$ 661.92	$ 700.10	$ 38.19	5.8%
18	0	7,500	$ 707.87	$ 748.78	$ 40.92	5.8%
19	0	8,000	$ 753.82	$ 797.46	$ 43.64	5.8%
20	0	8,500	$ 799.77	$ 846.14	$ 46.37	5.8%
21	0	9,000	$ 845.73	$ 894.82	$ 49.10	5.8%
22	0	9,500	$ 891.68	$ 943.50	$ 51.83	5.8%
23	0	10,000	$ 937.63	$ 992.18	$ 54.55	5.8%
24	0	10,500	$ 983.58	$ 1,040.86	$ 57.28	5.8%
25	0	11,000	$ 1,029.54	$ 1,089.55	$ 60.01	5.8%

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Water Heating						
1	0	250	$ 35.63	$ 36.45	$ 0.81	2.3%
2	0	500	$ 67.11	$ 68.74	$ 1.62	2.4%
3	0	750	$ 94.46	$ 96.90	$ 2.44	2.6%
4	0	1,000	$ 121.82	$ 125.06	$ 3.25	2.7%
5	0	1,250	$ 149.17	$ 153.23	$ 4.06	2.7%
6	0	1,500	$ 176.52	$ 181.39	$ 4.87	2.8%
7	0	2,000	$ 231.22	$ 237.72	$ 6.49	2.8%
8	0	2,500	$ 285.70	$ 293.81	$ 8.12	2.8%
9	0	3,000	$ 340.17	$ 349.91	$ 9.74	2.9%
10	0	3,500	$ 394.64	$ 406.01	$ 11.36	2.9%
11	0	4,000	$ 449.12	$ 462.11	$ 12.99	2.9%
12	0	4,500	$ 503.59	$ 518.20	$ 14.61	2.9%
13	0	5,000	$ 558.06	$ 574.30	$ 16.24	2.9%
14	0	5,500	$ 612.54	$ 630.40	$ 17.86	2.9%
15	0	6,000	$ 667.01	$ 686.49	$ 19.48	2.9%
16	0	6,500	$ 721.48	$ 742.59	$ 21.11	2.9%
17	0	7,000	$ 775.96	$ 798.69	$ 22.73	2.9%
18	0	7,500	$ 830.43	$ 854.78	$ 24.35	2.9%
19	0	8,000	$ 884.90	$ 910.88	$ 25.98	2.9%
20	0	8,500	$ 939.38	$ 966.98	$ 27.60	2.9%
21	0	9,000	$ 993.85	$ 1,023.07	$ 29.22	2.9%
22	0	9,500	$ 1,048.32	$ 1,079.17	$ 30.85	2.9%
23	0	10,000	$ 1,102.80	$ 1,135.27	$ 32.47	2.9%
24	0	10,500	$ 1,157.27	$ 1,191.36	$ 34.09	2.9%
25	0	11,000	$ 1,211.74	$ 1,247.46	$ 35.72	2.9%

IEU Set 3-INT-3 Attachment 1
Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

		Bill Data				
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Secondary (Rate GS)						
1	10	1,000	$ 188.86	$ 207.03	$ 18.18	9.6%
2	10	2,000	$ 275.26	$ 292.29	$ 17.03	6.2%
3	10	3,000	$ 361.27	$ 377.13	$ 15.87	4.4%
4	10	4,000	$ 447.25	$ 461.97	$ 14.72	3.3%
5	10	5,000	$ 533.25	$ 546.82	$ 13.57	2.5%
6	10	6,000	$ 619.19	$ 631.60	$ 12.41	2.0%
7	1,000	100,000	$ 20,364.04	$ 22,182.46	$ 1,818.42	8.9%
8	1,000	200,000	$ 28,905.79	$ 30,608.73	$ 1,702.94	5.9%
9	1,000	300,000	$ 37,447.54	$ 39,035.00	$ 1,587.45	4.2%
10	1,000	400,000	$ 45,989.29	$ 47,461.26	$ 1,471.97	3.2%
11	1,000	500,000	$ 54,531.05	$ 55,887.52	$ 1,356.48	2.5%
12	1,000	600,000	$ 63,072.79	$ 64,313.79	$ 1,241.00	2.0%

IEU Set 3-INT-3 Attachment 1

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Primary (Rate GP)						
1	500	50,000	$ 6,883.18	$ 8,014.77	$ 1,131.60	16.4%
2	500	100,000	$ 10,889.76	$ 11,991.45	$ 1,101.70	10.1%
3	500	150,000	$ 14,896.36	$ 15,968.16	$ 1,071.81	7.2%
4	500	200,000	$ 18,902.94	$ 19,944.85	$ 1,041.92	5.5%
5	500	250,000	$ 22,909.53	$ 23,921.55	$ 1,012.02	4.4%
6	500	300,000	$ 26,916.12	$ 27,898.25	$ 982.13	3.6%
7	5,000	500,000	$ 67,293.90	$ 78,609.83	$ 11,315.93	16.8%
8	5,000	1,000,000	$ 107,203.00	$ 118,220.01	$ 11,017.01	10.3%
9	5,000	1,500,000	$ 146,799.48	$ 157,517.56	$ 10,718.08	7.3%
10	5,000	2,000,000	$ 186,395.96	$ 196,815.12	$ 10,419.16	5.6%
11	5,000	2,500,000	$ 225,992.44	$ 236,112.67	$ 10,120.23	4.5%
12	5,000	3,000,000	$ 265,588.93	$ 275,410.24	$ 9,821.30	3.7%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Subtransmission (Rate GSU)						
1	1,000	100,000	$ 11,151.35	$ 13,071.72	$ 1,920.37	17.2%
2	1,000	200,000	$ 18,672.90	$ 20,468.59	$ 1,795.69	9.6%
3	1,000	300,000	$ 26,194.45	$ 27,865.45	$ 1,671.00	6.4%
4	1,000	400,000	$ 33,716.00	$ 35,262.32	$ 1,546.32	4.6%
5	1,000	500,000	$ 41,237.55	$ 42,659.18	$ 1,421.63	3.4%
6	1,000	600,000	$ 48,759.11	$ 50,056.05	$ 1,296.94	2.7%
7	10,000	1,000,000	$ 109,539.97	$ 128,743.68	$ 19,203.72	17.5%
8	10,000	2,000,000	$ 183,816.68	$ 201,773.54	$ 17,956.86	9.8%
9	10,000	3,000,000	$ 258,093.39	$ 274,803.40	$ 16,710.01	6.5%
10	10,000	4,000,000	$ 332,370.11	$ 347,833.26	$ 15,463.16	4.7%
11	10,000	5,000,000	$ 406,646.82	$ 420,863.12	$ 14,216.30	3.5%
12	10,000	6,000,000	$ 480,923.53	$ 493,892.98	$ 12,969.45	2.7%

IEU Set 3-INT-3 Attachment 1

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Transmission (Rate GT)						
1	2,000	200,000	$ 30,284.60	$ 32,484.43	$ 2,199.83	7.3%
2	2,000	400,000	$ 41,262.05	$ 43,218.71	$ 1,956.66	4.7%
3	2,000	600,000	$ 52,239.50	$ 53,952.99	$ 1,713.49	3.3%
4	2,000	800,000	$ 63,216.95	$ 64,687.27	$ 1,470.32	2.3%
5	2,000	1,000,000	$ 74,037.63	$ 75,264.77	$ 1,227.15	1.7%
6	2,000	1,200,000	$ 84,827.32	$ 85,811.30	$ 983.98	1.2%
7	20,000	2,000,000	$ 298,786.29	$ 320,784.58	$ 21,998.29	7.4%
8	20,000	4,000,000	$ 406,683.22	$ 426,249.80	$ 19,566.59	4.8%
9	20,000	6,000,000	$ 514,580.14	$ 531,715.02	$ 17,134.88	3.3%
10	20,000	8,000,000	$ 622,477.07	$ 637,180.24	$ 14,703.17	2.4%
11	20,000	10,000,000	$ 730,373.99	$ 742,645.46	$ 12,271.47	1.7%
12	20,000	12,000,000	$ 838,270.92	$ 848,110.68	$ 9,839.76	1.2%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Street Lighting Service (Rate STL)					
1	Company Owned - Incandescent Lighting (a)					
2	Overhead Service					
3	1,000	24	$ 12.62	$ 12.60	$ (0.02)	-0.2%
4	2,000	56	$ 14.82	$ 14.76	$ (0.06)	-0.4%
5	2,500	70	$ 15.80	$ 15.73	$ (0.07)	-0.4%
6	4,000	126	$ 19.68	$ 19.56	$ (0.12)	-0.6%
7	6,000	157	$ 21.80	$ 21.65	$ (0.15)	-0.7%
8	10,000	242	$ 27.67	$ 27.44	$ (0.23)	-0.8%
9	15,000	282	$ 30.42	$ 30.16	$ (0.26)	-0.9%
10	Underground Service					
11	1,000	24	$ 7.78	$ 7.76	$ (0.02)	-0.3%
12	2,000	56	$ 9.98	$ 9.92	$ (0.06)	-0.6%
13	2,500	70	$ 10.96	$ 10.89	$ (0.07)	-0.6%
14	4,000	126	$ 14.84	$ 14.72	$ (0.12)	-0.8%
15	6,000	157	$ 16.96	$ 16.81	$ (0.15)	-0.9%
16	10,000	242	$ 22.83	$ 22.60	$ (0.23)	-1.0%
17	15,000	282	$ 25.58	$ 25.32	$ (0.26)	-1.0%
18	Company Owned - Mercury Street Lighting (b)					
19	Overhead Service - Wood Pole					
20	175	69	$ 12.19	$ 12.12	$ (0.07)	-0.6%
21	250	104	$ 16.04	$ 15.95	$ (0.09)	-0.6%
22	400	158	$ 22.32	$ 22.17	$ (0.15)	-0.7%
23	1,000	380	$ 49.77	$ 49.42	$ (0.35)	-0.7%
24	Underground Service - Post Type					
25	175	69	$ 16.54	$ 16.47	$ (0.07)	-0.4%
26	Underground Service - Pole Type					
27	175	69	$ 23.10	$ 23.03	$ (0.07)	-0.3%
28	250	104	$ 27.76	$ 27.67	$ (0.09)	-0.3%
29	400	158	$ 34.26	$ 34.11	$ (0.15)	-0.4%
30	400*	158	$ 34.51	$ 34.36	$ (0.15)	-0.4%
31	400**	316	$ 54.69	$ 54.40	$ (0.29)	-0.5%
32	1000	380	$ 63.60	$ 63.25	$ (0.35)	-0.6%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Street Lighting Service (Rate STL)					
33	Company Owned - High Pressure Sodium Lighting (c)					
34	Overhead Service - Wood Pole					
35	100	42	$ 13.23	$ 13.18	$ (0.05)	-0.4%
36	150	62	$ 15.25	$ 15.19	$ (0.06)	-0.4%
37	250	105	$ 20.49	$ 20.40	$ (0.09)	-0.4%
38	400	163	$ 26.45	$ 26.30	$ (0.15)	-0.6%
39	Underground Service - Post Type					
40	100	42	$ 17.75	$ 17.70	$ (0.05)	-0.3%
41	Underground Service - Pole Type					
42	100	42	$ 24.69	$ 24.64	$ (0.05)	-0.2%
43	150	62	$ 27.06	$ 27.00	$ (0.06)	-0.2%
44	250	105	$ 32.14	$ 32.05	$ (0.09)	-0.3%
45	250**	210	$ 51.96	$ 51.77	$ (0.19)	-0.4%
46	400	163	$ 37.91	$ 37.76	$ (0.15)	-0.4%
47	Special Architectural Pole Installations					
48	100	42	$ 23.22	$ 23.17	$ (0.05)	-0.2%
49	100*	42	$ 35.25	$ 35.20	$ (0.05)	-0.1%
50	150	62	$ 25.79	$ 25.73	$ (0.06)	-0.2%
51	150*	62	$ 37.46	$ 37.40	$ (0.06)	-0.2%
52	250	105	$ 31.72	$ 31.63	$ (0.09)	-0.3%
53	250*	105	$ 43.55	$ 43.46	$ (0.09)	-0.2%
54	400	163	$ 37.68	$ 37.53	$ (0.15)	-0.4%
55	400*	163	$ 50.32	$ 50.17	$ (0.15)	-0.3%
56	Customer Owned - All Lamp Types					
57	N/A	25	$ 2.66	$ 2.64	$ (0.02)	-0.8%
58	N/A	50	$ 5.30	$ 5.26	$ (0.04)	-0.8%
59	N/A	75	$ 7.91	$ 7.85	$ (0.06)	-0.8%
60	N/A	100	$ 10.54	$ 10.44	$ (0.10)	-0.9%
61	N/A	125	$ 13.17	$ 13.05	$ (0.12)	-0.9%
62	N/A	150	$ 15.80	$ 15.65	$ (0.15)	-0.9%
63	N/A	175	$ 18.40	$ 18.23	$ (0.17)	-0.9%
64	N/A	200	$ 21.05	$ 20.87	$ (0.18)	-0.9%
65	N/A	225	$ 23.66	$ 23.46	$ (0.20)	-0.8%
66	N/A	250	$ 26.29	$ 26.05	$ (0.24)	-0.9%
67	N/A	275	$ 28.90	$ 28.65	$ (0.25)	-0.9%
68	N/A	300	$ 31.53	$ 31.25	$ (0.28)	-0.9%
69	N/A	325	$ 34.16	$ 33.86	$ (0.30)	-0.9%
70	N/A	350	$ 36.79	$ 36.46	$ (0.33)	-0.9%
71	N/A	375	$ 39.41	$ 39.06	$ (0.35)	-0.9%
72	N/A	400	$ 42.03	$ 41.65	$ (0.38)	-0.9%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Street Lighting Service (Rate STL)						
73	Customer Owned, Limited Company Maintenance - All Lamp Types					
74	N/A	25	$ 4.16	$ 4.14	$ (0.02)	-0.5%
75	N/A	50	$ 8.31	$ 8.27	$ (0.04)	-0.5%
76	N/A	75	$ 12.43	$ 12.37	$ (0.06)	-0.5%
77	N/A	100	$ 16.57	$ 16.47	$ (0.10)	-0.6%
78	N/A	125	$ 20.70	$ 20.58	$ (0.12)	-0.6%
79	N/A	150	$ 24.84	$ 24.69	$ (0.15)	-0.6%
80	N/A	175	$ 28.95	$ 28.78	$ (0.17)	-0.6%
81	N/A	200	$ 33.11	$ 32.93	$ (0.18)	-0.5%
82	N/A	225	$ 37.22	$ 37.02	$ (0.20)	-0.5%
83	N/A	250	$ 41.36	$ 41.12	$ (0.24)	-0.6%
84	N/A	275	$ 45.48	$ 45.23	$ (0.25)	-0.5%
85	N/A	300	$ 49.62	$ 49.34	$ (0.28)	-0.6%
86	N/A	325	$ 53.74	$ 53.44	$ (0.30)	-0.6%
87	N/A	350	$ 57.88	$ 57.55	$ (0.33)	-0.6%
88	N/A	375	$ 62.01	$ 61.66	$ (0.35)	-0.6%
89	N/A	400	$ 66.14	$ 65.76	$ (0.38)	-0.6%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Private Outdoor Lighting Service (Rate POL)					
1	Mercury Lighting					
2	Overhead Service - Wood Pole					
3	175	69	$ 13.56	$ 13.50	$ (0.06)	-0.4%
4	400	158	$ 27.00	$ 26.86	$ (0.14)	-0.5%
5	1,000	380	$ 51.70	$ 51.37	$ (0.33)	-0.6%
6	All Other Installations					
7	175	69	$ 15.90	$ 15.84	$ (0.06)	-0.4%
8	High Pressure Sodium Lighting					
9	Overhead Service - Wood Pole					
10	100	42	$ 15.99	$ 15.95	$ (0.04)	-0.3%
11	150	62	$ 19.66	$ 19.60	$ (0.06)	-0.3%
12	250	105	$ 24.17	$ 24.08	$ (0.09)	-0.4%
13	400	163	$ 32.27	$ 32.13	$ (0.14)	-0.4%
14	All Other Installations					
15	100	42	$ 19.07	$ 19.03	$ (0.04)	-0.2%
16	150	62	$ 25.06	$ 25.00	$ (0.06)	-0.2%
17	150*	88	$ 38.94	$ 38.86	$ (0.08)	-0.2%
18	250	105	$ 30.91	$ 30.82	$ (0.09)	-0.3%
19	250*	105	$ 42.65	$ 42.56	$ (0.09)	-0.2%
20	400	163	$ 36.59	$ 36.45	$ (0.14)	-0.4%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Traffic Lighting Schedule (Rate TRF)						
1	0	100	$ 5.76	$ 8.63	$ 2.87	49.9%
2	0	200	$ 11.36	$ 17.13	$ 5.77	50.8%
3	0	300	$ 16.93	$ 25.57	$ 8.64	51.0%
4	0	400	$ 22.52	$ 34.03	$ 11.51	51.1%
5	0	500	$ 28.12	$ 42.52	$ 14.40	51.2%
6	0	600	$ 33.72	$ 51.00	$ 17.28	51.2%

IEU Set 3-INT-3 Attachment 1

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - Standard (Rate RS)						
1	0	250	$ 36.45	$ 36.09	$ (0.36)	-1.0%
2	0	500	$ 68.74	$ 68.02	$ (0.71)	-1.0%
3	0	750	$ 101.02	$ 99.96	$ (1.07)	-1.1%
4	0	1,000	$ 133.31	$ 131.89	$ (1.42)	-1.1%
5	0	1,250	$ 165.60	$ 163.82	$ (1.78)	-1.1%
6	0	1,500	$ 197.89	$ 195.75	$ (2.14)	-1.1%
7	0	2,000	$ 262.47	$ 259.62	$ (2.85)	-1.1%
8	0	2,500	$ 326.81	$ 323.25	$ (3.56)	-1.1%
9	0	3,000	$ 391.16	$ 386.89	$ (4.27)	-1.1%
10	0	3,500	$ 455.51	$ 450.52	$ (4.98)	-1.1%
11	0	4,000	$ 519.86	$ 514.16	$ (5.70)	-1.1%
12	0	4,500	$ 584.20	$ 577.79	$ (6.41)	-1.1%
13	0	5,000	$ 648.55	$ 641.43	$ (7.12)	-1.1%
14	0	5,500	$ 712.90	$ 705.06	$ (7.83)	-1.1%
15	0	6,000	$ 777.24	$ 768.70	$ (8.54)	-1.1%
16	0	6,500	$ 841.59	$ 832.33	$ (9.26)	-1.1%
17	0	7,000	$ 905.94	$ 895.97	$ (9.97)	-1.1%
18	0	7,500	$ 970.28	$ 959.60	$ (10.68)	-1.1%
19	0	8,000	$ 1,034.63	$ 1,023.24	$ (11.39)	-1.1%
20	0	8,500	$ 1,098.98	$ 1,086.87	$ (12.10)	-1.1%
21	0	9,000	$ 1,163.32	$ 1,150.51	$ (12.82)	-1.1%
22	0	9,500	$ 1,227.67	$ 1,214.14	$ (13.53)	-1.1%
23	0	10,000	$ 1,292.02	$ 1,277.78	$ (14.24)	-1.1%
24	0	10,500	$ 1,356.36	$ 1,341.41	$ (14.95)	-1.1%
25	0	11,000	$ 1,420.71	$ 1,405.05	$ (15.66)	-1.1%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Electric Heating						
1	0	250	$ 35.36	$ 35.56	$ 0.20	0.6%
2	0	500	$ 66.57	$ 66.96	$ 0.39	0.6%
3	0	750	$ 91.02	$ 91.61	$ 0.59	0.6%
4	0	1,000	$ 115.48	$ 116.26	$ 0.78	0.7%
5	0	1,250	$ 139.94	$ 140.92	$ 0.98	0.7%
6	0	1,500	$ 164.39	$ 165.57	$ 1.18	0.7%
7	0	2,000	$ 213.30	$ 214.87	$ 1.57	0.7%
8	0	2,500	$ 261.98	$ 263.94	$ 1.96	0.7%
9	0	3,000	$ 310.66	$ 313.01	$ 2.35	0.8%
10	0	3,500	$ 359.34	$ 362.09	$ 2.75	0.8%
11	0	4,000	$ 408.02	$ 411.16	$ 3.14	0.8%
12	0	4,500	$ 456.70	$ 460.23	$ 3.53	0.8%
13	0	5,000	$ 505.38	$ 509.30	$ 3.92	0.8%
14	0	5,500	$ 554.06	$ 558.38	$ 4.31	0.8%
15	0	6,000	$ 602.74	$ 607.45	$ 4.71	0.8%
16	0	6,500	$ 651.42	$ 656.52	$ 5.10	0.8%
17	0	7,000	$ 700.10	$ 705.59	$ 5.49	0.8%
18	0	7,500	$ 748.78	$ 754.67	$ 5.88	0.8%
19	0	8,000	$ 797.46	$ 803.74	$ 6.28	0.8%
20	0	8,500	$ 846.14	$ 852.81	$ 6.67	0.8%
21	0	9,000	$ 894.82	$ 901.88	$ 7.06	0.8%
22	0	9,500	$ 943.50	$ 950.96	$ 7.45	0.8%
23	0	10,000	$ 992.18	$ 1,000.03	$ 7.84	0.8%
24	0	10,500	$ 1,040.86	$ 1,049.10	$ 8.24	0.8%
25	0	11,000	$ 1,089.55	$ 1,098.17	$ 8.63	0.8%

IEU Set 3-INT-3 Attachment 1

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Water Heating						
1	0	250	$ 36.45	$ 36.09	$ (0.36)	-1.0%
2	0	500	$ 68.74	$ 68.02	$ (0.71)	-1.0%
3	0	750	$ 96.90	$ 95.83	$ (1.07)	-1.1%
4	0	1,000	$ 125.06	$ 123.64	$ (1.42)	-1.1%
5	0	1,250	$ 153.23	$ 151.45	$ (1.78)	-1.2%
6	0	1,500	$ 181.39	$ 179.25	$ (2.14)	-1.2%
7	0	2,000	$ 237.72	$ 234.87	$ (2.85)	-1.2%
8	0	2,500	$ 293.81	$ 290.25	$ (3.56)	-1.2%
9	0	3,000	$ 349.91	$ 345.64	$ (4.27)	-1.2%
10	0	3,500	$ 406.01	$ 401.02	$ (4.98)	-1.2%
11	0	4,000	$ 462.11	$ 456.41	$ (5.70)	-1.2%
12	0	4,500	$ 518.20	$ 511.79	$ (6.41)	-1.2%
13	0	5,000	$ 574.30	$ 567.18	$ (7.12)	-1.2%
14	0	5,500	$ 630.40	$ 622.56	$ (7.83)	-1.2%
15	0	6,000	$ 686.49	$ 677.95	$ (8.54)	-1.2%
16	0	6,500	$ 742.59	$ 733.33	$ (9.26)	-1.2%
17	0	7,000	$ 798.69	$ 788.72	$ (9.97)	-1.2%
18	0	7,500	$ 854.78	$ 844.10	$ (10.68)	-1.2%
19	0	8,000	$ 910.88	$ 899.49	$ (11.39)	-1.3%
20	0	8,500	$ 966.98	$ 954.87	$ (12.10)	-1.3%
21	0	9,000	$ 1,023.07	$ 1,010.26	$ (12.82)	-1.3%
22	0	9,500	$ 1,079.17	$ 1,065.64	$ (13.53)	-1.3%
23	0	10,000	$ 1,135.27	$ 1,121.03	$ (14.24)	-1.3%
24	0	10,500	$ 1,191.36	$ 1,176.41	$ (14.95)	-1.3%
25	0	11,000	$ 1,247.46	$ 1,231.80	$ (15.66)	-1.3%

IEU Set 3-INT-3 Attachment 1

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Bill Data

Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Secondary (Rate GS)						
1	10	1,000	$ 207.03	$ 203.87	$ (3.16)	-1.5%
2	10	2,000	$ 292.29	$ 289.13	$ (3.16)	-1.1%
3	10	3,000	$ 377.13	$ 373.97	$ (3.16)	-0.8%
4	10	4,000	$ 461.97	$ 458.81	$ (3.16)	-0.7%
5	10	5,000	$ 546.82	$ 543.66	$ (3.16)	-0.6%
6	10	6,000	$ 631.60	$ 628.44	$ (3.16)	-0.5%
7	1,000	100,000	$ 22,182.46	$ 21,866.43	$ (316.03)	-1.4%
8	1,000	200,000	$ 30,608.73	$ 30,292.70	$ (316.03)	-1.0%
9	1,000	300,000	$ 39,035.00	$ 38,718.97	$ (316.03)	-0.8%
10	1,000	400,000	$ 47,461.26	$ 47,145.23	$ (316.03)	-0.7%
11	1,000	500,000	$ 55,887.52	$ 55,571.50	$ (316.03)	-0.6%
12	1,000	600,000	$ 64,313.79	$ 63,997.76	$ (316.03)	-0.5%

IEU Set 3-INT-3 Attachment 1

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

		Bill Data				
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Primary (Rate GP)						
1	500	50,000	$ 8,014.77	$ 7,663.99	$ (350.78)	-4.4%
2	500	100,000	$ 11,991.45	$ 11,640.67	$ (350.78)	-2.9%
3	500	150,000	$ 15,968.16	$ 15,617.38	$ (350.78)	-2.2%
4	500	200,000	$ 19,944.85	$ 19,594.07	$ (350.78)	-1.8%
5	500	250,000	$ 23,921.55	$ 23,570.76	$ (350.78)	-1.5%
6	500	300,000	$ 27,898.25	$ 27,547.46	$ (350.78)	-1.3%
7	5,000	500,000	$ 78,609.83	$ 75,101.99	$ (3,507.84)	-4.5%
8	5,000	1,000,000	$ 118,220.01	$ 114,712.17	$ (3,507.84)	-3.0%
9	5,000	1,500,000	$ 157,517.56	$ 154,009.72	$ (3,507.84)	-2.2%
10	5,000	2,000,000	$ 196,815.12	$ 193,307.28	$ (3,507.84)	-1.8%
11	5,000	2,500,000	$ 236,112.67	$ 232,604.83	$ (3,507.84)	-1.5%
12	5,000	3,000,000	$ 275,410.24	$ 271,902.40	$ (3,507.84)	-1.3%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Bill Data						
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Subtransmission (Rate GSU)						
1	1,000	100,000	$ 13,071.72	$ 12,424.79	$ (646.93)	-4.9%
2	1,000	200,000	$ 20,468.59	$ 19,821.65	$ (646.93)	-3.2%
3	1,000	300,000	$ 27,865.45	$ 27,218.52	$ (646.93)	-2.3%
4	1,000	400,000	$ 35,262.32	$ 34,615.39	$ (646.93)	-1.8%
5	1,000	500,000	$ 42,659.18	$ 42,012.25	$ (646.93)	-1.5%
6	1,000	600,000	$ 50,056.05	$ 49,409.12	$ (646.93)	-1.3%
7	10,000	1,000,000	$ 128,743.68	$ 122,274.36	$ (6,469.33)	-5.0%
8	10,000	2,000,000	$ 201,773.54	$ 195,304.22	$ (6,469.33)	-3.2%
9	10,000	3,000,000	$ 274,803.40	$ 268,334.08	$ (6,469.33)	-2.4%
10	10,000	4,000,000	$ 347,833.26	$ 341,363.94	$ (6,469.33)	-1.9%
11	10,000	5,000,000	$ 420,863.12	$ 414,393.79	$ (6,469.33)	-1.5%
12	10,000	6,000,000	$ 493,892.98	$ 487,423.65	$ (6,469.33)	-1.3%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

		Bill Data				
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Transmission (Rate GT)						
1	2,000	200,000	$ 32,484.43	$ 28,427.43	$ (4,057.00)	-12.5%
2	2,000	400,000	$ 43,218.71	$ 40,006.71	$ (3,212.00)	-7.4%
3	2,000	600,000	$ 53,952.99	$ 51,585.99	$ (2,367.00)	-4.4%
4	2,000	800,000	$ 64,687.27	$ 63,165.27	$ (1,522.00)	-2.4%
5	2,000	1,000,000	$ 75,264.77	$ 74,587.77	$ (677.00)	-0.9%
6	2,000	1,200,000	$ 85,811.30	$ 85,979.30	$ 168.00	0.2%
7	20,000	2,000,000	$ 320,784.58	$ 280,214.58	$ (40,570.00)	-12.6%
8	20,000	4,000,000	$ 426,249.80	$ 394,129.80	$ (32,120.00)	-7.5%
9	20,000	6,000,000	$ 531,715.02	$ 508,045.02	$ (23,670.00)	-4.5%
10	20,000	8,000,000	$ 637,180.24	$ 621,960.24	$ (15,220.00)	-2.4%
11	20,000	10,000,000	$ 742,645.46	$ 735,875.46	$ (6,770.00)	-0.9%
12	20,000	12,000,000	$ 848,110.68	$ 849,790.68	$ 1,680.00	0.2%

IEU Set 3-INT-3 Attachment 1
Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Bill Data: Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Street Lighting Service (Rate STL)						
1	Company Owned - Incandescent Lighting (a)					
2	Overhead Service					
3	1,000	24	$ 12.60	$ 12.60	$ -	0.0%
4	2,000	56	$ 14.76	$ 14.76	$ -	0.0%
5	2,500	70	$ 15.73	$ 15.73	$ -	0.0%
6	4,000	126	$ 19.56	$ 19.56	$ -	0.0%
7	6,000	157	$ 21.65	$ 21.65	$ -	0.0%
8	10,000	242	$ 27.44	$ 27.44	$ -	0.0%
9	15,000	282	$ 30.16	$ 30.16	$ -	0.0%
10	Underground Service					
11	1,000	24	$ 7.76	$ 7.76	$ -	0.0%
12	2,000	56	$ 9.92	$ 9.92	$ -	0.0%
13	2,500	70	$ 10.89	$ 10.89	$ -	0.0%
14	4,000	126	$ 14.72	$ 14.72	$ -	0.0%
15	6,000	157	$ 16.81	$ 16.81	$ -	0.0%
16	10,000	242	$ 22.60	$ 22.60	$ -	0.0%
17	15,000	282	$ 25.32	$ 25.32	$ -	0.0%
18	Company Owned - Mercury Street Lighting (b)					
19	Overhead Service - Wood Pole					
20	175	69	$ 12.12	$ 12.12	$ -	0.0%
21	250	104	$ 15.95	$ 15.95	$ -	0.0%
22	400	158	$ 22.17	$ 22.17	$ -	0.0%
23	1,000	380	$ 49.42	$ 49.42	$ -	0.0%
24	Underground Service - Post Type					
25	175	69	$ 16.47	$ 16.47	$ -	0.0%
26	Underground Service - Pole Type					
27	175	69	$ 23.03	$ 23.03	$ -	0.0%
28	250	104	$ 27.67	$ 27.67	$ -	0.0%
29	400	158	$ 34.11	$ 34.11	$ -	0.0%
30	400*	158	$ 34.36	$ 34.36	$ -	0.0%
31	400**	316	$ 54.40	$ 54.40	$ -	0.0%
32	1000	380	$ 63.25	$ 63.25	$ -	0.0%

IEU Set 3-INT-3 Attachment 1

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Street Lighting Service (Rate STL)						
33	Company Owned - High Pressure Sodium Lighting (c)					
34	Overhead Service - Wood Pole					
35	100	42	$ 13.18	$ 13.18	$ -	0.0%
36	150	62	$ 15.19	$ 15.19	$ -	0.0%
37	250	105	$ 20.40	$ 20.40	$ -	0.0%
38	400	163	$ 26.30	$ 26.30	$ -	0.0%
39	Underground Service - Post Type					
40	100	42	$ 17.70	$ 17.70	$ -	0.0%
41	Underground Service - Pole Type					
42	100	42	$ 24.64	$ 24.64	$ -	0.0%
43	150	62	$ 27.00	$ 27.00	$ -	0.0%
44	250	105	$ 32.05	$ 32.05	$ -	0.0%
45	250**	210	$ 51.77	$ 51.77	$ -	0.0%
46	400	163	$ 37.76	$ 37.76	$ -	0.0%
47	Special Architectural Pole Installations					
48	100	42	$ 23.17	$ 23.17	$ -	0.0%
49	100*	42	$ 35.20	$ 35.20	$ -	0.0%
50	150	62	$ 25.73	$ 25.73	$ -	0.0%
51	150*	62	$ 37.40	$ 37.40	$ -	0.0%
52	250	105	$ 31.63	$ 31.63	$ -	0.0%
53	250*	105	$ 43.46	$ 43.46	$ -	0.0%
54	400	163	$ 37.53	$ 37.53	$ -	0.0%
55	400*	163	$ 50.17	$ 50.17	$ -	0.0%
56	Customer Owned - All Lamp Types					
57	N/A	25	$ 2.64	$ 2.64	$ -	0.0%
58	N/A	50	$ 5.26	$ 5.26	$ -	0.0%
59	N/A	75	$ 7.85	$ 7.85	$ -	0.0%
60	N/A	100	$ 10.44	$ 10.44	$ -	0.0%
61	N/A	125	$ 13.05	$ 13.05	$ -	0.0%
62	N/A	150	$ 15.65	$ 15.65	$ -	0.0%
63	N/A	175	$ 18.23	$ 18.23	$ -	0.0%
64	N/A	200	$ 20.87	$ 20.87	$ -	0.0%
65	N/A	225	$ 23.46	$ 23.46	$ -	0.0%
66	N/A	250	$ 26.05	$ 26.05	$ -	0.0%
67	N/A	275	$ 28.65	$ 28.65	$ -	0.0%
68	N/A	300	$ 31.25	$ 31.25	$ -	0.0%
69	N/A	325	$ 33.86	$ 33.86	$ -	0.0%
70	N/A	350	$ 36.46	$ 36.46	$ -	0.0%
71	N/A	375	$ 39.06	$ 39.06	$ -	0.0%
72	N/A	400	$ 41.65	$ 41.65	$ -	0.0%

IEU Set 3-INT-3 Attachment 1

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Street Lighting Service (Rate STL)						
73	Customer Owned, Limited Company Maintenance - All Lamp Types					
74	N/A	25	$ 4.14	$ 4.14	$ -	0.0%
75	N/A	50	$ 8.27	$ 8.27	$ -	0.0%
76	N/A	75	$ 12.37	$ 12.37	$ -	0.0%
77	N/A	100	$ 16.47	$ 16.47	$ -	0.0%
78	N/A	125	$ 20.58	$ 20.58	$ -	0.0%
79	N/A	150	$ 24.69	$ 24.69	$ -	0.0%
80	N/A	175	$ 28.78	$ 28.78	$ -	0.0%
81	N/A	200	$ 32.93	$ 32.93	$ -	0.0%
82	N/A	225	$ 37.02	$ 37.02	$ -	0.0%
83	N/A	250	$ 41.12	$ 41.12	$ -	0.0%
84	N/A	275	$ 45.23	$ 45.23	$ -	0.0%
85	N/A	300	$ 49.34	$ 49.34	$ -	0.0%
86	N/A	325	$ 53.44	$ 53.44	$ -	0.0%
87	N/A	350	$ 57.55	$ 57.55	$ -	0.0%
88	N/A	375	$ 61.66	$ 61.66	$ -	0.0%
89	N/A	400	$ 65.76	$ 65.76	$ -	0.0%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Private Outdoor Lighting Service (Rate POL)					
1	Mercury Lighting					
2	Overhead Service - Wood Pole					
3	175	69	$ 13.50	$ 13.50	$ -	0.0%
4	400	158	$ 26.86	$ 26.86	$ -	0.0%
5	1,000	380	$ 51.37	$ 51.37	$ -	0.0%
6	All Other Installations					
7	175	69	$ 15.84	$ 15.84	$ -	0.0%
8	High Pressure Sodium Lighting					
9	Overhead Service - Wood Pole					
10	100	42	$ 15.95	$ 15.95	$ -	0.0%
11	150	62	$ 19.60	$ 19.60	$ -	0.0%
12	250	105	$ 24.08	$ 24.08	$ -	0.0%
13	400	163	$ 32.13	$ 32.13	$ -	0.0%
14	All Other Installations					
15	100	42	$ 19.03	$ 19.03	$ -	0.0%
16	150	62	$ 25.00	$ 25.00	$ -	0.0%
17	150*	88	$ 38.86	$ 38.86	$ -	0.0%
18	250	105	$ 30.82	$ 30.82	$ -	0.0%
19	250*	105	$ 42.56	$ 42.56	$ -	0.0%
20	400	163	$ 36.45	$ 36.45	$ -	0.0%

IEU Set 3-INT-3 Attachment 1
Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Traffic Lighting Schedule (Rate TRF)						
1	0	100	$ 8.63	$ 8.60	$ (0.03)	-0.3%
2	0	200	$ 17.13	$ 17.06	$ (0.07)	-0.4%
3	0	300	$ 25.57	$ 25.47	$ (0.10)	-0.4%
4	0	400	$ 34.03	$ 33.89	$ (0.14)	-0.4%
5	0	500	$ 42.52	$ 42.35	$ (0.17)	-0.4%
6	0	600	$ 51.00	$ 50.79	$ (0.21)	-0.4%

IEU Set 3-INT-3 Attachment 1

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - Standard (Rate RS)						
1	0	250	$ 36.09	$ 35.48	$ (0.61)	-1.7%
2	0	500	$ 68.02	$ 66.81	$ (1.21)	-1.8%
3	0	750	$ 99.96	$ 98.14	$ (1.82)	-1.8%
4	0	1,000	$ 131.89	$ 129.46	$ (2.43)	-1.8%
5	0	1,250	$ 163.82	$ 160.79	$ (3.03)	-1.9%
6	0	1,500	$ 195.75	$ 192.11	$ (3.64)	-1.9%
7	0	2,000	$ 259.62	$ 254.77	$ (4.85)	-1.9%
8	0	2,500	$ 323.25	$ 317.19	$ (6.07)	-1.9%
9	0	3,000	$ 386.89	$ 379.61	$ (7.28)	-1.9%
10	0	3,500	$ 450.52	$ 442.03	$ (8.49)	-1.9%
11	0	4,000	$ 514.16	$ 504.45	$ (9.71)	-1.9%
12	0	4,500	$ 577.79	$ 566.87	$ (10.92)	-1.9%
13	0	5,000	$ 641.43	$ 629.30	$ (12.13)	-1.9%
14	0	5,500	$ 705.06	$ 691.72	$ (13.35)	-1.9%
15	0	6,000	$ 768.70	$ 754.14	$ (14.56)	-1.9%
16	0	6,500	$ 832.33	$ 816.56	$ (15.77)	-1.9%
17	0	7,000	$ 895.97	$ 878.98	$ (16.99)	-1.9%
18	0	7,500	$ 959.60	$ 941.40	$ (18.20)	-1.9%
19	0	8,000	$ 1,023.24	$ 1,003.82	$ (19.41)	-1.9%
20	0	8,500	$ 1,086.87	$ 1,066.25	$ (20.63)	-1.9%
21	0	9,000	$ 1,150.51	$ 1,128.67	$ (21.84)	-1.9%
22	0	9,500	$ 1,214.14	$ 1,191.09	$ (23.05)	-1.9%
23	0	10,000	$ 1,277.78	$ 1,253.51	$ (24.27)	-1.9%
24	0	10,500	$ 1,341.41	$ 1,315.93	$ (25.48)	-1.9%
25	0	11,000	$ 1,405.05	$ 1,378.35	$ (26.69)	-1.9%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Electric Heating						
1	0	250	$ 35.56	$ 35.48	$ (0.08)	-0.2%
2	0	500	$ 66.96	$ 66.81	$ (0.15)	-0.2%
3	0	750	$ 91.61	$ 91.39	$ (0.23)	-0.2%
4	0	1,000	$ 116.26	$ 115.96	$ (0.30)	-0.3%
5	0	1,250	$ 140.92	$ 140.54	$ (0.38)	-0.3%
6	0	1,500	$ 165.57	$ 165.11	$ (0.45)	-0.3%
7	0	2,000	$ 214.87	$ 214.27	$ (0.60)	-0.3%
8	0	2,500	$ 263.94	$ 263.19	$ (0.75)	-0.3%
9	0	3,000	$ 313.01	$ 312.11	$ (0.91)	-0.3%
10	0	3,500	$ 362.09	$ 361.03	$ (1.06)	-0.3%
11	0	4,000	$ 411.16	$ 409.95	$ (1.21)	-0.3%
12	0	4,500	$ 460.23	$ 458.87	$ (1.36)	-0.3%
13	0	5,000	$ 509.30	$ 507.80	$ (1.51)	-0.3%
14	0	5,500	$ 558.38	$ 556.72	$ (1.66)	-0.3%
15	0	6,000	$ 607.45	$ 605.64	$ (1.81)	-0.3%
16	0	6,500	$ 656.52	$ 654.56	$ (1.96)	-0.3%
17	0	7,000	$ 705.59	$ 703.48	$ (2.11)	-0.3%
18	0	7,500	$ 754.67	$ 752.40	$ (2.26)	-0.3%
19	0	8,000	$ 803.74	$ 801.32	$ (2.41)	-0.3%
20	0	8,500	$ 852.81	$ 850.25	$ (2.57)	-0.3%
21	0	9,000	$ 901.88	$ 899.17	$ (2.72)	-0.3%
22	0	9,500	$ 950.96	$ 948.09	$ (2.87)	-0.3%
23	0	10,000	$ 1,000.03	$ 997.01	$ (3.02)	-0.3%
24	0	10,500	$ 1,049.10	$ 1,045.93	$ (3.17)	-0.3%
25	0	11,000	$ 1,098.17	$ 1,094.85	$ (3.32)	-0.3%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Water Heating						
1	0	250	$ 36.09	$ 35.48	$ (0.61)	-1.7%
2	0	500	$ 68.02	$ 66.81	$ (1.21)	-1.8%
3	0	750	$ 95.83	$ 94.01	$ (1.82)	-1.9%
4	0	1,000	$ 123.64	$ 121.21	$ (2.43)	-2.0%
5	0	1,250	$ 151.45	$ 148.41	$ (3.03)	-2.0%
6	0	1,500	$ 179.25	$ 175.61	$ (3.64)	-2.0%
7	0	2,000	$ 234.87	$ 230.02	$ (4.85)	-2.1%
8	0	2,500	$ 290.25	$ 284.19	$ (6.07)	-2.1%
9	0	3,000	$ 345.64	$ 338.36	$ (7.28)	-2.1%
10	0	3,500	$ 401.02	$ 392.53	$ (8.49)	-2.1%
11	0	4,000	$ 456.41	$ 446.70	$ (9.71)	-2.1%
12	0	4,500	$ 511.79	$ 500.87	$ (10.92)	-2.1%
13	0	5,000	$ 567.18	$ 555.05	$ (12.13)	-2.1%
14	0	5,500	$ 622.56	$ 609.22	$ (13.35)	-2.1%
15	0	6,000	$ 677.95	$ 663.39	$ (14.56)	-2.1%
16	0	6,500	$ 733.33	$ 717.56	$ (15.77)	-2.2%
17	0	7,000	$ 788.72	$ 771.73	$ (16.99)	-2.2%
18	0	7,500	$ 844.10	$ 825.90	$ (18.20)	-2.2%
19	0	8,000	$ 899.49	$ 880.07	$ (19.41)	-2.2%
20	0	8,500	$ 954.87	$ 934.25	$ (20.63)	-2.2%
21	0	9,000	$ 1,010.26	$ 988.42	$ (21.84)	-2.2%
22	0	9,500	$ 1,065.64	$ 1,042.59	$ (23.05)	-2.2%
23	0	10,000	$ 1,121.03	$ 1,096.76	$ (24.27)	-2.2%
24	0	10,500	$ 1,176.41	$ 1,150.93	$ (25.48)	-2.2%
25	0	11,000	$ 1,231.80	$ 1,205.10	$ (26.69)	-2.2%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

		Bill Data				
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Secondary (Rate GS)						
1	10	1,000	$ 203.87	$ 197.03	$ (6.84)	-3.4%
2	10	2,000	$ 289.13	$ 282.29	$ (6.84)	-2.4%
3	10	3,000	$ 373.97	$ 367.14	$ (6.84)	-1.8%
4	10	4,000	$ 458.81	$ 451.98	$ (6.84)	-1.5%
5	10	5,000	$ 543.66	$ 536.82	$ (6.84)	-1.3%
6	10	6,000	$ 628.44	$ 621.60	$ (6.84)	-1.1%
7	1,000	100,000	$ 21,866.43	$ 21,182.62	$ (683.81)	-3.1%
8	1,000	200,000	$ 30,292.70	$ 29,608.89	$ (683.81)	-2.3%
9	1,000	300,000	$ 38,718.97	$ 38,035.16	$ (683.81)	-1.8%
10	1,000	400,000	$ 47,145.23	$ 46,461.42	$ (683.81)	-1.5%
11	1,000	500,000	$ 55,571.50	$ 54,887.68	$ (683.81)	-1.2%
12	1,000	600,000	$ 63,997.76	$ 63,313.95	$ (683.81)	-1.1%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Primary (Rate GP)						
1	500	50,000	$ 7,663.99	$ 7,086.24	$ (577.75)	-7.5%
2	500	100,000	$ 11,640.67	$ 11,062.92	$ (577.75)	-5.0%
3	500	150,000	$ 15,617.38	$ 15,039.63	$ (577.75)	-3.7%
4	500	200,000	$ 19,594.07	$ 19,016.33	$ (577.75)	-2.9%
5	500	250,000	$ 23,570.76	$ 22,993.02	$ (577.75)	-2.5%
6	500	300,000	$ 27,547.46	$ 26,969.72	$ (577.75)	-2.1%
7	5,000	500,000	$ 75,101.99	$ 69,324.54	$ (5,777.46)	-7.7%
8	5,000	1,000,000	$ 114,712.17	$ 108,934.72	$ (5,777.46)	-5.0%
9	5,000	1,500,000	$ 154,009.72	$ 148,232.27	$ (5,777.46)	-3.8%
10	5,000	2,000,000	$ 193,307.28	$ 187,529.82	$ (5,777.46)	-3.0%
11	5,000	2,500,000	$ 232,604.83	$ 226,827.37	$ (5,777.46)	-2.5%
12	5,000	3,000,000	$ 271,902.40	$ 266,124.94	$ (5,777.46)	-2.1%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Subtransmission (Rate GSU)						
1	1,000	100,000	$ 12,424.79	$ 11,376.53	$ (1,048.26)	-8.4%
2	1,000	200,000	$ 19,821.65	$ 18,773.39	$ (1,048.26)	-5.3%
3	1,000	300,000	$ 27,218.52	$ 26,170.26	$ (1,048.26)	-3.9%
4	1,000	400,000	$ 34,615.39	$ 33,567.12	$ (1,048.26)	-3.0%
5	1,000	500,000	$ 42,012.25	$ 40,963.99	$ (1,048.26)	-2.5%
6	1,000	600,000	$ 49,409.12	$ 48,360.86	$ (1,048.26)	-2.1%
7	10,000	1,000,000	$ 122,274.36	$ 111,791.74	$ (10,482.62)	-8.6%
8	10,000	2,000,000	$ 195,304.22	$ 184,821.60	$ (10,482.62)	-5.4%
9	10,000	3,000,000	$ 268,334.08	$ 257,851.46	$ (10,482.62)	-3.9%
10	10,000	4,000,000	$ 341,363.94	$ 330,881.32	$ (10,482.62)	-3.1%
11	10,000	5,000,000	$ 414,393.79	$ 403,911.18	$ (10,482.62)	-2.5%
12	10,000	6,000,000	$ 487,423.65	$ 476,941.04	$ (10,482.62)	-2.2%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Bill Data						
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Transmission (Rate GT)						
1	2,000	200,000	$ 28,427.43	$ 23,928.83	$ (4,498.60)	-15.8%
2	2,000	400,000	$ 40,006.71	$ 36,398.31	$ (3,608.40)	-9.0%
3	2,000	600,000	$ 51,585.99	$ 48,867.79	$ (2,718.20)	-5.3%
4	2,000	800,000	$ 63,165.27	$ 61,337.27	$ (1,828.00)	-2.9%
5	2,000	1,000,000	$ 74,587.77	$ 73,649.97	$ (937.80)	-1.3%
6	2,000	1,200,000	$ 85,979.30	$ 85,931.70	$ (47.60)	-0.1%
7	20,000	2,000,000	$ 280,214.58	$ 235,228.58	$ (44,986.00)	-16.1%
8	20,000	4,000,000	$ 394,129.80	$ 358,045.80	$ (36,084.00)	-9.2%
9	20,000	6,000,000	$ 508,045.02	$ 480,863.02	$ (27,182.00)	-5.4%
10	20,000	8,000,000	$ 621,960.24	$ 603,680.24	$ (18,280.00)	-2.9%
11	20,000	10,000,000	$ 735,875.46	$ 726,497.46	$ (9,378.00)	-1.3%
12	20,000	12,000,000	$ 849,790.68	$ 849,314.68	$ (476.00)	-0.1%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Street Lighting Service (Rate STL)					
1	Company Owned - Incandescent Lighting (a)					
2	Overhead Service					
3	1,000	24	$ 12.60	$ 12.60	$ -	0.0%
4	2,000	56	$ 14.76	$ 14.76	$ -	0.0%
5	2,500	70	$ 15.73	$ 15.73	$ -	0.0%
6	4,000	126	$ 19.56	$ 19.56	$ -	0.0%
7	6,000	157	$ 21.65	$ 21.65	$ -	0.0%
8	10,000	242	$ 27.44	$ 27.44	$ -	0.0%
9	15,000	282	$ 30.16	$ 30.16	$ -	0.0%
10	Underground Service					
11	1,000	24	$ 7.76	$ 7.76	$ -	0.0%
12	2,000	56	$ 9.92	$ 9.92	$ -	0.0%
13	2,500	70	$ 10.89	$ 10.89	$ -	0.0%
14	4,000	126	$ 14.72	$ 14.72	$ -	0.0%
15	6,000	157	$ 16.81	$ 16.81	$ -	0.0%
16	10,000	242	$ 22.60	$ 22.60	$ -	0.0%
17	15,000	282	$ 25.32	$ 25.32	$ -	0.0%
18	Company Owned - Mercury Street Lighting (b)					
19	Overhead Service - Wood Pole					
20	175	69	$ 12.12	$ 12.12	$ -	0.0%
21	250	104	$ 15.95	$ 15.95	$ -	0.0%
22	400	158	$ 22.17	$ 22.17	$ -	0.0%
23	1,000	380	$ 49.42	$ 49.42	$ -	0.0%
24	Underground Service - Post Type					
25	175	69	$ 16.47	$ 16.47	$ -	0.0%
26	Underground Service - Pole Type					
27	175	69	$ 23.03	$ 23.03	$ -	0.0%
28	250	104	$ 27.67	$ 27.67	$ -	0.0%
29	400	158	$ 34.11	$ 34.11	$ -	0.0%
30	400*	158	$ 34.36	$ 34.36	$ -	0.0%
31	400**	316	$ 54.40	$ 54.40	$ -	0.0%
32	1000	380	$ 63.25	$ 63.25	$ -	0.0%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Street Lighting Service (Rate STL)					
33	Company Owned - High Pressure Sodium Lighting (c)					
34	Overhead Service - Wood Pole					
35	100	42	$ 13.18	$ 13.18	$ -	0.0%
36	150	62	$ 15.19	$ 15.19	$ -	0.0%
37	250	105	$ 20.40	$ 20.40	$ -	0.0%
38	400	163	$ 26.30	$ 26.30	$ -	0.0%
39	Underground Service - Post Type					
40	100	42	$ 17.70	$ 17.70	$ -	0.0%
41	Underground Service - Pole Type					
42	100	42	$ 24.64	$ 24.64	$ -	0.0%
43	150	62	$ 27.00	$ 27.00	$ -	0.0%
44	250	105	$ 32.05	$ 32.05	$ -	0.0%
45	250**	210	$ 51.77	$ 51.77	$ -	0.0%
46	400	163	$ 37.76	$ 37.76	$ -	0.0%
47	Special Architectural Pole Installations					
48	100	42	$ 23.17	$ 23.17	$ -	0.0%
49	100*	42	$ 35.20	$ 35.20	$ -	0.0%
50	150	62	$ 25.73	$ 25.73	$ -	0.0%
51	150*	62	$ 37.40	$ 37.40	$ -	0.0%
52	250	105	$ 31.63	$ 31.63	$ -	0.0%
53	250*	105	$ 43.46	$ 43.46	$ -	0.0%
54	400	163	$ 37.53	$ 37.53	$ -	0.0%
55	400*	163	$ 50.17	$ 50.17	$ -	0.0%
56	Customer Owned - All Lamp Types					
57	N/A	25	$ 2.64	$ 2.64	$ -	0.0%
58	N/A	50	$ 5.26	$ 5.26	$ -	0.0%
59	N/A	75	$ 7.85	$ 7.85	$ -	0.0%
60	N/A	100	$ 10.44	$ 10.44	$ -	0.0%
61	N/A	125	$ 13.05	$ 13.05	$ -	0.0%
62	N/A	150	$ 15.65	$ 15.65	$ -	0.0%
63	N/A	175	$ 18.23	$ 18.23	$ -	0.0%
64	N/A	200	$ 20.87	$ 20.87	$ -	0.0%
65	N/A	225	$ 23.46	$ 23.46	$ -	0.0%
66	N/A	250	$ 26.05	$ 26.05	$ -	0.0%
67	N/A	275	$ 28.65	$ 28.65	$ -	0.0%
68	N/A	300	$ 31.25	$ 31.25	$ -	0.0%
69	N/A	325	$ 33.86	$ 33.86	$ -	0.0%
70	N/A	350	$ 36.46	$ 36.46	$ -	0.0%
71	N/A	375	$ 39.06	$ 39.06	$ -	0.0%
72	N/A	400	$ 41.65	$ 41.65	$ -	0.0%

IEU Set 3-INT-3 Attachment 1
Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Street Lighting Service (Rate STL)					
73	Customer Owned, Limited Company Maintenance - All Lamp Types					
74	N/A	25	$ 4.14	$ 4.14	$ -	0.0%
75	N/A	50	$ 8.27	$ 8.27	$ -	0.0%
76	N/A	75	$ 12.37	$ 12.37	$ -	0.0%
77	N/A	100	$ 16.47	$ 16.47	$ -	0.0%
78	N/A	125	$ 20.58	$ 20.58	$ -	0.0%
79	N/A	150	$ 24.69	$ 24.69	$ -	0.0%
80	N/A	175	$ 28.78	$ 28.78	$ -	0.0%
81	N/A	200	$ 32.93	$ 32.93	$ -	0.0%
82	N/A	225	$ 37.02	$ 37.02	$ -	0.0%
83	N/A	250	$ 41.12	$ 41.12	$ -	0.0%
84	N/A	275	$ 45.23	$ 45.23	$ -	0.0%
85	N/A	300	$ 49.34	$ 49.34	$ -	0.0%
86	N/A	325	$ 53.44	$ 53.44	$ -	0.0%
87	N/A	350	$ 57.55	$ 57.55	$ -	0.0%
88	N/A	375	$ 61.66	$ 61.66	$ -	0.0%
89	N/A	400	$ 65.76	$ 65.76	$ -	0.0%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Private Outdoor Lighting Service (Rate POL)					
1	Mercury Lighting					
2	Overhead Service - Wood Pole					
3	175	69	$ 13.50	$ 13.50	$ -	0.0%
4	400	158	$ 26.86	$ 26.86	$ -	0.0%
5	1,000	380	$ 51.37	$ 51.37	$ -	0.0%
6	All Other Installations					
7	175	69	$ 15.84	$ 15.84	$ -	0.0%
8	High Pressure Sodium Lighting					
9	Overhead Service - Wood Pole					
10	100	42	$ 15.95	$ 15.95	$ -	0.0%
11	150	62	$ 19.60	$ 19.60	$ -	0.0%
12	250	105	$ 24.08	$ 24.08	$ -	0.0%
13	400	163	$ 32.13	$ 32.13	$ -	0.0%
14	All Other Installations					
15	100	42	$ 19.03	$ 19.03	$ -	0.0%
16	150	62	$ 25.00	$ 25.00	$ -	0.0%
17	150*	88	$ 38.86	$ 38.86	$ -	0.0%
18	250	105	$ 30.82	$ 30.82	$ -	0.0%
19	250*	105	$ 42.56	$ 42.56	$ -	0.0%
20	400	163	$ 36.45	$ 36.45	$ -	0.0%

The Cleveland Electric Illuminating Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Traffic Lighting Schedule (Rate TRF)						
1	0	100	$ 8.60	$ 8.55	$ (0.05)	-0.6%
2	0	200	$ 17.06	$ 16.95	$ (0.11)	-0.6%
3	0	300	$ 25.47	$ 25.31	$ (0.16)	-0.6%
4	0	400	$ 33.89	$ 33.68	$ (0.21)	-0.6%
5	0	500	$ 42.35	$ 42.09	$ (0.26)	-0.6%
6	0	600	$ 50.79	$ 50.47	$ (0.32)	-0.6%

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - Standard (Rate RS)						
1	0	250	$ 35.37	$ 36.30	$ 0.92	2.6%
2	0	500	$ 66.59	$ 68.43	$ 1.84	2.8%
3	0	750	$ 97.81	$ 100.57	$ 2.77	2.8%
4	0	1,000	$ 129.02	$ 132.71	$ 3.69	2.9%
5	0	1,250	$ 160.24	$ 164.85	$ 4.61	2.9%
6	0	1,500	$ 191.45	$ 196.98	$ 5.53	2.9%
7	0	2,000	$ 253.89	$ 261.26	$ 7.37	2.9%
8	0	2,500	$ 316.09	$ 325.30	$ 9.22	2.9%
9	0	3,000	$ 378.29	$ 389.35	$ 11.06	2.9%
10	0	3,500	$ 440.49	$ 453.39	$ 12.90	2.9%
11	0	4,000	$ 502.69	$ 517.44	$ 14.75	2.9%
12	0	4,500	$ 564.89	$ 581.48	$ 16.59	2.9%
13	0	5,000	$ 627.09	$ 645.53	$ 18.43	2.9%
14	0	5,500	$ 689.30	$ 709.57	$ 20.28	2.9%
15	0	6,000	$ 751.50	$ 773.62	$ 22.12	2.9%
16	0	6,500	$ 813.70	$ 837.66	$ 23.96	2.9%
17	0	7,000	$ 875.90	$ 901.71	$ 25.81	2.9%
18	0	7,500	$ 938.10	$ 965.75	$ 27.65	2.9%
19	0	8,000	$ 1,000.30	$ 1,029.80	$ 29.49	2.9%
20	0	8,500	$ 1,062.50	$ 1,093.84	$ 31.34	2.9%
21	0	9,000	$ 1,124.71	$ 1,157.89	$ 33.18	3.0%
22	0	9,500	$ 1,186.91	$ 1,221.93	$ 35.02	3.0%
23	0	10,000	$ 1,249.11	$ 1,285.98	$ 36.87	3.0%
24	0	10,500	$ 1,311.31	$ 1,350.02	$ 38.71	3.0%
25	0	11,000	$ 1,373.51	$ 1,414.07	$ 40.55	3.0%

IEU Set 3-INT-3 Attachment 2

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Electric Heating						
1	0	250	$ 35.37	$ 36.30	$ 0.92	2.6%
2	0	500	$ 66.59	$ 68.43	$ 1.84	2.8%
3	0	750	$ 90.92	$ 93.69	$ 2.77	3.0%
4	0	1,000	$ 115.26	$ 118.95	$ 3.69	3.2%
5	0	1,250	$ 139.59	$ 144.20	$ 4.61	3.3%
6	0	1,500	$ 161.91	$ 168.12	$ 6.21	3.8%
7	0	2,000	$ 206.54	$ 215.94	$ 9.40	4.6%
8	0	2,500	$ 250.93	$ 263.54	$ 12.60	5.0%
9	0	3,000	$ 295.33	$ 311.13	$ 15.80	5.3%
10	0	3,500	$ 339.73	$ 358.73	$ 19.00	5.6%
11	0	4,000	$ 384.13	$ 406.32	$ 22.19	5.8%
12	0	4,500	$ 428.52	$ 453.91	$ 25.39	5.9%
13	0	5,000	$ 472.92	$ 501.51	$ 28.59	6.0%
14	0	5,500	$ 517.32	$ 549.10	$ 31.79	6.1%
15	0	6,000	$ 561.71	$ 596.70	$ 34.98	6.2%
16	0	6,500	$ 606.11	$ 644.29	$ 38.18	6.3%
17	0	7,000	$ 650.51	$ 691.89	$ 41.38	6.4%
18	0	7,500	$ 694.91	$ 739.48	$ 44.58	6.4%
19	0	8,000	$ 739.30	$ 787.08	$ 47.77	6.5%
20	0	8,500	$ 783.70	$ 834.67	$ 50.97	6.5%
21	0	9,000	$ 828.10	$ 882.27	$ 54.17	6.5%
22	0	9,500	$ 872.50	$ 929.86	$ 57.37	6.6%
23	0	10,000	$ 916.89	$ 977.46	$ 60.57	6.6%
24	0	10,500	$ 961.29	$ 1,025.05	$ 63.76	6.6%
25	0	11,000	$ 1,005.69	$ 1,072.65	$ 66.96	6.7%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Water Heating						
1	0	250	$ 35.37	$ 36.30	$ 0.92	2.6%
2	0	500	$ 66.59	$ 68.43	$ 1.84	2.8%
3	0	750	$ 94.49	$ 97.25	$ 2.77	2.9%
4	0	1,000	$ 122.38	$ 126.07	$ 3.69	3.0%
5	0	1,250	$ 150.28	$ 154.89	$ 4.61	3.1%
6	0	1,500	$ 178.18	$ 183.71	$ 5.53	3.1%
7	0	2,000	$ 233.97	$ 241.35	$ 7.37	3.2%
8	0	2,500	$ 289.54	$ 298.75	$ 9.22	3.2%
9	0	3,000	$ 345.10	$ 356.16	$ 11.06	3.2%
10	0	3,500	$ 400.67	$ 413.57	$ 12.90	3.2%
11	0	4,000	$ 456.23	$ 470.98	$ 14.75	3.2%
12	0	4,500	$ 511.79	$ 528.38	$ 16.59	3.2%
13	0	5,000	$ 567.36	$ 585.79	$ 18.43	3.2%
14	0	5,500	$ 622.92	$ 643.20	$ 20.28	3.3%
15	0	6,000	$ 678.49	$ 700.61	$ 22.12	3.3%
16	0	6,500	$ 734.05	$ 758.01	$ 23.96	3.3%
17	0	7,000	$ 789.61	$ 815.42	$ 25.81	3.3%
18	0	7,500	$ 845.18	$ 872.83	$ 27.65	3.3%
19	0	8,000	$ 900.74	$ 930.23	$ 29.49	3.3%
20	0	8,500	$ 956.30	$ 987.64	$ 31.34	3.3%
21	0	9,000	$ 1,011.87	$ 1,045.05	$ 33.18	3.3%
22	0	9,500	$ 1,067.43	$ 1,102.46	$ 35.02	3.3%
23	0	10,000	$ 1,123.00	$ 1,159.86	$ 36.87	3.3%
24	0	10,500	$ 1,178.56	$ 1,217.27	$ 38.71	3.3%
25	0	11,000	$ 1,234.12	$ 1,274.68	$ 40.55	3.3%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Secondary (Rate GS)						
1	10	1,000	$ 163.41	$ 181.06	$ 17.65	10.8%
2	10	2,000	$ 248.50	$ 265.49	$ 16.99	6.8%
3	10	3,000	$ 333.17	$ 349.47	$ 16.30	4.9%
4	10	4,000	$ 417.81	$ 433.45	$ 15.64	3.7%
5	10	5,000	$ 502.48	$ 517.44	$ 14.96	3.0%
6	10	6,000	$ 587.13	$ 601.40	$ 14.27	2.4%
7	1,000	100,000	$ 16,908.76	$ 18,674.52	$ 1,765.76	10.4%
8	1,000	200,000	$ 25,317.86	$ 27,016.08	$ 1,698.22	6.7%
9	1,000	300,000	$ 33,726.96	$ 35,357.65	$ 1,630.69	4.8%
10	1,000	400,000	$ 42,136.06	$ 43,699.20	$ 1,563.14	3.7%
11	1,000	500,000	$ 50,545.16	$ 52,040.76	$ 1,495.60	3.0%
12	1,000	600,000	$ 58,954.26	$ 60,382.32	$ 1,428.06	2.4%

IEU Set 3-INT-3 Attachment 2
Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Primary (Rate GP)						
1	500	50,000	$ 6,640.74	$ 7,691.32	$ 1,050.58	15.8%
2	500	100,000	$ 10,534.99	$ 11,562.25	$ 1,027.26	9.8%
3	500	150,000	$ 14,429.27	$ 15,433.21	$ 1,003.94	7.0%
4	500	200,000	$ 18,323.52	$ 19,304.14	$ 980.62	5.4%
5	500	250,000	$ 22,217.79	$ 23,175.09	$ 957.30	4.3%
6	500	300,000	$ 26,112.05	$ 27,046.04	$ 933.99	3.6%
7	5,000	500,000	$ 64,869.50	$ 75,375.30	$ 10,505.80	16.2%
8	5,000	1,000,000	$ 103,722.25	$ 113,994.86	$ 10,272.61	9.9%
9	5,000	1,500,000	$ 142,395.78	$ 152,435.19	$ 10,039.41	7.1%
10	5,000	2,000,000	$ 181,069.31	$ 190,875.52	$ 9,806.21	5.4%
11	5,000	2,500,000	$ 219,742.84	$ 229,315.85	$ 9,573.01	4.4%
12	5,000	3,000,000	$ 258,416.38	$ 267,756.19	$ 9,339.81	3.6%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Bill Data

Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Subtransmission (Rate GSU)						
1	1,000	100,000	$ 10,474.96	$ 12,089.52	$ 1,614.56	15.4%
2	1,000	200,000	$ 17,871.86	$ 19,405.38	$ 1,533.52	8.6%
3	1,000	300,000	$ 25,268.76	$ 26,721.25	$ 1,452.48	5.7%
4	1,000	400,000	$ 32,665.67	$ 34,037.11	$ 1,371.44	4.2%
5	1,000	500,000	$ 40,062.57	$ 41,352.97	$ 1,290.40	3.2%
6	1,000	600,000	$ 47,459.47	$ 48,668.83	$ 1,209.36	2.5%
7	10,000	1,000,000	$ 102,662.99	$ 118,808.60	$ 16,145.60	15.7%
8	10,000	2,000,000	$ 176,093.81	$ 191,429.01	$ 15,335.21	8.7%
9	10,000	3,000,000	$ 249,524.62	$ 264,049.43	$ 14,524.81	5.8%
10	10,000	4,000,000	$ 322,955.43	$ 336,669.85	$ 13,714.41	4.2%
11	10,000	5,000,000	$ 396,386.24	$ 409,290.26	$ 12,904.02	3.3%
12	10,000	6,000,000	$ 469,817.06	$ 481,910.68	$ 12,093.62	2.6%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

	Bill Data					
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Transmission (Rate GT)						
1	2,000	200,000	$ 30,868.50	$ 33,679.22	$ 2,810.72	9.1%
2	2,000	400,000	$ 41,777.85	$ 44,434.29	$ 2,656.44	6.4%
3	2,000	600,000	$ 52,687.20	$ 55,189.36	$ 2,502.16	4.7%
4	2,000	800,000	$ 63,596.55	$ 65,944.44	$ 2,347.88	3.7%
5	2,000	1,000,000	$ 74,416.03	$ 76,609.63	$ 2,193.60	2.9%
6	2,000	1,200,000	$ 85,217.74	$ 87,257.06	$ 2,039.32	2.4%
7	20,000	2,000,000	$ 305,092.79	$ 333,200.00	$ 28,107.21	9.2%
8	20,000	4,000,000	$ 413,109.92	$ 439,674.33	$ 26,564.41	6.4%
9	20,000	6,000,000	$ 521,127.04	$ 546,148.66	$ 25,021.62	4.8%
10	20,000	8,000,000	$ 629,144.17	$ 652,622.99	$ 23,478.83	3.7%
11	20,000	10,000,000	$ 737,161.29	$ 759,097.33	$ 21,936.03	3.0%
12	20,000	12,000,000	$ 845,178.42	$ 865,571.66	$ 20,393.24	2.4%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Street Lighting Service (Rate STL)					
1	Company Owned - Incandescent Lighting (a)					
2	1,000	24	$ 18.26	$ 18.33	$ 0.07	0.4%
3	2,000	56	$ 20.31	$ 20.46	$ 0.15	0.7%
4	2,500	70	$ 21.20	$ 21.39	$ 0.19	0.9%
5	4,000	126	$ 24.78	$ 25.13	$ 0.35	1.4%
6	6,000	157	$ 26.76	$ 27.18	$ 0.42	1.6%
7	10,000	242	$ 32.18	$ 32.85	$ 0.67	2.1%
8	15,000	282	$ 34.75	$ 35.52	$ 0.77	2.2%
9	Company Owned - Mercury Street Lighting (b)					
10	Overhead Service - Wood Pole					
11	100	43	$ 8.61	$ 8.72	$ 0.11	1.3%
12	175	69	$ 9.50	$ 9.69	$ 0.19	2.0%
13	250	104	$ 11.94	$ 12.23	$ 0.29	2.4%
14	400	158	$ 15.37	$ 15.80	$ 0.43	2.8%
15	700	287	$ 24.09	$ 24.87	$ 0.78	3.2%
16	1,000	380	$ 29.67	$ 30.72	$ 1.05	3.5%
17	Overhead Service - Metal Pole					
18	100	43	$ 16.43	$ 16.54	$ 0.11	0.7%
19	175	69	$ 17.38	$ 17.57	$ 0.19	1.1%
20	250	104	$ 20.76	$ 21.05	$ 0.29	1.4%
21	250**	208	$ 30.47	$ 31.03	$ 0.56	1.8%
22	400	158	$ 23.61	$ 24.04	$ 0.43	1.8%
23	400**	316	$ 37.02	$ 37.89	$ 0.87	2.3%
24	700	287	$ 33.85	$ 34.63	$ 0.78	2.3%
25	1000	380	$ 39.55	$ 40.60	$ 1.05	2.7%
26	1000**	760	$ 69.97	$ 72.06	$ 2.09	3.0%
27	Underground Service - Post Type					
28	100	43	$ 11.45	$ 11.56	$ 0.11	1.0%
29	175	69	$ 12.87	$ 13.06	$ 0.19	1.5%
30	250	104	$ 16.36	$ 16.65	$ 0.29	1.8%
31	Underground Service - Pole Type					
32	100	43	$ 18.83	$ 18.94	$ 0.11	0.6%
33	175	69	$ 20.08	$ 20.27	$ 0.19	0.9%
34	250	104	$ 25.16	$ 25.45	$ 0.29	1.2%
35	400	158	$ 28.90	$ 29.33	$ 0.43	1.5%
36	700	287	$ 55.79	$ 56.57	$ 0.78	1.4%
37	1000	380	$ 61.20	$ 62.25	$ 1.05	1.7%
38	1000**	760	$ 89.93	$ 92.02	$ 2.09	2.3%
39	Bridge or Underpass Wallpack					
40	175	69	$ 11.93	$ 12.12	$ 0.19	1.6%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Bill Data Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Street Lighting Service (Rate STL)						
41	250	104	$ 14.60	$ 14.89	$ 0.29	2.0%
42	Company Owned - High Pressure Sodium Lighting (c)					
43	Overhead Service - Wood Pole					
44	70	29	$ 8.28	$ 8.36	$ 0.08	1.0%
45	100	42	$ 8.77	$ 8.88	$ 0.11	1.3%
46	150	62	$ 9.67	$ 9.84	$ 0.17	1.8%
47	215	89	$ 11.61	$ 11.86	$ 0.25	2.2%
48	250	105	$ 12.26	$ 12.55	$ 0.29	2.4%
49	400	163	$ 15.92	$ 16.37	$ 0.45	2.8%
50	1000	410	$ 34.02	$ 35.16	$ 1.14	3.4%
51	Overhead Service - Metal Pole					
52	70	29	$ 16.07	$ 16.15	$ 0.08	0.5%
53	100	42	$ 16.60	$ 16.71	$ 0.11	0.7%
54	150	62	$ 18.54	$ 18.71	$ 0.17	0.9%
55	215	89	$ 20.40	$ 20.65	$ 0.25	1.2%
56	250	105	$ 21.06	$ 21.35	$ 0.29	1.4%
57	400	163	$ 25.73	$ 26.18	$ 0.45	1.7%
58	1000	410	$ 42.99	$ 44.13	$ 1.14	2.7%
59	Underground Service - Post Type					
60	70	29	$ 11.38	$ 11.46	$ 0.08	0.7%
61	100	42	$ 12.21	$ 12.32	$ 0.11	0.9%
62	150	62	$ 13.76	$ 13.93	$ 0.17	1.2%
63	Underground Service - Pole Type					
64	70	29	$ 18.37	$ 18.45	$ 0.08	0.4%
65	100	42	$ 19.19	$ 19.30	$ 0.11	0.6%
66	150	62	$ 22.96	$ 23.13	$ 0.17	0.7%
67	200	88	$ 25.33	$ 25.57	$ 0.24	0.9%
68	215	89	$ 23.00	$ 23.25	$ 0.25	1.1%
69	250	105	$ 26.20	$ 26.49	$ 0.29	1.1%
70	310	128	$ 28.60	$ 28.96	$ 0.36	1.3%
71	400	163	$ 47.60	$ 48.05	$ 0.45	0.9%
72	400**	326	$ 62.31	$ 63.22	$ 0.91	1.5%
73	1000	410	$ 66.78	$ 67.92	$ 1.14	1.7%
74	Bridge or Underpass Wallpack					
75	70	29	$ 11.94	$ 12.02	$ 0.08	0.7%
76	100	42	$ 13.46	$ 13.57	$ 0.11	0.8%
77	150	62	$ 14.51	$ 14.68	$ 0.17	1.2%
78	215	89	$ 14.91	$ 15.16	$ 0.25	1.7%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
			Bill Data			
Street Lighting Service (Rate STL)						
79	250	105	$ 17.68	$ 17.97	$ 0.29	1.6%
80	Customer Owned - All Lamp Types					
81	N/A	25	$ 1.71	$ 1.78	$ 0.07	4.1%
82	N/A	50	$ 3.38	$ 3.53	$ 0.15	4.4%
83	N/A	75	$ 5.07	$ 5.28	$ 0.21	4.1%
84	N/A	100	$ 6.76	$ 7.03	$ 0.27	4.0%
85	N/A	125	$ 8.42	$ 8.77	$ 0.35	4.2%
86	N/A	150	$ 10.11	$ 10.53	$ 0.42	4.2%
87	N/A	175	$ 11.79	$ 12.27	$ 0.48	4.1%
88	N/A	200	$ 13.47	$ 14.03	$ 0.56	4.2%
89	N/A	225	$ 15.16	$ 15.78	$ 0.62	4.1%
90	N/A	250	$ 16.84	$ 17.52	$ 0.68	4.0%
91	N/A	275	$ 18.51	$ 19.27	$ 0.76	4.1%
92	N/A	300	$ 20.19	$ 21.01	$ 0.82	4.1%
93	N/A	325	$ 21.86	$ 22.74	$ 0.88	4.0%
94	N/A	350	$ 23.52	$ 24.48	$ 0.96	4.1%
95	N/A	375	$ 25.21	$ 26.23	$ 1.02	4.0%
96	N/A	400	$ 26.88	$ 27.97	$ 1.09	4.1%
97	Customer Owned, Limited Company Maintenance - All Lamp Types					
98	N/A	25	$ 2.33	$ 2.40	$ 0.07	3.0%
99	N/A	50	$ 4.61	$ 4.76	$ 0.15	3.3%
100	N/A	75	$ 6.92	$ 7.13	$ 0.21	3.0%
101	N/A	100	$ 9.23	$ 9.50	$ 0.27	2.9%
102	N/A	125	$ 11.51	$ 11.86	$ 0.35	3.0%
103	N/A	150	$ 13.81	$ 14.23	$ 0.42	3.0%
104	N/A	175	$ 16.10	$ 16.58	$ 0.48	3.0%
105	N/A	200	$ 18.40	$ 18.96	$ 0.56	3.0%
106	N/A	225	$ 20.71	$ 21.33	$ 0.62	3.0%
107	N/A	250	$ 23.00	$ 23.68	$ 0.68	3.0%
108	N/A	275	$ 25.29	$ 26.05	$ 0.76	3.0%
109	N/A	300	$ 27.59	$ 28.41	$ 0.82	3.0%
110	N/A	325	$ 29.88	$ 30.76	$ 0.88	2.9%
111	N/A	350	$ 32.15	$ 33.11	$ 0.96	3.0%
112	N/A	375	$ 34.46	$ 35.48	$ 1.02	3.0%
113	N/A	400	$ 36.75	$ 37.84	$ 1.09	3.0%
114	Efficiency Safety Incentive Program - All Lamp Types					
115	N/A	25	$ 3.10	$ 3.17	$ 0.07	2.3%
116	N/A	50	$ 6.15	$ 6.30	$ 0.15	2.4%
117	N/A	75	$ 9.23	$ 9.44	$ 0.21	2.3%
118	N/A	100	$ 12.31	$ 12.58	$ 0.27	2.2%
119	N/A	125	$ 15.35	$ 15.70	$ 0.35	2.3%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
			Bill Data			
Street Lighting Service (Rate STL)						
120	N/A	150	$ 18.43	$ 18.85	$ 0.42	2.3%
121	N/A	175	$ 21.49	$ 21.97	$ 0.48	2.2%
122	N/A	200	$ 24.55	$ 25.11	$ 0.56	2.3%
123	N/A	225	$ 27.63	$ 28.25	$ 0.62	2.2%
124	N/A	250	$ 30.70	$ 31.38	$ 0.68	2.2%
125	N/A	275	$ 33.75	$ 34.51	$ 0.76	2.3%
126	N/A	300	$ 36.82	$ 37.64	$ 0.82	2.2%
127	N/A	325	$ 39.87	$ 40.75	$ 0.88	2.2%
128	N/A	350	$ 42.92	$ 43.88	$ 0.96	2.2%
129	N/A	375	$ 46.00	$ 47.02	$ 1.02	2.2%
130	N/A	400	$ 49.05	$ 50.14	$ 1.09	2.2%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Private Outdoor Lighting Service (Rate POL)					
1	Mercury Lighting					
2	Overhead Service - Wood Pole					
3	175	69	$ 9.59	$ 11.30	$ 1.71	17.9%
4	400	158	$ 15.14	$ 19.08	$ 3.93	26.0%
5	1,000	380	$ 25.69	$ 35.16	$ 9.47	36.8%
6	All Other Installations					
7	175	69	$ 13.99	$ 15.70	$ 1.71	12.2%
8	High Pressure Sodium Lighting					
9	Overhead Service - Wood Pole					
10	100	42	$ 9.69	$ 10.72	$ 1.04	10.7%
11	250	105	$ 14.74	$ 17.34	$ 2.61	17.7%
12	400	163	$ 17.92	$ 21.99	$ 4.07	22.7%
13	All Other Installations					
14	100	42	$ 14.72	$ 15.75	$ 1.04	7.1%
15	Metal Halide Lighting					
16	Overhead Service - Wood Pole					
17	15,000	73	$ 14.46	$ 16.28	$ 1.83	12.6%
18	23,000	111	$ 16.09	$ 18.85	$ 2.76	17.2%
19	40,000	172	$ 18.64	$ 22.92	$ 4.28	22.9%
20	All Other Installations					
21	15,000	73	$ 24.24	$ 26.06	$ 1.83	7.5%
22	23,000	111	$ 25.87	$ 28.63	$ 2.76	10.7%
23	40,000	172	$ 28.42	$ 32.70	$ 4.28	15.0%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Traffic Lighting Schedule (Rate TRF)						
1	0	100	$ 8.03	$ 9.81	$ 1.79	22.3%
2	0	200	$ 15.80	$ 19.42	$ 3.61	22.9%
3	0	300	$ 23.66	$ 29.06	$ 5.40	22.8%
4	0	400	$ 31.47	$ 38.66	$ 7.19	22.8%
5	0	500	$ 39.31	$ 48.31	$ 9.01	22.9%
6	0	600	$ 47.12	$ 57.93	$ 10.80	22.9%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - Standard (Rate RS)						
1	0	250	$ 36.30	$ 35.97	$ (0.32)	-0.9%
2	0	500	$ 68.43	$ 67.79	$ (0.65)	-0.9%
3	0	750	$ 100.57	$ 99.60	$ (0.97)	-1.0%
4	0	1,000	$ 132.71	$ 131.41	$ (1.29)	-1.0%
5	0	1,250	$ 164.85	$ 163.23	$ (1.62)	-1.0%
6	0	1,500	$ 196.98	$ 195.04	$ (1.94)	-1.0%
7	0	2,000	$ 261.26	$ 258.67	$ (2.59)	-1.0%
8	0	2,500	$ 325.30	$ 322.07	$ (3.24)	-1.0%
9	0	3,000	$ 389.35	$ 385.47	$ (3.88)	-1.0%
10	0	3,500	$ 453.39	$ 448.86	$ (4.53)	-1.0%
11	0	4,000	$ 517.44	$ 512.26	$ (5.18)	-1.0%
12	0	4,500	$ 581.48	$ 575.66	$ (5.82)	-1.0%
13	0	5,000	$ 645.53	$ 639.06	$ (6.47)	-1.0%
14	0	5,500	$ 709.57	$ 702.45	$ (7.12)	-1.0%
15	0	6,000	$ 773.62	$ 765.85	$ (7.77)	-1.0%
16	0	6,500	$ 837.66	$ 829.25	$ (8.41)	-1.0%
17	0	7,000	$ 901.71	$ 892.65	$ (9.06)	-1.0%
18	0	7,500	$ 965.75	$ 956.05	$ (9.71)	-1.0%
19	0	8,000	$ 1,029.80	$ 1,019.44	$ (10.35)	-1.0%
20	0	8,500	$ 1,093.84	$ 1,082.84	$ (11.00)	-1.0%
21	0	9,000	$ 1,157.89	$ 1,146.24	$ (11.65)	-1.0%
22	0	9,500	$ 1,221.93	$ 1,209.64	$ (12.29)	-1.0%
23	0	10,000	$ 1,285.98	$ 1,273.03	$ (12.94)	-1.0%
24	0	10,500	$ 1,350.02	$ 1,336.43	$ (13.59)	-1.0%
25	0	11,000	$ 1,414.07	$ 1,399.83	$ (14.24)	-1.0%

IEU Set 3-INT-3 Attachment 2

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Electric Heating						
1	0	250	$ 36.30	$ 35.97	$ (0.32)	-0.9%
2	0	500	$ 68.43	$ 67.79	$ (0.65)	-0.9%
3	0	750	$ 93.69	$ 92.72	$ (0.97)	-1.0%
4	0	1,000	$ 118.95	$ 117.65	$ (1.29)	-1.1%
5	0	1,250	$ 144.20	$ 142.58	$ (1.62)	-1.1%
6	0	1,500	$ 168.12	$ 166.85	$ (1.26)	-0.8%
7	0	2,000	$ 215.94	$ 215.38	$ (0.56)	-0.3%
8	0	2,500	$ 263.54	$ 263.69	$ 0.15	0.1%
9	0	3,000	$ 311.13	$ 311.99	$ 0.86	0.3%
10	0	3,500	$ 358.73	$ 360.29	$ 1.56	0.4%
11	0	4,000	$ 406.32	$ 408.59	$ 2.27	0.6%
12	0	4,500	$ 453.91	$ 456.89	$ 2.98	0.7%
13	0	5,000	$ 501.51	$ 505.19	$ 3.69	0.7%
14	0	5,500	$ 549.10	$ 553.50	$ 4.39	0.8%
15	0	6,000	$ 596.70	$ 601.80	$ 5.10	0.9%
16	0	6,500	$ 644.29	$ 650.10	$ 5.81	0.9%
17	0	7,000	$ 691.89	$ 698.40	$ 6.51	0.9%
18	0	7,500	$ 739.48	$ 746.70	$ 7.22	1.0%
19	0	8,000	$ 787.08	$ 795.01	$ 7.93	1.0%
20	0	8,500	$ 834.67	$ 843.31	$ 8.63	1.0%
21	0	9,000	$ 882.27	$ 891.61	$ 9.34	1.1%
22	0	9,500	$ 929.86	$ 939.91	$ 10.05	1.1%
23	0	10,000	$ 977.46	$ 988.21	$ 10.76	1.1%
24	0	10,500	$ 1,025.05	$ 1,036.52	$ 11.46	1.1%
25	0	11,000	$ 1,072.65	$ 1,084.82	$ 12.17	1.1%

IEU Set 3-INT-3 Attachment 2

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Water Heating						
1	0	250	$ 36.30	$ 35.97	$ (0.32)	-0.9%
2	0	500	$ 68.43	$ 67.79	$ (0.65)	-0.9%
3	0	750	$ 97.25	$ 96.28	$ (0.97)	-1.0%
4	0	1,000	$ 126.07	$ 124.78	$ (1.29)	-1.0%
5	0	1,250	$ 154.89	$ 153.27	$ (1.62)	-1.0%
6	0	1,500	$ 183.71	$ 181.77	$ (1.94)	-1.1%
7	0	2,000	$ 241.35	$ 238.76	$ (2.59)	-1.1%
8	0	2,500	$ 298.75	$ 295.52	$ (3.24)	-1.1%
9	0	3,000	$ 356.16	$ 352.28	$ (3.88)	-1.1%
10	0	3,500	$ 413.57	$ 409.04	$ (4.53)	-1.1%
11	0	4,000	$ 470.98	$ 465.80	$ (5.18)	-1.1%
12	0	4,500	$ 528.38	$ 522.56	$ (5.82)	-1.1%
13	0	5,000	$ 585.79	$ 579.32	$ (6.47)	-1.1%
14	0	5,500	$ 643.20	$ 636.08	$ (7.12)	-1.1%
15	0	6,000	$ 700.61	$ 692.84	$ (7.77)	-1.1%
16	0	6,500	$ 758.01	$ 749.60	$ (8.41)	-1.1%
17	0	7,000	$ 815.42	$ 806.36	$ (9.06)	-1.1%
18	0	7,500	$ 872.83	$ 863.12	$ (9.71)	-1.1%
19	0	8,000	$ 930.23	$ 919.88	$ (10.35)	-1.1%
20	0	8,500	$ 987.64	$ 976.64	$ (11.00)	-1.1%
21	0	9,000	$ 1,045.05	$ 1,033.40	$ (11.65)	-1.1%
22	0	9,500	$ 1,102.46	$ 1,090.16	$ (12.29)	-1.1%
23	0	10,000	$ 1,159.86	$ 1,146.92	$ (12.94)	-1.1%
24	0	10,500	$ 1,217.27	$ 1,203.68	$ (13.59)	-1.1%
25	0	11,000	$ 1,274.68	$ 1,260.44	$ (14.24)	-1.1%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Secondary (Rate GS)						
1	10	1,000	$ 181.06	$ 178.43	$ (2.63)	-1.5%
2	10	2,000	$ 265.49	$ 262.86	$ (2.63)	-1.0%
3	10	3,000	$ 349.47	$ 346.84	$ (2.63)	-0.8%
4	10	4,000	$ 433.45	$ 430.82	$ (2.63)	-0.6%
5	10	5,000	$ 517.44	$ 514.81	$ (2.63)	-0.5%
6	10	6,000	$ 601.40	$ 598.77	$ (2.63)	-0.4%
7	1,000	100,000	$ 18,674.52	$ 18,411.62	$ (262.90)	-1.4%
8	1,000	200,000	$ 27,016.08	$ 26,753.18	$ (262.90)	-1.0%
9	1,000	300,000	$ 35,357.65	$ 35,094.75	$ (262.90)	-0.7%
10	1,000	400,000	$ 43,699.20	$ 43,436.30	$ (262.90)	-0.6%
11	1,000	500,000	$ 52,040.76	$ 51,777.86	$ (262.90)	-0.5%
12	1,000	600,000	$ 60,382.32	$ 60,119.42	$ (262.90)	-0.4%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

		Bill Data				
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Primary (Rate GP)						
1	500	50,000	$ 7,691.32	$ 7,422.82	$ (268.50)	-3.5%
2	500	100,000	$ 11,562.25	$ 11,293.75	$ (268.50)	-2.3%
3	500	150,000	$ 15,433.21	$ 15,164.71	$ (268.50)	-1.7%
4	500	200,000	$ 19,304.14	$ 19,035.64	$ (268.50)	-1.4%
5	500	250,000	$ 23,175.09	$ 22,906.59	$ (268.50)	-1.2%
6	500	300,000	$ 27,046.04	$ 26,777.54	$ (268.50)	-1.0%
7	5,000	500,000	$ 75,375.30	$ 72,690.30	$ (2,685.00)	-3.6%
8	5,000	1,000,000	$ 113,994.86	$ 111,309.86	$ (2,685.00)	-2.4%
9	5,000	1,500,000	$ 152,435.19	$ 149,750.19	$ (2,685.00)	-1.8%
10	5,000	2,000,000	$ 190,875.52	$ 188,190.52	$ (2,685.00)	-1.4%
11	5,000	2,500,000	$ 229,315.85	$ 226,630.85	$ (2,685.00)	-1.2%
12	5,000	3,000,000	$ 267,756.19	$ 265,071.19	$ (2,685.00)	-1.0%

IEU Set 3-INT-3 Attachment 2

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Subtransmission (Rate GSU)						
1	1,000	100,000	$ 12,089.52	$ 11,570.32	$ (519.20)	-4.3%
2	1,000	200,000	$ 19,405.38	$ 18,886.18	$ (519.20)	-2.7%
3	1,000	300,000	$ 26,721.25	$ 26,202.05	$ (519.20)	-1.9%
4	1,000	400,000	$ 34,037.11	$ 33,517.91	$ (519.20)	-1.5%
5	1,000	500,000	$ 41,352.97	$ 40,833.77	$ (519.20)	-1.3%
6	1,000	600,000	$ 48,668.83	$ 48,149.63	$ (519.20)	-1.1%
7	10,000	1,000,000	$ 118,808.60	$ 113,616.60	$ (5,192.00)	-4.4%
8	10,000	2,000,000	$ 191,429.01	$ 186,237.01	$ (5,192.00)	-2.7%
9	10,000	3,000,000	$ 264,049.43	$ 258,857.43	$ (5,192.00)	-2.0%
10	10,000	4,000,000	$ 336,669.85	$ 331,477.85	$ (5,192.00)	-1.5%
11	10,000	5,000,000	$ 409,290.26	$ 404,098.26	$ (5,192.00)	-1.3%
12	10,000	6,000,000	$ 481,910.68	$ 476,718.68	$ (5,192.00)	-1.1%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

	Bill Data					
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Transmission (Rate GT)						
1	2,000	200,000	$ 33,679.22	$ 29,429.62	$ (4,249.60)	-12.6%
2	2,000	400,000	$ 44,434.29	$ 41,029.69	$ (3,404.60)	-7.7%
3	2,000	600,000	$ 55,189.36	$ 52,629.76	$ (2,559.60)	-4.6%
4	2,000	800,000	$ 65,944.44	$ 64,229.84	$ (1,714.60)	-2.6%
5	2,000	1,000,000	$ 76,609.63	$ 75,740.03	$ (869.60)	-1.1%
6	2,000	1,200,000	$ 87,257.06	$ 87,232.46	$ (24.60)	0.0%
7	20,000	2,000,000	$ 333,200.00	$ 290,704.00	$ (42,496.00)	-12.8%
8	20,000	4,000,000	$ 439,674.33	$ 405,628.33	$ (34,046.00)	-7.7%
9	20,000	6,000,000	$ 546,148.66	$ 520,552.66	$ (25,596.00)	-4.7%
10	20,000	8,000,000	$ 652,622.99	$ 635,476.99	$ (17,146.00)	-2.6%
11	20,000	10,000,000	$ 759,097.33	$ 750,401.33	$ (8,696.00)	-1.1%
12	20,000	12,000,000	$ 865,571.66	$ 865,325.66	$ (246.00)	0.0%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Street Lighting Service (Rate STL)					
1	Company Owned - Incandescent Lighting (a)					
2	1,000	24	$ 18.33	$ 18.33	$ -	0.0%
3	2,000	56	$ 20.46	$ 20.46	$ -	0.0%
4	2,500	70	$ 21.39	$ 21.39	$ -	0.0%
5	4,000	126	$ 25.13	$ 25.13	$ -	0.0%
6	6,000	157	$ 27.18	$ 27.18	$ -	0.0%
7	10,000	242	$ 32.85	$ 32.85	$ -	0.0%
8	15,000	282	$ 35.52	$ 35.52	$ -	0.0%
9	Company Owned - Mercury Street Lighting (b)					
10	Overhead Service - Wood Pole					
11	100	43	$ 8.72	$ 8.72	$ -	0.0%
12	175	69	$ 9.69	$ 9.69	$ -	0.0%
13	250	104	$ 12.23	$ 12.23	$ -	0.0%
14	400	158	$ 15.80	$ 15.80	$ -	0.0%
15	700	287	$ 24.87	$ 24.87	$ -	0.0%
16	1,000	380	$ 30.72	$ 30.72	$ -	0.0%
17	Overhead Service - Metal Pole					
18	100	43	$ 16.54	$ 16.54	$ -	0.0%
19	175	69	$ 17.57	$ 17.57	$ -	0.0%
20	250	104	$ 21.05	$ 21.05	$ -	0.0%
21	250**	208	$ 31.03	$ 31.03	$ -	0.0%
22	400	158	$ 24.04	$ 24.04	$ -	0.0%
23	400**	316	$ 37.89	$ 37.89	$ -	0.0%
24	700	287	$ 34.63	$ 34.63	$ -	0.0%
25	1000	380	$ 40.60	$ 40.60	$ -	0.0%
26	1000**	760	$ 72.06	$ 72.06	$ -	0.0%
27	Underground Service - Post Type					
28	100	43	$ 11.56	$ 11.56	$ -	0.0%
29	175	69	$ 13.06	$ 13.06	$ -	0.0%
30	250	104	$ 16.65	$ 16.65	$ -	0.0%
31	Underground Service - Pole Type					
32	100	43	$ 18.94	$ 18.94	$ -	0.0%
33	175	69	$ 20.27	$ 20.27	$ -	0.0%
34	250	104	$ 25.45	$ 25.45	$ -	0.0%
35	400	158	$ 29.33	$ 29.33	$ -	0.0%
36	700	287	$ 56.57	$ 56.57	$ -	0.0%
37	1000	380	$ 62.25	$ 62.25	$ -	0.0%
38	1000**	760	$ 92.02	$ 92.02	$ -	0.0%
39	Bridge or Underpass Wallpack					
40	175	69	$ 12.12	$ 12.12	$ -	0.0%
41	250	104	$ 14.89	$ 14.89	$ -	0.0%

IEU Set 3-INT-3 Attachment 2

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

		Bill Data				
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Street Lighting Service (Rate STL)					
42	Company Owned - High Pressure Sodium Lighting (c)					
43	Overhead Service - Wood Pole					
44	70	29	$ 8.36	$ 8.36	$ -	0.0%
45	100	42	$ 8.88	$ 8.88	$ -	0.0%
46	150	62	$ 9.84	$ 9.84	$ -	0.0%
47	215	89	$ 11.86	$ 11.86	$ -	0.0%
48	250	105	$ 12.55	$ 12.55	$ -	0.0%
49	400	163	$ 16.37	$ 16.37	$ -	0.0%
50	1000	410	$ 35.16	$ 35.16	$ -	0.0%
51	Overhead Service - Metal Pole					
52	70	29	$ 16.15	$ 16.15	$ -	0.0%
53	100	42	$ 16.71	$ 16.71	$ -	0.0%
54	150	62	$ 18.71	$ 18.71	$ -	0.0%
55	215	89	$ 20.65	$ 20.65	$ -	0.0%
56	250	105	$ 21.35	$ 21.35	$ -	0.0%
57	400	163	$ 26.18	$ 26.18	$ -	0.0%
58	1000	410	$ 44.13	$ 44.13	$ -	0.0%
59	Underground Service - Post Type					
60	70	29	$ 11.46	$ 11.46	$ -	0.0%
61	100	42	$ 12.32	$ 12.32	$ -	0.0%
62	150	62	$ 13.93	$ 13.93	$ -	0.0%
63	Underground Service - Pole Type					
64	70	29	$ 18.45	$ 18.45	$ -	0.0%
65	100	42	$ 19.30	$ 19.30	$ -	0.0%
66	150	62	$ 23.13	$ 23.13	$ -	0.0%
67	200	88	$ 25.57	$ 25.57	$ -	0.0%
68	215	89	$ 23.25	$ 23.25	$ -	0.0%
69	250	105	$ 26.49	$ 26.49	$ -	0.0%
70	310	128	$ 28.96	$ 28.96	$ -	0.0%
71	400	163	$ 48.05	$ 48.05	$ -	0.0%
72	400**	326	$ 63.22	$ 63.22	$ -	0.0%
73	1000	410	$ 67.92	$ 67.92	$ -	0.0%
74	Bridge or Underpass Wallpack					
75	70	29	$ 12.02	$ 12.02	$ -	0.0%
76	100	42	$ 13.57	$ 13.57	$ -	0.0%
77	150	62	$ 14.68	$ 14.68	$ -	0.0%
78	215	89	$ 15.16	$ 15.16	$ -	0.0%
79	250	105	$ 17.97	$ 17.97	$ -	0.0%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Street Lighting Service (Rate STL)						
80	Customer Owned - All Lamp Types					
81	N/A	25	$ 1.78	$ 1.78	$ -	0.0%
82	N/A	50	$ 3.53	$ 3.53	$ -	0.0%
83	N/A	75	$ 5.28	$ 5.28	$ -	0.0%
84	N/A	100	$ 7.03	$ 7.03	$ -	0.0%
85	N/A	125	$ 8.77	$ 8.77	$ -	0.0%
86	N/A	150	$ 10.53	$ 10.53	$ -	0.0%
87	N/A	175	$ 12.27	$ 12.27	$ -	0.0%
88	N/A	200	$ 14.03	$ 14.03	$ -	0.0%
89	N/A	225	$ 15.78	$ 15.78	$ -	0.0%
90	N/A	250	$ 17.52	$ 17.52	$ -	0.0%
91	N/A	275	$ 19.27	$ 19.27	$ -	0.0%
92	N/A	300	$ 21.01	$ 21.01	$ -	0.0%
93	N/A	325	$ 22.74	$ 22.74	$ -	0.0%
94	N/A	350	$ 24.48	$ 24.48	$ -	0.0%
95	N/A	375	$ 26.23	$ 26.23	$ -	0.0%
96	N/A	400	$ 27.97	$ 27.97	$ -	0.0%
97	Customer Owned, Limited Company Maintenance - All Lamp Types					
98	N/A	25	$ 2.40	$ 2.40	$ -	0.0%
99	N/A	50	$ 4.76	$ 4.76	$ -	0.0%
100	N/A	75	$ 7.13	$ 7.13	$ -	0.0%
101	N/A	100	$ 9.50	$ 9.50	$ -	0.0%
102	N/A	125	$ 11.86	$ 11.86	$ -	0.0%
103	N/A	150	$ 14.23	$ 14.23	$ -	0.0%
104	N/A	175	$ 16.58	$ 16.58	$ -	0.0%
105	N/A	200	$ 18.96	$ 18.96	$ -	0.0%
106	N/A	225	$ 21.33	$ 21.33	$ -	0.0%
107	N/A	250	$ 23.68	$ 23.68	$ -	0.0%
108	N/A	275	$ 26.05	$ 26.05	$ -	0.0%
109	N/A	300	$ 28.41	$ 28.41	$ -	0.0%
110	N/A	325	$ 30.76	$ 30.76	$ -	0.0%
111	N/A	350	$ 33.11	$ 33.11	$ -	0.0%
112	N/A	375	$ 35.48	$ 35.48	$ -	0.0%
113	N/A	400	$ 37.84	$ 37.84	$ -	0.0%
114	Efficiency Safety Incentive Program - All Lamp Types					
115	N/A	25	$ 3.17	$ 3.17	$ -	0.0%
116	N/A	50	$ 6.30	$ 6.30	$ -	0.0%
117	N/A	75	$ 9.44	$ 9.44	$ -	0.0%
118	N/A	100	$ 12.58	$ 12.58	$ -	0.0%
119	N/A	125	$ 15.70	$ 15.70	$ -	0.0%
120	N/A	150	$ 18.85	$ 18.85	$ -	0.0%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Street Lighting Service (Rate STL)						
121	N/A	175	$ 21.97	$ 21.97	$ -	0.0%
122	N/A	200	$ 25.11	$ 25.11	$ -	0.0%
123	N/A	225	$ 28.25	$ 28.25	$ -	0.0%
124	N/A	250	$ 31.38	$ 31.38	$ -	0.0%
125	N/A	275	$ 34.51	$ 34.51	$ -	0.0%
126	N/A	300	$ 37.64	$ 37.64	$ -	0.0%
127	N/A	325	$ 40.75	$ 40.75	$ -	0.0%
128	N/A	350	$ 43.88	$ 43.88	$ -	0.0%
129	N/A	375	$ 47.02	$ 47.02	$ -	0.0%
130	N/A	400	$ 50.14	$ 50.14	$ -	0.0%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Private Outdoor Lighting Service (Rate POL)					
1	Mercury Lighting					
2	Overhead Service - Wood Pole					
3	175	69	$ 11.30	$ 11.30	$ -	0.0%
4	400	158	$ 19.08	$ 19.08	$ -	0.0%
5	1,000	380	$ 35.16	$ 35.16	$ -	0.0%
6	All Other Installations					
7	175	69	$ 15.70	$ 15.70	$ -	0.0%
8	High Pressure Sodium Lighting					
9	Overhead Service - Wood Pole					
10	100	42	$ 10.72	$ 10.72	$ -	0.0%
11	250	105	$ 17.34	$ 17.34	$ -	0.0%
12	400	163	$ 21.99	$ 21.99	$ -	0.0%
13	All Other Installations					
14	100	42	$ 15.75	$ 15.75	$ -	0.0%
15	Metal Halide Lighting					
16	Overhead Service - Wood Pole					
17	15,000	73	$ 16.28	$ 16.28	$ -	0.0%
18	23,000	111	$ 18.85	$ 18.85	$ -	0.0%
19	40,000	172	$ 22.92	$ 22.92	$ -	0.0%
20	All Other Installations					
21	15,000	73	$ 26.06	$ 26.06	$ -	0.0%
22	23,000	111	$ 28.63	$ 28.63	$ -	0.0%
23	40,000	172	$ 32.70	$ 32.70	$ -	0.0%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

		Bill Data				
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Traffic Lighting Schedule (Rate TRF)						
1	0	100	$ 9.81	$ 9.68	$ (0.13)	-1.4%
2	0	200	$ 19.42	$ 19.15	$ (0.27)	-1.4%
3	0	300	$ 29.06	$ 28.67	$ (0.40)	-1.4%
4	0	400	$ 38.66	$ 38.13	$ (0.53)	-1.4%
5	0	500	$ 48.31	$ 47.65	$ (0.66)	-1.4%
6	0	600	$ 57.93	$ 57.13	$ (0.80)	-1.4%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - Standard (Rate RS)						
1	0	250	$ 35.97	$ 35.44	$ (0.53)	-1.5%
2	0	500	$ 67.79	$ 66.73	$ (1.06)	-1.6%
3	0	750	$ 99.60	$ 98.01	$ (1.59)	-1.6%
4	0	1,000	$ 131.41	$ 129.30	$ (2.11)	-1.6%
5	0	1,250	$ 163.23	$ 160.59	$ (2.64)	-1.6%
6	0	1,500	$ 195.04	$ 191.87	$ (3.17)	-1.6%
7	0	2,000	$ 258.67	$ 254.44	$ (4.23)	-1.6%
8	0	2,500	$ 322.07	$ 316.78	$ (5.29)	-1.6%
9	0	3,000	$ 385.47	$ 379.12	$ (6.34)	-1.6%
10	0	3,500	$ 448.86	$ 441.46	$ (7.40)	-1.6%
11	0	4,000	$ 512.26	$ 503.80	$ (8.46)	-1.7%
12	0	4,500	$ 575.66	$ 566.14	$ (9.51)	-1.7%
13	0	5,000	$ 639.06	$ 628.49	$ (10.57)	-1.7%
14	0	5,500	$ 702.45	$ 690.83	$ (11.63)	-1.7%
15	0	6,000	$ 765.85	$ 753.17	$ (12.69)	-1.7%
16	0	6,500	$ 829.25	$ 815.51	$ (13.74)	-1.7%
17	0	7,000	$ 892.65	$ 877.85	$ (14.80)	-1.7%
18	0	7,500	$ 956.05	$ 940.19	$ (15.86)	-1.7%
19	0	8,000	$ 1,019.44	$ 1,002.53	$ (16.92)	-1.7%
20	0	8,500	$ 1,082.84	$ 1,064.87	$ (17.97)	-1.7%
21	0	9,000	$ 1,146.24	$ 1,127.21	$ (19.03)	-1.7%
22	0	9,500	$ 1,209.64	$ 1,189.55	$ (20.09)	-1.7%
23	0	10,000	$ 1,273.03	$ 1,251.89	$ (21.14)	-1.7%
24	0	10,500	$ 1,336.43	$ 1,314.23	$ (22.20)	-1.7%
25	0	11,000	$ 1,399.83	$ 1,376.57	$ (23.26)	-1.7%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Electric Heating						
1	0	250	$ 35.97	$ 35.44	$ (0.53)	-1.5%
2	0	500	$ 67.79	$ 66.73	$ (1.06)	-1.6%
3	0	750	$ 92.72	$ 91.13	$ (1.59)	-1.7%
4	0	1,000	$ 117.65	$ 115.54	$ (2.11)	-1.8%
5	0	1,250	$ 142.58	$ 139.94	$ (2.64)	-1.9%
6	0	1,500	$ 166.85	$ 164.35	$ (2.50)	-1.5%
7	0	2,000	$ 215.38	$ 213.15	$ (2.23)	-1.0%
8	0	2,500	$ 263.69	$ 261.73	$ (1.95)	-0.7%
9	0	3,000	$ 311.99	$ 310.31	$ (1.68)	-0.5%
10	0	3,500	$ 360.29	$ 358.89	$ (1.40)	-0.4%
11	0	4,000	$ 408.59	$ 407.47	$ (1.12)	-0.3%
12	0	4,500	$ 456.89	$ 456.04	$ (0.85)	-0.2%
13	0	5,000	$ 505.19	$ 504.62	$ (0.57)	-0.1%
14	0	5,500	$ 553.50	$ 553.20	$ (0.30)	-0.1%
15	0	6,000	$ 601.80	$ 601.78	$ (0.02)	0.0%
16	0	6,500	$ 650.10	$ 650.36	$ 0.26	0.0%
17	0	7,000	$ 698.40	$ 698.93	$ 0.53	0.1%
18	0	7,500	$ 746.70	$ 747.51	$ 0.81	0.1%
19	0	8,000	$ 795.01	$ 796.09	$ 1.08	0.1%
20	0	8,500	$ 843.31	$ 844.67	$ 1.36	0.2%
21	0	9,000	$ 891.61	$ 893.25	$ 1.64	0.2%
22	0	9,500	$ 939.91	$ 941.82	$ 1.91	0.2%
23	0	10,000	$ 988.21	$ 990.40	$ 2.19	0.2%
24	0	10,500	$ 1,036.52	$ 1,038.98	$ 2.47	0.2%
25	0	11,000	$ 1,084.82	$ 1,087.56	$ 2.74	0.3%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Water Heating						
1	0	250	$ 35.97	$ 35.44	$ (0.53)	-1.5%
2	0	500	$ 67.79	$ 66.73	$ (1.06)	-1.6%
3	0	750	$ 96.28	$ 94.70	$ (1.59)	-1.6%
4	0	1,000	$ 124.78	$ 122.66	$ (2.11)	-1.7%
5	0	1,250	$ 153.27	$ 150.63	$ (2.64)	-1.7%
6	0	1,500	$ 181.77	$ 178.60	$ (3.17)	-1.7%
7	0	2,000	$ 238.76	$ 234.53	$ (4.23)	-1.8%
8	0	2,500	$ 295.52	$ 290.23	$ (5.29)	-1.8%
9	0	3,000	$ 352.28	$ 345.94	$ (6.34)	-1.8%
10	0	3,500	$ 409.04	$ 401.64	$ (7.40)	-1.8%
11	0	4,000	$ 465.80	$ 457.34	$ (8.46)	-1.8%
12	0	4,500	$ 522.56	$ 513.04	$ (9.51)	-1.8%
13	0	5,000	$ 579.32	$ 568.75	$ (10.57)	-1.8%
14	0	5,500	$ 636.08	$ 624.45	$ (11.63)	-1.8%
15	0	6,000	$ 692.84	$ 680.15	$ (12.69)	-1.8%
16	0	6,500	$ 749.60	$ 735.86	$ (13.74)	-1.8%
17	0	7,000	$ 806.36	$ 791.56	$ (14.80)	-1.8%
18	0	7,500	$ 863.12	$ 847.26	$ (15.86)	-1.8%
19	0	8,000	$ 919.88	$ 902.97	$ (16.92)	-1.8%
20	0	8,500	$ 976.64	$ 958.67	$ (17.97)	-1.8%
21	0	9,000	$ 1,033.40	$ 1,014.37	$ (19.03)	-1.8%
22	0	9,500	$ 1,090.16	$ 1,070.07	$ (20.09)	-1.8%
23	0	10,000	$ 1,146.92	$ 1,125.78	$ (21.14)	-1.8%
24	0	10,500	$ 1,203.68	$ 1,181.48	$ (22.20)	-1.8%
25	0	11,000	$ 1,260.44	$ 1,237.18	$ (23.26)	-1.8%

IEU Set 3-INT-3 Attachment 2

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Secondary (Rate GS)						
1	10	1,000	$ 178.43	$ 173.05	$ (5.38)	-3.0%
2	10	2,000	$ 262.86	$ 257.48	$ (5.38)	-2.0%
3	10	3,000	$ 346.84	$ 341.47	$ (5.38)	-1.5%
4	10	4,000	$ 430.82	$ 425.44	$ (5.38)	-1.2%
5	10	5,000	$ 514.81	$ 509.44	$ (5.38)	-1.0%
6	10	6,000	$ 598.77	$ 593.39	$ (5.38)	-0.9%
7	1,000	100,000	$ 18,411.62	$ 17,874.02	$ (537.60)	-2.9%
8	1,000	200,000	$ 26,753.18	$ 26,215.58	$ (537.60)	-2.0%
9	1,000	300,000	$ 35,094.75	$ 34,557.15	$ (537.60)	-1.5%
10	1,000	400,000	$ 43,436.30	$ 42,898.70	$ (537.60)	-1.2%
11	1,000	500,000	$ 51,777.86	$ 51,240.26	$ (537.60)	-1.0%
12	1,000	600,000	$ 60,119.42	$ 59,581.82	$ (537.60)	-0.9%

IEU Set 3-INT-3 Attachment 2
Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Primary (Rate GP)						
1	500	50,000	$ 7,422.82	$ 6,964.77	$ (458.05)	-6.2%
2	500	100,000	$ 11,293.75	$ 10,835.70	$ (458.05)	-4.1%
3	500	150,000	$ 15,164.71	$ 14,706.66	$ (458.05)	-3.0%
4	500	200,000	$ 19,035.64	$ 18,577.59	$ (458.05)	-2.4%
5	500	250,000	$ 22,906.59	$ 22,448.54	$ (458.05)	-2.0%
6	500	300,000	$ 26,777.54	$ 26,319.49	$ (458.05)	-1.7%
7	5,000	500,000	$ 72,690.30	$ 68,109.80	$ (4,580.50)	-6.3%
8	5,000	1,000,000	$ 111,309.86	$ 106,729.36	$ (4,580.50)	-4.1%
9	5,000	1,500,000	$ 149,750.19	$ 145,169.69	$ (4,580.50)	-3.1%
10	5,000	2,000,000	$ 188,190.52	$ 183,610.02	$ (4,580.50)	-2.4%
11	5,000	2,500,000	$ 226,630.85	$ 222,050.35	$ (4,580.50)	-2.0%
12	5,000	3,000,000	$ 265,071.19	$ 260,490.69	$ (4,580.50)	-1.7%

IEU Set 3-INT-3 Attachment 2

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

		Bill Data				
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Subtransmission (Rate GSU)						
1	1,000	100,000	$ 11,570.32	$ 10,733.72	$ (836.60)	-7.2%
2	1,000	200,000	$ 18,886.18	$ 18,049.58	$ (836.60)	-4.4%
3	1,000	300,000	$ 26,202.05	$ 25,365.45	$ (836.60)	-3.2%
4	1,000	400,000	$ 33,517.91	$ 32,681.31	$ (836.60)	-2.5%
5	1,000	500,000	$ 40,833.77	$ 39,997.17	$ (836.60)	-2.0%
6	1,000	600,000	$ 48,149.63	$ 47,313.03	$ (836.60)	-1.7%
7	10,000	1,000,000	$ 113,616.60	$ 105,250.60	$ (8,366.00)	-7.4%
8	10,000	2,000,000	$ 186,237.01	$ 177,871.01	$ (8,366.00)	-4.5%
9	10,000	3,000,000	$ 258,857.43	$ 250,491.43	$ (8,366.00)	-3.2%
10	10,000	4,000,000	$ 331,477.85	$ 323,111.85	$ (8,366.00)	-2.5%
11	10,000	5,000,000	$ 404,098.26	$ 395,732.26	$ (8,366.00)	-2.1%
12	10,000	6,000,000	$ 476,718.68	$ 468,352.68	$ (8,366.00)	-1.8%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Transmission (Rate GT)						
1	2,000	200,000	$ 29,429.62	$ 24,634.22	$ (4,795.40)	-16.3%
2	2,000	400,000	$ 41,029.69	$ 37,124.49	$ (3,905.20)	-9.5%
3	2,000	600,000	$ 52,629.76	$ 49,614.76	$ (3,015.00)	-5.7%
4	2,000	800,000	$ 64,229.84	$ 62,105.04	$ (2,124.80)	-3.3%
5	2,000	1,000,000	$ 75,740.03	$ 74,505.43	$ (1,234.60)	-1.6%
6	2,000	1,200,000	$ 87,232.46	$ 86,888.06	$ (344.40)	-0.4%
7	20,000	2,000,000	$ 290,704.00	$ 242,750.00	$ (47,954.00)	-16.5%
8	20,000	4,000,000	$ 405,628.33	$ 366,576.33	$ (39,052.00)	-9.6%
9	20,000	6,000,000	$ 520,552.66	$ 490,402.66	$ (30,150.00)	-5.8%
10	20,000	8,000,000	$ 635,476.99	$ 614,228.99	$ (21,248.00)	-3.3%
11	20,000	10,000,000	$ 750,401.33	$ 738,055.33	$ (12,346.00)	-1.6%
12	20,000	12,000,000	$ 865,325.66	$ 861,881.66	$ (3,444.00)	-0.4%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Bill Data: Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Street Lighting Service (Rate STL)					
1	Company Owned - Incandescent Lighting (a)					
2	1,000	24	$ 18.33	$ 18.33	$ -	0.0%
3	2,000	56	$ 20.46	$ 20.46	$ -	0.0%
4	2,500	70	$ 21.39	$ 21.39	$ -	0.0%
5	4,000	126	$ 25.13	$ 25.13	$ -	0.0%
6	6,000	157	$ 27.18	$ 27.18	$ -	0.0%
7	10,000	242	$ 32.85	$ 32.85	$ -	0.0%
8	15,000	282	$ 35.52	$ 35.52	$ -	0.0%
9	Company Owned - Mercury Street Lighting (b)					
10	Overhead Service - Wood Pole					
11	100	43	$ 8.72	$ 8.72	$ -	0.0%
12	175	69	$ 9.69	$ 9.69	$ -	0.0%
13	250	104	$ 12.23	$ 12.23	$ -	0.0%
14	400	158	$ 15.80	$ 15.80	$ -	0.0%
15	700	287	$ 24.87	$ 24.87	$ -	0.0%
16	1,000	380	$ 30.72	$ 30.72	$ -	0.0%
17	Overhead Service - Metal Pole					
18	100	43	$ 16.54	$ 16.54	$ -	0.0%
19	175	69	$ 17.57	$ 17.57	$ -	0.0%
20	250	104	$ 21.05	$ 21.05	$ -	0.0%
21	250**	208	$ 31.03	$ 31.03	$ -	0.0%
22	400	158	$ 24.04	$ 24.04	$ -	0.0%
23	400**	316	$ 37.89	$ 37.89	$ -	0.0%
24	700	287	$ 34.63	$ 34.63	$ -	0.0%
25	1000	380	$ 40.60	$ 40.60	$ -	0.0%
26	1000**	760	$ 72.06	$ 72.06	$ -	0.0%
27	Underground Service - Post Type					
28	100	43	$ 11.56	$ 11.56	$ -	0.0%
29	175	69	$ 13.06	$ 13.06	$ -	0.0%
30	250	104	$ 16.65	$ 16.65	$ -	0.0%
31	Underground Service - Pole Type					
32	100	43	$ 18.94	$ 18.94	$ -	0.0%
33	175	69	$ 20.27	$ 20.27	$ -	0.0%
34	250	104	$ 25.45	$ 25.45	$ -	0.0%
35	400	158	$ 29.33	$ 29.33	$ -	0.0%
36	700	287	$ 56.57	$ 56.57	$ -	0.0%
37	1000	380	$ 62.25	$ 62.25	$ -	0.0%
38	1000**	760	$ 92.02	$ 92.02	$ -	0.0%
39	Bridge or Underpass Wallpack					
40	175	69	$ 12.12	$ 12.12	$ -	0.0%
41	250	104	$ 14.89	$ 14.89	$ -	0.0%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Street Lighting Service (Rate STL)						
42	Company Owned - High Pressure Sodium Lighting (c)					
43	Overhead Service - Wood Pole					
44	70	29	$ 8.36	$ 8.36	$ -	0.0%
45	100	42	$ 8.88	$ 8.88	$ -	0.0%
46	150	62	$ 9.84	$ 9.84	$ -	0.0%
47	215	89	$ 11.86	$ 11.86	$ -	0.0%
48	250	105	$ 12.55	$ 12.55	$ -	0.0%
49	400	163	$ 16.37	$ 16.37	$ -	0.0%
50	1000	410	$ 35.16	$ 35.16	$ -	0.0%
51	Overhead Service - Metal Pole					
52	70	29	$ 16.15	$ 16.15	$ -	0.0%
53	100	42	$ 16.71	$ 16.71	$ -	0.0%
54	150	62	$ 18.71	$ 18.71	$ -	0.0%
55	215	89	$ 20.65	$ 20.65	$ -	0.0%
56	250	105	$ 21.35	$ 21.35	$ -	0.0%
57	400	163	$ 26.18	$ 26.18	$ -	0.0%
58	1000	410	$ 44.13	$ 44.13	$ -	0.0%
59	Underground Service - Post Type					
60	70	29	$ 11.46	$ 11.46	$ -	0.0%
61	100	42	$ 12.32	$ 12.32	$ -	0.0%
62	150	62	$ 13.93	$ 13.93	$ -	0.0%
63	Underground Service - Pole Type					
64	70	29	$ 18.45	$ 18.45	$ -	0.0%
65	100	42	$ 19.30	$ 19.30	$ -	0.0%
66	150	62	$ 23.13	$ 23.13	$ -	0.0%
67	200	88	$ 25.57	$ 25.57	$ -	0.0%
68	215	89	$ 23.25	$ 23.25	$ -	0.0%
69	250	105	$ 26.49	$ 26.49	$ -	0.0%
70	310	128	$ 28.96	$ 28.96	$ -	0.0%
71	400	163	$ 48.05	$ 48.05	$ -	0.0%
72	400**	326	$ 63.22	$ 63.22	$ -	0.0%
73	1000	410	$ 67.92	$ 67.92	$ -	0.0%
74	Bridge or Underpass Wallpack					
75	70	29	$ 12.02	$ 12.02	$ -	0.0%
76	100	42	$ 13.57	$ 13.57	$ -	0.0%
77	150	62	$ 14.68	$ 14.68	$ -	0.0%
78	215	89	$ 15.16	$ 15.16	$ -	0.0%
79	250	105	$ 17.97	$ 17.97	$ -	0.0%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Bill Data: Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Street Lighting Service (Rate STL)					
80	Customer Owned - All Lamp Types					
81	N/A	25	$ 1.78	$ 1.78	$ -	0.0%
82	N/A	50	$ 3.53	$ 3.53	$ -	0.0%
83	N/A	75	$ 5.28	$ 5.28	$ -	0.0%
84	N/A	100	$ 7.03	$ 7.03	$ -	0.0%
85	N/A	125	$ 8.77	$ 8.77	$ -	0.0%
86	N/A	150	$ 10.53	$ 10.53	$ -	0.0%
87	N/A	175	$ 12.27	$ 12.27	$ -	0.0%
88	N/A	200	$ 14.03	$ 14.03	$ -	0.0%
89	N/A	225	$ 15.78	$ 15.78	$ -	0.0%
90	N/A	250	$ 17.52	$ 17.52	$ -	0.0%
91	N/A	275	$ 19.27	$ 19.27	$ -	0.0%
92	N/A	300	$ 21.01	$ 21.01	$ -	0.0%
93	N/A	325	$ 22.74	$ 22.74	$ -	0.0%
94	N/A	350	$ 24.48	$ 24.48	$ -	0.0%
95	N/A	375	$ 26.23	$ 26.23	$ -	0.0%
96	N/A	400	$ 27.97	$ 27.97	$ -	0.0%
97	Customer Owned, Limited Company Maintenance - All Lamp Types					
98	N/A	25	$ 2.40	$ 2.40	$ -	0.0%
99	N/A	50	$ 4.76	$ 4.76	$ -	0.0%
100	N/A	75	$ 7.13	$ 7.13	$ -	0.0%
101	N/A	100	$ 9.50	$ 9.50	$ -	0.0%
102	N/A	125	$ 11.86	$ 11.86	$ -	0.0%
103	N/A	150	$ 14.23	$ 14.23	$ -	0.0%
104	N/A	175	$ 16.58	$ 16.58	$ -	0.0%
105	N/A	200	$ 18.96	$ 18.96	$ -	0.0%
106	N/A	225	$ 21.33	$ 21.33	$ -	0.0%
107	N/A	250	$ 23.68	$ 23.68	$ -	0.0%
108	N/A	275	$ 26.05	$ 26.05	$ -	0.0%
109	N/A	300	$ 28.41	$ 28.41	$ -	0.0%
110	N/A	325	$ 30.76	$ 30.76	$ -	0.0%
111	N/A	350	$ 33.11	$ 33.11	$ -	0.0%
112	N/A	375	$ 35.48	$ 35.48	$ -	0.0%
113	N/A	400	$ 37.84	$ 37.84	$ -	0.0%
114	Efficiency Safety Incentive Program - All Lamp Types					
115	N/A	25	$ 3.17	$ 3.17	$ -	0.0%
116	N/A	50	$ 6.30	$ 6.30	$ -	0.0%
117	N/A	75	$ 9.44	$ 9.44	$ -	0.0%
118	N/A	100	$ 12.58	$ 12.58	$ -	0.0%
119	N/A	125	$ 15.70	$ 15.70	$ -	0.0%
120	N/A	150	$ 18.85	$ 18.85	$ -	0.0%

IEU Set 3-INT-3 Attachment 2
Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Street Lighting Service (Rate STL)						
121	N/A	175	$ 21.97	$ 21.97	$ -	0.0%
122	N/A	200	$ 25.11	$ 25.11	$ -	0.0%
123	N/A	225	$ 28.25	$ 28.25	$ -	0.0%
124	N/A	250	$ 31.38	$ 31.38	$ -	0.0%
125	N/A	275	$ 34.51	$ 34.51	$ -	0.0%
126	N/A	300	$ 37.64	$ 37.64	$ -	0.0%
127	N/A	325	$ 40.75	$ 40.75	$ -	0.0%
128	N/A	350	$ 43.88	$ 43.88	$ -	0.0%
129	N/A	375	$ 47.02	$ 47.02	$ -	0.0%
130	N/A	400	$ 50.14	$ 50.14	$ -	0.0%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
	Private Outdoor Lighting Service (Rate POL)					
1	Mercury Lighting					
2	Overhead Service - Wood Pole					
3	175	69	$ 11.30	$ 11.30	$ -	0.0%
4	400	158	$ 19.08	$ 19.08	$ -	0.0%
5	1,000	380	$ 35.16	$ 35.16	$ -	0.0%
6	All Other Installations					
7	175	69	$ 15.70	$ 15.70	$ -	0.0%
8	High Pressure Sodium Lighting					
9	Overhead Service - Wood Pole					
10	100	42	$ 10.72	$ 10.72	$ -	0.0%
11	250	105	$ 17.34	$ 17.34	$ -	0.0%
12	400	163	$ 21.99	$ 21.99	$ -	0.0%
13	All Other Installations					
14	100	42	$ 15.75	$ 15.75	$ -	0.0%
15	Metal Halide Lighting					
16	Overhead Service - Wood Pole					
17	15,000	73	$ 16.28	$ 16.28	$ -	0.0%
18	23,000	111	$ 18.85	$ 18.85	$ -	0.0%
19	40,000	172	$ 22.92	$ 22.92	$ -	0.0%
20	All Other Installations					
21	15,000	73	$ 26.06	$ 26.06	$ -	0.0%
22	23,000	111	$ 28.63	$ 28.63	$ -	0.0%
23	40,000	172	$ 32.70	$ 32.70	$ -	0.0%

Ohio Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Bill Data

Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Traffic Lighting Schedule (Rate TRF)						
1	0	100	$ 9.68	$ 9.48	$ (0.20)	-2.1%
2	0	200	$ 19.15	$ 18.74	$ (0.41)	-2.1%
3	0	300	$ 28.67	$ 28.05	$ (0.61)	-2.1%
4	0	400	$ 38.13	$ 37.31	$ (0.82)	-2.1%
5	0	500	$ 47.65	$ 46.63	$ (1.02)	-2.1%
6	0	600	$ 57.13	$ 55.90	$ (1.23)	-2.1%

IEU Set 3-INT-3 Attachment 3

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - Standard (Rate RS)						
1	0	250	$ 35.77	$ 36.87	$ 1.09	3.1%
2	0	500	$ 67.39	$ 69.57	$ 2.18	3.2%
3	0	750	$ 99.01	$ 102.28	$ 3.28	3.3%
4	0	1,000	$ 130.62	$ 134.99	$ 4.37	3.3%
5	0	1,250	$ 162.24	$ 167.70	$ 5.46	3.4%
6	0	1,500	$ 193.85	$ 200.40	$ 6.55	3.4%
7	0	2,000	$ 257.08	$ 265.82	$ 8.74	3.4%
8	0	2,500	$ 320.08	$ 331.01	$ 10.92	3.4%
9	0	3,000	$ 383.09	$ 396.19	$ 13.10	3.4%
10	0	3,500	$ 446.09	$ 461.38	$ 15.29	3.4%
11	0	4,000	$ 509.09	$ 526.56	$ 17.47	3.4%
12	0	4,500	$ 572.09	$ 591.74	$ 19.66	3.4%
13	0	5,000	$ 635.09	$ 656.93	$ 21.84	3.4%
14	0	5,500	$ 698.09	$ 722.11	$ 24.02	3.4%
15	0	6,000	$ 761.09	$ 787.30	$ 26.21	3.4%
16	0	6,500	$ 824.09	$ 852.48	$ 28.39	3.4%
17	0	7,000	$ 887.09	$ 917.67	$ 30.58	3.4%
18	0	7,500	$ 950.09	$ 982.85	$ 32.76	3.4%
19	0	8,000	$ 1,013.09	$ 1,048.04	$ 34.95	3.4%
20	0	8,500	$ 1,076.09	$ 1,113.22	$ 37.13	3.5%
21	0	9,000	$ 1,139.10	$ 1,178.41	$ 39.31	3.5%
22	0	9,500	$ 1,202.10	$ 1,243.59	$ 41.50	3.5%
23	0	10,000	$ 1,265.10	$ 1,308.78	$ 43.68	3.5%
24	0	10,500	$ 1,328.10	$ 1,373.96	$ 45.87	3.5%
25	0	11,000	$ 1,391.10	$ 1,439.15	$ 48.05	3.5%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Electric Heating						
1	0	250	$ 35.77	$ 36.87	$ 1.09	3.1%
2	0	500	$ 67.39	$ 69.57	$ 2.18	3.2%
3	0	750	$ 92.14	$ 95.42	$ 3.28	3.6%
4	0	1,000	$ 116.90	$ 121.26	$ 4.37	3.7%
5	0	1,250	$ 141.65	$ 147.11	$ 5.46	3.9%
6	0	1,500	$ 166.40	$ 172.95	$ 6.55	3.9%
7	0	2,000	$ 215.91	$ 224.65	$ 8.74	4.0%
8	0	2,500	$ 263.00	$ 274.67	$ 11.67	4.4%
9	0	3,000	$ 310.09	$ 324.69	$ 14.60	4.7%
10	0	3,500	$ 357.17	$ 374.71	$ 17.54	4.9%
11	0	4,000	$ 404.26	$ 424.73	$ 20.47	5.1%
12	0	4,500	$ 451.35	$ 474.76	$ 23.41	5.2%
13	0	5,000	$ 498.44	$ 524.78	$ 26.34	5.3%
14	0	5,500	$ 545.53	$ 574.80	$ 29.27	5.4%
15	0	6,000	$ 592.62	$ 624.82	$ 32.21	5.4%
16	0	6,500	$ 639.70	$ 674.85	$ 35.14	5.5%
17	0	7,000	$ 686.79	$ 724.87	$ 38.08	5.5%
18	0	7,500	$ 733.88	$ 774.89	$ 41.01	5.6%
19	0	8,000	$ 780.97	$ 824.91	$ 43.95	5.6%
20	0	8,500	$ 828.06	$ 874.94	$ 46.88	5.7%
21	0	9,000	$ 875.15	$ 924.96	$ 49.81	5.7%
22	0	9,500	$ 922.23	$ 974.98	$ 52.75	5.7%
23	0	10,000	$ 969.32	$ 1,025.00	$ 55.68	5.7%
24	0	10,500	$ 1,016.41	$ 1,075.03	$ 58.62	5.8%
25	0	11,000	$ 1,063.50	$ 1,125.05	$ 61.55	5.8%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Water Heating						
1	0	250	$ 35.77	$ 36.87	$ 1.09	3.1%
2	0	500	$ 67.39	$ 69.57	$ 2.18	3.2%
3	0	750	$ 94.77	$ 98.04	$ 3.28	3.5%
4	0	1,000	$ 122.15	$ 126.51	$ 4.37	3.6%
5	0	1,250	$ 149.52	$ 154.98	$ 5.46	3.7%
6	0	1,500	$ 176.90	$ 183.45	$ 6.55	3.7%
7	0	2,000	$ 231.66	$ 240.40	$ 8.74	3.8%
8	0	2,500	$ 286.18	$ 297.11	$ 10.92	3.8%
9	0	3,000	$ 340.71	$ 353.82	$ 13.10	3.8%
10	0	3,500	$ 395.24	$ 410.53	$ 15.29	3.9%
11	0	4,000	$ 449.76	$ 467.23	$ 17.47	3.9%
12	0	4,500	$ 504.29	$ 523.94	$ 19.66	3.9%
13	0	5,000	$ 558.81	$ 580.65	$ 21.84	3.9%
14	0	5,500	$ 613.34	$ 637.36	$ 24.02	3.9%
15	0	6,000	$ 667.87	$ 694.07	$ 26.21	3.9%
16	0	6,500	$ 722.39	$ 750.78	$ 28.39	3.9%
17	0	7,000	$ 776.92	$ 807.49	$ 30.58	3.9%
18	0	7,500	$ 831.44	$ 864.20	$ 32.76	3.9%
19	0	8,000	$ 885.97	$ 920.91	$ 34.95	3.9%
20	0	8,500	$ 940.49	$ 977.62	$ 37.13	3.9%
21	0	9,000	$ 995.02	$ 1,034.33	$ 39.31	4.0%
22	0	9,500	$ 1,049.55	$ 1,091.04	$ 41.50	4.0%
23	0	10,000	$ 1,104.07	$ 1,147.75	$ 43.68	4.0%
24	0	10,500	$ 1,158.60	$ 1,204.46	$ 45.87	4.0%
25	0	11,000	$ 1,213.12	$ 1,261.17	$ 48.05	4.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - All-Electric Apt.						
1	0	250	$ 34.03	$ 35.71	$ 1.68	4.9%
2	0	500	$ 63.91	$ 67.26	$ 3.35	5.2%
3	0	750	$ 86.92	$ 91.95	$ 5.03	5.8%
4	0	1,000	$ 109.94	$ 116.64	$ 6.70	6.1%
5	0	1,250	$ 132.95	$ 141.33	$ 8.38	6.3%
6	0	1,500	$ 155.96	$ 166.02	$ 10.05	6.4%
7	0	2,000	$ 201.99	$ 215.40	$ 13.40	6.6%
8	0	2,500	$ 251.27	$ 266.86	$ 15.59	6.2%
9	0	3,000	$ 300.54	$ 318.32	$ 17.77	5.9%
10	0	3,500	$ 349.82	$ 369.78	$ 19.96	5.7%
11	0	4,000	$ 399.10	$ 421.23	$ 22.14	5.5%
12	0	4,500	$ 448.37	$ 472.69	$ 24.32	5.4%
13	0	5,000	$ 497.65	$ 524.15	$ 26.51	5.3%
14	0	5,500	$ 546.92	$ 575.61	$ 28.69	5.2%
15	0	6,000	$ 596.20	$ 627.07	$ 30.88	5.2%
16	0	6,500	$ 645.47	$ 678.53	$ 33.06	5.1%
17	0	7,000	$ 694.75	$ 729.99	$ 35.24	5.1%
18	0	7,500	$ 744.03	$ 781.45	$ 37.43	5.0%
19	0	8,000	$ 793.30	$ 832.91	$ 39.61	5.0%
20	0	8,500	$ 842.58	$ 884.37	$ 41.80	5.0%
21	0	9,000	$ 891.85	$ 935.83	$ 43.98	4.9%
22	0	9,500	$ 941.13	$ 987.29	$ 46.16	4.9%
23	0	10,000	$ 990.41	$ 1,038.75	$ 48.35	4.9%
24	0	10,500	$ 1,039.68	$ 1,090.21	$ 50.53	4.9%
25	0	11,000	$ 1,088.96	$ 1,141.67	$ 52.72	4.8%

IEU Set 3-INT-3 Attachment 3

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Bill Data

Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Secondary (Rate GS)						
1	10	1,000	$ 177.05	$ 194.11	$ 17.05	9.6%
2	10	2,000	$ 260.92	$ 277.39	$ 16.47	6.3%
3	10	3,000	$ 344.32	$ 360.22	$ 15.91	4.6%
4	10	4,000	$ 427.71	$ 443.06	$ 15.35	3.6%
5	10	5,000	$ 511.12	$ 525.90	$ 14.78	2.9%
6	10	6,000	$ 594.50	$ 608.69	$ 14.19	2.4%
7	1,000	100,000	$ 19,729.45	$ 21,433.95	$ 1,704.50	8.6%
8	1,000	200,000	$ 28,012.94	$ 29,660.54	$ 1,647.60	5.9%
9	1,000	300,000	$ 36,296.43	$ 37,887.14	$ 1,590.71	4.4%
10	1,000	400,000	$ 44,579.92	$ 46,113.73	$ 1,533.81	3.4%
11	1,000	500,000	$ 52,863.42	$ 54,340.33	$ 1,476.91	2.8%
12	1,000	600,000	$ 61,146.90	$ 62,566.91	$ 1,420.01	2.3%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Bill Data

Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Primary (Rate GP)						
1	500	50,000	$ 6,342.18	$ 7,331.52	$ 989.34	15.6%
2	500	100,000	$ 10,397.38	$ 11,405.01	$ 1,007.63	9.7%
3	500	150,000	$ 14,452.60	$ 15,478.52	$ 1,025.92	7.1%
4	500	200,000	$ 18,507.80	$ 19,552.01	$ 1,044.21	5.6%
5	500	250,000	$ 22,563.01	$ 23,625.51	$ 1,062.50	4.7%
6	500	300,000	$ 26,618.22	$ 27,699.02	$ 1,080.80	4.1%
7	5,000	500,000	$ 61,883.95	$ 71,777.36	$ 9,893.41	16.0%
8	5,000	1,000,000	$ 102,367.86	$ 112,444.18	$ 10,076.32	9.8%
9	5,000	1,500,000	$ 142,715.84	$ 152,975.07	$ 10,259.23	7.2%
10	5,000	2,000,000	$ 183,063.82	$ 193,505.96	$ 10,442.14	5.7%
11	5,000	2,500,000	$ 223,411.80	$ 234,036.85	$ 10,625.05	4.8%
12	5,000	3,000,000	$ 263,759.79	$ 274,567.75	$ 10,807.96	4.1%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Subtransmission (Rate GSU)						
1	1,000	100,000	$ 9,678.35	$ 11,693.75	$ 2,015.40	20.8%
2	1,000	200,000	$ 16,558.64	$ 18,521.85	$ 1,963.20	11.9%
3	1,000	300,000	$ 23,438.93	$ 25,349.94	$ 1,911.01	8.2%
4	1,000	400,000	$ 30,319.23	$ 32,178.03	$ 1,858.81	6.1%
5	1,000	500,000	$ 37,199.52	$ 39,006.13	$ 1,806.61	4.9%
6	1,000	600,000	$ 44,079.81	$ 45,834.22	$ 1,754.41	4.0%
7	10,000	1,000,000	$ 94,718.60	$ 114,872.62	$ 20,154.02	21.3%
8	10,000	2,000,000	$ 163,113.32	$ 182,745.35	$ 19,632.04	12.0%
9	10,000	3,000,000	$ 231,508.03	$ 250,618.08	$ 19,110.05	8.3%
10	10,000	4,000,000	$ 299,902.74	$ 318,490.81	$ 18,588.07	6.2%
11	10,000	5,000,000	$ 368,297.45	$ 386,363.54	$ 18,066.09	4.9%
12	10,000	6,000,000	$ 436,692.17	$ 454,236.28	$ 17,544.11	4.0%

IEU Set 3-INT-3 Attachment 3

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Bill Data

Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Transmission (Rate GT)						
1	2,000	200,000	$ 31,781.88	$ 35,272.68	$ 3,490.80	11.0%
2	2,000	400,000	$ 42,607.41	$ 46,001.82	$ 3,394.41	8.0%
3	2,000	600,000	$ 53,432.94	$ 56,730.95	$ 3,298.01	6.2%
4	2,000	800,000	$ 64,258.47	$ 67,460.09	$ 3,201.61	5.0%
5	2,000	1,000,000	$ 75,015.84	$ 78,121.06	$ 3,105.22	4.1%
6	2,000	1,200,000	$ 85,759.73	$ 88,768.55	$ 3,008.82	3.5%
7	20,000	2,000,000	$ 314,378.30	$ 349,286.34	$ 34,908.04	11.1%
8	20,000	4,000,000	$ 421,817.23	$ 455,761.30	$ 33,944.07	8.0%
9	20,000	6,000,000	$ 529,256.15	$ 562,236.26	$ 32,980.11	6.2%
10	20,000	8,000,000	$ 636,695.08	$ 668,711.22	$ 32,016.14	5.0%
11	20,000	10,000,000	$ 744,134.00	$ 775,186.18	$ 31,052.18	4.2%
12	20,000	12,000,000	$ 851,572.93	$ 881,661.14	$ 30,088.22	3.5%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
1	Company Owned - Incandescent Street Lighting (a)					
2	Overhead Wood Service (Single lamps)					
3	1,000	24	$ 12.59	$ 12.59	$ (0.00)	0.0%
4	2,000	56	$ 14.72	$ 14.71	$ (0.01)	-0.1%
5	2,500	70	$ 15.65	$ 15.65	$ (0.01)	0.0%
6	4,000	126	$ 19.37	$ 19.35	$ (0.02)	-0.1%
7	6,000	157	$ 21.43	$ 21.40	$ (0.03)	-0.1%
8	10,000	242	$ 27.07	$ 27.04	$ (0.03)	-0.1%
9	15,000	282	$ 29.72	$ 29.68	$ (0.04)	-0.1%
10	Overhead Steel Service (Single lamps)					
11	1,000	24	$ 13.57	$ 13.57	$ (0.00)	0.0%
12	2,000	56	$ 15.70	$ 15.69	$ (0.01)	-0.1%
13	2,500	70	$ 16.63	$ 16.63	$ (0.01)	0.0%
14	4,000	126	$ 20.35	$ 20.33	$ (0.02)	-0.1%
15	6,000	157	$ 22.41	$ 22.38	$ (0.03)	-0.1%
16	10,000	242	$ 28.05	$ 28.02	$ (0.03)	-0.1%
17	15,000	282	$ 30.70	$ 30.66	$ (0.04)	-0.1%
18	Underground Service (Single lamps)					
19	1,000	24	$ 19.77	$ 19.77	$ (0.00)	0.0%
20	2,000	56	$ 21.90	$ 21.89	$ (0.01)	0.0%
21	2,500	70	$ 22.83	$ 22.83	$ (0.01)	0.0%
22	4,000	126	$ 26.55	$ 26.53	$ (0.02)	-0.1%
23	6,000	157	$ 28.61	$ 28.58	$ (0.03)	-0.1%
24	10,000	242	$ 34.25	$ 34.22	$ (0.03)	-0.1%
25	15,000	282	$ 36.90	$ 36.86	$ (0.04)	-0.1%
26	Underground Service (Dual lamps)					
27	1,000	48	$ 35.47	$ 35.47	$ (0.00)	0.0%
28	2,000	112	$ 39.73	$ 39.72	$ (0.01)	0.0%
29	2,500	140	$ 41.60	$ 41.58	$ (0.01)	0.0%
30	4,000	252	$ 49.02	$ 48.99	$ (0.03)	-0.1%
31	6,000	314	$ 53.16	$ 53.12	$ (0.04)	-0.1%
32	10,000	484	$ 64.45	$ 64.37	$ (0.07)	-0.1%
33	15,000	564	$ 69.76	$ 69.69	$ (0.08)	-0.1%
34	Company Owned - Fluorescent Street Lighting (a)					
35	Overhead Steel Service (Single lamps)					
36	6,000	45	$ 19.82	$ 19.80	$ (0.01)	-0.1%
37	13,800	94	$ 23.08	$ 23.07	$ (0.01)	0.0%
38	21,800	135	$ 25.81	$ 25.79	$ (0.01)	-0.1%
39	43,600	264	$ 34.38	$ 34.34	$ (0.04)	-0.1%
40	Underground Service (Single lamps)					
41	6,000	45	$ 18.08	$ 18.06	$ (0.01)	-0.1%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
42	13,800	94	$ 21.34	$ 21.33	$ (0.01)	0.0%
43	21,800	135	$ 24.07	$ 24.05	$ (0.01)	-0.1%
44	43,600	264	$ 32.64	$ 32.60	$ (0.04)	-0.1%
45	Underground Service (Dual lamps)					
46	6,000	90	$ 26.59	$ 26.58	$ (0.01)	0.0%
47	13,800	188	$ 33.08	$ 33.07	$ (0.02)	0.0%
48	21,800	270	$ 38.55	$ 38.51	$ (0.04)	-0.1%
49	43,600	528	$ 55.70	$ 55.62	$ (0.08)	-0.1%
50	Company Owned - Mercury Street Lighting - Single lamp (c)					
51	Overhead Service - Wood Pole					
52	175	69	$ 10.60	$ 10.59	$ (0.01)	-0.1%
53	250	104	$ 13.51	$ 13.51	$ (0.00)	0.0%
54	400	158	$ 18.77	$ 18.74	$ (0.03)	-0.1%
55	700	287	$ 32.52	$ 32.48	$ (0.04)	-0.1%
56	1000	380	$ 41.15	$ 41.10	$ (0.05)	-0.1%
57	Overhead Service - Metal Pole					
58	175	69	$ 12.88	$ 12.87	$ (0.01)	0.0%
59	250	104	$ 15.63	$ 15.63	$ (0.00)	0.0%
60	400	158	$ 21.47	$ 21.44	$ (0.03)	-0.1%
61	700	287	$ 35.43	$ 35.39	$ (0.04)	-0.1%
62	1000	380	$ 44.12	$ 44.07	$ (0.05)	-0.1%
63	Underground Service					
64	175	69	$ 16.60	$ 16.59	$ (0.01)	0.0%
65	250	104	$ 19.47	$ 19.47	$ (0.00)	0.0%
66	400	158	$ 25.10	$ 25.07	$ (0.03)	-0.1%
67	700	287	$ 37.29	$ 37.25	$ (0.04)	-0.1%
68	1000	380	$ 45.76	$ 45.71	$ (0.05)	-0.1%
69	Company Owned - Mercury Street Lighting - Dual lamps (c)					
70	Overhead Service - Wood Pole					
71	175	138	$ 19.37	$ 19.35	$ (0.02)	-0.1%
72	400	316	$ 35.58	$ 35.54	$ (0.04)	-0.1%
73	Overhead Service - Metal Pole					
74	400	316	$ 38.24	$ 38.20	$ (0.04)	-0.1%
75	Underground Service					
76	250	208	$ 31.38	$ 31.35	$ (0.03)	-0.1%
77	400	316	$ 41.51	$ 41.47	$ (0.04)	-0.1%
78	Company Owned - High Pressure Sodium Lighting - Single lamps (d)					
79	Overhead Service - Wood Pole					
80	100	42	$ 11.97	$ 11.96	$ (0.01)	0.0%
81	150	62	$ 14.52	$ 14.50	$ (0.02)	-0.1%
82	200	88	$ 19.09	$ 19.08	$ (0.01)	-0.1%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
83	250	105	$ 17.39	$ 17.38	$ (0.01)	-0.1%
84	400	163	$ 24.45	$ 24.44	$ (0.01)	-0.1%
85	Overhead Service - Metal Pole					
86	100	42	$ 13.82	$ 13.81	$ (0.01)	0.0%
87	150	62	$ 15.84	$ 15.82	$ (0.02)	-0.1%
88	200	88	$ 21.21	$ 21.20	$ (0.01)	0.0%
89	250	105	$ 21.36	$ 21.35	$ (0.01)	-0.1%
90	400	163	$ 27.88	$ 27.87	$ (0.01)	0.0%
91	Underground Service					
92	100	42	$ 17.57	$ 17.56	$ (0.01)	0.0%
93	100 (orn.)	42	$ 28.87	$ 28.86	$ (0.01)	0.0%
94	150	62	$ 16.85	$ 16.83	$ (0.02)	-0.1%
95	200	88	$ 25.16	$ 25.15	$ (0.01)	0.0%
96	250	105	$ 23.06	$ 23.05	$ (0.01)	-0.1%
97	250 (dwntwn)	105	$ 38.08	$ 38.07	$ (0.01)	0.0%
98	400	163	$ 28.61	$ 28.60	$ (0.01)	0.0%
99	400 (dwntwn)	25	$ 47.24	$ 47.24	$ (0.00)	0.0%
100	Company Owned - High Pressure Sodium Lighting - Dual lamps (d)					
101	Overhead Service - Wood Pole					
102	100	84	$ 23.47	$ 23.46	$ (0.01)	0.0%
103	150	124	$ 27.15	$ 27.13	$ (0.02)	-0.1%
104	250	210	$ 34.90	$ 34.87	$ (0.03)	-0.1%
105	Overhead Service - Metal Pole					
106	100	84	$ 24.36	$ 24.35	$ (0.01)	0.0%
107	150	124	$ 27.59	$ 27.57	$ (0.02)	-0.1%
108	250	210	$ 36.31	$ 36.28	$ (0.03)	-0.1%
109	Underground Service					
110	100	84	$ 28.60	$ 28.59	$ (0.01)	0.0%
111	150	124	$ 34.27	$ 34.25	$ (0.02)	-0.1%
112	250	210	$ 42.56	$ 42.53	$ (0.03)	-0.1%
113	400 (davit)	326	$ 44.78	$ 44.75	$ (0.04)	-0.1%
114	Customer Owned - Limited Company Maintenance - All Lamp Types					
115	N/A	25	$ 1.70	$ 1.70	$ (0.00)	-0.1%
116	N/A	50	$ 3.34	$ 3.35	$ 0.01	0.2%
117	N/A	75	$ 6.12	$ 6.11	$ (0.01)	-0.2%
118	N/A	100	$ 9.29	$ 9.27	$ (0.03)	-0.3%
119	N/A	125	$ 11.59	$ 11.58	$ (0.02)	-0.1%
120	N/A	150	$ 15.86	$ 15.84	$ (0.02)	-0.1%
121	N/A	175	$ 18.95	$ 18.92	$ (0.03)	-0.2%
122	N/A	200	$ 24.56	$ 24.54	$ (0.02)	-0.1%
123	N/A	225	$ 28.07	$ 28.04	$ (0.03)	-0.1%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
124	N/A	250	$ 16.63	$ 16.60	$ (0.03)	-0.2%
125	N/A	275	$ 19.43	$ 19.39	$ (0.04)	-0.2%
126	N/A	300	$ 22.57	$ 22.52	$ (0.05)	-0.2%
127	N/A	325	$ 24.87	$ 24.82	$ (0.05)	-0.2%
128	N/A	350	$ 29.14	$ 29.09	$ (0.05)	-0.2%
129	N/A	375	$ 32.21	$ 32.16	$ (0.05)	-0.2%
130	N/A	400	$ 37.84	$ 37.78	$ (0.06)	-0.2%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Private Outdoor Lighting Service (Rate POL)						
1	Mercury Lighting					
2	Overhead Service - Wood Pole					
3	175	69	$ 10.48	$ 10.48	$ (0.01)	-0.1%
4	400	158	$ 27.06	$ 27.03	$ (0.03)	-0.1%
5	1,000	380	$ 47.04	$ 46.98	$ (0.06)	-0.1%
6	All Other Installations					
7	175	69	$ 17.07	$ 17.07	$ (0.01)	0.0%
8	High Pressure Sodium Lighting					
9	Overhead Service - Wood Pole					
10	200	88	$ 14.29	$ 14.28	$ (0.01)	-0.1%
11	400	163	$ 25.48	$ 25.46	$ (0.02)	-0.1%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Existing ESP III vs. Year 1 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Traffic Lighting Schedule (Rate TRF)						
1	0	100	$ 9.63	$ 10.50	$ 0.87	9.1%
2	0	200	$ 19.06	$ 20.85	$ 1.78	9.4%
3	0	300	$ 28.52	$ 31.18	$ 2.65	9.3%
4	0	400	$ 37.97	$ 41.50	$ 3.54	9.3%
5	0	500	$ 47.43	$ 51.85	$ 4.43	9.3%
6	0	600	$ 56.89	$ 62.21	$ 5.32	9.3%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

	Bill Data					
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - Standard (Rate RS)						
1	0	250	$ 36.87	$ 36.56	$ (0.30)	-0.8%
2	0	500	$ 69.57	$ 68.97	$ (0.61)	-0.9%
3	0	750	$ 102.28	$ 101.37	$ (0.91)	-0.9%
4	0	1,000	$ 134.99	$ 133.78	$ (1.21)	-0.9%
5	0	1,250	$ 167.70	$ 166.18	$ (1.52)	-0.9%
6	0	1,500	$ 200.40	$ 198.59	$ (1.82)	-0.9%
7	0	2,000	$ 265.82	$ 263.39	$ (2.43)	-0.9%
8	0	2,500	$ 331.01	$ 327.97	$ (3.03)	-0.9%
9	0	3,000	$ 396.19	$ 392.55	$ (3.64)	-0.9%
10	0	3,500	$ 461.38	$ 457.13	$ (4.25)	-0.9%
11	0	4,000	$ 526.56	$ 521.71	$ (4.85)	-0.9%
12	0	4,500	$ 591.74	$ 586.29	$ (5.46)	-0.9%
13	0	5,000	$ 656.93	$ 650.87	$ (6.06)	-0.9%
14	0	5,500	$ 722.11	$ 715.44	$ (6.67)	-0.9%
15	0	6,000	$ 787.30	$ 780.02	$ (7.28)	-0.9%
16	0	6,500	$ 852.48	$ 844.60	$ (7.88)	-0.9%
17	0	7,000	$ 917.67	$ 909.18	$ (8.49)	-0.9%
18	0	7,500	$ 982.85	$ 973.76	$ (9.10)	-0.9%
19	0	8,000	$ 1,048.04	$ 1,038.34	$ (9.70)	-0.9%
20	0	8,500	$ 1,113.22	$ 1,102.91	$ (10.31)	-0.9%
21	0	9,000	$ 1,178.41	$ 1,167.49	$ (10.92)	-0.9%
22	0	9,500	$ 1,243.59	$ 1,232.07	$ (11.52)	-0.9%
23	0	10,000	$ 1,308.78	$ 1,296.65	$ (12.13)	-0.9%
24	0	10,500	$ 1,373.96	$ 1,361.23	$ (12.74)	-0.9%
25	0	11,000	$ 1,439.15	$ 1,425.81	$ (13.34)	-0.9%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Electric Heating						
1	0	250	$ 36.87	$ 36.56	$ (0.30)	-0.8%
2	0	500	$ 69.57	$ 68.97	$ (0.61)	-0.9%
3	0	750	$ 95.42	$ 94.51	$ (0.91)	-1.0%
4	0	1,000	$ 121.26	$ 120.05	$ (1.21)	-1.0%
5	0	1,250	$ 147.11	$ 145.59	$ (1.52)	-1.0%
6	0	1,500	$ 172.95	$ 171.14	$ (1.82)	-1.1%
7	0	2,000	$ 224.65	$ 222.22	$ (2.43)	-1.1%
8	0	2,500	$ 274.67	$ 272.39	$ (2.28)	-0.8%
9	0	3,000	$ 324.69	$ 322.55	$ (2.14)	-0.7%
10	0	3,500	$ 374.71	$ 372.72	$ (2.00)	-0.5%
11	*0*	*4,000*	*$ 424.73*	*$ 422.88*	*$ (1.85)*	*-0.4%*
12	0	4,500	$ 474.76	$ 473.05	$ (1.71)	-0.4%
13	0	5,000	$ 524.78	$ 523.22	$ (1.56)	-0.3%
14	0	5,500	$ 574.80	$ 573.38	$ (1.42)	-0.2%
15	0	6,000	$ 624.82	$ 623.55	$ (1.28)	-0.2%
16	0	6,500	$ 674.85	$ 673.71	$ (1.13)	-0.2%
17	0	7,000	$ 724.87	$ 723.88	$ (0.99)	-0.1%
18	0	7,500	$ 774.89	$ 774.05	$ (0.85)	-0.1%
19	0	8,000	$ 824.91	$ 824.21	$ (0.70)	-0.1%
20	0	8,500	$ 874.94	$ 874.38	$ (0.56)	-0.1%
21	0	9,000	$ 924.96	$ 924.54	$ (0.42)	0.0%
22	0	9,500	$ 974.98	$ 974.71	$ (0.27)	0.0%
23	0	10,000	$ 1,025.00	$ 1,024.88	$ (0.13)	0.0%
24	0	10,500	$ 1,075.03	$ 1,075.04	$ 0.01	0.0%
25	0	11,000	$ 1,125.05	$ 1,125.21	$ 0.16	0.0%

IEU Set 3-INT-3 Attachment 3

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Water Heating						
1	0	250	$ 36.87	$ 36.56	$ (0.30)	-0.8%
2	0	500	$ 69.57	$ 68.97	$ (0.61)	-0.9%
3	0	750	$ 98.04	$ 97.13	$ (0.91)	-0.9%
4	0	1,000	$ 126.51	$ 125.30	$ (1.21)	-1.0%
5	0	1,250	$ 154.98	$ 153.47	$ (1.52)	-1.0%
6	0	1,500	$ 183.45	$ 181.64	$ (1.82)	-1.0%
7	0	2,000	$ 240.40	$ 237.97	$ (2.43)	-1.0%
8	0	2,500	$ 297.11	$ 294.07	$ (3.03)	-1.0%
9	0	3,000	$ 353.82	$ 350.18	$ (3.64)	-1.0%
10	0	3,500	$ 410.53	$ 406.28	$ (4.25)	-1.0%
11	0	4,000	$ 467.23	$ 462.38	$ (4.85)	-1.0%
12	0	4,500	$ 523.94	$ 518.49	$ (5.46)	-1.0%
13	0	5,000	$ 580.65	$ 574.59	$ (6.06)	-1.0%
14	0	5,500	$ 637.36	$ 630.69	$ (6.67)	-1.0%
15	0	6,000	$ 694.07	$ 686.80	$ (7.28)	-1.0%
16	0	6,500	$ 750.78	$ 742.90	$ (7.88)	-1.1%
17	0	7,000	$ 807.49	$ 799.00	$ (8.49)	-1.1%
18	0	7,500	$ 864.20	$ 855.11	$ (9.10)	-1.1%
19	0	8,000	$ 920.91	$ 911.21	$ (9.70)	-1.1%
20	0	8,500	$ 977.62	$ 967.31	$ (10.31)	-1.1%
21	0	9,000	$ 1,034.33	$ 1,023.42	$ (10.92)	-1.1%
22	0	9,500	$ 1,091.04	$ 1,079.52	$ (11.52)	-1.1%
23	0	10,000	$ 1,147.75	$ 1,135.63	$ (12.13)	-1.1%
24	0	10,500	$ 1,204.46	$ 1,191.73	$ (12.74)	-1.1%
25	0	11,000	$ 1,261.17	$ 1,247.83	$ (13.34)	-1.1%

IEU Set 3-INT-3 Attachment 3

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - All-Electric Apt.						
1	0	250	$ 35.71	$ 35.99	$ 0.28	0.8%
2	0	500	$ 67.26	$ 67.82	$ 0.56	0.8%
3	0	750	$ 91.95	$ 92.79	$ 0.84	0.9%
4	0	1,000	$ 116.64	$ 117.76	$ 1.12	1.0%
5	0	1,250	$ 141.33	$ 142.73	$ 1.40	1.0%
6	0	1,500	$ 166.02	$ 167.70	$ 1.68	1.0%
7	0	2,000	$ 215.40	$ 217.64	$ 2.24	1.0%
8	0	2,500	$ 266.86	$ 268.49	$ 1.63	0.6%
9	0	3,000	$ 318.32	$ 319.34	$ 1.03	0.3%
10	0	3,500	$ 369.78	$ 370.20	$ 0.42	0.1%
11	0	4,000	$ 421.23	$ 421.05	$ (0.18)	0.0%
12	0	4,500	$ 472.69	$ 471.90	$ (0.79)	-0.2%
13	0	5,000	$ 524.15	$ 522.76	$ (1.40)	-0.3%
14	0	5,500	$ 575.61	$ 573.61	$ (2.00)	-0.3%
15	0	6,000	$ 627.07	$ 624.46	$ (2.61)	-0.4%
16	0	6,500	$ 678.53	$ 675.32	$ (3.22)	-0.5%
17	0	7,000	$ 729.99	$ 726.17	$ (3.82)	-0.5%
18	0	7,500	$ 781.45	$ 777.02	$ (4.43)	-0.6%
19	0	8,000	$ 832.91	$ 827.88	$ (5.04)	-0.6%
20	0	8,500	$ 884.37	$ 878.73	$ (5.64)	-0.6%
21	0	9,000	$ 935.83	$ 929.58	$ (6.25)	-0.7%
22	0	9,500	$ 987.29	$ 980.44	$ (6.86)	-0.7%
23	0	10,000	$ 1,038.75	$ 1,031.29	$ (7.46)	-0.7%
24	0	10,500	$ 1,090.21	$ 1,082.15	$ (8.07)	-0.7%
25	0	11,000	$ 1,141.67	$ 1,133.00	$ (8.68)	-0.8%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Bill Data

Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Secondary (Rate GS)						
1	10	1,000	$ 194.11	$ 190.96	$ (3.15)	-1.6%
2	10	2,000	$ 277.39	$ 274.24	$ (3.15)	-1.1%
3	10	3,000	$ 360.22	$ 357.08	$ (3.15)	-0.9%
4	10	4,000	$ 443.06	$ 439.91	$ (3.15)	-0.7%
5	10	5,000	$ 525.90	$ 522.76	$ (3.15)	-0.6%
6	10	6,000	$ 608.69	$ 605.54	$ (3.15)	-0.5%
7	1,000	100,000	$ 21,433.95	$ 21,119.15	$ (314.80)	-1.5%
8	1,000	200,000	$ 29,660.54	$ 29,345.74	$ (314.80)	-1.1%
9	1,000	300,000	$ 37,887.14	$ 37,572.34	$ (314.80)	-0.8%
10	1,000	400,000	$ 46,113.73	$ 45,798.93	$ (314.80)	-0.7%
11	1,000	500,000	$ 54,340.33	$ 54,025.53	$ (314.80)	-0.6%
12	1,000	600,000	$ 62,566.91	$ 62,252.11	$ (314.80)	-0.5%

IEU Set 3-INT-3 Attachment 3

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Bill Data

Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Primary (Rate GP)						
1	500	50,000	$ 7,331.52	$ 7,027.07	$ (304.45)	-4.2%
2	500	100,000	$ 11,405.01	$ 11,100.56	$ (304.45)	-2.7%
3	500	150,000	$ 15,478.52	$ 15,174.07	$ (304.45)	-2.0%
4	500	200,000	$ 19,552.01	$ 19,247.56	$ (304.45)	-1.6%
5	500	250,000	$ 23,625.51	$ 23,321.06	$ (304.45)	-1.3%
6	500	300,000	$ 27,699.02	$ 27,394.57	$ (304.45)	-1.1%
7	5,000	500,000	$ 71,777.36	$ 68,732.86	$ (3,044.50)	-4.2%
8	5,000	1,000,000	$ 112,444.18	$ 109,399.68	$ (3,044.50)	-2.7%
9	5,000	1,500,000	$ 152,975.07	$ 149,930.57	$ (3,044.50)	-2.0%
10	5,000	2,000,000	$ 193,505.96	$ 190,461.46	$ (3,044.50)	-1.6%
11	5,000	2,500,000	$ 234,036.85	$ 230,992.35	$ (3,044.50)	-1.3%
12	5,000	3,000,000	$ 274,567.75	$ 271,523.25	$ (3,044.50)	-1.1%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Subtransmission (Rate GSU)						
1	1,000	100,000	$ 11,693.75	$ 10,959.25	$ (734.50)	-6.3%
2	1,000	200,000	$ 18,521.85	$ 17,787.35	$ (734.50)	-4.0%
3	1,000	300,000	$ 25,349.94	$ 24,615.44	$ (734.50)	-2.9%
4	1,000	400,000	$ 32,178.03	$ 31,443.53	$ (734.50)	-2.3%
5	1,000	500,000	$ 39,006.13	$ 38,271.63	$ (734.50)	-1.9%
6	1,000	600,000	$ 45,834.22	$ 45,099.72	$ (734.50)	-1.6%
7	10,000	1,000,000	$ 114,872.62	$ 107,527.62	$ (7,345.00)	-6.4%
8	10,000	2,000,000	$ 182,745.35	$ 175,400.35	$ (7,345.00)	-4.0%
9	10,000	3,000,000	$ 250,618.08	$ 243,273.08	$ (7,345.00)	-2.9%
10	10,000	4,000,000	$ 318,490.81	$ 311,145.81	$ (7,345.00)	-2.3%
11	10,000	5,000,000	$ 386,363.54	$ 379,018.54	$ (7,345.00)	-1.9%
12	10,000	6,000,000	$ 454,236.28	$ 446,891.28	$ (7,345.00)	-1.6%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

		Bill Data				
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Transmission (Rate GT)						
1	2,000	200,000	$ 35,272.68	$ 30,793.28	$ (4,479.40)	-12.7%
2	2,000	400,000	$ 46,001.82	$ 42,367.42	$ (3,634.40)	-7.9%
3	2,000	600,000	$ 56,730.95	$ 53,941.55	$ (2,789.40)	-4.9%
4	2,000	800,000	$ 67,460.09	$ 65,515.69	$ (1,944.40)	-2.9%
5	2,000	1,000,000	$ 78,121.06	$ 77,021.66	$ (1,099.40)	-1.4%
6	2,000	1,200,000	$ 88,768.55	$ 88,514.15	$ (254.40)	-0.3%
7	20,000	2,000,000	$ 349,286.34	$ 304,492.34	$ (44,794.00)	-12.8%
8	20,000	4,000,000	$ 455,761.30	$ 419,417.30	$ (36,344.00)	-8.0%
9	20,000	6,000,000	$ 562,236.26	$ 534,342.26	$ (27,894.00)	-5.0%
10	20,000	8,000,000	$ 668,711.22	$ 649,267.22	$ (19,444.00)	-2.9%
11	20,000	10,000,000	$ 775,186.18	$ 764,192.18	$ (10,994.00)	-1.4%
12	20,000	12,000,000	$ 881,661.14	$ 879,117.14	$ (2,544.00)	-0.3%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
1	Company Owned - Incandescent Street Lighting (a)					
2	Overhead Wood Service (Single lamps)					
3	1,000	24	$ 12.59	$ 12.59	$ -	0.0%
4	2,000	56	$ 14.71	$ 14.71	$ -	0.0%
5	2,500	70	$ 15.65	$ 15.65	$ -	0.0%
6	4,000	126	$ 19.35	$ 19.35	$ -	0.0%
7	6,000	157	$ 21.40	$ 21.40	$ -	0.0%
8	10,000	242	$ 27.04	$ 27.04	$ -	0.0%
9	15,000	282	$ 29.68	$ 29.68	$ -	0.0%
10	Overhead Steel Service (Single lamps)					
11	1,000	24	$ 13.57	$ 13.57	$ -	0.0%
12	2,000	56	$ 15.69	$ 15.69	$ -	0.0%
13	2,500	70	$ 16.63	$ 16.63	$ -	0.0%
14	4,000	126	$ 20.33	$ 20.33	$ -	0.0%
15	6,000	157	$ 22.38	$ 22.38	$ -	0.0%
16	10,000	242	$ 28.02	$ 28.02	$ -	0.0%
17	15,000	282	$ 30.66	$ 30.66	$ -	0.0%
18	Underground Service (Single lamps)					
19	1,000	24	$ 19.77	$ 19.77	$ -	0.0%
20	2,000	56	$ 21.89	$ 21.89	$ -	0.0%
21	2,500	70	$ 22.83	$ 22.83	$ -	0.0%
22	4,000	126	$ 26.53	$ 26.53	$ -	0.0%
23	6,000	157	$ 28.58	$ 28.58	$ -	0.0%
24	10,000	242	$ 34.22	$ 34.22	$ -	0.0%
25	15,000	282	$ 36.86	$ 36.86	$ -	0.0%
26	Underground Service (Dual lamps)					
27	1,000	48	$ 35.47	$ 35.47	$ -	0.0%
28	2,000	112	$ 39.72	$ 39.72	$ -	0.0%
29	2,500	140	$ 41.58	$ 41.58	$ -	0.0%
30	4,000	252	$ 48.99	$ 48.99	$ -	0.0%
31	6,000	314	$ 53.12	$ 53.12	$ -	0.0%
32	10,000	484	$ 64.37	$ 64.37	$ -	0.0%
33	15,000	564	$ 69.69	$ 69.69	$ -	0.0%
34	Company Owned - Fluorescent Street Lighting (a)					
35	Overhead Steel Service (Single lamps)					
36	6,000	45	$ 19.80	$ 19.80	$ -	0.0%
37	13,800	94	$ 23.07	$ 23.07	$ -	0.0%
38	21,800	135	$ 25.79	$ 25.79	$ -	0.0%
39	43,600	264	$ 34.34	$ 34.34	$ -	0.0%
40	Underground Service (Single lamps)					
41	6,000	45	$ 18.06	$ 18.06	$ -	0.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
42	13,800	94	$ 21.33	$ 21.33	$ -	0.0%
43	21,800	135	$ 24.05	$ 24.05	$ -	0.0%
44	43,600	264	$ 32.60	$ 32.60	$ -	0.0%
45	Underground Service (Dual lamps)					
46	6,000	90	$ 26.58	$ 26.58	$ -	0.0%
47	13,800	188	$ 33.07	$ 33.07	$ -	0.0%
48	21,800	270	$ 38.51	$ 38.51	$ -	0.0%
49	43,600	528	$ 55.62	$ 55.62	$ -	0.0%
50	Company Owned - Mercury Street Lighting - Single lamp (c)					
51	Overhead Service - Wood Pole					
52	175	69	$ 10.59	$ 10.59	$ -	0.0%
53	250	104	$ 13.51	$ 13.51	$ -	0.0%
54	400	158	$ 18.74	$ 18.74	$ -	0.0%
55	700	287	$ 32.48	$ 32.48	$ -	0.0%
56	1000	380	$ 41.10	$ 41.10	$ -	0.0%
57	Overhead Service - Metal Pole					
58	175	69	$ 12.87	$ 12.87	$ -	0.0%
59	250	104	$ 15.63	$ 15.63	$ -	0.0%
60	400	158	$ 21.44	$ 21.44	$ -	0.0%
61	700	287	$ 35.39	$ 35.39	$ -	0.0%
62	1000	380	$ 44.07	$ 44.07	$ -	0.0%
63	Underground Service					
64	175	69	$ 16.59	$ 16.59	$ -	0.0%
65	250	104	$ 19.47	$ 19.47	$ -	0.0%
66	400	158	$ 25.07	$ 25.07	$ -	0.0%
67	700	287	$ 37.25	$ 37.25	$ -	0.0%
68	1000	380	$ 45.71	$ 45.71	$ -	0.0%
69	Company Owned - Mercury Street Lighting - Dual lamps (c)					
70	Overhead Service - Wood Pole					
71	175	138	$ 19.35	$ 19.35	$ -	0.0%
72	400	316	$ 35.54	$ 35.54	$ -	0.0%
73	Overhead Service - Metal Pole					
74	400	316	$ 38.20	$ 38.20	$ -	0.0%
75	Underground Service					
76	250	208	$ 31.35	$ 31.35	$ -	0.0%
77	400	316	$ 41.47	$ 41.47	$ -	0.0%
78	Company Owned - High Pressure Sodium Lighting - Single lamps (d)					
79	Overhead Service - Wood Pole					
80	100	42	$ 11.96	$ 11.96	$ -	0.0%
81	150	62	$ 14.50	$ 14.50	$ -	0.0%
82	200	88	$ 19.08	$ 19.08	$ -	0.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
83	250	105	$ 17.38	$ 17.38	$ -	0.0%
84	400	163	$ 24.44	$ 24.44	$ -	0.0%
85	Overhead Service - Metal Pole					
86	100	42	$ 13.81	$ 13.81	$ -	0.0%
87	150	62	$ 15.82	$ 15.82	$ -	0.0%
88	200	88	$ 21.20	$ 21.20	$ -	0.0%
89	250	105	$ 21.35	$ 21.35	$ -	0.0%
90	400	163	$ 27.87	$ 27.87	$ -	0.0%
91	Underground Service					
92	100	42	$ 17.56	$ 17.56	$ -	0.0%
93	100 (orn.)	42	$ 28.86	$ 28.86	$ -	0.0%
94	150	62	$ 16.83	$ 16.83	$ -	0.0%
95	200	88	$ 25.15	$ 25.15	$ -	0.0%
96	250	105	$ 23.05	$ 23.05	$ -	0.0%
97	250 (dwntwn)	105	$ 38.07	$ 38.07	$ -	0.0%
98	400	163	$ 28.60	$ 28.60	$ -	0.0%
99	400 (dwntwn)	25	$ 47.24	$ 47.24	$ -	0.0%
100	Company Owned - High Pressure Sodium Lighting - Dual lamps (d)					
101	Overhead Service - Wood Pole					
102	100	84	$ 23.46	$ 23.46	$ -	0.0%
103	150	124	$ 27.13	$ 27.13	$ -	0.0%
104	250	210	$ 34.87	$ 34.87	$ -	0.0%
105	Overhead Service - Metal Pole					
106	100	84	$ 24.35	$ 24.35	$ -	0.0%
107	150	124	$ 27.57	$ 27.57	$ -	0.0%
108	250	210	$ 36.28	$ 36.28	$ -	0.0%
109	Underground Service					
110	100	84	$ 28.59	$ 28.59	$ -	0.0%
111	150	124	$ 34.25	$ 34.25	$ -	0.0%
112	250	210	$ 42.53	$ 42.53	$ -	0.0%
113	400 (davit)	326	$ 44.75	$ 44.75	$ -	0.0%
114	Customer Owned - Limited Company Maintenance - All Lamp Types					
115	N/A	25	$ 1.70	$ 1.70	$ -	0.0%
116	N/A	50	$ 3.35	$ 3.35	$ -	0.0%
117	N/A	75	$ 6.11	$ 6.11	$ -	0.0%
118	N/A	100	$ 9.27	$ 9.27	$ -	0.0%
119	N/A	125	$ 11.58	$ 11.58	$ -	0.0%
120	N/A	150	$ 15.84	$ 15.84	$ -	0.0%
121	N/A	175	$ 18.92	$ 18.92	$ -	0.0%
122	N/A	200	$ 24.54	$ 24.54	$ -	0.0%
123	N/A	225	$ 28.04	$ 28.04	$ -	0.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
124	N/A	250	$ 16.60	$ 16.60	$ -	0.0%
125	N/A	275	$ 19.39	$ 19.39	$ -	0.0%
126	N/A	300	$ 22.52	$ 22.52	$ -	0.0%
127	N/A	325	$ 24.82	$ 24.82	$ -	0.0%
128	N/A	350	$ 29.09	$ 29.09	$ -	0.0%
129	N/A	375	$ 32.16	$ 32.16	$ -	0.0%
130	N/A	400	$ 37.78	$ 37.78	$ -	0.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
	Private Outdoor Lighting Service (Rate POL)					
1	Mercury Lighting					
2	Overhead Service - Wood Pole					
3	175	69	$ 10.48	$ 10.48	$ -	0.0%
4	400	158	$ 27.03	$ 27.03	$ -	0.0%
5	1,000	380	$ 46.98	$ 46.98	$ -	0.0%
6	All Other Installations					
7	175	69	$ 17.07	$ 17.07	$ -	0.0%
8	High Pressure Sodium Lighting					
9	Overhead Service - Wood Pole					
10	200	88	$ 14.28	$ 14.28	$ -	0.0%
11	400	163	$ 25.46	$ 25.46	$ -	0.0%

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 1 of Proposed ESP IV vs. Year 2 of Proposed ESP IV)

		Bill Data				
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Traffic Lighting Schedule (Rate TRF)						
1	0	100	$ 10.50	$ 10.42	$ (0.08)	-0.7%
2	0	200	$ 20.85	$ 20.69	$ (0.15)	-0.7%
3	0	300	$ 31.18	$ 30.95	$ (0.23)	-0.7%
4	0	400	$ 41.50	$ 41.20	$ (0.31)	-0.7%
5	0	500	$ 51.85	$ 51.47	$ (0.38)	-0.7%
6	0	600	$ 62.21	$ 61.75	$ (0.46)	-0.7%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

		Bill Data				
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - Standard (Rate RS)						
1	0	250	$ 36.56	$ 36.00	$ (0.56)	-1.5%
2	0	500	$ 68.97	$ 67.85	$ (1.12)	-1.6%
3	0	750	$ 101.37	$ 99.69	$ (1.68)	-1.7%
4	0	1,000	$ 133.78	$ 131.54	$ (2.24)	-1.7%
5	0	1,250	$ 166.18	$ 163.38	$ (2.80)	-1.7%
6	0	1,500	$ 198.59	$ 195.23	$ (3.36)	-1.7%
7	0	2,000	$ 263.39	$ 258.92	$ (4.47)	-1.7%
8	0	2,500	$ 327.97	$ 322.38	$ (5.59)	-1.7%
9	0	3,000	$ 392.55	$ 385.84	$ (6.71)	-1.7%
10	0	3,500	$ 457.13	$ 449.30	$ (7.83)	-1.7%
11	0	4,000	$ 521.71	$ 512.76	$ (8.95)	-1.7%
12	0	4,500	$ 586.29	$ 576.22	$ (10.07)	-1.7%
13	0	5,000	$ 650.87	$ 639.68	$ (11.19)	-1.7%
14	0	5,500	$ 715.44	$ 703.14	$ (12.30)	-1.7%
15	0	6,000	$ 780.02	$ 766.60	$ (13.42)	-1.7%
16	0	6,500	$ 844.60	$ 830.06	$ (14.54)	-1.7%
17	0	7,000	$ 909.18	$ 893.52	$ (15.66)	-1.7%
18	0	7,500	$ 973.76	$ 956.98	$ (16.78)	-1.7%
19	0	8,000	$ 1,038.34	$ 1,020.44	$ (17.90)	-1.7%
20	0	8,500	$ 1,102.91	$ 1,083.90	$ (19.02)	-1.7%
21	0	9,000	$ 1,167.49	$ 1,147.36	$ (20.13)	-1.7%
22	0	9,500	$ 1,232.07	$ 1,210.82	$ (21.25)	-1.7%
23	0	10,000	$ 1,296.65	$ 1,274.28	$ (22.37)	-1.7%
24	0	10,500	$ 1,361.23	$ 1,337.74	$ (23.49)	-1.7%
25	0	11,000	$ 1,425.81	$ 1,401.20	$ (24.61)	-1.7%

IEU Set 3-INT-3 Attachment 3
Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Electric Heating						
1	0	250	$ 36.56	$ 36.00	$ (0.56)	-1.5%
2	0	500	$ 68.97	$ 67.85	$ (1.12)	-1.6%
3	0	750	$ 94.51	$ 92.83	$ (1.68)	-1.8%
4	0	1,000	$ 120.05	$ 117.81	$ (2.24)	-1.9%
5	0	1,250	$ 145.59	$ 142.80	$ (2.80)	-1.9%
6	0	1,500	$ 171.14	$ 167.78	$ (3.36)	-2.0%
7	0	2,000	$ 222.22	$ 217.75	$ (4.47)	-2.0%
8	0	2,500	$ 272.39	$ 267.48	$ (4.91)	-1.8%
9	0	3,000	$ 322.55	$ 317.22	$ (5.34)	-1.7%
10	0	3,500	$ 372.72	$ 366.95	$ (5.77)	-1.5%
11	0	4,000	$ 422.88	$ 416.68	$ (6.20)	-1.5%
12	0	4,500	$ 473.05	$ 466.42	$ (6.63)	-1.4%
13	0	5,000	$ 523.22	$ 516.15	$ (7.06)	-1.3%
14	0	5,500	$ 573.38	$ 565.89	$ (7.49)	-1.3%
15	0	6,000	$ 623.55	$ 615.62	$ (7.92)	-1.3%
16	0	6,500	$ 673.71	$ 665.36	$ (8.35)	-1.2%
17	0	7,000	$ 723.88	$ 715.09	$ (8.78)	-1.2%
18	0	7,500	$ 774.05	$ 764.83	$ (9.22)	-1.2%
19	0	8,000	$ 824.21	$ 814.56	$ (9.65)	-1.2%
20	0	8,500	$ 874.38	$ 864.30	$ (10.08)	-1.2%
21	0	9,000	$ 924.54	$ 914.03	$ (10.51)	-1.1%
22	0	9,500	$ 974.71	$ 963.77	$ (10.94)	-1.1%
23	0	10,000	$ 1,024.88	$ 1,013.50	$ (11.37)	-1.1%
24	0	10,500	$ 1,075.04	$ 1,063.24	$ (11.80)	-1.1%
25	0	11,000	$ 1,125.21	$ 1,112.97	$ (12.23)	-1.1%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - Water Heating						
1	0	250	$ 36.56	$ 36.00	$ (0.56)	-1.5%
2	0	500	$ 68.97	$ 67.85	$ (1.12)	-1.6%
3	0	750	$ 97.13	$ 95.46	$ (1.68)	-1.7%
4	0	1,000	$ 125.30	$ 123.06	$ (2.24)	-1.8%
5	0	1,250	$ 153.47	$ 150.67	$ (2.80)	-1.8%
6	0	1,500	$ 181.64	$ 178.28	$ (3.36)	-1.8%
7	0	2,000	$ 237.97	$ 233.50	$ (4.47)	-1.9%
8	0	2,500	$ 294.07	$ 288.48	$ (5.59)	-1.9%
9	0	3,000	$ 350.18	$ 343.47	$ (6.71)	-1.9%
10	0	3,500	$ 406.28	$ 398.45	$ (7.83)	-1.9%
11	0	4,000	$ 462.38	$ 453.43	$ (8.95)	-1.9%
12	0	4,500	$ 518.49	$ 508.42	$ (10.07)	-1.9%
13	0	5,000	$ 574.59	$ 563.40	$ (11.19)	-1.9%
14	0	5,500	$ 630.69	$ 618.39	$ (12.30)	-2.0%
15	0	6,000	$ 686.80	$ 673.37	$ (13.42)	-2.0%
16	0	6,500	$ 742.90	$ 728.36	$ (14.54)	-2.0%
17	0	7,000	$ 799.00	$ 783.34	$ (15.66)	-2.0%
18	0	7,500	$ 855.11	$ 838.33	$ (16.78)	-2.0%
19	0	8,000	$ 911.21	$ 893.31	$ (17.90)	-2.0%
20	0	8,500	$ 967.31	$ 948.30	$ (19.02)	-2.0%
21	0	9,000	$ 1,023.42	$ 1,003.28	$ (20.13)	-2.0%
22	0	9,500	$ 1,079.52	$ 1,058.27	$ (21.25)	-2.0%
23	0	10,000	$ 1,135.63	$ 1,113.25	$ (22.37)	-2.0%
24	0	10,500	$ 1,191.73	$ 1,168.24	$ (23.49)	-2.0%
25	0	11,000	$ 1,247.83	$ 1,223.22	$ (24.61)	-2.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (E)
Residential Service - (Rate RS) - All-Electric Apt.						
1	0	250	$ 35.99	$ 36.00	$ 0.01	0.0%
2	0	500	$ 67.82	$ 67.85	$ 0.03	0.0%
3	0	750	$ 92.79	$ 92.83	$ 0.04	0.0%
4	0	1,000	$ 117.76	$ 117.81	$ 0.05	0.0%
5	0	1,250	$ 142.73	$ 142.80	$ 0.07	0.0%
6	0	1,500	$ 167.70	$ 167.78	$ 0.08	0.0%
7	0	2,000	$ 217.64	$ 217.75	$ 0.11	0.1%
8	0	2,500	$ 268.49	$ 267.48	$ (1.01)	-0.4%
9	0	3,000	$ 319.34	$ 317.22	$ (2.13)	-0.7%
10	0	3,500	$ 370.20	$ 366.95	$ (3.25)	-0.9%
11	0	4,000	$ 421.05	$ 416.68	$ (4.37)	-1.0%
12	0	4,500	$ 471.90	$ 466.42	$ (5.48)	-1.2%
13	0	5,000	$ 522.76	$ 516.15	$ (6.60)	-1.3%
14	0	5,500	$ 573.61	$ 565.89	$ (7.72)	-1.3%
15	0	6,000	$ 624.46	$ 615.62	$ (8.84)	-1.4%
16	0	6,500	$ 675.32	$ 665.36	$ (9.96)	-1.5%
17	0	7,000	$ 726.17	$ 715.09	$ (11.08)	-1.5%
18	0	7,500	$ 777.02	$ 764.83	$ (12.19)	-1.6%
19	0	8,000	$ 827.88	$ 814.56	$ (13.31)	-1.6%
20	0	8,500	$ 878.73	$ 864.30	$ (14.43)	-1.6%
21	0	9,000	$ 929.58	$ 914.03	$ (15.55)	-1.7%
22	0	9,500	$ 980.44	$ 963.77	$ (16.67)	-1.7%
23	0	10,000	$ 1,031.29	$ 1,013.50	$ (17.79)	-1.7%
24	0	10,500	$ 1,082.15	$ 1,063.24	$ (18.91)	-1.7%
25	0	11,000	$ 1,133.00	$ 1,112.97	$ (20.02)	-1.8%

IEU Set 3-INT-3 Attachment 3

Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Bill Data

Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Secondary (Rate GS)						
1	10	1,000	$ 190.96	$ 184.52	$ (6.44)	-3.4%
2	10	2,000	$ 274.24	$ 267.80	$ (6.44)	-2.3%
3	10	3,000	$ 357.08	$ 350.63	$ (6.44)	-1.8%
4	10	4,000	$ 439.91	$ 433.47	$ (6.44)	-1.5%
5	10	5,000	$ 522.76	$ 516.31	$ (6.44)	-1.2%
6	10	6,000	$ 605.54	$ 599.10	$ (6.44)	-1.1%
7	1,000	100,000	$ 21,119.15	$ 20,474.95	$ (644.20)	-3.1%
8	1,000	200,000	$ 29,345.74	$ 28,701.54	$ (644.20)	-2.2%
9	1,000	300,000	$ 37,572.34	$ 36,928.14	$ (644.20)	-1.7%
10	1,000	400,000	$ 45,798.93	$ 45,154.73	$ (644.20)	-1.4%
11	1,000	500,000	$ 54,025.53	$ 53,381.33	$ (644.20)	-1.2%
12	1,000	600,000	$ 62,252.11	$ 61,607.91	$ (644.20)	-1.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Primary (Rate GP)						
1	500	50,000	$ 7,027.07	$ 6,529.92	$ (497.15)	-7.1%
2	500	100,000	$ 11,100.56	$ 10,603.41	$ (497.15)	-4.5%
3	500	150,000	$ 15,174.07	$ 14,676.92	$ (497.15)	-3.3%
4	500	200,000	$ 19,247.56	$ 18,750.41	$ (497.15)	-2.6%
5	500	250,000	$ 23,321.06	$ 22,823.91	$ (497.15)	-2.1%
6	500	300,000	$ 27,394.57	$ 26,897.42	$ (497.15)	-1.8%
7	5,000	500,000	$ 68,732.86	$ 63,761.36	$ (4,971.50)	-7.2%
8	5,000	1,000,000	$ 109,399.68	$ 104,428.18	$ (4,971.50)	-4.5%
9	5,000	1,500,000	$ 149,930.57	$ 144,959.07	$ (4,971.50)	-3.3%
10	5,000	2,000,000	$ 190,461.46	$ 185,489.96	$ (4,971.50)	-2.6%
11	5,000	2,500,000	$ 230,992.35	$ 226,020.85	$ (4,971.50)	-2.2%
12	5,000	3,000,000	$ 271,523.25	$ 266,551.75	$ (4,971.50)	-1.8%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Subtransmission (Rate GSU)						
1	1,000	100,000	$ 10,959.25	$ 9,813.15	$ (1,146.10)	-10.5%
2	1,000	200,000	$ 17,787.35	$ 16,641.25	$ (1,146.10)	-6.4%
3	1,000	300,000	$ 24,615.44	$ 23,469.34	$ (1,146.10)	-4.7%
4	1,000	400,000	$ 31,443.53	$ 30,297.43	$ (1,146.10)	-3.6%
5	1,000	500,000	$ 38,271.63	$ 37,125.53	$ (1,146.10)	-3.0%
6	1,000	600,000	$ 45,099.72	$ 43,953.62	$ (1,146.10)	-2.5%
7	10,000	1,000,000	$ 107,527.62	$ 96,066.62	$ (11,461.00)	-10.7%
8	10,000	2,000,000	$ 175,400.35	$ 163,939.35	$ (11,461.00)	-6.5%
9	10,000	3,000,000	$ 243,273.08	$ 231,812.08	$ (11,461.00)	-4.7%
10	10,000	4,000,000	$ 311,145.81	$ 299,684.81	$ (11,461.00)	-3.7%
11	10,000	5,000,000	$ 379,018.54	$ 367,557.54	$ (11,461.00)	-3.0%
12	10,000	6,000,000	$ 446,891.28	$ 435,430.28	$ (11,461.00)	-2.6%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Bill Data

Line No.	Level of Demand (kVa) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
General Service Transmission (Rate GT)						
1	2,000	200,000	$ 30,793.28	$ 25,644.28	$ (5,149.00)	-16.7%
2	2,000	400,000	$ 42,367.42	$ 38,108.62	$ (4,258.80)	-10.1%
3	2,000	600,000	$ 53,941.55	$ 50,572.95	$ (3,368.60)	-6.2%
4	2,000	800,000	$ 65,515.69	$ 63,037.29	$ (2,478.40)	-3.8%
5	2,000	1,000,000	$ 77,021.66	$ 75,433.46	$ (1,588.20)	-2.1%
6	2,000	1,200,000	$ 88,514.15	$ 87,816.15	$ (698.00)	-0.8%
7	20,000	2,000,000	$ 304,492.34	$ 253,002.34	$ (51,490.00)	-16.9%
8	20,000	4,000,000	$ 419,417.30	$ 376,829.30	$ (42,588.00)	-10.2%
9	20,000	6,000,000	$ 534,342.26	$ 500,656.26	$ (33,686.00)	-6.3%
10	20,000	8,000,000	$ 649,267.22	$ 624,483.22	$ (24,784.00)	-3.8%
11	20,000	10,000,000	$ 764,192.18	$ 748,310.18	$ (15,882.00)	-2.1%
12	20,000	12,000,000	$ 879,117.14	$ 872,137.14	$ (6,980.00)	-0.8%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
1	Company Owned - Incandescent Street Lighting (a)					
2	Overhead Wood Service (Single lamps)					
3	1,000	24	$ 12.59	$ 12.59	$ -	0.0%
4	2,000	56	$ 14.71	$ 14.71	$ -	0.0%
5	2,500	70	$ 15.65	$ 15.65	$ -	0.0%
6	4,000	126	$ 19.35	$ 19.35	$ -	0.0%
7	6,000	157	$ 21.40	$ 21.40	$ -	0.0%
8	10,000	242	$ 27.04	$ 27.04	$ -	0.0%
9	15,000	282	$ 29.68	$ 29.68	$ -	0.0%
10	Overhead Steel Service (Single lamps)					
11	1,000	24	$ 13.57	$ 13.57	$ -	0.0%
12	2,000	56	$ 15.69	$ 15.69	$ -	0.0%
13	2,500	70	$ 16.63	$ 16.63	$ -	0.0%
14	4,000	126	$ 20.33	$ 20.33	$ -	0.0%
15	6,000	157	$ 22.38	$ 22.38	$ -	0.0%
16	10,000	242	$ 28.02	$ 28.02	$ -	0.0%
17	15,000	282	$ 30.66	$ 30.66	$ -	0.0%
18	Underground Service (Single lamps)					
19	1,000	24	$ 19.77	$ 19.77	$ -	0.0%
20	2,000	56	$ 21.89	$ 21.89	$ -	0.0%
21	2,500	70	$ 22.83	$ 22.83	$ -	0.0%
22	4,000	126	$ 26.53	$ 26.53	$ -	0.0%
23	6,000	157	$ 28.58	$ 28.58	$ -	0.0%
24	10,000	242	$ 34.22	$ 34.22	$ -	0.0%
25	15,000	282	$ 36.86	$ 36.86	$ -	0.0%
26	Underground Service (Dual lamps)					
27	1,000	48	$ 35.47	$ 35.47	$ -	0.0%
28	2,000	112	$ 39.72	$ 39.72	$ -	0.0%
29	2,500	140	$ 41.58	$ 41.58	$ -	0.0%
30	4,000	252	$ 48.99	$ 48.99	$ -	0.0%
31	6,000	314	$ 53.12	$ 53.12	$ -	0.0%
32	10,000	484	$ 64.37	$ 64.37	$ -	0.0%
33	15,000	564	$ 69.69	$ 69.69	$ -	0.0%
34	Company Owned - Fluorescent Street Lighting (a)					
35	Overhead Steel Service (Single lamps)					
36	6,000	45	$ 19.80	$ 19.80	$ -	0.0%
37	13,800	94	$ 23.07	$ 23.07	$ -	0.0%
38	21,800	135	$ 25.79	$ 25.79	$ -	0.0%
39	43,600	264	$ 34.34	$ 34.34	$ -	0.0%
40	Underground Service (Single lamps)					
41	6,000	45	$ 18.06	$ 18.06	$ -	0.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
42	13,800	94	$ 21.33	$ 21.33	$ -	0.0%
43	21,800	135	$ 24.05	$ 24.05	$ -	0.0%
44	43,600	264	$ 32.60	$ 32.60	$ -	0.0%
45	Underground Service (Dual lamps)					
46	6,000	90	$ 26.58	$ 26.58	$ -	0.0%
47	13,800	188	$ 33.07	$ 33.07	$ -	0.0%
48	21,800	270	$ 38.51	$ 38.51	$ -	0.0%
49	43,600	528	$ 55.62	$ 55.62	$ -	0.0%
50	Company Owned - Mercury Street Lighting - Single lamp (c)					
51	Overhead Service - Wood Pole					
52	175	69	$ 10.59	$ 10.59	$ -	0.0%
53	250	104	$ 13.51	$ 13.51	$ -	0.0%
54	400	158	$ 18.74	$ 18.74	$ -	0.0%
55	700	287	$ 32.48	$ 32.48	$ -	0.0%
56	1000	380	$ 41.10	$ 41.10	$ -	0.0%
57	Overhead Service - Metal Pole					
58	175	69	$ 12.87	$ 12.87	$ -	0.0%
59	250	104	$ 15.63	$ 15.63	$ -	0.0%
60	400	158	$ 21.44	$ 21.44	$ -	0.0%
61	700	287	$ 35.39	$ 35.39	$ -	0.0%
62	1000	380	$ 44.07	$ 44.07	$ -	0.0%
63	Underground Service					
64	175	69	$ 16.59	$ 16.59	$ -	0.0%
65	250	104	$ 19.47	$ 19.47	$ -	0.0%
66	400	158	$ 25.07	$ 25.07	$ -	0.0%
67	700	287	$ 37.25	$ 37.25	$ -	0.0%
68	1000	380	$ 45.71	$ 45.71	$ -	0.0%
69	Company Owned - Mercury Street Lighting - Dual lamps (c)					
70	Overhead Service - Wood Pole					
71	175	138	$ 19.35	$ 19.35	$ -	0.0%
72	400	316	$ 35.54	$ 35.54	$ -	0.0%
73	Overhead Service - Metal Pole					
74	400	316	$ 38.20	$ 38.20	$ -	0.0%
75	Underground Service					
76	250	208	$ 31.35	$ 31.35	$ -	0.0%
77	400	316	$ 41.47	$ 41.47	$ -	0.0%
78	Company Owned - High Pressure Sodium Lighting - Single lamps (d)					
79	Overhead Service - Wood Pole					
80	100	42	$ 11.96	$ 11.96	$ -	0.0%
81	150	62	$ 14.50	$ 14.50	$ -	0.0%
82	200	88	$ 19.08	$ 19.08	$ -	0.0%

IEU Set 3-INT-3 Attachment 3
Estimated Typical Bill Impacts of the Stipulation, Assuming the Stipulation is Accepted as Filed

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
83	250	105	$ 17.38	$ 17.38	$ -	0.0%
84	400	163	$ 24.44	$ 24.44	$ -	0.0%
85	Overhead Service - Metal Pole					
86	100	42	$ 13.81	$ 13.81	$ -	0.0%
87	150	62	$ 15.82	$ 15.82	$ -	0.0%
88	200	88	$ 21.20	$ 21.20	$ -	0.0%
89	250	105	$ 21.35	$ 21.35	$ -	0.0%
90	400	163	$ 27.87	$ 27.87	$ -	0.0%
91	Underground Service					
92	100	42	$ 17.56	$ 17.56	$ -	0.0%
93	100 (orn.)	42	$ 28.86	$ 28.86	$ -	0.0%
94	150	62	$ 16.83	$ 16.83	$ -	0.0%
95	200	88	$ 25.15	$ 25.15	$ -	0.0%
96	250	105	$ 23.05	$ 23.05	$ -	0.0%
97	250 (dwntwn)	105	$ 38.07	$ 38.07	$ -	0.0%
98	400	163	$ 28.60	$ 28.60	$ -	0.0%
99	400 (dwntwn)	25	$ 47.24	$ 47.24	$ -	0.0%
100	Company Owned - High Pressure Sodium Lighting - Dual lamps (d)					
101	Overhead Service - Wood Pole					
102	100	84	$ 23.46	$ 23.46	$ -	0.0%
103	150	124	$ 27.13	$ 27.13	$ -	0.0%
104	250	210	$ 34.87	$ 34.87	$ -	0.0%
105	Overhead Service - Metal Pole					
106	100	84	$ 24.35	$ 24.35	$ -	0.0%
107	150	124	$ 27.57	$ 27.57	$ -	0.0%
108	250	210	$ 36.28	$ 36.28	$ -	0.0%
109	Underground Service					
110	100	84	$ 28.59	$ 28.59	$ -	0.0%
111	150	124	$ 34.25	$ 34.25	$ -	0.0%
112	250	210	$ 42.53	$ 42.53	$ -	0.0%
113	400 (davit)	326	$ 44.75	$ 44.75	$ -	0.0%
114	Customer Owned - Limited Company Maintenance - All Lamp Types					
115	N/A	25	$ 1.70	$ 1.70	$ -	0.0%
116	N/A	50	$ 3.35	$ 3.35	$ -	0.0%
117	N/A	75	$ 6.11	$ 6.11	$ -	0.0%
118	N/A	100	$ 9.27	$ 9.27	$ -	0.0%
119	N/A	125	$ 11.58	$ 11.58	$ -	0.0%
120	N/A	150	$ 15.84	$ 15.84	$ -	0.0%
121	N/A	175	$ 18.92	$ 18.92	$ -	0.0%
122	N/A	200	$ 24.54	$ 24.54	$ -	0.0%
123	N/A	225	$ 28.04	$ 28.04	$ -	0.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Street Lighting Service (Rate STL)						
124	N/A	250	$ 16.60	$ 16.60	$ -	0.0%
125	N/A	275	$ 19.39	$ 19.39	$ -	0.0%
126	N/A	300	$ 22.52	$ 22.52	$ -	0.0%
127	N/A	325	$ 24.82	$ 24.82	$ -	0.0%
128	N/A	350	$ 29.09	$ 29.09	$ -	0.0%
129	N/A	375	$ 32.16	$ 32.16	$ -	0.0%
130	N/A	400	$ 37.78	$ 37.78	$ -	0.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

Line No.	Bulb Rating (Lumens or Watts) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change ($) (E)	Percent Change (%) (F)
Private Outdoor Lighting Service (Rate POL)						
1	Mercury Lighting					
2	Overhead Service - Wood Pole					
3	175	69	$ 10.48	$ 10.48	$ -	0.0%
4	400	158	$ 27.03	$ 27.03	$ -	0.0%
5	1,000	380	$ 46.98	$ 46.98	$ -	0.0%
6	All Other Installations					
7	175	69	$ 17.07	$ 17.07	$ -	0.0%
8	High Pressure Sodium Lighting					
9	Overhead Service - Wood Pole					
10	200	88	$ 14.28	$ 14.28	$ -	0.0%
11	400	163	$ 25.46	$ 25.46	$ -	0.0%

The Toledo Edison Company
Case No. 14-1297-EL-SSO
Typical Bills - Comparison (Year 2 of Proposed ESP IV vs. Year 3 of Proposed ESP IV)

			Bill Data			
Line No.	Level of Demand (kW) (A)	Level of Usage (kWH) (B)	Current Annual Bill ($) (C)	Proposed Annual Bill ($) (D)	Dollar Change (D)-(C) (E)	Percent Change (E)/(C) (F)
Traffic Lighting Schedule (Rate TRF)						
1	0	100	$ 10.42	$ 10.30	$ (0.12)	-1.1%
2	0	200	$ 20.69	$ 20.46	$ (0.24)	-1.1%
3	0	300	$ 30.95	$ 30.59	$ (0.35)	-1.1%
4	0	400	$ 41.20	$ 40.72	$ (0.47)	-1.1%
5	0	500	$ 51.47	$ 50.88	$ (0.59)	-1.1%
6	0	600	$ 61.75	$ 61.04	$ (0.71)	-1.1%

OCC Set 5
Witness: Santino L. Fanelli
As to Objections: Carrie M. Dunn

Case No. 14-1297-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and
The Toledo Edison Company for Authority to Provide for a Standard Service Offer
Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan

RESPONSES TO REQUEST

OCC Set 5–INT-125 Referring to pages 3-4 of the Direct Testimony of the Companies' witness Fanelli, please explain why an average annual increase in the revenue requirement over the seven years since the last base distribution rate case is the appropriate basis for the annual increase in DCR revenue cap.

Response: Objection. The request mischaracterizes the testimony of Companies' witness Fanelli. Subject to and without waiving the foregoing objection, the average annual Rider DCR revenue requirement increase since the Companies' last distribution rate case is a reasonable representation of the average annual Rider DCR revenue requirement increase during the term of ESP IV.

EXHIBIT
OCC 17
PENGAD 800-631-6989