JEA Comments to EPA on the Clean Power Plan (CPP) Proposal

Section 111(d) EGU Existing Source Performance Standards for Greenhouse Gases

Docket ID: EPA-HQ-OAR-2013-0602

I. Executive Summary

JEA is a northeast Florida community-owned combined utility system that provides service to 434,000 electric customers, 318,000 water customers and 244,000 wastewater customers. JEA owns 3,747 MW of generation capacity, over 730 miles of transmission lines and more than 6,500 miles of distribution lines.

JEA is committed to being protective of the environment and has been developing new electric generation over the past 15 years to that end. JEA will continue to move toward less carbon dioxide intensive generation in a manner that optimistically does not overly overburden JEA customers from a cost perspective. JEA is concerned that the proposed plan will result in a heavy financial impact to its customers. JEA's economically disadvantaged customers already pay a larger percentage of their incomes for basic services like utility bills including water and wastewater services which are energy intensive.

The United States Environmental Protection Agency (EPA) exceeds its authority under the Clean Air Act (CAA) by defining Best System of Emission Reduction (BSER) as the entire Florida electric system from the fuel and electric generating unit (EGU) to the HVAC units in consumer homes. By establishing BSER applicable to the entire electric system, EPA is inappropriately setting energy policy for the entire country.

The CPP, as proposed, is the most disruptive **energy policy** proposal in modern times. Policy as pervasive and disruptive as the CPP should not be implemented without explicit Congressional authorization.

Given the EPA's approach to proposing BSER as the entire electric system, JEA believes that a state plan for implementation should equitably distribute the burden of required improvements, emission reductions and the cost of implementing emission reductions across all electric customers and utilities within a state. All electricity customers and utilities should fairly share and contribute to carbon dioxide reductions in order to meet the energy policy being proposed by the EPA.

The proposed rule's stringency, including the mandatory numeric goals and the implementation dates, both interim and final, cause significant unnecessary expense to transform the electric system within an unrealistic timeframe. The proposed rule does not adequately consider fuel diversity and the long term impacts of relying too heavily on predominant fuels such as natural gas and intermittent generation from renewables. The rule does not consider its combined impact on future electric reliability and stability.

Application of the proposed rule to individual states, constructed to try to meet the intent of 111(d), does not consider interstate Electric Generating Unit (EGU) ownership or purchase power agreements (PPA). The option of multi-state plans is not a viable solution to dealing with interstate ownership or contracts.

As proposed, the Clean Power Plan (CPP) would strand $795 million of outstanding debt and 15 to 20 years remaining useful life on JEA's solid fuel plants in 2020 in order to comply with the proposed interim goal for Florida.

Recommendations:

1. The rule would be made better if the EPA CPP final rule stayed within the bounds of the CAA 111(d) and therefore within the fence line of the EGU, and set a procedure for states to develop standards based upon the BSER that has been adequately demonstrated for EGUs.
2. States should be allowed to comply with the final rule using a broad array of options.
3. Final goals should allow existing EGUs to operate for their design lives including useful life extensions from environmental and other upgrades in order to avoid significant stranded investments and to avoid serious reliability issues, or the final goal date should be extended.
4. The interim goals (2020-2029) should be eliminated.
5. Each state should define the glide path within its state plan for that state to meet the final goal.
6. EPA should clarify the expected accounting for interstate transfer of energy and CO_2 emissions and provide multiple options to states for dealing with those interstate energy transfers.
7. EPA should implement exemptions proposed in its Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources (November 2014) to encourage biomass generation and define specific biomass sources treatment as a carbon-neutral renewable generation sources.
8. EPA should withdraw and re-propose the proposed rule.

JEA will provide more detailed comment in the following pages on these key concerns and issues with the Clean Power Plan as proposed.

II. Introduction

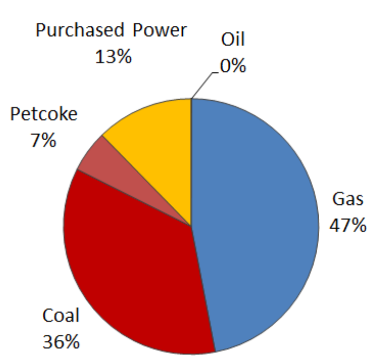
As a municipally-owned utility, JEA strives to provide reliable, clean energy to its customers at an affordable cost. Unlike investor-owned utilities, JEA does not answer to shareholders; our community represents our shareholders, and we take our commitment to environmental stewardship and responsible financial management very seriously. Over the past 40 years, JEA has made investments in generating assets to serve our growing community in order to continue to provide reliable and affordable service, substantially reducing our environmental footprint along the way. A table showing JEA generation development is shown in Appendix A.

JEA is a joint owner with Florida Power & Light Company (FPL) of the St. Johns River Power Park (SJRPP) in Jacksonville and Unit 4 of Plant Scherer, located in north-central Georgia. SJRPP is operated by JEA and Scherer Unit 4 is operated by Georgia Power Company. All of JEA's generating stations employ the applicable Best Available Control Technologies (BACT) for air emissions.

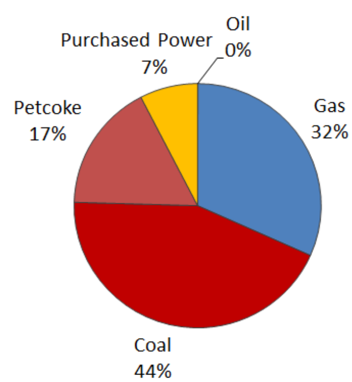
JEA's newest coal-fired units, Northside Generating Station 1 and 2, which commenced commercial operation in 2002, are two of the world's largest "circulating fluidized bed" (CFB) boilers in operation and have among the lowest emission rates for coal-fired EGUs in the world. Unit 2 was partially funded by a U.S. Department of Energy (DOE) Clean Coal technology grant. JEA also produces 9.6 megawatts from a methane-fueled generating facility at Trail Ridge Landfill through a purchase power agreement (PPA). A 12.6-megawatt PPA solar project came online in 2010. JEA's current generation capacity mix is 38% coal/pet coke, 55% natural gas, 6% oil/diesel and 1% renewables.

In 2013, JEA's energy mix was 61% coal/pet coke, 38% natural gas and 1% from renewable energy. In 2012, the year EPA selected as the baseline for reductions in the Clean Power Plan, JEA's energy mix was 41% coal/pet coke, 58% natural gas and 1% from renewable energy. The difference between 2012 and 2013 energy mix was based on economic dispatch related to natural gas pricing. An exhibit showing JEA's energy mix evolution from 1970 to 2013 is shown in Appendix B. The following excerpts show JEA's 2012 and 2013 energy mix.

2012



2013



The proposed CPP is drafted in the spirit of environmental stewardship, a goal JEA has consistently supported. However, the Plan fundamentally changes the regulatory landscape that shaped significant investment decisions of our customers' money, and tries to do far too much within a far too insufficient period of time. As will be delineated below, JEA has significant recent investment in its existing efficient, clean, environmentally compliant coal-fired generation fleet. The proposed rule threatens to strand these good faith investments, which will increase costs to customers. JEA has limited ability to further shift load to existing gas-fired generation because JEA's one natural gas combined cycle unit is already significantly dispatched. JEA does not have access to the level of renewable resources that the proposed rule anticipates. Developing more renewable energy (RE) will add disproportionately high and unnecessary costs. JEA has also invested in demand side management (DSM) and energy efficiency (EE) programs to the maximum extent that is cost effective under the Rate Impact Measure (RIM) test. Requiring DSM and EE beyond the level that is cost effective will add more costs. Fuel switching and RE will likely create a significant reliability concern due to heavy reliance on natural gas (availability, pricing, demand), transmission and load gaps to be resolved and stability with backing up and taking renewables onto the grid. For these reasons, JEA encourages EPA to be more deliberative and more contemplative of the concerns that JEA and industry colleagues express regarding the cost and reliability concerns associated with the proposed rule. JEA is supportive of environmental policy that balances the health and welfare benefits of a clean environment with the needs of our customers to have affordable and reliable power. For these reasons, JEA offers the following comments and is appreciative of the opportunity to do so.

JEA is a member of the American Public Power Association (APPA), the Alliance for Fuel Options, Reliability and Diversity (AFFORD), the Florida Municipal Electric Association (FMEA), the Large Public Power Council (LPPC), the Class of '85 Regulatory Group and the Florida Electric Power Coordinating Group's Environmental Committee (FCG-EC). JEA supports the comments of those groups on this rulemaking. JEA also supports comments submitted by the American Association of Blacks in Energy (AABE) and the Utility Air Regulatory Group (UARG). JEA's comments should be considered as reinforcing and complementary to comments provided by those groups.

Rule Overview

Under the CPP, EPA is proposing to regulate, for the first time ever, CO_2 emissions from existing electric generating units (EGUs) by authority of Section 111(d) of the Clean Air Act (CAA). Generally, the CPP establishes state-specific mandatory CO_2 emissions goals that the states are to achieve by application of some or all of four prescriptive "Building Blocks" (BB). An interim goal of 794 lbs CO_2/MWh, to be achieved on average during the 2020-29 time period, was established for Florida with a final goal of 740 lbs CO_2/MWh to be achieved by 2030. The four BBs used by the EPA to develop the goals are as follows:

1. Reducing carbon emissions at EGUs by improving the heat rate by 6%, BB 1;
2. Reducing carbon emissions by displacing generation from higher carbon intensity sources (coal-fired) with generation from existing lower carbon intensity sources, i.e., natural gas combined cycle units (NGCC), BB 2;
3. Increasing generation from low- or zero-carbon emitting sources (new renewable resources and nuclear units that are either existing or under construction), BB 3;
4. Reducing emissions by reducing the need to generate energy to serve load, afforded by aggressive increases in demand-side energy efficiency programs, BB 4.

CPP guidelines should provide states with options for establishing standards of performance that accommodate consideration for unique challenges or opportunities that may be realized in the states, respectively. The CPP does allow and encourage states to collaborate and demonstrate compliance on a multi-state or regional basis.

What Concepts to Keep in the Rule

JEA was pleased to see and encourages EPA to maintain, and enhance, the primacy of states in implementing the performance standards in the CPP. Section 111(d) of the CAA requires EPA to only provide the states with procedures or guidelines, whereby each state would develop and implement the performance standards for the EGUs in that state. EPA should not exceed its authorization under the CAA nor usurp the authority and the flexibility that the states have been given under the CAA by mandating the actual goals; the numbers should be left to the individual states.

JEA is also pleased that EPA recognized that there is not much that can be done at an EGU to reduce CO_2 emissions. JEA commends EPA for its recognition that there is no `silver bullet' solution to reduce CO_2 emissions at the EGU source by its suggested application of the four BBs. JEA also recognizes that the four EPA-suggested BBs are not an all-inclusive list of options available to reduce carbon intensity that can be deployed within our society. Other options exist than can be facilitated by additional public policy intervention and by market forces. JEA encourages EPA to be more liberal in determining and distinguishing the options or BBs that can deployed by an EGU from those that should be implemented in other public policy venues or facilitated by market forces.

JEA was pleased that the CPP proposal does not require carbon capture and sequestration (CCS), unlike the proposed rule for new coal EGUs. The fact that the proposed performance standards do not anticipate any CCS is a reasonable indication that EPA is cognizant that CCS is not a currently available emissions control technology for EGUs, nor is it soon to be. By the same token, EPA did not preclude CCS as a prospective option for implementation, should the technology ever become demonstrably available.

EPA recognized that special considerations should be made for municipal utilities and rural cooperatives. Consumer-owned utilities are generally smaller and have less access to capital than investor owned utilities (IOUs). Since it is not the goal of consumer-owned utilities to maximize return to shareholders, they also have less incentive to abandon used and useful assets, in anticipation of regulatory rate relief from a Public Utility Commission. EPA should further encourage states to be mindful of issues that impact municipal and rural cooperatives disparately, in comparison to investor owned utilities.

III. Energy Policy

The CPP as proposed is the most disruptive **energy policy** proposal in modern times. The CPP is supposed to be **environmental policy.** Among the most disruptive policies that we have seen are the Public Utilities Regulatory Act (and revisions), the Fuel Use Act, and the Energy Acts (and revisions). None of those caused anywhere near the level of disruption that the CPP threatens to cause, and all of those other policies were enacted by Congress. In fact, several previous Congresses have considered, but decided not to implement, some of the same provisions of the CPP. Because of that energy policy history and how jurisdictionally expansive the CPP is, the CPP proposal should not be implemented without explicit Congressional authorization.

<u>Fuel Switching</u>

The determination of national energy policy has historically been accomplished via legislative action, i.e. by laws duly passed by Congress and signed by the President. EPA's proposed CPP mandating fuel switching is energy policy, not environmental regulation of an individual source's emissions. Furthermore, there are other fundamental issues with EPA's Building Block 2 (mandating in effect a fuel switch to gas) that EPA has not addressed:

a. There are numerous technical constraints on increased utilization of NGCC that EPA has not accounted for such as gas supply, transmission constraints, and permit limitations on operating hours. Further, a certain amount of NGCC availability is needed for load following to support increasing renewable energy levels. At JEA, with our **one** NGCC plant, that plant is obviously critical to our load-following ability.
b. EPA has also failed to consider contractual limitations; some NGCC capacity is committed to out-of-state service and EPA cannot assume that these units will be available when they are contractually obligated to be available for other purposes.
c. Extensive re-dispatch will result in stranded investments at coal-fired EGUs. In order to meet their proposed targets, many states will be required to retire most of their coal units before the end of their useful lives.
d. In this rulemaking EPA has failed to consider "remaining useful life" as required by the CAA.
e. EPA has failed to pay adequate attention to reliability studies by the North American Electric Reliability Corporation (NERC) and by certain Regional Transmission Organizations (RTOs) regarding reliability impacts.
f. EPA has over-estimated the amount of NGCC capacity by using nameplate/gross capacity rather than actual/rated capacity. EPA is relying on "phantom" megawatts.

<u>Jurisdiction and Overreach</u>

EPA has clearly over-reached its authority under the Clean Air Act in other ways:

a. EPA's interpretation is fundamentally inconsistent with the Federal Power Act's (FPA) division of regulatory authority over the electric utility industry between the federal government and the states, and violates the Tenth Amendment ("The powers not delegated to the United States by the Constitution, nor prohibited by it to the States, are reserved to the States respectively, or to the people.")

b. EPA is effectively mandating a restructuring of state electric systems rather than regulating the environment. EPA is assuming authority greater than even that which Federal Energy Regulatory Commission (FERC) has under the FPA.
c. EPA's encroachment on FERC authority includes an attempt to force utilities "not to serve" customers (i.e., through jeopardizing reliability and mandating reduced use by consumers), which conflicts with the traditional FERC-recognized utility obligation to serve customers. It also interferes with some RTO/ISO designated "reliability must run" arrangements.
d. EPA has exceeded its authority in setting state emission limits. Under the CAA, EPA is to "establish a procedure…under which each State shall submit to the Administrator a plan" which establishes standards of performance. CAA § 111(d)(1). By setting the limits, EPA has usurped state authority.
e. If a state fails to submit a satisfactory plan, EPA would be required to implement a federal plan. EPA does not currently have the authority to enforce the requirements necessary to meet the emission rate limits established in the proposal. For example, EPA cannot currently legally force re-dispatch and increased utilization of NGCCs.
f. The Clean Air Act ("CAA") Section 111(a) defines Best System of Emissions Reduction (BSER). Even though the same definition of BSER applies to both Sections 111(b) and 111(d), EPA interpreted BSER much more liberally under the proposed 111(d) rule for existing units than it did under the proposed 111(b) rule for new units. EPA cannot apply a different interpretation of BSER when setting performance standards for new EGUs under Section 111(b) than for existing EGUs under Section 111(d), when both sections are subject to the same BESR definition.
g. Because of the regulatory scope of the CPP, no single regulatory agency in Florida has adequate authority to implement the performance standards of the CPP. A Florida statute limits the regulatory scope of its Department of Environmental Protection (FDEP) to environmental policy. Aspects of the CPP that are not environmental in nature will have to be addressed by other regulatory agencies and by the Florida Legislature. The elements of the four CPP building blocks are implemented/enforced by different state agencies and each element will likely require State legislative direction to those different agencies. JEA is concerned as to what it will have to do and to whom it will be required to demonstrate compliance or demonstrate progress towards meeting goals. FDEP normally enforces EPA rules, but it has no statutory authority to enforce standards associated with generation re-dispatch or the development of new renewable energy (RE) sources or the level of energy efficiency (EE) achieved by electricity end-users. While RE and EE are within the sole purview of the Florida Public Service Commission (FPSC), it is not clear if any Florida regulatory agency can direct the re-dispatch of generation. This approach will require almost every state to develop a new regulatory construct to meet an unprecedented federal rule.
h. CPP implementation in Florida could also be hampered by state law that may require legislative review or ratification. Florida's legislature meets for one 60-day session

annually. In addition to this confounding any state plan's implementation, EPA should not discount the political reality of a legislature's inability to reach consensus on a state's development and implementation of the CPP requirements, especially in states that are wary of expansive regulation.

Economic Impacts

The CPP will be disruptive to the entire economy. In addition to the macroeconomic impacts that were discussed previously, EPA should be mindful of additional economic dislocations that the rule will cause. Among these are:

a. Practically all of the NGCC-fired generation in Florida that the CPP anticipates to be dispatched prospectively is owned by a single investor owned utility (IOU). To meet the performance standard, JEA and all other entities in Florida will have to purchase NGCC-fired generation from that single IOU, while idling their own capable generation fleets (for which they are still recovering costs). This would cause an unwarranted wealth shift within Florida.
b. The requirement to develop substantially more RE will significantly increase the demand for equipment and construction for RE beyond the regions' ability to supply RE. This will cause the already uneconomic cost of RE to escalate further. This would cause a wealth shift away from Florida.
c. The requirement to invest in EE beyond the level that is cost effective to JEA and Florida ratepayers will cause rates to increase generally for all but disparately for customers that do not participate in utility-sponsored EE or customers that invest in RE without a utility incentive. History has shown that the most disenfranchised by this will be the already economically disadvantaged segments of the customer base. This would cause a wealth shift among JEA and Florida customers.

IV. General Concerns

111(d) Application

Section 111(d) of the CAA contains clear and explicit language limiting EPA's regulatory authority to EGU `sources' that actually `emit … or may emit any air pollutant'. The plain understanding of this statutory requirement of the CAA is that performance standards are only to be imposed on 'sources' that actually emit a regulated pollutant, i.e., fossil fuel-fired EGUs. By historic regulatory precedent, the public, JEA and the industry understand the source to be composed of the boiler, the generator, prime movers, pollution controls and other associated auxiliary equipment, generally situated within the fenceline of a generating unit. Correspondingly, emissions from any aspect of the source are to be controlled by imposing performance standards on the source, at the source.

Performance standards that require development of new generation sources, fuel switching, diminished demand and sustained energy demand destruction, or the termination of operation of useful generating units goes far beyond controlling at the source. In fact, JEA believes that such an approach seeks to impose performance standards on the entire energy consumption/supply chain. As such, JEA believes this is an overreach by EPA and goes far beyond the authority given to EPA by Congress under the CAA. JEA believes that the authority to impose standards on the energy supply chain of this scope and magnitude rests within legislative and regulatory jurisdictions other than EPA.

Impact on Fuel Diversity

JEA's history provides valuable lessons on the dangers of over-reliance on a single fuel for electric generation. JEA's investments in generation capacity prior to 1973 were based on historical fuel prices; for nearly 100 years prior, oil had been plentiful and price stable, and all of JEA's generation was fired either by a byproduct of oil refining called residual oil (#6 oil), or by diesel fuel (#2 oil). In the 1973 OPEC Oil Embargo, America saw its historically price-stable supply of oil increase four-fold in price virtually overnight, and oil supply artificially limited by more than 25%.

Because of that reliance on a predominant fuel, JEA was vilified, criticized, and accused of contributing to local economic instability by customers, by local media outlets, and by government. This financial instability lasted long after the initial crisis was over in 1974, while JEA sought alternatives to dependence on a single fuel. In 1977 President Jimmy Carter stated that electric utilities were moving too slowly away from limited gas and oil reserves toward abundant coal. In 1978, to discourage dependence on natural gas, the US Congress set an energy policy which banned the use of natural gas for new baseload power generation, (which they later reversed in 1987).

In the early 1980s, while natural gas was prohibited for baseload power generation by national energy policy, JEA initiated a long-term fuel diversity strategy by purchasing coal-by-wire from Southern Company and by beginning development of new state-of-the-art coal-fired units at St. Johns River Power Park (SJRPP). These units entered service in 1987 and 1988. They were, and are, fully compliant with all provisions of the Clean Air Act, and have remained in compliance with all environmental regulations through a series of substantial capital investments in the facilities.

When in 1987 Congress undid its prior ban on natural gas as a baseload fuel, natural gas prices began to increase sharply as pending Clean Air Act amendment expectations caused gas to become the fuel of choice for new power generation. With three potential fuel sources to choose from, as oil and gas prices climbed, JEA's diversified generation mix and ability to supply electricity from fuels other than oil and gas resulted in the lowest electric rates in Florida.

To further JEA's fuel flexibility, in the early 2000's JEA accepted a Department of Energy (DOE) clean coal grant of $72M to re-power old oil-fired units with the then largest circulating fluidized bed (CFB) boilers. Encouraged by the DOE to move away from natural gas, JEA redeveloped these units as a showcase model for environmental responsibility and fuel diversity. Emissions of regulated pollutants are among the lowest of any solid fuel facility in the world, and the design of the facility allows JEA to burn both coal and petroleum coke. Around the same time, JEA also developed a state-of-the-art natural gas combined cycle facility at Brandy Branch. Meanwhile, JEA's rates remained the lowest in the state. In fact, as late as 2006, the Florida Public Service Commission was encouraging Florida utilities to replicate JEA's model of investment in new coal-fired generation as a hedge against overdependence on highly-volatile natural gas supply, demand and prices and as a fuel diversification and risk management strategy.

The benefits of diversification were reinforced during the economic crisis of 2008. When the 2008 crisis occurred, it was accompanied by the global marketing of US coal (to meet Chinese demand) driving record high coal prices, coupled with shale gas production (as a byproduct of oil exploration) causing record low gas prices. By 2011, natural-gas fired electricity was displacing coal-fired electricity on an economic basis. In 2012, the baseline year for the proposed CPP rule, JEA experienced the lowest gas costs in modern history, causing JEA to maximize dispatch of our natural gas facilities. In 2013, as natural gas prices increased, JEA shifted its generation mix back to greater solid fuel dispatch, enabling us to provide our customers with the economic benefit of fuel price stability and cost optimization.

But the benefits of diversification extend far beyond simply optimizing price. Even with the promise of an endless gas supply via shale gas production, in January 2014 the natural gas supply to North Florida was curtailed during extreme winter weather conditions in the North (the polar vortex). A number of gas fired generating units in the Southeast sat idle during extreme winter weather because, unlike coal, natural gas cannot be practically stored locally. Fortunately for JEA's customers we were able to maximize output from our solid fuel facilities, providing uninterrupted power supply on the coldest morning of the year.

The Boston Globe (9/25/14) reported: "Massachusetts consumers will pay significantly higher electric bills this winter as a persistent shortage of natural gas for generating plants drives power prices to record levels. The cost for a typical household could top $150 a month, based on an announcement this week from one of the state's two dominant utilities, National Grid. It said its rates will increase by a whopping 37 percent over last winter's, solely because the cost of buying electricity from power plants has soared to the highest level in decades, according to a company spokesman. The price shock is driven by New England's increasing reliance on natural gas as a source for both heating homes and making electricity. The pipelines that ship natural gas into New England do not have enough capacity to meet the increased demand, and during winter, electric plants often end up paying much more for the fuel."

JEA urges the EPA to strongly consider the impact on fuel diversity in its rulemaking. Through history, JEA has learned valuable lessons about the wisdom in relying on abundance and price stability in making concentrated single-fuel generation capacity additions, as is likely to be the outcome with respect to natural gas. And unlike JEA's oil investments prior to 1973, natural gas has a clear history of price and supply volatility. For JEA, this rule (in practical terms if not by the rule itself) requires retirement of the very coal-fired capacity that has repeatedly come through for our customers in winter when gas has been unavailable. The end result will be impairment of JEA's ability to provide reliable service when it is needed most by our community and when we are most likely to suffer natural gas supply disruptions, such as during extreme cold or hurricanes. It will also impair JEA's ability to insulate our customers from price swings in the one of the most price volatile commodities.

In fact, it is the same coal-fired capacity that for years kept customer rates low when natural gas was expensive. In 2014 coal-fired energy is again less costly than gas fired energy, since the lows of 2012 gas prices have essentially doubled.[1] JEA's current experience (with shale gas) and JEA's history with natural gas supply and pricing together indicate that future gas prices will increase yet more with increasing demand.

JEA's only renewable potential is solar, which can go from full output to zero output over a simple weather change, doesn't operate at all at night, and cannot be used to supply the firm generating capacity that reliability requirements demand. If the proposed EPA CPP prevents JEA from using its coal-fired capacity, the only practical option left to JEA to avoid overdependence on a single fuel is construction of nuclear capacity, which is difficult to site, requires a very long lead time to permit and construct, and would be very costly for JEA's customers.

JEA believes that the proposed EPA CPP will result in significant loss of fuel flexibility in Florida and the nation and in so doing will create tangible adverse impacts to both reliability and the cost of service to our customers. JEA's history stands as clear evidence to the viability of that conclusion.

Impact on Rates and Economic Development

As a municipal utility, JEA's mission is to balance environmental responsibility with the economic prosperity of our community. JEA's generation investments were undertaken to provide our community with affordable electricity, insulate our customers from fuel-related price spikes, and embrace environmental responsibility while complying with every new EPA regulation. The dollars invested by our community in our generation assets were spent in good faith on long-term assets, complying with all environmental regulations. These assets could then supply our community with affordable power for many years.

As proposed, the CO_2 reduction requirements would effectively require JEA and other Florida utilities to retire many of these community investments prior to the end of their useful lives. JEA's solid fuel facilities were designed and constructed to run as base load energy supply, meaning they perform at very high capacity factors. When the base load units are operated as designed, they achieve heat rate efficiency and low dispatch cost. By requiring significant re-dispatch away from these base load units, the rule prevents them from running as designed, further degrading efficiency and ultimately making continued operation of these units non-economic. The rule forces early retirement in practice, even if it does not do so explicitly.

Early retirement of long-lived generation assets places an extraordinary burden of stranded costs on the very communities who invested that capital in good faith. At JEA, we have more than $1.5 billion in debt outstanding on our solid fuel generating assets, amortizing over the expected useful life of

[1] Low monthly settle of $2.04/mmBTU in May 2012, compared to a monthly settle of $3.96/mm BTU in September 2014. July 2014 monthly settle reached $4.40/mmBTU. (All prices Henry Hub),

those facilities to 2039. By forcing re-dispatch and retirement of the units beginning in 2020 – the practical consequence of having to meet even the interim goal – the EPA will leave JEA's customers holding a bill for $795 million in stranded costs.

The following chart summarizes JEA's current debt and maturities on its generation assets.

JEA DEBT ON GENERATION ASSETS

Unit	**Debt Outstanding**[1]			
	2014	**2020**	**2030**	**Final Maturity**
NS 1&2 estimate	$639,872,000	$452,100,000	$160,610,000	10/1/2039
SJRPP Issue Two (100%)	$377,700,000	$9,220,000	$-	10/1/2021
SJRPP Issue Three[2]	$333,495,000	$251,765,000	$86,715,000	10/1/2039
Scherer	$119,100,000	$81,885,000	$24,985,000	10/1/2038
Total Solid Fuel	$1,470,167,000	$794,970,000	$272,310,000	
BB1	$0	$0	$0	
BBCC 2&3	$351,476,000	$248,250,000	$88,190,000	10/1/2039
Ken CT 7	$2,644,000	$1,810,000	$640,000	10/1/2039
Ken CT 8	$77,972,000	$55,270,000	$19,630,000	10/1/2039
GEC CT1&2	$182,688,000	$128,650,000	$45,700,000	10/1/2039
NS3	$0	$0	$0	
Total Non-solid Fuel	$614,780,000	$433,980,000	$154,160,000	
Unallocated			$32,211,969	
Solid and Non-solid Fuel Units	$2,084,947,000	$1,228,950,000	$426,470,000	

Notes:

1 Bond issues are general capital bond issues, apportioned to specific units, but not collateralized by those units. SJRPP and Scherer bonds are specific issues.

2 SJRPP Three financed significant recent investments in pollution control equipment.

JEA's unique geographic position results in a double penalization under the rule: not only will we be forced to comply with the Florida state plan for generating assets, but we also will be forced to comply with Georgia's state plan. Two of JEA's key generating resources – Plant Scherer and Plant Vogtle – are located in the state of Georgia, but supply or will supply substantial load in northeast Florida. Georgia's goal is all but impossible to meet with the continued operation of Plant Scherer, jeopardizing JEA's lowest-cost generating unit despite the installation of more than $597 million in state-of-the-art pollution control investments for Scherer Unit 4 between 2007 and 2012, with JEA's share being $141 million. Georgia faces the further penalty of including new nuclear plants under construction in EPA's formula for setting Georgia's goal rather than as investments to help meet the goal, thereby eliminating the future zero carbon benefit of Plant Vogtle when it comes online later this decade. Given the remaining risks inherent in a construction project of this magnitude and the uncertainty around ultimate schedule and cost, including these units as if they are already on-line is punitive in a state that took proactive steps to reduce its carbon footprint ahead of any federal requirements. JEA entered a purchase power agreement for future Vogtle energy to increase fuel diversity and help reduce its environmental impacts.

JEA optimistically assumes that Florida's state plan would include a stranded cost recovery mechanism that would fairly apportion these extraordinary costs across all Florida ratepayers. With such a mechanism in place, and considering investments in replacement generating resources that would necessarily accompany the retirement of solid fuel resources, Florida ratepayers are facing average across the board rate increases of 25 to 50 percent which will be stifling to economic development in our state. While some states can comply with the EPA's proposed rule at very low cost, simply by retiring a single generating resource that was already slated for retirement (Washington), or continuing to operate substantially all solid fuel units with only heat rate improvements imposed (Kentucky), Florida and other states face a true and extraordinarily expensive transformation in generating resources. Despite hundreds of millions of dollars of investment in state-of-the-art pollution control equipment on solid fuel facilities located in our state required by other recent EPA rules, we would not be able to continue to operate those facilities. The resulting rate impact will make the entire state uncompetitive from an economic development perspective. As large projects compete for location sites in the U.S., states with non-disruptive compliance costs will be clear winners in economic development at the expense of those with very high compliance costs. Given the importance of attracting new business to Florida for its overall economic growth, this paints a bleak picture for the foreseeable future, potentially increasing unemployment and handicapping economic prosperity for citizens of our state.

<u>Building Block 1</u>: JEA has implemented all possible cost effective heat rate efficiency improvements to its solid fuel units. Additional investment in heat rate efficiency would result in a 1.5% improvement at best, and would not be economic. Investing additional capital in units under Building Block 2 that may only run at 10% of capacity, or be subject to early retirement, would be truly noneconomic.

<u>Building Block 2</u>: JEA currently utilizes optimal economic dispatch for the generating fleet; therefore any change in current dispatch decisions would result in more expensive power generation for our customers. Environmental constraints already impact economic dispatch decisions in that the cost of compliance with each new environmental regulation is included in the all-in cost of operating each unit.

<u>Building Block 3</u>: Renewables practical for Florida have a much higher cost per MWh than traditional units and do not provide base load capacity. Therefore, replacing solid fuel generation with renewables would increase cost in exchange for decreased reliability.

<u>Building Block 4</u>: JEA has embraced energy efficiency in our service territory over the past decade. Through a series of programs and incentives offered to customers, JEA has achieved a cumulative 3.3% reduction in energy sales (2004 to 2013). In fact, JEA's sales in the electric system have decreased approximately 10% from our peak despite growth in new customers of 6% over roughly the same time period (2006 to 2013), reflecting the effectiveness of JEA's programs. Each JEA

residential customer, on average, is using 13% less electricity than just ten years ago and these efficiency trends are expected to continue. Likewise, commercial customers are using 19% less electricity, on average. By utilizing a base year of 2012, the CPP provides no consideration for the efficiency improvements ***already achieved*** by JEA. JEA has already captured the "low-hanging fruit" for energy efficiency through a series of EE and DSM offerings. Because our EE/DSM program is mature, significant additional investment in demand side energy efficiency will likely not economically achieve results, and may not be cost-effective for our customers. This requirement places an additional cost burden on top of extraordinarily expensive compliance costs with the proposed CPP.

Impact on Reliability

At JEA, about 38% of the current generation capacity (including JEA's Scherer #4 portion) is from coal. JEA's Florida units are geographically situated adjacent to each other. Shuttering both plants, if in effect required to be retired prematurely, may cause an imbalance in JEA's grid and a remedy would require long term planning for replacement and stabilization.

The EPA's new CPP is predicated on the theory/approach that the Best System of Emission Reduction (BSER) involves the application of four "building blocks" against a "system" which is the entire US "bulk electric system"—including all generation, transmission and distribution assets, and further reaching into the customers' homes/businesses. The CPP however fails to capture any aspects of transmission base case constraints—not to mention contingency-based constraints—and is thus not workable in a practical sense. If the EPA's final approach with the CPP continues to consider the entire bulk electric system as the BSER "system", it must factor in all of the practical and real-world constraints associated with that "system".

As stated above, the proposed CPP does not reflect the realities of the transmission system in the Southeast. The electric transmission system is the 'glue" that binds both the local and remote generation resources to the load centers of the utility along with any possible exports. The electric transmission system consists of multiple voltages and transfer capabilities that have evolved over the years based on the normal transmission flows and location of generation resources. The electric transmission system has been built, analyzed, and upgraded all based on this mode of operation. The System has been studied and operated in accordance with all applicable NERC standards that provide acceptable reliability to our customers. All this work and effort has been based on a transmission system with long term fixed resources and resulting flows.

As large generation resources are displaced by other resources, whether local or remote or a combination thereof, the transmission flows may be altered significantly. It is entirely possible that the transmission system that previously met all NERC standards would no longer be in full compliance nor would it provide acceptable reliability to our customers. The transmission system may require modifications to existing facilities or the addition of new facilities to be fully compliant and provide an acceptable reliability at additional cost. The assessment and determination of the system impact requires in depth study and analysis for each of the proposed configurations. To that end JEA has contracted with a nationally recognized transmission planning consultant to help us navigate through the literally scores of possibilities to conduct a thorough analysis for each and determine costs for new plants that might be required.

As an example of the interrelationships involved, looking at the power import scenario in the JEA System, JEA's base import capability drops to just over 200 MW for certain contingencies. For regulatory compliance with NERC Reliability Standards for electric reliability, JEA must have plans including generation, load reduction or interchange to cover the import reduction into our system necessitated by these contingencies. We would have 30 minutes to replace the capacity, either contractually, through our own generation or load reduction. Note that a contractual solution for the required backup would likely be problematic as any neighbors would be facing the same level of cuts as we would, under the loss of transmission line scenario.

The huge rotating mass of a steam turbine-generator set provides a lot of stored energy to restore the stability of JEA's grid following a disturbance. The grid stability can become an issue when the coal units are replaced with gas turbine-generator sets (which have smaller mass) even for the same power (MW) generating capacity. Additionally, gas turbine-generator sets do not have as much reactive power (MVAR) generating capacity as that of coal units to maintain grid voltage and do not have MVAR absorbing capacity. Hence during the course of 24 hours, when the load fluctuates widely, a lot of support from reactive resources, i.e. capacitors and reactors, will be needed for maintenance of grid voltage. Capacitors will be required to generate reactive power during high demand periods and reactors will be required to absorb reactive power during low demand periods. Another issue with gas turbines is the flame lean-blowout (to control CO and NO_x emissions) when the turbines cannot keep up with disturbances in the grid and trip (as was the case of JEA's Brandy Branch NGCC plant tripping during the Southern Florida disturbance of February, 2008), thus exacerbating the already disturbed grid. Gas scheduling and supply condition could be another issue, especially during very cold winters in the northeastern region when gas heating takes priority and gas for electric generation can be curtailed, as occurred during the "polar vortex" incident.

One option will be buying power from utilities in the SERC region which comes through JEA owned 500 kV lines via FPL's Duval substation. Any major issue at Duval substation will force JEA to severely curtail its import capacity, forcing JEA to rotating blackouts and brownouts. Even today, for a single contingency of the 500 kV line or the 500/230 kV autotransformer at Duval substation, JEA's portion of import capacity from Georgia to Florida is significantly curtailed. Power import from the south is another option, but there is not much 230 kV transmission capacity in the southern part of JEA 's service territory and adjoining area that can support this. Another option for import from the south is through the 500 kV system owned by FPL south of Duval substation, which again is dependent on Duval substation and its reliability.[2]

[2] Detailed assessment of the capabilities and limitations of the transmission infrastructure are considered to be Critical Infrastructure Protection (CIP)-controlled information by the North American Electric Reliability Corporation (NERC). It is not appropriate to provide more detail in a public forum.

Complex issues such as generation planning, permitting, construction and stability of the electric grid, forced by retirement or redispatch, are outside the jurisdiction of EPA, or at least they have been before the proposed CPP.

Impacts on Different Utility Ownership Types

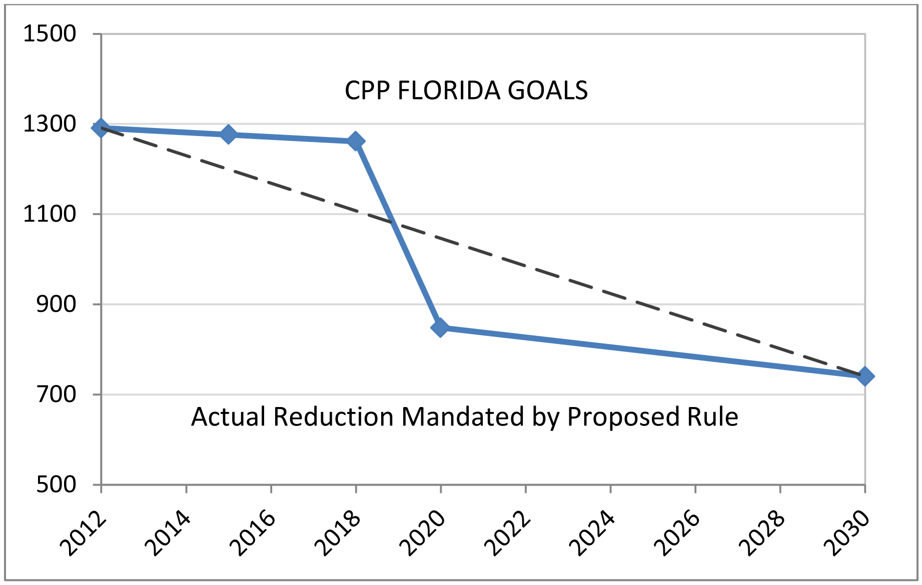
The CPP performance burdens apply indistinguishably to investor-owned (IOU) and consumer-owned utilities (COU), including municipal utilities such as JEA. However, there will be a disparate cost impact or burden on COUs to comply with the CPP. A fundamental distinction between IOUs and COUs is that IOUs seek to maximize wealth for their shareholders by increasing value to owners. COUs seek to give value to its owners via reasonable rates for reliable power. This distinction will allow IOUs to be more indifferent to the cost impacts of the rule because of prevailing cost recovery mechanisms that are afforded to IOUs. These mechanisms allow the significant costs of complying with CPP to be recovered from ratepayers in a manner that will not erode the earnings of stockholders. In some cases, investment in new generation will increase IOU "rate base", thereby increasing earnings. COUs will recover compliance costs by similar means. However, COU "owners" will see less value return because they will only see rate increases. Additionally, there are likely to be means of securitizing assets stranded by CPP that will be more accommodating for IOUs than COUs and, at least in Florida, COUs have relatively newer solid fuel generation assets that will be more prematurely stranded than will be for IOUs.

Interim and Final Goals – Lead Times and Planning

As proposed, the CPP regulations call for submittal of each state plan as late as June 2017, with the allowable one year extension, and June 2018 as part of a multi-state agreement. The EPA would then have up to one year to approve the plan. It is not unrealistic to imagine, then, that the final state plan could be approved as late as June 2018 for single state plans. Regardless of the timing of EPA approval of the state plan, the CPP requires compliance to begin January 1, 2020, as the ramp down begins. Regardless of what the final numbers are, or how the state chooses to meet those standards, eighteen months from final state plan approval (not accounting for the inevitable legal challenges) to implementation is far too short. Considering that nuclear generation's reliable, base-load, carbon free energy must be an important part of the plan, even the ten or so years from final plan approval to implementation of the 2030 standards is too short. The planning cycle for nuclear, from site selection and permitting through construction still exceeds ten years. It is unrealistic to expect that utilities will take action and spend their customers' money without absolute clarity as to what the final approved state plan will require. Investing significant time and resources for a regulation that is still being revised and has yet to withstand a serious legal challenge is not a prudent use of our customers' money. As a municipal utility, it is our obligation to meet the electric needs of our community by the lowest-cost, environmentally responsible means available. As a not-for-profit utility, the most reasonable way to keep costs down for our customers is to use our existing resources to their maximum potential, not by abandoning plants before the end of their useful life. On average, JEA's coal units have expected useful lives extending 15-20 years beyond the initial proposed compliance date of 2020.

Interim and Final Goals – Stringency/Timelines

Florida CO_2 lbs per MWh



This interim goal "cliff" is one of the most critical concerns to JEA. Meeting the numeric goals and the proposed dates for the interim and final goals will be difficult and unnecessarily costly. The EPA has proposed an average state of Florida interim goal of 794 lbs/MWh for 2020-2029 and 740 lbs/MWh in 2030. If the state were required to meet these targets, 1800 MW of JEA's existing solid fuel capacity that would not ordinarily have been retired by 2020 will be threatened. While the State is required to meet the goal as a whole, one way JEA might contribute to meeting the state goal is with significant re-dispatch or retirement of all of its solid fuel capacity and with purchase of replacement power. There is currently insufficient transmission infrastructure to accommodate such an import into JEA's service territory.

The Clean Power Plan as proposed is not prudently attainable in Florida. The speed at which the plan is proposed to be implemented and the great reduction in CO_2 emissions required makes the Clean Power Plan interim goal as proposed exorbitantly costly to attempt to attain between 2020 and 2029. If this plan is finalized and enforced as proposed, it will shift electric utilities away from reliable, base load solid fuel units to base load natural gas fired combined cycle units with simple cycle combustion turbine units filling the intermediate load gap and cycling to manage the electric system. This sudden shift would cause a market rise in the demand for, cost of, and delivery time for the construction of the required new units. At 2014 market demand levels for these units, a minimum lead time of 30 months, 36 months and 10 years could be expected for combustion turbine, NGCC and nuclear units, respectively. To have gas fired units in place in the quantity needed to meet the 2020-2029 average, the utility would need a plan of action underway and need rate payer funds before a final rule would be in place. At best, a new nuclear decision and build could be facilitated to help meet the 2030 target. However, as we understand it the CPP only counts increased generation from existing NGCC and the five nuclear units currently under construction (none in Florida) in its formula for meeting the state goals. Generation from “new” NGCC and “new” nuclear would not be given credit toward meeting the goal.

Allowing more flexibility to the states to allow for plants that are otherwise environmentally compliant to run for their remaining useful lives beyond 2030 or extending the final goal date would set in motion meaningful CO_2 reductions while protecting consumers from the costs of unnecessary deadlines.

<u>Baseline Year</u>

In its Goal Computation Technical Support Document, EPA states that it “carefully considered using a historic year data set, a projected year data set, or a hybrid of the two as a starting point…for calculating the state’s emission rate goals” but “chose the year 2012 as it represented the most recent year for which complete data were available at the time of the analysis.” EPA goes on to state that it “also considered the possibility of using average fossil generation and emission rate values over a baseline period (e.g., 2009 – 2012), but determined that there would be little variation in results compared to a 2012 base year data set due to the rate-based nature of the goal.” EPA also issued a Notice of Data Availability on October 30, 2014, requesting comment on EPA’s approach to a specific baseline.

The Florida Electric Coordinating Council Environmental Committee (FCG-EC), of which JEA is a member, agrees with EPA that a historic baseline is preferable to a projected year or a combination of historic and projected, but it does not agree with EPA’s decision to use a single year (2012) as the starting point for calculating the state’s emission rate goals. EPA has offered no data or analysis to support its stated finding that there would be little variation in results using a 2009 – 2012 baseline period compared to a 2012 base year.

The FCG-EC used data from 2009 – 2012 to calculate alternative baselines for Florida. Using EPA’s methodology, the FCG-EC found that EPA’s 2012 baseline is the lowest possible value and does not reflect a representative year or average for Florida. In fact, 2012 was the lowest mass and rate year recorded for CO_2 emissions in Florida’s emissions database. In addition to the fact that state baselines using years other than or in addition to 2012 do in fact vary from a 2012 baseline, there is the fact that it is inappropriate to use any single year as a baseline to represent the electric power sector. Sources and amounts of electricity generation can and do vary from year to year. The variability is due to many factors that include economic conditions, weather variability, year-to-year fluctuations in fuel prices, and significant unplanned and planned unit outages. With regard to fuel prices, natural gas prices in 2012 were at their lowest level since before 2000 (the 2012 annual average Henry Hub price was $2.75 per mmBtu), which is lower than today’s price and lower than any natural gas price the EIA projects into the future. This fact alone disqualifies 2012 as a representative single baseline year applicable to the electric power sector.

EPA clearly recognizes that there is year-to-year variability in the electric power sector, and has taken steps in previous power sector rulemakings to address it. For example, as part of EPA's Cross State Air Pollution Rule (CSAPR) regulating sulfur dioxide and oxides of nitrogen from the power sector, EPA believed that the power sector variability was significant enough that it prepared an entire Technical Support Document specifically to address the issue, and included provisions in the CSAPR to address that variability.

In its Existing-Unit CO_2 proposal, EPA states that there is "…year-to-year variability in economic and other factors, such as weather, that influence power system operations and affect EGU CO_2 emissions." EPA has proposed to include rolling three-year performance periods for compliance purposes, apparently in an effort to address the variability. However, EPA makes no mention of power sector variability with respect to its proposal to use 2012 as the single baseline year. EPA must address power sector variability in its selection of a baseline period as a critical factor in determining a representative baseline.

The FCG-EC and JEA recommend that EPA use a multi-year baseline rather than a single-year baseline. This will produce a more representative baseline than a single year.

Gross vs. Net Capacity to Set Goals

Nameplate capacity represents the design gross capacity of the generator before any internal plant usage (auxiliary power) is deducted, whereas the net capacity represents the value after auxiliary power is deducted. Net capacity is what a unit can supply to the electrical grid. There is also a seasonal component to net capacity, with summer net capacity being lower than winter net capacity, but both typically are lower than nameplate capacity - and occasionally significantly lower. EPA is using net generation (in megawatt-hours (MWh) as the input for emission rate calculations on a pound of CO_2 per net MWh basis. More information is required to understand the most representative value for determination since other emission limitations are based on gross versus net.

Rate or Mass Based Goals

EPA allows the states to use either mass-based or rate-based goals. But there is lack of direction and guidance from EPA on how mass-based goals should be calculated. More details are needed so that the states and utilities can determine which method is more advantageous and flexible to achieve the final CO_2 emission reductions. On November 6, 2014, EPA released additional information on mass and rate based goals. JEA is evaluating and may make additional comments.

Multi-State or Regional Plans

The prospect for the development of "regional cooperation" is not likely to be available to help meet the interim goal for Florida. There is little precedent in this region for regional interstate allowance crediting and no precedence for compliance enforcement. Implementation will require negotiation of political differences as well as administrative differences. Additionally, given Florida's peninsular geography and stringent goals, Florida is not likely to be an attractive partner for multi-state cooperation.

State Implementation:

As earlier stated, EPA should apply 111(d) standards at the EGU, limited to technologies that can be implemented specifically at the EGU. Given the EPA's approach to proposing BSER as the entire electric system, JEA believes that a state plan for implementation should equitably distribute the burden of required improvements, emission reductions and the cost of implementing emission reductions across all electric customers and utilities within a state. All electricity customers and utilities should fairly share and contribute to carbon dioxide reductions in order to meet the energy policy being proposed by the EPA.

Language should be added to the proposed CPP in the State Plan Components section, clarifying how owned or purchased generation, and associated CO_2 emissions, from generating units located in different states should be accounted, regardless of the development and implementation of multi-state plans. Item 8 of 12 in that section discusses possible accounting for renewables including wind and EE for distribution utilities that operate in multiple states.

EPA Notice of Data Availability (NODA) October 28, 2014

After an initial review of the NODA, JEA is appreciative of EPA's acknowledgement of the problem that stranding assets causes for utilities like JEA and EPA's recognition of how difficult it will be to meet the interim goals. JEA observes that the aspects of the NODA for which comment are sought may in fact add further complication to understanding the proposed rule and do not offer additional insight as to how EPA might ease the interim goals or glide path. It appears any easing of the interim goals will be offset with stricter goals from another building block or cause more stringent goals to be added to another state. JEA does not agree that EPA should require states to build more NGCC units in recalculating state goals or offset the growth opportunities that may be afforded in BBs 3 and 4. For these reasons, JEA encourages EPA to regard concerns expressed in JEA's general and building block comments as paramount. JEA anticipates little or no additional information can be provided in response to the NODA framework that will convince EPA to set goals that will be achievable and more balanced.

V. EPA's Proposed Four Building Blocks

EPA's CPP proposes four `Building Blocks' as a `system of emission reduction' under its `Option 1' approach; however, only the first Building Block can be applied to individual EGU sources subject to regulation under the 111(d) proposal. The other three Building Blocks are out of the control of any particular regulated source and are predicated on actions by others.

The Building Blocks used to develop the individual state goals are inappropriate and are, for Florida at least, based on inaccurate data. JEA is concerned that because none of the Building Blocks is fully achievable in Florida, there is no margin to make-up under one Building Block the amount to which Florida would fall short on another.

To determine the interim goal for each state, EPA assumed that all emission rate reductions from Building Blocks 1 and 2 could be achieved at the start of the ten-year interim goal compliance period. Under BB 1, EPA assumed that each state's fleet of coal-fired generating units could achieve a six percent heat rate improvement and that the improvement would directly translate to a six percent reduction in net CO_2 emission rate. Under BB 2, EPA assumed that states would be able to utilize existing and under-construction NGCC up to seventy percent of their capacity. Neither of these is achievable, prudent or economically logical. In contrast to its treatment of BBs 1 and 2, EPA assumed that emission rate reductions from BBs 3 and 4 would ramp up gradually throughout the ten-year interim compliance period. As a result of EPA's assumptions regarding the implementation of BBs 1 and 2, the interim goals for many states are so stringent almost all of the required emission rate reductions required by the Proposed Rule must be achieved in the first year of the ten-year interim goal compliance period. For Florida, EPA assumes 76% of the total reduction required in 2030 would be achieved by 2020.

If the structure of CPP withstands legal challenges and progresses under a building block regime, each state should be allowed to develop its own numeric goals based on what it determines is reasonable and achievable.

Building Block 1

EPA's application of rule 111(d) includes four building blocks EPA has determined to be a "system of emissions reduction" for CO_2. These comments are applicable in specific to Building Block 1, which calls for a 6% increase in solid-fuel fired EGU efficiency.

JEA has already performed all the efficiency improvements that are cost effective and do not expose JEA to a possible New Source Review (NSR). On JEA's Northside Units 1 and 2, JEA spent $26M on turbine upgrades yielding approximately a 1.2% improvement in efficiency. The only possible upgrades remaining for these units are not currently cost effective. There may be some room for a 1-2% increase in efficiency available for our SJRPP 1 and 2 units, but those improvements are not currently cost effective, and are at risk of triggering an NSR review. Georgia Power's Scherer 4, of which JEA is part owner, has received significant efficiency upgrades in the process and deploys the best available control technology (BACT).

The risk of an NSR review has historically been the single major driver preventing even cost effective efficiency upgrades from being implemented. Should maintenance or upgrades to a unit result in a net increase in emissions by virtue of an increase in output or in unit use, the unit would be subject to NSR. At this time no guidance has been given by EPA on how it intends to apply NSR provisions should an improvement in efficiency mandated by the CPP result in an actual increase in total emissions due to increased capacity or increased usage. It is not prudent for any utility to proceed with an upgrade that could trigger NSR without assurances (i.e. inclusion in the CPP rulemaking) that the rule driving the upgrade will in fact exempt the resultant upgrades from NSR. No such assurances have been given in the proposed NSR.

Perhaps a more significant hindrance to implementing Building Block 1 than NSR is the practical impact of implementing Building Block 2, the re-dispatch of coal-fired generation toward gas. Any attempt on JEA's system to implement Building Block 2 will result in both a reduced average load factor on the solid fuel EGUs, and an increase in the number of starts. Both of these actions result in a decrease in overall efficiency which certainly exceeds the 1-2% improvement that may be available to JEA, and is likely to exceed even the 6% efficiency called for by Building Block 1. Reduced load operation and increased starts will negate any improvements to overall unit efficiency, and the total net unit CO_2 emission rate (lb/MWh) will increase.

It is not at all reasonable or even possible for JEA to achieve the Florida State 2020-2029 or 2030 average emission goals for CPP regulated units even with all building blocks implemented. JEA can only achieve this goal by effectively retiring all solid fuel units and building gas units that are subject to Section 111(b). Since the CPP in effect (though not in the rule) mandates forced closure of coal units, Building Block 1 is rendered completely ineffective, impractical, irrelevant and unnecessary. It only exists to give credence to the desired appearance that this rule does not in fact force closure of coal units (though it does in practice). Building Block 1 at a more realistic rate of one to two percent might be viable if BB 2 were abandoned. BB1 is the only one of the four BBs that is effective at the "source" EGU.

Building Block 2

These comments are applicable to Building Block 2, re-dispatch of 90% of coal-fired energy to natural gas fired combined cycle (NGCC), and operation of NGCC at a minimum capacity factor of 70%.

JEA has a single NGCC Unit, Brandy Branch Combined Cycle (BBCC), comprised of two GE 7Fa CTs in a 2x1 configuration. It is technically possible from a manufacturer's standpoint to operate JEA's NGCC unit at an average 70% capacity factor, although there are maintenances costs associated with doing so. In limited practice, JEA finds that there are system limitations which affect JEA's ability to operate this unit at continual high capacity factors to displace solid fuel generation. In spite of those limitations, in calendar year 2012, driven by historically low gas prices, JEA successfully dispatched the BBCC NGCC unit at a record capacity factor of 80.9%, up from the previous record of 66% in CY 2011. Historically the capacity factor on this unit has been near 35%.

The increase in capacity factor (from 35% to 66%, then up to 80%) was made achievable only in conjunction with significant use of economic NGCC market power purchases, made in the operating horizon and backed up by idle coal-fired capacity. JEA purchased 12% of total net energy as gas-fired opportunity purchases in CY 2012, and JEA generated slightly less than 12% of total net energy using the BBCC NGCC unit. These strategic gas-fired market energy purchases allowed individual solid-fuel units to remain off-line seasonally (during shoulder months), and for a longer duration in 2012 than in 2011, a previous record year. With select solid fuel units seasonally off-line, there were fewer times when the NGCC unit had to be dispatched down at night to accommodate the minimum load of solid fuel units. This resulted in a historical maximum 80.9% capacity factor on the BBCC NGCC unit.

On JEA's system, it should be possible to operate the existing NGCC unit consistently at an average capacity factor of 70% when coupled with market purchases of NGCC energy adequate to allow solid fuel units to be seasonally idled. It may be more difficult, or may not be possible at all, to achieve a capacity factor over 70% without opportunity purchases, or without construction of another combined cycle natural gas unit (which is not otherwise planned). The key to higher NGCC capacity factors has been shutdown of solid fuel units in the shoulder months, and JEA's lone NGCC unit does not provide enough capacity or energy by itself to achieve that goal.

Keeping in mind that the goal of operating NGCC units at a capacity factor of 70% is to re-dispatch 90% of the energy produced from solid fuel units to gas-fired NGCC units, JEA has shown that operating our NGCC unit at these capacity factors may be possible, but doing so will not (for JEA) achieve the goal of re-dispatching 90% of coal-fired energy to gas. JEA's system (by 2020) is expected to be comprised of approximately 48% coal and/or petcoke fired steam units, 16% natural gas fired combined-cycle units, 5% Nuclear (PPA not ownership), 25% simple-cycle gas fired peaking units, and 6% other units (primarily distillate fired CTs), on a capacity basis. As JEA only has one third the natural gas fired combined cycle (NGCC) capacity as solid fuel, it will not be possible for JEA to displace 90% of coal-fired energy by re-dispatching existing NGCC units. JEA currently has no plans for additional capacity in this timeframe, and accordingly no additional NGCC Units are expected. As a result, JEA does not find it possible to displace 90% of solid fuel generation by re-dispatch using existing and planned (none planned) NGCC units by 2030.

JEA cannot expect to achieve 90% re-dispatch from coal to gas without constructing new gas-fired NGCC units under 111(b). Even in that case, technical issues remain. First, the replacement generation must be located at or near existing coal-fired sites in order to minimize local transmission impacts such as load and voltage issues. Second, there is not currently adequate gas transmission capacity into Northeast Florida to support the quantities of gas required for such an operation, either on a firm or non-firm basis, and extensive electric transmission upgrades would also be required. In order to support construction and operation of an adequate amount of new NGCC units under 111(b) to achieve 90% re-dispatch, there must be extensive improvements made to local gas delivery infrastructure as well as to the gas transportation infrastructure. EPA has considered none of this.

In addition to the technical reasons why it is not practical for JEA to re-dispatch 90% of its coal-fired energy to gas, there are economic and philosophical reasons for not doing so. As a municipal utility, JEA is tasked with the need to provide the community with the least cost electrical supply possible while still meeting all environmental regulations. To that end, JEA has slowly and methodically updated its generating fleet, transitioning from oil fired steam units to gas conversions, to its first (modern) coal-fired units, to gas fired CTs and one NGCC unit, and to (modern) petroleum coke (petcoke) and coal-fired circulating fluidized bed (CFB) units.

In good faith JEA's customers invested $630M to re-power two oil-and-gas fired units to coal and petcoke fired CFB boilers, including modifications to meet EPA rules. JEA's total investment in Northside 1 and 2 is currently almost one billion dollars.[3] The project entered commercial operation in 2002. This was a DOE sponsored Clean Coal project which demonstrated the first large scale CFBs and set a new standard for BACT. The project resulted in a 170% increase in electricity production, while reducing total emissions of NOx, SO_2 and PM. DOE established the technical requirements for this project, and supplied $72M toward construction. EPA has now drafted a rule that will prevent JEA from operating these units and receiving the value of the money that our customers (and Federal taxpayers) invested in good faith.

Furthermore, to comply with the Clean Air Interstate Rule (CAIR) regulations JEA and FPL invested $278 million to install Selective Catalytic Reduction (SCR) systems at SJRPP, the largest local coal units, with JEA's share being $222 million. These SCR systems became operational in 2010. CAIR and the Clean Air Mercury Rule (CAMR) were later replaced with CSAPR and MATS. It was ultimately determined that with these upgrades the units were expected to be capable of CSAPR and MATS compliance. EPA has now drafted a rule that will prevent JEA from operating these units and receiving the value of the money that our customers invested in good faith to meet other environmental rules.

For the same reasons as above, between 2007 and 2012, JEA participated in comprehensive environmental control upgrades to the Scherer 4 coal-fired generating unit, co-owned by JEA (23.64%) and FPL (76.36%). The unit is located within Georgia Power service territory, and operated by Georgia Power. The scope of these upgrades included installation of a wet scrubber, an SCR system, a fabric filter, and PAC injection for mercury control. EPA has now drafted a rule that will prevent JEA from operating these units and receiving the value of the money that our customers invested in good faith. The total investment in environmental upgrades for Scherer Unit 4 was over $597 million with JEA's portion being $141 million.

In all three cases above, JEA has proceeded in good faith to implement costly upgrades to its fleet, including Northside 2 repowering, partially funded by the DOE, in order to comply with new EPA regulations. Now, in a case of extreme over-reach, EPA is proposing regulations that will void these capital investments that recent EPA regulations required, and render five fully modern clean coal-fired generating units totaling 2,700 MW[4] capacity to be stranded assets. Assets for which JEA's customers will continue to pay while being prevented from reaping the benefits of their use. In 2020 JEA and its customers will have $795 million in debt outstanding on these three projects. That debt will have to be repaid without the benefit of use of the underlying assets due to BB 2 and the interim goal date. The CPP unnecessarily makes JEA customers' investments in costly environmental

[3] Northside Unit 1 - $459 million, Northside Unit 2 - $464 million – original construction cost plus modifications.

[4] Full net MW capacity of SJRPP 1&2 and Scherer 4 included.

rules obsolete. The CPP exceeds EPA's authority, and it requires JEA's customers to bear a disproportionate burden of the cost of compliance.

Building Block 3

As each of the potential alternative zero-carbon energy sources contemplated in Building Block 3 have different issues, it is useful to examine them individually. The targets for BB 3 should be determined by the states, but alternatively, they should not be based upon a single state RPS, should be reduced, and should provide states with the ability to adjust the goals for practical implementation. The section below details JEA's experience with and position on each of the technologies considered in Building Block 3.

Nuclear

JEA agrees that nuclear is the most reliable and possibly cost-effective method to generate carbon-free electricity. JEA, in anticipation of future environmental regulations, secured a 20-year PPA for 200 MW of capacity and energy from the two under construction units at Vogtle Nuclear Plant in Augusta, Georgia, expected to be available in 2017-18. JEA has also purchased an option for up to 440 MW of nuclear capacity and energy from a plant under consideration in South Carolina. Under the proposed Clean Power Plan, JEA would not see the CO_2 benefits of either of these, as the zero-carbon credits would stay in the states where they are generated (Georgia and South Carolina). This aspect of the regulation greatly reduces the value of any clean energy source not located within Florida.

JEA remains involved in discussions with other Florida utilities regarding siting and constructing new nuclear plants in Florida. With the current lead-time for nuclear construction, no new assets can be expected in the state before the mid-to-late 2020s, too late to support the CPP required ramp down beginning in 2020.

While the initial capital cost for a nuclear plant is high, it compares favorably to other generation on a Levelized Cost of Energy (LCOE) basis, due to the low and steady price of fuel. Municipal utilities such as JEA cannot however make a commitment to an alternative energy supply, such as nuclear, until there is a clear and final regulatory mandate, because any additional costs directly impacts our customers. With a final approved state plan conceivably no earlier than June 2018 (assuming applicable extensions), there is not enough time to implement any plan before the mid-2020s for a conventional energy source (NGCC), and 2030 if nuclear is a component of the solution.

EPA should clarify the expected accounting for interstate transfer of energy and CO_2 emissions and provide multiple options to states for dealing with those interstate energy transfers. EPA should also work for streamlined approval of new nuclear units to demonstrate support for zero carbon baseload generation.

Renewables

Renewables targets for the southeastern states including Florida were based on the Renewable Portfolio Standard (RPS) in North Carolina at 10% by 2030. From the Initial Reliability Review released by NERC in November 2014, "In addition to hydroelectric power, energy efficiency plays an important role in various states' RPSs. North Carolina's RPS includes a provision that allows up to 25 percent of its target to be met by energy efficiency gains. This provision, if it were properly excluded by the EPA, would reduce North Carolina's RPS target to 7.5 percent from 10 percent, thereby lowering targets for the entire Southeast region…"[5]

EPA's assertion that the North Carolina RPS is 10% is incorrect and its application to Florida is inappropriate and should be withdrawn. Florida has a unique geography and thus a unique capability and access to renewable resources. Florida's CO_2 reduction goal should not be based on any other state's renewable potential. The CPP should be revised to allow Florida to set the renewable goal for Florida.

Wind

The US Department of Energy's National Renewable Energy Laboratory (NREL) reports that onshore wind energy potential in Florida is low, at approximately 5 meters per second or less. Off-shore wind potential is better, but neither is a viable resource. The same rules regarding out of state generation as described in the nuclear section impact the ability to import wind from out of state.

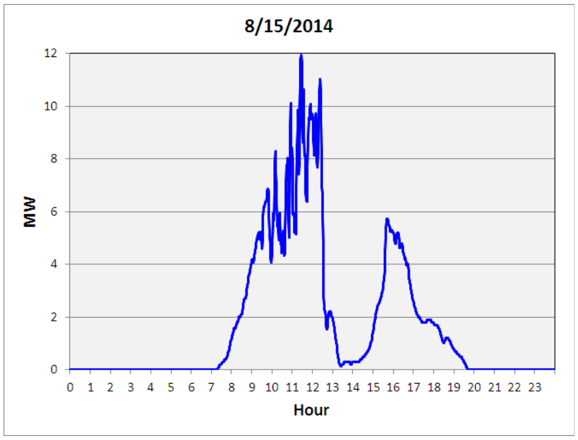
Solar

Florida is the "Sunshine State", but compared to southwestern states such as Arizona, we are really the "Partly-Cloudy State". The NREL shows solar potential in Florida as approximately 5 kWh/m2/day, compared to 7 kWh/m2/day in areas of the Southwest. Solar is a viable resource for energy only – it cannot be counted on as capacity, due to the unpredictability of when the solar generation will drop off due to weather. Also, given the lack of utility-scale electric storage, it is a daytime-only resource. JEA is a leader in solar utilization in Florida, and as the price for panels decrease we expect to add more. However, the nature of solar power and the manner in which it drops off the grid and comes back as a cloud passes, necessarily limits the total amount of solar that can be put on the system without introducing unacceptable instabilities.

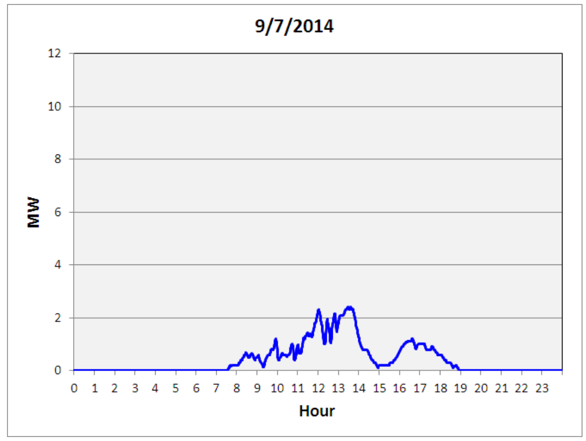
The following graphs are indicative of the existing Jax Solar 12.6 MW plant's daily performance with a) afternoon showers, b) a rainy day, and c) a sunny day. Alternate (natural gas-fired) capacity is required to be available to replace the solar generation when it drops off – and to drop off itself when the solar comes back. This need for system backup is a large component of the overall cost of solar when performing evaluations.

[5] NERC, Potential Reliablity Impacts of EPA's Proposed Clean Power Plan, November 2014, p. 12.

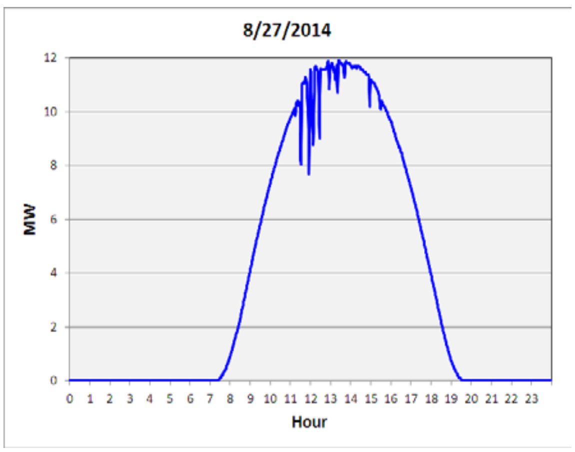
Afternoon Showers – 8/15/14



Rainy Day – 9/7/14



Sunny Day – 8/27/14



Biomass

Biomass treatment and biomass supply is uncertain, as is the EPA's eventual decision on CO_2 credits for biomass. JEA has the capacity to use biomass in its existing Northside 1 and 2 CFB units. However, JEA cannot include biomass in its resource planning until EPA clarifies the treatment of biomass.

Currently, biomass-fired electric generation is the most available RE option open to Florida for zero CO_2 emissions base load generation. EPA's proposed BB 3 goals for Florida for renewable energy are extremely optimistic. If Florida utilities have any hope of achieving CO_2 emission reductions envisioned in BB 3, EPA must amend its definition of affected facilities to fully account for carbon neutral biomass fuel streams in each of the three CPP rules. In addition, in all aspects of the three CPP rules, biomass fuels should be categorically defined as carbon neutral to facilitate the use of this carbon neutral renewable resource. This could be accomplished by designating the biomass fuel streams categorically identified as clean cellulosic biomass in EPA's Non-Hazardous Secondary Material (NHSM) rule as carbon neutral.

The 2011 “Draft Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources” prepared by EPA indicates that many biogenic fuels used to power electric generating units will be considered carbon neutral. Also, an earlier NREL study confirmed the carbon neutral/negative status of biomass generation. For this reason we believe that a categorical determination of carbon neutrality of clean cellulosic biomass fuels is justified. In addition, the categorical determination of carbon neutrality for biomass-fired generation will help incentivize this carbon neutral green energy, which is especially important in light of EPA’s projected low natural gas prices. EPA should implement exemptions proposed in its Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources (November 2014) to encourage biomass generation and define specific biomass sources treatment as a carbon-neutral renewable generation sources.

Geothermal

Florida does not have the geothermal potential to generate electricity. The practical limit for geothermal energy in Florida is for residential or commercial heat pumps, using the steady-temperature ground water to heat or cool a home. Even this use draws concerns over the groundwater usage, as water becomes a real issue for Florida.

Hydro

Florida has two small hydro-electric plants, totaling less than 15 MW. This supply is intermittent, as the water flows are subject to drought. There is limited potential for new hydro given the generally flat topography of the state. Other forms of hydro-electric power (wave, tidal, Gulf Stream, etc.) are still under development, and are still considered experimental. In addition, the process for licensing those new hydro resources is non-existent and likely to be very time-consuming. Recent efforts to license tidal power in Washington State have been abandoned due to delays and uncertainties in the licensing process.

<u>Building Block 4</u>

Attaining emissions reductions associated with a 1.5% annual increase in end-use energy efficiency (EE) is not cost effective and not within JEA’s control. This year, JEA participated in a bottom-up, statewide evaluation of available cost effective (Total Resource Cost test - TRC) energy efficiency for the Florida Public Service Commission’s goal setting proceedings under the Florida Energy Efficiency and Conservation Act. The study found that for JEA there is insufficient energy efficiency potential to meet the 1.5% target. The highest level JEA’s analysis indicated was no more than one percent (1%) per year. The ability to achieve and sustain indicated levels of EE are beyond the control of JEA. Incentives for these levels of EE would require untenable rate increases. Florida’s lower income population would be impacted disparately both through higher electric rates needed to fund programs and the inability to participate in many of the EE programs that their higher rates would fund.

EPA should recognize and give credit for early action on EE starting in 2005 and results of past EE achievements as published in EIA-861. Published results should not be subject to newly defined measurement and verification (M&V) approaches. New methods for M&V should apply only to future programs which would be designed to incorporate new M&V methods.

The CPP's no back-sliding provision is unrealistic and ignores the impacts of unpredictable changes in energy use, economic development and population growth over the next 20 years.

EPA should give credit for the effects of environmentally friendly technologies that may contribute to load growth such as plug-in electric vehicles, and other fuel switching technologies that have a net reduction of CO_2 emissions. An example may be replacing gasoline lawn mowers with electric lawn mowers.

VI. Recommendations

1. The rule would be made better if the EPA CPP final rule stayed within the bounds of the CAA 111(d) and therefore within the fence line of the EGU, and set a procedure for states to develop standards based upon the BSER that has been adequately demonstrated for EGUs.
2. States should be allowed to comply with the final rule using a broad array of options.
3. Final goals should allow existing EGUs to operate for their design lives including useful life extensions from environmental and other upgrades in order to avoid significant stranded investments and to avoid serious reliability issues, or the final goal date should be extended.
4. The interim goals (2020-2029) should be eliminated.
5. Each state should define the glide path within its state plan for that state to meet the final goal.
6. EPA should clarify the expected accounting for interstate transfer of energy and CO_2 emissions and provide multiple options to states for dealing with those interstate energy transfers.
7. EPA should implement exemptions proposed in its Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources (November 2014) to encourage biomass generation and define specific biomass sources treatment as a carbon-neutral renewable generation sources.
8. EPA should withdraw and re-propose the proposed rule.

APPENDICES

APPENDIX A

JEA GENERATING FACILITIES DEVELOPMENT							
Plant Name	Unit Number	Unit Type	Fuel Type	Commercial In-Service	Net MW Capability		Notes
			Primary	Mo/Year	Summer	Winter	
Northside	33-36	GT	FO2	01/1975	212	246	
Northside	3	ST	NG	07/1977	524	524	
SJRPP	1	ST	BIT	03/1987	501	510	(1)(a)
SJRPP	2	ST	BIT	05/1988	501	510	(1)(a)
Scherer (Georgia)	4	ST	BIT	02/1989	194	194	(2)(b)
Kennedy	7	GT	NG	06/2000	150	191	
Brandy Branch	1	GT	NG	05/2001	150	191	
Brandy Branch	2	CT	NG	05/2001	150	186	
Brandy Branch	3	CT	NG	10/2001	150	186	
Northside	1	ST	PC	05/2003	293	293	(c)
Northside	2	ST	PC	04/2003	293	293	
Brandy Branch	4	CA	WH	01/2005	201	223	
Kennedy	8	GT	NG	06/2009	150	191	
Greenland Energy Center	1	GT	NG	06/2011	150	186	
Greenland Energy Center	2	GT	NG	06/2011	150	186	
JEA System Total					**3,769**	**4,110**	(d)
(1) Environmental upgrades at SJRPP between 2006-09 totalled $278M with JEA's share at $222M							
(2) Environmental upgrades between 2007-12 totalled $579M with JEA's share at $141M							
(a) Net capability reflects JEA's 80% ownership of SJRPP (JEA currently receives 50% of energy)							
(b) Net capability reflects JEA's 23.64% ownership in Scherer 4							
(c) Partially funded with Clean Coal grant from DOE							
(d) Numbers may not add due to rounding							

APPENDIX B

ENERGY MIX DEVELOPMENT 1970-2013