TECO
TAMPA ELECTRIC

December 1, 2014

Environmental Protection Agency, EPA Docket Center
Attention: Docket ID No. EPA-HQ-OAR-2013-0602
1200 Pennsylvania Ave., N.W.
Mailcode 28221T
Washington, D.C. 20460

Via Electronic Submission:
a-and-r-docket@epa.gov

Re: Comments to the Proposed
Existing Source Performance Standards for
Electric Generating Units
Docket ID No. EPA-HQ-OAR-2013-0602

Dear Sir or Madam:

Tampa Electric Company (TEC) submits these comments on the proposed rule entitled *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (Proposed Rule) and issued by the Environmental Protection Agency (EPA or Agency) in Docket No. EPA-HQ-OAR-2013-0602. TEC believes that the Proposed Rule is fundamentally flawed and that EPA should withdraw the rule and reconsider the overall approach to reducing carbon emissions from existing stationary sources. The following comments are provided to assist the EPA in developing a rule that meets the Clean Air Act (CAA) requirements and minimizes the very significant economic and reliability impact to our customers that would occur if the Proposed Rule is finalized in its present form.

1) Introduction

The Proposed Rule creates national guidelines to be used by the states in addressing greenhouse (GHG) emissions from existing electric generating units (EGUs or units). These proposed performance standards, to be ultimately promulgated under EPA's CAA section 111(d) authority, establish guidelines for a *Best System of Emission Reductions (BSER)* for states to implement to regulate fossil fuel-based electric generating units (EGUs).

TEC is an investor-owned utility with EGU's located in West Central Florida serving over 687,000 residential, commercial, and industrial customers that depend on us to provide reliable power at a reasonable price. TEC has served our community for over 115 years and currently utilizes a balanced fuel mix of coal and natural gas. In 2005, TEC completed the first part of a $1.2 billion initiative that reduced carbon dioxide (CO_2) emissions by 20% from 1998 levels. By repowering the coal-fired units to a Natural Gas Combined Cycle system, 5 million tons of CO_2 reductions have been realized every year since 2005. These reductions were memorialized by our participation in a voluntary but legally binding GHG trading program from 2003 to 2010. TEC is also a primary participant in the only effort in Florida to scale up emerging carbon capture technology.[1] TEC's environmental leadership on the aforementioned and numerous other initiatives demonstrates the proper balance of environmental, economic, and energy policy necessary to ensure environmental stewardship, a prosperous economy, and the reliable delivery of energy.

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[1] *See* http://www.netl.doe.gov/research/coal/energy-systems/gasification/syngas-processing

The substantial CO_2 reductions discussed above resulted from an agreement with EPA. This was the very first agreement in EPA's ongoing NSR enforcement program. As a result of this agreement with the EPA, our customers have made a substantial investment to achieve early reductions, and EPA's proposal for existing sources neglects to account for this bold and early action. If the Florida limits outlined in this proposal are finalized in their current form, our customers will be paying again for the same reductions many other companies deferred until now. With the approval of the Florida Public Service Commission (FPSC), recently completed projects that are part of the billion dollar reductions are depreciated over the remaining lives of the affected facilities (beyond 2030) to minimize the economic impact to customers. This process is consistent with the statutory mandate that investor owned utilities such as TEC provide reliable electric service at a reasonable cost. The Proposed Rule would result in additional costs, including the cost of stranded assets that would have to be borne by these same customers, many of whom are on fixed incomes.

The benefits of these emission reductions of 5 million tons of CO_2 per year have been realized for each of the last 10 years. EPA should work with states to adjust the goals to a level that recognizes the environmental benefits of this early action, acknowledges the importance of fuel diversity, preserves the thousands of jobs at risk, and allows existing units to exist and operate within the confines of the Clean Air Act.

TEC appreciates the time extension EPA granted and the additional opportunity to provide robust comments on this important Proposed Rule that, as proposed, would undoubtedly have a significantly adverse economic impact to our customers. TEC has also been actively engaged in the rulemaking process by participating in EPA listening sessions, hearings, numerous stakeholder meetings and has expended substantial resources in evaluating rule achievability and associated customer impacts.

TEC is an active participant in the Florida Electric Power Coordinating Group Environmental Committee, the Edison Electric Institute, and the Class of ’85 Regulatory Response Group, each of which has filed comments on the Proposed Rule. TEC participated in the formulation of those comments and joins in them. As such, they will not be repeated here. Additionally, TEC supports the comments filed by the Florida Public Service Commission and those filed by a variety of state Attorneys General including Florida Attorney General Pamela Bondi.

2) Legal Concerns Must Be Properly Addressed

A. Applicable CAA Language is Contradictory

A threshold legal issue is whether EPA has authority to regulate greenhouse gases from electric generating units under Section 111(d) of the CAA. This section has been used infrequently and on a much more limited basis than other stationary source provisions of CAA. Of the 13 previous source categories for which rules have been promulgated under Section 111(d), 6 were solid waste incinerators subject to Section 129 of the CAA which mandates the use of 111(d) and one was the Clean Air Mercury Rule vacated by a court without interpreting Section 111(d). As a result, the central question of whether EPA is authorized to proceed under Section 111(d) in this Proposed Rule remains unresolved. The primary doubt concerning the EPA authority arises as a result of the 1990 CAA reauthorization process in Congress. In this reauthorization, the Senate first passed a package of CAA amendments, including amendments to Section 111(d). The House then passed amendments that were similar, but not identical. The bills went to conference committee to reconcile the separate Senate and House positions and, rather than reconcile the differences between both chambers in Section 111(d), both the Senate and the House versions were adopted and signed into law.

The result is that under the House version, EPA can adopt rules for categories of sources whose toxic (hazardous air pollutant) emissions EPA does not already regulate. Since mercury and air toxics from existing electric generating units are already regulated, the current greenhouse gas rule is prohibited. The Senate version allows EPA to regulate any non-toxic emissions, meaning the regulation of greenhouse gases from existing electric generating units would be permissible. EPA has opted to subscribe to the Senate version of the rule. Even though EPA chose to reconcile the different versions in favor of allowing the regulation of existing electric generating units, it is TEC's position that the EPA interpretation is not legally defensible under the CAA.

B. <u>"Standard of Performance" Should be Unit-Specific</u>

There are also legal issues associated with the substance of the EPA proposal itself. EPA has outlined "four building blocks" that can be used by the states in their plan. Of the four, only the first is directed at reducing the rate at which a generating plant actually emits CO_2. The other three building blocks essentially reduce CO_2 by reducing or eliminating the use of higher emitting units by substituting power from lower emitting facilities or by reducing the end use of electricity. To justify this approach, EPA argues that a "standard of performance" does not have to be directed at a single unit, but can be spread over a collection of sources. In essence, EPA argues that determining the statutorily required best system of emission reduction requires only that the "system" be one that reduces emissions of the affected sources. Under this theory, EPA can propose a collective, statewide reduction and not an individual, unit specific performance standard. This theory has not been tested in court and it is TEC's position that the CAA does not support the EPA interpretation. Enforcement of a system-based limit becomes unenforceable as a practical matter in the real world of unit-specific sources.

C. EPA & States Do Not Have Requisite Regulatory Authority

Ultimately, the states will be required to submit plans to meet reduction goals. The plans must include requirements that are quantifiable and legally enforceable. Depending upon the approach Florida chooses, several different agencies will be involved. The question of whether these agencies currently possess the requisite statutory authority to proceed is not addressed, and EPA does not appear to have attempted to resolve this in the Proposed Rule. This will involve both legal and timing considerations, assuming statutory revisions are required. That process is unlikely to be completed in the time-frames provided by EPA to submit the plans. Once the analysis has been completed, the Florida legislature would have to adopt the requisite changes, which again is going to take time. Therefore, if it is determined that Florida's preferred approach requires statutory changes and these cannot be completed by the EPA deadline, any plan promulgated by EPA to remedy the deficiency will necessarily be limited as EPA lacks the requisite authority to change Florida's statutes.

3) BSER Block 1 – Heat Rate Improvements

EPA erroneously assumes that all coal-fired units can implement equipment upgrades and operation & maintenance (O&M) “best practices” that will yield a 6 percent improvement in the unit's heat rate. EPA fails to consider the substantial ongoing efforts that companies undertake to maximize heat rate. The FPSC and other state regulatory authorities have various tools and incentives to encourage electric utilities to operate generating plants efficiently as a way of maintaining reasonable customer rates. As a result, the most cost-effective projects and best practices have long-since been accomplished. TEC supports EPA's proposal to exclude Integrated Gasification Combined Cycle units from implementing Block 1 requirements for the reasons cited in the preamble to the Proposed Rule and Technical Support Documents.[2]

A. EPA Penalizes TEC's Early Action on EGU Efficiency

EPA penalizes the early action TEC has already taken with respect to coal plant efficiency improvements. TEC and many other utilities have already completed the relevant efficiency improvement projects outlined by EPA. Since 1980, the FPSC has incentivized heat rate improvements utilizing a program called Generation Performance Incentive Factor (GPIF) Program for investor-owned utilities. Targets are set annually through a formal hearing procedure, and investor-owned utilities either gain rewards or suffer penalties based on the prior year's performance compared to the previously set annual targets.

EPA's goal-setting exercise for Florida simply assumes a reduction from efficiency improvements is plausible without due consideration of whether or not the potential measures have already been completed. As proposed, EPA would arbitrarily reward those who delayed maintenance on power plants until after 2012 and penalize others who have already completed such projects. States should be afforded the flexibility to work with EPA to adjust the goal if the appropriate efficiency projects that EPA assumes are feasible have already been completed or would not achieve the reduction that EPA predicts. The opportunities for efficiency

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[2] In 89 FR 34896 and Technical Support Document (TSD) for the CAA Section 111(d) Emission Guidelines for Existing Power Plants – Goal Computations, pps 5-6.

improvements are limited, and the resulting very low coal-fired unit capacity factors that would result from fuel switching render reductions from Building Block 1 insignificant.

B. EPA's Utilization of Sargent & Lundy Report is Flawed

EPA's reliance on the 2009 Sargent & Lundy report for support of the 6% potential heat rate improvement is misguided and inappropriate. The 2009 Sargent & Lundy report does not conclude that any individual coal-fired EGU can achieve 6% heat rate improvement or any broad target. Rather, the amount of heat rate reduction that can be achieved is site-specific and must be evaluated on a case-by-case basis, taking into account a number of factors, including plant design, previous equipment upgrades, and each unit's operational restrictions. TEC and many other utilities have already performed the most beneficial heat rate improvement projects and implemented the appropriate "best practices" that this report references. It is not technically feasible to further improve TEC's Big Bend Station's heat rate an additional 6%. The following section describes these already completed Block 1 accomplishments.

C. TEC Completed Beneficial Heat Rate Projects and Implemented O&M Best Practices

The following projects are listed in the Proposed Rule as projects that may be implemented as part of Block 1 and a summary describing how each project has already been completed or found to be inadequate for efficiency improvements at Big Bend Station:

i. Combustion control optimization –

   a. Combustion neural networks were installed on all the Big Bend Station coal units (multiple types and manufacturers) as part of a U. S.

Department of Energy NETL project during 2002 through 2004.[3,4] After implementation of the automated systems, operator training was found to be more effective.

b. Controls on all Big Bend Station unit boilers have been upgraded to Distributed Controls Systems. These DCS systems have sophisticated control schemes that help optimize boiler combustion.

ii. Cooling System Heat Loss Recovery – Once-through cooling is utilized on each of the 4 units at Big Bend Station. With the high cooling water flow and relatively small increase in cooling water discharge temperature, there is very little opportunity for recovering any usable thermal energy from the cooling water discharge from the condensers.

iii. Low-rank Coal Drying – the inherent moisture of our coals is below 10%. Since we burn higher rank coals, drying does not provide a significant benefit.

iv. Soot blower optimization - Tampa Electric has implemented soot blower optimization technology on all units at Big Bend Station.

It is possible that a steam path upgrade/retrofit with advanced steam path technology could provide some improvement in unit heat rate for each of the Big Bend units. However, the potential benefit is not as impactful as EPA assumes and the cost of this upgrade may not be prudent compared to other completed reduction opportunities and due to EPA's proposed Block

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[3] http://www.netl.doe.gov/File%20Library/Research/Coal/major%20demonstrations/ppii/bigbenddemo.pdf

[4] *Neural Network Based Intelligent Sootblowing System – Project Performance and Review.* Tampa Electric Company, Tampa, FL: 2005 (submitted to EPA January 20, 2006).

2 limitations on coal plant dispatch. TEC implemented many heat rate improvement projects while installing emission controls as part of the agreement with EPA referenced in Section 1 above. These emission controls introduce significant parasitic loads that offset the heat rate improvements to a significant degree and minimize the potential for additional heat rate improvement. TEC reported the implementation of these projects to EPA on a quarterly basis as part of the aforementioned consent decree agreement, therefore, EPA has access to the information necessary to verify the details and provide the appropriate credit to TEC and other utilities that have made similar accomplishments.

D. <u>EPA Should Adjust the Heat Rate Improvement Potential Downward and Recalculate Targets</u>

EPA solicits comment on increasing the technical potential for heat rate improvements from equipment upgrades incremental to the best-practices opportunity from 2 percent to 4 percent (*See 49 FR 34860)*. The results of TEC's analysis *(see Section 3.C above and associated references)* indicate that the most effective of these upgrades are already in place and that a 2 percent improvement overall is an overly-aggressive target. EPA solicits comment on increasing the technical potential for heat rate improvements through the adoption of best practices from 4 percent to 6 percent (*See 49 FR 34860)*. The results of TEC's analysis (see Section 3.C above and associated references) indicate that the most effective of these practices are already in place and that the proposed additional 4 percent improvement is not achievable. EPA should work with states to determine the proper efficiency improvement potential since EPA's analysis does not properly capture the heat rate variability (See EEI comments on Heat Rate Improvement) and some states such as Florida may be outperforming others since they have incentivized these improvements for decades. The specific examples above illustrate that EPA's assumptions regarding additional heat rate improvements are flawed. Therefore, if supported by a state evaluation of heat rate improvement potential, the Block 1 reduction calculations should be adjusted to reflect an accurate potential heat rate improvement, if any.

4) BSER Block 2 – Dispatch Changes Among Affected EGU's

EPA's BSER Building Block 2 involves increased dispatch of existing natural gas combined cycle (NGCC) units. EPA assumed that a reduction in mass emissions from higher-emitting coal-based and oil/gas-based steam EGUs can be achieved by shifting generation from these units to lower-emitting existing NGCC units (*See* 79 *FR* 34857). In order to estimate the magnitude of emission reductions that could be generated through increased re-dispatch of NGCC units, EPA assumed that each state's existing NGCC fleet, including NGCC units under construction as of January 8, 2014, could achieve a utilization rate of 70 percent and that steam EGU's could be operated at an extremely low capacity factor. EPA's analysis does not provide a reasonable basis for goals predicated on 70 percent NGCC utilization rates nor does it provide a reasonable basis for operating existing steam EGU's at an unsustainably low capacity factor. The Proposed Rule Block 2 approach would result in excessive disparity in stringency between the states, again penalizing states who have invested in natural gas combined cycle units to improve reliability (via reserve margin). TEC and the Florida Electric Power Coordinating

Group (FCG)[5] discovered apparent errors and flaws in EPA's goal development calculations. These are described in Section VI of the FCG comments.

A. <u>EPA Has Not Properly Considered Fuel Diversity Impacts and Concerns</u>

The United States has shale gas spread throughout much of the country and these discoveries have transformed the long-term outlook for natural gas supplies and pricing. As a result, growth in demand for natural gas from electricity generation and other markets is expected. This increased demand will have an impact on the availability and price of natural gas supply and transportation. Growth can come from several market segments, including natural gas exports, fuel conversions, emerging marine and rail transportation markets, fleet vehicle conversions, and other native load growth in and around Florida's ports. This growth in demand, coupled with the proposed restrictions on coal-fired and oil-fired generation throughout the U.S., will strain the ability of natural gas suppliers and pipelines to meet this growing demand. The result will be an increase in natural gas price volatility and a decrease in availability, ultimately leading to substantially higher commodity costs and electric rates for Floridians.

Currently, natural gas is transported to Florida by four companies: FGT, Gulfstream, SNG, and Gulf South. Sabal Trail, a joint venture of Spectra Energy and NextEra Energy, has announced plans to develop and construct a new pipeline originating in Tallapoosa County, Alabama, extending through Georgia, and ending at the proposed Central Florida Hub near Orlando. The expected in-service date for this 800,000 MMBtu per day project is summer of

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[5] The FCG is a non-profit, corporate organization, and its Environmental Committee represents its members on environmental matters. Members of the FCG-EC are a diverse group of investor-owned utilities, electric cooperatives, and municipal utilities that provide electricity to more than half of Florida's residents and industries.

2017. Collectively, these pipelines will have the capacity to deliver into Peninsular Florida approximately 5.6 billion cubic feet (Bcf) per day. It is important to note, however, that this capacity is not deliverable to all major load centers and generation locations. This is an important factor to consider given the inevitable increase in gas consumption at various locations throughout the state.

Also, a review of the ten-year site plans filed by Florida electric utilities on April 1, 2014 indicates that current and planned natural gas-fired generation units will be capable of consuming in excess of 5.9 Bcf per day (20 hours). The siting and construction of incremental pipeline capacity and delivery laterals will be necessary to accommodate dispatch of these resources. The development of these incremental infrastructure projects at the proposed scale can have adverse socio-economic, environmental, and land use impacts that EPA failed to consider. This development will take many years to complete and cost Floridians hundreds of millions of dollars. These additional pipelines would potentially provide additional capacity that approaches the EPA's guidelines in the Proposed Rule, but places Florida in a dubious position with an over-reliance on a single fuel. This creates reliability deterioration and cost increases.

In addition, with the recent advances in natural gas extraction technologies, environmental concerns have been raised that could erode or negate the EPA objectives. Natural gas can leak from wellheads, valves, tanks, pipes, processing plants, and other parts of the energy supply chain. A recent study[6] utilizing satellite measurements of methane found leakage rates in

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[6] Schneising, O., Burrows, J. P., Dickerson, R. R., Buchwitz, M., Reuter, M. and Bovensmann, H. (2014), "Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations." Earth's Future. doi: 10.1002/2014EF000265

certain gas producing regions in the 2 to 17 percent range, much higher than the 1.2 percent leakage rate calculated by EPA. Methane is 86 times as potent as CO_2 for the climate on a 20 year time scale. Scientists have stated that a methane leakage rate above 3.2 percent may negate the fuel's climate benefits in the power plant.[7] Other impacts potentially exacerbated by the additional gas production made necessary by the Proposed Rule include drilling fluids impacts to drinking water, flaring emissions, and seismic activity. These issues are likely to be addressed over time, but EPA's proposed schedule is too aggressive to allow the most optimal solutions to emerge. EPA should work with states to appropriately factor these findings into the goal-setting process, develop a measured and reasonable implementation schedule, and minimize over-reliance on natural gas.

B. EPA's Block 2 Proposal is Unreasonably Costly and Creates Stranded Costs for Coal Assets

EPA states that the proposed BSER provides states with the flexibility to determine how to achieve the reductions and to adjust the timing in which reductions are achieved in order to address key issues such as cost to consumers, electricity system reliability, and the remaining useful life of existing generating assets (*See 79 FR* 34836). However, TEC's analysis of the Proposed Rule revealed that the proposed standards are so stringent that if all of the building blocks proposed by EPA were successfully implemented in TEC's service territory to the fullest extent, TEC's CO_2 emission rate could not be in compliance with EPA's proposed limit.

[7] Alvarez RA, Pacala SW, Winebrake JJ, Chameides WL, Hamburg SP (2012) "Greater focus needed on methane leakage from natural gas infrastructure." Proc Natl Acad Sci USA 109(17):6435–6440.

Similarly, an evaluation by FCG indicated that the entire state of Florida could not meet the limit utilizing the currently existing affected sources. The only way to meet EPA's proposed numeric goal is to discontinue operating existing coal units and replace the energy with substantial new zero-emitting electricity generating technologies at great expense. The additional cost for TEC to construct additional generation to meet the proposed standard in 2030 is in the multi-billion dollar range (markedly higher than EPA indicates) for nuclear, solar, or biomass (not including any stranded asset costs). Retiring these existing coal units would result in substantial stranded assets and thus substantial costs to customers, a result contrary to the EPA's objectives as stated by EPA leadership.[8] TEC's substantial CO_2 reductions resulted from an agreement with EPA in the form of a consent decree. This was the very first agreement in EPA's ongoing NSR enforcement program. As a result of this agreement with EPA, our customers have made a substantial investment to make early reductions and EPA's Proposed Rule does not account for this bold and early action. If the Florida limits outlined in this proposal are finalized in their current form, our customers will be paying again for the same reductions other companies deferred until now. Projects that are part of the billion dollar reductions we recently completed are depreciated over the remaining useful life of the coal plant (beyond 2030) to minimize the impact to customer's bills and this proposal would require acceleration of the cost recovery and significant additional expense. This puts the EPA proposal in direct conflict with CAA section

[8] Hearing on EPA's Proposed Clean Power Plan - US House of Representatives, 113th Cong., 6 (2014) (testimony of Janet McCabe). Print. Statement: 'Under the proposal, the states have a flexible compliance path that allows them to design plans sensitive to their needs, including considering jobs and communities in a transitioning energy world. It also allows them enough time – fifteen years from when the rule is final until compliance with the final target – to consider and make the right investments, ensure reliability, and avoid "stranded assets."'

111(d)(1) provision *"permit[ting] the State in applying a standard of performance to any particular source under a [111(d)] plan…to take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies."* EPA claims that sufficient flexibility is provided in the state plan process and a *"separate application of the remaining useful life provision by states in the course of developing and implementing their CAA section 111(d) plan is unnecessary."* (*See 79 FR* 34925). Results of TEC and FCG analyses indicate that the proposed goal could not be reached by reasonable measures utilizing all blocks *(Also see Section 4.C below)* and that the EPA proposal is therefore devoid of the claimed flexibility. It is not appropriate to disregard this CAA requirement.

To analyze the Proposed Rule impacts, TEC utilized natural gas forecasts from the U.S. Energy Information Administration (EIA); the base EIA natural gas forecast assumes that gas prices would be unaffected by the greatly increased gas usage demand, which may be optimistic. TEC's analysis includes the following assumptions:

Additional firm gas transportation capacity (130,000 MMBtu/day) starting in 2020

- Natural gas generation maximized
- Operating constraints removed from coal units, which is not operationally feasible
- Co-firing the 4 Big Bend coal units, 70% coal 30% natural gas
- Polk 1 IGCC operating as a natural gas combined cycle only (although EPA's proposal does not require IGCC units to limit dispatch in Block 2)
- Implemented environmental dispatch to minimize CO_2 emissions

The analysis was conducted through 2043 with no cost impact until the Clean Power Plan (CPP) proposal commences in 2020. Assuming natural gas prices are unaffected by increased demand, the net present customer impact value in 2014 dollars for TEC to comply with Block 2 of the Proposed Rule is $2.0 billion from Block 2. However, assuming gas prices are affected by increased demand, which TEC believes to be likely, the net present customer impact value in 2014 dollars is approximately $5.3 billion. Despite maximizing re-dispatch of TEC resources from coal to natural gas, which is operationally infeasible, the best case result from Block 2 of 1,007 lbs/MWh falls short of the CPP proposed limit of 740 lbs/MWh. Additionally, the 2030 average customer rate impact would increase approximately between 13 to 32 percent due to Block 2 impacts alone. Additional cost impacts due to Block 3 requirements are described in Section 5 below.

The benefits of TEC's early reductions of 5 million tons of CO_2 per year have been realized for each of the last ten years. Costs incurred as part of TEC's agreement with EPA are amortized over the remaining life of the plants (retirements for Big Bend units range from 2035 to 2050). EPA should work with states to adjust the Block 2 goals to a level that complies with CAA 111(d)(1) remaining useful life considerations, recognizes early action, acknowledges the importance of fuel diversity, preserves the thousands of jobs at risk, and allows existing units to exist and operate as intended by the CAA.

C. <u>EPA's Cost Assessment Grossly Understates the Impacts to Florida</u>

As noted in the referenced FCG comments, the data upon which EPA based its IPM modeling contains errors and false assumptions, resulting in inaccurate projections that do not reflect Florida's actual compliance costs. Despite these errors, EPA's IPM modeling still predicted dramatic impacts on Florida. These impacts are even more dramatic when the data upon which EPA's model was based are corrected.

EPA's IPM projections do not consider the substantial state-wide stranded assets that would result from forcing units to retire prior to the end of their useful life, as well as the additional cost of developing new generation to replace those units. These overlooked costs will be substantial if, as EPA's IPM projections indicate, over 90% of Florida's coal generation is forced to retire before the end of its useful life. EPA's IPM modeling and its economic impact analysis fail to account for these real costs, and thus have not realistically considered the impact its proposal would have on Florida's electricity generating industry, and on the future cost of electricity.

Accordingly, EPA should correct all errors and inaccurate assumptions in its data, take into account the costs associated with stranded assets and replacing retired units, re-run the model for the Base Case and Policy Case scenarios to more accurately assess the proposal's impacts, and then provide stakeholders an opportunity to comment on EPA's revised projections.

The FCG membership collaborated on a modeling analysis to estimate the potential impacts of the Proposed Rule emission guidelines on Florida's electric generation system. The analysis focused on the most impactful component of the proposal, which is Building Block 2. The model results showed that dispatching units as prescribed in EPA's proposal does not achieve the goal. FCG then estimated the amount and cost of additional low- or zero-emitting generation that would be required in order to reach the proposed 2030 emissions goal for Florida.

To assess the potential impacts of the proposal over the entire state of Florida, which includes utilities located in 2 FERC regions (the FRCC and the SERC), each member utility ran its dispatch model for its service area for the study cases. The results were then aggregated in order to represent the entire state. The following cases were run for the years 2020 and 2030:

- Base Case: Business-as-usual in accordance with current utility generation plans and no additional fuel-switching.
- Change Case: In accordance with Building Block 2 of the Proposed Rule, natural gas combined-cycle units are increased up to a 70 percent capacity factor and the operation of other generating resources are decreased, using a base case natural gas price. Natural gas prices were derived from the current Energy Information Administration (EIA) fuel price projections. Since increasing natural gas demand puts upward pressure on gas prices, a high natural gas price forecast from EIA was used to estimate the cost impact from supply and demand.

Building Block 1, which focuses on heat rate improvements at coal-fired units, was not analyzed since the opportunities for efficiency improvements are limited and the resulting very low coal-fired unit capacity factors resulting from fuel switching make Building Block 1 insignificant.

The analysis then attempted to bridge the gap between the change case and compliance. Because the implementation of Building Block 2 resulted in a significant projected gap in the state's average emission rate between the modeled decrease and the proposed goal of 740 lb/MWh, the FCG estimated the theoretical amount each of nuclear power, solar photovoltaic (PV) power, or biomass to reduce emissions further to meet the goal (Building Block 3). Again, the base case and high gas price sensitivity cases were evaluated. The costs of the zero CO_2-emitting technologies were derived from public information, FPSC filings, and industry studies.

Estimates do not include consideration of potential stranded costs, deferral of planned investments, or potential technology improvements, including energy efficiency.[9]

Building Block 4, concerning substantial increases in energy efficiency, was not specifically evaluated due to limitations of the model and because significant increases in end-use energy efficiency are not in the control of utilities and regulatory agencies and ultimately are dependent on the customer. Moreover, as discussed in Section 6 below, Florida utilities have been implementing demand-side management measures for decades, and as required by the FPSC, have already implemented cost-effective measures. Accordingly, EPA's conclusion that substantial additional improvements can be made in Florida is unreasonable and unproven.

The results of this analysis are intended to be order-of-magnitude and directionally-representative estimates of the potential impacts to Florida's electric generation system and its customers. The following conclusions were derived from the analysis:

i. Florida Cannot Comply with Existing Utility Investments

Florida cannot meet EPA's Proposed Rule with current generation plants, regardless of how they are dispatched. The analysis first determined that Florida's rate in 2020 under a business-as-usual case would be 1100 lb/MWh. Next, the dispatch was changed from current economic dispatch (Base Case) to a dispatch to try to meet the Proposed Rule via fuel switching (Change Case), and the rate reduced to 950 lbs/MWh in 2020 and 900 in 2030. Depending on the details of rule implementation and future natural gas prices, fuel switching alone

[9] As discussed in Section 5, EPA's proposal for emission reductions due to demand-side energy efficiency is more expensive, more uncertain, and less feasible than the other building blocks.

is estimated to result in an average cost to Florida electric customers of $3/MWh to $20/MWh.

Importantly, however, this dispatch scenario would increase Florida's dependence on natural gas from 60% to around 80%, which would materially increase reliability risks resulting from over-reliance on a single fuel. Even with fuel switching, Florida's average emission rate would still be significantly greater than EPA's proposed requirement of 740 lbs/MWh by 2030 (950 lbs/MWh in 2020, 900 lbs/MWh in 2030). Inter-utility purchases incremental to Ten Year Site Plans were not estimated but are not sufficient to avoid new energy sources.

The results of this phase of the FCG analysis indicate that if EPA's Proposed Rule is implemented according to the proposed schedule, severe fuel cost increases and reliability deterioration would occur.

ii. Significant Additional Investments Required

In addition to fuel switching to natural gas, significant additional zero-emitting sources of energy will be required. Specifically, the equivalent of 5,000 to 20,000 MW of new zero-emitting capacity will need to be added, depending on the resource chosen. This is a substantial increase, especially when compared to Florida's current total capacity of 55,000 MW. If solar energy is used, for example, it will require adding new solar capacity resources equal to about 37% of current statewide capacity from all sources. This would require large scale solar plants such as Ivanpah in Nevada, the largest solar power plant of its type in the world. This system is not producing the expected energy due to unanticipated impacts from clouds, jet contrails, and weather. [10] Based on this recent development, the Proposed Rule does not provide sufficient time to site, construct, and optimize the operation of the requisite solar energy needed to meet the current targets.

iii. Estimated Impact for Most Economical Compliance Options

Overall Florida utility cost impacts likely will total in the billions - and perhaps tens of billions - of dollars, which will be borne by the citizens of Florida. Rate impacts will vary by utility, depending on utility size and current generation mix. Average potential rate increases may approach 25 to 50 percent. This is a substantially greater impact than projected by EPA.

iv. FCG Analysis Conclusions

The results of the FCG analysis indicate that if EPA's Proposed Rule is implemented according to the proposed schedule, the following severe impacts would occur:

- The cost of power would increase substantially more than EPA's estimates due to higher fuel costs,
- The resulting capacity factor for existing coal-based units would impose substantial stranded costs (although not quantified in this analysis),

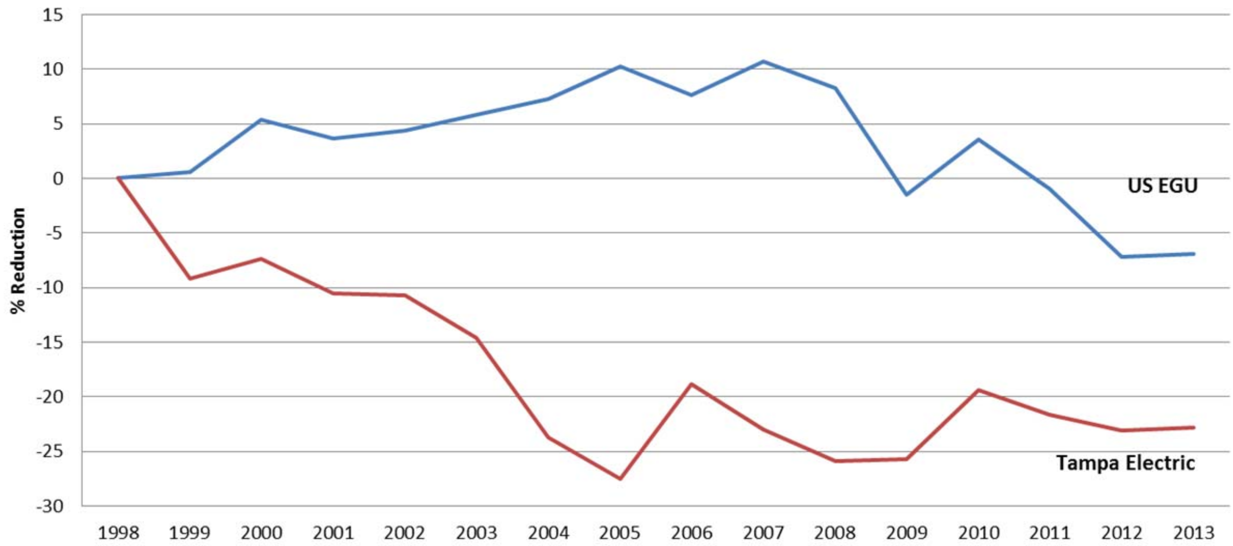
[10] "Huge Solar Plant Lags in Production." Tampa Tribune 23 Nov. 2014..

- An over-reliance on natural gas (33% increase in dependence) creates cost and reliability concerns, and
- Unprecedented amounts of costly zero-emitting sources would be required in an extremely short timeframe.

D. <u>The EPA Proposal Penalizes Early Action and Rewards Non-Action</u>

As described in the introduction, in 1999 TEC was the first utility in the nation to commit to emission reductions in an agreement with EPA as part of its NSR enforcement program. The largest part of that commitment was the repowering of 2 coal-fired units at Gannon Power Station to be part of the natural gas combined cycle (NGCC) system of Bayside Power Station. Other utilities with comparable coal-fired power plants continue operating those plants and can now take similar action, but get credit for the reductions in the current proposal. Considering the Proposed Rule, TEC would have been in a more favorable position by not taking early action to reduce emissions. As depicted in Figure 1 below, TEC implemented reductions beginning in 2005 when other utilities were emitting increasing amounts of CO_2.

Figure 1 – TEC CO_2 Emission Reductions Compared to the U.S. Power Industry



Source: U.S. Energy Information Administration, Monthly Energy Review; (http://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf) & TEC CAMD data.

Figure 1 illustrates the magnitude of early reductions (for which the Proposed Rule penalizes TEC) compared to the U.S. power industry as a whole. EPA can utilize several remedies that are consistent with EPA's Notice of Data Availability (NODA)[11] to correct this injustice. Example approaches include:

- In the emission limit calculation for a given state, credit electric generating units that repowered from coal to natural gas combined cycle as if they operated at the coal emission rate levels in the baseline years. Since there are relatively few repowered units, this approach would only slightly increase the calculated emission rate target but would provide the appropriate means of rewarding early action to reduce emissions.

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[11] 79 FR 64543 (Section II.A.1 – Early Reductions).

- In the emission limit calculation for a given state, do not restrict the dispatch of coal units that worked with EPA on commitments to reduce emissions that were memorialized in consent decrees. Utilities that made these commitments did so at substantial additional costs to customers. Appropriately, these substantial costs were amortized over the remaining useful life of these units to minimize the additional cost burden of taking early action. These units must operate at a much higher capacity factor than allowed by EPA's proposal in order to allow customers to recover their investment. Therefore, it is appropriate for EPA to recognize early investments that were made in good faith and reasoned judgment that EPA would not subsequently create new requirements that cause significant stranded costs.
- EPA can recognize reductions made in voluntary, but legally binding CO_2 reduction commitments. TEC participated in the Chicago Climate Exchange (CCX), launched in 2003 as the world's first and North America's only active voluntary, legally binding integrated trading system to reduce emissions of all 6 major greenhouse gases (GHGs). TEC participated in the program until 2010 when the CCX program ended. Although the value of the accrued allowances reached over $10 million, TEC did not sell any of the allowances representing over 18 million metric tons of surplus reductions to ensure that credit for the reductions could be justified in future regulatory initiatives such as the subject EPA proposal. Accommodating these significant commitments into the goal-setting process is appropriate and would not significantly deteriorate the EPA

objectives. EPA should allow credit for these unused allowances by incorporating accrued early action emission reductions into the goal setting or by providing an explicit mechanism for states to recognize them.

These prospective remedies to the proposal would help minimize the inequitable EPA requirement which would result in our customers paying again for the same level of reductions.

5) BSER Block 3 – Use Expanded Amount of Less Carbon-Intensive Generating Capacity

EPA's BSER Building Block 3 encompasses both renewable generating capacity and new and preserved nuclear capacity. EPA's approach to quantifying the potential emission reductions that could be achieved through increased deployment of renewable generating capacity raises a number of methodological concerns and may result in state emission goals that are not achievable. If EPA does not revise the approach to quantifying potential reductions from increased deployment of renewables, EPA should adjust state-specific goals to reflect state-specific concerns.

A. <u>EPA's assumptions in categorizing RE opportunities on a regional basis are flawed</u>

To calculate the state-specific Renewable Energy (RE) goals, EPA proposed a primary and an alternate approach. Under the primary approach, EPA averaged the individual state 2020 Renewable Energy Standard (RES) requirements within each of 6 EPA-determined regions and then set a regional renewable target for 2029 equal to this average. Next, EPA calculated a regional annual growth rate—an annual percentage increase in RE generation—required to reach the regional target. Finally, EPA applied that growth rate to each state's level of 2012 RE generation. EPA's state-specific RE goals assume states start increasing RE generation in 2017 and continue increasing RE generation every year through 2029 (*See* 79 *FR* at 34867).

EPA's alternate proposed approach addresses some of the key flaws in the proposed approach by focusing on state RE potential instead of individual state RES requirements. However, this approach relies on unsubstantiated assumptions about the rate at which states can develop renewables and the future costs of RE generation technologies.

While utilities are currently building and financing RE development and support including RE as an option for state compliance with the Proposed 111(d) Rule, EPA's proposed primary and alternate methods for setting RE generation goals raise significant concerns about whether the proposed goals can be achieved by the states. Specifically, the proposed approach relies on state RES to set regional goals (*See* 79 *FR* 34836). This regional approach inappropriately assumes that RES mandates are proxies for RE potential and that neighboring states have similar RE potential. Further, EPA's use of RES requirements fails to consider key design features of state RES programs that serve to reduce the stringency of these programs.

Finally, EPA fails to consider the technological challenges of integrating additional renewable generation into the interconnected power system and how the other proposed Building Blocks and the interconnected nature of the power system could affect a state's ability to achieve the proposed levels of RE generation.

B. <u>TEC Utilization of Block 3 to Achieve Compliance has Exorbitant Cost</u>

Since TEC cannot achieve the proposed limit utilizing Block 2 only, additional zero emission electric generation sources must be added to the system. An analysis was performed utilizing the following zero emission electric generation sources; a 25 year life biomass plant, a 25 year life solar plant, or a 40 year life nuclear plant with an in-service year of 2030. Table 1 below provides a cost breakdown of the various options evaluated for Block 3 (in net present value) to comply with the Proposed Rule.

Table 1 Block 3 Cost Impact to TEC Customers

Low-Emitting Technology	NPV 2014 Dollars	NPV 2030 Dollars
Biomass	$ 2.5 Billion	$ 7.9 Billion
Solar	$ 2.3 Billion	$ 7.2 Billion
Nuclear	$ 1.9 Billion	$ 5.8 Billion

Combining the 2030 average customer rate impacts of Blocks 2 and 3,

- If biomass, $43/MWh-$61/MWh (39%-56%)
- If solar, $40/MWh-$59/MWh (37%-54%)
- If nuclear $33/MWh-$51/MWh (30%-47%)

TEC assumed that indirect costs can be approximated as a percentage of capital costs, which is a typical industry practice utilized to estimate indirect costs. Indirect costs include owner's cost such as grid improvements, infrastructure additions, but not stranded asset recovery. Normal grid improvements would consist of new substation and transmission line additions, which would be influenced by permitting and land acquisition costs and infrastructure additions. The timing for grid improvements would begin 5 ½ to 6 years prior to the generator becoming commercial. All indirect costs would be incrementally added to the capital costs in the year of service to calculate customer impact.

- If biomass, TEC assumed owner's cost of 10 percent
- If solar, TEC assumed owner's cost of 5 percent
- If nuclear, TEC assumed owner's cost of 8 percent

TEC did not include the significant stranded costs for this analysis but assumed the existing assets remained in the rate base until their normal retirement date in order to minimize the customer rate impacts from early retirement. These exorbitant costs would create a substantial and disproportionate economic burden to our customers and our regional economy.

C. EPA's RE Goal for Florida is Unachievable

The renewable energy generation goal that EPA has calculated for Florida is unachievable. EPA's methodology for determining the goal is fatally flawed because it arbitrarily ties a state's goal to the RPS goals of other nearby states. The goals of these states reflect each state's highly unique renewable energy potential which often may not actually require as much renewable energy generation as the state goals purport. As a result, the state renewable energy generation targets, including that for Florida, are unreasonably aggressive and do not take into account factors affecting the actual renewable energy growth potential in each state. EPA's own IPM modeling results indicate that predicted renewable energy generation by the end of the compliance period is not economical to meet the renewable energy targets EPA used in its goal calculation. Accordingly, TEC urges EPA to withdraw the proposed state goals and reduce its renewable energy generation targets based on a state evaluation of renewable energy potential.

D. <u>EPA Should Defer to States on Feasibility of Renewables (Not Assume For Goal setting)</u>

When determining the need for new electric generating facilities, TEC always considers the utilization of renewable energy resources and, by Florida law, cost effectiveness must be considered.[12] The Florida Statutes require consideration of electric system reliability and integrity, reasonable cost, fuel diversity, and reasonably available renewable and conservation measures. Based on the above-referenced FCG analysis, the cost of achieving the proposed CO_2 emissions reductions using a proposed 10 percent renewable energy component for calculating the 2030 goal is not reasonable. Accordingly, the TEC requests that EPA withdraw the proposed state goals and work with states to adjust renewable energy generation targets to achievable levels within a reasonable time-frame.

6) BSER Block 4 – Demand Side Energy Efficiency

Demand side energy efficiency (EE) activities represent 1 of the 4 "Building Blocks" that make up the "Best System of Emission Reduction" (BSER) proposed by EPA. EPA has determined that states can achieve 1.5 percent EE savings rates annually over the course of the 10-year interim compliance period and beyond. EPA asserts that this level of EE savings is achievable and it forms part of the basis for each state's emission performance goal (*See* 79 *FR* 34871). The cumulative 2030 savings rates for the states range from nearly 10 percent to almost 13 percent. EPA's proposal of a 10 percent reduction due to EE in Florida is unreasonable both in terms of proposed cost and achievability based on Florida's actual historic data. Setting an

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[12] § 403.519(3), Fla. Stat. (2013).

arbitrary goal without considering the technical potential or the cost-effectiveness of the programs to achieve the goal is contrary to Florida Statutes. Since EE can only be incentivized by utilities (not implemented by them) and the results EPA proposes are unlikely to occur, utilities effectively only have 3 building blocks to work with.

A. EPA Gives Utility Customers No Credit For Early Action

EPA's proposal directly penalizes our customers. In addition to paying for the substantial emission reductions described earlier, they have been participating in EE programs TEC has incentivized since 1979. Participation in the programs has been diminishing as the energy efficiency opportunities have been depleted in the 35 years of this already successful program. Again, the EPA proposal penalizes these proactive customers who are now benefitting from a lower power bill. However, these customers would undoubtedly see a substantially higher bill due to the additional costs this proposal would bring. EPA should recognize that the decades of early action as well as new appliance and building codes are already reducing load demand. EPA should work with Florida to adjust the goal since any reductions beyond the current commitment have been shown to be too expensive or simply not practicable during the current Florida energy efficiency goal-setting process.

B. EPA Should Revise its Analysis of Estimated Savings from Electric Efficiency Activities to Use More Realistic Estimates.

EPA's assumptions on the projected EE savings and growth rates used in calculating the interim and final state goals go well beyond current experience with EE programs and the best practices of leading states. Achieving such dramatic increases in EE savings rates will require dramatic increases in EE program budgets, which EPA does not address. EPA also fails to address the existence of a range of constraints that will make attaining the state goals both more difficult and more expensive than EPA presumes. Accordingly, EPA should revise the projected EE savings used in calculating state goals to ensure that the state-specific goals are achievable. At a minimum, EPA must revise state emission rate goals to reflect the level of EE savings that the state can demonstrate are achievable.

EE programs can be cost-effective ways to transform how electricity is managed and used by households, business and industries across the U.S. The goal of utility EE programs is to produce capacity and energy savings that benefit the customer. For decades, utilities have supported their customers' interests in being efficient by administering electric efficiency programs that provide incentives that lower the cost of purchasing efficient devices and information that encourages sound energy management practices. The focus of these programs is to reduce electricity consumption. Utilities cannot force customers to be efficient, but do offer customers the opportunity to participate in demand response (DR) programs to reduce peak electricity demand during times when the wholesale price of electricity is relatively high or when an event creates a situation that affects the reliability of the interconnected power system.[13]

EPA's discussion of the potential for increased EE savings in the states focuses only on technical potential and ignores the reality of how EE savings are actually achieved. Electric utilities (including investor-owned utilities, municipal utilities and cooperatives) are by far the

[13] The Edison Foundation Institute for Electric Innovation (IEI), *Summary of Electric Utility Customer-Funded Energy Efficiency Savings, Expenditures, and Budgets*, Issue Brief, at p4-5 (Mar. 2014) (IEI Summary), http://www.edisonfoundation.net/iei/Documents/InstElectricInnovation_USEESummary_2014.pdf; *see also* FERC, *2012 Assessment of Demand Response and Net Metering* (Dec. 2012), ch. 3, Demand Response, http://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf.

largest providers of EE in the country; responsible for 89 percent of the total customer- (or ratepayer-) funded EE nationwide (*See* IEI Summary at Page 7). Electric utility customer-funded EE programs[14] -both EE and DR programs, such as load control and price-responsive demand- saved 126 terraWatt-hours (TWh) of electricity in 2012. This is enough electricity to power 122 million homes for 1 year; it also avoided generation of 89 million metric tons of CO_2 (*See id*. at Page 4). To date, TEC's residential, commercial, and industrial conservation program has cumulatively resulted in nearly 1,000 gigaWatt-hours of demand reduction.[15] These substantial reductions have already occurred and EPA's assumption that significant additional reductions can be achieved is flawed.

EPA used generalized historical data and EPA analysis to propose that an annual 1.5 percent reduction in capacity demand, culminating in a 10 percent reduction, is reasonable. Florida's historical demand-side energy management (DSM) data proves otherwise. Florida's DSM program began in 1981. The Florida Energy Efficiency and Conservation Act (FEECA) declares the use of DSM programs to be critical and directs the FPSC to adopt goals and approve plans to implement DSM programs in Florida.[16] Since the inception of the DSM program, Florida consumers have paid more than $5.7 billion for DSM programs.[17] Florida Statutes

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[14] Electric utility ratepayer- (or customer-) funded EE programs have been in place for over 3 decades in Florida. The costs of administering the programs are paid for by a utility's ratepayers, through a fixed charge added to electric bills, and are routinely reviewed by the Florida Public Service Commission to ensure that such programs pass a cost-benefit test.

[15] Tampa Electric Ten-Year Site Plan, January 2013 to January 2022, https://www.frcc.com/Planning/Shared%20Documents/FRCC%20Presentations%20and%20Utility%2010-Year%20Site%20Plans/2013%20TYSPs/2013%20TEC%20TYSP.pdf

[16] § 366.81, Fla. Stat. (2013).

[17] Florida Public Service Commission, Annual Report on Activities Pursuant to the Florida Energy and Conservation Act, 11 (February 2014).

require that the FPSC establish conservation goals at least every 5 years after a careful analysis of technical potential, cost-effectiveness, and other factors.[18] FEECA utilities then submit compliance plans that are reviewed and considered by the FPSC to ensure they do not result in an undue rate impact. Additionally, Florida has been aggressive in developing building codes and other methods to achieve cost-effective conservation.

In over 30 years of offering demand-side management and energy efficiency programs, the FEECA utilities have reduced winter peak demand by an estimated 6,465 MW and reduced annual energy consumption by an estimated 8,937 GWh. In 2012, FEECA utilities achieved an annual energy consumption reduction of 482.3 GWh. However, the FPSC has found that energy efficiency programs capable of achieving savings of 10 percent are not cost-effective. EPA's proposed use of 10 percent DSM avoided capacity, which equals 5,745 MW for the 2012 benchmark year, will cost Florida consumers billions of dollars each year.[19] Although DSM programs remain critical to the Florida energy mix, the EPA's proposal of a 10 percent reduction for purposes of calculating the Final Goal is unreasonable both in terms of proposed cost and achievability based on Florida's actual historic data. Setting an arbitrary goal without considering the technical potential or the cost-effectiveness of the programs to achieve the goal is contrary to Florida Statutes. If Block 4 reductions are deemed legally defensible, EPA should work with the states to properly evaluate the potential for further demand-side energy efficiency efforts and adjust the proposed target accordingly.

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[18] § 366.82, Fla. Stat. (2013).
[19] Estimate derived by extrapolating TEC's calculated cost (Rate Impact Measure test) of currently proposed 2019-2024 goals to EPA's proposed targets and further extrapolating these estimated costs for Florida.

7) Additional Considerations

A. <u>Glide path to reductions too aggressive</u>

EPA's proposed schedule for implementing the rule leaves states with little or no flexibility to determine a different compliance path and avoid the compliance cliff. EPA intends to finalize the Proposed Rule in 2015, which means that the earliest state implementation plans could be approved by EPA is 2017 or 2018. At most, this schedule leaves 3 years for electric generating companies to achieve aggressive emission reductions and states to make sweeping changes to their existing electric generating, transmission, and distribution systems. Given the stringency of the interim goals, the proposed implementation schedule will force states to adhere to EPA's prescribed redispatch and coal-unit closures to achieve compliance with the goals. EPA should forego the interim goals and work with states to develop a glide path toward a legally defensible BSER taking cost and remaining useful life into consideration as required by the CAA.

B. <u>EPA Should Continue Use of Gross Generation for Standards</u>

EPA solicits comment on the prospect of monitoring and reporting net versus gross generation (See 79 *FR 34894)*. TEC is concerned with EPA's proposed use of net rather than gross electricity generation as a basis for the emission rate goals in the proposal. The additional monitoring required to accurately determine net generation is burdensome and of little or no benefit beyond the current gross energy monitoring requirements. Use of net generation penalizes utilities for the electricity that is used to power pollution control systems that are, in fact, mandated by other federal environmental regulations. In addition, EPA's proposed new source CO_2 standards under section 111(b) are based on gross generation. For consistency and to minimize the monitoring and reporting burden, gross generation should also be used for the section 111(d) standards.

C. EPA Should Exclude CCS, Gas Co-firing, and Conversion of Coal-fired EGUs from BSER

EPA's proposal excludes natural gas co-firing or conversion at coal-fired EGUs from the definition of BSER *(see 79 FR 34875)*. However, despite the fact that EPA's own economic analysis "suggests that there are more cost-effective opportunities for coal-fired utility boilers to reduce their CO_2 emissions than through natural gas conversion or co-firing," EPA requests comment on this issue. In summary, EPA should retain the exclusion because requiring co-firing or conversion to gas options would constitute redefining the source.

The conditions under which gas conversion or co-firing would be considered a potentially economic option are site-specific and highly dependent upon, among other things, the proximity of a coal-fired plant to gas supply and boiler configuration. This variability across the fleet of coal-fired plants disqualifies gas co-firing or conversion from consideration as part of BSER. Also, EPA has already determined that co-firing and conversion are very expensive options for reducing CO_2 emissions from coal-fired EGUs without considering the cost of installing a gas pipeline *(see 79 FR 34875)*. The added cost of the pipelines would make both options even more expensive, thus further disqualifying them from consideration as part of BSER.

EPA also solicits comments regarding the viability of CCS as BSER for existing units *(see 79 FR 34876)*. As described in the introduction to these comments, TEC is a primary participant in the only effort in Florida to scale up emerging carbon capture technology on TEC's IGCC unit, Polk Power Station Unit 1. This carbon capture project is a crucial part of the effort to demonstrate the viability of carbon capture prior to scaling up the technology to commercial status. As a leader in operating IGCC technology and a primary participant in scaling up carbon capture technology, TEC is uniquely qualified to provide necessary insight to the viability of CCS as BSER. Based on the current status of the above referenced demonstration and a review of other ongoing CCS projects, CCS should not be considered BSER for existing units or for new units at this time. It is appropriate to evaluate the feasibility of CCS in this context after the demonstration projects have been completed and the proper scale-up has been achieved.

D. <u>Monitoring, Recordkeeping, Reporting Issues</u>

EPA is seeking comment on 2 possible adjustments to the Part 75 Relative Accuracy Test Audit (RATA) requirements for steam EGU stack gas flow monitors that can affect reported CO_2 emissions. The first possible adjustment would be to require use of the most accurate RATA reference method for specific stack configurations, while the second possible adjustment would be to require a computation adjustment when an EGU changes RATA reference methods. Although the proposed adjustments are reasonable, EPA should continue to allow the source to choose among the current methods and procedure options. The current procedures are sufficient to ensure the data is accurate enough to meet the rule objectives.

<u>E. Exemption for Simple Cycle Units is warranted.</u>

TEC continues to believe that exempting existing stationary simple cycle CTs is appropriate because these units provide important grid services that facilitate renewables integration and support reliability. An exemption would allow maximum operating flexibility for these units to perform these functions. If EPA determines it is necessary to provide an exemption threshold, TEC agrees that it is appropriate to exempt simple cycle units that supply less than a certain portion of its potential electric output to the grid on a 3-year rolling average. These units emit a small fraction of CO_2 relating to power generation, are used infrequently, and are necessary to maintain adequate grid stability and reliability.

Simple cycle units are mainly needed for their quick–start capabilities when there is a necessity to replace power immediately. The energy must be replaced within a short time-frame, which can be as little as 15 minutes, from when the capacity is needed. These simple cycle units are currently the only units that can meet this type of demand. Without the ability to operate this type of unit, as needed, grid stability could be compromised.

8) Conclusion

EPA's basis for "best system of emission reduction" (BSER) is flawed since it neglects to properly take costs into consideration, substantially exaggerates the purported benefits, relies on nebulous predictions of future fuels trends, fails to take the effects of each block in concert with the others, and penalizes those who have taken early action. EPA's proposal does not comply with the CAA section 111(a)(1) requirements that the standards of performance take into account "cost" and "energy requirements" (in the form of energy diversity) and be "adequately demonstrated." EPA's proposal does not comport with the CAA section 111(d)(1) requirements since the proposal effectively precludes states from taking "remaining useful life" of an existing unit into consideration. EPA should withdraw the subject proposal, work with states to develop a workable standard as intended by the CAA, and reissue the proposal for comment.

The U.S. electric power industry has a long history of providing abundant, reliable, low-cost electricity, which has helped power the nation's tremendous economic growth and high standards of living. The industry relies upon a diverse portfolio of fuels that can be used to generate electricity to support this success. Because Florida imports most of its fuel and is a peninsula, which limits opportunities to import power, fuel diversity is critical for electricity reliability in Florida. This is particularly acute during emergency situations including extreme weather events like the recent cold snaps and hurricanes when the supply of natural gas may not be available for sustained periods of time. The Proposed Rule severely limits the prospects of coal-fired generation and will exacerbate an evolving imbalance in fuel diversity in Florida. Therefore, the Proposed Rule will have adverse impacts on electrical reliability if it is not corrected.

Approximately half of TEC's generation capacity is coal-based, a higher fraction than the State in general. Historically, during the January 2010 extended cold snap in Florida, natural gas demand was higher than the available supply. TEC was only able to meet load demand at this time of critical need by utilizing stockpiled coal and oil supplies. Similar supply curtailment is experienced during storms affecting transportation of fuel across the Gulf of Mexico, impacting not only coal shipments, but also natural gas production and distribution to the 2 pipelines serving peninsular Florida consumers. TEC is concerned that the proposed implementation time-frame unnecessarily increases the reliability risk in the following ways:

- Over-reliance on natural gas in Florida
- Reduced fuel diversity
- Reduced operational flexibility

As the power industry in Florida contemplates what to modify, control and build in the future, and in order to ensure a reliable, affordable supply of electricity in the future, the full suite of generating options will need to be relied upon. The historical pattern of natural gas prices in the U.S. is one of volatility, not stability. This rule could result in significant economic impacts to residential and commercial customers, particularly minorities, elderly and economically disadvantaged customers. TEC and its customers have invested substantial resources in the current diverse portfolio of electricity generating units, which provides reliable power at rates among the lowest in Florida. TEC's Big Bend Station coal plant is a critical part of the Tampa Bay economy with good jobs and is a critical part of Tampa Bay ecology with warm water discharge serving as a winter refuge for manatees. The Proposed Rule would cause unsustainably premature plant closure, is not supported by sound science and will substantially degrade the ability to provide the expected level of service at a reasonable price unless it is corrected.

TEC appreciates the opportunity to comment on this regulatory proposal. Please contact me at (813) 228-4858 or Byron Burrows at (813) 228-1282, if you have any questions.

Sincerely,

Paul Carpinone

Paul Carpinone
Director
Environmental, Health and Safety

EHS/iym/PLC118