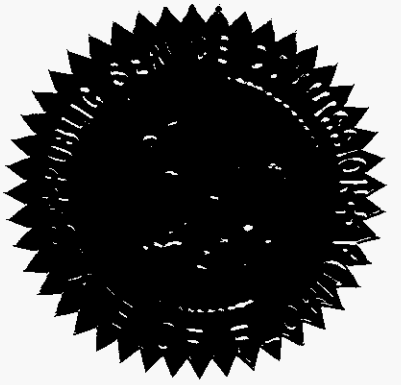
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080614-EM

In the Matter of:

PETITION TO DETERMINE NEED FOR GREENLAND ENERGY CENTER COMBINED CYCLE CONVERSION IN DUVAL COUNTY BY JEA.
_____/



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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN MATTHEW M. CARTER, II COMMISSIONER LISA POLAK EDGAR COMMISSIONER KATRINA J. McMURRIAN COMMISSIONER NANCY ARGENZIANO COMMISSIONER NATHAN A. SKOP
DATE:	Thursday, February 12, 2009
TIME:	Commenced at 9:30 a.m. Concluded at 9:41 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732

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PARTICIPATING:

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MARTHA BROWN, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, representing the Commission Staff.

I N D E X

WITNESSES

NAME:	PAGE NO.
DONALD C. GILBERT	
Prefiled Direct Testimony Inserted	8
Prefiled Supplemental Testimony Inserted	15
MICHAEL N. LAWSON	
Prefiled Direct Testimony Inserted	20
Prefiled Supplemental Testimony Inserted	28
MARY GUYTON-BAKER	
Prefiled Direct Testimony Inserted	31
JAMES T. MYERS	
Prefiled Direct Testimony Inserted	36
Prefiled Supplemental Testimony	44
JOHN A. WORLEY	
Prefiled Direct Testimony Inserted	47
RICHARD J. VENTO	
Prefiled Direct Testimony Inserted	59
Prefiled Supplemental Testimony	65
MYRON R. ROLLINS	
Prefiled Direct Testimony Inserted	68
Prefiled Supplemental Testimony	83
BRADLEY E. KUSHNER	
Prefiled Direct Testimony Inserted	88
Prefiled Supplemental Testimony	103

EXHIBITS

NUMBER:		ID.	ADMTD.
1	Comprehensive Exhibit List	110	110
2	Staff's Composite Exhibit	110	110
3-31	(Descriptions of Exhibits 3-31 contained in Exhibit 1, Comprehensive Exhibit List.)	110	110

P R O C E E D I N G S

CHAIRMAN CARTER: Good morning. I'd like to call this hearing to order. And, first, let's begin with staff reading the notice.

MS. BROWN: By notice issued December 22nd, 2008, this time and place is set for a hearing in Docket Number 080614-EM, petition to determine the need for Greenland Energy Center combined cycle conversion in Duval County by JEA. The purpose of the hearing is set out in the notice.

CHAIRMAN CARTER: Thank you.

Now let's take appearances of the parties.

MR. PERKO: Good morning, Mr. Chairman, Commissioners.

My name is Gary Perko of Hopping Green & Sams on behalf of JEA. And with me is Mr. Donald Gilbert from JEA Corporate Planning.

MS. BROWN: Martha Carter Brown on behalf of the Commission.

MS. HELTON: And Mary Anne Helton, advisor to the Commission.

CHAIRMAN CARTER: Okay. Now let's take up our preliminary matters.

Staff, you're recognized for preliminary matters.

MS. BROWN: Mr. Chairman, I'm not aware that there are any preliminary matters. I would point out that there are

proposed stipulations on all the issues and the witnesses have been excused. The Commissioners have indicated they have no questions for them. And I also understand that JEA does not intend to make an opening statement, and I suggest that you should finalize the evidentiary record by admitting testimony and exhibits, and then if the Commission chooses, it could make a bench decision on the proposed stipulations.

CHAIRMAN CARTER: Okay. Mr. Perko, is that your intention?

MR. PERKO: That's correct, Your Honor, or Mr. Chairman.

We would just like to thank staff for their hard work and professionalism.

CHAIRMAN CARTER: Okay. So let's proceed further then, staff. Let's do this.

Do we have anyone that wishes to speak? Let's go to our public testimony. Anyone here that wishes to speak on this matter?

Staff, you're recognized.

MS. BROWN: We can then move on to the prefiled testimony. We ask that the prefiled testimony of all the witnesses identified in the prehearing order be inserted into the record as though read. Cross examination has been waived.

CHAIRMAN CARTER: Okay. Any objections, Commissioners? The prefiled testimony and exhibits will be

entered into the record as though read.

You may proceed. Did I say exhibits, too? Testimony and exhibits are entered into the record as though read.

MS. BROWN: Well, let's do -- could we just do the testimony for a minute?

CHAIRMAN CARTER: Let's do testimony, then. The prefiled testimony of the witnesses will be inserted into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF DONALD C. GILBERT

ON BEHALF OF

JEA

DOCKET NO. _____

SEPTEMBER 30, 2008

Q. Please state your name and business address.

A. My name is Donald C. Gilbert. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA. My title is Manager, Electric System Planning.

Q. Please describe your responsibilities in that position.

A. I am responsible for planning activities including generation, transmission, and distribution related to JEA's electric system. It is my responsibility to ensure that JEA will be able to continue to reliably serve retail electric load at a reasonable cost.

Q. Please state your educational background and professional experience.

A. I received my Bachelor of Electrical Engineering degree from the Georgia Institute of Technology in 1982. I am a licensed professional engineer in the State of Florida, with more than 30 years of experience in the electric utility

industry, including 4 years in Georgia Power Company's corporate planning, 3 years in JEA's corporate planning, 20 years in JEA's system operations, and 4 years as current manager of JEA's Electric System Planning.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide a description of JEA's existing system and the need for the Greenland Energy Center (GEC) combined cycle conversion, demonstrate that the GEC combined cycle conversion will not adversely impact JEA's transmission system, discuss JEA's efforts to add nuclear generation to our portfolio, and to demonstrate that JEA will be able to finance the GEC combined cycle conversion.

Q. Are you sponsoring any exhibits as part of your pre-filed testimony?

A. Yes. I am sponsoring Exhibit No. ___ [DCG-1], which is a copy of my resume, and Exhibit No. __[DCG-2], which summarizes JEA's existing generating facilities.

Q. Are you sponsoring any sections of the GEC Need for Power Application, Exhibit No. __ [GEC-1]?

A. Yes. I am sponsoring all of Section 3.0 with the exception of Section 3.9, Section 10.0, and Section 19.0. All of these sections were prepared under my direct supervision.

Q. Please describe JEA.

A. JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers all of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves more than 400,000 customers. JEA's generating system consists of three financially separate components: the Electric System, the bulk power system St. Johns River Power Park Units 1 and 2 (the Power Park or SJRPP), and the bulk power system Robert W. Scherer Electric Generating Plant (Scherer Unit 4). The Electric System includes the Brandy Branch, Northside, and Kennedy generating stations. The total summer net capacity of the Electric System, SJRPP, and Scherer Unit 4 is 3,370 MW and the total winter net capacity is 3,620 MW. These resources are summarized in Exhibit No. __[DCG-2].

Q. Please summarize JEA's need for the conversion of the two simple cycle 7FA combustion turbine units at the Greenland Energy Center to a 2x1 combined cycle configuration.

A. As discussed in detail in the Need for Power Application and testimony of other witnesses, JEA needs the GEC combined cycle conversion to maintain system reliability. The GEC combined cycle conversion will improve system reliability and integrity by providing firm capacity to help satisfy future capacity requirements. The GEC combined cycle conversion is JEA's most cost-effective alternative, providing customers with adequate electricity at a

reasonable cost. The GEC combined cycle conversion will further diversify JEA's fuel mix. Peoples Gas System will reliably supply natural gas transportation capacity to GEC. The location of GEC provides for additional transmission system reliability and improved system efficiency.

Q. Does JEA utilize purchase power contracts as part of its power supply portfolio?

A. Yes. JEA has a contract with Southern Company for the purchase of 207 megawatts (MW) of coal fired capacity and energy through May 2010 (Southern UPS). JEA also has contracted with Constellation Energy Commodities Group, Inc. for peaking capacity of 75 MW, 150 MW, and 150 MW for the winter seasons of 2008, 2009, and 2010, respectively.

JEA continues to encourage and evaluate opportunities for cogeneration. Cogeneration facilities reduce the demand on JEA's system and/or provide additional capacity. JEA currently purchases power from four customer-owned qualifying facilities for a total installed summer capacity of 17 MW and a winter capacity of 19 MW. These service territory qualifying facilities are Anheuser-Busch, Baptist Hospital, Ring Power Landfill, and St. Vincent's Hospital.

Q. Please discuss The Energy Authority.

A. JEA is a member of The Energy Authority (TEA), which actively trades energy with a large number of counterparties throughout the United States. TEA is generally able to acquire capacity and energy from other market participants

when members, including JEA, require additional resources. JEA does not have any currently active firm purchases through TEA.

Q. Does JEA plan to retire any existing generating units?

A. Yes. JEA is planning to retire Kennedy CT 3 in the first quarter of 2009.

Q. Please describe JEA's transmission system.

A. The JEA transmission system consists of 728 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV. The 500 kV transmission lines are jointly owned by JEA and FPL and complete the path from FPL's Duval substation (to the west of JEA's system) to the Florida interconnect at the Georgia Integrated Transmission System. The 230kV and 138 kV transmission system provides a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest to fill in the area not covered by the 230 kV and 138 transmission backbone. In addition to these main transmission lines, JEA also owns and operates five 230 kV tie-lines and a 138 kV transmission loop.

Q. Has the Florida Reliability Coordinating Council (FRCC) reviewed the GEC combined cycle conversion with respect to the transmission system?

A. Yes. The FRCC's Transmission Working Group (TWG) and Stability Working Group (SWG) evaluated whether the addition of the GEC may cause any

thermal overloads and voltage limitations, instability or inadequately damped response to system disturbances, or short-circuit concerns. Based upon the review and analysis conducted by the TWG and SWG, the FRCC has determined that the proposed interconnection and integration of the GEC to serve JEA's native load is reliable, adequate, and does not adversely impact the reliability of FRCC transmission system.

Q. What steps has JEA taken to explore nuclear power?

A. In March 2008, the JEA Board of Directors approved the pursuit of nuclear energy partnerships with the goal of providing 10 percent of JEA's energy from nuclear sources. JEA entered into a purchase power agreement in June 2008 with the Municipal Electric Authority of Georgia (MEAG) for a total of 206 MW of firm nuclear capacity from the construction of Vogtle Units 3 and 4, and will continue to evaluate additional nuclear energy opportunities as appropriate.

The nuclear purchase from MEAG will use the Georgia-Florida transmission interface that is currently being used for the Southern Company UPS contract.

Q. How does JEA intend to finance the GEC combined cycle conversion?

A. JEA typically finances large generation capital projects using fixed and floating rate subordinate long-term debt. Up to a maximum of 30 percent of this debt may be floating rate. During preliminary design, engineering, and permitting, JEA may use internal funds from operations or from prior issuances to fund early project costs. As the initial development concludes and construction

commences, JEA may initiate various series of revenue bond issuances for long-term financing with terms of up to 30 years. For large projects, JEA may issue bonds every 1 to 2 years to cover expected construction related capital costs over these periods. By having multiple issuances, JEA will limit the amount of interest incurred during the conversion construction. In addition, JEA may pool the financing for GEC with other smaller capital projects that may be required concurrent with GEC.

Q. Is JEA confident in its ability to secure revenue bonds to finance GEC?

A. Yes. Based on the project's favorable economics and JEA's excellent credit rating, JEA will be able to issue debt to cover the cost of the project.

Q. What are JEA's current credit ratings?

A. JEA has credit ratings for long-term financing of AA- from S&P, Aa2 from Moody's Investors Services, and an AA- from Fitch.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL TESTIMONY OF DONALD C. GILBERT

ON BEHALF OF

JEA

DOCKET NO. 080614

NOVEMBER 21, 2008

Q. Please state your name and business address.

A. My name is Donald C. Gilbert. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA. My title is Manager, Electric System Planning.

Q. Have you previously filed testimony in this proceeding?

A. Yes. My direct testimony in this proceeding was filed September 30, 2008.

Q. Are there any changes or corrections to the sections of the GEC Need for Power Application, Exhibit No. __[GEC-1] that you sponsored in your direct testimony?

A. Yes. The discussion in Section 3.2 (page 3-1) should be changed to indicate that the GEC combustion turbine units are expected to be in commercial operation by the summer of 2011 and are proposed to be converted to combined cycle in 2013.

Q. What is the purpose of your supplemental testimony in this proceeding?

A. The purpose of my testimony is to discuss how the recent credit market developments have affected JEA and the Greenland Energy Center (GEC) combined cycle conversion project. I will also discuss potential sources of replacement power that JEA may require due to a delay of one year in the conversion of the two GEC simple cycle combustion turbines to combined cycle operation.

Q. Are you sponsoring any exhibits as part of your supplemental testimony?

A. No.

Q. How is the current credit market affecting JEA?

A. Like many other municipal utilities across the nation, JEA has minimized financing costs by utilizing variable rate financing for a portion of our overall debt financing. JEA currently holds approximately $6 billion of total debt for its three business units (electric, water/sewer, and chilled water). Roughly $2 billion of that debt carries a variable interest rate while the remainder is locked in with an average fixed rate of approximately 4.5 percent. Due to recent developments in the credit markets, JEA's variable rates have risen from an approximate aggregate of 2 percent to an approximate aggregate of 4 percent. This has temporarily placed a financial demand on JEA's business that required immediate action.

Q. How has JEA responded to the changes in municipal credit markets?

A. As a matter of policy, JEA has deferred a large portion of capital expenditures initially planned for Fiscal Year 2009, including the planned expenditures necessary to order long lead-time items for the GEC project. Delaying these expenditures will likely delay the combined cycle conversion commercial operation date. The new commercial operation date is not expected to be later than June 1, 2013. This date may be accelerated if credit market conditions improve expeditiously.

Q. How much of the 2009 Capital Budget is being deferred?

A. Currently, JEA plans to reduce the 2009 Capital Budget by approximately $305 million, reducing the previously approved budget from approximately $630 million to about $325 million.

Q. How much of the 2009 Capital Budget reduction is related to the GEC combined cycle conversion project?

A. The portion of the reduction in the 2009 Capital Budget related to the GEC combined cycle conversion project is approximately $11.9 million.

Q. How may the recent credit market developments affect JEA's ability to finance the GEC combined cycle conversion project?

A. As discussed in the supplemental testimony of Mr. Bradley Kushner, the economics of the project remain positive. Moreover, as demonstrated in rating agency reports submitted in response to Staff's request for production of documents, JEA's credit rating remains strong. For these reasons, JEA is still confident that it will be able to

issue debt to cover the cost of the project. However, financing costs may be affected. Assuming the current credit challenges persist, JEA is forecasting a long-term interest rate of no more than 7 percent. Because they are based on long-term fixed rate financing, the economic analyses presented in the GEC Need for Power Application (Exhibit No. __[GEC-1]) and Mr. Kushner's supplemental testimony do not include any potential benefits of a variable rate strategy that would most likely moderate the long-term finance costs.

Q. How will delaying the GEC conversion to combined cycle operation change JEA's short-term need for power?

A. JEA will have to replace part of the incremental capacity associated with the GEC combined cycle conversion during the period of the delay.

Q. How will JEA meet the capacity requirements arising from the one year delay of the conversion of the two GEC simple cycle combustion turbines to combined cycle operation?

A. JEA plans to issue a Request for Proposals (RFP) for power to meet the short-term capacity requirements caused by the one year delay in converting the two GEC simple cycle combustion turbines to combined cycle operation. Based on our previous experience with RFPs for power, JEA believes that a short-term source of capacity and energy will be available to meet the short-term need resulting from a one year delay of converting GEC to combined cycle operation.

Additionally, as discussed in my pre-filed testimony, JEA is a member of The Energy Authority (TEA), which actively trades energy with a large number of counterparties throughout the United States. TEA is generally able to acquire capacity and energy from other market participants when members, including JEA, require additional resources. TEA maintains interface capacity on the Georgia-Florida interface, which broadens the potential purchase power markets for JEA. This provides JEA with another potential source of short-term energy that can be used to meet a one year delay in the conversion of GEC to combined cycle operation.

Q. Does this complete your supplemental testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MICHAEL N. LAWSON

ON BEHALF OF

JEA

DOCKET NO. _____

SEPTEMBER 30, 2008

Q. Please state your name and address.

A. My name is Michael N. Lawson. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA as a Project Manager.

Q. Please describe your responsibilities in that position.

A. I am responsible for all phases of project management from start of engineering through startup and commissioning for new projects.

Q. Please state your educational background and professional experience.

A. I have a Bachelor's degree in Mechanical Engineering from the University of Alabama in Huntsville. I am a registered Professional Engineer in the State of Florida.

I have worked for JEA since 1983 and my responsibilities have included serving as Lead Project Administrator and Contracts Administration Manager for the St. Johns River Power Park, Construction Site Manager for the Northside Repowering Project, Project Manager for the Brandy Branch Combined Cycle Project, and Project Manager for the proposed Taylor Energy Center (TEC). Prior to JEA, I worked in a variety of engineering positions including Startup Engineer, Lead Project Engineer, and Plant Engineer.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an overview of the Greenland Energy Center (GEC) combined cycle conversion project.

Q. Have you prepared any exhibits to your testimony?

A. Yes. Exhibit No. __[MNL-1] is a copy of my resume. Exhibit No. __[MNL-2] summarizes the estimated capital cost for the GEC combined cycle conversion. Exhibit No. __[MNL-3] presents the estimated performance for the GEC combined cycle.

Q. Are you sponsoring any sections of Exhibit No. __ [GEC-1], the GEC Need for Power Application?

A. Yes, I am sponsoring Section 9.0, which was prepared under my direct supervision.

Q. Please describe the Greenland Energy Center combined cycle conversion.

A. The GEC combined cycle conversion will consist of converting the two simple cycle General Electric (GE) 7FA combustion turbines at the GEC site in Jacksonville, Florida to a 2x1 combined cycle configuration. The 2x1 GEC combined cycle will have a nominal net output of 522 MW at average ambient conditions.

The GEC combined cycle will be dual fueled with natural gas as the primary fuel and ultra-low sulfur diesel (ULSD) fuel oil as a backup fuel. The GEC combined cycle will include two heat recovery steam generators (HRSGs) with natural gas-fired duct burners (supplemental firing) to increase power generation and steam bypass to allow for simple cycle operation.

Q. Will GEC include best available control technologies to minimize environmental impacts?

A. Yes. The GEC combined cycle will be one of the most efficient and lowest polluting power plants in the State of Florida. Compared to simple cycle generating plants, combined cycle units have higher efficiency and, therefore, generate more electrical output per unit of fuel consumed. As a result, air pollutant emissions per MW are minimized. Pollution prevention is also incorporated through the use of clean fuels that minimize emissions of SO_2 and particulate matter. In addition, advanced dry low-NO_x combustion technology will be used to minimize NO_x emissions while ensuring that emissions of carbon monoxide and volatile organic compounds are within accepted limits.

Moreover, selective catalytic reduction, or SCR, will be installed in each HRSG to further reduce NO_x emissions when operating in combined cycle mode.

Q. Will adequate water be available for operation of the GEC combined cycle?

A. Yes. Reclaimed water for cooling tower makeup is expected to be supplied from JEA via a pipeline adjacent to the GEC site. In emergency situations municipal water could be used for backup cooling water makeup. Service water, potable water, demineralizer water makeup, and fire water will be supplied from the JEA municipal water system.

Q. How will GEC be interconnected to JEA's transmission system?

A. The additional steam turbine generator will connect to the JEA 230 kV transmission system via the GEC plant switchyard.

Q. Are there other important features that will be included in the design of the GEC combined cycle?

A. Yes. GEC will include several design features for cycling load operation. The steam turbine generator will be selected in combination with the HRSGs to provide a reasonable design throttle pressure to ensure satisfactory cycling operation. GEC will also have full steam bypass capability, allowing the combustion turbine units to operate in simple cycle mode.

Q. Please describe the fuel supply to the GEC site.

A. The primary fuel for the GEC combined cycle will be natural gas, while the backup will be ULSD. As discussed more in the testimony of Mr. James Myers, natural gas will be delivered to the GEC site through the SeaCoast Pipeline via a distribution lateral. The use of SeaCoast allows JEA to utilize a diverse natural gas supply portfolio, as SeaCoast is interconnected with both Florida Gas Transmission Company and Southern Natural Gas. Adequate natural gas pressure is anticipated to be available, with no need for the addition of gas compressors.

Q. Please describe the capital costs for the GEC combined cycle conversion.

A. The capital cost estimate is based on the conversion of the two GE 7FA simple cycle combustion turbines at GEC to a 2x1 combined cycle configuration. The construction cost includes direct costs for purchased equipment and materials, construction contract costs, and indirect costs. Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services. All direct costs include escalation for commercial operation June 1, 2012. Construction costs are based on an engineering, procurement, and construction (EPC) contracting philosophy.

Indirect costs associated with construction are included in the capital cost estimate. General indirect costs include all necessary services required for checkouts, testing services, and commissioning. Insurance for builder's risk and general liability are included. Contractor engineering, contractor field

construction management, technical direction, contingency, profit, equipment transportation costs, startup, and commissioning are also included.

The total capital cost is estimated to be $418,575,000 in 2012 dollars, and is summarized in Exhibit No. ___ [MNL-2]. This estimate includes equipment costs, EPC costs (direct and indirect), project contingency, and owner's costs. The capital cost estimate also includes interest during construction and is representative of an installed, in-service cost estimate for June 2012 commercial operation of the GEC combined cycle.

Q. Please discuss the estimated fixed O&M costs for the GEC combined cycle conversion.

A. Fixed O&M costs associated with the GEC combined cycle conversion are estimated to be $3.38 million per year in 2008 dollars, and are based on a full-time staff level of 22.

Q. Please discuss the estimated non-fuel variable O&M expenses for the GEC combined cycle conversion.

A. Non-fuel variable O&M costs include consumables, chemicals, lubricants, water, and major inspections and overhauls. Major inspection and overhaul costs can be covered under long-term service agreements with the turbine manufacturer, or each overhaul can be subcontracted to the turbine supplier or a third party maintenance provider. Because the plant is not staffed to fully perform these major inspections, it is assumed that these will be subcontracted

to the turbine supplier or a third party O&M provider. The incremental non-fuel variable O&M costs associated with the GEC combined cycle conversion are estimated to be $2.28 million per year in 2008 dollars.

Q. Please discuss the estimated scheduled and unscheduled outage rates of the GEC combined cycle.

A. GEC is assumed to have an annualized scheduled outage rate of 7 days per year. GEC is assumed to have an annual forced outage rate of 4 percent over the analysis period.

Q. Please describe the estimated performance for the GEC combined cycle.

A. Actual plant performance (including net plant output and net plant heat rate) will be a function of ambient conditions and other factors. Estimated performance at various load points was developed for summer ambient conditions, winter ambient conditions, and average ambient conditions. Nonrecoverable degradation factors of 2.7 percent for net plant output and 1.5 percent for net plant heat rate (NPHR) have been included. Exhibit No. __[MNL-3] presents the estimated degraded net plant output and NPHR for the GEC combined cycle.

Q. What is the overall schedule for construction completion of the GEC combined cycle conversion?

A. The GEC combined cycle is planned for commercial operation beginning in June 2012. Detailed engineering activities will commence in the first quarter 2009 in support of anticipated construction start of early 2010. Long lead time

procurement activities, such as specification, equipment proposal solicitation, and contract negotiations for the steam turbine generator and HRSGs will occur in 2008 to support the overall construction schedule.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL TESTIMONY OF MICHAEL N. LAWSON

ON BEHALF OF

JEA

DOCKET NO. 080614

NOVEMBER 21, 2008

Q. Please state your name and address.

A. My name is Michael N. Lawson. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA as a Project Manager.

Q. Have you previously filed testimony in this proceeding?

A. Yes. My Direct Testimony in this proceeding was filed September 30, 2008.

Q. What is the purpose of your supplemental testimony in this proceeding?

A. The purpose of my supplemental testimony is to address possible changes in the construction schedule of the Greenland Energy Center (GEC) combined cycle conversion project.

Q. Have you prepared any exhibits to your supplemental testimony?

A. No.

Q. Are there any changes or corrections to your direct testimony filed September 30, 2008?

A. Yes. The references to the commercial operation date of the GEC combined cycle conversion project should be changed to June 2013, reflecting a one year delay. The references to other activities related to the GEC combined cycle conversion should be delayed by about one year.

Q. Are there any changes or corrections to the sections of the GEC Need for Power Application, Exhibit No. __[GEC-1], that you sponsored in your direct testimony?

A. Yes. The references in the GEC Need for Power Application, Exhibit No. __[GEC-1] to the commercial operation date of the GEC combined cycle conversion project should be changed to June 2013, reflecting a one year delay. Additionally, Figure 9-3 and related discussion should be changed to reflect the one year delay in the commercial operation date.

Q. Please discuss the impacts on the schedule for the GEC combined cycle conversion project due to the one year delay to commercial operation of the GEC combined cycle.

A. Figure 9-3 in the GEC Need for Power Application (Exhibit No. __[GEC-1]) presents the original schedule for the GEC combined cycle conversion project. As a result of the deferral of the project discussed in Mr. Gilbert's supplemental testimony, we anticipate that the in-service date will be delayed one year, and also anticipate that all

activities associated with procurement and construction of the GEC combined cycle conversion project will be delayed by about one year. Additionally, in light of the one year delay to the project schedule, JEA and the Florida Department of Environmental Protection have requested that the Site Certification Application process for the GEC combined cycle conversion project be placed in abeyance for a period of 12 months, including postponement of all associated scheduled events and deadlines.

Q. How has the impact of the one year delay been accounted for in the capital cost of the GEC combined cycle conversion project?

A. For evaluation purposes as discussed in the supplemental testimony of Mr. Kushner, the interest during construction cost has been calculated using a 7 percent rate rather than the 5 percent rate presented in the GEC Need for Power Application, Exhibit No. __[GEC-1]. The resulting total capital cost was then increased by the general escalation rate of 2.5 percent presented in the GEC Need for Power Application, Exhibit No. __[GEC-1], to account for the one year delay.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MARY GUYTON-BAKER

ON BEHALF OF

JEA

DOCKET NO. _____

SEPTEMBER 30, 2008

Q. Please state your name and business address.

A. My name is Mary Guyton-Baker. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA as a Professional Engineer working in the JEA Resource Planning Group.

Q. Please describe your responsibilities in that position.

A. My major responsibilities include modeling and production of JEA's load and energy forecast, Integrated Resource Planning (IRP) studies, and the annual Ten Year Site Plan (TYSP).

Q. Please state your educational background and professional experience.

A. I received my Bachelor of Sciences degree in Industrial & Systems Engineering from the University of Florida and also have a degree in Math Education from the University of North Florida.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to discuss JEA's forecast of electrical power demand and energy consumption.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit No. __ [MGB-1] is a copy of my resume.

Q. Are you sponsoring any sections of Exhibit No. __ [GEC-1], the Greenland Energy Center Need for Power Application?

A. Yes. I am sponsoring Section 5.0, which was prepared under my direct supervision.

Q. Please briefly describe the methodology used to determine the load forecasts for JEA.

A. JEA prepares forecasts of both net energy for load (NEL) and peak demand. JEA currently furnishes wholesale power to Florida Public Utilities Company (FPUC) for resale in the City of Fernandina Beach in Nassau County, north of Jacksonville. JEA is contractually committed to supply FPUC until December 31, 2017. FPUC's historical loads are embedded in JEA's historical loads for the purpose of developing the load forecast used throughout the GEC Need for Power Application. JEA expects that the contract to sell power to FPUC will be renewed upon its expiration and therefore the FPUC loads are included throughout the 20 year evaluation period.

The NEL forecast is developed on a monthly and annual basis as a function of time and heating and cooling degree-day data. Inputs into the forecast include historical energy production, JEA territory sales, sales to FPUC, and heating and cooling degree-days. The JEA forecast modeling methodology separately accounts for and projects the temperature-dependent and non-temperature-dependent energy requirements over time, then combines these components to derive the system total NEL forecast. The temperature-dependent NEL is modeled as a function of parameter estimates for historical and projected heating and cooling degree-days.

To forecast peak demand, JEA has developed a linear regression analysis that utilizes Statistical Analysis Software (SAS) and Excel software. JEA develops a forecast of total peak demand, including interruptible and curtailable customers, and then subtracts these customers to derive an estimate of firm demand only. The peak demand forecast is driven by temperature and time-series data. The forecasting process involves the collection of historical hourly system load data and daily temperature data. A linear regression analysis is conducted to forecast the summer and winter peaks. The forecast temperature used in the regression is the 20 year median of the seasonal extreme temperatures (summer 97° F and winter 25° F) wherein the winter seasonal extreme for a year is the lowest temperature during the months of December, January, and February, and the summer seasonal extreme is the highest temperature during the months of July, August, and September.

Q. Does the load forecast account for interruptible and curtailable customers?

A. Yes. JEA initially develops a forecast of total peak demand that does not reflect the peak demand reductions associated with interruptible and curtailable customers. Once the total peak demand forecast is developed, the peak demand reductions associated with interruptible and curtailable customers are subtracted from the annual total peak demand forecasts, and the resulting firm peak demand forecast is used for capacity planning purposes.

Q. Please summarize the firm base case summer peak demand forecast.

A. The forecast summer firm peak demand for 2009 is 2,890 MW, and the 2027 forecast summer firm peak demand is 4,070 MW. The summer peak demand is projected to grow at a rate of 1.92 percent from 2009 to 2027.

Q. Please summarize the firm base case winter peak demand forecast.

A. The forecast winter firm peak demand for 2009 is 3,022 MW, and the 2027 forecast winter firm peak demand is 4,404 MW. The winter peak demand is projected to grow at a rate of 2.11 percent from 2009 to 2027.

Q. What is JEA's base case net energy for load forecast?

A. The forecast 2009 NEL is 15,016 GWh and the forecast NEL in 2027 is 21,726 GWh. The NEL is expected to grow at a rate of 2.07 percent from 2008 to 2027.

Q. Were any alternative load forecasts developed?

A. Yes. In addition to the base case forecast that I just described, high and low case projections were developed to reflect the effects that extreme and moderate temperatures could have on peak demand and NEL (Extreme and Moderate Condition forecasts). Summaries of the results of the moderate case and extreme case forecasts are presented in Table 5-3 of Exhibit No. __ [GEC-1].

Q. In your opinion, is the process used for developing the demand and energy forecasts reasonable for planning purposes?

A. Yes. The process used in developing the demand and energy forecasts is appropriate for planning purposes. The use of this approach has improved the accuracy of JEA's load forecast as compared to previously used methodologies.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JAMES T. MYERS

ON BEHALF OF

JEA

DOCKET NO. _____

SEPTEMBER 30, 2008

Q. Please state your name and business address.

A. My name is James T. Myers. My business address is JEA, 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA, where I am the Director of Fuel Management Services.

Q. Please describe your educational background and experience.

A. I have a bachelor's degree in Industrial Engineering from Georgia Institute of Technology. I am also a licensed professional engineer in the State of Florida.

I have over 27 years of work experience, all of which has been with JEA. From 1981 to 1986, I worked on load and energy forecasting and load research, which included development of economic, energy, and peak demand models. My responsibilities also included the production of load and energy forecasts for generation planning.

From 1987 to 1995, I was involved in energy resource planning. During this time, I was responsible for long range planning, which included the development of corporate financial models and the preparation of official statements to support bond issues. While in this position, I also assisted in the development of JEA's first integrated resource planning (IRP) study in 1994/1995. I also served as Chairman for the Florida Electric Power Coordinating Group's Generation Task Force, in which I presented the Florida Ten Year Plan to the Florida Public Service Commission.

I have worked in the Fuel Management Services Group since 1995 and have held my current position as Director since 2003. I was the Chairman for the Taylor Energy Center Fuels Committee (TEC Fuels), and have been a JEA representative on the SJRPP and Plant Scherer Fuel committees. I also achieved "Six Sigma Green Belt" designation in substantially reducing JEA's fuel procurement expenses, developed fuel acquisition strategies and market forecasts for JEA's electric system, negotiated agreements, and maintained documentation supporting fuel purchases.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe the availability of natural gas throughout the United States as a whole. I will also discuss the natural gas transportation system as it relates to Florida, and demonstrate that the Greenland Energy Center (GEC) will have a reliable supply of natural gas.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit No. __ [JTM-1] is a copy of my resume.

Q. Are you sponsoring any sections of the GEC Need for Power Application, Exhibit No. __ [GEC-1]?

A. Yes. I am sponsoring Sections 6.0 and 8.0, both of which were prepared under my direct supervision.

Q. Are there any concerns regarding the availability of natural gas?

A. No. Based on the information provided in the Energy Information Administration's Annual Energy Outlook 2008 (AEO2008), as well as other information from other sources, JEA believes that there will be an adequate supply of natural gas. The United States has sufficient natural gas reserves, and these reserves are consistently being replaced as existing natural gas reserves have been consumed. In order to better facilitate this process, existing natural gas storage facilities have recently been or are planned to be expanded. New storage facilities are also being constructed, and projects are under way to better provide natural gas to the pipelines that serve the Southeast US. This construction will allow for better management of gas volumes and increases in reliability of supply.

Q. Will liquefied natural gas (LNG) contribute to the availability of natural gas for GEC?

A. Yes. With US natural gas production remaining relatively constant, imports of natural gas are projected to rise to meet an increasing share of domestic consumption. Most of the expected growth in US natural gas imports would be in the form of LNG. The expansion of LNG supplies and associated infrastructure has increased the opportunity for GEC to receive natural gas from LNG terminals located in the southeastern United States.

Q. How will the anticipated increase in LNG imports affect receiving capacity in the United States?

A. Projected growth in the demand for LNG has resulted in companies adding LNG receiving capacity in the United States. Five LNG import terminals currently operate in the United States. These terminals have expanded to accommodate increased LNG import capabilities. In addition, EIA expects at least four new terminals to be operational in the next two years, more than doubling import capacity from 4.7 billion cubic feet per day (Bcf/d) at the end of 2006 to over 11 Bcf/d at the end of 2008. It is projected that the regasified natural gas send out capacity of onshore facilities could grow to more than 10 Bcf/d by the middle of 2010, with about half of this send out capacity coming from new terminals.

Q. Please discuss natural gas pipeline and storage infrastructure as it relates specifically to Florida.

A. The southeastern states of the United States account for over 38,000 miles of pipeline in 2008, with the State of Florida accounting for approximately 5,000 miles of pipeline. The total Florida pipeline capacity is served by four companies: Florida Gas Transmission Company, GulfSouth Pipeline, Gulfstream Natural Gas System, and Southern Natural Gas. The four interstate pipelines provide reliable and adequate natural gas capacity into Florida and, along with existing and proposed natural gas storage facilities, will provide adequate transportation and storage capacity for the Florida market.

There are a number of natural gas storage facilities in operation and under development that will serve the Florida market. These storage facilities will enhance the natural gas system in the state.

Q. Are there other proposed projects that will benefit the Florida natural gas market?

A. Yes. The Southeast Supply Header, LLC (SESH) is an ongoing, non-conventional domestic project that will further enhance the supply of natural gas to the State of Florida. The 270 mile, 36 inch and 42 inch diameter pipeline will provide transportation of onshore natural gas supplies in east Texas and northern Louisiana into the Southeast US, which is normally served by offshore supplies from the Gulf of Mexico. The SESH project will provide an alternative to offshore supplies to these areas, and improve the overall reliability of natural gas

supply through its additional capacity of over 1 Bcf/d. SESH will interconnect with Gulfstream and FGT.

Q. How will natural gas be delivered to the GEC site?

A. Delivery of natural gas to the GEC site will utilize the proposed SeaCoast Gas Transmission LLC intrastate pipeline (SeaCoast Pipeline). The SeaCoast Pipeline will initially extend from the interconnection of the existing Florida Gas Transmission (FGT) and Southern Natural Gas (SNG) pipelines located near Jacksonville.

FGT will deliver natural gas to the SeaCoast pipeline from its existing system in Florida, and SNG will deliver natural gas to the SeaCoast Pipeline from its existing system originating in Georgia. Peoples Gas System (PGS) is in the process of engineering a 16 inch diameter lateral (GEC Lateral) that will extend from the SeaCoast Pipeline to the GEC site.

Q. Please describe the route for the GEC Lateral.

A. Several routes extending from the main line to the GEC site are being considered: the lateral is likely to utilize a tie-in point near Highway 315 in Clay County, approximately 27 miles south of the FGT/SNG interconnect. Depending on the final route, the proposed lateral will extend a length of approximately 31 to 36 miles through Clay, St. Johns, and Duval Counties with a majority of the pipe co-located alongside highway and power line corridors.

Q. When will the GEC Lateral be in service?

A. The GEC Lateral will be in service prior to the commercial operation of the simple cycle combustion turbines that will be located at the GEC prior to the combined cycle conversion.

Q. Please describe PGS.

A. PGS is one of four business units of TECO Energy, an S&P 500 energy company headquartered in Tampa, Florida. PGS is Florida's largest natural gas distribution utility serving more than 320,000 commercial, industrial, and residential customers. PGS has long term agreements with FGT, Gulfstream Natural Gas System, LLC, and SNG for natural gas transportation into Florida.

PGS serves as Jacksonville's natural gas distribution company and provides commercial and residential gas service to the Jacksonville area through its pipeline system. In addition, JEA has existing agreements with PGS to receive natural gas delivery service through the local gas distribution to its generating units.

Q. Please describe FGT.

A. FGT operates a 5,000-mile natural gas pipeline system that extends from south Texas to south Florida with a current mainline capacity of 2.1 Bcf/d. FGT's total receipt point capacity is in excess of 3.0 Bcf/d and includes interconnections with 10 interstate and 10 intrastate pipelines to facilitate receiving supplies of natural gas into its pipeline system. The pipeline has

extensive access to diverse natural gas supplies, including the offshore Gulf of Mexico region.

Q. Please describe SNG.

A. SNG is a natural gas pipeline company headquartered in Birmingham, Alabama. It is a subsidiary of El Paso Corporation. The company transports more than 3 Bcf of natural gas per day during peak periods through approximately 8,000 miles of pipeline in the southeast. SNG owns and operates the Elba Island LNG regasification facility near Savannah, Georgia. Elba Island has approximately 4 Bcf of storage capacity and 440 million cubic feet per day (Mcf/d) of send-out capacity. The facility is currently being expanded to approximately 7.3 Bcf of storage capacity and a send-out capacity of 800 Mcf/d.

Q. Does JEA have adequate firm natural gas transportation capacity to reliably serve its generating units including the GEC combined cycle?

A. Yes. JEA has contracts for firm natural gas transportation capacity including increases in firm natural gas capacity to accommodate both its existing generating units and GEC.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL TESTIMONY OF JAMES T. MYERS

ON BEHALF OF

DOCKET NO. 080614

NOVEMBER 21, 2008

Q. Please state your name and business address.

A. My name is James T. Myers. My business address is JEA, 21 West Church Street; Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA, where I am the Director of Fuel Management Services.

Q. Have you previously filed testimony in this proceeding?

A. Yes. My Direct Testimony in this proceeding was filed September 30, 2008.

Q. What is the purpose of your supplemental testimony in this proceeding?

A. The purpose of my supplemental testimony is to discuss the impact on the natural gas fuel supply plans for the Greenland Energy Center (GEC) combined cycle conversion project as a result of a one year delay in the commercial operation date of the project.

Q. Are there any changes or corrections to your direct testimony filed September 30, 2008?

A. No.

Q. Are there any changes or corrections to the sections of the GEC Need for Power Application Exhibit No. __ [GEC-1] that you sponsored in your direct testimony?

A. Yes. The only correction is to Section 6.0 of the Application, which stated that the Floridian Natural Gas Storage Company LLC facility was pending before the Federal Energy Regulatory Commission (FERC). The Floridian facility has now received its approval from FERC.

Q. Has your opinion changed regarding the availability of natural gas for the GEC combined cycle conversion project if commercial operation is delayed one year?

A. No. Nothing has changed since the filing of my direct testimony in this proceeding that changes JEA's view that natural gas will be available for the GEC conversion project. Natural gas transportation via the SeaCoast Gas Transmission, LLC (SeaCoast) will be supplied to the GEC simple cycle combustion turbines. The GEC simple cycle combustion turbines will also be delayed one year, but they will be in service by June 1, 2011 which is two years before the GEC combined cycle conversion commercial operation date. No additional natural gas transportation capacity will be required for the GEC combined cycle conversion.

Q. Have there been any other regulatory developments concerning SeaCoast?

A. Yes. The Florida Public Service Commission unanimously approved the natural gas transmission pipeline tariff for SeaCoast on October 28, 2008 (Docket 080561-GP).

The tariff includes the general terms and conditions under which SeaCoast proposes to provide intrastate natural gas transportation service. A separate transportation service agreement will be negotiated between SeaCoast and JEA that contains the actual rates and charges.

Q. Does JEA anticipate any impact on the transportation service agreement to be negotiated with SeaCoast due to the delay in the commercial operation date of the GEC combined cycle conversion?

A. No. The transportation service agreement will provide natural gas transportation for the GEC simple cycle combustion turbines. No changes to the transportation service agreement will be necessary for the GEC combined cycle conversion.

Q. Does this conclude your supplemental testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JOHN A. WORLEY

ON BEHALF OF

JEA

DOCKET NO. _____

SEPTEMBER 30, 2008

Q. Please state your name and business address.

A. My name is John A. Worley. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA. My title is Director, Environmental Programs.

Q. Please describe your responsibilities in that position.

A. My responsibilities include directing JEA's renewable energy program, serving as the environmental permitting lead for current and future major permit initiatives, serving as the Environmental Service's lead in JEA's green house gas/climate change policy/initiatives, coordinating sustainability initiatives, and the development and implementation of internal environmental program review processes.

Q. Please state your educational background and professional experience.

A. I received a bachelor's degree in wildlife biology in 1978 and a master's degree in botany in 1980 from Northwestern State University of Louisiana. Post graduate studies have included business administration and engineering management.

For the past 23 years at JEA, I have held various environmental and production management positions at JEA's St. Johns River Power Park. I was employed by Southwestern Electric Power Company in 1980 as an environmental specialist before joining JEA in 1985. I am a member of Air & Waste Management Association and serve as a Subcommittee Chair on the Jacksonville Community Council's Air Quality Task Force.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss JEA's Clean Power Action Plan. I will also provide an overview of JEA's existing renewable energy resources, as well as potential new renewable energy resources that are being evaluated by JEA.

Q. Are you sponsoring any exhibits as part of your pre-filed testimony?

A. Yes. I am sponsoring Exhibit No. ___ [JAW-1], which is a copy of my resume.

Q. Are you sponsoring any sections of the Greenland Energy Center (GEC) Need for Power Application, Exhibit No. __ [GEC-1]?

A. Yes. I am sponsoring Sections 3.9 and 14.0, which were prepared under my direct supervision.

Q. Please describe JEA's Clean Power Action Plan.

A. JEA has worked closely with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups to establish a process to maintain the Clean Power Action Plan. The Clean Power Action Plan establishes an Advisory Panel, comprised of participants from the Jacksonville community, who provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program. Current members of the Advisory Panel include the Sierra Club, ALA, and the City of Jacksonville Environmental Protection Board.

JEA has implemented several projects as part of the Clean Power Action Plan, including installation of clean power systems, purchase power agreements, legislative and public education activities, and research into and development of clean power technologies. JEA has conducted a number of generating efficiency improvements, increasing the output of existing generating units without increasing the amount of fuel burned or emissions of carbon dioxide (CO_2) or other pollutants.

Q. What renewable energy projects are in JEA's existing energy portfolio?

A. JEA's existing renewable energy sources include installation of solar photovoltaic (PV), solar thermal, landfill and wastewater treatment biogas capacity, and wind.

Q. Please describe JEA's use of solar energy.

A. JEA has installed 35 solar PV systems, totaling 220 kW, on all of the public high schools in Duval County, as well as many of JEA's facilities, and the Jacksonville International Airport (one of the largest solar PV systems in the Southeast). To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in early 2002. This program provided cash incentives for customers to install solar PV and solar thermal systems on their homes or businesses.

JEA provided customer incentives for more than 25 solar PV systems (for a total of 98 kW) until January 2005, when the PV incentive was discontinued in favor of the solar water heating program discussed below, which provides more cost effective CO_2 reduction. In addition to the PV incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems. JEA also offers incentives for the installation of solar hot water heaters. To date, the program has resulted in over 500 incentives, or approximately 1.6 MW of capacity savings.

Q. How is JEA using landfill gas and biogas in its energy portfolio?

A. Since 1997, JEA has owned and operated four internal combustion engine generators fueled by landfill gas produced by the City of Jacksonville's Girvin Road landfill. Since that time, landfill gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility. The facility uses biogas produced by the wastewater treatment plant to fuel the 800 kW generator. JEA also utilizes landfill gas from the North Landfill at the Northside Generating Station, where it is used to generate power at Northside Unit 3.

In 2006, JEA signed a purchase power agreement with Landfill Energy Systems to obtain energy from a 9.6 MW landfill gas-to-energy facility at the Trail Ridge Landfill in Jacksonville. Once completed, the facility will be one of the largest landfill gas-to-energy facilities in the Southeast, providing enough renewable energy to supply electricity to approximately 2,275 homes. The projected date of completion for the facility is late 2008.

Q. Please describe JEA's wind power initiatives.

A. As part of its ongoing effort to utilize more sources of renewable energy, in 2005 JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. Under the wind generation agreement, JEA has agreed to purchase 10 MW of capacity from NPPD's wind generation facility for a 20 year period. In turn, NPPD will buy back the energy at specified on/off peak charges. JEA

retains the rights to the environmental attributes (renewable energy credits, or RECs) and will sell the RECs unless JEA needs them to meet possible state or federal environmental requirements.

Q. Please describe JEA's ongoing research efforts with respect to renewable resources.

A. JEA's renewable energy research efforts have focused on the development of technologies through a partnership with the University of North Florida's (UNF). The following projects are currently in progress:

- JEA is working with the UNF to quantify the winter peak reductions of solar hot water systems.
- UNF, along with the University of Florida, is evaluating the effect of biodiesel fuel in a pilot-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.
- UNF is evaluating the tidal hydro-electric potential for North Florida, particularly in the Intracoastal Waterway.
- UNF is in the preliminary stage of evaluating fuel cell technology utilizing methane produced at JEA's Buckman Wastewater Treatment Facility.
- JEA, UNF, and other Florida municipal utilities have partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for wind development in Florida.

- JEA is providing solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15 acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3 year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.
- JEA is evaluating the use of biofuels such as fats, oils and greases for potential use in solid fuel units.

Q. Please discuss the generating efficiency improvements undertaken by JEA.

A. JEA has been modernizing its fleet of generating units by replacing less efficient steam units and combustion turbines with more efficient combined cycle units and combustion turbines. The retirement of less efficient units with more efficient generating resources significantly reduces CO_2 emissions. The proposed conversion of the GEC simple cycle combustion turbines to combined cycle configuration is a key part of JEA's generating unit efficiency program, allowing for the output of GEC to increase over 60 percent without any increase in CO_2 emissions when compared to the simple cycle combustion turbines.

Q. What other efforts has JEA made to pursue renewable energy resources?

A. Since 2004, we have issued several requests for proposals (RFP) for renewable energy resources including specifically solar and wind resources.

Q. Please provide a brief overview of JEA's 2004 request for proposals (RFP) for renewable energy generation.

A. In February 2004, JEA issued a Request for Proposals (RFP) for Renewable Energy Generation for 1 MW to 300 MW. JEA received 13 acceptable responses with capacities between 1 MW and 50 MW. As a result of this RFP, JEA entered into negotiations with Landfill Energy Systems (9.6 MW) on the Trail Ridge landfill gas and signed a Power Purchase Agreement in May 2006. The project is expected to be operational by late 2008.

JEA also started negotiations with Evergreen Paper and Energy (13 MW using the City's yard waste) but these negotiations were cancelled by JEA in July 2007 after consultation with the City of Jacksonville on the City of Jacksonville-Evergreen yard waste fuel contract. The City of Jacksonville concluded that Evergreen, after several years of negotiation, had failed to deliver an executed contract and the bonding requirement. In addition, Evergreen had not prepared the site to take the yard waste within the timeframe proposed by City of Jacksonville.

Q. Please describe JEA's 2007 RFP for renewable energy generation.

A. In 2007, JEA issued a solicitation for letters of interest for renewable energy generation. Nineteen responses were received, including a response from Trail Ridge LLC regarding the generation energy of an additional 9.6 MW of landfill gas at the Trail Ridge Landfill. JEA and Trail Ridge LLC continue to evaluate this proposal. Another letter of interest was from a Florida municipal utility

indicating their interest in working with JEA on development of joint renewable energy projects. Because of the large size and risk of some renewable energy projects, JEA may consider working with other Florida utilities to develop joint projects similar to how several fossil fuel plants have been developed.

Thirteen of the responses were related to biomass and appeared to have the potential to move forward. As a result, JEA issued a RFP for the biomass respondents. Of the nine proposals received, four proposals were acceptable and five proposals were rejected because they did not meet the screening criteria. All the bids were significantly higher than JEA's avoided costs. In addition, none of the projects (with the exception of one project which was an existing operating biomass facility) could demonstrate a commitment on the fuel source or site nor did they demonstrate project financing by providing commitment letters from third-party institutions. For these reasons, JEA chose not to negotiate with any of the bidders.

Q. Please describe JEA's most recent RFP for solar and wind renewable energy resources.

A. Most recently, JEA issued a RFP for renewable energy, in particular solar and wind resources (Solar and Wind RFP), on March 17, 2008. Responses to the RFP were due on May 16, 2008. The RFP requested projects greater than 1 MW that generate electricity from solar (including photovoltaic or thermal electric) or wind. Solar projects greater than 250 kW at a JEA commercial customer's site were also included if the aggregate installation is greater than 1 MW. The RFP

also requested proposals for solar photovoltaic equipment (panels and inverters) for installation by JEA.

Q. Please describe the response to JEA's Solar and Wind RFP.

A. JEA received ten solar photovoltaic purchase power proposals and two proposals for solar photovoltaic panels (equipment purchase only). JEA did not receive any proposals for solar thermal electric or wind projects. Of the ten solar purchase power proposals received, eight were for ground-mounted systems from 8 MW to 12 MW in size and two were for roof-top distributed mounted systems from 2 MW to 4 MW in total size. All proposals submitted were for projects to be developed in the JEA service area.

Q. What technical factors were considered when evaluating the Solar and Wind RFP responses?

A. The proposals were all scored based on JEA's technical and pricing factors. The technical factors included: qualifications of the company, financial strength, technical feasibility, ease of interconnection, barriers to project site, other ancillary benefits of the project, level of development of financing plan, level of project development completed, status of major equipment, interconnection design maturity, level of resource assessment performed, level of site control, level of site infrastructure, status of obtaining permits, and project schedule.

Q. Please describe the pricing factors evaluated for the solar RFP responses.

A. The pricing proposals were first evaluated based on their levelized price with levelized costs ranging from approximately $186/MWh to approximately $343/MWh. All of the solar proposals reflect the assumed extension of the benefits of the existing Solar Incentive Tax Credits. Finally, the pricing proposals were evaluated by calculating an incremental cost for each proposal on the basis of all-in cost in nominal 2008 dollars. The incremental cost is the difference between the project's cost of power relative to JEA's existing system and base case plan, with the GEC combined cycle conversion representing the avoided unit. The incremental costs of the proposals ranged from approximately $10/MWh to approximately $150/MWh over a 20 year period.

Q. What were the conclusions of the evaluation of responses to the Solar and Wind RFP?

A. JEA is pursuing negotiations with the company that provided the lowest cost solar PV proposal described previously in my testimony.

Q. Is JEA continuing to explore the potential use of biomass generation?

A. Yes. In a continuing effort to obtain cost effective biomass generation, JEA is conducting a detailed feasibility study of both self-build stand-alone biomass units and the co-firing of biomass in Northside 1 and 2. JEA also periodically receives unsolicited offers for biomass and other renewable generation. JEA evaluates the feasible unsolicited offers, but has been unable to successfully execute a contract for cost-effective biomass generation.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF RICHARD J. VENTO

ON BEHALF OF

JEA

DOCKET NO. _____

SEPTEMBER 30, 2008

Q. Please state your name and business address.

A. My name is Richard J. Vento. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA. My current position is Director of Corporate Data Integration.

Q. What are your responsibilities in that position?

A. Directing and managing the utilities load research and DSM activities.

Q. Please state your educational background and experience.

A. I hold a Bachelor of Science in Business Administration from the University of Florida.

With 26 years in the utility industry, my experience includes electric production operations and maintenance, water and wastewater operations and maintenance, technology integration, load research and demand side management (DSM).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an overview of the DSM and conservation programs currently offered by JEA, as well as the portfolio of new DSM programs recently developed by JEA.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits: Exhibit No. __ [RJV-1], which is a copy of my professional resume; Exhibit No. __ [RJV-2] which presents the annual summer and winter peak demand and net energy for load reductions projected for JEA's new DSM portfolio; and Exhibit No. __ [RJV-3], which presents the projected annual costs of JEA's new DSM portfolio.

Q. Are you sponsoring any sections of Exhibit No. ___[GEC-1], the GEC Need for Power Application?

A. Yes. I am sponsoring Section 15.0 which was prepared under my direct supervision.

Q. Please describe JEA's existing DSM and conservation programs.

A. The DSM and conservation programs currently offered by JEA include the following:

- Energy audits (residential and commercial)
- Green Built Homes of Florida
- Chilled water services
- Interruptible load
- Educational seminars (residential and commercial)
- School activities
- Monthly newsletter

Q. Please describe how JEA developed its new DSM portfolio.

A. JEA contracted with Summit Blue Consulting, LLC (Summit Blue), an independent firm that specializes in DSM program evaluation and development, to identify potential DSM programs for JEA. Summit Blue conducted DSM benchmarking and best practices analyses and performed benefit-to-cost analysis. Based on the Summit Blue analyses, JEA's senior management approved a new DSM portfolio through 2012 in accordance with guidance from JEA's Board.

Q. Please discuss the benefit-to-cost analyses performed by Summit Blue.

A. DSM measures were evaluated with two different tests – the Total Resource Cost (TRC) test and the Rate Impact (RIM) test. Both of these tests are based on a net benefit to net cost analysis, and consider annualized avoided capacity costs, annualized avoided transmission and distribution costs, assumptions related to future rate increases, energy and demand savings over the lifetime of each measure, and DSM measure and program costs.

Q. Please describe the TRC test.

A. The TRC test considers the benefits (avoided costs) of generation, transmission and distribution investments and avoided fuel costs due to the conserved energy caused by the DSM measures. The costs for the TRC test are the DSM measure costs plus the DSM measure administration costs.

Q. What is the RIM test?

A. The RIM test considers the benefits (avoided costs) of generation, transmission and distribution investments and avoided fuel costs due to the conserved energy caused by the DSM measure. The costs for the RIM test are the DSM measure costs incurred by the utility plus the "lost revenues" due to the DSM programs. Typically, a DSM measure is considered cost-effective if it has a RIM value of 1.0 or greater.

Q. What criteria were used to develop the new DSM portfolio?

A. In June 2006, JEA's senior management established a policy to consider all DSM measures that passed the TRC test, and to maintain an overall portfolio RIM value of no less than 1.0. The RIM constraint was to ensure no future upward pressure on customer rates resulting from JEA's DSM programs. Because JEA utilized the overall portfolio RIM value rather individual RIM values for particular measures, the new DSM portfolio includes more measures than would be considered cost-effective under typical RIM analyses.

Q. Did JEA's new DSM portfolio raise any reliability concerns?

A. Yes. Demand response measures are key components of the new DSM portfolio. By their very nature, demand response measures are not available for extended durations and frequent implementation of these measures due to their unacceptable customer impacts. As a result, JEA was concerned that over-reliance on demand response measures could impact system reliability. These concerns are addressed in the direct testimony of Mr. Myron Rollins.

Q. What residential DSM measures are included in the new DSM portfolio?

A. The residential DSM measures included are domestic hot water measures, space heating and cooling measures, envelope measures, lighting measures, refrigeration and appliance measures and load management measures.

Q. Please discuss the commercial and industrial DSM measures included in the new DSM portfolio.

A. The commercial DSM measures included are domestic hot water measures, space heating and cooling measures, envelope measures, lighting measures and load management measures. The industrial measures include demand response and load control.

Q. Please discuss the annual peak demand and energy savings projections corresponding to the DSM portfolio.

A. Following approval of the DSM portfolio, Summit Blue provided the projected energy efficiency and demand response savings corresponding to the policies

and conservation funding limits. Exhibit No. __ [RJV-2] presents the annual summer and winter peak demand and net energy for load reductions.

Q. Please discuss the annual costs associated with the new DSM portfolio.

A. Summit Blue provided projected annual costs associated with JEA's new DSM portfolio, which are summarized in Exhibit No. __ [RJV-3].

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL TESTIMONY OF RICHARD J. VENTO

ON BEHALF OF

JEA

DOCKET NO. 080614

NOVEMBER 21, 2008

Q. Please state your name and address.

A. My name is Richard J. Vento. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA. My current position is Director of Corporate Data Integration.

Q. Have you previously filed testimony in this proceeding?

A. Yes. My direct testimony in this proceeding was filed September 30, 2008.

Q. What is the purpose of your supplemental testimony in this proceeding?

A. The purpose of my supplemental testimony is to discuss the potential delays in the implementation of two of the programs in JEA's new DSM portfolio.

Q. Are you sponsoring any exhibits to your supplemental testimony?

A. No.

Q. Are there any changes or corrections to your direct testimony filed September 30, 2008?

A. Yes. The Residential Efficiency Upgrade and Commercial Direct Load Control programs are being delayed one year. As a result, the values for those programs in Tables 1 through 4 of Exhibit No. __[RJV-2] will be delayed one year and the totals adjusted accordingly.

Q. Are there any changes or corrections to Section 15.0 of the GEC Need for Power Application, Exhibit No. __[GEC-1] that you are sponsoring?

A. Yes. The values shown in Tables 15-8 through 15-11 for Residential Efficiency Upgrades and Commercial Direct Load Control programs should be delayed one year and the totals adjusted accordingly. Also for Table 15-10, "009" should be "2009".

Q. Please discuss the potential delay in implementing the two programs in JEA's new DSM portfolio.

A. As discussed in Mr. Gilbert's supplemental testimony, in light of the current credit market, JEA is taking immediate measures to defer capital and operating expenses from fiscal year 2009 to fiscal year 2010. One such measure is to delay the implementation of the Residential Efficiency Upgrades and Commercial Direct Load Control programs. By delaying the Residential Efficiency Upgrades and Commercial Direct Load Control programs one year, the expected summer and winter demand and energy reductions for both programs as shown in Tables 15-8 through 15-10 in the GEC Need for Power Application, Exhibit No. __ [GEC-1], would be delayed one year. The Total reductions would also change to reflect the delays. The program costs

for the Residential Efficiency Upgrades and Commercial Direct Load Control programs shown in Table 15-11 would also be delayed one year and the Total Program Costs would change to reflect the delay.

Q. Is JEA going to implement the other DSM programs in the new DSM portfolio on the schedule presented in Section 15.0 of the GEC Need for Power Application, Exhibit No. __ [GEC – 1]?

A. Yes.

Q. Will the delay of the Residential Efficiency Upgrades and Commercial Direct Load Control Programs affect the need for the Greenland Energy Center Combined Cycle Conversion now scheduled for 2013?

A. No. By 2013, the projected reductions in demand and energy from JEA's new DSM portfolio are projected to be the same.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MYRON R. ROLLINS

ON BEHALF OF

JEA

DOCKET NO. _____

SEPTEMBER 30, 2008

Q. Please state your name and business address.

A. My name is Myron R. Rollins. My business address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation. My current position is Director.

Q. Please describe your responsibilities in that position.

A. I am responsible for the management of various projects for utility and non-utility clients. These projects encompass a wide variety of services for the power industry. The services include load forecasts, conservation and demand-side management, reliability criteria and evaluation, development of generating unit addition alternatives, fuel forecasts, screening evaluations, production cost simulations, optimal generation expansion modeling, economic and financial evaluation, sensitivity analysis, risk analysis, power purchase and sales evaluation, strategic considerations, analyses of the effects of environmental

regulations, feasibility studies, qualifying facility and independent power producer evaluations, power market studies, and power plant financing.

Q. Please describe Black & Veatch.

A. Black & Veatch Corporation has provided comprehensive engineering, consulting, and management services to utility, industrial, and governmental clients since 1915. Black & Veatch specializes in engineering, consulting, and construction associated with utility services, including electric, gas, water, wastewater, telecommunications, and waste disposal. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, rate and financial reports, appraisals, reports on operations, management studies, and general consulting services. Present engagements include work throughout the United States and numerous foreign countries.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Missouri – Columbia. I also have two years of graduate study in Nuclear Engineering at the University of Missouri – Columbia. I am a licensed professional engineer and a Senior Member of the Institute of Electrical and Electronic Engineers.

I have 32 years of experience in the power industry specializing in generation planning and project development. In the past ten years, I have been the project manager for over 100 projects, the vast majority of which have been for Florida

utilities. Florida utilities for which I have worked include Florida Municipal Power Agency (FMPA), Kissimmee Utility Authority, Lakeland Electric, Orlando Utilities Commission (OUC), JEA, City of Tallahassee, Reedy Creek Improvement District (RCID), City of St. Cloud, Utilities Commission of New Smyrna Beach, Sebring Utilities Commission, City of Homestead, Florida Power Corporation, Tampa Electric Company, and Seminole Electric Cooperative.

I was responsible for the development of Black & Veatch's POWRPRO chronological production costing program and POWROPT optimal generation expansion program. I am also responsible for power market analysis and project feasibility studies. I have been responsible for supporting need for power petitions on a number of power plants in Florida including Stanton 1, 2, A, and B; Cedar Bay; Cane Island 3 and 4; McIntosh 5; the Brandy Branch Combined Cycle Conversion, and Treasure Coast Unit 1;. I also participated in the need for power proceeding for the Hardee and Hines projects. I have presented expert testimony on several occasions before the Alaska, Indiana, Missouri, and Florida public service commissions and have presented numerous papers on strategic planning and cogeneration.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss JEA's need for the Greenland Energy Center (GEC) combined cycle conversion project. I will provide an overview and summary of the Greenland Energy Center (GEC) combined cycle

conversion Need for Power Application, Exhibit No. __ [GEC-1]. In addition to this general summary, I will discuss the economic parameters used in the economic analyses of the GEC combined cycle conversion. I will discuss the reliability criteria used by JEA and the projected need for additional capacity to satisfy these criteria. I will also discuss the purchase power request for proposals (RFP) that JEA issued in 2007.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit No. __ [MRR-1] is a copy of my résumé, Exhibit No. __[MRR-2] presents JEA capacity requirements, and Exhibit No. __[MRR-3] presents levels of capacity bid from JEA's RFP.

Q. Are you sponsoring any sections of the GEC combined cycle conversion Need for Power Application, Exhibit No __ [GEC-1]?

A. Yes. I am sponsoring Sections 1.0, 2.0, 4.0, 11.0, and 12.0, all of which were prepared by me or under my direct supervision.

Q. What events led to JEA develop the GEC combined cycle conversion?

A. For several years, JEA has shown a need for approximately 200 MW of base load capacity in the 2012 time frame with the need for peaking capacity prior to the 2012 base load capacity need as shown in JEA's Ten Year Site Plans as early as 2005. JEA's base load needs were primarily driven by the expiration of JEA's 207 MW UPS purchase from Southern Company on May 31, 2010. Initially, JEA planned to meet the base load requirements with JEA's share of

the proposed Taylor Energy Center Super Critical Pulverized Coal Unit scheduled for commercial operation in the summer of 2012. Prior to the 2012 base load need, JEA had needs for peaking power of approximately 450 MW in the 2009 and 2010 time frame which includes replacement of the Southern UPS purchase. That amount of peaking capacity need can be met with three 7FA simple cycle combustion turbines. Furthermore, JEA had a unique opportunity to acquire these combustion turbines at below market price through the transfer of an option that Florida Municipal Power Agency obtained when they purchased the combustion turbine for the Treasure Coast Energy Center. One of these combustion turbines is currently being installed as Kennedy Combustion Turbine 8 with a commercial operation date of March 2009. The other two combustion turbines are in the permitting process and will be installed at GEC for commercial operation in June 2010 as simple cycle combustion turbines until the combined cycle conversion in 2012. Exhibit No. __[MRR-2] shows JEA's capacity needs for these simple cycle combustion turbines during the 2009 through 2011 period.

Q. Are there additional benefits to JEA of installing generation at GEC?

A. Yes. JEA currently does not have any generation in the southern portion of its service area. This area is also the fastest growing portion of JEA's service area. Without the installation of GEC, JEA would be required to provide extensive transmission system improvements to continue to reliably serve its growing customer load in the southern part of JEA's service area. GEC's installation will displace the need for these transmission system improvements.

Q. Did JEA explore extension of the UPS contract?

A. Yes. JEA discussed extending the UPS contract with Southern Company. Southern Company would not extend the UPS agreement only offered a new contract which was predominately natural fired combined cycle capacity. The cost for this capacity including associated transmission costs and losses was greater than the JEA's cost for developing the GEC combined cycle project using JEA's low cost tax exempt financing. Furthermore, JEA conducted a RFP process as discussed later in my testimony. Southern Power Company provided several proposals all of which were more expensive than GEC, but none of the bids were cost effective compared JEA's phased combined cycle approach.

Q. Did JEA evaluate short term purchases?

A. Yes. As discussed later in my testimony, JEA issued an RFP for purchase power.

Q. Please summarize the GEC combined cycle conversion Need for Power Application, Exhibit No. __ [GEC-1].

A. JEA is submitting a Need for Power Application in support of a proposed conversion of two natural gas-fired "simple cycle" combustion turbines to a 2x1 combined cycle configuration at the GEC generating station in Duval County, Florida.

Exhibit No. __ [GEC-1] presents the results of a comprehensive analysis that was performed to demonstrate that the proposed conversion satisfies all of the statutory criteria set forth in Section 403.519 Florida Statutes.

Q. Please discuss these statutory criteria.

A. Section 403.519(3), Florida Statutes, sets forth the following criteria which the Commission must consider in making need determinations:

- The need for electric system reliability and integrity.
- The need for adequate electricity at a reasonable cost.
- The need for fuel diversity and supply reliability.
- Whether the proposed plant is the most cost effective alternative available.
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available.
- Whether there are conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant.

Q. Please summarize the process used to determine that GEC combined cycle conversion met each of these statutory criteria.

A. JEA went through a multistage evaluation process to ensure the proposed GEC combined cycle conversion is consistent with the criteria in Section 403.519(3).

The first step involved developing detailed cost and performance estimates for GEC combined cycle conversion. These estimates are presented in Section 9.0 of Exhibit No. __[GEC-1].

The second step involved the development of cost and performance estimates for numerous natural gas-fired supply-side alternatives to the GEC combined cycle conversion. These supply-side alternatives included three simple cycle combustion turbines and a combined cycle alternative. These alternatives are discussed in Section 13.0 of Exhibit No. __[GEC-1].

JEA is a municipality, and is therefore not required to issue an RFP in accordance with the Florida Public Service Commission's "Bid Rule" (i.e., Rule 25-22.082, F.A.C.). Nevertheless, JEA issued an RFP for purchase power in 2007 and in addition, has issued several RFPs for renewable generation. None of the RFPs resulted in cost effective purchase power that displaced the need for the GEC combined cycle conversion

Detailed economic evaluations were performed to evaluate the proposed combined cycle conversion as well as the bids received in response to the last RFP conducted by JEA which was the RFP for Solar and Wind capacity. The methodology and results of these evaluations are discussed in Sections 16.0 and 17.0 of Exhibit No. __ [GEC-1]. The combined cycle conversion of GEC in June 2012 represents the most cost-effective resource addition under all of the

scenarios and sensitivity cases evaluated, which included consideration of new renewable and demand-side management projects being considered by JEA.

Q. Please describe the economic parameters used in the GEC combined cycle conversion Need for Power Application, Exhibit No. __ [GEC-1].

A. A 2.5 percent annual general inflation rate was used. Escalation rates of 2.5 percent annually were used for capital and O&M costs. An annual rate of 5.0 percent was used for the long-term tax-exempt bond interest rate, interest during construction rate, and present worth discount rate. Detailed economic evaluations were performed over a 20 year planning period from 2008 through 2027.

Q. What is the fixed charge rate?

A. The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year.

Q. What fixed charge rates were used in the GEC combined cycle conversion Need for Power Application, Exhibit No. __ [GEC-1]?

A. The FCR calculations assume a 2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund equal to 100 percent of the average annual debt service requirement earning interest at an

interest rate equal to the bond interest rate. The resulting 20 year fixed charge rate is 8.972 percent and the 25 year fixed charge rate is 7.915 percent.

Q. Are these economic parameters appropriate for use in this Need for Power Application?

A. Yes. They are consistent with economic parameters that we have been using in similar evaluations before the Commission and more importantly, they are internally consistent across all the evaluations.

Q. What planning reliability criteria do JEA use?

A. JEA uses a minimum 15 percent reserve margin criterion for both summer and winter seasons. This is lower than the minimum 20 percent reserve margin criterion that the investor owned utilities in Peninsular Florida have stipulated to use. The 15 percent minimum reserve margin is equal to the 15 percent minimum reserve margin requirement in Rule 25-6.035, F.A.C., required for reserve sharing in the State. The 15 percent minimum reserve margin is also consistent with the reserve margin criterion used by many other utilities across the nation.

Q. How is the 15 percent reserve margin criterion applied?

A. The 15 percent reserve margin criterion is applied to firm load. In other words, JEA's peak demand is reduced by interruptible and curtailable loads before considering the 15 percent criterion.

Q. Does JEA apply limitations to the reserve margin criterion?

A. Yes. JEA limits the amount of demand response (DR), which includes interruptible and curtailable loads, to 7.5 percent of its forecast peak demand. This effectively limits DR to one half of JEA's planning reserves.

Q. Is this limitation appropriate?

A. Yes. As presented in Section 17.0 of Exhibit No. __ [GEC-1], JEA's proposed DR programs are projected to be cost-effective. These projections are based on limited use of the programs' customer load reductions and service interruptions. As DR becomes a larger and larger component of a utility's planning reserves, customer load reductions and service interruptions will become more frequent in order for the utility to maintain system reliability. When the frequency of these customer load reductions and service reductions reaches a point that the benefits to customers are negated by the inconvenience, discomfort, and loss of productivity due to the load reductions and service interruptions, customers will begin to leave the DR programs. This indeed occurred on Florida Power Corporation's system a few years ago. The situation can compound as customers leave the program, as the reserve margin decreases the utility is unable to install generation quick enough to compensate for the reduced DR, and the remaining DR customers are exposed to even more frequent interruptions resulting in even more customers leaving the program. The exact point at which DR accounts for too much of a utility's planning reserves is

difficult to ascertain and is also dependant upon many other factors such as the reliability of the utility's generating units. The 7.5 percent criterion is appropriate for JEA and compares favorably with the 6.6 percent level for the FRCC Region's 2008 projected summer peak demand.

Q. Is the limitation of the amount of DR as a component of JEA's planning reserve margin important to the cost-effectiveness of JEA's new Demand Side Management (DSM) portfolio?

A. Yes. As shown in Section 15.0 of Exhibit No. __[GEC-1], the DR program is essentially the only conservation and DSM program which is cost-effective for JEA from a rate impact (RIM) test perspective. Thus the RIM savings from DR allows the inclusion of the energy efficiency programs in order to still meet JEA's requirement for the entire DSM portfolio to be RIM neutral. If the level of DR were to become such a large component of JEA's planning reserves, causing frequent exercise of it such that customers were to leave the program as discussed above, the cost-effectiveness of JEA's entire DSM portfolio could be in jeopardy.

Q. Please describe JEA's expected need for additional capacity to satisfy reserve margin requirements under the base case load forecast.

A. Based on JEA's existing and committed capacity resources and the base case load forecast as presented in Table 12-1 of Exhibit No. __[GEC-1], JEA requires minor amounts of additional capacity to maintain its 15 percent summer reserve

margin up until 2011 when JEA's margin begins to decline rapidly. By the summer of 2012 (the proposed commercial operation date for the GEC combined cycle conversion), JEA's reserve margin declines to 9.6 percent, requiring 167 MW of additional capacity to maintain a 15 percent reserve. JEA's capacity requirements are expected to grow to 393 MW by 2015. These capacity requirements already include reductions associated with JEA's 117 MW of existing summer season curtailable loads.

Q. Will JEA still have a need for capacity after implementation of JEA's new DSM portfolio?

A. Yes. With the projected peak demand reductions from JEA's new DSM portfolio, JEA will need 41 MW of additional capacity in 2012 to maintain the 15 percent reserve margin criterion. By 2015, JEA will need 267 MW of additional capacity to maintain the 15 percent reserve margin criterion.

Q. Please discuss JEA's 2007 purchase power RFP.

A. As discussed previously, JEA planned to meet its 2012 capacity needs through its participation in the Taylor Energy Center, an 800 MW pulverized coal unit to be jointly owned with FMPA, RCID, and the City of Tallahassee. When the Taylor Energy Center project was suspended in 2007, JEA was faced with replacing its proposed ownership share of the base load capacity from Taylor Energy Center as well as continuing with its planned deployment of simple cycle combustion turbines that it had planned to construct in addition to Taylor

Energy Center. A 2x1 F class combined cycle represented JEA's best alternative for meeting these capacity requirements; however, JEA's need for capacity was such that the combined cycle could not be constructed in time to meet JEA's capacity requirements due to permitting and construction lead times. Given the timing of JEA's need for capacity, JEA is initially installing the two 7FA combustion turbines in simple cycle mode at the GEC site and then converting them to a 2x1 combined cycle. JEA's 2007 purchase power RFP was an attempt to determine if purchase power could be obtained at a lower cost than the phased combined cycle installation.

JEA's 2007 purchase power RFP was conducted by The Energy Authority (TEA) on JEA's behalf. TEA's RFP requested up to 600 MW of purchase power from 2010 to 2017. The request was for two different capacity purchases. The first was up to 200 MW of peaking power in 2010 and up to 400 MW of peaking power in 2011 through 2015 and the second was up to 200 MW of base load and intermediate capacity. Proposals were due on April 30, 2007. TEA received proposals from four bidders with one of the bidders providing eight different options. The terms of the bids ranged from 2010 through 2026 in various combinations based on the individual bid and options. Exhibit No. __ [MRR-3] presents amount of power bid. JEA's analyses indicated that none of the bids were cost-effective compared to JEA's phased 2x1 combined cycle approach. As a result, JEA continued the planned installation of the GEC simple cycle combustion turbines followed by their conversion to combined cycle.

Q. Does this conclude your pre-filed testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL TESTIMONY OF MYRON R. ROLLINS

ON BEHALF OF

JEA

DOCKET NO. 080614

NOVEMBER 21, 2008

Q. Please state your name and business address.

A. My name is Myron R. Rollins. My business address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation. My current position is Director.

Q. Have you previously filed testimony in this proceeding?

A. Yes. My direct testimony in this proceeding was filed September 30, 2008.

Q. What is the purpose of your supplemental testimony in this proceeding?

A. The purpose of my supplemental testimony is to discuss revisions to and additional analyses in support of the Greenland Energy Center (GEC) Combined Cycle Conversion Project Need for Power Application, Exhibit No. __[GEC-1]. I also will discuss how renewable energy technologies may be impacted by recent credit market developments, the impact of a one year delay of the Project on JEA's capacity needs,

and the potential impact of JEA's DSM portfolio on JEA's projected need for capacity.

Q. What precipitated the changes to the Need for Power Application and additional supporting analyses?

A. As discussed in the supplemental testimony of Mr. Gilbert, in response to recent credit market developments, JEA has changed its forecast of the long-term interest rate and is delaying capital expenditures from fiscal year 2009 to 2010. Additional economic analyses have been performed to reflect these changes. The results of the additional economic analyses are discussed in the supplemental testimony of Mr. Kushner.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit No. __[MRR-2R] is a revised version of Exhibit No. __[MRR-2] submitted with my original direct testimony. Exhibit No. __[MRR-4] and Exhibit No. [MRR-5] present JEA's annual capacity requirements for the base case load forecast for the summer and winter seasons, respectively. Exhibit No. __[MRR-6] and Exhibit No. __[MRR-7] present JEA's annual capacity requirements after including the impact of JEA's planned Demand Side Management (DSM) program on the base case load forecast for the summer and winter seasons, respectively. All of these exhibits reflect a one year delay in the commercial operation date of the GEC simple cycle combustion turbines.

Q. Are there any changes or corrections to your direct testimony filed September 30, 2008?

A. Yes. On page 9, line 8, the reference to a 5.0 percent long-term tax-exempt bond interest rate should be changed to 7.0 percent. On page 10, line 2, the 20-year fixed charge rate should be changed to 10.412 percent rather than 8.972 and the 25-year fixed charge rate should be 9.425 percent rather than 7.915 percent. On page 13, line 12, the 41 MW should be changed to approximately 48 MW. Exhibit No. __[MRR-2] should reflect the one year delay in the date that GEC combustion turbines 1 and 2 are added to JEA's system and is replaced by Exhibit No. __[MRR-2R].

Q. Are there any changes or corrections to the sections of the GEC Need for Power Application, Exhibit No. __[GEC-1] that you sponsored in your direct testimony?

A. Yes. On page 1-4 Section 1.9 of the GEC Need for Power Application, Exhibit No. – [GEC-1], $122.6 changes to $21.6. On pages 4-1 and 4-2, the tax exempt municipal bond rate, the present worth discount rate, and the interest during construction rate should all be changed to7.0 percent rather than 5.0 percent. On page 4-2, the 20-year FCR should be changed to 10.412 percent from 8.972 percent, and the 25-year FCR should be changed to 9.425 percent rather than 7.915 percent. On Page 12-1, the second bullet should be changed to indicate that the GEC simple cycle combustion turbines are planned for operation in 2011, rather than 2010. On pages 12-3 and 12-4, Tables 12-1 and 12-2 should be replaced by Exhibit No. __[MRR-4] and Exhibit No. __[MRR-5], respectively. Corresponding discussions of capacity requirements throughout the GEC Need for Power Application should reflect those presented in Exhibit No. __[MRR-4] and Exhibit No. __[MRR-5].

Q. Is the change in long-term interest rate (and the resulting FCR calculations) appropriate for estimating the economic impact of recent credit market developments?

A. Yes. JEA's current forecast of a long-term interest rate of no more than 7 percent is reasonable and appears to be conservative based on current interest rates for long-term municipal bonds, which are currently below 6 percent.

Q. How may the competitiveness of renewable resources be affected as a result of the recent credit market developments?

A. The recent credit market developments will likely impact (increase) the cost of financing renewable resources. An increase in financing costs would impact renewable resources whether they are developed by utilities or by private development companies. Due in part to their financial structure, private development companies could actually see larger increases in costs than utilities.

Q. How does a one year delay of the GEC combined cycle conversion project impact JEA's expected need for additional capacity?

A. A one year delay in the commercial operation date of the GEC combustion turbines increases JEA's need for capacity in the summer of 2010 to 300 MW, which will require JEA to purchase additional capacity in 2010 to meet projected loads plus reserve margin. A one year delay in the commercial operation date of the GEC conversion project will require JEA to purchase about 167 MW of capacity during the

summer of 2012 to meet the projected load plus reserve margin. The supplemental testimony of Mr. Gilbert discusses JEA's ability to make these increased short-term purchases. JEA's projected need for capacity without the GEC combined cycle conversion is about 242 MW in 2013 and grows to about 393 MW in 2015.

Q. How may DSM mitigate the need for additional short-term purchases?

A. The DSM portfolio discussed in the direct and supplemental testimony of Mr. Vento is projected to decrease the net firm load as the DSM portfolio is implemented and to decrease, but not eliminate, JEA's need for additional short-term purchases due to a one year delay in the GEC conversion project. Exhibit Nos. __[MRR-6] and [MRR-7] summarize JEA's need for additional capacity after the implementation of the DSM program discussed in Mr. Vento's supplemental testimony. The DSM program is projected to decrease JEA's need for summer capacity to about 269 MW in 2010 and to about 48 MW in 2012. Without the GEC combined cycle conversion, JEA's need for capacity is about 97 MW in 2013 and grows to about 248 MW by 2015.

Q. Does this conclude your supplemental testimony?

A. **Yes.**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF BRADLEY E. KUSHNER

ON BEHALF OF

JEA

DOCKET NO. _____

SEPTEMBER 30, 2008

Q. Please state your name and business address.

A. My name is Bradley E. Kushner. My business mailing address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation where I am currently a Manager.

Q. Please describe your responsibilities in that position.

A. I am responsible for the management of various projects for utility and non-utility clients. These projects include production cost modeling associated with power system expansion planning, feasibility studies, and demand-side management (DSM) evaluations. I also have involvement in the issuance and evaluation of requests for proposals (RFPs).

Q. Please describe Black & Veatch.

A. Black & Veatch Corporation has provided comprehensive engineering, consulting, and management services to utility, industrial, and governmental

clients since 1915. Black & Veatch specializes in engineering, consulting, and construction associated with utility services including electric, gas, water, wastewater, telecommunications, and waste disposal. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, rate and financial reports, appraisals, reports on operations, management studies, and general consulting services. Present engagements include work throughout the United States and numerous foreign countries.

Q. Please state your educational background and professional experience.

A. I received my Bachelors of Science in Mechanical Engineering from the University of Missouri – Columbia in 2000. I have more than 8 years of experience in the engineering and consulting industry. I have experience in the development of integrated resource plans, ten-year-site plans, demand-side management (DSM) plans, and other capacity planning studies for clients throughout the United States. Utilities in Florida for which I have worked include JEA, Florida Municipal Power Agency, Kissimmee Utility Authority, Orlando Utilities Commission, Lakeland Electric, Reedy Creek Improvement District, Tampa Electric Company, and the City of Tallahassee. I have performed production cost modeling and economic analysis, and otherwise participated in four previous Need for Power Applications that have been filed on behalf of Florida utilities and approved by the Florida Public Service Commission (FPSC). I have also testified before the FPSC in previous Need for Power proceedings.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the fuel and carbon dioxide (CO_2) emissions allowance price forecasts and supply-side alternatives used in the economic analysis of the Greenland Energy Center (GEC) combined cycle conversion. I will also discuss the methodology utilized in the economic evaluations, as well as the results of the economic evaluations that were performed for numerous scenarios and sensitivities.

Q. Have you prepared any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit No. __[BEK-1], which is a copy of my resume;
- Exhibit No. __[BEK-2] which includes a series of tables presenting the results of the economic evaluation of the GEC combined cycle conversion.

Q. Are you sponsoring any sections of Exhibit No. __ [GEC-1], the GEC Need for Power Application?

A. Yes. I am sponsoring Sections 7.0, 13.0, 14.0, 16.0, 17.0, and 18.0, all of which were prepared by me or under my direct supervision.

Q. Please describe the basis for the fuel price projections used in the GEC Need for Power Application, Exhibit No. __ [GEC-1].

A. The fuel price projections for natural gas, fuel oil, and coal used for the economic evaluations presented in Exhibit No. __ [GEC-1] were based on those

presented in the US Energy Information Administration's (EIA) Annual Energy Outlook 2008 (AEO2008).

The AEO2008 presents projections of energy supply, demand, and prices through the year 2030. The projections presented within the AEO2008 are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics.

AEO2008 includes the Reference Case, as well as numerous other cases. For purposes of the economic evaluations presented in Exhibit No. __[GEC-1], the AEO2008 High Price Case and Low Price Case were considered in addition to the Reference Case.

Q. How are state and federal legislation and regulations reflected in AEO2008?

A. Analyses developed by the EIA are required to be policy neutral. Therefore, the projections in the AEO2008 are based on federal and state laws and regulations in effect on or before December 31, 2007. As stated in the AEO2008, the potential impacts of pending or proposed legislation, regulations, and standards – or of sections of legislation that have been enacted, but that require

implementing regulations or appropriation of funds that are not provided or specified in the legislation itself – are not reflected in the projections.

Q. Does AEO2008 provide projections of fuel prices for fuel delivered to the Florida region?

A. Yes. The AEO2008 Reference Case includes fuel price projections for delivered fuel to numerous geographic areas throughout the US. The natural gas and fuel oil price projections used in the economic evaluations presented in Exhibit No. __ [GEC-1] were based on AEO2008 price projections for natural gas and fuel oil delivered to the Florida Reliability Coordinating Council (FRCC). Coal price projections were based on the AEO2008 price projections for coal delivered to the Georgia/Florida region.

The Reference Case fuel price projections considered throughout Exhibit No. __ [GEC-1] reflect the region-specific fuel price projections for use in the electric power sector.

Q. Were any adjustments made to the AEO2008 region-specific Reference Case fuel price projections?

A. Yes. The AEO2008 fuel price projections were developed in real 2006 dollars. For purposes of the economic evaluations presented in Exhibit No. __[GEC-1], these projections were converted to nominal dollars using the general inflation rate of 2.5 percent discussed in the testimony of Mr. Myron Rollins.

Q. Were solid fuel and nuclear alternatives among those considered as viable generation expansion options?

A. Biomass generation was the only solid fuel alternative considered for this analysis. Conventional solid fuel generating units were not included as generating unit alternatives because building additional coal or nuclear generation by 2012 is not feasible due to permitting constraints and construction lead times. However, JEA's purchase power agreement (PPA) with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to the proposed Plant Vogtle nuclear Units 3 and 4 was included for all cases considered in the economic evaluations throughout the GEC Need for Power Application (Exhibit No. __ [GEC-1]).

Q. Did the economic analyses consider the costs associated with CO_2 emissions allowances?

A. Yes. Several cases considered in the economic analyses reflected hypothetical sensitivity evaluations in which emissions of CO_2 would be regulated in the US.

Q. How were the emissions prices for CO_2 derived, given that CO_2 emissions are not currently regulated?

A. Although CO_2 emissions are not currently regulated, the EIA developed an analysis entitled *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007.* The EIA's analysis of S.2191 includes five different cases related to the proposed S.2191. Sensitivity evaluations presented in the GEC Need for Power Application reflect two of

these five cases – the *S.2191 Core Case* and the *S.2191 Limited/No International Case*. In general, the CO_2 emissions allowance prices and natural gas prices are higher in the Limited/No International Case than in the Core Case.

Q. How were the detailed economic analyses conducted?

A. The optimal generation expansion plan evaluations were performed using STRATEGIST, a computer software system developed by Ventyx (who recently acquired NewEnergy Associates, LLC, the original developer of STRATEGIST).

Q. How does STRATEGIST determine the most optimal generation plan?

A. STRATEGIST includes an automatic expansion planning module which determines the optimal balanced demand and supply plan for a utility system under a prescribed set of constraints and assumptions. It evaluates all combinations of generating unit alternatives and purchase power options in conjunction with existing capacity resources to satisfy forecast capacity requirements while maintaining user-defined reliability criteria. STRATEGIST simulates the operation of a utility system to determine the cost and reliability effects of adding resources to the system or modifying the load through DSM programs. The expansion plan that results in the lowest cumulative present worth of costs (CPWC) is the optimal generation plan.

Q. How did STRATEGIST simulate utility system operation to arrive at the optimal generation plan for JEA?

A. The simulation of the utility system operation is accomplished using dynamic programming, a mathematical technique useful for making a sequence of interrelated decisions for determining the combination of decisions that optimizes the desired outcome (lowest CPWC in this case). In this Application, all expansion plans were analyzed over a 20 year period from 2008 through 2027.

Q. What supply-side alternatives were included in the detailed economic analysis?

A. The detailed economic analysis considered the following generating unit alternatives:

- General Electric (GE) LM6000 Simple Cycle
- GE LMS100 Simple Cycle
- GE 7FA Simple Cycle
- GE 1x1 7FA Combined Cycle

Q. Were any new renewable energy technologies evaluated?

A. Yes. Several evaluations presented in the GEC Need for Power Application (Exhibit No. __ [GEC-1]) include consideration of a new biomass resource as well as solar photovoltaic (PV).

Q. Were any new conservation measures evaluated?

A. Yes. Several evaluations presented in the GEC Need for Power Application (Exhibit No. __ [GEC-1]) include consideration JEA's new DSM portfolio, which is discussed in the testimony of Mr. Richard Vento.

Q. Please describe the scenarios evaluated in the GEC Need for Power Application, Exhibit No. __ [GEC-1].

A. Four distinct scenarios were considered in the economic evaluations presented in the GEC Need for Power Application (Exhibit No. __ [GEC-1]). Scenario 1 considered the addition of only combustion turbine and combined cycle generating units. Scenario 2 considered the addition of new renewable energy resources supplemented by combustion turbine and combined cycle generating unit alternatives. Scenario 3 considered the annual demand and energy savings and corresponding annual costs associated with JEA's new DSM portfolio supplemented by combustion turbine and combined cycle generating unit alternatives. Scenario 4 considered the addition of both the new renewable energy resources and JEA's new DSM portfolio supplemented by combustion turbine and combined cycle generating alternatives.

Q. How was the least-cost capacity expansion plan identified for JEA?

A. STRATEGIST was used to identify the optimal, or least cost, expansion plan based on CPWC. The CPWC which are presented in Exhibit No.__[BEK-2] include production costs consisting of fuel, purchase power, and nonfuel variable O&M and fixed costs consisting of fixed O&M, fixed charges on new generating units, DSM costs (for scenarios in which JEA's new DSM portfolio was considered), and incremental natural gas transportation charges for new combined cycle units additions. The CPWC are presented in 2008 dollars over the 2008 through 2027 evaluation period using the 5.0 percent present worth discount rate discussed in the testimony of Mr. Myron Rollins.

Q. What were the results of the economic analysis for JEA?

A. Analysis of the CPWC associated with each of the cases analyzed indicates that expansion plans including the GEC combined cycle conversion in June 2012 are the most cost-effective expansion plans for all cases considered.

Q. Did you conduct any sensitivity analyses?

A. Yes.

Q. Please provide an overview of this sensitivity analysis.

A. Sensitivity analyses were performed on the Scenario 1 cases to supplement the reference case economic analysis and to demonstrate the robustness of the GEC combined cycle conversion as part of the most cost-effective expansion plans. The sensitivity analyses measure the impact of varying key assumptions used in

the reference case economic analysis, as well as the impacts of considerations not included in the reference case.

The general methodology used in the sensitivity analyses was similar to the methodology used in the reference case analysis described previously in my testimony. STRATEGIST was used to determine the optimal capacity expansion plan for all cases considered under different sensitivity cases.

Q. What sensitivity analyses were conducted for Scenario 1?

A. Sensitivity analyses were developed to evaluate the impact of:

1. High fuel prices;
2. Low fuel prices;
3. High loads;
4. Low loads;
5. High capital costs;
6. Regulated CO_2;
7. High fuel prices with regulated CO_2; and
8. High CO_2 costs.

Q. Were any sensitivity analyses conducted for Scenarios 2 through 4?

A. Yes. In addition to the reference case assumptions, Scenarios 2 through 4 each consider the potential impact of regulated CO_2 using the S.2191 Core Case evaluation assumptions.

Q. What were the results of these sensitivity analyses?

A. Exhibit No.____[BEK-2] presents a summary of the results of all of the economic evaluations, including each of the sensitivity analyses performed. As shown in Exhibit No.____ [BEK-2], the GEC combined cycle conversion in June 2012 represents the least-cost capacity expansion plan under all sensitivity evaluations.

The results of the sensitivity analyses, coupled with the results of the base case analysis, demonstrate that the capacity expansion plan including the GEC combined cycle conversion in June 2012 is a robust plan, and is sufficiently flexible to overcome variations and deviations from the base case assumptions.

Q. Is GEC combined cycle conversion the most cost-effective alternative available to JEA?

A. Yes. The GEC combined cycle conversion is the most cost-effective alternative available to JEA. In Scenario 1 (conventional resources), the GEC combined cycle conversion in June 2012 will result in CPWC savings of approximately $122.6 million when compared to the least cost plan without the GEC combined cycle conversion. The amount of CPWC savings for the sensitivity evaluations ranges from approximately $57.0 million to approximately $401.0 million.

In Scenario 2 (conventional and renewable resources), the GEC combined cycle conversion in June 2012 will result in CPWC savings of approximately $117.0 million when compared to the least cost plan without GEC combined cycle

conversion. In Scenario 3 (conventional and DSM), the GEC combined cycle conversion in June 2012 will result in CPWC savings of approximately $134.9 million when compared to the least cost plan without the GEC combined cycle conversion. In Scenario 4 (conventional, renewable, and DSM), the GEC combined cycle conversion in June 2012 will result in CPWC savings of approximately $70.6 million when compared to the least cost plan without the GEC combined cycle conversion.

Q. Will the GEC combined cycle conversion provide adequate electricity at a reasonable cost to JEA?

A. Yes. The expansion plan with the GEC combined cycle conversion in 2012 will help to meet JEA's electric generation needs at the lowest cost of all the alternatives evaluated.

Q. Have renewable energy sources and technologies, as well as conservation measures been evaluated to the extent that they are reasonably available to JEA in the economic evaluations?

A. Yes. As discussed in the testimony of Mr. John Worley, JEA has conducted request for proposals (RFP) processes to identify available renewable energy sources and technologies. The testimony of Mr. Richard Vento discusses JEA's new DSM portfolio. The results of the economic evaluations presented in Exhibit No. __[GEC-1] demonstrate that the GEC combined cycle conversion is the most cost-effective alternative available to JEA including consideration of

reasonably available renewable energy sources and technologies as well as conservation measures.

Q. What would be the consequences to JEA of delaying GEC combined cycle conversion?

A. As demonstrated by the economic evaluations presented in the Application, the results of which are summarized in Exhibit No.__ [BEK-2], the GEC combined cycle conversion in 2012 represents the most cost-effective addition to satisfy JEA's forecast capacity requirements to reliably serve its load. The consequences of delaying the commercial operation of the GEC combined cycle conversion would be significant from an economic and reliability standpoint for JEA.

If the commercial operation of the GEC combined cycle conversion is delayed, JEA would be required to replace the capacity and energy that would otherwise be provided by a new, efficient combined cycle generating unit. The economic consequence of delaying the commercial operation of the GEC combined cycle conversion from June 2012 until June 2013 is approximately $36.7 million in CPWC, compared to the next most cost-effective expansion plan.

JEA is projected to require a significant amount of capacity in 2012 to maintain its reserve margin requirements. If the GEC combined cycle conversion is delayed by one year and no additional generating capacity is installed to meet JEA's forecast capacity requirements by 2012, JEA's reserve margin will fall to

approximately 9.6% (or 167 MW less than the 15% reserve requirement) in 2012. The projected capacity deficit in the summer of 2012 is nearly all of the capacity that will be provided by the GEC combined cycle conversion. With an unacceptable reserve margin in 2012, JEA would not have enough reserves to provide reliable electricity to its customers. This will expose JEA to potentially high purchase power costs.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL TESTIMONY OF BRADLEY E. KUSHNER

ON BEHALF OF

JEA

DOCKET NO. 080614

NOVEMBER 21, 2008

Q. Please state your name and business address.

A. My name is Bradley E. Kushner. My business mailing address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation where I am currently a Manager.

Q. Have you previously filed testimony in this proceeding?

A. Yes. My Direct Testimony in this proceeding was filed September 30, 2008.

Q. What is the purpose of your supplemental testimony in this proceeding?

A. As discussed in the supplemental testimony of Mr. Gilbert, recent developments in the municipal credit markets have caused JEA to change its forecast of long term interest rates to a maximum of 7 percent. Additionally, as Mr. Gilbert explains, JEA will be delaying some capital expenditures from fiscal year 2009 to fiscal year 2010. The purpose of my supplemental testimony is to discuss additional economic analyses performed to address the possible impact of these changed circumstances on the

economics of the proposed Greenland Energy Center (GEC) combined cycle conversion. I will also discuss revisions to the economic analyses included in the GEC Need for Power Application (Exhibit No. __ [GEC-1]) and my direct testimony filed in this proceeding.

Q. Have you prepared any exhibits to your testimony?

A. Yes. Exhibit No. __[BEK-2R] is a revised version of Exhibit No. __[BEK-2] to my direct testimony. Exhibit No. __[BEK-2R] is a series of tables presenting the results of the revised economic evaluations originally included in the GEC Need for Power Application (Exhibit No. __[GEC-1] and my direct testimony. I am also sponsoring Exhibit No. __[BEK-3] which includes a table presenting results of the additional economic analyses performed as a result of recent credit market developments.

Q. Are there any changes or corrections to your direct testimony filed September 30, 2008?

A. Yes. The 5.0 percent present worth discount rate referenced on page 10, line 9 should be changed to 7.0 percent. The cumulative present worth costs (CPWC) results reported on pages 12 and 13 of my direct testimony, including Exhibit No. __[BEK-2], should be updated to reflect the revised results presented in my supplemental testimony.

Q. Are there any changes or corrections to the sections of the GEC Need for Power Application (Exhibit No. __[GEC-1]) that you sponsored in your direct testimony?

A. Yes. The CPWC results discussed in Sections 17 and 18 should be updated to reflect the revised results presented in my supplemental testimony. In addition, Exhibit No. __[BEK-2R] updates Table 17-2 and Table 17-3 of the GEC Need for Power Application.

Q. Please discuss the additional economic analyses that have been conducted as a result of recent credit market developments?

A. Additional STRATEGIST cases have been evaluated to address the impact of the increase in the interest rate to 7 percent, the resulting changes to the economic parameters, and a delay of one year in the conversion of GEC to combined cycle operation.

Q. What additional cases were evaluated to address potential impacts of the recent credit market developments?

A. The additional cases include:

1. The Scenario 1 Reference Case without the GEC conversion
2. The Scenario 1 Reference Case with the GEC conversion delayed one year to June 2013
3. The Scenario 3 (DSM) Reference Case without the GEC conversion
4. The Scenario 3 (DSM) Reference Case with the GEC conversion delayed one year to June 2013

In the cases with a one year delay in the conversion of GEC to combined cycle operation, a seasonal purchase was assumed to be made during the summer 2012 months to address the projected capacity deficit in 2012.

Collectively, these cases are referred to as the High Interest Rate cases.

Q. What are the CPWCs of the High Interest Rate cases?

A. The CPWCs for the High Interest Rate cases are presented in Exhibit No.__[BEK-3]. The CPWC are presented in 2008 dollars over the 2008 through 2027 evaluation period using the 7 percent present worth discount rate discussed previously.

Q. How did you reflect the changes to the DSM portfolio discussed in the supplemental testimony of Mr. Vento in the High Interest Rate cases for Scenario 3?

A. The changes to the DSM portfolio discussed in the supplemental testimony of Mr. Vento did not necessitate changes to the evaluation of the DSM portfolio in Scenario 3. The impact of the one year delay in the DSM programs discussed by Mr. Vento is the same for all cases in Scenario 3 prior to the commercial operation of the GEC combined cycle conversion, and therefore does not influence the comparative economics between cases in Scenario 3.

Q. Is the GEC combined cycle conversion the most cost-effective alternative as evaluated in the High Interest Rate cases?

A. Yes. Analysis of the CPWC associated with each of the High Interest Rate cases indicates that conversion of GEC to combined cycle operation in June 2013 is more cost-effective than not converting GEC to combined cycle operation. Conversion of GEC to combined cycle operation in June 2013 results in CPWC savings of approximately $21.6 million for the conventional expansion plan scenario (Scenario 1) and approximately $18.6 million for the DSM expansion plan scenario (Scenario 2).

Q. Please discuss the revised economic analyses you alluded to earlier in your supplemental testimony.

A. After the GEC Need for Power Application (Exhibit No. ___[GEC-1]) and my direct testimony were filed, it was discovered that STRATEGIST was not treating the calculation of peak demands properly. This resulted in STRATEGIST using higher peak demands than the peak demands projected by JEA. Given that JEA's need for power is governed by the difference in summer peak and the summer ratings of its generating resources, the higher summer peaks resulted in STRATEGIST selecting more capacity additions than required. The incorrect treatment of peak demands was confirmed with the developers of STRATEGIST and the method of inputting peak demands was changed for purposes of the economic analyses I am presenting in this supplemental testimony.

Q. Were the peak demands incorrect in all of the economic results presented in the Application?

A. No. The peak demands were incorrect in the economic analyses performed for Scenario 1 (Conventional Expansion Scenario) and Scenario 2 (Renewable Expansion Scenario). The peak demands used by STRATEGIST for Scenario 3 (DSM Expansion Scenario) and Scenario 4 (Renewables and DSM Expansion Scenario) were correct.

Q. Are there any other changes reflected in the revised economic analyses?

A. Yes. The costs for JEA's new DSM portfolio were improperly continued and escalated past 2012. This is corrected in the revised economic analyses, but the correction does not change the comparative savings of the GEC combined cycle conversion because the costs for DSM were included in both the cases with and without the GEC combined cycle conversion.

Q. Please discuss the revised CPWC results.

A. The CPWC projections for all of the cases (reference and sensitivity cases) from Scenarios 1 and 2 are presented in Exhibit No.__ [BEK-2R]. The CPWC are presented in 2008 dollars over the 2008 through 2027 evaluation period using the 5.0 percent present worth discount rate discussed in the direct testimony of Mr. Rollins. The results presented in Exhibit No. __ [BEK-2R] update the results presented in Tables 17-2 and 17-3 in the Application and in Tables 1 and 2 of Exhibit No. __ [BEK-2] in my direct testimony. Analysis of Exhibit No. __ [BEK-2R] indicates that conversion of GEC to combined cycle remains the most cost-effective alternative available to JEA after considering the revisions described previously.

Q. Did you perform a revised analysis of the economic consequences of delaying the GEC combined cycle conversion?

A. Yes. The revised analysis indicates the economic consequence of delaying the commercial operation of the GEC combined cycle conversion from June 2012 until June 2013 is approximately $31.8 million in CPWC, compared to the next most cost-effective expansion plan.

Q. Did the additional analyses you discussed earlier in your supplemental testimony use the correct peak demands and DSM costs addressed in your discussion of the revised economic analyses?

A. Yes. All additional analyses reflect the revised method of inputting peak demand into the STRATEGIST model and the proper treatment of the DSM costs.

Q. Do either the additional analyses or revised analyses you've discussed in your supplemental testimony change the overall conclusion presented in your direct testimony?

A. No. The GEC combined cycle conversion remains the most cost-effective alternative available to JEA.

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN CARTER: Staff, you're recognized.

MS. BROWN: And now move on to the exhibits.

We have passed out the Comprehensive Exhibit List for the Commissioners' convenience, and we would like to mark and move the exhibit list itself into the record as Exhibit 1.

CHAIRMAN CARTER: Show it done without objection.

MS. BROWN: The Comprehensive Exhibit List includes Staff's Stipulated Composite Exhibit as Exhibit 2. We ask that that be moved into the record at this time.

CHAIRMAN CARTER: Without objection, show it done.

MS. BROWN: We note that to save administrative expense and some trees, the Staff Composite Exhibit has been provided to the Commissioners and JEA on a CD.

CHAIRMAN CARTER: We're saving trees, Commissioners.

MS. BROWN: We have one hard copy of the exhibit available if we need it. We ask that all the other exhibits identified on the Comprehensive Exhibit List be moved into the record at this time.

CHAIRMAN CARTER: Any objections? Without objection, show it done.

(Exhibits 1 through 31 marked for identification and admitted into the record.)

MS. BROWN: Now, Mr. Chairman, if the Commission so chooses, we could make a bench decision on the proposed stipulations.

CHAIRMAN CARTER: Let me just say this, Staff, how much we -- as Commissioners, how much we appreciate putting the entire record on these CDs that we can look over and save some trees, but also have all information necessary for this hearing. So, good job. Keep on keeping on. That's a great thing to do.

Okay. Now your recommendation.

MS. BROWN: Yes. We recommend that the Commission could make a bench decision in this case. No post-hearing filings will be necessary, if it wishes.

CHAIRMAN CARTER: Commissioners, any questions or concerns?

Commissioner Skop, you're recognized.

COMMISSIONER SKOP: Thank you, Mr. Chairman.

With respect to the prospect of making a bench decision, typically I'm not in favor of that just by virtue of the fact that most of the need determinations that come before us are much larger plants or first of a kind. In this case, however, I would depart from that and support a bench vote to the extent that the capital cost is $418 million for a simple conversion on combined cycle -- to a combined cycle configuration. Very straightforward typically done, so I have a tremendous amount of comfort level with this.

CHAIRMAN CARTER: Commissioners, any further comments?

Commissioner Edgar, you're recognized for a motion.

COMMISSIONER EDGAR: Mr. Chairman, thank you.

I make a motion as this time that we approve the stipulated Issues 1 through 7.

COMMISSIONER SKOP: Second.

CHAIRMAN CARTER: It has been moved and properly seconded.

Commissioners, any comments, debate, discussion?

Hearing none. All those in favor, let it be known by the sign of aye.

(Simultaneous aye.)

CHAIRMAN CARTER: All those opposed, like sign.

Show it done.

Staff, you're recognized.

MS. BROWN: As I understand it, there are no further matters to be addressed. Staff would point out that no post-hearing filings are necessary, and the final order in the case will be issued by March 4th.

CHAIRMAN CARTER: Anything further, staff?

MS. BROWN: Nothing further.

CHAIRMAN CARTER: Anything further from the parties?

MR. PERKO: No, sir.

CHAIRMAN CARTER: Commissioners, anything further?

Therefore, we are adjourned.

(The hearing concluded at 9:41 a.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 19th day of February, 2009.

JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
Staff				
1		Exhibit List	Comprehensive Exhibit List	
Staff				
2	Staff	Staff's Composite Exhibit - 2 stipulated	**Interrogatories** 1. JEA's Responses to Staff's First Set Interrogatories (Nos. 1-21) *[Bates Nos. 00000001-000000043]* 2. JEA's Responses to Staff's Second Set Interrogatories (Nos. 25-29) *[Bates Nos. 00000044-000000051]* 3. JEA's Responses to Staff's Third Set Interrogatories (Nos. 30-43, 45-72, 74-76) *[Bates Nos. 00000052-00000419]* 4. JEA's Responses to Staff's Fourth Set Interrogatories (Nos. 82-92) *[Bates Nos. 00000420-00000429]* 5. JEA's Responses to Staff's Fifth Set Interrogatories (Nos. 93-101) *[Bates Nos. 00000430-00000443]* 6. JEA's Responses to Staff's Sixth Set Interrogatories (No. 102) *[Bates Nos. 00000444-00000449]*	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM **EXHIBIT** 1
COMPANY FL PSC Staff
WITNESS Comprehensive Exhibit List
DATE 02/12/09

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
			Request for Production of Documents 7. JEA's Responses to Staff's First Request for Production of Documents (Nos. 1-5) (excluding attachments 2A and 2B to POD 2) *[Bates Nos. 00000450-000000486]* 8. JEA's Responses to Staff's Second Request for Production of Documents (Nos. 6-9) (files from PODS 6-8 on CD) *[Bates Nos. 00000487-000000490]* 9. JEA's Responses to Staff's Third Request for Production of Documents (No. 15) *[Bates Nos. 00000491-000000519]*	
JEA (DIRECT)				
3	Donald C. Gilbert	DCG-1	Resumé of Donald C. Gilbert	
4	Donald C. Gilbert	DCG-2	JEA's Existing Generation Facilities	
5	Donald C. Gilbert	GEC-1	Sections 3.0 (except 3.9), 10.0 and 19.0	
6	Michael N. Lawson	MNL-1	Resumé of Michael N. Lawson	
7	Michael N. Lawson	MNL-2	Summary of Estimated Capital Costs of GEC Combined Cycle Conversion Project	
8	Michael N. Lawson	MNL-3	Estimated Performance of GEC Combined Cycle.	

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D.#	Witness	I.D. # As Filed	Exhibit Description	Entered
9	Michael N. Lawson	GEC-1	Section 9.0	
10	Mary Guyton-Baker	MGB-1	Resumé of Mary Guyton-Baker	
11	Mary Guyton-Baker	GEC-1	Section 5.0	
12	James T. Myers	JTM-1	Resumé of James T. Myers	
13	James T. Myers	GEC-1	Sections 6.0 and 8.0	
14	John A. Worley	JAW-1	Resumé of John A. Worley	
15	John A. Worley	GEC-1	Sections 3.9 and 14.0	
16	Richard J. Vento	RJV-1	Resumé of Richard J. Vento	
17	Richard J. Vento	RJV-2	Annual Summer and Winter Peak Demand and Net Energy for Load Reductions Projected for JEA's New DSM Portfolio	
18	Richard J. Vento	RJV-3	Projected Annual Costs of JEA's New DSM Portfolio	
19	Richard J. Vento	GEC-1	Section 15.0	
20	Myron R. Rollins	MRR-1	Resumé of Myron R. Rollins	
21	Myron R. Rollins	MRR-2R	JEA's Capacity Requirements	
22	Myron R. Rollins	MRR-3	Levels of Capacity Bid from JEA's RFP	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
23	Myron R. Rollins	MRR-4	JEA's Annual Capacity Requirements for Base Case Load Forecast (summer)	
24	Myron R. Rollins	MRR-5	JEA's Annual Capacity Requirements for Base Case Load Forecast (winter)	
25	Myron R. Rollins	MRR-6	JEA's Annual Capacity Requirements including impact of new DSM Program (summer)	
26	Myron R. Rollins	MRR-7	JEA's Annual Capacity Requirements Including Impact of New DSM Program (winter)	
27	Myron R. Rollins	GEC-1	Sections 1.0, 2.0, 4.0, 11.0 and 12.0	
28	Bradley E. Kushner	BEK-1	Resumé of Bradley E. Kushner	
29	Bradley E. Kushner	BEK-2R	Results of Economic Analyses	
30	Bradley E. Kushner	BEK-3	Results of Additional Economic Analyses	
31	Bradley E. Kushner	GEC-1	Sections 7.0, 13.0, 14.0, 16.0, 17.0, and 18.0	

1

JEA's Responses to Staff's First Set of Interrogatories (Nos. 1-21)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EI EXHIBIT 2
COMPANY FL PSC Staff's Composite
WITNESS Exhibit -2 Stipulated
DATE 02/12/09

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

RECEIVED
NOV - 3 2008
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

In re: Petition to determine need for Greenland Energy Center Combined Cycle Conversion in Duval County by JEA.	DOCKET NO. 080614-EM DATED: NOVEMBER 3, 2008

JEA'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES TO JEA (NOS. 1 - 24)

JEA, pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's First Set of Interrogatories (Nos. 1-24):

The answer to Question Nos. 1, 2, 3, 4, 5, and 6 of Staff's First Set of Interrogatories (Nos. 1-24) is provided by Myron Rollins (consultant to JEA), Black & Veatch Corporation, 11401 Lamar Avenue, Overland Park, Kansas 66211. Answers to Question Nos. 7, 19, 20, 21, 22, 23, and 24 of Staff's First Set of Interrogatories (Nos. 1-24) are provided by Bradley Kushner (consultant to JEA), Black & Veatch Corporation, 11401 Lamar Avenue, Overland Park, Kansas 66211. Answers to Question Nos. 8, 13, and 14 of Staff's First Set of Interrogatories (Nos. 1-24) are provided by Donald Gilbert (Manager, Electric System Planning, JEA). The answer to Question No. 9 of Staff's First Set of Interrogatories (Nos. 1-24) is provided by Michael Lawson (Project Manager, JEA). Answers to Question Nos. 10, 11, and 12 of Staff's First Set of Interrogatories (Nos. 1-24) are provided by John Worley (Director, Environmental Programs, JEA). Answers to Question Nos. 15, 16, 17, and 18 of Staff's First Set of Interrogatories (Nos. 1-24) are provided by Richard Vento (Director, Corporate Data Integration, JEA).

RESPONSES

1. **Regarding the economic parameters, how did JEA analyze and select 2.5% as the escalation rate, i.e., the general inflation rate?**

Response: The escalation and general inflation rate of 2.5 percent was selected along with the other economic parameters to be reasonable and appropriate and consistent with the other economic parameters. The Chained Consumer Price Index which was developed by the Bureau of Labor Statistics to more closely represent a "cost-of-living" index indicates an average annual increase of 2.3 percent from 2000 through 2007 and a increase of 2.5 percent from 2006 through 2007.

A 2.3 percent escalation and general inflation rate was used in the need determination for Cane Island Power Park Unit 4 in Docket No. 080253-EM. The Order granting the determination (PSC-08-0506-FOF-EM) was issued August 8, 2008.

2. **What is the basis for the 5.00% cost rate for new debt?**

Response: The assumed annual cost rate for new debt used throughout the Greenland Energy Center Need for Power Application is based on the long-term tax exempt municipal bond rate developed to be reasonable and appropriate and consistent with the other economic parameters. The revenue bond index from the Bond Buyer for the beginning of June 2008 was 5.04 percent. With the recent credit crisis, JEA recognizes that bond interest rates are increasing. JEA will address the higher interest rates in supplemental testimony.

3. **How does JEA use the 2.5% escalation rate in the evaluation process?**

Response: The 2.5 percent escalation rate was applied to capital costs and operating and maintenance costs in all economic evaluations throughout the Greenland Energy Center Need for Power Application. The projections of fuel and CO_2 emission allowance price forecasts based on projections provided by the Energy Information Administration (which were used throughout the Greenland Energy Center Need for Power Application) were presented in real 2006 dollars, and the 2.5 percent general inflation rate was used to convert these costs to nominal dollars.

4. **How does JEA use the 5.0% rate for interest during construction in the evaluation process?**

Response: The 5.0 percent interest during construction rate was used consistently throughout the Greenland Energy Center Need for Power Application in the economic evaluation of supply-side alternatives to calculate the interest during construction associated with each of the generating unit alternatives. The interest during construction required for Greenland Energy Center was estimated based on a projected monthly cash flow for project expenditures prior to commercial operation. The interest during construction for all other alternatives was estimated assuming interest would accrue for one half of the construction period for each alternative.

5. **How does JEA use the 5.0% present worth discount rate in the evaluation process?**

Response: The 5.0 percent present worth discount rate was used consistently throughout the Greenland Energy Center Need for Power Application to discount the annual system costs in the economic evaluations to 2008 values, and the annual present worth system costs were aggregated to determine the cumulative present worth costs for each expansion plan considered. These cumulative present worth costs were then compared to identify the least-cost capacity expansion plan under the base case and for each of the sensitivity cases considered.

6. **What is the basis for the 20 year 8.972% fixed charge rate, and the 25 year 7.915% fixed charge rate? Please discuss all assumptions and show all calculations.**

Response: Different generating technologies are assumed to have different economic lives and therefore different financing terms. For purposes of this analysis, simple cycle combustion turbines are assumed to have a 20 year financing term and combined cycle units are assumed to have a 25 year financing term. All levelized fixed charge rate calculations assume the 5.0 percent tax exempt municipal bond interest rate, a 2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund (DSRF) equal to twelve months of debt service requirement earning interest at an interest rate equal to the bond interest rate of 5.0 percent. The resulting 20 year fixed charge rate is 8.972 percent and the 25 year fixed charge rate is 7.915 percent.

The levelized fixed charge rate is essentially the capital recovery factor, adjusted to include the bond issuance fee and the debt service reserve fund, plus 0.50 percent for property insurance, and was calculated as follows:

For the 20 year fixed charge rate where i = 5.0 percent, n = 20 years, DSRF = 1.0 year, bond issuance fees (fees) = 2.0 percent, and property insurance = 0.5 percent:

Capital Recovery Factor (CRF) =

$$\frac{i \times \left[(1+i)^n\right]}{\left[(1+i)^n - 1\right]} = \frac{0.05 \times \left[(1+0.05)^{20}\right]}{\left[(1+0.05)^{20} - 1\right]} = 0.08024 = 8.024 \text{ Percent}$$

Adjusted CRF (ACRF) =

$$\frac{(1 - (i \times DSRF)) \times CRF}{[1 - fees - (DSRF \times CRF)]} = \frac{(1 - (0.05 \times 1.0)) \times 0.08024}{[1 - 0.02 - (1.0 \times 0.08024)]} = 0.08472 = 8.472 \text{ Percent}$$

Levelized Fixed Charge Rate =

ACRF + property insurance = 0.08472 + 0.005 = 0.08972 = 8.972 Percent

For the 25 year fixed charge rate where i = 5.0 percent, n = 25 years, DSRF = 1.0 year, bond issuance fees (fees) = 2.0 percent, and property insurance = 0.5 percent:

Capital Recovery Factor (CRF) =

$$\frac{i \times \left[(1+i)^n\right]}{\left[(1+i)^n - 1\right]} = \frac{0.05 \times \left[(1+0.05)^{25}\right]}{\left[(1+0.05)^{25} - 1\right]} = 0.07095 = 7.095 \text{ Percent}$$

Adjusted CRF (ACRF) =

$$\frac{(1 - (i \times DSRF)) \times CRF}{[1 - fees - (DSRF \times CRF)]} = \frac{(1 - (0.05 \times 1.0)) \times 0.07095}{[1 - 0.02 - (1.0 \times 0.07095)]} = 0.07415 = 7.415 \text{ Percent}$$

Levelized Fixed Charge Rate =

ACRF + property insurance = 0.07415 + 0.005 = 0.07915 = 7.915 Percent

7. **How does JEA use the two fixed charge rates in the evaluation process?**

Response: The two levelized fixed charge rates were applied to all estimated capital expenditures in the economic analyses performed in the Greenland Energy Center Need for Power Application. The levelized fixed charge rate, or FCR, represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. The resulting levelized capital cost was used in the determination of annual system costs for each expansion plan evaluated. The levelized fixed charge rates were applied to all capital expenditures consistently throughout the Application. The 20 year fixed charge rate was applied to simple cycle combustion turbine alternatives and the 25 year fixed charge rate was applied to combined cycle alternatives.

8. **Please provide the capital structure for this transaction for JEA.**

Response: JEA has yet to make a final decision regarding the capital structure for the Greenland Energy Center combined cycle conversion. The analyses presented throughout the Greenland Energy Center Need for Power Application assume that the Greenland Energy Center combined cycle conversion will be financed using 100 percent debt financing with long term tax exempt bonds.

9. **What is the total site capability for the Greenland Energy Center (GEC) site? How much land will the GEC occupy?**

Response: The Greenland Energy Center site is expected to be capable of accommodating the proposed Greenland Energy Center 2x1 combined cycle as well as an additional similar 2x1 combined cycle and a future simple cycle combustion turbine. The Greenland Energy Center site is proposed to consist of approximately 152.5 acres. The proposed Greenland Energy Center 2x1 combined cycle will occupy approximately 84.7 acres of the site.

10. **Has JEA done an assessment of what additional renewable generation is physically available? If so, what were the results?**

Response: Yes. JEA has issued three Requests for Proposals (RFPs) for renewable energy sources. In February 2004, JEA issued a RFP for Renewable Energy Generation for 1 MW to 300 MW. JEA received 13 acceptable responses with capacities between 1 MW and 50 MW. Landfill Energy Systems and Evergreen Paper and Energy (Evergreen) received top ranking and JEA entered into negotiations with both firms. JEA signed a

Purchase Power Agreement (PPA) with Landfill Energy System to take the output of a 9.6 MW landfill gas facility (Trail Ridge). JEA also negotiated with Evergreen on a 13 MW facility using City of Jacksonville yard waste, but the negotiations were cancelled in 2007 after Evergreen had failed to prepare the site to take yard waste.

In 2007 JEA issued a request for letters of interest from companies interested in developing renewable energy projects for JEA. JEA received 19 responses. One of these responses was from Trail Ridge to generate energy from an additional 9.6 MW of landfill gas at the Trail Ridge landfill. JEA and Trail Ridge continue to evaluate this proposal. JEA also received a letter of interest from a Florida municipal utility indicating an interest in working with JEA on development of joint renewable energy projects. JEA may consider working with other Florida utilities to develop joint projects similar to how several fossil fuel plants have been developed.

Due to the numerous biomass letters of interest received, JEA issued a RFP to the biomass respondents on August 13, 2007 with proposals due by September 28, 2007. JEA received nine proposals and rejected five that did not meet the screening criteria. The remaining four proposals ranged from 9 MW to 120 MW. One of these proposals was from an existing operating biomass facility; however, the remaining proposals could not demonstrate a commitment on the fuel source or site nor did they demonstrate project financing availability. Incremental costs were estimated for each of the four proposals, resulting in incremental costs ranging from about $10/MWh to about $59/MWh above base case ($51 million to $306 million in net additional cost to JEA over 20 years). Due to the high costs, the inability to demonstrate fuel or site availability, or project financing, JEA did not negotiate with any of the entities that made proposals.

JEA issued an RFP for renewable energy, in particular solar and wind resources on March 17, 2008 (the Solar and Wind RFP), with responses due on May 16, 2008. JEA received ten solar PV proposals and two proposals for solar PV panels (equipment purchase only). JEA did not receive any proposals for solar thermal electric or wind projects. Eight of the ten solar PV proposals were for ground-mounted systems from 8 MW to 12 MW and two were for distributed roof-top mounted systems from 2 MW to 4 MW in total size. The responses to the Solar and Wind RFP were ranked on both a technical and price basis. The proposals resulted in incremental costs ranging from about $10/MWh to about $150/MWh over a 20 year period. JEA is pursuing negotiations with the company that provided the lowest cost solar PV proposal.

11. **Please provide any information on JEA's current and planned solar projects, including the project description, MW size, kWh output, installation dates and square footage required for each project. Also, please provide the costs (capital, operating and maintenance of such projects).**

Response: JEA has installed 35 solar PV systems, totaling 220 kW, on public schools, a college, and university in Duval County, as well as local public buildings and on JEA facilities. Please find below a listing of the facilities which includes the requested information. The kWh generation presented in the table is for 2006, which is the most recent year for which data is available. Fiscal year 2008 operating and maintenance expenses have been estimated to be approximately $106,390 for the existing solar PV projects.

System	Location	On-Line	kW	kWh	Capital Cost	Square Footage
PV-1	JEA Pelotes Island	5/31/1999	4.8	2,127	$62,000	613
PV-2	Parker High School West	11/16/1999	4.08	3,530	$56,943	326
PV-3	Raines High School	5/5/2000	4.08	0	$52,442	326
PV-4	First Coast High School	5/26/2000	4.2	899	$123,236	341
PV-5	Ridenour Water Treatment Station	7/7/2000	4.56	2,787	$62,446	418
PV-6	Randolph Academies of Technology	8/24/2000	3.96	117	$61,859	336
PV-7	Jackson High School	8/24/2000	3.96	509	$61,859	336
PV-8	Lee High School	9/1/2000	3.96	3	$61,859	336
PV-9	Baldwin High School	9/1/2000	3.96	2,362	$61,859	336
PV-10	Peterson Academies of Technology	9/20/2000	3.96	0	$61,859	336
PV-11	Forrest High School	9/20/2000	3.96	0	$61,859	336
PV-12	White High School	9/20/2000	3.96	575	$61,859	336
PV-13	Ribault High School	9/21/2000	3.96	3,465	$61,859	336
PV-14	Sandalwood High School	9/21/2000	3.96	0	$61,859	336
PV-15	Wolfson High School	9/25/2000	3.96	0	$61,859	336
PV-16	Paxon School for Advanced Studies	9/28/2000	3.96	0	$61,859	336
PV-17	Stanton College Preparatory School W	9/28/2000	3.96	0	$40,507	336
PV-18	Stanton College Preparatory School E	9/28/2000	3.96	4,522	$40,507	336
PV-19	Anderson School for the Arts	9/28/2000	3.96	3,636	$40,507	336
PV-20	Englewood High School	9/28/2000	3.96	0	$40,507	336
PV-21	Mandarin High School West	9/29/2000	3.96	4,087	$40,507	336
PV-22	Mandarin High School East	9/29/2000	3.96	3,964	$40,507	336
PV-23	Parker High School East	9/29/2000	3.96	9	$40,507	336
PV-24	JEA Plaza III #1	2/6/2001	2.58	2,293	$46,939	480
PV-25	JEA Plaza III #2	2/6/2001	2.58	2,307	$46,939	480
PV-26	JEA Plaza III #3	2/6/2001	4.91	629	$85,503	421
PV-27	JEA Crew Setup - St. Johns Bluff Rd	11/25/2001	21.6	4,512	$219,696	1,831
PV-28	JEA Crew Setup – West US1	11/22/2001	13.5	12,435	$137,310	1,144
PV-29	JEA Crew Setup – East US1	11/21/2001	8.1	8,677	$82,386	687
PV-30	JEA Crew Setup – Hillman Drive	11/7/2001	13.5	165	$137,310	1,144
PV-31	Jax Chamber of Commerce	11/1/2002	3.96	5,003	$50,400	336
PV-32	Jacksonville Zoo	11/1/2002	2.1	2	$88,955	178
PVC-01	FCCJ ATC	1/30/2003	4.2	3,599	Not JEA Owned	163
PV-33	Jacksonville University	1/15/2003	4.2	29	$42,719	356
PV-34/35	Jacksonville International Airport	10/1/2003	48.6	83	$556,106	4,119

Based on the results of JEA's 2008 Solar and Wind RFP, JEA is in the process of negotiating a purchase power agreement (PPA) with Rocky Mountain Energy Group Inc. for the output of the Seminole Solar Project (Project). The project costs for this PPA have not yet been finalized as negotiations are currently in progress. The Project is to be a ground mounted photovoltaic system with solar panels installed on a fixed tilt and oriented due south. The proposal indicated that the project could be developed on any parcel of land that is larger than 120 acres (5,227,160 square feet) and has efficient inter-connection opportunities within JEA's distribution network. The proposal identified an in-service date as early as July 2010 and that the project may provide JEA with 15 MW (DC) of solar capacity. The Project corresponds to the equivalent of a 12.3 MW (AC) project with a maximum capacity of 9.22 MW expected to occur at noon between April and October. The Project is projected to provide average annual generation of 21,823,000 kWh.

12. **Please provide any information on JEA's current and planned wind projects. Including the project description, MW size, kWh output, installation dates and square footage required for each project. Also, please provide the costs (capital, operating and maintenance of such projects).**

Response: JEA has no self-build wind projects. In 2004, JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. Under the agreement, JEA has agreed to purchase 10 MW of capacity from NPPD's wind generation facility for a 20 year period ending December 31, 2024. JEA purchases the 10 MW of capacity and associated energy at specified capacity and energy charges. In turn, NPPD will buy back the energy at specified on /off peak charges. The on /off peak energy charge rates paid by NPPD to JEA are higher than the energy charge rates paid by JEA to NPPD. NPPD is responsible for operating and maintaining the wind generation project. NPPD retains ownership of the wind generation project and ownership of all Renewable Energy Production Incentive Credits attributable to the energy produced by the project. JEA acquires the rights to the intangible environmental benefits and other such attributes (defined as Green Tags in the agreement) associated with generating electric energy by a renewable resource.

The capacity charge rate that JEA pays NPPD is $4,500/MW-month. The energy charge rate that JEA pays NPPD is shown below.

Contract Year	Energy Charge Rate ($/MWh)
2005	$8.10
2006	$8.26
2007	$8.43
2008	$8.60

2009	$8.77
2010	$8.94
2011	$9.12
2012	$9.30
2013	$9.49
2014	$9.68
2015	$9.87
2016	$10.07
2017	$10.27
2018	$10.48
2019	.$10.69
2020	$10.90
2021	$11.12
2022	$11.34
2023	$11.57
2024	$11.80

The energy charge rate paid by NPPD to JEA is shown below.

Contract Year	Energy Charge Rate ($MWh)
2005	On Peak $14.50 / Off Peak $10.50
2006	On Peak $14.79 / Off Peak $10.71
2007	On Peak $15.09 / Off Peak $10.92
2008	On Peak $15.39 / Off Peak $11.14
2009	On Peak $15.70 / Off Peak $11.37
2010	On Peak $16.01 / Off Peak $11.59
2011	On Peak $16.33 / Off Peak $11.82
2012	On Peak $16.66 / Off Peak $12.06
2013	On Peak $16.99 / Off Peak $12.30
2014	On Peak $17.33 / Off Peak $12.55
2015	On Peak $17.68 / Off Peak $12.80
2016	On Peak $18.03 / Off Peak $13.06
2017	On Peak $18.39 / Off Peak $13.32
2018	On Peak $18.76 / Off Peak $13.58
2019	On Peak $19.13 / Off Peak $13.85
2020	On Peak $19.52 / Off Peak $14.13
2021	On Peak $19.90 / Off Peak $14.41
2022	On Peak $20.30 / Off Peak $14.70
2023	On Peak $20.71 / Off Peak $15.00
2024	On Peak $21.12 / Off Peak $15.30

JEA's purchase is from a 60 MW project that is built on an 11,000 acre site. Of the 11,000 acres, only 20 percent will be consumed by the wind turbines.

As discussed in response to Staff's Interrogatory No. 10, JEA issued a Request for Proposal (RFP) for renewable energy, in particular solar and wind resources on March 17, 2008. JEA did not receive any proposals for wind projects.

13. **Please list all purchase power contracts that will expire before the installation date of GEC Combined Cycle Conversion Project. Please list whom the contract is with, expiration date of the contract, amount of capacity lost, and whether JEA has considered renewing the contract.**

Response: A summary of the purchase power contracts that will expire before the installation date of GEC Combined Cycle Conversion Project is provided in Table 1.

Table 1
Response to Staff Interrogatory 13

Contract With	Expiration Date	Summer Capacity MW	Winter Capacity MW	Considered Renewing
Southern Co. UPS Purchase	May 2010	207	207	Yes
Constellation Energy Commodities Group, Inc.	March 2010	None	75 MW in 2008 150 MW in 2009 150 MW in 2010	Yes

14. **Has JEA assessed the availability of purchases from coal or nuclear baseload capacity from other utilities, including those outside of Florida?**

Response: Yes. With regard to coal capacity, as pointed out in the response to Staff's Interrogatory No. 13 JEA has an existing purchase power contract with Southern Company for 207 MW of coal fired capacity and energy. However, this contract will expire at the end of May 2010. JEA inquired about the possibility of renewing or replacing the purchase power contract, but Southern Company was unwilling to offer significant capacity from coal resources.

With regard to nuclear capacity, in June 2008 JEA entered into a PPA with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4, which are proposed new nuclear units to be constructed at the existing Plant Vogtle. After accounting for transmission losses, JEA is anticipated to receive a total of 200 MW from these proposed nuclear units. These units are assumed to be available beginning January 1, 2016 and January 1, 2017 with JEA receiving a net of 100 MW from each unit. This nuclear purchase is further discussed in Section 16.4 of the Greenland Energy Center Need for Power Application.

Both FPL and Progress Energy Florida (PEF) are in the process of licensing new nuclear units to be constructed at the Turkey Point (FPL) and Levy County (PEF) sites. JEA will continue to monitor the progress of and potential to participate in these potential nuclear resources.

15. **How many JEA customers (number and percentage of total customers) are participating in each DSM program that is offered?**

Response: A summary of the JEA customers participating in each quantifiable DSM program offered by JEA for calendar year 2007 as presented in JEA's March 2008 *Demand-Side Management Plan, 2007 Annual Report* (2007 DSM Report) is provided in Table 2. The 2007 DSM Report presents cumulative data beginning with the first year of the term of the numeric conservation goals that have most recently been approved by the Florida Public Service Commission, which is 2005 through 2014. Therefore, participation in DSM prior to 2005 has not been included, and the cumulative percentages shown in Table 2 are understated.

Table 2
Response to Staff's Interrogatory 15

DSM Program Name	Participating Customers 2007	Cumulative Number of Participants 2005 through 2007	Cumulative Percentage of Eligible Customers 2005 through 2007
Residential Energy Audits	2,985	8,985	2.8 %
Green Built Homes of Florida (Energy Star)	139	244	0.08 %
District Chilled Water	1	4	2.0 %
Commercial Energy Audits	213	607	1.5%

During 2007, JEA had 26 customers with interruptible service agreements and 6 customers with curtailable service agreements. JEA has limited participation in its

interruptible and curtailable service programs to this total, and therefore the participating customers represent 100 percent of the eligible customers. The number of participating customers has remained relatively constant since 2001.

During 2008, JEA added a Residential Lighting program that has provided an incentive for over 218,000 CFL bulbs. JEA also added a Neighborhood Efficiency program that provided energy rehabilitation services for 315 low income homes and provided over 100 energy kits for new first time homeowners.

16. **Please provide the number of DSM audits performed in 2007. What percentage of eligible customers have utilized JEA's DSM audits over the past five years?**

Response: In 2007, JEA staff performed 2,985 audits for residential customers and 213 small commercial audits, according to the March 8, 2008 Demand Side Management Plan, 2007 Annual Report. In addition, JEA mailed over 1,600 Home Energy & Water Check up DVD's. Approximately 4 percent of JEA's eligible customers have received audits over the past five years.

17. **Please describe any DSM programs offered by JEA that specifically provide consumer education.**

Response: JEA actively offers and participates in educational events and school activities designed to provide its customers with information about DSM and the DSM programs offered by JEA. Previously, JEA developed and presented formal seminars on DSM; however, attendance at these seminars has dropped to the point that they are no longer sustainable. JEA has replaced the seminars with other educational events targeting residential and commercial customers. Some of these events had primary topics other than energy conservation, but all of these events had conservation literature displayed for the customers attending. Events targeted to commercial customers include an annual business seminar, annual business summit, and a rate education program held on an as needed basis. Events targeted to residential customers include a solar photovoltaic array and display at the zoo and the Home & Patio Show. JEA also utilizes bill inserts; messages; and television, radio, and print advertising discussing DSM to target both residential and commercial customer.

JEA has distributed 64,000 energy conservation and 35,000 water conservation brochures to area schools. JEA has distributed 12,000 energy conservation and 6,000 water conservation brochures through its speaker's bureau and various community events such as Science Nights. JEA has developed an educational partnership with the Tree Hill

Nature Center and the JEA Science Theater and Aqua Expo located in the Museum of Science and History.

Since March 2006, JEA has published *JEA Commercial Connections*, the monthly electronic newsletter and web portal distributed to thousands of JEAs commercial and industrial customers. This resource provides access to industry specific information on benchmarking, best practices, green business, online audits.

18. Does JEA have any plans to expand the consumer education efforts of its DSM plan?

Response: Yes. Throughout its history, JEA has demonstrated a strong commitment to serve its customers' conservation needs. Customer education is part of every DSM program JEA offers. In addition to our existing customer education outreaches, customer education is a component of every new DSM program that JEA offers.

19. Please provide a levelized cost (in $/kWh) for various capacity factors comparing the GEC Combined Cycle Conversion Project, an IGCC unit, a single wind unit, and a roof top PV unit. Please show levelized capital costs and O&M/Fuel costs separately. Also, please provide the raw data and a chart depicting this information.

Response: The following table and graph summarize the levelized costs (in $/kWh) for various capacity factors for the GEC Combined Cycle Conversion Project, an IGCC unit, a single wind unit, and a roof top solar photovoltaic (PV) unit. Data used to estimate the levelized costs for the GEC Combined Cycle Conversion Project is consistent with what is included in Section 9 of the JEA Greenland Energy Center Need for Power Application. Data used to estimate the levelized costs of the IGCC unit, wind turbine unit, and PV unit were taken from the responses to the Florida Public Service Commission's July 14, 2008 RPS Data Request (Tampa Electric, IOU Data Response, and Photovoltaic PDF files) found on the Florida Public Service Commission website (www.floridapsc.com/utilities/electricgas/RenewableEnergy/07_11_2008_Data.aspx).

The capital cost for the GEC Combined Cycle Conversion used in the calculation of levelized costs is taken from Table 9-2 of the JEA Greenland Energy Center Need for Power and is equal to the total project cost less interest during construction (IDC) less *Escalation to Summer 2012 Commercial Operation.* The capital cost for the GEC Combined Cycle Conversion includes owner's costs, while capital costs for the other

resources are overnight costs that do not include IDC or owner's costs. Only one capacity factor (16.34 percent) is shown for the photovoltaic resources, as that was the only capacity factor provided in the input data. The range of capacity factors for the wind resource is based on that included in the RPS Data Request. The range of capacity factors for the GEC Combined Cycle Conversion is consistent with the possible range indicated in Section 9 of the GEC Need for Power Application. The maximum capacity factor for the IGCC resource is consistent with the data in the RPS Data Request.

See the attached sheets labeled Response to Interrogatory # 19 for the input values (raw data) used to calculate the levelized costs shown below. Please note that the total levelized cost shown in the table below may not equal the sum of the levelized capital and levelized O&M/fuel due to rounding.

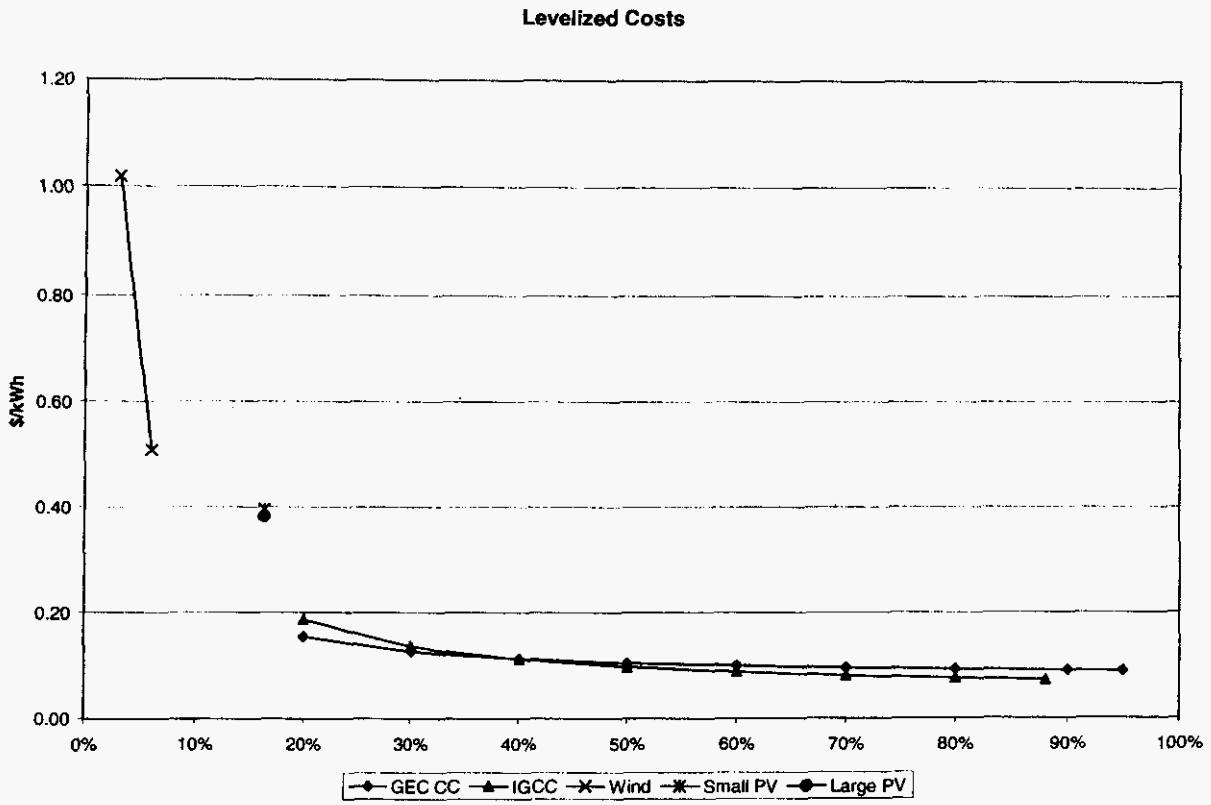
Small Photovoltaic (200 kW)			
Capacity Factor	Levelized Cost 2008$/kWh		
	Capital	O&M/Fuel	Total
16%	0.39	0.01	0.40

Large Photovoltaic (1 MW)			
Capacity Factor	Levelized Cost 2008$/kWh		
	Capital	O&M/Fuel	Total
16%	0.37	0.01	0.38

GEC CC Conversion			
Capacity Factor	Levelized Cost 2008$/kWh		
	Capital	O&M/Fuel	Total
20%	0.07	0.08	0.16
30%	0.05	0.08	0.13
40%	0.04	0.08	0.11
50%	0.03	0.08	0.11
60%	0.02	0.08	0.10
70%	0.02	0.08	0.10
80%	0.02	0.08	0.09
90%	0.02	0.08	0.09
95%	0.01	0.08	0.09

IGCC			
Capacity Factor	Levelized Cost 2008$/kWh		
	Capital	O&M/Fuel	Total
20%	0.15	0.04	0.19
30%	0.10	0.04	0.14
40%	0.07	0.04	0.11
50%	0.06	0.04	0.10
60%	0.05	0.04	0.09
70%	0.04	0.04	0.08
80%	0.04	0.04	0.08
88%	0.03	0.04	0.07

Wind			
Capacity Factor	Levelized Cost 2008$/kWh		
	Capital	O&M/Fuel	Total
3%	0.83	0.19	1.02
6%	0.41	0.10	0.51



It should be noted that the levelized costs shown for the GEC Combined Cycle Conversion include fuel (natural gas) costs based on the expected full load performance. However, the GEC Combined Cycle Conversion will not use more natural gas than the GEC simple cycle combustion turbines prior to conversion (except in instances where the GEC Combined Cycle is operating with supplemental firing) as the combined cycle conversion will utilize the waste heat generated by the simple cycle combustion turbines. Therefore, the levelized costs of the GEC Combined Cycle are actually lower than those shown in the figure above.

GEC Combined Cycle Conversion at 20% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000) *	308,603	First Year Fixed O&M Cost ($/kW-yr)	17.0	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 1,556	First Year Variable O&M ($/MWh)	2.57	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	8.20	
Total Net Output, Avg Ambient Cond. (kW)	198,269			
Capacity Factor	20.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	7,136	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Total Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	24,426	3,380	894	8.20	20,336	0	0	49,036	49,036	7.03	7.08	14.12	7.03	7.08	14.12
2009	24,426	3,465	916	8.74	21,668	0	0	50,475	48,072	7.03	7.50	14.53	6.70	7.14	13.84
2010	24,426	3,551	939	8.51	21,106	0	0	50,023	45,372	7.03	7.37	14.40	6.38	6.68	13.06
2011	24,426	3,640	963	8.42	20,873	0	0	49,901	43,107	7.03	7.33	14.37	6.07	6.34	12.41
2012	24,426	3,731	987	8.70	21,556	0	0	50,699	41,710	7.03	7.56	14.60	5.79	6.22	12.01
2013	24,426	3,824	1,012	8.49	21,056	0	0	50,317	39,425	7.03	7.45	14.49	5.51	5.84	11.35
2014	24,426	3,920	1,037	8.40	20,817	0	0	50,200	37,460	7.03	7.42	14.45	5.25	5.54	10.78
2015	24,426	4,018	1,063	8.39	20,786	0	0	50,293	35,742	7.03	7.45	14.48	5.00	5.29	10.29
2016	24,426	4,118	1,089	8.50	21,081	0	0	50,714	34,325	7.03	7.57	14.60	4.76	5.12	9.88
2017	24,426	4,221	1,117	8.74	21,666	0	0	51,430	33,152	7.03	7.77	14.81	4.53	5.01	9.54
2018	24,426	4,327	1,145	9.02	22,347	0	0	52,244	32,073	7.03	8.01	15.04	4.32	4.92	9.23
2019	24,426	4,435	1,173	9.31	23,086	0	0	53,120	31,058	7.03	8.26	15.29	4.11	4.83	8.94
2020	24,426	4,546	1,202	9.42	23,346	0	0	53,520	29,802	7.03	8.38	15.41	3.92	4.66	8.58
2021	24,426	4,659	1,233	9.50	23,538	0	0	53,856	28,561	7.03	8.47	15.50	3.73	4.49	8.22
2022	24,426	4,776	1,263	9.92	24,592	0	0	55,057	27,808	7.03	8.82	15.85	3.55	4.45	8.01
2023	24,426	4,895	1,295	10.25	25,418	0	0	56,034	26,953	7.03	9.10	16.13	3.38	4.38	7.76
2024	24,426	5,018	1,327	10.69	26,501	0	0	57,272	26,237	7.03	9.46	16.49	3.22	4.33	7.55
2025	24,426	5,143	1,361	11.18	27,702	0	0	58,632	25,581	7.03	9.85	16.88	3.07	4.30	7.36
2026	24,426	5,272	1,395	11.54	28,594	0	0	59,686	24,801	7.03	10.15	17.18	2.92	4.22	7.14
2027	24,426	5,403	1,429	11.98	29,690	0	0	60,949	24,120	7.03	10.51	17.55	2.78	4.16	6.94
2028	24,426	5,539	1,465	12.66	31,392	0	0	62,822	23,677	7.03	11.05	18.09	2.65	4.17	6.82
2029	24,426	5,677	1,502	13.13	32,540	0	0	64,144	23,024	7.03	11.43	18.47	2.52	4.10	6.63
2030	24,426	5,819	1,539	13.70	33,971	0	0	65,755	22,478	7.03	11.90	18.93	2.40	4.07	6.47
2031	24,426	5,964	1,578	14.31	35,466	0	0	67,434	21,954	7.03	12.38	19.41	2.29	4.03	6.32
2032	24,426	6,113	1,617	14.94	37,026	0	0	69,183	21,451	7.03	12.88	19.92	2.18	4.00	6.18
							Net Levelized Bus-bar Cost (c/kWh)						**7.03**	**8.47**	**15.50**
							Net Levelized Cost ($000s)								**53,855**

Note: EPC costs for GEC CC conversion are based on $418,575,000 from Table 9-2 in NFP less IDC ($40,805,000) and Escalation to Summer 2012 Commercial Operation ($69,167,000).

Hearing Exhibit - 00000017

GEC Combined Cycle Conversion at 30% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000) *	308,603	First Year Fixed O&M Cost ($/kW-yr)	17.0	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 1,556	First Year Variable O&M ($/MWh)	2.57	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	8.20	
Total Net Output, Avg Ambient Cond. (kW)	198,269			
Capacity Factor	30.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	7,136	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	24,426	3,380	1,341	8.20	30,504	0	0	59,651	59,651	4.69	6.76	11.45	4.69	6.76	11.45
2009	24,426	3,465	1,375	8.74	32,503	0	0	61,768	58,826	4.69	7.17	11.85	4.46	6.83	11.29
2010	24,426	3,551	1,409	8.51	31,659	0	0	61,045	55,370	4.69	7.03	11.72	4.25	6.37	10.63
2011	24,426	3,640	1,444	8.42	31,309	0	0	60,819	52,538	4.69	6.98	11.67	4.05	6.03	10.08
2012	24,426	3,731	1,480	8.70	32,333	0	0	61,971	50,983	4.69	7.21	11.89	3.86	5.93	9.78
2013	24,426	3,824	1,517	8.49	31,583	0	0	61,351	48,070	4.69	7.09	11.77	3.67	5.55	9.23
2014	24,426	3,920	1,555	8.40	31,225	0	0	61,126	45,613	4.69	7.04	11.73	3.50	5.26	8.75
2015	24,426	4,018	1,594	8.39	31,179	0	0	61,217	43,506	4.69	7.06	11.75	3.33	5.02	8.35
2016	24,426	4,118	1,634	8.50	31,621	0	0	61,799	41,828	4.69	7.17	11.86	3.17	4.85	8.03
2017	24,426	4,221	1,675	8.74	32,499	0	0	62,821	40,495	4.69	7.37	12.06	3.02	4.75	7.77
2018	24,426	4,327	1,717	9.02	33,520	0	0	63,990	39,284	4.69	7.59	12.28	2.88	4.66	7.54
2019	24,426	4,435	1,760	9.31	34,630	0	0	65,250	38,150	4.69	7.83	12.52	2.74	4.58	7.32
2020	24,426	4,546	1,804	9.42	35,019	0	0	65,794	36,637	4.69	7.94	12.63	2.61	4.42	7.03
2021	24,426	4,659	1,849	9.50	35,306	0	0	66,241	35,129	4.69	8.03	12.71	2.49	4.26	6.74
2022	24,426	4,776	1,895	9.92	36,888	0	0	67,985	34,337	4.69	8.36	13.05	2.37	4.22	6.59
2023	24,426	4,895	1,942	10.25	38,127	0	0	69,390	33,378	4.69	8.63	13.32	2.25	4.15	6.41
2024	24,426	5,018	1,991	10.69	39,752	0	0	71,186	32,611	4.69	8.97	13.66	2.15	4.11	6.26
2025	24,426	5,143	2,041	11.18	41,553	0	0	73,163	31,921	4.69	9.35	14.04	2.05	4.08	6.13
2026	24,426	5,272	2,092	11.54	42,891	0	0	74,680	31,031	4.69	9.64	14.33	1.95	4.01	5.96
2027	24,426	5,403	2,144	11.98	44,536	0	0	76,509	30,277	4.69	10.00	14.68	1.86	3.96	5.81
2028	24,426	5,539	2,198	12.66	47,089	0	0	79,251	29,869	4.69	10.52	15.21	1.77	3.97	5.73
2029	24,426	5,677	2,253	13.13	48,809	0	0	81,165	29,134	4.69	10.89	15.58	1.68	3.91	5.59
2030	24,426	5,819	2,309	13.70	50,957	0	0	83,510	28,548	4.69	11.34	16.03	1.60	3.88	5.48
2031	24,426	5,964	2,367	14.31	53,198	0	0	85,955	27,985	4.69	11.81	16.50	1.53	3.84	5.37
2032	24,426	6,113	2,426	14.94	55,539	0	0	88,504	27,442	4.69	12.30	16.99	1.45	3.81	5.27
							Net Levelized Bus-bar Cost (c/kWh)						**4.69**	**8.06**	**12.74**
							Net Levelized Cost ($000s)								**66,399**

Note: EPC costs for GEC CC conversion are based on $418,575,000 from Table 9-2 in NFP less IDC ($40,805,000) and Escalation to Summer 2012 Commercial Operation ($69,167,000).

Hearing Exhibit - 00000018

GEC Combined Cycle Conversion at 40% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000) *	308,603	First Year Fixed O&M Cost ($/kW-yr)	17.0	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 1,556	First Year Variable O&M ($/MWh)	2.57	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	8.20	
Total Net Output, Avg Ambient Cond. (kW)	198,269			
Capacity Factor	40.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	7,136	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	24,426	3,380	1,788	8.20	40,672	0	0	70,266	70,266	3.52	6.60	10.11	3.52	6.60	10.11
2009	24,426	3,465	1,833	8.74	43,337	0	0	73,060	69,581	3.52	7.00	10.52	3.35	6.67	10.02
2010	24,426	3,551	1,879	8.51	42,213	0	0	72,068	65,368	3.52	6.86	10.37	3.19	6.22	9.41
2011	24,426	3,640	1,926	8.42	41,745	0	0	71,737	61,969	3.52	6.81	10.33	3.04	5.88	8.92
2012	24,426	3,731	1,974	8.70	43,111	0	0	73,242	60,256	3.52	7.03	10.54	2.89	5.78	8.67
2013	24,426	3,824	2,023	8.49	42,111	0	0	72,384	56,715	3.52	6.90	10.42	2.75	5.41	8.16
2014	24,426	3,920	2,074	8.40	41,634	0	0	72,053	53,767	3.52	6.86	10.37	2.62	5.12	7.74
2015	24,426	4,018	2,126	8.39	41,572	0	0	72,142	51,270	3.52	6.87	10.38	2.50	4.88	7.38
2016	24,426	4,118	2,179	8.50	42,162	0	0	72,885	49,331	3.52	6.98	10.49	2.38	4.72	7.10
2017	24,426	4,221	2,233	8.74	43,333	0	0	74,213	47,838	3.52	7.17	10.68	2.27	4.62	6.89
2018	24,426	4,327	2,289	9.02	44,694	0	0	75,735	46,495	3.52	7.39	10.90	2.16	4.53	6.69
2019	24,426	4,435	2,346	9.31	46,173	0	0	77,380	45,243	3.52	7.62	11.14	2.06	4.46	6.51
2020	24,426	4,546	2,405	9.42	46,692	0	0	78,068	43,471	3.52	7.72	11.24	1.96	4.30	6.26
2021	24,426	4,659	2,465	9.50	47,075	0	0	78,626	41,697	3.52	7.80	11.32	1.86	4.14	6.00
2022	24,426	4,776	2,527	9.92	49,185	0	0	80,913	40,867	3.52	8.13	11.65	1.78	4.11	5.88
2023	24,426	4,895	2,590	10.25	50,836	0	0	82,747	39,803	3.52	8.39	11.91	1.69	4.04	5.73
2024	24,426	5,018	2,655	10.69	53,002	0	0	85,100	38,985	3.52	8.73	12.25	1.61	4.00	5.61
2025	24,426	5,143	2,721	11.18	55,404	0	0	87,694	38,261	3.52	9.11	12.62	1.53	3.97	5.51
2026	24,426	5,272	2,789	11.54	57,188	0	0	89,674	37,262	3.52	9.39	12.91	1.46	3.90	5.36
2027	24,426	5,403	2,859	11.98	59,381	0	0	92,069	36,435	3.52	9.74	13.25	1.39	3.85	5.24
2028	24,426	5,539	2,930	12.66	62,785	0	0	95,680	36,061	3.52	10.26	13.77	1.33	3.87	5.19
2029	24,426	5,677	3,003	13.13	65,079	0	0	98,186	35,243	3.52	10.62	14.13	1.26	3.81	5.07
2030	24,426	5,819	3,079	13.70	67,942	0	0	101,266	34,618	3.52	11.06	14.58	1.20	3.78	4.98
2031	24,426	5,964	3,156	14.31	70,931	0	0	104,477	34,015	3.52	11.52	15.04	1.14	3.75	4.90
2032	24,426	6,113	3,234	14.94	74,052	0	0	107,826	33,433	3.52	12.00	15.52	1.09	3.72	4.81
								Net Levelized Bus-bar Cost (c/kWh)					**3.52**	**7.85**	**11.36**
								Net Levelized Cost ($000s)							**78,943**

Note: EPC costs for GEC CC conversion are based on $418,575,000 from Table 9-2 in NFP less IDC ($40,805,000) and Escalation to Summer 2012 Commercial Operation ($69,167,000).

Hearing Exhibit - 00000019

GEC Combined Cycle Conversion at 50% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000) *	308,603	First Year Fixed O&M Cost ($/kW-yr)	17.0	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 1,556	First Year Variable O&M ($/MWh)	2.57	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	8.20	
Total Net Output, Avg Ambient Cond. (kW)	198,269			
Capacity Factor	50.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	7,136	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	24,426	3,380	2,235	8.20	50,840	0	0	80,881	80,881	2.81	6.50	9.31	2.81	6.50	9.31
2009	24,426	3,465	2,291	8.74	54,171	0	0	84,352	80,336	2.81	6.90	9.71	2.68	6.57	9.25
2010	24,426	3,551	2,348	8.51	52,766	0	0	83,091	75,366	2.81	6.76	9.57	2.55	6.13	8.68
2011	24,426	3,640	2,407	8.42	52,182	0	0	82,655	71,400	2.81	6.71	9.52	2.43	5.79	8.22
2012	24,426	3,731	2,467	8.70	53,889	0	0	84,513	69,529	2.81	6.92	9.73	2.31	5.69	8.01
2013	24,426	3,824	2,529	8.49	52,639	0	0	83,418	65,360	2.81	6.79	9.61	2.20	5.32	7.53
2014	24,426	3,920	2,592	8.40	52,042	0	0	82,980	61,921	2.81	6.74	9.56	2.10	5.03	7.13
2015	24,426	4,018	2,657	8.39	51,965	0	0	83,066	59,034	2.81	6.75	9.57	2.00	4.80	6.80
2016	24,426	4,118	2,723	8.50	52,702	0	0	83,970	56,834	2.81	6.86	9.67	1.90	4.64	6.54
2017	24,426	4,221	2,792	8.74	54,166	0	0	85,604	55,181	2.81	7.04	9.86	1.81	4.54	6.35
2018	24,426	4,327	2,861	9.02	55,867	0	0	87,481	53,706	2.81	7.26	10.07	1.73	4.46	6.18
2019	24,426	4,435	2,933	9.31	57,716	0	0	89,510	52,335	2.81	7.49	10.31	1.64	4.38	6.03
2020	24,426	4,546	3,006	9.42	58,365	0	0	90,343	50,306	2.81	7.59	10.40	1.57	4.23	5.79
2021	24,426	4,659	3,081	9.50	58,844	0	0	91,011	48,265	2.81	7.67	10.48	1.49	4.07	5.56
2022	24,426	4,776	3,158	9.92	61,481	0	0	93,841	47,396	2.81	7.99	10.81	1.42	4.04	5.46
2023	24,426	4,895	3,237	10.25	63,545	0	0	96,103	46,227	2.81	8.25	11.07	1.35	3.97	5.32
2024	24,426	5,018	3,318	10.69	66,253	0	0	99,015	45,360	2.81	8.59	11.40	1.29	3.93	5.22
2025	24,426	5,143	3,401	11.18	69,255	0	0	102,226	44,601	2.81	8.96	11.77	1.23	3.91	5.14
2026	24,426	5,272	3,486	11.54	71,485	0	0	104,669	43,492	2.81	9.24	12.05	1.17	3.84	5.01
2027	24,426	5,403	3,573	11.98	74,226	0	0	107,629	42,592	2.81	9.58	12.39	1.11	3.79	4.90
2028	24,426	5,539	3,663	12.66	78,481	0	0	112,108	42,252	2.81	10.10	12.91	1.06	3.81	4.87
2029	24,426	5,677	3,754	13.13	81,349	0	0	115,206	41,352	2.81	10.45	13.27	1.01	3.75	4.76
2030	24,426	5,819	3,848	13.70	84,928	0	0	119,021	40,687	2.81	10.89	13.71	0.96	3.72	4.69
2031	24,426	5,964	3,944	14.31	88,664	0	0	122,999	40,045	2.81	11.35	14.16	0.92	3.70	4.61
2032	24,426	6,113	4,043	14.94	92,565	0	0	127,147	39,424	2.81	11.83	14.64	0.87	3.67	4.54
								Net Levelized Bus-bar Cost (c/kWh)					**2.81**	**7.72**	**10.53**
								Net Levelized Cost ($000s)							**91,487**

Note: EPC costs for GEC CC conversion are based on $418,575,000 from Table 9-2 in NFP less IDC ($40,805,000) and Escalation to Summer 2012 Commercial Operation ($69,167,000).

Hearing Exhibit - 00000020

GEC Combined Cycle Conversion at 60% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000) *	308,603	First Year Fixed O&M Cost ($/kW-yr)	17.0	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 1,556	First Year Variable O&M ($/MWh)	2.57	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	8.20	
Total Net Output, Avg Ambient Cond. (kW)	198,269			
Capacity Factor	60.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	7.136	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	24,426	3,380	2,682	8.20	61,008	0	0	91,496	91,496	2.34	6.44	8.78	2.34	6.44	8.78
2009	24,426	3,465	2,749	8.74	65,005	0	0	95,645	91,090	2.34	6.83	9.18	2.23	6.51	8.74
2010	24,426	3,551	2,818	8.51	63,319	0	0	94,114	85,364	2.34	6.69	9.03	2.13	6.07	8.19
2011	24,426	3,640	2,889	8.42	62,618	0	0	93,573	80,832	2.34	6.64	8.98	2.02	5.73	7.76
2012	24,426	3,731	2,961	8.70	64,667	0	0	95,784	78,802	2.34	6.85	9.19	1.93	5.63	7.56
2013	24,426	3,824	3,035	8.49	63,167	0	0	94,452	74,005	2.34	6.72	9.06	1.84	5.27	7.10
2014	24,426	3,920	3,111	8.40	62,451	0	0	93,907	70,075	2.34	6.67	9.01	1.75	4.98	6.72
2015	24,426	4,018	3,188	8.39	62,359	0	0	93,991	66,797	2.34	6.68	9.02	1.67	4.74	6.41
2016	24,426	4,118	3,268	8.50	63,242	0	0	95,055	64,337	2.34	6.78	9.12	1.59	4.59	6.17
2017	24,426	4,221	3,350	8.74	64,999	0	0	96,996	62,524	2.34	6.96	9.31	1.51	4.49	6.00
2018	24,426	4,327	3,434	9.02	67,041	0	0	99,227	60,917	2.34	7.18	9.52	1.44	4.41	5.85
2019	24,426	4,435	3,519	9.31	69,259	0	0	101,640	59,427	2.34	7.41	9.75	1.37	4.33	5.70
2020	24,426	4,546	3,607	9.42	70,038	0	0	102,617	57,141	2.34	7.50	9.85	1.31	4.18	5.48
2021	24,426	4,659	3,698	9.50	70,613	0	0	103,396	54,833	2.34	7.58	9.92	1.24	4.02	5.26
2022	24,426	4,776	3,790	9.92	73,777	0	0	106,769	53,925	2.34	7.90	10.25	1.18	3.99	5.17
2023	24,426	4,895	3,885	10.25	76,254	0	0	109,460	52,652	2.34	8.16	10.50	1.13	3.93	5.05
2024	24,426	5,018	3,982	10.69	79,503	0	0	112,929	51,734	2.34	8.49	10.84	1.07	3.89	4.96
2025	24,426	5,143	4,082	11.18	83,106	0	0	116,757	50,941	2.34	8.86	11.20	1.02	3.87	4.89
2026	24,426	5,272	4,184	11.54	85,782	0	0	119,663	49,722	2.34	9.14	11.48	0.97	3.80	4.77
2027	24,426	5,403	4,288	11.98	89,071	0	0	123,189	48,750	2.34	9.48	11.82	0.93	3.75	4.68
2028	24,426	5,539	4,395	12.66	94,177	0	0	128,537	48,444	2.34	9.99	12.33	0.88	3.77	4.65
2029	24,426	5,677	4,505	13.13	97,619	0	0	132,227	47,462	2.34	10.34	12.69	0.84	3.71	4.55
2030	24,426	5,819	4,618	13.70	101,913	0	0	136,776	46,757	2.34	10.78	13.13	0.80	3.69	4.49
2031	24,426	5,964	4,733	14.31	106,397	0	0	141,520	46,075	2.34	11.24	13.58	0.76	3.66	4.42
2032	24,426	6,113	4,852	14.94	111,078	0	0	146,469	45,415	2.34	11.71	14.06	0.73	3.63	4.36
								Net Levelized Bus-bar Cost (c/kWh)					**2.34**	**7.64**	**9.98**
								Net Levelized Cost ($000s)							**104,031**

Note: EPC costs for GEC CC conversion are based on $418,575,000 from Table 9-2 in NFP less IDC ($40,805,000) and Escalation to Summer 2012 Commercial Operation ($69,167,000).

Hearing Exhibit - 00000021

GEC Combined Cycle Conversion at 70% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000) *	308,603	First Year Fixed O&M Cost ($/kW-yr)	17.0	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 1,556	First Year Variable O&M ($/MWh)	2.57	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	8.20	
Total Net Output, Avg Ambient Cond. (kW)	198,269			
Capacity Factor	70.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	7,136	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	24,426	3,380	3,129	8.20	71,176	0	0	102,111	102,111	2.01	6.39	8.40	2.01	6.39	8.40
2009	24,426	3,465	3,208	8.74	75,839	0	0	106,937	101,845	2.01	6.79	8.80	1.91	6.46	8.38
2010	24,426	3,551	3,288	8.51	73,872	0	0	105,137	95,362	2.01	6.64	8.65	1.82	6.02	7.84
2011	24,426	3,640	3,370	8.42	73,055	0	0	104,490	90,263	2.01	6.59	8.59	1.74	5.69	7.42
2012	24,426	3,731	3,454	8.70	75,444	0	0	107,056	88,075	2.01	6.80	8.81	1.65	5.59	7.24
2013	24,426	3,824	3,541	8.49	73,694	0	0	105,485	82,650	2.01	6.67	8.68	1.57	5.22	6.80
2014	24,426	3,920	3,629	8.40	72,859	0	0	104,834	78,229	2.01	6.61	8.62	1.50	4.94	6.43
2015	24,426	4,018	3,720	8.39	72,752	0	0	104,915	74,561	2.01	6.62	8.63	1.43	4.70	6.13
2016	24,426	4,118	3,813	8.50	73,783	0	0	106,140	71,840	2.01	6.72	8.73	1.36	4.55	5.91
2017	24,426	4,221	3,908	8.74	75,832	0	0	108,387	69,867	2.01	6.91	8.92	1.30	4.45	5.75
2018	24,426	4,327	4,006	9.02	78,214	0	0	110,972	68,127	2.01	7.12	9.13	1.23	4.37	5.60
2019	24,426	4,435	4,106	9.31	80,803	0	0	113,769	66,519	2.01	7.35	9.36	1.17	4.30	5.47
2020	24,426	4,546	4,209	9.42	81,711	0	0	114,891	63,976	2.01	7.44	9.45	1.12	4.14	5.26
2021	24,426	4,659	4,314	9.50	82,382	0	0	115,781	61,401	2.01	7.51	9.52	1.07	3.98	5.05
2022	24,426	4,776	4,422	9.92	86,073	0	0	119,697	60,455	2.01	7.84	9.85	1.01	3.96	4.97
2023	24,426	4,895	4,532	10.25	88,963	0	0	122,816	59,077	2.01	8.09	10.10	0.97	3.89	4.86
2024	24,426	5,018	4,646	10.69	92,754	0	0	126,843	58,108	2.01	8.42	10.43	0.92	3.86	4.78
2025	24,426	5,143	4,762	11.18	96,957	0	0	131,288	57,281	2.01	8.79	10.80	0.88	3.83	4.71
2026	24,426	5,272	4,881	11.54	100,079	0	0	134,657	55,953	2.01	9.07	11.08	0.83	3.77	4.60
2027	24,426	5,403	5,003	11.98	103,917	0	0	138,749	54,908	2.01	9.40	11.41	0.80	3.72	4.52
2028	24,426	5,539	5,128	12.66	109,874	0	0	144,966	54,636	2.01	9.91	11.92	0.76	3.74	4.49
2029	24,426	5,677	5,256	13.13	113,889	0	0	149,248	53,571	2.01	10.27	12.28	0.72	3.69	4.41
2030	24,426	5,819	5,388	13.70	118,899	0	0	154,531	52,826	2.01	10.70	12.71	0.69	3.66	4.35
2031	24,426	5,964	5,522	14.31	124,130	0	0	160,042	52,105	2.01	11.15	13.16	0.65	3.63	4.29
2032	24,426	6,113	5,660	14.94	129,591	0	0	165,790	51,406	2.01	11.63	13.64	0.62	3.61	4.23
								Net Levelized Bus-bar Cost (c/kWh)					**2.01**	**7.58**	**9.59**
								Net Levelized Cost ($000s)							**116,575**

Note: EPC costs for GEC CC conversion are based on $418,575,000 from Table 9-2 in NFP less IDC ($40,805,000) and Escalation to Summer 2012 Commercial Operation ($69,167,000).

Hearing Exhibit - 00000022

GEC Combined Cycle Conversion at 80% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000) *	308,603	First Year Fixed O&M Cost ($/kW-yr)	17.0	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 1,556	First Year Variable O&M ($/MWh)	2.57	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	8.20	
Total Net Output, Avg Ambient Cond. (kW)	198,269			
Capacity Factor	80.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	7,136	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	24,426	3,380	3,576	8.20	81,344	0	0	112,726	112,726	1.76	6.35	8.11	1.76	6.35	8.11
2009	24,426	3,465	3,666	8.74	86,673	0	0	118,230	112,600	1.76	6.75	8.51	1.67	6.43	8.10
2010	24,426	3,551	3,758	8.51	84,425	0	0	116,160	105,360	1.76	6.60	8.36	1.59	5.99	7.58
2011	24,426	3,640	3,851	8.42	83,491	0	0	115,408	99,694	1.76	6.55	8.31	1.52	5.66	7.17
2012	24,426	3,731	3,948	8.70	86,222	0	0	118,327	97,348	1.76	6.76	8.52	1.45	5.56	7.01
2013	24,426	3,824	4,046	8.49	84,222	0	0	116,519	91,295	1.76	6.63	8.39	1.38	5.19	6.57
2014	24,426	3,920	4,148	8.40	83,268	0	0	115,761	86,383	1.76	6.57	8.33	1.31	4.91	6.22
2015	24,426	4,018	4,251	8.39	83,145	0	0	115,840	82,325	1.76	6.58	8.34	1.25	4.68	5.92
2016	24,426	4,118	4,358	8.50	84,323	0	0	117,225	79,342	1.76	6.68	8.44	1.19	4.52	5.71
2017	24,426	4,221	4,467	8.74	86,665	0	0	119,779	77,210	1.76	6.86	8.62	1.13	4.42	5.56
2018	24,426	4,327	4,578	9.02	89,387	0	0	122,718	75,338	1.76	7.07	8.83	1.08	4.34	5.42
2019	24,426	4,435	4,693	9.31	92,346	0	0	125,899	73,611	1.76	7.30	9.06	1.03	4.27	5.30
2020	24,426	4,546	4,810	9.42	93,384	0	0	127,165	70,810	1.76	7.39	9.15	0.98	4.12	5.10
2021	24,426	4,659	4,930	9.50	94,151	0	0	128,166	67,969	1.76	7.47	9.22	0.93	3.96	4.89
2022	24,426	4,776	5,053	9.92	98,369	0	0	132,624	66,984	1.76	7.79	9.54	0.89	3.93	4.82
2023	24,426	4,895	5,180	10.25	101,672	0	0	136,173	65,501	1.76	8.04	9.80	0.85	3.87	4.71
2024	24,426	5,018	5,309	10.69	106,004	0	0	140,757	64,482	1.76	8.37	10.13	0.81	3.84	4.64
2025	24,426	5,143	5,442	11.18	110,808	0	0	145,819	63,621	1.76	8.74	10.49	0.77	3.81	4.58
2026	24,426	5,272	5,578	11.54	114,376	0	0	149,651	62,183	1.76	9.01	10.77	0.73	3.74	4.48
2027	24,426	5,403	5,718	11.98	118,762	0	0	154,309	61,065	1.76	9.35	11.11	0.70	3.70	4.39
2028	24,426	5,539	5,860	12.66	125,570	0	0	161,395	60,828	1.76	9.86	11.62	0.66	3.72	4.38
2029	24,426	5,677	6,007	13.13	130,159	0	0	166,268	59,681	1.76	10.21	11.97	0.63	3.66	4.30
2030	24,426	5,819	6,157	13.70	135,884	0	0	172,286	58,896	1.76	10.64	12.40	0.60	3.64	4.24
2031	24,426	5,964	6,311	14.31	141,862	0	0	178,564	58,135	1.76	11.09	12.85	0.57	3.61	4.18
2032	24,426	6,113	6,469	14.94	148,104	0	0	185,112	57,397	1.76	11.56	13.32	0.55	3.59	4.13
								Net Levelized Bus-bar Cost (c/kWh)					**1.76**	**7.53**	**9.29**
								Net Levelized Cost ($000s)							**129,119**

Note: EPC costs for GEC CC conversion are based on $418,575,000 from Table 9-2 in NFP less IDC ($40,805,000) and Escalation to Summer 2012 Commercial Operation ($69,167,000).

Hearing Exhibit - 00000023

GEC Combined Cycle Conversion at 90% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000) *	308,603	First Year Fixed O&M Cost ($/kW-yr)	17.0	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 1,556	First Year Variable O&M ($/MWh)	2.57	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	8.20	
Total Net Output, Avg Ambient Cond. (kW)	198,269			
Capacity Factor	90.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	7,136	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	24,426	3,380	4,024	8.20	91,512	0	0	123,341	123,341	1.56	6.33	7.89	1.56	6.33	7.89
2009	24,426	3,465	4,124	8.74	97,508	0	0	129,522	123,354	1.56	6.72	8.29	1.49	6.40	7.89
2010	24,426	3,551	4,227	8.51	94,978	0	0	127,182	115,358	1.56	6.57	8.14	1.42	5.96	7.38
2011	24,426	3,640	4,333	8.42	93,927	0	0	126,326	109,125	1.56	6.52	8.08	1.35	5.63	6.98
2012	24,426	3,731	4,441	8.70	97,000	0	0	129,598	106,621	1.56	6.73	8.29	1.29	5.54	6.82
2013	24,426	3,824	4,552	8.49	94,750	0	0	127,552	99,941	1.56	6.60	8.16	1.22	5.17	6.39
2014	24,426	3,920	4,666	8.40	93,676	0	0	126,688	94,536	1.56	6.54	8.10	1.17	4.88	6.05
2015	24,426	4,018	4,783	8.39	93,538	0	0	126,764	90,089	1.56	6.55	8.11	1.11	4.65	5.76
2016	24,426	4,118	4,902	8.50	94,864	0	0	128,310	86,845	1.56	6.65	8.21	1.06	4.50	5.56
2017	24,426	4,221	5,025	8.74	97,498	0	0	131,170	84,554	1.56	6.83	8.39	1.01	4.40	5.41
2018	24,426	4,327	5,150	9.02	100,561	0	0	134,464	82,549	1.56	7.04	8.60	0.96	4.32	5.28
2019	24,426	4,435	5,279	9.31	103,889	0	0	138,029	80,703	1.56	7.27	8.83	0.91	4.25	5.16
2020	24,426	4,546	5,411	9.42	105,057	0	0	139,440	77,645	1.56	7.36	8.92	0.87	4.10	4.97
2021	24,426	4,659	5,546	9.50	105,919	0	0	140,551	74,537	1.56	7.43	8.99	0.83	3.94	4.77
2022	24,426	4,776	5,685	9.92	110,665	0	0	145,552	73,514	1.56	7.75	9.31	0.79	3.91	4.70
2023	24,426	4,895	5,827	10.25	114,381	0	0	149,529	71,926	1.56	8.00	9.57	0.75	3.85	4.60
2024	24,426	5,018	5,973	10.69	119,255	0	0	154,671	70,857	1.56	8.33	9.89	0.72	3.82	4.53
2025	24,426	5,143	6,122	11.18	124,660	0	0	160,351	69,961	1.56	8.70	10.26	0.68	3.79	4.48
2026	24,426	5,272	6,275	11.54	128,672	0	0	164,645	68,414	1.56	8.97	10.53	0.65	3.73	4.38
2027	24,426	5,403	6,432	11.98	133,607	0	0	169,869	67,223	1.56	9.30	10.87	0.62	3.68	4.30
2028	24,426	5,539	6,593	12.66	141,266	0	0	177,824	67,020	1.56	9.81	11.38	0.59	3.70	4.29
2029	24,426	5,677	6,758	13.13	146,428	0	0	183,289	65,790	1.56	10.16	11.73	0.56	3.65	4.21
2030	24,426	5,819	6,927	13.70	152,870	0	0	190,042	64,966	1.56	10.59	12.16	0.53	3.62	4.16
2031	24,426	5,964	7,100	14.31	159,595	0	0	197,086	64,165	1.56	11.05	12.61	0.51	3.60	4.10
2032	24,426	6,113	7,277	14.94	166,617	0	0	204,434	63,388	1.56	11.52	13.08	0.48	3.57	4.06
								Net Levelized Bus-bar Cost (c/kWh)					**1.56**	**7.50**	**9.06**
								Net Levelized Cost ($000s)							**141,663**

Note: EPC costs for GEC CC conversion are based on $418,575,000 from Table 9-2 in NFP less IDC ($40,805,000) and Escalation to Summer 2012 Commercial Operation ($69,167,000).

Hearing Exhibit - 00000024

GEC Combined Cycle Conversion at 95% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000) *	308,603	First Year Fixed O&M Cost ($/kW-yr)	17.0	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 1,556	First Year Variable O&M ($/MWh)	2.57	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	8.20	
Total Net Output, Avg Ambient Cond. (kW)	198,269			
Capacity Factor	95.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	7,136	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	24,426	3,380	4,247	8.20	96,596	0	0	128,649	128,649	1.48	6.32	7.80	1.48	6.32	7.80
2009	24,426	3,465	4,353	8.74	102,925	0	0	135,168	128,732	1.48	6.71	8.19	1.41	6.39	7.80
2010	24,426	3,551	4,462	8.51	100,255	0	0	132,694	120,357	1.48	6.56	8.04	1.34	5.95	7.29
2011	24,426	3,640	4,574	8.42	99,145	0	0	131,785	113,841	1.48	6.51	7.99	1.28	5.62	6.90
2012	24,426	3,731	4,688	8.70	102,389	0	0	135,234	111,257	1.48	6.72	8.20	1.22	5.52	6.74
2013	24,426	3,824	4,805	8.49	100,014	0	0	133,069	104,263	1.48	6.58	8.06	1.16	5.16	6.32
2014	24,426	3,920	4,925	8.40	98,880	0	0	132,151	98,613	1.48	6.53	8.01	1.10	4.87	5.98
2015	24,426	4,018	5,048	8.39	98,734	0	0	132,227	93,971	1.48	6.53	8.01	1.05	4.64	5.70
2016	24,426	4,118	5,175	8.50	100,134	0	0	133,853	90,597	1.48	6.63	8.11	1.00	4.49	5.49
2017	24,426	4,221	5,304	8.74	102,915	0	0	136,866	88,225	1.48	6.81	8.29	0.95	4.39	5.35
2018	24,426	4,327	5,437	9.02	106,147	0	0	140,337	86,155	1.48	7.02	8.51	0.91	4.31	5.22
2019	24,426	4,435	5,573	9.31	109,661	0	0	144,094	84,249	1.48	7.25	8.73	0.87	4.24	5.11
2020	24,426	4,546	5,712	9.42	110,893	0	0	145,577	81,063	1.48	7.34	8.82	0.82	4.09	4.91
2021	24,426	4,659	5,855	9.50	111,804	0	0	146,744	77,821	1.48	7.41	8.89	0.79	3.93	4.72
2022	24,426	4,776	6,001	9.92	116,813	0	0	152,016	76,778	1.48	7.73	9.21	0.75	3.91	4.65
2023	24,426	4,895	6,151	10.25	120,735	0	0	156,207	75,138	1.48	7.99	9.47	0.71	3.84	4.55
2024	24,426	5,018	6,305	10.69	125,880	0	0	161,628	74,044	1.48	8.32	9.80	0.68	3.81	4.49
2025	24,426	5,143	6,462	11.18	131,585	0	0	167,616	73,131	1.48	8.68	10.16	0.65	3.79	4.43
2026	24,426	5,272	6,624	11.54	135,821	0	0	172,142	71,529	1.48	8.95	10.43	0.62	3.72	4.34
2027	24,426	5,403	6,790	11.98	141,030	0	0	177,649	70,302	1.48	9.29	10.77	0.59	3.67	4.26
2028	24,426	5,539	6,959	12.66	149,114	0	0	186,038	70,116	1.48	9.79	11.28	0.56	3.69	4.25
2029	24,426	5,677	7,133	13.13	154,563	0	0	191,800	68,845	1.48	10.14	11.62	0.53	3.64	4.17
2030	24,426	5,819	7,312	13.70	161,363	0	0	198,919	68,001	1.48	10.58	12.06	0.51	3.62	4.12
2031	24,426	5,964	7,494	14.31	168,462	0	0	206,346	67,180	1.48	11.03	12.51	0.48	3.59	4.07
2032	24,426	6,113	7,682	14.94	175,873	0	0	214,094	66,384	1.48	11.50	12.98	0.46	3.56	4.02
								Net Levelized Bus-bar Cost (c/kWh)					**1.48**	**7.49**	**8.97**
								Net Levelized Cost ($000s)							**147,935**

Note: EPC costs for GEC CC conversion are based on $418,575,000 from Table 9-2 in NFP less IDC ($40,805,000) and Escalation to Summer 2012 Commercial Operation ($69,167,000).

Hearing Exhibit - 00000025

IGCC at 20% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	1,985,862	First Year Fixed O&M Cost ($/kW-yr)	0.03	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 3,277	First Year Variable O&M ($/MWh)	6.02	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	2.39	
Total Net Output, Avg Ambient Cond. (kW)	606,000			
Capacity Factor	20.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	9,137	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	157,181	18	6,392	2.39	23,141	0	0	186,732	186,732	14.80	2.78	17.59	14.80	2.78	17.59
2009	157,181	19	6,551	2.56	24,857	0	0	188,608	179,627	14.80	2.96	17.76	14.10	2.82	16.92
2010	157,181	19	6,715	2.75	26,652	0	0	190,568	172,850	14.80	3.14	17.95	13.43	2.85	16.28
2011	157,181	20	6,883	2.85	27,658	0	0	191,742	165,634	14.80	3.26	18.06	12.79	2.81	15.60
2012	157,181	20	7,055	2.93	28,410	0	0	192,666	158,507	14.80	3.34	18.15	12.18	2.75	14.93
2013	157,181	21	7,231	3.00	29,105	0	0	193,538	151,642	14.80	3.42	18.23	11.60	2.68	14.28
2014	157,181	21	7,412	3.08	29,860	0	0	194,474	145,120	14.80	3.51	18.32	11.05	2.62	13.67
2015	157,181	22	7,597	3.14	30,430	0	0	195,230	138,746	14.80	3.58	18.39	10.52	2.55	13.07
2016	157,181	22	7,787	3.22	31,256	0	0	196,247	132,828	14.80	3.68	18.48	10.02	2.49	12.51
2017	157,181	23	7,982	3.31	32,067	0	0	197,253	127,151	14.80	3.77	18.58	9.54	2.43	11.98
2018	157,181	23	8,182	3.36	32,605	0	0	197,991	121,549	14.80	3.84	18.65	9.09	2.36	11.45
2019	157,181	24	8,386	3.47	33,636	0	0	199,227	116,484	14.80	3.96	18.76	8.66	2.32	10.97
2020	157,181	24	8,596	3.55	34,416	0	0	200,217	111,488	14.80	4.05	18.86	8.24	2.26	10.50
2021	157,181	25	8,811	3.63	35,206	0	0	201,223	106,713	14.80	4.15	18.95	7.85	2.20	10.05
2022	157,181	26	9,031	3.77	36,524	0	0	202,762	102,408	14.80	4.29	19.10	7.48	2.17	9.65
2023	157,181	26	9,257	3.88	37,611	0	0	204,075	98,164	14.80	4.42	19.22	7.12	2.12	9.25
2024	157,181	27	9,488	4.01	38,905	0	0	205,602	94,188	14.80	4.56	19.37	6.78	2.09	8.87
2025	157,181	28	9,725	4.15	40,213	0	0	207,147	90,378	14.80	4.71	19.51	6.46	2.05	8.51
2026	157,181	28	9,969	4.28	41,564	0	0	208,742	86,737	14.80	4.86	19.66	6.15	2.02	8.17
2027	157,181	29	10,218	4.43	42,961	0	0	210,389	83,258	14.80	5.01	19.82	5.86	1.98	7.84
2028	157,181	30	10,473	4.58	44,405	0	0	212,089	79,934	14.80	5.17	19.98	5.58	1.95	7.53
2029	157,181	31	10,735	4.73	45,897	0	0	213,843	76,757	14.80	5.34	20.14	5.31	1.92	7.23
2030	157,181	31	11,003	4.89	47,439	0	0	215,655	73,722	14.80	5.51	20.31	5.06	1.88	6.94
2031	157,181	32	11,279	5.05	49,033	0	0	217,525	70,820	14.80	5.68	20.49	4.82	1.85	6.67
2032	157,181	33	11,560	5.22	50,681	0	0	219,455	68,046	14.80	5.87	20.67	4.59	1.82	6.41
								Net Levelized Bus-bar Cost (c/kWh)					**14.80**	**3.90**	**18.71**
								Net Levelized Cost ($000s)							**198,632**

Hearing Exhibit - 00000026

IGCC at 30% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	1,985,862	First Year Fixed O&M Cost ($/kW-yr)	0.03	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 3,277	First Year Variable O&M ($/MWh)	6.02	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	2.39	
Total Net Output, Avg Ambient Cond. (kW)	606,000			
Capacity Factor	30.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	9,137	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	157,181	18	9,587	2.39	34,712	0	0	201,498	201,498	9.87	2.78	12.65	9.87	2.78	12.65
2009	157,181	19	9,827	2.56	37,286	0	0	204,313	194,584	9.87	2.96	12.83	9.40	2.82	12.22
2010	157,181	19	10,073	2.75	39,979	0	0	207,251	187,983	9.87	3.14	13.01	8.95	2.85	11.80
2011	157,181	20	10,324	2.85	41,488	0	0	209,013	180,553	9.87	3.25	13.12	8.53	2.81	11.34
2012	157,181	20	10,583	2.93	42,615	0	0	210,398	173,095	9.87	3.34	13.21	8.12	2.75	10.87
2013	157,181	21	10,847	3.00	43,658	0	0	211,706	165,877	9.87	3.42	13.29	7.73	2.68	10.42
2014	157,181	21	11,118	3.08	44,790	0	0	213,110	159,026	9.87	3.51	13.38	7.36	2.62	9.99
2015	157,181	22	11,396	3.14	45,645	0	0	214,244	152,259	9.87	3.58	13.45	7.01	2.55	9.56
2016	157,181	22	11,681	3.22	46,885	0	0	215,769	146,041	9.87	3.68	13.55	6.68	2.49	9.17
2017	157,181	23	11,973	3.31	48,101	0	0	217,278	140,059	9.87	3.77	13.64	6.36	2.43	8.79
2018	157,181	23	12,273	3.36	48,907	0	0	218,384	134,069	9.87	3.84	13.71	6.06	2.36	8.42
2019	157,181	24	12,579	3.47	50,454	0	0	220,238	128,769	9.87	3.96	13.83	5.77	2.32	8.09
2020	157,181	24	12,894	3.55	51,624	0	0	221,723	123,464	9.87	4.05	13.92	5.50	2.26	7.75
2021	157,181	25	13,216	3.63	52,810	0	0	223,232	118,385	9.87	4.15	14.02	5.23	2.20	7.43
2022	157,181	26	13,547	3.77	54,786	0	0	225,539	113,913	9.87	4.29	14.16	4.98	2.17	7.15
2023	157,181	26	13,885	3.88	56,417	0	0	227,509	109,436	9.87	4.42	14.29	4.75	2.12	6.87
2024	157,181	27	14,232	4.01	58,358	0	0	229,798	105,273	9.87	4.56	14.43	4.52	2.09	6.61
2025	157,181	28	14,588	4.15	60,319	0	0	232,116	101,271	9.87	4.71	14.57	4.31	2.05	6.36
2026	157,181	28	14,953	4.28	62,346	0	0	234,508	97,443	9.87	4.86	14.73	4.10	2.02	6.12
2027	157,181	29	15,327	4.43	64,441	0	0	236,978	93,780	9.87	5.01	14.88	3.91	1.98	5.89
2028	157,181	30	15,710	4.58	66,607	0	0	239,528	90,275	9.87	5.17	15.04	3.72	1.95	5.67
2029	157,181	31	16,103	4.73	68,845	0	0	242,159	86,921	9.87	5.34	15.21	3.54	1.92	5.46
2030	157,181	31	16,505	4.89	71,159	0	0	244,876	83,711	9.87	5.51	15.38	3.37	1.88	5.26
2031	157,181	32	16,918	5.05	73,550	0	0	247,681	80,638	9.87	5.68	15.55	3.21	1.85	5.06
2032	157,181	33	17,341	5.22	76,022	0	0	250,576	77,696	9.87	5.86	15.73	3.06	1.82	4.88
								Net Levelized Bus-bar Cost (c/kWh)					**9.87**	**3.90**	**13.77**
								Net Levelized Cost ($000s)							**219,346**

Hearing Exhibit - 00000027

IGCC at 40% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	1,985,862	First Year Fixed O&M Cost ($/kW-yr)	0.03	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 3,277	First Year Variable O&M ($/MWh)	6.02	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	2.39	
Total Net Output, Avg Ambient Cond. (kW)	606,000			
Capacity Factor	40.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	9,137	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	157,181	18	12,783	2.39	46,282	0	0	216,264	216,264	7.40	2.78	10.18	7.40	2.78	10.18
2009	157,181	19	13,103	2.56	49,715	0	0	220,017	209,540	7.40	2.96	10.36	7.05	2.82	9.87
2010	157,181	19	13,430	2.75	53,305	0	0	223,935	203,116	7.40	3.14	10.55	6.71	2.85	9.57
2011	157,181	20	13,766	2.85	55,317	0	0	226,283	195,472	7.40	3.25	10.66	6.39	2.81	9.21
2012	157,181	20	14,110	2.93	56,820	0	0	228,131	187,684	7.40	3.34	10.74	6.09	2.75	8.84
2013	157,181	21	14,463	3.00	58,210	0	0	229,875	180,113	7.40	3.42	10.83	5.80	2.68	8.48
2014	157,181	21	14,824	3.08	59,720	0	0	231,746	172,933	7.40	3.51	10.91	5.52	2.62	8.14
2015	157,181	22	15,195	3.14	60,860	0	0	233,257	165,772	7.40	3.58	10.98	5.26	2.55	7.81
2016	157,181	22	15,575	3.22	62,513	0	0	235,291	159,254	7.40	3.68	11.08	5.01	2.49	7.50
2017	157,181	23	15,964	3.31	64,134	0	0	237,302	152,967	7.40	3.77	11.18	4.77	2.43	7.20
2018	157,181	23	16,363	3.36	65,209	0	0	238,777	146,588	7.40	3.84	11.24	4.54	2.36	6.90
2019	157,181	24	16,772	3.47	67,272	0	0	241,250	141,054	7.40	3.96	11.36	4.33	2.31	6.64
2020	157,181	24	17,192	3.55	68,832	0	0	243,229	135,439	7.40	4.05	11.45	4.12	2.26	6.38
2021	157,181	25	17,622	3.63	70,413	0	0	245,240	130,056	7.40	4.15	11.55	3.93	2.20	6.12
2022	157,181	26	18,062	3.77	73,048	0	0	248,316	125,417	7.40	4.29	11.69	3.74	2.17	5.91
2023	157,181	26	18,514	3.88	75,223	0	0	250,943	120,708	7.40	4.42	11.82	3.56	2.12	5.68
2024	157,181	27	18,976	4.01	77,811	0	0	253,995	116,358	7.40	4.56	11.96	3.39	2.09	5.48
2025	157,181	28	19,451	4.15	80,426	0	0	257,085	112,165	7.40	4.70	12.11	3.23	2.05	5.28
2026	157,181	28	19,937	4.28	83,128	0	0	260,275	108,150	7.40	4.86	12.26	3.08	2.02	5.09
2027	157,181	29	20,436	4.43	85,922	0	0	263,567	104,303	7.40	5.01	12.41	2.93	1.98	4.91
2028	157,181	30	20,946	4.58	88,809	0	0	266,966	100,617	7.40	5.17	12.57	2.79	1.95	4.74
2029	157,181	31	21,470	4.73	91,794	0	0	270,475	97,085	7.40	5.34	12.74	2.66	1.92	4.57
2030	157,181	31	22,007	4.89	94,878	0	0	274,097	93,700	7.40	5.51	12.91	2.53	1.88	4.41
2031	157,181	32	22,557	5.05	98,067	0	0	277,837	90,456	7.40	5.68	13.08	2.41	1.85	4.26
2032	157,181	33	23,121	5.22	101,362	0	0	281,697	87,345	7.40	5.86	13.27	2.30	1.82	4.11
								Net Levelized Bus-bar Cost (c/kWh)					**7.40**	**3.90**	**11.31**
								Net Levelized Cost ($000s)							**240,060**

Hearing Exhibit - 00000028

IGCC at 50% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	1,985,862	First Year Fixed O&M Cost ($/kW-yr)	0.03	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 3,277	First Year Variable O&M ($/MWh)	6.02	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	2.39	
Total Net Output, Avg Ambient Cond. (kW)	606,000			
Capacity Factor	50.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	9,137	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	157,181	18	15,979	2.39	57,853	0	0	231,031	231,031	5.92	2.78	8.70	5.92	2.78	8.70
2009	157,181	19	16,378	2.56	62,144	0	0	235,721	224,497	5.92	2.96	8.88	5.64	2.82	8.46
2010	157,181	19	16,788	2.75	66,631	0	0	240,619	218,248	5.92	3.14	9.07	5.37	2.85	8.22
2011	157,181	20	17,207	2.85	69,146	0	0	243,554	210,391	5.92	3.25	9.18	5.12	2.81	7.93
2012	157,181	20	17,638	2.93	71,025	0	0	245,863	202,272	5.92	3.34	9.26	4.87	2.75	7.62
2013	157,181	21	18,079	3.00	72,763	0	0	248,043	194,348	5.92	3.42	9.35	4.64	2.68	7.32
2014	157,181	21	18,530	3.08	74,650	0	0	250,382	186,839	5.92	3.51	9.43	4.42	2.62	7.04
2015	157,181	22	18,994	3.14	76,075	0	0	252,271	179,284	5.92	3.58	9.50	4.21	2.55	6.75
2016	157,181	22	19,469	3.22	78,141	0	0	254,813	172,467	5.92	3.68	9.60	4.01	2.49	6.50
2017	157,181	23	19,955	3.31	80,168	0	0	257,327	165,875	5.92	3.77	9.69	3.82	2.43	6.25
2018	157,181	23	20,454	3.36	81,512	0	0	259,170	159,108	5.92	3.84	9.76	3.64	2.36	5.99
2019	157,181	24	20,966	3.47	84,090	0	0	262,261	153,338	5.92	3.96	9.88	3.46	2.31	5.78
2020	157,181	24	21,490	3.55	86,040	0	0	264,735	147,414	5.92	4.05	9.97	3.30	2.26	5.55
2021	157,181	25	22,027	3.63	88,016	0	0	267,249	141,728	5.92	4.15	10.07	3.14	2.20	5.34
2022	157,181	26	22,578	3.77	91,310	0	0	271,094	136,921	5.92	4.29	10.21	2.99	2.17	5.16
2023	157,181	26	23,142	3.88	94,028	0	0	274,378	131,980	5.92	4.42	10.34	2.85	2.12	4.97
2024	157,181	27	23,721	4.01	97,264	0	0	278,192	127,443	5.92	4.56	10.48	2.71	2.09	4.80
2025	157,181	28	24,314	4.15	100,532	0	0	282,054	123,059	5.92	4.70	10.63	2.58	2.05	4.64
2026	157,181	28	24,921	4.28	103,910	0	0	286,041	118,856	5.92	4.85	10.78	2.46	2.02	4.48
2027	157,181	29	25,544	4.43	107,402	0	0	290,157	114,825	5.92	5.01	10.93	2.34	1.98	4.33
2028	157,181	30	26,183	4.58	111,012	0	0	294,405	110,958	5.92	5.17	11.09	2.23	1.95	4.18
2029	157,181	31	26,838	4.73	114,742	0	0	298,791	107,249	5.92	5.34	11.26	2.13	1.92	4.04
2030	157,181	31	27,509	4.89	118,598	0	0	303,319	103,689	5.92	5.51	11.43	2.02	1.88	3.91
2031	157,181	32	28,196	5.05	122,583	0	0	307,993	100,274	5.92	5.68	11.60	1.93	1.85	3.78
2032	157,181	33	28,901	5.22	126,703	0	0	312,818	96,995	5.92	5.86	11.79	1.84	1.82	3.65
								Net Levelized Bus-bar Cost (c/kWh)					**5.92**	**3.90**	**9.82**
								Net Levelized Cost ($000s)							**260,773**

Hearing Exhibit - 00000029

IGCC at 60% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	1,985,862	First Year Fixed O&M Cost ($/kW-yr)	0.03	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 3,277	First Year Variable O&M ($/MWh)	6.02	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	2.39	
Total Net Output, Avg Ambient Cond. (kW)	606.000			
Capacity Factor	60.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	9,137	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	157,181	18	19,175	2.39	69,423	0	0	245,797	245,797	4.93	2.78	7.72	4.93	2.78	7.72
2009	157,181	19	19,654	2.56	74,572	0	0	251,426	239,453	4.93	2.96	7.89	4.70	2.82	7.52
2010	157,181	19	20,145	2.75	79,957	0	0	257,303	233,381	4.93	3.14	8.08	4.48	2.85	7.33
2011	157,181	20	20,649	2.85	82,975	0	0	260,825	225,310	4.93	3.25	8.19	4.26	2.81	7.07
2012	157,181	20	21,165	2.93	85,230	0	0	263,596	216,861	4.93	3.34	8.28	4.06	2.75	6.81
2013	157,181	21	21,694	3.00	87,315	0	0	266,211	208,583	4.93	3.42	8.36	3.87	2.68	6.55
2014	157,181	21	22,237	3.08	89,580	0	0	269,018	200,746	4.93	3.51	8.45	3.68	2.62	6.30
2015	157,181	22	22,792	3.14	91,289	0	0	271,284	192,797	4.93	3.58	8.52	3.51	2.55	6.05
2016	157,181	22	23,362	3.22	93,769	0	0	274,334	185,680	4.93	3.68	8.61	3.34	2.49	5.83
2017	157,181	23	23,946	3.31	96,201	0	0	277,351	178,783	4.93	3.77	8.71	3.18	2.43	5.61
2018	157,181	23	24,545	3.36	97,814	0	0	279,563	171,627	4.93	3.84	8.78	3.03	2.36	5.39
2019	157,181	24	25,159	3.47	100,909	0	0	283,272	165,623	4.93	3.96	8.89	2.89	2.31	5.20
2020	157,181	24	25,788	3.55	103,248	0	0	286,241	159,390	4.93	4.05	8.99	2.75	2.26	5.00
2021	157,181	25	26,432	3.63	105,619	0	0	289,258	153,400	4.93	4.15	9.08	2.62	2.20	4.82
2022	157,181	26	27,093	3.77	109,572	0	0	293,871	148,425	4.93	4.29	9.23	2.49	2.17	4.66
2023	157,181	26	27,770	3.88	112,834	0	0	297,812	143,252	4.93	4.42	9.35	2.37	2.12	4.50
2024	157,181	27	28,465	4.01	116,716	0	0	302,389	138,528	4.93	4.56	9.49	2.26	2.09	4.35
2025	157,181	28	29,176	4.15	120,639	0	0	307,023	133,953	4.93	4.70	9.64	2.15	2.05	4.21
2026	157,181	28	29,906	4.28	124,693	0	0	311,808	129,562	4.93	4.85	9.79	2.05	2.02	4.07
2027	157,181	29	30,653	4.43	128,883	0	0	316,746	125,347	4.93	5.01	9.94	1.95	1.98	3.94
2028	157,181	30	31,420	4.58	133,214	0	0	321,844	121,300	4.93	5.17	10.10	1.86	1.95	3.81
2029	157,181	31	32,205	4.73	137,690	0	0	327,107	117,413	4.93	5.33	10.27	1.77	1.91	3.69
2030	157,181	31	33,010	4.89	142,317	0	0	332,540	113,679	4.93	5.51	10.44	1.69	1.88	3.57
2031	157,181	32	33,836	5.05	147,100	0	0	338,149	110,091	4.93	5.68	10.62	1.61	1.85	3.46
2032	157,181	33	34,681	5.22	152,043	0	0	343,938	106,644	4.93	5.86	10.80	1.53	1.82	3.35
								Net Levelized Bus-bar Cost (c/kWh)					**4.93**	**3.90**	**8.84**
								Net Levelized Cost ($000s)							**281,487**

Hearing Exhibit - 00000030

IGCC at 70% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	1,985,862	First Year Fixed O&M Cost ($/kW-yr)	0.03	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 3,277	First Year Variable O&M ($/MWh)	6.02	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	2.39	
Total Net Output, Avg Ambient Cond. (kW)	606,000			
Capacity Factor	70.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	9,137	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	157,181	18	22,370	2.39	80,994	0	0	260,563	260,563	4.23	2.78	7.01	4.23	2.78	7.01
2009	157,181	19	22,930	2.56	87,001	0	0	267,130	254,410	4.23	2.96	7.19	4.03	2.82	6.85
2010	157,181	19	23,503	2.75	93,284	0	0	273,986	248,514	4.23	3.14	7.37	3.84	2.85	6.69
2011	157,181	20	24,090	2.85	96,805	0	0	278,096	240,229	4.23	3.25	7.48	3.65	2.81	6.46
2012	157,181	20	24,693	2.93	99,435	0	0	281,328	231,449	4.23	3.34	7.57	3.48	2.75	6.23
2013	157,181	21	25,310	3.00	101,868	0	0	284,379	222,819	4.23	3.42	7.65	3.31	2.68	6.00
2014	157,181	21	25,943	3.08	104,510	0	0	287,654	214,652	4.23	3.51	7.74	3.16	2.62	5.78
2015	157,181	22	26,591	3.14	106,504	0	0	290,298	206,309	4.23	3.58	7.81	3.01	2.55	5.55
2016	157,181	22	27,256	3.22	109,397	0	0	293,856	198,894	4.23	3.68	7.91	2.86	2.49	5.35
2017	157,181	23	27,937	3.31	112,235	0	0	297,376	191,691	4.23	3.77	8.00	2.73	2.43	5.16
2018	157,181	23	28,636	3.36	114,116	0	0	299,956	184,147	4.23	3.84	8.07	2.60	2.36	4.96
2019	157,181	24	29,352	3.47	117,727	0	0	304,283	177,908	4.23	3.96	8.19	2.47	2.31	4.79
2020	157,181	24	30,086	3.55	120,456	0	0	307,747	171,365	4.23	4.05	8.28	2.36	2.26	4.61
2021	157,181	25	30,838	3.63	123,223	0	0	311,266	165,071	4.23	4.15	8.38	2.24	2.20	4.44
2022	157,181	26	31,609	3.77	127,834	0	0	316,649	159,929	4.23	4.29	8.52	2.14	2.17	4.30
2023	157,181	26	32,399	3.88	131,639	0	0	321,246	154,525	4.23	4.42	8.64	2.03	2.12	4.16
2024	157,181	27	33,209	4.01	136,169	0	0	326,586	149,613	4.23	4.56	8.79	1.94	2.09	4.03
2025	157,181	28	34,039	4.15	140,745	0	0	331,993	144,847	4.23	4.70	8.93	1.85	2.05	3.90
2026	157,181	28	34,890	4.28	145,475	0	0	337,574	140,269	4.23	4.85	9.08	1.76	2.02	3.77
2027	157,181	29	35,762	4.43	150,363	0	0	343,336	135,870	4.23	5.01	9.24	1.67	1.98	3.66
2028	157,181	30	36,656	4.58	155,416	0	0	349,283	131,641	4.23	5.17	9.40	1.59	1.95	3.54
2029	157,181	31	37,573	4.73	160,639	0	0	355,423	127,576	4.23	5.33	9.56	1.52	1.91	3.43
2030	157,181	31	38,512	4.89	166,037	0	0	361,761	123,668	4.23	5.51	9.74	1.45	1.88	3.33
2031	157,181	32	39,475	5.05	171,617	0	0	368,304	119,909	4.23	5.68	9.91	1.38	1.85	3.23
2032	157,181	33	40,462	5.22	177,384	0	0	375,059	116,294	4.23	5.86	10.09	1.31	1.82	3.13
								Net Levelized Bus-bar Cost (c/kWh)					**4.23**	**3.90**	**8.13**
								Net Levelized Cost ($000s)							**302,201**

Hearing Exhibit - 00000031

IGCC at 80% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	1,985,862	First Year Fixed O&M Cost ($/kW-yr)	0.03	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 3,277	First Year Variable O&M ($/MWh)	6.02	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	2.39	
Total Net Output, Avg Ambient Cond. (kW)	606,000			
Capacity Factor	80.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	9,137	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	157,181	18	25,566	2.39	92,564	0	0	275,329	275,329	3.70	2.78	6.48	3.70	2.78	6.48
2009	157,181	19	26,205	2.56	99,430	0	0	282,835	269,366	3.70	2.96	6.66	3.52	2.82	6.34
2010	157,181	19	26,860	2.75	106,610	0	0	290,670	263,646	3.70	3.14	6.84	3.36	2.85	6.21
2011	157,181	20	27,532	2.85	110,634	0	0	295,366	255,149	3.70	3.25	6.95	3.20	2.81	6.01
2012	157,181	20	28,220	2.93	113,640	0	0	299,061	246,038	3.70	3.34	7.04	3.04	2.75	5.79
2013	157,181	21	28,926	3.00	116,420	0	0	302,548	237,054	3.70	3.42	7.12	2.90	2.68	5.58
2014	157,181	21	29,649	3.08	119,439	0	0	306,290	228,559	3.70	3.51	7.21	2.76	2.62	5.38
2015	157,181	22	30,390	3.14	121,719	0	0	309,312	219,822	3.70	3.58	7.28	2.63	2.55	5.18
2016	157,181	22	31,150	3.22	125,025	0	0	313,378	212,107	3.70	3.68	7.38	2.51	2.49	4.99
2017	157,181	23	31,928	3.31	128,269	0	0	317,401	204,599	3.70	3.77	7.47	2.39	2.43	4.82
2018	157,181	23	32,727	3.36	130,418	0	0	320,349	196,667	3.70	3.84	7.54	2.27	2.36	4.63
2019	157,181	24	33,545	3.47	134,545	0	0	325,294	190,193	3.70	3.96	7.66	2.16	2.31	4.48
2020	157,181	24	34,383	3.55	137,664	0	0	329,253	183,340	3.70	4.05	7.75	2.06	2.26	4.32
2021	157,181	25	35,243	3.63	140,826	0	0	333,275	176,743	3.70	4.15	7.85	1.96	2.20	4.16
2022	157,181	26	36,124	3.77	146,095	0	0	339,426	171,433	3.70	4.29	7.99	1.87	2.17	4.04
2023	157,181	26	37,027	3.88	150,445	0	0	344,680	165,797	3.70	4.42	8.12	1.78	2.12	3.90
2024	157,181	27	37,953	4.01	155,622	0	0	350,783	160,698	3.70	4.56	8.26	1.70	2.09	3.78
2025	157,181	28	38,902	4.15	160,851	0	0	356,962	155,741	3.70	4.70	8.41	1.61	2.05	3.67
2026	157,181	28	39,874	4.28	166,257	0	0	363,340	150,975	3.70	4.85	8.56	1.54	2.02	3.55
2027	157,181	29	40,871	4.43	171,844	0	0	369,925	146,392	3.70	5.01	8.71	1.46	1.98	3.45
2028	157,181	30	41,893	4.58	177,618	0	0	376,722	141,983	3.70	5.17	8.87	1.39	1.95	3.34
2029	157,181	31	42,940	4.73	183,587	0	0	383,739	137,740	3.70	5.33	9.04	1.33	1.91	3.24
2030	157,181	31	44,014	4.89	189,757	0	0	390,983	133,657	3.70	5.51	9.21	1.27	1.88	3.15
2031	157,181	32	45,114	5.05	196,133	0	0	398,460	129,727	3.70	5.68	9.38	1.20	1.85	3.05
2032	157,181	33	46,242	5.22	202,724	0	0	406,180	125,943	3.70	5.86	9.56	1.15	1.82	2.97
								Net Levelized Bus-bar Cost (c/kWh)					**3.70**	**3.90**	**7.60**
								Net Levelized Cost ($000s)							**322,915**

Hearing Exhibit - 00000032

IGCC at 88% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	1,985,862	First Year Fixed O&M Cost ($/kW-yr)	0.03	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 3,277	First Year Variable O&M ($/MWh)	6.02	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	2.39	
Total Net Output, Avg Ambient Cond. (kW)	606,000			
Capacity Factor	88.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)	9,137	Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	157,181	18	28,123	2.39	101,821	0	0	287,142	287,142	3.36	2.78	6.15	3.36	2.78	6.15
2009	157,181	19	28,826	2.56	109,373	0	0	295,398	281,331	3.36	2.96	6.32	3.20	2.82	6.02
2010	157,181	19	29,546	2.75	117,271	0	0	304,017	275,753	3.36	3.14	6.51	3.05	2.85	5.90
2011	157,181	20	30,285	2.85	121,697	0	0	309,183	267,084	3.36	3.25	6.62	2.91	2.81	5.72
2012	157,181	20	31,042	2.93	125,003	0	0	313,247	257,709	3.36	3.34	6.71	2.77	2.75	5.52
2013	157,181	21	31,818	3.00	128,062	0	0	317,082	248,442	3.36	3.42	6.79	2.64	2.68	5.32
2014	157,181	21	32,614	3.08	131,383	0	0	321,199	239,684	3.36	3.51	6.88	2.51	2.62	5.13
2015	157,181	22	33,429	3.14	133,891	0	0	324,523	230,632	3.36	3.58	6.95	2.39	2.55	4.94
2016	157,181	22	34,265	3.22	137,528	0	0	328,996	222,677	3.36	3.68	7.04	2.28	2.49	4.77
2017	157,181	23	35,121	3.31	141,095	0	0	333,420	214,926	3.36	3.77	7.14	2.17	2.43	4.60
2018	157,181	23	35,999	3.36	143,460	0	0	336,664	206,682	3.36	3.84	7.21	2.07	2.36	4.42
2019	157,181	24	36,899	3.47	147,999	0	0	342,103	200,021	3.36	3.96	7.32	1.97	2.31	4.28
2020	157,181	24	37,822	3.55	151,430	0	0	346,457	192,920	3.36	4.05	7.42	1.87	2.26	4.13
2021	157,181	25	38,767	3.63	154,908	0	0	350,882	186,080	3.36	4.15	7.51	1.78	2.20	3.98
2022	157,181	26	39,737	3.77	160,705	0	0	357,648	180,637	3.36	4.29	7.66	1.70	2.17	3.87
2023	157,181	26	40,730	3.88	165,490	0	0	363,427	174,815	3.36	4.41	7.78	1.62	2.12	3.74
2024	157,181	27	41,748	4.01	171,184	0	0	370,140	169,565	3.36	4.56	7.92	1.54	2.09	3.63
2025	157,181	28	42,792	4.15	176,937	0	0	376,937	164,456	3.36	4.70	8.07	1.47	2.05	3.52
2026	157,181	28	43,862	4.28	182,882	0	0	383,953	159,541	3.36	4.85	8.22	1.40	2.02	3.42
2027	157,181	29	44,958	4.43	189,028	0	0	391,196	154,810	3.36	5.01	8.37	1.33	1.98	3.31
2028	157,181	30	46,082	4.58	195,380	0	0	398,673	150,256	3.36	5.17	8.53	1.27	1.95	3.22
2029	157,181	31	47,234	4.73	201,946	0	0	406,392	145,871	3.36	5.33	8.70	1.21	1.91	3.12
2030	157,181	31	48,415	4.89	208,732	0	0	414,360	141,649	3.36	5.51	8.87	1.15	1.88	3.03
2031	157,181	32	49,625	5.05	215,747	0	0	422,585	137,582	3.36	5.68	9.05	1.10	1.85	2.95
2032	157,181	33	50,866	5.22	222,997	0	0	431,077	133,663	3.36	5.86	9.23	1.04	1.82	2.86
							Net Levelized Bus-bar Cost (c/kWh)						**3.36**	**3.90**	**7.27**
							Net Levelized Cost ($000s)								**339,486**

Hearing Exhibit - 00000033

Wind at 3% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	6,325	First Year Fixed O&M Cost ($/kW-yr)	39.00	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 2,750	First Year Variable O&M ($/MWh)	0.00	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	2,300			
Capacity Factor	3.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)		Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	501	90	0		0	0	0	590	590	82.82	14.84	97.66	82.82	14.84	97.66
2009	501	92	0		0	0	0	593	564	82.82	15.21	98.04	78.88	14.49	93.37
2010	501	94	0		0	0	0	595	540	82.82	15.59	98.42	75.12	14.14	89.27
2011	501	97	0		0	0	0	597	516	82.82	15.98	98.81	71.55	13.81	85.35
2012	501	99	0		0	0	0	600	493	82.82	16.38	99.21	68.14	13.48	81.62
2013	501	101	0		0	0	0	602	472	82.82	16.79	99.61	64.90	13.16	78.05
2014	501	104	0		0	0	0	605	451	82.82	17.21	100.03	61.80	12.84	74.65
2015	501	107	0		0	0	0	607	432	82.82	17.64	100.46	58.86	12.54	71.40
2016	501	109	0		0	0	0	610	413	82.82	18.08	100.91	56.06	12.24	68.30
2017	501	112	0		0	0	0	613	395	82.82	18.53	101.36	53.39	11.95	65.34
2018	501	115	0		0	0	0	615	378	82.82	19.00	101.82	50.85	11.66	62.51
2019	501	118	0		0	0	0	618	362	82.82	19.47	102.30	48.43	11.38	59.81
2020	501	121	0		0	0	0	621	346	82.82	19.96	102.78	46.12	11.11	57.23
2021	501	124	0		0	0	0	624	331	82.82	20.46	103.28	43.92	10.85	54.77
2022	501	127	0		0	0	0	627	317	82.82	20.97	103.79	41.83	10.59	52.42
2023	501	130	0		0	0	0	631	303	82.82	21.49	104.32	39.84	10.34	50.18
2024	501	133	0		0	0	0	634	290	82.82	22.03	104.85	37.94	10.09	48.04
2025	501	136	0		0	0	0	637	278	82.82	22.58	105.41	36.14	9.85	45.99
2026	501	140	0		0	0	0	641	266	82.82	23.15	105.97	34.42	9.62	44.03
2027	501	143	0		0	0	0	644	255	82.82	23.72	106.55	32.78	9.39	42.16
2028	501	147	0		0	0	0	648	244	82.82	24.32	107.14	31.22	9.16	40.38
2029	501	151	0		0	0	0	651	234	82.82	24.93	107.75	29.73	8.95	38.68
2030	501	154	0		0	0	0	655	224	82.82	25.55	108.37	28.31	8.73	37.05
2031	501	158	0		0	0	0	659	215	82.82	26.19	109.01	26.97	8.53	35.49
2032	501	162	0		0	0	0	663	206	82.82	26.84	109.67	25.68	8.32	34.00
								Net Levelized Bus-bar Cost (c/kWh)					**82.82**	**19.06**	**101.88**
								Net Levelized Cost ($000s)							**616**

Wind capital costs do not include real estate/leases or transmission system enhancement costs.

Hearing Exhibit - 00000034

Wind at 6% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	6,325	First Year Fixed O&M Cost ($/kW-yr)	39.00	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 2,750	First Year Variable O&M ($/MWh)	0.00	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	2,300			
Capacity Factor	6.0%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)		Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	501	90	0		0	0	0	590	590	41.41	7.42	48.83	41.41	7.42	48.83
2009	501	92	0		0	0	0	593	564	41.41	7.61	49.02	39.44	7.24	46.68
2010	501	94	0		0	0	0	595	540	41.41	7.80	49.21	37.56	7.07	44.63
2011	501	97	0		0	0	0	597	516	41.41	7.99	49.40	35.77	6.90	42.68
2012	501	99	0		0	0	0	600	493	41.41	8.19	49.60	34.07	6.74	40.81
2013	501	101	0		0	0	0	602	472	41.41	8.40	49.81	32.45	6.58	39.03
2014	501	104	0		0	0	0	605	451	41.41	8.61	50.02	30.90	6.42	37.32
2015	501	107	0		0	0	0	607	432	41.41	8.82	50.23	29.43	6.27	35.70
2016	501	109	0		0	0	0	610	413	41.41	9.04	50.45	28.03	6.12	34.15
2017	501	112	0		0	0	0	613	395	41.41	9.27	50.68	26.69	5.97	32.67
2018	501	115	0		0	0	0	615	378	41.41	9.50	50.91	25.42	5.83	31.25
2019	501	118	0		0	0	0	618	362	41.41	9.74	51.15	24.21	5.69	29.91
2020	501	121	0		0	0	0	621	346	41.41	9.98	51.39	23.06	5.56	28.62
2021	501	124	0		0	0	0	624	331	41.41	10.23	51.64	21.96	5.42	27.39
2022	501	127	0		0	0	0	627	317	41.41	10.48	51.90	20.92	5.30	26.21
2023	501	130	0		0	0	0	631	303	41.41	10.75	52.16	19.92	5.17	25.09
2024	501	133	0		0	0	0	634	290	41.41	11.02	52.43	18.97	5.05	24.02
2025	501	136	0		0	0	0	637	278	41.41	11.29	52.70	18.07	4.93	22.99
2026	501	140	0		0	0	0	641	266	41.41	11.57	52.99	17.21	4.81	22.02
2027	501	143	0		0	0	0	644	255	41.41	11.86	53.27	16.39	4.69	21.08
2028	501	147	0		0	0	0	648	244	41.41	12.16	53.57	15.61	4.58	20.19
2029	501	151	0		0	0	0	651	234	41.41	12.46	53.87	14.86	4.47	19.34
2030	501	154	0		0	0	0	655	224	41.41	12.77	54.19	14.16	4.37	18.52
2031	501	158	0		0	0	0	659	215	41.41	13.09	54.51	13.48	4.26	17.75
2032	501	162	0		0	0	0	663	206	41.41	13.42	54.83	12.84	4.16	17.00
								Net Levelized Bus-bar Cost (c/kWh)					**41.41**	**9.53**	**50.94**
								Net Levelized Cost ($000s)							**616**

Wind capital costs do not include real estate/leases or transmission system enhancement costs.

Hearing Exhibit - 00000035

Small PV at 16.34% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	1,400	First Year Fixed O&M Cost ($/kW-yr)	10.00	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 7,000	First Year Variable O&M ($/MWh)	0.00	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	200			
Capacity Factor	16.34%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)		Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	111	2	0		0	0	0	113	113	38.71	0.70	39.41	38.71	0.70	39.41
2009	111	2	0		0	0	0	113	107	38.71	0.72	39.42	36.86	0.68	37.55
2010	111	2	0		0	0	0	113	102	38.71	0.73	39.44	35.11	0.67	35.77
2011	111	2	0		0	0	0	113	98	38.71	0.75	39.46	33.44	0.65	34.09
2012	111	2	0		0	0	0	113	93	38.71	0.77	39.48	31.84	0.63	32.48
2013	111	2	0		0	0	0	113	89	38.71	0.79	39.50	30.33	0.62	30.95
2014	111	2	0		0	0	0	113	84	38.71	0.81	39.52	28.88	0.60	29.49
2015	111	2	0		0	0	0	113	80	38.71	0.83	39.54	27.51	0.59	28.10
2016	111	2	0		0	0	0	113	77	38.71	0.85	39.56	26.20	0.58	26.77
2017	111	2	0		0	0	0	113	73	38.71	0.87	39.58	24.95	0.56	25.51
2018	111	3	0		0	0	0	113	70	38.71	0.89	39.60	23.76	0.55	24.31
2019	111	3	0		0	0	0	113	66	38.71	0.92	39.62	22.63	0.54	23.17
2020	111	3	0		0	0	0	113	63	38.71	0.94	39.65	21.55	0.52	22.08
2021	111	3	0		0	0	0	114	60	38.71	0.96	39.67	20.53	0.51	21.04
2022	111	3	0		0	0	0	114	57	38.71	0.99	39.69	19.55	0.50	20.05
2023	111	3	0		0	0	0	114	55	38.71	1.01	39.72	18.62	0.49	19.11
2024	111	3	0		0	0	0	114	52	38.71	1.04	39.74	17.73	0.48	18.21
2025	111	3	0		0	0	0	114	50	38.71	1.06	39.77	16.89	0.46	17.35
2026	111	3	0		0	0	0	114	47	38.71	1.09	39.80	16.08	0.45	16.54
2027	111	3	0		0	0	0	114	45	38.71	1.12	39.82	15.32	0.44	15.76
2028	111	3	0		0	0	0	114	43	38.71	1.14	39.85	14.59	0.43	15.02
2029	111	3	0		0	0	0	114	41	38.71	1.17	39.88	13.89	0.42	14.31
2030	111	3	0		0	0	0	114	39	38.71	1.20	39.91	13.23	0.41	13.64
2031	111	4	0		0	0	0	114	37	38.71	1.23	39.94	12.60	0.40	13.00
2032	111	4	0		0	0	0	114	35	38.71	1.26	39.97	12.00	0.39	12.39
								Net Levelized Bus-bar Cost (c/kWh)					**38.71**	**0.90**	**39.60**
								Net Levelized Cost ($000s)							**113**

Without federal investment tax credit and without inverter replacement at 15 years.

Hearing Exhibit - 00000036

Large PV at 16.34% Capacity Factor

25 -Year Levelized Bus-bar Cost Calculation

Plant Input Data		Economic Input Data	Rate	Escalation
EPC Capital Cost ($1,000)	6,750	First Year Fixed O&M Cost ($/kW-yr)	10.00	2.5%
Cost per Net kW, Avg. Ambient Cond.	$ 6,750	First Year Variable O&M ($/MWh)	0.00	2.5%
Indirect Capital Cost Adder, Percent	0%	Fuel Rate ($/Mbtu)	0.00	
Total Net Output, Avg Ambient Cond. (kW)	1,000			
Capacity Factor	16.34%	Present Worth Discount Rate	5.0%	
Full Load Heat Rate, Btu/kWh (HHV)		Levelized Fixed Charge Rate	7.915%	

Year	Annual Capital Cost ($ 1,000)	Fixed O&M ($ 1,000)	Variable O&M ($ 1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($ 1,000)	Other ($ 1,000)	Other ($ 1,000)	Total Cost ($ 1,000)	PW Total Cost ($ 1,000)	Capital Cost Busbar Cost (c/kWh)	O&M/Fuel Busbar Cost (c/kWh)	Busbar Cost (c/kWh)	Net PW Capital Cost (c/kWh)	Net PW O&M/Fuel Cost (c/kWh)	Net PW Cost (c/kWh)
2008	534	10	0		0	0	0	544	544	37.32	0.70	38.02	37.32	0.70	38.02
2009	534	10	0		0	0	0	545	519	37.32	0.72	38.04	35.55	0.68	36.23
2010	534	11	0		0	0	0	545	494	37.32	0.73	38.06	33.85	0.67	34.52
2011	534	11	0		0	0	0	545	471	37.32	0.75	38.08	32.24	0.65	32.89
2012	534	11	0		0	0	0	545	449	37.32	0.77	38.10	30.71	0.63	31.34
2013	534	11	0		0	0	0	546	427	37.32	0.79	38.12	29.25	0.62	29.86
2014	534	12	0		0	0	0	546	407	37.32	0.81	38.14	27.85	0.60	28.46
2015	534	12	0		0	0	0	546	388	37.32	0.83	38.16	26.53	0.59	27.12
2016	534	12	0		0	0	0	546	370	37.32	0.85	38.18	25.26	0.58	25.84
2017	534	12	0		0	0	0	547	352	37.32	0.87	38.20	24.06	0.56	24.62
2018	534	13	0		0	0	0	547	336	37.32	0.89	38.22	22.91	0.55	23.46
2019	534	13	0		0	0	0	547	320	37.32	0.92	38.24	21.82	0.54	22.36
2020	534	13	0		0	0	0	548	305	37.32	0.94	38.26	20.78	0.52	21.31
2021	534	14	0		0	0	0	548	291	37.32	0.96	38.29	19.79	0.51	20.30
2022	534	14	0		0	0	0	548	277	37.32	0.99	38.31	18.85	0.50	19.35
2023	534	14	0		0	0	0	549	264	37.32	1.01	38.34	17.95	0.49	18.44
2024	534	15	0		0	0	0	549	252	37.32	1.04	38.36	17.10	0.48	17.57
2025	534	15	0		0	0	0	549	240	37.32	1.06	38.39	16.28	0.46	16.75
2026	534	16	0		0	0	0	550	228	37.32	1.09	38.41	15.51	0.45	15.96
2027	534	16	0		0	0	0	550	218	37.32	1.12	38.44	14.77	0.44	15.21
2028	534	16	0		0	0	0	551	208	37.32	1.14	38.47	14.07	0.43	14.50
2029	534	17	0		0	0	0	551	198	37.32	1.17	38.50	13.40	0.42	13.82
2030	534	17	0		0	0	0	551	189	37.32	1.20	38.53	12.76	0.41	13.17
2031	534	18	0		0	0	0	552	180	37.32	1.23	38.56	12.15	0.40	12.55
2032	534	18	0		0	0	0	552	171	37.32	1.26	38.59	11.57	0.39	11.97
							Net Levelized Bus-bar Cost (c/kWh)						**37.32**	**0.90**	**38.22**
							Net Levelized Cost ($000s)								**547**

Without federal investment tax credit and without inverter replacement at 15 years.

Hearing Exhibit - 00000037

20. Please complete the following chart to show JEA's actual total retail rate, base rate percentage, fuel cost percentage and generation by gas percentage:

Comparison of JEA's Residential Rate to % Generation by Gas For Fiscal Year ended September 30					
	1999	**2001**	**2003**	**2005**	**2007**
Total Residential Rate ¢/kWh	6.815	6.815	6.815	7.997	8.833
Base Rate %	73	73	73	62	56
Fuel Costs %	27	27	27	38	44
Generation by Gas %	8	6	7	6	10

Response: The table above provides residential rate information. The information provided in the above table is based on residential rates in effect in September of each year based on a usage level of 1,000 kWh. The values used to calculate the Base Rate percentage and Fuel Costs percentage are reported by the Florida Municipal Electric Association (FMEA) in a report titled *Florida Electric Utility Rate Comparison* , supplemented by information from JEA for years in which the FMEA data was not available. Data to calculate the generation by gas percentage was taken from JEA's annual reports and represents annual values for the fiscal year ending September 30 of each year.

21. Please complete the following table comparing JEA's proposed conversion project and other generation alternatives:

Comparison of JEA's Generation Options (all costs in 2008 dollars)					
Technology	**GEC Conversion**	**GE 7FA Simple Cycle**	**GE 1x1 7FA Combined Cycle**	**GE LM6000 Simple Cycle**	**GE LMS100 Simple Cycle**
Size(MW, Summer)	207	142	300	46	86
Costs					
Installed Costs ($ million)	349	138	349	72	113
Average Ambient Size (MW)	207	160	307	47	97
Capital ($/kW)	1,688	862	1,137	1,523	1,167
Fixed O&M ($/kW-yr)	16.33	8.41	4.56	26.47	13.45
Variable O&M ($/MWh)	2.47	15.57	3.30	3.64	3.29
Heat Rate (BTU/kWh)	7,280	11,241	7,445	10,171	9,360
Eq. Availability (%)	94	95	94	95	95
Capacity Factor (%)	51	15	51	15	15
Water Usage (gal/day)	3,260,000	27,360	1,921,000	80,640	79,200
Emission Rates					
NO_x (lb/MBTU)	0.0072	0.0072	0.0072	0.0072	0.0072
SO_2 (lb/MBTU)	0.0004	0.0005	0.0005	0.0005	0.0005
CO_2 (lb/MBTU)	114.8	114.8	114.8	114.8	114.8
Mercury (lb/MBTU)	0.0	0.0	0.0	0.0	0.0

Response: The following notes apply to the data provided in the above table as response to Interrogatory 21.

1. The summer capacity rating for the GEC combined cycle conversion assumes supplemental firing and is net of the summer capacity rating for the planned GEC combustion turbines.

2. The summer capacity rating for the GE 1x1 7FA combined cycle unit assumes supplemental firing.

3. The installed costs include Engineer, Procure, and Construct (EPC) costs, owner's costs, and contingency, but exclude interest during construction (IDC) as well as escalation.

4. A row labeled Average Ambient Size (MW) was added to the table to show the capacity rating used to calculate capital and fixed O&M costs. Refer also to Note 5.

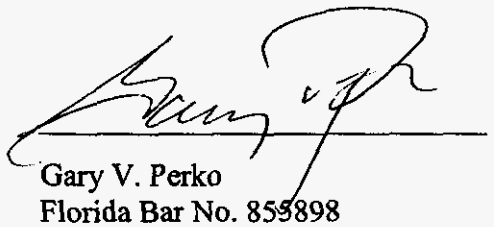
5. The capital ($/kW), variable O&M ($/MWh), and fixed O&M ($/kW-yr) costs are calculated based on average ambient capacity ratings.

6. The fixed O&M ($/kW-yr) and variable O&M ($/MWh) cost shown for the GEC Conversion is the incremental variable O&M ($/MWh) cost for the GEC Combined Cycle conversion.

7. The heat rate values are for full load operation at summer conditions.

8. The capacity factors shown are those used to estimate variable O&M ($/MWh) costs.

9. Water usage estimates reflect summer conditions for full load operation 24 hours per day. The water usage estimates for the combined cycle alternatives are net of volumes of water that are expected to be returned to the reclaimed water system.



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Attorneys for JEA

AFFIDAVIT

STATE OF KANSAS)

COUNTY OF Johnson)

I hereby certify that on this 29th day of October, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Myron R. Rollins, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 1, 2, 3, 4, 5, 6 from STAFF'S FIRST SET OF INTERROGATORIES TO JEA (NOS. 1 - 24) in Docket No(s). 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29th day of October, 2008.

Marsha M. Purinton

NOTARY PUBLIC STATE OF KANSAS MARSHA M. Purinton My Appt. Exp. 7-30-2011

Notary Public
State of Kansas, at large

My Commission Expires: 7-30-2011

Hearing Exhibit - 00000042

AFFIDAVIT

STATE OF KANSAS)

COUNTY OF Johnson)

I hereby certify that on this 29th day of October, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Bradley E. Kushner, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 7, 19, 20, 21, 22, 23, 24 from STAFF'S FIRST SET OF INTERROGATORIES TO JEA (NOS. 1 - 24) in Docket No(s). 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29th day of October, 2008.

Marsha M. Purinton

Notary Public
State of Kansas, at large

NOTARY PUBLIC STATE OF KANSAS | MARSHA M. PURINTON My Appt. Exp. 7-30-2011

My Commission Expires: 7-30-2011

2

JEA's Responses to Staff's Second Set of Interrogatories (Nos. 25-29)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Greenland Energy Center Combined Cycle Conversion in Duval County by JEA.	DOCKET NO. 080614-EM DATED: DECEMBER 2, 2008

JEA'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 25 - 29)

JEA pursuant to Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staff's Second Set of Interrogatories (Nos. 25-29).

The answers to Questions 25, 26, and 27 of Staff's Second Set of Interrogatories (Nos. 25-29) are provided by Michael N. Lawson, JEA, 21 West Church Street, Jacksonville, FL 32202. Answers to Questions 28 and 29 of Staff's Second Set of Interrogatories are provided by Bradley Kushner (consultant to JEA), Black & Veatch Corporation, 11401 Lamar Avenue, Overland Park, KS 66211.

Hearing Exhibit - 00000045

RESPONSES

25. On page 3 of his pre-filed testimony, witness Lawson stated: "advanced dry low-NOx (DLN) combustion technology will be used to minimize NOx emissions while ensuring that emissions of carbon monoxide (CO) and volatile organic compounds (VOC) are within acceptable limits."

A. Please provide more details of the DLN combustion technology that JEA will use in the GEC combined cycle.

Response: Dry low-NO_x (DLN) combustion technology limits NO_x emissions without water or steam injection. DLN technology premixes fuel and air prior to combustion and produces a very lean fuel-air mixture which reduces flame temperatures and results in reduced NO_x formation.

B. Please describe the "acceptable limits" for CO and VOC.

Response: CO emissions are estimated to be 7.6 ppmvd at 15% O_2 (natural gas fired) while VOC emissions are estimated to be 1.4 ppmvd at 15% O_2 (natural gas fired). These rates are consistent with what the Florida Department of Environmental Protection has established as Best Available Control Technology (BACT) for similar units. BACT is established taking into account energy, environmental, and economic impacts and other costs.

C. Please describe the amount of CO and VOC that is expected to be removed by using the proposed DLN technology.

Response: CO and VOC are not removed by dry low-NO_x combustion technology, but as described in response to Interrogatory No. 25B, CO and VOC emissions will remain within acceptable levels.

D. Please explain whether the costs associated with the DLN combustion technology have been included in JEA's cost estimations of the GEC Combined Cycle Conversion Project.

Response: The DLN combustion technology is included with the GEC simple cycle combustion turbines and thus the cost for the DLN combustion technology is also included with the total cost of GEC combined cycle unit. However, costs for the DLN combustion technology will be incurred before the conversion project and therefore are not included within the cost estimations for the project.

26. On page 4 of his pre-filed testimony, witness Lawson stated: "selective reduction, or SCR, will be installed in each HRSG (heat recovery steam generator) to further reduce NOx emissions when operating in combined cycle mode."

A. Please describe the costs (in nominal dollars) of these SCRs.

Response: The nominal (2008 $) installed capital cost associated with SCR for each HRSG is approximately $5.5 million.

B. Please provide the commencement dates of construction of each of the SCRs.

Response: The HRSGs will each be fabricated to include SCR. As indicated in Figure 9-3 of the GEC Need for Power Application, HRSG erection was originally estimated to begin in the first quarter of 2011. However, as discussed in the supplemental testimony of Witness Lawson (filed November 21, 2008), this timeframe will be delayed by about one year due to the one year deferral of the GEC combined cycle conversion.

C. Please provide the in-service dates of each of the SCRs.

Response: SCR will be in service on each HRSG when the GEC combined cycle begins commercial operation, which is currently scheduled for June 1, 2013.

D. Please explain whether the costs associated with the SCRs combustion technology have been included in JEA's cost estimations of the GEC Combined Cycle Conversion Project.

Response: The costs associated with SCR for both HRSGs are included in JEA's cost estimations of the GEC Combined Cycle Conversion Project.

27. Regarding Section 9.1.8, Water Use, sponsored by witness Lawson in the GEC Need for Power Application, please explain the following:

A. The expected total water consumption (gallons per day of fresh water and gallons per day of reclaimed water) of the proposed GEC Combined Cycle Project.

Response: The GEC Combined Cycle Project is estimated to consume approximately 111,000 gallons per day (gpd) of potable water under base conditions and approximately 127,000 gpd under maximum conditions. Reclaimed water usage is estimated to be approximately 3.15 million gallons per day (mgd) at full load average conditions (59° F, without duct firing) and approximately 4.34 mgd at full load maximum conditions (95° F, with duct firing).

B. Whether JEA has secured the supplies of the fresh water and reclaimed water described in question a.

Response: The potable water demand will be supplied by JEA's existing municipal water system. Reclaimed water will come from JEA's existing reclaimed water system. The system will be expanded over the next several years and will be capable of providing a reliable supply of reclaimed water for the GEC combined cycle. JEA is also planning to add reclaimed water storage at the GEC site, which will increase reclaimed water system reliability.

C. **Whether the costs associated with the water consumption described in question a. have been included in JEA's cost estimations of the GEC Combined Cycle Conversion Project.**

Response: The costs for on-site equipment associated with water consumption have been included in the capital cost estimate of the GEC combined cycle, while costs associated with the volume of water consumed are included in the nonfuel variable O&M estimate for the GEC combined cycle.

28. **In the second paragraph of Section 7.6, sponsored by witness Kushner, in the GEC Need for Power Application, it was stated: "the CO2 emission prices.....projections presented in S.2191 are higher than those presented in the EIA's analysis of S.1766 and the EIA's analysis of S.280, and price projections presented in EIA's analysis of S.2191 utilized the most advanced forecasting models." Please explain why the forecasting models utilized for analyzing S.2191 are deemed the most advanced ones compared with the other models; and what are the differences and the similarities between the forecasting models EIA utilized to perform the analysis of S.1766, S.280 and S2191.**

Response: The CO_2 price projections for S.1766 and S.280 were developed by EIA in 2007. The CO_2 price projections for S.2191 were developed by EIA with updated macroeconomic assumptions for the 2008 Annual Energy Outlook. EIA utilized its National Energy Modeling System (NEMS) in evaluating the economic impacts of S.2191. The model is based on macroeconomic principles and solves for prices of each energy product to achieve a balance of supply and demand. NEMS accounts for the interaction of key variables during the solution process such that values of key variables are reasonably adjusted to maintain a balanced relationship from iteration to iteration until convergence is achieved within the value tolerances of the inter-dependent variables. Fuel price is one of the inter-dependent variables provided by the NEMS model and were the basis for fuel price forecasts contained in the GEC Need for Power Application.

Other modeling approaches may involve Computable General Equilibrium (CGE) style models which are more microeconomic than the NEMS model. The CGE models are run separately and not integrated like the NEMS model. In general, macroeconomic models are better suited for short to medium-term projections, whereas microeconomic models are better for long-term projections. Since the study period for the JEA Need for Power Application can be considered medium-term (through 2027), medium-term projections were considered appropriate.

29. On page 6, lines 22-24, of his pre-filed testimony, witness Kushner stated: "The EIA's analysis of S.2191 includes five different cases to the proposed S.2191. Sensitivity evaluations presented in the GEC Need for Power Application reflect two of these five cases – the S2191 Core Case and the S.2191 Limited/No International Case." Please explain why JEA determined to use these two cases rather than using all five cases or selecting other cases out of the five.

Response: The EIA defines the "S.2191 Core" case as the primary policy case and the basis for the other sensitivity cases which reflect changes to various areas of uncertainty. Since the S.2191 Core case is the primary policy case, JEA utilized it as the basis for two of the three regulated CO_2 sensitivity cases that were evaluated in the GEC Need for Power Application.

The projected CO_2 emission allowance prices associated with the "S.2191 Limited/No International" case are the highest of the 5 cases considered by the EIA in their analysis of S.2191. This case assumes international offsets are unavailable and carbon reduction technologies are limited throughout the study period. By demonstrating the cost-effectiveness of GEC under the S.2191 Core case and the S.2191 Limited/No International case, it was determined unnecessary to evaluate the other cases containing projected CO_2 emission allowance prices which fall within the boundaries established by S.2191 Core and S.2191 Limited/No International.

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AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Duval)

I hereby certify that on this 2nd day of December, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Michael N. Lawson, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 25, 26, and 27 from STAFF'S SECOND SET OF INTERROGATORIES TO JEA (NOS. 25 - 29) in Docket No(s). 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 2nd day of December, 2008.

Michael Lawson

Notary Public
State of Florida, at large

My Commission Expires: 9-24-10

Cathy L Barnwell

CATHY L BARNWELL
Notary Public - State of Florida
My Commission Expires Sep 24, 2010
Commission # DD 556843
Bonded By National Notary Assn.

AFFIDAVIT

STATE OF KANSAS)

COUNTY OF Johnson)

I hereby certify that on this 25th day of November, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Bradley E. Kushner, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 28 and 29 from STAFF'S SECOND SET OF INTERROGATORIES TO JEA (NOS. 25 - 29) in Docket No(s). 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 25th day of November, 2008.

Notary Public
State of Kansas, at large
Marsha M. Purinton
My Commission Expires:
7-30-2011

MARSHA M. PURINTON NOTARY PUBLIC STATE OF KANSAS

Hearing Exhibit - 00000051

3

JEA's Responses to Staff's Third Set of Interrogatories (Nos. 30-43, 45-72, 74-76)

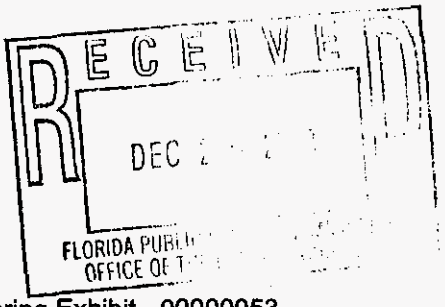
BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Greenland Energy Center Combined Cycle Conversion in Duval County by JEA.	DOCKET NO. 080614-EM DATED: DECEMBER 29, 2008

JEA'S RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 30 - 81)

JEA pursuant to Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staff's Third Set of Interrogatories (Nos. 30 – 81).

The answers to Interrogatories 30, 31, 42 – 44, 47, and 48 are provided by Donald C. Gilbert, JEA, 21 West Church St., Jacksonville, FL 32202. Answers to Interrogatories 32, 41, 45, 46, 66, 72, 74, 76, 80, and 81 are provided by Bradley E. Kushner (consultant to JEA), Black & Veatch, 11401 Lamar Ave., Overland Park, KS 66211. Answers to Interrogatories 35 – 40 and 50 are provided by Myron R. Rollins (consultant to JEA), Black & Veatch, 11401 Lamar Ave., Overland Park, KS 66211. Answers to Interrogatories 49 and 51 – 55 are provided by Richard J. Vento, JEA 21 West Church St., Jacksonville, FL 32202. Answers to Interrogatories 56 – 65 are provided by John A. Worley, JEA, 21 West Church St., Jacksonville, FL 32202. The answer to Interrogatory 73 is provided by Mary Guyton-Baker, JEA, 21 West Church St., Jacksonville, FL 32202. Answer to Interrogatories 75 and 76c is provided by James T. Myers, JEA, 21 West Church St., Jacksonville, FL 32202. Answers to Interrogatories 77 - 79 are provided by Michael N. Lawson, JEA, 21 West Church St., Jacksonville, FL 32202.



Hearing Exhibit - 00000053

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Greenland Energy Center Combined Cycle Conversion in Duval County by JEA.	DOCKET NO. 080614-EM DATED: JANUARY 5, 2009

JEA'S SUPPLEMENTAL RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 33, 34, 67 -71)

JEA pursuant to Rule 1.340, Florida Rules of Civil Procedure, hereby provides supplemental responses to Staff's Third Set of Interrogatories (Nos. 33, 34, 67 – 71).

Answers to Interrogatories 34, 67, 68, 69, 70, and 71 are provided by Bradley E. Kushner (consultant to JEA), Black & Veatch, 11401 Lamar Ave., Overland Park, KS 66211.

Hearing Exhibit - 00000054

RESPONSES TO INTERROGATORIES

30. Mr. Gilbert's testimony included how JEA intends to address its short-term capacity requirements resulting from the delay of the GEC combined cycle conversion from 2012 to 2013, but not the delay of the combustion turbines from 2010 to 2011. How will JEA meet the capacity requirements arising from the one year delay of the two GEC simple cycle combustion turbines?

Response: As discussed in the supplemental testimony of Witness Gilbert (filed November 21, 2008), JEA plans to issue a Request for Proposals (RFP) for power to meet the short-term capacity requirements caused by the one year delay in converting the two GEC simple cycle combustion turbines to combined cycle operation. The RFP will also address the one year delay of the two GEC simple cycle combustion turbines. Additionally, JEA's participation in The Energy Authority, or TEA, which is discussed throughout the GEC Need for Power Application as well as the direct and supplemental testimony of Witness Gilbert, could also be used to address this near-term capacity requirement.

31. With regard to purchased power agreements caused by the delay of the GEC Combustion Turbines and Combined Cycle Conversion, please provide the following information:

a) selling party
b) generating units
c) capacity size
d) anticipated capacity delivery date
e) anticipated termination date of the contract.

Response: JEA plans to issue a RFP to solicit the necessary purchase power, but has not yet developed the RFP. Until proposals are received in response to the RFP, the requested information is not known and therefore cannot be provided.

32. What impact will short-term purchased power contracts in 2010 and 2012 caused by the GEC delay have on rates? Please provide this information in impact on the average residential bill in $/month for 1200/kWh-month consumption.

Response: The impact that short-term purchased power contracts in 2010 and 2012 caused by the delay in commercial operation of GEC cannot be evaluated prior to completion of the RFP process discussed in response to Interrogatories Nos. 30 and 31 above. The analyses performed in support of the GEC Need for Power Application, consistent with established Commission policy and practice, focused on comparative economics across competing expansion plans. Rate impacts, however, include many other costs that are the same in all plans such as existing debt and customer service costs.

33. **Please indicate what the least cost alternative for each scenario and case is. Please explain answer. Please also include the additional High Interest Rate cases asked for in Question 68.**

Response: Please refer the table below, which presents a matrix of all cases for all scenarios that have been run reflecting the high interest rate and the 2013 commercial operation date for the GEC combined cycle conversion. Please note that for completeness JEA has evaluated all of the additional high interest rate cases requested by Staff, as well as the cases originally included in the GEC Need for Power Application, for Scenarios 1 through 4. When reviewing the table, please note that scenarios and cases labeled "GEC" indicate that the GEC CC conversion is cost-effective, while those labeled "No GEC" indicate that the GEC CC conversion is not cost-effective. Analysis of the table below indicates that the GEC combined cycle conversion is the most cost-effective alternative available for 38 of the 44 combinations of cases and scenarios considered.

		Scenario Number and Description			
		Scenario 1 Conventional	Scenario 2 Renewables	Scenario 3 DSM	Scenario 4 Renewables + DSM
Case (Sensitivity) Description	Reference Case	GEC	GEC	GEC	GEC
	High Fuel	GEC	GEC	GEC	GEC
	Low Fuel	GEC	GEC	GEC	GEC
	High Load	GEC	GEC	GEC	No GEC
	Low Load	GEC	GEC	No GEC	No GEC
	High Capital Cost	GEC	No GEC	GEC	GEC
	Regulated CO_2	GEC	GEC	GEC	GEC
	High Fuel with Regulated CO_2	GEC	GEC	GEC	GEC
	High Regulated CO_2	GEC	GEC	GEC	GEC
	High Fuel, High Load, & Regulated CO_2	GEC	GEC	GEC	GEC
	Low Fuel and Low Load	GEC	GEC	No GEC	No GEC

34. **Please explain the apparent change in trends seen in Table 1 of Exhibit BEK-2R when compared to Table 1 of Exhibit BEK-2. (Example: The original filing shows that the GEC conversion becomes more cost effective as load increases or as fuel costs increase. The supplemental testimony shows that the GEC conversion becomes less cost effective as load increases or as fuel costs increase.)**

Response: Upon review of the analyses used to develop Exhibits BEK-2 and BEK-2R it was discovered that the STRATEGIST runs for some of the cases did not use the proper fuel prices for future 1x1 7FA combined cycle alternatives. The cases impacted are the High Fuel, High Fuel with Regulated CO_2, High Regulated CO_2, Low Fuel, and Regulated CO_2 in both exhibits. The STRATEGIST analysis has since been updated to reflect the proper fuel for the future combined cycle resources, and the updated results are reflected in this discussion.

The table below provides the updated CPWC values for both Exhibit BEK-2 and BEK-2R. Note that the cases are sorted from most cost-effective to least cost-effective in each Exhibit, resulting

in the cases being in a different order in the column labeled *Exhibit BEK-2R Updated* than in the column labeled *Exhibit BEK-2 Updated.*

As shown in the table, the High Regulated CO_2, High Fuel with Regulated CO_2, and Regulated CO_2 cases are the most cost-effective cases and each is more cost-effective than the Reference case in both Exhibits BEK-2 Updated and BEK-2R Updated. Both Exhibits BEK-2 Updated and BEK-2R Updated also show that the High Fuel case is more cost-effective than the Reference Case. Additionally, the High Capital Cost, Low Fuel Cost, and Low Load cases are each less cost-effective than the Reference case in both Exhibits BEK-2 Updated and BEK-2R Updated.

Exhibit BEK-2 Updated Table 1		Exhibit BEK-2R Updated Table 1	
Case	CPWC Savings for GEC CC Conversion	Case	CPWC Savings for GEC CC Conversion
High Regulated CO_2	112,554	High Regulated CO_2	355,874
High Fuel with Regulated CO_2	139,074	High Fuel with Regulated CO_2	174,255
Regulated CO_2	156,981	Regulated CO_2	137,143
High Load	143,390	High Fuel	132,171
High Fuel	401,580	Reference Case	129,519
Reference Case	95,237	High Capital Cost	88,551
High Capital Cost	57,042	Low Load	86,158
Low Fuel	122,631	Low Fuel	85,668
Low Load	147,951	High Load	84,023

As shown in the table above, conversion of GEC to combined cycle operation results in CPWC savings for all of the cases in both Exhibit BEK-2 and Exhibit BEK-2R. The changes in relative cost-effectiveness shown above are explained by changes in the expansion plans that are chosen by STRATEGIST under the changed summer peak demands discussed in the supplemental

testimony of Bradley E. Kushner (filed November 21, 2008). These changes affect the timing of capacity additions, which in turn affect capital costs, fuel costs, operations and maintenance costs, and other costs. Note also that cost changes in the early years of the study period have more of an impact on CPWC than similar cost changes in later years due to application of the discount rate.

The greatest change in the relative cost-effectiveness of the various cases is that of the High Load case. In Exhibit BEK-2 the High Load case "with GEC CC conversion" is more cost-effective than the Reference case while in Exhibit BEK-2R it is less cost-effective than the Reference Case. The cause of this change in relative cost-effectiveness is also explained by the change in the expansion plans for the High Load cases. For the High Load case shown in Exhibit BEK-2, the expansion plan includes a 1x1 combined cycle unit in 2013 for the "with GEC CC conversion" run (two combined cycle units in the 2012-2013 timeframe). For the High Load case shown in Exhibit BEK-2R Updated, the revised expansion plan does not include a 1x1 combined cycle unit until 2022 for the "with GEC CC conversion" run. For both Exhibits BEK-2 Updated and BEK-2R Updated, the High Load case "without GEC CC conversion" expansion plans both include a 1x1 combined cycle unit in 2013. This results in the revised expansion plan for the "with GEC CC conversion" run in Exhibit BEK-2R Updated being more similar to the expansion plan "without GEC CC conversion" (each plan adds only one combined cycle resource, GEC CC or a new 1x1 CC). The "with GEC CC conversion" expansion plan in Exhibit BEK-2 Updated adds much more combined cycle generation in the 2012-2013 timeframe (both GEC CC and a new 1x1 CC) than the "without GEC CC conversion" expansion plan (only

a new 1x1 CC in 2013). Since the "with" and "without" GEC CC conversion expansion plans in Exhibit BEK-2R Updated are more similar (similar distribution of base, intermediate, and peaking resources) than the "with" and "without" GEC CC conversion expansion plans in Exhibit BEK-2 Updated, the relative cost-effectiveness for GEC CC conversion in Exhibit BEK-2R Updated is less than the relative cost-effectiveness for GEC CC conversion in Exhibit BEK-2 Updated.

For the questions 35 through 38, assuming the Expansion Plan includes the GEC Conversion in 2013 for all scenarios and cases, consider the following table:

Scenarios	Cases	
➢ 1 – Conventional Expansion ➢ 2 – Renewable Expansion ➢ 3 – DSM Expansion ➢ 4 – Renewables and DSM Expansion	• Reference • High Fuel • Low Fuel • High Load • Low Load	• High Capital Cost • Regulated CO2 • High Regulated CO2

35. Please indicate which scenario(s) JEA believes to be the most likely. Please explain answer.

Response: In general, JEA believes that scenarios that minimize total system costs while not having adverse impacts on customer rates would be the most likely scenarios. Scenarios that include increased amounts of renewable generation resources generally result in higher total system costs to serve the same annual energy requirements as corresponding scenarios that do not include increased amounts of renewable generation resources. Therefore, Scenarios 1 and 3, neither of which include increased renewable generation resources, may be considered most likely.

36. Please indicate which case(s) JEA believes to be the most likely. Please explain answer.

Response: The Reference Case was developed based on the best information available and is based on regulatory requirements in place at the time it was developed. However, the various cases evaluated throughout the GEC Need for Power Application were selected in order to provide analyses of the possible impact of variations to the Reference Case assumptions JEA

may not have control over (i.e. fuel prices, load forecasts, potential regulation of CO_2 emissions). Performing the numerous sensitivity evaluations helps to gauge the impact of varying underlying assumptions in evaluating the economics of the GEC combined cycle conversion.

37. Please indicate which scenario(s) JEA believes to be the least likely. Please explain answer.

Response: In general, JEA believes that scenarios that increase total system costs and/or have adverse impacts on customer rates would be the least likely scenarios. Scenarios that include increased amounts of renewable generation resources generally result in higher total system costs to serve the same annual energy requirements as corresponding scenarios that do not include increased amounts of renewable generation resources. Therefore, Scenarios 2 and 4, both of which include increased renewable generation resources, may be considered least likely.

38. Please indicate which case(s) JEA believes to be the least likely. Please explain answer.

Response: Please refer to the response to Interrogatory No. 36.

39. Please provide a version of Exhibit MRR-6, with and without the GEC Conversion, that includes Scenarios 1 through 4 and any DSM impacts or renewable additions assumed in each scenario.

Response: Please see the attached sheets labeled Response to Interrogatory No. 39, which present the requested information. All of the tables use the base load forecast and include JEA's existing DSM programs and existing renewable resources. Tables 1 (without the GEC Conversion) and 2 (with the GEC Conversion) are for Scenario 1. Scenario 1 does not include

any new DSM programs or any new renewable resources. Tables 3 (without the GEC Conversion) and 4 (with the GEC Conversion) are for Scenario 2. Scenario 2 does not include any new DSM programs; however, the new renewable resources are included. Tables 5 (without the GEC Conversion) and 6 (with the GEC Conversion) are for Scenario 3. Scenario 3 does include the new DSM programs; however, no new renewable resources are included. Tables 7 (without the GEC Conversion) and 8 (with the GEC Conversion) are for Scenario 4. Scenario 4 does include the new DSM programs and the new renewable resources.

Table 1

Scenario 1 without GEC CC Conversion
Projected Reliability Levels - Summer/Base Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	Base Forecast System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.5%	(176)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,007	2,890	9.9%	14.4%	(152)	(18)
2010	3,367	9	(376)	(51)	150	3,099	3,072	2,955	0.9%	4.9%	(435)	(300)
2011	3,367	9	(376)	(51)	434	3,383	3,138	3,021	7.8%	12.0%	(226)	(91)
2012	3,367	9	(376)	(51)	434	3,383	3,204	3,087	5.6%	9.6%	(301)	(167)
2013	3,367	9	(376)	(51)	434	3,383	3,269	3,152	3.5%	7.3%	(377)	(242)
2014	3,367	9	(376)	(51)	434	3,383	3,335	3,218	1.4%	5.1%	(452)	(317)
2015	3,367	9	(376)	(51)	434	3,383	3,400	3,283	-0.5%	3.0%	(527)	(393)
2016	3,367	9	0	(51)	434	3,759	3,466	3,349	8.5%	12.3%	(227)	(92)
2017	3,367	9	0	(51)	434	3,759	3,531	3,414	6.4%	10.1%	(302)	(167)
2018	3,367	0	0	(51)	434	3,750	3,597	3,480	4.3%	7.8%	(386)	(252)
2019	3,367	0	0	(51)	434	3,750	3,662	3,545	2.4%	5.8%	(462)	(327)
2020	3,367	0	0	(51)	434	3,750	3,728	3,611	0.6%	3.9%	(537)	(403)
2021	3,367	0	0	(51)	434	3,750	3,794	3,677	-1.1%	2.0%	(613)	(478)
2022	3,367	0	0	(51)	434	3,750	3,859	3,742	-2.8%	0.2%	(688)	(553)
2023	3,367	0	0	(51)	434	3,750	3,925	3,808	-4.5%	-1.5%	(763)	(629)
2024	3,367	0	0	(51)	434	3,750	3,990	3,873	-6.0%	-3.2%	(839)	(704)
2025	3,367	0	0	(51)	434	3,750	4,056	3,939	-7.5%	-4.8%	(914)	(780)
2026	3,367	0	0	(51)	434	3,750	4,121	4,004	-9.0%	-6.4%	(990)	(855)
2027	3,367	0	0	(51)	434	3,750	4,187	4,070	-10.4%	-7.9%	(1,065)	(930)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2011.

Hearing Exhibit - 00000065

Table 2

Scenario 1 with GEC CC Conversion
Projected Reliability Levels - Summer/Base Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	Base Forecast System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.5%	(176)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,007	2,890	9.9%	14.4%	(152)	(18)
2010	3,367	9	(376)	(51)	150	3,099	3,072	2,955	0.9%	4.9%	(435)	(300)
2011	3,367	9	(376)	(51)	434	3,383	3,138	3,021	7.8%	12.0%	(226)	(91)
2012	3,367	9	(376)	(51)	434	3,383	3,204	3,087	5.6%	9.6%	(301)	(167)
2013	3,367	9	(376)	(51)	641	3,590	3,269	3,152	9.8%	13.9%	(169)	(35)
2014	3,367	9	(376)	(51)	641	3,590	3,335	3,218	7.7%	11.6%	(245)	(110)
2015	3,367	9	(376)	(51)	641	3,590	3,400	3,283	5.6%	9.3%	(320)	(186)
2016	3,367	9	0	(51)	641	3,966	3,466	3,349	14.4%	18.4%	(19)	115
2017	3,367	9	0	(51)	641	3,966	3,531	3,414	12.3%	16.2%	(95)	40
2018	3,367	0	0	(51)	641	3,957	3,597	3,480	10.0%	13.7%	(179)	(45)
2019	3,367	0	0	(51)	641	3,957	3,662	3,545	8.0%	11.6%	(255)	(120)
2020	3,367	0	0	(51)	641	3,957	3,728	3,611	6.1%	9.6%	(330)	(196)
2021	3,367	0	0	(51)	641	3,957	3,794	3,677	4.3%	7.6%	(405)	(271)
2022	3,367	0	0	(51)	641	3,957	3,859	3,742	2.5%	5.7%	(481)	(346)
2023	3,367	0	0	(51)	641	3,957	3,925	3,808	0.8%	3.9%	(556)	(422)
2024	3,367	0	0	(51)	641	3,957	3,990	3,873	-0.8%	2.2%	(632)	(497)
2025	3,367	0	0	(51)	641	3,957	4,056	3,939	-2.4%	0.5%	(707)	(573)
2026	3,367	0	0	(51)	641	3,957	4,121	4,004	-4.0%	-1.2%	(783)	(648)
2027	3,367	0	0	(51)	641	3,957	4,187	4,070	-5.5%	-2.8%	(858)	(723)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009, GEC CTs 1 and 2 in June 2011, and conversion of GEC to combined cycle in June 2013.

Hearing Exhibit - 00000066

Table 3

Scenario 2 without GEC CC Conversion
Projected Reliability Levels - Summer/Renewables Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	Base Forecast System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.5%	(176)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,007	2,890	9.9%	14.4%	(152)	(18)
2010	3,367	9	(376)	(51)	153	3,102	3,072	2,955	0.9%	4.9%	(432)	(297)
2011	3,367	9	(376)	(51)	437	3,386	3,138	3,021	7.9%	12.1%	(223)	(88)
2012	3,367	9	(376)	(51)	472	3,421	3,204	3,087	6.8%	10.8%	(263)	(129)
2013	3,367	9	(376)	(51)	472	3,421	3,269	3,152	4.6%	8.5%	(339)	(204)
2014	3,367	9	(376)	(51)	472	3,421	3,335	3,218	2.6%	6.3%	(414)	(280)
2015	3,367	9	(376)	(51)	472	3,421	3,400	3,283	0.6%	4.2%	(490)	(355)
2016	3,367	9	0	(51)	472	3,797	3,466	3,349	9.6%	13.4%	(189)	(54)
2017	3,367	9	0	(51)	472	3,797	3,531	3,414	7.5%	11.2%	(264)	(130)
2018	3,367	0	0	(51)	472	3,788	3,597	3,480	5.3%	8.9%	(349)	(214)
2019	3,367	0	0	(51)	472	3,788	3,662	3,545	3.4%	6.8%	(424)	(289)
2020	3,367	0	0	(51)	472	3,788	3,728	3,611	1.6%	4.9%	(499)	(365)
2021	3,367	0	0	(51)	472	3,788	3,794	3,677	-0.2%	3.0%	(575)	(440)
2022	3,367	0	0	(51)	472	3,788	3,859	3,742	-1.8%	1.2%	(650)	(516)
2023	3,367	0	0	(51)	472	3,788	3,925	3,808	-3.5%	-0.5%	(726)	(591)
2024	3,367	0	0	(51)	472	3,788	3,990	3,873	-5.1%	-2.2%	(801)	(666)
2025	3,367	0	0	(51)	472	3,788	4,056	3,939	-6.6%	-3.8%	(876)	(742)
2026	3,367	0	0	(51)	472	3,788	4,121	4,004	-8.1%	-5.4%	(952)	(817)
2027	3,367	0	0	(51)	472	3,788	4,187	4,070	-9.5%	-6.9%	(1,027)	(893)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009, GEC CTs 1 and 2 in June 2011, Solar in 2010, and Biomass in 2012

Hearing Exhibit - 00000067

Table 4

Scenario 2 with GEC CC Conversion
Projected Reliability Levels - Summer/Renewables Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	Base Forecast System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.5%	(176)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,007	2,890	9.9%	14.4%	(152)	(18)
2010	3,367	9	(376)	(51)	153	3,102	3,072	2,955	0.9%	4.9%	(432)	(297)
2011	3,367	9	(376)	(51)	437	3,386	3,138	3,021	7.9%	12.1%	(223)	(88)
2012	3,367	9	(376)	(51)	472	3,421	3,204	3,087	6.8%	10.8%	(263)	(129)
2013	3,367	9	(376)	(51)	679	3,628	3,269	3,152	11.0%	15.1%	(132)	3
2014	3,367	9	(376)	(51)	679	3,628	3,335	3,218	8.8%	12.7%	(207)	(72)
2015	3,367	9	(376)	(51)	679	3,628	3,400	3,283	6.7%	10.5%	(282)	(148)
2016	3,367	9	0	(51)	679	4,004	3,466	3,349	15.5%	19.6%	18	153
2017	3,367	9	0	(51)	679	4,004	3,531	3,414	13.4%	17.3%	(57)	77
2018	3,367	0	0	(51)	679	3,995	3,597	3,480	11.1%	14.8%	(141)	(7)
2019	3,367	0	0	(51)	679	3,995	3,662	3,545	9.1%	12.7%	(217)	(82)
2020	3,367	0	0	(51)	679	3,995	3,728	3,611	7.2%	10.6%	(292)	(158)
2021	3,367	0	0	(51)	679	3,995	3,794	3,677	5.3%	8.7%	(368)	(233)
2022	3,367	0	0	(51)	679	3,995	3,859	3,742	3.5%	6.8%	(443)	(309)
2023	3,367	0	0	(51)	679	3,995	3,925	3,808	1.8%	4.9%	(518)	(384)
2024	3,367	0	0	(51)	679	3,995	3,990	3,873	0.1%	3.1%	(594)	(459)
2025	3,367	0	0	(51)	679	3,995	4,056	3,939	-1.5%	1.4%	(669)	(535)
2026	3,367	0	0	(51)	679	3,995	4,121	4,004	-3.1%	-0.2%	(745)	(610)
2027	3,367	0	0	(51)	679	3,995	4,187	4,070	-4.6%	-1.8%	(820)	(686)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009. GEC CTs 1 and 2 in June 2011. Solar in 2010. Biomass in 2012. and GEC CC Conversion in 2013

Hearing Exhibit - 00000068

Table 5

Scenario 3 without GEC CC Conversion
Projected Reliability Levels - Summer/DSM Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	Base Forecast System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.6%	(175)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,001	2,884	10.1%	14.6%	(146)	(11)
2010	3,367	9	(376)	(51)	150	3,099	3,045	2,928	1.8%	5.8%	(403)	(269)
2011	3,367	9	(376)	(51)	434	3,383	3,079	2,962	9.9%	14.2%	(158)	(24)
2012	3,367	9	(376)	(51)	434	3,383	3,100	2,983	9.1%	13.4%	(182)	(48)
2013	3,367	9	(376)	(51)	434	3,383	3,143	3,026	7.6%	11.8%	(232)	(97)
2014	3,367	9	(376)	(51)	434	3,383	3,209	3,092	5.4%	9.4%	(307)	(173)
2015	3,367	9	(376)	(51)	434	3,383	3,274	3,157	3.3%	7.2%	(382)	(248)
2016	3,367	9	0	(51)	434	3,759	3,340	3,223	12.5%	16.6%	(82)	53
2017	3,367	9	0	(51)	434	3,759	3,405	3,288	10.4%	14.3%	(157)	(22)
2018	3,367	0	0	(51)	434	3,750	3,471	3,354	8.0%	11.8%	(242)	(107)
2019	3,367	0	0	(51)	434	3,750	3,537	3,420	6.0%	9.7%	(317)	(183)
2020	3,367	0	0	(51)	434	3,750	3,602	3,485	4.1%	7.6%	(392)	(258)
2021	3,367	0	0	(51)	434	3,750	3,668	3,551	2.2%	5.6%	(468)	(334)
2022	3,367	0	0	(51)	434	3,750	3,733	3,616	0.5%	3.7%	(543)	(408)
2023	3,367	0	0	(51)	434	3,750	3,799	3,682	-1.3%	1.8%	(619)	(484)
2024	3,367	0	0	(51)	434	3,750	3,864	3,747	-2.9%	0.1%	(694)	(559)
2025	3,367	0	0	(51)	434	3,750	3,930	3,813	-4.6%	-1.6%	(769)	(635)
2026	3,367	0	0	(51)	434	3,750	3,996	3,879	-6.2%	-3.3%	(845)	(711)
2027	3,367	0	0	(51)	434	3,750	4,061	3,944	-7.7%	-4.9%	(920)	(786)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2011.

Hearing Exhibit - 00000069

Table 6

Scenario 3 with GEC CC Conversion
Projected Reliability Levels - Summer/DSM Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	Base Forecast System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.6%	(175)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,001	2,884	10.1%	14.6%	(146)	(11)
2010	3,367	9	(376)	(51)	150	3,099	3,045	2,928	1.8%	5.8%	(403)	(269)
2011	3,367	9	(376)	(51)	434	3,383	3,079	2,962	9.9%	14.2%	(158)	(24)
2012	3,367	9	(376)	(51)	434	3,383	3,100	2,983	9.1%	13.4%	(182)	(48)
2013	3,367	9	(376)	(51)	641	3,590	3,143	3,026	14.2%	18.6%	(24)	110
2014	3,367	9	(376)	(51)	641	3,590	3,209	3,092	11.9%	16.1%	(100)	34
2015	3,367	9	(376)	(51)	641	3,590	3,274	3,157	9.7%	13.7%	(175)	(41)
2016	3,367	9	0	(51)	641	3,966	3,340	3,223	18.7%	23.1%	125	260
2017	3,367	9	0	(51)	641	3,966	3,405	3,288	16.5%	20.6%	50	185
2018	3,367	0	0	(51)	641	3,957	3,471	3,354	14.0%	18.0%	(34)	100
2019	3,367	0	0	(51)	641	3,957	3,537	3,420	11.9%	15.7%	(110)	24
2020	3,367	0	0	(51)	641	3,957	3,602	3,485	9.9%	13.5%	(185)	(51)
2021	3,367	0	0	(51)	641	3,957	3,668	3,551	7.9%	11.4%	(261)	(126)
2022	3,367	0	0	(51)	641	3,957	3,733	3,616	6.0%	9.4%	(336)	(201)
2023	3,367	0	0	(51)	641	3,957	3,799	3,682	4.2%	7.5%	(412)	(277)
2024	3,367	0	0	(51)	641	3,957	3,864	3,747	2.4%	5.6%	(486)	(352)
2025	3,367	0	0	(51)	641	3,957	3,930	3,813	0.7%	3.8%	(562)	(428)
2026	3,367	0	0	(51)	641	3,957	3,996	3,879	-1.0%	2.0%	(638)	(504)
2027	3,367	0	0	(51)	641	3,957	4,061	3,944	-2.6%	0.3%	(713)	(578)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009. GEC CTs 1 and 2 in June 2011, and GEC CC Conversion in 2013

Hearing Exhibit - 00000070

Table 7

Scenario 4 without GEC CC Conversion
Projected Reliability Levels - Summer/DSM w Renewables Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	Base Forecast System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.6%	(175)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,001	2,884	10.1%	14.6%	(146)	(11)
2010	3,367	9	(376)	(51)	153	3,102	3,045	2,928	1.8%	5.9%	(401)	(266)
2011	3,367	9	(376)	(51)	437	3,386	3,079	2,962	10.0%	14.3%	(155)	(21)
2012	3,367	9	(376)	(51)	472	3,421	3,100	2,983	10.3%	14.7%	(145)	(10)
2013	3,367	9	(376)	(51)	472	3,421	3,143	3,026	8.8%	13.0%	(194)	(59)
2014	3,367	9	(376)	(51)	472	3,421	3,209	3,092	6.6%	10.6%	(270)	(135)
2015	3,367	9	(376)	(51)	472	3,421	3,274	3,157	4.5%	8.4%	(344)	(210)
2016	3,367	9	0	(51)	472	3,797	3,340	3,223	13.7%	17.8%	(44)	90
2017	3,367	9	0	(51)	472	3,797	3,405	3,288	11.5%	15.5%	(119)	16
2018	3,367	0	0	(51)	472	3,788	3,471	3,354	9.1%	12.9%	(204)	(69)
2019	3,367	0	0	(51)	472	3,788	3,537	3,420	7.1%	10.8%	(280)	(145)
2020	3,367	0	0	(51)	472	3,788	3,602	3,485	5.2%	8.7%	(354)	(220)
2021	3,367	0	0	(51)	472	3,788	3,668	3,551	3.3%	6.7%	(430)	(296)
2022	3,367	0	0	(51)	472	3,788	3,733	3,616	1.5%	4.8%	(505)	(370)
2023	3,367	0	0	(51)	472	3,788	3,799	3,682	-0.3%	2.9%	(581)	(446)
2024	3,367	0	0	(51)	472	3,788	3,864	3,747	-2.0%	1.1%	(656)	(521)
2025	3,367	0	0	(51)	472	3,788	3,930	3,813	-3.6%	-0.7%	(732)	(597)
2026	3,367	0	0	(51)	472	3,788	3,996	3,879	-5.2%	-2.3%	(807)	(673)
2027	3,367	0	0	(51)	472	3,788	4,061	3,944	-6.7%	-4.0%	(882)	(748)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009, GEC CTs 1 and 2 in June 2011. Solar in 2010 and Biomass in 2012.

Hearing Exhibit - 00000071

Table 8

Scenario 4 with GEC CC Conversion
Projected Reliability Levels - Summer/DSM w Renewables Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	Base Forecast System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.6%	(175)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,001	2,884	10.1%	14.6%	(146)	(11)
2010	3,367	9	(376)	(51)	153	3,102	3,045	2,928	1.8%	5.9%	(401)	(266)
2011	3,367	9	(376)	(51)	437	3,386	3,079	2,962	10.0%	14.3%	(155)	(21)
2012	3,367	9	(376)	(51)	472	3,421	3,100	2,983	10.3%	14.7%	(145)	(10)
2013	3,367	9	(376)	(51)	679	3,628	3,143	3,026	15.4%	19.9%	13	148
2014	3,367	9	(376)	(51)	679	3,628	3,209	3,092	13.1%	17.3%	(63)	72
2015	3,367	9	(376)	(51)	679	3,628	3,274	3,157	10.8%	14.9%	(137)	(3)
2016	3,367	9	0	(51)	679	4,004	3,340	3,223	19.9%	24.2%	163	298
2017	3,367	9	0	(51)	679	4,004	3,405	3,288	17.6%	21.8%	88	223
2018	3,367	0	0	(51)	679	3,995	3,471	3,354	15.1%	19.1%	3	138
2019	3,367	0	0	(51)	679	3,995	3,537	3,420	12.9%	16.8%	(73)	62
2020	3,367	0	0	(51)	679	3,995	3,602	3,485	10.9%	14.6%	(147)	(13)
2021	3,367	0	0	(51)	679	3,995	3,668	3,551	8.9%	12.5%	(223)	(89)
2022	3,367	0	0	(51)	679	3,995	3,733	3,616	7.0%	10.5%	(298)	(163)
2023	3,367	0	0	(51)	679	3,995	3,799	3,682	5.2%	8.5%	(374)	(239)
2024	3,367	0	0	(51)	679	3,995	3,864	3,747	3.4%	6.6%	(449)	(314)
2025	3,367	0	0	(51)	679	3,995	3,930	3,813	1.7%	4.8%	(525)	(390)
2026	3,367	0	0	(51)	679	3,995	3,996	3,879	0.0%	3.0%	(600)	(466)
2027	3,367	0	0	(51)	679	3,995	4,061	3,944	-1.6%	1.3%	(675)	(541)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009, GEC CTs 1 and 2 in June 2011, Solar in 2010, Biomass in 2012, and GEC CC Conversion in 2013

Hearing Exhibit - 00000072

40. Please provide a version of Exhibit MRR-6 that shows low load and the renewable additions assumed in Scenario 4.

Response: Please see the attached sheets labeled Response to Interrogatory No. 40, which present the requested information. The table shown in Response to Interrogatory No. 40 is based on the low load forecast and includes JEA's existing DSM programs and existing renewable resources and does not reflect the GEC combined cycle conversion. Scenario 4 does include the new DSM programs and the new renewable resources. JEA does not believe it is appropriate to combine Scenario 4 (DSM savings) with the low load case. The low load case would already reflect reductions due to conservation/DSM efforts. Thus, adding the full DSM savings on top of the low load case would likely result in "double counting" of load reductions due to conservation/DSM and thereby result in an unrealistically low demand.

Scenario 4 without GEC CC Conversion
Projected Reliability Levels - Summer/DSM w Renewables w Low Load Case wo GEC

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	Low Forecast System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,808	2,691	14.2%	19.2%	(22)	112
2009	3,367	216	(376)	(51)	150	3,306	2,865	2,748	15.4%	20.3%	10	145
2010	3,367	9	(376)	(51)	153	3,102	2,907	2,790	6.7%	11.2%	(241)	(107)
2011	3,367	9	(376)	(51)	437	3,386	2,938	2,821	15.2%	20.0%	7	141
2012	3,367	9	(376)	(51)	472	3,421	2,957	2,840	15.7%	20.5%	20	155
2013	3,367	9	(376)	(51)	472	3,421	2,997	2,880	14.1%	18.8%	(26)	109
2014	3,367	9	(376)	(51)	472	3,421	3,059	2,942	11.8%	16.3%	(98)	37
2015	3,367	9	(376)	(51)	472	3,421	3,122	3,005	9.6%	13.8%	(169)	(35)
2016	3,367	9	0	(51)	472	3,797	3,185	3,068	19.2%	23.7%	134	268
2017	3,367	9	0	(51)	472	3,797	3,248	3,131	16.9%	21.3%	62	197
2018	3,367	0	0	(51)	472	3,788	3,311	3,194	14.4%	18.6%	(20)	115
2019	3,367	0	0	(51)	472	3,788	3,375	3,258	12.3%	16.3%	(93)	42
2020	3,367	0	0	(51)	472	3,788	3,437	3,320	10.2%	14.1%	(165)	(30)
2021	3,367	0	0	(51)	472	3,788	3,499	3,382	8.2%	12.0%	(236)	(102)
2022	3,367	0	0	(51)	472	3,788	3,562	3,445	6.3%	10.0%	(308)	(174)
2023	3,367	0	0	(51)	472	3,788	3,625	3,508	4.5%	8.0%	(381)	(247)
2024	3,367	0	0	(51)	472	3,788	3,688	3,571	2.7%	6.1%	(453)	(318)
2025	3,367	0	0	(51)	472	3,788	3,751	3,634	1.0%	4.2%	(526)	(391)
2026	3,367	0	0	(51)	472	3,788	3,815	3,698	-0.7%	2.4%	(599)	(464)
2027	3,367	0	0	(51)	472	3,788	3,877	3,760	-2.3%	0.7%	(671)	(536)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009. GEC CTs 1 and 2 in June 2011. Solar in 2010, and Biomass in 2012.

Hearing Exhibit - 00000074

41. Please complete the following table comparing JEA's proposed conversion project and other generation alternatives. Please provide values which are reflective of the one-year delay.

Comparison of JEA's Generation Options					
Technology	**GEC Conversion**	**GE 7FA Simple Cycle**	**GE 1x1 7FA Combined Cycle**	**GE LM6000 Simple Cycle**	**GE LMS100 Simple Cycle**
Costs					
Installed Costs (2008$ million)					
Capital ($/kW)					

Response: Please refer to the completed table below. The installed costs, in 2008 dollars, were calculated by first calculating an installed cost for May 2013 commercial operation (the assumed commercial operation date of the GEC combined cycle conversion) and de-escalating these costs to 2008 dollars at the 2.5 percent escalation rate used throughout the GEC Need for Power Application. Installed costs were calculated based on the construction periods for each alternative as presented in the GEC Need for Power Application and using the 7.0 percent interest during construction rate discussed in the supplemental testimony of Witness Rollins (filed November 21, 2008).

The capital cost per kW presented in the table below was calculated for each alternative assuming the full load net plant output at average ambient conditions. For the GEC combined cycle conversion, the incremental capacity that is expected to be realized beyond the capacity of the two GEC simple cycle combustion turbines was used in this calculation. The capital cost per kW of the GEC combined cycle conversion is therefore higher than the other alternatives shown in the table. However, as discussed in response to Staff's Interrogatory No. 19, this higher capital cost is offset by the fact that the GEC combined cycle conversion will not use more

natural gas than the GEC simple cycle combustion turbines (except in instances where the GEC combined cycle is operating with supplemental firing) as the combined cycle conversion will utilize the waste heat generated by the simple cycle combustion turbines.

Comparison of JEA's Generation Options					
Technology	**GEC Conversion**	**GE 7FA Simple Cycle**	**GE 1x1 7FA Combined Cycle**	**GE LM6000 Simple Cycle**	**GE LMS100 Simple Cycle**
Costs					
Installed Costs (2008$ million)	395.2	142.0	366.2	73.9	116.0
Capital (2008$/kW)	1,909.3	901.3	1,192.2	1,563.0	1,201.7

42. Please complete the table below regarding the performance of JEA's Brandy Branch CC unit.

Year	Planned Outage Factor	Forced Outage Factor	Equivalent Availability Factor	Resulting Capacity Factor	Average Net Operating Heat Rate
2005					
2006					
2007					

Response: Please see the completed table below in response to this request. Note that Brandy Branch Combined Cycle began commercial operation in January 2005, and therefore the data is presented for fiscal year 2005/06 through fiscal year 2007/08 in order to capture 3 complete fiscal years of Brandy Branch Combined Cycle operation. It should be noted that the higher planned outage factor in fiscal year 2006/07 was due to a planned outage that replaced heat recovery steam generator (HRSG) tubing that was damaged due to faulty storage during construction and to chemically clean the HRSG.

Fiscal Year	Planned Outage Factor	Forced Outage Factor	Equivalent Availability Factor	Resulting Capacity Factor	Average Net Operating Heat Rate
2005/06	3.45%	0.56%	95.01%	30.10%	7,544
2006/07	16.50%	1.92%	78.67%	25.50%	7,741
2007/08	4.82%	1.97%	91.16%	32.60%	7,642

43. Please provide transmission costs associated with the GEC. Also please provide critical in service dates, reflective of the delay of the GEC conversion.

Response: There are no transmission system improvements directly related to the additional capacity associated with the GEC combined cycle conversion. The transmission switching station and associated transmission interconnections required for the GEC simple cycle combustion turbines have sufficient capacity to support the incremental generating capacity of the GEC combined cycle conversion. Therefore, no additional transmission system improvement costs or considerations are reflected in the GEC Need for Power Application, and there are no critical in-service dates for the GEC combined cycle conversion. The cost of interconnection of the GEC combined cycle steam turbine generator is included in the estimated capital cost of the GEC combined cycle conversion.

Due to forecasted load growth south of the GEC site, the JEA planned transmission circuit interconnection of the JEA planned Nocatee substation (required to support this load growth) has been identified as a necessary improvement for reliable load service with this additional generation. This additional transmission interconnection and system improvement based on the realization of load growth south of the GEC site is a separate decision apart from the decision to move forward with the GEC combined cycle conversion.

45. Were transmission costs included in JEA's economic evaluation?

Response: As discussed in response to Interrogatory No. 43, the costs for interconnection of the steam turbine generator to the GEC switchyard have been included in the GEC combined cycle conversion capital cost estimate. Capital cost estimates for all other supply-side alternatives include transmission costs as part of the owner's costs.

46. Please provide the projected transmission costs for each supply side alternative.

Response: As discussed in Section 13.0 of the GEC Need for Power Application, the capital cost estimates for the generating unit alternatives (besides the GEC combined cycle conversion) were developed on a greenfield basis. The capital cost estimates for the generating unit alternatives include direct and indirect costs, and allowances for possible general owner's cost items are included. The owner's costs are intended to cover a number of different possible costs, including costs associated with transmission.

47. Please refer to page 5, lines 18 through 24 of the testimony of Mr. Rollins dated September 30, 2008. Please quantify and provide the cost benefits related to avoiding the additional transmission that would be required if GEC was not developed.

Response: The southeast portion of JEA's service territory where GEC will be located is the fastest growing portion of JEA's service territory. It also does not have any generation to provide transmission support. If GEC is not constructed, additional transmission will be needed to support the area. Estimates for some of the transmission projects that were considered prior to the decision to construct GEC are as follows.

River Crossing Upgrade (918/926 reconductor)	$30.5 million
Partial Underground of Circuit 852	$15.5 million
Addition of Center Park to Greenland	$18.0 million
Total	$64.0 million

In addition, losses will be reduced with the addition of GEC. A January 2008 loss study estimated annual savings due to reduced losses ranging from $2.2 million to $3.4 million from 2010 to 2016.

48. Please refer to page 5, lines 18 through 24 of the testimony of Mr. Rollins dated September 30, 2008. Will these transmission system improvements be required with any purchased power contracts currently considered, including those relating to the delay of the GEC combustion turbines and combined cycle conversion?

Response: It is anticipated that only purchased power will be required to meet short-term seasonal reserve requirements and thus long-term capital investments and transmission system improvements will not be required.

49. What, if any incentives are being offered with JEA's new DSM portfolio?

Response: The following summarizes the incentives being offered with JEA's new DSM portfolio:

- Residential Lighting – The incentive for coupon sales is $1.50 per bulb. The coupon rebate represents just 2 percent of the program. Under the markdown program, the average incentive is $0.66 per bulb.

- Neighborhood Efficiency – JEA will install the list of measures in the identified homes at no cost to the homeowner. The actual equipment and installation costs to JEA are expected to average $360 per home.

- Residential Direct Load Control – While not yet tested, the incentives needed for the target penetrations include installation of a programmable communicating thermostat at no cost to the customer (which may reduce energy bills by up to 15 percent); installation of a home area network gateway that can be utilized for home applications other than JEA load control at no cost to the customer; and customer web access to thermostat, water heater, and pool pump monitoring and controlling at no cost to the customer.

50. Is the Residential Direct Load Control (DLC) Program or the Commercial DLC Program considered to be interruptible load or load management in JEA's calculations of capacity need? Please explain why.

Response: The interruptible and load management shown in Tables 12-1 and 12-2 of the GEC Need for Power Application represent JEA's existing curtailable and interruptible loads. The interruptible and load management shown in Exhibits MRR-4 and MRR-5 also represent JEA's existing curtailable and interruptible loads. The Residential Direct Load Control (DLC) program and the Commercial DLC programs are programs associated with JEA's new DSM portfolio. The Residential DLC and Commercial DLC programs are shown in Tables 15-8 and 15-9 of the GEC Need for Power Application (note that the Commercial DLC program has now been delayed one year). The interruptible and load management shown in Exhibits MRR-6 and MRR-7 include both the existing JEA curtailable and interruptible loads as well as the new Residential and Commercial DLC programs.

51. Please provide Exhibit RJV-2, Tables 15-8 through 15-11, updated to reflect the delay of the Residential Efficiency Upgrades and the commercial Direct Load Control programs, for the years 2008 through 2013.

Response: Please see the tables below, which provide updated versions of Exhibit RJV-2 and Tables 15-8 through 15-11 of the GEC Need for Power Application, as requested.

Exhibit RJV-2 Table 1 (GEC Need for Power Application Table 15-8)
Target JEA DSM Portfolio Summer Peak Demand Reductions
(Cumulative MW Reductions)

DSM Program	2008	2009	2010	2011	2012	2013
Residential Lighting	2.8	8.5	14.2	19.8	25.5	25.5
Neighborhood Efficiency	0.2	0.4	0.6	0.8	1.0	1.0
Residential Efficiency Upgrades	0.0	0.0	2.3	6.8	11.3	15.8
Residential Direct Load Control	0.0	7.1	21.2	36.5	51.8	51.8
Commercial Direct Load Control	0.0	0.0	5.9	17.8	35.6	53.4
Total Cumulative Demand Reductions[1]	3.0	16.0	44.2	81.7	125.2	147.5

[1] Totals may not exactly equal the sum of the individual program demand reductions due to rounding.

Exhibit RJV-2 Table 2 (GEC Need for Power Application Table 15-9)
Target JEA DSM Portfolio Winter Peak Demand Reductions
(Cumulative MW Reductions)

DSM Program	2008	2009	2010	2011	2012	2013
Residential Lighting	1.9	5.7	11.3	16.3	21.2	21.2
Neighborhood Efficiency	0.2	0.4	0.6	0.8	1.0	1.0
Residential Efficiency Upgrades	0.0	0.0	1.5	4.5	9.0	13.0
Residential Direct Load Control	0.0	8.2	26.9	51.4	75.9	75.9
Commercial Direct Load Control	0.0	0.0	5.8	17.4	31.3	45.3
Total Cumulative Demand Reductions[1]	2.0	14.3	46.1	90.4	138.4	156.3

[1] Totals may not exactly equal the sum of the individual program demand reductions due to rounding.

Exhibit RJV-2 Table 3 (GEC Need for Power Application Table 15-10)
Target JEA DSM Portfolio Total Annual Energy Reductions
(Cumulative GWh Reductions)

DSM Program	Calendar Year 2008[1]	Calendar Year 2009	Calendar Year 2010	Calendar Year 2011	Calendar Year 2012	Calendar Year 2013
Residential Lighting	2.2	14.1	37.2	67.1	87.2	87.2
Neighborhood Efficiency	0.2	1.0	1.8	2.6	3.2	3.2
Residential Efficiency Upgrades	0.0	0.0	3.8	17.4	41.9	66.3
Residential Direct Load Control	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Direct Load Control	0.0	0.0	0.0	0.0	0.0	0.0
Total Cumulative Energy Reductions[2]	2.4	15.1	42.8	87.1	132.3	156.8

[1] Energy reductions were not provided by Summit Blue for 2008. The 2008 GWh reductions have been estimated based on actual performance to date.
[2] Totals may not exactly equal the sum of the individual program energy reductions due to rounding.

Exhibit RJV-2 Table 4 (GEC Need for Power Application Table 15-11) Target JEA DSM Portfolio Annual Program Costs (Millions $)						
DSM Program	Fiscal Year 2008	Fiscal Year 2009	Fiscal Year 2010	Fiscal Year 2011	Fiscal Year 2012	Fiscal Year 2013
Residential Lighting	$0.6	$1.4	$2.2	$1.9	$1.9	$0
Neighborhood Efficiency	$0.25	$0.4	$0.35	$0.35	$0.35	$0
Residential Efficiency Upgrades	$0.0	$0.0	$1.0	$2.1	$3.1	$2.1
Residential Direct Load Control	$0.3	$1.2	$2.7	$3.6	$3.6	$3.6
Commercial Direct Load Control	$0.0	$0.0	$0.4	$0.9	$1.1	$1.1
Total Program Costs[1]	$1.15	$3.0	$6.65	$8.85	$10.05	$6.8
[1] Totals may not exactly equal the sum of the individual program costs due to rounding.						

52. In reference to the updated Exhibit RJV-2 in the previous question, how many participants does JEA expect from the new residential and commercial DSM programs?

Response: Please refer to the following table, which presents projected participation by program for JEA's new DSM portfolio. Note that data provided for fiscal year 2008 is actual data, while projections are provided for fiscal year 2009 through fiscal year 2012.

DSM Program (indicator of participation)	FY'08	FY'09	FY'10	FY'11	FY'12	Total
Neighborhood Efficiency (homes)	424	1,784	1,784	1,784	1,784	7,560
Residential Lighting (products)	218,383	688,564	1,014,726	906,005	887,885	3,715,563
Residential Direct Load Control (homes/small businesses)	0	2,733	6,233	8,167	8,167	25,300
Residential Efficiency Upgrades (products)	Program design is not yet complete					
Commercial Direct Load Control (large commercial/industrial)	Program design is not yet complete					

a. What effect would a greater level of participation have on the DSM savings?

Response: Greater levels of participation than those shown in the table above would result in an increase to energy and/or capacity reductions, depending on which programs experience greater

participation levels. Participation and savings associated with the Residential and Commercial Direct Load Control programs may be limited by the demand response limitations discussed in the direct testimony of Witness Rollins.

b. What effect would less participation have on DSM savings?

Response: Reduced levels of participation than those shown in the table above would result in a reduction to energy and/or capacity reductions, depending on which programs experience reduced participation levels.

53. With the delay in construction of new generation, why defer programs that help to defer the need for generation?

Response: As discussed in the supplemental testimony of Witness Gilbert, recent credit market developments have led JEA to defer a large portion of capital expenditures initially planned for fiscal year 2009, including the DSM programs discussed in the supplemental testimony of Witness Vento (filed November 21, 2008). The economic pressure to reduce costs forced JEA cost reductions across the board. The two DSM programs which were delayed were the two programs for which design had not been completed. It should be noted that even cost effective DSM programs may not be cost effective immediately due to design and startup costs.

54. Will the delay of the GEC Combined Cycle Conversion to 2013 result in any additional DSM savings from those programs that are not delayed?

Response: No. The demand savings projections for the new DSM program are considered aggressive and will not be impacted by the delay in the GEC conversion.

55. If two DSM programs are being delayed, how will the reductions from DSM programs be the same in 2013?

Response: The total annual capacity and energy reductions associated with the new DSM programs as presented in Witness Vento's direct testimony (filed September 30, 2008) and reflected in the GEC Need for Power Application would be held constant beginning in 2012 (that is, total reductions in 2013 and beyond were projected to be equal to those in 2012). Therefore, while delaying the DSM programs by one year results in reduced annual capacity and energy reductions for the years 2008 through 2012, by 2013 there is no impact of the one year delay to total projected reductions.

56. What role will renewables play in filling the need for energy and capacity due to the delay of the GEC Combustion Turbines and the GEC Combined Cycle Conversion by approximately one year?

Response: JEA is planning to continue its existing renewable initiatives including continuing negotiations with the company that provided the lowest cost solar photovoltaic (PV) proposal described in the direct testimony of Witness Worley (filed September 30, 2008) and discussed in response to Interrogatory No. 60. However, when taken in aggregate these renewable projects do not offer sufficient capacity to displace the need for capacity resulting from the delay of the GEC combustion turbines and combined cycle conversion.

57. What additional renewables projects is JEA exploring?

Response: In addition to the renewable projects discussed in the direct testimony of Witness Worley (filed September 30, 2008), JEA, under a confidentiality agreement, is evaluating an unsolicited proposal for a 50 MW purchase power agreement (PPA) from a biomass generating facility. JEA has also been approached regarding the potential for biomass generation comprised of City of Jacksonville yard waste.

58. What is the status of the contract with Landfill Energy Systems for generation at the Trail Ridge Landfill?

Response: JEA has a signed purchase power agreement in place with Landfill Energy Systems, and the Trail Ridge Landfill gas-to-energy facility achieved commercial operation effective December 6, 2008.

59. What issues have kept Biomass Investment Group from implementing its project?

Response: JEA does not know what issues have kept Biomass Investment Group (BIG) from implementing its project. JEA signed a purchase power agreement with BIG in 2001. None of the original milestones were ever reached by BIG. The plant was originally expected to come on-line in 2004. From 2004 through 2006, BIG contacted JEA to propose new contract terms (new location, larger facility, higher costs). BIG has since executed a contract with another utility at a different location.

60. What effect has the current financial situation had on any planned renewable projects, such as the PPA being negotiated with Rocky Mountain Energy Group, *mentioned in response to an earlier staff interrogatory?*

Response: JEA is currently in negotiations with juwi Holding AG (juwi), formerly referred to as Rocky Mountain Energy Group, for a PPA from a 12.3 MW (AC) nameplate solar photovoltaic (PV) facility. As discussed above, JEA is also negotiating a PPA from a biomass facility under a confidentiality agreement. From JEA's perspective, the current financial situation has had no effect on negotiations. JEA cannot speak to the effect that the current financial situation may have on project developers.

61. Is JEA still in negotiations for new solar generation that came about from the most recent RFP for solar and wind? How large is the project? Has an in-service date been chosen? *Is JEA still in negotiations with any companies for solar photovoltaic equipment?*

Response: Yes. Please see response to Interrogatory No. 60. The project is expected to have a maximum nameplate rating of approximately 12.3 MW (AC) and was proposed to be in-service in 2010, although an actual in-service date has not been determined as of yet. JEA is not involved in negotiations with any companies for solar photovoltaic equipment.

62. What issues have been raised that have kept JEA from accepting unsolicited biomass generation offers?

Response: Issues that have kept JEA from accepting unsolicited biomass proposals to enter into negotiations have included:

- High price

- Lack of identified fuel source
- Lack of identified site
- Lack of demonstration of ability to finance

63. Is JEA still considering working with other municipal utilities on renewable generation projects? If so, what types of generation and when would they be going into service?

Response: JEA is not currently working with other municipal utilities on any specific renewable generation projects. However, in the event a potential renewable energy project is identified with other municipal utilities which would benefit JEA's customers, the proposed project would be evaluated.

64. How many customers are taking advantage of net metering?

Response: JEA currently has 24 net metering customers.

65. How much is the incentive for solar hot water heaters?

Response: Please see the following table summarizing the solar water heating incentives. Note that JEA is not involved in pricing solar energy systems; this is determined by the customer and solar vendor. The customer coordinates financing and/or payment with the solar vendor they select.

JEA Solar Power Incentives		
Solar Thermal	**Local Vendor**	**Non-Local Vendor**
Residential Hot Water[1] Commercial Hot Water	$800 per installation 30% of total installed cost ($5,000 max)	$400 per installation 15% of total installed cost ($2,500 max)
Retrofits[2]	**Local Vendor**	**Non-Local Vendor**
To restore existing Solar Hot Water systems to working order	30% of total installed cost (up to $500)	15% of total installed cost (up to $250)
($5,000 maximum incentive per project)[3]		

1. Medium temperature collector.
2. For systems installed before April 22, 1997; Retrofits apply to solar hot water systems and exclude the hot water heater tank.
3. *JEA reserves the right to limit funds for this program.* This maximum may be waived by JEA based on business conditions, availability of funds, and projected residual funds required to fund the Program for the balance of the year. This potential waiver does not guarantee that 100% of the incentive (above $5,000) will be available.

66. Does JEA consider solar generation to be firm capacity?

a. If no, has JEA evaluated the potential for solar generators to provide firm capacity?

Response: Customer installed solar generation is not considered firm capacity. However, reductions in system hourly integrated demands and net energy for load from customer installed solar generation (including JEA's solar PV program) will be reflected in JEA's historical load data that is used as the basis for JEA's annual demand and energy forecast.

JEA does not currently own any central station solar generation and thus has no territorial specific data to use as a basis for determining the firmness of solar generation. However, JEA uses for its evaluation of developer proposals for solar generation projects a projected schedule of forecasted system output by hour. This hourly output will vary depending on the type of solar system proposed: (1) fixed position PV, (2) single-axis tracking PV, or (3) dual-axis tracking PV. For both fixed position and single-axis tracking PV, consideration is required for the design optimization of tilt relative to maximum annual energy or maximum capacity coincident with

utility peak or some optimum compromise. In general, the maximization of annual energy is economically more beneficial than providing capacity for utility coincident peaks.

Additional consideration is required for the effects of rain and clouds on the output of the solar generation. In general, cloud cover reduces the output of the solar PV, but also has a potential corresponding affect on load reduction. Statistics need to be developed over time correlating these two variables to determine if the potential high forced outage rate of solar generation would have a negative consequence on operating a balanced generation and load system.

As presented in this application, JEA experiences similar system peak levels in both the winter and summer seasons. Historically, JEA realizes its winter peak hours during nighttime hours either early in the morning before sunrise or later in the evening after sunset. Due to the nature of solar generation, no firm capacity credit would be allotted for winter peaks and thus a real limit for solar generation exists on JEA's system unless a cost effective complimentary supply-side or demand-side program can be implemented. Solar generation beyond any potential cost effective winter seasonal supply-side or demand-side program would be deemed variable or non-firm capacity.

b. If yes, please discuss the times at which this generation is considered firm and to what degree does solar contribute, partially or in full, its nameplate capacity to seasonal peak demand?

Response: Please see the response to Interrogatory 66a.

67. **Please expand Table 5 Exhibit BEK-3 to include the following cases with Scenario 3 and Scenario 4: High Fuel, Low Fuel, High Load, Low Load, Regulated CO_2, High Fuel with Regulated CO_2. Additionally please provide a case for both which assumes High Fuel, High Load, and Regulated CO_2 and another with Low Fuel and Low Load.**

High Interest Rate Scenario (3 or 4)	CPWC Summaries for High Interest Cases ($000)		
	CPWC of Expansion Plan Including GEC Conversion in 2013	CPWC of Expansion Plan Without GEC Conversion in 2013	CPWC Savings For Expansion Plan with GEC Conversion in 2013
High Fuel			
Low Fuel			
High Load			
Low Load			
Regulated CO2			
High Fuel & Regulated CO2			
High Fuel, High Load, & Regulated CO2			
Low Fuel & Low Load			

Response: As discussed in response to Interrogatory No. 33, for completeness JEA has evaluated all of the additional high interest rate cases requested by Staff, as well as the cases originally included in the GEC Need for Power Application, for Scenarios 1 through 4. Please refer to the completed tables below, which provide the requested information for all scenarios

and cases. Please note that cases showing positive CPWC savings indicate the GEC combined cycle conversion in 2013 is cost-effective, while those showing negatives CPWC savings indicate that the GEC combined cycle conversion is not cost-effective. Analysis of the following tables indicates the GEC combined cycle conversion is cost-effective in 33 of the 44 combinations of cases and scenarios considered.

	CPWC Summaries for High Interest Cases ($000)		
High Interest Rate Scenario 1	**CPWC of Expansion Plan Including GEC Conversion in 2013**	**CPWC of Expansion Plan Without GEC Conversion in 2013**	**CPWC Savings For Expansion Plan with GEC Conversion in 2013**
Reference Case	9,281,091	9,302,644	21,553
High Fuel	9,758,430	9,787,729	29,299
Low Fuel	8,834,056	8,838,960	4,903
High Load	10,800,299	10,807,283	6,984
Low Load	8,449,539	8,485,484	35,945
High Capital Cost	9,382,999	9,386,919	3,920
High Regulated CO_2	19,523,498	19,710,147	186,648
Regulated CO_2	13,077,136	13,115,422	38,285
High Fuel & Regulated CO_2	13,830,732	13,878,412	47,680
High Fuel, High Load, & Regulated CO_2	15,661,599	15,740,549	78,950
Low Fuel & Low Load	8,075,499	8,042,451	-33,048

	CPWC Summaries for High Interest Cases ($000)		
High Interest Rate Scenario 2	**CPWC of Expansion Plan Including GEC Conversion in 2013**	**CPWC of Expansion Plan Without GEC Conversion in 2013**	**CPWC Savings For Expansion Plan with GEC Conversion in 2013**
Reference Case	9,461,336	9,471,653	10,318
High Fuel	9,918,385	9,934,632	16,247
Low Fuel	9,036,136	9,028,436	-7,701
High Load	10,921,722	10,968,906	47,185
Low Load	8,592,949	8,657,157	64,208
High Capital Cost	9,602,888	9,639,248	36,360
High Regulated CO_2	19,601,389	19,731,562	130,174
Regulated CO_2	13,227,572	13,244,926	17,353
High Fuel & Regulated CO_2	13,954,597	13,982,364	27,767
High Fuel, High Load, & Regulated CO_2	15,769,461	15,849,035	79,574
Low Fuel & Low Load	8,236,637	8,228,690	-7,946

High Interest Rate Scenario 3	CPWC Summaries for High Interest Cases ($000)		
	CPWC of Expansion Plan Including GEC Conversion in 2013	CPWC of Expansion Plan Without GEC Conversion in 2013	CPWC Savings For Expansion Plan with GEC Conversion in 2013
Reference Case	9,079,387	9,097,998	18,610
High Fuel	9,546,163	9,571,903	25,740
Low Fuel	8,645,770	8,645,975	205
High Load	10,535,636	10,546,566	10,930
Low Load	8,291,782	8,273,320	-18,462
High Capital Cost	9,153,406	9,167,220	13,813
High Regulated CO_2	19,307,496	19,552,971	245,475
Regulated CO_2	12,857,755	12,891,370	33,615
High Fuel & Regulated CO_2	13,596,990	13,640,478	43,488
High Fuel, High Load, & Regulated CO_2	15,376,283	15,444,147	67,864
Low Fuel & Low Load	7,932,031	7,845,001	-87,031

High Interest Rate Scenario 4	CPWC Summaries for High Interest Cases ($000)		
	CPWC of Expansion Plan Including GEC Conversion in 2013	CPWC of Expansion Plan Without GEC Conversion in 2013	CPWC Savings For Expansion Plan with GEC Conversion in 2013
Reference Case	9,249,787	9,289,963	40,175
High Fuel	9,679,356	9,633,824	-45,532
Low Fuel	8,837,866	8,820,120	-17,746
High Load	10,693,432	10,688,882	-4,550
Low Load	8,484,061	8,439,476	-44,585
High Capital Cost	9,374,421	9,400,458	26,037
High Regulated CO_2	19,378,243	19,506,292	128,049
Regulated CO_2	12,996,629	13,077,770	81,141
High Fuel & Regulated CO_2	13,686,100	13,669,602	-16,498
High Fuel, High Load, & Regulated CO_2	15,385,279	15,422,474	37,195
Low Fuel & Low Load	8,142,151	8,027,733	-114,418

68. Please refer to Question 67. Please complete the following table (also provided electronically in Excel format) in electronic (Excel) and hard copy showing the annual and cumulative present value revenue requirements for the GEC Combined Cycle Conversion Project in 2013 and the least cost alternative, for each case-scenario.

	[Specific Scenario Number and Name]					
	[Specific Sensitivity - (With or Without GEC Conversion in 2013)]					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						

Response: Please refer to the attachment labeled *Response to Interrogatory No. 68*, which presents the requested data. Please note that the requested data has been provided for all combinations of cases and scenarios for which data has been provided in response to Interrogatory Nos. 33 and 67. As requested, data has also been provided in electronic (Excel) format.

	Scenario 1 - Conventional					
	Reference Case With GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	32,046	0	461,562	38,621	532,228	3,087,185
2014	39,234	0	447,543	40,055	526,832	3,614,017
2015	42,366	0	431,337	39,842	513,545	4,127,562
2016	39,594	0	361,823	69,746	471,163	4,598,725
2017	37,004	0	318,259	99,982	455,245	5,053,970
2018	34,583	0	322,564	91,158	448,305	5,502,275
2019	32,321	0	320,540	91,467	444,327	5,946,603
2020	30,206	0	322,087	86,379	438,673	6,385,275
2021	28,230	0	307,214	78,839	414,283	6,799,558
2022	26,383	0	318,713	78,422	423,518	7,223,076
2023	32,421	0	310,566	75,805	418,792	7,641,868
2024	30,300	0	311,808	69,837	411,945	8,053,814
2025	35,442	0	305,354	70,535	411,331	8,465,144
2026	33,124	0	308,611	67,298	409,033	8,874,177
2027	36,294	0	307,580	63,039	406,914	9,281,091

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional					
	Reference Case Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	0	458,233	46,865	532,942	3,087,900
2014	37,452	0	453,438	47,108	537,999	3,625,898
2015	35,002	0	436,889	45,603	517,494	4,143,392
2016	32,712	0	365,021	75,537	473,270	4,616,662
2017	30,572	0	320,258	105,668	456,498	5,073,159
2018	28,572	0	325,040	96,236	449,848	5,523,007
2019	26,703	0	323,286	96,064	446,053	5,969,060
2020	24,956	0	325,462	90,462	440,880	6,409,940
2021	23,323	0	309,913	82,653	415,890	6,825,830
2022	21,797	0	323,421	81,605	426,824	7,252,654
2023	20,371	0	313,871	78,192	412,435	7,665,089
2024	26,476	0	315,318	72,598	414,393	8,079,482
2025	24,744	0	308,965	72,477	406,186	8,485,667
2026	28,697	0	311,423	69,360	409,479	8,895,147
2027	32,157	0	310,527	64,812	407,497	9,302,644

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional High Fuel With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	32,046	0	491,213	38,620	561,880	3,175,004
2014	39,234	0	481,481	40,055	560,770	3,735,773
2015	42,366	0	471,677	39,842	553,884	4,289,658
2016	39,594	0	391,382	69,746	500,721	4,790,379
2017	37,004	0	340,669	99,982	477,656	5,268,035
2018	34,583	0	347,141	91,158	472,882	5,740,916
2019	32,321	0	346,236	91,467	470,024	6,210,940
2020	30,206	0	349,206	86,380	465,792	6,676,732
2021	28,230	0	332,597	78,839	439,666	7,116,398
2022	26,383	0	345,568	78,422	450,373	7,566,771
2023	32,421	0	335,626	75,805	443,852	8,010,624
2024	30,300	0	337,119	69,837	437,256	8,447,880
2025	35,442	0	329,321	70,535	435,298	8,883,178
2026	33,124	0	335,283	67,298	435,705	9,318,882
2027	36,294	0	340,214	63,039	439,548	9,758,430

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional					
	High Fuel Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	0	487,527	46,865	562,236	3,175,360
2014	37,452	0	488,169	47,108	572,729	3,748,089
2015	35,002	0	478,178	45,603	558,782	4,306,872
2016	32,712	0	395,158	75,537	503,407	4,810,278
2017	30,572	0	343,040	105,668	479,280	5,289,559
2018	28,572	0	350,055	96,236	474,863	5,764,422
2019	26,703	0	349,471	96,064	472,238	6,236,660
2020	24,956	0	353,143	90,462	468,561	6,705,221
2021	23,323	0	335,745	82,653	441,722	7,146,942
2022	21,797	0	350,928	81,605	454,330	7,601,273
2023	20,371	0	339,485	78,192	438,048	8,039,321
2024	26,476	0	341,174	72,598	440,249	8,479,570
2025	24,744	0	333,519	72,477	430,740	8,910,310
2026	28,697	0	338,603	69,360	436,660	9,346,969
2027	32,157	0	343,790	64,812	440,759	9,787,729

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000098

	Scenario 1 - Conventional Low Fuel With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	32,046	0	440,507	38,621	511,174	3,018,780
2014	39,234	0	422,505	40,055	501,794	3,520,574
2015	42,366	0	399,895	39,842	482,103	4,002,677
2016	39,594	0	336,907	69,746	446,246	4,448,923
2017	37,004	0	299,811	99,982	436,797	4,885,721
2018	34,583	0	301,403	91,158	427,145	5,312,865
2019	32,321	0	298,904	91,467	422,691	5,735,556
2020	30,206	0	299,307	86,380	415,892	6,151,449
2021	28,230	0	286,155	78,839	393,224	6,544,673
2022	26,383	0	293,126	78,422	397,931	6,942,603
2023	32,421	0	287,047	75,805	395,273	7,337,877
2024	30,300	0	287,175	69,837	387,312	7,725,189
2025	35,442	0	281,339	70,535	387,316	8,112,505
2026	33,124	0	282,701	67,298	383,122	8,495,627
2027	36,294	0	282,622	63,039	381,955	8,877,582

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000099

	Scenario 1 - Conventional					
	Low Fuel Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	0	437,422	46,865	512,132	3,019,738
2014	37,452	0	427,808	47,094	512,354	3,532,092
2015	35,002	0	404,743	45,574	485,319	4,017,412
2016	32,712	0	339,647	75,521	447,880	4,465,292
2017	30,572	0	301,517	105,656	437,745	4,903,037
2018	28,572	0	303,512	96,223	428,307	5,331,344
2019	26,703	0	301,252	96,053	424,007	5,755,351
2020	24,956	0	302,205	90,450	417,611	6,172,962
2021	23,323	0	288,497	82,642	394,462	6,567,424
2022	21,797	0	297,191	81,596	400,585	6,968,008
2023	20,371	0	289,880	78,180	388,431	7,356,439
2024	26,476	0	290,192	72,587	389,255	7,745,694
2025	24,744	0	284,412	72,464	381,621	8,127,315
2026	28,697	0	285,044	69,349	383,090	8,510,405
2027	32,157	0	285,133	64,804	382,094	8,892,498

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional High Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	57,699	0	516,215	54,685	628,600	3,648,620
2014	63,209	0	500,665	55,274	619,149	4,267,768
2015	59,074	0	482,968	53,328	595,370	4,863,138
2016	55,209	0	409,250	82,706	547,165	5,410,303
2017	51,597	0	363,091	112,257	526,946	5,937,250
2018	48,222	0	367,540	102,786	518,548	6,455,798
2019	45,067	0	365,125	102,438	512,630	6,968,428
2020	42,119	0	365,173	96,724	504,016	7,472,444
2021	39,363	0	349,071	88,679	477,114	7,949,558
2022	44,893	0	359,349	88,312	492,554	8,442,112
2023	41,956	0	352,672	84,602	479,230	8,921,342
2024	46,649	0	353,215	78,805	478,669	9,400,011
2025	43,597	0	346,482	78,396	468,475	9,868,486
2026	46,316	0	348,298	75,211	469,826	10,338,311
2027	43,286	0	348,574	70,128	461,988	10,800,299

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000101

	Scenario 1 - Conventional					
	High Load Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	39,775	0	533,012	52,838	625,625	3,645,645
2014	37,173	0	526,187	52,045	615,405	4,261,050
2015	43,679	0	504,893	51,052	599,625	4,860,675
2016	40,822	0	421,246	80,417	542,485	5,403,160
2017	38,151	0	371,681	110,275	520,107	5,923,267
2018	35,655	0	377,572	100,798	514,025	6,437,292
2019	33,323	0	376,198	100,574	510,095	6,947,387
2020	31,143	0	378,100	94,942	504,185	7,451,573
2021	29,105	0	359,764	86,976	475,845	7,927,418
2022	35,306	0	375,903	86,595	497,804	8,425,222
2023	32,996	0	365,670	83,146	481,812	8,907,034
2024	38,275	0	366,980	77,432	482,687	9,389,721
2025	35,771	0	360,593	77,219	473,582	9,863,303
2026	39,003	0	362,366	73,932	475,300	10,338,604
2027	36,451	0	363,278	68,950	468,679	10,807,283

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional Low Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	20,115	0	423,505	34,834	478,453	2,801,802
2014	28,083	0	411,992	36,345	476,421	3,278,223
2015	31,945	0	396,870	36,208	465,023	3,743,246
2016	29,855	0	334,073	66,478	430,406	4,173,652
2017	27,902	0	292,955	96,909	417,766	4,591,418
2018	26,076	0	296,904	88,141	411,121	5,002,539
2019	24,370	0	294,532	88,506	407,409	5,409,947
2020	22,776	0	296,005	83,449	402,230	5,812,177
2021	21,286	0	282,610	76,022	379,918	6,192,095
2022	19,893	0	292,955	75,626	388,475	6,580,569
2023	18,592	0	284,937	72,421	375,950	6,956,519
2024	24,813	0	286,322	67,195	378,330	7,334,848
2025	23,190	0	279,739	67,316	370,245	7,705,093
2026	28,498	0	282,281	64,726	375,504	8,080,597
2027	26,633	0	282,192	60,116	368,941	8,449,539

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional Low Load Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	0	420,605	44,335	492,784	2,816,133
2014	26,023	0	416,926	43,582	486,530	3,302,663
2015	24,320	0	401,658	42,080	468,058	3,770,721
2016	22,729	0	336,449	72,485	431,664	4,202,385
2017	21,242	0	294,326	102,803	418,372	4,620,756
2018	19,853	0	298,693	93,408	411,954	5,032,710
2019	18,554	0	296,536	93,271	408,361	5,441,071
2020	17,340	0	298,627	87,666	403,633	5,844,704
2021	16,206	0	284,548	79,975	380,729	6,225,432
2022	15,145	0	296,796	78,891	390,832	6,616,265
2023	14,155	0	287,519	75,563	377,237	6,993,502
2024	19,300	0	288,658	69,910	377,869	7,371,371
2025	18,038	0	282,043	69,781	369,862	7,741,232
2026	23,683	0	284,768	66,886	375,336	8,116,569
2027	22,133	0	284,760	62,022	368,915	8,485,484

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional High Capital Cost With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,455	0	461,562	38,621	538,637	3,093,595
2014	47,081	0	447,543	40,055	534,679	3,628,273
2015	50,839	0	431,337	39,842	522,018	4,150,291
2016	47,513	0	361,823	69,746	479,081	4,629,372
2017	44,404	0	318,259	99,982	462,646	5,092,018
2018	41,499	0	322,564	91,158	455,222	5,547,240
2019	38,785	0	320,540	91,467	450,791	5,998,031
2020	36,247	0	322,087	86,379	444,714	6,442,745
2021	33,876	0	307,214	78,839	419,929	6,862,674
2022	31,660	0	318,713	78,422	428,795	7,291,468
2023	38,905	0	310,566	75,805	425,277	7,716,745
2024	36,360	0	311,808	69,837	418,005	8,134,750
2025	42,531	0	305,354	70,535	418,419	8,553,169
2026	39,748	0	308,611	67,298	415,657	8,968,827
2027	43,553	0	307,580	63,039	414,173	9,382,999

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000105

	Scenario 1 - Conventional					
	High Capital Cost Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	33,413	0	458,233	46,865	538,511	3,093,468
2014	44,942	0	453,438	47,108	545,489	3,638,957
2015	42,002	0	436,889	45,603	524,494	4,163,452
2016	39,254	0	365,021	75,537	479,812	4,643,264
2017	36,686	0	320,258	105,668	462,612	5,105,876
2018	34,286	0	325,040	96,236	455,562	5,561,438
2019	32,043	0	323,286	96,065	451,394	6,012,832
2020	29,947	0	325,462	90,462	445,871	6,458,702
2021	27,988	0	309,913	82,653	420,555	6,879,257
2022	26,157	0	323,421	81,605	431,183	7,310,440
2023	24,446	0	313,871	78,192	416,509	7,726,950
2024	31,771	0	315,318	72,598	419,688	8,146,637
2025	29,693	0	308,965	72,477	411,135	8,557,772
2026	34,436	0	311,423	69,360	415,219	8,972,991
2027	38,589	0	310,527	64,812	413,928	9,386,919

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000106

	Scenario 1 - Conventional High Regulated CO2 With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	47,959	476,521	454,407	49,194	1,028,081	4,120,783
2014	54,106	462,250	466,784	50,947	1,034,087	5,154,870
2015	50,566	463,295	472,379	50,965	1,037,206	6,192,075
2016	47,258	486,113	425,169	82,945	1,041,485	7,233,560
2017	44,166	479,882	398,753	113,780	1,036,582	8,270,142
2018	41,277	474,191	428,593	107,043	1,051,104	9,321,246
2019	38,577	496,143	426,553	106,199	1,067,471	10,388,717
2020	36,053	521,283	425,740	99,904	1,082,980	11,471,697
2021	33,694	537,330	428,021	93,617	1,092,663	12,564,359
2022	31,490	581,361	417,417	90,280	1,120,548	13,684,908
2023	29,430	573,458	442,694	88,447	1,134,030	14,818,937
2024	44,862	547,398	477,875	89,653	1,159,789	15,978,726
2025	41,927	577,588	456,530	88,356	1,164,402	17,143,128
2026	55,112	544,559	489,939	90,825	1,180,435	18,323,562
2027	51,506	578,852	485,052	84,526	1,199,936	19,523,498

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000107

	Scenario 1 - Conventional High Regulated CO2 Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	482,961	464,379	47,079	1,022,264	4,114,966
2014	52,696	459,203	479,780	58,441	1,050,120	5,165,086
2015	49,248	468,617	476,756	57,139	1,051,761	6,216,846
2016	46,026	494,407	425,216	88,608	1,054,258	7,271,104
2017	43,015	468,640	415,303	120,876	1,047,834	8,318,938
2018	40,201	490,623	419,901	110,522	1,061,248	9,380,185
2019	37,571	512,195	418,608	109,141	1,077,515	10,457,700
2020	35,113	543,136	413,788	102,101	1,094,138	11,551,839
2021	32,816	570,005	405,224	94,388	1,102,433	12,654,272
2022	30,669	611,642	400,065	91,194	1,133,570	13,787,842
2023	28,663	598,974	430,992	89,387	1,148,016	14,935,858
2024	26,788	638,244	423,976	82,213	1,171,221	16,107,079
2025	41,662	605,021	443,985	88,871	1,179,540	17,286,619
2026	38,937	633,549	442,721	84,164	1,199,371	18,485,990
2027	36,390	671,838	437,832	78,097	1,224,157	19,710,147

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000108

	Scenario 1 - Conventional Regulated CO2 With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	32,046	188,557	454,663	38,623	713,888	3,437,683
2014	39,234	193,495	440,273	40,065	713,067	4,150,750
2015	42,366	203,086	422,682	39,847	707,982	4,858,732
2016	39,594	220,889	352,840	69,755	683,077	5,541,809
2017	37,004	226,643	309,228	100,009	672,884	6,214,693
2018	34,583	236,606	311,736	91,266	674,190	6,888,883
2019	32,321	245,140	308,617	91,558	677,635	7,566,518
2020	30,206	254,195	308,152	86,440	678,993	8,245,511
2021	28,230	268,949	292,486	78,997	668,662	8,914,173
2022	26,383	276,539	299,299	78,527	680,748	9,594,921
2023	42,776	276,216	293,620	81,625	694,237	10,289,159
2024	39,978	284,240	296,150	75,813	696,181	10,985,340
2025	37,362	288,053	292,203	76,374	693,992	11,679,332
2026	34,918	290,059	296,913	73,741	695,631	12,374,963
2027	36,037	296,816	299,342	69,979	702,173	13,077,136

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional					
	Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	187,913	451,405	46,867	714,030	3,437,825
2014	37,452	195,070	446,012	47,121	725,655	4,163,481
2015	35,002	204,642	428,075	45,611	713,330	4,876,811
2016	32,712	221,865	355,910	75,549	686,036	5,562,847
2017	30,572	227,314	311,115	105,696	674,696	6,237,543
2018	28,572	237,489	314,059	96,345	676,465	6,914,008
2019	26,703	246,250	311,100	96,162	680,215	7,594,223
2020	24,956	255,273	311,559	90,542	682,330	8,276,553
2021	23,323	270,345	294,775	82,781	671,224	8,947,777
2022	21,797	277,352	304,992	81,735	685,876	9,633,653
2023	20,371	280,765	301,075	78,843	681,053	10,314,706
2024	26,476	293,820	300,289	73,365	693,949	11,008,655
2025	24,744	300,882	293,912	73,760	693,298	11,701,953
2026	28,697	306,379	296,178	71,255	702,510	12,404,463
2027	32,157	320,349	291,951	66,501	710,958	13,115,422

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional High Fuel With Regulated CO2 With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	32,046	188,557	491,221	38,623	750,446	3,538,342
2014	39,234	193,587	481,488	40,056	754,365	4,292,707
2015	42,366	203,086	471,665	39,847	756,965	5,049,671
2016	39,594	220,870	391,349	69,755	721,568	5,771,239
2017	37,004	226,329	340,759	100,109	704,201	6,475,440
2018	34,583	236,606	347,173	91,266	709,628	7,185,067
2019	32,321	245,208	346,292	91,564	715,384	7,900,451
2020	30,206	254,273	349,232	86,447	720,158	8,620,609
2021	28,230	270,275	332,619	78,902	710,026	9,330,634
2022	26,383	277,580	345,597	78,460	728,020	10,058,654
2023	42,776	287,430	329,462	80,971	740,639	10,799,293
2024	39,978	302,455	330,379	74,619	747,430	11,546,724
2025	37,362	315,089	322,575	74,290	749,317	12,296,041
2026	34,918	325,719	327,740	70,751	759,128	13,055,169
2027	36,037	340,065	333,205	66,256	775,562	13,830,732

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional					
	High Fuel With Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	187,913	487,535	46,867	750,159	3,538,055
2014	37,452	195,193	488,176	47,109	767,930	4,305,985
2015	35,002	204,642	478,182	45,611	763,437	5,069,421
2016	32,712	221,846	395,135	75,549	725,242	5,794,663
2017	30,572	227,000	343,131	105,795	706,498	6,501,161
2018	28,572	237,489	350,102	96,345	712,508	7,213,669
2019	26,703	246,250	349,514	96,162	718,629	7,932,298
2020	24,956	255,638	353,204	90,530	724,329	8,656,627
2021	23,323	271,466	335,764	82,717	713,271	9,369,898
2022	21,797	279,753	350,961	81,644	734,155	10,104,053
2023	20,371	291,466	339,510	78,235	729,583	10,833,636
2024	36,396	303,622	333,819	77,568	751,404	11,585,040
2025	34,015	316,254	325,916	76,997	753,182	12,338,222
2026	31,789	326,779	331,947	73,139	763,655	13,101,876
2027	29,710	341,424	337,520	67,882	776,536	13,878,412

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000112

	Scenario 1 - Conventional					
	High Fuel High Load With Regulated CO2 With GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	57,699	195,568	551,815	54,686	859,768	4,127,977
2014	63,209	201,322	541,383	55,274	861,189	4,989,166
2015	59,074	211,463	531,607	53,332	855,477	5,844,643
2016	55,209	231,389	447,053	82,710	816,361	6,661,004
2017	51,597	239,136	393,129	112,332	796,195	7,457,198
2018	48,222	249,302	399,632	102,845	800,000	8,257,199
2019	45,067	258,145	398,302	102,491	804,005	9,061,204
2020	42,119	267,232	399,358	96,760	805,469	9,866,673
2021	39,363	284,121	381,440	88,710	793,634	10,660,307
2022	44,893	290,278	392,385	88,330	815,886	11,476,192
2023	41,956	304,092	384,027	84,623	814,698	12,290,891
2024	46,649	320,029	384,659	78,822	830,160	13,121,050
2025	43,597	333,186	376,371	78,410	831,564	13,952,614
2026	46,316	344,226	381,283	75,230	847,055	14,799,669
2027	43,286	359,326	389,175	70,142	861,929	15,661,599

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000113

	Scenario 1 - Conventional					
	High Fuel High Load With Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	37,584	198,563	568,379	52,448	856,974	4,125,183
2014	46,555	206,489	567,712	52,562	873,318	4,998,501
2015	43,509	216,399	556,914	51,060	867,883	5,866,384
2016	40,663	234,628	461,310	80,428	817,029	6,683,413
2017	38,003	241,676	403,370	110,353	793,402	7,476,816
2018	35,517	252,488	411,510	100,860	800,374	8,277,190
2019	33,193	261,792	411,343	100,630	806,958	9,084,148
2020	31,022	271,773	414,545	94,981	812,321	9,896,470
2021	28,992	288,354	394,021	87,008	798,375	10,694,844
2022	46,010	292,005	398,929	92,032	828,977	11,523,821
2023	43,000	305,500	388,701	88,241	825,442	12,349,262
2024	40,187	321,587	389,612	81,446	832,832	13,182,094
2025	43,374	334,285	380,614	81,273	839,546	14,021,640
2026	40,537	345,624	386,538	77,303	850,001	14,871,641
2027	41,288	360,684	394,475	72,461	868,908	15,740,549

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 1 - Conventional Low Fuel Low Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	20,115	0	405,356	34,834	460,305	2,741,536
2014	28,083	0	390,262	36,346	454,690	3,196,227
2015	31,945	0	369,562	36,208	437,715	3,633,942
2016	29,855	0	313,008	66,478	409,341	4,043,283
2017	27,902	0	277,826	96,909	402,636	4,445,920
2018	26,076	0	279,234	88,140	393,451	4,839,371
2019	24,370	0	276,329	88,506	389,205	5,228,576
2020	22,776	0	276,700	83,449	382,925	5,611,500
2021	21,286	0	264,737	76,022	362,045	5,973,545
2022	19,893	0	270,914	75,626	366,433	6,339,978
2023	18,592	0	264,726	72,421	355,738	6,695,717
2024	24,813	0	265,049	67,194	357,056	7,052,773
2025	23,190	0	259,106	67,316	349,612	7,402,385
2026	28,498	0	259,987	64,726	353,210	7,755,595
2027	26,633	0	260,509	60,116	347,258	8,102,853

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000115

	Scenario 1 - Conventional					
	Low Fuel Low Load Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	9,740	0	417,055	33,555	460,350	2,741,581
2014	20,532	0	411,128	34,616	466,276	3,207,857
2015	19,189	0	388,244	33,933	441,367	3,649,224
2016	17,934	0	321,863	64,429	404,225	4,053,449
2017	16,761	0	283,309	95,147	395,217	4,448,667
2018	15,664	0	286,084	86,349	388,097	4,836,764
2019	14,639	0	284,154	86,785	385,578	5,222,342
2020	13,682	0	286,017	81,738	381,437	5,603,779
2021	12,787	0	272,158	74,410	359,355	5,963,134
2022	11,950	0	283,637	74,025	369,612	6,332,746
2023	17,507	0	273,400	71,382	362,289	6,695,035
2024	16,361	0	274,282	65,524	356,168	7,051,203
2025	22,416	0	268,640	66,388	357,443	7,408,646
2026	20,949	0	270,006	63,213	354,168	7,762,814
2027	24,916	0	270,363	59,006	354,285	8,117,099

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 2 - Renewable Reference Case With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	50,753	0	454,188	43,551	548,492	3,120,842
2014	56,776	0	441,117	44,763	542,655	3,663,498
2015	58,815	0	425,395	44,347	528,556	4,192,054
2016	55,018	0	357,692	74,083	486,793	4,678,847
2017	51,467	0	315,010	104,126	470,603	5,149,449
2018	48,144	0	319,105	95,132	462,381	5,611,830
2019	45,036	0	316,918	95,269	457,223	6,069,054
2020	42,129	0	318,401	90,021	450,550	6,519,604
2021	39,409	0	304,019	82,326	425,755	6,945,359
2022	36,865	0	314,825	81,741	433,431	7,378,790
2023	34,485	0	306,971	78,332	419,788	7,798,577
2024	38,331	0	307,734	72,800	418,864	8,217,441
2025	42,975	0	301,199	73,343	417,518	8,634,959
2026	40,190	0	304,291	69,975	414,456	9,049,415
2027	42,922	0	303,374	65,625	411,921	9,461,336

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000117

	Scenario 2 - Renewable					
	Reference Case Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	0	451,261	51,874	549,687	3,122,037
2014	43,565	0	446,747	50,891	541,203	3,663,240
2015	49,708	0	429,492	49,887	529,086	4,192,326
2016	46,507	0	360,129	79,838	486,474	4,678,800
2017	43,512	0	316,568	109,800	469,880	5,148,680
2018	40,710	0	321,050	100,181	461,941	5,610,621
2019	38,088	0	319,037	99,810	456,936	6,067,557
2020	35,636	0	321,037	94,002	450,675	6,518,232
2021	33,341	0	306,121	86,076	425,538	6,943,770
2022	31,194	0	318,452	84,748	434,394	7,378,164
2023	35,523	0	309,052	81,832	426,407	7,804,571
2024	33,229	0	310,357	75,395	418,981	8,223,552
2025	36,899	0	303,280	75,583	415,761	8,639,313
2026	41,336	0	306,371	72,503	420,211	9,059,524
2027	38,656	0	306,070	67,403	412,129	9,471,653

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 2 - Renewable High Fuel With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	50,753	0	482,429	43,551	576,734	3,205,867
2014	56,776	0	473,559	44,763	575,097	3,780,965
2015	58,815	0	463,958	44,347	567,119	4,348,083
2016	55,018	0	385,745	74,083	514,846	4,862,929
2017	51,467	0	336,213	104,126	491,805	5,354,735
2018	48,144	0	342,458	95,132	485,734	5,840,468
2019	45,036	0	341,371	95,269	481,676	6,322,144
2020	42,129	0	344,292	90,021	476,442	6,798,586
2021	39,409	0	328,274	82,326	450,010	7,248,596
2022	36,865	0	340,492	81,741	459,098	7,707,694
2023	34,485	0	331,060	78,332	443,877	8,151,571
2024	38,331	0	331,976	72,800	443,106	8,594,677
2025	42,975	0	324,135	73,343	440,454	9,035,131
2026	40,190	0	329,860	69,975	440,025	9,475,156
2027	42,922	0	334,682	65,625	443,229	9,918,385

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000119

	Scenario 2 - Renewable					
	High Fuel Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	0	479,180	51,874	577,605	3,206,739
2014	43,565	0	479,965	50,891	574,420	3,781,159
2015	49,708	0	468,781	49,887	568,376	4,349,535
2016	46,507	0	388,619	79,838	514,964	4,864,499
2017	43,512	0	338,063	109,800	491,375	5,355,874
2018	40,710	0	344,750	100,181	485,641	5,841,515
2019	38,088	0	343,870	99,810	481,768	6,323,284
2020	35,636	0	347,375	94,002	477,013	6,800,297
2021	33,341	0	330,734	86,077	450,151	7,250,448
2022	31,194	0	344,651	84,748	460,593	7,711,041
2023	35,523	0	333,416	81,832	450,771	8,161,812
2024	33,229	0	335,004	75,395	443,628	8,605,440
2025	36,899	0	326,559	75,583	439,041	9,044,481
2026	41,336	0	332,302	72,503	446,141	9,490,622
2027	38,656	0	337,951	67,403	444,010	9,934,632

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000120

	Scenario 2 - Renewable Low Fuel With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	50,753	0	434,145	43,551	528,449	3,054,452
2014	56,776	0	417,202	44,763	518,741	3,573,192
2015	58,815	0	395,316	44,347	498,477	4,071,670
2016	55,018	0	334,019	74,083	463,120	4,534,790
2017	51,467	0	297,533	104,126	453,126	4,987,916
2018	48,144	0	298,981	95,132	442,257	5,430,173
2019	45,036	0	296,299	95,269	436,604	5,866,777
2020	42,129	0	296,636	90,021	428,786	6,295,563
2021	39,409	0	283,856	82,326	405,592	6,701,155
2022	36,865	0	290,305	81,741	408,911	7,110,066
2023	34,485	0	284,353	78,332	397,170	7,507,236
2024	38,331	0	284,082	72,800	395,212	7,902,448
2025	42,975	0	278,177	73,343	394,495	8,296,943
2026	40,190	0	279,413	69,975	389,578	8,686,521
2027	42,922	0	279,360	65,625	387,907	9,074,428

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000121

	Scenario 2 - Renewable Low Fuel Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	0	431,439	51,874	529,865	3,055,867
2014	43,565	0	422,268	50,877	516,710	3,572,577
2015	49,708	0	398,901	49,859	498,468	4,071,045
2016	46,507	0	336,120	79,822	462,449	4,533,494
2017	43,512	0	298,864	109,789	452,165	4,985,659
2018	40,710	0	300,639	100,169	441,517	5,427,176
2019	38,088	0	298,116	99,799	436,003	5,863,179
2020	35,636	0	298,905	93,991	428,532	6,291,711
2021	33,341	0	285,675	86,065	405,081	6,696,792
2022	31,194	0	293,433	84,739	409,366	7,106,158
2023	35,523	0	286,176	81,820	403,519	7,509,677
2024	33,229	0	286,344	75,384	394,957	7,904,634
2025	36,899	0	279,943	75,571	392,413	8,297,048
2026	41,336	0	281,157	72,493	394,986	8,692,034
2027	38,656	0	281,659	67,395	387,710	9,079,744

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000122

	Scenario 2 - Renewable High Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	62,684	0	529,382	49,827	641,893	3,676,969
2014	67,926	0	510,707	50,905	629,539	4,306,508
2015	63,537	0	492,486	49,586	605,609	4,912,117
2016	59,432	0	412,454	78,698	550,584	5,462,701
2017	55,591	0	364,934	108,422	528,947	5,991,647
2018	51,999	0	370,147	99,407	521,553	6,513,200
2019	48,639	0	368,624	99,528	516,791	7,029,991
2020	45,496	0	370,423	94,266	510,185	7,540,177
2021	42,556	0	353,011	86,412	481,980	8,022,156
2022	47,911	0	366,688	86,613	501,212	8,523,368
2023	44,808	0	358,039	83,076	485,924	9,009,292
2024	59,264	0	349,775	82,007	491,046	9,500,338
2025	55,414	0	343,054	81,470	479,938	9,980,276
2026	51,815	0	345,356	77,684	474,855	10,455,131
2027	48,450	0	345,620	72,521	466,591	10,921,722

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000123

	Scenario 2 - Renewable					
	High Load Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	52,762	0	524,298	57,621	634,680	3,669,756
2014	60,798	0	517,754	57,554	636,105	4,305,861
2015	56,875	0	499,117	55,841	611,833	4,917,694
2016	53,205	0	416,683	84,921	554,809	5,472,503
2017	49,772	0	367,863	114,547	532,182	6,004,685
2018	46,561	0	373,623	104,908	525,091	6,529,776
2019	43,556	0	372,209	104,525	520,290	7,050,066
2020	40,746	0	374,239	98,752	513,736	7,563,802
2021	38,117	0	356,211	90,605	484,933	8,048,735
2022	43,762	0	371,989	90,140	505,891	8,554,625
2023	40,931	0	361,995	86,502	489,428	9,044,053
2024	45,720	0	363,339	80,655	489,715	9,533,768
2025	42,757	0	356,925	80,323	480,004	10,013,772
2026	45,557	0	358,706	76,894	481,157	10,494,930
2027	42,601	0	359,575	71,800	473,976	10,968,906

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000124

	Scenario 2 - Renewable Low Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,822	0	416,776	39,771	495,369	2,836,570
2014	45,625	0	406,131	41,057	492,813	3,329,383
2015	42,695	0	391,628	39,836	474,160	3,803,543
2016	39,953	0	330,469	69,934	440,356	4,243,899
2017	37,387	0	290,151	100,203	427,741	4,671,640
2018	34,986	0	293,906	91,301	420,193	5,091,833
2019	32,739	0	291,424	91,539	415,701	5,507,534
2020	30,636	0	292,765	86,363	409,765	5,917,299
2021	28,668	0	279,779	78,807	387,254	6,304,553
2022	26,827	0	289,589	78,308	394,724	6,699,277
2023	25,103	0	281,868	74,983	381,955	7,081,232
2024	30,928	0	283,154	69,655	383,737	7,464,969
2025	28,933	0	276,598	69,672	375,202	7,840,171
2026	33,891	0	279,008	66,990	379,889	8,220,060
2027	31,698	0	278,907	62,285	372,889	8,592,949

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000125

	Scenario 2 - Renewable Low Load Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	30,639	0	430,324	38,856	499,819	2,841,021
2014	28,693	0	429,568	38,774	497,035	3,338,056
2015	32,569	0	412,806	38,705	484,079	3,822,135
2016	30,489	0	340,656	68,877	440,023	4,262,158
2017	28,542	0	296,423	99,359	424,324	4,686,482
2018	26,720	0	301,806	90,404	418,930	5,105,412
2019	25,013	0	300,380	90,683	416,077	5,521,489
2020	23,416	0	303,627	85,501	412,544	5,934,033
2021	21,920	0	288,296	77,995	388,211	6,322,244
2022	20,520	0	304,502	77,537	402,560	6,724,804
2023	25,548	0	291,727	74,691	391,966	7,116,771
2024	23,906	0	293,788	68,701	386,395	7,503,166
2025	29,495	0	287,539	69,443	386,476	7,889,642
2026	27,591	0	290,638	66,143	384,372	8,274,014
2027	31,148	0	290,179	61,816	383,143	8,657,157

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000126

	Scenario 2 - Renewable					
	High Capital Cost With GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	60,904	0	454,188	43,551	558,643	3,135,883
2014	68,131	0	441,117	44,763	554,011	3,689,893
2015	70,578	0	425,395	44,347	540,319	4,230,212
2016	66,022	0	357,692	74,083	497,796	4,728,009
2017	61,760	0	315,010	104,126	480,896	5,208,905
2018	57,773	0	319,105	95,132	472,010	5,680,915
2019	54,043	0	316,918	95,269	466,230	6,147,145
2020	50,555	0	318,401	90,021	458,976	6,606,121
2021	47,291	0	304,019	82,326	433,636	7,039,758
2022	44,238	0	314,825	81,741	440,804	7,480,561
2023	41,382	0	306,971	78,332	426,685	7,907,246
2024	45,997	0	307,734	72,800	426,530	8,333,776
2025	51,570	0	301,199	73,343	426,113	8,759,889
2026	48,228	0	304,291	69,975	422,494	9,182,382
2027	51,507	0	303,374	65,625	420,505	9,602,888

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000127

	Scenario 2 - Renewable					
	High Capital Cost Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	55,862	0	451,261	51,874	558,997	3,136,237
2014	52,278	0	446,747	50,891	549,916	3,686,153
2015	59,649	0	429,492	49,887	539,028	4,225,181
2016	55,808	0	360,129	79,838	495,775	4,720,956
2017	52,214	0	316,568	109,800	478,582	5,199,539
2018	48,852	0	321,050	100,181	470,083	5,669,621
2019	45,706	0	319,037	99,810	464,554	6,134,175
2020	42,763	0	321,037	94,002	457,802	6,591,977
2021	40,009	0	306,121	86,076	432,207	7,024,184
2022	37,432	0	318,452	84,748	440,633	7,464,817
2023	42,628	0	309,052	81,832	433,512	7,898,328
2024	39,875	0	310,357	75,395	425,627	8,323,955
2025	44,279	0	303,280	75,583	423,141	8,747,096
2026	49,603	0	306,371	72,503	428,478	9,175,574
2027	46,387	0	306,070	67,403	419,861	9,595,434

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000128

	Scenario 2 - Renewable					
	High Regulated CO2 With GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	66,667	470,922	448,682	54,251	1,040,522	4,143,707
2014	71,648	456,214	461,912	55,788	1,045,563	5,189,269
2015	67,015	456,359	468,320	55,656	1,047,349	6,236,619
2016	62,682	478,679	422,327	87,533	1,051,222	7,287,841
2017	58,629	471,334	397,402	118,278	1,045,644	8,333,485
2018	54,838	464,683	427,564	111,424	1,058,509	9,391,994
2019	51,292	486,352	425,458	110,414	1,073,517	10,465,511
2020	47,976	511,139	424,373	103,920	1,087,409	11,552,919
2021	44,874	526,325	427,249	97,541	1,095,989	12,648,908
2022	41,972	570,369	415,919	93,976	1,122,235	13,771,143
2023	39,258	561,491	441,895	92,039	1,134,682	14,905,826
2024	36,719	599,601	434,618	84,874	1,155,812	16,061,638
2025	50,972	565,059	455,932	91,666	1,163,630	17,225,268
2026	63,591	532,678	488,610	93,952	1,178,831	18,404,098
2027	59,455	566,519	483,788	87,528	1,197,290	19,601,389

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000129

	Scenario 2 - Renewable					
	High Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	476,982	457,931	52,145	1,033,610	4,136,795
2014	43,565	472,392	471,829	51,890	1,039,676	5,176,472
2015	49,708	483,979	465,102	51,668	1,050,457	6,226,928
2016	46,507	511,554	405,873	83,007	1,046,941	7,273,870
2017	43,512	494,708	385,756	114,972	1,038,948	8,312,818
2018	40,710	517,857	391,313	105,137	1,055,017	9,367,835
2019	38,088	542,060	389,868	104,185	1,074,202	10,442,036
2020	35,636	571,954	388,944	97,745	1,094,278	11,536,315
2021	33,341	600,710	378,911	90,144	1,103,106	12,639,420
2022	50,108	600,122	397,200	95,449	1,142,880	13,782,300
2023	46,862	586,281	429,647	93,580	1,156,370	14,938,670
2024	43,826	624,192	423,438	86,219	1,177,675	16,116,346
2025	57,614	590,787	444,268	92,808	1,185,477	17,301,822
2026	53,870	619,035	442,583	87,887	1,203,375	18,505,197
2027	50,370	654,670	439,622	81,702	1,226,365	19,731,562

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000130

	Scenario 2 - Renewable Regulated CO2 With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	50,753	186,408	447,715	43,598	728,474	3,468,071
2014	56,776	191,396	434,213	44,810	727,194	4,195,266
2015	58,815	200,988	417,115	44,381	721,298	4,916,563
2016	55,018	218,467	349,314	74,207	697,006	5,613,569
2017	51,467	223,844	306,741	104,323	686,375	6,299,944
2018	48,144	233,805	309,064	95,387	686,400	6,986,344
2019	45,036	242,329	305,768	95,485	688,619	7,674,963
2020	42,129	251,343	305,204	90,184	688,860	8,363,823
2021	39,409	266,004	290,011	82,591	678,016	9,041,839
2022	36,865	273,537	296,230	81,922	688,554	9,730,393
2023	34,485	278,926	292,959	78,984	685,354	10,415,747
2024	38,331	288,155	294,556	73,911	694,953	11,110,700
2025	42,975	293,908	288,978	75,164	701,026	11,811,726
2026	40,190	298,493	292,540	72,414	703,637	12,515,363
2027	42,922	308,102	292,635	68,550	712,209	13,227,572

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000131

	Scenario 2 - Renewable					
	Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	185,830	444,852	51,920	729,154	3,468,752
2014	43,565	192,863	439,690	50,940	727,058	4,195,810
2015	49,708	201,961	421,080	49,921	722,669	4,918,480
2016	46,507	219,028	351,654	79,963	697,152	5,615,632
2017	43,512	224,236	308,213	109,997	685,958	6,301,589
2018	40,710	234,330	310,879	100,437	686,357	6,987,946
2019	38,088	243,024	307,685	100,033	688,830	7,676,776
2020	35,636	251,892	307,920	94,185	689,632	8,366,409
2021	33,341	266,934	291,776	86,311	678,362	9,044,771
2022	31,194	273,463	301,018	84,954	690,628	9,735,399
2023	35,523	276,546	297,375	82,561	692,005	10,427,404
2024	33,229	289,193	296,602	76,245	695,270	11,122,673
2025	36,899	295,487	290,010	76,973	699,368	11,822,042
2026	41,336	300,719	293,406	74,563	710,023	12,532,065
2027	38,656	315,242	289,724	69,239	712,860	13,244,926

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000132

	Scenario 2 - Renewable High Fuel With Regulated CO2 With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	50,753	186,408	482,538	43,598	763,297	3,565,284
2014	56,776	191,482	473,652	44,801	766,711	4,331,995
2015	58,815	200,988	464,022	44,381	768,206	5,100,201
2016	55,018	218,440	385,946	74,207	733,611	5,833,812
2017	51,467	223,509	336,673	104,431	716,080	6,549,891
2018	48,144	233,805	342,796	95,387	720,132	7,270,023
2019	45,036	242,394	341,683	95,491	724,604	7,994,627
2020	42,129	251,418	344,536	90,191	728,275	8,722,902
2021	39,409	267,316	328,513	82,497	717,736	9,440,638
2022	36,865	274,584	340,677	81,854	733,979	10,174,617
2023	34,485	286,751	331,336	78,440	731,012	10,905,629
2024	38,331	301,527	332,220	72,903	744,981	11,650,610
2025	42,975	314,157	324,386	73,433	754,951	12,405,561
2026	40,190	325,489	330,084	70,053	765,815	13,171,377
2027	42,922	339,718	334,901	65,679	783,221	13,954,597

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000133

	Scenario 2 - Renewable					
	High Fuel With Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	185,830	479,287	51,920	763,589	3,565,576
2014	43,565	192,979	480,056	50,929	767,529	4,333,106
2015	49,708	201,961	468,842	49,921	770,432	5,103,537
2016	46,507	219,001	388,827	79,963	734,298	5,837,835
2017	43,512	223,901	338,527	110,105	716,044	6,553,880
2018	40,710	234,330	345,086	100,437	720,563	7,274,443
2019	38,088	243,024	344,179	100,033	725,324	7,999,767
2020	35,636	252,262	347,624	94,173	729,694	8,729,461
2021	33,341	268,052	330,978	86,248	718,618	9,448,079
2022	31,194	275,926	344,838	84,861	736,819	10,184,898
2023	35,523	287,422	333,597	81,947	738,489	10,923,387
2024	33,229	302,710	335,163	75,506	746,607	11,669,994
2025	36,899	314,928	326,732	75,678	754,237	12,424,231
2026	41,336	326,063	332,767	72,593	772,759	13,196,991
2027	38,656	340,819	338,428	67,470	785,373	13,982,364

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 2 - Renewable					
	High Fuel High Load With Regulated CO2 With GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	62,684	197,881	565,706	49,848	876,120	4,158,543
2014	67,926	202,993	551,840	50,922	873,682	5,032,224
2015	63,537	212,915	541,583	49,606	867,642	5,899,866
2016	59,432	231,355	450,162	78,776	819,725	6,719,591
2017	55,591	238,284	394,900	108,627	797,402	7,516,993
2018	51,999	248,909	402,279	99,571	802,759	8,319,752
2019	48,639	258,090	401,880	99,669	808,277	9,128,030
2020	45,496	267,852	404,956	94,371	812,675	9,940,705
2021	42,556	284,409	385,558	86,514	799,038	10,739,742
2022	58,720	288,084	387,786	91,859	826,449	11,566,192
2023	54,911	301,756	379,586	87,993	824,246	12,390,438
2024	51,348	317,613	380,315	81,413	830,689	13,221,126
2025	53,833	330,314	371,574	81,407	837,128	14,058,255
2026	50,337	341,719	376,947	77,610	846,614	14,904,868
2027	50,471	356,627	384,567	72,927	864,593	15,769,461

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000135

	Scenario 2 - Renewable					
	High Fuel High Load With Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	52,762	196,942	560,188	57,642	867,533	4,149,956
2014	60,798	204,843	559,937	57,571	883,149	5,033,105
2015	56,875	214,703	549,426	55,862	876,866	5,909,971
2016	53,205	232,638	455,248	85,001	826,093	6,736,063
2017	49,772	239,286	398,415	114,753	802,226	7,538,290
2018	46,561	250,134	406,387	105,073	808,155	8,346,444
2019	43,556	259,441	406,149	104,665	813,812	9,160,256
2020	40,746	269,450	409,516	98,856	818,568	9,978,825
2021	38,117	285,921	389,376	90,706	804,120	10,782,944
2022	54,571	289,721	394,052	95,586	833,929	11,616,874
2023	51,033	302,992	384,261	91,614	829,900	12,446,774
2024	47,724	318,996	385,229	84,682	836,631	13,283,404
2025	50,446	331,646	376,181	84,369	842,642	14,126,046
2026	47,172	342,922	382,089	80,267	852,450	14,978,496
2027	47,513	357,963	389,762	75,300	870,538	15,849,035

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000136

	Scenario 2 - Renewable Low Fuel Low Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,822	0	399,572	39,771	478,165	2,778,280
2014	45,625	0	385,454	41,057	472,136	3,250,415
2015	42,695	0	365,568	39,836	448,099	3,698,515
2016	39,953	0	310,521	69,934	420,408	4,118,923
2017	37,387	0	275,870	100,203	413,460	4,532,383
2018	34,986	0	277,148	91,301	403,434	4,935,817
2019	32,739	0	274,119	91,539	398,396	5,334,213
2020	30,636	0	274,367	86,363	391,366	5,725,580
2021	28,668	0	262,713	78,807	370,188	6,095,768
2022	26,827	0	268,495	78,308	373,630	6,469,398
2023	25,103	0	262,489	74,983	362,576	6,831,974
2024	30,928	0	262,721	69,655	363,304	7,195,278
2025	28,933	0	256,791	69,672	355,395	7,550,672
2026	33,891	0	257,582	66,990	358,463	7,909,136
2027	31,698	0	258,027	62,285	352,010	8,261,145

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000137

	Scenario 2 - Renewable Low Fuel Low Load Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	30,639	0	412,066	38,856	481,561	2,781,675
2014	28,693	0	406,658	38,775	474,125	3,255,800
2015	32,569	0	384,161	38,705	455,434	3,711,235
2016	30,489	0	319,158	68,877	418,525	4,129,760
2017	28,542	0	281,183	99,359	409,084	4,538,844
2018	26,720	0	283,828	90,404	400,952	4,939,796
2019	25,013	0	281,757	90,683	397,453	5,337,249
2020	23,416	0	283,675	85,501	392,592	5,729,841
2021	21,920	0	270,026	77,995	369,941	6,099,781
2022	20,520	0	281,233	77,537	379,290	6,479,072
2023	25,548	0	271,001	74,691	371,239	6,850,311
2024	23,906	0	271,868	68,701	364,475	7,214,786
2025	29,495	0	266,205	69,443	365,142	7,579,929
2026	27,591	0	267,533	66,143	361,268	7,941,196
2027	31,148	0	267,784	61,816	360,748	8,301,944

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000138

	Scenario 3 - DSM Reference Case With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	26,325	0	453,181	39,995	519,501	3,076,403
2014	33,887	0	439,841	39,424	513,151	3,589,554
2015	31,670	0	424,157	38,347	494,174	4,083,729
2016	29,598	0	355,731	68,353	453,682	4,537,411
2017	27,662	0	312,965	98,668	439,295	4,976,705
2018	25,852	0	317,318	89,902	433,071	5,409,777
2019	24,161	0	315,358	90,258	429,776	5,839,553
2020	22,580	0	316,843	85,205	424,628	6,264,181
2021	21,103	0	302,509	77,727	401,339	6,665,520
2022	19,722	0	313,731	77,372	410,825	7,076,345
2023	26,196	0	305,930	74,768	406,895	7,483,239
2024	24,482	0	307,232	68,844	400,558	7,883,798
2025	30,005	0	300,751	69,558	400,314	8,284,112
2026	28,042	0	304,035	66,363	398,440	8,682,552
2027	31,545	0	303,147	62,143	396,836	9,079,387

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000139

	Scenario 3 - DSM					
	Reference Case Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	0	450,212	48,355	526,411	3,083,313
2014	26,023	0	445,603	45,541	517,167	3,600,480
2015	24,320	0	429,468	44,062	497,851	4,098,331
2016	22,729	0	358,737	74,164	455,631	4,553,961
2017	21,242	0	314,859	104,380	440,481	4,994,443
2018	19,853	0	319,703	94,992	434,548	5,428,990
2019	18,554	0	317,941	94,854	431,349	5,860,339
2020	17,340	0	320,092	89,268	426,700	6,287,039
2021	16,206	0	305,040	81,527	402,773	6,689,812
2022	15,145	0	318,212	80,493	413,850	7,103,662
2023	14,155	0	309,115	77,139	400,409	7,504,071
2024	20,666	0	310,607	71,571	402,843	7,906,914
2025	19,314	0	304,192	71,466	394,972	8,301,886
2026	23,622	0	306,774	68,406	398,802	8,700,688
2027	27,414	0	305,988	63,907	397,310	9,097,998

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000140

	Scenario 3 - DSM					
	High Fuel With GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	26,325	0	481,967	39,995	548,287	3,164,312
2014	33,887	0	472,853	39,424	546,164	3,710,476
2015	31,670	0	463,450	38,347	533,467	4,243,943
2016	29,598	0	384,243	68,353	482,194	4,726,137
2017	27,662	0	334,489	98,668	460,819	5,186,956
2018	25,852	0	341,050	89,902	456,804	5,643,760
2019	24,161	0	340,237	90,258	454,655	6,098,415
2020	22,580	0	343,150	85,205	450,935	6,549,350
2021	21,103	0	327,159	77,727	425,989	6,975,339
2022	19,722	0	339,983	77,372	437,077	7,412,416
2023	26,196	0	330,368	74,768	431,332	7,843,748
2024	24,482	0	331,932	68,844	425,258	8,269,006
2025	30,005	0	324,107	69,558	423,670	8,692,676
2026	28,042	0	330,066	66,363	424,471	9,117,147
2027	31,545	0	335,008	62,143	428,697	9,545,844

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000141

	Scenario 3 - DSM					
	High Fuel Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	0	478,641	48,355	554,840	3,170,866
2014	26,023	0	479,373	45,541	550,937	3,721,803
2015	24,320	0	469,631	44,062	538,013	4,259,816
2016	22,729	0	387,782	74,164	484,675	4,744,491
2017	21,242	0	336,730	104,380	462,353	5,206,844
2018	19,853	0	343,851	94,992	458,696	5,665,539
2019	18,554	0	343,261	94,854	456,669	6,122,208
2020	17,340	0	346,911	89,268	453,519	6,575,727
2021	16,206	0	330,094	81,527	427,826	7,003,553
2022	15,145	0	344,998	80,493	440,636	7,444,189
2023	14,155	0	334,084	77,139	425,378	7,869,567
2024	20,666	0	335,805	71,571	428,042	8,297,609
2025	19,314	0	328,109	71,466	418,889	8,716,498
2026	23,622	0	333,289	68,405	425,317	9,141,815
2027	27,414	0	338,447	63,907	429,769	9,571,584

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000142

	Scenario 3 - DSM Low Fuel With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	26,325	0	432,758	39,995	499,078	3,008,096
2014	33,887	0	415,506	39,424	488,816	3,496,912
2015	31,670	0	393,548	38,347	463,565	3,960,477
2016	29,598	0	331,686	68,353	429,637	4,390,114
2017	27,662	0	295,236	98,668	421,566	4,811,680
2018	25,852	0	296,881	89,902	412,635	5,224,315
2019	24,161	0	294,406	90,257	408,824	5,633,139
2020	22,580	0	294,763	85,205	402,548	6,035,687
2021	21,103	0	282,052	77,727	380,883	6,416,570
2022	19,722	0	288,785	77,372	385,879	6,802,449
2023	26,196	0	282,992	74,768	383,956	7,186,405
2024	24,482	0	283,179	68,844	376,505	7,562,910
2025	30,005	0	277,336	69,558	376,899	7,939,809
2026	28,042	0	278,738	66,363	373,142	8,312,952
2027	31,545	0	278,746	62,143	372,435	8,685,387

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM					
	Low Fuel Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	0	430,019	48,355	506,218	3,015,236
2014	26,023	0	420,703	45,527	492,253	3,507,489
2015	24,320	0	398,212	44,034	466,567	3,974,056
2016	22,729	0	334,275	74,146	431,151	4,405,207
2017	21,242	0	296,855	104,369	422,466	4,827,672
2018	19,853	0	298,916	94,979	413,747	5,241,420
2019	18,554	0	296,625	94,842	410,021	5,651,440
2020	17,340	0	297,566	89,257	404,164	6,055,604
2021	16,206	0	284,255	81,515	381,976	6,437,579
2022	15,145	0	292,687	80,484	388,316	6,825,895
2023	14,155	0	285,728	77,127	377,010	7,202,905
2024	20,666	0	286,095	71,559	378,320	7,581,225
2025	19,314	0	280,258	71,454	371,027	7,952,251
2026	23,622	0	281,034	68,395	373,051	8,325,302
2027	27,414	0	281,170	63,899	372,483	8,697,786

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM High Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	41,786	0	523,747	45,901	611,435	3,604,230
2014	48,337	0	505,528	45,342	599,206	4,203,436
2015	45,175	0	487,769	44,146	577,089	4,780,526
2016	42,219	0	407,206	73,688	523,113	5,303,639
2017	39,457	0	360,031	103,627	503,115	5,806,754
2018	36,876	0	365,228	94,821	496,925	6,303,680
2019	34,464	0	363,812	95,068	493,343	6,797,023
2020	32,209	0	365,568	89,982	487,759	7,284,782
2021	30,102	0	348,718	82,305	461,125	7,745,907
2022	36,237	0	362,298	82,574	481,110	8,227,017
2023	33,867	0	354,052	79,194	467,113	8,694,130
2024	39,088	0	354,760	73,804	467,653	9,161,782
2025	36,531	0	348,134	73,794	458,459	9,620,241
2026	39,713	0	350,080	70,845	460,638	10,080,879
2027	37,115	0	351,502	66,140	454,757	10,535,636

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM High Load Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	0	520,636	53,047	601,526	3,594,322
2014	37,452	0	514,426	51,195	603,074	4,197,395
2015	35,002	0	495,965	49,775	580,742	4,778,137
2016	32,712	0	412,145	79,104	523,961	5,302,098
2017	30,572	0	363,237	108,971	502,780	5,804,877
2018	28,572	0	369,008	99,578	497,158	6,302,036
2019	26,703	0	367,971	99,391	494,065	6,796,100
2020	24,956	0	370,370	93,825	489,151	7,285,251
2021	23,323	0	352,421	85,873	461,617	7,746,868
2022	29,902	0	368,836	85,600	484,338	8,231,206
2023	27,946	0	358,839	82,118	468,902	8,700,109
2024	33,555	0	359,884	76,430	469,869	9,169,977
2025	31,360	0	353,454	76,310	461,124	9,631,102
2026	29,308	0	356,529	72,679	458,516	10,089,618
2027	30,794	0	357,924	68,230	456,948	10,546,566

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000146

	Scenario 3 - DSM Low Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	20,115	0	415,332	36,317	471,764	2,799,552
2014	28,083	0	404,688	35,801	468,572	3,268,124
2015	26,246	0	390,154	34,785	451,185	3,719,309
2016	24,529	0	328,287	65,127	417,943	4,137,253
2017	22,924	0	287,732	95,624	406,281	4,543,533
2018	21,425	0	291,772	86,909	400,106	4,943,639
2019	20,023	0	289,538	87,324	396,885	5,340,524
2020	18,713	0	290,839	82,312	391,864	5,732,389
2021	17,489	0	278,018	74,935	370,442	6,102,831
2022	16,345	0	288,102	74,601	379,048	6,481,879
2023	15,275	0	280,548	71,426	367,249	6,849,128
2024	14,276	0	282,008	65,610	361,895	7,211,023
2025	20,467	0	275,414	66,390	362,271	7,573,294
2026	19,128	0	277,664	63,234	360,026	7,933,320
2027	21,279	0	277,943	59,239	358,462	8,291,782

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000147

	Scenario 3 - DSM					
	Low Load Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	0	0	429,415	34,329	463,744	2,791,532
2014	9,331	0	426,593	33,044	468,967	3,260,499
2015	8,720	0	410,307	32,371	451,398	3,711,897
2016	8,150	0	337,964	63,046	409,160	4,121,057
2017	7,617	0	293,698	93,836	395,151	4,516,207
2018	7,118	0	299,364	85,088	391,570	4,907,778
2019	6,653	0	298,023	85,564	390,239	5,298,017
2020	6,217	0	301,140	80,522	387,880	5,685,897
2021	5,811	0	286,105	73,281	365,197	6,051,093
2022	5,431	0	302,540	72,877	380,848	6,431,941
2023	11,414	0	290,013	70,347	371,774	6,803,714
2024	10,667	0	292,092	64,531	367,289	7,171,004
2025	17,094	0	285,734	65,401	368,229	7,539,233
2026	15,975	0	288,657	62,248	366,880	7,906,113
2027	20,268	0	288,825	58,114	367,207	8,273,320

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM High Capital Cost With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	24,138	0	453,432	39,478	517,047	3,079,876
2014	33,700	0	440,016	38,512	512,228	3,592,104
2015	38,333	0	424,157	38,347	500,838	4,092,942
2016	35,826	0	355,731	68,353	459,909	4,552,851
2017	33,482	0	312,965	98,668	445,115	4,997,966
2018	31,291	0	317,318	89,902	438,511	5,436,477
2019	29,244	0	315,358	90,258	434,860	5,871,336
2020	27,331	0	316,843	85,205	429,379	6,300,715
2021	25,543	0	302,509	77,727	405,779	6,706,494
2022	23,872	0	313,731	77,372	414,974	7,121,468
2023	31,627	0	305,930	74,768	412,326	7,533,794
2024	29,558	0	307,232	68,844	405,634	7,939,428
2025	36,174	0	300,751	69,558	406,483	8,345,910
2026	33,807	0	304,035	66,363	404,205	8,750,115
2027	38,001	0	303,147	62,143	403,291	9,153,406

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM					
	High Capital Cost Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	33,413	0	450,212	48,764	532,389	3,095,218
2014	31,227	0	445,603	45,541	522,372	3,617,590
2015	29,184	0	429,468	44,062	502,715	4,120,305
2016	27,275	0	358,737	74,164	460,177	4,580,481
2017	25,491	0	314,859	104,380	444,730	5,025,211
2018	23,823	0	319,703	94,992	438,518	5,463,729
2019	22,265	0	317,941	94,854	435,060	5,898,788
2020	20,808	0	320,092	89,268	430,168	6,328,957
2021	19,447	0	305,040	81,527	406,014	6,734,971
2022	18,174	0	318,212	80,493	416,879	7,151,850
2023	16,985	0	309,115	77,139	403,240	7,555,089
2024	24,799	0	310,607	71,571	406,976	7,962,066
2025	23,177	0	304,192	71,466	398,835	8,360,901
2026	28,347	0	306,774	68,406	403,527	8,764,427
2027	32,897	0	305,988	63,907	402,792	9,167,220

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000150

	Scenario 3 - DSM					
	High Regulated CO2 With GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	20,115	485,247	455,260	39,211	999,833	4,104,884
2014	28,083	473,575	462,396	39,620	1,003,674	5,108,557
2015	31,945	480,208	462,985	40,805	1,015,943	6,124,500
2016	29,855	502,809	409,053	72,958	1,014,675	7,139,175
2017	27,902	501,193	375,427	103,913	1,008,435	8,147,610
2018	26,076	504,196	400,875	97,223	1,028,371	9,175,982
2019	24,370	529,015	397,895	96,871	1,048,152	10,224,134
2020	22,776	555,305	399,698	91,302	1,069,081	11,293,215
2021	21,286	576,096	398,360	84,994	1,080,735	12,373,950
2022	38,808	574,987	412,955	90,660	1,117,410	13,491,360
2023	36,269	566,725	438,695	88,846	1,130,535	14,621,895
2024	33,896	605,009	431,504	81,811	1,152,221	15,774,116
2025	48,306	570,508	453,332	88,754	1,160,900	16,935,016
2026	61,074	537,462	487,029	91,225	1,176,789	18,111,805
2027	57,078	571,621	482,089	84,902	1,195,691	19,307,496

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000151

	Scenario 3 - DSM					
	High Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	479,150	456,515	48,576	1,012,085	4,117,136
2014	26,023	475,479	469,773	46,456	1,017,731	5,134,867
2015	24,320	489,114	463,728	45,710	1,022,872	6,157,739
2016	22,729	515,749	403,806	77,162	1,019,446	7,177,185
2017	21,242	499,801	382,512	109,255	1,012,810	8,189,995
2018	19,853	522,945	388,505	99,699	1,031,002	9,220,997
2019	18,554	547,212	387,562	99,010	1,052,338	10,273,336
2020	17,340	577,564	386,820	92,837	1,074,561	11,347,897
2021	16,206	606,303	376,544	85,399	1,084,452	12,432,348
2022	34,060	605,972	395,094	90,898	1,126,024	13,558,372
2023	31,832	592,483	426,828	89,147	1,140,290	14,698,662
2024	29,749	631,690	419,834	81,972	1,163,245	15,861,907
2025	44,430	598,046	440,574	88,667	1,171,717	17,033,623
2026	41,523	626,640	439,073	83,946	1,191,183	18,224,806
2027	38,807	664,771	434,082	77,881	1,215,542	19,440,348

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM					
	Regulated CO2 With GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	26,325	187,030	446,485	39,998	699,838	3,427,468
2014	33,887	192,004	432,749	39,434	698,074	4,125,542
2015	31,670	201,681	415,704	38,353	687,408	4,812,951
2016	29,598	219,429	346,976	68,362	664,365	5,477,316
2017	27,662	225,045	304,203	98,694	655,604	6,132,919
2018	25,852	234,898	306,808	90,016	657,573	6,790,493
2019	24,161	243,402	303,774	90,355	661,692	7,452,185
2020	22,580	252,467	303,255	85,270	663,572	8,115,756
2021	21,103	267,062	288,105	77,894	654,164	8,769,920
2022	19,722	274,564	294,763	77,483	666,532	9,436,452
2023	36,551	274,343	289,646	80,619	681,159	10,117,611
2024	34,160	282,278	292,311	74,850	683,598	10,801,209
2025	31,925	285,987	288,538	75,452	681,902	11,483,111
2026	29,837	287,617	293,576	72,889	683,919	12,167,030
2027	31,288	294,243	296,113	69,177	690,820	12,857,850

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM					
	Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	186,554	443,578	48,358	706,334	3,433,964
2014	26,023	193,618	438,368	45,555	703,564	4,137,528
2015	24,320	203,217	420,863	44,071	692,471	4,829,999
2016	22,729	220,332	349,869	74,176	667,106	5,497,105
2017	21,242	225,677	305,997	104,407	657,322	6,154,427
2018	19,853	235,740	309,035	95,108	659,736	6,814,163
2019	18,554	244,470	306,116	94,958	664,098	7,478,261
2020	17,340	253,516	306,561	89,354	666,771	8,145,032
2021	16,206	268,422	290,269	81,664	656,561	8,801,593
2022	15,145	275,399	300,198	80,627	671,369	9,472,962
2023	14,155	278,787	296,785	77,798	667,525	10,140,487
2024	20,666	291,738	296,088	72,348	680,840	10,821,328
2025	19,314	298,861	289,685	72,752	680,611	11,501,939
2026	23,622	303,936	292,384	70,336	690,277	12,192,216
2027	27,414	317,844	288,363	65,628	699,249	12,891,465

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM High Fuel With Regulated CO2 With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	26,325	187,030	481,971	39,998	735,324	3,529,151
2014	33,887	192,089	472,860	39,426	738,261	4,267,412
2015	31,670	201,681	463,450	38,353	735,155	5,002,566
2016	29,598	219,403	384,185	68,362	701,549	5,704,115
2017	27,662	224,726	334,587	98,797	685,772	6,389,888
2018	25,852	234,898	341,083	90,016	691,849	7,081,737
2019	24,161	243,469	340,297	90,361	698,287	7,780,024
2020	22,580	252,549	343,181	85,277	703,588	8,483,612
2021	21,103	268,403	327,174	77,798	694,478	9,178,090
2022	19,722	275,617	340,010	77,415	712,765	9,890,854
2023	36,551	285,542	324,468	79,964	726,525	10,617,379
2024	34,160	300,494	325,468	73,654	733,775	11,351,154
2025	31,925	313,082	317,747	73,360	736,114	12,087,269
2026	29,837	323,685	322,938	69,859	746,318	12,833,587
2027	31,288	337,974	328,322	65,400	762,983	13,596,570

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM					
	High Fuel With Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	186,554	478,646	48,358	741,402	3,535,229
2014	26,023	193,738	479,380	45,543	744,684	4,279,913
2015	24,320	203,217	469,647	44,071	741,255	5,021,168
2016	22,729	220,306	387,740	74,176	704,952	5,726,120
2017	21,242	225,358	336,836	104,510	687,947	6,414,066
2018	19,853	235,740	343,884	95,108	694,585	7,108,652
2019	18,554	244,470	343,315	94,958	701,298	7,809,949
2020	17,340	253,889	346,966	89,342	707,536	8,517,485
2021	16,206	269,560	330,111	81,599	697,475	9,214,961
2022	15,145	277,755	345,037	80,538	718,474	9,933,435
2023	14,155	289,485	334,114	77,188	714,941	10,648,377
2024	30,586	301,620	328,785	76,600	737,591	11,385,967
2025	28,585	314,210	320,916	76,055	739,765	12,125,733
2026	26,715	324,685	326,972	72,233	750,604	12,876,337
2027	24,967	339,316	332,436	67,002	763,721	13,640,058

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000156

	Scenario 3 - DSM					
	High Fuel High Load With Regulated CO2 With GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	47,959	194,235	539,975	55,298	837,466	4,084,167
2014	54,106	200,010	530,716	53,856	838,689	4,922,856
2015	50,566	210,083	521,488	51,968	834,106	5,756,962
2016	47,258	230,597	437,854	81,230	796,939	6,553,901
2017	44,166	238,416	384,293	110,906	777,781	7,331,682
2018	41,277	248,318	390,971	101,504	782,071	8,113,753
2019	38,577	257,184	389,595	101,212	786,569	8,900,321
2020	36,053	265,858	390,762	95,609	788,282	9,688,603
2021	33,694	282,852	373,578	87,568	777,693	10,466,296
2022	39,595	288,801	384,162	87,321	799,879	11,266,174
2023	37,005	302,497	376,598	83,610	799,709	12,065,883
2024	42,021	318,173	376,904	77,879	814,977	12,880,860
2025	39,272	331,539	368,831	77,478	817,120	13,697,980
2026	36,703	342,702	373,804	73,835	827,043	14,525,023
2027	37,705	357,611	382,381	69,357	847,053	15,372,077

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM					
	High Fuel High Load With Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	27,844	197,444	556,665	53,047	834,999	4,081,700
2014	37,452	205,406	556,794	51,196	850,848	4,932,548
2015	35,002	215,215	546,538	49,784	846,538	5,779,086
2016	32,712	233,533	450,310	79,115	795,670	6,574,756
2017	30,572	240,719	393,146	109,043	773,481	7,348,237
2018	28,572	251,207	401,281	99,639	780,700	8,128,937
2019	26,703	260,658	401,508	99,440	788,309	8,917,246
2020	24,956	270,354	405,320	93,863	794,493	9,711,738
2021	23,323	287,013	385,281	85,907	781,524	10,493,262
2022	40,712	290,498	390,630	91,016	812,856	11,306,119
2023	38,048	303,870	381,199	87,230	810,348	12,116,466
2024	35,559	319,669	381,654	80,494	817,376	12,933,843
2025	33,233	333,060	373,560	79,875	819,727	13,753,570
2026	36,631	343,621	378,366	76,385	835,003	14,588,573
2027	34,234	358,901	387,123	71,111	851,368	15,439,941

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 3 - DSM Low Fuel Low Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	20,115	0	397,812	36,317	454,244	2,741,038
2014	28,083	0	383,639	35,801	447,524	3,188,561
2015	26,246	0	363,650	34,785	424,681	3,613,242
2016	24,529	0	308,056	65,127	397,712	4,010,954
2017	22,924	0	273,344	95,624	391,892	4,402,846
2018	21,425	0	274,832	86,909	383,166	4,786,011
2019	20,023	0	272,020	87,324	379,367	5,165,378
2020	18,713	0	272,252	82,312	373,277	5,538,655
2021	17,489	0	260,757	74,935	353,181	5,891,836
2022	16,345	0	266,737	74,601	357,683	6,249,519
2023	15,275	0	260,912	71,426	347,614	6,597,133
2024	14,276	0	261,277	65,610	341,164	6,938,297
2025	20,467	0	255,365	66,390	342,222	7,280,519
2026	19,128	0	255,992	63,234	338,354	7,618,873
2027	21,279	0	256,790	59,239	337,309	7,956,182

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000159

	Scenario 3 - DSM Low Fuel Low Load Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	0	0	410,785	34,329	445,114	2,731,907
2014	9,331	0	403,453	33,044	445,828	3,177,735
2015	8,720	0	381,322	32,370	422,413	3,600,148
2016	8,150	0	316,256	63,046	387,453	3,987,600
2017	7,617	0	278,394	93,836	379,847	4,367,447
2018	7,118	0	281,248	85,088	373,454	4,740,901
2019	6,653	0	279,251	85,564	371,467	5,112,368
2020	6,217	0	281,070	80,523	367,810	5,480,178
2021	5,811	0	267,690	73,281	346,781	5,826,959
2022	5,431	0	279,024	72,877	357,331	6,184,290
2023	11,414	0	269,071	70,347	350,831	6,535,121
2024	10,667	0	269,962	64,531	345,159	6,880,280
2025	17,094	0	264,235	65,401	346,729	7,227,010
2026	15,975	0	265,414	62,248	343,638	7,570,648
2027	20,268	0	266,215	58,114	344,597	7,915,245

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM Reference Case With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,822	0	446,150	43,994	528,966	3,102,972
2014	45,625	0	433,706	43,215	522,547	3,625,519
2015	48,394	0	418,340	42,848	509,582	4,135,101
2016	45,279	0	351,690	72,688	469,657	4,604,757
2017	42,364	0	309,781	102,811	454,957	5,059,714
2018	39,638	0	313,917	93,873	447,427	5,507,142
2019	37,086	0	311,799	94,057	442,942	5,950,084
2020	34,699	0	313,203	88,845	436,747	6,386,831
2021	32,465	0	299,336	81,213	413,014	6,799,845
2022	30,375	0	309,904	80,681	420,960	7,220,805
2023	28,420	0	302,405	77,307	408,132	7,628,938
2024	32,662	0	303,292	71,821	407,775	8,036,712
2025	37,678	0	296,731	72,385	406,794	8,443,507
2026	35,239	0	299,848	69,061	404,148	8,847,654
2027	38,295	0	299,091	64,746	402,133	9,249,787

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM					
	Reference Case Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	0	443,364	53,373	543,290	3,117,295
2014	43,565	0	439,008	50,341	532,914	3,650,209
2015	40,769	0	423,346	48,637	512,753	4,162,962
2016	38,153	0	354,420	78,577	471,151	4,634,113
2017	35,705	0	311,515	108,589	455,809	5,089,921
2018	33,414	0	316,113	99,027	448,554	5,538,475
2019	31,270	0	314,211	98,713	444,193	5,982,668
2020	29,263	0	316,292	92,963	438,518	6,421,186
2021	27,385	0	301,694	85,066	414,145	6,835,331
2022	25,627	0	314,130	83,854	423,611	7,258,943
2023	23,983	0	305,423	80,370	409,776	7,668,719
2024	29,881	0	306,879	74,667	411,427	8,080,145
2025	27,954	0	300,408	74,417	402,779	8,482,924
2026	29,703	0	303,530	71,335	404,568	8,887,492
2027	33,122	0	302,635	66,715	402,471	9,289,963

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000162

	Scenario 4 - Renewables and DSM High Fuel With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,822	0	473,590	43,994	556,407	3,188,041
2014	45,625	0	465,288	43,216	554,129	3,742,170
2015	48,394	0	455,870	42,848	547,112	4,289,282
2016	45,279	0	378,706	72,688	496,672	4,785,955
2017	42,364	0	330,115	102,811	475,291	5,261,245
2018	39,638	0	336,440	93,873	469,950	5,731,196
2019	37,086	0	335,448	94,056	466,590	6,197,786
2020	34,699	0	338,284	88,845	461,828	6,659,614
2021	32,465	0	322,855	81,213	436,533	7,096,148
2022	30,375	0	334,954	80,681	446,010	7,542,157
2023	28,420	0	325,909	77,307	431,636	7,973,793
2024	32,662	0	326,948	71,821	431,431	8,405,224
2025	37,678	0	319,082	72,385	429,144	8,834,368
2026	35,239	0	324,801	69,061	429,101	9,263,470
2027	38,295	0	329,660	64,746	432,702	9,696,171

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM					
	High Fuel Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	0	470,443	53,373	570,368	3,202,003
2014	43,565	0	471,250	50,341	565,156	3,767,159
2015	40,769	0	461,695	48,637	551,101	4,318,260
2016	38,153	0	381,922	78,577	498,653	4,816,913
2017	35,705	0	332,168	108,589	476,462	5,293,375
2018	33,414	0	339,021	99,027	471,462	5,764,837
2019	31,270	0	338,269	98,713	468,251	6,233,089
2020	29,263	0	341,866	92,963	464,092	6,697,181
2021	27,385	0	325,596	85,066	438,047	7,135,227
2022	25,627	0	339,703	83,854	449,185	7,584,412
2023	23,983	0	329,324	80,370	433,677	8,018,089
2024	29,881	0	331,032	74,667	435,579	8,453,668
2025	27,954	0	323,323	74,417	425,694	8,879,362
2026	29,703	0	329,093	71,335	430,130	9,309,492
2027	33,122	0	333,924	66,715	433,760	9,743,252

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000164

	Scenario 4 - Renewables and DSM Low Fuel With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,822	0	426,699	43,994	509,516	3,036,708
2014	45,625	0	410,452	43,215	499,293	3,536,001
2015	48,394	0	389,078	42,848	480,320	4,016,321
2016	45,279	0	328,880	72,688	446,847	4,463,167
2017	42,364	0	293,009	102,811	438,185	4,901,352
2018	39,638	0	294,504	93,873	428,014	5,329,366
2019	37,086	0	291,851	94,057	422,994	5,752,360
2020	34,699	0	292,132	88,845	415,676	6,168,036
2021	32,465	0	279,774	81,213	393,453	6,561,489
2022	30,375	0	286,025	80,681	397,082	6,958,570
2023	28,420	0	280,348	77,307	386,074	7,344,645
2024	32,662	0	280,199	71,821	384,682	7,729,327
2025	37,678	0	274,284	72,385	384,347	8,113,674
2026	35,239	0	275,560	69,061	379,860	8,493,534
2027	38,295	0	275,612	64,746	378,653	8,872,188

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM					
	Low Fuel Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	0	424,143	53,373	524,068	3,051,261
2014	43,565	0	415,259	50,328	509,152	3,560,412
2015	40,769	0	393,488	48,611	482,868	4,043,281
2016	38,153	0	331,235	78,559	447,948	4,491,228
2017	35,705	0	294,490	108,578	438,773	4,930,002
2018	33,414	0	296,377	99,014	428,805	5,358,806
2019	31,270	0	293,927	98,701	423,898	5,782,704
2020	29,263	0	294,803	92,952	417,018	6,199,722
2021	27,385	0	281,821	85,055	394,260	6,593,983
2022	25,627	0	289,696	83,846	399,169	6,993,152
2023	23,983	0	282,988	80,358	387,329	7,380,481
2024	29,881	0	283,319	74,656	387,855	7,768,336
2025	27,954	0	277,429	74,406	379,789	8,148,124
2026	29,703	0	278,679	71,324	379,706	8,527,830
2027	33,122	0	278,644	66,707	378,473	8,906,303

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM					
	High Load With GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	56,963	0	516,572	51,039	624,574	3,632,501
2014	62,580	0	499,075	50,198	611,852	4,244,353
2015	58,540	0	481,913	48,803	589,256	4,833,609
2016	54,762	0	402,821	78,071	535,654	5,369,263
2017	51,227	0	356,312	107,803	515,341	5,884,604
2018	47,920	0	361,378	98,835	508,132	6,392,736
2019	44,827	0	359,862	98,921	503,609	6,896,346
2020	41,933	0	361,560	93,703	497,196	7,393,542
2021	39,226	0	345,091	85,856	470,173	7,863,715
2022	44,799	0	358,351	86,033	489,183	8,352,898
2023	41,900	0	350,309	82,474	474,682	8,827,581
2024	46,626	0	351,005	76,954	474,584	9,302,165
2025	43,603	0	344,412	76,815	464,829	9,766,994
2026	46,349	0	346,328	73,741	466,417	10,233,412
2027	43,341	0	347,759	68,920	460,020	10,693,432

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000167

	Scenario 4 - Renewables and DSM High Load Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	0	512,527	58,039	617,118	3,625,044
2014	43,565	0	506,524	54,964	605,053	4,230,097
2015	49,708	0	487,162	53,884	590,753	4,820,850
2016	46,507	0	406,214	83,374	536,094	5,356,944
2017	43,512	0	358,627	113,083	515,222	5,872,166
2018	40,710	0	364,195	103,496	508,401	6,380,567
2019	38,088	0	362,730	103,085	503,903	6,884,471
2020	35,636	0	364,825	97,286	497,747	7,382,217
2021	33,341	0	347,729	89,245	470,315	7,852,533
2022	39,298	0	362,907	88,648	490,853	8,343,386
2023	36,759	0	353,434	85,097	475,290	8,818,676
2024	41,821	0	354,335	79,260	475,417	9,294,093
2025	39,113	0	347,889	78,931	465,933	9,760,025
2026	42,152	0	349,884	75,518	467,554	10,227,579
2027	39,419	0	351,421	70,463	461,303	10,688,882

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM Low Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,822	0	408,712	41,264	488,799	2,834,554
2014	45,625	0	398,933	40,516	485,074	3,319,627
2015	42,695	0	384,903	39,293	466,891	3,786,518
2016	39,953	0	324,626	69,461	434,040	4,220,558
2017	37,387	0	284,992	99,763	422,143	4,642,701
2018	34,986	0	288,795	90,877	414,658	5,057,359
2019	32,739	0	286,421	91,125	410,284	5,467,643
2020	30,636	0	287,565	85,956	404,157	5,871,800
2021	28,668	0	275,160	78,425	382,253	6,254,053
2022	26,827	0	284,651	77,921	389,399	6,643,452
2023	25,103	0	277,444	74,621	377,168	7,020,620
2024	23,491	0	278,808	68,667	370,966	7,391,586
2025	21,982	0	272,235	68,717	362,933	7,754,519
2026	27,395	0	274,370	66,036	367,800	8,122,320
2027	25,627	0	274,711	61,404	361,741	8,484,061

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM					
	Low Load Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	18,708	0	421,755	39,268	479,730	2,825,485
2014	17,542	0	421,219	37,174	475,935	3,301,420
2015	22,148	0	405,031	37,127	464,305	3,765,726
2016	20,750	0	334,064	67,490	422,304	4,188,030
2017	19,440	0	290,712	98,040	408,193	4,596,222
2018	18,213	0	296,140	89,139	403,491	4,999,714
2019	17,063	0	294,721	89,456	401,240	5,400,954
2020	15,986	0	297,860	84,278	398,124	5,799,078
2021	14,976	0	283,124	76,861	374,961	6,174,039
2022	14,031	0	299,155	76,380	389,565	6,563,604
2023	19,483	0	286,789	73,649	379,921	6,943,525
2024	18,238	0	288,843	67,700	374,781	7,318,306
2025	24,197	0	282,477	68,447	375,122	7,693,428
2026	22,640	0	285,358	65,170	373,169	8,066,597
2027	26,521	0	285,441	60,917	372,879	8,439,476

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000170

	Scenario 4 - Renewables and DSM High Capital Cost With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,587	0	446,150	44,403	537,140	3,121,962
2014	54,751	0	433,706	43,215	531,672	3,653,635
2015	58,072	0	418,340	42,848	519,261	4,172,895
2016	54,335	0	351,690	72,688	478,712	4,651,608
2017	50,837	0	309,781	102,811	463,430	5,115,037
2018	47,565	0	313,917	93,873	455,355	5,570,392
2019	44,503	0	311,799	94,057	450,359	6,020,751
2020	41,639	0	313,203	88,845	443,687	6,464,438
2021	38,958	0	299,336	81,214	419,507	6,883,945
2022	36,450	0	309,904	80,681	427,035	7,310,981
2023	34,104	0	302,405	77,307	413,816	7,724,797
2024	39,195	0	303,292	71,821	414,307	8,139,104
2025	45,213	0	296,731	72,385	414,330	8,553,433
2026	42,287	0	299,848	69,061	411,196	8,964,629
2027	45,954	0	299,091	64,746	409,792	9,374,421

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM High Capital Cost Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	55,862	0	443,364	53,783	553,010	3,137,831
2014	52,278	0	439,008	50,341	541,627	3,679,459
2015	48,923	0	423,346	48,637	520,907	4,200,365
2016	45,784	0	354,420	78,577	478,782	4,679,147
2017	42,846	0	311,515	108,589	462,950	5,142,096
2018	40,097	0	316,113	99,027	455,237	5,597,333
2019	37,523	0	314,211	98,713	450,447	6,047,780
2020	35,115	0	316,292	92,963	444,371	6,492,151
2021	32,862	0	301,694	85,066	419,622	6,911,773
2022	30,753	0	314,130	83,854	428,737	7,340,510
2023	28,779	0	305,423	80,370	414,572	7,755,082
2024	35,857	0	306,879	74,667	417,403	8,172,485
2025	33,544	0	300,408	74,417	408,369	8,580,854
2026	35,644	0	303,530	71,335	410,508	8,991,363
2027	39,746	0	302,635	66,715	409,095	9,400,458

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000172

	Scenario 4 - Renewables and DSM High Regulated CO2 With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,822	479,521	448,007	44,189	1,010,540	4,125,345
2014	45,625	467,370	456,408	44,407	1,013,810	5,139,156
2015	48,394	472,891	458,279	45,467	1,025,030	6,164,186
2016	45,279	495,183	405,679	77,523	1,023,665	7,187,851
2017	42,364	492,899	373,243	108,348	1,016,854	8,204,705
2018	39,638	494,618	399,401	101,571	1,035,227	9,239,932
2019	37,086	519,127	396,185	101,030	1,053,427	10,293,359
2020	34,699	545,257	397,624	95,262	1,072,841	11,366,201
2021	32,465	565,156	397,109	88,873	1,083,603	12,449,804
2022	30,375	609,942	390,518	86,300	1,117,135	13,566,938
2023	28,420	617,609	399,225	83,838	1,129,091	14,696,030
2024	43,947	592,665	430,690	85,253	1,152,556	15,848,585
2025	57,727	558,011	452,785	92,069	1,160,593	17,009,178
2026	69,904	525,601	485,749	94,351	1,175,605	18,184,784
2027	65,356	559,312	480,886	87,906	1,193,459	19,378,243

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM High Regulated CO2 Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	473,170	450,136	53,657	1,023,514	4,138,319
2014	43,565	468,569	463,853	51,350	1,027,337	5,165,656
2015	40,769	481,465	458,686	50,423	1,031,344	6,197,000
2016	38,153	507,578	400,516	81,814	1,028,061	7,225,061
2017	35,705	490,030	381,335	113,840	1,020,909	8,245,970
2018	33,414	513,202	386,889	104,067	1,037,572	9,283,542
2019	31,270	537,174	385,562	103,172	1,057,178	10,340,720
2020	29,263	567,632	384,243	96,782	1,077,920	11,418,640
2021	27,385	595,930	374,453	89,216	1,086,983	12,505,623
2022	25,627	638,778	375,011	86,898	1,126,314	13,631,938
2023	23,983	641,959	387,147	84,348	1,137,438	14,769,375
2024	39,800	619,380	418,762	85,398	1,163,340	15,932,716
2025	53,851	585,326	440,096	91,987	1,171,261	17,103,976
2026	50,354	613,814	438,284	87,103	1,189,555	18,293,532
2027	47,084	651,539	433,232	80,905	1,212,760	19,506,292

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM Regulated CO2 With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,822	184,973	439,885	44,048	707,729	3,450,738
2014	45,625	189,970	426,987	43,268	705,851	4,156,590
2015	48,394	199,566	410,273	42,888	701,120	4,857,709
2016	45,279	217,020	343,527	72,814	678,640	5,536,350
2017	42,364	222,235	301,779	103,010	669,389	6,205,738
2018	39,638	232,099	304,197	94,137	670,071	6,875,810
2019	37,086	240,576	300,983	94,283	672,929	7,548,739
2020	34,699	249,619	300,348	89,014	673,679	8,222,418
2021	32,465	264,121	285,659	81,489	663,733	8,886,151
2022	30,375	271,559	291,750	80,871	674,555	9,560,706
2023	28,420	277,086	288,708	77,959	672,173	10,232,879
2024	43,947	279,120	290,184	78,025	691,277	10,924,157
2025	41,100	282,441	286,764	78,514	688,820	11,612,976
2026	38,437	283,533	292,200	75,870	690,040	12,303,016
2027	35,947	289,901	294,946	71,547	692,341	12,995,357

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000175

	Scenario 4 - Renewables and DSM Regulated CO2 Without GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	184,445	437,158	53,427	721,582	3,464,592
2014	43,565	191,402	432,152	50,396	717,515	4,182,106
2015	40,769	201,005	415,122	48,679	705,575	4,887,681
2016	38,153	217,839	346,166	78,706	680,865	5,568,547
2017	35,705	222,807	303,418	108,789	670,719	6,239,266
2018	33,414	232,868	306,242	99,293	671,816	6,911,082
2019	31,270	241,568	303,179	98,946	674,962	7,586,044
2020	29,263	250,583	303,523	93,153	676,521	8,262,566
2021	27,385	265,402	287,680	85,312	665,779	8,928,344
2022	25,627	272,233	297,015	84,067	678,943	9,607,288
2023	23,983	275,498	294,115	81,113	674,709	10,281,997
2024	26,314	287,976	293,502	75,451	683,244	10,965,240
2025	30,437	294,175	286,814	76,193	687,619	11,652,860
2026	32,024	298,942	290,596	73,788	695,349	12,348,208
2027	35,291	312,845	286,612	68,950	703,698	13,051,906

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM High Fuel With Regulated CO2 With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,822	184,973	473,709	44,048	741,552	3,548,866
2014	45,625	190,055	465,391	43,260	744,332	4,293,198
2015	48,394	199,566	455,962	42,888	746,810	5,040,007
2016	45,279	216,985	378,870	72,814	713,948	5,753,955
2017	42,364	221,904	330,584	103,120	697,973	6,451,928
2018	39,638	232,099	336,785	94,137	702,660	7,154,588
2019	37,086	240,640	335,766	94,289	707,780	7,862,368
2020	34,699	249,698	338,540	89,020	711,958	8,574,326
2021	32,465	265,451	323,089	81,394	702,398	9,276,724
2022	30,375	272,619	335,143	80,801	718,938	9,995,662
2023	28,420	284,780	326,206	77,424	716,830	10,712,493
2024	43,947	297,538	321,509	76,825	739,820	11,452,312
2025	41,100	310,081	313,796	76,387	741,364	12,193,677
2026	38,437	320,611	318,859	72,748	750,656	12,944,332
2027	35,947	335,007	323,961	67,635	762,551	13,706,883

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000177

	Scenario 4 - Renewables and DSM					
	High Fuel With Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	184,445	470,560	53,427	754,985	3,562,298
2014	43,565	191,515	471,352	50,386	756,817	4,319,116
2015	40,769	201,005	461,782	48,679	752,235	5,071,351
2016	38,153	217,805	382,115	78,707	716,780	5,788,131
2017	35,705	222,476	332,644	108,899	699,724	6,487,854
2018	33,414	232,868	339,360	99,293	704,935	7,192,789
2019	31,270	241,568	338,587	98,946	710,370	7,903,159
2020	29,263	250,958	342,140	93,141	715,501	8,618,660
2021	27,385	266,536	325,836	85,248	705,004	9,323,664
2022	25,627	274,646	339,899	83,976	724,147	10,047,812
2023	23,983	286,387	329,506	80,495	720,371	10,768,183
2024	26,314	301,515	331,202	74,707	733,738	11,501,921
2025	30,437	313,533	322,643	74,899	741,512	12,243,434
2026	32,024	324,589	328,785	71,788	757,186	13,000,620
2027	35,291	338,760	333,736	67,153	774,939	13,775,559

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000178

	Scenario 4 - Renewables and DSM High Fuel High Load With Regulated CO2 With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	66,667	192,319	531,572	60,308	850,866	4,111,924
2014	71,648	198,105	522,987	58,623	851,363	4,963,286
2015	67,015	208,139	513,922	56,525	845,601	5,808,888
2016	62,682	228,536	432,103	85,659	808,981	6,617,868
2017	58,629	235,981	379,622	115,211	789,444	7,407,313
2018	54,838	245,889	386,155	105,608	792,491	8,199,803
2019	51,292	254,705	384,610	105,128	795,736	8,995,539
2020	47,976	263,362	385,732	99,344	796,413	9,791,952
2021	44,874	280,283	368,986	91,154	785,298	10,577,250
2022	41,972	286,182	379,215	90,036	797,405	11,374,655
2023	47,022	299,823	371,829	86,881	805,555	12,180,210
2024	43,975	315,384	372,181	80,359	811,898	12,992,108
2025	48,251	328,742	364,072	80,467	821,532	13,813,640
2026	45,120	339,765	368,979	76,693	830,558	14,644,198
2027	42,193	354,836	377,248	71,579	845,856	15,490,054

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM					
	High Fuel High Load With Regulated CO2 Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	46,552	195,357	547,088	58,056	847,053	4,108,111
2014	43,565	203,160	547,272	54,977	848,974	4,957,085
2015	49,708	212,356	535,552	53,900	851,516	5,808,601
2016	46,507	230,737	442,552	83,438	803,234	6,611,836
2017	43,512	237,735	387,186	113,270	781,703	7,393,539
2018	40,710	248,136	395,101	103,649	787,596	8,181,135
2019	38,088	257,457	394,822	103,210	793,577	8,974,712
2020	35,636	266,965	398,310	97,382	798,293	9,773,005
2021	33,341	283,650	379,269	89,338	785,598	10,558,603
2022	50,108	287,157	384,398	94,355	816,018	11,374,620
2023	46,862	300,682	375,854	90,446	813,844	12,188,464
2024	43,826	316,316	376,255	83,564	819,961	13,008,425
2025	46,803	329,283	367,608	83,305	826,999	13,835,424
2026	43,767	340,100	372,879	79,187	835,933	14,671,357
2027	44,331	355,072	381,340	74,283	855,025	15,526,382

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

Hearing Exhibit - 00000180

	Scenario 4 - Renewables and DSM Low Fuel Low Load With GEC ($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	38,822	0	392,123	41,264	472,210	2,777,988
2014	45,625	0	378,923	40,516	465,064	3,243,052
2015	42,695	0	359,652	39,293	441,640	3,684,692
2016	39,953	0	305,529	69,461	414,943	4,099,635
2017	37,387	0	271,435	99,764	408,586	4,508,221
2018	34,986	0	272,765	90,877	398,628	4,906,848
2019	32,739	0	269,805	91,125	393,669	5,300,517
2020	30,636	0	269,895	85,956	386,487	5,687,004
2021	28,668	0	258,717	78,425	365,810	6,052,815
2022	26,827	0	264,267	77,921	369,015	6,421,829
2023	25,103	0	258,653	74,621	358,378	6,780,207
2024	23,491	0	258,932	68,667	351,090	7,131,297
2025	21,982	0	252,993	68,717	343,692	7,474,989
2026	27,395	0	253,577	66,036	347,008	7,821,997
2027	25,627	0	254,351	61,404	341,381	8,163,379

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

	Scenario 4 - Renewables and DSM					
	Low Fuel Low Load Without GEC					
	($000, 2008$)					
Year	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2013	18,708	0	404,137	39,268	462,113	2,767,891
2014	17,542	0	399,056	37,174	453,772	3,221,663
2015	22,148	0	377,291	37,127	436,566	3,658,229
2016	20,750	0	313,520	67,490	401,760	4,059,989
2017	19,440	0	276,277	98,040	393,757	4,453,746
2018	18,213	0	278,971	89,139	386,322	4,840,069
2019	17,063	0	276,869	89,456	383,389	5,223,457
2020	15,986	0	278,703	84,278	378,967	5,602,424
2021	14,976	0	265,541	76,861	357,378	5,959,802
2022	14,031	0	276,588	76,380	366,998	6,326,800
2023	19,483	0	266,696	73,649	359,828	6,686,628
2024	18,238	0	267,560	67,700	353,498	7,040,126
2025	24,197	0	261,821	68,447	354,465	7,394,591
2026	22,640	0	262,979	65,170	350,789	7,745,381
2027	26,521	0	263,647	60,917	351,085	8,096,465

Note: Cumulative Present Worth of Total Costs includes costs for 2008 through 2012.

69. **Please complete the table below regarding JEA's fuel requirements for the periods 2009-2018 with the GEC Combined Cycle Conversion Project and for each alternative. Please complete the table using the following cases for both Scenario 3 and Scenario 4: High Load, Low Load, Reference, and Regulated CO2. Please be reflective the 2013 in-service date.**

Scenario: FUEL REQUIREMENTS	Case: UNITS	ACTUAL 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
NUCLEAR	TRILLION BTU											
COAL	1000 TON											
RESIDUAL	1000 BBL											
DISTILLATE	1000 BBL											
NATURAL GAS	1000 MCF											
PETCOKE	TRILLION BTU											

Response: Please refer to the attachment labeled *Response to Interrogatory No. 69*, which presents the requested data for 2009 through 2018, which is consistent with the text of Interrogatory No. 69 (the sample table requests data for 2007 through 2017). Providing data for 2009 through 2018 is also consistent with the data requested and provided in response to Interrogatory No. 70 . Please note that the requested data has been provided for all combinations of cases and scenarios for which data has been provided in response to Interrogatory Nos. 33 and 67.

Response to Interrogatory # 69

Scenario 1 Conventional	Reference Case w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,811	5,572	5,779	5,750
Distillate	1000 BBL	8	7	15	7	6	6	7	1	1	1
Natural Gas	1000 MCF	22,324	30,932	39,519	43,922	39,130	41,778	42,946	26,806	19,509	23,327
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000184

Response to Interrogatory # 69

Scenario 1 Conventional	Reference Case wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,810	5,572	5,779	5,750
Distillate	1000 BBL	8	7	15	7	3	2	3	0	0	0
Natural Gas	1000 MCF	22,324	30,932	39,519	43,922	38,686	42,943	44,134	27,432	19,921	23,856
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000185

Response to Interrogatory # 69

Scenario 1 Conventional	High Fuel w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,811	5,572	5,779	5,750
Distillate	1000 BBL	8	7	15	7	6	6	7	1	1	1
Natural Gas	1000 MCF	22,324	30,932	39,519	43,920	39,130	41,778	42,946	26,806	19,509	23,327
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000186

Response to Interrogatory # 69

Scenario 1 Conventional	High Fuel wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,810	5,572	5,779	5,750
Distillate	1000 BBL	8	7	15	7	3	2	3	0	0	0
Natural Gas	1000 MCF	22,324	30,932	39,519	43,920	38,686	42,943	44,134	27,432	19,921	23,856
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000187

Response to Interrogatory # 69

Scenario 1 Conventional	Low Fuel w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,811	5,572	5,779	5,750
Distillate	1000 BBL	8	7	15	7	6	6	7	1	1	1
Natural Gas	1000 MCF	22,324	30,932	39,519	43,922	39,130	41,778	42,946	26,806	19,509	23,327
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000188

Response to Interrogatory # 69

Scenario 1 Conventional	Low Fuel wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,810	5,572	5,779	5,750
Distillate	1000 BBL	8	7	15	7	3	2	3	0	0	0
Natural Gas	1000 MCF	22,324	30,932	39,519	43,922	38,686	42,946	44,140	27,435	19,924	23,860
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000189

Response to Interrogatory # 69

Scenario 1 Conventional	High Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,558	4,981	4,736	4,453	4,809	4,718	4,824	5,650	5,913	5,860
Distillate	1000 BBL	24	23	41	10	5	4	7	1	1	1
Natural Gas	1000 MCF	31,453	41,722	51,544	54,515	47,767	50,892	52,419	35,458	27,539	31,929
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000190

Response to Interrogatory # 69

Scenario 1 Conventional	High Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,558	4,981	4,736	4,453	4,809	4,718	4,824	5,650	5,914	5,860
Distillate	1000 BBL	24	23	41	10	4	7	6	1	1	1
Natural Gas	1000 MCF	31,453	41,722	51,544	54,515	50,366	55,153	56,363	37,792	29,288	34,044
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000191

Response to Interrogatory # 69

Scenario 1 Conventional	Low Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,385	4,889	4,679	4,427	4,764	4,679	4,792	5,502	5,679	5,658
Distillate	1000 BBL	3	3	7	7	6	6	6	1	1	1
Natural Gas	1000 MCF	18,015	25,611	33,549	38,629	33,300	35,903	36,820	21,957	15,182	18,649
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000192

Response to Interrogatory # 69

Scenario 1 Conventional	Low Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,385	4,889	4,679	4,427	4,764	4,679	4,792	5,502	5,679	5,658
Distillate	1000 BBL	3	3	7	7	6	6	6	1	1	0
Natural Gas	1000 MCF	18,015	25,611	33,549	38,629	33,300	35,903	36,820	21,957	15,182	19,033
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000192

Response to Interrogatory # 69

Scenario 1 Conventional	Low Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,385	4,889	4,679	4,427	4,764	4,679	4,792	5,502	5,679	5,658
Distillate	1000 BBL	3	3	7	7	1	2	3	0	0	0
Natural Gas	1000 MCF	18,015	25,611	33,549	38,629	32,882	36,810	37,786	22,420	15,465	19,033
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000193

Response to Interrogatory # 69

Scenario 1 Conventional	High Capital Cost w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,811	5,572	5,779	5,750
Distillate	1000 BBL	8	7	15	7	6	6	7	1	1	1
Natural Gas	1000 MCF	22,324	30,932	39,519	43,922	39,130	41,778	42,946	26,806	19,509	23,327
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000194

Response to Interrogatory # 69

Scenario 1 Conventional	High Capital Cost wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5.462	4.933	4.711	4.443	4.789	4.702	4.810	5.572	5.779	5.750
Distillate	1000 BBL	8	7	15	7	3	2	3	0	0	0
Natural Gas	1000 MCF	22.324	30.932	39.519	43.922	38.686	42.943	44.134	27.432	19.921	23.856
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000195

Response to Interrogatory # 69

Scenario 1 Conventional	High Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,400	4,670	4,251	3,897	4,184	3,977	3,442
Distillate	1000 BBL	8	7	15	7	3	2	4	1	0	1
Natural Gas	1000 MCF	22,324	30,932	39,519	44,808	39,037	47,658	55,046	46,068	45,903	58,593
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000196

Response to Interrogatory # 69

Scenario 1 Conventional	High Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,400	4,680	4,145	3,945	4,307	3,752	3,727
Distillate	1000 BBL	8	7	15	7	3	1	1	0	0	0
Natural Gas	1000 MCF	22,324	30,932	39,519	44,808	40,507	49,676	54,689	44,812	50,321	54,491
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000197

Response to Interrogatory # 69

Scenario 1 Conventional	Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,811	5,570	5,762	5,718
Distillate	1000 BBL	8	7	15	7	6	6	7	1	1	1
Natural Gas	1000 MCF	22,324	30,932	39,519	43,919	39,130	41,778	42,943	26,801	19,506	23,323
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000198

Scenario 1 Conventional	Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,811	5,570	5,762	5,718
Distillate	1000 BBL	8	7	15	7	3	2	3	0	0	0
Natural Gas	1000 MCF	22,324	30,932	39,519	43,919	38,686	42,944	44,133	27,429	19,919	23,855
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000199

Response to Interrogatory # 69

Scenario 1 Conventional	High Fuel & Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,811	5,569	5,740	5,718
Distillate	1000 BBL	8	7	15	7	6	6	7	1	1	1
Natural Gas	1000 MCF	22,324	30,932	39,519	44,047	39,130	41,777	42,943	26,801	19,507	23,323
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000200

Response to Interrogatory # 69

Scenario 1 Conventional	High Fuel & Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,702	4,811	5,569	5,740	5,718
Distillate	1000 BBL	8	7	15	7	3	2	3	0	0	0
Natural Gas	1000 MCF	22,324	30,932	39,519	44,047	38,686	42,943	44,133	27,428	19,920	23,855
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000201

Response to Interrogatory # 69

Scenario 1 Conventional	High Fuel, High Load, & Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,558	4,981	4,736	4,453	4,809	4,718	4,824	5,649	5,892	5,844
Distillate	1000 BBL	24	23	41	10	5	4	7	1	1	1
Natural Gas	1000 MCF	31,453	41,722	51,544	54,821	47,767	50,892	52,421	35,454	27,536	31,925
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000202

Response to Interrogatory # 69

Scenario 1 Conventional	High Fuel, High Load, & Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,558	4,981	4,736	4,453	4,809	4,718	4,824	5,649	5,892	5,845
Distillate	1000 BBL	24	23	41	10	6	4	6	1	1	1
Natural Gas	1000 MCF	31,453	41,722	51,544	54,821	50,062	54,822	56,360	37,797	29,289	34,046
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000203

Response to Interrogatory # 69

Scenario 1 Conventional	Low Fuel & Low Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,385	4,889	4,679	4,427	4,764	4,679	4,792	5,502	5,679	5,658
Distillate	1000 BBL	3	3	7	7	6	6	6	1	1	1
Natural Gas	1000 MCF	18,015	25,611	33,549	38,629	33,300	35,903	36,820	21,957	15,182	18,649
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000204

Response to Interrogatory # 69

Scenario 1 Conventional	Low Fuel & Low Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5.385	4.889	4.679	4.427	4.764	4.679	4.792	5.503	5.679	5.659
Distillate	1000 BBL	3	3	7	7	5	3	4	1	0	1
Natural Gas	1000 MCF	18.015	25,611	33,549	38,629	35,310	39,832	40,725	23,983	16,506	20,366
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000205

Response to Interrogatory # 69

Scenario 2 Renewable	Reference Case w GEC									
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,701	4,810	5,571	5,777	5,748
Distillate	1000 BBL	8	7	15	5	5	4	5	1	1	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,709	37,116	39,800	40,945	25,225	18,221	21,916
Biomass	1000 MBtu	0	0	0	3,037	2,931	2,964	3,012	2,460	2,007	2,183

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000206

Response to Interrogatory # 69

Scenario 2 Renewable	Reference Case wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,701	4,810	5,571	5,777	5,748
Distillate	1000 BBL	8	7	15	5	2	4	3	0	0	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,709	36,709	40,859	41,830	25,695	18,541	22,330
Biomass	1000 MBtu	0	0	0	3,037	2,931	2,964	3,012	2,461	2,007	2,183

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000207

Response to Interrogatory # 69

Scenario 2 Renewable	High Fuel w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,701	4,810	5,571	5,777	5,748
Distillate	1000 BBL	8	7	15	5	5	4	5	1	1	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,707	37,116	39,800	40,945	25,225	18,221	21,916
Biomass	1000 MBtu	0	0	0	3,037	2,931	2,964	3,012	2,460	2,007	2,183

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000208

Response to Interrogatory # 69

Scenario 2 Renewable	High Fuel wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,701	4,810	5,571	5,777	5,748
Distillate	1000 BBL	8	7	15	5	2	4	3	0	0	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,707	36,709	40,859	41,830	25,695	18,541	22,330
Biomass	1000 MBtu	0	0	0	3,037	2,931	2,964	3,012	2,461	2,007	2,183

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000209

Response to Interrogatory # 69

Scenario 2 Renewable	Low Fuel w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,701	4,810	5,571	5,777	5,748
Distillate	1000 BBL	8	7	15	5	5	4	5	1	1	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,709	37,116	39,800	40,945	25,225	18,221	21,916
Biomass	1000 MBtu	0	0	0	3,037	2,931	2,964	3,012	2,460	2,007	2,183

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000210

Response to Interrogatory # 69

Scenario 2 Renewable	Low Fuel wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,701	4,810	5,571	5,777	5,748
Distillate	1000 BBL	8	7	15	5	2	4	3	0	0	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,709	36,709	40,861	41,836	25,698	18,544	22,334
Biomass	1000 MBtu	0	0	0	3,037	2,931	2,964	3,012	2,461	2,007	2,183

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000211

Response to Interrogatory # 69

Scenario 2 Renewable	High Load w GEC									
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,558	4,981	4,736	4,453	4,809	4,718	4,824	5,649	5,912	5,859
Distillate	1000 BBL	24	23	41	9	7	6	9	1	1	2
Natural Gas	1000 MCF	31,453	41,581	51,341	52,538	48,690	51,346	52,868	35,174	27,137	31,670
Biomass	1000 MBtu	0	0	0	3,140	3,077	3,097	3,123	2,756	2,352	2,488

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000212

Response to Interrogatory # 69

Scenario 2 Renewable	High Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,558	4,981	4,736	4,453	4,809	4,718	4,823	5,649	5,912	5,859
Distillate	1000 BBL	24	23	41	9	6	4	6	1	1	1
Natural Gas	1000 MCF	31,453	41,581	51,341	52,538	48,086	52,823	54,353	36,024	27,767	32,435
Biomass	1000 MBtu	0	0	0	3,140	3,076	3,097	3,123	2,756	2,352	2,488

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000213

Response to Interrogatory # 69

Scenario 2 Renewable	Low Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,385	4,888	4,679	4,426	4,763	4,679	4,791	5,501	5,676	5,657
Distillate	1000 BBL	3	3	7	6	5	4	7	1	1	1
Natural Gas	1000 MCF	18,015	25,485	33,363	36,483	31,420	34,051	34,961	20,535	14,054	17,405
Biomass	1000 MBtu	0	0	0	2,917	2,786	2,833	2,884	2,279	1,801	1,974

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000214

Response to Interrogatory # 69

Scenario 2 Renewable	Low Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,385	4,888	4,679	4,426	4,763	4,679	4,791	5,501	5,677	5,657
Distillate	1000 BBL	3	3	7	6	2	4	4	1	0	1
Natural Gas	1000 MCF	18,015	25,485	33,363	36,483	33,583	38,039	38,850	22,521	15,337	19,079
Biomass	1000 MBtu	0	0	0	2,917	2,786	2,833	2,884	2,279	1,801	1,975

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000215

Response to Interrogatory # 69

Scenario 2 Renewable	High Capital Cost w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,701	4,810	5,571	5,777	5,748
Distillate	1000 BBL	8	7	15	5	5	4	5	1	1	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,709	37,116	39,800	40,945	25,225	18,221	21,916
Biomass	1000 MBtu	0	0	0	3,037	2,931	2,964	3,012	2,460	2,007	2,183

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000216

Response to Interrogatory # 69

Scenario 2 Renewable	High Capital Cost wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,443	4,789	4,701	4,810	5,571	5,777	5,748
Distillate	1000 BBL	8	7	15	5	2	4	3	0	0	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,709	36,709	40,859	41,830	25,695	18,541	22,330
Biomass	1000 MBtu	0	0	0	3,037	2,931	2,964	3,012	2,461	2,007	2,183

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000217

Response to Interrogatory # 69

Scenario 2 Renewable	High Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,389	4,652	4,224	3,854	4,129	3,902	3,356
Distillate	1000 BBL	8	7	15	5	2	2	3	0	0	0
Natural Gas	1000 MCF	22,324	30,802	39,325	42,678	37,325	46,092	53,662	44,999	45,227	58,210
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000218

Response to Interrogatory # 69

Scenario 2 Renewable	High Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,389	4,662	4,336	4,213	4,645	4,273	4,241
Distillate	1000 BBL	8	7	15	5	2	4	3	0	0	1
Natural Gas	1000 MCF	22,324	30,802	39,325	42,678	38,685	46,802	50,679	38,673	40,805	45,071
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000219

Scenario 2 Renewable	Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	4,496	4,895	4,859	4,942	5,090	5,110	5,121	6,226	6,382	6,528
Distillate	1000 BBL	0	156	272	10	183	328	405	0	0	0
Natural Gas	1000 MCF	56,658	49,965	54,557	50,979	52,795	52,906	55,365	40,057	34,013	35,105
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000220

Response to Interrogatory # 69

Scenario 2 Renewable	Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,437	4,780	4,694	4,804	5,545	5,721	5,681
Distillate	1000 BBL	8	7	15	5	2	4	3	0	0	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,710	36,712	40,861	41,830	25,694	18,541	22,329
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000221

Response to Interrogatory # 69

Scenario 2 Renewable	High Fuel & Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,437	4,780	4,694	4,804	5,543	5,697	5,681
Distillate	1000 BBL	8	7	15	5	5	4	5	1	1	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,843	37,118	39,803	40,945	25,223	18,221	21,916
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000222

Response to Interrogatory # 69

Scenario 2 Renewable	High Fuel & Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,462	4,933	4,711	4,437	4,780	4,694	4,804	5,543	5,697	5,681
Distillate	1000 BBL	8	7	15	5	2	4	3	0	0	1
Natural Gas	1000 MCF	22,324	30,802	39,325	41,843	36,712	40,861	41,830	25,694	18,541	22,329
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000223

Response to Interrogatory # 69

Scenario 2 Renewable	High Fuel, High Load, & Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,558	4,981	4,736	4,451	4,805	4,715	4,821	5,633	5,861	5,818
Distillate	1000 BBL	24	23	41	9	7	6	9	1	1	2
Natural Gas	1000 MCF	31,453	41,581	51,341	52,812	48,692	51,348	52,869	35,177	27,142	31,674
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000224

Response to Interrogatory # 69

Scenario 2 Renewable	High Fuel, High Load, & Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,558	4,981	4,736	4,451	4,805	4,715	4,821	5,633	5,861	5,818
Distillate	1000 BBL	24	23	41	9	6	4	6	1	1	1
Natural Gas	1000 MCF	31,453	41,581	51,341	52,812	48,088	52,825	54,353	36,038	27,774	32,439
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000225

Response to Interrogatory # 69

Scenario 2 Renewable	Low Fuel & Low Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5.385	4.888	4.679	4.426	4.763	4.679	4.791	5.501	5.676	5.657
Distillate	1000 BBL	3	3	7	6	5	4	7	1	1	1
Natural Gas	1000 MCF	18.015	25.485	33.363	36.483	31.420	34.051	34.961	20.535	14.054	17.405
Biomass	1000 MBtu	0	0	0	2.917	2.786	2.833	2.884	2.279	1.801	1.974

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000226

Response to Interrogatory # 69

Scenario 2 Renewable	Low Fuel & Low Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,385	4,888	4,679	4,426	4,763	4,679	4,791	5,501	5,677	5,657
Distillate	1000 BBL	3	3	7	6	2	4	4	1	0	1
Natural Gas	1000 MCF	18,015	25,485	33,363	36,483	33,583	38,039	38,850	22,521	15,337	19,079
Biomass	1000 MBtu	0	0	0	2,917	2,786	2,833	2,884	2,279	1,801	1,975

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000227

Response to Interrogatory # 69

Scenario 3 DSM	Reference Case w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,805	5,563	5,763	5,734
Distillate	1000 BBL	7	6	12	10	7	7	10	2	1	2
Natural Gas	1000 MCF	22,130	30,481	38,561	43,516	37,846	40,508	41,644	25,692	18,557	22,341
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000228

Response to Interrogatory # 69

Scenario 3 DSM	Reference Case wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,805	5,563	5,763	5,734
Distillate	1000 BBL	7	6	12	10	2	3	5	1	1	1
Natural Gas	1000 MCF	22,130	30,481	38,561	43,516	37,469	41,628	42,797	26,280	18,950	22,855
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000229

Response to Interrogatory # 69

Scenario 3 DSM	High Fuel w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,805	5,563	5,763	5,734
Distillate	1000 BBL	7	6	12	10	7	7	10	2	1	2
Natural Gas	1000 MCF	22,130	30,481	38,561	43,516	37,846	40,508	41,644	25,692	18,557	22,341
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000230

Scenario 3 DSM	High Fuel wo GEC									
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,805	5,563	5,763	5,734
Distillate	1000 BBL	7	6	12	10	2	3	5	1	1	1
Natural Gas	1000 MCF	22,130	30,481	38,561	43,516	37,469	41,628	42,797	26,280	18,950	22,855
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000231

Response to Interrogatory # 69

Scenario 3 DSM	Low Fuel w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,805	5,563	5,763	5,734
Distillate	1000 BBL	7	6	12	10	7	7	10	2	1	2
Natural Gas	1000 MCF	22,130	30,481	38,561	43,516	37,846	40,508	41,644	25,692	18,557	22,341
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000232

Response to Interrogatory # 69

Scenario 3 DSM	Low Fuel wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,805	5,563	5,763	5,734
Distillate	1000 BBL	7	6	12	10	2	3	5	1	1	1
Natural Gas	1000 MCF	22,130	30,481	38,561	43,516	37,469	41,630	42,802	26,283	18,953	22,858
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000233

Response to Interrogatory # 69

Scenario 3 DSM	High Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,583	4,996	4,739	4,454	4,811	4,721	4,826	5,667	5,934	5,875
Distillate	1000 BBL	16	14	25	10	5	5	8	1	1	1
Natural Gas	1000 MCF	30,526	40,531	50,105	54,039	48,703	51,394	52,977	34,880	26,711	31,301
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000234

Scenario 3 DSM	High Load wo GEC									
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5.583	4.996	4.739	4.454	4.811	4.721	4.826	5.667	5.934	5.875
Distillate	1000 BBL	16	14	25	10	5	3	5	1	1	1
Natural Gas	1000 MCF	30.526	40.531	50.105	54.039	48.405	53.157	54.734	35.846	27.382	32.099
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000235

Response to Interrogatory # 69

Scenario 3 DSM	Low Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,386	4,889	4,672	4,418	4,756	4,672	4,785	5,493	5,668	5,646
Distillate	1000 BBL	3	3	5	5	4	4	6	1	1	1
Natural Gas	1000 MCF	17,799	25,076	32,602	37,301	32,076	34,724	35,641	20,905	14,205	17,665
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000236

Response to Interrogatory # 69

Scenario 3 DSM	Low Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,386	4,889	4,672	4,418	4,756	4,672	4,785	5,493	5,668	5,646
Distillate	1000 BBL	3	3	5	5	6	5	7	1	1	1
Natural Gas	1000 MCF	17,799	25,076	32,602	37,301	34,283	38,431	39,306	22,786	15,422	19,269
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000237

Response to Interrogatory # 69

Scenario 3 DSM	High Capital Cost w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,805	5,563	5,763	5,734
Distillate	1000 BBL	7	6	12	10	9	9	10	2	1	2
Natural Gas	1000 MCF	22,130	30,481	38,561	43,516	37,866	40,519	41,644	25,692	18,557	22,341
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000238

Response to Interrogatory # 69

Scenario 3 DSM	High Capital Cost wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,805	5,563	5,763	5,734
Distillate	1000 BBL	7	6	12	10	2	3	5	1	1	1
Natural Gas	1000 MCF	22,130	30,481	38,561	43,516	37,469	41,628	42,797	26,280	18,950	22,855
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000239

Response to Interrogatory # 69

Scenario 3 DSM	High Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,414	4,746	4,396	4,170	4,494	4,395	3,982
Distillate	1000 BBL	7	6	12	10	9	9	10	2	1	2
Natural Gas	1000 MCF	22,130	30,481	38,561	43,936	38,446	45,616	51,402	40,657	38,634	48,877
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000240

Response to Interrogatory # 69

Scenario 3 DSM	High Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,414	4,668	4,357	4,250	4,677	4,326	4,289
Distillate	1000 BBL	7	6	12	10	2	3	5	1	1	1
Natural Gas	1000 MCF	22,130	30,481	38,561	43,936	39,355	47,252	51,142	39,034	40,778	45,132
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000241

Response to Interrogatory # 69

Scenario 3 DSM	Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,806	5,560	5,745	5,699
Distillate	1000 BBL	7	6	12	10	7	7	10	2	1	2
Natural Gas	1000 MCF	22,130	30,481	38,561	43,516	37,846	40,508	41,643	25,684	18,553	22,337
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000242

Response to Interrogatory # 69

Scenario 3 DSM	Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,805	5,560	5,745	5,699
Distillate	1000 BBL	7	6	12	10	2	3	5	1	1	1
Natural Gas	1000 MCF	22,130	30,481	38,561	43,516	37,468	41,630	42,798	26,274	18,948	22,850
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000243

Scenario 3 DSM	High Fuel & Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,806	5,558	5,722	5,699
Distillate	1000 BBL	7	6	12	10	7	7	10	2	1	2
Natural Gas	1000 MCF	22,130	30,481	38,561	43,531	37,846	40,507	41,643	25,684	18,553	22,337
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000244

Scenario 3 DSM	High Fuel & Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,929	4,704	4,439	4,782	4,695	4,805	5,558	5,722	5,699
Distillate	1000 BBL	7	6	12	10	2	3	5	1	1	1
Natural Gas	1000 MCF	22,130	30,481	38,561	43,531	37,468	41,627	42,798	26,274	18,948	22,850
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000245

Scenario 3 DSM	High Fuel, High Load, & Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,583	4,996	4,739	4,454	4,811	4,721	4,826	5,666	5,914	5,859
Distillate	1000 BBL	16	14	25	10	4	4	6	1	1	1
Natural Gas	1000 MCF	30,526	40,531	50,105	54,161	46,086	49,273	50,833	33,808	25,877	30,272
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000246

Response to Interrogatory # 69

Scenario 3 DSM	High Fuel, High Load, & Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,583	4,996	4,739	4,454	4,811	4,721	4,826	5,666	5,914	5,859
Distillate	1000 BBL	16	14	25	10	5	3	5	1	1	1
Natural Gas	1000 MCF	30,526	40,531	50,105	54,161	48,405	53,157	54,732	35,841	27,383	32,101
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000247

Response to Interrogatory # 69

Scenario 3 DSM	Low Fuel & Low Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,386	4,889	4,672	4,418	4,756	4,672	4,785	5,493	5,668	5,646
Distillate	1000 BBL	3	3	5	5	4	4	6	1	1	1
Natural Gas	1000 MCF	17,799	25,076	32,602	37,301	32,076	34,724	35,641	20,905	14,205	17,665
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000248

Response to Interrogatory # 69

Scenario 3 DSM	Low Fuel & Low Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,386	4,889	4,672	4,418	4,756	4,672	4,785	5,493	5,668	5,646
Distillate	1000 BBL	3	3	5	5	6	5	7	1	1	1
Natural Gas	1000 MCF	17,799	25,076	32,602	37,301	34,283	38,431	39,306	22,786	15,422	19,269
Biomass	1000 MBtu	0	0	0	0	0	0	0	0	0	0

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000249

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	Reference Case w GEC									
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,438	4,782	4,695	4,805	5,562	5,761	5,732
Distillate	1000 BBL	7	6	11	8	8	7	8	1	1	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,278	35,884	38,577	39,680	24,126	17,291	20,953
Biomass	1000 MBtu	0	0	0	3,010	2,892	2,931	2,977	2,457	1,991	2,161

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000250

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	Reference Case wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,438	4,782	4,695	4,805	5,562	5,761	5,732
Distillate	1000 BBL	7	6	11	8	1	2	4	0	0	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,278	35,522	39,596	40,746	24,659	17,650	21,424
Biomass	1000 MBtu	0	0	0	3,010	2,892	2,930	2,977	2,457	1,991	2,161

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000251

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	High Fuel w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,438	4,782	4,695	4,805	5,562	5,761	5,732
Distillate	1000 BBL	7	6	11	8	8	7	8	1	1	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,278	35,884	38,577	39,680	24,126	17,291	20,953
Biomass	1000 MBtu	0	0	0	3,010	2,892	2,931	2,977	2,457	1,991	2,161

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000252

Scenario 4 Renewables & DSM	High Fuel wo GEC									
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,438	4,782	4,695	4,805	5,562	5,761	5,732
Distillate	1000 BBL	7	6	11	8	1	2	4	0	0	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,278	35,522	39,596	40,746	24,659	17,650	21,424
Biomass	1000 MBtu	0	0	0	3,010	2,892	2,930	2,977	2,457	1,991	2,161

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000253

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	Low Fuel w GEC									
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,438	4,782	4,695	4,805	5,562	5,761	5,732
Distillate	1000 BBL	7	6	11	8	8	7	8	1	1	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,278	35,884	38,577	39,680	24,126	17,291	20,953
Biomass	1000 MBtu	0	0	0	3,010	2,892	2,931	2,977	2,457	1,991	2,161

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000254

Scenario 4 Renewables & DSM	Low Fuel wo GEC									
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5.463	4.928	4.704	4.438	4.782	4.695	4.805	5.562	5.761	5.732
Distillate	1000 BBL	7	6	11	8	1	2	4	0	0	1
Natural Gas	1000 MCF	22.130	30.348	38.368	41.278	35.522	39.598	40.751	24.663	17.653	21.427
Biomass	1000 MBtu	0	0	0	3.010	2.892	2.930	2.977	2.457	1.991	2.161

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000255

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	High Load w GEC									
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5.583	4.996	4.739	4.454	4.811	4.721	4.826	5.667	5.933	5.874
Distillate	1000 BBL	16	14	25	10	5	5	8	1	1	1
Natural Gas	1000 MCF	30.526	40.388	49.901	52.057	46.681	49.380	50.955	33.125	25,196	29.699
Biomass	1000 MBtu	0	0	0	3.146	3.099	3.122	3.144	2.841	2.431	2.555

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000256

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	High Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,583	4,996	4,739	4,454	4,811	4,721	4,826	5,667	5,933	5,874
Distillate	1000 BBL	16	14	25	10	4	6	5	1	1	1
Natural Gas	1000 MCF	30,526	40,388	49,901	52,057	46,239	50,858	52,163	33,786	25,678	30,283
Biomass	1000 MBtu	0	0	0	3,146	3,099	3,122	3,144	2,842	2,431	2,555

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000257

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	Low Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,386	4,888	4,672	4,418	4,755	4,671	4,785	5,491	5,665	5,644
Distillate	1000 BBL	3	3	5	4	3	3	5	1	1	1
Natural Gas	1000 MCF	17,799	24,952	32,418	35,175	30,218	32,892	33,800	19,465	13,104	16,428
Biomass	1000 MBtu	0	0	0	2,875	2,754	2,798	2,849	2,305	1,770	1,975

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000258

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	Low Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,386	4,888	4,672	4,418	4,755	4,671	4,785	5,492	5,666	5,644
Distillate	1000 BBL	3	3	5	4	4	7	7	1	1	1
Natural Gas	1000 MCF	17,799	24,952	32,418	35,175	32,268	36,658	37,454	21,305	14,268	17,978
Biomass	1000 MBtu	0	0	0	2,875	2,754	2,799	2,849	2,305	1,770	1,975

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000259

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	High Capital Cost w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,438	4,782	4,695	4,805	5,562	5,761	5,732
Distillate	1000 BBL	7	6	11	8	8	7	8	1	1	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,278	35,884	38,577	39,680	24,126	17,291	20,953
Biomass	1000 MBtu	0	0	0	3,010	2,892	2,931	2,977	2,457	1,991	2,161

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000260

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	High Capital Cost wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,438	4,782	4,695	4,805	5,562	5,761	5,732
Distillate	1000 BBL	7	6	11	8	1	2	4	0	0	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,278	35,522	39,596	40,746	24,659	17,650	21,424
Biomass	1000 MBtu	0	0	0	3,010	2,892	2,930	2,977	2,457	1,991	2,161

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000261

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	High Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,406	4,734	4,374	4,127	4,441	4,328	3,899
Distillate	1000 BBL	7	6	11	8	8	7	8	1	1	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,715	36,475	43,885	49,948	39,524	37,731	48,335
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000262

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	High Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,406	4,650	4,326	4,205	4,618	4,236	4,206
Distillate	1000 BBL	7	6	11	8	1	2	4	0	0	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,715	37,543	45,556	49,615	37,890	40,232	44,449
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000263

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	Regulated CO2 w GEC									
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,432	4,772	4,686	4,798	5,534	5,702	5,661
Distillate	1000 BBL	7	6	11	8	8	7	8	1	1	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,281	35,886	38,581	39,682	24,119	17,289	20,950
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000264

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,432	4,772	4,686	4,798	5,534	5,702	5,661
Distillate	1000 BBL	7	6	11	8	1	2	4	1	0	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,281	35,524	39,600	40,748	24,657	17,649	21,420
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000265

Scenario 4 Renewables & DSM	High Fuel & Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,432	4,772	4,686	4,798	5,532	5,678	5,661
Distillate	1000 BBL	7	6	11	8	8	7	8	1	1	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,297	35,886	38,579	39,682	24,120	17,289	20,950
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000266

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	High Fuel & Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,463	4,928	4,704	4,432	4,772	4,686	4,798	5,532	5,678	5,661
Distillate	1000 BBL	7	6	11	8	1	2	4	1	0	1
Natural Gas	1000 MCF	22,130	30,348	38,368	41,297	35,524	39,598	40,748	24,657	17,649	21,420
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000267

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	High Fuel, High Load, & Regulated CO2 w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,583	4,996	4,739	4,452	4,808	4,718	4,824	5,653	5,886	5,835
Distillate	1000 BBL	16	14	25	10	3	3	5	1	1	1
Natural Gas	1000 MCF	30,526	40,388	49,901	52,155	44,066	47,276	48,814	32,081	24,395	28,703
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000268

Scenario 4 Renewables & DSM	High Fuel, High Load, & Regulated CO2 wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,583	4,996	4,739	4,452	4,808	4,718	4,824	5,653	5,886	5,835
Distillate	1000 BBL	16	14	25	10	4	6	5	1	1	1
Natural Gas	1000 MCF	30,526	40,388	49,901	52,155	46,241	50,860	52,166	33,785	25,681	30,288
Biomass	1000 MBtu	0	0	0	3,217	3,207	3,207	3,207	3,217	3,207	3,207

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000269

Scenario 4 Renewables & DSM	Low Fuel & Low Load w GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5,386	4,888	4,672	4,418	4,755	4,671	4,785	5,491	5,665	5,644
Distillate	1000 BBL	3	3	5	4	3	3	5	1	1	1
Natural Gas	1000 MCF	17,799	24,952	32,418	35,175	30,218	32,892	33,800	19,465	13,104	16,428
Biomass	1000 MBtu	0	0	0	2,875	2,754	2,798	2,849	2,305	1,770	1,975

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000270

Response to Interrogatory # 69

Scenario 4 Renewables & DSM	Low Fuel & Low Load wo GEC										
Fuel Requirements	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	Trillion BTU	0	0	0	0	0	0	0	8	16	15
Coal [1]	1000 Ton	5.386	4.888	4.672	4.418	4.755	4.671	4.785	5.492	5.666	5.644
Distillate	1000 BBL	3	3	5	4	4	7	7	1	1	1
Natural Gas	1000 MCF	17.799	24.952	32.418	35.175	32.268	36.658	37.454	21.305	14.268	17.978
Biomass	1000 MBtu	0	0	0	2.875	2.754	2.799	2.849	2.305	1.770	1.975

Note 1: Coal includes petcoke and UPS purchase.

Hearing Exhibit - 00000271

70. **Please complete the table below regarding JEA's fuel mix for the periods 2009-2018 with the GEC Combined Cycle Conversion Project and for each alternative. Please complete the table using the following cases for both Scenario 3 and Scenario 4: High Load, Low Load, Reference, and Regulated CO2. Please be reflective the 2013 in-service date.**

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
GWH	**JEA Energy Mix**									
Nuclear										
Coal										
Natural Gas										
Oil										
Renewable										
Purchased Power										
Coal PPA										
Gas PPA										
Nuclear PPA										
Renewable PPA										
Total										

Response: Please refer to the attachment labeled *Response to Interrogatory No. 70*, which presents the requested data. Please note that the requested data has been provided for all combinations of cases and scenarios for which data has been provided in response to Interrogatory Nos. 33 and 67.

Response to Interrogatory # 70

Scenario 1 - Reference w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.041	11,126.075	10,986.337	11,179.445	12,898.539	13,438.745	13,450.179
Natural Gas	2,874.189	3,916.673	4,682.118	5,113.157	5,194.962	5,684.173	5,840.101	3,737.358	2,725.001	3,245.335
Oil	3.515	3.302	6.795	3.003	2.666	2.465	2.915	0.440	0.344	0.487
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	452.328	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	1.101	0.869	0.995	0.146	0.105	0.157
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.600	16,763.639	17,113.251	17,505.837	17,815.436	18,166.265

Hearing Exhibit - 00000273

Response to Interrogatory # 70

Scenario 1 - Reference wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.041	11,125.961	10,986.315	11,179.367	12,898.581	13,438.685	13,450.253
Natural Gas	2,874.189	3,916.673	4,682.118	5,113.157	5,196.992	5,686.460	5,842.414	3,737.676	2,725.323	3,245.641
Oil	3.515	3.302	6.795	3.003	1.407	0.844	1.308	0.183	0.151	0.211
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	452.328	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	0.445	0.225	0.368	0.045	0.033	0.053
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.600	16,763.640	17,113.252	17,505.838	17,815.434	18,166.266

Hearing Exhibit - 00000274

Response to Interrogatory # 70

Scenario 1 - High Fuel w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.034	11,126.075	10,986.337	11,179.445	12,898.539	13,438.745	13,450.179
Natural Gas	2,874.189	3,916.673	4,682.118	5,080.459	5,194.962	5,684.173	5,840.101	3,737.358	2,725.001	3,245.335
Oil	3.515	3.302	6.795	3.003	2.666	2.465	2.915	0.440	0.344	0.487
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	485.033	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	1.101	0.869	0.995	0.146	0.105	0.157
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.600	16,763.639	17,113.251	17,505.837	17,815.436	18,166.265

Hearing Exhibit - 00000275

Response to Interrogatory # 70

Scenario 1 - High Fuel wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.034	11,125.961	10,986.315	11,179.367	12,898.581	13,438.685	13,450.253
Natural Gas	2,874.189	3,916.673	4,682.118	5,080.459	5,196.992	5,686.460	5,842.414	3,737.676	2,725.323	3,245.641
Oil	3.515	3.302	6.795	3.003	1.407	0.844	1.308	0.183	0.151	0.211
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	485.033	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	0.445	0.225	0.368	0.045	0.033	0.053
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.600	16,763.640	17,113.252	17,505.838	17,815.434	18,166.266

Hearing Exhibit - 00000276

Response to Interrogatory # 70

Scenario 1 - Low Fuel w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.041	11,126.075	10,986.337	11,179.445	12,898.539	13,438.745	13,450.179
Natural Gas	2,874.189	3,916.673	4,682.118	5,113.157	5,194.962	5,684.173	5,840.101	3,737.358	2,725.001	3,245.335
Oil	3.515	3.302	6.795	3.003	2.666	2.465	2.915	0.440	0.344	0.487
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	452.328	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	1.101	0.869	0.995	0.146	0.105	0.157
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.600	16,763.639	17,113.251	17,505.837	17,815.436	18,166.265

Hearing Exhibit - 00000277

Response to Interrogatory # 70

Scenario 1 - Low Fuel wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.041	11,125.961	10,986.316	11,179.377	12,898.587	13,438.667	13,450.238
Natural Gas	2,874.189	3,916.673	4,682.118	5,113.157	5,196.992	5,686.459	5,842.402	3,737.669	2,725.342	3,245.657
Oil	3.515	3.302	6.795	3.003	1.407	0.844	1.309	0.183	0.151	0.211
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	452.328	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	0.445	0.225	0.368	0.045	0.033	0.053
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.600	16,763.639	17,113.252	17,505.838	17,815.434	18,166.267

Hearing Exhibit - 00000278

Response to Interrogatory # 70

Scenario 1 - High Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,470.490	10,720.478	10,994.849	10,469.220	11,175.443	11,028.414	11,212.470	13,096.193	13,782.725	13,733.140
Natural Gas	3,948.371	5,139.544	5,982.675	5,654.340	6,579.202	7,102.453	7,293.236	5,052.277	3,920.322	4,528.193
Oil	10.485	10.236	18.389	4.228	2.274	1.965	3.117	0.493	0.434	0.608
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.248	1.468	0.000	1,289.859	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	3.535	3.075	5.865	1.132	0.848	0.626	1.040	0.164	0.128	0.185
Total	16,338.243	16,714.764	17,091.574	17,508.821	17,847.563	18,223.253	18,599.658	19,018.481	19,354.850	19,732.234

Hearing Exhibit - 00000279

Response to Interrogatory # 70

Scenario 1 - High Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,470.490	10,720.478	10,994.849	10,469.220	11,175.446	11,028.444	11,212.476	13,096.402	13,782.903	13,733.455
Natural Gas	3,948.371	5,139.544	5,982.675	5,654.340	6,579.897	7,101.301	7,294.087	5,052.237	3,920.252	4,528.058
Oil	10.485	10.236	18.389	4.228	1.883	2.900	2.597	0.393	0.373	0.495
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.248	1.468	0.000	1,289.859	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	3.535	3.075	5.865	1.132	0.544	0.812	0.704	0.094	0.079	0.119
Total	16,338.243	16,714.764	17,091.574	17,508.821	17,847.564	18,223.253	18,599.660	19,018.479	19,354.850	19,732.234

Hearing Exhibit - 00000280

Response to Interrogatory # 70

Scenario 1 - Low Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,033.804	10,486.639	10,850.182	10,401.435	11,061.306	10,929.348	11,131.641	12,720.917	13,181.614	13,217.151
Natural Gas	2,353.672	3,300.682	4,021.307	4,845.477	4,483.802	4,951.280	5,084.145	3,096.561	2,149.098	2,630.786
Oil	1.497	1.327	3.142	3.207	2.734	2.472	2.869	0.458	0.321	0.452
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.257	0.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.428	0.334	0.764	0.894	1.124	0.859	0.968	0.153	0.098	0.144
Total	14,292.773	14,629.114	14,965.191	15,341.055	15,638.762	15,973.755	16,309.418	16,687.443	16,982.371	17,318.640

Hearing Exhibit - 00000281

Response to Interrogatory # 70

Scenario 1 - Low Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,033.804	10,486.639	10,850.182	10,401.435	11,061.308	10,929.320	11,131.613	12,720.768	13,181.688	13,217.136
Natural Gas	2,353.672	3,300.682	4,021.307	4,845.477	4,486.987	4,953.601	5,086.407	3,097.104	2,149.280	2,631.159
Oil	1.497	1.327	3.142	3.207	0.528	0.821	1.251	0.175	0.130	0.191
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.257	0.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.428	0.334	0.764	0.894	0.146	0.219	0.351	0.044	0.030	0.048
Total	14,292.773	14,629.114	14,965.191	15,341.055	15,638.765	15,973.756	16,309.418	16,687.444	16,982.371	17,318.641

Hearing Exhibit - 00000282

Response to Interrogatory # 70

Scenario 1 - High Capital Cost w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.041	11,126.075	10,986.337	11,179.445	12,898.539	13,438.745	13,450.179
Natural Gas	2,874.189	3,916.673	4,682.118	5,113.157	5,194.962	5,684.173	5,840.101	3,737.358	2,725.001	3,245.335
Oil	3.515	3.302	6.795	3.003	2.666	2.465	2.915	0.440	0.344	0.487
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	452.328	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	1.101	0.869	0.995	0.146	0.105	0.157
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.600	16,763.639	17,113.251	17,505.837	17,815.436	18,166.265

Hearing Exhibit - 00000283

Response to Interrogatory # 70

Scenario 1 - High Capital Cost wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.041	11,125.961	10,986.315	11,179.367	12,898.581	13,438.685	13,450.253
Natural Gas	2,874.189	3,916.673	4,682.118	5,113.157	5,196.992	5,686.460	5,842.414	3,737.676	2,725.323	3,245.641
Oil	3.515	3.302	6.795	3.003	1.407	0.844	1.308	0.183	0.151	0.211
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	452.328	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	0.445	0.225	0.368	0.045	0.033	0.053
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.600	16,763.640	17,113.252	17,505.838	17,815.434	18,166.266

Hearing Exhibit - 00000284

Response to Interrogatory # 70

Scenario 1 - High Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,338.656	10,830.427	9,875.775	9,165.771	9,934.965	9,492.786	8,186.399
Natural Gas	2,874.189	3,916.673	4,682.118	4,936.406	5,492.839	6,796.696	7,855.504	6,701.191	6,671.153	8,509.401
Oil	3.515	3.302	6.795	3.003	1.111	1.034	1.636	0.246	0.199	0.273
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	733.464	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	0.429	0.339	0.546	0.080	0.055	0.084
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.602	16,763.639	17,113.253	17,505.836	17,815.434	18,166.264

Hearing Exhibit - 00000285

Response to Interrogatory # 70

Scenario 1 - High Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,338.656	10,854.050	9,660.399	9,295.357	10,158.347	8,844.873	8,820.858
Natural Gas	2,874.189	3,916.673	4,682.118	4,936.406	5,468.903	7,013.050	7,727.463	6,478.048	7,319.263	7,875.202
Oil	3.515	3.302	6.795	3.003	1.407	0.318	0.510	0.073	0.050	0.080
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	733.464	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	0.445	0.075	0.128	0.015	0.010	0.017
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.601	16,763.638	17,113.253	17,505.836	17,815.438	18,166.265

Hearing Exhibit - 00000286

Response to Interrogatory # 70

Scenario 1 - Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.044	11,126.097	10,986.377	11,179.482	12,898.599	13,438.789	13,450.205
Natural Gas	2,874.189	3,916.673	4,682.118	5,080.450	5,194.941	5,684.132	5,840.065	3,737.299	2,724.955	3,245.309
Oil	3.515	3.302	6.795	3.003	2.666	2.465	2.915	0.438	0.345	0.487
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	485.033	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	1.101	0.869	0.995	0.146	0.105	0.157
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.600	16,763.638	17,113.253	17,505.836	17,815.436	18,166.266

Hearing Exhibit - 00000287

Response to Interrogatory # 70

Scenario 1 - Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.044	11,125.983	10,986.341	11,179.391	12,898.638	13,438.766	13,450.284
Natural Gas	2,874.189	3,916.673	4,682.118	5,080.450	5,196.971	5,686.435	5,842.389	3,737.620	2,725.245	3,245.613
Oil	3.515	3.302	6.795	3.003	1.407	0.843	1.307	0.181	0.148	0.211
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	485.033	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	0.445	0.225	0.368	0.045	0.033	0.053
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.602	16,763.640	17,113.252	17,505.837	17,815.434	18,166.267

Hearing Exhibit - 00000288

Response to Interrogatory # 70

Scenario 1 - High Fuel & Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.037	11,126.097	10,986.368	11,179.482	12,898.620	13,438.738	13,450.205
Natural Gas	2,874.189	3,916.673	4,682.118	4,876.967	5,194.941	5,684.142	5,840.065	3,737.279	2,725.005	3,245.309
Oil	3.515	3.302	6.795	3.003	2.666	2.465	2.915	0.438	0.348	0.487
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	688.522	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	1.101	0.869	0.995	0.146	0.105	0.157
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.600	16,763.639	17,113.253	17,505.837	17,815.438	18,166.266

Hearing Exhibit - 00000289

Response to Interrogatory # 70

Scenario 1 - High Fuel & Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,598.893	10,931.177	10,443.037	11,125.983	10,986.346	11,179.391	12,898.657	13,438.732	13,450.284
Natural Gas	2,874.189	3,916.673	4,682.118	4,876.967	5,196.971	5,686.429	5,842.389	3,737.601	2,725.282	3,245.613
Oil	3.515	3.302	6.795	3.003	1.407	0.844	1.307	0.181	0.148	0.211
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.411	0.000	688.522	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.926	1.953	0.843	0.445	0.225	0.368	0.045	0.033	0.053
Total	15,010.325	15,360.169	15,711.839	16,102.414	16,414.602	16,763.639	17,113.252	17,505.837	17,815.436	18,166.267

Hearing Exhibit - 00000290

Response to Interrogatory # 70

Scenario 1 - High Fuel, High Load, & Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,470.490	10,720.478	10,994.849	10,469.224	11,175.464	11,028.429	11,212.483	13,096.249	13,782.718	13,733.201
Natural Gas	3,948.371	5,139.544	5,982.675	5,075.935	6,579.182	7,102.437	7,293.223	5,052.222	3,920.327	4,528.135
Oil	10.485	10.236	18.389	4.225	2.273	1.965	3.117	0.492	0.436	0.608
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.248	1.468	0.000	1,868.262	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	3.535	3.075	5.865	1.132	0.848	0.626	1.040	0.164	0.128	0.185
Total	16,338.243	16,714.764	17,091.574	17,508.820	17,847.562	18,223.252	18,599.659	19,018.481	19,354.850	19,732.236

Hearing Exhibit - 00000291

Response to Interrogatory # 70

Scenario 1 - High Fuel, High Load, & Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,470.490	10,720.478	10,994.849	10,469.224	11,175.469	11,028.459	11,212.479	13,096.457	13,782.913	13,733.547
Natural Gas	3,948.371	5,139.544	5,982.675	5,075.935	6,578.763	7,102.946	7,294.085	5,052.185	3,920.245	4,527.970
Oil	10.485	10.236	18.389	4.225	2.715	1.637	2.596	0.391	0.373	0.493
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.248	1.468	0.000	1,868.262	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	3.535	3.075	5.865	1.132	0.820	0.416	0.704	0.094	0.079	0.119
Total	16,338.243	16,714.764	17,091.574	17,508.820	17,847.562	18,223.254	18,599.659	19,018.480	19,354.852	19,732.236

Hearing Exhibit - 00000292

Response to Interrogatory # 70

Scenario 1 - Low Fuel & Low Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,033.804	10,486.639	10,850.182	10,401.435	11,061.306	10,929.348	11,131.641	12,720.917	13,181.614	13,217.151
Natural Gas	2,353.672	3,300.682	4,021.307	4,845.477	4,483.802	4,951.280	5,084.145	3,096.561	2,149.098	2,630.786
Oil	1.497	1.327	3.142	3.207	2.734	2.472	2.869	0.458	0.321	0.452
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.257	0.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.428	0.334	0.764	0.894	1.124	0.859	0.968	0.153	0.098	0.144
Total	14,292.773	14,629.114	14,965.191	15,341.055	15,638.762	15,973.755	16,309.418	16,687.443	16,982.371	17,318.640

Hearing Exhibit - 00000293

Response to Interrogatory # 70

Scenario 1 - Low Fuel & Low Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,033.804	10,486.639	10,850.182	10,401.435	11,061.280	10,929.401	11,131.573	12,721.322	13,182.039	13,217.646
Natural Gas	2,353.672	3,300.682	4,021.307	4,845.477	4,485.050	4,953.039	5,085.740	3,096.451	2,148.861	2,630.543
Oil	1.497	1.327	3.142	3.207	2.014	1.203	1.809	0.259	0.186	0.275
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.257	0.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.428	0.334	0.764	0.894	0.624	0.316	0.502	0.060	0.044	0.068
Total	14,292.773	14,629.114	14,965.191	15,341.055	15,638.763	15,973.754	16,309.421	16,687.445	16,982.370	17,318.639

Hearing Exhibit - 00000294

Response to Interrogatory # 70

Scenario 2 - Reference w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,442.577	11,125.426	10,985.700	11,179.002	12,896.079	13,434.213	13,446.788
Natural Gas	2,874.189	3,901.699	4,661.324	4,875.459	4,946.682	5,433.188	5,585.322	3,526.813	2,551.873	3,057.357
Oil	3.515	3.244	6.673	2.311	2.126	1.967	2.328	0.322	0.252	0.366
Renewable	0.000	0.000	0.000	236.283	227.970	230.555	234.288	191.325	155.980	169.731
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	433.304	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.789	0.621	0.709	0.095	0.067	0.103
Total	15,010.325	15,344.080	15,690.039	16,080.552	16,392.788	16,741.826	17,091.444	17,483.988	17,793.626	18,144.452

Hearing Exhibit - 00000295

Response to Interrogatory # 70

Scenario 2 - Reference wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,442.577	11,125.324	10,985.637	11,178.908	12,896.189	13,434.256	13,446.905
Natural Gas	2,874.189	3,901.699	4,661.324	4,875.459	4,948.331	5,433.709	5,586.597	3,526.881	2,551.959	3,057.432
Oil	3.515	3.244	6.673	2.311	1.082	1.687	1.482	0.188	0.153	0.223
Renewable	0.000	0.000	0.000	236.283	227.952	230.540	234.279	191.332	155.985	169.734
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	433.304	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.304	0.456	0.384	0.045	0.031	0.051
Total	15,010.325	15,344.080	15,690.039	16,080.552	16,392.788	16,741.825	17,091.445	17,483.987	17,793.626	18,144.453

Hearing Exhibit - 00000296

Response to Interrogatory # 70

Scenario 2 - High Fuel w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,442.567	11,125.426	10,985.700	11,179.002	12,896.079	13,434.213	13,446.788
Natural Gas	2,874.189	3,901.699	4,661.324	4,842.048	4,946.682	5,433.188	5,585.322	3,526.813	2,551.873	3,057.357
Oil	3.515	3.244	6.673	2.311	2.126	1.967	2.328	0.322	0.252	0.366
Renewable	0.000	0.000	0.000	236.281	227.970	230.555	234.288	191.325	155.980	169.731
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	466.725	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.789	0.621	0.709	0.095	0.067	0.103
Total	15,010.325	15,344.080	15,690.039	16,080.551	16,392.788	16,741.826	17,091.444	17,483.988	17,793.626	18,144.452

Hearing Exhibit - 00000297

Response to Interrogatory # 70

Scenario 2 - High Fuel wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,442.567	11,125.324	10,985.637	11,178.908	12,896.189	13,434.256	13,446.905
Natural Gas	2,874.189	3,901.699	4,661.324	4,842.048	4,948.331	5,433.709	5,586.597	3,526.881	2,551.959	3,057.432
Oil	3.515	3.244	6.673	2.311	1.082	1.687	1.482	0.188	0.153	0.223
Renewable	0.000	0.000	0.000	236.281	227.952	230.540	234.279	191.332	155.985	169.734
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	466.725	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.304	0.456	0.384	0.045	0.031	0.051
Total	15,010.325	15,344.080	15,690.039	16,080.551	16,392.788	16,741.825	17,091.445	17,483.987	17,793.626	18,144.453

Hearing Exhibit - 00000298

Response to Interrogatory # 70

Scenario 2 - Low Fuel w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,442.577	11,125.426	10,985.700	11,179.002	12,896.079	13,434.213	13,446.788
Natural Gas	2,874.189	3,901.699	4,661.324	4,875.459	4,946.682	5,433.188	5,585.322	3,526.813	2,551.873	3,057.357
Oil	3.515	3.244	6.673	2.311	2.126	1.967	2.328	0.322	0.252	0.366
Renewable	0.000	0.000	0.000	236.283	227.970	230.555	234.288	191.325	155.980	169.731
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	433.304	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.789	0.621	0.709	0.095	0.067	0.103
Total	15,010.325	15,344.080	15,690.039	16,080.552	16,392.788	16,741.826	17,091.444	17,483.988	17,793.626	18,144.452

Hearing Exhibit - 00000299

Response to Interrogatory # 70

Scenario 2 - Low Fuel wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,442.577	11,125.324	10,985.649	11,178.925	12,896.179	13,434.229	13,446.879
Natural Gas	2,874.189	3,901.699	4,661.324	4,875.459	4,948.331	5,433.692	5,586.560	3,526.890	2,551.985	3,057.458
Oil	3.515	3.244	6.673	2.311	1.082	1.687	1.501	0.189	0.154	0.223
Renewable	0.000	0.000	0.000	236.283	227.952	230.545	234.281	191.332	155.985	169.735
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	433.304	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.304	0.456	0.384	0.045	0.031	0.051
Total	15,010.325	15,344.080	15,690.039	16,080.552	16,392.788	16,741.825	17,091.445	17,483.987	17,793.626	18,144.453

Hearing Exhibit - 00000300

Response to Interrogatory # 70

Scenario 2 - High Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,470.490	10,719.966	10,994.423	10,469.329	11,175.156	11,028.209	11,212.292	13,094.918	13,779.874	13,730.831
Natural Gas	3,948.371	5,124.194	5,961.738	5,566.398	6,317.301	6,839.123	7,027.435	4,817.205	3,718.291	4,315.029
Oil	10.485	10.072	18.070	4.044	3.069	2.611	4.057	0.601	0.567	0.778
Renewable	0.000	0.000	0.000	244.320	239.359	240.925	242.996	214.374	182.915	193.458
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.248	1.459	0.000	1,111.834	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	3.535	3.020	5.750	0.989	1.070	0.777	1.274	0.180	0.150	0.220
Total	16,338.243	16,698.674	17,069.776	17,486.956	17,825.751	18,201.440	18,577.849	18,996.631	19,333.038	19,710.423

Hearing Exhibit - 00000301

Response to Interrogatory # 70

Scenario 2 - High Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,470.490	10,719.966	10,994.423	10,469.329	11,175.073	11,028.192	11,212.244	13,095.235	13,780.181	13,731.088
Natural Gas	3,948.371	5,124.194	5,961.738	5,566.398	6,318.051	6,840.509	7,029.535	4,817.195	3,718.288	4,315.171
Oil	10.485	10.072	18.070	4.044	2.728	1.637	2.634	0.373	0.334	0.481
Renewable	0.000	0.000	0.000	244.320	239.345	240.925	242.986	214.390	182.926	193.472
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.248	1.459	0.000	1,111.834	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	3.535	3.020	5.750	0.989	0.759	0.382	0.656	0.082	0.067	0.103
Total	16,338.243	16,698.674	17,069.776	17,486.956	17,825.751	18,201.442	18,577.850	18,996.629	19,333.039	19,710.423

Hearing Exhibit - 00000302

Response to Interrogatory # 70

Scenario 2 - Low Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,033.804	10,485.376	10,848.997	10,400.453	11,060.026	10,928.284	11,130.696	12,716.997	13,175.360	13,212.154
Natural Gas	2,353.672	3,285.889	4,000.769	4,598.697	4,247.441	4,710.925	4,838.833	2,901.468	1,993.592	2,460.518
Oil	1.497	1.302	3.084	2.469	2.174	1.971	3.002	0.458	0.319	0.453
Renewable	0.000	0.000	0.000	226.918	216.715	220.359	224.330	177.176	139.957	153.461
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.257	0.167	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.428	0.327	0.749	0.611	0.799	0.610	0.955	0.142	0.090	0.134
Total	14,292.773	14,613.025	14,943.394	15,319.191	15,616.950	15,951.945	16,287.611	16,665.595	16,960.560	17,296.828

Hearing Exhibit - 00000303

Response to Interrogatory # 70

Scenario 2 - Low Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,033.804	10,485.376	10,848.997	10,400.453	11,060.013	10,928.345	11,130.585	12,717.640	13,175.965	13,212.825
Natural Gas	2,353.672	3,285.889	4,000.769	4,598.697	4,249.083	4,711.350	4,840.630	2,901.115	1,993.157	2,460.093
Oil	1.497	1.302	3.084	2.469	1.062	1.664	1.818	0.234	0.183	0.255
Renewable	0.000	0.000	0.000	226.918	216.714	220.366	224.320	177.202	139.977	153.490
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.257	0.167	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.428	0.327	0.749	0.611	0.282	0.422	0.464	0.051	0.036	0.058
Total	14,292.773	14,613.025	14,943.394	15,319.191	15,616.949	15,951.943	16,287.613	16,665.596	16,960.559	17,296.827

Hearing Exhibit - 00000304

Response to Interrogatory # 70

Scenario 2 - High Capital Cost w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,442.577	11,125.426	10,985.700	11,179.002	12,896.079	13,434.213	13,446.788
Natural Gas	2,874.189	3,901.699	4,661.324	4,875.459	4,946.682	5,433.188	5,585.322	3,526.813	2,551.873	3,057.357
Oil	3.515	3.244	6.673	2.311	2.126	1.967	2.328	0.322	0.252	0.366
Renewable	0.000	0.000	0.000	236.283	227.970	230.555	234.288	191.325	155.980	169.731
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	433.304	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.789	0.621	0.709	0.095	0.067	0.103
Total	15,010.325	15,344.080	15,690.039	16,080.552	16,392.788	16,741.826	17,091.444	17,483.988	17,793.626	18,144.452

Hearing Exhibit - 00000305

Response to Interrogatory # 70

Scenario 2 - High Capital Cost wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,442.577	11,125.324	10,985.637	11,178.908	12,896.189	13,434.256	13,446.905
Natural Gas	2,874.189	3,901.699	4,661.324	4,875.459	4,948.331	5,433.709	5,586.597	3,526.881	2,551.959	3,057.432
Oil	3.515	3.244	6.673	2.311	1.082	1.687	1.482	0.188	0.153	0.223
Renewable	0.000	0.000	0.000	236.283	227.952	230.540	234.279	191.332	155.985	169.734
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	433.304	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.304	0.456	0.384	0.045	0.031	0.051
Total	15,010.325	15,344.080	15,690.039	16,080.552	16,392.788	16,741.825	17,091.445	17,483.987	17,793.626	18,144.453

Hearing Exhibit - 00000306

Response to Interrogatory # 70

Scenario 2 - High Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,312.608	10,785.783	9,813.220	9,076.331	9,814.168	9,313.289	7.983.334
Natural Gas	2,874.189	3,901.699	4,661.324	4,691.162	5,266.427	6,588.150	7,673.992	6,549.846	6,579.300	8,441.137
Oil	3.515	3.244	6.673	2.311	0.872	0.811	1.327	0.182	0.146	0.205
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	733.464	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.299	0.234	0.385	0.051	0.034	0.054
Total	15,010.325	15,344.080	15,690.039	16,080.551	16,392.790	16,741.826	17,091.445	17,483.988	17,793.625	18,144.452

Hearing Exhibit - 00000307

Response to Interrogatory # 70

Scenario 2 - High Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,312.608	10,808.880	10,088.760	9,859.009	10,924.428	10,068.196	10,047.753
Natural Gas	2,874.189	3,901.699	4,661.324	4,691.162	5,243.112	6,311.519	6,891.151	5,439.594	5,824.379	6,376.704
Oil	3.515	3.244	6.673	2.311	1.082	1.682	1.492	0.182	0.165	0.223
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	733.464	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.304	0.456	0.384	0.045	0.031	0.051
Total	15,010.325	15,344.080	15,690.039	16,080.551	16,392.788	16,741.826	17,091.446	17,483.989	17,793.627	18,144.453

Hearing Exhibit - 00000308

Response to Interrogatory # 70

Scenario 2 - Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,428.058	11,103.454	10,966.327	11,163.346	12,836.593	13,340.312	13,366.492
Natural Gas	2,874.189	3,901.699	4,661.324	4,842.423	4,947.004	5,433.489	5,585.635	3,527.218	2,552.124	3,057.771
Oil	3.515	3.244	6.673	2.311	2.131	1.981	2.344	0.340	0.267	0.366
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	466.753	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.789	0.621	0.709	0.095	0.067	0.103
Total	15,010.325	15,344.080	15,690.039	16,080.551	16,392.788	16,741.827	17,091.444	17,483.987	17,793.625	18,144.453

Hearing Exhibit - 00000309

Response to Interrogatory # 70

Scenario 2 - Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,428.058	11,103.348	10,966.268	11,163.263	12,836.701	13,340.376	13,366.615
Natural Gas	2,874.189	3,901.699	4,661.324	4,842.423	4,948.644	5,434.005	5,586.899	3,527.294	2,552.195	3,057.845
Oil	3.515	3.244	6.673	2.311	1.082	1.687	1.490	0.208	0.168	0.223
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	466.753	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.304	0.456	0.384	0.045	0.031	0.051
Total	15,010.325	15,344.080	15,690.039	16,080.551	16,392.789	16,741.826	17,091.446	17,483.988	17,793.626	18,144.455

Hearing Exhibit - 00000310

Response to Interrogatory # 70

Scenario 2 - High Fuel & Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,428.046	11,103.454	10,966.308	11,163.346	12,836.544	13,340.266	13,366.492
Natural Gas	2,874.189	3,901.699	4,661.324	4,629.918	4,947.004	5,433.511	5,585.635	3,527.266	2,552.168	3,057.771
Oil	3.515	3.244	6.673	2.311	2.131	1.976	2.344	0.342	0.268	0.366
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	679.271	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.789	0.621	0.709	0.095	0.067	0.103
Total	15,010.325	15,344.080	15,690.039	16,080.551	16,392.788	16,741.826	17,091.444	17,483.988	17,793.626	18,144.453

Hearing Exhibit - 00000311

Response to Interrogatory # 70

Scenario 2 - High Fuel & Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,227.763	10,597.857	10,930.330	10,428.046	11,103.348	10,966.246	11,163.263	12,836.651	13,340.332	13,366.615
Natural Gas	2,874.189	3,901.699	4,661.324	4,629.918	4,948.644	5,434.025	5,586.899	3,527.342	2,552.239	3,057.845
Oil	3.515	3.244	6.673	2.311	1.082	1.689	1.490	0.211	0.169	0.223
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.626	0.408	0.000	679.271	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.116	0.908	1.916	0.577	0.304	0.456	0.384	0.045	0.031	0.051
Total	15,010.325	15,344.080	15,690.039	16,080.551	16,392.789	16,741.826	17,091.446	17,483.989	17,793.626	18,144.455

Hearing Exhibit - 00000312

Response to Interrogatory # 70

Scenario 2 - High Fuel, High Load, & Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,470.490	10,719.966	10,994.423	10,463.030	11,164.613	11,019.240	11,205.390	13,058.243	13,712.577	13,674.212
Natural Gas	3,948.371	5,124.194	5,961.738	5,052.200	6,317.576	6,839.390	7,027.704	4,817.838	3,718.850	4,315.470
Oil	10.485	10.072	18.070	4.044	3.082	2.624	4.072	0.629	0.606	0.799
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.248	1.459	0.000	1,626.264	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	3.535	3.020	5.750	0.989	1.070	0.777	1.274	0.180	0.150	0.220
Total	16,338.243	16,698.674	17,069.776	17,486.955	17,825.751	18,201.441	18,577.850	18,996.631	19,333.039	19,710.423

Hearing Exhibit - 00000313

Response to Interrogatory # 70

Scenario 2 - High Fuel, High Load, & Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,470.490	10,719.966	10,994.423	10,463.030	11,164.543	11,019.247	11,205.348	13,058.505	13,712.892	13,674.587
Natural Gas	3,948.371	5,124.194	5,961.738	5,052.200	6,318.311	6,840.765	7,029.802	4,817.878	3,718.843	4,315.534
Oil	10.485	10.072	18.070	4.044	2.728	1.638	2.634	0.423	0.381	0.479
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.248	1.459	0.000	1,626.264	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	3.535	3.020	5.750	0.989	0.759	0.382	0.656	0.082	0.067	0.103
Total	16,338.243	16,698.674	17,069.776	17,486.955	17,825.752	18,201.441	18,577.850	18,996.629	19,333.040	19,710.424

Hearing Exhibit - 00000314

Response to Interrogatory # 70

Scenario 2 - Low Fuel & Low Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,033.804	10,485.376	10,848.997	10,400.453	11,060.026	10,928.284	11,130.696	12,716.997	13,175.360	13,212.154
Natural Gas	2,353.672	3,285.889	4,000.769	4,598.697	4,247.441	4,710.925	4,838.833	2,901.468	1,993.592	2,460.518
Oil	1.497	1.302	3.084	2.469	2.174	1.971	3.002	0.458	0.319	0.453
Renewable	0.000	0.000	0.000	226.918	216.715	220.359	224.330	177.176	139.957	153.461
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.257	0.167	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.428	0.327	0.749	0.611	0.799	0.610	0.955	0.142	0.090	0.134
Total	14,292.773	14,613.025	14,943.394	15,319.191	15,616.950	15,951.945	16,287.611	16,665.595	16,960.560	17,296.828

Hearing Exhibit - 00000315

Response to Interrogatory # 70

Scenario 2 - Low Fuel & Low Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,033.804	10,485.376	10,848.997	10,400.453	11,060.013	10,928.345	11,130.585	12,717.640	13,175.965	13,212.825
Natural Gas	2,353.672	3,285.889	4,000.769	4,598.697	4,249.083	4,711.350	4,840.630	2,901.115	1,993.157	2,460.093
Oil	1.497	1.302	3.084	2.469	1.062	1.664	1.818	0.234	0.183	0.255
Renewable	0.000	0.000	0.000	226.918	216.714	220.366	224.320	177.202	139.977	153.490
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.257	0.167	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.428	0.327	0.749	0.611	0.282	0.422	0.464	0.051	0.036	0.058
Total	14,292.773	14,613.025	14,943.394	15,319.191	15,616.949	15,951.943	16,287.613	16,665.596	16,960.559	17,296.827

Hearing Exhibit - 00000316

Response to Interrogatory # 70

Scenario 3 - Reference w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.854	11,107.867	10,970.080	11,166.308	12,874.068	13,397.586	13,409.603
Natural Gas	2,853.119	3,871.062	4,587.352	5,347.390	5,053.746	5,541.102	5,692.385	3,602.781	2,607.342	3,126.971
Oil	3.278	2.715	5.133	4.366	3.195	2.984	4.604	0.714	0.554	0.764
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	68.894	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	1.274	1.006	1.583	0.248	0.175	0.253
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.879	16,604.967	16,954.676	17,347.165	17,656.898	18,007.698

Hearing Exhibit - 00000317

Response to Interrogatory # 70

Scenario 3 - Reference wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.854	11,107.817	10,970.039	11,166.232	12,873.944	13,397.552	13,409.617
Natural Gas	2,853.119	3,871.062	4,587.352	5,347.390	5,057.151	5,543.418	5,695.960	3,603.491	2,607.807	3,127.544
Oil	3.278	2.715	5.133	4.366	0.870	1.346	2.096	0.301	0.242	0.343
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	68.894	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	0.246	0.365	0.593	0.076	0.057	0.088
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.880	16,604.965	16,954.677	17,347.167	17,656.899	18,007.699

Hearing Exhibit - 00000318

Response to Interrogatory # 70

Scenario 3 - High Fuel w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.855	11,107.867	10,970.080	11,166.308	12,874.068	13,397.586	13,409.603
Natural Gas	2,853.119	3,871.062	4,587.352	5,343.639	5,053.746	5,541.102	5,692.385	3,602.781	2,607.342	3,126.971
Oil	3.278	2.715	5.133	4.366	3.195	2.984	4.604	0.714	0.554	0.764
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	72.646	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	1.274	1.006	1.583	0.248	0.175	0.253
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.879	16,604.967	16,954.676	17,347.165	17,656.898	18,007.698

Hearing Exhibit - 00000319

Response to Interrogatory # 70

Scenario 3 - High Fuel wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.855	11,107.817	10,970.039	11,166.232	12,873.944	13,397.552	13,409.617
Natural Gas	2,853.119	3,871.062	4,587.352	5,343.639	5,057.151	5,543.418	5,695.960	3,603.491	2,607.807	3,127.544
Oil	3.278	2.715	5.133	4.366	0.870	1.346	2.096	0.301	0.242	0.343
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	72.646	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	0.246	0.365	0.593	0.076	0.057	0.088
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.880	16,604.965	16,954.677	17,347.167	17,656.899	18,007.699

Hearing Exhibit - 00000320

Response to Interrogatory # 70

Scenario 3 - Low Fuel w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.854	11,107.867	10,970.080	11,166.308	12,874.068	13,397.586	13,409.603
Natural Gas	2,853.119	3,871.062	4,587.352	5,347.390	5,053.746	5,541.102	5,692.385	3,602.781	2,607.342	3,126.971
Oil	3.278	2.715	5.133	4.366	3.195	2.984	4.604	0.714	0.554	0.764
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	68.894	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	1.274	1.006	1.583	0.248	0.175	0.253
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.879	16,604.967	16,954.676	17,347.165	17,656.898	18,007.698

Hearing Exhibit - 00000321

Response to Interrogatory # 70

Scenario 3 - Low Fuel wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.854	11,107.817	10,970.057	11,166.265	12,873.949	13,397.536	13,409.594
Natural Gas	2,853.119	3,871.062	4,587.352	5,347.390	5,057.151	5,543.401	5,695.921	3,603.486	2,607.823	3,127.565
Oil	3.278	2.715	5.133	4.366	0.870	1.346	2.102	0.302	0.242	0.344
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	68.894	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	0.246	0.365	0.593	0.076	0.057	0.088
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.880	16,604.965	16,954.676	17,347.167	17,656.899	18,007.698

Hearing Exhibit - 00000322

Response to Interrogatory # 70

Scenario 3 - High Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,536.466	10,759.659	11,002.907	10,471.218	11,181.819	11,035.739	11,217.358	13,140.904	13,834.499	13,770.695
Natural Gas	3,870.255	5,051.450	5,872.761	6,040.224	6,416.633	6,939.551	7,132.452	4,852.047	3,713.264	4,335.627
Oil	6.972	6.411	11.208	4.621	2.380	2.219	3.612	0.554	0.424	0.620
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.013	1.217	0.000	745.831	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	2.262	1.824	3.282	1.242	0.870	0.691	1.160	0.179	0.123	0.178
Total	16,321.083	16,660.525	16,979.953	17,353.178	17,691.499	18,067.997	18,444.378	18,863.037	19,199.553	19,577.227

Hearing Exhibit - 00000323

Response to Interrogatory # 70

Scenario 3 - High Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,536.466	10,759.659	11,002.907	10,471.218	11,181.755	11,035.716	11,217.335	13,141.014	13,834.510	13,770.878
Natural Gas	3,870.255	5,051.450	5,872.761	6,040.224	6,417.310	6,940.939	7,134.679	4,852.296	3,713.508	4,335.810
Oil	6.972	6.411	11.208	4.621	2.026	1.236	2.034	0.304	0.242	0.354
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.013	1.217	0.000	745.831	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	2.262	1.824	3.282	1.242	0.612	0.310	0.533	0.073	0.050	0.078
Total	16,321.083	16,660.525	16,979.953	17,353.178	17,691.499	18,067.998	18,444.377	18,863.042	19,199.551	19,577.227

Hearing Exhibit - 00000324

Response to Interrogatory # 70

Scenario 3 - Low Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,035.303	10,485.891	10,831.538	10,379.806	11,040.941	10,910.510	11,115.711	12,697.036	13,153.508	13,186.082
Natural Gas	2,332.720	3,244.416	3,926.854	4,709.883	4,347.139	4,813.164	4,942.615	2,962.098	2,018.551	2,503.103
Oil	1.469	1.140	2.288	2.167	1.785	1.781	2.645	0.425	0.318	0.432
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.216	0.130	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.412	0.285	0.528	0.554	0.667	0.572	0.875	0.137	0.092	0.130
Total	14,273.235	14,571.826	14,851.004	15,182.451	15,480.328	15,815.823	16,151.641	16,529.049	16,823.710	17,159.854

Hearing Exhibit - 00000325

Response to Interrogatory # 70

Scenario 3 - Low Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,035.303	10,485.891	10,831.538	10,379.806	11,040.967	10,910.583	11,115.599	12,697.378	13,154.049	13,186.583
Natural Gas	2,332.720	3,244.416	3,926.854	4,709.883	4,346.299	4,812.760	4,942.197	2,961.733	2,017.968	2,502.524
Oil	1.469	1.140	2.288	2.167	2.502	2.117	3.162	0.471	0.368	0.517
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.216	0.130	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.412	0.285	0.528	0.554	0.763	0.570	0.887	0.115	0.085	0.125
Total	14,273.235	14,571.826	14,851.004	15,182.451	15,480.326	15,815.825	16,151.641	16,529.050	16,823.710	17,159.855

Hearing Exhibit - 00000326

Response to Interrogatory # 70

Scenario 3 - High Capital Cost w GEC

JEA Energy Mix

GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.854	11,107.875	10,970.071	11,166.308	12,874.068	13,397.586	13,409.603
Natural Gas	2,853.119	3,871.062	4,587.352	5,347.390	5,052.254	5,539.842	5,692.385	3,602.781	2,607.342	3,126.971
Oil	3.278	2.715	5.133	4.366	4.194	3.882	4.604	0.714	0.554	0.764
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	68.894	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	1.761	1.377	1.583	0.248	0.175	0.253
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.879	16,604.967	16,954.676	17,347.165	17,656.898	18,007.698

Hearing Exhibit - 00000327

Response to Interrogatory # 70

Scenario 3 - High Capital Cost wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.854	11,107.817	10,970.039	11,166.232	12,873.944	13,397.552	13,409.617
Natural Gas	2,853.119	3,871.062	4,587.352	5,347.390	5,057.151	5,543.418	5,695.960	3,603.491	2,607.807	3,127.544
Oil	3.278	2.715	5.133	4.366	0.870	1.346	2.096	0.301	0.242	0.343
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	68.894	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	0.246	0.365	0.593	0.076	0.057	0.088
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.880	16,604.965	16,954.677	17,347.167	17,656.899	18,007.699

Hearing Exhibit - 00000328

Response to Interrogatory # 70

Scenario 3 - High Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,375.328	11,023.215	10,224.589	9,742.992	10,618.350	10,475.054	9,471.943
Natural Gas	2,853.119	3,871.062	4,587.352	5,371.797	5,136.914	6,285.311	7,115.716	5,858.498	5,529.873	7,064.630
Oil	3.278	2.715	5.133	4.365	4.194	3.894	4.587	0.715	0.554	0.764
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	101.016	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	1.761	1.377	1.583	0.248	0.175	0.253
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.880	16,604.967	16,954.674	17,347.165	17,656.897	18,007.697

Hearing Exhibit - 00000329

Response to Interrogatory # 70

Scenario 3 - High Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,375.328	10,826.326	10,139.621	9,936.525	10,993.935	10,189.018	10,160.103
Natural Gas	2,853.119	3,871.062	4,587.352	5,371.797	5,338.641	6,373.837	6,925.659	5,483.520	5,816.331	6,377.062
Oil	3.278	2.715	5.133	4.365	0.870	1.345	2.103	0.283	0.252	0.336
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	101.016	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	0.246	0.365	0.593	0.076	0.057	0.088
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.880	16,604.963	16,954.674	17,347.167	17,656.900	18,007.697

Hearing Exhibit - 00000330

Response to Interrogatory # 70

Scenario 3 - Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.875	11,107.903	10,970.113	11,166.352	12,874.128	13,397.648	13,409.636
Natural Gas	2,853.119	3,871.062	4,587.352	5,343.619	5,053.712	5,541.062	5,692.341	3,602.722	2,607.277	3,126.938
Oil	3.278	2.715	5.133	4.366	3.194	2.991	4.604	0.714	0.556	0.764
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	72.646	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	1.274	1.006	1.583	0.248	0.175	0.253
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.880	16,604.968	16,954.676	17,347.165	17,656.897	18,007.699

Hearing Exhibit - 00000331

Response to Interrogatory # 70

Scenario 3 - Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.875	11,107.852	10,970.080	11,166.267	12,874.012	13,397.642	13,409.654
Natural Gas	2,853.119	3,871.062	4,587.352	5,343.619	5,057.117	5,543.378	5,695.927	3,603.428	2,607.720	3,127.510
Oil	3.278	2.715	5.133	4.366	0.870	1.345	2.095	0.296	0.238	0.339
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	72.646	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	0.246	0.365	0.593	0.076	0.057	0.088
Total	14,990.415	15,302.636	15,597.415	15,943.774	16,255.880	16,604.964	16,954.677	17,347.167	17,656.899	18,007.699

Hearing Exhibit - 00000332

Response to Interrogatory # 70

Scenario 3 - High Fuel & Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.875	11,107.903	10,970.105	11,166.352	12,874.147	13,397.571	13,409.636
Natural Gas	2,853.119	3,871.062	4,587.352	5,319.114	5,053.712	5,541.076	5,692.341	3,602.703	2,607.348	3,126.938
Oil	3.278	2.715	5.133	4.365	3.194	2.984	4.604	0.714	0.562	0.764
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	97.152	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	1.274	1.006	1.583	0.248	0.175	0.253
Total	14,990.415	15,302.636	15,597.415	15,943.775	16,255.880	16,604.967	16,954.676	17,347.166	17,656.899	18,007.699

Hearing Exhibit - 00000333

Response to Interrogatory # 70

Scenario 3 - High Fuel & Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,587.805	10,913.777	10,431.875	11,107.852	10,970.064	11,166.267	12,874.031	13,397.603	13,409.654
Natural Gas	2,853.119	3,871.062	4,587.352	5,319.114	5,057.117	5,543.393	5,695.927	3,603.410	2,607.761	3,127.510
Oil	3.278	2.715	5.133	4.365	0.870	1.346	2.095	0.296	0.237	0.339
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.350	0.000	97.152	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.740	1.357	1.227	0.246	0.365	0.593	0.076	0.057	0.088
Total	14,990.415	15,302.636	15,597.415	15,943.775	16,255.880	16,604.965	16,954.677	17,347.167	17,656.900	18,007.699

Hearing Exhibit - 00000334

Response to Interrogatory # 70

Scenario 3 - High Fuel, High Load. & Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,536.466	10,759.659	11,002.907	10,471.225	11,181.767	11,035.708	11,217.350	13,140.910	13,834.400	13,770.785
Natural Gas	3,870.255	5,051.450	5,872.761	5,799.419	6,417.644	6,940.439	7,133.760	4,852.235	3,713.516	4,335.784
Oil	6.972	6.411	11.208	4.618	1.668	1.565	2.623	0.406	0.308	0.425
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.013	1.217	0.000	986.632	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	2.262	1.824	3.282	1.242	0.624	0.491	0.847	0.134	0.088	0.127
Total	16,321.083	16,660.525	16,979.953	17,353.178	17,691.499	18,067.999	18,444.377	18,863.040	19,199.552	19,577.228

Hearing Exhibit - 00000335

Response to Interrogatory # 70

Scenario 3 - High Fuel, High Load, & Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,536.466	10,759.659	11,002.907	10,471.225	11,181.772	11,035.731	11,217.342	13,141.059	13,834.522	13,770.958
Natural Gas	3,870.255	5,051.450	5,872.761	5,799.419	6,417.293	6,940.924	7,134.672	4,852.254	3,713.488	4,335.737
Oil	6.972	6.411	11.208	4.618	2.026	1.236	2.034	0.302	0.250	0.349
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.013	1.217	0.000	986.632	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	2.262	1.824	3.282	1.242	0.612	0.310	0.533	0.073	0.050	0.078
Total	16,321.083	16,660.525	16,979.953	17,353.178	17,691.499	18,067.998	18,444.377	18,863.041	19,199.552	19,577.228

Hearing Exhibit - 00000336

Response to Interrogatory # 70

Scenario 3 - Low Fuel & Low Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,035.303	10,485.891	10,831.538	10,379.806	11,040.941	10,910.510	11,115.711	12,697.036	13,153.508	13,186.082
Natural Gas	2,332.720	3,244.416	3,926.854	4,709.883	4,347.139	4,813.164	4,942.615	2,962.098	2,018.551	2,503.103
Oil	1.469	1.140	2.288	2.167	1.785	1.781	2.645	0.425	0.318	0.432
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.216	0.130	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.412	0.285	0.528	0.554	0.667	0.572	0.875	0.137	0.092	0.130
Total	14,273.235	14,571.826	14,851.004	15,182.451	15,480.328	15,815.823	16,151.641	16,529.049	16,823.710	17,159.854

Hearing Exhibit - 00000337

Response to Interrogatory # 70

Scenario 3 - Low Fuel & Low Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,035.303	10,485.891	10,831.538	10,379.806	11,040.967	10,910.583	11,115.599	12,697.378	13,154.049	13,186.583
Natural Gas	2,332.720	3,244.416	3,926.854	4,709.883	4,346.299	4,812.760	4,942.197	2,961.733	2,017.968	2,502.524
Oil	1.469	1.140	2.288	2.167	2.502	2.117	3.162	0.471	0.368	0.517
Renewable	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.216	0.130	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.412	0.285	0.528	0.554	0.763	0.570	0.887	0.115	0.085	0.125
Total	14,273.235	14,571.826	14,851.004	15,182.451	15,480.326	15,815.825	16,151.641	16,529.050	16,823.710	17,159.855

Hearing Exhibit - 00000338

Response to Interrogatory # 70

Scenario 4 - Reference w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,431.225	11,107.039	10,969.315	11,165.715	12,871.594	13,392.230	13,405.997
Natural Gas	2,853.119	3,855.870	4,566.629	5,095.778	4,807.643	5,291.969	5,440.960	3,392.618	2,436.350	2,941.069
Oil	3.278	2.667	5.043	3.369	3.366	3.126	3.689	0.536	0.411	0.574
Renewable	0.000	0.000	0.000	234.110	224.957	227.958	231.575	191.051	154.743	167.971
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	66.546	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	1.266	0.988	1.133	0.163	0.113	0.167
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.067	16,583.152	16,932.867	17,325.316	17,635.089	17,985.885

Hearing Exhibit - 00000339

Response to Interrogatory # 70

Scenario 4 - Reference wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,431.225	11,107.041	10,969.286	11,165.600	12,871.537	13,392.213	13,406.018
Natural Gas	2,853.119	3,855.870	4,566.629	5,095.778	4,811.479	5,294.863	5,443.894	3,393.121	2,436.679	2,941.482
Oil	3.278	2.667	5.043	3.369	0.657	1.021	1.614	0.208	0.175	0.251
Renewable	0.000	0.000	0.000	234.110	224.937	227.942	231.560	191.052	154.748	167.973
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	66.546	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	0.161	0.244	0.404	0.046	0.034	0.055
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.070	16,583.152	16,932.869	17,325.318	17,635.089	17,985.886

Hearing Exhibit - 00000340

Response to Interrogatory # 70

Scenario 4 - High Fuel w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,431.223	11,107.039	10,969.315	11,165.715	12,871.594	13,392.230	13,405.997
Natural Gas	2,853.119	3,855.870	4,566.629	5,091.745	4,807.643	5,291.969	5,440.960	3,392.618	2,436.350	2,941.069
Oil	3.278	2.667	5.043	3.369	3.366	3.126	3.689	0.536	0.411	0.574
Renewable	0.000	0.000	0.000	234.110	224.957	227.958	231.575	191.051	154.743	167.971
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	70.581	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	1.266	0.988	1.133	0.163	0.113	0.167
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.067	16,583.152	16,932.867	17,325.316	17,635.089	17,985.885

Hearing Exhibit - 00000341

Response to Interrogatory # 70

Scenario 4 - High Fuel wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,431.223	11,107.041	10,969.286	11,165.600	12,871.537	13,392.213	13,406.018
Natural Gas	2,853.119	3,855.870	4,566.629	5,091.745	4,811.479	5,294.863	5,443.894	3,393.121	2,436.679	2,941.482
Oil	3.278	2.667	5.043	3.369	0.657	1.021	1.614	0.208	0.175	0.251
Renewable	0.000	0.000	0.000	234.110	224.937	227.942	231.560	191.052	154.748	167.973
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	70.581	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	0.161	0.244	0.404	0.046	0.034	0.055
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.070	16,583.152	16,932.869	17,325.318	17,635.089	17,985.886

Hearing Exhibit - 00000342

Response to Interrogatory # 70

Scenario 4 - Low Fuel w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,431.225	11,107.039	10,969.315	11,165.715	12,871.594	13,392.230	13,405.997
Natural Gas	2,853.119	3,855.870	4,566.629	5,095.778	4,807.643	5,291.969	5,440.960	3,392.618	2,436.350	2,941.069
Oil	3.278	2.667	5.043	3.369	3.366	3.126	3.689	0.536	0.411	0.574
Renewable	0.000	0.000	0.000	234.110	224.957	227.958	231.575	191.051	154.743	167.971
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	66.546	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	1.266	0.988	1.133	0.163	0.113	0.167
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.067	16,583.152	16,932.867	17,325.316	17,635.089	17,985.885

Hearing Exhibit - 00000343

Response to Interrogatory # 70

Scenario 4 - Low Fuel wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,431.225	11,107.041	10,969.313	11,165.645	12,871.525	13,392.201	13,405.989
Natural Gas	2,853.119	3,855.870	4,566.629	5,095.778	4,811.479	5,294.830	5,443.831	3,393.131	2,436.689	2,941.511
Oil	3.278	2.667	5.043	3.369	0.657	1.021	1.628	0.209	0.175	0.252
Renewable	0.000	0.000	0.000	234.110	224.937	227.948	231.565	191.052	154.747	167.973
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	66.546	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	0.161	0.244	0.404	0.046	0.034	0.055
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.070	16,583.152	16,932.869	17,325.318	17,635.088	17,985.886

Hearing Exhibit - 00000344

Response to Interrogatory # 70

Scenario 4 - High Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,536.466	10,759.192	11,002.520	10,470.927	11,181.509	11,035.505	11,217.221	13,139.754	13,831.689	13,768.424
Natural Gas	3,870.255	5,035.974	5,851.611	5,962.443	6,154.026	6,675.088	6,866.134	4,610.369	3,505.262	4,117.406
Oil	6.972	6.305	11.010	4.470	2.426	2.247	3.710	0.542	0.416	0.603
Renewable	0.000	0.000	0.000	244.759	241.126	242.913	244.625	221.011	189.025	198.719
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.013	1.210	0.000	557.582	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	2.262	1.790	3.219	1.094	0.805	0.635	1.084	0.160	0.106	0.155
Total	16,321.083	16,644.434	16,958.156	17,331.317	17,669.688	18,046.184	18,422.570	18,841.189	19,177.739	19,555.414

Hearing Exhibit - 00000345

Response to Interrogatory # 70

Scenario 4 - High Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,536.466	10,759.192	11,002.520	10,470.927	11,181.400	11,035.442	11,217.190	13,139.941	13,831.791	13,768.661
Natural Gas	3,870.255	5,035.974	5,851.611	5,962.443	6,155.414	6,674.903	6,868.052	4,610.486	3,505.375	4,117.482
Oil	6.972	6.305	11.010	4.470	1.557	2.503	2.348	0.306	0.245	0.352
Renewable	0.000	0.000	0.000	244.759	241.107	242.899	244.620	221.028	189.037	198.734
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.013	1.210	0.000	557.582	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	2.262	1.790	3.219	1.094	0.413	0.641	0.564	0.076	0.048	0.075
Total	16,321.083	16,644.434	16,958.156	17,331.317	17,669.686	18,046.184	18,422.571	18,841.191	19,177.738	19,555.411

Hearing Exhibit - 00000346

Response to Interrogatory # 70

Scenario 4 - Low Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,035.303	10,484.337	10,830.113	10,378.828	11,039.774	10,909.490	11,114.709	12,693.404	13,146.870	13,180.814
Natural Gas	2,332.720	3,229.912	3,906.539	4,466.157	4,112.885	4,575.274	4,700.986	2,764.834	1,865.997	2,333.245
Oil	1.469	1.117	2.242	1.627	1.397	1.401	2.111	0.313	0.228	0.319
Renewable	0.000	0.000	0.000	223.567	214.207	217.656	221.618	179.210	137.505	153.476
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.216	0.129	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.412	0.279	0.517	0.365	0.458	0.393	0.612	0.086	0.057	0.083
Total	14,273.235	14,555.737	14,829.207	15,160.586	15,458.516	15,794.010	16,129.832	16,507.202	16,801.898	17,138.044

Hearing Exhibit - 00000347

Response to Interrogatory # 70

Scenario 4 - Low Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,035.303	10,484.337	10,830.113	10,378.828	11,039.809	10,909.592	11,114.607	12,694.052	13,147.567	13,181.519
Natural Gas	2,332.720	3,229.912	3,906.539	4,466.157	4,112.261	4,573.308	4,699.827	2,764.028	1,865.149	2,332.343
Oil	1.469	1.117	2.242	1.627	1.925	2.898	3.183	0.434	0.345	0.463
Renewable	0.000	0.000	0.000	223.567	214.207	217.663	221.603	179.236	137.527	153.507
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.216	0.129	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.412	0.279	0.517	0.365	0.518	0.753	0.818	0.097	0.071	0.106
Total	14,273.235	14,555.737	14,829.207	15,160.586	15,458.516	15,794.010	16,129.833	16,507.201	16,801.900	17,138.044

Hearing Exhibit - 00000348

Response to Interrogatory # 70

Scenario 4 - High Capital Cost w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,431.225	11,107.039	10,969.315	11,165.715	12,871.594	13,392.230	13,405.997
Natural Gas	2,853.119	3,855.870	4,566.629	5,095.778	4,807.643	5,291.969	5,440.960	3,392.618	2,436.350	2,941.069
Oil	3.278	2.667	5.043	3.369	3.366	3.126	3.689	0.536	0.411	0.574
Renewable	0.000	0.000	0.000	234.110	224.957	227.958	231.575	191.051	154.743	167.971
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	66.546	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	1.266	0.988	1.133	0.163	0.113	0.167
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.067	16,583.152	16,932.867	17,325.316	17,635.089	17,985.885

Hearing Exhibit - 00000349

Response to Interrogatory # 70

Scenario 4 - High Capital Cost wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,431.225	11,107.041	10,969.286	11,165.600	12,871.537	13,392.213	13,406.018
Natural Gas	2,853.119	3,855.870	4,566.629	5,095.778	4,811.479	5,294.863	5,443.894	3,393.121	2,436.679	2,941.482
Oil	3.278	2.667	5.043	3.369	0.657	1.021	1.614	0.208	0.175	0.251
Renewable	0.000	0.000	0.000	234.110	224.937	227.942	231.560	191.052	154.748	167.973
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	66.546	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	0.161	0.244	0.404	0.046	0.034	0.055
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.070	16,583.152	16,932.869	17,325.318	17,635.089	17,985.886

Hearing Exhibit - 00000350

Response to Interrogatory # 70

Scenario 4 - High Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,355.120	10,995.568	10,171.055	9,649.982	10,503.176	10,321.598	9,275.163
Natural Gas	2,853.119	3,855.870	4,566.629	5,121.134	4,894.444	6,068.533	6,938.638	5,701.701	5,412.111	6,990.260
Oil	3.278	2.667	5.043	3.372	3.379	3.165	3.705	0.536	0.411	0.574
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	101.016	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	1.266	0.988	1.133	0.163	0.113	0.167
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.068	16,583.152	16,932.868	17,325.317	17,635.089	17,985.885

Hearing Exhibit - 00000351

Response to Interrogatory # 70

Scenario 4 - High Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,355.120	10,781.081	10,067.789	9,840.552	10,862.318	9,977.796	9,963.765
Natural Gas	2,853.119	3,855.870	4,566.629	5,121.134	5,112.763	6,174.681	6,750.870	5,343.012	5,756.221	6,302.100
Oil	3.278	2.667	5.043	3.372	0.656	1.029	1.632	0.200	0.182	0.246
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	101.016	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	0.161	0.244	0.404	0.046	0.034	0.055
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.071	16,583.153	16,932.868	17,325.317	17,635.088	17,985.887

Hearing Exhibit - 00000352

Response to Interrogatory # 70

Scenario 4 - Regulated CO2 w GEC
JEA Energy Mix

GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,414.526	11,082.073	10,947.368	11,147.350	12,811.909	13,297.182	13,324.020
Natural Gas	2,853.119	3,855.870	4,566.629	5,092.151	4,807.942	5,292.235	5,441.265	3,392.959	2,436.515	2,941.403
Oil	3.278	2.667	5.043	3.380	3.376	3.150	3.709	0.546	0.422	0.574
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	70.585	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	1.266	0.988	1.133	0.163	0.113	0.167
Total	14,990.415	15,286.546	15,575.615	15,921.914	16,234.067	16,583.151	16,932.867	17,325.317	17,635.088	17,985.886

Hearing Exhibit - 00000353

Response to Interrogatory # 70

Scenario 4 - Regulated CO2 wo GEC
JEA Energy Mix

GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,414.526	11,082.067	10,947.369	11,147.252	12,811.829	13,297.184	13,324.039
Natural Gas	2,853.119	3,855.870	4,566.629	5,092.151	4,811.770	5,295.103	5,444.182	3,393.477	2,436.832	2,941.825
Oil	3.278	2.667	5.043	3.380	0.662	1.026	1.619	0.225	0.182	0.248
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	70.585	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	0.161	0.244	0.404	0.046	0.034	0.055
Total	14,990.415	15,286.546	15,575.615	15,921.914	16,234.070	16,583.152	16,932.868	17,325.318	17,635.089	17,985.887

Hearing Exhibit - 00000354

Response to Interrogatory # 70

Scenario 4 - High Fuel & Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,414.525	11,082.073	10,947.360	11,147.350	12,811.873	13,297.124	13,324.020
Natural Gas	2,853.119	3,855.870	4,566.629	5,066.581	4,807.942	5,292.253	5,441.265	3,392.994	2,436.571	2,941.403
Oil	3.278	2.667	5.043	3.379	3.376	3.140	3.709	0.547	0.426	0.574
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	96.156	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	1.266	0.988	1.133	0.163	0.113	0.167
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.067	16,583.151	16,932.867	17,325.318	17,635.089	17,985.886

Hearing Exhibit - 00000355

Response to Interrogatory # 70

Scenario 4 - High Fuel & Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,229.311	10,586.973	10,912.818	10,414.525	11,082.067	10,947.329	11,147.252	12,811.805	13,297.127	13,324.039
Natural Gas	2,853.119	3,855.870	4,566.629	5,066.581	4,811.770	5,295.143	5,444.182	3,393.501	2,436.887	2,941.825
Oil	3.278	2.667	5.043	3.379	0.662	1.026	1.619	0.225	0.185	0.248
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.565	0.348	0.000	96.156	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	1.027	0.725	1.330	0.843	0.161	0.244	0.404	0.046	0.034	0.055
Total	14,990.415	15,286.546	15,575.615	15,921.913	16,234.070	16,583.152	16,932.868	17,325.319	17,635.089	17,985.887

Hearing Exhibit - 00000356

Response to Interrogatory # 70

Scenario 4 - High Fuel, High Load, & Regulated CO2 w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,536.466	10,759.192	11,002.520	10,465.098	11,172.633	11,028.469	11,211.990	13,109.591	13,770.421	13,717.088
Natural Gas	3,870.255	5,035.974	5,851.611	5,773.316	6,155.893	6,676.737	6,868.476	4,611.462	3,506.174	4,118.207
Oil	6.972	6.305	11.010	4.462	1.317	1.232	2.095	0.309	0.234	0.316
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.013	1.210	0.000	746.918	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	2.262	1.790	3.219	1.094	0.432	0.337	0.596	0.088	0.055	0.081
Total	16,321.083	16,644.434	16,958.156	17,331.316	17,669.686	18,046.185	18,422.567	18,841.191	19,177.740	19,555.414

Hearing Exhibit - 00000357

Response to Interrogatory # 70

Scenario 4 - High Fuel, High Load, & Regulated CO2 wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,536.466	10,759.192	11,002.520	10,465.098	11,172.639	11,028.491	11,211.981	13,109.756	13,770.645	13,717.310
Natural Gas	3,870.255	5,035.974	5,851.611	5,773.316	6,155.664	6,675.139	6,868.261	4,611.269	3,505.913	4,117.919
Oil	6.972	6.305	11.010	4.462	1.560	2.503	2.352	0.349	0.278	0.387
Renewable	0.000	0.000	0.000	250.387	249.614	249.614	249.614	250.387	249.614	249.614
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	2.013	1.210	0.000	746.918	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	2.262	1.790	3.219	1.094	0.413	0.641	0.564	0.076	0.048	0.075
Total	16,321.083	16,644.434	16,958.156	17,331.316	17,669.686	18,046.184	18,422.569	18,841.191	19,177.740	19,555.413

Hearing Exhibit - 00000358

Response to Interrogatory # 70

Scenario 4 - Low Fuel & Low Load w GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,035.303	10,484.337	10,830.113	10,378.828	11,039.774	10,909.490	11,114.709	12,693.404	13,146.870	13,180.814
Natural Gas	2,332.720	3,229.912	3,906.539	4,466.157	4,112.885	4,575.274	4,700.986	2,764.834	1,865.997	2,333.245
Oil	1.469	1.117	2.242	1.627	1.397	1.401	2.111	0.313	0.228	0.319
Renewable	0.000	0.000	0.000	223.567	214.207	217.656	221.618	179.210	137.505	153.476
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.216	0.129	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.412	0.279	0.517	0.365	0.458	0.393	0.612	0.086	0.057	0.083
Total	14,273.235	14,555.737	14,829.207	15,160.586	15,458.516	15,794.010	16,129.832	16,507.202	16,801.898	17,138.044

Hearing Exhibit - 00000359

Response to Interrogatory # 70

Scenario 4 - Low Fuel & Low Load wo GEC										
JEA Energy Mix										
GWH	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coal	10,035.303	10,484.337	10,830.113	10,378.828	11,039.809	10,909.592	11,114.607	12,694.052	13,147.567	13,181.519
Natural Gas	2,332.720	3,229.912	3,906.539	4,466.157	4,112.261	4,573.308	4,699.827	2,764.028	1,865.149	2,332.343
Oil	1.469	1.117	2.242	1.627	1.925	2.898	3.183	0.434	0.345	0.463
Renewable	0.000	0.000	0.000	223.567	214.207	217.663	221.603	179.236	137.527	153.507
Purchased Power										
Coal PPA	1,813.320	750.168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gas PPA	0.216	0.129	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear PPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	779.312	1,561.446	1,460.027
Renewable PPA	89.796	89.796	89.796	90.042	89.796	89.796	89.796	90.042	89.796	10.080
Emergency Energy	0.412	0.279	0.517	0.365	0.518	0.753	0.818	0.097	0.071	0.106
Total	14,273.235	14,555.737	14,829.207	15,160.586	15,458.516	15,794.010	16,129.833	16,507.201	16,801.900	17,138.044

Hearing Exhibit - 00000360

71. **Please complete the following table (also provided in Excel format) in electronic (Excel) and hard copy below regarding the Residential Rate Impact of the GEC Combined Cycle Conversion Project in 2013 and the least cost alternative, for each scenario and case presented in Question 68, in $/1,200 kWh from 2012 through 2027.**

Year	Annual Total Revenue Requirements ($millions, Nominal $) with GEC Conversion in 2013	*Annual Total* Revenue Requirements ($millions, Nominal $) with Least Cost *Alternative*	Differential in Annual Total Revenue Requirements ($millions, Nominal $)	Projected Total Sales After DSM (GWh at the meter)	System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						

Response: Please refer to the attachment labeled *Response to Interrogatory No. 71*, which presents the requested data. Please note that the requested data has been provided for all combinations of cases and scenarios for which data has been provided in response to Interrogatory Nos. 33 and 67. As requested, data has also been provided in electronic (Excel) format.

Response to Interrogatory #71

	Scenario 1 Conventional - Reference Case					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	738	738	0	16,102	0.00	0.00
2013	746	747	-1	16,415	-0.01	-0.07
2014	791	807	-17	16,764	-0.10	-1.20
2015	825	831	-6	17,113	-0.04	-0.44
2016	810	813	-4	17,506	-0.02	-0.25
2017	837	839	-2	17,815	-0.01	-0.16
2018	882	885	-3	18,166	-0.02	-0.20
2019	935	939	-4	18,517	-0.02	-0.24
2020	988	993	-5	18,911	-0.03	-0.32
2021	998	1,002	-4	19,216	-0.02	-0.24
2022	1,092	1,101	-9	19,566	-0.04	-0.52
2023	1,155	1,138	18	19,917	0.09	1.06
2024	1,216	1,223	-7	20,318	-0.04	-0.43
2025	1,299	1,283	16	20,618	0.08	0.95
2026	1,383	1,384	-2	20,983	-0.01	-0.09
2027	1,472	1,474	-2	21,318	-0.01	-0.12

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000362

Response to Interrogatory #71

	Scenario 1 Conventional - High Fuel					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	773	773	0	16,102	0.00	0.00
2013	788	789	-1	16,415	0.00	-0.04
2014	842	860	-18	16,764	-0.11	-1.28
2015	889	897	-8	17,113	-0.05	-0.55
2016	860	865	-5	17,506	-0.03	-0.32
2017	878	881	-3	17,815	-0.02	-0.20
2018	930	934	-4	18,166	-0.02	-0.26
2019	989	994	-5	18,517	-0.03	-0.30
2020	1,049	1,055	-6	18,911	-0.03	-0.40
2021	1,060	1,064	-5	19,216	-0.03	-0.31
2022	1,161	1,172	-10	19,566	-0.05	-0.63
2023	1,225	1,209	16	19,917	0.08	0.96
2024	1,291	1,300	-9	20,318	-0.04	-0.52
2025	1,375	1,361	14	20,618	0.07	0.84
2026	1,473	1,476	-3	20,983	-0.02	-0.18
2027	1,590	1,594	-4	21,318	-0.02	-0.25

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000363

Response to Interrogatory #71

	Scenario 1 Conventional - Low Fuel					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	714	714	0	16,102	0.00	0.00
2013	717	718	-1	16,415	-0.01	-0.10
2014	753	769	-16	16,764	-0.09	-1.13
2015	774	779	-5	17,113	-0.03	-0.36
2016	767	770	-3	17,506	-0.02	-0.19
2017	803	805	-2	17,815	-0.01	-0.12
2018	840	843	-2	18,166	-0.01	-0.15
2019	890	892	-3	18,517	-0.01	-0.18
2020	937	941	-4	18,911	-0.02	-0.25
2021	948	951	-3	19,216	-0.02	-0.19
2022	1,026	1,033	-7	19,566	-0.03	-0.42
2023	1,091	1,072	19	19,917	0.09	1.14
2024	1,143	1,149	-6	20,318	-0.03	-0.34
2025	1,223	1,205	18	20,618	0.09	1.05
2026	1,295	1,295	0	20,983	0.00	0.01
2027	1,381	1,382	-1	21,318	0.00	-0.03

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000364

Response to Interrogatory #71

	Scenario 1 Conventional - High Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	869	869	0	17,509	0.00	0.00
2013	882	877	4	17,848	0.02	0.28
2014	929	924	6	18,223	0.03	0.37
2015	956	963	-7	18,600	-0.04	-0.44
2016	940	932	8	19,018	0.04	0.51
2017	969	956	13	19,355	0.06	0.78
2018	1,020	1,011	9	19,732	0.05	0.54
2019	1,079	1,074	5	20,109	0.03	0.32
2020	1,135	1,136	0	20,530	0.00	-0.02
2021	1,150	1,147	3	20,862	0.01	0.18
2022	1,270	1,284	-14	21,238	-0.06	-0.76
2023	1,322	1,329	-7	21,616	-0.03	-0.40
2024	1,413	1,425	-12	22,043	-0.05	-0.65
2025	1,480	1,496	-16	22,370	-0.07	-0.87
2026	1,588	1,606	-19	22,746	-0.08	-0.98
2027	1,671	1,695	-24	23,122	-0.10	-1.26

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000365

Response to Interrogatory #71

	Scenario 1 Conventional - Low Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	671	671	0	15,341	0.00	0.00
2013	671	691	-20	15,639	-0.13	-1.54
2014	715	730	-15	15,974	-0.09	-1.14
2015	747	752	-5	16,309	-0.03	-0.36
2016	740	742	-2	16,687	-0.01	-0.16
2017	768	769	-1	16,982	-0.01	-0.08
2018	809	810	-2	17,319	-0.01	-0.11
2019	858	860	-2	17,654	-0.01	-0.14
2020	906	909	-3	18,034	-0.02	-0.21
2021	916	917	-2	18,325	-0.01	-0.13
2022	1,002	1,008	-6	18,660	-0.03	-0.39
2023	1,037	1,041	-4	18,997	-0.02	-0.22
2024	1,117	1,116	1	19,383	0.01	0.08
2025	1,170	1,168	1	19,669	0.01	0.07
2026	1,269	1,269	1	20,004	0.00	0.03
2027	1,334	1,334	0	20,339	0.00	0.01

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000366

Response to Interrogatory #71

	Scenario 1 Conventional - High Capital Cost					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	738	738	0	16,102	0.00	0.00
2013	755	755	0	16,415	0.00	0.01
2014	802	819	-16	16,764	-0.10	-1.16
2015	838	842	-4	17,113	-0.02	-0.28
2016	823	824	-1	17,506	-0.01	-0.09
2017	851	850	0	17,815	0.00	0.00
2018	895	896	-1	18,166	0.00	-0.04
2019	949	950	-1	18,517	-0.01	-0.08
2020	1,002	1,004	-3	18,911	-0.01	-0.17
2021	1,012	1,013	-2	19,216	-0.01	-0.09
2022	1,106	1,112	-6	19,566	-0.03	-0.38
2023	1,173	1,149	24	19,917	0.12	1.46
2024	1,234	1,239	-5	20,318	-0.02	-0.29
2025	1,322	1,299	23	20,618	0.11	1.34
2026	1,405	1,403	1	20,983	0.01	0.08
2027	1,498	1,497	1	21,318	0.00	0.05

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000367

Response to Interrogatory #71

	Scenario 1 Conventional - High Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,443	1,443	0	16,102	0.00	0.00
2013	1,442	1,434	8	16,415	0.05	0.60
2014	1,552	1,576	-24	16,764	-0.14	-1.72
2015	1,666	1,689	-23	17,113	-0.14	-1.64
2016	1,789	1,811	-22	17,506	-0.13	-1.50
2017	1,906	1,926	-21	17,815	-0.12	-1.39
2018	2,068	2,088	-20	18,166	-0.11	-1.32
2019	2,247	2,268	-21	18,517	-0.11	-1.37
2020	2,439	2,464	-25	18,911	-0.13	-1.59
2021	2,633	2,657	-24	19,216	-0.12	-1.47
2022	2,889	2,923	-34	19,566	-0.17	-2.06
2023	3,129	3,167	-39	19,917	-0.19	-2.32
2024	3,424	3,458	-34	20,318	-0.17	-1.99
2025	3,678	3,726	-48	20,618	-0.23	-2.78
2026	3,990	4,054	-64	20,983	-0.31	-3.66
2027	4,340	4,427	-88	21,318	-0.41	-4.93

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000368

Response to Interrogatory #71

	Scenario 1 Conventional - Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	960	960	0	16,102	0.00	0.00
2013	1,001	1,001	0	16,415	0.00	-0.01
2014	1,070	1,089	-19	16,764	-0.11	-1.35
2015	1,137	1,145	-9	17,113	-0.05	-0.60
2016	1,174	1,179	-5	17,506	-0.03	-0.35
2017	1,237	1,240	-3	17,815	-0.02	-0.22
2018	1,326	1,331	-4	18,166	-0.02	-0.30
2019	1,426	1,432	-5	18,517	-0.03	-0.35
2020	1,529	1,537	-8	18,911	-0.04	-0.48
2021	1,611	1,618	-6	19,216	-0.03	-0.39
2022	1,755	1,769	-13	19,566	-0.07	-0.81
2023	1,915	1,879	36	19,917	0.18	2.19
2024	2,055	2,049	7	20,318	0.03	0.39
2025	2,192	2,190	2	20,618	0.01	0.13
2026	2,351	2,374	-23	20,983	-0.11	-1.33
2027	2,539	2,571	-32	21,318	-0.15	-1.79

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000369

Response to Interrogatory #71

	Scenario 1 Conventional - High Fuel Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,002	1,002	0	16,102	0.00	0.00
2013	1,053	1,052	0	16,415	0.00	0.03
2014	1,132	1,152	-20	16,764	-0.12	-1.46
2015	1,216	1,226	-10	17,113	-0.06	-0.73
2016	1,240	1,246	-6	17,506	-0.04	-0.43
2017	1,295	1,299	-4	17,815	-0.02	-0.28
2018	1,396	1,402	-6	18,166	-0.03	-0.37
2019	1,506	1,513	-7	18,517	-0.04	-0.44
2020	1,622	1,631	-9	18,911	-0.05	-0.60
2021	1,711	1,719	-8	19,216	-0.04	-0.49
2022	1,877	1,893	-16	19,566	-0.08	-0.97
2023	2,043	2,013	31	19,917	0.15	1.84
2024	2,207	2,218	-12	20,318	-0.06	-0.69
2025	2,367	2,379	-12	20,618	-0.06	-0.71
2026	2,566	2,581	-15	20,983	-0.07	-0.87
2027	2,805	2,808	-4	21,318	-0.02	-0.20

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000370

Response to Interrogatory #71

	Scenario 1 Conventional - High Fuel High Load Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,139	1,139	0	17,509	0.00	0.00
2013	1,206	1,202	4	17,848	0.02	0.26
2014	1,292	1,311	-18	18,223	-0.10	-1.20
2015	1,374	1,394	-20	18,600	-0.11	-1.29
2016	1,403	1,404	-1	19,018	-0.01	-0.07
2017	1,464	1,459	5	19,355	0.03	0.32
2018	1,574	1,574	-1	19,732	0.00	-0.04
2019	1,692	1,699	-6	20,109	-0.03	-0.37
2020	1,814	1,830	-15	20,530	-0.08	-0.90
2021	1,913	1,924	-11	20,862	-0.05	-0.66
2022	2,104	2,138	-34	21,238	-0.16	-1.91
2023	2,248	2,277	-30	21,616	-0.14	-1.65
2024	2,451	2,459	-8	22,043	-0.04	-0.43
2025	2,627	2,652	-25	22,370	-0.11	-1.35
2026	2,863	2,873	-10	22,746	-0.04	-0.53
2027	3,117	3,142	-25	23,122	-0.11	-1.31

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000371

Response to Interrogatory #71

	Scenario 1 Conventional - Low Fuel Low Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	648	648	0	15,341	0.00	0.00
2013	646	646	0	15,639	0.00	0.00
2014	682	700	-17	15,974	-0.11	-1.31
2015	703	709	-6	16,309	-0.04	-0.43
2016	703	695	9	16,687	0.05	0.63
2017	740	727	14	16,982	0.08	0.96
2018	774	763	11	17,319	0.06	0.73
2019	819	812	8	17,654	0.04	0.52
2020	862	859	3	18,034	0.02	0.22
2021	872	866	6	18,325	0.04	0.42
2022	945	953	-8	18,660	-0.04	-0.53
2023	981	1,000	-18	18,997	-0.10	-1.14
2024	1,054	1,051	3	19,383	0.01	0.16
2025	1,104	1,129	-25	19,669	-0.13	-1.51
2026	1,194	1,197	-3	20,004	-0.02	-0.19
2027	1,256	1,281	-25	20,339	-0.12	-1.50

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000372

Response to Interrogatory #71

	Scenario 2 Renewables - Reference Case					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	759	759	0	16,102	0.00	0.00
2013	769	771	-2	16,415	-0.01	-0.12
2014	814	812	2	16,764	0.01	0.16
2015	849	850	-1	17,113	0.00	-0.06
2016	836	836	1	17,506	0.00	0.04
2017	865	864	1	17,815	0.01	0.09
2018	910	909	1	18,166	0.00	0.06
2019	962	962	1	18,517	0.00	0.04
2020	1,015	1,015	0	18,911	0.00	-0.02
2021	1,026	1,025	1	19,216	0.00	0.03
2022	1,118	1,120	-2	19,566	-0.01	-0.15
2023	1,158	1,176	-18	19,917	-0.09	-1.10
2024	1,237	1,237	0	20,318	0.00	-0.02
2025	1,319	1,313	6	20,618	0.03	0.32
2026	1,401	1,420	-19	20,983	-0.09	-1.11
2027	1,490	1,490	-1	21,318	0.00	-0.04

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000373

Response to Interrogatory #71

	Scenario 2 Renewables - High Fuel					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	791	791	0	16,102	0.00	0.00
2013	809	810	-1	16,415	-0.01	-0.09
2014	863	862	1	16,764	0.01	0.07
2015	911	913	-2	17,113	-0.01	-0.14
2016	885	885	0	17,506	0.00	-0.01
2017	904	903	1	17,815	0.00	0.05
2018	956	955	0	18,166	0.00	0.01
2019	1,014	1,014	0	18,517	0.00	-0.01
2020	1,073	1,074	-1	18,911	-0.01	-0.08
2021	1,084	1,085	0	19,216	0.00	-0.02
2022	1,184	1,188	-4	19,566	-0.02	-0.24
2023	1,225	1,244	-19	19,917	-0.10	-1.15
2024	1,308	1,310	-2	20,318	-0.01	-0.09
2025	1,391	1,387	4	20,618	0.02	0.26
2026	1,487	1,508	-21	20,983	-0.10	-1.18
2027	1,603	1,606	-3	21,318	-0.01	-0.16

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000374

Response to Interrogatory #71

	Scenario 2 Renewables - Low Fuel					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	736	736	0	16,102	0.00	0.00
2013	741	743	-2	16,415	-0.01	-0.15
2014	778	775	3	16,764	0.02	0.22
2015	800	800	0	17,113	0.00	0.00
2016	796	795	1	17,506	0.01	0.08
2017	833	831	2	17,815	0.01	0.12
2018	870	869	1	18,166	0.01	0.10
2019	919	918	1	18,517	0.01	0.08
2020	966	965	1	18,911	0.00	0.04
2021	977	976	1	19,216	0.01	0.08
2022	1,054	1,056	-1	19,566	-0.01	-0.07
2023	1,096	1,113	-18	19,917	-0.09	-1.06
2024	1,167	1,166	1	20,318	0.00	0.04
2025	1,246	1,240	7	20,618	0.03	0.38
2026	1,317	1,335	-18	20,983	-0.09	-1.05
2027	1,403	1,402	1	21,318	0.00	0.04

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000375

Response to Interrogatory #71

	Scenario 2 Renewables - High Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	887	887	0	17,509	0.00	0.00
2013	900	890	10	17,848	0.06	0.68
2014	945	955	-10	18,223	-0.05	-0.65
2015	972	982	-10	18,600	-0.05	-0.64
2016	946	953	-7	19,018	-0.04	-0.46
2017	972	978	-6	19,355	-0.03	-0.37
2018	1,026	1,033	-7	19,732	-0.04	-0.42
2019	1,088	1,095	-7	20,109	-0.04	-0.44
2020	1,149	1,157	-8	20,530	-0.04	-0.47
2021	1,161	1,169	-7	20,862	-0.03	-0.41
2022	1,292	1,304	-12	21,238	-0.06	-0.68
2023	1,341	1,350	-10	21,616	-0.04	-0.54
2024	1,450	1,446	4	22,043	0.02	0.21
2025	1,516	1,516	0	22,370	0.00	-0.01
2026	1,605	1,626	-21	22,746	-0.09	-1.12
2027	1,687	1,714	-27	23,122	-0.12	-1.39

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000376

Response to Interrogatory #71

	Scenario 2 Renewables - Low Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	691	691	0	15,341	0.00	0.00
2013	695	701	-6	15,639	-0.04	-0.48
2014	740	746	-6	15,974	-0.04	-0.48
2015	761	777	-16	16,309	-0.10	-1.17
2016	757	756	1	16,687	0.00	0.04
2017	786	780	6	16,982	0.04	0.44
2018	827	824	2	17,319	0.01	0.17
2019	875	876	-1	17,654	0.00	-0.05
2020	923	929	-6	18,034	-0.03	-0.42
2021	933	936	-2	18,325	-0.01	-0.15
2022	1,018	1,038	-20	18,660	-0.11	-1.30
2023	1,054	1,081	-28	18,997	-0.15	-1.74
2024	1,133	1,141	-8	19,383	-0.04	-0.49
2025	1,185	1,221	-36	19,669	-0.18	-2.17
2026	1,284	1,299	-15	20,004	-0.08	-0.91
2027	1,349	1,386	-37	20,339	-0.18	-2.19

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000377

Response to Interrogatory #71

	Scenario 2 Renewables - High Capital Cost					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	764	764	0	16,102	0.00	0.00
2013	784	784	0	16,415	0.00	-0.04
2014	831	825	6	16,764	0.04	0.44
2015	868	866	2	17,113	0.01	0.15
2016	855	852	3	17,506	0.02	0.24
2017	884	880	4	17,815	0.02	0.29
2018	929	925	4	18,166	0.02	0.25
2019	981	978	4	18,517	0.02	0.23
2020	1,034	1,031	3	18,911	0.01	0.17
2021	1,045	1,042	3	19,216	0.02	0.22
2022	1,137	1,136	0	19,566	0.00	0.03
2023	1,177	1,196	-19	19,917	-0.09	-1.13
2024	1,259	1,257	3	20,318	0.01	0.16
2025	1,346	1,337	9	20,618	0.05	0.55
2026	1,428	1,448	-20	20,983	-0.10	-1.16
2027	1,521	1,518	2	21,318	0.01	0.13

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000378

Response to Interrogatory #71

	Scenario 2 Renewables - High Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,455	1,455	0	16,102	0.00	0.00
2013	1,459	1,450	10	16,415	0.06	0.71
2014	1,569	1,560	9	16,764	0.05	0.63
2015	1,682	1,687	-5	17,113	-0.03	-0.35
2016	1,806	1,799	7	17,506	0.04	0.50
2017	1,922	1,910	12	17,815	0.07	0.83
2018	2,082	2,075	7	18,166	0.04	0.45
2019	2,260	2,261	-1	18,517	-0.01	-0.09
2020	2,449	2,465	-15	18,911	-0.08	-0.98
2021	2,641	2,658	-17	19,216	-0.09	-1.07
2022	2,894	2,947	-53	19,566	-0.27	-3.26
2023	3,131	3,190	-60	19,917	-0.30	-3.61
2024	3,412	3,477	-65	20,318	-0.32	-3.81
2025	3,676	3,745	-69	20,618	-0.33	-4.02
2026	3,984	4,067	-83	20,983	-0.40	-4.74
2027	4,330	4,435	-105	21,318	-0.49	-5.92

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000379

Response to Interrogatory #71

	Scenario 2 Renewables - Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	978	978	0	16,102	0.00	0.00
2013	1,022	1,023	-1	16,415	-0.01	-0.07
2014	1,091	1,091	0	16,764	0.00	0.01
2015	1,158	1,160	-2	17,113	-0.01	-0.15
2016	1,198	1,198	0	17,506	0.00	-0.02
2017	1,262	1,261	1	17,815	0.00	0.05
2018	1,350	1,350	0	18,166	0.00	0.01
2019	1,449	1,450	0	18,517	0.00	-0.03
2020	1,551	1,553	-2	18,911	-0.01	-0.11
2021	1,634	1,635	-1	19,216	0.00	-0.05
2022	1,775	1,781	-5	19,566	-0.03	-0.33
2023	1,891	1,909	-18	19,917	-0.09	-1.11
2024	2,052	2,053	-1	20,318	0.00	-0.06
2025	2,214	2,209	5	20,618	0.03	0.30
2026	2,378	2,400	-22	20,983	-0.10	-1.23
2027	2,576	2,578	-2	21,318	-0.01	-0.13

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000380

Response to Interrogatory #71

	Scenario 2 Renewables - High Fuel Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,018	1,018	0	16,102	0.00	0.00
2013	1,071	1,071	0	16,415	0.00	-0.03
2014	1,151	1,152	-1	16,764	-0.01	-0.09
2015	1,234	1,237	-4	17,113	-0.02	-0.25
2016	1,260	1,262	-1	17,506	-0.01	-0.08
2017	1,316	1,316	0	17,815	0.00	0.00
2018	1,417	1,417	-1	18,166	0.00	-0.06
2019	1,525	1,527	-2	18,517	-0.01	-0.10
2020	1,640	1,643	-3	18,911	-0.02	-0.20
2021	1,730	1,732	-2	19,216	-0.01	-0.13
2022	1,893	1,900	-7	19,566	-0.04	-0.45
2023	2,017	2,038	-21	19,917	-0.10	-1.24
2024	2,199	2,204	-5	20,318	-0.02	-0.28
2025	2,385	2,382	2	20,618	0.01	0.13
2026	2,588	2,612	-23	20,983	-0.11	-1.34
2027	2,833	2,840	-8	21,318	-0.04	-0.44

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000381

Response to Interrogatory #71

	Scenario 2 Renewables - High Fuel High Load Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,156	1,156	0	17,509	0.00	0.00
2013	1,229	1,217	12	17,848	0.07	0.81
2014	1,311	1,325	-14	18,223	-0.08	-0.94
2015	1,393	1,408	-15	18,600	-0.08	-0.96
2016	1,408	1,419	-11	19,018	-0.06	-0.69
2017	1,466	1,475	-9	19,355	-0.05	-0.55
2018	1,579	1,590	-11	19,732	-0.05	-0.65
2019	1,701	1,713	-12	20,109	-0.06	-0.70
2020	1,830	1,844	-13	20,530	-0.06	-0.78
2021	1,926	1,938	-12	20,862	-0.06	-0.70
2022	2,131	2,150	-19	21,238	-0.09	-1.09
2023	2,274	2,290	-16	21,616	-0.07	-0.87
2024	2,452	2,470	-18	22,043	-0.08	-0.95
2025	2,644	2,662	-17	22,370	-0.08	-0.93
2026	2,861	2,881	-20	22,746	-0.09	-1.04
2027	3,127	3,148	-22	23,122	-0.09	-1.12

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000382

Response to Interrogatory #71

	Scenario 2 Renewables - Low Fuel Low Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	670	670	0	15,341	0.00	0.00
2013	671	675	-5	15,639	-0.03	-0.37
2014	709	712	-3	15,974	-0.02	-0.22
2015	720	731	-12	16,309	-0.07	-0.87
2016	722	719	3	16,687	0.02	0.23
2017	760	752	8	16,982	0.05	0.57
2018	794	789	5	17,319	0.03	0.34
2019	839	837	2	17,654	0.01	0.13
2020	881	884	-3	18,034	-0.02	-0.18
2021	892	891	1	18,325	0.00	0.04
2022	963	978	-15	18,660	-0.08	-0.94
2023	1,000	1,024	-24	18,997	-0.13	-1.51
2024	1,073	1,076	-3	19,383	-0.02	-0.21
2025	1,123	1,153	-31	19,669	-0.16	-1.88
2026	1,212	1,221	-9	20,004	-0.05	-0.57
2027	1,273	1,305	-32	20,339	-0.16	-1.86

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000383

Response to Interrogatory #71

	Scenario 3 DSM - Reference Case					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	729	729	0	15,949	0.00	0.00
2013	729	738	-10	16,261	-0.06	-0.72
2014	770	776	-6	16,612	-0.04	-0.44
2015	794	799	-6	16,962	-0.03	-0.42
2016	780	783	-3	17,354	-0.02	-0.23
2017	808	810	-2	17,663	-0.01	-0.15
2018	852	855	-3	18,013	-0.02	-0.19
2019	905	908	-3	18,364	-0.02	-0.22
2020	956	961	-5	18,760	-0.02	-0.30
2021	967	971	-3	19,065	-0.02	-0.22
2022	1,059	1,067	-8	19,415	-0.04	-0.48
2023	1,123	1,105	18	19,766	0.09	1.09
2024	1,183	1,189	-7	20,165	-0.03	-0.40
2025	1,265	1,248	17	20,467	0.08	0.99
2026	1,347	1,348	-1	20,817	-0.01	-0.07
2027	1,435	1,437	-2	21,167	-0.01	-0.10

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000384

Response to Interrogatory #71

	Scenario 3 DSM - High Fuel					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	766	766	0	15,949	0.00	0.00
2013	769	778	-9	16,261	-0.06	-0.68
2014	820	827	-7	16,612	-0.04	-0.52
2015	857	864	-7	16,962	-0.04	-0.52
2016	828	833	-4	17,354	-0.02	-0.29
2017	847	850	-3	17,663	-0.02	-0.19
2018	899	902	-4	18,013	-0.02	-0.25
2019	957	961	-4	18,364	-0.02	-0.28
2020	1,016	1,021	-6	18,760	-0.03	-0.37
2021	1,027	1,031	-4	19,065	-0.02	-0.28
2022	1,127	1,136	-9	19,415	-0.05	-0.57
2023	1,190	1,174	16	19,766	0.08	1.00
2024	1,255	1,264	-8	20,165	-0.04	-0.49
2025	1,338	1,323	15	20,467	0.07	0.89
2026	1,435	1,438	-3	20,817	-0.01	-0.16
2027	1,550	1,554	-4	21,167	-0.02	-0.22

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000385

Response to Interrogatory #71

	Scenario 3 DSM - Low Fuel					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	704	704	0	15,949	0.00	0.00
2013	700	710	-10	16,261	-0.06	-0.74
2014	734	739	-5	16,612	-0.03	-0.37
2015	744	749	-5	16,962	-0.03	-0.34
2016	738	741	-3	17,354	-0.01	-0.18
2017	775	777	-2	17,663	-0.01	-0.11
2018	812	814	-2	18,013	-0.01	-0.15
2019	861	863	-3	18,364	-0.01	-0.16
2020	907	910	-4	18,760	-0.02	-0.23
2021	918	921	-3	19,065	-0.01	-0.17
2022	995	1,001	-6	19,415	-0.03	-0.39
2023	1,059	1,040	19	19,766	0.10	1.16
2024	1,112	1,117	-5	20,165	-0.03	-0.32
2025	1,191	1,172	19	20,467	0.09	1.09
2026	1,261	1,261	0	20,817	0.00	0.02
2027	1,347	1,347	0	21,167	0.00	-0.01

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000386

Response to Interrogatory #71

	Scenario 3 DSM - High Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	853	853	0	17,357	0.00	0.00
2013	858	844	14	17,696	0.08	0.94
2014	899	905	-6	18,073	-0.03	-0.39
2015	927	933	-6	18,450	-0.03	-0.38
2016	899	900	-1	18,869	-0.01	-0.09
2017	925	924	1	19,205	0.00	0.04
2018	978	978	0	19,582	0.00	-0.03
2019	1,038	1,040	-2	19,959	-0.01	-0.09
2020	1,099	1,102	-3	20,381	-0.02	-0.18
2021	1,111	1,112	-1	20,713	-0.01	-0.07
2022	1,241	1,249	-8	21,090	-0.04	-0.47
2023	1,289	1,294	-5	21,467	-0.02	-0.28
2024	1,381	1,387	-7	21,893	-0.03	-0.36
2025	1,448	1,457	-8	22,221	-0.04	-0.45
2026	1,557	1,550	7	22,583	0.03	0.38
2027	1,645	1,653	-8	22,975	-0.03	-0.41

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000387

Response to Interrogatory #71

	Scenario 3 DSM - Low Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	665	665	0	15,188	0.00	0.00
2013	662	650	11	15,486	0.07	0.87
2014	703	704	-1	15,822	0.00	-0.04
2015	725	725	0	16,159	0.00	-0.03
2016	718	703	15	16,537	0.09	1.10
2017	747	726	20	16,831	0.12	1.46
2018	787	770	17	17,167	0.10	1.17
2019	835	821	14	17,502	0.08	0.96
2020	883	874	9	17,883	0.05	0.60
2021	893	880	13	18,174	0.07	0.83
2022	977	982	-5	18,510	-0.03	-0.30
2023	1,013	1,026	-12	18,846	-0.07	-0.79
2024	1,068	1,084	-16	19,231	-0.08	-0.99
2025	1,144	1,163	-19	19,518	-0.10	-1.16
2026	1,217	1,240	-23	19,838	-0.12	-1.40
2027	1,296	1,328	-32	20,189	-0.16	-1.88

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000388

Response to Interrogatory #71

	Scenario 3 DSM - High Capital Cost					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	731	731	0	15,949	0.00	0.00
2013	725	747	-22	16,261	-0.13	-1.59
2014	769	784	-15	16,612	-0.09	-1.10
2015	804	807	-3	16,962	-0.02	-0.21
2016	790	791	0	17,354	0.00	-0.03
2017	818	818	1	17,663	0.00	0.05
2018	863	863	0	18,013	0.00	0.00
2019	915	916	0	18,364	0.00	-0.03
2020	967	969	-2	18,760	-0.01	-0.11
2021	978	978	-1	19,065	0.00	-0.04
2022	1,070	1,075	-5	19,415	-0.03	-0.30
2023	1,138	1,113	25	19,766	0.13	1.52
2024	1,197	1,201	-4	20,165	-0.02	-0.24
2025	1,284	1,260	24	20,467	0.12	1.42
2026	1,366	1,364	2	20,817	0.01	0.13
2027	1,459	1,457	2	21,167	0.01	0.10

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000389

Response to Interrogatory #71

	Scenario 3 DSM - High Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,448	1,448	0	15,949	0.00	0.00
2013	1,402	1,420	-17	16,261	-0.11	-1.27
2014	1,506	1,527	-21	16,612	-0.13	-1.52
2015	1,631	1,643	-11	16,962	-0.07	-0.79
2016	1,743	1,752	-8	17,354	-0.05	-0.57
2017	1,854	1,862	-8	17,663	-0.05	-0.55
2018	2,023	2,028	-5	18,013	-0.03	-0.34
2019	2,206	2,215	-9	18,364	-0.05	-0.58
2020	2,408	2,420	-12	18,760	-0.07	-0.79
2021	2,604	2,613	-9	19,065	-0.05	-0.56
2022	2,881	2,903	-22	19,415	-0.11	-1.37
2023	3,119	3,146	-27	19,766	-0.14	-1.63
2024	3,402	3,434	-33	20,165	-0.16	-1.94
2025	3,667	3,701	-34	20,467	-0.17	-2.00
2026	3,977	4,026	-49	20,817	-0.23	-2.80
2027	4,324	4,396	-72	21,167	-0.34	-4.07

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000390

Response to Interrogatory #71

	Scenario 3 DSM - Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	953	953	0	15,949	0.00	0.00
2013	982	991	-9	16,261	-0.06	-0.67
2014	1,048	1,056	-8	16,612	-0.05	-0.60
2015	1,104	1,112	-8	16,962	-0.05	-0.58
2016	1,142	1,146	-5	17,354	-0.03	-0.33
2017	1,205	1,208	-3	17,663	-0.02	-0.21
2018	1,294	1,298	-4	18,013	-0.02	-0.28
2019	1,393	1,398	-5	18,364	-0.03	-0.33
2020	1,494	1,502	-7	18,760	-0.04	-0.46
2021	1,576	1,582	-6	19,065	-0.03	-0.36
2022	1,719	1,731	-12	19,415	-0.06	-0.77
2023	1,879	1,842	38	19,766	0.19	2.28
2024	2,018	2,010	8	20,165	0.04	0.48
2025	2,154	2,150	4	20,467	0.02	0.24
2026	2,312	2,333	-21	20,817	-0.10	-1.24
2027	2,498	2,529	-30	21,167	-0.14	-1.73

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000391

Response to Interrogatory #71

	Scenario 3 DSM - High Fuel Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	999	999	0	15,949	0.00	0.00
2013	1,031	1,040	-9	16,261	-0.05	-0.63
2014	1,108	1,118	-10	16,612	-0.06	-0.70
2015	1,180	1,190	-10	16,962	-0.06	-0.69
2016	1,205	1,211	-6	17,354	-0.03	-0.40
2017	1,261	1,265	-4	17,663	-0.02	-0.27
2018	1,361	1,366	-5	18,013	-0.03	-0.36
2019	1,470	1,476	-6	18,364	-0.03	-0.41
2020	1,585	1,594	-9	18,760	-0.05	-0.57
2021	1,674	1,681	-7	19,065	-0.04	-0.45
2022	1,838	1,853	-15	19,415	-0.08	-0.91
2023	2,005	1,973	32	19,766	0.16	1.94
2024	2,166	2,177	-11	20,165	-0.06	-0.67
2025	2,325	2,337	-12	20,467	-0.06	-0.68
2026	2,523	2,537	-14	20,817	-0.07	-0.84
2027	2,759	2,762	-3	21,167	-0.01	-0.15

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000392

Response to Interrogatory #71

	Scenario 3 DSM - High Fuel High Load Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,137	1,137	0	17,357	0.00	0.00
2013	1,175	1,171	3	17,696	0.02	0.23
2014	1,259	1,277	-18	18,073	-0.10	-1.21
2015	1,339	1,359	-20	18,450	-0.11	-1.30
2016	1,369	1,367	2	18,869	0.01	0.14
2017	1,430	1,422	8	19,205	0.04	0.49
2018	1,538	1,536	3	19,582	0.01	0.17
2019	1,656	1,659	-4	19,959	-0.02	-0.22
2020	1,775	1,789	-14	20,381	-0.07	-0.82
2021	1,874	1,883	-9	20,713	-0.04	-0.53
2022	2,063	2,096	-33	21,090	-0.16	-1.90
2023	2,206	2,236	-29	21,467	-0.14	-1.64
2024	2,406	2,413	-7	21,893	-0.03	-0.39
2025	2,581	2,589	-8	22,221	-0.04	-0.44
2026	2,795	2,822	-27	22,583	-0.12	-1.43
2027	3,063	3,079	-16	22,975	-0.07	-0.82

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000393

Response to Interrogatory #71

	Scenario 3 DSM - Low Fuel Low Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	643	643	0	15,188	0.00	0.00
2013	637	624	13	15,486	0.08	0.99
2014	672	669	3	15,822	0.02	0.19
2015	682	678	4	16,159	0.02	0.27
2016	683	666	18	16,537	0.11	1.28
2017	720	698	22	16,831	0.13	1.58
2018	754	735	19	17,167	0.11	1.34
2019	799	782	17	17,502	0.10	1.14
2020	841	828	12	17,883	0.07	0.83
2021	851	836	15	18,174	0.08	1.02
2022	922	921	1	18,510	0.00	0.06
2023	959	968	-9	18,846	-0.05	-0.57
2024	1,007	1,019	-12	19,231	-0.06	-0.74
2025	1,081	1,095	-14	19,518	-0.07	-0.88
2026	1,144	1,161	-18	19,838	-0.09	-1.08
2027	1,220	1,246	-26	20,189	-0.13	-1.57

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000394

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - Reference Case					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	749	749	0	15,949	0.00	0.00
2013	742	762	-20	16,261	-0.12	-1.48
2014	784	800	-16	16,612	-0.09	-1.12
2015	818	823	-5	16,962	-0.03	-0.36
2016	807	810	-3	17,354	-0.01	-0.18
2017	836	838	-2	17,663	-0.01	-0.11
2018	880	882	-2	18,013	-0.01	-0.15
2019	932	935	-3	18,364	-0.01	-0.17
2020	984	988	-4	18,760	-0.02	-0.26
2021	995	998	-3	19,065	-0.01	-0.17
2022	1,085	1,092	-7	19,415	-0.04	-0.42
2023	1,126	1,131	-5	19,766	-0.02	-0.28
2024	1,204	1,215	-11	20,165	-0.05	-0.64
2025	1,285	1,272	13	20,467	0.06	0.74
2026	1,366	1,367	-1	20,817	-0.01	-0.08
2027	1,454	1,456	-1	21,167	-0.01	-0.07

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000395

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - High Fuel					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	784	784	0	15,949	0.00	0.00
2013	780	800	-20	16,261	-0.12	-1.45
2014	832	848	-17	16,612	-0.10	-1.20
2015	879	885	-6	16,962	-0.04	-0.45
2016	853	857	-3	17,354	-0.02	-0.24
2017	874	876	-2	17,663	-0.01	-0.15
2018	924	927	-3	18,013	-0.02	-0.20
2019	982	986	-3	18,364	-0.02	-0.23
2020	1,040	1,045	-5	18,760	-0.03	-0.33
2021	1,052	1,056	-4	19,065	-0.02	-0.23
2022	1,150	1,158	-8	19,415	-0.04	-0.51
2023	1,191	1,197	-6	19,766	-0.03	-0.34
2024	1,274	1,286	-12	20,165	-0.06	-0.73
2025	1,356	1,345	11	20,467	0.05	0.64
2026	1,450	1,454	-3	20,817	-0.02	-0.20
2027	1,565	1,569	-4	21,167	-0.02	-0.22

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000396

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - Low Fuel					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	725	725	0	15,949	0.00	0.00
2013	715	735	-20	16,261	-0.13	-1.51
2014	749	764	-15	16,612	-0.09	-1.07
2015	771	775	-4	16,962	-0.02	-0.29
2016	768	770	-2	17,354	-0.01	-0.13
2017	806	807	-1	17,663	-0.01	-0.07
2018	842	844	-2	18,013	-0.01	-0.10
2019	890	892	-2	18,364	-0.01	-0.12
2020	936	939	-3	18,760	-0.02	-0.19
2021	948	950	-2	19,065	-0.01	-0.12
2022	1,024	1,029	-5	19,415	-0.03	-0.33
2023	1,065	1,069	-3	19,766	-0.02	-0.21
2024	1,136	1,145	-9	20,165	-0.05	-0.56
2025	1,214	1,200	14	20,467	0.07	0.84
2026	1,284	1,283	1	20,817	0.00	0.03
2027	1,369	1,369	1	21,167	0.00	0.04

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000397

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - High Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	870	870	0	17,357	0.00	0.00
2013	876	866	10	17,696	0.06	0.71
2014	918	908	10	18,073	0.06	0.68
2015	946	949	-2	18,450	-0.01	-0.16
2016	920	921	-1	18,869	0.00	-0.05
2017	947	947	0	19,205	0.00	0.01
2018	1,000	1,000	-1	19,582	0.00	-0.03
2019	1,060	1,061	-1	19,959	0.00	-0.04
2020	1,120	1,121	-1	20,381	-0.01	-0.07
2021	1,133	1,133	0	20,713	0.00	-0.02
2022	1,261	1,266	-4	21,090	-0.02	-0.24
2023	1,310	1,311	-2	21,467	-0.01	-0.09
2024	1,401	1,404	-2	21,893	-0.01	-0.13
2025	1,468	1,472	-3	22,221	-0.02	-0.19
2026	1,576	1,580	-4	22,583	-0.02	-0.20
2027	1,664	1,668	-5	22,975	-0.02	-0.24

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000398

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - Low Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	686	686	0	15,188	0.00	0.00
2013	686	673	13	15,486	0.08	0.99
2014	728	714	14	15,822	0.09	1.04
2015	750	746	4	16,159	0.03	0.31
2016	746	726	20	16,537	0.12	1.46
2017	776	750	26	16,831	0.15	1.83
2018	816	794	22	17,167	0.13	1.54
2019	864	845	19	17,502	0.11	1.31
2020	910	897	14	17,883	0.08	0.91
2021	921	904	18	18,174	0.10	1.16
2022	1,004	1,005	0	18,510	0.00	-0.03
2023	1,041	1,048	-8	18,846	-0.04	-0.48
2024	1,095	1,106	-11	19,231	-0.06	-0.70
2025	1,146	1,185	-39	19,518	-0.20	-2.37
2026	1,243	1,261	-18	19,838	-0.09	-1.10
2027	1,308	1,349	-40	20,189	-0.20	-2.39

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000399

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - High Capital Cost					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	756	756	0	15,949	0.00	0.00
2013	753	776	-22	16,261	-0.14	-1.64
2014	798	813	-15	16,612	-0.09	-1.08
2015	834	836	-3	16,962	-0.02	-0.19
2016	823	823	0	17,354	0.00	-0.01
2017	852	851	1	17,663	0.00	0.06
2018	896	896	0	18,013	0.00	0.02
2019	948	948	0	18,364	0.00	-0.01
2020	999	1,001	-2	18,760	-0.01	-0.10
2021	1,011	1,011	0	19,065	0.00	-0.02
2022	1,101	1,106	-4	19,415	-0.02	-0.27
2023	1,142	1,144	-2	19,766	-0.01	-0.13
2024	1,223	1,232	-9	20,165	-0.05	-0.54
2025	1,309	1,290	19	20,467	0.09	1.10
2026	1,390	1,387	2	20,817	0.01	0.13
2027	1,482	1,480	3	21,167	0.01	0.14

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000400

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - High Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,458	1,458	0	15,949	0.00	0.00
2013	1,417	1,436	-18	16,261	-0.11	-1.34
2014	1,521	1,542	-20	16,612	-0.12	-1.47
2015	1,646	1,656	-10	16,962	-0.06	-0.72
2016	1,759	1,766	-8	17,354	-0.04	-0.52
2017	1,869	1,877	-7	17,663	-0.04	-0.51
2018	2,036	2,041	-5	18,013	-0.03	-0.31
2019	2,217	2,225	-8	18,364	-0.04	-0.52
2020	2,416	2,428	-11	18,760	-0.06	-0.73
2021	2,611	2,619	-8	19,065	-0.04	-0.51
2022	2,881	2,904	-24	19,415	-0.12	-1.46
2023	3,115	3,138	-23	19,766	-0.12	-1.40
2024	3,403	3,434	-32	20,165	-0.16	-1.89
2025	3,666	3,700	-34	20,467	-0.16	-1.98
2026	3,973	4,021	-47	20,817	-0.23	-2.72
2027	4,316	4,386	-70	21,167	-0.33	-3.96

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000401

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	971	971	0	15,949	0.00	0.00
2013	993	1,012	-19	16,261	-0.12	-1.43
2014	1,059	1,077	-18	16,612	-0.11	-1.26
2015	1,126	1,133	-7	16,962	-0.04	-0.51
2016	1,166	1,170	-4	17,354	-0.02	-0.26
2017	1,231	1,233	-2	17,663	-0.01	-0.17
2018	1,318	1,322	-3	18,013	-0.02	-0.23
2019	1,416	1,421	-4	18,364	-0.02	-0.28
2020	1,517	1,524	-6	18,760	-0.03	-0.41
2021	1,599	1,604	-5	19,065	-0.03	-0.31
2022	1,739	1,751	-11	19,415	-0.06	-0.70
2023	1,855	1,862	-7	19,766	-0.04	-0.42
2024	2,041	2,017	24	20,165	0.12	1.41
2025	2,176	2,172	4	20,467	0.02	0.22
2026	2,332	2,350	-18	20,817	-0.09	-1.03
2027	2,504	2,545	-41	21,167	-0.19	-2.33

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000402

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - High Fuel Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,014	1,014	0	15,949	0.00	0.00
2013	1,040	1,059	-19	16,261	-0.12	-1.39
2014	1,117	1,136	-19	16,612	-0.11	-1.35
2015	1,199	1,208	-9	16,962	-0.05	-0.62
2016	1,227	1,232	-5	17,354	-0.03	-0.34
2017	1,283	1,286	-3	17,663	-0.02	-0.22
2018	1,382	1,387	-4	18,013	-0.02	-0.30
2019	1,490	1,495	-5	18,364	-0.03	-0.36
2020	1,603	1,611	-8	18,760	-0.04	-0.51
2021	1,693	1,699	-6	19,065	-0.03	-0.40
2022	1,854	1,867	-13	19,415	-0.07	-0.83
2023	1,978	1,988	-10	19,766	-0.05	-0.59
2024	2,184	2,166	18	20,165	0.09	1.07
2025	2,342	2,342	0	20,467	0.00	-0.03
2026	2,537	2,559	-22	20,817	-0.11	-1.27
2027	2,758	2,803	-45	21,167	-0.21	-2.54

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000403

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - High Fuel High Load Regulated CO2					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	1,149	1,149	0	17,357	0.00	0.00
2013	1,193	1,188	5	17,696	0.03	0.36
2014	1,278	1,274	4	18,073	0.02	0.24
2015	1,358	1,367	-9	18,450	-0.05	-0.62
2016	1,390	1,380	10	18,869	0.05	0.63
2017	1,451	1,437	14	19,205	0.07	0.89
2018	1,559	1,549	10	19,582	0.05	0.59
2019	1,675	1,670	5	19,959	0.02	0.27
2020	1,794	1,798	-4	20,381	-0.02	-0.25
2021	1,892	1,893	-1	20,713	0.00	-0.04
2022	2,056	2,104	-48	21,090	-0.23	-2.73
2023	2,223	2,245	-23	21,467	-0.11	-1.28
2024	2,397	2,421	-24	21,893	-0.11	-1.30
2025	2,595	2,612	-17	22,221	-0.08	-0.93
2026	2,807	2,825	-18	22,583	-0.08	-0.97
2027	3,059	3,092	-33	22,975	-0.14	-1.73

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000404

Response to Interrogatory #71

	Scenario 4 Renewables and DSM - Low Fuel Low Load					
	($000, 2008$)					
Year	Annual Total Incremental Costs w GEC Conversion in 2013 ($millions, Nominal $)	Annual Total Incremental Costs w/o GEC Conversion ($millions, Nominal $)	Differential in Annual Total Incremental Costs ($millions, Nominal $)	Projected Total Sales After DSM (GWh)	Differential System Average Electric Rates (cents/kWh)	Differential in Customer Bill of 1,200 kWh ($)
2012	665	665	0	15,188	0.00	0.00
2013	662	648	14	15,486	0.09	1.10
2014	698	681	17	15,822	0.11	1.29
2015	709	701	8	16,159	0.05	0.61
2016	713	690	23	16,537	0.14	1.64
2017	751	724	27	16,831	0.16	1.94
2018	784	760	24	17,167	0.14	1.69
2019	829	807	22	17,502	0.12	1.48
2020	870	854	17	17,883	0.09	1.14
2021	882	861	20	18,174	0.11	1.34
2022	952	946	5	18,510	0.03	0.34
2023	989	993	-4	18,846	-0.02	-0.25
2024	1,036	1,044	-7	19,231	-0.04	-0.44
2025	1,086	1,120	-34	19,518	-0.17	-2.09
2026	1,173	1,186	-13	19,838	-0.06	-0.77
2027	1,235	1,270	-35	20,189	-0.17	-2.09

Note: Data provided for Annual Total Incremental Costs does not include existing JEA embedded costs which are identical across all scenarios and cases. Annual Total Incremental Costs are representative of variable costs and incremental fixed costs to serve projected annual energy requirements.

Note: Negative values for differentials indicate the expansion plan including the GEC conversion in 2013 results in lower Annual Total Incremental Costs than expansion plan that does not include the GEC conversion.

Note: Differential System Average Electric Rates based on Differential Annual Total Incremental Costs and Projected Total Sales After DSM and have been rounded to two (2) decimal places.

Hearing Exhibit - 00000405

72. **Please refer to JEA's response to Staff Interrogatory 20. Does this response represent only residential energy sales, or does it include all retail sales by JEA? Also, please provide the data used to calculate the generation by gas percentage.**

Response: The data presented in response to Staff Interrogatory 20 reflects residential energy sales only. The generation by gas percentages presented in response to Staff Interrogatory 20 were pulled directly from the JEA Annual Reports for the years 2000, 2003, and 2007. Specifically, the generation by gas percentage for 1999 is shown in the 2000 Annual Report, the generation by gas percentages for 2001 and 2003 are shown in the 2003 Annual Report, and the generation by gas percentages for 2005 and 2007 are shown in the 2007 Annual Report. Please see the attached sheets labeled Response to Interrogatory No. 72 which presents the cover and appropriate pages from the annual reports.

74. Please refer to pages 3 through 6 of the testimony of Bradley Kushner and to Section 7.0 of the Need Application.

a. Did JEA consider any long-term fuel price projections other than the Annual Energy Outlook (AEO) 2008 projections?

Response: No. The GEC Need for Power Application only considers fuel prices based on the projections included in the AEO 2008. However, it should be noted that in addition to the AEO 2008 Reference Case, the GEC Need for Power Application considers the AEO 2008 High Price and Low Price cases, as well as three different sensitivity cases that considered the possible costs associated with potential regulation of carbon dioxide (CO_2) emissions impact on the assumed price of fuel. In total, six unique sets of fuel price projections were considered in the GEC Need for Power Application.

b. Did JEA compare the AEO 2008 fuel price projections to any other long-term fuel price projections? Please explain.

Response: Yes. Comparisons were made between the AEO 2008 Henry Hub natural gas price projections and the Henry Hub natural gas price projections included in AEO 2007 as well as Florida Power & Light's West County Unit 3 Need for Power Application (Docket No. 080203). Additionally, comparisons were made between the projected delivered prices of natural gas for the electric power sector included in the AEO 2008 and AEO 2007.

c. If yes to above, please identify and describe the other fuel price projections considered by JEA.

Response: Please see response to Interrogatory 74b.

d. Why are the AEO 2008 fuel price projections reasonable for use in this need application?

Response: AEO 2008 fuel price projections are reasonable for use in the GEC Need for Power Application as they were developed by the US Energy Information Administration (EIA) using a fully integrated model which balances overall supply and demand in developing fuel price projections for the US as a whole, as well as specific geographic regions. The methodology used by the US EIA to develop the AEO 2008 is similar to that used by EIA throughout recent years, including the AEO 2007. Similar to the manner in which the AEO 2008 fuel price projections were used in the GEC Need for Power Application, the AEO 2007 fuel price projections were used as the basis of the fuel price projections considered in Florida Municipal Power Agency's Petition to Determine Need for Cane Island Power Park Unit 4 (Docket No. 080253). The Florida Public Service Commission issued its Final Order granting the petition for determination of need for Cane Island Power Park Unit 4 on August 8, 2008. In light of the Florida Public Service Commission's conclusions related to the appropriateness of using AEO 2007 in the Cane Island Unit 4 need determination docket, as well as the comparisons JEA made between AEO 2008 to AEO 2007 and other recent fuel price projections, JEA concluded that AEO 2008 was reasonable to use as the basis for the GEC Need for Power Application.

75. Please refer to page 4 of the testimony of James Myers, lines 1 through 8. Given the growth in unconventional natural gas production (shale and tight sands formations), is it still the expectation that LNG imports will increase from current levels? Please explain.

Response: The degree to which LNG imports increase from current levels is dependent upon various market factors that influence the overall balance of natural gas supply and demand. Depending on how such factors develop, it is possible that the growth in unconventional natural gas production may be sufficient such that a decrease in LNG imports develops. However, if

such circumstances were to develop, the overall balance of supply and demand would remain intact.

76. Please refer to Section 16.3 of the need application.

a. Given that JEA will receive natural gas from both Southern Natural Gas and FGT through SeaCoast Pipeline, what is the basis for the $1.28 firm natural gas transportation charge?

Response: The $1.28 per MBtu firm natural gas transportation charge is consistent with the rate used in the Florida Municipal Power Agency's Petition to Determine Need for Cane Island Power Park Unit 4 (Docket No. 080253). Please see the response to Interrogatory 76b for further explanation.

b. Why does JEA consider the $1.28 firm natural gas transportation charge reasonable and competitive?

Response: FGT is the largest natural gas transportation company in the State of Florida and is undergoing the largest natural gas pipeline expansion project in the State. JEA believes that FGT will continue to offer adequate natural gas transportation capacity to support future natural gas demands. As such, JEA believes that using the $1.28 per MBtu rate that had been used by FMPA in its recent determination of need filing to represent firm natural gas transportation charges for incremental capacity provided by FGT provides a reasonable estimate of a competitive rate for firm natural gas transportation service.

c. In considering the simple cycle combustion turbine alternative, why did JEA include the cost of gas transportation based on an interruptible tariff rate? Why did JEA not use a firm gas transportation rate in modeling the simple cycle alternative?

Response: JEA's projections of natural gas use indicated that, on a system-wide basis, additional firm natural gas transportation capacity would be required. JEA will increase its firm natural gas transportation capacity prior to the commercial operation of the GEC simple cycle combustion turbines. The evaluations presented in the GEC Need for Power Application assume that all natural gas generating alternatives (both existing and future units, including combined cycle and simple cycle configurations) would only incur a cost for interruptible natural gas if the system-wide limit of firm natural gas transportation capacity was exceeded. For purposes of modeling generating units added beyond GEC, simple cycle units are added using interruptible natural gas transportation and combined cycle units are added using firm natural gas transportation. In general, the operation of simple cycle units is less and does not justify additional firm natural gas transportation, while the operation of combined cycle units is generally greater, thus justifying additional firm natural gas transportation.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF DUVAL)

I hereby certify that on this 17th day of DECEMBER, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Donald C. Gilbert, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 30, 31, 42, 43, 44, 47, and 48 from STAFF'S THIRD SET OF INTERROGATORIES TO JEA (NOS. 30-81) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 17th day of December, 2008.

CATHY L. BARNWELL
Notary Public - State of Florida
My Commission Expires Sep 24, 2010
Commission # DD 556843
Bonded By National Notary Assn.

Notary Public
State of Florida, at large

My Commission Expires: 9-24-10

Cathy L Barnwell

AFFIDAVIT

STATE OF KANSAS)

COUNTY OF JOHNSON)

I hereby certify that on this 29th day of December, 2008, before me, an officer duly authorized Bradley E. Kushner, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 32, 41, 45, 46, 66, 72, 74, 76, 80, and 81 from STAFF'S THIRD SET OF INTERROGATORIES TO JEA (NOS. 30-81) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29th day of December, 2008.

Bradley E Kushner

Notary Public
State of Kansas, at large
Marsha M. Purinton
My Commission Expires:
1-30-2011

MARSHA M. PURINTON NOTARY PUBLIC STATE OF KANSAS

AFFIDAVIT

STATE OF KANSAS)

COUNTY OF JOHNSON)

I hereby certify that on this 22nd day of December, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Myron R. Rollins, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 35, 36, 37, 38, 39, 40, 50 from STAFF'S THIRD SET OF INTERROGATORIES TO JEA (NOS. 30-81) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

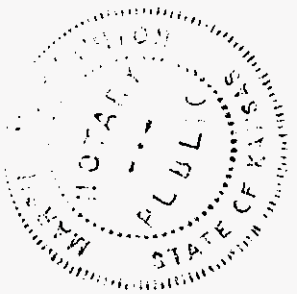
In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 22nd day of December, 2008.

Myron R. Rollins

Notary Public
State of Kansas, at large

My Commission Expires: 7-30-11

Marsha M. Purnton



AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Duval)

I hereby certify that on this 17th day of December, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Richard J. Vento, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 49, 51, 52, 53, 54, and 55 from STAFF'S THIRD SET OF INTERROGATORIES TO JEA (NOS. 30-81) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 17th day of December, 2008.

CATHY L. BARNWELL
Notary Public - State of Florida
My Commission Expires Sep 24, 2010
Commission # DD 556843
Bonded By National Notary Assn.

Notary Public
State of Florida, at large

My Commission Expires: 9-24-10

Cathy L. Barnwell

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Duval)

I hereby certify that on this 18th day of December, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John A. Worley, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 56, 57, 58, 59, 60, 61, 62, 63, 64, and 65 from STAFF'S THIRD SET OF INTERROGATORIES TO JEA (NOS. 30-81) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18th day of December, 2008.

Notary Public
State of Florida, at large
Shannon J. Sprinkle
My Commission Expires:

SHANNON J. SPRINKLE
MY COMMISSION EXPIRES
February 14, 2012
#DD 758875
Bonded thru
Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Duval)

I hereby certify that on this 19 day of December, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Mary Guyton-Baker, who is personally known to me, and he/she acknowledged before me that he/she provided the answer to interrogatory number 73 from STAFF'S THIRD SET OF INTERROGATORIES TO JEA (NOS. 30-81) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 19 day of December, 2008.

Notary Public
State of Florida, at large

My Commission Expires:

April 27, 2010

Peggy West

PEGGY WEST
Notary Public - State of Florida
My Commission Expires Apr 27, 2010
Commission # DD 546001
Bonded By National Notary Assn.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Duval)

I hereby certify that on this 19th day of December, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared James T. Myers, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 75 and 76c from STAFF'S THIRD SET OF INTERROGATORIES TO JEA (NOS. 30-81) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 19th day of December, 2008.

Notary Public
State of Florida, at large
Bethany Heatwole
My Commission Expires:

BETHANY A. HEATWOLE
MY COMMISSION # DD 644752
EXPIRES: March 2, 2011
Bonded Thru Budget Notary Services

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Duval)

I hereby certify that on this 15th day of December, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Michael N. Lawson, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 77, 78, and 79 from STAFF'S THIRD SET OF INTERROGATORIES TO JEA (NOS. 30 - 81) in Docket No(s). 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 15 day of December, 2008.

Michael Lawson

Notary Public
State of Florida, at large

My Commission Expires: 9/24/10

Cathy L Barnwell

CATHY L. BARNWELL
Notary Public - State of Florida
My Commission Expires Sep 24, 2010
Commission # DD 556843
Bonded By National Notary Assn.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing JEA's Supplemental Responses to the Florida Public Service Commission STAFF'S THIRD SET OF INTERROGATORIES (30-81), its Responses to STAFF'S FOURTH SET OF INTERROGATORIES TO JEA (NOS.82-92), and STAFF'S THIRD REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 15) have been served by hand-delivery to the following parties on this 5th day of January, 2009.

Martha C. Brown, Esq.
Senior Attorney
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Attorney

4

JEA's Responses to Staff's Fourth Set of Interrogatories (Nos. 82-92)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Greenland Energy Center Combined Cycle Conversion in Duval County by JEA.	DOCKET NO. 080614-EM DATED: JANUARY 5, 2009

JEA'S RESPONSE TO STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 82 - 92)

JEA, pursuant to Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staff's Fourth Set of Interrogatories (Nos. 82 – 92).

The answers to Interrogatories 82 and 86 – 92 are provided by Donald C. Gilbert, JEA, 21 West Church St., Jacksonville, FL 32202. Answers to Interrogatories 83 – 85 are provided by Myron R. Rollins (consultant to JEA), Black & Veatch, 11401 Lamar Ave., Overland Park, KS 66211.

RESPONSES

82. What is the basis for the *revised* 7.00% cost rate for new debt?

Response: Like the 5.0 percent tax exempt long term municipal bond rate used in the GEC Need for Power Application, the 7.0 percent tax exempt long term municipal bond rate is a judgment made by JEA of the appropriate tax exempt long term municipal bond rate consistent with the other economic parameters for evaluating generating unit alternatives throughout the 20-year evaluation period. While the judgment of the 5 percent tax exempt long term municipal bond rate was made during more stable economic conditions, the judgment of the 7 percent tax exempt long term municipal bond rate was made during very volatile economic conditions following JEA's decision to defer capital expenditures and to delay the commercial operation of

the GEC combined cycle conversion by one year. While the 7 percent tax exempt long term municipal bond rate assumption appeared to be most appropriative at the time it was made, ensuing events may indicate that the 7 percent rate may be slightly high. There are several indications that support the 7 percent rate or a rate slightly lower as follows.

The Municipal Market Data (MMD) scales presented in the response to POD request No. 15 and the actual financing for the Scherer 4 Project on November 13, 2008, also presented in the response to POD request No. 15, indicate on that same date JEA's aggregate long term tax exempt bonds traded at a spread of 64 basis points to the 30-year AAA MMD. The 30 year AAA MMD on December 11, 2008 was 5.81 percent and with a 64 basis point spread would be 6.45 percent. Additionally, on January 15, 2008, the 30 year AAA MMD was 4.12 percent and on December 11, 2008 it was 5.81 percent, an increase of approximately 1.7 percent which if applied to the 5 percent long term tax exempt municipal bond rate would result in a 6.7 percent rate.

JEA believes that the real long term bond interest rate will increase as a result of the financial crisis. A two percent increase from 5 percent to 7 percent appears reasonable, but may ultimately be slightly high.

83. How does JEA use the *revised* 7.0% rate for interest during construction in the evaluation process?

Response: The 7 percent interest during construction rate was used consistently throughout the revised economic evaluations of supply-side alternatives to calculate the interest during

construction associated with each of the generating unit alternatives. The interest during construction required for the Greenland Energy Center combined cycle conversion was estimated based on a projected monthly cash flow for project expenditures prior to commercial operation. The interest during construction for all other alternatives was estimated assuming interest would accrue for one half of the construction period for each alternative.

84. How does JEA use the *revised* 7.0% present worth discount rate in the evaluation process?

Response: The 7 percent present worth discount rate was used consistently throughout the revised economic evaluations of supply-side alternatives to discount the annual system costs to 2008 values, and the annual present worth system costs were aggregated to determine the cumulative present worth costs for each expansion plan considered. These cumulative present worth costs were then compared to identify the least-cost capacity expansion plan for a given scenario and case.

85. What is the basis for the *revised* 20 year 10.412% fixed charge rate, and the *revised* 25 year 9.425% fixed charge rate? Please discuss all assumptions and show all calculations.

Response: Different generating technologies are assumed to have different economic lives and therefore different financing terms. For purposes of this analysis, simple cycle combustion turbines are assumed to have a 20 year financing term and combined cycle units are assumed to have a 25 year financing term. All levelized fixed charge rate calculations assume the 7.0 percent tax exempt municipal bond interest rate, a 2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund (DSRF) equal to

twelve months of debt service requirement earning interest at an interest rate equal to the bond interest rate of 7.0 percent. The resulting 20 year fixed charge rate is 10.412 percent and the 25 year fixed charge rate is 9.425 percent.

The levelized fixed charge rate is essentially the capital recovery factor, adjusted to include the bond issuance fee and the debt service reserve fund, plus 0.50 percent for property insurance, and was calculated as follows:

For the 20 year fixed charge rate where i = 7.0 percent, n = 20 years, DSRF = 1.0 year, bond issuance fees (fees) = 2.0 percent, and property insurance = 0.5 percent:

Capital Recovery Factor (CRF) =

$$\frac{i \times \left[(1+i)^n\right]}{\left[(1+i)^n - 1\right]} = \frac{0.07 \times \left[(1+0.07)^{20}\right]}{\left[(1+0.07)^{20} - 1\right]} = 0.09439 = 9.439 \text{ Percent}$$

Adjusted CRF (ACRF) =

$$\frac{(1-(i \times DSRF)) \times CRF}{[1 - fees - (DSRF \times CRF)]} = \frac{(1-(0.07 \times 1.0)) \times 0.09439}{[1 - 0.02 - (1.0 \times 0.09439)]} = 0.09912 = 9.912 \text{ Percent}$$

Levelized Fixed Charge Rate =

ACRF + property insurance = 0.09912 + 0.005 = 0.10412 = 10.412 Percent

For the 25 year fixed charge rate where i = 7.0 percent, n = 25 years, DSRF = 1.0 year, bond issuance fees (fees) = 2.0 percent, and property insurance = 0.5 percent:

Capital Recovery Factor (CRF) =

$$\frac{i \times \left[(1+i)^n\right]}{\left[(1+i)^n - 1\right]} = \frac{0.07 \times \left[(1+0.07)^{25}\right]}{\left[(1+0.07)^{25} - 1\right]} = 0.08581 = 8.581 \text{ Percent}$$

Adjusted CRF (ACRF) =

$$\frac{(1 - (i \times DSRF)) \times CRF}{[1 - fees - (DSRF \times CRF)]} = \frac{(1 - (0.07 \times 1.0)) \times 0.08581}{[1 - 0.02 - (1.0 \times 0.08581)]} = 0.08925 = 8.925 \text{ Percent}$$

Levelized Fixed Charge Rate =

ACRF + property insurance = 0.08925 + 0.005 = 0.09425 = 9.425 Percent

86. Please describe the "flight to quality" effect on JEA that has been historically beneficial to utilities and other high quality securities and bonds during times of financial uncertainty.

Response: Historically, in times of financial uncertainty, highly rated securities, including those of JEA (rated AA2/AA-/AA-) would generally benefit as investors sought to reduce risk. Currently, US Government backed securities have benefited the most from the "flight to quality" effect with 1 month and 3 month T-Bills yielding as low as 0 percent. With JEA maintaining its AA credit rating, JEA benefits from the "flight to quality" effect on municipal securities, but currently US Government backed securities are benefiting more.

87. Please explain JEA's future projections for estimating the timeframe over which the utility expects to pay a premium over historical rates for new municipal debt financing.

Response: JEA cannot forecast at this time with any reasonable confidence the timeframe over which it expects to pay a premium compared to the historical rates for new municipal debt financing at this time.

88. Has JEA made any recent contingency plans to mitigate future interest rate and liquidity risk?

Response: Yes. JEA has reviewed and reduced capital spending plans for fiscal year 2009 and any debt that is issued by JEA in the near-term will be fixed rate.

89. Based on JEA's response to Staff's 1st Request for Production of Documents No. 2, which of the underwriters listed on the bottom of Bates Stamp JEA- POD1-00007 are involved with the proposed transaction?

Response: Final decisions related to the financing of the Greenland Energy Center combined cycle conversion have not yet been made. However, JEA typically uses Bank of America, Citigroup, Merrill Lynch, Barclays Capital, Goldman Sachs, and Morgan Stanley for debt financing.

90. Has JEA incurred any additional expenses due to the underwriters listed on the bottom of Bates Stamp JEA- POD1-00007?

Response: JEA has not incurred additional expenses specifically due to the financial situations of its underwriters. However, in general, JEA's costs to the underwriters are increasing.

91. Please describe all the adverse effects on JEA from the credit crisis.

Response: The credit crisis has had the following adverse effects on JEA:

- Higher variable rates at certain times on both auction rate securities as well as variable rate demand bonds
- Much higher costs for back up lines of credit used to support variable rate demand bonds
- Lack of adequate liquidity provided by banks in the variable rate market which could force the debt to be refunded with higher fixed rates

92. Please describe any changing terms and conditions with any relationship banking entities with JEA.

Response: JEA's main day to day bank, Wachovia Bank, has been purchased by Wells Fargo. The future impact on terms and conditions is not yet known. Regarding bank liquidity facilities, JEA has had many unfavorable changes to the Standby Bond Purchase Agreements that provide back up liquidity for JEA's variable rate debt. In general, credit is harder to obtain, it is more expensive, terms are more difficult, and the length of the agreement is generally 1 year.

SERVED this 5th day of January, 2009.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko
Florida Bar No. 855898
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: garyp@hgslaw.com

Attorneys for JEA

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF DUVAL)

I hereby certify that on this 5th day of JANUARY, 2009, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Donald C. Gilbert, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 82, 86, 87, 88, 89, 90, 91, and 92 from STAFF'S FOURTH SET OF INTERROGATORIES TO JEA (NOS. 82-92) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 5th day of January, 2009.

CATHY L. BARNWELL
Notary Public - State of Florida
My Commission Expires Sep 24, 2010
Commission # DD 559843
Bonded By National Notary Assn.

Notary Public
State of Florida, at large 9-24-10

My Commission Expires:

Cathy L Barnwell

AFFIDAVIT

STATE OF KANSAS)

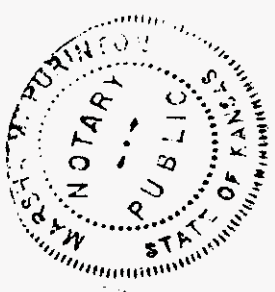
COUNTY OF JOHNSON)

I hereby certify that on this 5th day of January, 2009, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Myron R. Rollins, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 83, 84, and 85 from STAFF'S FOURTH SET OF INTERROGATORIES TO JEA (NOS. 82-92) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 5th day of January, 2009.

Myron Rollins

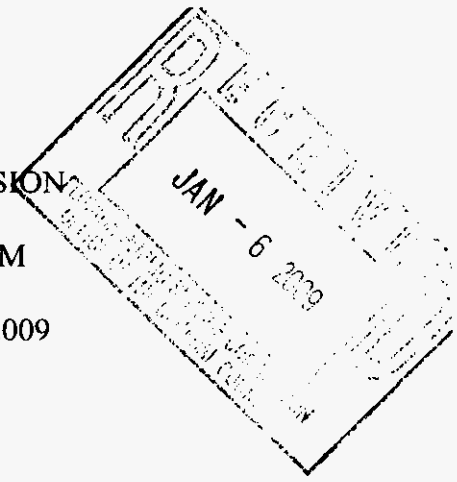
Notary Public
State of Kansas, at large
Marsha M. Purinton
My Commission Expires:
7-30-2011



Hearing Exhibit - 00000429

5

JEA's Responses to Staff's Fifth Set of Interrogatories (Nos. 93-101)



BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Greenland Energy Center Combined Cycle Conversion in Duval County by JEA.	DOCKET NO. 080614-EM DATED: JANUARY 6, 2009

JEA'S RESPONSE TO STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 93 - 101)

JEA, pursuant to Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staff's Fifth Set of Interrogatories (Nos. 93 – 101).

The answer to Interrogatory 93 is provided by Donald C. Gilbert, JEA, 21 West Church St., Jacksonville, FL 32202. Answers to Interrogatories 94 - 98 are provided by James T. Myers, JEA, 21 West Church St., Jacksonville, FL 32202. Answers to Interrogatories 99 and 100 are provided by Bradley E. Kushner (consultant to JEA), Black & Veatch, 11401 Lamar Ave., Overland Park, KS 66211. The answer to Interrogatory 101 is provided by Mary Guyton-Baker, JEA, 21 West Church St., Jacksonville, FL 32202.

RESPONSES

93. **Witness Gilbert states that JEA plans to issue a Request for Proposals (RFP) for power to meet the short term-requirements caused by the one year delay. Please indicate when the RFP will be issued.**

Response: JEA is currently planning on issuing the RFP by mid-January 2009.

a. **When must JEA accept a proposal in order to ensure delivery of power?**

Response: The lead time required in order to ensure delivery of power is dependant upon the source of the power being delivered. In general, JEA expects that accepting a proposal no less than three months prior to when the power is required will be adequate to ensure delivery of power.

b. Does JEA have an estimate of the amount of capacity to be requested in the RFP?

Response: JEA is expecting to request sufficient capacity to maintain reserve margin requirements prior to commercial operation of the proposed Greenland Energy Center combined cycle conversion.

94. Please complete the table below regarding JEA's projected natural gas storage availability.

Response: As shown in the completed table below, JEA is not projecting to have any natural gas storage.

	0	0	0	0	0	0	0	0	0

95. Please discuss the current status of the proposed SeaCoast pipeline and the GEC lateral.

Response: SeaCoast Gas Transmission, LLC (SeaCoast) is pursuing construction of the SeaCoast Pipeline. In addition, JEA has contracted with Peoples Gas System (PGS) for construction of the GEC lateral. Both projects have target completion dates of January 1, 2011 and are on schedule.

SeaCoast is in the process of finalizing its permit applications for the Florida Department of Environmental Protection and the US Army Corps of Engineers.

For both the SeaCoast Pipeline and the GEC lateral, land surveys are underway, land owners have been identified, and preliminary right-of-way acquisition activities are underway. In addition, requests for pipe bids have been submitted. Pipeline alignment sheets are being developed as survey data is obtained. SeaCoast project diagrams are under development and are expected to be completed in February 2009.

96. Please indicate the projected capacity of the GEC lateral.

Response: The GEC lateral is expected to have a maximum capacity of 100,000 million Btu (MBtu) per day.

97. Please complete the table below regarding the projected firm natural gas transportation available to JEA.

Response: JEA's portfolio of natural gas resources includes firm natural gas transportation and firm delivered natural gas volumes. JEA's firm gas transportation volumes increase in future years. The table below presents the firm natural gas transportation capacity available to JEA. Conversions from MBtu to mcf were made assuming 1.05 MBtu/mcf. Unless otherwise noted, the mcf per day transportation capacities are available for all months of a given year.

Year								2016	2017
(January-April months only)	109,523	109,523	130,095	130,095	130,095	130,095	130,095	130,095	130,095
(May-October months only)[1]	109,523	130,095	130,095	132,952	134,857	134,857	134,857	134,857	134,857
(November-December months only)	109,523	130,095	130,095	130,095	130,095	130,095	130,095	130,095	130,095
SeaCoast	0	0	61,905	76,190	95,238	95,238	95,238	95,238	95,238

1. Increase to 130,095 mcf/day begins in June 2010

98. Please complete the table below regarding the projected firm natural gas transportation available to the GEC.

Response: All of JEA's firm interstate gas transportation and delivered gas volumes described in response to Interrogatory No. 97 can be utilized to serve any of JEA's natural gas-fired generating units, including those to be located at the GEC site subject to the limitations of the laterals serving each unit. As discussed in the response to Interrogatory No. 96, the GEC lateral will have a maximum capacity of 100,000 MBtu/day (95,238 mcf/day assuming 1.05 MBtu/mcf). Service to GEC is limited by the intrastate capacity contracted for via SeaCoast, as presented in response to No. 97.

99. Please complete the table below regarding the projected firm natural gas transportation requirements for the GEC.

Response: Please see completed table below in response to this question. The data presents the average daily requirements by year based on annual requirements for the Scenario 1 Reference Case including the GEC combined cycle conversion. Data reflects commercial operation of the GEC simple cycle combustion turbines in May 2011 and the GEC combined cycle conversion in May 2013. Conversions from MBtu to mcf were made assuming 1.05 MBtu/mcf.

							2016	2017	
	0	0	960	749	20,099	35,611	34,617	20,691	14,863

100. Please complete the table below for JEA's existing and proposed generating facilities.

		Capacity Factor (%) by Year																	
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Unit Name																			

Response: Please see the completed table below in response to this request. Data for 2000 through 2007 is actual historical data that may reflect off-system (economy) sales. Data for 2008 through 2017 is projected based on the Scenario 1 Reference Case including the GEC combined cycle conversion reflected in the GEC Need for Power Application and represents JEA native load and firm contracted power sales to Florida Public Utilities Company. The data presented in the table does not include JEA's existing purchased power resources (i.e. Southern UPS and Constellation) nor does it include the Girvin Road or Trail Ridge landfill gas-to-energy facilities.

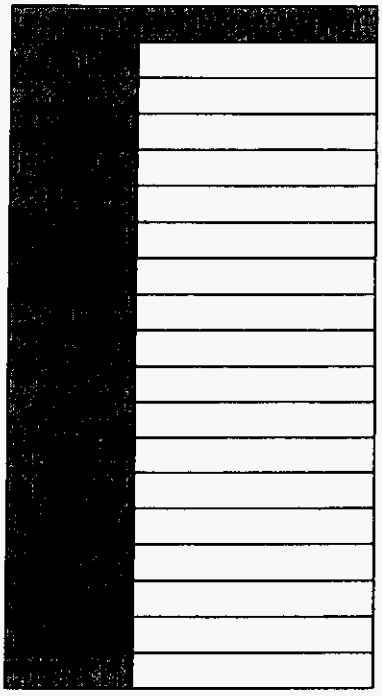
Hearing Exhibit - 00000436

Unit Name	Capacity Factor (%) by Year																	
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Northside 1	41%	42%	35%	66%	80%	87%	76%	85%	81%	71%	84%	82%	79%	86%	86%	86%	77%	74%
Northside 2	0%	0%	39%	69%	56%	77%	80%	80%	57%	69%	78%	77%	76%	82%	82%	83%	71%	64%
Northside 3	34%	39%	44%	34%	33%	24%	18%	15%	12%	16%	20%	41%	31%	19%	15%	13%	5%	4%
Northside CT 3	3%	1%	5%	2%	1%	2%	1%	1%	1%	0%	0%	1%	0%	0%	0%	0%	0%	0%
Northside CT 4	3%	2%	4%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Northside CT 5	3%	2%	2%	3%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Northside CT 6	2%	1%	4%	2%	1%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Southside 4 (retired 2002)	36%	35%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southside 5 (retired 2002)	28%	35%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennedy CT 3 (assumed to retire 2009)	4%	1%	2%	1%	0%	0%	0%	0%	0%	0%	-	-	-	-	-	-	-	-
Kennedy CT 4 (retired 2007)	4%	2%	2%	1%	0%	0%	0%	0%	-	-	-	-	-	-	-	-	-	-
Kennedy CT 5 (retired 2007)	4%	1%	1%	0%	0%	0%	0%	0%	-	-	-	-	-	-	-	-	-	-
Kennedy CT 7	19%	8%	12%	5%	4%	4%	4%	4%	1%	1%	4%	7%	3%	2%	1%	2%	0%	0%
Kennedy CT 8 (2009 COD)	-	-	-	-	-	-	-	-	-	3%	8%	13%	8%	4%	3%	4%	1%	1%
Brandy Branch 1	-	22%	14%	4%	3%	5%	3%	3%	3%	2%	8%	12%	8%	3%	3%	4%	1%	0%
Brandy Branch 2	-	22%	13%	3%	8%	-	-	-	-	-	-	-	-	-	-	-	-	-
Brandy Branch 3	-	64%	12%	5%	8%	-	-	-	-	-	-	-	-	-	-	-	-	-
Brandy Branch Combined Cycle	-	-	-	-	-	22%	31%	36%	32%	44%	57%	49%	71%	65%	64%	67%	49%	37%
SJRPP 1	93%	90%	94%	85%	92%	75%	90%	87%	97%	82%	97%	89%	97%	89%	97%	89%	96%	88%
SJRPP 2	86%	92%	82%	90%	71%	81%	78%	86%	98%	98%	90%	98%	89%	98%	90%	98%	90%	98%
Scherer 4	91%	78%	74%	85%	81%	76%	78%	91%	99%	99%	76%	99%	76%	99%	89%	99%	89%	99%
GEC Simple Cycle Combustion Turbine 1 (2011 COD)	-	-	-	-	-	-	-	-	-	-	-	2%	1%	0%	0%	0%	0%	0%
GEC Simple Cycle Combustion Turbine 2 (2011 COD)	-	-	-	-	-	-	-	-	-	-	-	1%	1%	0%	0%	0%	0%	0%
GEC Combined Cycle Conversion (2013 COD)	-	-	-	-	-	-	-	-	-	-	-	-	-	18%	41%	40%	24%	18%
LM6000 Simple Cycle Combustion Turbine (2015 COD)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12%	6%	3%
7FA Simple Cycle Combustion Turbine (2013 COD)	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	0%	0%	0%	0%
100 MW MEAG Vogtle 3 (2016 COD)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90%	90%
100 MW MEAG Vogtle 4 (2017 COD)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90%

Notes: Northside 1 data for 2000 through 2002 represents operation on both oil and natural gas. Beginning in 2003, data represents operation on natural gas only.
Kennedy CT7 began commercial operation in June 2000.
Brandy Branch 2 and 3 converted to Brandy Branch Combined Cycle January 2005.

Hearing Exhibit - 00000437

101. Please complete the table below regarding JEA's projected minimum load requirements.



Response: Please see the completed table below which shows JEA's projected minimum firm load requirements for the base case load forecast.

962
976
981
970
1,051
1,062
1,080
1,056
1,054
1,063
1,138
1,155
1,154
1,149
1,147
1,215
1,227
1,247

SERVED this 6th day of January, 2009.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko
Florida Bar No. 855898
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: garyp@hgslaw.com

Attorneys for JEA

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF DUVAL)

I hereby certify that on this 6th day of JANUARY, 2009, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Donald C. Gilbert, who is personally known to me, and he/she acknowledged before me that he/she provided the answer to interrogatory number 93 from STAFF'S FIFTH SET OF INTERROGATORIES TO JEA (NOS. 93-101) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of January, 2009.

Notary Public
State of Florida, at large

My Commission Expires: 9-24-10

Cathy L Barnwell

CATHY L. BARNWELL
Notary Public - State of Florida
My Commission Expires Sep 24, 2010
Commission # DD 556843
Bonded By National Notary Assn.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Duval)

I hereby certify that on this 14th day of January, 2009, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared James T. Myers, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 94, 95, 96, 97, and 98 from STAFF'S FIFTH SET OF INTERROGATORIES TO JEA (NOS. 93-101) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of January, 2009.

Notary Public
State of Florida, at large

My Commission Expires: 9-24-10

Cathy L Barnwell

CATHY L. BARNWELL
Notary Public - State of Florida
My Commission Expires Sep 24, 2010
Commission # DD 556843
Bonded By National Notary Assn.

AFFIDAVIT

STATE OF KANSAS)

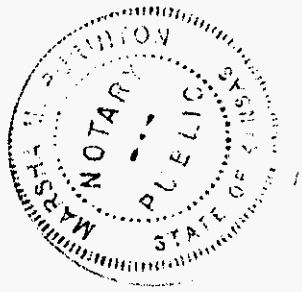
COUNTY OF JOHNSON)

I hereby certify that on this 6th day of January, 2009, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Bradley E. Kushner, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 99 and 100 from STAFF'S FIFTH SET OF INTERROGATORIES TO JEA (NOS. 93-101) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of January, 2009.

Bradley E Kushner

Notary Public
State of Kansas, at large
Marsha M. Purinton
My Commission Expires:
7-30-2011



AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Duval)

I hereby certify that on this 19 day of December, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Mary Guyton-Baker, who is personally known to me, and he/she acknowledged before me that he/she provided the answer to interrogatory number 101 from STAFF'S FIFTH SET OF INTERROGATORIES TO JEA (NOS. 93-101) in Docket No. 080614-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 19 day of December, 2008.

Notary Public
State of Florida, at large

My Commission Expires:

April 27, 2010

PEGGY WEST
Notary Public - State of Florida
My Commission Expires Apr 27, 2010
Commission # DD 546001
Bonded By National Notary Assn.

6

JEA's Responses to Staff's Sixth Set of Interrogatories (No. 102)

Hearing Exhibit - 00000444

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Greenland Energy Center Combined Cycle Conversion in Duval County by JEA.	DOCKET NO. 080614-EM DATED: JANUARY 12, 2009

JEA'S RESPONSE TO STAFF'S SIXTH SET OF INTERROGATORIES (NO. 102)

JEA, pursuant to Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staff's Sixth Set of Interrogatories (No. 102).

The answer to Interrogatory 102 is provided by Myron R. Rollins (consultant to JEA), Black & Veatch Corporation, 11401 Lamar Ave, Overland Park, KS 66211.

RESPONSES TO INTERROGATORIES

102. Witness Rollins, in his direct testimony, indicates that JEA requires minor amounts of additional capacity to maintain its 15 percent summer reserve margin up until 2011. Additionally Exhibit No. MRR-4 and Exhibit No. MRR-6 indicate a need for additional capacity through 2012.

a. Please discuss how JEA intends to satisfy the 15 percent reserve margin criteria for these years.

Response: As discussed in witness Gilbert's response to Staff's Interrogatory No. 93, JEA is intending to issue a request for proposals (RFP) for power to satisfy reserve margin requirements prior to commercial operation of the proposed Greenland Energy Center (GEC) combined cycle conversion.

b. Please discuss capacity and terms of any purchased power contracts assumed.

Response: For purposes of the analyses presented in the GEC Need for Power Application, the capacity required to maintain the 15 percent reserve margin prior to the originally proposed May 2012 commercial operation date of the GEC combined

Hearing Exhibit - 00000445

cycle conversion was not addressed. Capacity requirements prior to commercial operation of the GEC combined cycle conversion have no material impact on the comparative economic analysis of the GEC combined cycle conversion.

To address the one year delay in commercial operation of the GEC combined cycle conversion, a seasonal purchase for the summer of 2012 was assumed. The terms of this purchased power contract are considered confidential as it was generally based on a proposal received in response to a recent JEA purchase power RFP. As alluded to previously, however, the terms of the assumed purchase have no material impact on the comparative economic analysis of the GEC combined cycle conversion.

c. Please revise Exhibit No. MRR-4 and Exhibit No. MRR-6 to reflect the proposed capacity additions.

Response: Please see responses to Questions 102a and 102b. For informational purposes, the attached tables represent revisions to Exhibit No. MRR-4 and Exhibit No. MRR-6 to reflect unspecified capacity purchases that are sufficient to maintain JEA's 15 percent reserve margin requirements prior to the assumed May 2013 commercial operation of the GEC combined cycle conversion. The unspecified purchased capacity is included in the "Purchases" column of the attached tables to maintain the 15 percent reserve margin requirements as specified in the notes for each of the tables.

Projected Reliability Levels - Summer/Base Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	257	(376)	0	0	3,248	2,941	2,824	10.4%	15.0%	(135)	0
2009	3,367	234	(376)	(51)	150	3,324	3,007	2,890	10.5%	15.0%	(134)	0
2010	3,367	309	(376)	(51)	150	3,399	3,072	2,955	10.6%	15.0%	(135)	0
2011	3,367	100	(376)	(51)	434	3,474	3,138	3,021	10.7%	15.0%	(135)	0
2012	3,367	176	(376)	(51)	434	3,550	3,204	3,087	10.8%	15.0%	(134)	0
2013	3,367	9	(376)	(51)	434	3,383	3,269	3,152	3.5%	7.3%	(377)	(242)
2014	3,367	9	(376)	(51)	434	3,383	3,335	3,218	1.4%	5.1%	(452)	(317)
2015	3,367	9	(376)	(51)	434	3,383	3,400	3,283	-0.5%	3.0%	(527)	(393)
2016	3,367	9	0	(51)	434	3,759	3,466	3,349	8.5%	12.3%	(227)	(92)
2017	3,367	9	0	(51)	434	3,759	3,531	3,414	6.4%	10.1%	(302)	(167)
2018	3,367	0	0	(51)	434	3,750	3,597	3,480	4.3%	7.8%	(386)	(252)
2019	3,367	0	0	(51)	434	3,750	3,662	3,545	2.4%	5.8%	(462)	(327)
2020	3,367	0	0	(51)	434	3,750	3,728	3,611	0.6%	3.9%	(537)	(403)
2021	3,367	0	0	(51)	434	3,750	3,794	3,677	-1.1%	2.0%	(613)	(478)
2022	3,367	0	0	(51)	434	3,750	3,859	3,742	-2.8%	0.2%	(688)	(553)
2023	3,367	0	0	(51)	434	3,750	3,925	3,808	-4.5%	-1.5%	(763)	(629)
2024	3,367	0	0	(51)	434	3,750	3,990	3,873	-6.0%	-3.2%	(839)	(704)
2025	3,367	0	0	(51)	434	3,750	4,056	3,939	-7.5%	-4.8%	(914)	(780)
2026	3,367	0	0	(51)	434	3,750	4,121	4,004	-9.0%	-6.4%	(990)	(855)
2027	3,367	0	0	(51)	434	3,750	4,187	4,070	-10.4%	-7.9%	(1,065)	(930)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).

[2] Assumes UPS purchase through May 2010. Portion of purchases prior to 2013 have been assumed to maintain reserve margin requirements (41 MW in 2008, 18 MW in 2009, 300 MW in 2010, 91 MW in 2011, and 167 MW in 2012).

[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.

[4] Retirement of JD Kennedy CT 3 in March 2009.

[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2011.

Hearing Exhibit - 00000447

Projected Reliability Levels - Summer/DSM Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	257	(376)	0	0	3,248	2,941	2,824	10.4%	15.0%	(134)	0
2009	3,367	227	(376)	(51)	150	3,317	3,001	2,884	10.5%	15.0%	(135)	0
2010	3,367	278	(376)	(51)	150	3,368	3,045	2,928	10.6%	15.0%	(134)	0
2011	3,367	33	(376)	(51)	434	3,407	3,079	2,962	10.6%	15.0%	(134)	0
2012	3,367	57	(376)	(51)	434	3,431	3,100	2,983	10.7%	15.0%	(134)	0
2013	3,367	9	(376)	(51)	434	3,383	3,143	3,026	7.6%	11.8%	(232)	(97)
2014	3,367	9	(376)	(51)	434	3,383	3,209	3,092	5.4%	9.4%	(307)	(173)
2015	3,367	9	(376)	(51)	434	3,383	3,274	3,157	3.3%	7.2%	(382)	(248)
2016	3,367	9	0	(51)	434	3,759	3,340	3,223	12.5%	16.6%	(82)	53
2017	3,367	9	0	(51)	434	3,759	3,405	3,288	10.4%	14.3%	(157)	(22)
2018	3,367	0	0	(51)	434	3,750	3,471	3,354	8.0%	11.8%	(242)	(107)
2019	3,367	0	0	(51)	434	3,750	3,537	3,420	6.0%	9.7%	(317)	(183)
2020	3,367	0	0	(51)	434	3,750	3,602	3,485	4.1%	7.6%	(392)	(258)
2021	3,367	0	0	(51)	434	3,750	3,668	3,551	2.2%	5.6%	(468)	(334)
2022	3,367	0	0	(51)	434	3,750	3,733	3,616	0.5%	3.7%	(543)	(408)
2023	3,367	0	0	(51)	434	3,750	3,799	3,682	-1.3%	1.8%	(619)	(484)
2024	3,367	0	0	(51)	434	3,750	3,864	3,747	-2.9%	0.1%	(694)	(559)
2025	3,367	0	0	(51)	434	3,750	3,930	3,813	-4.6%	-1.6%	(769)	(635)
2026	3,367	0	0	(51)	434	3,750	3,996	3,879	-6.2%	-3.3%	(845)	(711)
2027	3,367	0	0	(51)	434	3,750	4,061	3,944	-7.7%	-4.9%	(920)	(786)

[1] Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand).

[2] Assumes UPS purchase through May 2010. Portion of purchases prior to 2013 have been assumed to maintain reserve margin requirements (41 MW in 2008, 11 MW in 2009, 269 MW in 2010, 24 MW in 2011, and 48 MW in 2012).

[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.

[4] Retirement of JD Kennedy CT 3 in March 2009.

[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2011.

Hearing Exhibit - 00000448

SERVED this 12th day of January, 2009.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko
Florida Bar No. 855898
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Email: garyp@hgslaw.com

Attorneys for JEA

7

JEA's Responses to Staff's First Request for Production of Documents (Nos. 1-5) (excluding attachments 2A and 2B to POD 2)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

NOV - 6 2008

In re: Petition to determine need for Greenland Energy Center Combined Cycle Conversion in Duval County by JEA.	DOCKET NO. 080614-EM DATED: NOVEMBER 6, 2008

JEA'S RESPONSES TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1 – 5)

JEA, pursuant to Rule 28-106.206, Florida Administrative Code, and Rule 1.350, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's First Request for Production of Documents (Nos. 1-5).

RESPONSES

1. **Regarding the economic parameters in the application, please provide complete copies of all source documents, reports, etc. that support the selection of 2.5% as the assumed escalation rate, 5.0% as the assumed long-term tax-exempt municipal bond interest rate, and 5.0% as the present worth discount rate.**

   Response: Attachment POD-1a presents a description of Chained Consumer Price Index and the monthly and annual indices. Attachment POD-1b presents Page 4-1 from the Need for Power Application for Cane Island Power Park Unit 4 in Docket No. 080253-EM. Attachment POD-1c presents Bond Buyer indices from June 2008. Attachment POD-1d presents Bloomberg's National Municipal Bond Yields for General Obligation Bonds from October 21, 2008. The present worth discount rate is equal to the cost of capital which is the long-term tax-exempt municipal bond rate.

Attachment POD-1a

Chained CPI-All Urban Consumers (SU)
su.txt

Section Listing

1. Survey Definition
2. FTP files listed in the survey directory
3. Time series, series file, data file, & mapping file definitions and relationships
4. Series file format and field definitions
5. Data file format and field definitions
6. Mapping file formats and field defintions
7. Data Element Dictionary

==========

Section 1

==========

The following is a definition of: CHAINED CONSUMER PRICE INDEX - All Urban Consumers (SU)

Survey Description:

The Chained Consumer Price Index for All Urban Consumers, was introduced with the release of July data in August 2002. Designated the C-CPI-U, the index supplements the existing Consumer Price Indexes already produced by the BLS: the CPI for All Urban Consumers (CPI-U) and the CPI for Urban Wage Earners and Clerical Workers (CPI-W).

The C-CPI-U employs a Tornqvist formula and utilizes expenditure data in adjacent time periods in order to reflect the effect of any substitution that consumers make across item categories in response to changes in relative prices. The new measure is designed to be a closer approximation to a "cost-of-living" index than the present measures. The use of expenditure data for both a base period and the current period in order to average price change across item categories distinguishes the C-CPI-U from the existing CPI measures, which use only a single expenditure base period to compute the price change over time.

In 1999, the BLS introduced a geometric mean estimator for averaging prices within most of the index's item categories in order to approximate the effect of consumers' responses to changes in relative prices within these item categories. The geometric mean estimator will be used in the C-CPI-U in the same item categories in which it is now used in the CPI-U and CPI-W.

Expenditure data required for the calculation of the C-CPI-U are available only with a time lag. Thus, the C-CPI-U is issued first in preliminary form using the latest available expenditure data at that time and will be subject to two subsequent revisions. Accordingly, at the time of its introduction in August, "final" values of the C-CPI-U will be issued for the 12 months of 2000, "interim" values will be issued for the 12 months of 2001, and "initial" values will be issued for January-July of 2002. In February 2003, with release of the January 2003 index, revised interim indexes for the 12 months of 2002 will be published, and the index values for 2001 will be revised and will become final. Then, in February 2004, when the monthly expenditure data from calendar year 2002 become available, C-CPI-U indexes for the 12 months of 2002 will be issued in final form and values for the 12 months of 2003 will be revised and issued as interim. The C-CPI-U index revisions are expected to be small, but in principle each monthly index could be revised from its previously published level.

The C-CPI-U will be issued for national averages only and will not be seasonally adjusted. It employs a December 1999=100 reference base. Data for periods prior to December 1999 will not be calculated. The component series that will be published are listed below:</P>

Consumer Price Index - Chained Consumer Price Index

Series Id: SUUR0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: DECEMBER 1999=100

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
1999												100.0	
2000	100.3	100.9	101.6	101.6	101.7	102.1	102.3	102.3	102.8	102.9	102.8	102.6	102.0
2001	103.3	103.7	103.9	104.2	104.6	104.8	104.5	104.6	104.9	104.7	104.4	103.9	104.3
2002	104.2	104.5	105.1	105.6	105.6	105.6	105.7	106.0	106.3	106.4	106.3	106.0	105.6
2003	106.5	107.3	107.9	107.7	107.5	107.6	107.7	108.2	108.5	108.4	108.0	107.8	107.8
2004	108.5	109.1	109.7	110.0	110.6	110.8	110.7	110.7	111.0	111.6	111.6	111.2	110.5
2005	111.3	111.9	112.6	113.4	113.3	113.2	113.7	114.3	115.6	115.7	114.9	114.4	113.7
2006	115.2	115.4	116.0	116.9	117.5	117.7	118.1	118.3	117.8	117.1	116.9	117.0	117.0
2007	117.310(U)	117.897(U)	118.978(U)	119.712(U)	120.290(U)	120.478(U)	120.384(U)	120.198(U)	120.538(U)	120.823(U)	121.443(U)	121.322(U)	119.948(U)
2008	121.895(I)	122.251(I)	123.204(I)	123.845(I)	124.645(I)	125.582(I)	126.116(I)	125.843(I)	125.774(I)				

U : Interim
I : Initial

JEA-PQR1-000003455
Hearing Exhibit

Attachment POD-1b

4.0 Economic Parameters

This section presents the economic evaluation criteria and methodology used to evaluate the economics of Cane Island 4 as part of FMPA's least-cost expansion plan to satisfy forecast capacity requirements throughout the 20 year evaluation period.

4.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and nonfuel variable O&M escalation rate were each assumed to be 2.3 percent.

4.2 Municipal Bond Interest Rate

The long-term tax exempt municipal bond interest rate was assumed to be 5.0 percent.

4.3 Present Worth Discount Rate

The present worth discount rate was assumed to be equal to the tax exempt municipal bond interest rate of 5.0 percent.

4.4 Interest During Construction Interest Rate

The interest during construction (IDC) rate was assumed to be 5.0 percent.

4.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR), represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year fixed charge rate.

Different generating technologies are assumed to have different economic lives and, therefore, different financing terms. Simple cycle combustion turbines are assumed to have a 25 year financing term, while natural gas fired combined cycle units are assumed to be financed over 30 years. Given the various economic lives and corresponding financing terms, different levelized FCRs were developed. All levelized FCR calculations assume a 2.0 percent bond issuance fee and include an assumed 0.50 percent annual property insurance cost and a 6 month debt service reserve fund

Attachment POD-1c

Bond Buyer Indexes

Date	20-Bond GO Index	11-Bond GO Index	**Revenue Bond Index**	10-Year Tresury Note Yield	30-Year Tresury Bond Yield
6/5/2008	4.59	4.49	**5.04**	4.05	4.75
6/12/2008	4.69	4.6	**5.14**	4.22	4.77
6/19/2008	4.76	4.66	**5.2**	4.22	4.77
6/26/2008	4.83	4.74	**5.25**	4.05	4.61

From The Bond Buyer index website (www.bondbuyer.com/msa_search.hyml?product+1&details=true)

Faster Access to Better Data

The Bond Buyer Online's FREE W
Starts October 27t

Bond Buyer Indexes

The 20-Bond Index consists of 20 general obligation bonds that mature in 20 years. The average rating of the 20 bonds is roughly equivalent to Moody's Investors Service's Aa2 rating and Standard & Poor's Corp.'s AA. The 11-Bond Index uses a select group of 11 bonds in the 20-Bond Index. The average rating of the 11 bonds is roughly equivalent to Moody's Aa1 and S&P's AA-plus. The Revenue Bond Index consists of 25 various revenue bonds that mature in 30 years. The average rating is roughly equivalent to Moody's A1 and S&P's A-plus.

The indexes represent theoretical yields rather than actual price or yield quotations. Municipal bond traders are asked to estimate what a current-coupon bond for each issuer in the indexes would yield if the bond was sold at par value. The indexes are simple averages of the average estimated yields of the bonds.

The 10-year and 30-year Treasury yields are the market quotes for those securities at the time that the indexes are calculated.

Quick reports:
Annual Averages, Highs & Lows

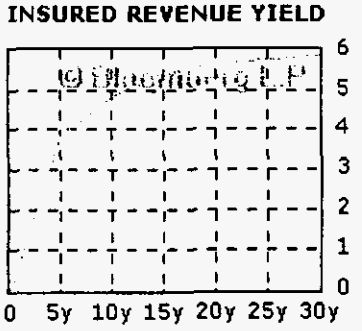
JEA-POD1-00005
Hearing Exhibit - 00000459

Attachment POD-1d

Municipal Bonds

National Municipal Bond Yields:
Triple-A rated, Tax-Exempt General Obligation Bonds

	CURRENT YIELD	PREVIOUS YIELD	CHANGE IN YIELD	28% EQ YIELD	1 WEEK PRIOR YIELD	1 MONTH PRIOR YIELD	6 MONTH PRIOR YIELD
2-Year	2.88%	2.81%	0.07%	4.00%	2.65%	2.21%	2.20%
5-Year	3.86%	3.71%	0.15%	5.36%	3.40%	2.92%	2.88%
7-Year	4.32%	4.17%	0.15%	6.00%	3.81%	3.27%	3.20%
10-Year	4.93%	4.78%	0.15%	6.85%	4.40%	3.85%	3.76%
15-Year	5.66%	5.58%	0.08%	7.86%	5.15%	4.49%	4.33%
20-Year	5.86%	5.78%	0.08%	8.14%	5.35%	4.73%	4.66%
30-Year	5.89%	5.81%	0.08%	8.18%	5.38%	4.93%	4.79%



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Contact Information ›
Muni Material Events ›

JEA-POD1-00006
Hearing Exhibit - 00000461

2. **Please provide a complete copy of JEA's most recent registration statement for the issuance of securities.**

Response: As a municipal utility, JEA does have registration statements for the issuance of securities. Attachment POD-2a is JEA's Official Statement for $54,050,000 Electric System Revenue Bonds, Series Three 2008E and $18,645,000 Electric System Subordinated Revenue Bonds, 2008 Series E. Attachment POD-2b is JEA's Annual Disclosure Report for Fiscal Year Ended September 30, 2007 dated as of May 30, 2008.

3. **Please provide complete copies of the most recent credit/bond rating reports for JEA done by Standard & Poor's Rating Service.**

Response: Attachment POD-3 is the latest Standard & Poor's rating report.

JEA'S RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS NO. 3

Hearing Exhibit - 00000463

STANDARD &POOR'S

PUBLIC FINANCE

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Credit Profile		
US$19. mil elec sys subord rev bnd ser 2008E due 10/01/2028		
Long Term Rating	A-/Stable	New
US$11. mil elec sys sr rev bnd ser THREE 2008E due 10/01/2028		
Long Term Rating	AA-/Stable	New
JEA elec sys subord rev bnds ser 2000D 2003E 2001A		
Long Term Rating	A-/Stable	Affirmed
JEA elec sys (ARS)		
Unenhanced Rating	AA (SPUR)/Stable	Affirmed
JEA elec sys (St Johns River Pwr Pk)		
Unenhanced Rating	AA-(SPUR)/Stable	Affirmed

Rationale

Standard & Poor's Ratings Services has assigned its 'AA' rating to JEA, Fla.'s fixed rate senior lien electric system revenue bonds series three 2008E and its 'A+' rating to JEA's fixed rate subordinate lien electric system revenue bonds 2008 Series E. At the same time, Standard and Poor's affirmed the 'AA-' and 'A+' ratings on respective parity debt. The outlook is stable.

JEA's general credit characteristics include:

- A low-cost and diversified fuel mix for all of the utility's generating facilities, including coal, petroleum coke (petcoke), oil, and gas.
- Rates across all customer classes that are among the lowest in the state, affording the utility the ability to raise rates without compromising its competitive position.
- Solid service area growth.
- Sophisticated management, which has an established track record of identifying and managing operating and financial risks, while producing significant efficiencies; and

RatingsDirect
Publication Date
Aug. 2[illegible] 2[illegible]

Hearing Exhibit - 00000464

- Adequate liquidity and coverage of fixed costs at the current rating level

Constraining the ratings are very high debt levels, coupled with the expected debt financing of a substantial portion of JEA's sizable capital program.

Financial metrics have stabilized in recent years as the utility reversed a trend of not passing increased operating costs on to ratepayers, which resulted in eroded coverage and liquidity. Management's increased willingness to pass through costs to ratepayers was most recently demonstrated when JEA, in response to rising coal and gas prices, imposed a $15 per megawatt hour (MWh) surcharge for 90 days, effective July 1, 2008 (effective Oct. 1, the surcharge will decrease to $10.86/MWh).

The recent actions build on previous efforts, including a revised pricing philosophy that more adequately passed on the cost of service to ratepayers. These changes included fuel rate increases, a fuel recovery charge, and a charge to establish a fuel-rate stabilization fund, with the latter two charges likely to be in place for five-to-seven years. In addition, JEA adopted a policy requiring annual fuel rates to include a "true-up" component, enabling the utility to recoup the spread between actual costs and forecast expenses in the previous 12-month period.

In the past two years, JEA has adopted additional charges that Standard & Poor's expects will lend stability to the utility. These charges include a conservation charge to fund demand-side management efforts, an environmental charge to fund known and future environmental liabilities, and a series of base rate increases to be phased in during fiscals 2008-2011 to help meet capital expenditures and reduce the need to issue additional debt.

These rate increases and policy changes have helped JEA improve coverage levels and liquidity, giving Standard & Poor's a degree of comfort regarding the utility's ability to achieve projected financial metrics. Furthermore, we do not expect these increases to significantly affect JEA's competitive position as one of the lowest cost providers of electricity in Florida, although the competitive advantage has narrowed in recent years, particularly for industrial customers.

JEA's financial metrics from operations were off slightly in 2007. Before applying rate stabilization money, fiscal 2007 net available revenue was sufficient to provide 1.39x coverage of fixed costs (which includes debt service on senior-lien, off-balance-sheet, and subordinate-lien debt after transfers to the city's general fund), which was down from 1.51x in fiscal 2006. The strong coverage in fiscal 2006 enabled JEA to transfer $27 million from the revenue fund to the rate stabilization fund, and the utility used $14 million in rate stabilization funds in 2007, boosting adjusted coverage to 1.46x for that year. Both figures were well in excess of the 1.21x coverage posted in 2005, before the rate stabilization reserve was established. Using rate stabilization money resulted in somewhat lower liquidity, which dipped to 32 days' unrestricted cash on hand in 2007 -- down from 40 days in 2006, but up from 14 days in 2005.

Constraining the ratings are mounting debt levels, as JEA has modernized its generating fleet. While the utility has diverse capacity, coal based generation is currently the backbone of its operating profile, exposing JEA to potential future mandates in what is expected to be a carbon constrained world. With already high debt levels, the burden of addressing mandates will likely fall more directly on ratepayers.

Debt, including off balance sheet debt, increased to $3.83 billion in 2007 ($9,281 per customer) from $1.7 billion in 1999. JEA's 2008-2012 capital plan is sizable, totaling $2.2 billion, with about half to be debt financed. Management recently declined to proceed with the efforts to participate in the development of the proposed Taylor Energy Center (TEC), which was scheduled to begin service in 2012. Permitting on TEC had been suspended in the wake of concerns regarding carbon dioxide

JEA-POD1-005-00000465
Hearing Exhibit

emissions which have effectively scuttled the construction of coal based generation in Florida. JEA has booked a $5 million charge associated with the abandoned project.

In its stead, JEA expects to develop a green site in Duval County, placing two simple cycle combustion turbines (CTs) in service in 2009 and 2010, with conversion to combined cycle in 2012. The utility expects the total cost of the CTs and combined cycle conversion to be about the same as TEC, but operating costs will likely be higher.

JEA's board has authorized the utility to acquire 10% of its annual energy requirements from nuclear sources by 2018. Accordingly, JEA has entered a 20-year take-or-pay power purchase agreement (PPA) with Municipal Electric Agency of Georgia (MEAG) for 206 MW of capacity and energy from MEAG's planned new units at its Vogtle Station. The utility expects that the MEAG PPA will account for about 5% of its energy needs when it is placed in service in 2016. Additional nuclear resources could be in the form of additional PPAs or direct ownership in other nuclear projects. JEA's current capital plan does not include the costs associated with the nuclear project(s).

Standard & Poor's assigned JEA a business profile of '3' on Standard & Poor's 10-point business profile scale with '1' being the strongest score. The business profile reflects the utility's competitive position (afforded by low rates), despite substantial contributions to Jacksonville, Fla.'s general fund.

We have also assigned JEA a Standard & Poor's Debt Derivative Profile (DDP) overall score of '2' on a scale of '1' to '4', with a '1' representing the lowest risk. The '2' score on JEA's electric revenue bonds reflects Standard & Poor's view that the swaps do not pose significant risks to credit quality.

Outlook

The stable outlook reflects improved financial metrics, including enhanced coverage and liquidity, which have followed new policies that addressed the underrecovery of fuel costs. The outlook also expects continued fixed-cost coverage and liquidity levels that are at or above metrics produced in 2007. Constraining further credit improvement are high debt levels that are likely to increase as JEA progresses through its sizable capital program.

Service Area And Markets: Eighth-Largest U.S. Municipal Electric Utility

JEA's service area includes Jacksonville and northern portions of Clay and St. Johns counties. The system also provides power to the Florida Public Utilities Co. for resale in Ferdinanda Beach in Nassau County.

The greater Jacksonville metropolitan statistical area has a population of 1.25 million and has experienced solid, stable growth during the past decade. Job growth has begun to lag labor force growth, increasing unemployment rates to 4.7% in November 2007, a level that is nevertheless below the national rate. Wealth levels are about on par with the nation (98% of the national level), bolstered by the low cost of living and utilities.

Serving about 412,294 customers, JEA is the eighth-largest municipal electric utility in the U.S. It also sells electricity to two electric systems in neighboring counties. The revenue mix is good, with about 50% of revenue coming from residential accounts. The 10 leading customers (not including Florida Power & Light Co. [FP&L], which contractually purchases from the St. Johns River Power Park [SJRPP]) are not concentrated, accounting for 12% of revenue.

JEA-POD1-00515
Hearing Exhibit - 00000466

Operations: Possible Environmental Challenges Ahead

The electric system includes generation, transmission, interconnection, and distribution facilities. JEA has 3,241 MW of installed capacity, including wholly owned Northside and Brandy Branch units, and shares of SJRPP and the Scherer Unit 4. The generation system benefits from a diverse mix of fuel resources capable of burning coal, natural gas, and petcoke, although high gas prices (and, to a lesser extent, petcoke prices), are resulting in a heightened reliance on coal to meet energy needs. Generation and firm purchases are sufficient to meet peak demand and a 15% reserve through 2013. However, the recently cancelled TEC project, which would have added a baseload coal resource, will force JEA to add gas-fired generation to meet post-2013 demand, which is expected to have implications for operating costs and customer rates.

Environmental regulation and compliance

All units comply with existing environmental regulations. JEA's capital plan estimates up to $350 million in compliance costs through 2012 as it phases in additional provisions of the Clean Air Interstate Rule, which the courts recently vacated and remanded. Management estimates an additional $100 million to $200 million in costs related to other proposed, but yet to be enacted, environmental regulations unrelated to greenhouse gases.

JEA's units have significant carbon footprints, and the utility is exposed to possible environmental regulation of greenhouse gas emissions. Management has modeled the impact of a carbon dioxide tax ranging from $5-$10 per ton per year, estimating an annual cost of $67 million-$134 million, beginning in 2012. At the high end, this estimate would represent 11% of current operating revenue. However, if a carbon tax (or cap-and-trade program) happens, actual costs could be significantly higher.

Standard & Poor's is concerned that carbon dioxide legislation could impose a new paradigm on the industry by rendering some generating units uneconomical and some utilities uncompetitive.

However, significant uncertainties exist. First, Congress has yet to enact legislation, so the extent of the problem is currently unclear. Second, utilities can take a wide range of remedial actions, each with varying operational and financial impacts. Third, although carbon dioxide control technology is in its infancy, it could be viable by the time legislation takes effect.

Management's willingness to use their rate-setting autonomy to preserve margins and bondholder security will continue to influence the ratings.

Diverse multiunit power supply

JEA's main generating facilities consist of three locations and 14 generating units using a diversified mix of coal, petcoke, natural gas, and (under more optimal price conditions) oil and diesel fuel.

Running on a 90/10 blend of petcoke and coal, JEA's Northside 1 and 2 units provide the utility with about 25% of total energy generated and purchased. Low fuel costs for these units are somewhat offset by substantial capital costs incurred, as they were repowered earlier this decade to run on petcoke and use circulating fluidized bed technology. Northside 3, a natural gas powered combined cycle unit, accounted for about 8% of JEA's 2007 energy needs.

JEA also maintains an 80% interest in SJRPP (FP&L has a 20% interest). However, it has, on a take or pay basis, sold 37.5% of the interest to FP&L through 2022, resulting in a functional 50/50 split of the facility through the term of the contract. In 2007, SJRPP supplied JEA with 34% of total

JEA-POD1-00516
Hearing Exhibit - 00000467

energy needs. SJRPP's two coal-fired units have operated at high capacity factors over the past five years. JEA can use a 70:30 blend of coal and petcoke at SJRPP, but given recently elevated prices for petcoke, SJRPP largely ran on coal in 2007.

JEA owns a 23.64% share of the coal-fired Scherer Unit 4 (FP&L owns the remainder), with other units owned by Municipal Electric Authority of Georgia, Oglethorpe, and Georgia Power Corp. Scherer 4 supplied JEA with 10% of total energy needs in 2007.

In addition to installed capacity, JEA also currently purchases 200 MW of firm power from Southern Co., producing a small capacity surplus and supplying JEA with 11% of fiscal 2007 energy needs. The contract with Southern runs through May 2010.

Diverse fuel mix

JEA benefits from a diverse fuel mix that has helped it maintain its position as a low-cost provider because generation versus purchased energy decisions are driven by cost. Coal-fueled energy accounted for 51% of the mix in 2007 (owned, generation, and purchased), while petcoke accounted for 30%, gas 16%, and oil 2%.

JEA's hedging programs help build in budgetary predictability, which bodes well for the utility's ability to achieve projected results. Solid fuels (coal and petcoke) are hedged at 93% and 60%, respectively, for fiscals 2008 and 2009 with multiple vendors, both domestic and international (all coal for SJRPP comes from Columbia S.A. under a three-year fixed-price contract). About 67% and 10% of gas needs are hedged over each of the next two years. JEA has a commitment to purchase gas under a long-term contract with BG Energy Merchants, expiring in 2021.

Fuel price increases have led to increased costs; annual fuel costs were $34.78 per MWh in 2007, down from $35.58 per MWh in 2006, but up from $29.42 per MWh in 2005.

The Energy Authority

JEA has entered into a joint-power marketing, fuel, and risk management alliance with five other publicly owned utilities, forming The Energy Authority (TEA), which purchases and sells energy by and between members based on the lowest economic cost. Combined, TEA members have more than 14,400 MW of generating capacity. As of fiscal year ended Sept. 30, 2007, TEA produced, through buying and selling JEA energy, net revenues for the utility totaling $20.2 million.

Purchased power

The bulk of JEA's purchased power comes from a firm 200 MW power contract with Southern Co.

Competitive Position: Among The Lowest State And Regional Rates

Historically, JEA's rates have been among the lowest in the state and region across all rate classes. Before recent rate increases, the utility had not raised residential rates in 14 years.

In 2004, JEA began adopting fuel and purchased power cost adjustments and continues to adjust these variable rates as needed.

On April 1, 2005, JEA also adopted:

- A 97 cent per 1,000 kilowatt-hour (kWh) charge to establish a fuel rate stabilization fund until an amount equal to 15% of JEA's annual fuel budget is collected. Under current forecasts, this amounts to $60 million, which will take the utility about five years to reach. At fiscal year end 2007, the fuel

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stabilization fund had a balance of $12 million and management expects to build this to more than $24 million by fiscal year-end 2008

- A $2.90 per 1,000-kWh fuel recovery charge that will remain in effect for seven years, or until $2.52 million is recovered; and
- An annual fuel rate true-up mechanism that will recoup the forecast to actual spread over the previous 12 month period

According to the Energy Information Administration, revenue from residential customers was 8.97 cents per kWh in 2006, while average revenue per kWh for commercial and industrial customers was 7.64 cents and 5.85 cents, respectively, well below the state average

To support necessary capital expenditures, JEA's board recently adopted:

- Annual base rate increases ranging from 3.00% to 7.25% during fiscals 2008-2011 (varying by customer class);
- A 62 cent per 1,000-kWh charge to fund compliance with future environmental regulations; and
- A 1 cent per kWh conservation charge on residential customers intended to fund demand-side management programs.

The utility rates are likely to remain among the lowest in the state, although we note some erosion in the competitive advantage, primarily in related to industrial customers.

As a municipal utility, JEA is largely self-governing. It sets its own budget, and its board of directors may raise rates as it sees fit. It sets its own rates, but it must get approval from Jacksonville for its budget, and the mayor's appointments of JEA's board members are subject to city council approval

The utility makes, and has always made, substantial transfers to Jacksonville. Although it identifies them as "contributions" in its financial statements, the transfers are based on a formula involving a percent of electric revenues and are set forth in JEA's charter. For this reason, Standard & Poor's does not think the transfers are voluntary, and includes them in assessing the utility's ability to meet other unavoidable costs, such as debt service, even if they are paid after debt service

The Jacksonville city council enacted a franchise fee of 3% of JEA's gross revenue, effective April 2008. The fee provides for the ability to pass the franchise fee on to ratepayers, and JEA management has indicated it intends to do so. The utility will record the franchise fee as a revenue and operating expense and it will have no affect on its coverage levels. The franchise fee would be in addition to JEA's direct transfer, which amounted to about 7.1% of gross operating revenue in fiscal 2007. Although not recorded as such, Standard & Poor's treats those transfers as an operating cost of the utility

Strong Management Team

JEA's management team is deep, highly experienced, and sophisticated. Management has adopted many of the organizational training models employed by leading private sector companies. This has enhanced JEA's ability to identify productivity improvements and drive down expenses. However, JEA is not overly insulated and has built on its own competencies by developing key strategic partnerships with TEA, Colectric Partners Inc., and a mutual aid alliance

JEA's previous CEO retired in August 2004; the former chief operating officer, who has been with JEA more than 30 years, replaced him. Standard & Poor's believes that previous management's success in achieving expense-side savings led JEA to gain comfort in adopting an operating profile that included lower coverage levels and reduced liquidity. These levels, however, were not consistent with previous ratings, and resulted in a downgrade in May 2004 and a negative outlook in December 2004

JEA-POD1-00518
Hearing Exhibit - 00000469

The recent rate actions and ensuing improvement in coverage and liquidity mark an apparent change in operating philosophy under the current CEO.

The utility maintains a strong enterprise risk management program that is ongoing and constantly re-evaluated. JEA uses its impact matrix to prioritize planning and resource allocation, and focuses on issues related to customer service and reliability, environmental risks, financial and credit risks, health and safety, and staffing.

Stable Finances, But Increasing Debt

JEA's recent rate increases have enhanced financial stability. However, maintaining the strong ratings necessitates high levels of coverage of not just debt service, but total fixed charges, including transfers to the city and a proportionate share of the SJRPP bonds.

From 1996-1999, fixed-charge coverage had been fairly good, at an average of 1.50x. However, fixed-charge coverage during fiscals 2000-2005 was substantially lower, at 1.10x in 2000, 1.12x in 2001, 1.13x in 2002, 1.21x in 2003, 1.13x in 2004, and 1.21x in 2005.

Rate actions and cost adjustments taken in 2005 helped boost fixed-cost coverage to 1.51x, including money raised to fund a fuel-rate stabilization reserve (1.38x excluding this money) in fiscal 2006. For fiscal 2007, these numbers were 1.39x and 1.16x, respectively, as JEA utilized $14 million in stabilization fund monies. Management expects to post coverage ranging from 1.46x-1.80x during fiscals 2007-2011, not including the transfers in or out of the rate stabilization fund.

Liquidity is adequate. Cash on hand measured 32 days' operating expenses at fiscal year-end 2006, down from 40 days in 2006 but up from 14 days in 2005 (after auditor restatement). In addition, JEA has a $100 million line of credit that boosts liquidity to 71 days. The utility has yet to borrow from this line for operating purposes. Additional secondary sources of liquidity exist through loans of available reserves at JEA's water system and from the city of Jacksonville.

Debt has increased in recent years as the utility has added new generation. Including off-balance sheet obligations, debt increased to $3.8 billion in 2007 from $1.7 billion in 1999. Meanwhile, equity has fallen to 11% from 58%. Unhedged variable-rate debt accounts for a manageable 25% of debt outstanding.

Additional issuance is likely to push debt levels higher. JEA's five-year capital plan (2008-2012) for the bulk electric system, the Scherer 4 unit, and SJRPP totals $2.2 billion, virtually unchanged from the 2007-2011 plan. About half the current plan should be debt-financed, as recently enacted rate increases will likely fund an increasing share of capital needs. However, with principal repayments at about 57% of issuance, JEA's debt levels should continue rising.

Debt Derivative Profile: '2'

We have assigned JEA a Standard & Poor's DDP overall score of '2' on a scale of 1 to 4, with a 1 representing the lowest risk. The '2' score on JEA's electric revenue bonds reflects Standard & Poor's view that the swaps do not pose significant risks to credit quality. Key determinants behind the DDP score include economically viable swap structures, strong policies governing the oversight of the swap management program, low counterparty risk bolstered by counterparty collateral posting before termination, and the remoteness of termination risks for the utility. Given these strengths, Standard & Poor's has not factored in JEA's swaps as contingent liabilities. Under JEA's bonding program, the utility has three swaps indexed at 68% of LIBOR: one with Goldman Sachs Group Inc., and two with

JEA-POD1-00519
Hearing Exhibit - 00000470

Bear Stearns, for a combined notional amount of $326.43 million. In addition, it has five swaps indexed at the Securities Industry and Financial Markets Association, two of which are with Morgan Stanley Capital Services Inc. (guaranteed by Morgan Stanley [A- Negative/A-1]), and one each with Goldman, Citigroup Inc., and Bear Stearns, for a combined notional amount of $368.03 million. The total notional amount of the swaps is $694.5 million.

JEA manages its swap program through its comprehensive debt management plan. Each potential swap is evaluated in the context of the utility's plan, with particular attention paid to counterparty risk profile and variable-rate exposure. A debt/investment strategy committee meets quarterly to review the performance of fixed-to-floating interest rate swaps and review current interest rate swap and cap decision rules. JEA's board must approve any changes to the decision rules.

Ratings Detail (As Of 21-Aug-2008)		
JEA elec sys sr lien		
Long Term Rating	AA-/Stable	Affirmed
JEA elec sys sr lien		
Unenhanced Rating	AA-(SPUR)/Stable	Affirmed
JEA elec sys subord		
Unenhanced Rating	A-(SPUR)/Stable	Affirmed

Many issues are enhanced by bond insurance.

Hearing Exhibit - 00000471

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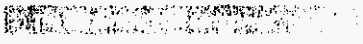

4. **Please provide complete copies of the most recent credit/bond rating reports for JEA done by Moody's Investor Service.**

Response: Attachment POD-4 is the latest Moody's Investors Service rating report.

JEA'S RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS NO. 4

Hearing Exhibit - 00000474

Moody's Investors Service

Global Credit Research
New Issue
27 AUG 2008

New Issue: JEA, FL

MOODY'S ASSIGNS Aa2 TO JEA'S SENIOR LIEN REVENUE BONDS; STABLE OUTLOOK

JEA SELLING SENIOR AND SUBORDINATE LIEN BONDS IN SEPTEMBER 2008

Electric Utilities
FL

Moody's Rating

ISSUE		RATING
Electric System Subordianted Revenue Bonds, Series 2008E		Aa3
Sale Amount	$24,660,000	
Expected Sale Date	09/07/08	
Rating Description	Revenue Bonds	
Electric System Revenue Bonds (Senior Lien) Series Three 2008E		NA
Sale Amount	$43,615,000	
Expected Sale Date	09/07/08	
Rating Description	Revenue	

Opinion

NEW YORK, Aug 27, 2008 -- Moody's Investors Service has assigned the credit rating of Aa2 to JEA's $43,615,000 Electric System Revenue Bonds, Series Three 2008 E and Aa3 to the $24,660,000 Electric System Subordinated Revenue Bonds, 2008 Series E. The amounts could change due to market conditions at time of pricing. The outlook is stable.

Please refer to Moody's High Profile New Issue Report dated March 14 for additional credit information.

We are also affirming the credit rating of Aa2 on JEA's outstanding $ 1,533,800,000 senior lien electric system revenue bonds, the Aa3 rating on the outstanding $1,312,565,226 subordinate lien electric system revenue bonds and the Aa2 credit rating on the outstanding $1,187,569,000 St. Johns River Power Park revenue bonds. JEA provides electric and water and sewer service to the City of Jacksonville, Florida. JEA water and sewer bonds are separately secured.

The long-term rating assignment took into consideration JEA's diverse energy resource mix and transmission ownership, both of which position it well to serve its growing service area. JEA has very competitive retail rates for all customer classes and has played an important role in Jacksonville's continued economic expansion. JEA rate setting process is unregulated and the JEA board has raised rates to ensure a sound financial condition is maintained. JEA's financial record includes sound debt service coverage margins. Debt service coverage on JEA's senior and subordinated electric system debt was times 2.37 times in 2007 and 2.28 times in 2006. The debt service coverage on the St. Johns River Power Park bonds for the past five year period has averaged 1.25 times

USE OF PROCEEDS:

The current offering of bonds will refund various maturities of outstanding debt and replace debt service reserve sureties with cash

LEGAL SECURITY

JEA's senior lien bonds are payable from a first lien on the net revenues of JEA's electric system. There is a rate covenant for the senior lien bonds that requires net revenues to cover debt service by 120% and an additional bonds test that requires net revenues to cover maximum annual debt service by 120%. A renewal and replacement account required to be funded to 5% of gross revenues of the preceding year. Senior lien bonds also secured by a debt service reserve sized at maximum annual interest; subordinate lien bonds do not require a debt service reserve.

INTEREST RATE DERIVATIVES:

JEA provides strong and established management and overview of its variable rate debt and swaps portfolio. There is monthly reporting to the JEA board on the swap performance. JEA has various variable to fixed interest rate swap agreements with strong counterparties with a total notional amount of $890.2 million, executed in conjunction with debt financings to hedge a portion of its variable rate obligations. Basis risk (a mismatch between the variable rate received and the rate JEA pays on its variable rate bonds) is manageable. Additionally, JEA is not required to post collateral. JEA would be required to post only in the case of certain insured swaps and only then (a) certain specified credit events occurred with respect to the insurer, and (b) JEA elected to post collateral to avoid the occurrence of an additional termination event under the swap triggered by (a) above. Termination risk is remote as it generally would require a downgrade of JEA or counterparties below a range of A3 to Baa2, depending on the specific swap agreement. JEA has some potential termination risk exposure with a forward starting swap with Merrill Lynch which has an effective date of 1/11/2011.

JEA has detailed disclosure of swap policies and agreements in its financial statements. JEA performs periodic stress case assessments and based on its latest assessment from March 1, 2008, its current liquidity levels indicate the stress cases to be manageable. Additionally, any losses could be recovered in JEA's base rate and rates are unregulated. Rate increases could take between 45-60 days if necessary.

RECENT DEVELOPMENTS:

JEA Board approved a power purchase agreement with MEAG Power for 206 MW of capacity from MEAG Power's interest in two new nuclear generating units expected to be constructed adjacent to the existing Vogtle Nuclear Station. The 206 MW is forecasted to represent 5% of JEA's total capacity in 2017 when the plants are projected to come online. There has also been an 8-year extension of the JEA-City of Jacksonville General Fund Transfer agreement which provides predictability to the level of the transfer which grows at the same rate of growth as JEA's electricity sales.. The Jacksonville City Council did approve a three percent franchise fee commencing April 1, 2008, which will be a pass through to electricity customers.

Forecasted financial results reflect senior and subordinate lien debt service coverage for 2008-2012 in the 2 times range. Debt service coverage for all electric system bonds was estimated at 2.12 for the 10-month period ending July 31, 2008.

St. John's Power Park had an 88.9% capacity factor in 2007. Total revenues in 2007 were 2.3% higher than 2006, while expenses decreased by 0.2%. Sales to retail customers were slighting lower than prior year but off-system sales were 9.3% higher.

STRENGTHS:

*Fuel and generation fleet diversity and competitive generation production costs

*Competitive retail rates

*JEA board and management closely focused on enterprise risk management

*Demonstrated willingness to raise rates

*The Energy Authority has provided advantage in power marketing and gas acquisition

*Strong service area economy and no dominant high load factor customers

CHALLENGES

*Rising fuel prices pressure internal liquidity

*Uncertainty about greenhouse gas emission regulation could impact cost of JEA's coal-fired generation

*Unexpected forced outage of coal-fired St. Johns River Power Park could pose cost pressure

*Management of system growth remains a challenge

MARKET POSITION/COMPETITIVE STRATEGY: SYSTEM RELIABILITY AND MANAGING GROWTH ARE CONSISTENT JEA STRENGTHS

JEA serves over 412,000 customers in a 900 square-mile service area. Growth slowed in 2007 partly due to general economic trends but JEA forecast is for 2% annual demand growth over next decade. Total MWh sales during 10-month period ending July 31, 2008 increased by only 0.2%. Management's most significant challenge continues to be managing system growth, whether it is increased system sales or decreasing sales due to a slower economy or conservation.

JEA's power resource reserve margin is about 13%. Diversity of its fuel mix and the multiple fuel transportation options strengthen system reliability. JEA's active participation in The Energy Authority (TEA) is also a positive factor in providing the utility with a strong marketing presence in regional power markets. For example, JEA had a 9.3% increase in off-system sales through the use of TEA. In 2007.

JEA has approved a power purchase agreement with MEAG Power to purchase 206 MW of nuclear power from the expansion of the Vogtle Nuclear Station. The new capacity and energy is expected by 2017 and will further diversify JEA fuel mix and provide a non-carbon source of energy.

JEA's owns a significant amount of its electric generation capacity with the St. Johns River Power Park (SJRPP) providing 18% of its capacity and 34% of its energy. SJRPP has been an important power resource in North Florida providing both JEA and Florida Power & Light with reliable coal-fired generating capacity. The two-unit coal and pet coke-fired electric generating station had an equivalent availability factor in 2007 of 90.1% at Unit 1 and 87.7% at Unit 2. Sound performance has been also reported for 2008. The Power Park facility can burn up to 30% pet-coke which contributes to JEA's fuel diversity strength. JEA's other generation facilities have performed well.

Florida has begun to actively assess ways to lower greenhouse gas emissions in the state which could place some pressure on JEA since coal-fired generation is a significant portion of its overall fuel mix. Uncertainty exists over the extent of state and future federal regulation and the impact on existing coal-fired generation facilities. The permit process for the Taylor Energy Center, the proposed 800MW power plant, was suspended after it became clear the plant may have trouble getting approved due the Governor's Office concerns about global warming issues.

JEA's retail rates are set by the JEA's board and are not subject to external regulation, which provides relative certainty to cost recovery. An important consideration in the rating is the cost competitiveness of JEA's retail rates in most customer classes, even after the pass through of higher fuel costs. JEA implemented a fuel recovery charge which has provided more stability to cash flow.

JEA completed a cost of service study and then implemented increases in the base rate and the fuel and purchased power rates effective October 2007. JEA's average residential rate remains below the nearest investor-owned utility's residential rate.

FINANCIAL POSITION AND PERFORMANCE: STRONG FINANCIAL RECORD IS A FUNDAMENTAL CREDIT STRENGTH

JEA has had a well-established record of strong financial results for its electric system. JEA's board has a consistent record of establishing retail rates required to maintain a sound financial position. This represents fundamental credit strength. The audited fiscal year 2007 electric system revenue bond debt service coverage ratio reflected sound results with senior lien debt service coverage at 4.60 times and senior and subordinated debt service coverage at 2.37 times. Fiscal year 2008 is certain to achieve similar results as the unaudited results to date remain sound.

JEA's share of St. Johns River Power Park debt service is paid as an O&M expense of the JEA electric system. Debt service coverage for 2007 on Power Park bonds was 1.25 times, which is the same margin it has been over the past five years.

Forecasted total electric system debt service coverage between 2008 and 2012 is projected to be approximately two times. Additionally, JEA's net working capital for the electric system and the St. Johns River Power Park remains sound. The lack of a debt service reserve requirement for subordinate lien bonds represents a credit weakness.

CAPITAL IMPROVEMENTS: JEA's IMPLEMENTATION OF INTEGRATED RESOURCE PLAN IS MAJOR CAPITAL REQUIREMENT

JEA's debt ratio is above average for a major public power utility and the utility will need to continue to soundly manage its debt as it meets the resource requirements of its growing service area. JEA is in the process of re-evaluating its integrated resource plan without the suspended Taylor Energy Center project. It first decision was approval of the purchased power agreement with MEAG Power for 206 MW of the Plant Vogtle expansion. JEA's projected 2008-2012 capital improvement plan includes $1.8 billion of capital requirements with about $912 million funded by additional borrowing. JEA has substantially completed a debt restructuring program to refund all of its auction rate securities and mitigate exposure on its variable rate bonds to downgraded bond insurers.

Outlook

Moody's credit outlook for JEA's electric system revenue bond is stable based on the expectation management will continue to focus its considerable strengths on running this competitive enterprise.

What Could Change Rating UP:

JEA's continued demonstration of effectively managing growth while maintaining sound debt service coverage levels, competitive rates and a more moderate debt ratio could result in an upgrade.

What Could Change Rating DOWN:

A reduction in debt service coverage margins could result in a lower rating.

KEY FACTS:

Debt Service Coverage Electric System Senior and Subordinate Lien Bonds), 2007: 2.37 times

2006: 2.28 times

St. Johns River Power Park Debt Service Coverage, 2000-2007: 1.25 times

Debt Ratio, 2007: 86.9%

Electric Service Territory: 900 square miles

% Total Fuel Mix, 2007

SJRPP Coal and Petcoke: 33.5%

Northside Coal and Pet coke 26.4%

Scherer Coal: 9.7%

Combined Cycle 11.9%

DEBT STATEMENT, as of August 2008 ($000).

JEA-POD1-00525

St. Johns Power Park Revenue Bonds $1,187,569

Electric System Senior Lien Revenue Bonds $1,533,800

Electric System Subordinated Lien Revenue Bonds $1,312,569

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5. **Please provide complete copies of the most recent credit/bond rating reports for JEA done by Fitch Ratings.**

Response: Attachment POD-5 is the latest Fitch Ratings report.

SERVED this 6th day of November, 2008.

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JEA'S RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS NO. 5

Hearing Exhibit - 00000481

Public Power
North America
New Issue

JEA (Florida)

Electric Utility System

Ratings

New Issues

$44,000,000 Senior Electric System Revenue Bonds	AA–
$22,000,000 Subordinate Electric System Revenue Bonds	AA–

Outstanding Debt

$2,841,792,000 Senior and Subordinate Electric System Revenue Bonds	AA–
$1,312,569,226 St. John's River Power Park Revenue Bonds	AA–

Rating Outlook

Stable

Analysts

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Key Utility Statistics

(Fiscal Year Ended 9/30/07)

System Type	Retail
No. of Customers	410,000
Annual Revenues ($ Mil.)	1,074,504
Top User (% of Revenues)	2.2
Primary Fuel Source	Gas/Oil
Peak Demand (MW)	2,919
Energy Growth (%)	1.5–2.0
Debt Service Coverage (x)	2.05
Days Operating Cash	32
Equity/Capitalization (%)	19

Related Research

- *Jacksonville, Florida, Aug. 28, 2008*
- *State of Florida, June 20, 2008*

Rating Rationale

- The 'AA–' rating and Stable Outlook incorporates JEA's strong management practices, solid financial performance and a diverse customer base.
- Fitch Ratings notes, however, that JEA, like many other utilities throughout Florida (municipal and investor-owned utilities), must cope with volatile natural gas prices, a weakened Florida economy and more limited options for fuel diversification due to the state's moratorium on coal plant development. While these factors may put pressure on JEA's future rating, the utility continues to manage its exposure to these risks and seeks to increase financial and operating predictability.
- Despite recent spikes in natural gas prices, JEA's retail electric rates are still competitive in the region. Fitch believes that JEA's plan to add nuclear generation to its fuel portfolio should provide greater diversity to its generation portfolio.
- Although increased outages in 2007 at the St. John's River Power Park (SJRPP) coal/petroleum (pet) coke plant briefly increased JEA's use of natural gas, the unit is expected to remain efficient.
- Additional support comes from JEA's demonstrated willingness to increase fuel and base rates to provide financial stability and fund necessary expansions of the electric utility system.
- Furthermore, JEA hedged 100% of it coal and 81% of its natural gas supply for fiscal year 2009, adding some measure of predictability to its power costs.
- Fitch will monitor the potential for changes in JEA's total payments to the city of Jacksonville (general fund transfers, franchise fees and other payments) as the state of Florida copes with a weakened economy.

Key Rating Drivers

- Maintenance of financial metrics (debt-service coverage and liquidity) consistent with the 'AA–'rating, given fuel cost pressures, Florida's economic challenges and payments to the city of Jacksonville.
- Ability to recover volatile fuel costs in a timely manner and replenish the rate stabilization fund.
- Implementation of a large capital plan ($2.2 billion) balanced with debt and cash.

Credit Summary

JEA is an integrated utility providing electric and water service within the city of Jacksonville, Fla., and surrounding portions of three neighboring counties. JEA serves 410,000 electric customers, and is one of the largest public power systems in the U.S. with 3,300 megawatts (MW) of net generating capacity.

Series Issue Details

Proceeds from the 20-year 2008E senior and subordinate electric bonds will refund existing bonds to achieve savings, deposit funds to the construction reserve account and restructure bullet payments.

Rating History

Rating	Action	Outlook/ Watch	Date
AA-	Affirm	Stable	9/12/07
AA-	Downgrade	Stable	7/6/05
AA	Affirm	Stable	1/13/05

Although directed by a seven-member board, which is appointed by the mayor and approved by the city council, JEA is governed as an autonomous agency of the city of Jacksonville. JEA's management team, which reports to the board, includes a general manager/CEO, chief financial officer and chief operating officer. The city council approves JEA's annual operating budget and authorizes the maximum dollar amount of debt issuances.

Power Supply

Through ownership and purchases, JEA has 3,300 MW of net generating capacity. The utility owns and operates all of the transmission and distribution facilities that support its service area. In 2007, JEA's power was comprised of coal/pet coke (82%), natural gas/oil (14%) and other purchases (4%). This power mix has historically helped JEA to maintain competitive retail rates.

To support its fuel diversification efforts and long-term regional rate competitiveness, JEA is looking into adding nuclear resources to its fuel portfolio. JEA entered into a 20-year purchase power agreement with Municipal Electric Authority of Georgia (MEAG, rated 'A+'/Stable Outlook) for 200 MW of nuclear power from Vogtle Unit 3, beginning in 2017, and Unit 4, beginning in 2018. This purchase power agreement will allow JEA to derive 5% of its capacity and 10% of energy from nuclear power.

St. John's River Power Park

JEA shares ownership of the St. Johns River Power Park with Florida Power & Light (FPL, rated 'A/F1'/Stable Outlook) in which JEA is the plant operator. The power park is a two-unit 1,276 average net MW coal and pet coke-fired steam electric generating station in Jacksonville, Fla. JEA owns an 80% interest in the power park while FPL owns 20%. However, JEA sells a portion of its energy to FPL, resulting in a 50% share of SJRPP power for each entity. Fitch rates JEA's outstanding SJRPP bonds 'AA–' with a Stable Outlook. Fitch views the 'AA–' rating to be reflective of JEA's strong ability to make timely payments on its full debt burden, including the power park obligations. Additional support for the 'AA–' rating for the power park bonds reflects JEA's credit characteristics, summarized in the Rating Rationale section on page 1 of this report. The power park accounts for 31% of JEA's total energy.

Fitch notes that JEA may have to provide FPL power longer than it anticipated under the SJRPP agreement. FPL filed a complaint against JEA in which the Duval County court determined that the nameplate capacity for SJRPP is 679.6 MW per unit rather than 612 MW, as JEA asserted. However, the ruling does not adversely affect the 'AA–' rating. As it stands, JEA has sufficient capacity to meet current needs, has time to develop a plan to temporarily obtain alternative power sources, and the differential power only represents a modest portion of JEA's 3,300 MW net capacity. JEA plans to appeal the ruling and is still determining its financial impact.

Rates

Even in the midst of rising fuel costs, JEA's overall retail electric rates are competitive. The retail rates are set by JEA's board and are comprised of a fuel rate and a base rate. To manage its exposure to volatile fuel costs, JEA implemented a policy to adjust the fuel component of its electric rates on an annual basis, which can be adjusted as needed if fuel costs are projected to increases more than 10%. JEA also established a rate stabilization fund to be equal to 15% of the utility's annual fuel forecast. Short term, if fuel costs exceed the annual budget, the costs would be absorbed by funds set aside in the rate stabilization fund. Subsequently, the fuel cost adjustments would

JEA-POD1-00518
Hearing Exhibit - 00000483

allow JEA to recoup the cost of past fuel increases. However, this strategy was somewhat hampered by fuel prices that rose faster than JEA expected, depleting the utility's rate stabilization fund. Accordingly, JEA's board extended a $15 per megawatt-hour (MWh) fuel rate increase through the remainder of fiscal year 2008 and throughout fiscal year 2009. As a result of the fuel rate increase, JEA expects that it will collect projected fuel expenses and replenish the stabilization fund by the end of fiscal year 2009. Management is reviewing its pricing methodology to determine how best to recover costs in a timely manner and sufficiently fund the rate stabilization fund. Fitch notes that timely recovery of fuel costs is an important component of the 'AA-' rating. Fitch will monitor the utility's cost recovery efforts and their impact on JEA's financial position.

JEA's base rates support other costs such as the utility's capital plan, debt service and contribution to the city. Planned base rate increases remain on schedule. The second (5.5%) of four base rate increases will be implemented on Oct. 1, 2008 (for fiscal year 2009), to support implementation of JEA's capital plan. Currently, JEA plans to implement additional base rate increases of 5.25% and 3% in fiscal years 2010 and 2011, respectively.

Capital Plan

JEA's capital plan is approximately $2.2 billion (2008–2012), including plans for St. John's River Power Park. The capital plan is still on schedule and expected to be funded with about 43% cash and 57% debt. JEA is in the permitting stage for a 350-MW combined-cycle gas plant at the Greenland Energy Center to be operational by 2012. It is estimated to cost $640 million. The capital plan also includes a new turbine for $81 million, which is expected to be operational in 2009. The remainder of JEA's plan includes $1.5 billion for transmission, distribution and environmental improvements.

Financial Position

Overall, financial metrics are solid. By Fitch's estimate, debt-service coverage in 2007 was 2.05 times (x). Debt-service coverage by the end of 2008 is expected to reflect historical levels of at least 2x as rate increases are implemented. JEA has met its goal of 45 days liquidity, which is supported by a $100 million line of credit with Sun Trust Bank. Currently, JEA has $15 million outstanding on its line of credit.

JEA and the city reached an eight-year agreement beginning October 2008 on transfer payments based upon millage rate and based upon gross kilowatt-hours sold. However, the minimum annual increase is $2.5 million. In fiscal year 2008, the transfer amount is $73.8 million and in FY07, JEA transferred $73.1 million to the city. The city also imposed a franchise fee of 3%, not to exceed 6% of electric system revenues. While transfer payments reduce JEA's net revenues, the franchise fee is passed directly to customers and does not reduce JEA's net revenues. Still, Fitch will monitor JEA's ability to maintain financial metrics in line with the current rating, as the utility increases debt to support implementation of the capital plan, copes with volatile fuel costs and provides payments to the city.

Between January and May 2008, JEA restructured its $4.1 billion debt portfolio to eliminate its exposure to volatile interest rates in the auction-rate securities market. There is little change to the portion of debt that is variable-rate, currently 38% ($1.59 billion) compared to 41% ($1.644 billion) previously. Half of JEA's variable-rate debt ($790 million) is swapped to fixed interest rates.

JEA-POD1-00519

Hearing Exhibit - 00000484

Electric System Revenue Bonds

Principal and interest payments on all senior electric system bonds (including the Series Three 2008E Bonds) are secured equally by a first lien on the net revenues (after operation and maintenance expenses) derived from the operation of the electric system and the amounts on deposit in the revenue fund and the debt-service account in the sinking fund.

Subordinated Electric System Revenue Bonds

Principal and interest payments on the 2008E subordinated bonds are on parity with all subordinated electric system bonds (fixed- and variable-rate debt) and commercial paper notes. All subordinated bonds are secured equally by a lien upon and a pledge of the amounts on deposit in the revenue fund established by the Electric System Resolution and the amounts on deposit in the funds established under the Subordinated Electric System Resolution. The pledge on the subordinated bonds is junior and subordinate to the senior electric system bonds.

There will be no debt-service reserve account for the 2008E subordinated bonds. The Subordinated Electric System Resolution establishes a Subordinated Bond Construction Fund, a Subordinated Bond Fund and a Subordinated Bond Rate Stabilization Fund.

St. John's River Power Park Obligations

Principal and interest payments on all power park bonds are secured by a pledge on the net revenues derived from the operation of the SJRPP.

Since March 2007, borrowings for environmental upgrades and expansions to the power park have and will continue to be issued under a new second bond resolution. The second resolution bonds (Issue Three) will be on parity with JEA's outstanding first resolution power park revenue bonds (Issues One and Two). JEA maintains separate debt service and reserve accounts for the bonds issued under each resolution. Under the second resolution, JEA is wholly responsible for debt service on the new series of bonds while FPL will finance its portion of capital expenditures separately.

However, JEA's and FPL's obligations under the first bond resolution are several and not joint. As such, outstanding power park bonds are dependent on FPL's ability to make payments to JEA. Fitch notes that the SJRPP is still relevant to FPL's energy needs, mitigating FPL's potential default risk. Furthermore, with volatile natural gas prices, Fitch believes that there is value for the resale of SJRPP's power in the Florida energy market.

JEA-POD1-00520

Hearing Exhibit - 00000485

Financial Summary — JEA

($000, Fiscal Years Ended Sept. 30)

	2007	2006	2005	2004
Cash Flow (x)				
Debt-Service Coverage	2.05	2.52	2.18	1.91
Adjusted Debt-Service Coverage with General Fund Transfer	1.48	1.87	1.38	1.15
Coverage of Full Obligations	1.27	1.45	1.19	1.07
Liquidity				
Days Cash on Hand	32	48	14	15
Days Liquidity on Hand	75	91	53	15
Leverage (%)				
Debt/Funds Available for Debt Service	9.7	9.4	12.6	12.9
Equity/Capitalization	13	15	16	21
Equity/Adjusted Capitalization	10	11	13	16
Other (%)				
General Fund Transfer/Total Revenue	6.8	6.5	7.7	8.7
Variable Rate Exposure/Capitalization	17	27	1	36
Income Statement				
Total Operating Revenues	1,074,504	1,090,715	891,177	778,533
Total Operating Expenses	982,449	989,478	859,363	749,847
Operating Income				
Adjustment to Operating Income for Debt-Service Coverage	171,193	175,454	160,046	140,876
Funds Available for Debt Service	263,248	272,813	187,982	169,562
Total Annual Debt Service	128,548	108,143	86,233	88,744
Balance Sheet				
Unrestricted Funds	71,925	107,040	2,415	25,979
Restricted Finds	60,098	53,906	102,712	69,710
Total Cash	**132,023**	**160,946**	**105,127**	**95,689**
Total Debt	2,555,787	2,577,756	2,360,991	2,181,966
Equity and/or Retained Earnings	390,512	438,744	463,605	564,289

Source: JEA's financial reports.

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JEA-POD1-00521
Hearing Exhibit - 00000486

8

JEA's Responses to Staff's Second Request for Production of Documents (Nos. 6-9) (files from PODS 6-8 on CD)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Greenland Energy Center Combined Cycle Conversion in Duval County by JEA.	DOCKET NO. 080614-EM DATED: DECEMBER 29, 2008

JEA'S RESPONSES TO STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 6 – 14)

JEA, pursuant to Rule 28-106.206, Florida Administrative Code, and Rule 1.350, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Second Request for Production of Documents (Nos. 6-14).

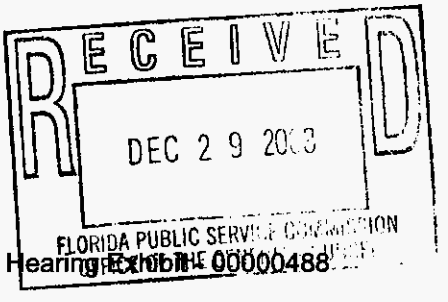
RESPONSES

6. **Please provide an electronic copy of the historical and forecasted input values for the multiple regression models used to forecast Net Energy for Load by revenue class.**

Response: Please see the file titled ***2007NELForecast.xls*** on the attached CD. This file provides historical and forecasted input values for the multiple regression models used to forecast total Net Energy for Load. JEA does not project Net Energy for Load by revenue class.

7. **Please provide an electronic copy of the historical and forecasted input values for the multiple regression models used to forecast Peak Demand by revenue class.**

Response: Please see the files included in the folders titled ***EEI*** and ***NOAA*** as well as the individual files titled ***2007WinterForecast.xls*** and ***2007SummerForecast.xls*** on the attached CD. These files provide historical and forecasted input values for the multiple regression models used to forecast total Peak Demand. JEA does not project Peak dmand by revenue class.



Hearing Exhibit 00000488

8. **Please provide an electronic copy of the output and statistics of the forecasting models.**

Response: Please see the files titled ***SASProgramSummer.docx, SASOutputSummer.docx, SASProgramWinter.docx, SASOutputWinter.docx, 2007WinterForecast.xls, 2007SummerForecast.xls,*** and ***2007NELForecast.xls*** on the attached CD. These files provide the output and statistics from the forecasting models.

9. **Please provide JEA's actual NEL for Load by month for 2008.**

Response: Please see the file titled ***2007NELForecast.xls*** on the attached CD. Refer to the worksheet titled ***MonthlyNEL2008***. This worksheet provides JEA's actual Net Energy for Load by month for calendar year 2008 through November (year to date).

JEA 2008
Net Energy for Load

Month	MWH
January	1,157,138
February	985,292
March	991,532
April	1,038,055
May	1,191,317
June	1,298,270
July	1,435,251
August	1,367,869
September	1,172,208
October	1,071,943
November	978,643
December	
YTD	12,687,517

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Greenland Energy Center Combined Cycle Conversion in Duval County by JEA.	DOCKET NO. 080614-EM DATED: JANUARY 5, 2009

JEA'S RESPONSE TO STAFF'S THIRD REQUEST FOR PRODUCTION OF DOCUMENTS TO JEA (NO. 15)

JEA, pursuant to Rule 28-106.206, Florida Administrative Code, and Rule 1.350, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Third Request for Production of Documents (No. 15)

RESPONSE

15. **Regarding the economic parameters in the application, please provide complete copies of all source documents, reports, etc. that support the *revised* selections of 7.0% as the assumed long-term tax-exempt municipal bond interest rate and 7.0% as the present worth discount rate.**

Response: Please refer to the attached documents that support the revised selection of 7% as the assumed long-term tax-exempt municipal bond interest rate. The present worth discount rate is equal to the cost of capital, which is the long-term tax-exempt municipal bond interest rate.

Served this 5th day of January, 2009.

HOPPING GREEN & SAMS, P.A.

Gary V. Perko
Florida Bar No. 855898
Hopping Green & Sams, P.A.
123 S. Calhoun Street
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(850) 224-8551 (facsimile)
Email: garyp@hgslaw.com

Attorneys for JEA

BOND SUMMARY STATISTICS

JEA, Scherer 4 Project
Scherer 4 Project Issue, Series 2008
Final Pricing - 11.13.2008
11:18am

Dated Date	11/25/2008
Delivery Date	11/25/2008
First Coupon	04/01/2009
Last Maturity	10/01/2038
Arbitrage Yield	5.502242%
True Interest Cost (TIC)	5.561947%
Net Interest Cost (NIC)	5.591142%
All-In TIC	5.592525%
Average Coupon	5.523198%
Average Life (years)	18.307
Duration of Issue (years)	11.236
Par Amount	77,945,000.00
Bond Proceeds	77,480,379.55
Total Interest	78,810,692.56
Net Interest	79,780,186.76
Bond Years from Dated Date	1,426,903,250.00
Bond Years from Delivery Date	1,426,903,250.00
Total Debt Service	156,755,692.56
Maximum Annual Debt Service	8,059,587.50
Average Annual Debt Service	5,251,446.99
Underwriter's Fees (per $1000)	
Average Takedown	5.789579
Other Fee	0.687729
Total Underwriter's Discount	6.477308
Bid Price	98.756182

Bond Component	Par Value	Price	Average Coupon	Average Life
2028 Serial Bonds	42,475,000.00	99.322	4.993%	11.984
2033 Term Bond	14,850,000.00	98.219	5.625%	22.850
2037 Term Bond	15,225,000.00	101.128	6.000%	27.423
2038 Serial Bond	5,395,000.00	98.448	5.750%	29.850
	77,945,000.00			18.307

JEA-POD3-00001
Hearing Exhibit - 00000493

BOND PRICING

JEA, Scherer 4 Project
Scherer 4 Project Issue, Series 2008
Final Pricing - 11.13.2008
11:18am

Bond Component	Maturity Date	Amount	Rate	Yield	Price		Yield to Maturity	Premium (-Discount)	Takedown
2028 Serial Bonds:									
	10/01/2012	1,475,000	4.000%	3.300%	102.508			36,993.00	5.000
	10/01/2013	1,535,000	4.000%	3.550%	101.985			30,469.75	5.000
	10/01/2014	1,595,000	3.750%	3.770%	99.892			-1,722.60	5.000
	10/01/2015	1,655,000	4.000%	4.010%	99.936			-1,059.20	5.000
	10/01/2016	2,720,000	4.200%	4.280%	99.466			-14,524.80	5.000
	10/01/2017	2,305,000	4.375%	4.500%	99.090			-20,975.50	5.000
	10/01/2018	2,200,000	4.600%	4.700%	99.213			-17,314.00	5.000
	10/01/2019	3,550,000	4.750%	4.900%	98.743			-44,623.50	6.250
	10/01/2020	4,500,000	5.000%	5.070%	99.375			-28,125.00	6.250
	10/01/2021	4,905,000	5.100%	5.180%	99.249			-36,836.55	6.250
	10/01/2022	3,915,000	5.125%	5.250%	98.773			-48,037.05	6.250
	10/01/2023	3,485,000	5.200%	5.320%	98.771			-42,830.65	6.250
	10/01/2024	3,385,000	5.250%	5.400%	98.408			-53,889.20	6.250
	10/01/2025	1,150,000	5.375%	5.450%	99.172			-9,522.00	6.250
	10/01/2026	1,185,000	5.375%	5.500%	98.582			-16,803.30	6.250
	10/01/2027	1,075,000	5.500%	5.530%	99.643			-3,837.75	6.250
	10/01/2028	1,840,000	5.500%	5.570%	99.157			-15,511.20	6.250
		42,475,000						-288,149.55	
2033 Term Bond:									
	10/01/2029	2,970,000	5.625%	5.760%	98.219			-52,895.70	6.250
	10/01/2030	2,970,000	5.625%	5.760%	98.219			-52,895.70	6.250
	10/01/2031	2,970,000	5.625%	5.760%	98.219			-52,895.70	6.250
	10/01/2032	2,970,000	5.625%	5.760%	98.219			-52,895.70	6.250
	10/01/2033	2,970,000	5.625%	5.760%	98.219			-52,895.70	6.250
		14,850,000						-264,478.50	
2037 Term Bond:									
	10/01/2034	3,480,000	6.000%	5.750%	101.128	C	5.917%	39,254.40	5.000

JEA Hearing Exhibit 1 - 00000494

BOND PRICING

JEA, Scherer 4 Project
Scherer 4 Project Issue, Series 2008
Final Pricing - 11.13.2008
11:18am

Bond Component	Maturity Date	Amount	Rate	Yield	Price	Yield to Maturity	Premium (-Discount)	Takedown
2037 Term Bond:								
	10/01/2035	3,690,000	6.000%	5.750%	101.128 C	5.917%	41,623.20	5.000
	10/01/2036	3,910,000	6.000%	5.750%	101.128 C	5.917%	44,104.80	5.000
	10/01/2037	4,145,000	6.000%	5.750%	101.128 C	5.917%	46,755.60	5.000
		15,225,000					171,738.00	
2038 Serial Bond:								
	10/01/2038	5,395,000	5.750%	5.860%	98.448		-83,730.40	6.250
		77,945,000					-464,620.45	

Dated Date	11/25/2008	
Delivery Date	11/25/2008	
First Coupon	04/01/2009	
Par Amount	77,945,000.00	
Original Issue Discount	-464,620.45	
Production	77,480,379.55	99.403912%
Underwriter's Discount	-504,873.75	-0.647731%
Purchase Price	76,975,505.80	98.756182%
Accrued Interest		
Net Proceeds	76,975,505.80	

JEA-POD3-00003 Hearing Exhibit - 00000495

MMD Scales for JEA

Term	Year	7/1	7/2	7/3	7/4	7/7	7/8	7/9	7/10	7/11	7/14	7/15	7/16	7/17	7/18	7/21	7/22	7/23	7/24	7/25	7/28	7/29	7/30	7/31	8/1
1	2009	1.7	1.7	1.68	H	1.68	1.58	1.58	1.55	1.55	1.55	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52
2	2010	2.59	2.56	2.54	O	2.5	2.43	2.35	2.31	2.29	2.28	2.18	2.15	2.15	2.15	2.15	2.19	2.22	2.21	2.21	2.21	2.21	2.21	2.17	2.15
3	2011	2.95	2.91	2.89	L	2.85	2.78	2.71	2.68	2.67	2.66	2.59	2.57	2.57	2.58	2.6	2.64	2.67	2.66	2.66	2.66	2.68	2.68	2.64	2.62
4	2012	3.16	3.12	3.1	I	3.06	3.01	2.94	2.91	2.9	2.89	2.82	2.8	2.8	2.81	2.83	2.87	2.9	2.88	2.88	2.87	2.89	2.89	2.86	2.85
5	2013	3.28	3.24	3.22	D	3.18	3.14	3.08	3.05	3.05	3.04	2.98	2.98	2.99	3	3.02	3.06	3.1	3.07	3.07	3.06	3.08	3.08	3.05	3.04
6	2014	3.4	3.36	3.34	A	3.3	3.26	3.2	3.17	3.17	3.16	3.11	3.13	3.15	3.16	3.18	3.23	3.28	3.25	3.25	3.24	3.26	3.26	3.23	3.22
7	2015	3.51	3.47	3.45	Y	3.41	3.38	3.32	3.29	3.29	3.28	3.24	3.27	3.3	3.31	3.33	3.38	3.43	3.4	3.4	3.39	3.41	3.41	3.38	3.37
8	2016	3.62	3.58	3.56		3.52	3.49	3.44	3.41	3.41	3.4	3.36	3.4	3.44	3.45	3.47	3.53	3.58	3.55	3.55	3.54	3.56	3.56	3.53	3.52
9	2017	3.73	3.69	3.67		3.63	3.6	3.56	3.53	3.53	3.52	3.48	3.52	3.57	3.58	3.6	3.67	3.72	3.69	3.69	3.68	3.7	3.7	3.67	3.66
10	2018	3.84	3.8	3.78		3.74	3.71	3.67	3.64	3.65	3.64	3.6	3.64	3.69	3.7	3.72	3.79	3.84	3.81	3.81	3.8	3.82	3.82	3.79	3.78
11	2019	3.94	3.9	3.88	H	3.85	3.83	3.79	3.76	3.77	3.76	3.73	3.78	3.84	3.85	3.86	3.93	3.98	3.95	3.95	3.94	3.96	3.96	3.93	3.92
12	2020	4.04	4	3.98	O	3.95	3.93	3.89	3.86	3.88	3.87	3.85	3.9	3.96	3.98	3.99	4.06	4.11	4.08	4.08	4.07	4.09	4.09	4.06	4.05
13	2021	4.11	4.07	4.05	L	4.03	4.01	3.98	3.95	3.97	3.97	3.95	4	4.06	4.09	4.09	4.17	4.22	4.19	4.19	4.18	4.2	4.2	4.17	4.16
14	2022	4.17	4.13	4.11	I	4.09	4.07	4.04	4.01	4.03	4.03	4.01	4.06	4.12	4.16	4.16	4.24	4.29	4.26	4.26	4.24	4.26	4.26	4.23	4.23
15	2023	4.22	4.18	4.16	D	4.15	4.13	4.1	4.07	4.09	4.09	4.07	4.12	4.18	4.22	4.22	4.3	4.36	4.32	4.32	4.3	4.32	4.32	4.29	4.29
16	2024	4.28	4.24	4.22	A	4.21	4.19	4.16	4.13	4.15	4.15	4.13	4.18	4.24	4.28	4.28	4.36	4.42	4.38	4.38	4.36	4.38	4.38	4.35	4.35
17	2025	4.33	4.29	4.27	Y	4.26	4.24	4.21	4.18	4.2	4.2	4.18	4.23	4.3	4.34	4.34	4.42	4.48	4.44	4.44	4.42	4.44	4.44	4.41	4.41
18	2026	4.38	4.34	4.32		4.31	4.29	4.26	4.23	4.25	4.25	4.23	4.28	4.35	4.4	4.4	4.48	4.54	4.5	4.5	4.48	4.5	4.5	4.47	4.47
19	2027	4.43	4.39	4.37		4.36	4.34	4.31	4.28	4.3	4.3	4.28	4.33	4.4	4.45	4.45	4.53	4.59	4.55	4.55	4.53	4.55	4.55	4.52	4.52
20	2028	4.48	4.44	4.42		4.41	4.39	4.36	4.33	4.35	4.35	4.33	4.38	4.45	4.5	4.5	4.58	4.64	4.6	4.6	4.58	4.6	4.6	4.57	4.57
21	2029	4.53	4.49	4.47	H	4.46	4.44	4.41	4.38	4.4	4.4	4.38	4.43	4.5	4.56	4.56	4.64	4.7	4.65	4.65	4.63	4.65	4.65	4.62	4.62
22	2030	4.57	4.53	4.52	O	4.51	4.49	4.45	4.42	4.44	4.44	4.42	4.47	4.54	4.61	4.61	4.68	4.75	4.69	4.7	4.68	4.7	4.7	4.67	4.67
23	2031	4.6	4.56	4.55	L	4.54	4.52	4.48	4.45	4.48	4.48	4.46	4.51	4.58	4.65	4.65	4.71	4.79	4.71	4.72	4.7	4.72	4.72	4.69	4.69
24	2032	4.62	4.58	4.57	I	4.56	4.54	4.5	4.47	4.5	4.5	4.48	4.53	4.6	4.67	4.67	4.73	4.81	4.72	4.74	4.71	4.73	4.73	4.7	4.7
25	2033	4.64	4.59	4.59	D	4.58	4.55	4.51	4.48	4.51	4.51	4.5	4.54	4.61	4.68	4.68	4.74	4.82	4.73	4.75	4.72	4.74	4.74	4.71	4.71
26	2034	4.65	4.6	4.6	A	4.59	4.56	4.52	4.49	4.52	4.52	4.51	4.55	4.63	4.7	4.7	4.76	4.84	4.74	4.76	4.73	4.75	4.75	4.72	4.72
27	2035	4.66	4.61	4.61	Y	4.6	4.57	4.53	4.5	4.53	4.53	4.52	4.56	4.65	4.71	4.71	4.77	4.85	4.75	4.77	4.74	4.76	4.76	4.73	4.73
28	2036	4.67	4.62	4.62		4.61	4.58	4.54	4.51	4.54	4.54	4.53	4.57	4.66	4.72	4.72	4.78	4.86	4.76	4.78	4.75	4.77	4.77	4.74	4.74
29	2037	4.68	4.63	4.63		4.62	4.59	4.55	4.52	4.55	4.55	4.54	4.58	4.67	4.73	4.73	4.79	4.87	4.77	4.79	4.76	4.78	4.78	4.75	4.75
30	2038	4.69	4.64	4.64		4.63	4.59	4.56	4.53	4.56	4.56	4.55	4.59	4.68	4.74	4.74	4.8	4.88	4.78	4.8	4.76	4.78	4.78	4.75	4.75

Term	Year	7/1	7/2	7/3	7/4	7/7	7/8	7/9	7/10	7/11	7/14	7/15	7/16	7/17	7/18	7/21	7/22	7/23	7/24	7/25	7/28	7/29	7/30	7/31	8/1
1	2009	1.76	1.76	1.74	H	1.74	1.64	1.64	1.59	1.59	1.59	1.56	1.56	1.56	1.56	1.56	1.58	1.58	1.58	1.58	1.58	1.52	1.52	1.52	1.58
2	2010	2.68	2.65	2.63	O	2.59	2.52	2.43	2.38	2.36	2.35	2.25	2.21	2.21	2.22	2.22	2.28	2.31	2.29	2.29	2.29	2.21	2.21	2.17	2.22
3	2011	3.05	3.01	2.99	L	2.95	2.88	2.8	2.75	2.74	2.73	2.66	2.64	2.64	2.65	2.67	2.73	2.76	2.74	2.74	2.74	2.68	2.68	2.64	2.7
4	2012	3.26	3.22	3.2	I	3.16	3.11	3.04	2.99	2.98	2.97	2.9	2.88	2.88	2.89	2.91	2.97	3	2.96	2.96	2.95	2.89	2.89	2.86	2.93
5	2013	3.38	3.34	3.32	D	3.28	3.24	3.18	3.14	3.14	3.13	3.07	3.07	3.08	3.09	3.11	3.16	3.2	3.16	3.16	3.15	3.08	3.08	3.05	3.13
6	2014	3.5	3.46	3.44	A	3.4	3.36	3.3	3.26	3.26	3.25	3.2	3.22	3.24	3.25	3.27	3.33	3.38	3.34	3.34	3.33	3.26	3.26	3.23	3.31
7	2015	3.61	3.57	3.55	Y	3.51	3.48	3.42	3.38	3.38	3.37	3.33	3.36	3.39	3.4	3.42	3.48	3.53	3.49	3.49	3.48	3.41	3.41	3.38	3.46
8	2016	3.72	3.68	3.66		3.62	3.59	3.54	3.5	3.5	3.49	3.45	3.49	3.53	3.54	3.56	3.63	3.68	3.64	3.64	3.63	3.56	3.56	3.53	3.61
9	2017	3.83	3.79	3.77		3.73	3.7	3.66	3.62	3.62	3.61	3.57	3.61	3.66	3.67	3.69	3.77	3.82	3.78	3.78	3.77	3.7	3.7	3.67	3.75
10	2018	3.94	3.9	3.88		3.84	3.81	3.77	3.73	3.74	3.73	3.69	3.73	3.78	3.79	3.81	3.89	3.94	3.9	3.9	3.89	3.82	3.82	3.79	3.87
11	2019	4.04	4	3.98	H	3.95	3.93	3.89	3.85	3.86	3.85	3.82	3.88	3.94	3.95	3.96	4.04	4.09	4.05	4.05	4.04	3.96	3.96	3.93	4.02
12	2020	4.14	4.1	4.08	O	4.05	4.03	3.99	3.96	3.98	3.97	3.95	4.01	4.07	4.09	4.1	4.18	4.23	4.19	4.19	4.18	4.09	4.09	4.06	4.16
13	2021	4.21	4.17	4.15	L	4.13	4.11	4.08	4.05	4.07	4.07	4.05	4.11	4.17	4.2	4.2	4.28	4.34	4.3	4.3	4.29	4.2	4.2	4.17	4.27
14	2022	4.27	4.23	4.21	I	4.19	4.17	4.14	4.11	4.13	4.13	4.11	4.17	4.23	4.27	4.27	4.35	4.41	4.37	4.37	4.35	4.26	4.26	4.23	4.34
15	2023	4.32	4.28	4.26	D	4.25	4.23	4.2	4.17	4.19	4.19	4.17	4.23	4.29	4.33	4.33	4.41	4.47	4.43	4.43	4.41	4.32	4.32	4.29	4.4
16	2024	4.38	4.34	4.32	A	4.31	4.29	4.25	4.22	4.24	4.24	4.22	4.28	4.34	4.38	4.38	4.47	4.53	4.49	4.49	4.47	4.38	4.38	4.35	4.46
17	2025	4.43	4.39	4.37	Y	4.36	4.34	4.3	4.27	4.29	4.29	4.27	4.33	4.4	4.44	4.44	4.53	4.59	4.55	4.55	4.53	4.44	4.44	4.41	4.52
18	2026	4.48	4.44	4.42		4.41	4.39	4.35	4.32	4.34	4.34	4.32	4.38	4.45	4.5	4.5	4.59	4.65	4.6	4.6	4.59	4.5	4.5	4.47	4.58
19	2027	4.53	4.49	4.47		4.46	4.44	4.4	4.37	4.39	4.39	4.37	4.43	4.5	4.55	4.55	4.64	4.7	4.65	4.65	4.64	4.55	4.55	4.52	4.63
20	2028	4.58	4.54	4.52		4.51	4.49	4.45	4.42	4.44	4.44	4.42	4.48	4.55	4.6	4.6	4.69	4.75	4.7	4.7	4.69	4.6	4.6	4.57	4.68
21	2029	4.63	4.59	4.57	H	4.56	4.54	4.5	4.47	4.49	4.49	4.47	4.53	4.6	4.66	4.66	4.75	4.81	4.75	4.75	4.74	4.65	4.65	4.62	4.73
22	2030	4.67	4.63	4.62	O	4.61	4.59	4.54	4.51	4.53	4.53	4.51	4.57	4.64	4.71	4.71	4.79	4.86	4.79	4.8	4.79	4.7	4.7	4.67	4.78
23	2031	4.7	4.66	4.65	L	4.64	4.62	4.57	4.54	4.57	4.57	4.55	4.61	4.68	4.75	4.75	4.82	4.89	4.81	4.82	4.81	4.72	4.72	4.69	4.8
24	2032	4.72	4.68	4.67	I	4.66	4.64	4.59	4.56	4.59	4.59	4.57	4.63	4.7	4.77	4.77	4.84	4.91	4.82	4.84	4.82	4.73	4.73	4.7	4.81
25	2033	4.74	4.69	4.69	D	4.68	4.65	4.6	4.57	4.6	4.6	4.59	4.64	4.71	4.78	4.78	4.85	4.92	4.83	4.85	4.83	4.74	4.74	4.71	4.82
26	2034	4.75	4.7	4.7	A	4.69	4.66	4.61	4.58	4.61	4.61	4.6	4.65	4.73	4.8	4.8	4.87	4.94	4.84	4.86	4.84	4.75	4.75	4.72	4.83
27	2035	4.76	4.71	4.71	Y	4.7	4.67	4.62	4.59	4.62	4.62	4.61	4.66	4.75	4.81	4.81	4.88	4.95	4.85	4.87	4.85	4.76	4.76	4.73	4.84
28	2036	4.77	4.72	4.72		4.71	4.68	4.63	4.6	4.63	4.63	4.62	4.67	4.77	4.83	4.83	4.89	4.96	4.86	4.88	4.86	4.77	4.77	4.74	4.85
29	2037	4.78	4.73	4.73		4.72	4.69	4.64	4.61	4.64	4.64	4.63	4.68	4.78	4.84	4.84	4.9	4.97	4.87	4.89	4.87	4.78	4.78	4.75	4.86
30	2038	4.79	4.74	4.74		4.73	4.69	4.65	4.62	4.65	4.65	4.64	4.69	4.79	4.85	4.85	4.91	4.98	4.88	4.9	4.87	4.78	4.78	4.75	4.86

JEA-Hearing Exhibit 4 - 00000496

MMD Scales

Term	Year	8/4	8/5	8/6	8/7	8/8	8/11	8/12	8/13	8/14	8/15	8/18	8/19	8/20	8/21	8/22	8/25	8/26	8/27	8/28	8/29	9/1	9/2	9/3	9/4
1	2009	1.52	1.58	1.58	1.58	1.58	1.58	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.58	1.58	H	1.58	1.58	1.58
2	2010	2.15	2.15	2.15	2.13	2.11	2.1	2.05	2	2.02	2.02	2.03	2.03	2.03	2.03	2.04	2.03	2.03	2.03	2.03	2.03	O	2.03	2.02	2.01
3	2011	2.62	2.62	2.63	2.6	2.58	2.57	2.5	2.46	2.43	2.41	2.4	2.39	2.38	2.38	2.39	2.38	2.38	2.38	2.38	2.38	L	2.38	2.34	2.32
4	2012	2.85	2.85	2.86	2.83	2.81	2.8	2.73	2.69	2.65	2.63	2.62	2.61	2.6	2.6	2.61	2.6	2.6	2.6	2.6	2.6	I	2.59	2.55	2.53
5	2013	3.04	3.04	3.06	3.03	3.01	3	2.94	2.9	2.86	2.84	2.82	2.81	2.8	2.8	2.81	2.79	2.79	2.79	2.79	2.79	D	2.78	2.74	2.72
6	2014	3.22	3.22	3.24	3.2	3.18	3.18	3.12	3.09	3.05	3.02	3	3	2.99	2.99	3	2.98	2.98	2.98	2.98	2.98	A	2.97	2.93	2.91
7	2015	3.37	3.37	3.39	3.35	3.33	3.33	3.27	3.24	3.2	3.17	3.15	3.15	3.14	3.14	3.15	3.13	3.13	3.14	3.14	3.14	Y	3.13	3.09	3.07
8	2016	3.52	3.52	3.54	3.5	3.48	3.48	3.42	3.39	3.35	3.32	3.3	3.3	3.29	3.29	3.3	3.28	3.28	3.29	3.29	3.29		3.28	3.24	3.22
9	2017	3.66	3.67	3.69	3.64	3.62	3.62	3.56	3.54	3.5	3.47	3.45	3.45	3.44	3.44	3.45	3.43	3.43	3.45	3.45	3.45		3.44	3.4	3.37
10	2018	3.78	3.79	3.81	3.76	3.74	3.74	3.68	3.68	3.64	3.61	3.59	3.59	3.58	3.59	3.6	3.58	3.58	3.6	3.6	3.6		3.59	3.55	3.52
11	2019	3.92	3.93	3.96	3.91	3.89	3.89	3.83	3.83	3.79	3.76	3.74	3.74	3.73	3.74	3.75	3.73	3.73	3.75	3.75	3.75	H	3.74	3.71	3.68
12	2020	4.05	4.06	4.09	4.04	4.02	4.02	3.96	3.96	3.93	3.9	3.88	3.88	3.87	3.88	3.9	3.88	3.88	3.9	3.9	3.9	O	3.89	3.86	3.83
13	2021	4.16	4.17	4.2	4.15	4.13	4.13	4.07	4.07	4.04	4.01	3.99	3.99	3.98	3.99	4.01	3.99	3.99	4.02	4.02	4.02	L	4.01	3.98	3.94
14	2022	4.23	4.24	4.27	4.22	4.2	4.2	4.14	4.14	4.12	4.09	4.07	4.07	4.06	4.07	4.09	4.07	4.07	4.1	4.1	4.1	I	4.1	4.08	4.04
15	2023	4.29	4.3	4.33	4.28	4.26	4.26	4.2	4.2	4.18	4.15	4.13	4.13	4.12	4.13	4.15	4.13	4.13	4.16	4.16	4.16	D	4.16	4.14	4.1
16	2024	4.35	4.36	4.39	4.34	4.32	4.32	4.26	4.26	4.24	4.21	4.19	4.19	4.18	4.19	4.21	4.19	4.19	4.22	4.22	4.22	A	4.22	4.2	4.16
17	2025	4.41	4.42	4.45	4.39	4.37	4.37	4.32	4.32	4.29	4.26	4.25	4.25	4.24	4.25	4.27	4.25	4.25	4.28	4.28	4.28	Y	4.28	4.26	4.21
18	2026	4.47	4.48	4.5	4.44	4.42	4.42	4.37	4.37	4.34	4.31	4.3	4.3	4.29	4.31	4.33	4.31	4.31	4.33	4.33	4.33		4.33	4.31	4.26
19	2027	4.52	4.53	4.55	4.49	4.47	4.47	4.42	4.42	4.39	4.36	4.35	4.35	4.34	4.36	4.38	4.36	4.36	4.38	4.38	4.38		4.38	4.36	4.31
20	2028	4.57	4.58	4.6	4.54	4.52	4.52	4.47	4.47	4.44	4.41	4.4	4.4	4.39	4.41	4.43	4.41	4.41	4.43	4.43	4.43		4.43	4.41	4.36
21	2029	4.62	4.63	4.66	4.6	4.58	4.58	4.53	4.53	4.49	4.46	4.45	4.45	4.44	4.46	4.48	4.46	4.46	4.48	4.48	4.48	H	4.48	4.46	4.41
22	2030	4.67	4.68	4.72	4.66	4.64	4.64	4.59	4.59	4.54	4.51	4.5	4.5	4.49	4.51	4.53	4.51	4.51	4.53	4.53	4.53	O	4.53	4.51	4.46
23	2031	4.69	4.71	4.75	4.69	4.67	4.68	4.63	4.63	4.59	4.55	4.54	4.55	4.54	4.56	4.58	4.56	4.56	4.58	4.58	4.58	L	4.58	4.56	4.51
24	2032	4.7	4.74	4.78	4.72	4.7	4.72	4.67	4.67	4.63	4.59	4.58	4.59	4.58	4.6	4.62	4.6	4.6	4.62	4.62	4.62	I	4.62	4.6	4.55
25	2033	4.71	4.76	4.81	4.75	4.72	4.75	4.7	4.7	4.65	4.61	4.6	4.61	4.6	4.62	4.64	4.62	4.62	4.65	4.65	4.65	D	4.65	4.63	4.58
26	2034	4.72	4.77	4.83	4.76	4.73	4.76	4.71	4.71	4.66	4.62	4.61	4.63	4.62	4.64	4.66	4.64	4.64	4.67	4.67	4.67	A	4.67	4.65	4.6
27	2035	4.73	4.78	4.84	4.77	4.74	4.77	4.72	4.72	4.67	4.63	4.62	4.64	4.63	4.65	4.67	4.65	4.65	4.68	4.68	4.68	Y	4.68	4.66	4.61
28	2036	4.74	4.79	4.85	4.78	4.75	4.78	4.73	4.73	4.68	4.64	4.63	4.65	4.64	4.66	4.68	4.66	4.66	4.69	4.69	4.69		4.69	4.67	4.62
29	2037	4.75	4.8	4.86	4.79	4.76	4.79	4.74	4.74	4.69	4.65	4.64	4.66	4.65	4.67	4.69	4.67	4.67	4.7	4.7	4.7		4.7	4.68	4.63
30	2038	4.75	4.81	4.87	4.8	4.77	4.8	4.75	4.75	4.7	4.66	4.65	4.67	4.66	4.68	4.7	4.68	4.68	4.71	4.71	4.71		4.71	4.69	4.64

Term	Year	8/4	8/5	8/6	8/7	8/8	8/11	8/12	8/13	8/14	8/15	8/18	8/19	8/20	8/21	8/22	8/25	8/26	8/27	8/28	8/29	9/1	9/2	9/3	9/4
1	2009	1.58	1.64	1.64	1.64	1.64	1.64	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.64	1.64	H	1.64	1.64	1.64
2	2010	2.22	2.22	2.22	2.2	2.18	2.17	2.12	2.07	2.09	2.09	2.1	2.1	2.1	2.1	2.11	2.1	2.1	2.1	2.1	2.1	O	2.1	2.09	2.08
3	2011	2.7	2.7	2.71	2.69	2.67	2.65	2.58	2.54	2.51	2.49	2.48	2.47	2.47	2.47	2.48	2.47	2.47	2.47	2.47	2.47	L	2.47	2.43	2.41
4	2012	2.93	2.93	2.94	2.91	2.89	2.88	2.81	2.77	2.73	2.71	2.7	2.69	2.69	2.69	2.7	2.69	2.69	2.69	2.69	2.69	I	2.68	2.64	2.62
5	2013	3.13	3.13	3.15	3.12	3.1	3.08	3.02	2.98	2.94	2.92	2.9	2.89	2.89	2.89	2.9	2.88	2.88	2.88	2.88	2.88	D	2.87	2.83	2.81
6	2014	3.31	3.31	3.33	3.29	3.27	3.26	3.2	3.17	3.13	3.1	3.08	3.08	3.08	3.08	3.09	3.07	3.07	3.07	3.07	3.07	A	3.06	3.02	3
7	2015	3.46	3.46	3.48	3.44	3.42	3.41	3.35	3.32	3.28	3.25	3.23	3.23	3.23	3.23	3.24	3.22	3.22	3.23	3.23	3.23	Y	3.22	3.18	3.16
8	2016	3.61	3.61	3.63	3.59	3.57	3.56	3.5	3.47	3.43	3.4	3.38	3.38	3.38	3.38	3.39	3.37	3.37	3.38	3.38	3.38		3.38	3.34	3.32
9	2017	3.75	3.76	3.78	3.73	3.71	3.7	3.64	3.62	3.58	3.55	3.53	3.53	3.53	3.53	3.54	3.52	3.53	3.55	3.55	3.55		3.55	3.51	3.48
10	2018	3.87	3.88	3.9	3.85	3.83	3.82	3.76	3.76	3.72	3.69	3.67	3.67	3.67	3.68	3.69	3.67	3.68	3.7	3.7	3.7		3.7	3.66	3.63
11	2019	4.02	4.03	4.06	4.01	3.99	3.98	3.92	3.92	3.88	3.85	3.83	3.83	3.83	3.84	3.85	3.83	3.84	3.86	3.86	3.86	H	3.86	3.82	3.79
12	2020	4.16	4.17	4.2	4.15	4.13	4.12	4.06	4.06	4.03	4	3.98	3.98	3.98	3.99	4.01	3.99	4	4.02	4.02	4.02	O	4.02	3.98	3.95
13	2021	4.27	4.28	4.31	4.26	4.24	4.24	4.18	4.18	4.15	4.12	4.1	4.1	4.1	4.11	4.13	4.11	4.12	4.15	4.15	4.15	L	4.15	4.11	4.07
14	2022	4.34	4.35	4.38	4.33	4.31	4.31	4.25	4.25	4.23	4.2	4.18	4.18	4.18	4.19	4.21	4.19	4.2	4.23	4.23	4.23	I	4.23	4.21	4.17
15	2023	4.4	4.41	4.44	4.39	4.37	4.37	4.31	4.31	4.29	4.26	4.24	4.25	4.25	4.26	4.28	4.25	4.26	4.29	4.29	4.29	D	4.29	4.27	4.23
16	2024	4.46	4.47	4.5	4.45	4.43	4.43	4.37	4.37	4.35	4.32	4.3	4.31	4.31	4.32	4.34	4.31	4.32	4.35	4.35	4.35	A	4.35	4.33	4.29
17	2025	4.52	4.53	4.56	4.5	4.48	4.48	4.43	4.43	4.4	4.37	4.36	4.37	4.37	4.38	4.4	4.37	4.38	4.41	4.41	4.41	Y	4.41	4.39	4.34
18	2026	4.58	4.59	4.61	4.55	4.53	4.53	4.48	4.48	4.45	4.42	4.41	4.42	4.42	4.44	4.46	4.43	4.44	4.46	4.46	4.46		4.46	4.44	4.39
19	2027	4.63	4.64	4.66	4.6	4.58	4.58	4.53	4.53	4.5	4.47	4.46	4.47	4.47	4.49	4.51	4.48	4.49	4.51	4.51	4.51		4.51	4.49	4.44
20	2028	4.68	4.69	4.71	4.65	4.63	4.63	4.58	4.58	4.55	4.52	4.51	4.52	4.52	4.54	4.56	4.53	4.54	4.56	4.56	4.56		4.56	4.54	4.49
21	2029	4.73	4.74	4.77	4.71	4.69	4.69	4.64	4.64	4.6	4.57	4.56	4.57	4.57	4.59	4.61	4.58	4.59	4.61	4.61	4.61	H	4.61	4.59	4.54
22	2030	4.78	4.79	4.83	4.77	4.75	4.75	4.7	4.7	4.65	4.62	4.61	4.62	4.62	4.64	4.66	4.63	4.64	4.66	4.66	4.66	O	4.66	4.64	4.59
23	2031	4.8	4.82	4.87	4.8	4.78	4.79	4.74	4.74	4.7	4.66	4.65	4.67	4.67	4.69	4.71	4.68	4.68	4.7	4.7	4.7	L	4.7	4.68	4.63
24	2032	4.81	4.85	4.9	4.83	4.81	4.83	4.78	4.78	4.74	4.7	4.69	4.71	4.71	4.73	4.75	4.72	4.72	4.74	4.74	4.74	I	4.74	4.72	4.67
25	2033	4.82	4.87	4.93	4.86	4.83	4.86	4.81	4.81	4.76	4.72	4.71	4.73	4.73	4.75	4.77	4.74	4.74	4.77	4.77	4.77	D	4.77	4.75	4.7
26	2034	4.83	4.88	4.95	4.87	4.84	4.87	4.82	4.82	4.77	4.73	4.72	4.75	4.75	4.77	4.79	4.76	4.76	4.79	4.79	4.79	A	4.79	4.77	4.72
27	2035	4.84	4.89	4.96	4.88	4.85	4.88	4.83	4.83	4.78	4.74	4.73	4.76	4.76	4.78	4.8	4.77	4.77	4.8	4.8	4.8	Y	4.8	4.78	4.73
28	2036	4.85	4.9	4.97	4.89	4.86	4.89	4.84	4.84	4.79	4.75	4.74	4.77	4.77	4.79	4.81	4.78	4.78	4.81	4.81	4.81		4.81	4.79	4.74
29	2037	4.86	4.91	4.98	4.9	4.87	4.9	4.85	4.85	4.8	4.76	4.75	4.78	4.78	4.8	4.82	4.79	4.79	4.82	4.82	4.82		4.82	4.8	4.75
30	2038	4.86	4.92	4.99	4.91	4.88	4.91	4.86	4.86	4.81	4.77	4.76	4.79	4.79	4.81	4.83	4.8	4.8	4.83	4.83	4.83		4.83	4.81	4.76

JEA-POD3-00005 Hearing Exhibit - 00000497

MMD Scales

Term	Year	9/5	9/8	9/9	9/10	9/11	9/12	9/15	9/16	9/17	9/18	9/19	9/22	9/23	9/24	9/25	9/26	9/29	9/30	10/1	10/2	10/3	10/6	10/7	10/8
1	2009	1.58	1.58	1.58	1.58	1.68	1.68	1.53	1.63	1.73	2	2	2.1	2.15	2.15	2.1	2.1	2.1	2.1	2.1	2.15	2.18	2.18	2.18	2.18
2	2010	2.01	2.02	2	2	2	2	1.98	2.01	2.06	2.26	2.26	2.29	2.34	2.35	2.35	2.45	2.47	2.49	2.51	2.51	2.51	2.51	2.51	2.51
3	2011	2.32	2.33	2.29	2.29	2.28	2.29	2.27	2.3	2.36	2.56	2.56	2.58	2.63	2.66	2.67	2.77	2.8	2.83	2.85	2.85	2.85	2.85	2.85	2.85
4	2012	2.53	2.54	2.5	2.5	2.49	2.51	2.49	2.52	2.6	2.8	2.8	2.82	2.87	2.9	2.93	3.01	3.06	3.1	3.12	3.12	3.12	3.12	3.12	3.14
5	2013	2.72	2.73	2.69	2.69	2.68	2.7	2.68	2.71	2.79	3	3	3.02	3.07	3.1	3.13	3.21	3.26	3.3	3.32	3.32	3.32	3.31	3.31	3.34
6	2014	2.9	2.91	2.87	2.87	2.85	2.88	2.86	2.89	2.97	3.19	3.19	3.21	3.26	3.29	3.32	3.4	3.45	3.49	3.51	3.51	3.51	3.5	3.5	3.55
7	2015	3.06	3.07	3.03	3.03	3.01	3.04	3.02	3.05	3.13	3.38	3.38	3.4	3.45	3.48	3.51	3.59	3.64	3.68	3.7	3.7	3.7	3.69	3.69	3.76
8	2016	3.21	3.22	3.18	3.18	3.16	3.19	3.18	3.21	3.29	3.54	3.54	3.56	3.63	3.67	3.7	3.76	3.81	3.85	3.88	3.88	3.88	3.87	3.87	3.95
9	2017	3.36	3.37	3.33	3.33	3.31	3.34	3.33	3.36	3.44	3.71	3.7	3.72	3.8	3.85	3.89	3.93	3.98	4.03	4.06	4.06	4.06	4.05	4.05	4.14
10	2018	3.51	3.52	3.48	3.48	3.46	3.49	3.48	3.51	3.59	3.88	3.86	3.88	3.97	4.02	4.06	4.1	4.15	4.2	4.23	4.23	4.22	4.21	4.21	4.31
11	2019	3.67	3.68	3.64	3.64	3.62	3.66	3.65	3.68	3.76	4.06	4.01	4.04	4.13	4.18	4.22	4.28	4.33	4.38	4.42	4.42	4.39	4.39	4.4	4.49
12	2020	3.81	3.83	3.79	3.79	3.77	3.81	3.81	3.86	3.94	4.24	4.18	4.21	4.3	4.36	4.42	4.48	4.53	4.58	4.63	4.63	4.58	4.58	4.6	4.67
13	2021	3.92	3.94	3.9	3.9	3.88	3.92	3.93	4	4.08	4.38	4.31	4.35	4.44	4.52	4.59	4.65	4.7	4.76	4.81	4.81	4.76	4.75	4.77	4.84
14	2022	4.02	4.04	3.99	3.99	3.97	4.01	4.03	4.13	4.21	4.51	4.44	4.49	4.58	4.66	4.73	4.79	4.84	4.9	4.94	4.94	4.89	4.88	4.9	4.97
15	2023	4.08	4.1	4.05	4.05	4.03	4.06	4.11	4.21	4.29	4.59	4.52	4.57	4.66	4.74	4.81	4.87	4.92	4.98	5	5	4.95	4.93	4.95	5.02
16	2024	4.13	4.15	4.1	4.1	4.08	4.11	4.17	4.28	4.36	4.66	4.59	4.64	4.73	4.81	4.88	4.92	4.97	5.02	5.04	5.04	4.98	4.96	4.98	5.05
17	2025	4.18	4.2	4.15	4.15	4.13	4.16	4.23	4.34	4.42	4.72	4.65	4.7	4.78	4.86	4.93	4.97	5.01	5.05	5.07	5.07	5.01	4.99	5.01	5.08
18	2026	4.23	4.25	4.2	4.2	4.18	4.21	4.29	4.4	4.48	4.78	4.71	4.75	4.83	4.91	4.97	5.01	5.04	5.08	5.1	5.1	5.04	5.02	5.04	5.11
19	2027	4.28	4.3	4.25	4.25	4.23	4.26	4.35	4.46	4.54	4.84	4.76	4.79	4.87	4.95	5.01	5.04	5.07	5.11	5.13	5.13	5.07	5.05	5.07	5.14
20	2028	4.33	4.35	4.3	4.3	4.28	4.31	4.41	4.52	4.6	4.89	4.81	4.83	4.91	4.99	5.04	5.07	5.1	5.14	5.16	5.16	5.1	5.08	5.1	5.17
21	2029	4.38	4.4	4.35	4.35	4.33	4.36	4.46	4.58	4.68	4.94	4.85	4.87	4.95	5.02	5.07	5.09	5.12	5.17	5.19	5.19	5.12	5.09	5.12	5.2
22	2030	4.43	4.45	4.4	4.4	4.38	4.41	4.51	4.65	4.75	4.98	4.88	4.91	4.99	5.05	5.1	5.11	5.14	5.2	5.22	5.22	5.14	5.1	5.14	5.23
23	2031	4.48	4.49	4.44	4.44	4.43	4.47	4.57	4.71	4.82	5.01	4.91	4.94	5.02	5.07	5.11	5.12	5.15	5.21	5.24	5.24	5.15	5.11	5.16	5.26
24	2032	4.52	4.53	4.48	4.48	4.47	4.51	4.61	4.76	4.88	5.03	4.93	4.96	5.03	5.08	5.11	5.12	5.15	5.22	5.25	5.25	5.16	5.12	5.17	5.28
25	2033	4.54	4.55	4.5	4.5	4.49	4.53	4.63	4.79	4.9	5.05	4.95	4.98	5.04	5.09	5.12	5.13	5.16	5.23	5.26	5.26	5.16	5.12	5.18	5.3
26	2034	4.56	4.56	4.51	4.51	4.5	4.54	4.64	4.8	4.91	5.05	4.95	4.99	5.04	5.09	5.12	5.13	5.16	5.23	5.27	5.26	5.16	5.12	5.18	5.31
27	2035	4.57	4.57	4.52	4.52	4.51	4.55	4.65	4.82	4.92	5.06	4.96	5	5.05	5.1	5.13	5.14	5.17	5.24	5.28	5.27	5.17	5.13	5.19	5.32
28	2036	4.58	4.58	4.52	4.52	4.51	4.55	4.65	4.83	4.93	5.06	4.96	5.01	5.06	5.11	5.14	5.14	5.17	5.24	5.28	5.27	5.17	5.13	5.19	5.33
29	2037	4.59	4.59	4.53	4.53	4.52	4.56	4.66	4.84	4.94	5.07	4.97	5.02	5.07	5.12	5.15	5.15	5.18	5.25	5.29	5.28	5.18	5.14	5.2	5.34
30	2038	4.6	4.6	4.53	4.53	4.52	4.56	4.66	4.84	4.94	5.07	4.97	5.03	5.08	5.13	5.16	5.16	5.19	5.25	5.29	5.28	5.18	5.14	5.2	5.35

Term	Year	9/5	9/8	9/9	9/10	9/11	9/12	9/15	9/16	9/17	9/18	9/19	9/22	9/23	9/24	9/25	9/26	9/29	9/30	10/1	10/2	10/3	10/6	10/7	10/8
1	2009	1.58	1.58	1.58	1.58	1.68	1.74	1.59	1.69	1.79	2.06	2.06	2.16	2.21	2.21	2.16	2.16	2.16	2.16	2.16	2.21	2.24	2.24	2.24	2.24
2	2010	2.01	2.02	2	2	2	2.07	2.05	2.08	2.16	2.36	2.36	2.39	2.44	2.45	2.45	2.55	2.57	2.59	2.61	2.61	2.61	2.61	2.61	2.61
3	2011	2.32	2.33	2.29	2.29	2.28	2.38	2.36	2.39	2.48	2.68	2.68	2.7	2.75	2.78	2.79	2.89	2.92	2.95	2.97	2.97	2.97	2.97	2.97	2.97
4	2012	2.53	2.54	2.5	2.5	2.49	2.61	2.59	2.62	2.72	2.94	2.94	2.96	3.01	3.04	3.07	3.15	3.2	3.24	3.26	3.26	3.26	3.26	3.26	3.28
5	2013	2.72	2.73	2.69	2.69	2.68	2.8	2.78	2.81	2.91	3.14	3.14	3.16	3.21	3.24	3.27	3.35	3.4	3.44	3.46	3.46	3.46	3.45	3.45	3.48
6	2014	2.9	2.91	2.87	2.87	2.85	2.98	2.96	2.99	3.09	3.35	3.35	3.36	3.41	3.44	3.47	3.55	3.6	3.64	3.66	3.66	3.66	3.65	3.65	3.7
7	2015	3.06	3.07	3.03	3.03	3.01	3.14	3.12	3.15	3.25	3.54	3.54	3.55	3.6	3.63	3.66	3.74	3.79	3.83	3.85	3.85	3.85	3.84	3.84	3.91
8	2016	3.21	3.22	3.18	3.18	3.16	3.3	3.29	3.32	3.42	3.71	3.71	3.72	3.79	3.83	3.86	3.92	3.97	4.01	4.04	4.04	4.04	4.03	4.03	4.11
9	2017	3.36	3.37	3.33	3.33	3.31	3.46	3.45	3.48	3.58	3.88	3.87	3.88	3.96	4.01	4.05	4.09	4.14	4.19	4.22	4.22	4.22	4.21	4.21	4.3
10	2018	3.51	3.52	3.48	3.48	3.46	3.61	3.6	3.63	3.73	4.05	4.03	4.04	4.13	4.18	4.22	4.26	4.31	4.36	4.39	4.39	4.38	4.37	4.37	4.47
11	2019	3.67	3.68	3.64	3.64	3.62	3.78	3.77	3.8	3.9	4.23	4.18	4.21	4.3	4.35	4.39	4.45	4.5	4.55	4.59	4.59	4.56	4.55	4.56	4.65
12	2020	3.81	3.83	3.79	3.79	3.77	3.94	3.94	3.99	4.09	4.41	4.35	4.38	4.47	4.53	4.59	4.65	4.7	4.75	4.8	4.8	4.75	4.74	4.76	4.83
13	2021	3.92	3.94	3.9	3.9	3.88	4.05	4.06	4.13	4.23	4.55	4.48	4.52	4.61	4.69	4.76	4.82	4.87	4.93	4.98	4.98	4.93	4.91	4.93	5
14	2022	4.02	4.04	3.99	3.99	3.97	4.14	4.16	4.26	4.36	4.68	4.61	4.66	4.75	4.83	4.9	4.96	5.01	5.06	5.09	5.09	5.04	5.02	5.04	5.11
15	2023	4.08	4.1	4.05	4.05	4.03	4.19	4.24	4.34	4.44	4.76	4.69	4.74	4.83	4.91	4.98	5.04	5.09	5.14	5.15	5.15	5.1	5.08	5.09	5.16
16	2024	4.13	4.15	4.1	4.1	4.08	4.24	4.31	4.42	4.51	4.83	4.76	4.81	4.9	4.98	5.05	5.09	5.14	5.18	5.19	5.19	5.13	5.11	5.12	5.19
17	2025	4.18	4.2	4.15	4.15	4.13	4.29	4.37	4.48	4.57	4.89	4.82	4.87	4.95	5.03	5.1	5.14	5.18	5.21	5.22	5.22	5.16	5.14	5.15	5.22
18	2026	4.23	4.25	4.2	4.2	4.18	4.34	4.43	4.54	4.63	4.95	4.88	4.92	5	5.08	5.14	5.18	5.21	5.24	5.25	5.25	5.19	5.17	5.18	5.25
19	2027	4.28	4.3	4.25	4.25	4.23	4.39	4.49	4.6	4.69	5.01	4.93	4.96	5.04	5.12	5.18	5.21	5.24	5.27	5.28	5.28	5.22	5.2	5.21	5.28
20	2028	4.33	4.35	4.3	4.3	4.28	4.44	4.55	4.66	4.75	5.05	4.97	4.99	5.07	5.15	5.2	5.23	5.26	5.3	5.31	5.31	5.25	5.23	5.24	5.31
21	2029	4.38	4.4	4.35	4.35	4.33	4.49	4.6	4.72	4.82	5.08	4.99	5.01	5.09	5.16	5.21	5.23	5.27	5.32	5.34	5.34	5.27	5.24	5.26	5.34
22	2030	4.43	4.45	4.4	4.4	4.38	4.54	4.65	4.79	4.88	5.11	5.01	5.04	5.12	5.18	5.22	5.23	5.27	5.33	5.35	5.35	5.27	5.24	5.28	5.37
23	2031	4.48	4.49	4.44	4.44	4.43	4.6	4.71	4.85	4.94	5.14	5.04	5.07	5.15	5.2	5.23	5.24	5.28	5.34	5.37	5.37	5.28	5.24	5.29	5.39
24	2032	4.52	4.53	4.48	4.48	4.47	4.63	4.75	4.9	4.99	5.15	5.05	5.08	5.15	5.21	5.23	5.24	5.28	5.35	5.38	5.38	5.29	5.25	5.3	5.41
25	2033	4.54	4.55	4.5	4.5	4.49	4.65	4.77	4.93	5.01	5.16	5.06	5.09	5.15	5.21	5.24	5.25	5.29	5.36	5.39	5.39	5.29	5.25	5.31	5.43
26	2034	4.56	4.56	4.51	4.51	4.5	4.66	4.78	4.94	5.02	5.16	5.06	5.1	5.15	5.21	5.24	5.25	5.29	5.36	5.4	5.39	5.29	5.25	5.31	5.44
27	2035	4.57	4.57	4.52	4.52	4.51	4.67	4.79	4.96	5.03	5.17	5.07	5.11	5.16	5.21	5.25	5.26	5.3	5.37	5.41	5.4	5.3	5.26	5.32	5.45
28	2036	4.58	4.58	4.52	4.52	4.51	4.67	4.79	4.97	5.04	5.17	5.07	5.12	5.17	5.22	5.25	5.26	5.3	5.37	5.41	5.4	5.3	5.26	5.32	5.46
29	2037	4.59	4.59	4.53	4.53	4.52	4.68	4.8	4.98	5.05	5.18	5.08	5.13	5.18	5.23	5.26	5.26	5.31	5.38	5.42	5.41	5.31	5.27	5.33	5.47
30	2038	4.6	4.6	4.53	4.53	4.52	4.68	4.8	4.98	5.05	5.18	5.08	5.14	5.19	5.24	5.27	5.27	5.31	5.38	5.42	5.41	5.31	5.27	5.33	5.48

MMD Scales

Term	Year	10/9	10/10	10/13	10/14	10/15	10/16	10/17	10/20	10/21	10/22	10/23	10/24	10/27	10/28	10/29	10/30	10/31	11/3	11/4	11/5	11/6	11/7	11/10	11/11
1	2009	2.15	2.1	H	2.11	2.16	2.16	2.16	2.16	2	1.8	1.75	1.68	1.68	1.68	1.68	1.65	1.55	1.55	1.5	1.5	1.3	1.28	1.28	H
2	2010	2.51	2.55	O	2.76	2.81	2.82	2.82	2.82	2.78	2.73	2.68	2.61	2.61	2.61	2.58	2.55	2.48	2.48	2.45	2.38	2.3	2.25	2.25	O
3	2011	2.86	2.9	L	3.11	3.19	3.23	3.23	3.23	3.19	3.09	3.04	2.97	2.97	2.97	2.94	2.92	2.85	2.85	2.82	2.7	2.62	2.57	2.57	L
4	2012	3.17	3.22	I	3.43	3.51	3.56	3.57	3.57	3.53	3.43	3.36	3.29	3.29	3.29	3.26	3.24	3.17	3.16	3.13	3.03	2.95	2.9	2.9	I
5	2013	3.37	3.42	D	3.63	3.71	3.76	3.78	3.78	3.74	3.63	3.55	3.48	3.48	3.48	3.45	3.44	3.39	3.38	3.34	3.25	3.16	3.1	3.1	D
6	2014	3.58	3.66	A	3.86	3.94	3.98	4	4	3.95	3.82	3.74	3.66	3.66	3.67	3.64	3.63	3.58	3.57	3.52	3.43	3.33	3.27	3.27	A
7	2015	3.8	3.93	Y	4.1	4.18	4.21	4.22	4.22	4.16	3.99	3.91	3.82	3.82	3.83	3.82	3.82	3.77	3.76	3.7	3.64	3.54	3.46	3.46	Y
8	2016	4.02	4.16		4.33	4.41	4.43	4.43	4.43	4.36	4.18	4.09	3.99	3.99	4	3.99	3.99	3.94	3.93	3.88	3.83	3.76	3.68	3.68	
9	2017	4.24	4.39		4.57	4.65	4.65	4.65	4.64	4.56	4.37	4.27	4.16	4.16	4.17	4.16	4.16	4.12	4.11	4.06	4.01	3.96	3.89	3.89	
10	2018	4.41	4.58		4.78	4.86	4.86	4.86	4.85	4.76	4.56	4.46	4.34	4.34	4.35	4.35	4.35	4.31	4.3	4.25	4.2	4.15	4.09	4.09	
11	2019	4.58	4.78	H	4.97	5.03	5.03	5.03	5.02	4.91	4.71	4.61	4.49	4.49	4.51	4.51	4.51	4.47	4.47	4.43	4.39	4.34	4.29	4.29	H
12	2020	4.76	4.96	O	5.15	5.2	5.18	5.18	5.17	5.04	4.84	4.73	4.62	4.62	4.64	4.66	4.66	4.63	4.63	4.59	4.56	4.51	4.47	4.47	O
13	2021	4.92	5.12	L	5.29	5.34	5.3	5.3	5.29	5.14	4.94	4.81	4.7	4.7	4.73	4.75	4.75	4.72	4.72	4.68	4.66	4.61	4.58	4.58	L
14	2022	5.04	5.22	I	5.37	5.41	5.37	5.37	5.36	5.21	4.99	4.86	4.76	4.76	4.79	4.81	4.81	4.78	4.78	4.74	4.72	4.68	4.65	4.65	I
15	2023	5.08	5.26	D	5.42	5.47	5.43	5.43	5.42	5.27	5.04	4.9	4.81	4.81	4.85	4.87	4.87	4.84	4.84	4.8	4.78	4.74	4.72	4.72	D
16	2024	5.11	5.3	A	5.47	5.53	5.5	5.5	5.48	5.33	5.08	4.94	4.86	4.86	4.91	4.93	4.93	4.9	4.89	4.86	4.84	4.81	4.79	4.79	A
17	2025	5.14	5.34	Y	5.52	5.59	5.56	5.56	5.54	5.39	5.12	4.98	4.9	4.9	4.95	4.97	4.98	4.95	4.94	4.91	4.89	4.86	4.84	4.84	Y
18	2026	5.17	5.37		5.57	5.64	5.62	5.62	5.6	5.45	5.14	5	4.92	4.92	4.98	5	5.02	5	4.98	4.95	4.94	4.91	4.89	4.89	
19	2027	5.2	5.4		5.61	5.69	5.67	5.67	5.65	5.5	5.17	5.02	4.94	4.94	5.01	5.03	5.05	5.03	5.01	4.98	4.97	4.95	4.93	4.93	
20	2028	5.23	5.43		5.65	5.74	5.72	5.72	5.7	5.55	5.21	5.04	4.96	4.96	5.04	5.06	5.08	5.06	5.04	5.01	5	4.98	4.97	4.97	
21	2029	5.26	5.47	H	5.69	5.79	5.77	5.77	5.75	5.59	5.25	5.07	4.99	4.99	5.08	5.1	5.12	5.1	5.08	5.05	5.04	5.02	5.01	5.01	H
22	2030	5.29	5.51	O	5.73	5.82	5.8	5.8	5.78	5.61	5.27	5.09	5.02	5.02	5.12	5.14	5.16	5.14	5.12	5.09	5.08	5.06	5.05	5.05	O
23	2031	5.32	5.55	L	5.76	5.84	5.82	5.82	5.8	5.63	5.29	5.11	5.05	5.05	5.16	5.18	5.2	5.18	5.16	5.13	5.12	5.1	5.09	5.09	L
24	2032	5.34	5.57	I	5.78	5.86	5.84	5.84	5.82	5.64	5.31	5.13	5.07	5.07	5.19	5.21	5.23	5.22	5.2	5.17	5.16	5.14	5.13	5.13	I
25	2033	5.36	5.59	D	5.8	5.88	5.86	5.86	5.84	5.65	5.32	5.14	5.09	5.09	5.22	5.24	5.26	5.25	5.24	5.2	5.19	5.17	5.16	5.16	D
26	2034	5.37	5.61	A	5.82	5.9	5.88	5.88	5.86	5.66	5.33	5.15	5.11	5.11	5.25	5.27	5.29	5.28	5.27	5.23	5.22	5.2	5.19	5.19	A
27	2035	5.38	5.63	Y	5.84	5.91	5.89	5.89	5.87	5.67	5.34	5.16	5.13	5.13	5.28	5.3	5.32	5.31	5.3	5.26	5.25	5.22	5.22	5.22	Y
28	2036	5.39	5.65		5.86	5.92	5.9	5.9	5.88	5.68	5.35	5.17	5.15	5.15	5.3	5.32	5.34	5.34	5.33	5.29	5.28	5.24	5.24	5.24	
29	2037	5.4	5.67		5.88	5.93	5.91	5.91	5.89	5.69	5.36	5.18	5.16	5.16	5.31	5.33	5.35	5.35	5.34	5.3	5.29	5.25	5.25	5.25	
30	2038	5.41	5.69		5.89	5.94	5.92	5.92	5.9	5.7	5.37	5.19	5.17	5.17	5.32	5.34	5.36	5.36	5.35	5.31	5.3	5.26	5.26	5.26	

Term	Year	10/9	10/10	10/13	10/14	10/15	10/16	10/17	10/20	10/21	10/22	10/23	10/24	10/27	10/28	10/29	10/30	10/31	11/3	11/4	11/5	11/6	11/7	11/10	11/11
1	2009	2.21	2.16	H	2.17	2.22	2.22	2.22	2.22	2.06	1.86	1.81	1.74	1.74	1.74	1.74	1.71	1.61	1.61	1.56	1.56	1.36	1.34	1.34	H
2	2010	2.61	2.65	O	2.86	2.91	2.93	2.93	2.93	2.88	2.83	2.77	2.69	2.68	2.68	2.65	2.62	2.57	2.56	2.53	2.46	2.38	2.33	2.33	O
3	2011	2.98	3.02	L	3.23	3.32	3.36	3.36	3.36	3.31	3.21	3.14	3.06	3.05	3.05	3.02	3	2.95	2.94	2.91	2.79	2.71	2.66	2.66	L
4	2012	3.31	3.36	I	3.57	3.65	3.7	3.71	3.71	3.66	3.56	3.47	3.39	3.38	3.38	3.35	3.33	3.26	3.25	3.22	3.12	3.04	2.99	2.99	I
5	2013	3.51	3.56	D	3.77	3.85	3.9	3.92	3.92	3.87	3.76	3.66	3.58	3.58	3.58	3.55	3.54	3.49	3.48	3.44	3.35	3.26	3.2	3.2	D
6	2014	3.73	3.81	A	4.01	4.09	4.13	4.15	4.15	4.09	3.96	3.85	3.76	3.76	3.77	3.74	3.73	3.68	3.67	3.62	3.53	3.43	3.37	3.37	A
7	2015	3.95	4.08	Y	4.25	4.33	4.36	4.37	4.37	4.3	4.13	4.02	3.92	3.92	3.93	3.92	3.92	3.87	3.86	3.8	3.74	3.64	3.56	3.56	Y
8	2016	4.18	4.32		4.49	4.57	4.59	4.59	4.59	4.5	4.32	4.21	4.09	4.09	4.1	4.09	4.09	4.04	4.03	3.98	3.93	3.86	3.78	3.78	
9	2017	4.4	4.55		4.73	4.81	4.81	4.81	4.8	4.7	4.51	4.39	4.26	4.26	4.27	4.26	4.26	4.22	4.21	4.16	4.11	4.06	3.99	3.99	
10	2018	4.57	4.74		4.94	5.02	5.02	5.02	5	4.89	4.69	4.58	4.44	4.44	4.45	4.45	4.45	4.41	4.4	4.35	4.3	4.25	4.19	4.19	
11	2019	4.74	4.94	H	5.13	5.19	5.19	5.19	5.17	5.03	4.83	4.73	4.59	4.59	4.61	4.61	4.61	4.57	4.57	4.53	4.49	4.44	4.39	4.39	H
12	2020	4.92	5.12	O	5.31	5.36	5.34	5.34	5.32	5.16	4.96	4.85	4.72	4.72	4.75	4.77	4.77	4.74	4.74	4.7	4.67	4.62	4.58	4.58	O
13	2021	5.08	5.28	L	5.45	5.5	5.46	5.45	5.43	5.26	5.06	4.93	4.8	4.8	4.85	4.87	4.87	4.84	4.84	4.8	4.78	4.72	4.69	4.69	L
14	2022	5.18	5.36	I	5.51	5.55	5.51	5.51	5.49	5.33	5.11	4.98	4.86	4.86	4.91	4.93	4.93	4.9	4.9	4.86	4.84	4.79	4.76	4.76	I
15	2023	5.22	5.4	D	5.56	5.61	5.57	5.57	5.55	5.39	5.16	5.02	4.91	4.91	4.97	4.99	4.99	4.96	4.96	4.92	4.9	4.85	4.83	4.83	D
16	2024	5.25	5.44	A	5.61	5.67	5.64	5.64	5.61	5.45	5.2	5.06	4.96	4.96	5.03	5.05	5.05	5.02	5	4.97	4.95	4.92	4.9	4.9	A
17	2025	5.28	5.48	Y	5.66	5.73	5.7	5.7	5.67	5.51	5.24	5.09	4.99	4.99	5.07	5.09	5.1	5.07	5.05	5.02	5	4.97	4.95	4.95	Y
18	2026	5.31	5.51		5.71	5.78	5.76	5.76	5.73	5.57	5.26	5.11	5.01	5.01	5.1	5.12	5.14	5.12	5.09	5.06	5.05	5.02	5	5	
19	2027	5.34	5.54		5.75	5.83	5.81	5.81	5.78	5.62	5.29	5.13	5.03	5.03	5.13	5.15	5.17	5.15	5.12	5.09	5.08	5.06	5.04	5.04	
20	2028	5.37	5.57		5.79	5.88	5.86	5.86	5.83	5.67	5.33	5.15	5.05	5.05	5.16	5.18	5.2	5.18	5.15	5.12	5.11	5.09	5.08	5.08	
21	2029	5.4	5.61	H	5.83	5.93	5.91	5.91	5.88	5.71	5.37	5.18	5.08	5.08	5.2	5.22	5.24	5.22	5.19	5.16	5.15	5.13	5.12	5.12	H
22	2030	5.43	5.65	O	5.87	5.96	5.94	5.94	5.91	5.73	5.39	5.2	5.11	5.11	5.24	5.26	5.28	5.26	5.23	5.2	5.19	5.17	5.16	5.16	O
23	2031	5.45	5.68	L	5.89	5.97	5.95	5.95	5.93	5.75	5.41	5.22	5.14	5.14	5.28	5.3	5.32	5.3	5.27	5.24	5.23	5.21	5.2	5.2	L
24	2032	5.47	5.7	I	5.91	5.99	5.97	5.97	5.95	5.76	5.43	5.24	5.16	5.16	5.31	5.33	5.35	5.34	5.31	5.28	5.27	5.25	5.24	5.24	I
25	2033	5.49	5.72	D	5.93	6.01	5.99	5.99	5.97	5.77	5.44	5.25	5.18	5.18	5.34	5.36	5.38	5.37	5.34	5.3	5.29	5.27	5.26	5.26	D
26	2034	5.5	5.74	A	5.95	6.03	6.01	6.01	5.99	5.78	5.45	5.26	5.2	5.2	5.37	5.39	5.41	5.4	5.37	5.33	5.32	5.3	5.29	5.29	A
27	2035	5.51	5.76	Y	5.97	6.04	6.02	6.02	6	5.79	5.46	5.26	5.21	5.22	5.39	5.41	5.43	5.42	5.4	5.36	5.35	5.32	5.32	5.32	Y
28	2036	5.52	5.78		5.99	6.05	6.03	6.03	6.01	5.8	5.47	5.27	5.22	5.23	5.41	5.43	5.45	5.45	5.43	5.39	5.38	5.34	5.34	5.34	
29	2037	5.53	5.8		6	6.05	6.03	6.03	6.01	5.8	5.47	5.27	5.23	5.24	5.42	5.44	5.46	5.46	5.44	5.4	5.39	5.35	5.35	5.35	
30	2038	5.54	5.82		6.01	6.06	6.04	6.04	6.02	5.81	5.48	5.27	5.24	5.25	5.43	5.45	5.47	5.47	5.45	5.41	5.4	5.36	5.36	5.36	

JEA-POD3-00007 Hearing Exhibit - 00000499

MMD Scales

AAA MMD Scale

Term	Year	11/12	11/13	11/14	11/17	11/18	11/19	11/20	11/21	11/24	11/25	11/26	11/27	11/28	12/1	12/2	12/3	12/4	12/5	12/8	12/9	12/10	12/11
1	2009	1.28	1.25	1.25	1.25	1.15	1.1	1.05	1.05	1.05	1.05	1.05	H	1.05	1.05	1.05	1.05	1	1	1	0.95	0.95	0.95
2	2010	2.21	2.18	2.18	2.18	2.12	2.07	2.05	2.05	2.08	2.13	2.13	O	2.13	2.13	2.13	2.13	2.1	2.1	2.1	2.1	2.1	2.1
3	2011	2.53	2.49	2.46	2.42	2.36	2.31	2.29	2.29	2.32	2.37	2.37	L	2.37	2.37	2.37	2.37	2.34	2.34	2.34	2.34	2.34	2.34
4	2012	2.86	2.82	2.79	2.75	2.69	2.64	2.61	2.61	2.66	2.71	2.71	I	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.72
5	2013	3.06	3.02	2.98	2.95	2.88	2.84	2.81	2.83	2.88	2.93	2.93	D	2.93	2.93	2.93	2.95	2.95	2.95	2.95	2.95	2.95	2.96
6	2014	3.23	3.19	3.14	3.12	3.05	3.02	3	3.02	3.07	3.12	3.12	A	3.12	3.12	3.13	3.15	3.15	3.15	3.15	3.15	3.15	3.16
7	2015	3.42	3.38	3.32	3.3	3.23	3.2	3.19	3.22	3.28	3.33	3.33	Y	3.33	3.33	3.34	3.36	3.36	3.36	3.36	3.36	3.36	3.37
8	2016	3.63	3.59	3.53	3.51	3.44	3.41	3.4	3.43	3.51	3.58	3.58		3.58	3.58	3.59	3.61	3.61	3.62	3.63	3.63	3.64	3.65
9	2017	3.84	3.8	3.75	3.73	3.66	3.63	3.62	3.65	3.75	3.82	3.82		3.82	3.82	3.84	3.87	3.87	3.89	3.91	3.93	3.95	3.96
10	2018	4.04	4	3.95	3.93	3.86	3.83	3.82	3.85	3.95	4.02	4.02		4.02	4.02	4.05	4.09	4.1	4.13	4.16	4.18	4.2	4.21
11	2019	4.24	4.21	4.17	4.16	4.09	4.06	4.05	4.08	4.18	4.26	4.26	H	4.26	4.26	4.29	4.33	4.34	4.38	4.43	4.45	4.47	4.48
12	2020	4.42	4.39	4.36	4.36	4.3	4.27	4.27	4.3	4.39	4.47	4.47	O	4.47	4.47	4.5	4.55	4.56	4.6	4.65	4.67	4.69	4.7
13	2021	4.53	4.51	4.48	4.48	4.42	4.4	4.4	4.44	4.52	4.61	4.61	L	4.61	4.61	4.64	4.69	4.7	4.74	4.79	4.81	4.83	4.84
14	2022	4.6	4.58	4.56	4.56	4.5	4.49	4.49	4.54	4.61	4.71	4.71	I	4.71	4.71	4.75	4.82	4.83	4.87	4.92	4.94	4.96	4.97
15	2023	4.67	4.65	4.63	4.63	4.57	4.57	4.57	4.62	4.69	4.79	4.79	D	4.79	4.79	4.83	4.9	4.91	4.95	5	5.02	5.04	5.05
16	2024	4.74	4.72	4.7	4.7	4.65	4.65	4.65	4.7	4.77	4.87	4.87	A	4.87	4.87	4.92	4.99	5	5.04	5.09	5.11	5.13	5.14
17	2025	4.8	4.79	4.77	4.77	4.73	4.73	4.73	4.78	4.85	4.95	4.95	Y	4.95	4.95	5	5.07	5.08	5.13	5.18	5.2	5.22	5.24
18	2026	4.85	4.84	4.83	4.83	4.8	4.8	4.8	4.85	4.92	5.02	5.02		5.02	5.02	5.07	5.14	5.15	5.21	5.27	5.29	5.31	5.33
19	2027	4.89	4.88	4.88	4.88	4.86	4.86	4.86	4.91	4.98	5.08	5.08		5.08	5.08	5.13	5.2	5.21	5.29	5.36	5.38	5.4	5.42
20	2028	4.93	4.92	4.92	4.92	4.9	4.9	4.9	4.96	5.02	5.12	5.12		5.12	5.12	5.17	5.24	5.26	5.36	5.44	5.46	5.48	5.5
21	2029	4.97	4.97	4.97	4.97	4.95	4.95	4.95	5.01	5.06	5.16	5.16	H	5.16	5.16	5.21	5.28	5.31	5.41	5.5	5.52	5.55	5.57
22	2030	5.01	5.01	5.02	5.02	5	5	5	5.06	5.1	5.2	5.2	O	5.2	5.2	5.24	5.31	5.35	5.45	5.54	5.57	5.61	5.63
23	2031	5.05	5.05	5.06	5.06	5.04	5.04	5.04	5.09	5.13	5.23	5.23	L	5.23	5.23	5.27	5.34	5.38	5.48	5.57	5.6	5.64	5.66
24	2032	5.09	5.09	5.1	5.1	5.07	5.07	5.07	5.12	5.16	5.26	5.26	I	5.26	5.26	5.3	5.37	5.41	5.51	5.6	5.63	5.67	5.69
25	2033	5.12	5.12	5.14	5.14	5.1	5.1	5.1	5.15	5.19	5.29	5.29	D	5.29	5.29	5.33	5.4	5.44	5.54	5.63	5.66	5.7	5.72
26	2034	5.15	5.15	5.17	5.17	5.13	5.13	5.13	5.18	5.22	5.32	5.32	A	5.32	5.32	5.35	5.42	5.47	5.56	5.65	5.68	5.73	5.75
27	2035	5.18	5.18	5.2	5.2	5.16	5.16	5.16	5.21	5.24	5.34	5.34	Y	5.34	5.34	5.37	5.44	5.5	5.58	5.67	5.7	5.75	5.77
28	2036	5.2	5.2	5.22	5.22	5.18	5.18	5.18	5.23	5.26	5.36	5.36		5.36	5.36	5.39	5.46	5.52	5.6	5.69	5.72	5.77	5.79
29	2037	5.21	5.21	5.23	5.23	5.19	5.19	5.19	5.24	5.27	5.37	5.37		5.37	5.37	5.4	5.47	5.54	5.61	5.7	5.73	5.78	5.8
30	2038	5.22	5.22	5.24	5.24	5.2	5.2	5.2	5.25	5.28	5.38	5.38		5.38	5.38	5.41	5.48	5.55	5.62	5.71	5.74	5.79	5.81

AA MMD Scale

Term	Year	11/12	11/13	11/14	11/17	11/18	11/19	11/20	11/21	11/24	11/25	11/26	11/27	11/28	12/1	12/2	12/3	12/4	12/5	12/8	12/9	12/10	12/11
1	2009	1.34	1.31	1.31	1.31	1.21	1.16	1.11	1.11	1.11	1.11	1.11	H	1.11	1.11	1.11	1.11	1.09	1.09	1.09	1.07	1.07	1.07
2	2010	2.29	2.26	2.26	2.26	2.2	2.15	2.13	2.13	2.16	2.21	2.21	O	2.21	2.21	2.22	2.22	2.2	2.2	2.2	2.22	2.22	2.24
3	2011	2.62	2.58	2.55	2.51	2.45	2.4	2.38	2.39	2.42	2.47	2.47	L	2.47	2.47	2.49	2.49	2.46	2.46	2.46	2.48	2.48	2.5
4	2012	2.95	2.91	2.88	2.84	2.78	2.73	2.7	2.71	2.76	2.81	2.81	I	2.81	2.81	2.83	2.83	2.83	2.83	2.83	2.85	2.85	2.88
5	2013	3.16	3.12	3.08	3.05	2.98	2.94	2.91	2.94	2.99	3.04	3.04	D	3.04	3.04	3.06	3.08	3.08	3.08	3.08	3.09	3.09	3.12
6	2014	3.33	3.29	3.24	3.22	3.15	3.12	3.1	3.13	3.18	3.23	3.23	A	3.23	3.23	3.26	3.28	3.28	3.28	3.29	3.29	3.29	3.33
7	2015	3.52	3.48	3.42	3.4	3.33	3.3	3.29	3.33	3.39	3.44	3.44	Y	3.44	3.44	3.47	3.49	3.49	3.49	3.5	3.5	3.5	3.54
8	2016	3.73	3.69	3.63	3.61	3.54	3.51	3.5	3.54	3.62	3.69	3.69		3.69	3.69	3.72	3.74	3.74	3.75	3.77	3.78	3.79	3.82
9	2017	3.94	3.9	3.85	3.83	3.76	3.73	3.72	3.76	3.86	3.93	3.93		3.93	3.93	3.97	4	4.01	4.03	4.06	4.09	4.11	4.14
10	2018	4.14	4.1	4.05	4.03	3.96	3.93	3.92	3.96	4.06	4.13	4.13		4.13	4.13	4.18	4.22	4.24	4.27	4.31	4.35	4.37	4.4
11	2019	4.34	4.31	4.27	4.26	4.2	4.17	4.16	4.2	4.3	4.38	4.38	H	4.38	4.38	4.43	4.47	4.49	4.53	4.58	4.62	4.65	4.67
12	2020	4.53	4.5	4.47	4.47	4.42	4.39	4.39	4.43	4.52	4.6	4.6	O	4.6	4.6	4.64	4.69	4.71	4.75	4.8	4.84	4.87	4.89
13	2021	4.64	4.62	4.59	4.59	4.54	4.52	4.52	4.57	4.65	4.74	4.74	L	4.74	4.74	4.78	4.84	4.86	4.9	4.95	4.99	5.01	5.03
14	2022	4.71	4.69	4.67	4.67	4.62	4.61	4.61	4.67	4.74	4.84	4.84	I	4.84	4.84	4.89	4.97	4.99	5.03	5.08	5.12	5.14	5.16
15	2023	4.78	4.76	4.74	4.74	4.69	4.69	4.7	4.76	4.83	4.93	4.93	D	4.93	4.93	4.98	5.06	5.08	5.12	5.17	5.2	5.22	5.25
16	2024	4.85	4.83	4.81	4.81	4.77	4.77	4.78	4.84	4.91	5.01	5.01	A	5.01	5.01	5.07	5.15	5.17	5.21	5.26	5.29	5.31	5.35
17	2025	4.91	4.9	4.88	4.88	4.85	4.85	4.86	4.92	4.99	5.09	5.09	Y	5.09	5.09	5.15	5.23	5.25	5.3	5.35	5.38	5.4	5.45
18	2026	4.96	4.95	4.94	4.94	4.92	4.92	4.93	4.99	5.06	5.16	5.16		5.16	5.16	5.22	5.3	5.32	5.38	5.44	5.47	5.49	5.54
19	2027	5	4.99	4.99	4.99	4.98	4.98	4.99	5.05	5.12	5.22	5.22		5.22	5.22	5.28	5.36	5.38	5.46	5.53	5.56	5.58	5.63
20	2028	5.04	5.03	5.03	5.03	5.02	5.02	5.03	5.1	5.16	5.26	5.26		5.26	5.26	5.32	5.4	5.43	5.53	5.61	5.64	5.66	5.71
21	2029	5.08	5.08	5.08	5.08	5.07	5.07	5.08	5.15	5.2	5.3	5.3	H	5.3	5.3	5.36	5.44	5.48	5.58	5.67	5.7	5.73	5.78
22	2030	5.12	5.13	5.14	5.14	5.12	5.12	5.13	5.2	5.24	5.34	5.34	O	5.34	5.34	5.4	5.48	5.53	5.63	5.72	5.75	5.78	5.83
23	2031	5.16	5.17	5.18	5.18	5.15	5.16	5.17	5.23	5.27	5.37	5.37	L	5.37	5.37	5.43	5.51	5.56	5.66	5.75	5.78	5.81	5.86
24	2032	5.2	5.21	5.22	5.22	5.18	5.2	5.21	5.27	5.31	5.41	5.41	I	5.41	5.41	5.45	5.54	5.59	5.69	5.78	5.81	5.84	5.89
25	2033	5.22	5.24	5.26	5.26	5.21	5.23	5.24	5.3	5.34	5.44	5.44	D	5.44	5.44	5.48	5.57	5.62	5.72	5.81	5.84	5.87	5.92
26	2034	5.25	5.27	5.29	5.29	5.24	5.26	5.27	5.33	5.37	5.47	5.47	A	5.47	5.47	5.5	5.59	5.65	5.74	5.83	5.86	5.9	5.94
27	2035	5.28	5.3	5.32	5.32	5.27	5.29	5.3	5.36	5.39	5.49	5.49	Y	5.49	5.49	5.52	5.61	5.68	5.76	5.85	5.88	5.92	5.96
28	2036	5.3	5.32	5.35	5.35	5.29	5.31	5.32	5.38	5.41	5.51	5.51		5.51	5.51	5.54	5.63	5.7	5.78	5.87	5.9	5.94	5.98
29	2037	5.31	5.33	5.36	5.36	5.3	5.32	5.33	5.39	5.42	5.52	5.52		5.52	5.52	5.55	5.64	5.72	5.79	5.88	5.91	5.95	5.99
30	2038	5.32	5.34	5.37	5.37	5.31	5.33	5.34	5.4	5.43	5.53	5.53		5.53	5.53	5.56	5.65	5.73	5.8	5.89	5.92	5.96	6

JEA-POD3-00008 Hearing Exhibit - 00000500

MMD Scales for JEA

Term	Year	1/2	1/3	1/4	1/7	1/8	1/9	1/10	1/11	1/14	1/15	1/16	1/17	1/18	1/21	1/22	1/23	1/24	1/25	1/28	1/29	1/30	1/31	2/1	2/4
1	2009	2.88	2.86	2.81	2.8	2.75	2.7	2.65	2.64	2.64	2.6	2.57	2.55	2.5	H	2.25	2.1	2.1	2	2	1.95	1.9	1.9	1.85	1.85
2	2010	2.96	2.93	2.86	2.84	2.8	2.73	2.71	2.69	2.67	2.62	2.59	2.55	2.5	O	2.3	2.18	2.18	2.18	2.18	2.2	2.22	2.2	2.2	2.2
3	2011	3.03	3	2.93	2.9	2.87	2.81	2.8	2.78	2.76	2.71	2.68	2.62	2.58	L	2.38	2.26	2.3	2.3	2.3	2.35	2.38	2.35	2.35	2.36
4	2012	3.11	3.08	3.01	2.98	2.95	2.89	2.89	2.87	2.85	2.8	2.77	2.71	2.68	I	2.57	2.47	2.52	2.5	2.5	2.54	2.56	2.53	2.51	2.52
5	2013	3.19	3.16	3.09	3.06	3.03	2.97	2.97	2.95	2.93	2.88	2.86	2.8	2.78	D	2.69	2.61	2.68	2.68	2.68	2.72	2.74	2.71	2.68	2.69
6	2014	3.26	3.23	3.16	3.13	3.1	3.04	3.04	3.02	3.01	2.97	2.95	2.89	2.88	A	2.79	2.72	2.8	2.8	2.8	2.84	2.86	2.84	2.81	2.82
7	2015	3.34	3.31	3.24	3.21	3.19	3.14	3.15	3.13	3.11	3.07	3.05	3	2.99	Y	2.9	2.84	2.92	2.92	2.92	2.96	2.99	2.97	2.94	2.96
8	2016	3.43	3.4	3.33	3.3	3.28	3.24	3.25	3.23	3.21	3.17	3.16	3.11	3.1		3.01	2.95	3.04	3.04	3.04	3.09	3.12	3.11	3.09	3.11
9	2017	3.53	3.5	3.43	3.4	3.38	3.34	3.35	3.33	3.31	3.27	3.26	3.21	3.2		3.11	3.06	3.16	3.16	3.16	3.21	3.24	3.23	3.22	3.24
10	2018	3.61	3.59	3.52	3.49	3.47	3.43	3.44	3.42	3.4	3.36	3.35	3.31	3.31		3.22	3.17	3.28	3.28	3.28	3.33	3.37	3.36	3.35	3.37
11	2019	3.67	3.66	3.6	3.57	3.55	3.51	3.52	3.5	3.49	3.45	3.45	3.41	3.41	H	3.32	3.28	3.4	3.4	3.4	3.45	3.49	3.48	3.47	3.49
12	2020	3.73	3.72	3.66	3.63	3.61	3.57	3.59	3.57	3.56	3.52	3.52	3.49	3.5	O	3.43	3.39	3.51	3.51	3.51	3.57	3.61	3.6	3.59	3.61
13	2021	3.79	3.78	3.72	3.69	3.67	3.63	3.66	3.64	3.63	3.59	3.59	3.57	3.58	L	3.53	3.5	3.62	3.62	3.62	3.68	3.72	3.71	3.69	3.7
14	2022	3.85	3.84	3.78	3.75	3.73	3.69	3.72	3.71	3.7	3.66	3.66	3.64	3.65	I	3.61	3.59	3.72	3.72	3.73	3.79	3.83	3.82	3.79	3.79
15	2023	3.91	3.9	3.84	3.81	3.79	3.75	3.78	3.77	3.76	3.72	3.72	3.71	3.72	D	3.69	3.67	3.8	3.8	3.82	3.88	3.92	3.91	3.88	3.88
16	2024	3.97	3.96	3.9	3.87	3.85	3.81	3.84	3.83	3.82	3.78	3.78	3.77	3.78	A	3.76	3.75	3.88	3.88	3.9	3.97	4.01	3.99	3.96	3.96
17	2025	4.01	4.01	3.95	3.93	3.91	3.87	3.9	3.89	3.88	3.84	3.84	3.83	3.84	Y	3.82	3.81	3.95	3.95	3.97	4.04	4.08	4.06	4.03	4.03
18	2026	4.06	4.06	4	3.98	3.97	3.93	3.96	3.95	3.94	3.9	3.9	3.89	3.9		3.88	3.87	4.02	4.02	4.04	4.11	4.15	4.13	4.08	4.08
19	2027	4.1	4.1	4.05	4.03	4.02	3.97	4	3.99	3.98	3.94	3.94	3.93	3.95		3.93	3.92	4.07	4.07	4.09	4.16	4.2	4.18	4.13	4.13
20	2028	4.13	4.13	4.08	4.07	4.06	4.01	4.04	4.03	4.02	3.98	3.98	3.97	3.99		3.97	3.96	4.12	4.12	4.14	4.21	4.25	4.23	4.18	4.18
21	2029	4.16	4.16	4.11	4.1	4.09	4.04	4.07	4.06	4.05	4.01	4.01	4	4.02	H	4	4	4.17	4.17	4.19	4.26	4.3	4.28	4.22	4.22
22	2030	4.18	4.18	4.13	4.12	4.11	4.06	4.1	4.09	4.08	4.04	4.04	4.03	4.05	O	4.03	4.03	4.2	4.2	4.22	4.29	4.33	4.3	4.24	4.24
23	2031	4.19	4.19	4.14	4.13	4.13	4.08	4.12	4.11	4.1	4.06	4.06	4.05	4.07	L	4.05	4.05	4.22	4.22	4.24	4.31	4.35	4.32	4.25	4.26
24	2032	4.2	4.2	4.15	4.14	4.14	4.09	4.13	4.12	4.11	4.07	4.07	4.06	4.09	I	4.06	4.06	4.23	4.23	4.25	4.32	4.36	4.33	4.26	4.27
25	2033	4.21	4.21	4.16	4.15	4.15	4.1	4.14	4.13	4.12	4.08	4.08	4.07	4.1	D	4.07	4.07	4.24	4.24	4.26	4.33	4.37	4.34	4.27	4.28
26	2034	4.22	4.22	4.17	4.16	4.16	4.11	4.15	4.14	4.13	4.09	4.09	4.08	4.11	A	4.08	4.08	4.25	4.25	4.27	4.34	4.38	4.35	4.28	4.29
27	2035	4.23	4.23	4.18	4.17	4.17	4.12	4.16	4.15	4.14	4.1	4.1	4.09	4.12	Y	4.09	4.09	4.26	4.26	4.28	4.35	4.39	4.35	4.28	4.3
28	2036	4.24	4.24	4.19	4.18	4.18	4.13	4.17	4.16	4.15	4.11	4.11	4.1	4.13		4.1	4.1	4.27	4.27	4.29	4.36	4.4	4.35	4.28	4.3
29	2037	4.25	4.25	4.2	4.19	4.19	4.14	4.18	4.17	4.16	4.12	4.12	4.11	4.14		4.11	4.11	4.28	4.28	4.3	4.37	4.41	4.36	4.29	4.31
30	2038	4.25	4.25	4.2	4.19	4.19	4.14	4.18	4.17	4.16	4.12	4.12	4.11	4.14		4.11	4.11	4.28	4.28	4.3	4.37	4.41	4.36	4.29	4.31

Term	Year	1/2	1/3	1/4	1/7	1/8	1/9	1/10	1/11	1/14	1/15	1/16	1/17	1/18	1/21	1/22	1/23	1/24	1/25	1/28	1/29	1/30	1/31	2/1	2/4
1	2009	2.93	2.91	2.86	2.82	2.78	2.73	2.68	2.67	2.67	2.63	2.6	2.58	2.53	H	2.28	2.13	2.13	2.03	2.03	1.98	1.93	1.93	1.88	1.88
2	2010	3.04	3.01	2.94	2.89	2.85	2.78	2.76	2.74	2.72	2.67	2.64	2.6	2.55	O	2.35	2.23	2.24	2.24	2.24	2.26	2.28	2.26	2.26	2.26
3	2011	3.12	3.09	3.02	2.99	2.93	2.87	2.86	2.84	2.82	2.77	2.74	2.68	2.64	L	2.44	2.32	2.37	2.38	2.38	2.42	2.45	2.42	2.42	2.43
4	2012	3.2	3.17	3.1	3.07	3.02	2.96	2.96	2.94	2.92	2.87	2.84	2.78	2.75	I	2.64	2.54	2.6	2.59	2.59	2.63	2.65	2.62	2.6	2.61
5	2013	3.28	3.25	3.18	3.15	3.11	3.05	3.05	3.03	3.01	2.96	2.93	2.87	2.85	D	2.76	2.68	2.76	2.77	2.77	2.81	2.83	2.8	2.77	2.79
6	2014	3.36	3.33	3.25	3.22	3.18	3.12	3.12	3.1	3.09	3.05	3.02	2.96	2.95	A	2.86	2.79	2.88	2.89	2.89	2.93	2.95	2.93	2.9	2.92
7	2015	3.44	3.41	3.33	3.3	3.27	3.22	3.23	3.21	3.19	3.15	3.13	3.08	3.07	Y	2.98	2.92	3.02	3.02	3.02	3.06	3.09	3.07	3.04	3.06
8	2016	3.53	3.5	3.42	3.39	3.36	3.32	3.33	3.31	3.29	3.25	3.24	3.19	3.18		3.09	3.03	3.14	3.14	3.14	3.19	3.22	3.21	3.19	3.21
9	2017	3.62	3.59	3.52	3.49	3.46	3.42	3.43	3.41	3.39	3.35	3.34	3.29	3.28		3.19	3.14	3.26	3.26	3.26	3.31	3.34	3.33	3.32	3.34
10	2018	3.7	3.68	3.61	3.58	3.55	3.51	3.52	3.5	3.48	3.44	3.43	3.39	3.39		3.3	3.25	3.38	3.38	3.38	3.43	3.47	3.46	3.45	3.47
11	2019	3.76	3.75	3.69	3.66	3.63	3.59	3.6	3.58	3.57	3.53	3.53	3.49	3.49	H	3.4	3.36	3.5	3.5	3.5	3.55	3.59	3.58	3.57	3.59
12	2020	3.82	3.81	3.75	3.72	3.7	3.66	3.68	3.66	3.65	3.61	3.61	3.58	3.59	O	3.52	3.48	3.62	3.62	3.62	3.68	3.72	3.71	3.69	3.71
13	2021	3.88	3.87	3.81	3.78	3.76	3.72	3.75	3.73	3.72	3.68	3.68	3.66	3.67	L	3.62	3.59	3.73	3.73	3.73	3.79	3.83	3.82	3.79	3.8
14	2022	3.94	3.93	3.87	3.84	3.82	3.78	3.81	3.8	3.79	3.75	3.75	3.73	3.74	I	3.7	3.68	3.83	3.83	3.84	3.9	3.94	3.93	3.89	3.89
15	2023	4	3.99	3.93	3.9	3.88	3.84	3.87	3.86	3.85	3.81	3.81	3.8	3.81	D	3.78	3.76	3.91	3.91	3.93	3.99	4.03	4.02	3.98	3.98
16	2024	4.06	4.05	3.99	3.96	3.94	3.9	3.93	3.92	3.91	3.87	3.87	3.86	3.87	A	3.85	3.84	3.99	3.99	4.01	4.08	4.12	4.1	4.06	4.06
17	2025	4.1	4.1	4.04	4.02	4	3.96	3.99	3.98	3.97	3.93	3.93	3.92	3.93	Y	3.91	3.9	4.06	4.06	4.08	4.15	4.19	4.17	4.13	4.12
18	2026	4.15	4.15	4.09	4.07	4.06	4.02	4.05	4.04	4.03	3.99	3.99	3.98	3.99		3.97	3.96	4.13	4.13	4.15	4.22	4.26	4.24	4.18	4.17
19	2027	4.19	4.19	4.14	4.12	4.11	4.06	4.09	4.08	4.07	4.03	4.03	4.02	4.04		4.02	4.01	4.18	4.18	4.2	4.27	4.31	4.29	4.23	4.22
20	2028	4.22	4.22	4.17	4.16	4.15	4.1	4.13	4.12	4.11	4.07	4.07	4.06	4.08		4.06	4.05	4.23	4.23	4.25	4.32	4.36	4.34	4.28	4.27
21	2029	4.25	4.25	4.2	4.19	4.18	4.13	4.16	4.15	4.14	4.1	4.1	4.09	4.11	H	4.09	4.09	4.28	4.28	4.3	4.37	4.41	4.39	4.32	4.31
22	2030	4.27	4.27	4.22	4.21	4.2	4.15	4.19	4.18	4.17	4.13	4.13	4.12	4.14	O	4.12	4.12	4.31	4.31	4.33	4.4	4.44	4.41	4.33	4.33
23	2031	4.28	4.28	4.23	4.22	4.22	4.16	4.21	4.2	4.19	4.15	4.15	4.14	4.16	L	4.14	4.14	4.33	4.33	4.35	4.42	4.46	4.43	4.34	4.35
24	2032	4.29	4.29	4.24	4.23	4.23	4.17	4.22	4.21	4.2	4.16	4.16	4.15	4.18	I	4.15	4.15	4.34	4.34	4.36	4.43	4.47	4.44	4.35	4.36
25	2033	4.3	4.3	4.25	4.24	4.24	4.18	4.23	4.22	4.21	4.17	4.17	4.16	4.19	D	4.16	4.16	4.35	4.35	4.37	4.44	4.48	4.45	4.36	4.37
26	2034	4.31	4.31	4.26	4.25	4.25	4.19	4.24	4.23	4.22	4.18	4.18	4.17	4.2	A	4.17	4.17	4.36	4.36	4.38	4.45	4.49	4.46	4.37	4.38
27	2035	4.32	4.32	4.27	4.26	4.26	4.2	4.25	4.24	4.23	4.19	4.19	4.18	4.21	Y	4.18	4.18	4.37	4.37	4.39	4.46	4.5	4.46	4.37	4.39
28	2036	4.33	4.33	4.28	4.27	4.27	4.21	4.25	4.24	4.23	4.19	4.19	4.19	4.22		4.19	4.19	4.38	4.38	4.4	4.47	4.51	4.46	4.37	4.39
29	2037	4.34	4.34	4.29	4.28	4.28	4.22	4.26	4.25	4.24	4.2	4.2	4.2	4.23		4.2	4.2	4.39	4.39	4.41	4.48	4.52	4.47	4.38	4.4
30	2038	4.34	4.34	4.29	4.28	4.28	4.22	4.26	4.25	4.24	4.2	4.2	4.2	4.23		4.2	4.2	4.39	4.39	4.41	4.48	4.52	4.47	4.38	4.4

MMD Scales

Term	Year	2/5	2/6	2/7	2/8	2/11	2/12	2/13	2/14	2/15	2/18	2/19	2/20	2/21	2/22	2/25	2/26	2/27	2/28	2/29	3/3	3/4	3/5	3/6	3/7
1	2009	1.7	1.65	1.5	1.35	1.1	1.1	1.05	1.05	1.25	H	1.6	1.85	1.95	2	2	2.1	2.2	2.25	2.25	2.25	2.17	2.16	2.08	2.05
2	2010	2.1	2.09	2.09	2.07	2.05	2.05	2.03	2.05	2.07	O	2.14	2.19	2.24	2.27	2.3	2.4	2.5	2.6	2.63	2.63	2.53	2.48	2.36	2.21
3	2011	2.32	2.32	2.32	2.3	2.28	2.32	2.3	2.32	2.34	L	2.39	2.43	2.47	2.5	2.54	2.63	2.75	2.85	2.88	2.88	2.78	2.71	2.59	2.44
4	2012	2.49	2.49	2.5	2.49	2.47	2.51	2.51	2.53	2.55	I	2.6	2.64	2.68	2.71	2.77	2.85	2.97	3.07	3.12	3.12	3.01	2.94	2.82	2.69
5	2013	2.66	2.66	2.68	2.66	2.64	2.67	2.67	2.68	2.7	D	2.75	2.8	2.84	2.88	2.95	3.03	3.13	3.23	3.30	3.30	3.17	3.11	2.99	2.86
6	2014	2.79	2.79	2.82	2.81	2.79	2.82	2.82	2.83	2.85	A	2.9	2.95	2.98	3.04	3.13	3.19	3.29	3.39	3.48	3.48	3.34	3.28	3.15	3.04
7	2015	2.93	2.93	2.96	2.95	2.93	2.96	2.97	2.99	3	Y	3.05	3.1	3.13	3.2	3.3	3.35	3.45	3.55	3.65	3.65	3.50	3.44	3.31	3.21
8	2016	3.08	3.08	3.11	3.1	3.08	3.11	3.12	3.14	3.15		3.2	3.25	3.29	3.36	3.46	3.51	3.61	3.71	3.81	3.81	3.66	3.60	3.47	3.37
9	2017	3.21	3.21	3.24	3.23	3.21	3.24	3.26	3.29	3.3		3.35	3.4	3.45	3.52	3.62	3.67	3.77	3.87	3.97	3.97	3.82	3.76	3.63	3.53
10	2018	3.34	3.34	3.38	3.36	3.34	3.37	3.4	3.45	3.46		3.51	3.55	3.6	3.66	3.76	3.82	3.92	4.02	4.12	4.11	3.96	3.90	3.79	3.69
11	2019	3.46	3.46	3.51	3.49	3.48	3.51	3.54	3.61	3.63	H	3.67	3.71	3.75	3.8	3.9	3.96	4.06	4.19	4.30	4.28	4.11	4.05	3.94	3.84
12	2020	3.58	3.58	3.63	3.61	3.6	3.63	3.66	3.75	3.77	O	3.81	3.85	3.88	3.92	4.02	4.08	4.19	4.33	4.47	4.45	4.26	4.20	4.08	3.98
13	2021	3.66	3.67	3.72	3.7	3.69	3.72	3.75	3.84	3.86	L	3.91	3.95	3.98	4.02	4.12	4.18	4.3	4.45	4.58	4.57	4.37	4.32	4.20	4.10
14	2022	3.75	3.75	3.8	3.78	3.77	3.8	3.83	3.93	3.95	I	4.01	4.04	4.07	4.11	4.21	4.27	4.4	4.57	4.69	4.68	4.48	4.44	4.32	4.22
15	2023	3.83	3.83	3.88	3.86	3.85	3.88	3.91	4.01	4.04	D	4.1	4.13	4.16	4.2	4.3	4.36	4.49	4.68	4.80	4.79	4.59	4.55	4.43	4.33
16	2024	3.91	3.91	3.96	3.94	3.93	3.96	3.99	4.09	4.12	A	4.18	4.21	4.24	4.28	4.38	4.44	4.58	4.77	4.89	4.88	4.68	4.64	4.52	4.42
17	2025	3.98	3.98	4.03	4.01	3.99	4.02	4.06	4.16	4.2	Y	4.26	4.29	4.32	4.36	4.45	4.51	4.65	4.84	4.96	4.94	4.74	4.71	4.59	4.50
18	2026	4.03	4.03	4.08	4.06	4.04	4.07	4.11	4.21	4.25		4.31	4.34	4.37	4.41	4.5	4.57	4.71	4.9	5.01	4.98	4.78	4.75	4.63	4.56
19	2027	4.08	4.08	4.13	4.11	4.09	4.12	4.16	4.26	4.3		4.36	4.39	4.42	4.46	4.55	4.62	4.76	4.93	5.03	5.00	4.81	4.78	4.67	4.61
20	2028	4.12	4.12	4.17	4.15	4.13	4.16	4.2	4.3	4.35		4.41	4.44	4.47	4.51	4.6	4.67	4.81	4.96	5.05	5.02	4.84	4.81	4.71	4.66
21	2029	4.16	4.16	4.21	4.19	4.17	4.2	4.24	4.34	4.39	H	4.45	4.48	4.51	4.55	4.64	4.71	4.84	4.98	5.06	5.03	4.85	4.82	4.73	4.71
22	2030	4.18	4.18	4.24	4.22	4.2	4.23	4.27	4.38	4.43	O	4.49	4.52	4.55	4.59	4.68	4.74	4.87	5	5.07	5.04	4.86	4.83	4.75	4.73
23	2031	4.2	4.2	4.26	4.24	4.22	4.26	4.3	4.41	4.47	L	4.53	4.56	4.59	4.63	4.72	4.77	4.9	5.02	5.08	5.05	4.87	4.84	4.77	4.75
24	2032	4.21	4.21	4.27	4.25	4.23	4.27	4.31	4.43	4.5	I	4.56	4.59	4.62	4.66	4.75	4.8	4.92	5.03	5.09	5.06	4.88	4.85	4.79	4.77
25	2033	4.22	4.22	4.28	4.26	4.24	4.28	4.32	4.44	4.51	D	4.57	4.6	4.63	4.67	4.76	4.81	4.93	5.04	5.10	5.07	4.89	4.86	4.81	4.79
26	2034	4.23	4.23	4.29	4.27	4.25	4.29	4.33	4.45	4.52	A	4.58	4.61	4.64	4.68	4.77	4.81	4.93	5.04	5.11	5.08	4.90	4.87	4.82	4.81
27	2035	4.24	4.24	4.3	4.28	4.26	4.3	4.34	4.46	4.53	Y	4.59	4.62	4.65	4.69	4.78	4.81	4.93	5.04	5.12	5.09	4.91	4.88	4.83	4.82
28	2036	4.24	4.25	4.31	4.29	4.27	4.31	4.35	4.47	4.54		4.6	4.63	4.65	4.69	4.78	4.81	4.93	5.04	5.13	5.09	4.91	4.88	4.83	4.82
29	2037	4.25	4.26	4.32	4.3	4.28	4.32	4.36	4.48	4.55		4.61	4.64	4.66	4.7	4.79	4.82	4.94	5.05	5.14	5.10	4.92	4.89	4.84	4.83
30	2038	4.25	4.26	4.32	4.3	4.28	4.32	4.36	4.48	4.55		4.61	4.64	4.66	4.7	4.79	4.82	4.94	5.05	5.14	5.10	4.92	4.89	4.84	4.83

Term	Year	2/5	2/6	2/7	2/8	2/11	2/12	2/13	2/14	2/15	2/18	2/19	2/20	2/21	2/22	2/25	2/26	2/27	2/28	2/29	3/3	3/4	3/5	3/6	3/7
1	2009	1.73	1.68	1.53	1.38	1.13	1.13	1.08	1.05	1.25	H	1.65	1.9	2	2.05	2.05	2.15	2.25	2.33	2.33	2.33	2.25	2.24	2.16	2.13
2	2010	2.16	2.15	2.15	2.13	2.11	2.11	2.09	2.11	2.13	O	2.22	2.28	2.33	2.36	2.39	2.49	2.59	2.7	2.73	2.71	2.58	2.53	2.41	2.26
3	2011	2.39	2.39	2.39	2.37	2.35	2.39	2.37	2.39	2.41	L	2.48	2.53	2.57	2.6	2.64	2.73	2.85	2.97	3.00	2.98	2.85	2.78	2.66	2.51
4	2012	2.58	2.58	2.59	2.58	2.56	2.6	2.6	2.62	2.64	I	2.7	2.75	2.79	2.82	2.88	2.96	3.08	3.2	3.25	3.23	3.09	3.02	2.90	2.77
5	2013	2.76	2.76	2.78	2.76	2.74	2.77	2.77	2.78	2.8	D	2.85	2.91	2.95	2.99	3.06	3.14	3.24	3.36	3.43	3.41	3.25	3.19	3.07	2.94
6	2014	2.89	2.89	2.92	2.91	2.89	2.92	2.92	2.93	2.95	A	3	3.06	3.09	3.15	3.24	3.3	3.4	3.52	3.61	3.59	3.42	3.36	3.23	3.12
7	2015	3.03	3.03	3.06	3.05	3.03	3.06	3.07	3.08	3.1	Y	3.15	3.21	3.24	3.31	3.41	3.46	3.56	3.68	3.78	3.77	3.59	3.53	3.40	3.30
8	2016	3.18	3.18	3.21	3.2	3.18	3.21	3.22	3.24	3.25		3.3	3.36	3.4	3.47	3.57	3.62	3.72	3.84	3.94	3.93	3.75	3.69	3.56	3.46
9	2017	3.31	3.31	3.34	3.33	3.31	3.34	3.36	3.39	3.4		3.45	3.51	3.56	3.63	3.73	3.78	3.88	4	4.10	4.09	3.91	3.85	3.72	3.62
10	2018	3.44	3.44	3.48	3.46	3.44	3.47	3.5	3.55	3.56		3.61	3.66	3.71	3.77	3.87	3.93	4.03	4.15	4.25	4.23	4.05	3.99	3.88	3.78
11	2019	3.56	3.56	3.61	3.59	3.58	3.61	3.64	3.71	3.73	H	3.77	3.82	3.86	3.91	4.01	4.07	4.17	4.32	4.43	4.40	4.20	4.14	4.03	3.93
12	2020	3.68	3.68	3.73	3.71	3.7	3.73	3.76	3.86	3.88	O	3.92	3.97	4	4.04	4.14	4.2	4.31	4.47	4.61	4.57	4.35	4.29	4.17	4.07
13	2021	3.76	3.77	3.82	3.8	3.79	3.82	3.86	3.96	3.98	L	4.03	4.07	4.1	4.14	4.24	4.3	4.42	4.59	4.72	4.69	4.46	4.41	4.29	4.19
14	2022	3.85	3.85	3.9	3.88	3.87	3.9	3.94	4.05	4.07	I	4.13	4.16	4.19	4.23	4.33	4.39	4.52	4.7	4.82	4.80	4.57	4.53	4.41	4.31
15	2023	3.93	3.93	3.98	3.96	3.95	3.98	4.02	4.13	4.16	D	4.22	4.25	4.28	4.32	4.42	4.48	4.61	4.81	4.93	4.91	4.68	4.64	4.52	4.42
16	2024	4.01	4.01	4.06	4.04	4.03	4.06	4.1	4.21	4.24	A	4.3	4.33	4.36	4.4	4.5	4.56	4.7	4.9	5.02	5.00	4.77	4.73	4.61	4.51
17	2025	4.07	4.07	4.12	4.1	4.08	4.11	4.17	4.28	4.32	Y	4.38	4.41	4.44	4.48	4.57	4.63	4.77	4.97	5.09	5.05	4.82	4.79	4.67	4.58
18	2026	4.12	4.12	4.17	4.15	4.13	4.16	4.22	4.33	4.37		4.43	4.46	4.49	4.53	4.62	4.69	4.83	5.03	5.13	5.09	4.86	4.83	4.71	4.64
19	2027	4.17	4.17	4.22	4.2	4.18	4.21	4.27	4.38	4.42		4.48	4.51	4.54	4.58	4.67	4.74	4.88	5.06	5.15	5.11	4.89	4.86	4.75	4.69
20	2028	4.21	4.21	4.26	4.24	4.22	4.25	4.31	4.42	4.47		4.53	4.56	4.59	4.63	4.72	4.79	4.93	5.08	5.17	5.13	4.92	4.89	4.79	4.74
21	2029	4.25	4.25	4.3	4.28	4.26	4.29	4.35	4.46	4.51	H	4.57	4.6	4.63	4.67	4.76	4.83	4.96	5.11	5.18	5.14	4.93	4.90	4.81	4.79
22	2030	4.27	4.27	4.33	4.31	4.29	4.32	4.38	4.49	4.55	O	4.61	4.64	4.67	4.71	4.8	4.86	4.99	5.12	5.19	5.15	4.95	4.92	4.83	4.81
23	2031	4.29	4.29	4.35	4.33	4.31	4.35	4.41	4.52	4.59	L	4.65	4.68	4.71	4.75	4.84	4.89	5.02	5.14	5.20	5.16	4.96	4.93	4.85	4.83
24	2032	4.3	4.3	4.36	4.34	4.32	4.36	4.42	4.54	4.62	I	4.68	4.71	4.74	4.78	4.87	4.92	5.04	5.15	5.21	5.17	4.97	4.94	4.87	4.85
25	2033	4.31	4.31	4.37	4.35	4.33	4.37	4.43	4.55	4.63	D	4.69	4.72	4.75	4.79	4.88	4.93	5.05	5.16	5.22	5.18	4.98	4.95	4.89	4.87
26	2034	4.32	4.32	4.38	4.36	4.34	4.38	4.44	4.56	4.64	A	4.7	4.73	4.76	4.8	4.89	4.93	5.05	5.16	5.23	5.18	4.98	4.95	4.90	4.89
27	2035	4.33	4.33	4.39	4.37	4.35	4.39	4.45	4.57	4.65	Y	4.71	4.74	4.77	4.81	4.9	4.93	5.05	5.16	5.24	5.19	4.99	4.96	4.91	4.90
28	2036	4.33	4.34	4.4	4.38	4.36	4.4	4.46	4.58	4.66		4.72	4.75	4.77	4.81	4.9	4.93	5.05	5.16	5.25	5.19	4.99	4.96	4.91	4.90
29	2037	4.34	4.35	4.41	4.39	4.37	4.41	4.47	4.59	4.67		4.73	4.76	4.78	4.82	4.91	4.94	5.06	5.17	5.26	5.20	5.00	4.97	4.92	4.91
30	2038	4.34	4.35	4.41	4.39	4.37	4.41	4.47	4.59	4.67		4.73	4.76	4.78	4.82	4.91	4.94	5.06	5.17	5.26	5.20	5.00	4.97	4.92	4.91

JEA-POD3 Hearing Exhibit - 00000502

MMD Scales

Term	Year	3/10	3/11	3/12	3/13	3/14	3/17	3/18	3/19	3/20	3/21	3/24	3/25	3/26	3/27	3/28	3/31	4/1	4/2	4/3	4/4	4/7	4/8	4/9	4/10
1	2009	2.05	2.05	2.00	1.95	1.94	1.90	1.80	1.75	1.75	H	1.77	1.70	1.65	1.65	1.65	1.65	1.65	1.60	1.60	1.55	1.55	1.55	1.55	1.55
2	2010	2.19	2.22	2.22	2.22	2.21	2.20	2.20	2.18	2.18	O	2.20	2.20	2.20	2.22	2.22	2.22	2.26	2.27	2.26	2.21	2.22	2.22	2.22	2.19
3	2011	2.41	2.45	2.45	2.45	2.43	2.42	2.43	2.41	2.40	L	2.44	2.44	2.45	2.49	2.48	2.48	2.52	2.54	2.53	2.48	2.49	2.49	2.48	2.48
4	2012	2.66	2.71	2.70	2.70	2.68	2.67	2.69	2.67	2.64	I	2.68	2.69	2.72	2.77	2.77	2.77	2.81	2.84	2.83	2.78	2.79	2.79	2.76	2.76
5	2013	2.83	2.89	2.88	2.88	2.86	2.85	2.87	2.84	2.80	D	2.84	2.85	2.87	2.92	2.92	2.92	2.97	3.00	2.99	2.94	2.95	2.95	2.92	2.92
6	2014	3.00	3.07	3.06	3.07	3.05	3.04	3.06	3.03	2.99	A	3.03	3.04	3.05	3.09	3.09	3.09	3.14	3.17	3.16	3.10	3.12	3.12	3.08	3.08
7	2015	3.17	3.24	3.23	3.24	3.22	3.21	3.23	3.21	3.17	Y	3.21	3.22	3.23	3.26	3.26	3.25	3.30	3.33	3.32	3.26	3.28	3.28	3.23	3.23
8	2016	3.33	3.40	3.39	3.41	3.39	3.38	3.40	3.39	3.35		3.39	3.40	3.41	3.44	3.44	3.42	3.47	3.49	3.48	3.41	3.43	3.43	3.37	3.37
9	2017	3.50	3.57	3.56	3.58	3.56	3.55	3.57	3.56	3.53		3.57	3.58	3.59	3.62	3.61	3.59	3.64	3.65	3.63	3.56	3.58	3.57	3.50	3.51
10	2018	3.66	3.73	3.72	3.74	3.72	3.71	3.73	3.72	3.69		3.73	3.74	3.74	3.77	3.75	3.73	3.78	3.79	3.77	3.70	3.72	3.70	3.62	3.63
11	2019	3.81	3.88	3.87	3.89	3.87	3.86	3.88	3.88	3.85	H	3.89	3.90	3.90	3.93	3.91	3.89	3.94	3.95	3.92	3.85	3.86	3.83	3.75	3.76
12	2020	3.95	4.00	3.99	4.01	3.99	3.98	4.00	4.00	3.97	O	4.01	4.01	4.01	4.04	4.02	4.00	4.05	4.06	4.02	3.95	3.96	3.93	3.85	3.86
13	2021	4.07	4.12	4.11	4.13	4.11	4.10	4.12	4.12	4.09	L	4.13	4.13	4.13	4.16	4.13	4.11	4.16	4.16	4.12	4.05	4.06	4.03	3.95	3.96
14	2022	4.19	4.24	4.23	4.25	4.23	4.21	4.23	4.23	4.21	I	4.25	4.25	4.25	4.28	4.24	4.22	4.26	4.26	4.22	4.15	4.16	4.12	4.03	4.04
15	2023	4.30	4.35	4.34	4.36	4.34	4.32	4.34	4.34	4.32	D	4.36	4.36	4.36	4.39	4.35	4.32	4.36	4.36	4.32	4.24	4.25	4.20	4.10	4.12
16	2024	4.40	4.45	4.44	4.46	4.44	4.42	4.44	4.44	4.43	A	4.47	4.47	4.47	4.50	4.46	4.43	4.46	4.46	4.41	4.33	4.34	4.28	4.17	4.19
17	2025	4.49	4.54	4.53	4.55	4.53	4.51	4.53	4.52	4.51	Y	4.56	4.56	4.56	4.59	4.55	4.52	4.55	4.55	4.50	4.42	4.42	4.35	4.23	4.25
18	2026	4.56	4.62	4.61	4.63	4.61	4.59	4.61	4.60	4.59		4.64	4.64	4.64	4.67	4.63	4.60	4.63	4.63	4.58	4.50	4.50	4.42	4.29	4.31
19	2027	4.61	4.68	4.67	4.69	4.67	4.65	4.67	4.66	4.65		4.70	4.70	4.70	4.73	4.69	4.66	4.69	4.69	4.64	4.56	4.56	4.47	4.34	4.36
20	2028	4.66	4.73	4.72	4.74	4.72	4.70	4.72	4.71	4.70		4.75	4.75	4.75	4.78	4.74	4.71	4.74	4.74	4.69	4.61	4.61	4.52	4.39	4.41
21	2029	4.71	4.78	4.77	4.79	4.77	4.75	4.77	4.76	4.75	H	4.80	4.80	4.80	4.83	4.79	4.75	4.78	4.78	4.73	4.65	4.65	4.56	4.43	4.45
22	2030	4.74	4.82	4.81	4.83	4.81	4.79	4.81	4.80	4.79	O	4.84	4.84	4.84	4.87	4.83	4.79	4.82	4.82	4.77	4.69	4.69	4.60	4.46	4.48
23	2031	4.77	4.85	4.84	4.86	4.84	4.82	4.84	4.83	4.82	L	4.87	4.87	4.87	4.90	4.86	4.82	4.85	4.85	4.80	4.72	4.73	4.64	4.49	4.51
24	2032	4.79	4.87	4.86	4.88	4.86	4.84	4.86	4.85	4.84	I	4.90	4.90	4.90	4.93	4.88	4.84	4.87	4.87	4.82	4.74	4.75	4.66	4.51	4.53
25	2033	4.81	4.89	4.88	4.90	4.88	4.86	4.88	4.87	4.86	D	4.92	4.92	4.92	4.95	4.90	4.86	4.89	4.88	4.83	4.75	4.76	4.67	4.52	4.54
26	2034	4.83	4.91	4.90	4.92	4.90	4.88	4.90	4.88	4.87	A	4.93	4.93	4.93	4.96	4.91	4.87	4.90	4.89	4.84	4.76	4.77	4.68	4.53	4.55
27	2035	4.84	4.92	4.91	4.93	4.91	4.89	4.91	4.89	4.88	Y	4.94	4.94	4.94	4.97	4.92	4.88	4.91	4.90	4.85	4.77	4.78	4.69	4.54	4.56
28	2036	4.84	4.92	4.91	4.93	4.91	4.89	4.91	4.89	4.88		4.94	4.94	4.94	4.97	4.92	4.88	4.91	4.90	4.85	4.77	4.78	4.69	4.54	4.56
29	2037	4.85	4.93	4.92	4.94	4.92	4.90	4.92	4.90	4.89		4.95	4.95	4.95	4.98	4.93	4.89	4.92	4.91	4.86	4.78	4.79	4.70	4.55	4.57
30	2038	4.85	4.93	4.92	4.94	4.92	4.90	4.92	4.90	4.89		4.95	4.95	4.95	4.98	4.93	4.89	4.92	4.91	4.86	4.78	4.79	4.70	4.55	4.57

Term	Year	3/10	3/11	3/12	3/13	3/14	3/17	3/18	3/19	3/20	3/21	3/24	3/25	3/26	3/27	3/28	3/31	4/1	4/2	4/3	4/4	4/7	4/8	4/9	4/10
1	2009	2.13	2.13	2.08	2.03	2.02	1.98	1.88	1.83	1.83	H	1.85	1.78	1.73	1.73	1.73	1.73	1.73	1.68	1.68	1.63	1.63	1.63	1.63	1.63
2	2010	2.24	2.30	2.30	2.30	2.29	2.28	2.28	2.26	2.26	O	2.28	2.29	2.29	2.31	2.31	2.31	2.36	2.37	2.35	2.30	2.31	2.31	2.31	2.28
3	2011	2.48	2.54	2.54	2.54	2.52	2.51	2.52	2.50	2.49	L	2.53	2.54	2.55	2.59	2.59	2.59	2.63	2.65	2.62	2.57	2.58	2.58	2.56	2.56
4	2012	2.74	2.81	2.80	2.80	2.78	2.77	2.79	2.77	2.74	I	2.78	2.79	2.82	2.87	2.87	2.87	2.92	2.95	2.92	2.87	2.88	2.88	2.84	2.84
5	2013	2.91	2.99	2.98	2.98	2.96	2.95	2.97	2.94	2.90	D	2.94	2.95	2.97	3.02	3.02	3.02	3.07	3.10	3.09	3.04	3.05	3.05	3.01	3.01
6	2014	3.08	3.17	3.16	3.17	3.15	3.14	3.16	3.13	3.09	A	3.13	3.14	3.15	3.19	3.19	3.19	3.24	3.27	3.26	3.20	3.22	3.22	3.17	3.17
7	2015	3.26	3.34	3.33	3.34	3.32	3.31	3.33	3.31	3.27	Y	3.31	3.32	3.33	3.36	3.36	3.35	3.40	3.43	3.42	3.36	3.38	3.38	3.31	3.31
8	2016	3.42	3.50	3.49	3.51	3.49	3.48	3.50	3.49	3.45		3.49	3.50	3.51	3.54	3.54	3.52	3.57	3.59	3.58	3.51	3.53	3.53	3.46	3.46
9	2017	3.59	3.67	3.66	3.68	3.66	3.65	3.67	3.66	3.63		3.67	3.68	3.69	3.72	3.71	3.69	3.74	3.75	3.73	3.66	3.68	3.67	3.59	3.6
10	2018	3.75	3.83	3.82	3.84	3.82	3.81	3.83	3.82	3.79		3.83	3.84	3.84	3.87	3.85	3.83	3.88	3.89	3.87	3.80	3.82	3.80	3.71	3.72
11	2019	3.9	3.98	3.97	3.99	3.97	3.96	3.98	3.98	3.95	H	3.99	4.00	4.00	4.03	4.01	3.99	4.04	4.05	4.02	3.95	3.96	3.93	3.84	3.85
12	2020	4.04	4.10	4.09	4.11	4.09	4.08	4.10	4.10	4.07	O	4.11	4.11	4.11	4.14	4.12	4.10	4.15	4.16	4.12	4.05	4.06	4.03	3.94	3.95
13	2021	4.16	4.22	4.21	4.23	4.21	4.20	4.22	4.22	4.19	L	4.23	4.23	4.23	4.26	4.23	4.21	4.26	4.26	4.22	4.15	4.16	4.12	4.03	4.05
14	2022	4.28	4.34	4.33	4.35	4.33	4.31	4.33	4.33	4.31	I	4.35	4.35	4.35	4.38	4.34	4.32	4.36	4.36	4.32	4.25	4.26	4.21	4.12	4.13
15	2023	4.39	4.45	4.44	4.46	4.44	4.42	4.44	4.44	4.42	D	4.46	4.46	4.46	4.49	4.45	4.42	4.46	4.46	4.42	4.34	4.35	4.29	4.18	4.21
16	2024	4.49	4.55	4.54	4.56	4.54	4.52	4.54	4.54	4.53	A	4.57	4.57	4.57	4.60	4.56	4.53	4.56	4.56	4.51	4.43	4.44	4.37	4.25	4.28
17	2025	4.57	4.64	4.63	4.65	4.63	4.61	4.63	4.62	4.61	Y	4.66	4.66	4.66	4.69	4.65	4.62	4.65	4.65	4.60	4.52	4.52	4.44	4.31	4.34
18	2026	4.64	4.72	4.71	4.73	4.71	4.69	4.71	4.70	4.69		4.74	4.74	4.74	4.77	4.73	4.70	4.73	4.73	4.68	4.60	4.60	4.51	4.37	4.4
19	2027	4.69	4.78	4.77	4.79	4.77	4.75	4.77	4.76	4.75		4.80	4.80	4.80	4.83	4.79	4.76	4.79	4.79	4.74	4.66	4.66	4.56	4.42	4.45
20	2028	4.74	4.83	4.82	4.84	4.82	4.80	4.82	4.81	4.80		4.85	4.85	4.85	4.88	4.84	4.81	4.83	4.83	4.78	4.70	4.70	4.60	4.46	4.49
21	2029	4.79	4.88	4.87	4.89	4.87	4.85	4.87	4.86	4.85	H	4.90	4.90	4.90	4.93	4.89	4.85	4.87	4.87	4.82	4.74	4.74	4.64	4.50	4.53
22	2030	4.82	4.92	4.91	4.93	4.91	4.89	4.91	4.90	4.89	O	4.94	4.94	4.94	4.97	4.93	4.89	4.91	4.91	4.86	4.78	4.78	4.68	4.53	4.56
23	2031	4.85	4.95	4.94	4.96	4.94	4.92	4.94	4.93	4.92	L	4.97	4.97	4.97	5.00	4.96	4.92	4.94	4.94	4.89	4.81	4.82	4.72	4.56	4.59
24	2032	4.87	4.97	4.96	4.98	4.96	4.94	4.96	4.95	4.94	I	5.00	4.99	4.99	5.02	4.97	4.93	4.96	4.95	4.90	4.82	4.83	4.73	4.57	4.6
25	2033	4.89	4.98	4.97	4.99	4.97	4.95	4.97	4.96	4.95	D	5.01	5.00	5.00	5.03	4.98	4.94	4.97	4.96	4.91	4.83	4.84	4.74	4.58	4.61
26	2034	4.91	5.00	4.99	5.01	4.99	4.97	4.99	4.97	4.96	A	5.02	5.01	5.01	5.04	4.99	4.95	4.98	4.97	4.92	4.84	4.85	4.75	4.59	4.62
27	2035	4.92	5.01	5.00	5.02	5.00	4.98	5.00	4.98	4.97	Y	5.03	5.02	5.02	5.05	5.00	4.96	4.99	4.98	4.93	4.85	4.86	4.76	4.60	4.63
28	2036	4.92	5.01	5.00	5.02	5.00	4.98	5.00	4.98	4.97		5.03	5.02	5.02	5.05	5.00	4.96	4.99	4.98	4.93	4.85	4.86	4.76	4.60	4.63
29	2037	4.93	5.02	5.01	5.03	5.01	4.99	5.01	4.99	4.98		5.04	5.03	5.03	5.06	5.01	4.97	5.00	4.99	4.94	4.86	4.87	4.77	4.61	4.64
30	2038	4.93	5.02	5.01	5.03	5.01	4.99	5.01	4.99	4.98		5.04	5.03	5.03	5.06	5.01	4.97	5.00	4.99	4.94	4.86	4.87	4.77	4.61	4.64

MMD Scales

Term	Year	4/11	4/14	4/15	4/16	4/17	4/18	4/21	4/22	4/23	4/24	4/25	4/28	4/29	4/30	5/1	5/2	5/5	5/6	5/7	5/8	5/9	5/12	5/13	5/14
1	2009	1.55	1.55	1.55	1.55	1.57	1.6	1.6	1.65	1.7	1.77	1.77	1.77	1.77	1.8	1.8	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83
2	2010	2.17	2.17	2.17	2.17	2.19	2.22	2.22	2.24	2.26	2.33	2.35	2.35	2.35	2.35	2.35	2.38	2.38	2.37	2.37	2.35	2.31	2.31	2.31	2.3
3	2011	2.46	2.46	2.46	2.46	2.49	2.52	2.52	2.54	2.56	2.63	2.65	2.65	2.65	2.65	2.65	2.68	2.68	2.68	2.68	2.64	2.6	2.6	2.61	2.61
4	2012	2.72	2.71	2.7	2.7	2.73	2.75	2.75	2.77	2.79	2.86	2.88	2.88	2.88	2.88	2.88	2.91	2.91	2.91	2.91	2.86	2.82	2.82	2.84	2.84
5	2013	2.87	2.86	2.85	2.85	2.88	2.9	2.9	2.9	2.92	2.99	3.01	3.01	3.01	3.01	3	3.03	3.03	3.03	3.03	2.98	2.94	2.94	2.97	2.97
6	2014	3.01	3	2.99	2.99	3.02	3.04	3.04	3.04	3.06	3.13	3.15	3.15	3.14	3.14	3.12	3.15	3.15	3.15	3.15	3.1	3.06	3.06	3.1	3.1
7	2015	3.16	3.15	3.14	3.14	3.17	3.19	3.19	3.19	3.21	3.27	3.29	3.29	3.28	3.28	3.26	3.29	3.29	3.29	3.29	3.23	3.19	3.19	3.23	3.23
8	2016	3.3	3.29	3.28	3.29	3.32	3.34	3.34	3.34	3.36	3.41	3.43	3.43	3.42	3.42	3.4	3.43	3.43	3.43	3.43	3.37	3.33	3.33	3.37	3.37
9	2017	3.44	3.43	3.42	3.43	3.46	3.48	3.48	3.48	3.5	3.55	3.57	3.57	3.56	3.56	3.54	3.57	3.57	3.57	3.57	3.51	3.47	3.46	3.5	3.5
10	2018	3.56	3.55	3.54	3.55	3.58	3.6	3.6	3.6	3.62	3.68	3.7	3.7	3.69	3.69	3.67	3.7	3.7	3.7	3.7	3.64	3.6	3.58	3.62	3.62
11	2019	3.69	3.68	3.68	3.69	3.72	3.75	3.75	3.74	3.76	3.82	3.83	3.83	3.82	3.81	3.79	3.82	3.82	3.82	3.82	3.76	3.72	3.7	3.74	3.73
12	2020	3.79	3.78	3.78	3.79	3.82	3.86	3.86	3.85	3.87	3.93	3.94	3.94	3.93	3.92	3.9	3.93	3.93	3.93	3.93	3.88	3.83	3.81	3.85	3.84
13	2021	3.89	3.88	3.88	3.89	3.92	3.96	3.96	3.95	3.97	4.03	4.04	4.04	4.03	4.02	4	4.03	4.03	4.03	4.03	3.98	3.92	3.9	3.94	3.93
14	2022	3.97	3.97	3.97	3.98	4	4.04	4.04	4.03	4.05	4.11	4.12	4.12	4.11	4.1	4.08	4.11	4.11	4.11	4.11	4.06	4	3.98	4.02	4.01
15	2023	4.05	4.05	4.05	4.06	4.08	4.12	4.12	4.11	4.13	4.19	4.2	4.2	4.18	4.17	4.15	4.18	4.18	4.18	4.18	4.13	4.07	4.05	4.09	4.08
16	2024	4.12	4.12	4.13	4.14	4.16	4.2	4.2	4.19	4.21	4.27	4.28	4.28	4.25	4.24	4.21	4.24	4.24	4.24	4.24	4.19	4.13	4.11	4.15	4.14
17	2025	4.18	4.18	4.19	4.2	4.22	4.25	4.25	4.24	4.26	4.32	4.33	4.33	4.3	4.29	4.26	4.29	4.29	4.29	4.29	4.24	4.18	4.16	4.2	4.19
18	2026	4.23	4.23	4.24	4.26	4.27	4.3	4.3	4.29	4.31	4.37	4.38	4.38	4.35	4.34	4.31	4.34	4.34	4.34	4.34	4.29	4.23	4.21	4.25	4.24
19	2027	4.28	4.28	4.29	4.31	4.32	4.35	4.35	4.33	4.36	4.42	4.43	4.43	4.4	4.39	4.36	4.39	4.39	4.39	4.39	4.34	4.28	4.26	4.3	4.29
20	2028	4.33	4.33	4.34	4.36	4.37	4.4	4.4	4.38	4.41	4.47	4.48	4.48	4.45	4.44	4.41	4.44	4.44	4.44	4.44	4.39	4.33	4.31	4.35	4.34
21	2029	4.37	4.37	4.39	4.41	4.42	4.45	4.45	4.43	4.45	4.51	4.52	4.52	4.49	4.48	4.46	4.49	4.49	4.49	4.49	4.44	4.38	4.36	4.4	4.39
22	2030	4.4	4.4	4.42	4.45	4.46	4.49	4.49	4.48	4.49	4.55	4.56	4.56	4.53	4.52	4.5	4.53	4.53	4.53	4.53	4.48	4.42	4.4	4.44	4.43
23	2031	4.42	4.42	4.45	4.48	4.49	4.51	4.51	4.5	4.51	4.57	4.59	4.59	4.56	4.54	4.52	4.55	4.55	4.55	4.55	4.51	4.45	4.43	4.47	4.46
24	2032	4.44	4.44	4.47	4.5	4.51	4.53	4.53	4.52	4.53	4.59	4.61	4.6	4.57	4.55	4.53	4.56	4.56	4.57	4.56	4.53	4.47	4.45	4.49	4.48
25	2033	4.45	4.46	4.49	4.52	4.53	4.55	4.54	4.53	4.54	4.6	4.62	4.61	4.58	4.56	4.54	4.57	4.57	4.58	4.57	4.54	4.48	4.46	4.5	4.49
26	2034	4.46	4.47	4.5	4.54	4.55	4.56	4.55	4.54	4.55	4.61	4.63	4.62	4.59	4.57	4.55	4.58	4.58	4.59	4.58	4.55	4.49	4.47	4.51	4.5
27	2035	4.47	4.48	4.51	4.55	4.56	4.57	4.56	4.55	4.56	4.62	4.64	4.63	4.6	4.58	4.56	4.59	4.59	4.6	4.59	4.56	4.5	4.48	4.52	4.51
28	2036	4.47	4.48	4.52	4.56	4.57	4.58	4.57	4.56	4.57	4.63	4.65	4.64	4.61	4.59	4.57	4.6	4.6	4.61	4.6	4.57	4.51	4.49	4.53	4.52
29	2037	4.48	4.49	4.53	4.57	4.58	4.59	4.58	4.57	4.58	4.64	4.66	4.65	4.62	4.6	4.58	4.61	4.61	4.62	4.61	4.58	4.52	4.5	4.54	4.53
30	2038	4.48	4.49	4.53	4.58	4.59	4.6	4.59	4.58	4.59	4.65	4.67	4.66	4.63	4.61	4.59	4.62	4.62	4.63	4.62	4.59	4.53	4.51	4.55	4.54

Term	Year	4/11	4/14	4/15	4/16	4/17	4/18	4/21	4/22	4/23	4/24	4/25	4/28	4/29	4/30	5/1	5/2	5/5	5/6	5/7	5/8	5/9	5/12	5/13	5/14
1	2009	1.63	1.63	1.63	1.63	1.66	1.69	1.69	1.74	1.79	1.86	1.86	1.86	1.86	1.89	1.89	1.92	1.92	1.92	1.92	1.92	1.9	1.9	1.9	1.9
2	2010	2.26	2.26	2.26	2.26	2.29	2.32	2.32	2.34	2.36	2.43	2.45	2.44	2.44	2.44	2.44	2.47	2.47	2.46	2.46	2.44	2.39	2.39	2.39	2.38
3	2011	2.54	2.54	2.54	2.54	2.57	2.6	2.6	2.62	2.64	2.71	2.73	2.74	2.74	2.74	2.74	2.77	2.77	2.77	2.77	2.73	2.69	2.69	2.7	2.7
4	2012	2.8	2.79	2.78	2.78	2.81	2.83	2.83	2.85	2.87	2.94	2.96	2.97	2.97	2.97	2.97	3	3	3	3	2.95	2.91	2.91	2.93	2.93
5	2013	2.96	2.95	2.94	2.94	2.97	2.99	2.99	2.99	3.01	3.08	3.1	3.1	3.1	3.1	3.09	3.12	3.12	3.12	3.12	3.07	3.03	3.03	3.06	3.06
6	2014	3.1	3.09	3.08	3.08	3.12	3.14	3.14	3.14	3.16	3.23	3.25	3.25	3.24	3.24	3.22	3.25	3.25	3.25	3.25	3.2	3.16	3.16	3.2	3.2
7	2015	3.24	3.24	3.23	3.23	3.27	3.29	3.29	3.29	3.31	3.37	3.39	3.39	3.38	3.38	3.36	3.39	3.39	3.39	3.39	3.33	3.29	3.29	3.33	3.33
8	2016	3.39	3.38	3.37	3.38	3.42	3.44	3.44	3.44	3.46	3.51	3.53	3.53	3.52	3.52	3.5	3.53	3.53	3.53	3.53	3.47	3.43	3.43	3.47	3.47
9	2017	3.53	3.52	3.51	3.52	3.56	3.58	3.58	3.58	3.6	3.65	3.67	3.67	3.66	3.66	3.64	3.67	3.67	3.67	3.67	3.61	3.57	3.56	3.6	3.6
10	2018	3.65	3.64	3.63	3.64	3.68	3.7	3.7	3.7	3.72	3.78	3.8	3.8	3.79	3.79	3.77	3.8	3.8	3.8	3.8	3.74	3.7	3.68	3.72	3.72
11	2019	3.78	3.77	3.78	3.79	3.82	3.85	3.85	3.84	3.86	3.92	3.93	3.93	3.92	3.91	3.89	3.92	3.92	3.92	3.92	3.86	3.82	3.8	3.84	3.83
12	2020	3.88	3.87	3.88	3.89	3.92	3.96	3.96	3.95	3.97	4.03	4.04	4.04	4.03	4.02	4	4.03	4.03	4.03	4.03	3.98	3.93	3.91	3.95	3.94
13	2021	3.98	3.97	3.98	3.99	4.02	4.06	4.06	4.05	4.07	4.13	4.14	4.14	4.13	4.12	4.1	4.13	4.13	4.13	4.13	4.08	4.02	4	4.04	4.03
14	2022	4.06	4.06	4.07	4.08	4.1	4.14	4.14	4.13	4.15	4.21	4.22	4.22	4.21	4.2	4.18	4.21	4.21	4.21	4.21	4.16	4.1	4.08	4.12	4.11
15	2023	4.14	4.14	4.15	4.16	4.18	4.22	4.22	4.21	4.23	4.29	4.3	4.3	4.28	4.27	4.25	4.28	4.28	4.28	4.28	4.23	4.17	4.15	4.19	4.18
16	2024	4.21	4.21	4.23	4.24	4.26	4.3	4.3	4.29	4.31	4.37	4.38	4.38	4.35	4.34	4.31	4.34	4.34	4.34	4.34	4.29	4.23	4.21	4.25	4.24
17	2025	4.27	4.27	4.29	4.3	4.32	4.35	4.35	4.34	4.36	4.42	4.43	4.43	4.4	4.39	4.36	4.39	4.39	4.39	4.39	4.34	4.28	4.26	4.3	4.29
18	2026	4.32	4.32	4.34	4.36	4.37	4.4	4.4	4.39	4.41	4.47	4.48	4.48	4.45	4.44	4.41	4.44	4.44	4.44	4.44	4.39	4.33	4.31	4.35	4.34
19	2027	4.37	4.37	4.39	4.41	4.42	4.45	4.45	4.43	4.46	4.52	4.53	4.53	4.5	4.49	4.46	4.49	4.49	4.49	4.49	4.44	4.38	4.36	4.4	4.39
20	2028	4.41	4.41	4.43	4.45	4.46	4.49	4.49	4.47	4.5	4.56	4.57	4.57	4.54	4.53	4.5	4.53	4.53	4.53	4.53	4.48	4.42	4.4	4.44	4.43
21	2029	4.45	4.45	4.48	4.5	4.51	4.54	4.54	4.52	4.54	4.6	4.61	4.61	4.58	4.57	4.55	4.58	4.58	4.58	4.58	4.53	4.47	4.45	4.49	4.48
22	2030	4.47	4.47	4.51	4.54	4.55	4.58	4.58	4.57	4.58	4.64	4.65	4.65	4.62	4.61	4.59	4.62	4.62	4.62	4.62	4.57	4.51	4.49	4.53	4.52
23	2031	4.49	4.49	4.54	4.57	4.58	4.6	4.6	4.59	4.6	4.66	4.68	4.68	4.65	4.63	4.61	4.64	4.64	4.65	4.64	4.6	4.54	4.52	4.56	4.55
24	2032	4.5	4.51	4.56	4.59	4.6	4.62	4.62	4.61	4.62	4.68	4.7	4.69	4.66	4.64	4.62	4.65	4.65	4.67	4.65	4.62	4.56	4.54	4.58	4.57
25	2033	4.51	4.52	4.57	4.61	4.62	4.64	4.63	4.62	4.63	4.69	4.71	4.7	4.67	4.65	4.63	4.66	4.66	4.68	4.66	4.63	4.57	4.55	4.59	4.58
26	2034	4.52	4.53	4.58	4.63	4.64	4.65	4.64	4.63	4.64	4.7	4.72	4.71	4.68	4.66	4.64	4.67	4.67	4.69	4.67	4.64	4.58	4.56	4.6	4.59
27	2035	4.53	4.54	4.59	4.64	4.65	4.66	4.65	4.64	4.65	4.71	4.73	4.72	4.69	4.67	4.65	4.68	4.68	4.7	4.68	4.65	4.59	4.57	4.61	4.6
28	2036	4.53	4.54	4.6	4.65	4.66	4.67	4.66	4.65	4.66	4.72	4.74	4.73	4.7	4.68	4.66	4.69	4.69	4.71	4.69	4.66	4.6	4.58	4.62	4.61
29	2037	4.54	4.55	4.61	4.66	4.67	4.68	4.67	4.66	4.67	4.73	4.75	4.74	4.71	4.69	4.67	4.7	4.7	4.72	4.7	4.67	4.61	4.59	4.63	4.62
30	2038	4.54	4.55	4.61	4.67	4.68	4.69	4.68	4.67	4.68	4.74	4.76	4.75	4.72	4.7	4.68	4.71	4.71	4.73	4.71	4.68	4.62	4.6	4.64	4.63

MMD Scales

Term	Year	5/15	5/18	5/19	5/20	5/21	5/22	5/23	5/26	5/27	5/28	5/29	5/30	6/2	6/3	6/4	6/5	6/6	6/9	6/10	6/11	6/12	6/13	6/16	6/17
1	2009	1.8	1.8	1.8	1.77	1.77	1.77	1.77	H	1.77	1.77	1.77	1.77	1.77	1.77	1.72	1.72	1.72	1.72	1.74	1.78	1.78	1.78	1.78	1.78
2	2010	2.27	2.23	2.23	2.22	2.22	2.25	2.23	O	2.24	2.25	2.28	2.28	2.26	2.24	2.22	2.23	2.21	2.23	2.29	2.33	2.37	2.42	2.44	2.51
3	2011	2.59	2.57	2.57	2.56	2.56	2.6	2.59	L	2.61	2.62	2.65	2.64	2.62	2.6	2.6	2.62	2.6	2.62	2.69	2.72	2.77	2.8	2.8	2.87
4	2012	2.82	2.8	2.8	2.78	2.77	2.82	2.8	I	2.82	2.85	2.89	2.88	2.85	2.83	2.83	2.85	2.83	2.86	2.92	2.93	3	3.02	3.02	3.09
5	2013	2.94	2.92	2.92	2.9	2.89	2.94	2.92	D	2.94	2.97	3.02	3.01	2.98	2.96	2.96	3	2.98	3.01	3.07	3.08	3.17	3.18	3.18	3.24
6	2014	3.07	3.05	3.05	3.02	3.01	3.06	3.04	A	3.06	3.1	3.16	3.15	3.12	3.1	3.11	3.15	3.12	3.15	3.21	3.22	3.32	3.33	3.33	3.38
7	2015	3.2	3.18	3.18	3.15	3.14	3.19	3.17	Y	3.19	3.24	3.3	3.29	3.26	3.24	3.25	3.29	3.26	3.29	3.35	3.36	3.46	3.47	3.47	3.52
8	2016	3.33	3.31	3.31	3.28	3.27	3.33	3.3		3.33	3.38	3.44	3.42	3.39	3.37	3.39	3.43	3.4	3.43	3.49	3.49	3.59	3.6	3.6	3.65
9	2017	3.46	3.44	3.44	3.41	3.4	3.46	3.43		3.46	3.51	3.57	3.55	3.52	3.5	3.52	3.56	3.53	3.56	3.62	3.62	3.72	3.73	3.73	3.78
10	2018	3.58	3.56	3.56	3.53	3.52	3.58	3.55		3.58	3.63	3.69	3.67	3.64	3.62	3.64	3.69	3.66	3.68	3.74	3.74	3.84	3.85	3.85	3.89
11	2019	3.69	3.67	3.67	3.64	3.64	3.7	3.67	H	3.7	3.75	3.81	3.79	3.76	3.74	3.76	3.81	3.78	3.79	3.84	3.84	3.94	3.95	3.95	3.99
12	2020	3.8	3.78	3.78	3.74	3.74	3.8	3.77	O	3.8	3.85	3.91	3.89	3.86	3.84	3.86	3.91	3.88	3.89	3.94	3.94	4.04	4.05	4.05	4.09
13	2021	3.89	3.87	3.87	3.83	3.83	3.89	3.86	L	3.89	3.94	4	3.97	3.94	3.92	3.94	3.99	3.96	3.97	4.02	4.02	4.12	4.13	4.13	4.17
14	2022	3.96	3.94	3.94	3.89	3.89	3.95	3.92	I	3.96	4.01	4.07	4.04	4.01	3.99	4.01	4.06	4.03	4.04	4.08	4.08	4.18	4.19	4.19	4.22
15	2023	4.03	4.01	4.01	3.96	3.96	4.02	3.99	D	4.03	4.08	4.14	4.1	4.07	4.05	4.07	4.12	4.08	4.09	4.13	4.13	4.23	4.24	4.24	4.26
16	2024	4.08	4.06	4.06	4.01	4.01	4.07	4.04	A	4.08	4.13	4.2	4.15	4.12	4.1	4.12	4.17	4.13	4.14	4.18	4.18	4.28	4.29	4.29	4.3
17	2025	4.13	4.11	4.11	4.06	4.06	4.12	4.09	Y	4.13	4.18	4.25	4.2	4.17	4.15	4.17	4.22	4.18	4.19	4.23	4.23	4.33	4.34	4.34	4.35
18	2026	4.18	4.16	4.16	4.11	4.11	4.17	4.14		4.18	4.23	4.3	4.25	4.22	4.2	4.22	4.27	4.23	4.24	4.28	4.28	4.38	4.39	4.39	4.4
19	2027	4.23	4.21	4.21	4.16	4.16	4.22	4.19		4.23	4.28	4.35	4.3	4.27	4.25	4.27	4.32	4.28	4.29	4.33	4.33	4.43	4.44	4.44	4.44
20	2028	4.28	4.26	4.26	4.21	4.21	4.27	4.24		4.28	4.33	4.4	4.35	4.32	4.3	4.32	4.37	4.33	4.34	4.38	4.38	4.48	4.49	4.49	4.49
21	2029	4.33	4.31	4.31	4.26	4.26	4.32	4.29	H	4.33	4.38	4.45	4.4	4.37	4.35	4.37	4.42	4.38	4.38	4.42	4.42	4.52	4.53	4.53	4.53
22	2030	4.37	4.35	4.35	4.31	4.31	4.36	4.33	O	4.37	4.42	4.49	4.44	4.41	4.38	4.4	4.45	4.41	4.41	4.46	4.46	4.56	4.57	4.57	4.57
23	2031	4.4	4.38	4.38	4.34	4.34	4.39	4.36	L	4.4	4.44	4.51	4.46	4.43	4.4	4.42	4.47	4.43	4.43	4.49	4.49	4.59	4.6	4.6	4.6
24	2032	4.42	4.4	4.39	4.35	4.35	4.4	4.37	I	4.41	4.45	4.53	4.47	4.45	4.41	4.43	4.48	4.44	4.44	4.5	4.51	4.6	4.61	4.61	4.61
25	2033	4.43	4.41	4.4	4.36	4.36	4.41	4.38	D	4.42	4.46	4.54	4.48	4.46	4.42	4.44	4.49	4.45	4.45	4.51	4.52	4.61	4.62	4.62	4.62
26	2034	4.44	4.42	4.41	4.37	4.37	4.42	4.39	A	4.43	4.47	4.55	4.49	4.47	4.43	4.45	4.5	4.46	4.46	4.52	4.53	4.62	4.63	4.63	4.63
27	2035	4.45	4.43	4.42	4.38	4.38	4.43	4.4	Y	4.44	4.48	4.56	4.5	4.48	4.44	4.46	4.51	4.47	4.47	4.53	4.54	4.63	4.64	4.64	4.64
28	2036	4.46	4.44	4.43	4.39	4.39	4.44	4.41		4.45	4.49	4.57	4.51	4.49	4.44	4.47	4.52	4.48	4.48	4.54	4.55	4.64	4.65	4.65	4.65
29	2037	4.47	4.45	4.44	4.4	4.4	4.45	4.42		4.46	4.5	4.58	4.52	4.5	4.45	4.48	4.53	4.49	4.49	4.55	4.56	4.65	4.66	4.66	4.66
30	2038	4.48	4.46	4.45	4.41	4.41	4.46	4.43		4.47	4.51	4.59	4.53	4.51	4.46	4.49	4.54	4.5	4.5	4.56	4.57	4.66	4.67	4.67	4.67

Term	Year	5/15	5/18	5/19	5/20	5/21	5/22	5/23	5/26	5/27	5/28	5/29	5/30	6/2	6/3	6/4	6/5	6/6	6/9	6/10	6/11	6/12	6/13	6/16	6/17
1	2009	1.87	1.87	1.87	1.83	1.83	1.83	1.83	H	1.83	1.83	1.83	1.83	1.83	1.83	1.78	1.78	1.76	1.76	1.8	1.84	1.84	1.84	1.84	1.84
2	2010	2.35	2.31	2.31	2.3	2.3	2.33	2.31	O	2.32	2.34	2.37	2.37	2.35	2.33	2.31	2.32	2.3	2.32	2.38	2.42	2.46	2.51	2.53	2.6
3	2011	2.68	2.66	2.66	2.65	2.65	2.69	2.68	L	2.7	2.72	2.75	2.74	2.72	2.7	2.7	2.72	2.7	2.72	2.8	2.83	2.87	2.9	2.9	2.97
4	2012	2.91	2.89	2.89	2.87	2.86	2.91	2.89	I	2.91	2.95	2.99	2.98	2.95	2.93	2.93	2.95	2.93	2.96	3.02	3.03	3.1	3.12	3.12	3.19
5	2013	3.03	3.01	3.01	2.99	2.98	3.03	3.01	D	3.03	3.07	3.12	3.11	3.08	3.06	3.06	3.1	3.08	3.11	3.17	3.18	3.27	3.28	3.28	3.34
6	2014	3.17	3.15	3.15	3.12	3.11	3.16	3.14	A	3.16	3.2	3.26	3.25	3.22	3.2	3.21	3.25	3.22	3.25	3.31	3.32	3.42	3.43	3.43	3.48
7	2015	3.3	3.28	3.28	3.25	3.24	3.29	3.27	Y	3.29	3.34	3.4	3.39	3.36	3.34	3.35	3.39	3.36	3.39	3.45	3.46	3.56	3.57	3.57	3.62
8	2016	3.43	3.41	3.41	3.38	3.37	3.43	3.4		3.43	3.48	3.54	3.52	3.49	3.47	3.49	3.53	3.5	3.53	3.59	3.59	3.69	3.7	3.7	3.75
9	2017	3.56	3.54	3.54	3.51	3.5	3.56	3.53		3.56	3.61	3.67	3.65	3.62	3.6	3.62	3.66	3.63	3.66	3.72	3.72	3.82	3.83	3.83	3.88
10	2018	3.68	3.66	3.66	3.63	3.62	3.68	3.65		3.68	3.73	3.79	3.77	3.74	3.72	3.74	3.79	3.76	3.78	3.84	3.84	3.94	3.95	3.95	3.99
11	2019	3.79	3.77	3.77	3.74	3.74	3.8	3.77	H	3.8	3.85	3.91	3.89	3.86	3.84	3.86	3.91	3.88	3.89	3.94	3.94	4.04	4.05	4.05	4.09
12	2020	3.9	3.88	3.88	3.84	3.84	3.9	3.87	O	3.9	3.95	4.01	3.99	3.96	3.94	3.96	4.01	3.98	3.99	4.04	4.04	4.14	4.15	4.15	4.19
13	2021	3.99	3.97	3.97	3.93	3.93	3.99	3.96	L	3.99	4.04	4.1	4.07	4.04	4.02	4.04	4.09	4.06	4.07	4.12	4.12	4.22	4.23	4.23	4.27
14	2022	4.06	4.04	4.04	3.99	3.99	4.05	4.02	I	4.06	4.11	4.17	4.14	4.11	4.09	4.11	4.16	4.13	4.14	4.18	4.18	4.28	4.29	4.29	4.32
15	2023	4.13	4.11	4.11	4.06	4.06	4.12	4.09	D	4.13	4.18	4.24	4.2	4.17	4.15	4.17	4.22	4.18	4.19	4.23	4.23	4.33	4.34	4.34	4.36
16	2024	4.18	4.16	4.16	4.11	4.11	4.17	4.14	A	4.18	4.23	4.3	4.25	4.22	4.2	4.22	4.27	4.23	4.24	4.28	4.28	4.38	4.39	4.39	4.4
17	2025	4.23	4.21	4.21	4.16	4.16	4.22	4.19	Y	4.23	4.28	4.35	4.3	4.27	4.25	4.27	4.32	4.28	4.29	4.33	4.33	4.43	4.44	4.44	4.45
18	2026	4.28	4.26	4.26	4.21	4.21	4.27	4.24		4.28	4.33	4.4	4.35	4.32	4.3	4.32	4.37	4.33	4.34	4.38	4.38	4.48	4.49	4.49	4.5
19	2027	4.33	4.31	4.31	4.26	4.26	4.32	4.29		4.33	4.38	4.45	4.4	4.37	4.35	4.37	4.42	4.38	4.39	4.43	4.43	4.53	4.54	4.54	4.54
20	2028	4.37	4.35	4.35	4.3	4.3	4.36	4.33		4.37	4.42	4.49	4.44	4.41	4.39	4.41	4.46	4.42	4.43	4.47	4.47	4.57	4.58	4.58	4.58
21	2029	4.42	4.4	4.4	4.35	4.35	4.41	4.38	H	4.42	4.47	4.54	4.49	4.46	4.44	4.46	4.51	4.47	4.47	4.51	4.51	4.61	4.62	4.62	4.62
22	2030	4.46	4.44	4.44	4.4	4.4	4.45	4.42	O	4.46	4.51	4.58	4.53	4.5	4.47	4.49	4.54	4.5	4.5	4.55	4.55	4.65	4.66	4.66	4.66
23	2031	4.49	4.47	4.47	4.43	4.43	4.48	4.45	L	4.49	4.53	4.6	4.55	4.52	4.49	4.51	4.56	4.52	4.52	4.58	4.58	4.68	4.69	4.69	4.69
24	2032	4.51	4.49	4.48	4.44	4.44	4.49	4.46	I	4.5	4.54	4.62	4.56	4.54	4.5	4.52	4.57	4.53	4.53	4.59	4.6	4.69	4.7	4.7	4.7
25	2033	4.52	4.5	4.49	4.45	4.45	4.5	4.47	D	4.51	4.55	4.63	4.57	4.55	4.51	4.53	4.58	4.54	4.54	4.6	4.61	4.7	4.71	4.71	4.71
26	2034	4.53	4.51	4.5	4.46	4.46	4.51	4.48	A	4.52	4.56	4.64	4.58	4.56	4.52	4.54	4.59	4.55	4.55	4.61	4.62	4.71	4.72	4.72	4.72
27	2035	4.54	4.52	4.51	4.47	4.47	4.52	4.49	Y	4.53	4.57	4.65	4.59	4.57	4.53	4.55	4.6	4.56	4.56	4.62	4.63	4.72	4.73	4.73	4.73
28	2036	4.55	4.53	4.52	4.48	4.48	4.53	4.5		4.54	4.58	4.66	4.6	4.58	4.53	4.56	4.61	4.57	4.57	4.63	4.64	4.73	4.74	4.74	4.74
29	2037	4.56	4.54	4.53	4.49	4.49	4.54	4.51		4.55	4.59	4.67	4.61	4.59	4.54	4.57	4.62	4.58	4.58	4.64	4.65	4.74	4.75	4.75	4.75
30	2038	4.57	4.55	4.54	4.5	4.5	4.55	4.52		4.56	4.6	4.68	4.62	4.6	4.55	4.58	4.63	4.59	4.59	4.65	4.66	4.75	4.76	4.76	4.76

MMD Scales

Term	Year	6/18	6/19	6/20	6/23	6/24	6/25	6/26	6/27	6/30	7/1	7/2	7/3	7/4	7/7	7/8	7/9	7/10
1	2009	1.72	1.72	1.72	1.72	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.68	H	1.68	1.58	1.58	1.55
2	2010	2.55	2.6	2.62	2.65	2.67	2.69	2.68	2.65	2.63	2.59	2.56	2.54	O	2.5	2.43	2.35	2.31
3	2011	2.92	2.95	2.97	3	3.02	3.04	3.03	3	2.99	2.95	2.91	2.89	L	2.85	2.78	2.71	2.68
4	2012	3.12	3.17	3.19	3.22	3.24	3.26	3.24	3.21	3.2	3.16	3.12	3.1	I	3.06	3.01	2.94	2.91
5	2013	3.26	3.31	3.33	3.36	3.38	3.4	3.37	3.34	3.33	3.28	3.24	3.22	D	3.18	3.14	3.08	3.05
6	2014	3.39	3.44	3.45	3.48	3.51	3.53	3.5	3.47	3.45	3.4	3.36	3.34	A	3.3	3.26	3.2	3.17
7	2015	3.52	3.57	3.58	3.61	3.62	3.64	3.61	3.58	3.56	3.51	3.47	3.45	Y	3.41	3.38	3.32	3.29
8	2016	3.65	3.7	3.71	3.74	3.74	3.76	3.72	3.69	3.67	3.62	3.58	3.56		3.52	3.49	3.44	3.41
9	2017	3.78	3.83	3.84	3.87	3.87	3.89	3.85	3.82	3.79	3.73	3.69	3.67		3.63	3.6	3.56	3.53
10	2018	3.89	3.94	3.95	3.98	3.98	4	3.96	3.93	3.9	3.84	3.8	3.78		3.74	3.71	3.67	3.64
11	2019	4	4.05	4.06	4.09	4.09	4.11	4.07	4.03	4	3.94	3.9	3.88	H	3.85	3.83	3.79	3.76
12	2020	4.1	4.15	4.16	4.19	4.19	4.21	4.17	4.13	4.1	4.04	4	3.98	O	3.95	3.93	3.89	3.86
13	2021	4.18	4.22	4.24	4.27	4.27	4.29	4.25	4.2	4.17	4.11	4.07	4.05	L	4.03	4.01	3.98	3.95
14	2022	4.23	4.26	4.28	4.31	4.32	4.34	4.3	4.25	4.23	4.17	4.13	4.11	I	4.09	4.07	4.04	4.01
15	2023	4.27	4.3	4.32	4.35	4.36	4.38	4.35	4.3	4.28	4.22	4.18	4.16	D	4.15	4.13	4.1	4.07
16	2024	4.31	4.34	4.36	4.39	4.41	4.42	4.4	4.35	4.33	4.28	4.24	4.22	A	4.21	4.19	4.16	4.13
17	2025	4.36	4.39	4.41	4.44	4.46	4.47	4.45	4.4	4.38	4.33	4.29	4.27	Y	4.26	4.24	4.21	4.18
18	2026	4.41	4.44	4.47	4.49	4.51	4.52	4.5	4.45	4.43	4.38	4.34	4.32		4.31	4.29	4.26	4.23
19	2027	4.45	4.48	4.52	4.54	4.57	4.58	4.55	4.5	4.48	4.43	4.39	4.37		4.36	4.34	4.31	4.28
20	2028	4.5	4.53	4.58	4.6	4.63	4.64	4.6	4.55	4.53	4.48	4.44	4.42		4.41	4.39	4.36	4.33
21	2029	4.54	4.57	4.64	4.66	4.69	4.69	4.65	4.6	4.58	4.53	4.49	4.47	H	4.46	4.44	4.41	4.38
22	2030	4.58	4.61	4.68	4.7	4.73	4.73	4.69	4.64	4.62	4.57	4.53	4.52	O	4.51	4.49	4.45	4.42
23	2031	4.61	4.64	4.71	4.73	4.76	4.76	4.72	4.67	4.65	4.6	4.56	4.55	L	4.54	4.52	4.48	4.45
24	2032	4.62	4.66	4.74	4.76	4.79	4.79	4.75	4.7	4.67	4.62	4.58	4.57	I	4.56	4.54	4.5	4.47
25	2033	4.63	4.68	4.77	4.79	4.82	4.82	4.78	4.73	4.69	4.64	4.59	4.59	D	4.58	4.55	4.51	4.48
26	2034	4.64	4.69	4.79	4.81	4.84	4.84	4.79	4.74	4.7	4.65	4.6	4.6	A	4.59	4.56	4.52	4.49
27	2035	4.65	4.7	4.81	4.83	4.85	4.85	4.8	4.75	4.71	4.66	4.61	4.61	Y	4.6	4.57	4.53	4.5
28	2036	4.66	4.71	4.83	4.85	4.86	4.86	4.81	4.76	4.72	4.67	4.62	4.62		4.61	4.58	4.54	4.51
29	2037	4.68	4.73	4.85	4.87	4.87	4.87	4.82	4.77	4.73	4.68	4.63	4.63		4.62	4.59	4.55	4.52
30	2038	4.69	4.74	4.86	4.88	4.88	4.88	4.83	4.78	4.74	4.69	4.64	4.64		4.63	4.59	4.56	4.53

Term	Year	6/18	6/19	6/20	6/23	6/24	6/25	6/26	6/27	6/30	7/1	7/2	7/3	7/4	7/7	7/8	7/9	7/10
1	2009	1.78	1.78	1.78	1.78	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.74	H	1.74	1.64	1.64	1.59
2	2010	2.64	2.69	2.71	2.74	2.76	2.78	2.77	2.74	2.72	2.68	2.65	2.63	O	2.59	2.52	2.43	2.38
3	2011	3.02	3.05	3.07	3.1	3.12	3.14	3.13	3.1	3.09	3.05	3.01	2.99	L	2.95	2.88	2.8	2.75
4	2012	3.22	3.27	3.29	3.32	3.34	3.36	3.34	3.31	3.3	3.26	3.22	3.2	I	3.16	3.11	3.04	2.99
5	2013	3.36	3.41	3.43	3.46	3.48	3.5	3.47	3.44	3.43	3.38	3.34	3.32	D	3.28	3.24	3.18	3.14
6	2014	3.49	3.54	3.55	3.58	3.61	3.63	3.6	3.57	3.55	3.5	3.46	3.44	A	3.4	3.36	3.3	3.26
7	2015	3.62	3.67	3.68	3.71	3.72	3.74	3.71	3.68	3.66	3.61	3.57	3.55	Y	3.51	3.48	3.42	3.38
8	2016	3.75	3.8	3.81	3.84	3.84	3.86	3.82	3.79	3.77	3.72	3.68	3.66		3.62	3.59	3.54	3.5
9	2017	3.88	3.93	3.94	3.97	3.97	3.99	3.95	3.92	3.89	3.83	3.79	3.77		3.73	3.7	3.66	3.62
10	2018	3.99	4.04	4.05	4.08	4.08	4.1	4.06	4.03	4	3.94	3.9	3.88		3.84	3.81	3.77	3.73
11	2019	4.1	4.15	4.16	4.19	4.19	4.21	4.17	4.13	4.1	4.04	4	3.98	H	3.95	3.93	3.89	3.85
12	2020	4.2	4.25	4.26	4.29	4.29	4.31	4.27	4.23	4.2	4.14	4.1	4.08	O	4.05	4.03	3.99	3.96
13	2021	4.28	4.32	4.34	4.37	4.37	4.39	4.35	4.3	4.27	4.21	4.17	4.15	L	4.13	4.11	4.08	4.05
14	2022	4.33	4.36	4.38	4.41	4.42	4.44	4.4	4.35	4.33	4.27	4.23	4.21	I	4.19	4.17	4.14	4.11
15	2023	4.37	4.4	4.42	4.45	4.46	4.48	4.45	4.4	4.38	4.32	4.28	4.26	D	4.25	4.23	4.2	4.17
16	2024	4.41	4.44	4.46	4.49	4.51	4.52	4.5	4.45	4.43	4.38	4.34	4.32	A	4.31	4.29	4.25	4.22
17	2025	4.46	4.49	4.51	4.54	4.56	4.57	4.55	4.5	4.48	4.43	4.39	4.37	Y	4.36	4.34	4.3	4.27
18	2026	4.51	4.54	4.57	4.59	4.61	4.62	4.6	4.55	4.53	4.48	4.44	4.42		4.41	4.39	4.35	4.32
19	2027	4.55	4.58	4.62	4.64	4.67	4.68	4.65	4.6	4.58	4.53	4.49	4.47		4.46	4.44	4.4	4.37
20	2028	4.6	4.63	4.68	4.7	4.73	4.74	4.7	4.65	4.63	4.58	4.54	4.52		4.51	4.49	4.45	4.42
21	2029	4.64	4.67	4.74	4.76	4.79	4.79	4.75	4.7	4.68	4.63	4.59	4.57	H	4.56	4.54	4.5	4.47
22	2030	4.68	4.71	4.78	4.8	4.83	4.83	4.79	4.74	4.72	4.67	4.63	4.62	O	4.61	4.59	4.54	4.51
23	2031	4.71	4.74	4.81	4.83	4.86	4.86	4.82	4.77	4.75	4.7	4.66	4.65	L	4.64	4.62	4.57	4.54
24	2032	4.72	4.76	4.84	4.86	4.89	4.89	4.85	4.8	4.77	4.72	4.68	4.67	I	4.66	4.64	4.59	4.56
25	2033	4.73	4.78	4.87	4.89	4.92	4.92	4.88	4.83	4.79	4.74	4.69	4.69	D	4.68	4.65	4.6	4.57
26	2034	4.74	4.79	4.89	4.91	4.94	4.94	4.89	4.84	4.8	4.75	4.7	4.7	A	4.69	4.66	4.61	4.58
27	2035	4.75	4.8	4.91	4.93	4.95	4.95	4.9	4.85	4.81	4.76	4.71	4.71	Y	4.7	4.67	4.62	4.59
28	2036	4.76	4.81	4.93	4.95	4.96	4.96	4.91	4.86	4.82	4.77	4.72	4.72		4.71	4.68	4.63	4.6
29	2037	4.78	4.83	4.95	4.97	4.97	4.97	4.92	4.87	4.83	4.78	4.73	4.73		4.72	4.69	4.64	4.61
30	2038	4.79	4.84	4.96	4.98	4.98	4.98	4.93	4.88	4.84	4.79	4.74	4.74		4.73	4.69	4.65	4.62

JEA-POD3-00014
Hearing Exhibit - 00000506

MMD Scales for JEA

Term	Year	1/2	1/3	1/4	1/5	1/8	1/9	1/10	1/11	1/12	1/15	1/16	1/17	1/18	1/19	1/22	1/23	1/24	1/25	1/26	1/29	1/30	1/31	2/1	2/2
1	2008	3.51	3.51	3.50	3.51	3.51	3.51	3.51	3.55	3.56	H	3.56	3.57	3.57	3.57	3.57	3.57	3.57	3.60	3.61	3.61	3.61	3.61	3.61	3.61
2	2009	3.53	3.53	3.52	3.54	3.54	3.54	3.54	3.58	3.60	O	3.60	3.61	3.61	3.61	3.61	3.61	3.61	3.65	3.67	3.67	3.67	3.67	3.67	3.66
3	2010	3.54	3.54	3.53	3.55	3.55	3.55	3.56	3.60	3.62	L	3.62	3.63	3.63	3.63	3.63	3.63	3.63	3.67	3.68	3.68	3.68	3.68	3.68	3.67
4	2011	3.54	3.54	3.53	3.55	3.55	3.55	3.56	3.60	3.62	I	3.62	3.63	3.63	3.63	3.63	3.63	3.64	3.68	3.68	3.68	3.68	3.68	3.68	3.67
5	2012	3.55	3.55	3.53	3.55	3.55	3.55	3.56	3.60	3.62	D	3.62	3.63	3.63	3.63	3.63	3.64	3.65	3.69	3.69	3.69	3.69	3.69	3.69	3.68
6	2013	3.57	3.57	3.55	3.57	3.57	3.57	3.58	3.62	3.64	A	3.64	3.65	3.65	3.65	3.65	3.66	3.67	3.71	3.71	3.72	3.72	3.72	3.72	3.70
7	2014	3.60	3.59	3.57	3.59	3.59	3.59	3.60	3.65	3.67	Y	3.67	3.68	3.68	3.68	3.67	3.68	3.69	3.73	3.73	3.75	3.75	3.75	3.75	3.73
8	2015	3.63	3.62	3.59	3.61	3.61	3.61	3.63	3.68	3.70		3.70	3.71	3.71	3.71	3.70	3.71	3.73	3.77	3.77	3.78	3.78	3.78	3.78	3.76
9	2016	3.67	3.66	3.63	3.65	3.65	3.65	3.67	3.72	3.74		3.74	3.75	3.75	3.75	3.74	3.76	3.77	3.81	3.81	3.82	3.82	3.82	3.82	3.80
10	2017	3.71	3.70	3.67	3.69	3.69	3.69	3.71	3.76	3.78		3.78	3.79	3.79	3.79	3.78	3.80	3.82	3.86	3.86	3.87	3.87	3.86	3.86	3.84
11	2018	3.75	3.74	3.71	3.73	3.73	3.73	3.75	3.80	3.82	H	3.82	3.83	3.82	3.83	3.82	3.84	3.86	3.90	3.90	3.91	3.91	3.90	3.90	3.88
12	2019	3.79	3.78	3.75	3.77	3.77	3.77	3.79	3.84	3.86	O	3.85	3.86	3.85	3.86	3.85	3.87	3.89	3.93	3.93	3.94	3.94	3.93	3.93	3.91
13	2020	3.83	3.82	3.79	3.81	3.81	3.81	3.83	3.87	3.89	L	3.88	3.89	3.88	3.89	3.88	3.90	3.92	3.96	3.96	3.97	3.97	3.95	3.95	3.93
14	2021	3.86	3.85	3.82	3.84	3.84	3.84	3.86	3.90	3.92	I	3.91	3.92	3.91	3.92	3.91	3.93	3.95	3.99	3.99	3.99	3.99	3.97	3.97	3.95
15	2022	3.88	3.87	3.84	3.86	3.86	3.86	3.88	3.92	3.94	D	3.93	3.95	3.94	3.95	3.94	3.96	3.97	4.01	4.01	4.01	4.01	3.99	3.99	3.97
16	2023	3.90	3.89	3.86	3.88	3.88	3.88	3.90	3.94	3.96	A	3.95	3.97	3.96	3.97	3.96	3.98	3.99	4.03	4.03	4.03	4.03	4.01	4.01	3.99
17	2024	3.92	3.91	3.88	3.90	3.90	3.90	3.92	3.96	3.98	Y	3.97	3.99	3.98	3.99	3.98	4.00	4.01	4.05	4.05	4.05	4.05	4.03	4.03	4.01
18	2025	3.94	3.93	3.90	3.92	3.92	3.92	3.94	3.98	4.00		3.99	4.01	4.00	4.01	4.00	4.02	4.03	4.07	4.07	4.07	4.07	4.05	4.05	4.03
19	2026	3.96	3.95	3.92	3.94	3.94	3.94	3.96	4.00	4.02		4.01	4.03	4.02	4.03	4.02	4.04	4.05	4.09	4.09	4.09	4.09	4.07	4.07	4.05
20	2027	3.98	3.97	3.94	3.96	3.96	3.96	3.98	4.02	4.04		4.03	4.05	4.04	4.05	4.04	4.06	4.07	4.11	4.11	4.11	4.11	4.09	4.09	4.07
21	2028	3.99	3.98	3.95	3.97	3.97	3.97	3.99	4.03	4.05	H	4.05	4.06	4.05	4.06	4.05	4.07	4.08	4.12	4.12	4.12	4.12	4.10	4.10	4.08
22	2029	4.00	3.99	3.96	3.98	3.98	3.98	4.00	4.04	4.06	O	4.06	4.07	4.06	4.07	4.06	4.08	4.09	4.13	4.13	4.14	4.14	4.11	4.11	4.09
23	2030	4.01	4.00	3.97	3.99	3.99	3.99	4.01	4.05	4.07	L	4.07	4.08	4.07	4.08	4.07	4.09	4.10	4.14	4.14	4.15	4.15	4.12	4.12	4.10
24	2031	4.02	4.01	3.98	4.00	4.00	4.00	4.02	4.06	4.08	I	4.08	4.09	4.08	4.09	4.08	4.10	4.11	4.15	4.15	4.16	4.16	4.13	4.13	4.11
25	2032	4.03	4.02	3.99	4.01	4.01	4.01	4.03	4.07	4.09	D	4.09	4.10	4.09	4.10	4.09	4.11	4.12	4.16	4.16	4.17	4.17	4.14	4.14	4.12
26	2033	4.04	4.03	4.00	4.02	4.02	4.02	4.04	4.08	4.10	A	4.10	4.11	4.10	4.11	4.10	4.12	4.13	4.17	4.17	4.18	4.18	4.15	4.15	4.13
27	2034	4.05	4.04	4.01	4.03	4.03	4.03	4.05	4.09	4.11	Y	4.11	4.12	4.11	4.12	4.11	4.13	4.14	4.18	4.18	4.19	4.19	4.16	4.16	4.14
28	2035	4.06	4.05	4.02	4.04	4.04	4.04	4.06	4.10	4.12		4.12	4.13	4.11	4.13	4.11	4.13	4.14	4.18	4.18	4.19	4.19	4.16	4.16	4.15
29	2036	4.07	4.06	4.03	4.05	4.05	4.05	4.07	4.11	4.13		4.13	4.14	4.12	4.14	4.12	4.14	4.15	4.19	4.19	4.20	4.20	4.17	4.17	4.16
30	2037	4.07	4.06	4.03	4.05	4.05	4.05	4.07	4.11	4.13		4.13	4.14	4.12	4.14	4.12	4.14	4.15	4.19	4.19	4.20	4.20	4.17	4.17	4.16

Term	Year	1/2	1/3	1/4	1/5	1/8	1/9	1/10	1/11	1/12	1/15	1/16	1/17	1/18	1/19	1/22	1/23	1/24	1/25	1/26	1/29	1/30	1/31	2/1	2/2
1	2008	3.54	3.56	3.55	3.56	3.56	3.56	3.56	3.60	3.61	H	3.61	3.62	3.62	3.62	3.62	3.62	3.62	3.65	3.66	3.66	3.67	3.67	3.67	3.67
2	2009	3.58	3.60	3.59	3.61	3.61	3.61	3.61	3.65	3.67	O	3.67	3.68	3.68	3.68	3.68	3.68	3.68	3.72	3.73	3.73	3.74	3.74	3.74	3.73
3	2010	3.62	3.62	3.61	3.63	3.63	3.63	3.64	3.68	3.70	L	3.70	3.71	3.71	3.71	3.71	3.71	3.71	3.75	3.76	3.77	3.77	3.77	3.77	3.76
4	2011	3.62	3.62	3.61	3.63	3.63	3.63	3.64	3.68	3.70	I	3.70	3.71	3.71	3.72	3.72	3.72	3.73	3.77	3.77	3.78	3.78	3.78	3.78	3.77
5	2012	3.64	3.64	3.62	3.64	3.64	3.64	3.65	3.69	3.71	D	3.71	3.72	3.72	3.73	3.72	3.73	3.74	3.78	3.78	3.79	3.79	3.79	3.79	3.78
6	2013	3.67	3.67	3.65	3.67	3.67	3.67	3.68	3.72	3.74	A	3.74	3.75	3.74	3.75	3.74	3.75	3.76	3.80	3.80	3.82	3.82	3.82	3.82	3.80
7	2014	3.70	3.69	3.67	3.69	3.69	3.69	3.71	3.76	3.78	Y	3.78	3.79	3.78	3.79	3.77	3.78	3.79	3.83	3.83	3.85	3.85	3.85	3.85	3.83
8	2015	3.73	3.72	3.69	3.71	3.71	3.71	3.74	3.79	3.81		3.81	3.82	3.82	3.82	3.80	3.81	3.83	3.87	3.87	3.88	3.88	3.88	3.88	3.86
9	2016	3.78	3.77	3.74	3.76	3.76	3.75	3.78	3.83	3.85		3.85	3.86	3.86	3.86	3.84	3.86	3.87	3.91	3.91	3.92	3.92	3.92	3.92	3.90
10	2017	3.82	3.81	3.78	3.80	3.80	3.79	3.82	3.87	3.89		3.89	3.90	3.90	3.90	3.88	3.90	3.92	3.96	3.96	3.97	3.97	3.96	3.96	3.94
11	2018	3.86	3.85	3.82	3.84	3.84	3.83	3.86	3.91	3.93	H	3.93	3.94	3.93	3.94	3.92	3.94	3.96	4.00	4.00	4.01	4.01	4.00	4.00	3.98
12	2019	3.90	3.89	3.86	3.88	3.88	3.88	3.90	3.95	3.97	O	3.96	3.97	3.96	3.97	3.95	3.97	3.99	4.03	4.03	4.04	4.04	4.03	4.03	4.01
13	2020	3.94	3.93	3.90	3.92	3.92	3.92	3.94	3.98	4.00	L	3.99	4.00	3.99	4.00	3.98	4.00	4.02	4.06	4.06	4.07	4.07	4.05	4.05	4.03
14	2021	3.97	3.96	3.93	3.95	3.95	3.95	3.97	4.01	4.03	I	4.02	4.03	4.02	4.03	4.01	4.03	4.05	4.09	4.09	4.09	4.09	4.07	4.07	4.05
15	2022	3.99	3.98	3.95	3.97	3.97	3.97	3.99	4.03	4.05	D	4.04	4.06	4.05	4.06	4.04	4.06	4.07	4.11	4.11	4.11	4.11	4.09	4.09	4.07
16	2023	4.01	4.00	3.97	3.99	3.99	3.99	4.01	4.05	4.07	A	4.06	4.08	4.07	4.08	4.06	4.08	4.09	4.13	4.13	4.13	4.13	4.11	4.11	4.09
17	2024	4.03	4.02	3.99	4.01	4.01	4.01	4.03	4.07	4.09	Y	4.08	4.10	4.09	4.10	4.08	4.10	4.11	4.15	4.15	4.15	4.15	4.13	4.13	4.11
18	2025	4.05	4.04	4.01	4.03	4.03	4.03	4.05	4.09	4.11		4.10	4.12	4.11	4.12	4.10	4.12	4.13	4.17	4.17	4.17	4.17	4.15	4.15	4.13
19	2026	4.07	4.06	4.03	4.05	4.05	4.05	4.07	4.11	4.13		4.12	4.14	4.13	4.14	4.12	4.14	4.15	4.19	4.19	4.19	4.19	4.17	4.17	4.15
20	2027	4.08	4.07	4.04	4.06	4.06	4.06	4.08	4.12	4.14		4.13	4.15	4.14	4.15	4.13	4.15	4.16	4.20	4.20	4.20	4.20	4.18	4.18	4.16
21	2028	4.08	4.07	4.04	4.06	4.06	4.06	4.08	4.12	4.14	H	4.14	4.15	4.14	4.15	4.14	4.16	4.17	4.21	4.21	4.21	4.21	4.19	4.19	4.17
22	2029	4.09	4.08	4.05	4.07	4.07	4.07	4.09	4.13	4.15	O	4.15	4.16	4.15	4.16	4.15	4.17	4.18	4.22	4.22	4.23	4.23	4.20	4.20	4.18
23	2030	4.10	4.09	4.06	4.08	4.08	4.08	4.10	4.14	4.16	L	4.16	4.17	4.16	4.17	4.16	4.18	4.19	4.23	4.23	4.24	4.24	4.21	4.21	4.19
24	2031	4.11	4.10	4.07	4.09	4.09	4.09	4.11	4.15	4.17	I	4.17	4.18	4.17	4.18	4.17	4.19	4.20	4.24	4.24	4.25	4.25	4.22	4.22	4.20
25	2032	4.12	4.11	4.08	4.10	4.10	4.10	4.12	4.16	4.18	D	4.18	4.19	4.18	4.19	4.18	4.20	4.21	4.25	4.25	4.26	4.26	4.23	4.23	4.21
26	2033	4.13	4.12	4.09	4.11	4.11	4.11	4.13	4.17	4.19	A	4.19	4.20	4.19	4.20	4.19	4.21	4.22	4.26	4.26	4.27	4.27	4.24	4.24	4.22
27	2034	4.14	4.13	4.10	4.12	4.12	4.12	4.14	4.18	4.20	Y	4.20	4.21	4.20	4.21	4.20	4.22	4.23	4.27	4.27	4.28	4.28	4.25	4.25	4.23
28	2035	4.15	4.14	4.11	4.13	4.13	4.13	4.15	4.19	4.21		4.21	4.22	4.20	4.22	4.20	4.22	4.23	4.27	4.27	4.28	4.28	4.25	4.25	4.24
29	2036	4.16	4.15	4.12	4.14	4.14	4.14	4.16	4.20	4.22		4.22	4.23	4.21	4.23	4.21	4.23	4.24	4.28	4.28	4.29	4.29	4.26	4.26	4.25
30	2037	4.16	4.15	4.12	4.14	4.14	4.14	4.16	4.20	4.22		4.22	4.23	4.21	4.23	4.21	4.23	4.24	4.28	4.28	4.29	4.29	4.26	4.26	4.25

JEA-POD3-00015Hearing Exhibit - 00000507

MMD Scales

Year	2/5	2/6	2/7	2/8	2/9	2/12	2/13	2/14	2/15	2/16	2/19	2/20	2/21	2/22	2/23	2/26	2/27	2/28	3/1	3/2	3/5	3/6	3/7	3/8
2008	3.60	3.60	3.60	3.60	3.60	3.60	3.61	3.60	3.58	3.58	H	3.58	3.58	3.60	3.60	3.58	3.56	3.56	3.56	3.56	3.56	3.55	3.53	3.53
2009	3.65	3.63	3.61	3.61	3.61	3.62	3.63	3.61	3.59	3.59	O	3.59	3.60	3.62	3.60	3.58	3.55	3.55	3.55	3.52	3.52	3.52	3.50	3.50
2010	3.66	3.63	3.61	3.61	3.62	3.63	3.64	3.62	3.60	3.60	L	3.60	3.60	3.62	3.60	3.58	3.54	3.54	3.54	3.49	3.49	3.49	3.47	3.47
2011	3.66	3.63	3.61	3.61	3.62	3.63	3.64	3.62	3.60	3.60	I	3.60	3.60	3.62	3.60	3.58	3.54	3.54	3.54	3.49	3.49	3.49	3.47	3.47
2012	3.67	3.64	3.62	3.62	3.64	3.65	3.66	3.63	3.61	3.61	D	3.61	3.61	3.63	3.60	3.58	3.54	3.55	3.55	3.51	3.51	3.51	3.49	3.49
2013	3.69	3.66	3.64	3.64	3.66	3.67	3.68	3.65	3.62	3.62	A	3.62	3.62	3.64	3.61	3.59	3.55	3.56	3.56	3.54	3.54	3.54	3.52	3.52
2014	3.72	3.69	3.67	3.67	3.69	3.70	3.71	3.68	3.65	3.64	Y	3.64	3.64	3.66	3.63	3.61	3.57	3.58	3.58	3.56	3.56	3.56	3.54	3.54
2015	3.75	3.72	3.70	3.70	3.72	3.74	3.75	3.72	3.68	3.67		3.67	3.67	3.69	3.66	3.63	3.59	3.61	3.61	3.59	3.59	3.59	3.57	3.57
2016	3.78	3.75	3.73	3.73	3.75	3.77	3.78	3.75	3.71	3.70		3.70	3.70	3.72	3.69	3.66	3.62	3.64	3.64	3.62	3.62	3.63	3.61	3.61
2017	3.82	3.78	3.76	3.76	3.78	3.80	3.81	3.78	3.74	3.73		3.73	3.73	3.75	3.72	3.69	3.65	3.67	3.67	3.65	3.65	3.66	3.64	3.64
2018	3.86	3.82	3.80	3.80	3.82	3.83	3.84	3.81	3.77	3.76	H	3.76	3.76	3.78	3.75	3.72	3.68	3.70	3.70	3.68	3.68	3.69	3.68	3.68
2019	3.89	3.86	3.84	3.83	3.86	3.87	3.87	3.83	3.79	3.78	O	3.78	3.78	3.80	3.77	3.74	3.70	3.72	3.72	3.70	3.70	3.71	3.71	3.71
2020	3.91	3.88	3.86	3.85	3.88	3.89	3.89	3.85	3.81	3.80	L	3.80	3.80	3.82	3.79	3.76	3.72	3.74	3.74	3.72	3.72	3.73	3.73	3.73
2021	3.93	3.90	3.88	3.87	3.90	3.91	3.91	3.87	3.83	3.82	I	3.82	3.82	3.84	3.81	3.78	3.74	3.76	3.76	3.74	3.74	3.75	3.75	3.75
2022	3.95	3.92	3.90	3.89	3.92	3.93	3.93	3.89	3.85	3.84	D	3.84	3.84	3.86	3.83	3.80	3.76	3.78	3.78	3.76	3.76	3.77	3.77	3.77
2023	3.98	3.95	3.93	3.92	3.95	3.96	3.96	3.92	3.88	3.87	A	3.87	3.87	3.89	3.86	3.83	3.78	3.80	3.80	3.78	3.78	3.79	3.79	3.79
2024	4.00	3.97	3.95	3.94	3.97	3.98	3.98	3.94	3.91	3.90	Y	3.90	3.90	3.92	3.88	3.85	3.80	3.82	3.82	3.80	3.80	3.81	3.81	3.81
2025	4.02	3.99	3.97	3.96	3.99	4.00	4.00	3.96	3.93	3.92		3.92	3.92	3.94	3.90	3.87	3.82	3.84	3.84	3.82	3.82	3.83	3.83	3.83
2026	4.04	4.01	3.99	3.98	4.01	4.02	4.02	3.98	3.95	3.94		3.94	3.94	3.96	3.92	3.89	3.84	3.86	3.86	3.84	3.84	3.85	3.85	3.85
2027	4.06	4.03	4.01	4.00	4.03	4.04	4.04	3.99	3.97	3.96		3.96	3.96	3.98	3.94	3.91	3.86	3.88	3.88	3.86	3.86	3.87	3.87	3.87
2028	4.07	4.04	4.02	4.01	4.04	4.05	4.05	4.00	3.98	3.97	H	3.97	3.98	4.00	3.96	3.93	3.87	3.89	3.89	3.88	3.88	3.89	3.89	3.89
2029	4.08	4.05	4.03	4.02	4.05	4.06	4.06	4.01	3.99	3.98	O	3.98	3.99	4.01	3.97	3.94	3.88	3.90	3.90	3.89	3.89	3.90	3.90	3.90
2030	4.09	4.06	4.04	4.03	4.06	4.07	4.07	4.02	4.00	3.99	L	3.99	4.00	4.02	3.98	3.95	3.89	3.91	3.91	3.90	3.90	3.91	3.91	3.91
2031	4.10	4.07	4.05	4.04	4.07	4.08	4.08	4.03	4.01	4.00	I	4.00	4.01	4.03	3.99	3.96	3.90	3.92	3.92	3.91	3.91	3.92	3.92	3.92
2032	4.11	4.08	4.06	4.05	4.08	4.09	4.09	4.04	4.02	4.01	D	4.01	4.02	4.04	4.00	3.97	3.91	3.93	3.93	3.92	3.92	3.93	3.93	3.93
2033	4.12	4.09	4.07	4.06	4.09	4.10	4.10	4.05	4.03	4.02	A	4.02	4.03	4.05	4.01	3.98	3.92	3.94	3.94	3.93	3.93	3.94	3.94	3.94
2034	4.13	4.10	4.08	4.07	4.10	4.11	4.11	4.06	4.04	4.03	Y	4.03	4.04	4.06	4.02	3.99	3.93	3.95	3.95	3.94	3.94	3.95	3.95	3.95
2035	4.14	4.11	4.09	4.08	4.11	4.12	4.12	4.07	4.05	4.04		4.04	4.05	4.07	4.03	4.00	3.94	3.96	3.96	3.95	3.95	3.95	3.95	3.95
2036	4.15	4.12	4.10	4.09	4.12	4.13	4.13	4.08	4.06	4.05		4.05	4.06	4.08	4.04	4.01	3.95	3.97	3.97	3.96	3.96	3.96	3.96	3.96
2037	4.15	4.12	4.10	4.09	4.12	4.13	4.13	4.08	4.06	4.05		4.05	4.06	4.08	4.04	4.01	3.95	3.97	3.97	3.96	3.96	3.96	3.96	3.96

Year	2/5	2/6	2/7	2/8	2/9	2/12	2/13	2/14	2/15	2/16	2/19	2/20	2/21	2/22	2/23	2/26	2/27	2/28	3/1	3/2	3/5	3/6	3/7	3/8
2008	3.66	3.66	3.66	3.66	3.66	3.66	3.67	3.66	3.64	3.64	H	3.64	3.64	3.66	3.66	3.64	3.62	3.62	3.62	3.60	3.60	3.58	3.56	3.56
2009	3.72	3.69	3.67	3.67	3.67	3.68	3.69	3.67	3.65	3.65	O	3.65	3.66	3.68	3.66	3.64	3.61	3.61	3.61	3.57	3.57	3.57	3.55	3.55
2010	3.75	3.71	3.69	3.69	3.70	3.71	3.72	3.69	3.67	3.67	L	3.67	3.67	3.69	3.67	3.65	3.61	3.61	3.61	3.55	3.55	3.55	3.53	3.53
2011	3.76	3.72	3.70	3.70	3.71	3.72	3.73	3.70	3.68	3.68	I	3.68	3.68	3.70	3.68	3.66	3.62	3.62	3.62	3.56	3.56	3.56	3.54	3.54
2012	3.77	3.73	3.71	3.71	3.73	3.74	3.75	3.71	3.69	3.69	D	3.69	3.69	3.71	3.68	3.66	3.62	3.63	3.63	3.58	3.58	3.58	3.56	3.56
2013	3.79	3.75	3.73	3.73	3.75	3.76	3.77	3.73	3.70	3.70	A	3.70	3.70	3.72	3.69	3.67	3.63	3.64	3.64	3.62	3.62	3.62	3.60	3.60
2014	3.82	3.78	3.76	3.76	3.78	3.79	3.81	3.77	3.74	3.73	Y	3.73	3.73	3.75	3.72	3.70	3.66	3.67	3.67	3.65	3.65	3.65	3.63	3.63
2015	3.85	3.81	3.79	3.79	3.81	3.83	3.85	3.81	3.77	3.76		3.76	3.76	3.78	3.75	3.72	3.68	3.7	3.70	3.68	3.68	3.68	3.66	3.66
2016	3.88	3.84	3.82	3.82	3.84	3.87	3.89	3.85	3.80	3.79		3.79	3.79	3.81	3.78	3.75	3.71	3.74	3.74	3.72	3.72	3.73	3.71	3.71
2017	3.92	3.88	3.86	3.85	3.88	3.90	3.92	3.88	3.83	3.82		3.82	3.82	3.84	3.81	3.78	3.74	3.77	3.77	3.75	3.75	3.76	3.74	3.74
2018	3.96	3.92	3.90	3.89	3.92	3.93	3.95	3.91	3.86	3.85	H	3.85	3.85	3.87	3.84	3.81	3.77	3.8	3.80	3.78	3.78	3.79	3.78	3.78
2019	3.99	3.96	3.94	3.93	3.96	3.97	3.98	3.94	3.89	3.88	O	3.88	3.88	3.90	3.87	3.84	3.79	3.82	3.82	3.80	3.80	3.81	3.81	3.81
2020	4.01	3.98	3.96	3.95	3.98	3.99	4.00	3.96	3.91	3.90	L	3.90	3.90	3.92	3.89	3.86	3.81	3.84	3.84	3.82	3.82	3.83	3.84	3.84
2021	4.03	4.00	3.98	3.97	4.00	4.01	4.02	3.98	3.93	3.92	I	3.92	3.92	3.94	3.91	3.88	3.83	3.86	3.86	3.84	3.84	3.85	3.86	3.86
2022	4.05	4.02	4.00	3.99	4.02	4.03	4.04	4.00	3.95	3.94	D	3.94	3.94	3.96	3.93	3.90	3.85	3.88	3.88	3.86	3.86	3.87	3.88	3.88
2023	4.08	4.05	4.03	4.02	4.05	4.06	4.07	4.03	3.98	3.97	A	3.97	3.97	3.99	3.96	3.93	3.87	3.9	3.90	3.88	3.88	3.89	3.90	3.90
2024	4.10	4.07	4.05	4.04	4.07	4.08	4.09	4.05	4.01	4.00	Y	4.00	4.00	4.02	3.98	3.95	3.89	3.92	3.92	3.90	3.90	3.91	3.92	3.92
2025	4.12	4.09	4.07	4.06	4.09	4.10	4.11	4.07	4.03	4.02		4.02	4.02	4.04	4.00	3.97	3.91	3.94	3.94	3.92	3.92	3.93	3.94	3.94
2026	4.14	4.11	4.09	4.08	4.11	4.12	4.13	4.08	4.05	4.04		4.04	4.04	4.06	4.02	3.99	3.93	3.96	3.96	3.94	3.94	3.95	3.96	3.96
2027	4.15	4.12	4.10	4.09	4.12	4.13	4.14	4.09	4.07	4.06		4.06	4.06	4.08	4.04	4.01	3.95	3.98	3.98	3.96	3.96	3.97	3.98	3.98
2028	4.16	4.13	4.11	4.10	4.13	4.14	4.15	4.10	4.08	4.07	H	4.07	4.08	4.10	4.06	4.03	3.96	3.99	3.99	3.98	3.98	3.99	4.00	4.00
2029	4.17	4.14	4.12	4.11	4.14	4.15	4.16	4.11	4.09	4.08	O	4.08	4.09	4.11	4.07	4.04	3.97	4.00	4.00	3.99	3.99	4.00	4.01	4.01
2030	4.18	4.15	4.13	4.12	4.15	4.16	4.17	4.12	4.10	4.09	L	4.09	4.10	4.12	4.08	4.05	3.98	4.01	4.01	4.00	4.00	4.01	4.01	4.01
2031	4.19	4.16	4.14	4.13	4.16	4.17	4.18	4.13	4.11	4.10	I	4.10	4.11	4.13	4.09	4.06	3.99	4.02	4.02	4.01	4.01	4.02	4.02	4.02
2032	4.20	4.17	4.15	4.14	4.17	4.18	4.19	4.14	4.12	4.11	D	4.11	4.12	4.14	4.10	4.07	4.00	4.03	4.03	4.02	4.02	4.03	4.03	4.03
2033	4.21	4.18	4.16	4.15	4.18	4.19	4.20	4.15	4.13	4.12	A	4.12	4.13	4.15	4.11	4.08	4.01	4.04	4.04	4.03	4.03	4.04	4.04	4.04
2034	4.22	4.19	4.17	4.16	4.19	4.20	4.21	4.16	4.14	4.13	Y	4.13	4.14	4.16	4.12	4.09	4.02	4.05	4.05	4.04	4.04	4.05	4.05	4.05
2035	4.23	4.20	4.18	4.17	4.20	4.21	4.21	4.16	4.14	4.13		4.13	4.14	4.16	4.12	4.09	4.02	4.05	4.05	4.04	4.04	4.05	4.05	4.05
2036	4.24	4.21	4.19	4.18	4.21	4.22	4.22	4.17	4.15	4.14		4.14	4.15	4.17	4.13	4.10	4.03	4.06	4.06	4.05	4.05	4.05	4.05	4.05
2037	4.24	4.21	4.19	4.18	4.21	4.22	4.22	4.17	4.15	4.14		4.14	4.15	4.17	4.13	4.10	4.03	4.06	4.06	4.05	4.05	4.05	4.05	4.05

MMD Scales

Term	Year	3/9	3/12	3/13	3/14	3/15	3/16	3/19	3/20	3/21	3/22	3/23	3/26	3/27	3/28	3/29	3/30	4/2	4/3	4/4	4/5	4/6	4/9	4/10	4/11
1	2008	3.55	3.55	3.54	3.54	3.54	3.54	3.55	3.55	3.54	3.54	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.57	3.58	3.58	3.58
2	2009	3.53	3.53	3.52	3.52	3.52	3.52	3.53	3.52	3.51	3.52	3.53	3.53	3.53	3.53	3.54	3.54	3.54	3.54	3.54	3.54	3.56	3.58	3.58	3.58
3	2010	3.51	3.51	3.50	3.50	3.50	3.50	3.52	3.51	3.50	3.51	3.52	3.52	3.52	3.52	3.54	3.54	3.54	3.55	3.55	3.55	3.57	3.59	3.59	3.59
4	2011	3.51	3.51	3.49	3.49	3.49	3.49	3.51	3.50	3.49	3.51	3.52	3.52	3.52	3.52	3.54	3.54	3.54	3.55	3.55	3.55	3.57	3.60	3.60	3.60
5	2012	3.53	3.53	3.51	3.51	3.51	3.51	3.53	3.52	3.51	3.53	3.54	3.54	3.54	3.54	3.56	3.56	3.56	3.57	3.57	3.57	3.59	3.62	3.62	3.62
6	2013	3.56	3.56	3.54	3.54	3.54	3.54	3.55	3.54	3.53	3.55	3.56	3.56	3.56	3.57	3.59	3.59	3.59	3.61	3.61	3.61	3.63	3.66	3.66	3.66
7	2014	3.58	3.58	3.56	3.56	3.56	3.56	3.57	3.56	3.55	3.58	3.59	3.59	3.59	3.60	3.62	3.62	3.62	3.64	3.64	3.65	3.67	3.70	3.70	3.70
8	2015	3.62	3.61	3.58	3.59	3.59	3.59	3.60	3.59	3.58	3.61	3.62	3.62	3.63	3.64	3.66	3.67	3.67	3.69	3.69	3.70	3.72	3.75	3.74	3.74
9	2016	3.66	3.65	3.62	3.63	3.63	3.63	3.63	3.62	3.61	3.65	3.66	3.66	3.67	3.68	3.71	3.72	3.72	3.75	3.75	3.76	3.78	3.81	3.80	3.80
10	2017	3.69	3.68	3.65	3.66	3.66	3.66	3.67	3.66	3.65	3.69	3.70	3.70	3.71	3.72	3.76	3.77	3.77	3.80	3.80	3.81	3.83	3.86	3.85	3.85
11	2018	3.73	3.72	3.70	3.71	3.71	3.71	3.72	3.71	3.70	3.74	3.75	3.75	3.76	3.77	3.80	3.81	3.81	3.84	3.84	3.85	3.87	3.90	3.89	3.89
12	2019	3.76	3.75	3.74	3.75	3.75	3.75	3.77	3.76	3.75	3.79	3.80	3.80	3.82	3.82	3.84	3.85	3.85	3.88	3.88	3.89	3.91	3.94	3.93	3.93
13	2020	3.79	3.78	3.77	3.78	3.78	3.78	3.80	3.79	3.78	3.82	3.83	3.83	3.85	3.85	3.87	3.88	3.88	3.91	3.91	3.92	3.94	3.97	3.96	3.96
14	2021	3.81	3.80	3.79	3.80	3.81	3.81	3.83	3.82	3.81	3.85	3.86	3.86	3.88	3.88	3.90	3.91	3.91	3.94	3.94	3.95	3.97	4.00	3.99	3.99
15	2022	3.83	3.82	3.81	3.82	3.83	3.83	3.85	3.84	3.83	3.87	3.88	3.88	3.91	3.91	3.93	3.94	3.94	3.97	3.97	3.98	4.00	4.03	4.02	4.02
16	2023	3.85	3.84	3.84	3.85	3.86	3.86	3.87	3.86	3.85	3.89	3.90	3.90	3.93	3.94	3.96	3.97	3.97	4.00	4.00	4.01	4.03	4.06	4.04	4.04
17	2024	3.87	3.86	3.86	3.87	3.88	3.88	3.89	3.88	3.87	3.91	3.92	3.92	3.95	3.96	3.98	3.99	3.99	4.02	4.02	4.03	4.05	4.08	4.06	4.06
18	2025	3.89	3.88	3.88	3.89	3.90	3.90	3.91	3.90	3.89	3.93	3.94	3.94	3.97	3.98	4.00	4.01	4.01	4.04	4.04	4.05	4.07	4.10	4.08	4.08
19	2026	3.90	3.89	3.89	3.90	3.91	3.91	3.92	3.91	3.90	3.94	3.96	3.96	3.98	3.99	4.01	4.02	4.02	4.05	4.05	4.06	4.08	4.11	4.09	4.09
20	2027	3.91	3.90	3.90	3.91	3.92	3.92	3.93	3.92	3.91	3.95	3.97	3.97	3.99	4.00	4.02	4.03	4.03	4.06	4.06	4.07	4.09	4.12	4.10	4.10
21	2028	3.93	3.92	3.92	3.93	3.93	3.93	3.94	3.93	3.92	3.96	3.98	3.98	4.00	4.01	4.03	4.04	4.04	4.07	4.07	4.08	4.10	4.13	4.11	4.11
22	2029	3.94	3.93	3.93	3.94	3.94	3.94	3.95	3.94	3.93	3.97	3.99	3.99	4.01	4.02	4.04	4.05	4.05	4.08	4.08	4.09	4.11	4.14	4.12	4.12
23	2030	3.95	3.94	3.94	3.95	3.95	3.95	3.96	3.95	3.94	3.98	4.00	4.00	4.02	4.03	4.05	4.06	4.06	4.08	4.08	4.09	4.11	4.14	4.12	4.12
24	2031	3.96	3.95	3.95	3.96	3.96	3.96	3.97	3.96	3.95	3.99	4.01	4.01	4.03	4.04	4.06	4.07	4.07	4.09	4.09	4.10	4.12	4.15	4.13	4.13
25	2032	3.97	3.96	3.96	3.97	3.97	3.97	3.98	3.97	3.96	4.00	4.02	4.02	4.04	4.05	4.07	4.08	4.08	4.10	4.10	4.11	4.13	4.16	4.14	4.14
26	2033	3.98	3.97	3.97	3.98	3.98	3.98	3.99	3.98	3.97	4.01	4.03	4.03	4.05	4.06	4.08	4.09	4.09	4.10	4.10	4.11	4.13	4.16	4.14	4.14
27	2034	3.99	3.98	3.98	3.99	3.99	3.99	4.00	3.99	3.98	4.02	4.04	4.04	4.06	4.07	4.09	4.10	4.10	4.11	4.11	4.12	4.14	4.17	4.15	4.15
28	2035	4.00	3.99	3.98	3.99	3.99	3.99	4.00	3.99	3.98	4.03	4.05	4.05	4.07	4.08	4.10	4.11	4.11	4.12	4.12	4.13	4.15	4.18	4.16	4.16
29	2036	4.01	4.00	3.99	4.00	4.00	4.00	4.01	4.00	3.99	4.04	4.06	4.06	4.08	4.09	4.11	4.12	4.12	4.13	4.13	4.14	4.16	4.19	4.17	4.17
30	2037	4.01	4.00	3.99	4.00	4.00	4.00	4.01	4.00	3.99	4.04	4.06	4.06	4.08	4.09	4.11	4.12	4.12	4.13	4.13	4.14	4.16	4.19	4.17	4.17

Term	Year	3/9	3/12	3/13	3/14	3/15	3/16	3/19	3/20	3/21	3/22	3/23	3/26	3/27	3/28	3/29	3/30	4/2	4/3	4/4	4/5	4/6	4/9	4/10	4/11
1	2008	3.58	3.58	3.56	3.56	3.56	3.56	3.57	3.57	3.56	3.56	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.59	3.60	3.60	3.60
2	2009	3.58	3.57	3.56	3.56	3.56	3.57	3.58	3.57	3.56	3.57	3.58	3.58	3.58	3.58	3.59	3.59	3.59	3.59	3.59	3.59	3.61	3.63	3.63	3.63
3	2010	3.58	3.57	3.56	3.56	3.56	3.57	3.59	3.58	3.57	3.58	3.59	3.58	3.58	3.58	3.61	3.61	3.61	3.62	3.62	3.62	3.64	3.66	3.66	3.66
4	2011	3.59	3.58	3.56	3.57	3.57	3.58	3.60	3.59	3.58	3.60	3.61	3.60	3.60	3.60	3.63	3.63	3.63	3.64	3.64	3.64	3.66	3.69	3.69	3.69
5	2012	3.61	3.60	3.58	3.59	3.59	3.60	3.62	3.61	3.60	3.62	3.63	3.63	3.63	3.63	3.66	3.66	3.66	3.67	3.67	3.67	3.69	3.72	3.72	3.72
6	2013	3.65	3.64	3.62	3.63	3.63	3.63	3.64	3.63	3.62	3.64	3.65	3.65	3.65	3.66	3.69	3.69	3.69	3.71	3.71	3.71	3.73	3.76	3.76	3.76
7	2014	3.68	3.67	3.65	3.66	3.66	3.66	3.67	3.66	3.65	3.68	3.69	3.69	3.69	3.70	3.72	3.73	3.73	3.75	3.74	3.75	3.77	3.80	3.80	3.80
8	2015	3.72	3.71	3.68	3.70	3.70	3.70	3.71	3.70	3.69	3.72	3.73	3.73	3.74	3.75	3.77	3.78	3.78	3.81	3.80	3.81	3.83	3.86	3.85	3.85
9	2016	3.76	3.75	3.72	3.74	3.74	3.74	3.74	3.73	3.72	3.76	3.77	3.77	3.78	3.79	3.82	3.83	3.83	3.87	3.86	3.87	3.89	3.92	3.91	3.91
10	2017	3.79	3.78	3.75	3.77	3.77	3.77	3.78	3.77	3.76	3.80	3.81	3.81	3.82	3.83	3.87	3.88	3.88	3.92	3.91	3.92	3.94	3.97	3.96	3.96
11	2018	3.83	3.82	3.80	3.82	3.82	3.82	3.83	3.82	3.81	3.85	3.86	3.86	3.87	3.88	3.91	3.92	3.92	3.96	3.95	3.96	3.98	4.01	3.99	3.99
12	2019	3.86	3.85	3.84	3.86	3.86	3.86	3.88	3.87	3.86	3.90	3.91	3.91	3.93	3.93	3.95	3.96	3.96	4.00	3.99	4.00	4.02	4.05	4.03	4.03
13	2020	3.90	3.89	3.88	3.89	3.89	3.89	3.91	3.90	3.89	3.93	3.94	3.94	3.96	3.96	3.98	3.99	3.99	4.03	4.02	4.03	4.05	4.08	4.06	4.06
14	2021	3.92	3.91	3.90	3.91	3.92	3.92	3.94	3.93	3.92	3.96	3.97	3.97	3.99	3.99	4.01	4.02	4.02	4.06	4.05	4.06	4.08	4.11	4.09	4.09
15	2022	3.94	3.93	3.92	3.93	3.94	3.94	3.96	3.95	3.94	3.98	3.99	3.99	4.02	4.02	4.04	4.05	4.05	4.09	4.08	4.09	4.11	4.14	4.12	4.12
16	2023	3.96	3.95	3.95	3.96	3.97	3.97	3.98	3.97	3.96	4.00	4.01	4.01	4.04	4.05	4.07	4.08	4.08	4.12	4.11	4.12	4.14	4.17	4.14	4.14
17	2024	3.98	3.97	3.97	3.98	3.99	3.99	4.00	3.99	3.98	4.02	4.03	4.03	4.06	4.07	4.09	4.10	4.10	4.14	4.13	4.14	4.16	4.19	4.16	4.16
18	2025	4.00	3.99	3.99	4.00	4.01	4.01	4.02	4.01	4.00	4.04	4.05	4.05	4.08	4.09	4.11	4.12	4.12	4.16	4.15	4.16	4.18	4.21	4.18	4.18
19	2026	4.01	4.00	4.00	4.01	4.02	4.02	4.03	4.02	4.01	4.05	4.07	4.07	4.09	4.10	4.12	4.13	4.13	4.17	4.16	4.17	4.19	4.22	4.19	4.19
20	2027	4.02	4.01	4.01	4.02	4.03	4.03	4.04	4.03	4.02	4.06	4.08	4.08	4.10	4.11	4.13	4.14	4.14	4.18	4.17	4.18	4.20	4.23	4.20	4.20
21	2028	4.04	4.03	4.03	4.04	4.04	4.04	4.05	4.04	4.03	4.07	4.09	4.09	4.11	4.12	4.14	4.15	4.15	4.19	4.18	4.19	4.21	4.24	4.21	4.21
22	2029	4.05	4.04	4.04	4.05	4.05	4.05	4.06	4.05	4.04	4.08	4.10	4.10	4.12	4.13	4.15	4.16	4.16	4.20	4.19	4.20	4.22	4.25	4.22	4.22
23	2030	4.05	4.04	4.04	4.05	4.05	4.05	4.06	4.05	4.04	4.08	4.11	4.11	4.13	4.14	4.16	4.17	4.17	4.20	4.19	4.20	4.22	4.25	4.22	4.22
24	2031	4.06	4.05	4.05	4.06	4.06	4.06	4.07	4.06	4.05	4.09	4.12	4.12	4.14	4.15	4.17	4.18	4.18	4.21	4.20	4.21	4.23	4.26	4.23	4.23
25	2032	4.07	4.06	4.06	4.07	4.07	4.07	4.08	4.07	4.06	4.11	4.13	4.13	4.15	4.16	4.18	4.19	4.19	4.21	4.20	4.21	4.23	4.26	4.24	4.24
26	2033	4.08	4.07	4.07	4.08	4.08	4.08	4.09	4.08	4.07	4.12	4.14	4.14	4.16	4.17	4.19	4.20	4.20	4.21	4.20	4.21	4.23	4.26	4.24	4.24
27	2034	4.09	4.08	4.08	4.09	4.09	4.09	4.10	4.09	4.08	4.13	4.15	4.15	4.17	4.18	4.20	4.21	4.21	4.22	4.21	4.22	4.24	4.27	4.25	4.25
28	2035	4.10	4.09	4.08	4.09	4.09	4.09	4.10	4.09	4.08	4.13	4.15	4.15	4.17	4.18	4.21	4.22	4.22	4.23	4.22	4.23	4.25	4.28	4.26	4.26
29	2036	4.10	4.09	4.08	4.09	4.09	4.09	4.10	4.10	4.09	4.14	4.16	4.16	4.18	4.19	4.22	4.23	4.23	4.24	4.23	4.24	4.26	4.29	4.27	4.27
30	2037	4.10	4.09	4.08	4.09	4.09	4.09	4.10	4.10	4.09	4.14	4.16	4.16	4.18	4.19	4.22	4.23	4.23	4.24	4.23	4.24	4.26	4.29	4.27	4.27

JEA-POD3-00017 Hearing Exhibit - 00000509

MMD Scales

Term	Year	4/12	4/13	4/16	4/17	4/18	4/19	4/20	4/23	4/24	4/25	4/26	4/27	4/30	5/1	5/2	5/3	5/4	5/7	5/8	5/9	5/10	5/11	5/14	5/15
1	2008	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.59	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60
2	2009	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.59	3.59	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60
3	2010	3.60	3.61	3.61	3.61	3.60	3.60	3.60	3.59	3.59	3.60	3.60	3.60	3.59	3.59	3.59	3.60	3.59	3.59	3.59	3.60	3.60	3.60	3.61	3.61
4	2011	3.60	3.63	3.63	3.61	3.56	3.56	3.56	3.58	3.58	3.59	3.60	3.61	3.59	3.59	3.59	3.60	3.59	3.59	3.59	3.60	3.60	3.60	3.61	3.62
5	2012	3.62	3.65	3.65	3.63	3.58	3.58	3.58	3.58	3.58	3.59	3.61	3.62	3.60	3.60	3.60	3.62	3.60	3.60	3.60	3.61	3.61	3.61	3.62	3.63
6	2013	3.66	3.69	3.69	3.67	3.62	3.62	3.62	3.61	3.60	3.61	3.63	3.64	3.62	3.62	3.62	3.64	3.62	3.62	3.62	3.63	3.63	3.63	3.64	3.65
7	2014	3.70	3.73	3.73	3.71	3.67	3.67	3.67	3.66	3.64	3.65	3.67	3.68	3.65	3.65	3.65	3.67	3.64	3.64	3.64	3.65	3.65	3.65	3.66	3.67
8	2015	3.75	3.77	3.77	3.75	3.71	3.71	3.71	3.70	3.68	3.69	3.71	3.72	3.69	3.69	3.69	3.71	3.68	3.67	3.66	3.67	3.67	3.67	3.68	3.69
9	2016	3.80	3.82	3.82	3.80	3.76	3.76	3.76	3.75	3.72	3.73	3.75	3.76	3.73	3.73	3.73	3.75	3.72	3.71	3.69	3.70	3.70	3.70	3.71	3.72
10	2017	3.85	3.87	3.87	3.84	3.80	3.80	3.80	3.79	3.76	3.77	3.79	3.80	3.76	3.76	3.76	3.78	3.75	3.75	3.73	3.74	3.74	3.74	3.75	3.76
11	2018	3.89	3.91	3.91	3.88	3.84	3.84	3.84	3.83	3.80	3.81	3.83	3.84	3.80	3.80	3.80	3.82	3.79	3.79	3.78	3.79	3.79	3.79	3.80	3.81
12	2019	3.93	3.95	3.94	3.91	3.87	3.87	3.87	3.86	3.84	3.85	3.87	3.88	3.84	3.84	3.84	3.86	3.83	3.83	3.82	3.83	3.83	3.83	3.84	3.85
13	2020	3.96	3.98	3.97	3.94	3.90	3.90	3.90	3.89	3.87	3.88	3.90	3.91	3.88	3.88	3.88	3.90	3.87	3.87	3.86	3.87	3.87	3.87	3.88	3.89
14	2021	3.99	4.01	4.00	3.97	3.93	3.93	3.93	3.92	3.90	3.91	3.93	3.94	3.91	3.91	3.91	3.93	3.90	3.90	3.89	3.90	3.90	3.90	3.92	3.93
15	2022	4.02	4.04	4.03	4.00	3.96	3.96	3.96	3.95	3.93	3.94	3.96	3.97	3.94	3.94	3.94	3.96	3.93	3.93	3.92	3.93	3.93	3.93	3.95	3.96
16	2023	4.04	4.06	4.05	4.02	3.98	3.98	3.98	3.97	3.96	3.97	3.99	4.00	3.97	3.97	3.97	3.99	3.96	3.96	3.95	3.96	3.96	3.96	3.98	3.99
17	2024	4.06	4.08	4.07	4.04	4.00	4.00	4.00	3.99	3.98	3.99	4.02	4.03	4.00	4.00	4.00	4.02	3.99	3.99	3.98	3.99	3.99	3.99	4.01	4.02
18	2025	4.08	4.10	4.09	4.05	4.01	4.01	4.01	4.00	3.99	4.00	4.03	4.04	4.01	4.01	4.01	4.03	4.01	4.01	4.00	4.01	4.01	4.01	4.03	4.04
19	2026	4.09	4.11	4.10	4.06	4.02	4.02	4.02	4.01	4.00	4.01	4.04	4.05	4.02	4.02	4.02	4.04	4.02	4.02	4.01	4.02	4.02	4.02	4.04	4.05
20	2027	4.10	4.12	4.11	4.07	4.03	4.03	4.03	4.02	4.01	4.02	4.05	4.06	4.03	4.03	4.03	4.05	4.03	4.03	4.02	4.03	4.03	4.03	4.05	4.06
21	2028	4.11	4.13	4.12	4.08	4.04	4.04	4.04	4.03	4.02	4.03	4.06	4.07	4.04	4.04	4.04	4.06	4.04	4.04	4.03	4.04	4.04	4.04	4.06	4.07
22	2029	4.12	4.14	4.13	4.09	4.05	4.05	4.05	4.04	4.03	4.04	4.07	4.08	4.05	4.05	4.05	4.07	4.05	4.05	4.04	4.05	4.05	4.05	4.07	4.08
23	2030	4.12	4.14	4.13	4.09	4.05	4.05	4.05	4.05	4.04	4.05	4.08	4.09	4.06	4.06	4.06	4.08	4.06	4.06	4.05	4.06	4.06	4.06	4.08	4.09
24	2031	4.13	4.15	4.14	4.10	4.06	4.06	4.06	4.06	4.05	4.06	4.09	4.10	4.07	4.07	4.07	4.09	4.06	4.06	4.06	4.07	4.07	4.07	4.09	4.10
25	2032	4.14	4.16	4.15	4.11	4.07	4.07	4.07	4.07	4.06	4.07	4.10	4.11	4.08	4.08	4.08	4.10	4.07	4.07	4.07	4.08	4.08	4.08	4.10	4.11
26	2033	4.14	4.16	4.15	4.11	4.07	4.07	4.08	4.08	4.07	4.08	4.10	4.11	4.08	4.08	4.08	4.10	4.07	4.07	4.07	4.08	4.08	4.08	4.10	4.11
27	2034	4.15	4.17	4.16	4.12	4.08	4.08	4.09	4.09	4.07	4.09	4.11	4.12	4.09	4.09	4.09	4.11	4.08	4.08	4.08	4.09	4.09	4.09	4.11	4.12
28	2035	4.16	4.18	4.17	4.13	4.09	4.09	4.10	4.10	4.08	4.09	4.11	4.12	4.09	4.09	4.09	4.11	4.08	4.08	4.08	4.09	4.09	4.09	4.11	4.12
29	2036	4.17	4.19	4.18	4.14	4.10	4.10	4.11	4.11	4.09	4.10	4.12	4.13	4.10	4.10	4.10	4.12	4.09	4.09	4.09	4.10	4.10	4.10	4.12	4.13
30	2037	4.17	4.19	4.18	4.14	4.10	4.10	4.11	4.11	4.09	4.10	4.12	4.13	4.10	4.10	4.10	4.12	4.09	4.09	4.09	4.10	4.10	4.10	4.12	4.13

Term	Year	4/12	4/13	4/16	4/17	4/18	4/19	4/20	4/23	4/24	4/25	4/26	4/27	4/30	5/1	5/2	5/3	5/4	5/7	5/8	5/9	5/10	5/11	5/14	5/15
1	2008	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.61	3.62	3.62	3.62	3.62	3.62	3.62	3.62	3.62	3.62	3.62	3.62	3.62	3.62	3.62	3.62	3.62
2	2009	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.63	3.63	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64
3	2010	3.67	3.68	3.68	3.68	3.67	3.67	3.67	3.65	3.65	3.66	3.66	3.66	3.65	3.65	3.64	3.65	3.64	3.64	3.64	3.66	3.66	3.66	3.67	3.67
4	2011	3.69	3.72	3.72	3.70	3.65	3.65	3.65	3.66	3.66	3.67	3.68	3.69	3.67	3.67	3.66	3.67	3.66	3.66	3.66	3.68	3.68	3.68	3.69	3.70
5	2012	3.72	3.75	3.75	3.73	3.68	3.68	3.68	3.68	3.68	3.69	3.71	3.72	3.69	3.69	3.68	3.70	3.68	3.68	3.68	3.70	3.70	3.70	3.71	3.72
6	2013	3.76	3.79	3.79	3.77	3.72	3.72	3.72	3.71	3.70	3.71	3.73	3.74	3.71	3.71	3.71	3.73	3.71	3.71	3.71	3.72	3.72	3.72	3.73	3.74
7	2014	3.80	3.83	3.83	3.81	3.77	3.77	3.77	3.76	3.74	3.75	3.77	3.78	3.74	3.74	3.74	3.76	3.73	3.73	3.73	3.74	3.74	3.74	3.75	3.77
8	2015	3.85	3.87	3.87	3.85	3.81	3.81	3.81	3.80	3.78	3.79	3.81	3.82	3.78	3.78	3.78	3.80	3.77	3.76	3.75	3.76	3.76	3.76	3.77	3.79
9	2016	3.90	3.92	3.92	3.90	3.86	3.86	3.86	3.85	3.82	3.83	3.85	3.86	3.82	3.82	3.82	3.84	3.81	3.80	3.78	3.79	3.79	3.79	3.80	3.82
10	2017	3.95	3.97	3.97	3.94	3.90	3.90	3.90	3.89	3.86	3.87	3.89	3.90	3.86	3.86	3.86	3.88	3.85	3.84	3.82	3.83	3.83	3.83	3.84	3.86
11	2018	3.99	4.01	4.01	3.98	3.94	3.94	3.94	3.93	3.90	3.91	3.93	3.94	3.90	3.90	3.90	3.92	3.89	3.89	3.88	3.89	3.89	3.89	3.90	3.92
12	2019	4.03	4.05	4.04	4.01	3.97	3.97	3.97	3.96	3.94	3.95	3.97	3.98	3.94	3.94	3.94	3.96	3.93	3.93	3.92	3.93	3.93	3.93	3.94	3.96
13	2020	4.06	4.08	4.07	4.04	4.00	4.00	4.00	3.99	3.97	3.98	4.00	4.01	3.98	3.98	3.98	4.00	3.97	3.97	3.96	3.97	3.97	3.97	3.98	4.00
14	2021	4.09	4.11	4.10	4.07	4.03	4.03	4.03	4.02	4.00	4.01	4.03	4.04	4.01	4.01	4.01	4.03	4.00	4.00	3.99	4.00	4.00	4.00	4.02	4.04
15	2022	4.12	4.14	4.13	4.10	4.06	4.06	4.06	4.05	4.03	4.04	4.06	4.07	4.04	4.04	4.04	4.06	4.03	4.03	4.02	4.03	4.03	4.03	4.05	4.07
16	2023	4.14	4.16	4.15	4.12	4.08	4.08	4.08	4.07	4.06	4.07	4.09	4.10	4.07	4.07	4.07	4.09	4.06	4.06	4.05	4.06	4.06	4.06	4.08	4.10
17	2024	4.16	4.18	4.17	4.14	4.10	4.10	4.10	4.09	4.08	4.09	4.12	4.13	4.10	4.10	4.10	4.12	4.09	4.09	4.08	4.09	4.09	4.09	4.11	4.13
18	2025	4.18	4.20	4.19	4.15	4.11	4.11	4.11	4.10	4.09	4.10	4.13	4.14	4.11	4.11	4.11	4.13	4.11	4.11	4.10	4.11	4.11	4.11	4.13	4.15
19	2026	4.19	4.21	4.20	4.16	4.12	4.12	4.12	4.11	4.10	4.11	4.14	4.15	4.12	4.12	4.12	4.14	4.12	4.12	4.11	4.12	4.12	4.12	4.14	4.16
20	2027	4.20	4.22	4.21	4.17	4.13	4.13	4.13	4.12	4.11	4.12	4.15	4.16	4.13	4.13	4.13	4.15	4.13	4.13	4.12	4.13	4.13	4.13	4.15	4.17
21	2028	4.21	4.23	4.22	4.18	4.14	4.14	4.14	4.13	4.12	4.13	4.16	4.17	4.14	4.14	4.14	4.16	4.14	4.14	4.13	4.14	4.14	4.14	4.16	4.18
22	2029	4.22	4.24	4.23	4.19	4.15	4.15	4.15	4.14	4.13	4.14	4.17	4.18	4.15	4.15	4.15	4.17	4.15	4.15	4.14	4.15	4.15	4.15	4.17	4.19
23	2030	4.22	4.24	4.23	4.19	4.15	4.15	4.15	4.15	4.14	4.15	4.18	4.19	4.16	4.16	4.16	4.18	4.16	4.16	4.15	4.16	4.16	4.16	4.18	4.20
24	2031	4.23	4.25	4.24	4.20	4.16	4.16	4.16	4.16	4.15	4.16	4.19	4.20	4.17	4.17	4.17	4.19	4.16	4.16	4.16	4.17	4.17	4.17	4.19	4.20
25	2032	4.24	4.26	4.25	4.21	4.17	4.17	4.17	4.17	4.16	4.17	4.20	4.21	4.18	4.18	4.18	4.20	4.17	4.17	4.17	4.18	4.18	4.18	4.20	4.21
26	2033	4.24	4.26	4.25	4.21	4.17	4.17	4.18	4.18	4.17	4.18	4.20	4.21	4.18	4.18	4.18	4.20	4.17	4.17	4.17	4.18	4.18	4.18	4.20	4.21
27	2034	4.25	4.27	4.26	4.22	4.18	4.18	4.19	4.19	4.17	4.19	4.21	4.22	4.19	4.19	4.19	4.21	4.18	4.18	4.18	4.19	4.19	4.19	4.21	4.22
28	2035	4.26	4.28	4.27	4.23	4.19	4.19	4.20	4.20	4.18	4.19	4.21	4.22	4.19	4.19	4.19	4.21	4.18	4.18	4.18	4.19	4.19	4.19	4.21	4.22
29	2036	4.27	4.29	4.28	4.24	4.20	4.20	4.21	4.21	4.19	4.20	4.22	4.23	4.20	4.20	4.20	4.22	4.19	4.19	4.19	4.20	4.20	4.20	4.22	4.23
30	2037	4.27	4.29	4.28	4.24	4.20	4.20	4.21	4.21	4.19	4.20	4.22	4.23	4.20	4.20	4.20	4.22	4.19	4.19	4.19	4.20	4.20	4.20	4.22	4.23

JEA-POD3-00018 Hearing Exhibit - 00000510

MMD Scales

Term	Year	5/16	5/17	5/18	5/21	5/22	5/23	5/24	5/25	5/28	5/29	5/30	5/31
1	2008	3.60	3.61	3.62	3.62	3.62	3.63	3.63	3.63	H	3.63	3.63	3.63
2	2009	3.60	3.62	3.64	3.64	3.64	3.66	3.66	3.67	O	3.67	3.67	3.68
3	2010	3.61	3.63	3.65	3.65	3.66	3.69	3.70	3.71	L	3.71	3.71	3.73
4	2011	3.62	3.64	3.66	3.66	3.67	3.69	3.70	3.71	I	3.72	3.72	3.74
5	2012	3.63	3.65	3.68	3.68	3.69	3.71	3.72	3.73	D	3.74	3.74	3.76
6	2013	3.65	3.68	3.71	3.71	3.72	3.74	3.74	3.75	A	3.76	3.76	3.78
7	2014	3.67	3.70	3.73	3.73	3.75	3.77	3.77	3.78	Y	3.79	3.79	3.80
8	2015	3.69	3.72	3.76	3.76	3.78	3.81	3.81	3.81		3.82	3.82	3.83
9	2016	3.72	3.75	3.79	3.79	3.81	3.84	3.84	3.84		3.85	3.85	3.86
10	2017	3.76	3.79	3.83	3.83	3.85	3.88	3.88	3.88		3.89	3.89	3.91
11	2018	3.81	3.84	3.88	3.88	3.90	3.93	3.93	3.94	H	3.95	3.95	3.97
12	2019	3.85	3.88	3.92	3.92	3.94	3.97	3.97	3.98	O	3.99	3.99	4.01
13	2020	3.89	3.92	3.96	3.96	3.98	4.01	4.01	4.02	L	4.03	4.03	4.05
14	2021	3.93	3.96	4.00	4.00	4.02	4.05	4.05	4.05	I	4.06	4.06	4.08
15	2022	3.96	3.99	4.03	4.03	4.05	4.08	4.08	4.08	D	4.09	4.09	4.11
16	2023	3.99	4.02	4.06	4.06	4.08	4.10	4.10	4.10	A	4.11	4.11	4.13
17	2024	4.02	4.05	4.08	4.08	4.10	4.12	4.12	4.12	Y	4.13	4.13	4.15
18	2025	4.04	4.07	4.10	4.10	4.12	4.14	4.14	4.14		4.15	4.15	4.16
19	2026	4.05	4.08	4.11	4.11	4.13	4.15	4.15	4.15		4.16	4.16	4.17
20	2027	4.06	4.09	4.12	4.12	4.14	4.16	4.16	4.16		4.17	4.17	4.18
21	2028	4.07	4.10	4.13	4.13	4.15	4.17	4.17	4.17	H	4.18	4.18	4.19
22	2029	4.08	4.11	4.14	4.14	4.16	4.18	4.18	4.18	O	4.19	4.19	4.20
23	2030	4.09	4.12	4.15	4.15	4.17	4.19	4.19	4.19	L	4.20	4.20	4.21
24	2031	4.10	4.13	4.16	4.16	4.18	4.20	4.20	4.20	I	4.21	4.21	4.22
25	2032	4.11	4.14	4.17	4.17	4.19	4.21	4.21	4.21	D	4.22	4.22	4.23
26	2033	4.11	4.14	4.17	4.17	4.19	4.21	4.21	4.21	A	4.22	4.22	4.23
27	2034	4.12	4.15	4.18	4.18	4.20	4.22	4.22	4.22	Y	4.23	4.23	4.24
28	2035	4.12	4.15	4.18	4.18	4.20	4.22	4.22	4.22		4.23	4.23	4.24
29	2036	4.13	4.16	4.19	4.19	4.21	4.23	4.23	4.23		4.24	4.24	4.25
30	2037	4.13	4.16	4.19	4.19	4.21	4.23	4.23	4.23		4.24	4.24	4.25

Term	Year	5/16	5/17	5/18	5/21	5/22	5/23	5/24	5/25	5/28	5/29	5/30	5/31
1	2008	3.62	3.63	3.64	3.64	3.64	3.66	3.66	3.66	H	3.67	3.67	3.67
2	2009	3.64	3.66	3.68	3.68	3.68	3.71	3.71	3.72	O	3.73	3.73	3.74
3	2010	3.67	3.69	3.71	3.71	3.72	3.75	3.77	3.78	L	3.79	3.79	3.81
4	2011	3.70	3.72	3.74	3.74	3.75	3.77	3.79	3.80	I	3.81	3.81	3.83
5	2012	3.72	3.74	3.77	3.77	3.78	3.80	3.81	3.82	D	3.83	3.83	3.85
6	2013	3.74	3.77	3.80	3.80	3.81	3.83	3.84	3.85	A	3.86	3.86	3.88
7	2014	3.77	3.80	3.83	3.83	3.85	3.87	3.87	3.88	Y	3.89	3.89	3.90
8	2015	3.79	3.82	3.86	3.86	3.88	3.91	3.91	3.91		3.92	3.92	3.93
9	2016	3.82	3.85	3.89	3.89	3.91	3.94	3.94	3.95		3.96	3.96	3.97
10	2017	3.86	3.89	3.93	3.93	3.95	3.98	3.98	3.99		4	4.00	4.02
11	2018	3.92	3.95	3.99	3.99	4.01	4.04	4.04	4.05	H	4.06	4.06	4.08
12	2019	3.96	3.99	4.03	4.03	4.05	4.08	4.08	4.09	O	4.1	4.10	4.12
13	2020	4.00	4.03	4.07	4.07	4.09	4.12	4.12	4.13	L	4.14	4.14	4.16
14	2021	4.04	4.07	4.11	4.11	4.13	4.16	4.16	4.16	I	4.17	4.17	4.19
15	2022	4.07	4.10	4.14	4.14	4.16	4.19	4.19	4.19	D	4.2	4.20	4.22
16	2023	4.10	4.13	4.17	4.17	4.19	4.21	4.21	4.21	A	4.22	4.22	4.24
17	2024	4.13	4.16	4.19	4.19	4.21	4.23	4.23	4.23	Y	4.24	4.24	4.26
18	2025	4.15	4.18	4.21	4.21	4.23	4.25	4.25	4.25		4.26	4.26	4.27
19	2026	4.16	4.19	4.22	4.22	4.24	4.26	4.26	4.26		4.27	4.27	4.28
20	2027	4.17	4.20	4.23	4.23	4.25	4.27	4.27	4.27		4.28	4.28	4.29
21	2028	4.18	4.21	4.24	4.24	4.26	4.28	4.28	4.28	H	4.29	4.29	4.30
22	2029	4.19	4.22	4.25	4.25	4.27	4.29	4.29	4.29	O	4.3	4.30	4.31
23	2030	4.20	4.23	4.26	4.26	4.28	4.30	4.30	4.30	L	4.31	4.31	4.32
24	2031	4.20	4.23	4.26	4.26	4.28	4.30	4.30	4.30	I	4.31	4.31	4.32
25	2032	4.21	4.24	4.27	4.27	4.29	4.31	4.31	4.31	D	4.32	4.32	4.33
26	2033	4.21	4.24	4.27	4.27	4.29	4.31	4.31	4.31	A	4.32	4.32	4.33
27	2034	4.22	4.25	4.28	4.28	4.30	4.32	4.32	4.32	Y	4.33	4.33	4.34
28	2035	4.22	4.25	4.28	4.28	4.30	4.32	4.32	4.32		4.33	4.33	4.34
29	2036	4.23	4.26	4.29	4.29	4.31	4.33	4.33	4.33		4.34	4.34	4.35
30	2037	4.23	4.26	4.29	4.29	4.31	4.33	4.33	4.33		4.34	4.34	4.35

JEA-POD3-00019 Hearing Exhibit - 00000511

MMD Scales for JEA

Term	Year	MMD Scales 6/1	6/4	6/5	6/6	6/7	6/8	6/11	6/12	6/13	6/14	6/15	6/18	6/19	6/20	6/21	6/22	6/25	6/26	6/27	6/28	6/29	7/2	7/3	7/4
1	2008	3.65	3.65	3.65	3.65	3.67	3.68	3.7	3.73	3.73	3.73	3.73	3.73	3.73	3.73	3.73	3.73	3.73	3.73	3.7	3.7	3.7	3.7	3.7	H
2	2009	3.71	3.71	3.71	3.71	3.74	3.75	3.77	3.81	3.81	3.81	3.8	3.8	3.79	3.79	3.79	3.79	3.78	3.78	3.77	3.77	3.76	3.75	3.75	O
3	2010	3.76	3.76	3.77	3.77	3.81	3.82	3.83	3.88	3.88	3.88	3.87	3.87	3.85	3.85	3.85	3.85	3.82	3.82	3.81	3.82	3.81	3.8	3.8	L
4	2011	3.77	3.77	3.79	3.79	3.85	3.86	3.87	3.93	3.93	3.93	3.92	3.92	3.89	3.89	3.9	3.89	3.86	3.86	3.85	3.87	3.85	3.84	3.84	I
5	2012	3.79	3.79	3.82	3.82	3.89	3.9	3.91	3.97	3.97	3.97	3.95	3.95	3.92	3.93	3.94	3.93	3.9	3.9	3.88	3.9	3.88	3.87	3.87	D
6	2013	3.81	3.81	3.84	3.84	3.92	3.93	3.94	4	4	4	3.98	3.98	3.95	3.96	3.97	3.96	3.93	3.93	3.91	3.93	3.91	3.9	3.9	A
7	2014	3.84	3.84	3.87	3.87	3.95	3.96	3.97	4.03	4.02	4.03	4.01	4.01	3.98	3.99	4	3.99	3.96	3.96	3.94	3.96	3.94	3.93	3.94	Y
8	2015	3.87	3.87	3.9	3.9	3.98	3.99	4	4.06	4.05	4.06	4.04	4.04	4.01	4.02	4.04	4.03	4	4	3.98	4	3.98	3.97	3.98	
9	2016	3.90	3.9	3.93	3.93	4.01	4.03	4.04	4.1	4.09	4.1	4.08	4.08	4.05	4.06	4.08	4.07	4.05	4.05	4.03	4.05	4.02	4.01	4.02	
10	2017	3.95	3.95	3.98	3.98	4.06	4.07	4.08	4.15	4.14	4.15	4.13	4.13	4.1	4.11	4.13	4.12	4.1	4.1	4.08	4.1	4.07	4.05	4.07	H
11	2018	4.01	4.01	4.04	4.04	4.12	4.13	4.14	4.21	4.2	4.2	4.18	4.18	4.15	4.16	4.18	4.17	4.15	4.15	4.13	4.15	4.12	4.1	4.12	O
12	2019	4.05	4.05	4.08	4.08	4.16	4.17	4.18	4.25	4.24	4.24	4.22	4.22	4.19	4.2	4.22	4.21	4.19	4.19	4.17	4.19	4.16	4.14	4.16	L
13	2020	4.09	4.09	4.12	4.12	4.2	4.21	4.22	4.29	4.28	4.28	4.26	4.26	4.23	4.24	4.26	4.25	4.23	4.23	4.21	4.22	4.19	4.17	4.19	I
14	2021	4.12	4.12	4.15	4.15	4.23	4.25	4.26	4.33	4.32	4.32	4.29	4.29	4.26	4.27	4.29	4.28	4.26	4.26	4.24	4.25	4.22	4.2	4.22	D
15	2022	4.15	4.14	4.17	4.17	4.26	4.28	4.29	4.36	4.35	4.35	4.32	4.32	4.29	4.3	4.32	4.31	4.29	4.29	4.27	4.28	4.25	4.23	4.25	A
16	2023	4.17	4.16	4.19	4.19	4.28	4.3	4.32	4.39	4.38	4.38	4.35	4.35	4.32	4.33	4.35	4.34	4.32	4.32	4.3	4.31	4.28	4.26	4.28	Y
17	2024	4.19	4.18	4.21	4.21	4.3	4.32	4.34	4.41	4.4	4.4	4.37	4.37	4.34	4.36	4.38	4.37	4.35	4.35	4.33	4.34	4.3	4.28	4.30	
18	2025	4.20	4.19	4.22	4.22	4.31	4.33	4.35	4.43	4.42	4.42	4.39	4.39	4.36	4.38	4.4	4.39	4.37	4.37	4.35	4.36	4.32	4.3	4.32	
19	2026	4.21	4.2	4.23	4.23	4.32	4.34	4.36	4.44	4.43	4.43	4.4	4.4	4.37	4.39	4.41	4.4	4.38	4.38	4.36	4.37	4.33	4.31	4.33	
20	2027	4.22	4.21	4.24	4.24	4.33	4.35	4.37	4.45	4.44	4.44	4.41	4.41	4.38	4.4	4.42	4.41	4.39	4.39	4.37	4.38	4.34	4.32	4.34	H
21	2028	4.23	4.22	4.25	4.25	4.34	4.36	4.38	4.46	4.45	4.45	4.42	4.42	4.39	4.41	4.43	4.42	4.4	4.4	4.38	4.39	4.35	4.33	4.35	O
22	2029	4.24	4.23	4.26	4.26	4.35	4.37	4.39	4.47	4.46	4.46	4.43	4.43	4.4	4.42	4.45	4.44	4.42	4.42	4.4	4.41	4.37	4.35	4.37	L
23	2030	4.25	4.24	4.27	4.27	4.36	4.38	4.4	4.48	4.47	4.47	4.44	4.44	4.41	4.44	4.47	4.46	4.43	4.43	4.41	4.42	4.38	4.36	4.38	I
24	2031	4.26	4.25	4.28	4.28	4.37	4.39	4.41	4.49	4.47	4.47	4.45	4.45	4.42	4.45	4.48	4.47	4.44	4.44	4.42	4.43	4.39	4.37	4.39	D
25	2032	4.27	4.26	4.29	4.29	4.38	4.4	4.42	4.5	4.48	4.48	4.46	4.46	4.43	4.46	4.49	4.48	4.45	4.45	4.43	4.44	4.4	4.38	4.40	A
26	2033	4.27	4.26	4.29	4.3	4.39	4.41	4.43	4.51	4.49	4.49	4.47	4.47	4.44	4.47	4.5	4.49	4.46	4.46	4.44	4.45	4.41	4.39	4.41	Y
27	2034	4.28	4.27	4.3	4.31	4.4	4.42	4.44	4.52	4.5	4.5	4.48	4.48	4.45	4.48	4.51	4.5	4.47	4.47	4.45	4.46	4.42	4.4	4.42	
28	2035	4.28	4.27	4.3	4.31	4.4	4.42	4.44	4.53	4.51	4.51	4.49	4.49	4.46	4.49	4.52	4.51	4.48	4.48	4.46	4.47	4.43	4.41	4.43	
29	2036	4.29	4.28	4.31	4.32	4.41	4.43	4.45	4.54	4.52	4.52	4.5	4.5	4.47	4.5	4.53	4.52	4.49	4.49	4.47	4.48	4.44	4.42	4.44	
30	2037	4.29	4.28	4.31	4.32	4.41	4.43	4.45	4.54	4.52	4.52	4.5	4.5	4.47	4.5	4.53	4.52	4.49	4.49	4.47	4.48	4.44	4.42	4.44	

Term	Year	MMD Scales 6/1	6/4	6/5	6/6	6/7	6/8	6/11	6/12	6/13	6/14	6/15	6/18	6/19	6/20	6/21	6/22	6/25	6/26	6/27	6/28	6/29	7/2	7/3	7/4
1	2008	3.69	3.69	3.69	3.69	3.71	3.72	3.74	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.74	3.74	3.74	3.74	3.74	H
2	2009	3.77	3.77	3.77	3.77	3.8	3.81	3.83	3.88	3.88	3.88	3.87	3.87	3.86	3.86	3.86	3.86	3.85	3.85	3.84	3.84	3.83	3.82	3.82	O
3	2010	3.84	3.84	3.85	3.85	3.89	3.91	3.92	3.98	3.98	3.98	3.96	3.96	3.94	3.94	3.94	3.94	3.91	3.9	3.89	3.9	3.89	3.88	3.88	L
4	2011	3.86	3.86	3.88	3.88	3.94	3.96	3.97	4.03	4.03	4.03	4.01	4.01	3.98	3.98	3.99	3.98	3.95	3.94	3.93	3.95	3.93	3.92	3.92	I
5	2012	3.88	3.88	3.91	3.91	3.98	4	4.01	4.07	4.07	4.07	4.04	4.04	4.01	4.02	4.03	4.02	3.99	3.98	3.96	3.98	3.96	3.95	3.95	D
6	2013	3.91	3.91	3.94	3.94	4.02	4.04	4.05	4.11	4.1	4.1	4.07	4.07	4.04	4.05	4.06	4.05	4.02	4.01	3.99	4.01	3.99	3.98	3.98	A
7	2014	3.94	3.94	3.97	3.97	4.05	4.06	4.07	4.13	4.12	4.13	4.1	4.1	4.07	4.08	4.09	4.08	4.05	4.04	4.02	4.04	4.02	4.01	4.02	Y
8	2015	3.97	3.97	4	4	4.08	4.09	4.1	4.16	4.15	4.16	4.13	4.13	4.1	4.11	4.13	4.12	4.09	4.08	4.06	4.08	4.06	4.05	4.06	
9	2016	4.01	4.01	4.04	4.04	4.12	4.14	4.15	4.21	4.2	4.21	4.18	4.18	4.15	4.16	4.18	4.17	4.15	4.14	4.12	4.14	4.11	4.1	4.11	
10	2017	4.06	4.06	4.09	4.09	4.17	4.18	4.19	4.26	4.25	4.26	4.23	4.23	4.2	4.21	4.23	4.22	4.2	4.19	4.17	4.19	4.16	4.14	4.16	H
11	2018	4.12	4.12	4.15	4.15	4.23	4.24	4.25	4.32	4.31	4.31	4.28	4.28	4.25	4.26	4.28	4.27	4.25	4.24	4.22	4.24	4.21	4.19	4.21	O
12	2019	4.16	4.16	4.19	4.19	4.27	4.28	4.29	4.36	4.35	4.35	4.32	4.32	4.29	4.3	4.32	4.31	4.29	4.28	4.26	4.28	4.25	4.23	4.25	L
13	2020	4.20	4.2	4.23	4.23	4.31	4.32	4.33	4.4	4.39	4.39	4.36	4.36	4.33	4.34	4.36	4.35	4.33	4.32	4.3	4.31	4.28	4.26	4.28	I
14	2021	4.23	4.23	4.26	4.26	4.34	4.36	4.37	4.44	4.43	4.43	4.39	4.39	4.36	4.37	4.39	4.38	4.36	4.35	4.33	4.34	4.31	4.29	4.31	D
15	2022	4.26	4.25	4.28	4.28	4.37	4.39	4.4	4.47	4.46	4.46	4.42	4.42	4.39	4.4	4.42	4.41	4.39	4.38	4.36	4.37	4.34	4.32	4.34	A
16	2023	4.28	4.27	4.3	4.3	4.39	4.41	4.43	4.5	4.49	4.49	4.45	4.45	4.42	4.43	4.45	4.44	4.42	4.41	4.39	4.4	4.37	4.35	4.37	Y
17	2024	4.30	4.29	4.32	4.32	4.41	4.43	4.45	4.52	4.51	4.51	4.47	4.47	4.44	4.46	4.48	4.47	4.45	4.44	4.42	4.43	4.39	4.37	4.39	
18	2025	4.31	4.3	4.33	4.33	4.42	4.44	4.46	4.54	4.53	4.53	4.49	4.49	4.46	4.48	4.5	4.49	4.47	4.46	4.44	4.45	4.41	4.39	4.41	
19	2026	4.32	4.31	4.34	4.34	4.43	4.45	4.47	4.55	4.54	4.54	4.5	4.5	4.47	4.49	4.51	4.5	4.48	4.47	4.45	4.46	4.42	4.4	4.42	
20	2027	4.33	4.32	4.35	4.35	4.44	4.46	4.48	4.56	4.55	4.55	4.51	4.51	4.48	4.5	4.52	4.51	4.49	4.48	4.46	4.47	4.43	4.41	4.43	H
21	2028	4.34	4.33	4.36	4.36	4.45	4.47	4.49	4.57	4.56	4.56	4.52	4.52	4.49	4.51	4.53	4.52	4.5	4.49	4.47	4.48	4.44	4.42	4.44	O
22	2029	4.35	4.34	4.37	4.37	4.46	4.48	4.5	4.58	4.56	4.56	4.53	4.53	4.5	4.52	4.55	4.54	4.52	4.51	4.49	4.5	4.46	4.44	4.46	L
23	2030	4.36	4.35	4.38	4.38	4.47	4.49	4.51	4.59	4.57	4.57	4.54	4.54	4.51	4.54	4.57	4.56	4.53	4.52	4.5	4.51	4.47	4.45	4.47	I
24	2031	4.36	4.35	4.38	4.38	4.47	4.49	4.51	4.59	4.57	4.57	4.55	4.55	4.52	4.55	4.58	4.57	4.54	4.53	4.51	4.52	4.48	4.46	4.48	D
25	2032	4.37	4.36	4.39	4.39	4.48	4.5	4.52	4.6	4.58	4.58	4.56	4.56	4.53	4.56	4.59	4.58	4.55	4.54	4.52	4.53	4.49	4.47	4.49	A
26	2033	4.37	4.36	4.39	4.4	4.49	4.51	4.53	4.61	4.59	4.59	4.57	4.57	4.54	4.57	4.6	4.59	4.56	4.55	4.53	4.54	4.5	4.48	4.5	Y
27	2034	4.38	4.37	4.4	4.41	4.5	4.52	4.54	4.62	4.6	4.6	4.58	4.58	4.55	4.58	4.61	4.6	4.57	4.56	4.54	4.55	4.51	4.49	4.51	
28	2035	4.38	4.37	4.4	4.41	4.5	4.52	4.54	4.63	4.61	4.61	4.59	4.59	4.56	4.59	4.62	4.61	4.58	4.57	4.55	4.56	4.52	4.5	4.52	
29	2036	4.39	4.38	4.41	4.42	4.51	4.53	4.55	4.64	4.62	4.62	4.6	4.6	4.57	4.6	4.63	4.62	4.59	4.58	4.56	4.57	4.53	4.51	4.53	
30	2037	4.39	4.38	4.41	4.42	4.51	4.53	4.55	4.64	4.62	4.62	4.6	4.6	4.57	4.6	4.63	4.62	4.59	4.58	4.56	4.57	4.53	4.51	4.53	

JEA-POD3-00020 Hearing Exhibit - 00000512

MMD Scale

Term	Year	7/5	7/6	7/9	7/10	7/11	7/12	7/13	7/16	7/17	7/18	7/19	7/20	7/23	7/24	7/25	7/26	7/27	7/30	7/31	8/1	8/2	8/3	8/6	8/7	8/8	8/9
1	2008	3.71	3.72	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.69	3.69	3.68	3.68	3.68	3.68	3.66	3.66	3.65	3.65	3.64	3.64	3.64	3.64	3.64	3.64	3.62
2	2009	3.78	3.8	3.77	3.74	3.74	3.74	3.74	3.73	3.73	3.72	3.72	3.7	3.7	3.7	3.7	3.67	3.67	3.67	3.67	3.65	3.65	3.65	3.65	3.65	3.66	3.64
3	2010	3.83	3.85	3.82	3.78	3.78	3.78	3.78	3.77	3.77	3.75	3.75	3.72	3.72	3.72	3.72	3.69	3.69	3.69	3.69	3.67	3.69	3.69	3.68	3.68	3.7	3.68
4	2011	3.88	3.9	3.87	3.83	3.83	3.83	3.83	3.82	3.82	3.79	3.79	3.76	3.76	3.76	3.75	3.71	3.71	3.71	3.71	3.7	3.72	3.72	3.72	3.71	3.74	3.72
5	2012	3.91	3.94	3.91	3.86	3.87	3.88	3.88	3.86	3.86	3.83	3.83	3.8	3.8	3.8	3.79	3.75	3.75	3.75	3.75	3.75	3.77	3.77	3.76	3.75	3.78	3.76
6	2013	3.94	3.97	3.95	3.89	3.91	3.92	3.92	3.9	3.9	3.87	3.88	3.85	3.85	3.85	3.84	3.79	3.79	3.79	3.79	3.79	3.81	3.81	3.8	3.8	3.84	3.82
7	2014	3.98	4.01	3.99	3.93	3.95	3.97	3.96	3.94	3.94	3.91	3.92	3.89	3.89	3.89	3.88	3.83	3.83	3.83	3.83	3.83	3.85	3.85	3.84	3.85	3.89	3.88
8	2015	4.02	4.05	4.03	3.97	3.99	4.02	4.01	3.99	3.99	3.95	3.96	3.93	3.93	3.93	3.92	3.87	3.87	3.87	3.87	3.87	3.89	3.89	3.89	3.9	3.94	3.93
9	2016	4.06	4.09	4.07	4.01	4.04	4.07	4.06	4.04	4.04	4	4.01	3.98	3.98	3.98	3.97	3.92	3.92	3.92	3.92	3.92	3.94	3.94	3.94	3.95	4	3.99
10	2017	4.11	4.14	4.12	4.06	4.09	4.12	4.11	4.09	4.1	4.06	4.07	4.03	4.04	4.04	4.02	3.97	3.97	3.97	3.97	3.97	3.99	3.99	4	4.01	4.06	4.05
11	2018	4.16	4.19	4.17	4.11	4.14	4.17	4.16	4.14	4.15	4.12	4.13	4.09	4.1	4.1	4.08	4.03	4.03	4.03	4.03	4.03	4.05	4.05	4.07	4.08	4.14	4.13
12	2019	4.2	4.23	4.21	4.15	4.17	4.2	4.19	4.17	4.18	4.15	4.16	4.12	4.13	4.13	4.12	4.08	4.08	4.08	4.08	4.08	4.1	4.1	4.13	4.14	4.2	4.19
13	2020	4.24	4.27	4.24	4.18	4.2	4.23	4.22	4.2	4.21	4.18	4.19	4.15	4.16	4.16	4.15	4.11	4.11	4.11	4.11	4.11	4.13	4.13	4.16	4.17	4.23	4.22
14	2021	4.27	4.3	4.27	4.21	4.23	4.26	4.25	4.23	4.24	4.21	4.22	4.18	4.19	4.19	4.18	4.14	4.14	4.14	4.14	4.14	4.16	4.16	4.19	4.2	4.26	4.25
15	2022	4.3	4.33	4.3	4.24	4.26	4.29	4.28	4.25	4.26	4.23	4.24	4.2	4.21	4.21	4.2	4.16	4.16	4.16	4.16	4.16	4.18	4.18	4.21	4.22	4.29	4.28
16	2023	4.33	4.36	4.33	4.27	4.29	4.31	4.3	4.27	4.28	4.25	4.26	4.22	4.23	4.23	4.22	4.18	4.18	4.18	4.18	4.18	4.2	4.2	4.23	4.24	4.31	4.3
17	2024	4.35	4.38	4.35	4.29	4.31	4.33	4.32	4.29	4.3	4.27	4.28	4.24	4.25	4.25	4.24	4.2	4.2	4.2	4.2	4.2	4.22	4.22	4.26	4.27	4.33	4.32
18	2025	4.37	4.4	4.37	4.31	4.33	4.35	4.34	4.31	4.32	4.29	4.3	4.26	4.27	4.27	4.26	4.22	4.22	4.22	4.22	4.22	4.24	4.24	4.28	4.29	4.35	4.34
19	2026	4.38	4.42	4.39	4.33	4.35	4.37	4.36	4.33	4.34	4.31	4.32	4.28	4.29	4.29	4.28	4.24	4.24	4.24	4.24	4.24	4.26	4.26	4.3	4.31	4.37	4.36
20	2027	4.39	4.43	4.41	4.35	4.37	4.39	4.38	4.35	4.36	4.33	4.34	4.3	4.31	4.31	4.3	4.26	4.26	4.26	4.26	4.26	4.28	4.28	4.32	4.33	4.39	4.38
21	2028	4.4	4.44	4.42	4.36	4.38	4.4	4.39	4.36	4.37	4.35	4.36	4.32	4.33	4.33	4.32	4.28	4.28	4.28	4.28	4.28	4.3	4.3	4.34	4.35	4.41	4.4
22	2029	4.42	4.46	4.43	4.37	4.39	4.41	4.4	4.37	4.38	4.36	4.37	4.33	4.34	4.34	4.34	4.3	4.3	4.3	4.3	4.3	4.31	4.31	4.36	4.37	4.43	4.42
23	2030	4.43	4.47	4.44	4.38	4.4	4.42	4.41	4.38	4.39	4.37	4.38	4.34	4.35	4.35	4.35	4.32	4.31	4.31	4.31	4.31	4.32	4.32	4.37	4.38	4.45	4.44
24	2031	4.44	4.48	4.45	4.39	4.41	4.43	4.42	4.39	4.4	4.38	4.39	4.35	4.36	4.36	4.36	4.33	4.32	4.32	4.32	4.32	4.33	4.33	4.38	4.39	4.46	4.45
25	2032	4.45	4.49	4.46	4.4	4.42	4.44	4.43	4.4	4.41	4.39	4.4	4.36	4.37	4.37	4.37	4.34	4.33	4.33	4.33	4.33	4.34	4.34	4.39	4.4	4.47	4.46
26	2033	4.46	4.5	4.47	4.41	4.43	4.45	4.44	4.41	4.42	4.4	4.41	4.37	4.38	4.38	4.38	4.35	4.34	4.34	4.34	4.34	4.35	4.35	4.4	4.41	4.48	4.47
27	2034	4.47	4.51	4.48	4.42	4.44	4.46	4.45	4.42	4.43	4.41	4.42	4.38	4.39	4.39	4.39	4.36	4.35	4.35	4.35	4.35	4.36	4.36	4.41	4.42	4.49	4.48
28	2035	4.48	4.52	4.49	4.43	4.45	4.47	4.45	4.42	4.43	4.41	4.42	4.39	4.4	4.4	4.4	4.37	4.36	4.36	4.36	4.36	4.37	4.37	4.42	4.43	4.5	4.49
29	2036	4.49	4.53	4.5	4.44	4.46	4.48	4.46	4.43	4.44	4.42	4.43	4.4	4.41	4.41	4.41	4.38	4.37	4.37	4.37	4.37	4.38	4.38	4.43	4.44	4.51	4.5
30	2037	4.49	4.53	4.5	4.44	4.46	4.48	4.46	4.43	4.44	4.42	4.43	4.4	4.41	4.41	4.41	4.38	4.37	4.37	4.37	4.37	4.38	4.38	4.43	4.44	4.51	4.5

Term	Year	7/5	7/6	7/9	7/10	7/11	7/12	7/13	7/16	7/17	7/18	7/19	7/20	7/23	7/24	7/25	7/26	7/27	7/30	7/31	8/1	8/2	8/3	8/6	8/7	8/8	8/9
1	2008	3.75	3.76	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.73	3.73	3.72	3.72	3.72	3.72	3.7	3.7	3.69	3.69	3.68	3.68	3.68	3.68	3.68	3.68	3.66
2	2009	3.85	3.87	3.84	3.81	3.81	3.81	3.81	3.79	3.79	3.78	3.78	3.76	3.76	3.76	3.76	3.73	3.73	3.73	3.73	3.71	3.71	3.71	3.71	3.71	3.72	3.7
3	2010	3.91	3.93	3.9	3.86	3.86	3.86	3.86	3.84	3.84	3.82	3.82	3.79	3.79	3.79	3.79	3.75	3.75	3.75	3.75	3.73	3.76	3.76	3.75	3.75	3.77	3.75
4	2011	3.96	3.98	3.95	3.91	3.91	3.91	3.91	3.89	3.89	3.86	3.86	3.83	3.83	3.83	3.82	3.78	3.78	3.78	3.78	3.77	3.8	3.8	3.8	3.79	3.82	3.8
5	2012	4	4.03	4	3.95	3.96	3.97	3.97	3.94	3.94	3.91	3.91	3.88	3.88	3.88	3.87	3.83	3.83	3.83	3.83	3.83	3.86	3.86	3.85	3.84	3.87	3.85
6	2013	4.03	4.06	4.04	3.98	4	4.01	4.01	3.98	3.98	3.95	3.96	3.93	3.93	3.93	3.92	3.87	3.87	3.87	3.87	3.87	3.9	3.9	3.89	3.89	3.93	3.91
7	2014	4.07	4.1	4.08	4.02	4.04	4.06	4.05	4.03	4.03	3.99	4	3.97	3.97	3.97	3.96	3.91	3.91	3.91	3.91	3.91	3.94	3.94	3.93	3.94	3.98	3.97
8	2015	4.11	4.14	4.12	4.06	4.08	4.12	4.11	4.09	4.09	4.04	4.05	4.02	4.02	4.02	4.01	3.96	3.96	3.96	3.96	3.96	3.99	3.99	3.99	4	4.04	4.03
9	2016	4.16	4.19	4.17	4.11	4.14	4.17	4.16	4.14	4.14	4.09	4.1	4.07	4.07	4.07	4.06	4.01	4.01	4.01	4.01	4.01	4.04	4.04	4.04	4.05	4.1	4.09
10	2017	4.21	4.24	4.22	4.16	4.19	4.22	4.21	4.19	4.2	4.15	4.16	4.12	4.13	4.13	4.11	4.06	4.06	4.06	4.06	4.06	4.09	4.09	4.1	4.11	4.16	4.15
11	2018	4.26	4.29	4.27	4.21	4.24	4.27	4.26	4.24	4.25	4.22	4.23	4.19	4.2	4.2	4.18	4.13	4.13	4.13	4.13	4.13	4.16	4.16	4.18	4.19	4.25	4.24
12	2019	4.3	4.33	4.31	4.25	4.27	4.3	4.29	4.27	4.28	4.25	4.26	4.22	4.23	4.23	4.22	4.18	4.18	4.18	4.18	4.18	4.21	4.21	4.24	4.25	4.31	4.3
13	2020	4.34	4.37	4.34	4.28	4.3	4.33	4.32	4.3	4.31	4.28	4.29	4.25	4.26	4.26	4.25	4.21	4.21	4.21	4.21	4.21	4.24	4.24	4.27	4.28	4.34	4.33
14	2021	4.37	4.4	4.37	4.31	4.33	4.36	4.35	4.33	4.34	4.31	4.32	4.28	4.29	4.29	4.28	4.24	4.24	4.24	4.24	4.24	4.27	4.27	4.3	4.31	4.37	4.36
15	2022	4.4	4.43	4.4	4.34	4.36	4.39	4.38	4.35	4.36	4.33	4.34	4.3	4.31	4.31	4.3	4.26	4.26	4.26	4.26	4.26	4.29	4.29	4.32	4.33	4.4	4.39
16	2023	4.43	4.46	4.43	4.37	4.39	4.41	4.4	4.37	4.38	4.35	4.36	4.32	4.33	4.33	4.32	4.28	4.28	4.28	4.28	4.28	4.31	4.31	4.34	4.35	4.42	4.41
17	2024	4.45	4.48	4.45	4.39	4.41	4.43	4.42	4.39	4.4	4.37	4.38	4.34	4.35	4.35	4.34	4.3	4.3	4.3	4.3	4.3	4.33	4.33	4.37	4.38	4.44	4.43
18	2025	4.47	4.5	4.47	4.41	4.43	4.45	4.44	4.41	4.42	4.39	4.4	4.36	4.37	4.37	4.36	4.32	4.32	4.32	4.32	4.32	4.35	4.35	4.39	4.4	4.46	4.45
19	2026	4.48	4.52	4.49	4.43	4.45	4.47	4.46	4.43	4.44	4.41	4.42	4.38	4.39	4.39	4.38	4.34	4.34	4.34	4.34	4.34	4.37	4.37	4.41	4.42	4.48	4.47
20	2027	4.49	4.53	4.51	4.45	4.47	4.49	4.48	4.45	4.46	4.43	4.44	4.4	4.41	4.41	4.4	4.36	4.36	4.36	4.36	4.36	4.39	4.39	4.43	4.44	4.5	4.49
21	2028	4.5	4.54	4.52	4.46	4.48	4.5	4.49	4.46	4.47	4.45	4.46	4.42	4.43	4.43	4.42	4.38	4.38	4.38	4.38	4.38	4.41	4.41	4.45	4.46	4.52	4.51
22	2029	4.51	4.55	4.52	4.46	4.48	4.5	4.49	4.46	4.47	4.45	4.46	4.42	4.43	4.43	4.44	4.4	4.4	4.4	4.4	4.4	4.42	4.42	4.47	4.48	4.54	4.53
23	2030	4.52	4.56	4.53	4.47	4.49	4.51	4.5	4.47	4.48	4.46	4.47	4.43	4.44	4.44	4.45	4.42	4.41	4.41	4.41	4.41	4.43	4.43	4.48	4.49	4.56	4.55
24	2031	4.53	4.57	4.54	4.48	4.5	4.52	4.51	4.48	4.49	4.47	4.48	4.44	4.45	4.45	4.46	4.43	4.42	4.42	4.42	4.42	4.44	4.44	4.49	4.5	4.57	4.56
25	2032	4.54	4.58	4.55	4.49	4.51	4.53	4.52	4.49	4.5	4.48	4.49	4.45	4.46	4.46	4.47	4.44	4.43	4.43	4.43	4.43	4.45	4.45	4.5	4.51	4.58	4.57
26	2033	4.55	4.59	4.56	4.5	4.52	4.54	4.53	4.5	4.51	4.49	4.5	4.46	4.47	4.47	4.48	4.45	4.44	4.44	4.44	4.44	4.46	4.46	4.51	4.52	4.59	4.58
27	2034	4.56	4.6	4.57	4.51	4.53	4.55	4.54	4.51	4.52	4.5	4.51	4.47	4.48	4.48	4.49	4.46	4.45	4.45	4.45	4.45	4.47	4.47	4.52	4.53	4.6	4.59
28	2035	4.57	4.61	4.58	4.52	4.54	4.56	4.54	4.51	4.52	4.5	4.51	4.48	4.49	4.49	4.5	4.47	4.46	4.46	4.46	4.46	4.48	4.48	4.53	4.54	4.61	4.6
29	2036	4.58	4.62	4.59	4.53	4.55	4.57	4.55	4.52	4.53	4.51	4.52	4.49	4.5	4.5	4.51	4.48	4.47	4.47	4.47	4.47	4.49	4.49	4.54	4.55	4.62	4.61
30	2037	4.58	4.62	4.59	4.53	4.55	4.57	4.55	4.52	4.53	4.51	4.52	4.49	4.5	4.5	4.51	4.48	4.47	4.47	4.47	4.47	4.49	4.49	4.54	4.55	4.62	4.61

MMD Scale

Term	Year	8/10	8/13	8/14	8/15	8/16	8/17	8/20	8/21	8/22	8/23	8/24	8/27	8/28	8/29	8/30	8/31	9/3	9/4	9/5	9/6	9/7	9/10	9/11	9/12	9/13	9/14
1	2008	3.62	3.62	3.62	3.62	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	H	3.6	3.58	3.58	3.53	3.5	3.5	3.46	3.46	3.46
2	2009	3.64	3.64	3.64	3.64	3.63	3.64	3.64	3.63	3.63	3.63	3.62	3.62	3.61	3.6	3.59	3.59	O	3.59	3.57	3.56	3.51	3.48	3.48	3.46	3.47	3.47
3	2010	3.68	3.68	3.68	3.68	3.67	3.68	3.68	3.67	3.67	3.66	3.64	3.64	3.62	3.6	3.58	3.58	L	3.58	3.56	3.55	3.48	3.45	3.45	3.45	3.48	3.48
4	2011	3.72	3.72	3.72	3.72	3.72	3.73	3.73	3.71	3.71	3.69	3.67	3.67	3.64	3.61	3.58	3.58	I	3.58	3.56	3.55	3.48	3.45	3.46	3.46	3.49	3.49
5	2012	3.76	3.76	3.76	3.77	3.77	3.79	3.79	3.77	3.77	3.75	3.73	3.73	3.7	3.65	3.62	3.62	D	3.62	3.59	3.57	3.49	3.46	3.47	3.47	3.5	3.5
6	2013	3.82	3.82	3.83	3.84	3.84	3.86	3.86	3.83	3.83	3.82	3.81	3.81	3.78	3.73	3.69	3.68	A	3.68	3.64	3.61	3.51	3.47	3.48	3.48	3.52	3.52
7	2014	3.88	3.88	3.89	3.9	3.9	3.92	3.92	3.89	3.89	3.88	3.88	3.88	3.85	3.8	3.76	3.75	Y	3.74	3.69	3.65	3.54	3.49	3.5	3.5	3.54	3.54
8	2015	3.93	3.94	3.96	3.97	3.98	4	4	3.97	3.97	3.96	3.96	3.95	3.92	3.87	3.83	3.82		3.81	3.75	3.7	3.58	3.53	3.54	3.54	3.59	3.59
9	2016	3.99	4	4.03	4.04	4.05	4.08	4.08	4.05	4.05	4.04	4.04	4.03	3.99	3.94	3.9	3.89		3.88	3.82	3.76	3.64	3.59	3.6	3.61	3.66	3.66
10	2017	4.05	4.06	4.09	4.1	4.12	4.15	4.15	4.12	4.13	4.12	4.12	4.11	4.07	4.01	3.97	3.96	H	3.95	3.89	3.83	3.71	3.66	3.67	3.68	3.73	3.73
11	2018	4.13	4.14	4.17	4.18	4.2	4.23	4.23	4.21	4.22	4.21	4.22	4.21	4.16	4.1	4.06	4.05	O	4.04	3.98	3.92	3.79	3.74	3.75	3.77	3.82	3.82
12	2019	4.19	4.2	4.23	4.25	4.27	4.3	4.3	4.28	4.29	4.29	4.3	4.29	4.24	4.18	4.14	4.13	L	4.12	4.06	4	3.87	3.82	3.83	3.85	3.9	3.9
13	2020	4.22	4.23	4.26	4.29	4.32	4.35	4.35	4.34	4.36	4.36	4.37	4.36	4.31	4.25	4.21	4.2	I	4.19	4.13	4.07	3.94	3.88	3.89	3.91	3.96	3.96
14	2021	4.25	4.26	4.29	4.32	4.36	4.4	4.4	4.39	4.41	4.41	4.42	4.41	4.36	4.3	4.26	4.25	D	4.24	4.18	4.12	3.99	3.93	3.94	3.96	4.01	4.01
15	2022	4.28	4.29	4.32	4.35	4.39	4.43	4.43	4.43	4.46	4.46	4.47	4.46	4.41	4.35	4.31	4.3	A	4.29	4.23	4.17	4.04	3.98	3.99	4.01	4.06	4.06
16	2023	4.3	4.31	4.34	4.37	4.42	4.46	4.46	4.46	4.49	4.49	4.5	4.49	4.44	4.39	4.35	4.35	Y	4.34	4.28	4.22	4.09	4.03	4.04	4.06	4.1	4.1
17	2024	4.32	4.33	4.36	4.39	4.45	4.49	4.49	4.49	4.52	4.52	4.53	4.52	4.47	4.42	4.38	4.38		4.38	4.32	4.26	4.13	4.07	4.08	4.1	4.14	4.14
18	2025	4.34	4.35	4.38	4.41	4.47	4.51	4.51	4.51	4.54	4.55	4.56	4.55	4.5	4.45	4.41	4.41		4.41	4.36	4.3	4.17	4.11	4.12	4.14	4.18	4.18
19	2026	4.36	4.37	4.4	4.43	4.49	4.53	4.53	4.53	4.56	4.57	4.59	4.58	4.53	4.48	4.44	4.44		4.44	4.39	4.33	4.2	4.14	4.15	4.17	4.21	4.21
20	2027	4.38	4.39	4.42	4.45	4.51	4.55	4.55	4.55	4.58	4.59	4.62	4.61	4.56	4.51	4.47	4.47	H	4.47	4.42	4.36	4.23	4.17	4.18	4.2	4.24	4.24
21	2028	4.4	4.41	4.44	4.47	4.54	4.58	4.58	4.58	4.61	4.62	4.65	4.64	4.59	4.54	4.5	4.5	O	4.5	4.45	4.39	4.26	4.2	4.21	4.23	4.27	4.27
22	2029	4.42	4.43	4.46	4.49	4.57	4.61	4.61	4.61	4.64	4.66	4.69	4.68	4.63	4.57	4.53	4.53	L	4.53	4.48	4.42	4.29	4.23	4.24	4.26	4.3	4.3
23	2030	4.44	4.45	4.48	4.51	4.6	4.64	4.64	4.64	4.66	4.68	4.71	4.7	4.65	4.59	4.55	4.55	I	4.55	4.5	4.44	4.32	4.26	4.27	4.29	4.33	4.33
24	2031	4.45	4.46	4.5	4.53	4.62	4.66	4.66	4.66	4.68	4.7	4.73	4.72	4.67	4.61	4.57	4.57	D	4.57	4.52	4.46	4.34	4.28	4.29	4.31	4.35	4.35
25	2032	4.46	4.47	4.51	4.54	4.64	4.68	4.68	4.67	4.69	4.71	4.74	4.73	4.68	4.62	4.58	4.58	A	4.58	4.53	4.47	4.36	4.29	4.3	4.32	4.36	4.36
26	2033	4.47	4.48	4.52	4.55	4.65	4.69	4.69	4.68	4.7	4.72	4.75	4.74	4.69	4.63	4.59	4.59	Y	4.59	4.54	4.48	4.37	4.3	4.31	4.33	4.37	4.37
27	2034	4.48	4.49	4.53	4.56	4.66	4.7	4.7	4.69	4.71	4.73	4.76	4.75	4.7	4.64	4.6	4.6		4.6	4.55	4.49	4.38	4.31	4.32	4.34	4.38	4.38
28	2035	4.49	4.5	4.54	4.57	4.67	4.71	4.71	4.7	4.72	4.74	4.77	4.76	4.71	4.65	4.61	4.61		4.61	4.56	4.5	4.39	4.32	4.33	4.35	4.39	4.39
29	2036	4.5	4.51	4.55	4.58	4.68	4.72	4.72	4.71	4.73	4.75	4.78	4.77	4.72	4.66	4.62	4.62		4.62	4.57	4.51	4.4	4.33	4.34	4.36	4.4	4.4
30	2037	4.5	4.51	4.55	4.59	4.69	4.73	4.73	4.72	4.74	4.76	4.78	4.77	4.72	4.66	4.62	4.62		4.62	4.57	4.51	4.4	4.33	4.34	4.36	4.4	4.4

Term	Year	8/10	8/13	8/14	8/15	8/16	8/17	8/20	8/21	8/22	8/23	8/24	8/27	8/28	8/29	8/30	8/31	9/3	9/4	9/5	9/6	9/7	9/10	9/11	9/12	9/13	9/14
1	2008	3.66	3.66	3.66	3.66	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	H	3.64	3.61	3.61	3.56	3.53	3.53	3.49	3.49	3.49
2	2009	3.7	3.7	3.7	3.7	3.69	3.7	3.7	3.69	3.69	3.69	3.68	3.68	3.67	3.66	3.65	3.65	O	3.65	3.61	3.6	3.55	3.52	3.52	3.5	3.52	3.52
3	2010	3.75	3.75	3.75	3.75	3.74	3.75	3.75	3.74	3.74	3.73	3.71	3.71	3.69	3.67	3.65	3.65	L	3.65	3.61	3.6	3.53	3.5	3.51	3.51	3.54	3.54
4	2011	3.8	3.8	3.8	3.8	3.8	3.81	3.81	3.79	3.79	3.77	3.75	3.75	3.72	3.69	3.66	3.66	I	3.66	3.63	3.62	3.55	3.52	3.53	3.53	3.56	3.56
5	2012	3.85	3.85	3.85	3.86	3.86	3.88	3.88	3.86	3.86	3.84	3.82	3.82	3.79	3.74	3.71	3.71	D	3.71	3.68	3.65	3.57	3.54	3.55	3.55	3.59	3.59
6	2013	3.91	3.91	3.92	3.93	3.93	3.95	3.95	3.92	3.92	3.91	3.9	3.9	3.87	3.82	3.78	3.77	A	3.77	3.73	3.69	3.59	3.55	3.57	3.57	3.61	3.61
7	2014	3.97	3.97	3.98	3.99	3.99	4.01	4.01	3.98	3.98	3.97	3.97	3.97	3.94	3.89	3.85	3.84	Y	3.83	3.78	3.73	3.62	3.57	3.59	3.6	3.64	3.64
8	2015	4.03	4.04	4.06	4.07	4.08	4.1	4.1	4.07	4.07	4.06	4.06	4.05	4.01	3.96	3.92	3.91		3.9	3.84	3.78	3.66	3.61	3.63	3.64	3.69	3.69
9	2016	4.09	4.11	4.14	4.15	4.16	4.19	4.19	4.16	4.16	4.15	4.15	4.14	4.09	4.04	4	3.99		3.98	3.92	3.85	3.73	3.68	3.69	3.71	3.76	3.76
10	2017	4.15	4.17	4.2	4.21	4.23	4.26	4.26	4.23	4.24	4.23	4.23	4.22	4.17	4.11	4.07	4.06	H	4.05	3.99	3.92	3.8	3.75	3.76	3.78	3.83	3.83
11	2018	4.24	4.25	4.28	4.29	4.31	4.34	4.34	4.32	4.33	4.32	4.33	4.32	4.26	4.2	4.16	4.15	O	4.14	4.08	4.01	3.88	3.83	3.85	3.87	3.92	3.92
12	2019	4.3	4.31	4.34	4.36	4.38	4.41	4.41	4.39	4.4	4.4	4.41	4.4	4.34	4.28	4.24	4.23	L	4.22	4.16	4.09	3.96	3.91	3.93	3.95	4	4
13	2020	4.33	4.34	4.37	4.4	4.43	4.46	4.46	4.45	4.47	4.47	4.48	4.47	4.41	4.35	4.31	4.3	I	4.29	4.23	4.16	4.03	3.97	3.99	4.01	4.06	4.06
14	2021	4.36	4.37	4.4	4.44	4.48	4.52	4.52	4.51	4.53	4.53	4.54	4.53	4.47	4.41	4.37	4.35	D	4.34	4.28	4.21	4.08	4.02	4.04	4.06	4.11	4.11
15	2022	4.39	4.4	4.43	4.47	4.51	4.55	4.55	4.55	4.58	4.58	4.59	4.58	4.52	4.46	4.42	4.4	A	4.39	4.33	4.26	4.13	4.07	4.09	4.11	4.16	4.16
16	2023	4.41	4.42	4.46	4.49	4.54	4.58	4.58	4.58	4.61	4.61	4.62	4.61	4.55	4.5	4.46	4.45	Y	4.44	4.38	4.31	4.18	4.12	4.14	4.16	4.2	4.2
17	2024	4.43	4.44	4.48	4.51	4.57	4.61	4.61	4.61	4.64	4.64	4.65	4.64	4.58	4.53	4.49	4.48		4.48	4.42	4.35	4.22	4.16	4.18	4.2	4.24	4.24
18	2025	4.45	4.46	4.5	4.53	4.59	4.63	4.63	4.63	4.66	4.67	4.68	4.67	4.61	4.56	4.52	4.51		4.51	4.46	4.39	4.26	4.2	4.22	4.24	4.28	4.28
19	2026	4.47	4.48	4.52	4.55	4.61	4.65	4.65	4.65	4.68	4.69	4.71	4.7	4.64	4.59	4.55	4.54		4.54	4.49	4.42	4.29	4.23	4.25	4.27	4.31	4.31
20	2027	4.49	4.5	4.54	4.57	4.63	4.67	4.67	4.67	4.7	4.71	4.74	4.73	4.67	4.62	4.58	4.57	H	4.57	4.52	4.45	4.32	4.26	4.28	4.3	4.34	4.34
21	2028	4.51	4.52	4.56	4.59	4.66	4.7	4.7	4.7	4.73	4.74	4.77	4.76	4.7	4.65	4.61	4.6	O	4.6	4.55	4.48	4.35	4.29	4.31	4.33	4.37	4.37
22	2029	4.53	4.54	4.58	4.61	4.69	4.73	4.73	4.73	4.76	4.78	4.81	4.8	4.74	4.67	4.63	4.63	L	4.63	4.57	4.5	4.37	4.31	4.34	4.36	4.4	4.4
23	2030	4.55	4.56	4.6	4.63	4.72	4.76	4.76	4.76	4.78	4.8	4.83	4.82	4.76	4.69	4.65	4.65	I	4.65	4.59	4.52	4.4	4.34	4.36	4.38	4.42	4.42
24	2031	4.56	4.57	4.62	4.65	4.74	4.78	4.78	4.78	4.8	4.82	4.85	4.84	4.78	4.71	4.67	4.67	D	4.67	4.61	4.54	4.42	4.36	4.38	4.4	4.44	4.44
25	2032	4.57	4.58	4.63	4.66	4.76	4.8	4.8	4.79	4.81	4.83	4.86	4.85	4.79	4.72	4.68	4.68	A	4.68	4.62	4.55	4.44	4.37	4.39	4.41	4.45	4.45
26	2033	4.58	4.59	4.64	4.67	4.77	4.81	4.81	4.8	4.82	4.84	4.87	4.86	4.8	4.73	4.69	4.69	Y	4.69	4.63	4.56	4.45	4.38	4.4	4.42	4.46	4.46
27	2034	4.59	4.6	4.65	4.68	4.78	4.82	4.82	4.81	4.83	4.85	4.88	4.87	4.81	4.74	4.7	4.7		4.7	4.64	4.57	4.46	4.39	4.41	4.43	4.47	4.47
28	2035	4.6	4.61	4.66	4.69	4.79	4.83	4.83	4.82	4.84	4.86	4.89	4.88	4.82	4.75	4.71	4.71		4.71	4.65	4.58	4.47	4.4	4.42	4.44	4.48	4.48
29	2036	4.61	4.62	4.67	4.7	4.8	4.84	4.84	4.83	4.85	4.87	4.9	4.89	4.83	4.76	4.72	4.72		4.72	4.66	4.59	4.48	4.41	4.43	4.45	4.49	4.49
30	2037	4.61	4.62	4.67	4.71	4.81	4.85	4.85	4.84	4.86	4.88	4.9	4.89	4.83	4.76	4.72	4.72		4.72	4.66	4.59	4.48	4.41	4.43	4.45	4.49	4.49

MMD Scale

Term	Year	9/17	9/18	9/19	9/20	9/21	9/24	9/25	9/26	9/27	9/28	10/1	10/2	10/3	10/4	10/5	10/8	10/9	10/10	10/11	10/12	10/15	10/16	10/17	10/18	10/19	10/22
1	2008	3.46	3.44	3.43	3.44	3.44	3.44	3.43	3.43	3.42	3.41	3.4	3.38	3.38	3.38	3.38	H	3.38	3.38	3.38	3.38	3.38	3.38	3.36	3.35	3.35	3.35
2	2009	3.47	3.45	3.43	3.45	3.45	3.45	3.43	3.43	3.42	3.41	3.4	3.38	3.38	3.38	3.39	O	3.39	3.39	3.39	3.39	3.39	3.39	3.37	3.36	3.35	3.35
3	2010	3.48	3.47	3.45	3.48	3.48	3.48	3.46	3.46	3.45	3.44	3.43	3.41	3.41	3.4	3.42	L	3.42	3.43	3.44	3.44	3.44	3.44	3.41	3.39	3.37	3.37
4	2011	3.49	3.48	3.46	3.5	3.5	3.5	3.48	3.48	3.47	3.47	3.47	3.45	3.45	3.44	3.47	I	3.48	3.49	3.5	3.5	3.5	3.49	3.46	3.44	3.4	3.4
5	2012	3.5	3.5	3.48	3.52	3.52	3.52	3.5	3.51	3.5	3.5	3.5	3.48	3.48	3.47	3.51	D	3.52	3.53	3.54	3.54	3.55	3.54	3.5	3.48	3.44	3.44
6	2013	3.52	3.52	3.51	3.56	3.55	3.55	3.53	3.54	3.53	3.53	3.53	3.51	3.51	3.5	3.55	A	3.56	3.57	3.59	3.59	3.6	3.59	3.55	3.53	3.48	3.48
7	2014	3.55	3.55	3.55	3.61	3.6	3.6	3.59	3.6	3.59	3.59	3.58	3.56	3.56	3.55	3.61	Y	3.62	3.63	3.65	3.65	3.66	3.64	3.6	3.58	3.53	3.53
8	2015	3.6	3.6	3.61	3.68	3.67	3.67	3.66	3.67	3.66	3.66	3.65	3.62	3.63	3.62	3.68		3.69	3.7	3.72	3.72	3.73	3.71	3.66	3.63	3.58	3.58
9	2016	3.67	3.67	3.68	3.76	3.75	3.75	3.74	3.75	3.73	3.73	3.72	3.69	3.7	3.69	3.75		3.76	3.77	3.79	3.79	3.8	3.78	3.73	3.7	3.64	3.65
10	2017	3.74	3.75	3.76	3.84	3.83	3.83	3.82	3.83	3.81	3.81	3.79	3.76	3.77	3.76	3.82	H	3.83	3.84	3.86	3.86	3.87	3.85	3.8	3.77	3.71	3.72
11	2018	3.83	3.84	3.86	3.94	3.93	3.93	3.92	3.93	3.9	3.9	3.88	3.85	3.85	3.83	3.89	O	3.9	3.91	3.93	3.93	3.93	3.91	3.86	3.83	3.78	3.79
12	2019	3.91	3.92	3.94	4.02	4.01	4.01	4	4.01	3.98	3.98	3.96	3.93	3.93	3.91	3.97	L	3.97	3.97	3.99	3.99	3.99	3.97	3.92	3.89	3.84	3.84
13	2020	3.97	3.98	4	4.08	4.07	4.07	4.06	4.07	4.04	4.04	4.02	3.99	3.99	3.97	4.03	I	4.03	4.03	4.04	4.04	4.04	4.02	3.97	3.94	3.89	3.89
14	2021	4.02	4.03	4.05	4.13	4.12	4.12	4.11	4.12	4.09	4.09	4.07	4.04	4.04	4.02	4.08	D	4.08	4.08	4.09	4.09	4.09	4.07	4.02	3.99	3.94	3.94
15	2022	4.06	4.08	4.09	4.17	4.16	4.16	4.15	4.16	4.13	4.13	4.11	4.08	4.08	4.06	4.12	A	4.12	4.12	4.13	4.13	4.13	4.11	4.06	4.03	3.98	3.98
16	2023	4.1	4.12	4.12	4.21	4.2	4.2	4.18	4.19	4.16	4.16	4.15	4.12	4.12	4.1	4.16	Y	4.16	4.16	4.17	4.17	4.17	4.15	4.1	4.07	4.01	4.01
17	2024	4.14	4.16	4.16	4.25	4.24	4.24	4.21	4.22	4.19	4.19	4.18	4.15	4.15	4.13	4.19		4.19	4.19	4.2	4.2	4.2	4.18	4.13	4.1	4.04	4.04
18	2025	4.18	4.2	4.2	4.29	4.28	4.28	4.24	4.25	4.22	4.22	4.21	4.18	4.18	4.16	4.22		4.22	4.22	4.23	4.23	4.23	4.21	4.16	4.13	4.07	4.07
19	2026	4.21	4.23	4.23	4.32	4.31	4.31	4.27	4.28	4.25	4.25	4.24	4.21	4.21	4.19	4.25		4.25	4.25	4.26	4.26	4.26	4.24	4.19	4.16	4.1	4.1
20	2027	4.24	4.26	4.26	4.35	4.34	4.34	4.3	4.31	4.28	4.28	4.27	4.24	4.24	4.22	4.28	H	4.28	4.28	4.29	4.29	4.29	4.27	4.22	4.19	4.13	4.13
21	2028	4.27	4.29	4.29	4.38	4.37	4.37	4.33	4.34	4.31	4.31	4.3	4.27	4.27	4.25	4.31	O	4.31	4.31	4.32	4.32	4.32	4.3	4.25	4.22	4.16	4.16
22	2029	4.3	4.32	4.32	4.41	4.4	4.4	4.36	4.37	4.34	4.34	4.32	4.29	4.29	4.28	4.34	L	4.34	4.34	4.35	4.35	4.35	4.33	4.28	4.25	4.19	4.19
23	2030	4.33	4.35	4.35	4.44	4.43	4.43	4.38	4.39	4.36	4.36	4.34	4.31	4.31	4.3	4.36	I	4.36	4.36	4.37	4.37	4.37	4.35	4.3	4.27	4.21	4.21
24	2031	4.35	4.37	4.38	4.47	4.46	4.45	4.4	4.41	4.38	4.38	4.36	4.33	4.33	4.32	4.38	D	4.38	4.38	4.39	4.39	4.39	4.37	4.32	4.29	4.23	4.23
25	2032	4.36	4.38	4.4	4.49	4.48	4.47	4.42	4.43	4.4	4.4	4.38	4.34	4.34	4.33	4.39	A	4.39	4.39	4.4	4.4	4.4	4.38	4.33	4.3	4.24	4.24
26	2033	4.37	4.39	4.41	4.5	4.49	4.48	4.43	4.44	4.41	4.41	4.39	4.35	4.35	4.34	4.4	Y	4.4	4.4	4.41	4.41	4.41	4.39	4.34	4.31	4.25	4.25
27	2034	4.38	4.4	4.42	4.51	4.5	4.49	4.44	4.45	4.42	4.42	4.4	4.36	4.36	4.35	4.41		4.41	4.41	4.42	4.42	4.42	4.4	4.35	4.32	4.26	4.26
28	2035	4.39	4.41	4.43	4.52	4.51	4.5	4.45	4.46	4.43	4.43	4.41	4.37	4.37	4.36	4.42		4.42	4.42	4.43	4.43	4.43	4.41	4.36	4.33	4.27	4.27
29	2036	4.4	4.42	4.44	4.53	4.52	4.51	4.46	4.47	4.44	4.44	4.42	4.38	4.38	4.37	4.43		4.43	4.43	4.44	4.44	4.44	4.42	4.37	4.34	4.28	4.28
30	2037	4.4	4.42	4.44	4.53	4.52	4.51	4.46	4.47	4.44	4.44	4.42	4.38	4.38	4.37	4.43		4.43	4.43	4.44	4.44	4.44	4.42	4.37	4.34	4.28	4.28

Term	Year	9/17	9/18	9/19	9/20	9/21	9/24	9/25	9/26	9/27	9/28	10/1	10/2	10/3	10/4	10/5	10/8	10/9	10/10	10/11	10/12	10/15	10/16	10/17	10/18	10/19	10/22
1	2008	3.49	3.47	3.46	3.47	3.47	3.47	3.46	3.46	3.45	3.44	3.43	3.41	3.41	3.41	3.41	H	3.41	3.41	3.41	3.41	3.41	3.41	3.39	3.38	3.37	3.37
2	2009	3.53	3.51	3.49	3.51	3.51	3.51	3.49	3.49	3.47	3.46	3.45	3.43	3.43	3.43	3.44	O	3.44	3.45	3.45	3.45	3.46	3.46	3.44	3.43	3.42	3.42
3	2010	3.55	3.54	3.52	3.55	3.55	3.55	3.53	3.53	3.51	3.5	3.49	3.47	3.48	3.47	3.49	L	3.5	3.51	3.52	3.52	3.53	3.53	3.49	3.47	3.45	3.45
4	2011	3.57	3.56	3.54	3.58	3.58	3.58	3.56	3.56	3.54	3.54	3.54	3.52	3.53	3.52	3.55	I	3.57	3.58	3.59	3.59	3.6	3.59	3.55	3.53	3.49	3.49
5	2012	3.6	3.6	3.58	3.62	3.62	3.62	3.6	3.61	3.59	3.59	3.59	3.57	3.58	3.56	3.6	D	3.62	3.63	3.64	3.64	3.65	3.64	3.59	3.57	3.53	3.53
6	2013	3.62	3.62	3.61	3.66	3.65	3.65	3.63	3.64	3.62	3.62	3.62	3.6	3.61	3.6	3.65	A	3.66	3.67	3.69	3.69	3.7	3.69	3.64	3.62	3.57	3.57
7	2014	3.65	3.65	3.65	3.71	3.7	3.7	3.69	3.7	3.68	3.68	3.67	3.65	3.66	3.65	3.71	Y	3.72	3.73	3.75	3.75	3.76	3.74	3.7	3.68	3.63	3.63
8	2015	3.7	3.7	3.71	3.78	3.77	3.77	3.76	3.77	3.75	3.75	3.74	3.71	3.73	3.72	3.78		3.79	3.8	3.82	3.82	3.83	3.81	3.76	3.73	3.68	3.68
9	2016	3.77	3.77	3.78	3.86	3.85	3.85	3.84	3.85	3.83	3.83	3.82	3.79	3.8	3.79	3.85		3.86	3.87	3.89	3.89	3.9	3.88	3.83	3.8	3.74	3.75
10	2017	3.85	3.86	3.87	3.95	3.94	3.94	3.93	3.94	3.91	3.91	3.89	3.86	3.87	3.86	3.92	H	3.93	3.94	3.96	3.96	3.97	3.95	3.9	3.87	3.81	3.82
11	2018	3.94	3.95	3.97	4.05	4.04	4.04	4.03	4.04	4	4	3.98	3.95	3.95	3.93	3.99	O	4	4.01	4.03	4.03	4.03	4.01	3.96	3.93	3.88	3.89
12	2019	4.02	4.03	4.05	4.13	4.12	4.12	4.11	4.12	4.08	4.08	4.06	4.03	4.03	4.01	4.07	L	4.07	4.07	4.09	4.09	4.09	4.07	4.02	3.99	3.94	3.94
13	2020	4.08	4.09	4.11	4.19	4.18	4.18	4.17	4.18	4.14	4.14	4.12	4.09	4.09	4.07	4.13	I	4.13	4.13	4.14	4.14	4.14	4.12	4.07	4.04	3.99	3.99
14	2021	4.12	4.14	4.16	4.24	4.23	4.23	4.22	4.23	4.19	4.19	4.17	4.14	4.14	4.12	4.18	D	4.18	4.18	4.19	4.19	4.19	4.17	4.12	4.09	4.04	4.04
15	2022	4.16	4.19	4.2	4.28	4.27	4.27	4.26	4.27	4.23	4.23	4.21	4.18	4.18	4.16	4.22	A	4.22	4.22	4.23	4.23	4.23	4.21	4.16	4.13	4.08	4.08
16	2023	4.2	4.23	4.23	4.32	4.31	4.31	4.29	4.3	4.26	4.26	4.25	4.22	4.22	4.19	4.26	Y	4.26	4.26	4.27	4.27	4.27	4.25	4.2	4.17	4.11	4.11
17	2024	4.24	4.27	4.27	4.36	4.35	4.35	4.32	4.33	4.29	4.29	4.28	4.25	4.25	4.22	4.29		4.29	4.29	4.3	4.3	4.3	4.28	4.23	4.2	4.14	4.14
18	2025	4.28	4.31	4.31	4.4	4.39	4.38	4.34	4.35	4.32	4.32	4.31	4.28	4.28	4.25	4.32		4.32	4.32	4.33	4.33	4.33	4.31	4.26	4.23	4.17	4.17
19	2026	4.31	4.34	4.34	4.43	4.42	4.41	4.37	4.38	4.35	4.35	4.34	4.31	4.31	4.28	4.35		4.35	4.35	4.36	4.36	4.36	4.34	4.29	4.26	4.2	4.2
20	2027	4.34	4.37	4.37	4.46	4.45	4.44	4.4	4.41	4.38	4.38	4.37	4.34	4.34	4.31	4.38	H	4.38	4.38	4.39	4.39	4.39	4.37	4.32	4.29	4.23	4.23
21	2028	4.37	4.4	4.4	4.49	4.48	4.47	4.43	4.44	4.41	4.41	4.4	4.37	4.37	4.34	4.41	O	4.41	4.41	4.42	4.42	4.42	4.4	4.35	4.32	4.26	4.26
22	2029	4.4	4.42	4.42	4.51	4.5	4.5	4.46	4.47	4.44	4.44	4.42	4.39	4.39	4.37	4.44	L	4.44	4.44	4.45	4.45	4.45	4.43	4.38	4.35	4.29	4.29
23	2030	4.42	4.44	4.44	4.53	4.52	4.52	4.47	4.48	4.45	4.45	4.43	4.4	4.4	4.39	4.46	I	4.46	4.46	4.47	4.47	4.47	4.45	4.4	4.37	4.31	4.31
24	2031	4.44	4.46	4.47	4.56	4.55	4.54	4.49	4.5	4.47	4.47	4.45	4.42	4.42	4.41	4.47	D	4.47	4.47	4.48	4.48	4.48	4.46	4.41	4.38	4.32	4.32
25	2032	4.45	4.47	4.49	4.58	4.57	4.56	4.51	4.52	4.49	4.49	4.47	4.43	4.43	4.42	4.48	A	4.48	4.48	4.49	4.49	4.49	4.47	4.42	4.39	4.33	4.33
26	2033	4.46	4.48	4.5	4.59	4.58	4.57	4.52	4.53	4.5	4.5	4.48	4.44	4.44	4.43	4.49	Y	4.49	4.49	4.5	4.5	4.5	4.48	4.43	4.4	4.34	4.34
27	2034	4.47	4.49	4.51	4.6	4.59	4.58	4.53	4.54	4.51	4.51	4.49	4.45	4.45	4.44	4.5		4.5	4.5	4.51	4.51	4.51	4.49	4.44	4.41	4.35	4.35
28	2035	4.48	4.5	4.52	4.61	4.6	4.59	4.54	4.55	4.52	4.52	4.5	4.46	4.46	4.45	4.51		4.51	4.51	4.52	4.52	4.52	4.5	4.45	4.42	4.36	4.36
29	2036	4.49	4.51	4.53	4.62	4.61	4.6	4.55	4.56	4.53	4.53	4.51	4.47	4.47	4.46	4.52		4.52	4.52	4.53	4.53	4.53	4.51	4.46	4.43	4.37	4.37
30	2037	4.49	4.51	4.53	4.62	4.61	4.6	4.55	4.56	4.53	4.53	4.51	4.47	4.47	4.46	4.52		4.52	4.52	4.53	4.53	4.53	4.51	4.46	4.43	4.37	4.37

JEA-POD3-00023 Hearing Exhibit - 00000515

MMD Scale

Term	Year	10/23	10/24	10/25	10/26	10/29	10/30	10/31	11/1	11/2	11/5	11/6	11/7	11/8	11/9	11/12	11/13	11/14	11/15	11/16	11/19	11/20	11/21	11/22	11/23	11/26	11/27
1	2008	3.35	3.35	3.32	3.32	3.32	3.32	3.32	3.3	3.3	3.3	3.3	3.3	3.3	3.3	H	3.3	3.3	3.3	3.3	3.3	3.3	3.28	H	3.28	3.28	3.28
2	2009	3.35	3.34	3.32	3.32	3.32	3.32	3.33	3.3	3.3	3.3	3.3	3.3	3.3	3.3	O	3.3	3.3	3.3	3.29	3.27	3.26	3.24	O	3.24	3.22	3.22
3	2010	3.36	3.33	3.32	3.32	3.32	3.33	3.35	3.31	3.3	3.3	3.31	3.32	3.31	3.31	L	3.31	3.31	3.3	3.29	3.25	3.24	3.21	L	3.21	3.17	3.17
4	2011	3.4	3.37	3.36	3.37	3.37	3.38	3.41	3.37	3.35	3.35	3.37	3.39	3.37	3.37	I	3.37	3.37	3.35	3.32	3.28	3.27	3.24	I	3.24	3.2	3.2
5	2012	3.44	3.41	3.41	3.42	3.42	3.43	3.47	3.42	3.4	3.4	3.43	3.46	3.44	3.44	D	3.44	3.44	3.41	3.38	3.34	3.33	3.3	D	3.3	3.26	3.26
6	2013	3.48	3.46	3.46	3.48	3.48	3.49	3.53	3.48	3.46	3.46	3.49	3.52	3.51	3.51	A	3.51	3.51	3.47	3.44	3.4	3.39	3.36	A	3.36	3.32	3.32
7	2014	3.53	3.51	3.51	3.53	3.53	3.54	3.58	3.53	3.51	3.52	3.56	3.59	3.58	3.58	Y	3.58	3.58	3.54	3.51	3.47	3.47	3.44	Y	3.44	3.39	3.39
8	2015	3.59	3.57	3.58	3.6	3.6	3.61	3.65	3.6	3.58	3.6	3.64	3.67	3.66	3.66		3.66	3.66	3.61	3.58	3.55	3.55	3.52		3.52	3.46	3.47
9	2016	3.66	3.64	3.65	3.68	3.68	3.69	3.73	3.68	3.66	3.68	3.73	3.76	3.75	3.75		3.75	3.75	3.7	3.66	3.63	3.63	3.6		3.6	3.54	3.55
10	2017	3.73	3.71	3.73	3.76	3.76	3.77	3.81	3.76	3.74	3.76	3.82	3.84	3.83	3.83		3.83	3.83	3.78	3.74	3.71	3.71	3.68		3.68	3.62	3.63
11	2018	3.8	3.78	3.8	3.83	3.83	3.85	3.89	3.84	3.83	3.85	3.91	3.93	3.92	3.92	H	3.92	3.92	3.87	3.83	3.8	3.8	3.77	H	3.77	3.71	3.72
12	2019	3.85	3.83	3.85	3.89	3.89	3.92	3.96	3.91	3.91	3.93	3.99	4.01	4.01	4.01	O	4.01	4.01	3.96	3.92	3.89	3.89	3.86	O	3.86	3.8	3.81
13	2020	3.9	3.88	3.9	3.94	3.94	3.97	4.01	3.96	3.96	3.98	4.04	4.07	4.07	4.07	L	4.07	4.07	4.02	3.98	3.95	3.95	3.92	L	3.92	3.86	3.87
14	2021	3.95	3.93	3.95	3.99	3.99	4.02	4.06	4.01	4.01	4.03	4.09	4.12	4.13	4.13	I	4.13	4.13	4.08	4.04	4.01	4.01	3.98	I	3.98	3.92	3.93
15	2022	3.99	3.97	3.99	4.02	4.02	4.06	4.1	4.06	4.06	4.08	4.14	4.17	4.18	4.18	D	4.18	4.18	4.14	4.1	4.07	4.07	4.04	D	4.04	3.98	3.99
16	2023	4.02	4	4.02	4.05	4.05	4.09	4.13	4.1	4.1	4.12	4.18	4.21	4.23	4.23	A	4.23	4.23	4.19	4.16	4.13	4.13	4.1	A	4.1	4.04	4.05
17	2024	4.05	4.03	4.05	4.08	4.08	4.12	4.16	4.14	4.14	4.16	4.22	4.25	4.27	4.27	Y	4.27	4.27	4.23	4.21	4.18	4.18	4.16	Y	4.16	4.1	4.11
18	2025	4.08	4.06	4.08	4.11	4.11	4.15	4.19	4.18	4.18	4.2	4.26	4.29	4.31	4.31		4.31	4.31	4.27	4.25	4.22	4.22	4.2		4.2	4.14	4.15
19	2026	4.11	4.09	4.11	4.14	4.14	4.18	4.22	4.21	4.21	4.23	4.3	4.33	4.35	4.35		4.35	4.35	4.31	4.29	4.26	4.26	4.24		4.24	4.18	4.19
20	2027	4.14	4.12	4.14	4.17	4.17	4.21	4.25	4.24	4.24	4.26	4.33	4.36	4.39	4.39		4.39	4.39	4.35	4.33	4.3	4.3	4.28		4.28	4.22	4.23
21	2028	4.17	4.15	4.17	4.2	4.2	4.24	4.28	4.27	4.27	4.29	4.36	4.39	4.42	4.42	H	4.42	4.42	4.38	4.36	4.33	4.31	H	4.3	4.24	4.25
22	2029	4.2	4.18	4.2	4.23	4.23	4.26	4.3	4.29	4.29	4.31	4.39	4.42	4.45	4.45	O	4.45	4.45	4.41	4.39	4.36	4.35	4.33	O	4.32	4.26	4.27
23	2030	4.22	4.2	4.22	4.25	4.25	4.28	4.32	4.31	4.31	4.33	4.41	4.44	4.47	4.47	L	4.47	4.47	4.43	4.41	4.38	4.37	4.35	L	4.34	4.28	4.29
24	2031	4.24	4.22	4.24	4.27	4.27	4.3	4.34	4.33	4.33	4.35	4.43	4.46	4.49	4.49	I	4.49	4.49	4.45	4.43	4.4	4.39	4.37	I	4.36	4.3	4.31
25	2032	4.25	4.23	4.25	4.28	4.28	4.31	4.35	4.34	4.34	4.36	4.44	4.47	4.5	4.5	D	4.5	4.5	4.46	4.44	4.42	4.41	4.39	D	4.38	4.32	4.33
26	2033	4.26	4.24	4.26	4.29	4.29	4.32	4.36	4.35	4.35	4.37	4.45	4.48	4.51	4.51	A	4.51	4.51	4.47	4.45	4.43	4.42	4.4	A	4.39	4.33	4.34
27	2034	4.27	4.25	4.27	4.3	4.3	4.33	4.37	4.36	4.36	4.38	4.46	4.49	4.52	4.52	Y	4.52	4.52	4.48	4.46	4.44	4.43	4.41	Y	4.4	4.34	4.35
28	2035	4.28	4.26	4.28	4.31	4.31	4.34	4.38	4.37	4.37	4.39	4.47	4.5	4.53	4.53		4.53	4.53	4.49	4.47	4.45	4.44	4.42		4.41	4.35	4.36
29	2036	4.29	4.27	4.29	4.32	4.32	4.35	4.39	4.38	4.38	4.4	4.48	4.51	4.54	4.54		4.54	4.54	4.5	4.48	4.46	4.45	4.43		4.42	4.36	4.37
30	2037	4.29	4.27	4.29	4.32	4.32	4.36	4.4	4.39	4.39	4.41	4.49	4.52	4.55	4.55		4.55	4.55	4.51	4.49	4.47	4.46	4.44		4.43	4.37	4.38

Term	Year	10/23	10/24	10/25	10/26	10/29	10/30	10/31	11/1	11/2	11/5	11/6	11/7	11/8	11/9	11/12	11/13	11/14	11/15	11/16	11/19	11/20	11/21	11/22	11/23	11/26	11/27
1	2008	3.37	3.37	3.34	3.34	3.34	3.35	3.35	3.34	3.34	3.34	3.34	3.34	3.34	3.34	H	3.34	3.34	3.32	3.32	3.32	3.32	3.3	H	3.3	3.3	3.3
2	2009	3.41	3.38	3.36	3.37	3.37	3.38	3.39	3.37	3.37	3.37	3.37	3.37	3.37	3.37	O	3.37	3.37	3.34	3.33	3.31	3.3	3.28	O	3.28	3.26	3.26
3	2010	3.43	3.39	3.38	3.39	3.39	3.4	3.42	3.39	3.38	3.38	3.39	3.4	3.39	3.39	L	3.39	3.39	3.36	3.35	3.31	3.3	3.27	L	3.27	3.23	3.23
4	2011	3.48	3.44	3.43	3.44	3.44	3.45	3.48	3.45	3.43	3.43	3.45	3.47	3.45	3.45	I	3.45	3.45	3.43	3.4	3.36	3.35	3.32	I	3.32	3.28	3.28
5	2012	3.53	3.49	3.49	3.5	3.5	3.51	3.55	3.51	3.49	3.49	3.52	3.55	3.53	3.53	D	3.53	3.53	3.5	3.47	3.43	3.42	3.39	D	3.39	3.35	3.35
6	2013	3.57	3.54	3.54	3.56	3.56	3.57	3.61	3.57	3.55	3.55	3.58	3.61	3.6	3.6	A	3.6	3.6	3.56	3.53	3.49	3.48	3.45	A	3.45	3.41	3.41
7	2014	3.63	3.6	3.6	3.62	3.62	3.63	3.67	3.63	3.61	3.62	3.66	3.69	3.68	3.68	Y	3.68	3.68	3.64	3.61	3.57	3.57	3.54	Y	3.54	3.49	3.49
8	2015	3.69	3.67	3.68	3.7	3.7	3.71	3.75	3.71	3.69	3.71	3.75	3.78	3.77	3.77		3.76	3.76	3.71	3.68	3.65	3.65	3.62		3.62	3.56	3.57
9	2016	3.76	3.74	3.75	3.78	3.78	3.79	3.83	3.79	3.77	3.79	3.84	3.87	3.86	3.86		3.85	3.85	3.8	3.76	3.73	3.73	3.7		3.7	3.64	3.65
10	2017	3.83	3.81	3.83	3.86	3.86	3.87	3.91	3.87	3.85	3.87	3.93	3.95	3.94	3.94		3.93	3.93	3.88	3.84	3.81	3.81	3.78		3.78	3.72	3.73
11	2018	3.9	3.88	3.9	3.93	3.93	3.95	3.99	3.95	3.94	3.96	4.02	4.04	4.03	4.03	H	4.03	4.03	3.98	3.93	3.9	3.9	3.87	H	3.87	3.81	3.82
12	2019	3.95	3.93	3.95	3.99	3.99	4.03	4.07	4.03	4.02	4.04	4.1	4.12	4.12	4.12	O	4.12	4.12	4.07	4.02	3.99	3.99	3.96	O	3.96	3.9	3.91
13	2020	4	3.98	4	4.04	4.04	4.08	4.12	4.08	4.07	4.09	4.15	4.18	4.18	4.18	L	4.18	4.18	4.13	4.08	4.05	4.05	4.02	L	4.02	3.96	3.97
14	2021	4.05	4.03	4.05	4.09	4.09	4.13	4.17	4.13	4.12	4.14	4.2	4.23	4.24	4.24	I	4.24	4.24	4.19	4.14	4.11	4.11	4.08	I	4.08	4.02	4.03
15	2022	4.09	4.07	4.09	4.12	4.12	4.17	4.21	4.18	4.17	4.19	4.25	4.28	4.29	4.29	D	4.29	4.29	4.25	4.2	4.17	4.17	4.14	D	4.14	4.08	4.09
16	2023	4.12	4.1	4.12	4.15	4.15	4.2	4.24	4.22	4.21	4.23	4.29	4.32	4.34	4.34	A	4.34	4.34	4.3	4.26	4.23	4.23	4.2	A	4.2	4.14	4.15
17	2024	4.15	4.13	4.15	4.18	4.18	4.23	4.27	4.26	4.25	4.27	4.33	4.36	4.38	4.38	Y	4.38	4.38	4.34	4.31	4.28	4.28	4.26	Y	4.26	4.2	4.21
18	2025	4.18	4.16	4.18	4.21	4.21	4.26	4.3	4.3	4.29	4.31	4.37	4.4	4.42	4.42		4.42	4.42	4.38	4.35	4.32	4.32	4.3		4.3	4.24	4.25
19	2026	4.21	4.19	4.21	4.24	4.24	4.29	4.33	4.33	4.32	4.34	4.41	4.44	4.46	4.46		4.46	4.46	4.42	4.39	4.36	4.36	4.34		4.34	4.28	4.29
20	2027	4.24	4.22	4.24	4.27	4.27	4.32	4.36	4.36	4.35	4.37	4.44	4.47	4.5	4.5		4.5	4.5	4.46	4.43	4.4	4.4	4.38		4.38	4.32	4.33
21	2028	4.27	4.25	4.27	4.3	4.3	4.35	4.39	4.39	4.38	4.4	4.47	4.5	4.53	4.53	H	4.53	4.53	4.49	4.46	4.43	4.43	4.41	H	4.4	4.34	4.35
22	2029	4.3	4.28	4.3	4.33	4.33	4.37	4.41	4.41	4.4	4.42	4.5	4.53	4.56	4.56	O	4.56	4.56	4.52	4.49	4.46	4.45	4.43	O	4.42	4.36	4.37
23	2030	4.32	4.3	4.32	4.35	4.35	4.39	4.43	4.43	4.42	4.44	4.52	4.55	4.58	4.58	L	4.58	4.58	4.54	4.51	4.48	4.47	4.45	L	4.44	4.38	4.39
24	2031	4.33	4.31	4.33	4.36	4.36	4.4	4.44	4.44	4.44	4.46	4.54	4.57	4.6	4.6	I	4.59	4.59	4.55	4.52	4.49	4.48	4.46	I	4.45	4.39	4.4
25	2032	4.34	4.32	4.34	4.37	4.37	4.41	4.45	4.45	4.45	4.47	4.55	4.58	4.61	4.61	D	4.6	4.6	4.56	4.53	4.51	4.5	4.48	D	4.47	4.41	4.42
26	2033	4.35	4.33	4.35	4.38	4.38	4.42	4.46	4.46	4.46	4.48	4.56	4.59	4.62	4.62	A	4.61	4.61	4.57	4.54	4.52	4.51	4.49	A	4.48	4.42	4.43
27	2034	4.36	4.34	4.36	4.39	4.39	4.43	4.47	4.47	4.47	4.49	4.57	4.6	4.63	4.63	Y	4.62	4.62	4.58	4.55	4.53	4.52	4.5	Y	4.49	4.43	4.44
28	2035	4.37	4.35	4.37	4.4	4.4	4.44	4.48	4.48	4.48	4.5	4.58	4.61	4.64	4.64		4.63	4.63	4.59	4.56	4.54	4.53	4.51		4.5	4.44	4.45
29	2036	4.38	4.36	4.38	4.41	4.41	4.45	4.49	4.49	4.49	4.51	4.59	4.62	4.65	4.65		4.64	4.64	4.6	4.57	4.55	4.54	4.52		4.51	4.45	4.46
30	2037	4.38	4.36	4.38	4.41	4.41	4.46	4.5	4.5	4.5	4.52	4.6	4.63	4.66	4.66		4.65	4.65	4.61	4.58	4.56	4.55	4.53		4.52	4.46	4.47

MMD Scale

Term	Year	11/28	11/29	11/30	12/3	12/4	12/5	12/6	12/7	12/10	12/11	12/12	12/13	12/14	12/17	12/18	12/19	12/20	12/21	12/24	12/25	12/26	12/27	12/28	12/31
1	2008	3.25	3.2	3.2	3.18	3.05	3	2.97	2.97	2.97	2.93	2.9	2.85	2.85	2.85	2.85	2.85	2.85	2.9	2.9	H	2.9	2.9	2.9	2.9
2	2009	3.22	3.18	3.18	3.16	3.08	3.07	3.05	3.05	3.05	3.01	2.99	2.97	2.97	2.97	2.97	2.97	2.96	3	3	O	3	2.99	2.97	2.97
3	2010	3.17	3.16	3.16	3.14	3.1	3.08	3.07	3.09	3.09	3.05	3.05	3.05	3.07	3.07	3.05	3.04	3.03	3.07	3.08	L	3.09	3.07	3.05	3.04
4	2011	3.21	3.2	3.2	3.17	3.14	3.12	3.11	3.13	3.14	3.1	3.11	3.12	3.14	3.14	3.12	3.11	3.1	3.14	3.16	I	3.17	3.15	3.13	3.12
5	2012	3.27	3.26	3.26	3.23	3.2	3.18	3.18	3.2	3.21	3.17	3.19	3.2	3.22	3.22	3.2	3.19	3.18	3.22	3.24	D	3.25	3.23	3.21	3.2
6	2013	3.33	3.32	3.32	3.29	3.26	3.24	3.25	3.28	3.3	3.25	3.27	3.29	3.31	3.31	3.28	3.27	3.26	3.3	3.32	A	3.33	3.31	3.28	3.27
7	2014	3.4	3.39	3.39	3.37	3.34	3.32	3.33	3.36	3.38	3.33	3.35	3.37	3.4	3.4	3.37	3.35	3.34	3.38	3.4	Y	3.42	3.4	3.37	3.35
8	2015	3.48	3.46	3.46	3.44	3.41	3.4	3.42	3.45	3.47	3.42	3.44	3.46	3.49	3.49	3.46	3.44	3.43	3.47	3.49		3.51	3.49	3.46	3.44
9	2016	3.56	3.54	3.54	3.52	3.49	3.49	3.51	3.55	3.57	3.52	3.54	3.56	3.59	3.59	3.56	3.54	3.53	3.57	3.59		3.61	3.59	3.56	3.54
10	2017	3.64	3.62	3.62	3.6	3.57	3.57	3.6	3.64	3.66	3.61	3.63	3.65	3.67	3.67	3.64	3.62	3.61	3.65	3.68		3.7	3.68	3.65	3.63
11	2018	3.73	3.71	3.71	3.69	3.66	3.66	3.69	3.73	3.75	3.7	3.73	3.75	3.77	3.77	3.74	3.71	3.68	3.72	3.75	H	3.77	3.75	3.72	3.7
12	2019	3.82	3.79	3.79	3.77	3.74	3.74	3.77	3.82	3.84	3.79	3.82	3.84	3.86	3.86	3.82	3.79	3.75	3.79	3.82	O	3.84	3.82	3.79	3.76
13	2020	3.88	3.85	3.85	3.84	3.81	3.81	3.84	3.9	3.92	3.87	3.9	3.92	3.94	3.94	3.9	3.86	3.82	3.86	3.89	L	3.91	3.89	3.85	3.82
14	2021	3.94	3.91	3.91	3.9	3.88	3.88	3.91	3.97	3.99	3.94	3.97	3.98	4	4	3.96	3.92	3.88	3.92	3.95	I	3.97	3.95	3.91	3.88
15	2022	4	3.97	3.97	3.96	3.94	3.94	3.97	4.03	4.05	4	4.03	4.04	4.06	4.06	4.02	3.98	3.94	3.98	4.01	D	4.03	4.01	3.97	3.94
16	2023	4.06	4.03	4.03	4.02	4	4	4.03	4.09	4.11	4.06	4.09	4.1	4.12	4.12	4.08	4.04	4	4.04	4.07	A	4.09	4.07	4.03	4
17	2024	4.12	4.09	4.09	4.08	4.06	4.06	4.09	4.15	4.17	4.11	4.14	4.15	4.17	4.17	4.14	4.1	4.06	4.1	4.13	Y	4.15	4.13	4.09	4.06
18	2025	4.16	4.13	4.13	4.12	4.1	4.1	4.13	4.19	4.21	4.15	4.18	4.19	4.21	4.21	4.18	4.14	4.1	4.14	4.17		4.19	4.17	4.13	4.1
19	2026	4.2	4.17	4.17	4.16	4.14	4.14	4.17	4.23	4.25	4.19	4.22	4.23	4.25	4.25	4.22	4.18	4.14	4.18	4.21		4.23	4.21	4.17	4.14
20	2027	4.23	4.2	4.2	4.19	4.17	4.17	4.2	4.26	4.28	4.22	4.25	4.26	4.28	4.28	4.25	4.21	4.17	4.21	4.24		4.26	4.24	4.2	4.17
21	2028	4.25	4.22	4.22	4.21	4.19	4.2	4.23	4.29	4.31	4.25	4.28	4.29	4.31	4.31	4.28	4.24	4.2	4.24	4.27	H	4.29	4.27	4.23	4.2
22	2029	4.27	4.24	4.24	4.23	4.21	4.22	4.25	4.31	4.33	4.27	4.3	4.31	4.33	4.33	4.3	4.26	4.23	4.27	4.3	O	4.32	4.3	4.26	4.23
23	2030	4.29	4.26	4.26	4.24	4.23	4.24	4.27	4.33	4.35	4.29	4.32	4.33	4.35	4.35	4.32	4.28	4.25	4.29	4.32	L	4.34	4.32	4.28	4.25
24	2031	4.31	4.28	4.27	4.25	4.24	4.25	4.28	4.35	4.37	4.3	4.33	4.34	4.36	4.36	4.33	4.29	4.26	4.3	4.33	I	4.35	4.34	4.3	4.27
25	2032	4.33	4.29	4.28	4.26	4.25	4.26	4.29	4.36	4.38	4.31	4.34	4.35	4.37	4.37	4.34	4.3	4.27	4.31	4.34	D	4.36	4.35	4.31	4.28
26	2033	4.34	4.3	4.29	4.27	4.26	4.27	4.3	4.37	4.39	4.32	4.35	4.36	4.38	4.38	4.35	4.31	4.28	4.32	4.35	A	4.37	4.36	4.32	4.29
27	2034	4.35	4.31	4.3	4.28	4.27	4.28	4.31	4.38	4.4	4.33	4.36	4.37	4.39	4.39	4.36	4.32	4.29	4.33	4.36	Y	4.38	4.37	4.33	4.3
28	2035	4.36	4.32	4.31	4.28	4.27	4.28	4.32	4.39	4.41	4.34	4.36	4.37	4.39	4.39	4.36	4.32	4.29	4.34	4.37		4.39	4.38	4.34	4.31
29	2036	4.37	4.33	4.32	4.29	4.28	4.29	4.33	4.4	4.42	4.35	4.37	4.38	4.4	4.4	4.37	4.33	4.3	4.35	4.38		4.4	4.39	4.35	4.32
30	2037	4.38	4.34	4.32	4.29	4.28	4.29	4.33	4.4	4.42	4.35	4.37	4.38	4.4	4.4	4.37	4.33	4.3	4.35	4.38		4.4	4.39	4.35	4.32

Term	Year	11/28	11/29	11/30	12/3	12/4	12/5	12/6	12/7	12/10	12/11	12/12	12/13	12/14	12/17	12/18	12/19	12/20	12/21	12/24	12/25	12/26	12/27	12/28	12/31
1	2008	3.27	3.22	3.22	3.2	3.07	3.02	2.99	2.99	2.99	2.95	2.92	2.87	2.87	2.87	2.87	2.87	2.87	2.92	2.92	H	2.92	2.92	2.92	2.92
2	2009	3.26	3.22	3.22	3.2	3.12	3.11	3.09	3.09	3.09	3.05	3.03	3.01	3.01	3.02	3.02	3.02	3.01	3.05	3.05	O	3.05	3.04	3.02	3.02
3	2010	3.23	3.22	3.22	3.2	3.16	3.14	3.13	3.15	3.16	3.12	3.12	3.12	3.14	3.15	3.13	3.12	3.11	3.15	3.16	L	3.17	3.15	3.13	3.12
4	2011	3.29	3.28	3.28	3.25	3.22	3.2	3.19	3.21	3.22	3.18	3.2	3.21	3.23	3.23	3.21	3.2	3.19	3.23	3.25	I	3.26	3.24	3.22	3.21
5	2012	3.36	3.35	3.35	3.32	3.29	3.27	3.27	3.29	3.3	3.26	3.29	3.3	3.32	3.32	3.29	3.28	3.27	3.31	3.33	D	3.34	3.32	3.3	3.29
6	2013	3.42	3.41	3.41	3.38	3.35	3.33	3.35	3.38	3.4	3.35	3.37	3.39	3.41	3.41	3.37	3.36	3.35	3.39	3.41	A	3.42	3.4	3.37	3.36
7	2014	3.5	3.49	3.49	3.47	3.43	3.41	3.43	3.46	3.48	3.43	3.46	3.47	3.5	3.5	3.47	3.45	3.44	3.48	3.5	Y	3.52	3.5	3.47	3.45
8	2015	3.58	3.56	3.56	3.54	3.5	3.49	3.52	3.55	3.57	3.52	3.55	3.56	3.59	3.59	3.56	3.54	3.53	3.57	3.59		3.61	3.59	3.56	3.54
9	2016	3.66	3.64	3.64	3.62	3.58	3.58	3.61	3.65	3.67	3.62	3.65	3.66	3.69	3.69	3.66	3.64	3.63	3.67	3.69		3.71	3.69	3.66	3.64
10	2017	3.74	3.72	3.72	3.7	3.66	3.66	3.7	3.74	3.76	3.71	3.74	3.75	3.77	3.77	3.74	3.72	3.71	3.75	3.77		3.79	3.77	3.74	3.72
11	2018	3.83	3.81	3.81	3.79	3.75	3.75	3.79	3.83	3.85	3.8	3.83	3.85	3.87	3.87	3.84	3.81	3.78	3.82	3.84	H	3.86	3.84	3.81	3.79
12	2019	3.92	3.89	3.89	3.87	3.83	3.83	3.87	3.92	3.94	3.89	3.92	3.94	3.96	3.96	3.92	3.89	3.84	3.88	3.9	O	3.93	3.91	3.88	3.85
13	2020	3.98	3.95	3.95	3.94	3.9	3.9	3.94	4	4.02	3.97	4	4.02	4.04	4.04	4	3.96	3.91	3.95	3.97	L	4	3.98	3.94	3.91
14	2021	4.04	4.01	4.01	4	3.97	3.97	4.01	4.07	4.09	4.04	4.07	4.08	4.1	4.1	4.06	4.02	3.97	4.01	4.03	I	4.06	4.04	4	3.97
15	2022	4.1	4.07	4.07	4.06	4.03	4.03	4.07	4.13	4.15	4.1	4.13	4.14	4.16	4.16	4.12	4.08	4.03	4.07	4.09	D	4.12	4.1	4.06	4.03
16	2023	4.16	4.13	4.13	4.12	4.09	4.09	4.13	4.19	4.21	4.16	4.19	4.2	4.22	4.22	4.18	4.14	4.09	4.13	4.15	A	4.18	4.16	4.12	4.09
17	2024	4.22	4.19	4.19	4.18	4.15	4.15	4.18	4.24	4.27	4.21	4.24	4.25	4.27	4.27	4.24	4.2	4.15	4.19	4.21	Y	4.24	4.22	4.18	4.15
18	2025	4.26	4.23	4.23	4.22	4.19	4.19	4.22	4.28	4.31	4.25	4.28	4.29	4.31	4.31	4.28	4.24	4.19	4.23	4.25		4.28	4.26	4.22	4.19
19	2026	4.3	4.27	4.27	4.26	4.23	4.23	4.26	4.32	4.35	4.29	4.32	4.33	4.35	4.35	4.32	4.28	4.23	4.27	4.29		4.32	4.3	4.26	4.23
20	2027	4.33	4.3	4.3	4.29	4.26	4.26	4.29	4.35	4.38	4.32	4.35	4.36	4.38	4.38	4.35	4.31	4.26	4.3	4.32		4.35	4.33	4.29	4.26
21	2028	4.35	4.32	4.32	4.31	4.28	4.29	4.32	4.38	4.41	4.35	4.38	4.39	4.41	4.41	4.38	4.34	4.29	4.33	4.35	H	4.38	4.36	4.32	4.29
22	2029	4.37	4.34	4.34	4.33	4.3	4.31	4.34	4.4	4.43	4.37	4.4	4.41	4.43	4.43	4.4	4.36	4.32	4.36	4.38	O	4.41	4.39	4.35	4.32
23	2030	4.39	4.36	4.35	4.33	4.31	4.32	4.35	4.41	4.44	4.38	4.41	4.42	4.44	4.44	4.41	4.37	4.34	4.38	4.4	L	4.43	4.41	4.37	4.34
24	2031	4.4	4.37	4.36	4.34	4.32	4.33	4.36	4.43	4.46	4.39	4.42	4.43	4.45	4.45	4.42	4.38	4.35	4.39	4.41	I	4.44	4.43	4.39	4.36
25	2032	4.42	4.38	4.37	4.35	4.33	4.34	4.37	4.44	4.47	4.4	4.43	4.44	4.46	4.46	4.43	4.39	4.36	4.4	4.42	D	4.45	4.44	4.4	4.37
26	2033	4.43	4.39	4.38	4.36	4.34	4.35	4.38	4.45	4.48	4.41	4.44	4.45	4.47	4.47	4.44	4.4	4.37	4.41	4.43	A	4.46	4.45	4.41	4.38
27	2034	4.44	4.4	4.39	4.36	4.35	4.36	4.39	4.46	4.49	4.42	4.45	4.46	4.48	4.48	4.45	4.41	4.38	4.42	4.44	Y	4.47	4.46	4.42	4.39
28	2035	4.45	4.41	4.39	4.36	4.35	4.36	4.4	4.47	4.5	4.43	4.45	4.46	4.48	4.48	4.45	4.41	4.38	4.43	4.45		4.48	4.47	4.43	4.4
29	2036	4.46	4.42	4.4	4.36	4.35	4.36	4.4	4.48	4.51	4.44	4.46	4.47	4.49	4.49	4.46	4.42	4.39	4.44	4.46		4.49	4.48	4.44	4.41
30	2037	4.47	4.43	4.4	4.36	4.35	4.36	4.4	4.48	4.51	4.44	4.46	4.47	4.49	4.49	4.46	4.42	4.39	4.44	4.46		4.49	4.48	4.44	4.41

MMD Scales for JEA

Term	Year	AAA MMD Scales																								
		10/31	11/1	11/2	11/3	11/6	11/7	11/8	11/9	11/10	11/13	11/14	11/15	11/16	11/17	11/20	11/21	11/22	11/24	11/27	11/28	11/29	11/30	12/1	12/4	12/5	12/6	12/7
1	2007	3.48	3.48	3.48	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.5	3.50	3.48	3.45	3.45	3.45	3.45	3.48
2	2008	3.47	3.46	3.46	3.51	3.51	3.50	3.50	3.50	3.50	3.50	3.48	3.50	3.51	3.49	3.49	3.49	3.49	3.49	3.47	3.47	3.45	3.42	3.42	3.42	3.42	3.42	3.45
3	2009	3.46	3.45	3.45	3.51	3.51	3.49	3.49	3.49	3.49	3.50	3.48	3.50	3.51	3.49	3.49	3.48	3.48	3.48	3.48	3.46	3.46	3.43	3.40	3.40	3.40	3.40	3.45
4	2010	3.45	3.44	3.45	3.51	3.51	3.49	3.49	3.49	3.49	3.50	3.48	3.50	3.51	3.49	3.49	3.48	3.48	3.48	3.48	3.46	3.46	3.43	3.40	3.40	3.40	3.40	3.47
5	2011	3.45	3.43	3.44	3.51	3.51	3.49	3.49	3.49	3.49	3.50	3.48	3.50	3.52	3.50	3.50	3.49	3.49	3.48	3.48	3.46	3.46	3.43	3.40	3.40	3.40	3.40	3.48
6	2012	3.48	3.46	3.47	3.54	3.54	3.52	3.52	3.52	3.51	3.52	3.49	3.51	3.53	3.51	3.51	3.50	3.50	3.49	3.49	3.47	3.47	3.44	3.41	3.41	3.41	3.41	3.50
7	2013	3.52	3.49	3.50	3.58	3.58	3.55	3.54	3.54	3.53	3.54	3.51	3.53	3.55	3.53	3.53	3.52	3.52	3.51	3.51	3.48	3.48	3.45	3.42	3.42	3.42	3.43	3.54
8	2014	3.55	3.52	3.54	3.62	3.62	3.59	3.58	3.58	3.56	3.57	3.54	3.56	3.58	3.56	3.56	3.55	3.55	3.54	3.54	3.51	3.51	3.48	3.45	3.45	3.45	3.47	3.58
9	2015	3.59	3.56	3.58	3.66	3.66	3.63	3.62	3.62	3.60	3.61	3.58	3.60	3.62	3.60	3.60	3.59	3.59	3.58	3.58	3.55	3.55	3.52	3.49	3.49	3.49	3.51	3.63
10	2016	3.64	3.60	3.62	3.70	3.70	3.67	3.66	3.66	3.64	3.65	3.62	3.64	3.66	3.64	3.64	3.63	3.63	3.62	3.62	3.59	3.59	3.56	3.53	3.53	3.53	3.55	3.67
11	2017	3.69	3.65	3.67	3.75	3.75	3.72	3.71	3.71	3.69	3.70	3.67	3.69	3.71	3.69	3.69	3.68	3.68	3.67	3.67	3.63	3.63	3.60	3.57	3.57	3.57	3.59	3.72
12	2018	3.73	3.69	3.72	3.80	3.80	3.77	3.76	3.76	3.74	3.75	3.72	3.74	3.76	3.74	3.74	3.73	3.73	3.72	3.72	3.68	3.68	3.64	3.61	3.61	3.61	3.63	3.76
13	2019	3.77	3.73	3.76	3.85	3.84	3.81	3.80	3.80	3.78	3.79	3.76	3.78	3.80	3.78	3.78	3.77	3.77	3.76	3.76	3.72	3.72	3.68	3.65	3.65	3.65	3.67	3.80
14	2020	3.81	3.77	3.80	3.89	3.88	3.84	3.83	3.83	3.81	3.82	3.79	3.81	3.83	3.81	3.81	3.80	3.80	3.79	3.79	3.75	3.75	3.71	3.68	3.68	3.68	3.70	3.83
15	2021	3.84	3.80	3.83	3.92	3.91	3.87	3.86	3.86	3.84	3.85	3.82	3.84	3.86	3.84	3.84	3.83	3.83	3.82	3.82	3.78	3.78	3.74	3.71	3.71	3.71	3.73	3.86
16	2022	3.87	3.83	3.86	3.95	3.94	3.90	3.89	3.89	3.87	3.88	3.85	3.87	3.89	3.87	3.87	3.86	3.85	3.84	3.84	3.8	3.80	3.76	3.73	3.73	3.73	3.75	3.88
17	2023	3.90	3.86	3.89	3.98	3.97	3.93	3.92	3.92	3.89	3.90	3.87	3.89	3.91	3.89	3.89	3.88	3.87	3.86	3.86	3.82	3.82	3.78	3.75	3.75	3.75	3.77	3.90
18	2024	3.92	3.88	3.91	4.00	3.99	3.95	3.94	3.94	3.91	3.92	3.89	3.91	3.93	3.91	3.91	3.90	3.89	3.88	3.88	3.84	3.84	3.80	3.77	3.77	3.77	3.79	3.92
19	2025	3.94	3.90	3.93	4.02	4.01	3.97	3.96	3.96	3.93	3.94	3.91	3.93	3.95	3.93	3.93	3.92	3.91	3.90	3.90	3.86	3.86	3.82	3.79	3.79	3.79	3.81	3.93
20	2026	3.96	3.92	3.95	4.04	4.03	3.99	3.98	3.98	3.95	3.96	3.93	3.95	3.97	3.94	3.94	3.93	3.92	3.91	3.91	3.88	3.87	3.83	3.81	3.81	3.81	3.83	3.94
21	2027	3.98	3.94	3.97	4.05	4.05	4.00	3.99	3.99	3.96	3.97	3.94	3.96	3.98	3.95	3.95	3.94	3.93	3.92	3.92	3.89	3.88	3.84	3.82	3.82	3.83	3.85	3.95
22	2028	4.00	3.95	3.98	4.06	4.06	4.01	4.00	4.00	3.97	3.98	3.95	3.97	3.99	3.96	3.96	3.95	3.94	3.93	3.93	3.9	3.89	3.85	3.83	3.83	3.84	3.86	3.96
23	2029	4.01	3.96	3.99	4.07	4.07	4.02	4.01	4.01	3.98	3.99	3.96	3.98	4.00	3.97	3.97	3.96	3.95	3.94	3.94	3.91	3.90	3.86	3.84	3.84	3.85	3.87	3.97
24	2030	4.02	3.97	4.00	4.08	4.08	4.03	4.02	4.02	3.99	4.00	3.97	3.99	4.01	3.98	3.98	3.97	3.96	3.95	3.95	3.92	3.91	3.87	3.85	3.85	3.86	3.88	3.97
25	2031	4.03	3.98	4.01	4.09	4.09	4.04	4.03	4.03	4.00	4.01	3.98	4.00	4.02	3.99	3.99	3.98	3.97	3.96	3.96	3.93	3.92	3.88	3.86	3.86	3.87	3.89	3.98
26	2032	4.04	3.99	4.02	4.10	4.10	4.05	4.04	4.04	4.01	4.02	3.99	4.01	4.03	4.00	4.00	3.99	3.98	3.97	3.97	3.94	3.93	3.89	3.87	3.87	3.88	3.90	3.99
27	2033	4.05	4.00	4.03	4.11	4.11	4.06	4.05	4.05	4.02	4.03	4.00	4.02	4.04	4.01	4.01	4.00	3.99	3.98	3.98	3.95	3.94	3.90	3.88	3.88	3.89	3.91	4.00
28	2034	4.06	4.01	4.04	4.12	4.12	4.07	4.06	4.06	4.02	4.03	4.00	4.02	4.04	4.01	4.01	4.00	3.99	3.98	3.98	3.95	3.94	3.90	3.88	3.88	3.89	3.91	4.00
29	2035	4.07	4.02	4.05	4.13	4.13	4.08	4.07	4.07	4.03	4.04	4.01	4.03	4.05	4.02	4.02	4.01	4.00	3.99	3.99	3.96	3.95	3.91	3.89	3.89	3.90	3.92	4.01
30	2036	4.07	4.02	4.05	4.13	4.13	4.08	4.07	4.07	4.03	4.04	4.01	4.03	4.05	4.02	4.02	4.01	4.00	3.99	3.99	3.96	3.95	3.91	3.89	3.89	3.90	3.92	4.01

Term	Year	AAA MMD Scales																								
		10/31	11/1	11/2	11/3	11/6	11/7	11/8	11/9	11/10	11/13	11/14	11/15	11/16	11/17	11/20	11/21	11/22	11/24	11/27	11/28	11/29	11/30	12/1	12/4	12/5	12/6	12/7
1	2007	3.50	3.49	3.49	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.51	3.48	3.48	3.48	3.48	3.45
2	2008	3.50	3.49	3.49	3.54	3.54	3.53	3.53	3.53	3.53	3.53	3.51	3.53	3.54	3.52	3.52	3.52	3.52	3.52	3.52	3.50	3.50	3.48	3.45	3.45	3.45	3.45	3.42
3	2009	3.51	3.50	3.50	3.56	3.56	3.54	3.54	3.54	3.53	3.54	3.52	3.54	3.56	3.55	3.55	3.54	3.54	3.54	3.54	3.52	3.52	3.49	3.45	3.45	3.45	3.45	3.40
4	2010	3.52	3.51	3.52	3.58	3.58	3.56	3.56	3.56	3.55	3.57	3.55	3.57	3.59	3.57	3.57	3.56	3.56	3.56	3.56	3.54	3.54	3.51	3.47	3.47	3.47	3.47	3.40
5	2011	3.54	3.52	3.53	3.60	3.60	3.58	3.58	3.58	3.57	3.59	3.57	3.59	3.61	3.59	3.59	3.58	3.58	3.57	3.57	3.55	3.55	3.52	3.48	3.48	3.48	3.48	3.40
6	2012	3.57	3.54	3.56	3.63	3.63	3.61	3.61	3.61	3.60	3.61	3.58	3.61	3.63	3.61	3.61	3.60	3.60	3.59	3.59	3.57	3.57	3.54	3.50	3.50	3.50	3.50	3.41
7	2013	3.61	3.58	3.60	3.68	3.68	3.65	3.63	3.63	3.62	3.63	3.60	3.63	3.65	3.63	3.63	3.62	3.62	3.61	3.61	3.58	3.58	3.55	3.52	3.52	3.52	3.53	3.44
8	2014	3.64	3.61	3.64	3.72	3.72	3.69	3.67	3.67	3.65	3.66	3.63	3.66	3.68	3.66	3.66	3.65	3.65	3.64	3.64	3.61	3.61	3.58	3.55	3.55	3.55	3.57	3.48
9	2015	3.68	3.65	3.68	3.76	3.76	3.73	3.71	3.71	3.69	3.71	3.68	3.70	3.73	3.70	3.70	3.69	3.69	3.68	3.68	3.65	3.65	3.62	3.59	3.59	3.59	3.61	3.52
10	2016	3.73	3.69	3.72	3.80	3.80	3.77	3.75	3.75	3.73	3.75	3.72	3.74	3.77	3.74	3.74	3.73	3.73	3.72	3.72	3.69	3.69	3.66	3.63	3.63	3.63	3.65	3.56
11	2017	3.78	3.74	3.77	3.85	3.85	3.82	3.80	3.80	3.78	3.80	3.77	3.79	3.82	3.79	3.79	3.78	3.78	3.77	3.77	3.73	3.73	3.70	3.67	3.67	3.67	3.70	3.61
12	2018	3.82	3.78	3.82	3.90	3.90	3.87	3.85	3.85	3.83	3.85	3.82	3.84	3.87	3.84	3.84	3.83	3.83	3.82	3.82	3.78	3.78	3.74	3.71	3.71	3.71	3.74	3.65
13	2019	3.86	3.82	3.86	3.95	3.94	3.91	3.89	3.89	3.87	3.89	3.86	3.88	3.91	3.88	3.88	3.87	3.87	3.86	3.86	3.82	3.82	3.78	3.75	3.75	3.75	3.78	3.69
14	2020	3.90	3.86	3.90	3.99	3.98	3.94	3.92	3.92	3.90	3.92	3.89	3.91	3.94	3.91	3.91	3.90	3.90	3.89	3.89	3.85	3.85	3.81	3.78	3.78	3.78	3.81	3.72
15	2021	3.93	3.89	3.93	4.02	4.01	3.97	3.95	3.95	3.93	3.95	3.92	3.94	3.97	3.94	3.94	3.93	3.93	3.92	3.92	3.88	3.88	3.84	3.81	3.81	3.81	3.84	3.75
16	2022	3.96	3.92	3.96	4.05	4.04	4.00	3.98	3.98	3.96	3.97	3.94	3.97	4.00	3.97	3.97	3.96	3.95	3.94	3.94	3.90	3.90	3.86	3.83	3.83	3.83	3.86	3.77
17	2023	3.99	3.95	3.98	4.08	4.07	4.03	4.01	4.01	3.98	3.99	3.96	3.99	4.02	3.99	3.99	3.98	3.97	3.96	3.96	3.92	3.92	3.88	3.85	3.85	3.85	3.88	3.79
18	2024	4.01	3.97	4.00	4.10	4.09	4.05	4.03	4.03	4.00	4.01	3.98	4.01	4.04	4.01	4.01	4.00	3.99	3.98	3.98	3.94	3.94	3.90	3.87	3.87	3.87	3.90	3.81
19	2025	4.03	3.99	4.02	4.12	4.11	4.07	4.05	4.05	4.02	4.03	4.00	4.03	4.06	4.03	4.03	4.02	4.01	4.00	4.00	3.96	3.96	3.91	3.88	3.88	3.88	3.91	3.83
20	2026	4.05	4.01	4.04	4.14	4.13	4.09	4.07	4.07	4.04	4.05	4.02	4.05	4.08	4.04	4.04	4.03	4.02	4.01	4.01	3.98	3.97	3.92	3.90	3.90	3.90	3.92	3.85
21	2027	4.07	4.03	4.06	4.15	4.15	4.10	4.08	4.08	4.05	4.06	4.03	4.06	4.09	4.05	4.05	4.04	4.03	4.02	4.02	3.99	3.98	3.93	3.91	3.91	3.91	3.93	3.86
22	2028	4.09	4.04	4.07	4.16	4.16	4.11	4.09	4.09	4.06	4.07	4.04	4.07	4.10	4.06	4.06	4.05	4.04	4.03	4.03	4.00	3.99	3.94	3.92	3.92	3.92	3.94	3.87
23	2029	4.10	4.05	4.08	4.17	4.17	4.12	4.10	4.10	4.07	4.08	4.05	4.08	4.11	4.07	4.07	4.06	4.05	4.04	4.04	4.01	4.00	3.95	3.93	3.93	3.93	3.95	3.88
24	2030	4.11	4.06	4.09	4.18	4.18	4.13	4.11	4.11	4.08	4.09	4.06	4.08	4.11	4.08	4.08	4.07	4.06	4.05	4.05	4.02	4.01	3.96	3.94	3.94	3.94	3.96	3.89
25	2031	4.12	4.07	4.10	4.19	4.19	4.14	4.12	4.12	4.09	4.10	4.07	4.09	4.12	4.09	4.09	4.08	4.07	4.06	4.06	4.03	4.02	3.97	3.95	3.95	3.95	3.97	3.90
26	2032	4.13	4.08	4.11	4.20	4.20	4.15	4.13	4.13	4.10	4.11	4.08	4.10	4.13	4.10	4.10	4.09	4.08	4.07	4.07	4.04	4.02	3.97	3.95	3.95	3.95	3.98	3.91
27	2033	4.14	4.09	4.12	4.21	4.21	4.16	4.14	4.14	4.10	4.11	4.08	4.10	4.13	4.10	4.10	4.09	4.08	4.07	4.07	4.04	4.03	3.98	3.96	3.96	3.96	3.99	3.92
28	2034	4.15	4.10	4.13	4.21	4.21	4.16	4.14	4.14	4.10	4.11	4.08	4.10	4.13	4.10	4.10	4.09	4.08	4.07	4.07	4.04	4.03	3.98	3.96	3.96	3.96	3.99	3.92
29	2035	4.16	4.11	4.14	4.22	4.22	4.17	4.15	4.15	4.11	4.12	4.09	4.11	4.14	4.11	4.11	4.10	4.09	4.08	4.08	4.05	4.04	3.99	3.97	3.97	3.97	4.00	3.93
30	2036	4.16	4.11	4.14	4.22	4.22	4.17	4.15	4.15	4.11	4.12	4.09	4.11	4.14	4.11	4.11	4.10	4.09	4.08	4.08	4.05	4.04	3.99	3.97	3.97	3.97	4.00	3.93

JEA-POD3-00000518 Hearing Exhibit - 00000518

MMD Scale

Term	Year	12/8	12/11	12/12	12/13	12/14	12/15	12/18	12/19	12/20	12/21	12/22	12/26	12/27	12/28
1	2007	3.45	3.45	3.45	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.50
2	2008	3.45	3.45	3.44	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.49	3.52
3	2009	3.43	3.44	3.43	3.48	3.49	3.49	3.49	3.49	3.50	3.50	3.50	3.50	3.52	3.54
4	2010	3.43	3.43	3.42	3.46	3.48	3.48	3.48	3.48	3.49	3.49	3.49	3.49	3.51	3.54
5	2011	3.43	3.43	3.42	3.46	3.48	3.48	3.48	3.48	3.49	3.49	3.49	3.49	3.51	3.54
6	2012	3.45	3.45	3.44	3.48	3.50	3.50	3.50	3.50	3.51	3.51	3.51	3.51	3.53	3.55
7	2013	3.48	3.48	3.47	3.51	3.53	3.53	3.53	3.53	3.54	3.53	3.54	3.54	3.56	3.58
8	2014	3.52	3.51	3.50	3.55	3.57	3.57	3.57	3.57	3.57	3.56	3.57	3.57	3.59	3.61
9	2015	3.56	3.55	3.53	3.58	3.60	3.60	3.60	3.60	3.60	3.59	3.60	3.60	3.62	3.64
10	2016	3.60	3.59	3.57	3.62	3.64	3.64	3.64	3.64	3.64	3.63	3.64	3.64	3.66	3.68
11	2017	3.65	3.64	3.62	3.67	3.69	3.69	3.69	3.69	3.69	3.68	3.69	3.69	3.71	3.73
12	2018	3.69	3.68	3.66	3.71	3.73	3.73	3.73	3.73	3.73	3.72	3.73	3.73	3.75	3.77
13	2019	3.73	3.72	3.70	3.75	3.77	3.77	3.77	3.77	3.77	3.76	3.77	3.77	3.79	3.81
14	2020	3.76	3.75	3.73	3.78	3.80	3.80	3.80	3.80	3.80	3.79	3.80	3.80	3.82	3.84
15	2021	3.79	3.78	3.76	3.81	3.83	3.83	3.83	3.83	3.83	3.82	3.83	3.83	3.85	3.87
16	2022	3.81	3.80	3.78	3.83	3.85	3.85	3.85	3.85	3.85	3.84	3.85	3.85	3.87	3.89
17	2023	3.83	3.82	3.80	3.85	3.87	3.87	3.87	3.87	3.87	3.86	3.87	3.87	3.89	3.91
18	2024	3.85	3.84	3.82	3.87	3.89	3.89	3.89	3.89	3.89	3.88	3.89	3.89	3.91	3.93
19	2025	3.87	3.86	3.84	3.89	3.91	3.91	3.91	3.91	3.91	3.90	3.91	3.91	3.93	3.95
20	2026	3.89	3.88	3.86	3.91	3.93	3.93	3.93	3.93	3.93	3.92	3.93	3.93	3.95	3.97
21	2027	3.90	3.89	3.87	3.92	3.94	3.94	3.94	3.95	3.95	3.94	3.95	3.95	3.97	3.99
22	2028	3.91	3.90	3.88	3.93	3.95	3.95	3.95	3.96	3.96	3.95	3.96	3.96	3.98	4.00
23	2029	3.92	3.91	3.89	3.94	3.96	3.96	3.96	3.97	3.97	3.96	3.97	3.97	3.99	4.01
24	2030	3.93	3.92	3.90	3.95	3.97	3.97	3.97	3.98	3.98	3.97	3.98	3.98	4.00	4.02
25	2031	3.94	3.93	3.91	3.96	3.98	3.98	3.98	3.99	3.99	3.98	3.99	3.99	4.01	4.03
26	2032	3.95	3.94	3.92	3.97	3.99	3.99	3.99	4.00	4.00	3.99	4.00	4.00	4.02	4.04
27	2033	3.96	3.95	3.93	3.98	4.00	4.00	4.00	4.01	4.01	4.00	4.01	4.01	4.03	4.05
28	2034	3.96	3.95	3.94	3.99	4.01	4.01	4.01	4.02	4.02	4.01	4.02	4.02	4.04	4.06
29	2035	3.97	3.96	3.95	4.00	4.02	4.02	4.02	4.03	4.03	4.02	4.03	4.03	4.05	4.07
30	2036	3.97	3.96	3.95	4.00	4.02	4.02	4.02	4.03	4.03	4.02	4.03	4.03	4.05	4.07

Term	Year	12/8	12/11	12/12	12/13	12/14	12/15	12/18	12/19	12/20	12/21	12/22	12/26	12/27	12/28
1	2007	3.48	3.48	3.48	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.53
2	2008	3.49	3.49	3.48	3.52	3.52	3.52	3.52	3.52	3.53	3.53	3.53	3.53	3.54	3.57
3	2009	3.50	3.51	3.50	3.55	3.57	3.57	3.57	3.57	3.58	3.58	3.58	3.58	3.60	3.62
4	2010	3.51	3.51	3.50	3.54	3.57	3.57	3.57	3.57	3.58	3.58	3.58	3.58	3.60	3.62
5	2011	3.52	3.52	3.51	3.55	3.58	3.58	3.58	3.58	3.59	3.59	3.59	3.59	3.61	3.63
6	2012	3.54	3.54	3.53	3.57	3.60	3.60	3.60	3.60	3.61	3.61	3.61	3.61	3.63	3.65
7	2013	3.58	3.58	3.57	3.61	3.63	3.63	3.63	3.63	3.64	3.63	3.64	3.64	3.66	3.68
8	2014	3.62	3.61	3.60	3.65	3.67	3.67	3.67	3.67	3.67	3.66	3.67	3.67	3.69	3.71
9	2015	3.67	3.66	3.64	3.69	3.71	3.71	3.71	3.71	3.71	3.70	3.71	3.71	3.73	3.75
10	2016	3.71	3.70	3.68	3.73	3.75	3.75	3.75	3.75	3.75	3.74	3.75	3.75	3.77	3.79
11	2017	3.76	3.75	3.73	3.78	3.80	3.80	3.80	3.80	3.80	3.79	3.80	3.80	3.82	3.84
12	2018	3.80	3.79	3.77	3.82	3.84	3.84	3.84	3.84	3.84	3.83	3.84	3.84	3.86	3.88
13	2019	3.84	3.83	3.81	3.86	3.88	3.88	3.88	3.88	3.88	3.87	3.88	3.88	3.90	3.92
14	2020	3.87	3.86	3.84	3.89	3.91	3.91	3.91	3.91	3.91	3.90	3.91	3.91	3.93	3.95
15	2021	3.90	3.89	3.87	3.92	3.94	3.94	3.94	3.94	3.94	3.93	3.94	3.94	3.96	3.98
16	2022	3.92	3.91	3.89	3.94	3.96	3.96	3.96	3.96	3.96	3.95	3.96	3.96	3.98	4.00
17	2023	3.94	3.93	3.91	3.96	3.98	3.98	3.98	3.98	3.98	3.97	3.98	3.98	4.00	4.02
18	2024	3.96	3.95	3.93	3.98	4.00	4.00	4.00	4.00	4.00	3.99	4.00	4.00	4.02	4.04
19	2025	3.97	3.96	3.94	3.99	4.01	4.01	4.01	4.02	4.02	4.01	4.02	4.02	4.04	4.06
20	2026	3.98	3.97	3.95	4.00	4.02	4.02	4.02	4.03	4.03	4.02	4.03	4.03	4.05	4.07
21	2027	3.99	3.98	3.96	4.01	4.03	4.03	4.03	4.04	4.04	4.03	4.04	4.04	4.06	4.08
22	2028	4.00	3.99	3.97	4.02	4.04	4.04	4.04	4.05	4.05	4.04	4.05	4.05	4.07	4.09
23	2029	4.01	4.00	3.98	4.03	4.05	4.05	4.05	4.06	4.06	4.05	4.06	4.06	4.08	4.10
24	2030	4.01	4.00	3.98	4.04	4.06	4.06	4.06	4.07	4.07	4.06	4.07	4.07	4.09	4.11
25	2031	4.02	4.01	3.99	4.05	4.07	4.07	4.07	4.08	4.08	4.07	4.08	4.08	4.10	4.12
26	2032	4.03	4.02	4.00	4.06	4.08	4.08	4.08	4.09	4.09	4.08	4.09	4.09	4.11	4.13
27	2033	4.04	4.03	4.01	4.07	4.09	4.09	4.09	4.10	4.10	4.09	4.10	4.10	4.12	4.14
28	2034	4.04	4.03	4.02	4.08	4.10	4.10	4.10	4.11	4.11	4.10	4.11	4.11	4.13	4.15
29	2035	4.05	4.04	4.03	4.09	4.11	4.11	4.11	4.12	4.12	4.11	4.12	4.12	4.14	4.16
30	2036	4.05	4.04	4.03	4.09	4.11	4.11	4.11	4.12	4.12	4.11	4.12	4.12	4.14	4.16

JEA-POD3-00027 Hearing Exhibit - 00000519

RESUME OF

Donald (Don) Gilbert, Manager, Electric System Planning

JEA

Qualifications and Experience:

Mr. Gilbert has over 30 years experience in the electric utility business including four years in Georgia Power Company's Corporate Planning, three years in JEA's Corporate Planning (transmission & generation planning), and 20 years in JEA's system operations. Don has held chair positions of the Florida Coordinating Group (FRCC) Telecommunication committee, Florida/Southern Inter-utility data exchange working group, and the technical subcommittee responsible for the implementation of the Automated Interchange Matching System. Don served on JEA's management team as a System Operation Control Systems manager from April 1998 until October 2001. Since June 2005, Don has been the Manager of JEA's Electric System Planning area responsible for Generation, Transmission, and Distribution planning activities. Since 1985, Don has been licensed to practice as a Professional Engineer in the state of Florida.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EI EXHIBIT 3
COMPANY JEA (Direct)
WITNESS Donald C. Gilbert (DCG-1)
DATE 02/12/09

Employment

History:	1982-Present	JEA
	1977-1982	Georgia Power Company
Education:	B.S.	Electrical Engineering, Georgia Institute of Technology

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 4
COMPANY JEA (Direct)
WITNESS Donald C. Gilbert (DCG-2)
DATE 02/12/09

Existing Generating Facilities

Plant Name	Unit Number	Unit Type	Fuel Type Primary	Alt.	Fuel Transport Primary	Alt.	Commercial Service (Mo/Yr)	Gen Max Nameplate (kW)	Net MW Capacity		Ownership
									Summer	Winter	
Kennedy											
	3	GT	FO2		WA	TK	7/1973	68,600	51	63	Sole
	7	GT	NG	FO2	PL	WA	6/2000	203,800	150	191	Sole
Northside											
	1	ST	PC	BIT	WA	RR	11/1966[1]	350,000	293	293	Sole
	2	ST	PC	BIT	WA	RR	3/1972[1]	350,000	293	293	Sole
	3	ST	NG	FO6	PL	WA	7/1977	563,700	524	524	Sole
	3-6	GT	FO2		WA	TK	1/1975	248,400	212	246	Sole
Brandy Branch											
	1	CT	NG	FO2	PL	TK	5/2001	203,800	150	191	Sole
	2	CT	NG	FO2	PL	TK	5/2001	203,800	150	191	Sole
	3	CT	NG	FO2	PL	TK	11/2001	203,800	150	191	Sole
	4	ST	NG	FO2	PL	TK	1/2005	268,400	201	223	Sole
Girvin Landfill	1-4	IC	LFG		PL		6/1997	1.2	1.2	1.2	Sole
St. Johns River Power Park											
	1	ST	BIT/PC		RR	WA	3/1987	679,600	501[2]	510[2]	Joint
	2	ST	BIT/PC		RR	WA	5/1988	679,600	501[2]	510[2]	Joint
Scherer	4	A	SUB	BIT	RR	RR	2/1989	846,000[4]	194[3]	194[3]	Joint
JEA System Total[4,]									**3,370**	**3,620**	

[1]Northside steam Units 1 and 2 were repowered as CFBs and returned to service in May 2002 and February 2002, respectively.
[2]Net capacity reflects JEA's 80 percent ownership of Power Park. Nameplate is original nameplate of the unit.
[3]Nameplate and net capacity reflect JEA's 23.64 percent ownership in Scherer 4.
[4]Numbers may not add up due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EI EXHIBIT 5
COMPANY SEA (Direct)
WITNESS Donald C. Gilbert (GEC-1)
DATE 02/12/09 Sections 3.0 (except 3.9) 10.0 & 19.0

3.0 Description of Existing System

This section provides details related to JEA's existing generating facilities, PPAs, power sales, planned unit retirements, spinning and operating reserve requirements, JEA's clean power portfolio, and JEA's transmission system.

3.1 JEA Structure

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. The JEA electric service area covers all of Duval County and portions of Clay and St. Johns counties within Florida. JEA's service area covers approximately 900 square miles and serves more than 400,000 customers.

JEA's generation system consists of three financially separate components: the electric system, the bulk power system SJRPP Units 1 and 2, and the bulk power system Robert W. Scherer Electric Generating Plant (Scherer Unit 4). The total summer net capacity of the electric system, SJRPP, and Scherer Unit 4 is 3,370 MW, and the total available winter net capacity is 3,620 MW.

3.2 JEA Electric System

JEA solely owns and operates three generating plants: the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), and the Brandy Branch Generating Station (Brandy Branch). In addition, JEA owns and operates methane-fueled internal combustion engine generators located at the City of Jacksonville's Girvin Road Landfill (Girvin Road). SJRPP is owned jointly by JEA and FPL; it is operated by JEA. JEA and FPL are also joint owners of Unit 4 at Georgia Power Company's coal fired Robert W. Scherer Plant (Scherer), which is located in Macon, Georgia. JEA ownership interest in SJRPP and Scherer are structured as separate JEA bulk power supply systems. Details of the existing facilities are described in the following subsections and are summarized in Table 3-1.

In addition to the units presented in Table 3-1, JEA is planning to add two 7FA simple cycle combustion turbine units at the new Greenland Energy Center site in Jacksonville, Florida. These new combustion turbine units are expected to be in commercial operation by the summer of 2010 and are proposed to be converted to combined cycle in 2012.

Table 3-1
Existing Generating Facilities

Plant Name	Unit Number	Unit Type	Fuel Type Primary	Alt.	Fuel Transport Primary	Alt.	Commercial Service (Mo/Yr)	Gen Max Nameplate (kW)	Net MW Capacity		Ownership
									Summer	Winter	
Kennedy											
	3	GT	FO2		WA	TK	7/1973	68,600	51	63	Sole
	7	GT	NG	FO2	PL	WA	6/2000	203,800	150	191	Sole
Northside											
	1	ST	PC	BIT	WA	RR	11/1966[1]	350,000	293	293	Sole
	2	ST	PC	BIT	WA	RR	3/1972[1]	350,000	293	293	Sole
	3	ST	NG	FO6	PL	WA	7/1977	563,700	524	524	Sole
	3-6	GT	FO2		WA	TK	1/1975	248,400	212	246	Sole
Brandy Branch											
	1	CT	NG	FO2	PL	TK	5/2001	203,800	150	191	Sole
	2	CT	NG	FO2	PL	TK	5/2001	203,800	150	191	Sole
	3	CT	NG	FO2	PL	TK	11/2001	203,800	150	191	Sole
	4	ST	NG	FO2	PL	TK	1/2005	268,400	201	223	Sole
Girvin Landfill	1-4	IC	LFG		PL		6/1997	1.2	1.2	1.2	Sole
St. Johns River Power Park											
	1	ST	BIT/PC		RR	WA	3/1987	679,600	501[2]	510[2]	Joint
	2	ST	BIT/PC		RR	WA	5/1988	679,600	501[2]	510[2]	Joint
Scherer	4	A	SUB	BIT	RR	RR	2/1989	846,000[4]	194[3]	194[3]	Joint
JEA System Total[4,]									**3,370**	**3,620**	

[1]Northside steam Units 1 and 2 were repowered as CFBs and returned to service in May 2002 and February 2002, respectively.
[2]Net capacity reflects JEA's 80 percent ownership of Power Park. Nameplate is original nameplate of the unit.
[3]Nameplate and net capacity reflect JEA's 23.64 percent ownership in Scherer 4.
[4]Numbers may not add up due to rounding.

3.2.1 Kennedy Generating Station

The Kennedy Generating Station is located in JEA's urban load center and is interconnected to the 69 kV transmission system. Kennedy Generating Station consists of a simple cycle General Electric (GE) 7FA dual fuel (gas/oil) capable combustion turbine generator (CTG) unit (Kennedy CT 7) that was placed in commercial operation in June 2000, and one oil fueled CTG (Kennedy CT 3) that was placed in commercial operation in the summer of 1973. The total summer net capacity at the Kennedy Generating Station is 201 MW, and the total winter net capacity is 254 MW.

3.2.2 Northside Generating Station

The Northside Generating Station is located in JEA's north district load center, just north of the west-to-east portion of the St. Johns River. The total summer net capacity of Northside Generating Station is 1,322 MW, and the total winter net capacity is 1,355 MW. Northside Generating Station consists of two petroleum coke (petcoke) and coal fired circulating fluidized bed (CFB) steam turbine generator (STG) units (Northside steam Units 1 and 2), one dual fuel (gas/oil) STG unit (Northside steam Unit 3), and four oil fired CTG units (Northside CTs 3, 4, 5, and 6).

Northside steam Unit 1 was originally placed in service in November 1966 as an oil fired STG. The steam unit was repowered as a CFB and returned to service in May 2002, and has a net 293 MW capacity for summer and winter. Northside steam Unit 2 was originally placed in service in March 1972 as an oil fired STG. The steam unit was repowered as a CFB and returned to service in February 2002, and has a net 293 MW capacity for summer and winter. Limestone is blended with petcoke and coal for sulfur dioxide (SO_2) removal for Northside steam Units 1 and 2.

Northside steam Unit 3 was originally placed in service in July 1977 and has a net 524 MW capacity for summer and winter. Northside steam Unit 3 is a unit capable of burning residual oil (1.8 percent sulfur) and natural gas. Northside Unit 3 has received approximately 1,500 kilowatts (kW) of landfill gas on an as-available basis by pipeline from the closed City of Jacksonville North Landfill since 1999.

Northside CTs 3 through 6 were placed in service in late 1974 through early 1975, as distillate-fired CTGs. The total summer net capacity of these four CT units is 212 MW, and the total winter net capacity is 246 MW.

Northside steam Unit 1 and CTs 3 through 6 are interconnected to the 138 kV transmission system. Northside steam Unit 2 and steam Unit 3 are interconnected to the 230 kV transmission system.

3.2.3 Brandy Branch Generating Station

The Brandy Branch Generating Station is located in JEA's northwest district load center. Brandy Branch consists of three dual fuel (gas/oil) GE 7FA CTG units (Brandy Branch CT 1, 2, and 3) and one STG unit (Brandy Branch STG 4); CTs 1 and 2 were placed in commercial operation in May 2001, and CT 3 was placed in commercial operation in November 2001. Brandy Branch is interconnected with the 230 kV system.

Heat recovery steam generators (HRSGs) were added to Brandy Branch CTs 2 and 3 to provide heat input for Brandy Branch steam Unit 4, and the CTs and steam turbine currently operate in combined cycle configuration. The CTs can be operated with steam bypass to the condenser. An HRSG was installed on each CT exhaust, which recovers energy to produce the steam that powers the STG. The steam turbine, STG 4, has a summer net capacity of 201 MW, including supplemental duct firing capacity. STG 4's winter net capacity is 223 MW, which includes supplemental duct firing capacity. With supplemental duct firing, the overall combined cycle (CT 2, CT 3, and STG 4) operation has a net summer capability of 501 MW and a net winter capacity of 605 MW. The total summer net capacity of Brandy Branch Generating Station is 651 MW, and the total winter net capacity is 796 MW.

3.2.4 Girvin Road Landfill

JEA owns and operates three internal combustion engine generators located at the City of Jacksonville's Girvin Road Landfill. This facility was placed into service in July 1997 and is fueled by gas produced by the landfill. The facility originally had four generators. Since that time, gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility.

3.3 JEA Electric Bulk Systems

3.3.1 SJRPP

The SJRPP generating station is located in JEA's north district load center, adjacent to and northeast of the Northside Generating Station. SJRPP consists of two pulverized bituminous coal and petcoke fired steam electric generating units (SJRPP 1 and 2). SJRPP 1 began commercial operation in March 1987, and SJRPP 2 followed in May 1988. SJRPP is jointly owned by JEA and FPL, with JEA maintaining an 80 percent ownership interest in the facility. JEA is currently entitled to 50 percent (equal to 626 MW net summer and 637.5 MW net winter) of the facility capacity. JEA has sold its remaining 30 percent (equal to 376 MW net summer and 382.5 MW net winter) ownership interest of the facility capacity to FPL. Based on the terms and conditions of the sales agreement, the total amount of energy that FPL can take under the agreement is

limited. For the purpose of modeling in this Application, the term of the FPL-SJRPP sale is assumed to end on March 31, 2016. After the terms of the energy sales agreement are satisfied, JEA will be entitled to its full 80 percent ownership share of SJRPP, representing a summer net capacity of 1,002 MW and a winter net capacity of 1,020 MW.

3.3.2 Scherer Plant

The Scherer Plant is located near Forsyth, Georgia. Scherer Unit 4, a pulverized coal fired steam electric generator, is jointly owned by JEA and FPL. JEA has a 23.6 percent ownership interest in Unit 4 (equal to 200 MW net) and proportionate ownership interests in associated common facilities and an associated coal stockpile. JEA purchased 150 MW of Scherer Unit 4 in July 1991 and purchased an additional 50 MW on June 1, 1995. The output of Scherer 4 is available to JEA via Georgia Power Company transmission services delivered to the Georgia/Florida transmission interface. JEA's joint ownership in the 500 kV transmission lines from the Duval Substation to the Georgia/Florida interface completes the transmission path into JEA's service territory. Scherer Unit 4 has a net summer and winter capacity of 846 MW.

3.4 JEA Purchased Power

3.4.1 Southern Company

JEA contracted with Southern Company for the purchase of 207 MW of coal fired capacity and energy from June 1995 through May 2010 (Southern Unit Power Sales [UPS] Purchase). These capacity obligations of Southern Company are firm, subject only to the availability of the units involved (Miller Units 1 through 4 and Scherer Unit 3). The capacity and energy are priced according to the specific cost of the units allocated to JEA. In addition, JEA occasionally purchases economy interchange power from Southern Company over and above the Southern UPS Purchase. JEA has exercised its rollover rights to retain the transmission rights for this capacity even after the expiration of the UPS Purchase.

3.4.2 Constellation Energy Commodities Group, Inc

JEA contracted with Constellation Energy Commodities Group, Inc. (Constellation) for peaking capacity of 75 MW, 150 MW, and 150 MW for the winter seasons 2008, 2009, and 2010, respectively. This system capacity is in Georgia and will be delivered to the Georgia/Florida interconnection. From this point of interconnection, JEA is responsible for delivery to its own territorial load.

3.4.3 *Qualifying Facilities*

JEA continues to encourage and evaluate opportunities for cogeneration. Cogeneration facilities reduce the demand on JEA's system and/or provide additional system capacity. JEA purchases power from four customer-owned qualifying facilities (QFs), as defined in the Public Utilities Regulatory Policy Act of 1978. These have a total installed summer peak capacity of 17 MW and a winter peak capacity of 19 MW. JEA purchases energy from these QFs on an as-available (non-firm) basis. Due to the non-firm nature of the purchases, these resources are not relied upon for capacity planning purposes.

Table 3-2 summarizes JEA's customers with QFs that are located within JEA's service territory.

Table 3-2
JEA Service Territory Qualifying Facilities

Cogenerator Name	Unit Type	In-Service Date	Net Capacity[1] – MW	
			Summer	Winter
Anheuser-Busch	COG[2]	April 1988	8	9
Baptist Hospital	COG	October 1982	7	8
Ring Power Landfill	SPP[3]	April 1992	1	1
St Vincent's Hospital	COG	December 1991	1	1
Total			17	19

[1]Net generating capacity, not net generation sold to JEA.
[2]Cogenerator.
[3]Small Power Producer.

3.5 The Energy Authority

JEA is a member of The Energy Authority (TEA), which actively trades energy with a large number of counterparties throughout the United States. TEA is generally able to acquire capacity and energy from other market participants when any of its members, including JEA, require additional resources. TEA has reserved firm transmission rights across the Georgia Integrated Transmission System (ITS) to the Florida/Georgia border. Therefore, capacity from generating units located in Georgia should provide similar levels of reliability as the capacity available within Florida.

At this time, TEA has no active firm purchases on behalf of JEA. However, since its inception, TEA has purchased capacity and energy on behalf of JEA for seasonal

periods. Typically, TEA acquires necessary short-term purchases the season before the additional energy is needed (based on market conditions), identifies a number of potential suppliers within Florida and Georgia, selects the best offer, and enters into PPAs with the supplier and JEA. TEA's ability to acquire capacity and/or energy, along with TEA's firm transmission rights across the Georgia ITS, give JEA assurance that short-term market purchases are viable.

3.6 Power Sales

3.6.1 Florida Public Utilities Company Sale

JEA furnishes wholesale power to Florida Public Utilities Company (FPUC) for resale in the city of Fernandina Beach in Nassau County, north of Jacksonville. JEA has provided FPUC's power requirements for many years, and under the current 10 year renewal term, JEA is contractually committed to supply power to FPUC from January 1, 2008, through December 31, 2017. FPUC's historical loads are embedded in JEA's historical loads for the purpose of developing the load forecast used throughout the GEC Need for Power Application. JEA expects that the contract to sell power to FPUC will be renewed upon its expiration. Therefore, FPUC's load will be treated as JEA's native load and will be served by JEA's resources throughout the 20 year evaluation period considered in this Application.

3.6.2 FPL-SJRPP Sale

As noted previously, JEA has sold 30 percent (equal to 376 MW net summer and 382.5 MW net winter) of the SJRPP capacity to FPL. Based on the terms and conditions of the sales agreement, the total amount of energy that FPL can take under the agreement is limited. For the purpose of modeling in this Application, the term of FPL-SJRPP sale is assumed to end on March 31, 2016.

3.7 Unit Retirements

Over the planning horizon considered in this Application, the only existing unit that is planned for retirement is Kennedy CT 3, with retirement planned during the first quarter of 2009. The following subsections discuss JEA's generating fleet with regard to unit age and possible future maintenance activities to help ensure continued reliable operation.

3.7.1 Steam Turbine Units

JEA owns all or part of six steam units: Northside 1, Northside 2, Northside 3, SJRPP 1, SJRPP 2, and Scherer 4.

Northside 1 and Northside 2 were originally commissioned in 1966 and 1972, respectively, as heavy oil-fired units. As noted above, both units were repowered with coal and petcoke fired CFB boilers in 2002The 2002 repowering is expected to prolong the original design life of these units, allowing them to remain operational throughout the 20 year evaluation period considered in this Application.

The Northside 3 steam unit was originally commissioned in 1977. A recent condition assessment has shown that the unit is in typical condition for the type, age, and operating mode of the unit. A major maintenance plan has been developed to preserve reliability and availability of the unit through the 20 year evaluation period considered in this Application. It is expected that currently pending environmental regulations could be applicable to the unit and may necessitate either modified operating practices, major upgrades, or economic retirement. JEA will continue to evaluate future plans for this unit as pending environmental regulations are brought forth.

SJRPP Unit 1 was commissioned in 1987 and SJRPP Unit 2 was commissioned in 1988. These units are well within their original design life, and there is no prospect for their retirement throughout the 20 year evaluation period considered in this Application.

Scherer Unit 4 was commissioned in 1989. This unit is well within its original design life, and there is no prospect for its retirement throughout the 20 year evaluation period considered in this Application.

3.7.2 Combustion Turbine Units

JEA currently has three types of combustion turbines distributed between the Northside, Kennedy and Brandy Branch Stations.

Kennedy Station has one nominal 182 MW GE 7FA gas fired (with distillate backup) combustion turbine, commissioned in 2000 and designated as Kennedy CT 7. An additional gas fired (with distillate oil backup) 7FA designated as Kennedy CT 8 is under construction with a scheduled commercial operation date of March 2009. No major repairs or upgrades beyond those dictated by unit starts and operating hours are planned. Kennedy Station also has one operating 54.3 MW Westinghouse distillate oil-fired CT designated as Kennedy CT 3, which was commissioned in 1973, and is scheduled for retirement in 2009 (contingent on the successful commercial operation of Kennedy CT 8).

Northside Station was constructed with four distillate oil-fired GE Frame 7 CTs with a nominal capacity of 52.4 MW each. All four units were commissioned from late 1974 through early 1975 and designated as Northside CT 3, 4, 5, and 6. These units are late in their planned life cycle and could require increased O&M, additional capital expenditures, or possibly retirement within the term of this planning cycle. No additional

major repairs or upgrades beyond those dictated by unit starts and operating hours are currently planned and the units are not assumed to retire during the 20 year evaluation period in this Application.

Brandy Branch Station was constructed with three gas fired (with distillate oil backup) GE 7FA CTs with a nominal capacity of 182 MW each. All three units were commissioned as simple-cycle units in 2001 and designated as Brandy Branch CT 1, 2, and 3. Subsequently, Units 2 and 3 were converted to a 2 x 1 combined-cycle configuration in 2005. All three units are well within their design life cycles throughout the 20 year evaluation period considered in this Application. No major repairs or upgrades beyond those dictated by unit starts and operating hours are planned.

3.8 JEA Operating and Spinning Reserve Requirements

JEA is a member of the FRCC and party to the Florida Reserve Sharing Group (FRSG) agreement. The FRSG participants collectively share contingency reserves within the FRCC region to meet the individual participant's obligations to comply with reliability standards and requirements. FRCC members collectively carry operating reserves to cover the loss of at least the single largest unit of the participant's generator resources. When an FRSG participant requests operating reserves, the reserve capacity is immediately scheduled by all other FRSG participants and the requesting participant may hold this operating reserve for up to 30 minutes.

JEA is currently obligated to maintain operating reserves of 82.5 MW. Approximately 20.6 MW of the 82.5 MW must be spinning reserve. The remaining 61.9 MW reserve requirement can be met by quick start units.

3.9 JEA Clean Power Portfolio not Included in this Exhibit

Since 1999, JEA has worked closely with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups to establish a process to maintain an action plan entitled Clean Power Action Plan. The Clean Power Action Plan has an Advisory Panel that is composed of participants from the Jacksonville community, including representatives from the Sierra Club, ALA, and the newest member, the City of Jacksonville Environmental Protection Board. These local members provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program. Although the Clean Power Action Plan does not speak directly to CO_2 emissions, projects undertaken by JEA pursuant to the Plan have reduced JEA's CO_2 emissions.

JEA has made considerable progress towards the goals set forth in the Clean Power Action Plan through installation of clean power systems, PPAs, legislative and

public education activities, and research into and development of clean power technologies. In particular, JEA has conducted a number of generation efficiency improvements, such as turbine upgrades, which increase the output of generating units without increasing the amount of fuel burned or the amount of CO_2 emitted. As further discussed in the following subsections, JEA has also undertaken several renewable energy projects as part of the Clean Power Program including installation of solar photovoltaic (PV), solar thermal, landfill and wastewater treatment biogas capacity, and wind. As discussed in Section 14, JEA continues to evaluate new renewable energy initiatives and opportunities, including biomass generation and participating in ongoing research efforts to promote development of renewable energy technologies.

Over the past several years, JEA has received several awards for its clean power program, including a Sierra Club Clean Power Award in 2005 for its voluntary commitment to increasing the use of solar, wind, and other renewable or green power sources.

3.9.1 Solar and the Solar Incentive Program

JEA has installed 35 solar PV systems, totaling 220 kW, on all of the public high schools in Duval County, as well as many of JEA's facilities, and the Jacksonville International Airport (one of the largest solar PV systems in the Southeast). To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in early 2002. This program provides cash incentives for customers to install solar PV and solar thermal systems on their homes or businesses.

JEA provided customer incentives for more than 25 solar PV systems (for a total of 98 kW) until January 2005, when the PV incentive was discontinued in favor of the solar water heating program, which provides more cost-effective CO_2 reduction. In addition to the PV incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems. JEA also offers incentives for the installation of solar water heaters. To date, the program has resulted in over 500 incentives, or approximately 1.6 MW of capacity savings.

3.9.2 Landfill Gas and Biogas

Since 1997, JEA has owned and operated internal combustion engine generators fueled by landfill gas produced by the City of Jacksonville's Girvin Road landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility. The facility uses biogas produced by the wastewater treatment plant to fuel the 800 kW generator. JEA has received

approximately 1,500 kW of landfill gas from the North Landfill, where it is used to generate power at Northside Unit 3.

In 2006, JEA signed a PPA with Landfill Energy Systems to obtain energy from a 9.6 MW landfill gas-to-energy facility at the Trail Ridge Landfill in Jacksonville. Once completed, the facility will be one of the largest landfill gas-to-energy facilities in the Southeast, providing enough renewable energy to supply electricity to approximately 2,275 homes. The projected date for completion of the facility is late 2008.

3.9.3 Wind

As part of its ongoing effort to utilize more sources of renewable energy, in 2004 JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits associated with this green power project. Under the wind generation agreement, JEA has agreed to purchase 10 MW of capacity from NPPD's wind generation facility for a 20 year period. In turn, NPPD will buy back the energy at specified on/off peak charges. JEA retains the rights to the environmental attributes (renewable energy credits, or RECs) and will sell the RECs unless JEA needs them to meet state or federal environmental requirements.

3.10 JEA Transmission and Interconnections

The JEA transmission system consists of 728 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kilovolts (kV), 138 kV, 230 kV, and 500 kV.

The 500 kV transmission lines are jointly owned by JEA and FPL and complete the path from FPL's Duval substation (to the west of JEA's system) to the Florida interconnect at the ITS. Along with JEA and FPL, Progress Energy Florida and the City of Tallahassee each also own transmission interconnections with the Georgia ITS. JEA's first contingency import entitlement over these transmission lines is 1,228 MW out of 3,600 MW.

The 230 kV and 138 kV transmission system provides a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest to fill in the area not covered by the 230 kV and 138 kV transmission backbone.

JEA owns and operates three 230 kV tie-lines terminating at FPL's Duval substation in Duval County, one 230 kV tie-line terminating at Beaches Energy's

Sampson substation (FPL metered tie-line) in St. Johns County, one 230 kV tie-line terminating at Seminole Electric Cooperative's Black Creek substation in Clay County, and one 138 kV tie-line terminating at Beaches Energy's Penman Road substation.

JEA also owns and operates a 138 kV transmission loop that extends from the 138 kV backbone, north to the Nassau substation, where JEA delivers wholesale power to FPUC for resale within the City of Fernandina Beach, Nassau County, Florida.

3.11 JEA Transmission System Considerations

JEA continues to evaluate and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. JEA continually assesses, in compliance with North American Electric Reliability Corporation (NERC) and FRCC standards, the needs and options for increasing the capability of the transmission system.

JEA performs system assessments using JEA's published Transmission Planning Process in conjunction with and as an integral part of the FRCC's published Regional Transmission Planning Process which facilitates coordinated planning by all transmission providers, owners, and stakeholders with the FRCC Region. FRCC's members include investor owned utilities, cooperative utilities, municipal utilities, a federal power agency, power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee, which includes representation by all FRCC members, directs the FRCC Transmission Working Group, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The FRCC Regional Transmission Planning Process meets the principles of the FERC Final Rule in Docket No. RM05-25-000 (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects.

10.0 Transmission System Impacts

The GEC facility will be interconnected with the existing JEA system. The proposed interconnection and integration of GEC have been evaluated by the FRCC Transmission Working Group (TWG) and Stability Working Group (SWG). This evaluation concluded that the project is reliable and adequate, with no adverse impact on the FRCC transmission system. The remainder of this section describes the GEC interconnection, as well as the FRCC transmission study.

10.1 Description of Interconnection

The GEC is located near the Greenland Substation in Duval County, Florida. The addition of the simple cycle units in June 2010 will necessitate the following upgrades to the transmission system:

- Loop existing Greenland – Center Park 230 kV line into GEC.
- Loop existing Greenland – SE Jax 230 kV line into GEC.

10.2 System Impact Analysis

The FRCC study evaluated whether the addition of the GEC may cause any thermal overloads and voltage limitations, instability or inadequately damped response to system disturbances, or short-circuit concerns. The following previously planned and committed projects by JEA and FPL were already identified as necessary to support the area reliability under certain contingencies assessed using the NERC standards TPL-001, TPL-002, and TPL-003.

- Upgrade Greenland – GEC 230 kV circuit 1 from 637 megavolt-ampere (MVA) to 668 MVA by the summer of 2010.
- Upgrade Hasting – Elkton 115.kV line from 73 MVA to 149 MVA by the summer of 2010 or earlier.
- Upgrade St. Johns – Elkton 115 kV from 73 MVA to 180 MVA by the summer of 2010.
- Construct GEC – Nocatee – Bartram 230 kV by the summer of 2015 (presently scheduled for 2012).
- Bartram – Switzerland 230 kV will be rated 668 MVA by the summer of 2012 when Bartram Substation is constructed.

The TWG reviewed the results of the steady-state single contingency analysis. The results identified incremental system impacts under certain single and double contingency events due to the addition of the GEC. JEA, FPL, and Florida Municipal Power Agency (representing Beaches Energy System, Inc.) addressed these incremental

impacts by providing corrective action plans that included either post-contingency operating procedures (remedial action plans) or additional system improvements.

For the installation of the GEC simple cycle combustion turbines, JEA identified and committed to one additional project to further improve the reliability of the bulk electric system: Re-conductor Center Park – Neptune 138 kV from 155 MVA to 289 MVA by the summer of 2010 or earlier. The GEC simple cycle combustion turbines and the combined cycle conversion project will result in the deferral of several major transmission system projects due to its favorable location in the southern part of JEA's transmission system.

In addition to the steady-state analysis, the SWG reviewed the dynamic simulations showing a stable response at peak load levels for normally cleared and delayed cleared three-phase faults in the vicinity of GEC. The results indicate that there are no grid stability concerns with the addition of the GEC.

A review of the short-circuit analysis has shown that there are no short-circuit concerns with the addition of the GEC.

Based upon the review and analysis conducted by the TWG and SWG, the FRCC has determined that the proposed interconnection and integration of the GEC to serve JEA's native load is reliable, adequate, and does not adversely impact the reliability of FRCC transmission system.

19.0 Financial Analysis

JEA has the necessary funding sources available to finance the GEC combined cycle conversion. JEA anticipates the need to finance an estimated $419 million for the conversion, including direct and indirect engineering, procurement, and construction costs, owner's costs, and interest during construction.

JEA typically finances large generation capital projects using fixed and floating rate subordinate long-term debt. Up to a maximum of 30 percent of the debt may be floating rate. During the preliminary design, engineering, and permitting, JEA may use internal funds from operations or from prior issuances to fund early project costs. As the initial development concludes and construction commences, JEA may initiate various tranches of revenue bond issuances for long-term financing with terms of up to 30 years. For large projects, JEA may issue bonds every one to two years to cover expected construction related capital costs over these periods. By having multiple issuances, JEA will limit the amount of interest incurred during construction of the plant. In addition, JEA may pool the financing for GEC with other smaller capital addition costs that may be required concurrent with GEC.

JEA's senior electric system debt has a long-term credit rating of AA- from S&P, Aa2 from Moody's Investor Services, and an AA- from Fitch. To protect against fluctuations in the interest rate, JEA may use interest rate swap contracts to take advantage of favorable market conditions and caps, to limit risk associated with variable rate debt exposure. With its excellent credit rating, JEA should expect that it will have no difficulties in obtaining bond financing for the GEC construction. The actual financing for GEC is expected to result in debt service requirements less than the assumed debt service presented in the economic parameters in Section 4.0.

EMPLOYMENT

Update?

02/05 – Present **JEA, Taylor Energy Center**

Project Manager for 800 MW solid fuel fire electric generating plant. Project cost $1,200 million. Responsible for all phases of project management from start of engineering through start-up and commissioning for a multi-participant project.

02/02 – 02/05 **JEA, Brandy Branch Combined Cycle Project, Jacksonville, FL**

Project Manager for the addition of a combined cycle plant on two 7FA GE CT's. Project cost $201 million. Responsible for all phases of project management from start of engineering through start-up and commissioning.

4/98 – 02/02 **JEA, Northside Repowering Project, Jacksonville Fl.**

Construction Site Manager for repowering two – 275 MW oil/gas fired units with two 300 MW solid fuel fired CFB boilers. Project cost $650 million. Responsible for all site construction activities including work scope delineation, change management, laydown coordination, security, safety program, owners providied insurance program, and budget responsibility.

8/83 – 4/98 **Jacksonville Electric Authority,** St Johns River Power Park, Jacksonville, Fl.

Contracts Administration Manager: Responsible for all phases of major capital and maintenance projects ranging from power piping, boiler modifications, and major equipment installations to yard utilities. Heavy involvement with plant planned and forced outages. Duties include: development, biding and management of all site Contracts; review of engineering packages; daily interface and direction of contractors; project scheduling, budgeting, estimating, equipment procurement and cost controls; construction and maintenance field inspections; and direct supervision of up to 40 Contract Management employees.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 6
COMPANY JEA (Direct)
WITNESS Michael N. Lawson (MNL-1)
DATE 02-12-09

Lead Project Administrator: Owner representative for boiler, coal handling, cooling tower and other various contracts on construction of two 624 megawatt coal fired electric generating units. Responsible for Owner inspections, budget control, preparation of change orders, payment approvals, contract interpretations, claims negotiations, and managing 38 million dollars of project force contract work.

11/82 - 8/83 **Tennessee Valley Authority,** Bellefonte Nuclear Plant, Hollywood, Al.

Start-up Engineer: Group leader of four engineers. Prepared flush procedures; prepared construction operating instructions; coordinated start-up of various plant systems; maintained construction schedules; and prepared turnover packages for plant systems .

4/79 - 7/82 **Gardinier, Inc.,** Ft. Meade Mine, Ft. Meade, Florida

Lead Project Engineer: Concept, design and control of $40 million slimes thickening project. Supervised six person engineering staff.

Plant Engineer: Phosphate mining and beneficiation; full control of various plant modifications and additions such as slurry pumps, conveyor stackers, classifiers, log washers, hydraulic stations, and thickeners from concept through design and construction. Lead Project Engineer for new $3.5 million matrix pumping system. Was on design team for $25 million major plant expansion. All projects involved concept, design, equipment selection, procurement, and construction.

3/78 - 4/79 **Gulf States Utilities Company,** Sabine Station, Bridge City, Texas

Engineer: Power Plant maintenance planning; boiler, pump, and turbine maintenance supervision; specification preparation, bidding, and procurement. Major projects: Outage Coordinator for a 380 megawatt steam turbine generator; boiler inspections and maintenance on four boilers including leak records and supervision of repair crews.

12/76 - 3/78 **United Parcel Service,** Huntsville, Alabama

Pre-load Splitter: Sorted packages into driver routes, loaded package trucks.

9/75 - 12/76 **Montgomery Ward and Company,** Huntsville, Alabama

Salesman: Sales in hardware department. 30 - 40 hours per week.

71 - 75 **Ala-Tenn Natural Gas Company,** Muscle Shoals, Alabama
Summer Crew Foreman: Supervised six to eight men on general pipeline maintenance. Summers 40 hours per week.

EDUCATION

1974 - 1978 University of Alabama in Huntsville
Mechanical Engineering Degree obtained in 1978

1973 - 1974 University of North Alabama, Florence, Alabama

1969 - 1973 Bradshaw High School, Florence, Alabama

Licensing: **Professional Engineer,** State of Florida, certificate #32619

GEC 2x1 Combined Cycle Conversion
In-Service Capital Cost Estimate
(000s)

Cost Item Descriptions	Total Cost
Major Procurements	
STG	41,000
HRSGs	60,000
Subtotal	101,000
EPC	
Civil/Structural Engineered Materials/Equipment	4,753
Mechanical Engineered Materials/Equipment	23,190
Electrical Engineered Materials/Equipment	6,141
Control Engineered Materials/Equipment	656
Chemical Engineered Materials/Equipment	3,100
Civil/Structural Construction	9,973
Mechanical/Chemical Construction	16,409
Electrical/Control Construction	1,121
Service Contracts and Construction Indirects	12,700
Startup Spare Parts	1,083
Field Management	14,080
Engineering	14,218
Overhead and Profit	35,856
Subtotal	143,280
Total Direct Costs	244,280
Owner/Other Cost Items	
Balance of Owner's Costs	41,346
Contingency	22,977
Escalation to Summer 2012 Commercial Operation	69,167
IDC	40,805
Subtotal	174,295
Project Total Cost	418,575

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614EI EXHIBIT 7
COMPANY JEA (Direct)
WITNESS Michael N. Lawson (MNL-2)
DATE 02/12/09

Estimated Greenland Energy Center Estimated Combined Cycle Performance		
Performance Point	Net Plant Output (kW)	Net Plant Heat Rate (Btu/kWh, Higher Heating value[HHV])
95° F, Full Load with Supplemental Firing	491,346	7,280
24° F, Full Load with Supplemental Firing	562,423	7,159
69° F, Full Load with Supplemental Firing	522,190	7,136
69° F, Full Load without Supplemental Firing	490,314	7,019
69° F, 2 CTGs at 80% Load without Supplemental Firing	405,420	7,226
69° F, 2 CTGs at 50% Load without Supplemental Firing	284,534	7,908
69° F, 1 CTG at 100% Load without Supplemental Firing	240,136	7,165
69° F, 1 CTG at 80% Load without Supplemental Firing	197,091	7,432
69° F, 1 CTG at 50% Load without Supplemental Firing	134,644	8,355

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 8
COMPANY JEA (Direct)
WITNESS Michael N. Lawson (MNL-3)
DATE 02/12/09

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 9
COMPANY Jea (Direct)
WITNESS Michael N. Lawson (GEC-1) Section 9.0
DATE 02/12/09

9.0 Project Overview

9.1 Description of Project

The GEC combined cycle conversion will consist of converting the two simple cycle GE 7FA combustion turbines planned for operation by the summer of 2010 at the GEC site in Jacksonville, Florida, to a 2x1 combined cycle configuration. The 2x1 GEC combined cycle will have a nominal net output rating of 522 MW at average ambient temperature conditions. Consideration will be made for installing future units at the site through space allocation. In general, consideration will be given to installing facilities required to support future units at the site when appropriate.

The GEC combined cycle will be dual fueled with natural gas as the primary fuel and ULSD fuel oil as a backup fuel. The combined cycle power plant will include HRSGs provided with natural gas-fired supplemental duct burners to increase power generation and a steam turbine bypass to the condenser to allow for simple cycle operation.

9.1.1 Mode of Operation

Subject to final approval by the Siting Board and the Florida Department of Environmental Protection (FDEP), GEC will be permitted for unlimited operation on natural gas and up to 500 hours per year on ULSD in combined cycle mode. GEC will have full steam bypass capability, allowing the combustion turbine units to operate in simple cycle mode.

9.1.2 Combustion Turbine Generator

The CTGs will be GE Model PG 7241 (FA) enhanced combustion turbines with dry low NO_x (DLN) combustors and modulating inlet guide vanes. The CTGs will be installed outdoors and will include the following major features:

- Dual fuel firing system using natural gas or ULSD.
- DLN combustion system for pipeline gas firing.
- Direct connected generator with static excitation.
- Acoustic enclosure for turbine.
- Inlet air filter system with silencers.
- Lube oil systems.
- Static starting system.
- Water injection system for NO_x reduction when firing fuel oil.
- Fire detection/CO_2 fire protection systems.

- Mark VI control system with remote work stations.
- Off-line water wash system.
- Package electrical and electronics control compartments.
- Natural gas heating for maintaining the fuel gas temperature at the CTG manufacturer's recommended margin above hydrocarbon dew point temperature.

9.1.3 Heat Recovery Steam Generators

The HRSGs will be installed outdoors and will utilize exhaust heat from the combustion turbines to generate steam for use in driving the STG. The HRSGs are expected to be natural circulation, three-pressure, reheat units with supplemental duct firing by pipeline gas to increase unit output. Nominal cycle operating pressure will be 1,800 pounds per square inch gauge (psig). SCR for NO_x emission control is expected to be included within each HRSG. Each HRSG will discharge to an exhaust stack. A stack damper will be included to minimize heat loss during shutdowns. Two 100 percent capacity boiler feedwater pumps will be included for each HRSG.

9.1.4 Steam Turbine Generator

The steam turbine is expected to be a tandem-compound single reheat condensing turbine operating at 3,600 revolutions per minute (rpm). The steam turbine will have one HP section with a nominal 1,800 psig throttle pressure, one IP section, and one low-pressure (LP) section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring and control systems will be utilized. A surface condenser will be provided for condensing steam from the turbine exhaust and will utilize a recirculating cooling tower system for cooling. The condenser will be designed for full steam flow bypass around the steam turbine. A synchronous generator will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment; supervisory, monitoring, and control systems; and static excitation system will be utilized. The steam turbine will be installed indoors with a fully enclosed turbine building.

A standby power diesel engine generator will be provided to maintain the plant in a ready condition if the transmission interconnection and, therefore, plant auxiliary power is lost. The standby power engine generator will use ULSD as fuel.

9.1.5 Cooling Tower

A multiple cell, mechanical draft, counterflow water cooling tower will be used for plant cooling. The cooling tower will be installed on a reinforced concrete basin that

will include a pump intake structure housing two 50 percent capacity circulating water pumps and one 100 percent capacity auxiliary cooling water pump. A circulating water chemical feed system also will be included. The cooling tower will be equipped with drift eliminators.

9.1.6 Air Quality Control

GEC will be subject to FDEP's Prevention of Significant Deterioration (PSD) permitting program, which requires Best Available Control Technology for emissions of various pollutants. GEC will minimize air pollutant emissions by using the most efficient and pollutant-preventing generating technology. This concept has been incorporated with the selection of a combined cycle process utilizing advanced combustion turbines. Compared to simple cycle generating plants, combined cycle units have higher efficiency and, therefore, generate more electrical output (megawatts) per unit of fuel consumed. As a result, air pollutant emissions per megawatt output are minimized. Pollution prevention is also incorporated through the use of clean fuels that minimize emissions of SO_2 and particulate matter. In addition, advanced DLN combustion technology will be used to minimize NO_x emissions while ensuring that emissions of carbon monoxide (CO) and volatile organic compounds (VOCs) are within accepted limits. Moreover, SCR will be installed in each HRSG to further reduce NO_x emissions when operating in combined cycle mode. Taken together, these design features will make GEC one of the most efficient and lowest polluting power plants in the state of Florida.

9.1.7 Control System

GEC will be designed for control through a plant distributed control and information system (DCIS). A GE Mark VI control system for turbine control will also be included. The DCIS operator control stations will be located in the main plant control room that will be in a new Administration/Control/Maintenance Building.

9.1.8 Water Use

Water for cooling tower makeup is expected to be reclaimed water (treated wastewater). Reclaimed water is expected to be supplied from JEA via a pipeline adjacent to the plant site. If needed, municipal water will be used for backup cooling water makeup supply. Cooling water makeup water flow will vary depending upon the plant load and operating conditions.

Service water, potable water, demineralizer water makeup, and fire water will be supplied from the JEA municipal water system. Water will be stored onsite in a fire water/service water storage tank. GEC will include a site fire protection system consisting of a fire/service water storage tank, in addition to the municipal water supplied

hydrant system, one diesel engine driven fire water pump, a site hydrant system, and deluge systems as required. A CO_2 fire suppression system will be provided for each CTG as provided in the CTG manufacturer's standard scope of supply.

A new demineralizer system will be installed to provide demineralized water for combustion turbine water injection for NO_x control when firing fuel oil and for steam cycle makeup. Two 800,000 gallon demineralized water storage tanks will be provided for a total capacity of approximately 40 hours of storage/makeup capacity under maximum demineralized water demand conditions.

9.1.9 Project Process Wastewaters

There will be four major sources of wastewater: sanitary waste, oil/water separator effluent, cooling tower blowdown, and treated chemical wastewaters. Cooling tower blowdown will be reblended into the JEA reclaimed water distribution system. All other wastewaters will be routed via the adjacent force main to the JEA municipal wastewater treatment plant.

9.1.10 Storm Water Management

A complete storm water management system will be developed for the site. Storm water system design will be in accordance with FDEP, St. Johns Water Management District (SJWMD), and Duval County requirements. Storm water runoff will be collected in an onsite detention pond for percolation into the ground water.

9.1.11 Transmission Interconnection

GEC will be interconnected to JEA's 230 kV transmission system. The CTGs and STG will each connect to separate 18 kV/230 kV generator step-up (GSU) transformers. The CTGs and the STG will each have generator breakers. Auxiliary power will be provided by auxiliary transformers connected to each unit's 18 kV power.

9.1.12 Site Design Conditions

Table 9-1 presents the conceptual site design conditions for the GEC site.

Table 9-1
Conceptual Design Conditions for the Project Site

Condition	Value or Range	Reference
Maximum Temperature	103° F	Weatherbase Web site
Minimum Temperature	7° F	Weatherbase Web site
Average Temperature	69° F	Weatherbase Web site
Wind Loading	Basic Wind Speed: 130 miles per hour (mph), (3 second gust), Occupancy Category IV, Importance Factor: 1.15, Exposure Category C	ASCE 7-05, with applicable addenda
Seismic Loading	Occupancy Category: IV, Seismic Design Category: C, Site Soil Classification (stiff soil): D, Mapped 1 Second Spectral Response Acceleration (S1), g: .06, Mapped Short-Term (0.25 sec) Spectral Response Acceleration (Ss), g: 0.15	ASCE 7-05
Site Elevation	Nominal 30.0 feet above mean sea level (msl)	
Location	Outdoors	

9.1.13 Site Arrangement

Figure 9-1 is a conceptual drawing that shows the arrangement and locations of the major equipment for each unit at the GEC site.

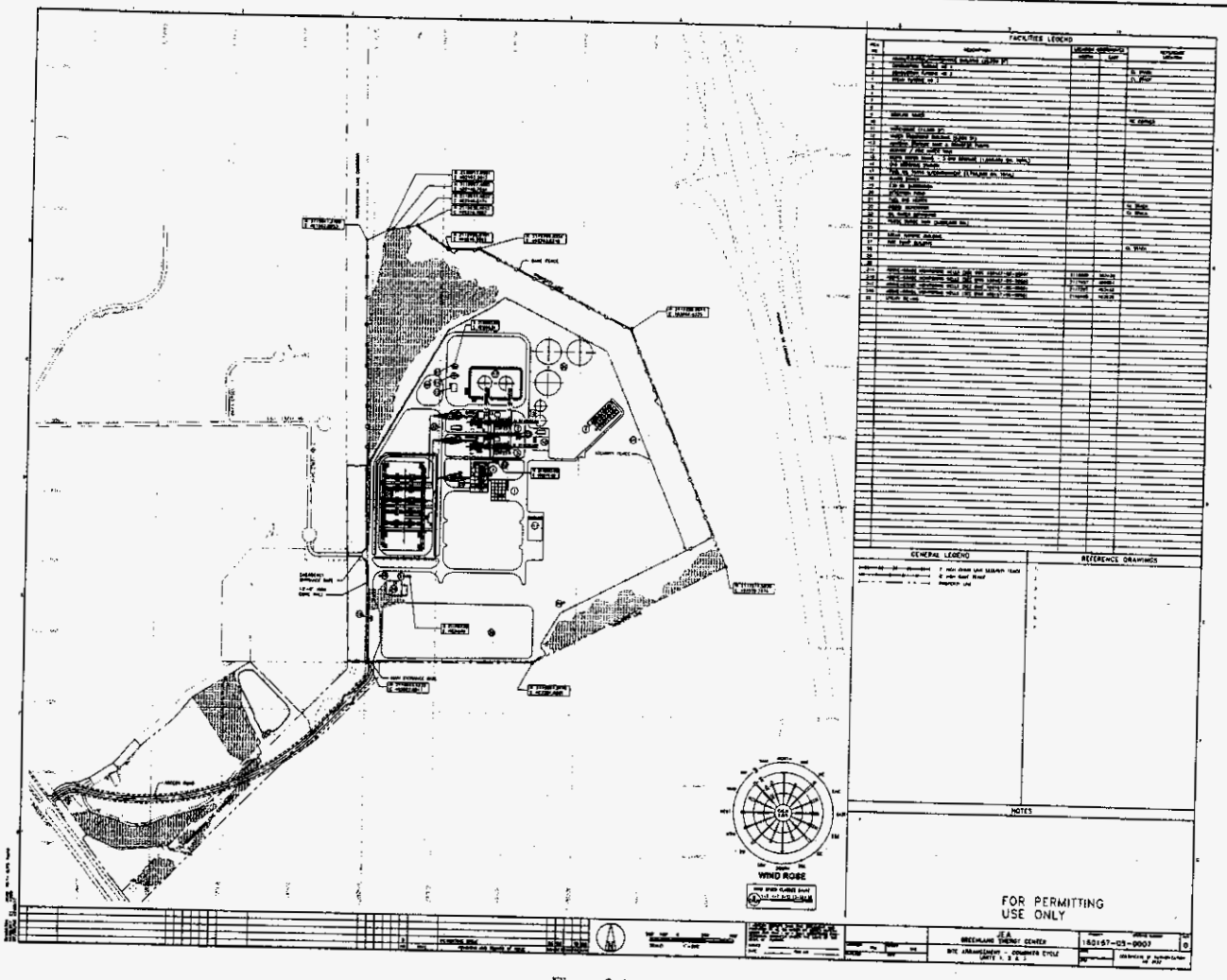


Figure 9-1
Conceptual Site Arrangement Drawing

9.1.14 Overall One-Line Diagram

Figure 9-2 is a conceptual electrical one-line diagram that shows the arrangement of the electrical interconnections to the existing transmission system and electrical power distribution for GEC.

9.1.15 Cycling Design Features

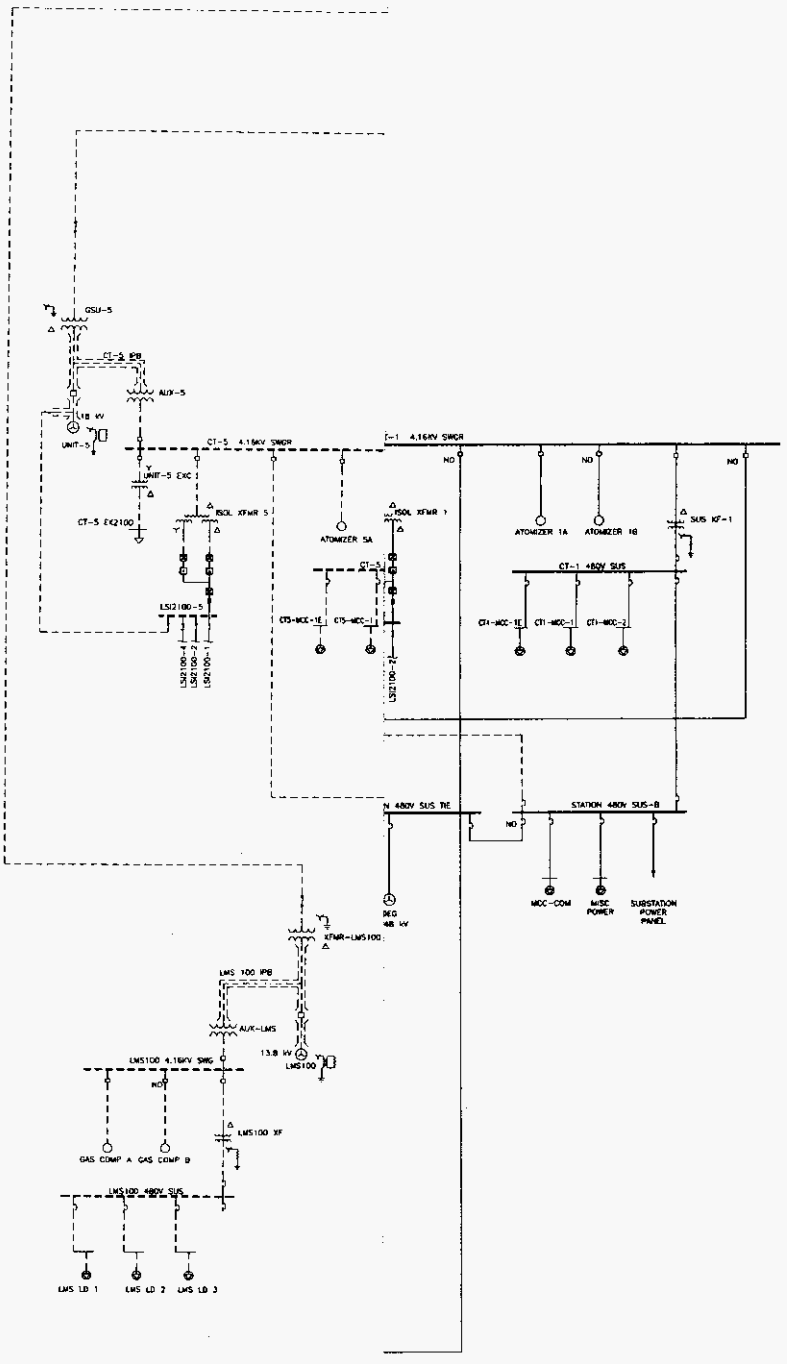
GEC will include several design features for cycling load operation. The STG will be selected in combination with the HRSGs to provide a reasonable design throttle pressure to ensure satisfactory cycling operation. Because the unit is going to be designed for cycling operation, a nominal throttle pressure of 1,800 psig will be used for design purposes. In comparison to a higher design throttle pressure such as 2,400 psig, a 1,800 psig operating pressure allows reduced wall thicknesses in HRSG drums and piping, thereby reducing thermal stresses and allowing reduced warm-up times. This reduces overall startup time and increases ramp rates when changing loads.

HRSG design for cycling operation will include nozzle arrangement and connections, use of full penetration welds, separation of headers, and use of higher strength drum and header materials to enable thinner wall construction to reduce stress from temperature gradients. HRSG design will also include a stack damper for heat retention, automated vent and drain valves to control pressure and drain condensate during shutdowns and startups, and 100 percent bypass systems to enable steam/turbine temperature matching.

9.1.16 Ammonia Systems

Ammonia will be required for use in the SCR process for NO_x control. Vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed, which is installed in the HRSGs. The onsite ammonia system will include unloading facilities, aqueous ammonia storage tank, forwarding system, and vaporizing facilities. Aqueous ammonia will be used and will be delivered to the GEC site by tanker trucks, which include integral unloading pumps. The aqueous ammonia will be stored as a liquid in a nominal 20,000 gallon tank, which provides for two full tanker truck deliveries. The liquid ammonia will be forwarded to the HRSGs, vaporized, and injected upstream of the catalyst.

NOTES:
(1) FURNISHED BY OWNER.



9.1.17 Capability for Future Expansion

The GEC site will have the capability for the future installation of combined cycle and simple cycle units. The site layout and infrastructure will support the future installation of an identical combined cycle power plant and future peaking unit capacity, for an ultimate certification capacity of approximately 1,300 MW.

It is anticipated that the site will be cleared and developed, including the storm water detention pond, for ultimate build out of future units during the construction of the initial simple cycle combustion turbines at GEC. It is also anticipated that most offsite facilities will be sized for ultimate build out including the reclaimed water pipeline, natural gas supply pipelines, wastewater return lines, and potable waterlines.

9.2 Fuel Supply

The primary fuel for GEC will be natural gas, while the backup fuel will be ULSD fuel oil. Natural gas will be delivered to the GEC site through the SeaCoast Pipeline and a distribution lateral utilizing firm transportation service from SeaCoast. The initial phase of the SeaCoast pipeline will extend from interconnections with FGT and SNG Cypress Lateral, near Jacksonville, Florida, to the interconnection between the SeaCoast Pipeline and PGS located in Clay County, Florida. The lateral will extend from the SeaCoast–PGS interconnection to the inlet of the meter located at GEC. SeaCoast's interconnection with both FGT and SNG will allow JEA to utilize a diverse natural gas supply portfolio. It is anticipated that adequate natural gas pressure will be available with no need for the addition of gas compressors.

9.2.1 Natural Gas Transportation, Delivery, and Metering

Natural gas will be delivered to the GEC site by SeaCoast via the GEC Lateral and will be regulated, metered, and conditioned onsite. The pipeline to the site will be sized for ultimate site capacity. Carbon steel pipe with cathodic protection will be installed underground from the main pipeline to the site. A new meter run and natural gas conditioning equipment is included. The natural gas conditioning equipment includes a fuel gas scrubber, two coalescing gas filters, and a dew point control fuel gas heater.

9.2.2 Fuel Oil Storage and Handling

A complete fuel oil unloading, storage, and supply system will be installed. Two 1,875,000 gallon tanks will be installed that will provide a minimum 5 days of full load operation at minimum ambient conditions for GEC. The tanks will be single wall design fabricated from carbon steel and will be installed inside a dike containment area. Normal fuel oil delivery will be by truck. A truck unloading system will be installed including

truck connections. Fuel oil forwarding skids will be included to transfer fuel oil from the storage tanks to the CTGs. Two 100 percent capacity electric motor driven pumps will be included for each skid and the skids will be installed outdoors on concrete pads near the new fuel oil storage tanks.

9.3 Capital Cost

The capital cost estimate is based on the conversion of the two GE 7FA simple cycle combustion turbines at GEC to a 2x1 combined cycle configuration. The construction cost includes direct costs for purchased equipment and materials, construction contract costs, and indirect costs. The direct construction cost estimate is based on site development for the ultimate capacity and also sizing interconnecting pipelines for the ultimate capacity. Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services. All direct costs include escalation to spring 2012 commercial operation.

Construction costs are based on an engineering, procurement, and construction (EPC) contracting philosophy. Construction is assumed to be performed based on a 50 hour work week, with some 60 hour work weeks. Local labor craft rates that include payroll, payroll taxes, and benefits were used in developing the estimated construction costs. Construction indirects and construction equipment costs are included in the construction and service contracts portion of the estimate.

Indirect costs associated with construction are included in the base cost estimate. General indirect costs include all necessary services required for checkouts, testing services, and commissioning. Insurance for builder's risk and general liability are included. Contractor engineering, contractor field construction management, technical direction, contingency, profit, equipment transportation costs, startup, and commissioning are also included.

Table 9-2 provides a summary of the capital cost estimate for the GEC combined cycle conversion. Financing fees are not included in the estimate. These are estimated separately and included in the economic evaluations using the assumptions presented in Section 4.0.

Table 9-2
GEC 2x1 Combined Cycle Conversion
In-Service Capital Cost Estimate
(000s)

Cost Item Descriptions	Total Cost
Major Procurements	
STG	41,000
HRSGs	60,000
Subtotal	101,000
EPC	
Civil/Structural Engineered Materials/Equipment	4,753
Mechanical Engineered Materials/Equipment	23,190
Electrical Engineered Materials/Equipment	6,141
Control Engineered Materials/Equipment	656
Chemical Engineered Materials/Equipment	3,100
Civil/Structural Construction	9,973
Mechanical/Chemical Construction	16,409
Electrical/Control Construction	1,121
Service Contracts and Construction Indirects	12,700
Startup Spare Parts	1,083
Field Management	14,080
Engineering	14,218
Overhead and Profit	35,856
Subtotal	143,280
Total Direct Costs	244,280
Owner/Other Cost Items	
Balance of Owner's Costs	41,346
Contingency	22,977
Escalation to Summer 2012 Commercial Operation	69,167
IDC	40,805
Subtotal	174,295
Project Total Cost	418,575

9.4 Operating and Maintenance Cost

O&M costs include fixed and variable costs. Fixed costs are independent of plant operation while variable costs are directly related to the plant operation. The O&M cost estimates were based on the following assumptions:

- Primary fuel is natural gas.
- Potable water will be provided by JEA, cooling tower makeup water will be provided by JEA as reclaimed water, and service water will be provided by JEA's municipal water supply. JEA's municipal water supply will also provide an emergency source of makeup water.
- A full-time plant staff of 22 personnel consisting of a plant manager, three administrative staff, and 18 O&M personnel.
- An operating profile consisting of up to 300 starts per year, weekly starts during the summer months, and daily starts during the non-summer months with an average capacity factor ranging from 20 to 95 percent.

9.4.1 Fixed O&M Costs

Fixed costs include labor, payroll burden, fixed routine maintenance, and administration costs. The incremental fixed O&M costs associated with the GEC combined cycle conversion are estimated to be $3.38 million per year in 2008 dollars.

9.4.2 Nonfuel Variable O&M

Nonfuel variable O&M costs include consumables, chemicals, lubricants, water, and major inspections and overhauls. Major inspection and overhaul costs can be covered under long-term service agreements with the turbine manufacturer, or each overhaul can be subcontracted to the turbine supplier or a third party maintenance provider. Because the plant is not staffed to fully perform these major inspections, it is assumed that these will be subcontracted to the turbine supplier or a third party O&M provider. Nonfuel variable O&M costs vary as a function of plant generation. The incremental nonfuel variable O&M costs associated with the GEC combined cycle conversion are estimated to be $2.28 million per year in 2008 dollars. The estimated nonfuel variable O&M costs assume operation on natural gas.

9.5 Heat Rate

Based on the heat balances developed for the project, Table 9-3 presents a summary of the estimated performance for the GEC combined cycle. Nonrecoverable performance degradation factors of 2.7 percent for output and 1.5 percent for heat rate have been included in the estimated performance.

Table 9-3
Estimated Greenland Energy Center
Estimated Combined Cycle Performance

Performance Point	Net Plant Output (kW)	Net Plant Heat Rate (Btu/kWh, Higher Heating value[HHV])
95° F, Full Load with Supplemental Firing	491,346	7,280
24° F, Full Load with Supplemental Firing	562,423	7,159
69° F, Full Load with Supplemental Firing	522,190	7,136
69° F, Full Load without Supplemental Firing	490,314	7,019
69° F, 2 CTGs at 80% Load without Supplemental Firing	405,420	7,226
69° F, 2 CTGs at 50% Load without Supplemental Firing	284,534	7,908
69° F, 1 CTG at 100% Load without Supplemental Firing	240,136	7,165
69° F, 1 CTG at 80% Load without Supplemental Firing	197,091	7,432
69° F, 1 CTG at 50% Load without Supplemental Firing	134,644	8,355

9.6 Emissions

The estimated emissions for the GEC combined cycle are presented in Table 9-4. The estimated emissions include operation of SCR and DLN burners.

9.7 Availability

Equivalent availability is a measure of the capacity of a generating unit to produce power considering operational limitations such as equipment failures, repairs, routine maintenance, and scheduled maintenance activities. Equipment outages and forced outages are not predictable and, as a result, a forced outage of 4 percent is assumed for each year. Scheduled outages will be determined by the hours of operation and number of starts. The CTG maintenance program typically consists of combustion inspections, hot gas path inspections, and major overhauls. Typical durations for these outages have been assumed as follows: 7 days for a combustion inspection, 14 days for a hot gas path inspection, and 25 days for a major overhaul. Based on the expected operating profile for

the plant, the equivalent availability for GEC is estimated to be 94 percent. On average, 7 maintenance days per year and a 4 percent forced outage rate have been assumed.

Table 9-4
Greenland Energy Center Combined Cycle Estimated Emissions (1)

NO_x, parts per million volumetric dry (ppmvd) at 15% Oxygen (O_2)	2.0
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0004
Hg, lb/MBtu	Negligible
CO_2, lb/MBtu	114.8 lb/MBtu
CO, ppmvd at 15% O_2	7.6
CO, lb/MBtu	0.0166

(1)Emissions are at full load at average ambient conditions, reflect operation on natural gas, and include the effects of SCR and DLN burners.

9.8 Schedule

The GEC combined cycle conversion is planned for commercial operation beginning in June 2012. In order to achieve the planned commercial operation date, detailed engineering activities will be required in advance of the June 2010 start of initial construction. These activities are planned to commence during the first quarter of 2009. Similarly, procurement activities such as specification, equipment proposal solicitation, and contract negotiation for the STG and HRSGs, which are all long lead equipment items, will occur starting in 2008 to allow for delivery of this equipment to support the schedule. A schedule of these activities is provided on Figure 9-3.

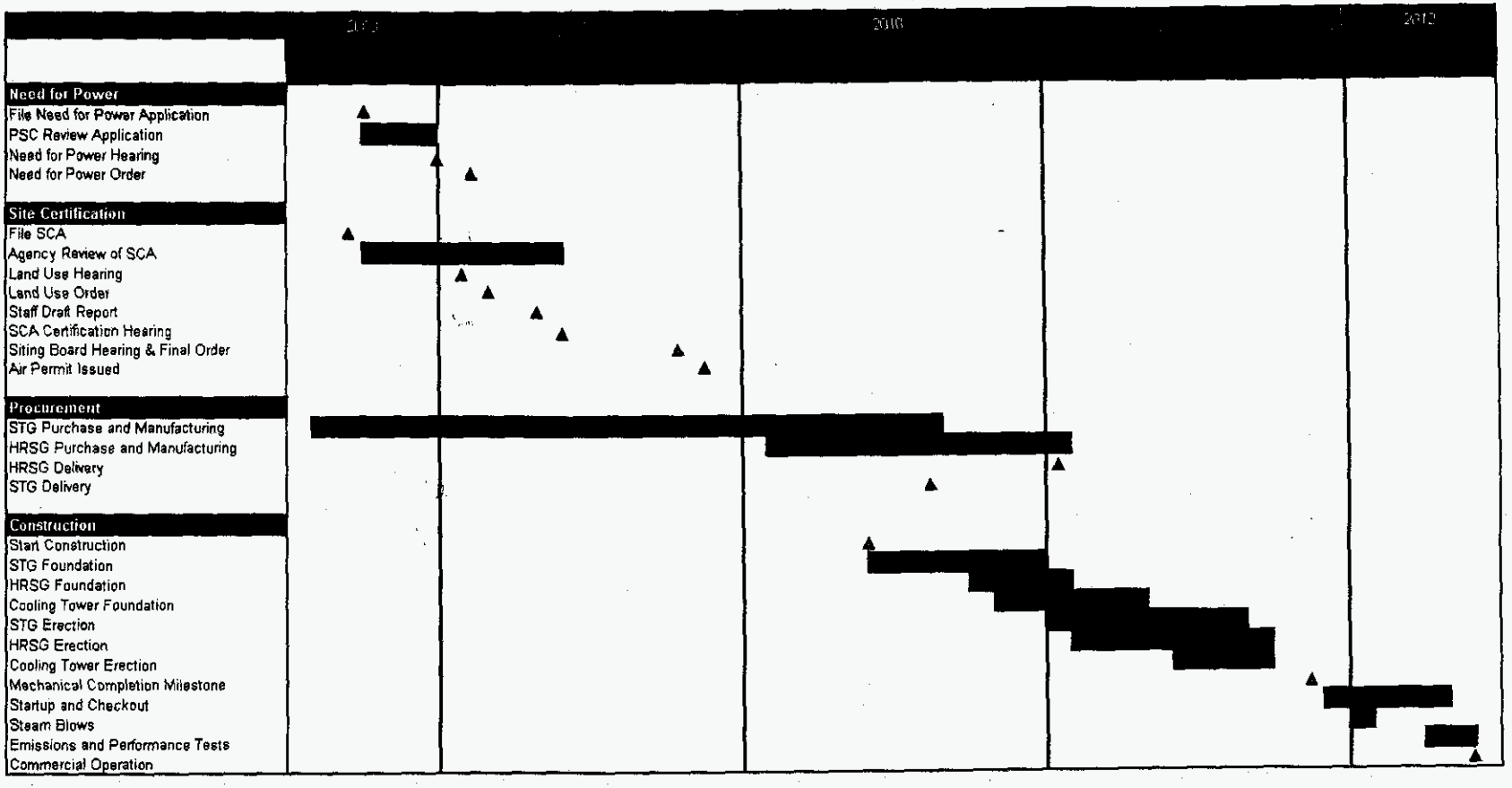
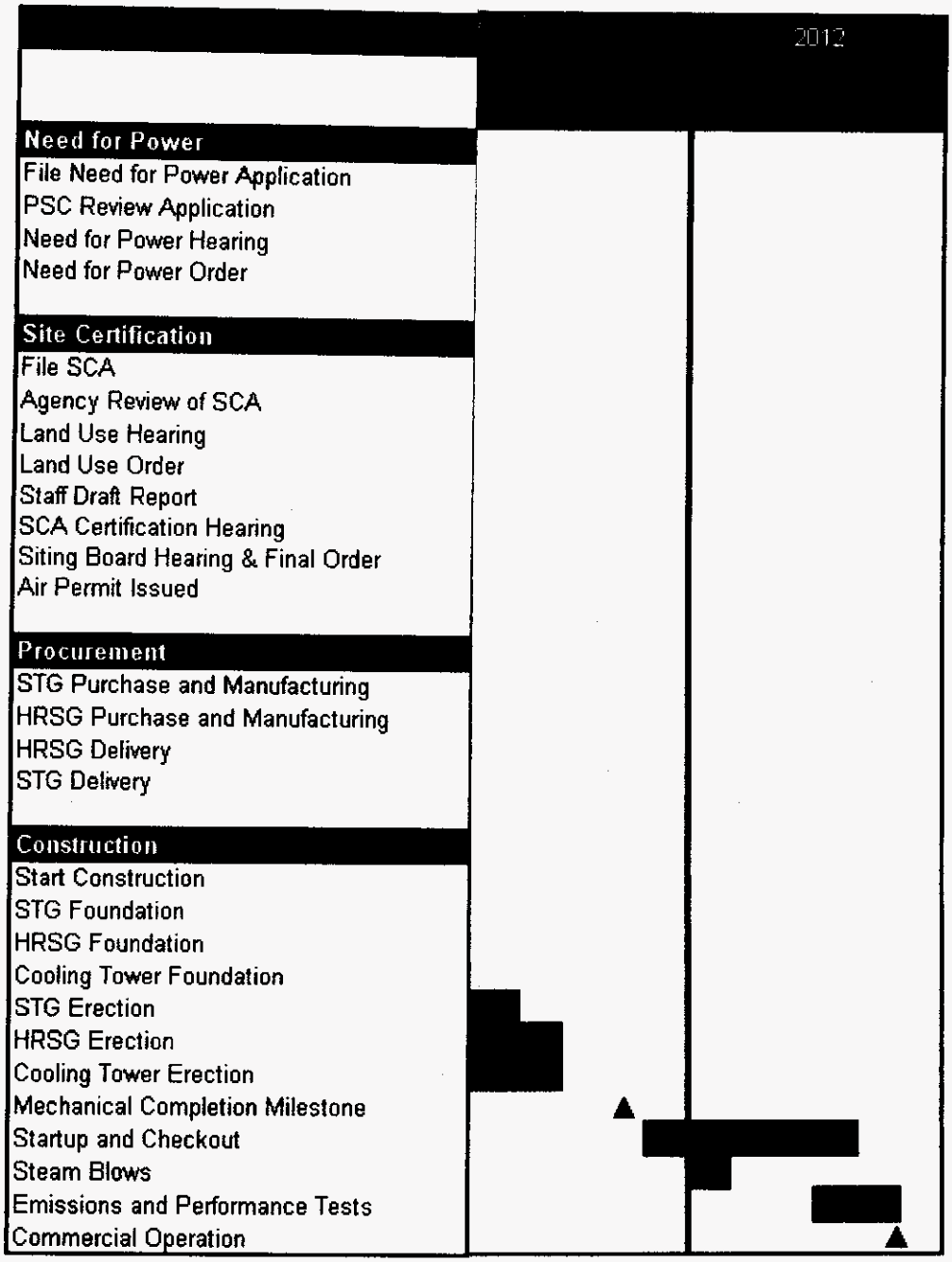


Figure 9-3
Schedule of Combined Cycle Conversion Construction Activities


2012
Need for Power
File Need for Power Application
PSC Review Application
Need for Power Hearing
Need for Power Order
Site Certification
File SCA
Agency Review of SCA
Land Use Hearing
Land Use Order
Staff Draft Report
SCA Certification Hearing
Siting Board Hearing & Final Order
Air Permit Issued
Procurement
STG Purchase and Manufacturing
HRSG Purchase and Manufacturing
HRSG Delivery
STG Delivery
Construction
Start Construction
STG Foundation
HRSG Foundation
Cooling Tower Foundation
STG Erection
HRSG Erection
Cooling Tower Erection
Mechanical Completion Milestone
Startup and Checkout
Steam Blows
Emissions and Performance Tests
Commercial Operation

RESUME OF

Mary Guyton-Baker

Professional Engineer, JEA Resource Planning Group

JEA

EDUCATION

Polk Community College	Fall 1983	AA, Pre-Engineering
University of Florida	Fall 1986	BS, Industrial & Systems Engineering Gainesville, FL
University of North Florida	Spring 2006	ME, Math Education

PROFESSIONAL EXPERIENCE

JEA — January 12, 1987 - Present — Engineer, Electric System Planning
Jacksonville, FL

Major responsibilities include modeling and production of JEA's load and energy forecast, Integrated Resource Planning (IRP) studies, and the annual Ten Year Site Plan (TYSP). Other responsibilities include the economic analysis and/or support of JEA's annual disclosure document, annual marginal cost projections and budget, demand side management plan, emission projections and various internal production cost analyses. I also provide support to and serve on behalf of JEA on the Florida Reliability Coordinating Council's Resource Working Group, interfacing with resource planners from other Florida utilities and staff of the Florida Public Service Commission.

PROFESSIONAL LICENSES

Professional Engineer — State of Florida Board of Professional Engineers
License Number: 65611
Expiration: February 28, 2009

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614EI EXHIBIT 10
COMPANY JEA (Direct)
WITNESS Mary Guyton-Baker (MGB-1)
DATE 02/12/09

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EI EXHIBIT 11
COMPANY JEA (Direct)
WITNESS Mary Guyton-Baker (GEC-1) Section 5.0
DATE 02/12/09

5.0 Forecast of Electrical Demand and Consumption

5.1 Load Forecast

This section describes the methodology used to develop the peak demand and net energy for load forecasts for JEA for the years 2008 through 2027 and presents the resulting forecasts.

5.1.1 JEA Historical Peak Demand

The forecast of peak demand requires projecting both the summer and winter peaks. JEA has historically experienced annual peaks in both the summer and winter periods. Table 5-1 indicates that between 1998 and 2007, the system peak occurred seven times during the winter period and three times in the summer period.

Table 5-1 indicates that from 1998 to 2007, the winter peak demand increased from 1,938 MW to 2,722 MW, which is an average annual growth rate of 3.85 percent. The 1998 summer peak demand level was 2,338 MW, and the 2007 summer peak was 2,897 MW. The average annual growth rate for the summer peak demand was 2.41 percent.

Table 5-1
Historical JEA Peak Demand (with FPUC)

Year	Winter (MW)	Summer (MW)
1998	1,938	2,338
1999	2,403	2,427
2000	2,478	2,380
2001	2,666	2,389
2002	2,590	2,562
2003	3,083	2,535
2004	2,668	2,539
2005	2,860	2,815
2006	2,919	2,835
2007	2,722	2,897
Average Annual Percent Change 1998-2007	3.85%	2.41%

5.1.2 JEA Peak Demand Forecast

To forecast peak demand, JEA has developed a regression analysis technique that utilizes SAS and Excel software. JEA develops a forecast of total load, including interruptible and curtailable customers, and then subtracts these customers to derive an estimate of firm demand only.

The peak demand forecast is driven by temperature and time-series data. The forecasting process involves the collection of historical hourly system load data and daily temperature data. Since the historical system peak has occurred on non-holiday weekdays, JEA has found that the most accurate historical forecasting method involves removing the data for weekends and holidays from the historical database. To further eliminate historical data that would tend to understate peak demand levels, summer load data was further reduced if a day was a summer rain day and if the 5:00 p.m. load is lower than the 3:00 p.m. load. Since JEA demand peaks in the late afternoon during the summer, the highest value between 2:00 p.m. and 8:00 p.m. was identified as the daily peak for the remaining summer days. For winter days, the daily peak occurs early in the morning because of heating requirements. To eliminate historical data that would tend to distort the analysis, daily load data was removed if a cold front moved in and caused the 11:00 a.m. load to be higher than the load between 1:00 a.m. and 11:00 a.m.

After the summer and winter data were adjusted, as described previously, a regression analysis was conducted to forecast the summer and winter peaks. The forecast temperature used in the regression was 97° F (summer) and 25° F (winter) where the winter seasonal extreme for a year was the lowest temperature during the months of December, January, and February, and the summer seasonal extreme was the highest temperature during the months of July, August, and September.

The results of the summer and winter peak demand forecasts are shown in Table 5-2 for total peak demand, non-firm demand, and firm peak demand. During the 20 year forecast period, total summer peak demand is forecast to increase at an average annual growth rate of 1.88 percent. The annual growth rate in summer firm peak demand is 1.94 percent. Total winter peak demand is forecast to increase at an average annual growth rate of 2.06 percent. The annual growth rate in winter firm peak demand is 2.14 percent. The winter and summer non-firm demand values are projected to remain constant at 133 MW and 117 MW, respectively.

Table 5-2 indicates that the total JEA peak demand in 2008 is projected to be 3,079 MW in the winter, compared to a summer total peak demand of 2,941 MW. In the final year of the forecast, the 2027 total winter peak demand is projected to be 4,537 MW, compared to 4,187 MW during the summer period. A similar pattern holds for the firm peak demand projections. The firm winter peak demand is projected to increase from 2,946 MW in 2008 to 4,404 MW in 2027, and the firm summer peak demand is projected to increase from 2,824 MW in 2008 to 4,070 MW in 2027. These projections assume that the FPUC load (refer to Section 3.0) will continue to be served through the end of the study period.

In addition to a base case forecast, JEA performed a forecast that incorporates the effects that extreme or moderate temperatures could have on peak demand (Extreme and Moderate Condition forecasts). The temperatures used for the winter season were 7° F and 32° F for the Extreme and Moderate forecasts, respectively. The temperatures used for the summer season were 103° F and 93° F for the Extreme and Moderate forecasts, respectively. The Extreme and Moderate peak demand forecasts for the summer and winter seasons are presented in Table 5-3.

Table 5-2
JEA Peak Demand Forecast (with FPUC)

Year	Total Peak Demand		Non-Firm Demand		Firm Peak Demand	
	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)
2008	3,079	2,941	133	117	2,946	2,824
2009	3,155	3,007	133	117	3,022	2,890
2010	3,232	3,072	133	117	3,099	2,955
2011	3,309	3,138	133	117	3,176	3,021
2012	3,386	3,204	133	117	3,253	3,087
2013	3,462	3,269	133	117	3,329	3,152
2014	3,539	3,335	133	117	3,406	3,218
2015	3,616	3,400	133	117	3,483	3,283
2016	3,693	3,466	133	117	3,560	3,349
2017	3,770	3,531	133	117	3,637	3,414
2018	3,846	3,597	133	117	3,713	3,480
2019	3,923	3,662	133	117	3,790	3,545
2020	4,000	3,728	133	117	3,867	3,611
2021	4,077	3,794	133	117	3,944	3,677
2022	4,153	3,859	133	117	4,020	3,742
2023	4,230	3,925	133	117	4,097	3,808
2024	4,307	3,990	133	117	4,174	3,873
2025	4,384	4,056	133	117	4,251	3,939
2026	4,461	4,121	133	117	4,328	4,004
2027	4,537	4,187	133	117	4,404	4,070
Average Annual Percent Change	2.06%	1.88%	0.00%	0.00%	2.14%	1.94%

Table 5-3
JEA Moderate and Extreme Peak Demand Forecast (with FPUC)

Year	Moderate Case[1]				Extreme Case[2]			
	Winter Total (MW)	Winter Firm (MW)	Summer Total (MW)	Summer Firm (MW)	Winter Total (MW)	Winter Firm (MW)	Summer Total (MW)	Summer Firm (MW)
2008	2,897	2,764	2,808	2,691	3,244	3,111	3,019	2,902
2009	2,970	2,837	2,871	2,754	3,326	3,193	3,086	2,969
2010	3,042	2,909	2,934	2,817	3,408	3,275	3,154	3,037
2011	3,114	2,981	2,997	2,880	3,490	3,357	3,221	3,104
2012	3,186	3,053	3,060	2,943	3,572	3,439	3,288	3,171
2013	3,258	3,125	3,122	3,005	3,655	3,522	3,355	3,238
2014	3,331	3,198	3,185	3,068	3,737	3,604	3,422	3,305
2015	3,403	3,270	3,248	3,131	3,819	3,686	3,489	3,372
2016	3,475	3,342	3,311	3,194	3,901	3,768	3,556	3,439
2017	3,547	3,414	3,374	3,257	3,983	3,850	3,624	3,507
2018	3,619	3,486	3,437	3,320	4,065	3,932	3,691	3,574
2019	3,692	3,559	3,500	3,383	4,147	4,014	3,758	3,641
2020	3,764	3,631	3,563	3,446	4,229	4,096	3,825	3,708
2021	3,836	3,703	3,625	3,508	4,312	4,179	3,892	3,775
2022	3,908	3,775	3,688	3,571	4,394	4,261	3,959	3,842
2023	3,980	3,847	3,751	3,634	4,476	4,343	4,027	3,910
2024	4,052	3,919	3,814	3,697	4,558	4,425	4,094	3,977
2025	4,125	3,992	3,877	3,760	4,640	4,507	4,161	4,044
2026	4,197	4,064	3,940	3,823	4,722	4,589	4,228	4,111
2027	4,269	4,136	4,003	3,886	4,766	4,633	4,295	4,178
Average Annual Percent Change	2.06%	2.14%	1.88%	1.95%	2.05%	2.12%	1.87%	1.94%

[1]Based on a 32° F low winter temperature and a 93° F high summer temperature.
[2]Based on a 7° F low winter temperature and a 103° F high summer temperature.

5.1.3 JEA Historical Net Energy for Load

JEA's historical NEL requirements are shown in Table 5-4. NEL is defined as the energy generated and purchased minus off-system sales. From 1998 through 2007, the annual average growth rate in NEL on the JEA system was 2.12 percent. This growth rate was lower than the growth rate in JEA's winter and summer peak demand during the same period. Total NEL requirements during the period increased from 11,470 GWh in 1998 to 13,854 GWh in 2007.

Table 5-4
Historical JEA Net Energy for Load Requirements
(with FPUC)

Year	Actual NEL (GWh)
1998	11,470
1999	11,782
2000	12,190
2001	12,322
2002	12,983
2003	13,204
2004	13,243
2005	13,696
2006	13,811
2007	13,854
Average Annual Percent Increase	2.12%

5.1.4 JEA Net Energy for Load Forecast

The NEL forecast was developed on a monthly and annual basis as a function of time and heating and cooling degree-day data. Inputs into the forecast include energy production, JEA territory sales, off-system sales, and heating and cooling degree-days. The JEA forecast modeling methodology separately accounts for and projects the temperature-dependent and non-temperature-dependent energy requirements over time, then combines these components to derive the system total NEL forecast. The temperature-dependent NEL is modeled as a function of parameter estimates for historical and projected heating degree-days (HDDs) and cooling degree-days (CDDs). The HDD and CDD parameter estimate projections were based on the 1985 through 2006 historical averages.

The NEL forecast for JEA is shown in Table 5-5. The NEL is forecast to increase at an average annual growth rate of 2.08 percent during the 2008 through 2027 forecast period. NEL is forecast to increase from 14,701 GWh in 2008 to 21,726 GWh in 2027. These projections assume that the FPUC load (refer to Section 3.0) will continue to be served through the end of the study period.

Table 5-5
JEA Forecasted Net Energy for Load
(with FPUC)

Year	NEL (GWh)
2008	14,701
2009	15,016
2010	15,367
2011	15,717
2012	16,106
2013	16,418
2014	16,768
2015	17,119
2016	17,511
2017	17,820
2018	18,170
2019	18,520
2020	18,916
2021	19,222
2022	19,572
2023	19,922
2024	20,321
2025	20,623
2026	21,324
2027	21,726
Average Annual Percent Increase	2.08%

As previously discussed, in addition to the base NEL forecast JEA prepares an Extreme Condition forecast and a Moderate Condition forecast. The Extreme Condition forecast is based on the maximum HDDs and CDDs, by month, since 1985. The Moderate Condition forecast is based on the minimum HDDs and CDDs, by month, since 1985.

Results of these alternative forecasts are shown in Table 5-6. Under the Extreme Condition forecast, the total NEL would increase from 16,003 GWh in 2008 to 23,132 GWh in 2027, yielding an average annual growth rate of 1.96 percent. Under the Moderate Condition forecast, the total NEL would increase from 14,000 GWh in 2008 to 20,346 GWh in 2027, yielding an average annual growth rate of 1.99 percent.

Table 5-6
JEA Net Energy for Load--Moderate and Extreme Cases
(with FPUC)

Year	Moderate Forecast[1] (GWh)	Extreme Forecast[2] (GWh)
2008	14,000	16,003
2009	14,301	16,345
2010	14,636	16,722
2011	14,972	17,099
2012	15,347	17,515
2013	15,644	17,853
2014	15,980	18,230
2015	16,315	18,607
2016	16,693	19,026
2017	16,988	19,361
2018	17,323	19,738
2019	17,659	20,115
2020	18,040	20,538
2021	18,331	20,870
2022	18,667	21,247
2023	19,002	21,623
2024	19,387	22,049
2025	19,675	22,378
2026	20,010	22,755
2027	20,346	23,132
Average Annual Percent Change	1.99%	1.96%

[1]Based on minimum HDDs and CDDs, by month, since 1985.
[2]Based on maximum HDDs and CDDs, by month, since 1985.

JAMES T. MYERS

Director, Fuel Management Services
JEA
21 West Church Street
Jacksonville, FL 32202
904-665-6224
Email: myerjt@jea.com

SUMMARY

Over twenty-six years experience in fuel procurement, generation planning, and related activities at JEA including three years in current position as Director, Fuel Management Services.

PROFESSIONAL EXPERIENCE

FUEL MANAGEMENT SERVICES **1995-Present**

Team member and, since 2003, Director of group responsible for design and implementation of fuel management processes including fuel supply planning, procurement and scheduling, and reporting. Developed fuel acquisition strategies and market forecasts for JEA Electric System, negotiated agreements, and maintained documentation supporting fuel purchases.

Selected Accomplishments

- Directly responsible for approximately $300 million of current annual JEA fuel and purchased power budget including the procurement of all petroleum coke, coal, natural gas, #6 fuel oil, #2 fuel oil, and limestone for JEA Electric System.
- JEA representative on St. John's River Power Park and Plant Scherer Fuel Committees.
- Chairman, Taylor Energy Center Fuel Committee.
- Maintained sufficient economic supply of fuel during various recent storm events and 2003 Venezuelan worker strike.
- Acquired delivered gas supplies at below market rate to support long term JEA needs.
- Negotiated natural gas agreements that provide flexible gas volumes and the construction of laterals serving JEA's Brandy Branch Generating Station.
- Coordinated the transfer of daily gas procurement activity to The Energy Authority's natural gas trading group.
- Achieved "Six Sigma Green Belt" designation in reducing JEA's #6 oil procurement by over $2 million since June 2004.
- Developed fuel price forecasts to support budget analysis, Ten Year Site Plans and Integrated Resource Planning Studies.

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DOCKET NO. 080614-EM EXHIBIT 12
COMPANY JEA (Direct)
WITNESS James T. Myers (JTM-1)
DATE 02/12/09

ENERGY RESOURCE PLANNING **1987-1995**

Responsible for long range planning. This effort included the development of corporate financial models and preparation of Official Statements to support bond issues. Prepared and submitted various regulatory filings such as the Ten Year Site Plan required by the Florida Public Utilities Commission.

Selected Accomplishments

- Participated in JEA's first IRP study in 1994/95.
- Developed economic analysis supporting Scherer 4 capacity purchase in 1991.
- Served as Chairman (1991-92) and Vice-Chairman (1990-91) of the Florida Electric Power Coordinating Group's Generation Task Force.
  - Presented the Florida Ten Year Plan and JEA Ten Year Site Plan to FPSC staff.
  - Represented Florida subregion before NERC Reliability Assessment subcommittee.
- Evaluated various computer models for load research/forecasting and generation planning.

LOAD AND ENERGY FORECASTING / LOAD RESEARCH **1981-1986**

Developed economic, energy, and peak demand models and produced load and energy forecasts for generation planning.

Selected Accomplishments

- Reduced expenses by bringing the forecast process in-house in 1983.
- Developed annual forecast documents.
- Produced statistically valid estimates of residential appliance use and developed annual residential customer survey documents.

EDUCATION

Bachelor of Industrial Engineering, Georgia Institute of Technology - 1981
Numerous Professional Seminars
"Six Sigma Green Belt" training and designation
Working knowledge of Excel, Word, and Power Point

ACCREDITATION

Registered Professional Engineer in Florida, February 1986

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 13
COMPANY JEA (Direct
WITNESS James T. Myers (GEC-1) Sections 6.0 & 8.0
DATE 02/12/09

6.0 Natural Gas Availability

This section discusses the availability of natural gas based on information from the US Energy Information Administration (EIA) and other sources as described in this section. Due to projected increases in natural gas production and imports of liquefied natural gas (LNG), natural gas supplies are projected to meet projected demand in the United States. There are also several new natural gas storage and pipeline projects that will help facilitate reliable delivery of natural gas to the Southeast region. For these and other reasons, the GEC will have a reliable supply of natural gas.

6.1 Domestic Natural Gas Production and Imports

The fuel price projections presented in Section 7.0 for natural gas, fuel oil, and coal used in this Application were developed based on those included in the US EIA Annual Energy Outlook 2008 (AEO 2008). AEO 2008 presents projections of energy supply, demand, and prices through 2030. The projections presented within AEO 2008 are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer based, energy-economy modeling system of US energy markets. It projects the production, imports, conversion, consumption, and prices of energy.

According to the AEO 2008 reference case, total domestic US natural gas production, including supplemental natural gas supply, is projected to increase from 19.24 trillion cubic feet (Tcf) in 2008 to peak at 20.04 Tcf in 2022, before slightly declining to 19.44 Tcf in 2030. The overall projected trend in domestic natural gas production between 2008 and 2030 reflects a shift in sources of domestic supply from large fields in Alaska and the Gulf of Mexico to newer but smaller sources.

A large proportion of the lower 48 onshore conventional natural gas resource base has been discovered. Discoveries of new conventional natural gas reservoirs are expected to be smaller and deeper, and thus more expensive and riskier to develop and produce. Accordingly, total onshore production within the lower 48 US states will decline from 15.49 Tcf in 2008 to 13.95 Tcf by 2030. This reduced overall production will be due in part to the decrease in onshore conventional natural gas production in the lower 48 states, which the AEO 2008 reference case predicts will decrease from 5.09 Tcf in 2008 to 3.23 Tcf in 2030.

Given the decline in conventional sources, the incremental production of lower 48 onshore natural gas is projected to come primarily from unconventional resources, including coalbed methane, tight sandstones, and gas shales. The increased role of unconventional resources was evident as more than half of the increase in natural gas production between the first-quarter of 2007 and the first-quarter of 2008 came from

Texas, where supplies grew by an exceptionally high 15 percent. Other contributing regions included Wyoming (with growth of 9 percent), Oklahoma (with 6 percent growth), and Louisiana (with 4 percent growth). Even natural gas production from the offshore Gulf of Mexico, which had been declining for years, increased 2 percent from first-quarter 2007 to first-quarter 2008. The startup last year of production from the deepwater Independence Hub, with wells in 9,000 feet of water, alone added about 1 percent to lower 48 states production while production in the rest of the states as a whole increased by 8 percent from first-quarter 2007 to first-quarter 2008.

Of the unconventional resources for domestic natural gas, shales seem particularly promising. As can be seen on Figure 6-1, shale formations in the lower 48 states are large and widely distributed. They contain huge resources of natural gas that are just starting to be fully developed. Production from the Barnett Shale field in Texas, alone, contributes more than 6 percent of production to the lower 48 states. Considerable natural gas resources also remain in the offshore Gulf of Mexico, especially in the deep waters.

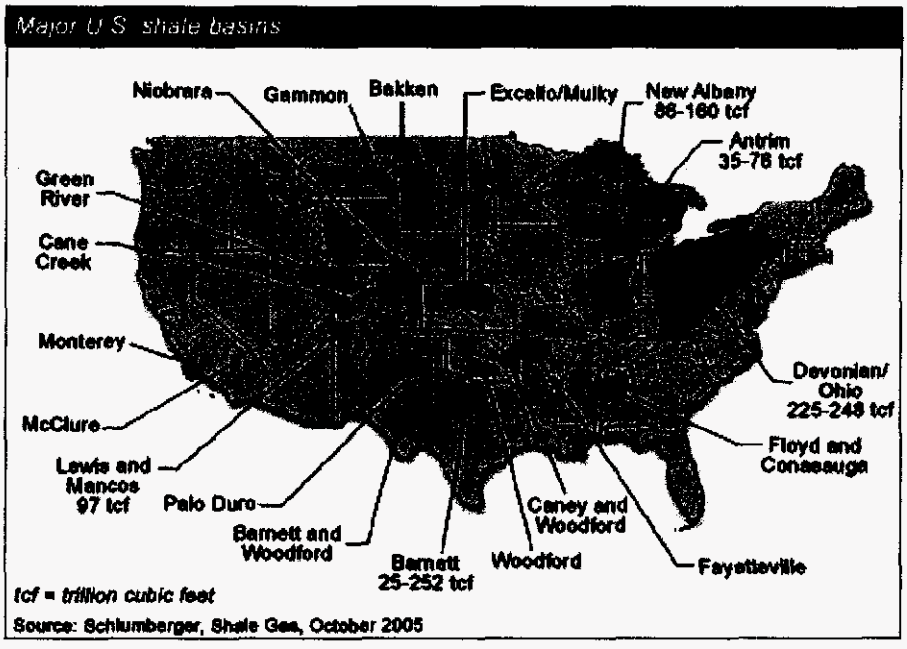

Figure 6-1
Major US Shale Basins
(Source: www.eia.doe.gov)

The Alaska pipeline is expected to be an even more significant source of domestic natural gas. It will begin to transport gas to the lower 48 States in 2020, when the pipeline is expected to be completed. The projected total amount of natural gas produced

in Alaska remains around 0.41 Tcf from 2008 until it spikes to 1.19 Tcf in 2020 with the pipeline completion, and then doubles its production to 2.0 Tcf in 2021 as the pipeline goes fully online. Production remains at that approximate level, ending at 2.01 Tcf in 2030. Figure 6-2 indicates domestic sources of gas supply.

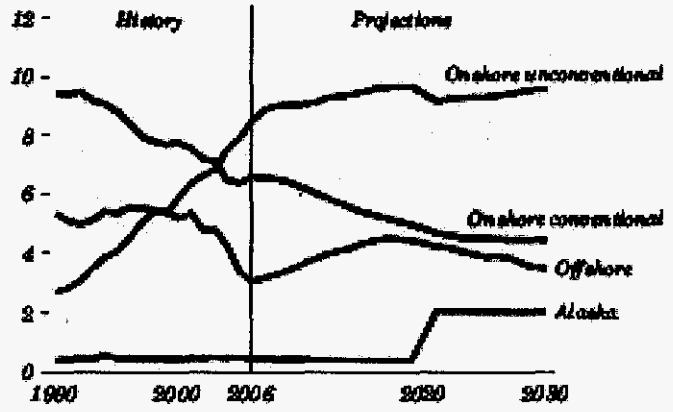

Figure 6-2
Domestic Sources of Gas Supply (Tcf per year)
(Source: www.eia.doe.gov)

While not domestic sources of natural gas, Canada and Mexico's supplies are closely linked to the US via pipeline. Net pipeline imports of natural gas from these two countries are projected to decrease from 2.95 Tcf in 2008 to 0.33 Tcf in 2030 in the AEO 2008 reference case. However as described later in this section, total net imports of LNG to the United States in the AEO 2008 reference case are expected to increase from 0.90 Tcf in 2008 to 2.8 Tcf in 2030, as other countries begin to export more LNG to the United States.

6.2 Liquefied Natural Gas

LNG is natural gas that has been cooled to -260° F at atmospheric pressure, the point at which natural gas condenses to a liquid. When natural gas is converted to a liquid (i.e., LNG), its volume is reduced by a ratio of 600 to 1, allowing considerably more natural gas to be stored and shipped in its liquid form. The LNG is stored in double-walled tanks at atmospheric pressure and shipped aboard specially designed LNG storage vessels.

Upon the vessel's arrival at an LNG receiving facility, the LNG is pumped onshore in its liquid state. It is then stored in permanent double-walled tanks, or is heated, vaporized, and regulated for temperature and pressure, and delivered as natural gas into a pipeline network. The former method provides the greatest flexibility in terms

of where the LNG is stored until needed, acting similar in nature to deliveries from natural gas storage. In the latter instance, the gas must be received and used as a supplemental baseload supply.

6.2.1 Liquefied Natural Gas in North America

The United States is one of the world's leading importers of LNG. In 2007, the US LNG imports totaled 770,812 Tcf. These imports were sourced from six countries: Trinidad and Tobago, Egypt, Equatorial Guinea, Nigeria, Qatar, and Algeria. According to the reference case, net imports of LNG are expected to increase by an annual value of 5.4 percent between 2008 and 2030. In terms of actual volume, LNG imports will rise from 0.90 Tcf in 2008 to 2.84 Tcf in 2030. LNG receiving terminal capacity is anticipated to also increase from 1.5 Tcf in 2006 to 5.2 Tcf in 2009 (with no further increase through 2030) in order to accommodate this growth.

Currently, the United States maintains four onshore LNG terminals: Distrigas Facility in Everett, Massachusetts; Dominion Cove Point LNG in Lusby, Maryland; Southern LNG in Elba Island, Georgia; and Trunkline LNG in Lake Charles, Louisiana. The United States also has one offshore LNG terminal, the Gulf Gateway Energy Bridge. These existing energy terminals are shown on Figure 6-3.

The Distrigas facility is owned by Suez, North America and receives the largest volume of any onshore terminal in the United States at 184 billion cubic feet (Bcf). The sustainable daily capacity of the Distrigas facility is approximately 725 million cubic feet (Mcf). By comparison, the Dominion Cove Point LNG facility received 117 Bcf in 2006, and plans are in place to expand the regasification capability of the facility to 657 Bcf per year by late 2008. StatoilHydro, Shell, and BP currently share the capacity rights to the Dominion Cove Point LNG facility.

Southern LNG and Trunkline LNG received 147 Bcf and 144 Bcf of LNG, respectively, in 2006. The United Kingdom based BG Group owns the capacity rights to the Southern and Trunkline LNG facilities. Both facilities have undergone recent expansions and plans are in place to further expand each facility. El Paso Corporation, which owns Southern LNG, has formulated a plan to increase its regasification capacity from the current 1.2 Bcf per day (Bcf/d) to 2.1 Bcf/d by 2010, as well as constructing new pipeline connections to access new markets. The Southern Union Company owns Trunkline LNG, which maintains a regasification capacity of 1.8 Bcf/d. Currently, the sendout capacity of the Trunkline LNG facility is 0.3 Bcf/d, but plans are in place to increase the sendout capacity to 2.1 Bcf/d by 2009.

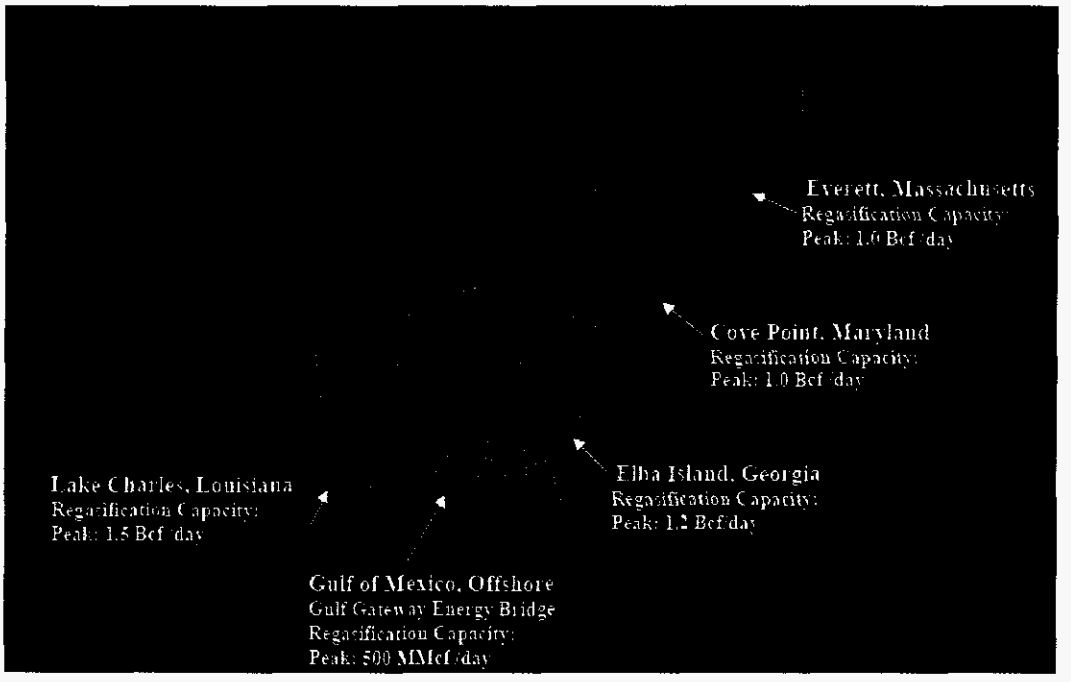

Figure 6-3
Current US LNG Import Terminals
(Source: www.eia.doe.gov)

6.2.2 Existing LNG Importing Countries for North America

LNG imports to the United States were generally not competitive with domestic supplies of natural gas and pipeline imports from Canada through the 1980s and 1990s, resulting in low levels of these imports during these decades. However, higher natural gas prices in the United States in recent years have attracted larger volumes of LNG imports to this country, including a record US total in 2007 equaling 771 Bcf of natural gas in gaseous form.

Deliveries of LNG from Trinidad and Tobago account for the majority of LNG imports to the United States. The Atlantic LNG facility located in Port Fortin, Trinidad and Tobago, now produces nearly 700 Bcf a year. In recent years, several African countries, including Egypt, Nigeria, and Algeria, also have been suppliers of LNG to the United States.

Growth in LNG imports to US markets is expected to come from new trading partners, one of which is Equatorial Guinea, where Marathon Oil Corporation has begun operation of an LNG plant. This plant, located on Bioko Island, has recently begun deliveries to the United States. In total, Trinidad and Tobago supplied 451 Bcf of LNG to the United States in 2007. This was 59 percent of the total LNG imported by the United States for the year.

Algeria, which was formerly the largest exporter of LNG supply to the United States, exported a total 17 Bcf of LNG in 2006. This was a drastic reduction from the 97 Bcf of LNG it exported to the US in 2005. In 2007, that trend reversed, with Algeria supplying 75 Bcf, or 10 percent of the US annual LNG import.

Egypt began exporting LNG to the United States in 2005. During 2005, Egypt exported a total of 73 Bcf to the United States. In 2006, Egypt increased LNG exports to the United States by 47 Bcf, or 64.8 percent, for a total of 120 Bcf. This amount dropped slightly to 115 Bcf in 2007.

Nigeria increased LNG exports to the United States from 8 Bcf in 2005 to 57 Bcf in 2006 after increasing the liquefaction capacity on the Bonny Island facility. Its exports to the United States increased significantly to 95 Bcf in 2007, equivalent to 12 percent of the overall supply in the United States. Figure 6-4 shows the leading LNG exporters to the United States, by volume and percent.

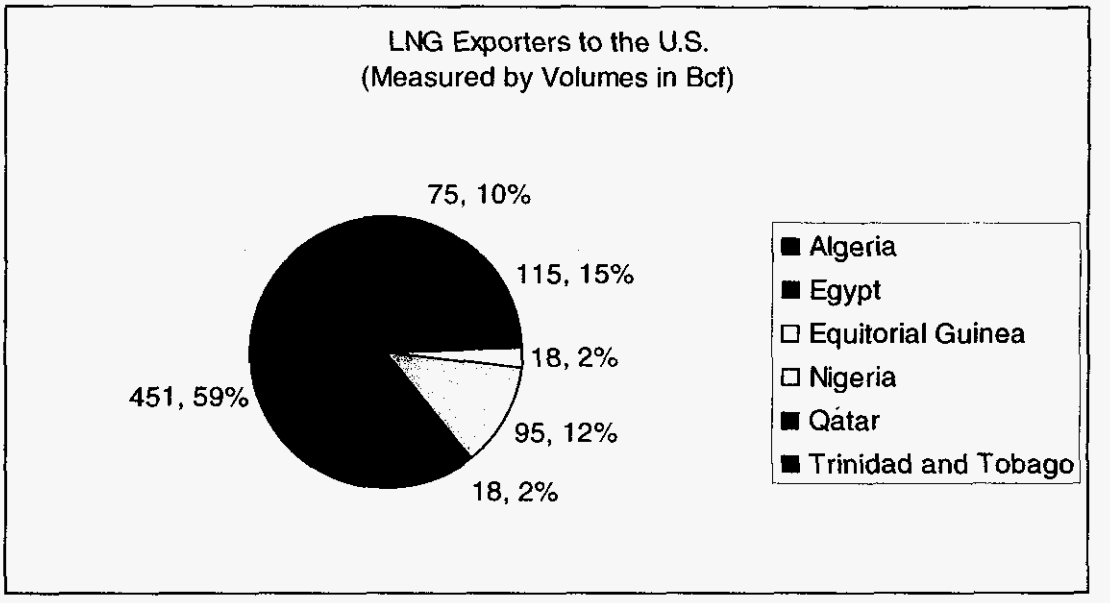

Figure 6-4
Top LNG Exporters to the United States in 2007
(Source: www.eia.doe.gov)

6.2.2.1 Potential LNG Importing Countries for North America. International LNG trade has grown rapidly in recent years as new export facilities have started operations in several countries. In 2006, 13 countries exported natural gas in the form of LNG to 17 importing countries. International trade equaled more than 7.5 Tcf of natural gas in 2006. By the end of 2010, there will likely be five additional exporting countries

for a total of 18 LNG source countries, although not all will be consistent suppliers of LNG to the United States.

LNG has the potential to be exported from countries with large, proven natural gas reserves and relatively high reserves-to-production ratios. Some countries meeting these criteria include the Republic of Peru, Republic of Venezuela, Azerbaijan Republic, Republic of Kazakhstan, Islamic Republic of Iran, Republic of Iraq, State of Kuwait, State of Qatar, United Arab Emirates (also known as Al Imarat al-Arabiyah al-Muttahidah), Republic of Yemen, Federal Republic of Nigeria, and the Independent State of Papua New Guinea.

However, not all of these countries are exporters of natural gas as LNG due to domestic need, inaccessibility to international natural gas trade and infrastructure, geopolitics, and lack of capital or technological investment. As largely populated countries such as the People's Republic of China and the Republic of India enter the international LNG market, the need to overcome these particular barriers, while further discovering and exploring accessible, proven natural gas reserves, is evident.

As traditional, economically viable oil and gas fields deplete, exploration and discovery have reached out to the furthest ends of the earth. The Arctic Ocean, long regarded as international territory, has experienced a recent rush for claims by not only Russia, but Denmark (via territory Greenland), Norway, the United States, and Canada.

The Antarctic landmass, traditionally used for research, has also seen a recent surge of land and maritime claims, most recently by the United Kingdom. Argentina, Australia, Chile, France, New Zealand, Norway, and the United Kingdom all claim portions of the great landmass, although the United States does not recognize any of these claims. Along with Russia, the United States has reserved the right to make claims in the future on the southern-most continent.

Currently, natural gas supplies are expected to arrive to the United States from the Snohvit LNG project in Norway through a contract with StatoilHydro ASA. In the Middle East, Qatar, the largest LNG exporter in the world, is expected to begin regular deliveries to the United States in the next couple of years. New supplies are expected to come online in Yemen by early 2009, with much of the LNG projected to be delivered to US markets.

6.2.2.2 Future LNG Import Terminals in North America. Projected growth in the demand for LNG has resulted in companies adding LNG receiving capacity in the United States. Five LNG import terminals currently operate in the United States. Four of these have recently been expanded. EIA expects additional new terminals to be operational in the next 2 years, increasing import capacity from 4.7 Bcf/d at the end of 2006 to over 11 Bcf/d at the end of 2008. It is projected that the regasified natural gas

sendout capacity of onshore facilities could grow to more than 10 Bcf/d by the middle of 2010, with about half of this sendout capacity coming from new terminals.

6.2.2.2.1 Freeport LNG Terminal. One of these terminals is the Freeport LNG terminal on Quintana Island, Texas. It is nearing completion and will mark the first new onshore terminal in the United States in more than 25 years. Operations are expected to begin in 2008 with deliverability of 1.5 Bcf/d. The terminal is owned by a partnership of Michael S. Smith and ConocoPhillips, Cheniere Energy, Dow Chemical, and Contango Oil and Gas companies. ConocoPhillips has contracted for 500 Mcf/d of the capacity until mid-2009 and 1 Bcf/d thereafter; Dow Chemical, 500 Mcf/d; and Mitsubishi Corp., 150 Mcf/d for 17 years starting in 2009. Freeport LNG has also received approval from the FERC to expand the terminal's regasification capacity to 4.0 Bcf/d, which would make it the largest regasification terminal in the United States.

6.2.2.2.2 Sabine Pass Terminal. Cheniere Energy, Incorporated, is nearing completion of its new Sabine Pass LNG terminal in Cameron Parish, Louisiana. That facility will have 2.6 Bcf/d of sendout capacity. Total S.A. has reserved 1 Bcf/d of capacity for 20 years, while Chevron Corp. has reserved 700 Mcf/day for 20 years. Sabine Pass operations began in March 2008, and Cheniere Energy has received permission from FERC to expand the LNG terminal to 4.0 Bcf/d.

6.2.2.2.3 Cameron LNG Terminal. Sempra Energy's Cameron LNG facility on Lake Charles, Louisiana, is under construction with an expected initial capacity of 1.5 Bcf/d and an estimated operation date of late 2008. Italy's Eni SpA has agreed to purchase 0.6 Bcf/d of capacity at the facility for 20 years, while Algeria's Sonantrach, Suez North America, and Merrill Lynch Commodities are nearing final capacity arrangements. While the first phase of construction is ongoing, Sempra has initiated regulatory applications for a second phase of construction that would increase regasification capacity to about 2.7 Bcf/d by 2010.

6.2.2.2.4 Golden Pass LNG Terminal. ExxonMobil has received approval from FERC and has begun construction of its Golden Pass project near Sabine Pass, Texas. In the first phase of operations, Golden Pass, majority owned by Qatar Petroleum, will have the capacity to deliver up to 1 Bcf/d into the pipeline grid. It will likely be employed for receiving LNG from Qatar starting in 2009. ExxonMobil has signed contracts of agreement with Qatar for 2 Bcf/d of supply starting in 2009.

6.2.2.2.5 Florida LNG Supply Options. Recognizing pipeline transportation limitations, there are four viable options to supply Florida directly with LNG. These four options are: (1) Gulf LNG Clean Energy Project; (2) Elba Island with deliveries to Florida Gas Transmission Company (FGT) via the Cypress pipeline; (3) the Calypso Project; and (4) the Port Dolphin Project. The first two projects are onshore LNG storage

facilities that either exist (Elba Island) or are under construction. The latter two are deepwater port facilities that will gasify LNG onboard the delivering vessel. The Gulf LNG Clean Energy Project and the Dolphin Port Project are still obtaining the necessary permits and certifications. The following subsections discuss each of these projects.

6.2.2.2.5.1 Gulf LNG Clean Energy Project. The Gulf LNG Clean Energy Project is jointly owned. El Paso Corporation owns 50 percent of the facility. The remaining 50 percent is shared by The Crest Group, consisting of Houston-based investors, with a 30 percent ownership in the project, and Sonangol USA with 20 percent. Sonangol is the state-owned national oil company of Angola, responsible for the development of Angola's hydrocarbon resources.

The project received its FERC certificate in February 2007 and is currently under construction. The terminal includes the construction of two 160,000 cubic meter storage tanks with a combined capacity of 6.6 Bcf, 10 high pressure submerged combustion vaporizers; and 5 miles of 36 inch pipeline. The pipeline will connect the terminal to Gulfstream, Destin Pipeline, FGT, and Transco. The terminal is expected to be placed into service in late 2011 at an estimated cost of $1.1 billion.

6.2.2.2.5.2 Elba Island. Southern LNG plans to expand its Elba Island facilities in order to supply new gas to growth markets in the Southeastern United States. Specifically, it plans to further expand its Elba Island LNG receiving terminal in Savannah, Georgia. Southern LNG also proposes to construct, own, and operate a new 190 mile interstate natural gas pipeline, Elba Express.

Construction has already begun on the significant expansions to the Elba Island LNG terminal. The expansion will add 8.4 Bcf of total storage capacity at the facility. The expansion will take place in two phases. Phase I of the project will add one 200,000 cubic meter storage tank that holds 1,250,000 barrels. The new tank will be complete by mid-year of 2010 and will add approximately 4.2 Bcf of LNG storage capacity to the terminal. Maximum sendout capacity will be 0.405 Bcf/d. Phase I of the project will also include modifying the north and south docks to accommodate new larger vessels and to facilitate simultaneous unloading of two ships.

Phase II of the project will add an additional 200,000 cubic meter (1,250,000 barrel) storage tank. This tank will add approximately 4.2 Bcf storage capacity to the terminal in 2012 and increase sendout by 0.495 Bcf/d. The LNG for the expansion will be transported by ship from gas rich regions outside of the United States. Southern LNG's facilities at Elba Island will vaporize the LNG and inject the natural gas into Southern's existing pipeline.

6.2.2.2.5.3 The Calypso System. Calypso LNG LLC (a subsidiary of SUEZ Energy International) is proposing the development of a submerged buoy system known as a "Deep Water Port" (DWP) located off the southeastern coast of Florida. The Calypso DWP will serve as an offshore delivery point for connection to specially built LNG tankers. The LNG tankers will vaporize stored LNG and send it through the buoy system into the FERC-permitted Calypso US Pipeline, which will transport the natural gas onshore to deliver to the FGT system. When the offloading system is not in use, it will reside approximately 120 feet under the ocean surface. The DWP will consist of two buoys approximately 2.6 miles apart.

According to Suez Energy International, the Calypso Pipeline will be capable of delivering over 1 Bcf of natural gas per day, which represents approximately 25 percent of Florida's peak demand on a hot summer day.

The Maritime Administration (MARAD) and the US Coast Guard (USCG) announced in the Federal Register on November 2, 2007, the availability of the Draft Environmental Impact Statement (DEIS) for the Calypso LNG LLC, Calypso Natural Gas Deep Water Port (Calypso) license application (DWPA). The application describes a project that would be located in the federal waters of the Outer Continental Shelf in the OCS NG 17–06 (Bahamas) lease area, approximately 8 to 10 miles off the east coast of Florida to the northeast of Port Everglades, in a water depth of 800 to 950 feet.

USCG and MARAD have 240 days from the date of the Notice of Application to hold one or more public license hearings in the adjacent coastal state of Florida. The Governor of Florida must approve, approve with conditions, or deny the DWPA license within 45 days of the last DWPA public hearing. If the Governor does not act within 45 days, approval will be conclusively presumed. Approval or denial of the license application by MARAD must occur not more than 90 days after the last public hearing.

6.2.2.2.5.4 Port Dolphin Energy. Port Dolphin Energy LLC, a wholly owned US subsidiary of the Norwegian based company Hoegh LNG AS, is also proposing development of a deep water port. The proposed project would consist of two submerged unloading and mooring buoys to receive an average of up to 800 Mcf/d of natural gas from LNG Shuttle and Regasification Vessels (SRVs), which are oceangoing LNG vessels designed to regasify the LNG onboard and deliver natural gas to a subsea pipeline. The DWP would be connected to a subsea pipeline that would bring the regasified natural gas from the offshore terminal to Port Manatee in Tampa Bay. The pipeline is planned to interconnect with the Gulfstream Natural Gas System and the facilities of TECO Energy, Inc. (TECO). The proposed offshore terminal would be located approximately 28 miles from the coast. Initial average daily throughput will be approximately 400 million British thermal units per day (MBtu/d) of natural gas will

have a capacity of 800 MBtu/d of natural gas with peak delivery capacity of approximately 1.2 Bcf/d of natural gas.

Port Dolphin filed its DWPA with the USCG in March 2007 and expects the approval process for the Deepwater Port License and its associated permits will take approximately 18 months. Construction of the proposed project would consist of two phases with operations of Port Dolphin beginning in the second quarter of 2011.

6.3 Natural Gas Reserves

The United States had 211,085 Bcf of dry natural gas proven reserves as of December 31, 2006, the highest level since 1976. Proven reserves of natural gas increased by 3 percent from 2005 to 2006.

Texas led the nation in natural gas reserves additions in 2006 with a 9 percent increase in dry gas proven reserves, due to rapid development of Barnett Shale reservoirs in the Newark East Field. Advances in horizontal drilling and hydraulic fracturing technology, as well as relatively high natural gas prices, supported this development. Alaska and Utah were second and third for dry natural gas proven reserves additions in 2006, respectively. The total US reserves additions replaced 136 percent of 2006 dry gas production as illustrated on Figure 6-5.

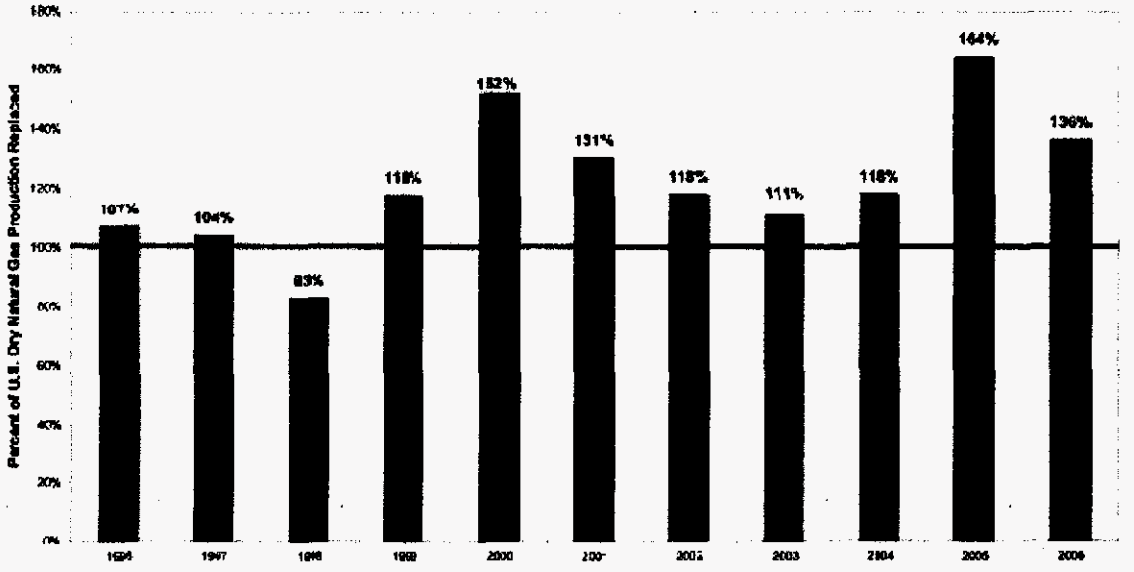

Figure 6-5
Replacement of Dry Natural Gas Productions by Reserve Additions 1996 - 2006
(Source: www.eia.dov.gov)

The proven reserves by state are shown on the map on Figure 6-8. Eight areas accounted for 81 percent of the nation's dry natural gas proven reserves, which amounts to about 171,000 Bcf. The highest concentration of natural gas reserves, as well as the highest potential production of natural gas, clusters around the Gulf Coast states. Strong potential exists in transporting natural gas reserves on the Transco Pipeline into the FRCC region making the necessary connection onto the Gulfstream Pipeline. Figure 6-6 illustrates the proven natural gas reserves in North America.

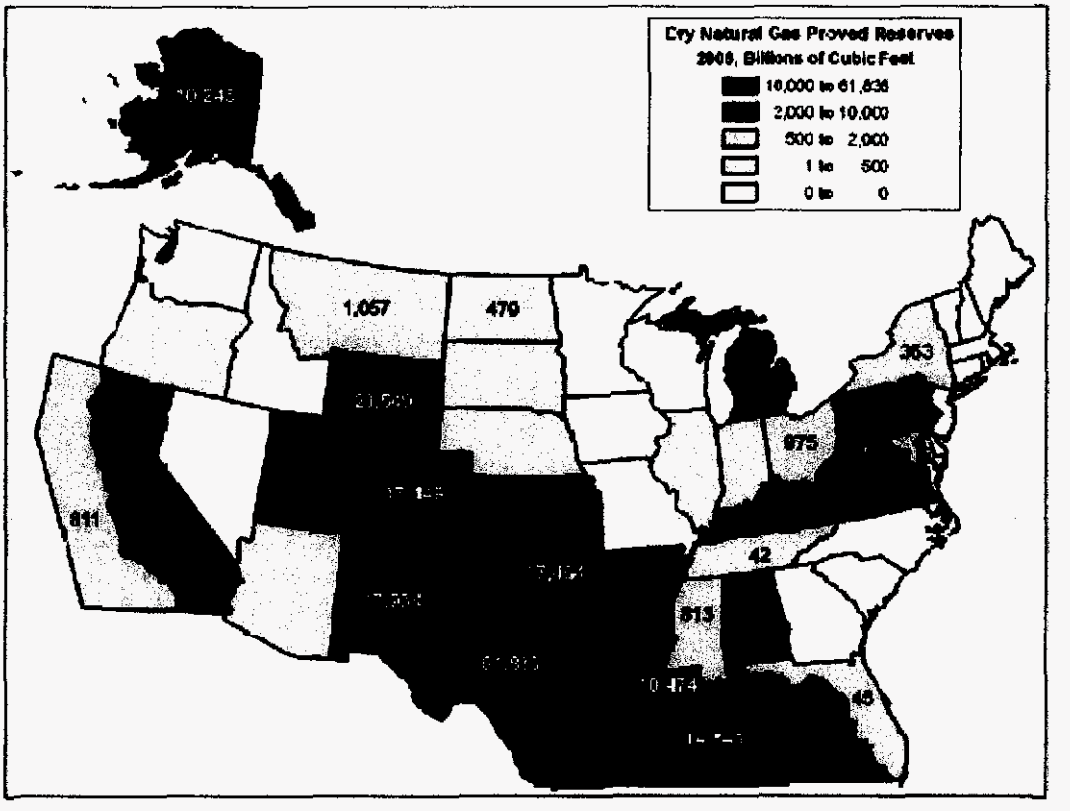

Figure 6-6
Dry Natural Gas Proven Reserves
(Source: www.eia.dov.gov)

6.4 Natural Gas Demand

In the AEO 2008 reference case, total natural gas consumption is projected to increase from 23.12 Tcf in 2008 to a peak value of 23.83 Tcf in 2016, followed by a decline to 22.72 Tcf in 2030.

The projected path of total natural gas consumption depends almost entirely on the amount consumed in the electric power sector. In the AEO 2008 reference case, natural gas consumption for electricity generation in the power sector declines from

current levels to 5.0 Tcf in 2030, as a result of a projected increase in natural gas prices that begins after 2016. Consumption of natural gas in the residential, commercial, and industrial sectors is influenced not only by fuel prices but also by economic trends. Fuel price assumptions have a smaller effect on natural gas consumption because fuel substitution options are limited and stocks of equipment that use natural gas have relatively slow turnover rates.

6.5 Natural Gas Storage

Natural gas storage facilities are being developed along the Gulf Coast in numerous locations. The southeastern states of the United States accounted for over 38,000 miles of pipeline mileage in 2007, with the State of Florida accounting for approximately 5,000 miles of pipeline. The total Florida pipeline capacity is served by four companies: FGT, GulfSouth Pipeline, Gulfstream Natural Gas System, and Southern Natural Gas (SNG). These four interstate pipelines provide reliable and adequate natural gas transportation capacity into Florida and, along with the existing and proposed natural gas storage facilities, will provide adequate transportation and storage capacity for the Florida market.

6.5.1 Existing Natural Gas Storage Facilities Near Florida

As shown on Figure 6-7, a number of natural gas storage facilities have been built or expanded in recent years. These provide immediate benefits to the Florida market because of their respective locations, and the three most recent additions are described in the following subsections.

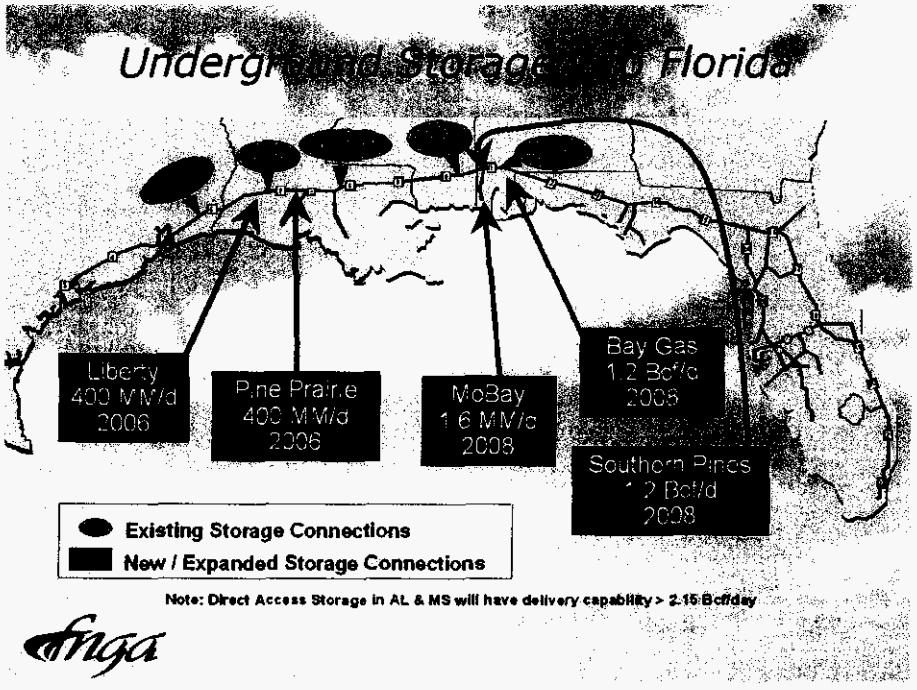

Figure 6-7
Underground Storage into Florida
(Source: www.floridagas.org)

6.5.1.1 Southern Pines Energy Center. Southern Pines Energy Center is being developed in Mississippi as a FERC-regulated natural gas storage facility. The project site has the capability to develop up to five 8 Bcf caverns for a total working gas capacity of 40 Bcf. Currently, the project is constructing a 16 Bcf multi-cycle natural gas storage facility consisting of two underground storage caverns, each capable of storing up to 8 Bcf each. The first cavern entered commercial operation May 1, 2008, and the second is scheduled for commercial operation later in the year. A third cavern is planned for 2008 with commercial operation in 2010.

The natural gas storage facilities will include the following:

- Three salt caverns capable of storing 24 Bcf in an underground salt-dome (with the capability of constructing two additional caverns for a total of five caverns and 40 Bcf of storage capacity).
- Aboveground facilities with 48,000 horsepower of compression for the three storage caverns and with 1.6 Bcf/d of maximum withdrawal capability and 0.8 Bcf/d of maximum injection capability. This configuration enables Southern Pines to cycle its working gas capacity a maximum of 12 times per year, thus providing its customers with the ultimate flexibility to quickly balance operational flows and meet peaking demands.

- Southern Pines will initially have direct interconnects to three existing interstate pipelines, Destin Pipeline Company, FGT, and Transcontinental Gas Pipeline Corporation. An interconnection with the Southeast Supply Header is scheduled for service in second quarter 2008 as that pipeline is constructed.

Figure 6-8 presents a map of the Southern Pines Energy Center.

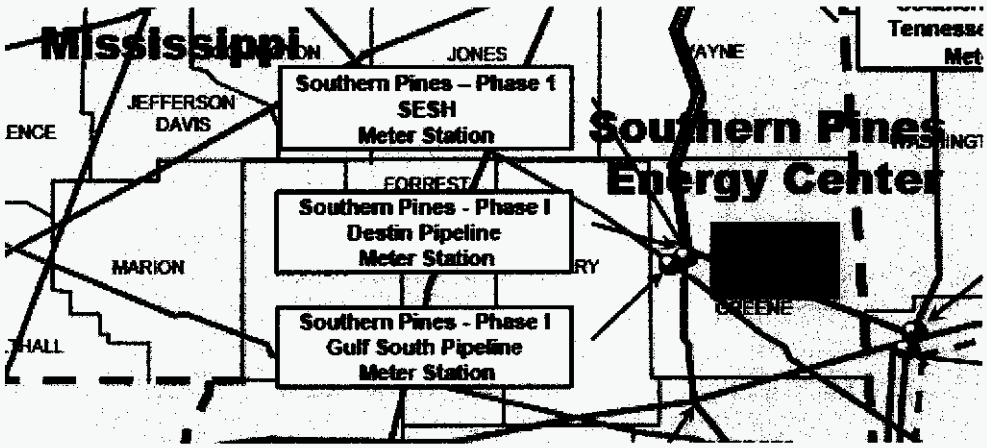

Figure 6-8
Southern Pines Energy Center
(Source: www.sgr-holdings.com)

6.5.1.2 MoBay Storage Hub, LLC. MoBay Storage Hub, LLC, will provide high-deliverability, multi-cycle (HDMC) gas storage services to the Southeast market. Located at the confluence of major market and supply area pipeline systems, MoBay would initially connect with four major interstate pipelines systems serving the Southeast and Northeast markets. Currently, the combined pipeline takeaway capacity at MoBay is 6.9 Bcf/d to the east and 3.9 Bcf/d to the west. MoBay would be the most southeasterly HDMC storage facility in the United States. The proposed MoBay compressor station will be located directly adjacent to Gulfstream Station 410 in Mobile County, Alabama. Working gas capacity will be 50 Bcf with maximum injection and withdrawal capability of 1 Bcf/d.

Figure 6-9 illustrates the relative proximity of the MoBay Storage Hub to the relative gas pipeline interconnections.

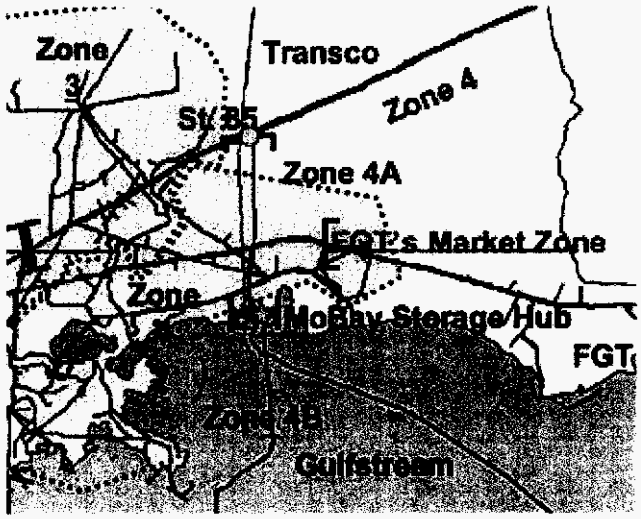

Figure 6-9
MoBay Storage Hub
(Source: www.falcongasstorage.com)

6.5.1.3 Bay Gas Storage. Bay Gas Storage is owned by EnergySouth Midstream, Inc., based in Houston, Texas. Bay Gas began the operation of its third underground natural gas storage cavern in April 2008. The new cavern increases total working gas capacity by 5.4 Bcf, bringing total working gas capacity to 11.4 Bcf at the McIntosh, Alabama facility.

In concert with bringing Cavern 3 in service, Bay Gas Storage will begin salt cavern leaching of its fourth underground storage cavern in McIntosh. The development of the company's fourth cavern is the first phase of a planned 10 Bcf expansion that will include a fifth cavern at the south Alabama facility. Cavern 4 has an expected in-service date of the first quarter of 2010 and will add 5 Bcf of total working gas capacity. A map of the facility is shown below on Figure 6-10.

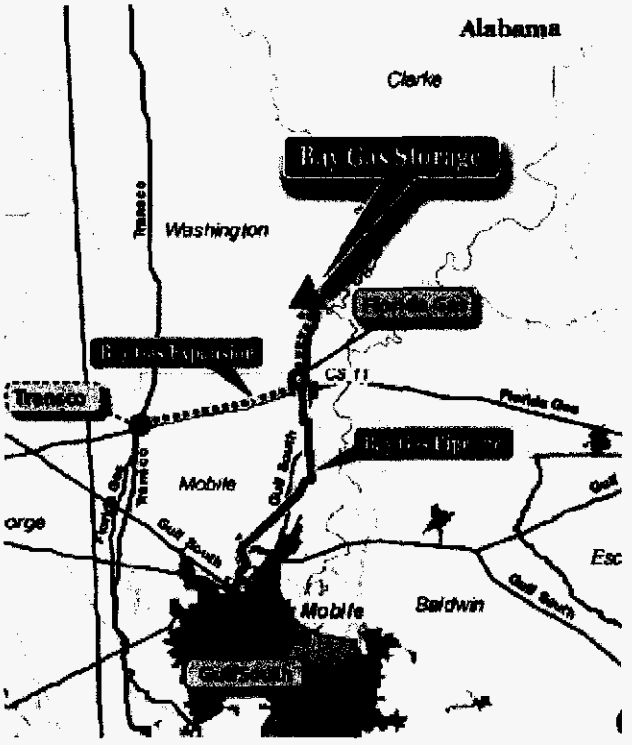

Figure 6-10
Bay Gas Storage Facility
(Source: www.esmidstream.com)

6.5.2 Floridian Natural Gas Storage Company

The Floridian Natural Gas Storage Company LLC (FGS) facility is expected to be located in an industrial area near Indiantown in Martin County, Florida. The FGS facility will ultimately consist of two aboveground liquid natural gas storage tanks each capable of storing up to 4 Bcf of natural gas, refrigeration compressors to cool the gas, and regasification equipment. Natural gas will be delivered to and from FGS using both the FGT and Gulfstream natural gas pipeline systems. FGS is expected to begin commercial operation in mid-2011.

FGS will be regulated by the FERC. In October 2007, FGS filed an abbreviated application pursuant to Section 7(c) of the Natural Gas Act (NGA) and Parts 157 and 284 of FERC's regulations for a certificate of public convenience and necessity to construct and operate the FGS project; a blanket certificate to perform certain routine activities and operations; and a blanket certificate to provide open access storage services. The proposed project is currently under FERC review with a target decision date of October 23, 2008. The addition of downstream storage facilities will effectively increase the capacities of the FGT/Gulfstream systems.

6.6 Southeast Supply Header

The Southeast Supply Header, LLC (SESH) is a joint venture between subsidiaries of CenterPoint Energy, Inc. and Spectra Energy. The 270 mile, 36 inch and 42 inch diameter pipeline has an estimated capacity of 1 Bcf/d. The pipeline will extend from the Perryville Hub in northeastern Louisiana to Gulfstream in southern Mobile County, Alabama, and will have two interconnects with FGT, the combination of which will have a capacity of 1.5 Bcf/d.

SESH will link the onshore natural gas supply basins of east Texas and northern Louisiana to Southeast markets now predominantly served by offshore natural gas supplies from the Gulf of Mexico. This pipeline will give customers an important alternative to offshore supply, which can be vulnerable to weather related disruptions. Figure 6-11 illustrates a map of the SESH route.

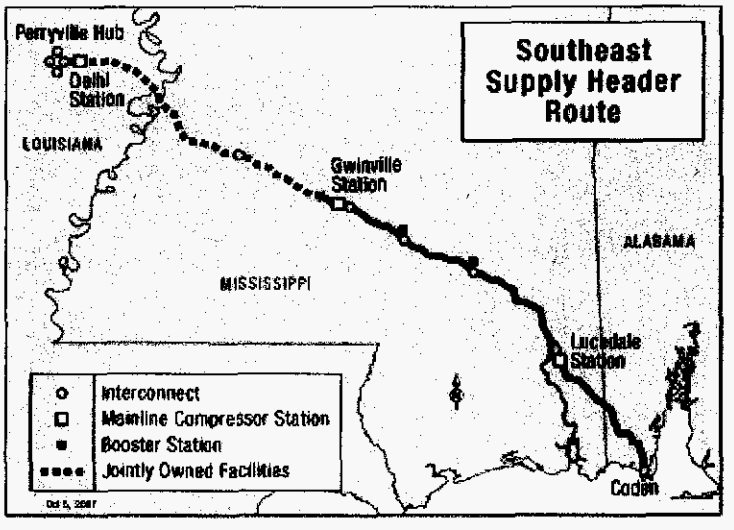

Figure 6-11
Southeast Supply Header Route Pipeline

6.7 Summary of Natural Gas Availability

As discussed throughout this section, the AEO 2008 reference case identifies growth trends in the supply and consumption of natural gas in the United States. Although conventional production in the lower 48 states will decline slightly by 2030, many sources of natural gas will continue to be available and new sources will come online, ensuring a reliable supply of natural gas. These sources of domestic natural gas production will be increasingly unconventional, and from sources that are both onshore and offshore. Of these, Alaska and the lower 48 states are forecast to not only maintain,

but also increase, their production. Specifically, Alaskan natural gas production is expected to increase to almost five times its present level, from 0.41 Tcf in 2008 to 2.01 Tcf in 2030. The lower 48 states offshore production is also expected to increase by approximately 6 percent, from 3.28 Tcf in 2008 to 3.47 Tcf in 2030. While this additional gas supply may not be delivered directly to the Southeast US, it will displace the use of natural gas elsewhere in the United States, allowing more gas to be delivered to the Southeast. Imports of natural gas into the United States will also continue, and the amount of imported LNG is projected to increase by over threefold from 0.90 Tcf in 2008 to 2.84 Tcf in 2030.

Not only will access to supplies of LNG improve, so will the infrastructure to support natural gas storage and delivery. The United States has sufficient natural gas reserves, and these reserves are consistently being replaced as existing natural gas reserves have been consumed. In order to better facilitate this process, existing natural gas storage facilities have recently been or are planned to be expanded. New storage facilities are also being constructed, and projects are under way to better provide natural gas to the pipelines that serve the Southeast US. This construction will allow for better management of gas volumes and increases in reliability of supply.

8.0 Natural Gas Transportation

Florida's natural gas transportation system is highly reliable and interconnected. Several areas of the system are also undergoing planned expansions. For these reasons, natural gas transportation capacity will be more than adequate to meet the needs of the GEC. As described later in this section, the combustion turbines on this site will be served by the SeaCoast Gas Transmission, LLC (SeaCoast) intrastate pipeline via the GEC Lateral (the distribution lateral to the GEC site) being developed by Peoples Gas System (PGS). Therefore, the necessary natural gas transportation infrastructure will already be in place at the GEC site to accommodate the combined cycle conversion. The PGS natural gas transportation supply system, along with additional natural gas pipeline systems that serve the State of Florida as a whole, are discussed in this section.

8.1 Peoples Gas System

PGS is one of four business units of TECO Energy, an S&P 500 energy company headquartered in Tampa, Florida. PGS is Florida's largest natural gas distribution utility serving more than 320,000 commercial, industrial, and residential customers. PGS has long-term agreements with FGT, Gulfstream Natural Gas System, LLC (Gulfstream), and SNG for natural gas transportation into Florida.

PGS serves as Jacksonville's natural gas distribution company and provides commercial and residential gas service to the Jacksonville area through its pipeline system. In addition, JEA has existing agreements with PGS to receive natural gas delivery service through the local gas distribution system to its generating units. Figure 8-1 illustrates the Florida counties served by PGS.

8.1.1 Existing PGS in Jacksonville Area

JEA and PGS have a successful history of working together to ensure reliable natural gas deliveries to JEA generating units. JEA and PGS are joint owners of a portion of the natural gas pipeline network in the Jacksonville area including the pipelines that serve the Northside Generating Station and the Brandy Branch Generating Station. PGS owns the pipeline system that serves the Kennedy Generating Station and JEA's Buckman Street Wastewater facility.

8.1.2 Planned PGS Expansion

The JEA-PGS working relationship has resulted in several ongoing projects. PGS is currently improving gas delivery capability to JEA's Kennedy Generating Station. Installation of additional pipe and the uprating of existing pipeline infrastructure will allow JEA to operate Kennedy CT 7 and Kennedy CT 8 simultaneously. PGS is

constructing a lateral to add natural gas service to SJRPP. In addition, PGS is constructing a natural gas pipeline (the GEC Lateral) to serve the GEC simple cycle combustion turbines prior to the combined cycle conversion.

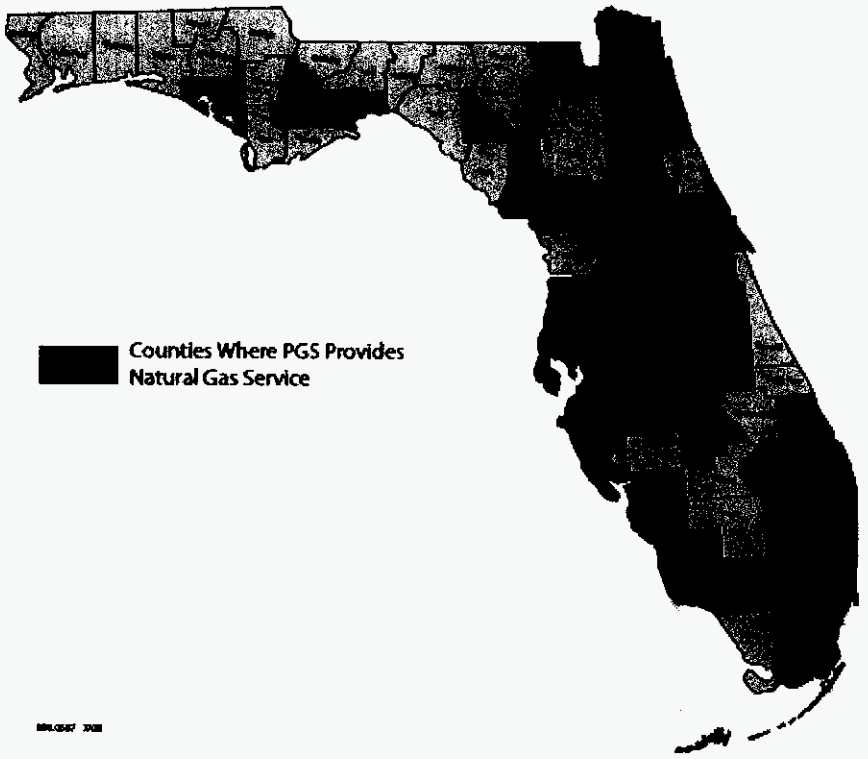

Figure 8-1
Florida Counties Served by PGS

PGS is in the process of engineering a 16 inch diameter delivery lateral that will extend from the proposed SeaCoast Pipeline in Clay County to the GEC site. JEA will receive natural gas from both the SNG and FGT systems through the SeaCoast Pipeline to the GEC Lateral for delivery to GEC. The SeaCoast Pipeline will initially extend from the point of interconnection of SNG and FGT located near Jacksonville to the commencement of the GEC Lateral in Clay County.

Several lateral routes extending from the mainline to the GEC site are being considered; the lateral is likely to utilize a tie-in point near Highway 315 in Clay County, approximately 27 miles south of the FGT/SNG interconnect. Depending on the final route, the proposed lateral will extend a length of approximately 31 to 36 miles through Clay, St. Johns, and Duval counties with a majority of the pipe co-located alongside highway and power line corridors.

8.2 Florida Gas Transmission Company

FGT, a subsidiary of Citrus Corporation (Citrus Corp.), operates a 5,000 mile natural gas pipeline system that extends from south Texas to south Florida with a current mainline capacity of 2.1 Bcf/d. FGT offers natural gas transportation service for third parties. Citrus Corp. is 50 percent owned by Southern Union Company (NYSE:SUG) and 50 percent owned by El Paso Corporation (NYSE:EP). The FGT system is illustrated in Figure 8-2.

Figure 8-2
FGT System
(Source: http://www.crosscountryenergy.com/about/fgt.shtml)

8.2.1 Existing FGT System

The FGT pipeline system transports natural gas to cogeneration facilities, electric utilities, independent power producers, municipal generators, and local distribution companies through a 5,000 mile natural gas pipeline that extends from south Texas to south Florida. It delivers 2.1 Bcf of natural gas per day to more than 240 delivery points, consisting of more than 50 natural gas fired electric generation facilities. FGT's total receipt point capacity is in excess of 3.0 Bcf/d and includes interconnects with 10 interstate and 10 intrastate pipelines to facilitate receiving supplies of natural gas into its pipeline system. The pipeline has extensive access to diverse natural gas supplies, including the offshore Gulf of Mexico region.

The pipeline enters the Florida Panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the primary pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns in a

southeasterly direction to a point in southern Brevard County, where it turns south generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County westerly to terminate in the Tampa, St. Petersburg, and Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through eastern Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

FGT has completed numerous system expansions since its initial Phase III expansion in 1995. The following is a summary of the projects that were of sufficient significance to warrant a "phase" designation:

- Phase IV expansion project completed in May 2001. This project consisted of approximately 205 miles of various diameter pipelines, additional compression totaling 48,570 horsepower, and four new delivery points (including three new measurement stations) in the states of Mississippi, Alabama, and Florida. The Phase IV expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 272,000 MBtu/d at an estimated cost of $268 million.
- Phase V expansion project completed in May 2003. This project consisted of approximately 166 miles of pipeline and 133,000 horsepower of compression, including three new compressor stations, to its existing system in the states of Mississippi, Alabama, and Florida. The Phase V expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 428 Mcf/d at an estimated cost of $452 million.
- Phase VI expansion project completed in November 2003. This project consisted of approximately 33 miles of pipeline and 18,600 horsepower of compression to its existing system in the states of Louisiana, Mississippi, Alabama, and Florida. The Phase VI expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 121 Mcf/d at an estimated cost of $100 million.
- Phase VII expansion project construction completed in May 2007, with modifications to a compressor station completed in December 2007. This project added approximately 33 miles of pipeline and 9,800 horsepower of compression to FGT's existing Florida system. The Phase VII expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 160 Mcf/d at an estimated cost of $104 million. This

expansion provides access to an additional natural gas supply from the SNG LNG Elba Island LNG import terminal near Savannah, Georgia.

8.2.2 Market Area Pipeline Interconnections

FGT's pipeline system has three pipeline interconnections that are capable of making natural gas deliveries within the state of Florida. FGT has two interconnections with Gulfstream: one interconnection in Osceola County and the other in Hardee County. Both of these interconnections offer delivery of Gulf Coast supplies directly into FGT's system in its market area of central Florida. SNG also has an interconnection with FGT in Clay County near Jacksonville. This interconnection allows for the delivery of natural gas off of the SNG system, the majority of which comes from SNG's Elba Island LNG import terminal in Savannah, Georgia.

8.2.3 Planned FGT System Expansions

As presented previously in the summary of system expansions, FGT has continuously added pipeline capacity to increase its ability to offer firm transportation service into the state of Florida and to meet the growing demand for natural gas within the state. FGT conducted an Open Season ending on February 15, 2008, for a proposed Phase VIII expansion project. On February 11, 2008, FGT announced that FPL had agreed to become the anchor shipper of a proposed natural gas pipeline expansion project through a 25 year service agreement for 400 Mcf/d of capacity. FGT is in the regulatory approval process for construction of the proposed Phase VIII system expansion at an estimated cost of $2 billion to provide approximately 800 Mcf/d of increased natural gas capacity to Florida. The proposed Phase VIII expansion includes construction of approximately 500 miles of additional large diameter pipeline and the installation of approximately 170,000 horsepower of additional compression. The Phase VIII expansion will increase the capacity of FGT's mainline facilities from the Mobile Bay, Alabama, area to southern Florida to provide additional firm transportation service capacity throughout Florida. Pending regulatory approvals, FGT is anticipating a spring 2011 in-service date for the project. The FPL commitment will help ensure that the Phase VIII expansion will be built, filling 50 percent of the incremental capacity that is planned.

The FGT Phase VIII Expansion will increase gas deliverability into Florida in the time frame necessary to support operation of the units at the GEC site. FGT plans to file a FERC certificate by the fall of 2008 and expects FERC approval by February 2009. The target in-service date for the project is spring 2011.

8.3 Gulfstream Natural Gas System, LLC

Gulfstream is a joint development between Williams and Spectra Energy. The Gulfstream system consists of a 691 mile pipeline that was placed in service in May 2002; the pipeline is illustrated on Figure 8-3.

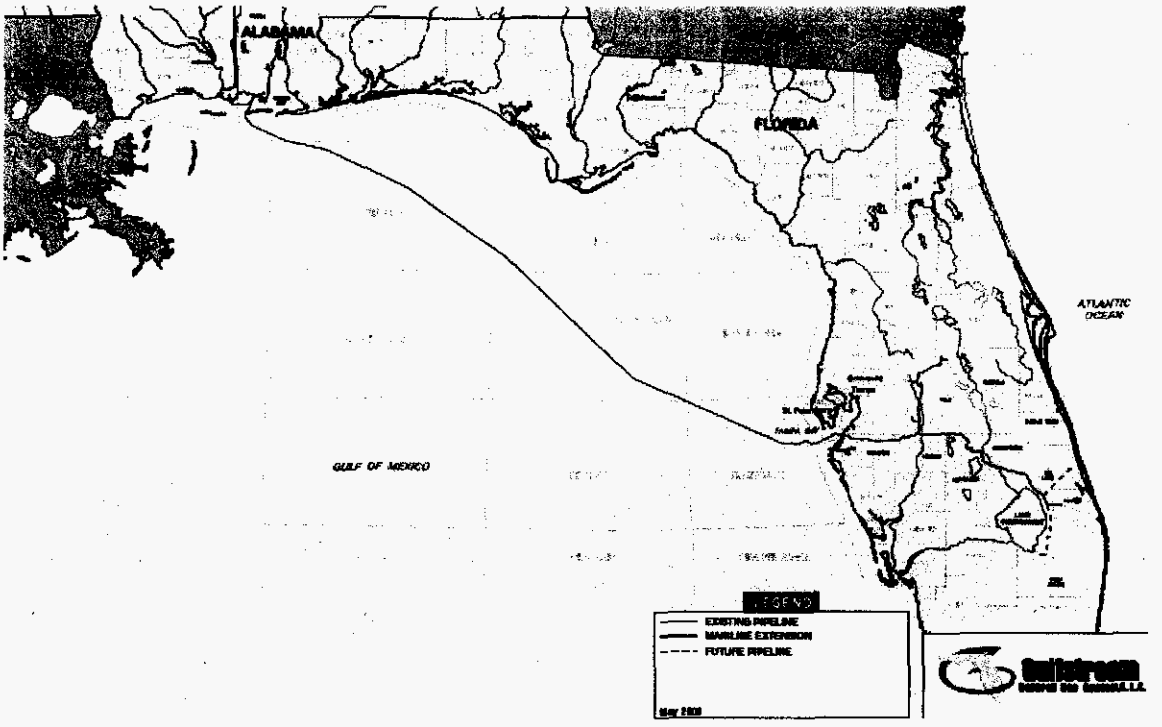

Figure 8-3
Gulfstream System
(Source: http://www.gulfstreamgas.com/images/gulfstream05_03.pdf)

8.3.1 Existing Gulfstream System

The Gulfstream pipeline originates near Pascagoula, Mississippi and Mobile, Alabama, and crosses the Gulf of Mexico with more than 430 miles of 36 inch diameter pipeline to Manatee County, Florida. Once onshore, 240 miles of 30 inch to 36 inch diameter pipeline crosses Manatee, Hardee, Polk, Osceola, Highlands, Okeechobee, and Martin counties in Florida. Gulfstream can serve customers on both the east and west coasts of Florida, as well as in the interior of the peninsula. The Gulfstream system went into service with a capacity of 1.1 Bcf/d of gas. The initial subscribed capacity was less than 200 MBtu/s, leaving approximately 900 MBtu/d of capacity available for new and existing industrial and electric generation customers in central and southern Florida. Gulfstream currently does not have any direct interconnections that would allow it to serve the GEC site.

Gulfstream has undertaken several system extensions/expansions since its initial in-service date of May 2002. These system expansions were designed to connect Gulfstream to facilities that were more remote from its initial routing. These project expansions are as follows:

- The Phase II extension of the Gulfstream pipeline was placed into service in February 2005. The 110 mile extension was designed to provide 350,000 dekatherms per day of firm natural gas transportation service for FPL's Martin and Manatee power plant expansions. The new pipeline traverses five counties: Polk, Hardee, Highlands, Okeechobee, and Martin.
- FERC approved commencement of service for the Phase III project in August 2008. The Phase III project extends the Gulfstream pipeline approximately 35 miles south from Martin to Palm Beach County (approximately 8.8 miles in Martin County and approximately 26.2 miles in Palm Beach County). This volume commitment used the remaining available system capacity.
- The Phase IV expansion project is scheduled for completion in January 2009. The Phase IV project will add compression and extend the pipeline to a new market, increasing Gulfstream's mainline capacity from 1.1 Bcf/d to 1.255 Bcf/d by early 2009. The Phase IV expansion project will include construction of approximately 17.5 miles of 20 inch diameter pipeline, connecting the existing Gulfstream pipeline to Progress Energy's Bartow Generating Station. It will also include the installation of an additional 45,000 horsepower of compression for service by January 2009: 15,000 horsepower at an existing compressor station in Coden, Alabama, and 30,000 horsepower at a new station in Manatee County, Florida. The Phase IV expansion project will increase Gulfstream's system capacity by approximately 155,000 MBtu/d to a total of 1.25 Bcf/d.

8.3.2 Market Area Pipeline Interconnections

Gulfstream's pipeline system has two pipeline interconnections that are capable of delivering natural gas within the state of Florida. FGT has two interconnections with Gulfstream: one in Osceola County and one in Hardee County. Both of these interconnections offer delivery of Gulf Coast supplies directly into Gulfstream's system via displacement in the system's market delivery area of central Florida.

8.3.3 Planned Gulfstream System Expansions

Gulfstream conducted an Open Season from June 1 to August 31, 2007, to gauge market interest in an expansion of its existing natural gas pipeline system to serve

Florida's rapidly growing natural gas market. Based on the response received by Gulfstream, Gulfstream's "G2" expansion is expected to provide approximately 500,000 to 1,000,000 MBtu/d of incremental firm transportation service to the west side of Florida beginning in 2012. The expansion will provide access to supplies from new shale production areas located primarily in north Texas and Arkansas as well as reserves located onshore and offshore in the Gulf Coast area. Facilities will include a combination of compression, pipe looping, and necessary onshore facilities.

8.4 Southern Natural Gas

SNG is a natural gas pipeline company headquartered in Birmingham, Alabama. It is a subsidiary of El Paso Corporation. The company transports more than 3 Bcf of natural gas per day during peak periods through approximately 8,000 miles of pipeline in the southeast. SNG owns and operates the Elba Island LNG regasification facility near Savannah, Georgia. Elba has approximately 4 Bcf of storage capacity and 440 Mcf/d of sendout capacity. The facility is currently being expanded to approximately 7.3 Bcf of storage capacity and a sendout capacity of 800 Mcf/d. Figure 8-4 shows the SNG natural gas transportation system.

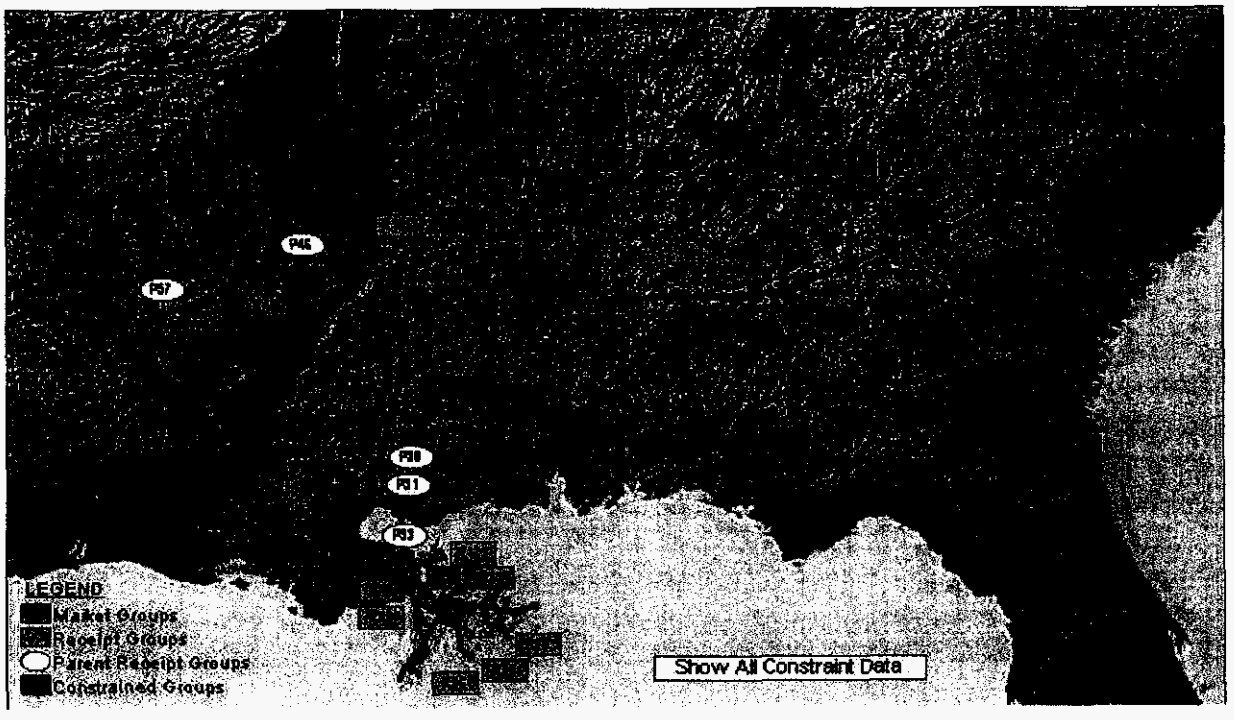

Figure 8-4
SNG System
(Source: http://premier.sonetpremier.com/snghomepage)

8.4.1 Cypress Pipeline

The Cypress pipeline is a specific section of the SNG system. This pipeline was placed into service on May 1, 2007. The new pipeline provided an incremental 220,000 MBtu/d of takeaway capacity from Elba Island, SNG's LNG facility near Savannah, Georgia. From Elba Island, the 167 mile, 24 inch pipeline extends the SNG system into southern Georgia and northern Florida and interconnects with the FGT system near Jacksonville, Florida.

The Phase 2 expansion project included the addition of 10,350 horsepower of compression at the new compressor station in Glynn County, Georgia. Phase 2 went into service in May 2008 and increased the capacity an additional 116 MBtu/d from 220,000 MBtu/d up to a total of 336,000 MBtu/d. The Cypress pipeline is illustrated on Figure 8-5.

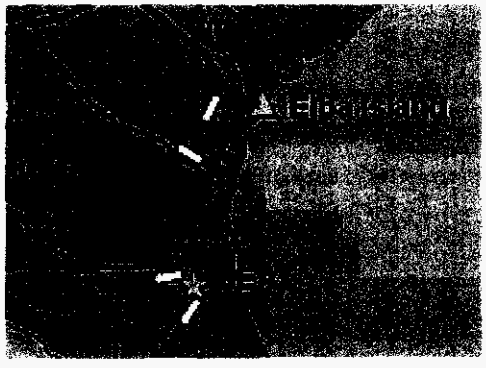

Figure 8-5
Cypress Pipeline
(Source: http://www.elpaso.com/cypresspipeline/default.shtm)

8.4.2 Planned Cypress Pipeline Expansions

There is currently one more planned expansion of the Cypress pipeline. The Phase 3 expansion project will consist of approximately 10 miles of 30 inch diameter pipeline, the addition of 10,350 horsepower of compression at the new compressor station in Liberty County, Georgia, and an additional 10,350 horsepower of compression at the new compressor station in Nassau County, Florida. Phase 3 is scheduled for completion by May 2010. Phase 3 will increase the capacity an additional 164,000 MBtu/d from 336,000 MBtu/d up to a total of 500,000 MBtu/d.

8.5 BG Group

BG Group is an energy production and distribution company headquartered near London, England. The company has established itself as the leading importer of LNG in the United States. In 2006, it was responsible for approximately 50 percent of the US

LNG imports. In 2004, BG LNG Services (BGLS), a wholly owned subsidiary of BG Group, began marketing regasified LNG from Elba Island after assuming responsibility for 446 Mcf/d of terminal capacity and long-term LNG supply from El Paso in late 2003. Additionally, BGLS maintains a long-term commitment for firm transportation on SNG to allow delivery of Elba's regasified LNG through the SNG's Cypress pipeline into the Florida market near Jacksonville.

In 2005, SNG announced plans to expand the total terminal capacity to just over 2 Bcf/d, of which BG Group currently has 0.57 Bcf/d. BGLS agreed with SNG that it will, by the start of 2014, increase its share of capacity to 1.17 Bcf/d.

JEA has a long-term contract extending through May 31, 2021, with BG Energy Merchants (BGEM), a subsidiary of BGLS, for the supply of natural gas delivered to Jacksonville. BGEM markets natural gas to intermediary and end use customers. In 2006, BGEM's marketing activities in the United States met 1.3 percent of the daily US gas demand (data source: EIA). Figure 8-6 shows the Elba Island Express Pipeline.

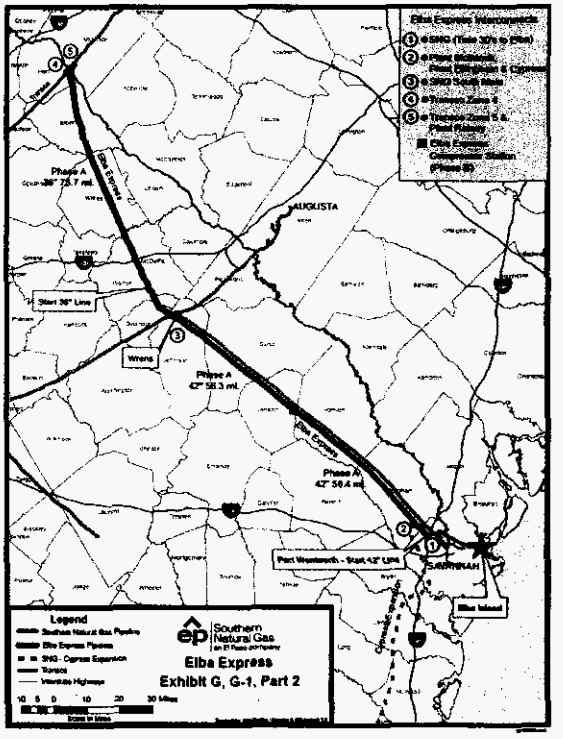

Figure 8-6
Elba Express Pipeline
(Source: www.elba3.com)

8.6 Southeast Supply Header

The SESH project is an ongoing, nonconventional domestic project that will further enhance the supply of natural gas into the State of Florida. The project will provide transportation of onshore supplies in east Texas and northern Louisiana into the Southeast US, which is normally served by offshore supplies from the Gulf of Mexico. The SESH project will provide an alternative to offshore supplies and improve the overall reliability of natural gas supply.

SESH and SNG will co-own the first 115 miles of the pipeline from the Perryville Hub to an interconnection with SNG in Mississippi. The SESH pipeline will also interconnect with Gulfstream and FGT. The SESH pipeline will connect the Florida market area with two new unconventional natural gas production basins – the Barnett Shale in east Texas and the Bossier Sands in north Louisiana. The Barnett Shale formation is estimated to extend from Dallas, Texas, to west of Ft. Worth, Texas, and to contain as much as 30 Tcf of natural gas reserves. Natural gas production from the Barnett Shale and Bossier Sand reservoirs has become economically viable due to higher natural gas prices and improvements in hydraulic fracturing and horizontal drilling.

8.7 Availability of Natural Gas Transportation Capacity

As discussed throughout this section, the Florida natural gas transportation system has become increasingly diverse and interconnected. Natural gas transportation providers have a long history of expanding the system to meet the needs of Florida's natural gas transportation customers. With all of the proposed natural gas supply expansion projects under way, JEA is confident that adequate natural gas transportation capacity will be available to provide reliable service for the GEC.

Although not all of the natural gas transportation infrastructure discussed previously in this section is interconnected directly to the GEC site, the entire infrastructure system plays an important role in providing reliable natural gas supplies to the State of Florida, as natural gas is sourced from geographically diverse locations. Ongoing domestic projects and increased imports of LNG will also contribute to sufficient availability of natural gas to serve the needs of GEC and JEA's other natural gas fired generating units. JEA is uniquely situated to obtain conventional natural gas supplies for the US Gulf, nonconventional supplies from SESH, and LNG sourced from Elba Island.

RESUME OF

John A. Worley, Director, Environmental Programs

JEA

EDUCATION

1998 – 1999
University of Phoenix
Jacksonville, Florida
Masters of Business Administration
Post Graduate Studies

1992
University of South Florida
Tampa, Florida
Principles in Engineering Management
Post Graduate Studies

1978 - 1980
Northwestern State University of Louisiana
Natchitoches, Louisiana
M.S., Botany

1974 - 1978
Northwestern State University of Louisiana
Natchitoches, Louisiana
B.S., Wildlife Management

PROFESSIONAL EXPERIENCE

JEA
Jacksonville, Florida

August 2007 to Present
Director, Environmental Programs *– Responsibilities include JEA's renewable energy program, environmental permitting lead for current and future major permit initiatives, Environmental Service's lead in JEA's green house gas/climate change policy/initiatives, coordinating sustainability initiatives and the development and implementation of internal environmental program review processes.*

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM **EXHIBIT** 14
COMPANY JEA (Direct)
WITNESS John A. Worley (JAW-1)
DATE 02/12/09

JEA / St. Johns River Power Park (SJRPP)
Jacksonville, Florida

June 2000 to August 2007
Superintendent Bulk Materials, Laboratory & Environmental Compliance *- Provide leadership for 90 employees, which include: BM Operations and Maintenance and SJRPP Environmental. Responsibilities include the oversight of operational and maintenance activities; close interaction with SJRPP Fuels regarding fuel procurement, preparation and maintenance of operational (O&M) and capital budgets; project management and coordination; regulatory and legal liaison; environmental reporting, permit acquisition and renewals; SO_2 allowance management, port activities and dredging; SHAPE safety committee member; environmental laboratory operations; personnel development, regulatory, safety and technical skills training. SJRPP Employer Negotiating Team Member. Facilitator of WorkSmart process and trainer for Covey Seven Habits course. Nature preserve management.*

May 1999 to June 2000
Group Leader Air & Water Quality (AWQ) Production *– Provide leadership for 72 employees, which include: AWQ Operations and Maintenance, SJRPP Environmental, SJRPP Laboratory Chemical Process. Responsibilities include the oversight of operational and maintenance activities; preparation and maintenance of operational (O&M) and capital budgets (3.5MM); project management and coordination; regulatory and legal liaison; environmental reporting, permit acquisition and renewals; SO_2 allowance management, port activities and dredging; safety committee member; development and monitoring of OSHA and Dept. of Labor safety programs; environmental and industrial laboratory operations; personnel development, regulatory, safety and technical skills training. Media relations for SJRPP. SJRPP Employer Negotiating Team Member. Facilitator of WorkSmart process and trainer for Covey Seven Habits course. Nature preserve management.*

January 1997 to May 1999
Group Leader Production Support Process/Regulatory *– Provide leadership for five (5) departments (33 employees) which included: Environmental, Safety & Security, Training, Laboratory Chemical Process and Document Control. Responsibilities included the preparation and maintenance of departmental operation & maintenance (O & M) and capital budgets; project management and coordination; regulatory and legal liaison; environmental reporting, permit acquisition and renewals; port activities and dredging; development and monitoring of OSHA and Dept. of Labor safety programs; environmental and industrial laboratory operations; personnel development, regulatory, safety and technical skills training; electronic document management and retention. Interface responsibilities regarding all insurance and public relations activities associated with SJRPP and JEA. Facilitator and trainer of Covey Seven Habits course; nature preserve management.*

October 1994 to January 1997
Director of Environmental & Safety *– Provide leadership for three (3) departments: Environmental, Safety & Security and Document Control. Responsibilities included the preparation and maintenance of departmental operation & maintenance and capital budgets; project management and coordination; port activities and dredging; regulatory and legal liaison; environmental reporting, permit acquisition and renewals; development and monitoring of OSHA and Dept. of Labor safety programs; electronic document management and retention; nature preserve management.*

October 1987 to October 1994

Sr. Environmental Engineer *– Provide leadership for two (2) departments: Environmental and Safety & Security. Responsibilities included the preparation and maintenance of departmental operation & maintenance and capital budgets; project management and coordination; port activities and dredging; regulatory and legal liaison; environmental reporting, permit acquisition and renewals; development and monitoring of OSHA and Dept. of Labor safety programs; nature preserve management.*

August 1985 to October 1987

Environmental Engineer *- Manage and lead the Environmental Dept. with responsibilities which included the preparation and maintenance of departmental operation & maintenance and capital budgets; project management and coordination; port activities and dredging; regulatory and legal liaison; environmental reporting, permit acquisition & renewals.*

Southwestern Electric Power Company
Shreveport, Louisiana

October 1980 to August 1985

Environmental Specialist *- Assistant to the Manager of Environmental Affairs. Responsibilities included project management and coordination, regulatory and legal liaison, environmental permit acquisitions and renewals; environmental reporting.*

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 15
COMPANY JEA (Direct)
WITNESS John A. Worley (GEC-1) Sections 3.9 & 14.0
DATE 2/12/09

major repairs or upgrades beyond those dictated by unit starts and operating hours are currently planned and the units are not assumed to retire during the 20 year evaluation period in this Application.

Brandy Branch Station was constructed with three gas fired (with distillate oil backup) GE 7FA CTs with a nominal capacity of 182 MW each. All three units were commissioned as simple-cycle units in 2001 and designated as Brandy Branch CT 1, 2, and 3. Subsequently, Units 2 and 3 were converted to a 2 x 1 combined-cycle configuration in 2005. All three units are well within their design life cycles throughout the 20 year evaluation period considered in this Application. No major repairs or upgrades beyond those dictated by unit starts and operating hours are planned.

3.8 JEA Operating and Spinning Reserve Requirements

JEA is a member of the FRCC and party to the Florida Reserve Sharing Group (FRSG) agreement. The FRSG participants collectively share contingency reserves within the FRCC region to meet the individual participant's obligations to comply with reliability standards and requirements. FRCC members collectively carry operating reserves to cover the loss of at least the single largest unit of the participant's generator resources. When an FRSG participant requests operating reserves, the reserve capacity is immediately scheduled by all other FRSG participants and the requesting participant may hold this operating reserve for up to 30 minutes.

JEA is currently obligated to maintain operating reserves of 82.5 MW. Approximately 20.6 MW of the 82.5 MW must be spinning reserve. The remaining 61.9 MW reserve requirement can be met by quick start units.

3.9 JEA Clean Power Portfolio

Since 1999, JEA has worked closely with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups to establish a process to maintain an action plan entitled Clean Power Action Plan. The Clean Power Action Plan has an Advisory Panel that is composed of participants from the Jacksonville community, including representatives from the Sierra Club, ALA, and the newest member, the City of Jacksonville Environmental Protection Board. These local members provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program. Although the Clean Power Action Plan does not speak directly to CO_2 emissions, projects undertaken by JEA pursuant to the Plan have reduced JEA's CO_2 emissions.

JEA has made considerable progress towards the goals set forth in the Clean Power Action Plan through installation of clean power systems, PPAs, legislative and

approximately 1,500 kW of landfill gas from the North Landfill, where it is used to generate power at Northside Unit 3.

In 2006, JEA signed a PPA with Landfill Energy Systems to obtain energy from a 9.6 MW landfill gas-to-energy facility at the Trail Ridge Landfill in Jacksonville. Once completed, the facility will be one of the largest landfill gas-to-energy facilities in the Southeast, providing enough renewable energy to supply electricity to approximately 2,275 homes. The projected date for completion of the facility is late 2008.

3.9.3 Wind

As part of its ongoing effort to utilize more sources of renewable energy, in 2004 JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits associated with this green power project. Under the wind generation agreement, JEA has agreed to purchase 10 MW of capacity from NPPD's wind generation facility for a 20 year period. In turn, NPPD will buy back the energy at specified on/off peak charges. JEA retains the rights to the environmental attributes (renewable energy credits, or RECs) and will sell the RECs unless JEA needs them to meet state or federal environmental requirements.

3.10 JEA Transmission and Interconnections

The JEA transmission system consists of 728 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kilovolts (kV), 138 kV, 230 kV, and 500 kV.

The 500 kV transmission lines are jointly owned by JEA and FPL and complete the path from FPL's Duval substation (to the west of JEA's system) to the Florida interconnect at the ITS. Along with JEA and FPL, Progress Energy Florida and the City of Tallahassee each also own transmission interconnections with the Georgia ITS. JEA's first contingency import entitlement over these transmission lines is 1,228 MW out of 3,600 MW.

The 230 kV and 138 kV transmission system provides a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest to fill in the area not covered by the 230 kV and 138 kV transmission backbone.

JEA owns and operates three 230 kV tie-lines terminating at FPL's Duval substation in Duval County, one 230 kV tie-line terminating at Beaches Energy's

14.0 Renewable Energy and Clean Power

JEA recognizes the importance of integrating renewable energy into its power supply portfolio. JEA has pursued several clean power initiatives and is in the process of evaluating potential new renewable energy resources. The remainder of this section discusses JEA's clean power portfolio (including JEA's existing renewable energy resources), and potential new renewable energy resources being evaluated by JEA.

14.1 JEA Clean Power Portfolio

Since 1999, JEA has been working closely with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups to establish a process to maintain an action plan entitled *Clean Power Action Plan.* The Clean Power Action Plan establishes an Advisory Panel that is comprised of participants from the Jacksonville community, including representatives from the Sierra Club, ALA, and the newest member, the City of Jacksonville Environmental Protection Board. These local members provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program. Although the Clean Power Action Plan does not speak directly to CO_2 emissions, projects undertaken by JEA pursuant to the Plan have reduced JEA's CO_2 emissions.

JEA has implemented several projects as part of the Clean Power Action Plan, including installation of clean power systems, purchase power agreements, legislative and public education activities, and research into and development of clean power technologies. In particular, JEA has conducted a number of generation efficiency improvements, such as turbine upgrades, which increase the output of generating units without increasing the amount of fuel burned or the amount of CO_2 emitted. These particular projects are described later in this section.

14.1.1 Renewable Energy

In 2005, JEA received a Sierra Club Clean Power Award for its voluntary commitment to increasing the use of solar, wind, and other renewable or green power sources. Since that time, JEA has implemented new renewable energy projects and continues to explore additional opportunities to increase its utilization of renewable energy. As further discussed below, JEA's existing renewable energy sources include installation of solar PV, solar thermal, landfill and wastewater treatment biogas capacity, and wind.

14.1.1.1 Solar Energy. JEA has installed 35 solar PV systems, totaling 220 kW, on all of the public high schools in Duval County, as well as many of JEA's facilities, and

the Jacksonville International Airport (one of the largest solar PV systems in the Southeast). To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in early 2002. This program provided cash incentives for customers to install solar PV and solar thermal systems on their homes or businesses.

JEA provided customer incentives for more than 25 solar PV systems (for a total of 98 kW) until January 2005, when the PV incentive was discontinued in favor of the solar water heating program discussed below, which provides more cost effective CO_2 reduction. In addition to the PV incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems. JEA also offers incentives for the installation of solar hot water heaters. To date, the program has resulted in over 500 incentives, or approximately 1.6 MW of capacity savings.

14.1.1.2 Landfill Gas and Biogas. Since 1997, JEA has owned and operated internal combustion engine generators fueled by landfill gas produced by the City of Jacksonville's Girvin Road landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, landfill gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility. The facility uses biogas produced by the wastewater treatment plant to fuel the 800 kW generator. JEA has received approximately 1,500 kW of landfill gas from the North Landfill, where it is used to generate power at Northside Unit 3.

In 2006, JEA signed a purchase power agreement with Landfill Energy Systems to obtain energy from a 9.6 MW landfill gas-to-energy facility at the Trail Ridge Landfill in Jacksonville. Once completed, the facility will be one of the largest landfill gas-to-energy facilities in the Southeast, providing enough renewable energy to supply electricity to approximately 2,275 homes. The projected date of completion for the facility is late 2008.

14.1.1.3 Wind. As part of its ongoing effort to utilize more sources of renewable energy, in 2005 JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits associated with this green power project. Under the wind generation agreement, JEA has agreed to purchase 10 MW of capacity from NPPD's wind generation facility for a 20 year period. In turn, NPPD will buy back the energy at specified on/off peak charges. JEA retains the rights to the environmental attributes (renewable energy credits, or RECs) and will sell the RECs unless JEA needs them to meet state or federal environmental requirements.

14.1.1.4 Biomass. JEA has issued several RFPs for renewable energy resources. The only bids that JEA has received that were cost effective were for the Trail Ridge Landfill

project (discussed previously) and a yard waste power project proposed by Evergreen. JEA attempted to negotiate a purchase power agreement with Evergreen, but the parties were unable to reach agreement on issues surrounding the yard waste fuel source, prompting JEA, in agreement with the City of Jacksonville, to suspend negotiations. JEA will continue to work with the City of Jacksonville and potential third party developers to establish a yard waste biomass project that will be beneficial to both JEA customers and the residents of Jacksonville.

In a continuing effort to obtain cost effective biomass generation, JEA is conducting a detailed feasibility study of both self-build stand-alone biomass units and the co-firing of biomass in Northside 1 and 2. The JEA self-build projects would not be eligible for the tax advantages afforded to developers, but would take advantage of JEA's low cost tax exempt financing. Northside 1 and 2 are two of JEA's least cost units, and therefore any decreases in reliability due to the co-firing alternative for Northside 1 and 2 would result in significant increases in costs to JEA's customers due to the higher costs of replacement power.

JEA also periodically receives unsolicited offers for biomass and other renewable generation. JEA evaluates the feasible unsolicited offers, but has been unable to successfully execute a contract for cost-effective biomass or other renewable generation. One notable example is the 70 MW biomass project burning E-grass that JEA executed in 2002 with Biomass Investment Group, Inc. (BIG). Even though JEA executed the purchase power agreement, BIG has not implemented the project.

14.1.1.5 Ongoing Research Efforts. Many of Florida's renewable resources, such as offshore wind, tidal, and energy crops, have potential and need additional research and development before they can become large-scale technologies. JEA's renewable energy research efforts have focused on the development of technologies through a partnership with the UNF. The following projects are currently in progress:

- JEA is working with the UNF to quantify the winter peak reductions of solar hot water systems.
- UNF, along with the University of Florida, is evaluating the effect of biodiesel fuel in a pilot-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.
- UNF is evaluating the tidal hydro-electric potential for North Florida, particularly in the Intracoastal Waterway.
- UNF is in the preliminary stage of evaluating fuel cell technology utilizing methane produced at JEA's Buckman Wastewater Treatment Facility.

- JEA, UNF, and other Florida municipal utilities have partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for wind development in Florida.
- JEA is providing solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15 acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3 year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.
- JEA is evaluating the use of biofuels such as fats, oils and greases for potential use in solid fuel units.

14.1.2 Generation Efficiency and New Natural Gas Generation

Since the late 1990s, JEA has been modernizing their natural gas/oil fleet of generating units by replacing less efficient steam units and less efficient combustion turbines with a more efficient combined cycle unit and more efficient combustion turbines. Natural gas emits approximately 70 percent of the CO_2 of No. 6 oil on a fuel basis. This program, coupled with the much greater efficiency of a combined cycle unit compared to No. 6 oil steam units and less efficient combustion turbines, results in significant reduction of CO_2 on a per MWh basis.

14.1.2.1 Prior and Ongoing Projects. As a result of its system efficiency improvement efforts, JEA has retired the following units:

- Kennedy Steam Unit 8--43 MW Summer Heavy Oil/Natural Gas.
- Kennedy Steam Unit 9--43 MW Summer Natural Gas/Heavy Oil.
- Kennedy Steam Unit 10--97 MW Summer Natural Gas/Heavy Oil.
- Kennedy Combustion Turbine Unit 4--51 MW Summer No. 2 Oil.
- Kennedy Combustion Turbine Unit 5--51 MW Summer No. 2 Oil.
- Southside Steam Unit 4--67 MW Summer Natural Gas/Heavy Oil.
- Southside Steam Unit 5--142 MW Summer Natural Gas/Heavy Oil.

The retirement of these units and their replacement with an efficient combined cycle and efficient simple cycle combustion turbines significantly reduces CO_2 emissions. JEA's replacement units include Brandy Branch Unit 1, a 7FA simple cycle combustion turbine, Brandy Branch Combined Cycle, a 2x1 7FA combined cycle, and Kennedy 7, a 7FA simple cycle combustion turbine. These units all burn natural gas as their primary fuel with ultra low sulfur diesel as a backup fuel.

JEA also is installing Kennedy Combustion Turbine Unit 8, which is an efficient 7FA simple cycle combustion turbine designed to burn natural gas as its primary fuel and

ultra low sulfur diesel as a backup. Kennedy Combustion Turbine Unit 3, an inefficient diesel fired unit, will be retired with the installation of Kennedy Combustion Turbine Unit 8 further increasing the efficiency of JEA's generating fleet. Commercial operation of Kennedy Combustion Turbine Unit 8 is scheduled for March 2009.

14.1.2.2 Greenland Energy Center. JEA is in the process of permitting the installation of Greenland Units 1 and 2, which will be efficient 7FA simple cycle combustion turbines designed to burn natural gas as their primary fuel with ultra low sulfur oil as backup. The installation of Greenland Units 1 and 2 further increases the efficiency of JEA's natural gas fueled generating fleet.

The conversion of Greenland Units 1 and 2 to combined cycle is a key part of JEA's generating unit efficiency improvement program. The combined cycle conversion allows the output of the GEC to increase over 60 percent without any increase in CO_2 emissions when compared to the simple cycle combustion turbines. The conversion of the Greenland combustion turbines to combined cycle, along with the Brandy Branch combined cycle, allows JEA to generate a large amount of energy with natural gas with its attendant lower CO_2 emissions per unit of electrical output.

The Greenland combined cycle project replaces capacity and energy that JEA planned to receive as its share in the suspended Taylor Energy Center Supercritical Pulverized Coal Unit. Replacing JEA's share of Taylor Energy Center capacity with capacity and energy from the Greenland combined cycle reduces JEA's CO_2 emissions by more than 1 million tons per year from what would have been emitted by JEA's share of Taylor Energy Center.

14.2 History of JEA RFPs for Renewable Energy

As discussed previously in this section, JEA has issued several RFPs for renewable energy sources. The following discussion summarizes the renewable energy RFP processes undertaken by JEA.

14.2.1 2004 RFP for Renewable Energy Generation

In February 2004, JEA issued a RFP for Renewable Energy Generation for 1 MW to 300 MW. The RFP covered projects for all renewable energy resources that resulted in energy being delivered to JEA's service territory. JEA received 13 acceptable responses with capacities between 1 MW and 50 MW. Several of the projects competed for the same fuel - four proposed the City of Jacksonville yard waste as fuel and three proposed the Trail Ridge landfill gas for fuel. The remaining projects were two existing biomass facilities, a proposed biomass facility in Southeast Georgia, a proposed addition to a biomass facility in west Florida, a solar PV and a wind project. Proposals were scored

based on JEA's technical and pricing criteria. The technical criteria consisted of company experience, financial capabilities, team member qualifications, impact of the project on the environment, age and location of the facility, community support and size of the project.

The pricing proposals were evaluated by calculating an incremental cost for each proposal on the basis of all-in cost in nominal 2004 dollars. This evaluation involves calculating an annual busbar cost ($/MWh) for the project using the proposed energy, capacity, and transmission wheeling costs, if applicable. Annual avoided fuel, capacity, and O&M costs were calculated. Avoided fuel expenses were calculated by modeling the proposed project as a must-run unit in JEA's production cost model. The model generates a fuel cost or savings using the proposed project in the production cost model versus JEA's base case (i.e., JEA's planned dispatch of generation units without the renewable energy project). The avoided costs for capacity, fixed, and variable O&M were based on the then-current JEA planning estimates for a natural gas fired combustion turbine. The renewable projects were given avoided capacity credit for each year even though they may not avoid capacity from being constructed given the small size of some of the proposed projects. The renewable project also receives a sulfur dioxide (SO_2) reduction credit for the SO_2 avoided by the project. The net cost (or benefit) to JEA over 10 years was calculated by adding the busbar costs, the avoided costs, and the SO_2 credit. Incremental costs for the 13 projects ranged from $6/MWh below to $285/MWh above the base case and a $5 million net savings to $103 million net additional cost to JEA over 10 years.

A final score was calculated for all proposals and Landfill Energy Systems and Evergreen Paper and Energy received the top scores. JEA entered into negotiations with Landfill Energy Systems (9.6 MW) on the Trail Ridge landfill gas and signed a PPA in May 2006. The project is expected to be operational by late 2008. JEA started negotiations with Evergreen Paper and Energy (13 MW using the City's yard waste) but these negotiations were cancelled by JEA in July 2007 after consultation with the City of Jacksonville on the City of Jacksonville-Evergreen yard waste fuel contract. The City of Jacksonville concluded that Evergreen, after several years of negotiation, had failed to deliver an executed contract and the bonding requirement. In addition, Evergreen had not prepared the site to take the yard waste within the timeframe proposed by the City of Jacksonville.

14.2.2 2007 RFP for Renewable Energy Generation

In 2007, JEA decided to again issue a request for renewable energy proposals. In order to allow more creativity and flexibility in the solicitation process, JEA started the

process by soliciting letters of interest from companies interested in developing renewable energy projects for JEA. The solicitation was widely distributed, encouraged creativity in power purchase structures, included all renewable energy resources, and allowed project sizes up to 300 MW. Of the 19 responses received, 13 were for biomass projects, and the remaining were tidal, landfill gas, and digester gas projects as discussed below:

One of the projects was proposed by Trail Ridge LLC to generate energy from an additional 9.6 MW of landfill gas at the Trail Ridge landfill. JEA and Trail Ridge LLC continue to evaluate this proposal.

Two of the projects proposed a landfill gas technology but did not identify the landfill gas site that would be used. Since JEA was in negotiations with Trail Ridge LLC on the Trail Ridge landfill, JEA did not believe there was additional landfill opportunities in the JEA service area and did not pursue these technology-only proposals.

One letter of interest was from another Florida municipal utility indicating their interest in working with JEA on development of joint renewable energy projects. Specific projects were not mentioned. Because of the large size and risk of some renewable energy projects, JEA may consider working with other Florida utilities to develop joint projects similar to how several fossil fuel plants have been developed.

One letter of interest was an anaerobic digester using agricultural waste (1 MW). JEA was interested in pursuing this project but further discussion with the developer indicated that a fuel source had not been identified. JEA invited the proposer to contact JEA to begin project negotiations when a fuel source and location had been identified. The proposer has not contacted JEA since the initial discussion.

The final project was a 100 kW tidal demonstration project in the Intracoastal Waterway. JEA started negotiations with Integral Aqua Systems (IAS) on a PPA. However, the capital investor withdrew from this project in May 2007 and IAS has not been able to restructure the project although they did test a prototype hydro turbine in the Intracoastal Waterway in August 2007.

Because of the numerous biomass proposals that were received from the Letter of Interest, JEA issued a RFP for the biomass respondents on August 13, 2007. Proposals were due on September 21, 2007 (extended to September 28, 2007). JEA received four acceptable proposals and rejected five proposals because they did not meet the screening criteria. As part of the screening criteria, JEA required the respondents to complete all the RFP sections, propose a renewable energy resource, use proven technology, and have an availability factor of at least 85 percent. The availability factor is the percent of time a unit is capable of service if adequate resources are available. This factor is used in the purchase contracts as a default mechanism to ensure that the facility is capable of

operation during the terms of the contract. Of the five rejected projects, three did not meet the mandatory requirements of the RFP and two of the projects were not received by the due date.

The remaining four acceptable proposals, ranging from 9 MW to 120 MW, were scored based on JEA's technical and pricing scoring criteria. These proposals were evaluated on the following technical aspects: technical viability, fuel availability and security, team experience, financial stability, project financing, site control, and performance guarantees. Each of the four projects proposed viable technology and demonstrated team experience with utility-scale generation projects. However, none of the projects (with the exception of one project which was an existing operating biomass facility) could demonstrate a commitment on the fuel source or site nor did they demonstrate project financing by providing commitment letters from third-party institutions.

The pricing proposals were evaluated by calculating an incremental cost for each proposal on the basis of all-in cost in nominal 2007 dollars. The incremental cost is the difference between the project's cost of power relative to JEA's existing system and base case plan. The avoided unit was a new natural gas-fired combustion turbine and the process is similar to the pricing evaluation used in the 2004 RFP process and described previously in this section. In addition, biomass projects were given credit for reductions in sulfur dioxide and carbon credits. Incremental costs for the four projects ranged from $10/MWh to $59/MWh above base case and $51 million to $306 million in net additional cost to JEA over 20 years.

JEA chose not to negotiate with any of the proposers because of the high costs and the inability of the proposers to demonstrate fuel or site availability or project financing.

14.3 Renewable Energy (Solar and Wind) RFP

Most recently, JEA issued a RFP for renewable energy, in particular solar and wind resources (Solar and Wind RFP), on March 17, 2008. Responses to the RFP were due on May 16, 2008. The RFP requested projects greater than 1 MW that generate electricity from solar (including PV or thermal electric) or wind. Solar projects greater than 250 kW at a JEA commercial customer's site were also included if the aggregate installation is greater than 1 MW. The RFP also requested proposals for solar PV equipment (panels and inverters) for installation by JEA. These proposals were scored on technical and economic factors very similar to the 2004 and 2007 RFP processes.

14.3.1 Summary of RFP Responses

JEA received ten solar PV proposals and two proposals for solar PV panels (equipment purchase only). JEA did not receive any proposals for solar thermal electric or wind projects. Of the ten solar PV proposals received, eight were for ground-mounted systems from 8 MW to 12 MW in size and two were for distributed roof-top mounted systems from 2 MW to 4 MW in total size. All proposals submitted were for projects to be developed in the JEA service area.

14.3.2 Solar and Wind RFP Response Evaluation Process

The proposals were all scored based on JEA's technical and pricing factors. The technical areas, which were scored on a point scale of 1-10, evaluated the company qualifications, the technical project, and the readiness of the project. Specifically, these factors included: qualifications of the company, financial strength, technical feasibility, ease of interconnection, barriers to project site, other ancillary benefits of the project, level of development of financing plan, level of project development completed, status of major equipment, interconnection design maturity, level of resource assessment performed, level of site control, level of site infrastructure, status of obtaining permits, and project schedule. Questions were submitted to all Bidders and responses were due on June 13, 2008. Projects were ranked based on the technical score. MMA Renewable Ventures, Sun Power, and Rocky Mountain Energy Group submitted the top three technical scoring projects.

The pricing proposals were first evaluated based on their levelized price with levelized costs ranging from approximately $186/MWh to approximately $343/MWh. All of the solar proposals reflect the assumed extension of the benefits of the existing Solar Incentive Tax Credits. Finally, the pricing proposals were evaluated by calculating an incremental cost for each proposal on the basis of all-in cost in nominal 2008 dollars. The incremental cost is the difference between the project's cost of power relative to JEA's existing system and base case plan, with the GEC combined cycle conversion representing the avoided unit. The incremental costs of the proposals ranged from approximately $10/MWh to approximately $150/MWh over a 20 year period. JEA is pursuing negotiations with the company that provided the lowest cost solar PV proposal. That proposal has been carried forward to the detailed economic evaluations as described in Section 17.0 of this Application.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 16
COMPANY JEA (Direct)
WITNESS Richard J. Ventosa (RJV-1)
DATE 01/12/09

RESUME OF

Richard Vento, Director of Corporate Data Integration

JEA

Qualifications and Experience:

Summary

25 years of progressive experience in electric, water and sewer utility planning, operations and maintenance.

Areas of Experience

- Water and Electric System Operations and Maintenance
- New Product Development
- Program Development and Implementation
- Load Research
- Demand Side Management
- Advanced Metering Data Integration

Experience

JEA **2005-Present**
Director of Corporate Data Integration
Responsible for:
- Development and delivery of electric system demand side management program
- Development and delivery of water and sewer system demand side management program
- Development and delivery of electric and water Load Research
- Development and delivery of advanced uses of AMI systems and data to internal business process owners

JEA **2002-2005**
Director of New Technologies
Established a division to identify evaluate and recommend emerging technologies that would benefit the utility.

JEA **1999-2002**
Director of Water and Wastewater Operations and Maintenance
Managed all aspects of water and wastewater treatment O&M. Reorganized to ensure all regional treatment plants were managed as individual cost centers with performance accountabilities at the plant manager level.

JEA **1988-1999**
Manager, Generation Station Systems
Jointly Managed the maintenance of 3 steam units and 4 combustion turbines.

Education

Bachelor of Science in Business Administration from University of Florida
Associates Degree in Biology
Associates Degree in Electronics

Memberships

American Society of Energy Professionals
Toastmasters International

Table 1
Target JEA DSM Portfolio Summer Peak Demand Reductions
(Cumulative MW Reductions)

DSM Program	2008	2009	2010	2011	2012
Residential Lighting	2.8	8.5	14.2	19.8	25.5
Neighborhood Efficiency	0.2	0.4	0.6	0.8	1.0
Residential Efficiency Upgrades	0.0	2.3	6.8	11.3	15.8
Residential Direct Load Control	0.0	7.1	21.2	36.5	51.8
Commercial Direct Load Control	0.0	5.9	17.8	35.6	53.4
Total Cumulative Demand Reductions[1]	3.0	24.2	60.5	104.0	147.5

[1] Totals may not exactly equal the sum of the individual program demand reductions due to rounding.

Table 2
Target JEA DSM Portfolio Winter Peak Demand Reductions
(Cumulative MW Reductions)

DSM Program	2008	2009	2010	2011	2012
Residential Lighting	1.9	5.7	11.3	16.3	21.2
Neighborhood Efficiency	0.2	0.4	0.6	0.8	1.0
Residential Efficiency Upgrades	0.0	1.5	4.5	9.0	13.0
Residential Direct Load Control	0.0	8.2	26.9	51.4	75.9
Commercial Direct Load Control	0.0	5.8	17.4	31.3	45.3
Total Cumulative Demand Reductions[1]	2.0	21.5	60.7	108.7	156.3

[1] Totals may not exactly equal the sum of the individual program demand reductions due to rounding.

Table 3
Target JEA DSM Portfolio Total Annual Energy Reductions
(Cumulative GWh Reductions)

DSM Program	Calendar Year 2008[1]	Calendar Year 2009	Calendar Year 2010	Calendar Year 2011	Calendar Year 2012
Residential Lighting	2.2	14.1	37.2	67.1	87.2
Neighborhood Efficiency	0.2	1.0	1.8	2.6	3.2
Residential Efficiency Upgrades	0.3	3.8	17.4	41.9	66.3
Residential Direct Load Control	0.0	0.0	0.0	0.0	0.0
Commercial Direct Load Control	0.0	0.0	0.0	0.0	0.0
Total Cumulative Energy Reductions[2]	2.7	18.8	56.4	111.6	156.8

[1] Energy reductions were not provided by Summit Blue for 2008. The 2008 GWh reductions have been estimated based on actual performance to date.
[2] Totals may not exactly equal the sum of the individual program energy reductions due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 17
COMPANY JEA (Direct)
WITNESS Richard J. Vento (RJV-2)
DATE 02/12/09

Table 4
Target JEA DSM Portfolio Annual Program Costs
(Millions $)

DSM Program	Fiscal Year 2008	Fiscal Year 2009	Fiscal Year 2010	Fiscal Year 2011	Fiscal Year 2012
Residential Lighting	$0.6	$1.5	$2.2	$1.9	$1.9
Neighborhood Efficiency	$0.25	$0.35	$0.35	$0.35	$0.35
Residential Efficiency Upgrades	$0.1	$1.0	$2.1	$3.1	$2.7
Residential Direct Load Control	$0.6	$1.2	$2.7	$3.6	$3.6
Commercial Direct Load Control	$0.2	$0.4	$0.9	$1.1	$1.1
Total Program Costs[1]	$1.85	$4.45	$8.35	$10.05	$9.65

[1] Totals may not exactly equal the sum of the individual program costs due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 18
COMPANY JEA (Direct)
WITNESS Richard J. Vento (RJV-3)
DATE 02/12/09

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EI EXHIBIT 19
COMPANY JEA (Direct)
WITNESS Richard J. Ventosa (GEC-1) Section 15
DATE 02/12/09

15.0 Conservation and Demand Side Management Portfolio

Throughout its history, JEA has demonstrated a strong commitment to serve its customers' conservation needs. To that end, JEA has undertaken numerous conservation and DSM programs in order to decrease overall energy demands on its system while continuing to provide competitive levels of cost and service to customers.

15.1 Description of Historical Conservation and DSM Programs

JEA's 2005 DSM plan was approved by the FPSC on September 1, 2004. Upon reviewing the plan, the FPSC determined that there were no cost-effective conservation measures available for use by JEA, so the FPSC established and approved zero DSM and conservation goals for JEA's residential and commercial/industrial sectors through 2014 (Docket No. 040030-EG). Nevertheless, JEA has voluntarily continued its historical programs, because it had determined that these programs were in the overall best interest of its customers.

This subsection discusses the historical DSM programs that continue to be offered by JEA. As discussed in future portions of this section, JEA has collaborated with Summit Blue Consulting, LLC (Summit Blue), an independent firm that specializes in DSM program evaluation and development, to identify new DSM programs that are in the process of being implemented

The DSM and conservation programs historically offered by JEA include the following:

- Energy audits (residential and commercial).
- Green Built Homes of Florida.
- Chilled water services.
- Interruptible load.
- Educational events
- School activities.
- Monthly newsletter.

15.1.1 Energy Audits

JEA offers energy audits for both residential and commercial customers free of charge. A home energy audit can be completed online, in person, or by video. A business energy audit can also be done online or in person. The online audit considers the facility location, type of business or home, and floor space, among other factors. An audit completed in person involves a JEA representative performing an inspection and then

offering cost-effective ideas to lower energy costs. A video audit is also available upon request and offers tips on energy and water conservation.

In addition to the energy audits, JEA offers an appliance calculator. The calculator performs energy calculations concerning lighting, refrigeration, washer, dryer, cooling systems, room air conditioners, water heaters, and thermostat adjustments, and provides customers with a way to measure their appliance energy use.

15.1.2 Green Built Homes of Florida

Green Built Homes of Florida is an incentive-based program offered by JEA and the Northeast Florida Builders Association (NEFBA), which was launched on June 1, 2006, to promote the use of energy and water efficient building practices in new single-family homes. The incentive is a $255 rebate to builders for each home that passes certification requirements. To be eligible for the incentive, a home must be a newly constructed, single-family home in JEA's electric service area and be Energy Star® inspected and certified by a Class 1 Home Energy Rating Systems (HERS) rater.

Energy Star® is a program developed by the Environmental Protection Agency and the Department of Energy to promote energy efficiency. Common features of an Energy Star® qualified home include tight construction, improved insulation, high performance windows, tightly sealed ducts, and high efficiency, appropriately sized heating and cooling equipment.

15.1.3 Chilled Water Services

JEA's central chilled water system circulates cold water in a continuous flow throughout buildings, then cools the warmed water in a centralized chiller plant. This system is intended to replace central air conditioning in individual buildings. JEA is providing the services to several buildings. These buildings include the new arena, library, baseball park, and Shands Hospital.

15.1.4 Interruptible Load

Interruptible load represents energy usage that can be shed during times of peak demand. This reduces the need for capacity additions to meet future peak periods. Typically, interruptible load is sold as capacity that is available during off-peak times, but not guaranteed during times of peak demand. JEA's current interruptible load program is forecast to be approximately 4.3 percent of the forecast winter 2008 peak demand and 2.9 percent of the forecast winter 2027 peak demand, and approximately 4.0 percent of the forecast summer 2008 peak demand and 2.8 percent of the forecast summer 2027 peak demand.

Interruptible load is available to any customer eligible for the General Service Large Demand (GSLD) rate schedule. To be eligible for GSLD, a customer must have a measured monthly billing demand of at least 1,000 kW or more for 4 or more months out of 12 consecutive monthly billing periods. Additionally, the customer must have an average load factor of 35 percent or more and have agreed to the Interruptible Service Agreement with JEA. Under this agreement, JEA reserves the right to limit the total load served and may interrupt service during any time period in consideration of the limits described in the next paragraph. In exchange for interruptible services, the customer's billing rate is reduced.

JEA is only allowed to interrupt electric power and energy delivery to the customer when it is required to (a) maintain service to JEA's firm power customers and firm power sales commitments, or (b) supply emergency interchange service to another utility for its firm load obligations only, or (c) when the price of power available to JEA from other sources exceeds 30 cents per kWh.

15.1.5 Educational Events

JEA has found that attendance at formal seminars dropped to the point it was not possible to sustain the seminars. Therefore, JEA replaced the seminars with other educational events as summarized in Table 15-1. Although some of the events listed in Table 15-1 had primary topics other than energy conservation, all of these events had conservation literature displayed for the customers attending.

Table 15-1
Educational Events

Event	Target	Total No. Events/Yr	Estimated Contacts
Annual Business Seminar	Commercial	1	250
Annual Business Summit	Commercial	1	225
Rate Education Program	Commercial	As needed	100
Bill Inserts, Messages, TV, Radio & Print Ads	Commercial / Residential	Continuous	65 million
Solar PV Array & Display at the Zoo	Residential	Continuous	350,000
Home & Patio Show	Residential	1	3,000

15.1.6 School Activities

JEA distributed 64,000 energy conservation and 35,000 water conservation brochures to area schools JEA reached an additional 89,500 students through its educational partnership with Tree Hill Nature Center and approximately 200,000 students with the JEA Science Theater and Aqua Expo located in the Museum of Science and History.. JEA also distributed 12,000 energy conservation and 6,000 water conservation brochures through its speaker's bureau and various community events such as Science Nights.

15.1.7 Monthly Newsletter

Since March 2006, JEA has published *JEACommercial Connections*, the monthly electronic newsletter and web portal distributed to thousands of commercial and industrial customers of JEA. The monthly publication allows access to useful industry specific information on benchmarking, best practices, green business, online audits and the like. A searchable library contains thousands of current articles, ask-an-expert, as well as RSS capability.

15.2 Portfolio of New DSM Programs

In June 2006, JEA contracted with Summit Blue to identify potential DSM programs for JEA. As part of this effort, Summit Blue conducted a DSM bench marking and best practices analysis to ensure that the DSM potential estimates and DSM program plans that Summit Blue develops for JEA are reasonable and appropriate, and to identify best practices regarding DSM programs. Summit Blue then characterized reasonable and appropriate DSM measures, which included estimating per unit energy and demand savings, incremental costs compared to standard efficiency measures, and measure lifetimes. Benefit-to-cost analyses were then conducted for the DSM measures, and DSM potential for the 2008 through 2017 period for residential and commercial and industrial customers were estimated.

The remainder of this section summarizes Summit Blue's characterization of DSM measures, the cost effectiveness analysis, the DSM potential study performed by Summit Blue, and the resulting portfolio of new DSM programs developed by Summit Blue for consideration by JEA.

15.2.1 Characterization of Residential DSM and Energy Efficiency Measures

The following subsections describe the residential DSM measures considered by Summit Blue.

15.2.1.1 Domestic Hot Water Measures. The following domestic hot water measures were considered by Summit Blue.

Efficient Water Heaters

Traditional electric water heaters have an overall efficiency of about 90 percent, including standby and distribution losses. High efficiency units achieve 95 percent efficiency with improved insulation and heat traps that minimize convection into under insulated distribution pipes. The savings estimate for the high-efficiency units were calculated based on total hot water energy use and unit efficiencies.

Heat Pump Water Heaters

Heat pump water heaters use compressed refrigerants to extract heat from ambient air (or water) and move that heat to stored hot water. During warm weather these machines can move four units of heat for every one comparable unit of input energy, thus achieving a coefficient of performance (COP) up to 4.0. COP decreases as ambient air temperature decreases. At about 10° F to 20° F, heat pumps become ineffective. At cold ambient temperatures traditional electric resistance heating elements backup the heat pump compressor. Savings were determined using engineering estimates with a linear relationship between COP and outdoor air temperature until 20° F, at which point it was assumed that electric resistance heat would take over.

Tankless Water Heaters

Tankless water heaters are more efficient than standard water heaters since they avoid the energy lost from the hot water that is stored in conventional tanks. Tankless water heaters have "energy factors" of about 98 percent. The savings estimate for the high-efficiency unit is calculated based on total hot water energy use and unit efficiencies.

Solar-Assisted Water Heaters

Solar-assisted water heaters use thermal solar collectors to heat a solution to temperatures high enough to heat water to useful hot water temperatures. While very efficient, these solar collectors are not effective if the sun is not shining. During prolonged cloudy stretches or if sufficient hot water demand occurs at night, the solar collector must be supplemented with traditional electric resistance or gas-fired heating to provide adequate service. Furthermore, a small amount of energy must be consumed by circulating pumps and controls. The cost estimate includes federal incentives that buy-down the cost of solar collectors.

Low Flow Showerheads

Low flow showerheads use an orifice plate inside the fixture to restrict the water flow to a maximum 2.5 gallons per minute versus a 3.5 gallon per minute permitted with standard new showerheads. Water flow from older showerheads typically exceeds 5.0 gallons per minute. Engineering methods were used to estimate savings between the 2.5 and 3.5 gpm showerheads assuming one 7 minute shower per occupant per day.

Faucet Aerators

Faucet aerators introduce air into the water as it leaves the faucet. The result is perceived full flow at a much reduced actual flow rate. It has been estimated that a faucet aerator reduces flow from 2 gallons per minute to 1 gallon per minute during 5 minutes of water use per occupant per day.

Hot Water Pipe Insulation

Pre-formed segments of foam insulation are placed around hot water distribution pipes to minimize heat loss. While useful for the entire length of hot water piping, it is most cost-effective in the first 5-10 feet of pipe extending from the water heater. Engineering estimates of steady state heat loss from the pipes to conditioned indoor air were used to estimate savings.

Hot Water Set-back Thermostat

Similar to a heating, ventilating, and air conditioning (HVAC) set-back thermostat, a water heater setback thermostat reduces the temperature set point of the water tank during periods when full service is not required. Savings accrue from reduced stand-by and distribution system losses. Engineering estimates of steady state heat loss were used to estimate savings.

Drain Water Heat Recovery

These systems recover some of the heat from drain pipe hot water. Savings were based on US Department of Energy information and manufacturer case studies[1]. These devices are typically more expensive to install as retrofits.

[1] http://www.eere.energy.gov/consumer/your_home/water_heating/index.cfm/mytopic=13040 and http://gfxtechnology.com/ELWH.pdf

Energy Star Clothes Washers

Effective January 1, 2007, the minimum efficiency requirement for Energy Star status increased to 48.45 L/kWh/cycle, or 1.72 cu.ft./kWh/cycle. Savings are not climate dependent and were based on the Database for Energy Efficient Resources (DEER). Energy Star horizontal-axis washers are generally more efficient than vertical-axis counterparts due to reduced water use in a horizontal drum.

Energy Star Dishwashers

Energy Star dishwashers must exceed minimum energy efficiency standards by at least 25 percent. Savings are not climate dependent and were based on the DEER database.

15.2.1.2 Residential Space Heating and Cooling Measures. The following residential space heating and cooling measures were considered by Summit Blue.

Energy Star Residential Room Air Conditioners

Energy Star room air conditioners must be at least 10 percent more efficient than standard U.S. models, which are defined as units with a minimum energy efficiency ratio (EER) rating of 9.4-10.8 depending upon the size and type of the unit.[2] Minimum efficiency standards for room air conditioners range from 8.5 EER to 9.8 EER depending on the unit size and type. The savings calculation assumes 2,500 hours of full-load operation and improving from 8.9 to 10.7 EER.

Energy Star Residential Air-Source Heat Pumps

Energy Star air-source heat pumps are units with minimum ratings of 14 seasonal energy efficiency ratio (SEER), EER ratings of 11.0-11.5, and heating system performance factors of 7.0-7.1 or higher[3]. 2006 minimum efficiency standards for heat pumps are 13 SEER and 6.7 heating seasonal performance factor (HSPF).

Energy Star Residential Water-Source Heat Pumps

Water-source heat pumps use the ground as the heat source and sink in the heating and cooling cycles, respectively, rather than ambient air. Since the efficiency of the heat-pump process improves when the heat source is warmer and the cooling energy sink is cooler (near constant 55° F ground temperature versus design ambient air temperatures of 32° F and 94° F), this equipment can achieve very high efficiencies upwards of 15.0 SEER and 5.0 heating COP.

[2] See US DoE Energy Star web site: http://www.energystar.gov/index.cfm?c=roomac.pr_room_ac .
[3] Ibid.

HVAC Diagnostic Repair, Testing, and Maintenance

Many residential and commercial HVAC systems are not operating as efficiently as possible due to inadequate maintenance. This package of services includes ensuring proper refrigerant charge, lubrication, cleanliness and fan operation. The savings estimate assumes that the tune-up improves efficiency by 0.5 EER.

HVAC Duct Sealing, Operations and Maintenance

Many HVAC ducts are not sealed well and leak conditioned air into unconditioned spaces such as basements and attics. Duct sealing reduces such heat loss and reduces fan power. Savings estimates assume 3 percent savings over typical HVAC systems.

HVAC Duct Insulation

Uninsulated HVAC ducts that run through uninsulated spaces like basements or attics transfer some of the heated or cooled air into those spaces rather than the conditioned zones. The amount of this heat loss is reduced with duct insulation. Savings were determined by modeling R-2 insulated ducts versus R-6 insulation.

Ceiling Insulation

Ceiling insulation includes both insulating uninsulated roof areas and adding insulation to under-insulated roof areas. Savings were determined by comparing R-0 versus R-20 roof constructions.

Wall Insulation

Wall insulation is most cost-effective when insulating un-insulated wall areas. Savings were determined by comparing insulated versus un-insulated walls.

Floor Insulation

Savings were determined by comparing insulated versus un-insulated floors.

Efficient Windows

Efficient windows are generally considered to be either triple paned windows, windows with a radiant barrier to reflect heat back into the conditioned space, or windows with low "shading coefficients". Reducing the shading coefficients of glass will reduce the amount of solar heat gain into the building. This reduced solar gain will decrease the cooling load for the building, but may increase the heating load. On the

other hand these windows usually have a higher R-value than the windows they replace, thus heating energy can decrease.

Comprehensive Shell Air Sealing

This measure includes caulking, weather stripping, and sealing other visible cracks and penetrations in the building shell. Practically speaking a house should be able to breathe to purge contaminants so a lower limit of 0.35 air changes per hour (ACH) is advised without the addition of mechanical ventilation. Savings were determined by comparing 0.5 ACH versus 0.35 ACH.

15.2.1.3 Residential Lighting Measures. The following residential lighting measures were considered by Summit Blue.

Compact Fluorescent Lamps and Fixtures

Compact fluorescent lamps (CFLs) are the most common alternatives to standard incandescent lamps. CFLs are generally about four times as efficient as incandescent lamps, and last about 10 times as long. The newer "spiral" CFLs are also generally about the same size as incandescent lamps of similar light output. Numerous CFL measures were considered, with savings estimates corresponding to specific measures.

Light Emitting Diode (LED) Holiday Lights

LED holiday lights use LED lamps instead of incandescent lamps. Savings estimates assumed 5 operating hours per night for 30 days per year.

LED Night Lights

LED night lights substitute LED lights for incandescent lamps. Savings estimates assumed 10 operating hours per night.

15.2.1.4 Residential Refrigeration and Appliance Measures

The following residential refrigeration and appliance measures were considered by Summit Blue.

Energy Star Refrigerators and Freezers

Energy Star refrigerators must exceed current federal energy efficiency standards by at least 15 percent for full-size units, and 20 percent for compact size units[4]. Energy Star freezers must exceed minimum energy efficiency standards by at least 10 percent for full-sized units and 20 percent for compact units.

Remove Secondary Refrigerators and Freezers

Second refrigerators and freezers that customers own are often older and less efficient appliances. For example, the most common refrigerator sold in 1990 used between 60-70 kWh per cubic foot, compared to 2003, when the most common refrigerator sold used less than 30 kWh per cubic foot.[5]

Convection Ovens

Convection ovens are similar to traditional ovens except they have circulating fans to increase heat transfer to the food. Food cooks faster and at a slightly lower temperature in a convection oven.

Clothes Dryer with Moisture Sensor

Clothes dryers with moisture sensors tend to run fewer hours than those without because they sense when the clothes are dry rather than operating for a fixed period of time.

Power Strips with Occupancy Sensors

Power strips with occupancy sensors have several inputs that are controlled by an associated occupancy sensor and some that are not controlled. In an office environment, a computer could be plugged into an uncontrolled input and a monitor and task lamp could be plugged into the sensor controlled inputs.

15.2.2 Demand Response and Load Management Measures

The following demand response and load management measures were considered by Summit Blue. Direct load control measures apply to both residential and commercial/industrial customers.

[4] See Energy Star web site: http://www.energystar.gov/index.cfm?c=refrig.pr_refrigerators.
[5] Natural Resources Canada, "Energy Consumption of Major Household Appliances Shipped in Canada, Trends for 1990-2003 ", (NRCAN, Gatineau, QC, December 2005) p.8. U.S. and Canadian efficiency standards and availability are very similar; therefore, we conclude that the old equipment stock that would be removed is similar as well.

Direct Load Control (DLC) - AC/HP Cycling and Water Heater Cycling

DLC programs involve cycling or shutting off customers' air conditioners, heat pumps, water heaters, pool pumps, electric heating systems, or other electrical equipment during utilities' peak demand periods. This measure includes only air-conditioning/heat pumps and water heating.

Critical Peak Pricing (CPP)

CPP programs require the ability to inform customers in advance of a critical peak situation. Customers are given pricing information for the critical peak and they can elect to reduce loads to save cost or continue to purchase electricity at a significantly higher cost during the critical peak period.

Programmable Thermostats

Programmable thermostat measures enable customers to vary the comfort set points for heating and cooling equipment automatically, even when the customer is not present. This permits higher cooling set points during the mid-afternoon when a customer is at work, but preferred comfort settings just prior to when the customer comes home.

15.2.3 Characterization of Commercial/Industrial DSM and Energy Efficiency Measures

The following subsections describe the commercial/industrial DSM measures considered by Summit Blue.

15.2.3.1 Commercial/Industrial Lighting Measures. The following commercial/industrial lighting measures were considered by Summit Blue.

Compact Fluorescent Lamps

CFLs are the most common alternatives to standard incandescent lamps. CFLs are generally about four times as efficient as incandescent lamps, and last about 10 times as long. CFLs can either be screw-in replacements for incandescent lamps or plug-in lamps in fixtures specifically designed around CFL technology. Plug-in lamps in CFL fixtures are assumed to last the life of the fixture, because failed lamps must be replaced with comparable CFLs.

Premium/Regular T8 Lamps and Electronic Ballasts

T8 lamps and electronic ballasts are the most common alternative for standard T12 lamp and magnetic ballast tubular fluorescent lighting systems. T8 fluorescent

lamps are one inch in diameter, and are thinner than T12 lamps, which are 1.5 inches in diameter. T8 systems are approximately 30 percent more efficient than standard T12 systems, and Premium T8s are approximately 38 percent more efficient than standard T12 systems.

T5 Lamps and Electronic Ballasts

T5 lamps and electronic ballasts are a newer alternative tubular fluorescent lighting system. T5 fluorescent lamps are 5/8 of an inch in diameter, thinner than both T8 lamps and T12 lamps. T5 lighting systems are primarily used in new construction but are sometimes installed in retrofit situations, although the fixture would have to be changed in that case.

Occupancy Sensors

Occupancy sensors automatically turn off the lights in a room or an area when the area is unoccupied. Occupancy sensors are an alternative to standard wall mounted on/off lighting switches. Savings assume that 10 percent of lighting is controlled by occupancy sensors with an average reduction of 4 hours of use per day. HVAC interactions are included in the estimates.

Daylighting Sensors

Lighting systems are designed assuming no contribution from ambient daylight. In areas where daylight is available, artificial light is unnecessary and possibly detrimental to occupant comfort. Daylight sensors measure the contribution of ambient daylight and either turn-off or dim the lamps of the artificial lighting system. Savings assumed that perimeter zone (less than 12 feet from an exterior fenestrated wall) lighting is controlled by daylight sensors to maintain required lighting levels with 3 steps of lighting control.[6] HVAC interactions are included in the estimates.

LED Exit Signs

LED exit signs are one of the most efficient types of exit signs on the market. They generally only draw about two to three watts of power, compared to 10 watts or more for CFLs, or 20 watts or more for incandescent exit signs.

[6] 3-level switching is an option that can be used with three-lamp fixtures where the first stage of light is energizing the in-board lamp, the second level is energizing the two outboard lamps, and the third level is using all three lamps. This control can be accomplished with special 3-lamp ballasts or by tandem-wiring a 4-lamp and a 2-lamp ballast between two fixtures in close proximity.

15.2.3.2 Commercial/Industrial HVAC and Envelope Measures. The following commercial/industrial HVAC and envelope measures were considered by Summit Blue.

Efficient Commercial Air Conditioning Systems – Chillers, Packaged AC, Heat Pumps, and PTACs/PTHPs

These different types of HVAC equipment can be replaced with higher efficiency units. Efficiencies are specified in terms of kW/ton for chillers, EER for packaged AC, EER and COP for heat pumps, and EER for packaged terminal AC or heat pump.

Energy Management Systems (EMS)

Sophisticated EMS can result in considerable savings if programmed correctly. Most new buildings are built with some kind of EMS in place, but these are not always programmed the most effectively. Therefore, the measure for new buildings is to reprogram the EMS. Existing buildings may not have an EMS, so the measure in that case is to install an EMS. The savings from the retrofitted EMS are higher than those for reprogramming an EMS. Savings estimates were taken from industry literature on savings achieved from actual EMS installations and reprogramming operations, as it was not possible to simulate this measure.

Envelope Measures – Cool Roofs, Roof Insulation, Window Films, and High Efficiency Windows

All of the envelope measures can contribute to savings in both or either heating and cooling loads. Cool roofs reduce direct heating of the building via the roof in the summer, and window films reduce the amount of light and heat entering the building via windows in the summer. High efficiency windows reduce both heating and cooling needs by reducing the amount of thermal conduction through the windows.

15.2.3.3 Commercial/Industrial Process Measures. The following commercial/ industrial process measures were considered by Summit Blue.

Energy-Efficient Motors

The National Electrical Manufacturers Association (NEMA) has defined "premium" efficiency motors, and the savings for this measure were estimated based on the different efficiencies of the baseline and premium efficiency motors and the hours of operation.

Variable Frequency Drives

Variable frequency drives (VFDs) or adjustable speed drives (ASDs) vary the speed of motors so that their speeds are proportionate to the loads the motors are serving. This saves energy because motor energy use varies with the cube of the speed at which it runs for applications such as HVAC fans and pumps. Variable frequency drives produce small demand savings but high annual energy savings. Savings are determined by comparing the energy use of a motor with and without a VSD.

Compressed Air Measures – High Efficiency Compressors, Leak Maintenance, and Efficient Nozzles

Compressed air measures can be effective for industrial customers. Energy requirements for compressed air generation typically make up 20 percent of energy used for all industrial processes. The measures of leak maintenance and efficient nozzles are suitable for retrofitting existing compressed air equipment, and the higher efficiency compressors are suitable for either retrofit or new installations

15.2.3.4 Commercial/Industrial Refrigeration Measures. The following commercial/industrial refrigeration measures were considered by Summit Blue.

Strip Curtains and Night Covers

Strip curtains and night covers save energy by increasing the insulation between the cooled area within open case cooling units and the warmer air in the indoor environment. These are standard on new cooling units but may not be installed on older units. Savings are calculated on a linear foot basis, and are calculated by comparing energy use for refrigeration with and without the strip curtains or night covers. There are no demand savings for night covers.

High Efficiency Evaporator Fan Motors, Ice Makers and Refrigeration Compressors

High efficiency refrigeration equipment such as ice makers, evaporator fan motors, and refrigeration compressors save both energy and demand by operating at higher efficiencies. The evaporator fan motor measure definition is to replace a permanent split capacitor unit with an electrically commutated motor. The refrigeration compressor EER was raised from a baseline level of 8.5 to a more efficient level of 9. Savings for the ice maker were taken from industry literature and manufacturers' data.

Vending Machine Controls

Vending machines consume energy at all times of the day with cooling and lighting, but when an area is unoccupied and no one is purchasing products, these energy uses are wasteful. Vending machine controls can reduce lighting and decrease the number of compressor cycles based on occupancy sensor. Savings are based on mid-range savings estimates published by a controls manufacturer.[7]

15.2.4 DSM Cost Effectiveness Analysis

Following characterization of the DSM and energy efficiency measures summarized previously in this section, Summit Blue performed a cost effectiveness analysis. The cost effectiveness analysis evaluated measures using two different tests – the Total Resource Cost (TRC) test and the Rate Impact (RIM) test.

Key general inputs (i.e., inputs that are common across all measures) in the cost effectiveness analysis include avoided capacity costs, avoided transmission and distribution (T&D) costs, and assumptions related to future rate increases. These key inputs are summarized as follows:

- Annualized avoided capacity costs - $80/kW.
- Annualized avoided T&D costs - $25/kW.
- Rate Increases – 30 percent increase from 2006 rates by 2011.

The key inputs into the cost-effectiveness analysis by measure are the energy and demand savings, lifetime, and cost of the measure. The final input into the cost-effectiveness analysis is the program cost. Summit Blue assumed, based on the program benchmarking results, that for existing residential programs, the cost of the program will be $389 per peak kW saved for lighting, and $881 for central AC and heat pumps. It was also assumed that of that amount, 55 percent would be spent on rebate costs, and 45 percent will be spent on administration costs. Commercial and industrial program costs were assumed to vary from $255/kW for demand response measures up to $598/kW for new construction measures. With all of the above information, combined with the load profiles supplied by various sources, there was sufficient information to generate the cost-effectiveness numbers for each measure.

15.2.4.1 DSM Measure Cost Effectiveness Results. This section summarizes the results of the cost effectiveness analysis for both the TRC test and RIM test on the measure level. The TRC test considers the benefits (avoided costs) of generation, transmission and distribution investments and avoided fuel costs due to the conserved energy caused by the DSM measures. The costs for the TRC test are the DSM measure

[7] USA Technologies produces the VendingMiser
http://www.usatech.com/energy_management/energy_vm.php

costs plus the DSM measure administration costs. The RIM test considers the benefits (avoided costs) of generation, transmission and distribution investments, and avoided fuel costs due to the conserved energy caused by the DSM measure. The costs for the RIM test are the DSM measure costs plus the "lost revenues" due to the DSM programs.

The TRC and RIM tests are based on a net benefit to net cost analysis, and therefore test scores above 1.0 indicate that a measure may be cost effective (i.e., the net benefits of a measure are greater than the net costs). Tables 15-2 and 15-3 present the cost effectiveness results for existing single family homes and new single family homes, respectively while Table 15-4 presents the cost effectiveness results for the commercial/industrial sector

15.2.5 DSM Potential Analysis

This section describes the DSM potential analysis approach and methods. The DSM potential analysis used the results of the customer baseline profiles and the DSM measure characterization, along with the DSM benchmarking results, as inputs to the DSM potential spreadsheets.

The general approach for estimating DSM resource potentials consisted of three steps: (1) estimate technical and economic DSM potential; (2) estimate preliminary market penetrations and the resulting achievable potential for each measure; and (3) calibrate the achievable DSM potential estimates using the benchmarking information described in a previous section. This third step is the most important step in Summit Blue's DSM potential estimation process. For this benchmarking analysis, the average annual DSM potential values for each end use and sector were compared to actual program results for corresponding top performing programs and portfolios.

Technical DSM potential represents the amount of DSM savings that could be achieved, not considering economic and market barriers to customers installing DSM measures. Technical potential is calculated as the product of the DSM measures' savings per unit, the quantity of applicable equipment in each facility, the number of facilities in JEA's service area, and the difference between 100 percent and the measure's current market saturation. Technical potential estimates include DSM measures that are not cost effective, and technical potential does not consider market barriers such as customers' lack of awareness of DSM measures. Therefore, technical DSM potential estimates do not provide a realistic basis for setting DSM program goals.

Economic DSM potential represents the amount of technical DSM potential that is "cost effective," as defined by the results of the TRC test. Measures had to pass the TRC test in order to be considered to be cost effective and considered in the DSM potential estimates.

Table 15-2
DSM Cost Effectiveness Results for Existing Single Family Homes

Measure*	TRC	RIM
ENERGY STAR or better Room AC, < 20 kBtu, EER 10.7	4.59	0.67
Diagnostic repair, testing, maintenance	2.04	0.69
Duct Insulation and Sealing	2.02	0.93
Ceiling insulation (R-0 improved to R-20)	2.10	0.94
Ceiling insulation (R-20 improved to R-40)	0.34	0.95
High Efficiency Windows, Low-e; U=0.35	2.22	0.87
Floor insulation (R-0 to R-20)	0.03	0.45
Wall insulation (R-0 to R-20)	1.08	0.72
Comprehensive air shell sealing	0.57	0.38
ENERGY STAR or better Air Source Heat Pump, SEER=14; HSPF=8.5	1.06	0.71
ENERGY STAR or better Air Source Heat Pump, SEER=18; HSPF=9.4	2.10	0.88
Geothermal Heat Pump (4 Ton, w/ water heating)	0.44	0.88
Central AC SEER 14.0	2.73	0.98
High Efficiency Dryer With Moisture Sensor	0.68	0.49
ENERGY STAR or better Freezer	0.29	0.48
ENERGY STAR or better Refrigerator	0.57	0.48
Remove secondary refrigerator/freezer	1.68	0.47
Convection oven	0.24	0.48
Power strips with occupancy sensors	0.22	0.40
CFL, 6.0 hr/day	4.89	0.39
CFL, 0.5 hr/day	1.27	0.69
CFL, 2.5 hr/day	3.26	0.44
LED nightlights	2.01	0.77
LED holiday lights	0.29	0.12
CFL Fixtures, 0.5 hr/day	0.25	0.74
CFL Fixtures, 2.5 hr/day	0.66	0.45
CFL Fixtures, 6.0 hr/day	1.09	0.39
Low flow showerheads	4.71	0.48
HE Water Heater (EF=0.95)	1.42	0.51
Energy Star Dish Washer (EF=0.58)	0.53	0.70
Heat Pump Water Heater (EF=2.9)	0.78	0.65

Table 15-2 (Continued)
DSM Cost Effectiveness Results for Existing Single Family Homes

Measure*	TRC	RIM
Tankless Water Heater (EF=0.98)	0.11	0.42
Solar Assisted Water Heating	0.24	0.43
Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5)	0.57	0.62
Energy Star Vertical-Axis Clothes Washer: SEHA CW Tier 2 (EF=3.25)	0.13	0.64
Faucet Aerators	5.15	1.19
Hot water pipe insulation	9.35	0.76
Drain water heat recovery	0.79	0.62
DHW insulation blanket	4.59	0.47
A/C Cycling Switch	14.07	6.60
WH Cycling Switch	2.34	1.35
RTP	2.61	1.26
Programmable thermostat	2.34	0.80

*Measures are listed multiple times depending whether the savings are for air conditioning, electric resistance heating, or heat pump systems.

Table 15-3
DSM Cost Effectiveness Results for New Single Family Homes

Measure*	TRC	RIM
ENERGY STAR or better Room AC, < 20 kBtu, EER 10.7	4.98	0.88
Diagnostic repair, testing, maintenance	3.12	0.85
Duct Sealing and insulation	1.39	0.76
Ceiling insulation (R-20 improved to R-40)	0.25	0.60
High Efficiency Windows, Low-e; U=0.35	1.44	0.65
Floor insulation (R-10 to R-20)	0.02	0.92
Wall insulation (R-10 to R-20)	0.97	0.68
Comprehensive air shell sealing	0.74	0.57
ENERGY STAR or better Air Source Heat Pump, SEER=14; HSPF=8.5	0.58	0.65
ENERGY STAR or better Air Source Heat Pump, SEER=18; HSPF=9.4	1.58	0.62
Geothermal Heat Pump (4 Ton, w/ water heating)	0.41	0.62
Central AC SEER 14.0	2.02	0.72
High Efficiency Dryer With Moisture Sensor	1.01	0.72
ENERGY STAR or better Freezer	0.38	0.72
ENERGY STAR or better Refrigerator	0.73	0.69
Remove secondary refrigerator/freezer	2.20	0.68
Convection oven	0.36	0.69
Power strips with occupancy sensors	0.34	0.64
CFL, 6.0 hr/day	8.86	0.74
CFL, 0.5 hr/day	1.21	0.69
CFL, 2.5 hr/day	5.03	0.73
LED nightlights	1.75	0.71
LED holiday lights	1.35	0.67
CFL Fixtures, 0.5 hr/day	0.24	0.72
CFL Fixtures, 2.5 hr/day	1.05	0.73
CFL Fixtures, 6.0 hr/day	2.07	0.74
HE Water Heater (EF=0.95)	1.79	0.68
Energy Star Dish Washer (EF=0.58)	0.54	0.73
Heat Pump Water Heater (EF=2.9)	0.82	0.63
Tankless Water Heater (EF=0.98)	0.18	0.69
Solar Assisted Water Heating	0.37	0.68

Table 15-3 (Continued)
DSM Cost Effectiveness Results for New Single Family Homes

Measure*	TRC	RIM
Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5)	0.62	0.65
Energy Star Vertical-Axis Clothes Washer: SEHA CW Tier 2 (EF=3.25)	0.15	0.66
Faucet Aerators	2.86	0.75
Hot water pipe insulation	7.56	0.73
Drain water heat recovery	1.50	0.73
A/C Cycling Switch	2.36	1.31
WH Cycling Switch	2.48	1.38
RTP	2.75	1.26
Programmable thermostat	3.12	0.80

*Measures are listed multiple times depending whether the savings are for air conditioning, electric resistance heating, or heat pump systems.

Table 15-4
DSM Cost Effectiveness Results for Commercial/Industrial

Measure	TRC	RIM
CFLs	3.32	0.62
Regular T8 w/ EB	2.59	0.68
Premium T8 w/ EB	3.21	0.72
T5 w/ EB from T12	1.29	0.58
T5 w/ EB from PSMH	1.08	0.71
LED Exit Signs	1.9	0.58
Occupancy Sensors - FLTG	1.91	0.56
Occupancy Sensors - HID	2.97	0.65
Daylighting	2.34	0.74
Hi-E Air-Cooled Chillers	5.65	0.77
Hi-E Water-Cooled Chillers	4.14	0.75
Hi-E Packaged DX	1.66	0.81
Hi-E Heat Pump	2.74	0.76
Hi-E PTAC/PTHP	2.62	0.85
Roof Insulation	0.22	0.78
Cool Roofs	0.1	0.74
Window Films	0.45	0.78
Premium Efficiency Motors	0.8	0.74
Motor VFDs	11.04	0.74
Hi-E Evaporator Fan Motors	0.57	0.27
Hi-E Refrigeration Compressors	0.72	0.61
Hi-E Ice Makers	1.32	0.56
Strip Curtains	1.2	0.42
Night Covers	0.76	0.37
Hi-E Air Compressors	13.05	0.77
Leak Maintenance	0.17	0.08
Efficient Nozzles	0.34	0.19
Energy Mgmt System Install	15.13	0.75
Solar PV	3.64	0.84
Premium T8 w/ EB	2.18	0.55
T5 w/ EB from T8	0.66	0.29

Table 15-4 (Continued)
DSM Cost Effectiveness Results for Commercial/Industrial

Measure	TRC	RIM
T5 w/ EB from PSMH	2.05	0.74
Occupancy Sensors - FLTG	1.72	0.53
Occupancy Sensors - HID	2.82	0.64
Daylighting	2.07	0.73
Hi-E Air-Cooled Chillers	5.78	0.81
Hi-E Water-Cooled Chillers	3.96	0.74
Hi-E Packaged DX	1.64	0.8
Hi-E Heat Pump	2.66	0.75
Hi-E PTAC/PTHP	2.3	0.82
Hi-E Windows	1.9	0.81
Cool Roofs	0.04	0.54
Premium Efficiency Motors	4.9	0.73
Motor VFDs	11.02	0.74
Hi-E Refrigeration Compressors	0.71	0.59
Hi-E Air Compressors	12.93	0.77
Energy Mgmt System Reprogram	10.91	0.76
Solar PV	3.64	0.84

Achievable potential is an estimate of the amount of DSM potential that could be captured by realistic DSM programs over the ten-year forecast period (2008-2017) covered by this DSM potential analysis. The key parameter that must be estimated to forecast achievable DSM potential is the market penetration for each DSM measure at the end of the forecast period in 2017. Summit Blue estimated this parameter for each DSM measure based primarily on the DSM benchmarking analysis, as well as previous DSM potential projects conducted by Summit Blue.

For most nonlighting measures, maximum market penetrations of 20 percent over the forecast period were assumed, while lighting DSM measure saturations were generally assumed to reach 70 percent to 90 percent saturation by 2017, as that range of CFL measure saturations are widely expected to be achieved over the long term, and some utilities with aggressive DSM program histories have already achieved the lower end of that range in the commercial/industrial sector. However, it is important to emphasize that Summit Blue's assumptions regarding end of period DSM measure saturation estimates were made so as to produce DSM potential estimates for each sector and end use that are consistent with the utility and agency DSM program benchmarking results discussed previously.

15.2.5.1 Residential DSM Potential Results. This section provides the overall DSM potential results for the residential sector. The total and annual residential achievable DSM potential results for the 10 year forecast period are presented in Table 15-5. The energy values shown in Table 15-5 are for the DSM measures' first-year energy savings at the generator, the demand savings are the peak coincident demand savings, and the program costs are the total estimated DSM program budgets for a given year, including rebate or other customer incentive costs, as well as administrative, implementation, and evaluation costs.

15.2.5.2 Residential Demand Response Results. Summit Blue estimated the potential for two residential demand response options:

1. Direct load control of central air conditioners and heat pumps.
2. Direct load control of electric water heaters.

Some utilities include other types of end use equipment in direct load control programs. However, water heaters are the most common additional type of equipment covered by DLC programs after central air conditioners and heat pumps.

Table 15-5
Total 10 Year Residential Achievable Potential Estimates[1]

Residential Total	10 Year Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Lighting											
Achievable Potential Summer Demand Savings (MW)	38.8	1.9	3.1	3.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Achievable Potential Winter Demand Savings (MW)	38.8	1.9	3.1	3.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Achievable Potential Energy Savings (GWh)	296.4	14.8	23.7	29.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6
Program Costs (Million $)	$15.1	$0.8	$1.2	$1.5	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7
Heating /HVAC											
Achievable Potential Summer Demand Savings (MW)	32.2	1.6	2.6	3.2	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Achievable Potential Winter Demand Savings (MW)	35.0	1.8	2.8	3.5	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Achievable Potential Energy Savings (GWh)	112.8	5.6	9.0	11.3	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Program costs (Million $)	$30.8	$1.5	$2.5	$3.1	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4
Water Heating											
Achievable Potential Summer Demand Savings (MW)	8.4	0.4	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Achievable Potential Winter Demand Savings (MW)	7.8	0.4	0.6	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Achievable Potential Energy Savings (GWh)	47.2	2.4	3.8	4.7	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Program Costs (Million $)	$3.3	$0.2	$0.3	$0.3	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
Load Management/DLC											
Achievable Potential Summer Demand Savings (MW)	81.3	4.1	6.5	8.1	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Achievable Potential Winter Demand Savings (MW)	130.5	6.5	10.4	13.1	14.4	14.4	14.4	14.4	14.4	14.4	14.4
Achievable Potential Energy Savings (GWh)	-0.34	-0.02	-0.03	-0.03	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
Program Costs (Million $)	$18.9	$0.9	$1.5	$1.9	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1
Refrigeration & Miscellaneous											
Achievable Potential Summer Demand Savings (MW)	0.5	0.02	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Achievable Potential Winter Demand Savings (MW)	0.5	0.02	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Achievable Potential Energy Savings (GWh)	4.2	0.2	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Program Costs (Million $)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Residential Total											
Achievable Potential Summer Demand Savings (MW)	161.1	8.1	12.9	16.1	17.7	17.7	17.7	17.7	17.7	17.7	17.7
Achievable Potential Winter Demand Savings (MW)	212.5	10.6	17.0	21.3	23.4	23.4	23.4	23.4	23.4	23.4	23.4
Achievable Potential Energy Savings (GWh)	460.2	23.0	36.8	46.0	50.6	50.6	50.6	50.6	50.6	50.6	50.6
Program Costs (Million $)	$68.3	$3.4	$5.5	$6.8	$7.5	$7.5	$7.5	$7.5	$7.5	$7.5	$7.5

[1]. Totals may not exactly equal the sum of the individual year demand and energy savings and program costs due to rounding.

For purposes of comparison, Summit Blue reviewed the results its demand response potential assessment for the International Energy Agency's demand response resources project. [8] As part of that project, Summit Blue surveyed 40 North American utilities on their demand response programs in late 2004. The survey indicated that the top-performing residential direct load control programs had achieved impacts that amounted to 10 percent or more of the utilities' residential peak demands. Large majorities of the impacts from these utilities' demand response programs were from direct load control of central air conditioners during summer peak demand periods.

15.2.5.3 Residential Energy Efficiency Results by End Use. Residential lighting measures, primarily CFLs in high-use, medium-use, and low-use fixtures, account for about 64 percent of the total estimated residential energy conservation potential, a total of about 39 MW of coincident peak demand reduction and 296 GWh of energy savings over the ten-year forecast period. The average energy savings are similar to the top-performing residential lighting programs.

HVAC and building envelope DSM measures are estimated to have second largest total energy savings impacts of about 112 GWh and 35 MW of peak demand reduction potential over the ten year period. Water heating measures are estimated to have the third largest total energy savings impacts, of about 47 GWh of energy savings potential and 7.8 MW of peak demand reduction potential. Refrigeration and other measures have relatively small DSM potentials of 4 GWh of energy savings impacts and 0.5 MW of peak demand reductions. The small refrigeration DSM potential is primarily due to the fact that government minimum energy efficiency standards have already caused most of the energy conservation potential for more efficient refrigeration measures to be realized. Each of these three DSM measure categories have about 5-10 or more applicable DSM measures each that were included in the DSM potential analysis.

The largest HVAC or building envelope measure in terms of energy conservation potential is insulating uninsulated walls. The largest impact water heating conservation measure is drain water heat recovery.

15.2.5.4 Commercial/Industrial DSM Potential Results. The total and annual commercial/industrial achievable demand response potential results for the 10 year forecast period are shown in Table 15-6. The demand savings shown are for both the winter and summer peak coincident demand savings, and the program costs are the total estimated DSM program budgets for a given year, including rebates or other customer incentive costs, as well as administrative, implementation, and evaluation costs.

[8] Limited results from this study are publicly available at www.demandresponseresources.com.

Table 15-6
Total 10 Year Commercial/Industrial Demand Response Achievable Potential Estimates[1]

Demand Response	10 Year Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Direct Load Control											
Achievable Potential Summer Demand Savings (MW)	23.74	1.19	2.37	3.56	3.56	3.56	1.90	1.90	1.90	1.90	1.90
Achievable Potential Winter Demand Savings (MW)	16.58	0.83	1.66	2.49	2.49	2.49	1.331	1.33	1.33	1.33	1.33
Achievable Potential Energy Savings (GWh)	0.36	0.02	0.04	0.05	0.05	0.05	0.03	0.03	0.03	0.03	0.03
Program Costs (Million $)	$4.2	0.21	0.42	0.63	0.63	0.63	0.34	0.34	0.34	0.34	0.34
Interruptible/Callable Rates											
Achievable Potential Summer Demand Savings (MW)	118.70	5.94	11.87	17.81	17.81	17.81	9.50	9.50	9.50	9.50	9.50
Achievable Potential Winter Demand Savings (MW)	82.90	4.15	8.29	12.44	12.44	12.44	6.63	6.63	6.63	6.63	6.63
Achievable Potential Energy Savings (GWh)	6.0	0.30	0.60	0.90	0.90	0.90	0.48	0.48	0.48	0.48	0.48
Program Costs (Million $)	$4.6	0.23	0.46	0.68	0.68	0.68	0.36	0.36	0.36	0.36	0.36
RTP											
Achievable Potential Summer Demand Savings (MW)	23.74	1.19	2.37	3.56	3.56	3.56	1.90	1.90	1.90	1.90	1.90
Achievable Potential Winter Demand Savings (MW)	16.58	0.83	1.66	2.49	2.49	2.49	1.33	1.33	1.33	1.33	1.33
Achievable Potential Energy Savings (GWh)	0	0	0	0	0	0	0	0	0	0	0
Program Costs (Million $)	$0.2	0.01	0.02	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02
Total											
Achievable Potential Summer Demand Savings (MW)	166.18	8.31	16.62	24.93	24.93	24.93	13.29	13.29	13.29	13.29	13.29
Achievable Potential Winter Demand Savings (MW)	116.06	5.80	11.61	17.41	17.41	17.41	9.28	9.28	9.28	9.28	9.28
Achievable Potential Energy Savings (GWh)	6.37	0.32	0.64	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Program Costs (Million $)	$9.0	0.45	0.90	1.35	1.35	1.35	0.72	0.72	0.72	0.72	0.72

[1]. Totals may not exactly equal the sum of the individual year demand and energy savings and program costs due to rounding.

Summit Blue estimated the DSM potentials for three demand response program options:

1. Direct load control of commercial and industrial customers' air conditioners and heat pumps.
2. Interruptible rates, somewhat similar to JEA's existing program.
3. Real-time pricing.

To estimate the commercial/industrial demand response potential, Summit Blue reviewed the results from its International Energy Agency demand response resources project. The 2004 utility survey that Summit Blue conducted for that project revealed that utilities with top-performing interruptible rate programs can reduce their commercial/industrial peak demands by about 10 percent through these programs. However, with a very small number of exceptions, the demand response program impacts realized by most utilities from commercial/industrial direct load control and RTP programs are generally quite modest, at about 2 percent of utility commercial/industrial peak demands each.

In total, Summit Blue estimates that total commercial/industrial demand response programs would have a demand reduction potential of about 166 MW over the ten year forecast period. Estimated annual program impacts would follow the regular s-shaped diffusion curve initially and then taper off in the latter part of the forecast period as the programs achieve increasing market saturation.

15.2.5.5 Overall Commercial/Industrial Energy Efficiency Results. The total and annual commercial/industrial achievable energy efficiency potential results for the 10 year forecast period are presented in Table 15-7.

The total estimated commercial and industrial energy efficiency potential over the 10 year forecast period is about 610 GWh, 48 MW of winter peak demand reduction, and 106 MW of summer peak demand reduction. About 30 percent of this energy efficiency potential is projected to come from energy efficient lighting products, about 40 percent is projected to come from energy efficient motors and air compressors, and about 26 percent of the total potential is expected to come from efficient HVAC measures and energy management systems.

Table 15-7
Total 10 Year Commercial/Industrial Energy Efficiency Potential Estimates[1]

Total Commercial and Industrial	10 Year Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Lighting											
Achievable Potential Summer Demand Savings (MW)	37.81	1.13	2.27	3.40	3.78	4.54	4.54	4.54	4.54	4.54	4.54
Achievable Potential Winter Demand Savings (MW)	10.29	0.31	0.62	0.93	1.03	1.24	1.24	1.24	1.24	1.24	1.24
Achievable Potential Energy Savings (GWh)	182.05	5.46	10.92	16.38	18.21	21.85	21.85	21.85	21.85	21.85	21.85
Program Costs (Million $)	$57.05	1.71	3.42	5.13	5.71	6.85	6.85	6.85	6.85	6.85	6.85
HVAC											
Achievable Potential Summer Demand Savings (MW)	36.76	1.10	2.21	3.31	3.68	4.41	4.41	4.41	4.41	4.41	4.41
Achievable Potential Winter Demand Savings (MW)	13.31	0.40	0.80	1.20	1.33	1.60	1.60	1.60	1.60	1.60	1.60
Achievable Potential Energy Savings (GWh)	78.86	2.31	4.61	6.92	7.69	9.22	9.22	9.22	9.22	9.22	9.22
Program Costs (Million $)	$21.20	0.64	1.27	1.91	2.12	2.54	2.54	2.54	2.54	2.54	2.54
Building Envelope											
Achievable Potential Summer Demand Savings (MW)	0.12	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Achievable Potential Winter Demand Savings (MW)	0.22	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Achievable Potential Energy Savings (GWh)	0.40	0.01	0.02	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Program Costs (Million $)	$0.18	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Motors											
Achievable Potential Summer Demand Savings (MW)	2.57	0.08	0.15	0.23	0.26	0.31	0.31	0.31	0.31	0.31	0.31
Achievable Potential Winter Demand Savings (MW)	3.26	0.10	0.20	0.29	0.33	0.39	0.39	0.39	0.39	0.39	0.39
Achievable Potential Energy Savings (GWh)	123.22	3.70	7.39	11.09	12.32	14.79	14.79	14.79	14.79	14.79	14.79
Program Costs (Million $)	$7.22	0.22	0.43	0.65	0.72	0.87	0.87	0.87	0.87	0.87	0.87
Refrigeration											
Achievable Potential Summer Demand Savings (MW)	0.90	0.03	0.05	0.08	0.09	0.11	0.11	0.11	0.11	0.11	0.11
Achievable Potential Winter Demand Savings (MW)	0.90	0.03	0.05	0.08	0.09	0.11	0.11	0.11	0.11	0.11	0.11
Achievable Potential Energy Savings (GWh)	9.86	0.30	0.59	0.89	0.99	1.18	1.18	1.18	1.18	1.18	1.18
Program Costs (Million $)	$1.44	0.04	0.09	0.13	0.14	0.17	0.17	0.17	0.17	0.17	0.17

Table 15-7 (Continued)
Total 10 Year Commercial/Industrial Energy Efficiency Potential Estimates[1]

Total Commercial and Industrial	10 Year Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Compressed Air											
Achievable Potential Summer Demand Savings (MW)	16.56	0.50	0.99	1.49	1.66	1.99	1.99	1.99	1.99	1.99	1.99
Achievable Potential Winter Demand Savings (MW)	16.56	0.50	0.99	1.49	1.66	1.99	1.99	1.99	1.99	1.99	1.99
Achievable Potential Energy Savings (GWh)	122.03	3.66	7.32	10.98	12.20	14.64	14.64	14.64	14.64	14.64	14.64
Program Costs (Million $)	$6.28	0.19	0.38	0.56	0.63	0.75	0.75	0.75	0.75	0.75	0.75
EMS											
Achievable Potential Summer Demand Savings (MW)	6.35	0.19	0.38	0.57	0.64	0.76	0.76	0.76	0.76	0.76	0.76
Achievable Potential Winter Demand Savings (MW)	3.70	0.11	0.22	0.33	0.37	0.44	0.44	0.44	0.44	0.44	0.44
Achievable Potential Energy Savings (GWh)	83.94	2.52	5.04	7.55	8.39	10.07	10.07	10.07	10.07	10.07	10.07
Program Costs (Million $)	$1.98	0.06	0.12	0.18	0.20	0.24	0.24	0.24	0.24	0.24	0.24
Renewables											
Achievable Potential Summer Demand Savings (MW)	4.79	0.14	0.29	0.43	0.48	0.57	0.57	0.57	0.57	0.57	0.57
Achievable Potential Winter Demand Savings (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Achievable Potential Energy Savings (GWh)	12.11	0.36	0.73	1.09	1.21	1.45	1.45	1.45	1.45	1.45	1.45
Program Costs (Million $)	$46.12	1.38	2.77	4.15	4.61	5.53	5.53	5.53	5.53	5.53	5.53
Total											
Achievable Potential Summer Demand Savings (MW)	105.86	3.18	6.35	9.53	10.59	12.70	12.70	12.70	12.70	12.70	12.70
Achievable Potential Winter Demand Savings (MW)	48.25	1.45	2.90	4.34	4.83	5.79	5.79	5.79	5.79	5.79	5.79
Achievable Potential Energy Savings (GWh)	610.48	18.31	36.63	54.94	61.05	73.26	73.26	73.26	73.26	73.26	73.26
Program Costs (Million $)	$141.47	4.24	8.49	12.73	14.15	16.98	$16.98	$16.98	$16.98	$16.98	$16.98

[1]. Totals may not exactly equal the sum of the individual year demand and energy savings and program costs due to rounding.

The total commercial/industrial energy efficiency potential amounts to approximately 8.5 percent of JEA's 2007 commercial/industrial energy consumption of about 7,160 GWh. This is equal to annual average energy savings of about 61 GWh. Based on the histories of the benchmark utilities and energy agencies, Summit Blue estimates that a three to four year ramp-up period will generally be required before most of JEA's DSM results would hit the annual average impacts for the forecast period. It is estimated that the annual achievements of the total DSM potential will follow an s-shaped curve for most end use categories, with impacts of 3 percent of the total energy efficiency potential in the first year, 6 percent in the second year, 9 percent in the third year, 10 percent in the fourth year, and 12 percent in the fifth year and beyond to the end of the 10-year forecast period.

15.2.5.6 Commercial/Industrial Energy Efficiency Results by End Use. Commercial/industrial lighting measures account for the largest share of commercial/ industrial energy efficiency potential of any individual end use, comprising about 30 percent of the total estimated commercial/industrial energy conservation potential, a total of about 182 GWh of energy conservation potential, 10 MW of winter coincident peak demand reduction, and 38 MW of summer peak demand reduction potential over the ten-year forecast period. This amounts to an average of about 1 MW of winter peak and 18 GWh per year.

T8 lamps and electronic ballasts in regular and high-bay applications are expected to account for the largest share of commercial/industrial lighting energy efficiency potential, about one-third of the total. CFL lamps and fixtures, T5 lamps and electronic ballasts, and LED exit signs are expected to account for most of the other commercial/industrial lighting potential.

Efficient air compressors and variable speed drives applied to motor systems are expected to account for about 40 percent of total commercial/industrial energy savings at about 245 GWh of first year energy savings in total. The energy efficiency process potential is almost exactly equally divided between these two process DSM measures.

Efficient HVAC and control systems are estimated to account for the third largest share of commercial/industrial energy efficiency potential, 161 GWh of first year energy savings and 17 MW of winter peak demand reduction over the 10 year forecast period. Energy management systems account for slightly more than half of the energy savings from HVAC and control measures.

Other end use categories such as refrigeration are expected to account for small shares of energy efficiency potential over the forecast period. This expectation is primarily drawn from the results of the DSM benchmarking analysis discussed previously.

15.2.6 Resulting DSM Portfolio for JEA

Based on the Summit Blue analyses, JEA's senior management approved a new DSM portfolio through 2012 in accordance with guidance established by JEA's Board. The portfolio will be funded by a JEA Board approved conservation charge of $0.50 per MWh for all customers and an additional $1.00 per MWh for residential customers with consumption above 2.75 MWh per month. The new DSM portfolio was designed to address all customer classes (i.e. residential and commercial/industrial). It also ensures no future upward pressure on customer rates by maintaining portfolio RIM of no less than 1. The approved DSM portfolio consists of the following five programs:

- **JEA's Residential Lighting Program** promotes the use of energy efficient compact fluorescent light bulbs in homes and small businesses by offering a financial incentive and recycling options to its customers. JEA has aligned itself with the Department of Energy's "Change a Light, Change the World" campaign in an effort to educate its customers in the use of energy efficient lighting products. JEA includes appropriate messaging concerning the proper disposal of compact fluorescent light bulbs.
- **JEA's Neighborhood Efficiency Program** offers education concerning the efficient use of energy and water as well as the direct installation of an array of energy and water efficient measures at no cost to income qualified customers. The Neighborhood Efficiency Program is a partnership with the City of Jacksonville.
- **JEA's Residential Efficiency Upgrades Program** will promote the use of energy and water efficient building practices in existing homes. The program targets measures such as energy audits, HVAC equipment and envelope upgrades. The program will align itself with the Department of Energy's "Home Performance with Energy Star" campaign in an effort to educate its customers in the use of energy efficient home products.
- **JEA's Residential Direct Load Control (DLC) Program** will offer financial incentives to residential and small commercial customers to control central air conditioners, central electric heating systems, water heaters, and pool pumps during critical periods to reduce JEA's winter and summer peak demands.
- **JEA's Commercial Direct Load Control Program** will offer financial incentives to mid-to-large-sized commercial/industrial customers to curtail loads when requested by JEA in response to winter and summer peaks or system emergencies. The program focuses on utilizing customer sited energy management systems and standby generation.

Following JEA's approval of the DSM portfolio, Summit Blue provided the projected energy efficiency and peak demand response savings corresponding to the policies and conservation funding limits. In addition to seasonal peak demand and energy savings, Summit Blue provided projected annual costs of the approved DSM portfolio. Tables 15-8 through 15-11 present the annual summer and winter coincident peak demand and net energy for load reductions, as well as the annual program costs, corresponding to the DSM portfolio being implemented by JEA.

Table 15-8
Target JEA DSM Portfolio Summer Peak Demand Reductions
(Cumulative MW Reductions)

DSM Program	2008	2009	2010	2011	2012
Residential Lighting	2.8	8.5	14.2	19.8	25.5
Neighborhood Efficiency	0.2	0.4	0.6	0.8	1.0
Residential Efficiency Upgrades	0.0	2.3	6.8	11.3	15.8
Residential Direct Load Control	0.0	7.1	21.2	36.5	51.8
Commercial Direct Load Control	0.0	5.9	17.8	35.6	53.4
Total Cumulative Demand Reductions[(1)]	3.0	24.2	60.5	104.0	147.5

[(1)] Totals may not exactly equal the sum of the individual program demand reductions due to rounding.

Table 15-9
Target JEA DSM Portfolio Winter Peak Demand Reductions
(Cumulative MW Reductions)

DSM Program	2008	2009	2010	2011	2012
Residential Lighting	1.9	5.7	11.3	16.3	21.2
Neighborhood Efficiency	0.2	0.4	0.6	0.8	1.0
Residential Efficiency Upgrades	0.0	1.5	4.5	9.0	13.0
Residential Direct Load Control	0.0	8.2	26.9	51.4	75.9
Commercial Direct Load Control	0.0	5.8	17.4	31.3	45.3
Total Cumulative Demand Reductions[(1)]	2.0	21.5	60.7	108.7	156.3

[(1)] Totals may not exactly equal the sum of the individual program demand reductions due to rounding.

Table 15-10
Target JEA DSM Portfolio Total Annual Energy Reductions
(GWh Reductions)

DSM Program	Calendar Year 2008[1]	Calendar Year 009	Calendar Year 2010	Calendar Year 2011	Calendar Year 2012
Residential Lighting	2.2	14.1	37.2	67.1	87.2
Neighborhood Efficiency	0.2	1.0	1.8	2.6	3.2
Residential Efficiency Upgrades	0.3	3.8	17.4	41.9	66.3
Residential Direct Load Control	0.0	0.0	0.0	0.0	0.0
Commercial Direct Load Control	0.0	0.0	0.0	0.0	0.0
Total Cumulative Energy Reductions[2]	2.7	18.8	56.4	111.6	156.8

[1] Energy reductions were not provided by Summit Blue for 2008. The 2008 GWh reductions have been estimated based on actual performance to date.
[2] Totals may not exactly equal the sum of the individual program energy reductions due to rounding.

Table 15-11
Target JEA DSM Portfolio Annual Program Costs
(Millions $)

DSM Program	Fiscal Year 2008	Fiscal Year 2009	Fiscal Year 2010	Fiscal Year 2011	Fiscal Year 2012
Residential Lighting	$0.6	$1.5	$2.2	$1.9	$1.9
Neighborhood Efficiency	$0.25	$0.35	$0.35	$0.35	$0.35
Residential Efficiency Upgrades	$0.1	$1.0	$2.1	$3.1	$2.7
Residential Direct Load Control	$0.6	$1.2	$2.7	$3.6	$3.6
Commercial Direct Load Control	$0.2	$0.4	$0.9	$1.1	$1.1
Total Program Costs[1]	$1.85	$4.45	$8.35	$10.05	$9.65

[1] Totals may not exactly equal the sum of the individual program costs due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 20
COMPANY JEA (Direct)
WITNESS Myron R. Rollins (MRR-1)
DATE 02/12/09

RESUME OF

MYRON R. ROLLINS

Black & Veatch

Director

Project Management; Integrated Resource Planning; Permitting and Licensing; Feasibility Studies and Project Development

Education
Bachelors, Electrical, University of Missouri at Columbia, 1974

Professional Registration
Engineer (PE), Missouri, 1982

Total Years Experience
32
Joined B&V
1976

Professional Associations
MoKan American Nuclear Society – Past President
Institute of Electrical and Electronics Engineers – Senior Member

Language Capabilities
English

Mr. Rollins is a Director in Enterprise Management Solutions. He is responsible for management of system planning and feasibility studies encompassing the areas of integrated resource planning, load forecasting, generation planning, cogeneration, site selection, and other special studies.

Mr. Rollins specializes in generation planning and project development. He is responsible for numerous power supply studies incorporating integrated planning techniques. Mr. Rollins was responsible for the development of Black & Veatch's POWRPRO chronological production costing program and POWROPT optimal generation expansion program. He is also responsible for power market analysis and project feasibility studies. Mr. Rollins extends his expertise in generation system planning to the area of need for power certification of power plants.

Mr. Rollins has broad expertise in planning and project development that enables him to assist clients in the development of expansion plans and specific projects in a realistic manner that incorporates the required balance between engineering and cost considerations as well as sociopolitical and licensing considerations. With this experience, Mr. Rollins has successfully helped utility and developer clients add value to their systems and projects throughout his career.

Mr. Rollins has presented expert testimony on several occasions before the Alaska, Florida, Indiana and Missouri Public Service Commissions, and has published numerous papers on strategic planning and cogeneration. He is past chairman of the Mo-Kan section of the American Nuclear Society and a senior member of IEEE.

Representative Project Experience

Need for Power Certification, Orlando Utilities Commission, Florida 2005-2006
Project Manager. Managed the preparation of a Need for Power Application for Orlando Utilities Commission's Stanton Energy Center Unit B. Stanton B is a proposed IGCC unit to be constructed at Stanton Energy Center in Orlando, Florida. The application was submitted to the Florida Public Service Commission under the Electrical Power Plant Siting Act. The Need for Power Application evaluated Stanton B against

other self-build alternatives and demand-side management alternatives. The Florida Public Service Commission unanimously approved the need for Stanton B.

Need for Power Certification, Florida Municipal Power Agency, Florida
2005
Project Manager. Managed the preparation of a Need for Power Application for Florida Municipal Power Agency's (FMPA's) Treasure Coast Energy Center (TCEC) Unit 1. TCEC Unit 1 is a proposed 1x1 F class combined cycle unit to be constructed on a greenfield site in Ft. Pierce, Florida. The application that was submitted to the Florida Public Service Commission under the Florida Electrical Power Plant Siting Act. The Need for Power Application evaluated TCEC Unit 1 against other self-build alternatives, purchase power from a request for proposals (RFP) process, and demand-side management alternatives. The Florida Public Service Commission unanimously approved the need for TCEC Unit 1.

Integrated Resource Plan, City of Tallahassee, Florida
2005-2006
Project Manager. Managing an integrated resource plan (IRP) for the City of Tallahassee. The IRP involves extensive evaluation of gas and coal fueled alternatives. More than 140 demand-side management (DSM) measures were evaluated. The IRP includes extensive evaluation of the impacts from the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). Biomass generation was evaluated as part of the IRP. Extensive probabilistic risk analysis was also conducted.

Integrated Resource Plan, JEA, Florida
2005-2006
Project Manager. Managing an integrated resource plan (IRP) in conjunction with JEA. The IRP involves extensive evaluation of gas and coal fueled alternatives including the development of site-specific estimates. Requirements for the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) were included in determining air quality control additions necessary for existing units. Demand-side management (DSM) evaluation made use of previous work conducted by Black & Veatch as part of JEA's Conservation Goal Docket before the Florida Public Service Commission.

Integrated Resource Plan Review, City of Lakeland, Florida
2005
Project Manager. Managed the review of the development of the City of Lakeland's integrated resource plan (IRP). The review encompasses all aspects of the IRP including load forecast, fuel forecast, development of supply side alternatives, life extension, and expansion planning. In

addition, Black & Veatch evaluated demand-side management alternatives for the City of Lakeland.

Expert Testimony, Indiana Municipal Power Agency, Indiana
2004
Project Manager. Presented expert testimony before the Indiana Utility Regulatory Commission for issuance of a Certificate of Public Convenience and Necessity. The testimony covered the technical and economic feasibility for three coal generating unit projects in which the Indiana Municipal Power Agency planned to participate.

St. Johns River Power Park Annual Report, JEA, Florida
2004
Project Manager. Managed preparation of the annual report on the operation and maintenance of St. Johns River Power Park consisting of two 675 MW pulverized coal units burning a mix of coal and petroleum coke. The units are jointly owned by Florida Power & Light Company and JEA. The annual operation and maintenance report is required to be submitted to the bond trustee under JEA's bond covenants.

Ten Year Site Plan, Orlando Utilities Commission, Florida
2004
Project Manager. Managed the preparation of the Ten Year Site Plan for Orlando Utilities Commission as required by the Florida Public Service Commission. The Ten Year Site Plan is an integrated resource expansion plan for the utility including load forecast, fuel price forecast, demand side management, and generation expansion.

Stock Island Combustion Turbine Unit 4 Development and Licensing, Florida Municipal Power Agency, Florida
2004
Project Manager. Managed development of the project description, the conceptual design, the development of lease and operating agreements, and permitting and licensing of a LM6000 simple cycle combustion turbine located at Key West, Florida. In addition, studies of the method of project execution, either EPC or traditional design and construction management, were developed along with a detailed schedule and cost estimate.

Combined Cycle Site Selection Study, Florida Municipal Power Agency, Florida
2004
Project Manager. Managed the site selection study for a 1x1 F class combined cycle for Florida Municipal Power Agency (FMPA). The site selection study initially evaluated four FMPA member generation sites. From those four sites, two were selected for detailed evaluation. The site selection study evaluated fatal flaws and permitting requirements, natural gas supply, water supply, wastewater disposal, and transmission

interconnection requirements. The study evaluated construction and operating costs differences between the two sites. The study also evaluated the ability to deliver power to the East system and the associated economic impacts of wheeling costs to get power to the East system. The study recommended selection of a site in St. Lucie County.

Independent Assessment, Edwards & Angell, Florida
2003
Project Manager. Managed an independent assessment of the current state and cost to complete a partially completed combined cycle repowering project in Lake Worth, Florida for Edwards & Angell, the City of Lake Worth's bond attorney. The study involved developing an estimate to complete the project as a simple cycle combustion turbine and providing consultation on the development of a new natural gas transportation agreement and a memorandum of understanding between the existing owner, AES, and the new purchaser of the project, Florida Municipal Power Agency. The assignment also involved review and advise on numerous other project agreements.

Cane Island Feasibility Study, Florida Municipal Power Agency, Florida
2002
Project Manager. Managed a feasibility study for the installation of a 1 x 1 F class combined cycle at the existing Cane Island Power Park. The study addressed site arrangement, the availability of cooling water, and the disposal of wastewater.

JEA Simple Cycle Combustion Turbine Additions

SUMMER			
Year	Capacity Need MW	CT Addition MW	Remaining Capacity Need MW
2009	168	Kennedy-150	18
2010	450	-----	300
2011	525	GEC 1 & 2-284	91
2012	601	-----	167

WINTER			
Year	Capacity Need MW	CT Addition MW	Remaining Capacity Need MW
2008/2009	(129)	-----	(129)
2009/2010	22	Kennedy 8-191	(169)
2010/2011	468	-----	277
2011/2012	556	GEC 1 & 2 – 376	(11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EI EXHIBIT 21
COMPANY JEA (Direct)
WITNESS Myron R. Rollins (MRR-2R)
DATE 02/12/09

Capacity Bid in Response to RFP (Summer MW)

Proposal / Option

Year	A	B	C	D1	D2	D3	E1	E2	F1	F2	F3
2010		200		155			157	157	200	200	200
2011	50	150	92	310	310	310	314	314	200	200	200
2012	50	150	92	310	310	310	314	314	200	200	200
2013	50	100	92	310	310	310	314	314	200	200	200
2014			92	310	310	310	314	314	200	200	200
2015			92	310	310	310	314	314	200	200	200
2016					310	310	314	314	200	200	200
2017					310	310	314	314	200	200	200
2018						310	314	314		200	200
2019						310	314	314		200	200
2020						310	314	314		200	200
2021								314		200	200
2022								314			200
2023								314			200
2024								314			200
2025								314			200
2026								314			200

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EI EXHIBIT 22
COMPANY SEA (Direct)
WITNESS Myron E. Rollins (MRR-3)
DATE 02/12/09

Projected Reliability Levels - Summer/Base Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.5%	(176)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,007	2,890	9.9%	14.4%	(152)	(18)
2010	3,367	9	(376)	(51)	150	3,099	3,072	2,955	0.9%	4.9%	(435)	(300)
2011	3,367	9	(376)	(51)	434	3,383	3,138	3,021	7.8%	12.0%	(226)	(91)
2012	3,367	9	(376)	(51)	434	3,383	3,204	3,087	5.6%	9.6%	(301)	(167)
2013	3,367	9	(376)	(51)	434	3,383	3,269	3,152	3.5%	7.3%	(377)	(242)
2014	3,367	9	(376)	(51)	434	3,383	3,335	3,218	1.4%	5.1%	(452)	(317)
2015	3,367	9	(376)	(51)	434	3,383	3,400	3,283	-0.5%	3.0%	(527)	(393)
2016	3,367	9	0	(51)	434	3,759	3,466	3,349	8.5%	12.3%	(227)	(92)
2017	3,367	9	0	(51)	434	3,759	3,531	3,414	6.4%	10.1%	(302)	(167)
2018	3,367	0	0	(51)	434	3,750	3,597	3,480	4.3%	7.8%	(386)	(252)
2019	3,367	0	0	(51)	434	3,750	3,662	3,545	2.4%	5.8%	(462)	(327)
2020	3,367	0	0	(51)	434	3,750	3,728	3,611	0.6%	3.9%	(537)	(403)
2021	3,367	0	0	(51)	434	3,750	3,794	3,677	-1.1%	2.0%	(613)	(478)
2022	3,367	0	0	(51)	434	3,750	3,859	3,742	-2.8%	0.2%	(688)	(553)
2023	3,367	0	0	(51)	434	3,750	3,925	3,808	-4.5%	-1.5%	(763)	(629)
2024	3,367	0	0	(51)	434	3,750	3,990	3,873	-6.0%	-3.2%	(839)	(704)
2025	3,367	0	0	(51)	434	3,750	4,056	3,939	-7.5%	-4.8%	(914)	(780)
2026	3,367	0	0	(51)	434	3,750	4,121	4,004	-9.0%	-6.4%	(990)	(855)
2027	3,367	0	0	(51)	434	3,750	4,187	4,070	-10.4%	-7.9%	(1,065)	(930)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2011.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 23
COMPANY JEA (Direct)
WITNESS Myron R. Rollins (MRR-4)
DATE 02/12/09

Projected Reliability Levels - Winter/Base Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,621	291	(383)	0	0	3,529	3,079	2,946	14.6%	19.8%	(11)	142
2009	3,621	366	(383)	0	0	3,604	3,155	3,022	14.2%	19.3%	(24)	129
2010	3,621	366	(383)	(63)	191	3,733	3,232	3,099	15.5%	20.4%	16	169
2011	3,621	9	(383)	(63)	191	3,376	3,309	3,176	2.0%	6.3%	(430)	(277)
2012	3,621	9	(383)	(63)	567	3,751	3,386	3,253	10.8%	15.3%	(142)	11
2013	3,621	9	(383)	(63)	567	3,751	3,462	3,329	8.3%	12.7%	(230)	(77)
2014	3,621	9	(383)	(63)	567	3,751	3,539	3,406	6.0%	10.1%	(319)	(166)
2015	3,621	9	(383)	(63)	567	3,751	3,616	3,483	3.7%	7.7%	(407)	(254)
2016	3,621	9	(383)	(63)	567	3,751	3,693	3,560	1.6%	5.4%	(495)	(342)
2017	3,621	9	0	(63)	567	4,134	3,770	3,637	9.7%	13.7%	(201)	(48)
2018	3,621	0	0	(63)	567	4,125	3,846	3,713	7.3%	11.1%	(298)	(145)
2019	3,621	0	0	(63)	567	4,125	3,923	3,790	5.2%	8.8%	(386)	(233)
2020	3,621	0	0	(63)	567	4,125	4,000	3,867	3.1%	6.7%	(474)	(321)
2021	3,621	0	0	(63)	567	4,125	4,077	3,944	1.2%	4.6%	(563)	(410)
2022	3,621	0	0	(63)	567	4,125	4,153	4,020	-0.7%	2.6%	(651)	(498)
2023	3,621	0	0	(63)	567	4,125	4,230	4,097	-2.5%	0.7%	(739)	(586)
2024	3,621	0	0	(63)	567	4,125	4,307	4,174	-4.2%	-1.2%	(828)	(675)
2025	3,621	0	0	(63)	567	4,125	4,384	4,251	-5.9%	-2.9%	(916)	(763)
2026	3,621	0	0	(63)	567	4,125	4,461	4,328	-7.5%	-4.7%	(1,004)	(851)
2027	3,621	0	0	(63)	567	4,125	4,537	4,404	-9.1%	-6.3%	(1,092)	(940)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2011.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM **EXHIBIT** 24
COMPANY JEA (Direct)
WITNESS Myron R. Collins (MRR-5)
DATE 02/12/09

Projected Reliability Levels - Summer/DSM Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.6%	(175)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,001	2,884	10.1%	14.6%	(146)	(11)
2010	3,367	9	(376)	(51)	150	3,099	3,045	2,928	1.8%	5.8%	(403)	(269)
2011	3,367	9	(376)	(51)	434	3,383	3,079	2,962	9.9%	14.2%	(158)	(24)
2012	3,367	9	(376)	(51)	434	3,383	3,100	2,983	9.1%	13.4%	(182)	(48)
2013	3,367	9	(376)	(51)	434	3,383	3,143	3,026	7.6%	11.8%	(232)	(97)
2014	3,367	9	(376)	(51)	434	3,383	3,209	3,092	5.4%	9.4%	(307)	(173)
2015	3,367	9	(376)	(51)	434	3,383	3,274	3,157	3.3%	7.2%	(382)	(248)
2016	3,367	9	0	(51)	434	3,759	3,340	3,223	12.5%	16.6%	(82)	53
2017	3,367	9	0	(51)	434	3,759	3,405	3,288	10.4%	14.3%	(157)	(22)
2018	3,367	0	0	(51)	434	3,750	3,471	3,354	8.0%	11.8%	(242)	(107)
2019	3,367	0	0	(51)	434	3,750	3,537	3,420	6.0%	9.7%	(317)	(183)
2020	3,367	0	0	(51)	434	3,750	3,602	3,485	4.1%	7.6%	(392)	(258)
2021	3,367	0	0	(51)	434	3,750	3,668	3,551	2.2%	5.6%	(468)	(334)
2022	3,367	0	0	(51)	434	3,750	3,733	3,616	0.5%	3.7%	(543)	(408)
2023	3,367	0	0	(51)	434	3,750	3,799	3,682	-1.3%	1.8%	(619)	(484)
2024	3,367	0	0	(51)	434	3,750	3,864	3,747	-2.9%	0.1%	(694)	(559)
2025	3,367	0	0	(51)	434	3,750	3,930	3,813	-4.6%	-1.6%	(769)	(635)
2026	3,367	0	0	(51)	434	3,750	3,996	3,879	-6.2%	-3.3%	(845)	(711)
2027	3,367	0	0	(51)	434	3,750	4,061	3,944	-7.7%	-4.9%	(920)	(786)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2011.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614EM **EXHIBIT** 25
COMPANY JEA (Direct)
WITNESS Myron R. Rollins (MRR-6)
DATE 02/12/09

Projected Reliability Levels - Winter/DSM Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,621	291	(383)	0	0	3,529	3,079	2,946	14.6%	19.8%	(12)	141
2009	3,621	366	(383)	0	0	3,604	3,147	3,014	14.5%	19.6%	(15)	138
2010	3,621	366	(383)	(63)	191	3,733	3,198	3,065	16.7%	21.8%	55	208
2011	3,621	9	(383)	(63)	191	3,376	3,235	3,102	4.3%	8.8%	(345)	(192)
2012	3,621	9	(383)	(63)	567	3,751	3,276	3,143	14.5%	19.4%	(16)	137
2013	3,621	9	(383)	(63)	567	3,751	3,334	3,201	12.5%	17.2%	(83)	70
2014	3,621	9	(383)	(63)	567	3,751	3,411	3,278	10.0%	14.4%	(171)	(18)
2015	3,621	9	(383)	(63)	567	3,751	3,488	3,355	7.6%	11.8%	(260)	(107)
2016	3,621	9	(383)	(63)	567	3,751	3,565	3,432	5.2%	9.3%	(348)	(195)
2017	3,621	9	0	(63)	567	4,134	3,642	3,509	13.5%	17.8%	(54)	99
2018	3,621	0	0	(63)	567	4,125	3,718	3,585	11.0%	15.1%	(150)	3
2019	3,621	0	0	(63)	567	4,125	3,795	3,662	8.7%	12.7%	(239)	(86)
2020	3,621	0	0	(63)	567	4,125	3,872	3,739	6.5%	10.3%	(327)	(174)
2021	3,621	0	0	(63)	567	4,125	3,949	3,816	4.5%	8.1%	(416)	(263)
2022	3,621	0	0	(63)	567	4,125	4,025	3,892	2.5%	6.0%	(503)	(350)
2023	3,621	0	0	(63)	567	4,125	4,102	3,969	0.6%	3.9%	(592)	(439)
2024	3,621	0	0	(63)	567	4,125	4,179	4,046	-1.3%	2.0%	(680)	(527)
2025	3,621	0	0	(63)	567	4,125	4,256	4,123	-3.1%	0.1%	(769)	(616)
2026	3,621	0	0	(63)	567	4,125	4,333	4,200	-4.8%	-1.8%	(858)	(705)
2027	3,621	0	0	(63)	567	4,125	4,409	4,276	-6.4%	-3.5%	(945)	(792)

[1] Reserve margin caluclated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2011.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614EM **EXHIBIT** 26
COMPANY JEA (Direct)
WITNESS Myron R. Rollins (MRR-7)
DATE 02/12/09

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080614-EM EXHIBIT 27
COMPANY JEA (Direct)
WITNESS Myron R. Rollins (GEC-1) Sections
DATE 08/12/09 1.0, 2.0, 4.0, 11.0 & 12.0

1.0 Executive Summary

JEA submits this Need for Power Application in support of a proposed conversion of two natural gas fired simple cycle combustion turbines to a 2x1 combined cycle configuration at the Greenland Energy Center (GEC) generating station in Duval County, Florida. The analyses summarized below and discussed throughout this Application demonstrate that the combined cycle conversion is needed to meet the growing electrical demands of JEA's customers in the most cost-effective manner.

1.1 The Applicant

JEA's electric service area covers all of Duval County and portions of Clay and St. Johns counties, serving a total of approximately 400,000 customers. JEA owns and operates three generating plants and all transmission and distribution facilities. A fourth power plant, the St. Johns River Power Park (SJRPP), is owned jointly by JEA and the Florida Power & Light Company (FPL); it is operated by JEA. JEA and FPL are also joint owners of Unit 4 at Georgia Power Company's coal fired Robert W. Scherer Plant (Plant Scherer), which is located in Macon, Georgia. In addition, JEA produces 1.2 megawatts (MW) using landfill gas produced by the Girvin Road Landfill. JEA's total available summer net capacity is 3,370 MW, and its total available winter net capacity is 3,620 MW.

1.2 The Proposed GEC Combined Cycle Conversion

The proposed GEC combined cycle conversion will result in a high-efficiency, natural gas fueled combined cycle unit, consisting of two combustion turbines and two heat recovery steam generators (HRSGs) that will drive a steam turbine generator. The new unit will have a net output rating of 522 MW at average ambient temperature conditions. All of the generation capacity from the unit will be committed for sale to JEA's customers. The proposed GEC combined cycle conversion is needed to meet energy and capacity needs of JEA's customers.

1.3 The Power Plant Siting Act Process

The Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes, provides a "centrally coordinated, one-stop licensing process" for power plant projects. The PPSA provides a centralized process to ensure that all affected state and local agencies review a project before the Siting Board, consisting of the Governor and Cabinet, takes final action on the site certification application. The Florida Public

Service Commission's (FPSC) need determination is a critical step in the PPSA certification process. Along with the reports submitted by the Florida Department of Environmental Protection (DEP) and other agencies, the Commission's need determination allows the Siting Board to balance "the increasing demand for electrical power plants with the broad interests of the public."

1.4 The Commission's Need Determination

Section 403.519(3), Florida Statutes, sets forth the following criteria that the Commission must consider in making need determinations:

- The need for electric system reliability and integrity.
- The need for adequate electricity at a reasonable cost.
- The need for fuel diversity and supply reliability.
- Whether the proposed plant is the most cost-effective alternative available.
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available.
- Whether there are conservation measures taken by, or reasonably available to, the applicant or its members that might mitigate the need for the proposed plant.

The Legislature did not assign the weight this Commission is to give each of these factors. Rule 25-22.081, Florida Administrative Code, sets forth specific information that each Need for Power Application must include to allow the Commission to address the statutory factors. The required information is summarized below and discussed in detail throughout this Application.

1.5 The Need for the GEC Combined Cycle Conversion

JEA's capacity needs are projected to continuously increase. As discussed in Section 12.0 of this Need for Power Application, by the summer of 2012, JEA's reserve margin decreases to 9.6 percent, or 167 MW below the capacity required to continue to reliably serve JEA's customers and maintain a 15 percent reserve margin. By the summer of 2013, the need for additional capacity to maintain a 15 percent reserve margin will increase to 242 MW. The need for additional capacity reflects the impact of interruptible and curtailable loads. A number of JEA's capacity and power purchase contracts are expiring, or nearing the end of their lifetime. By providing capacity necessary to meet JEA's growing needs, the GEC combined cycle conversion will contribute to the reliability and integrity of JEA's electric system.

1.6 Analysis of Generating (Supply-Side) Alternatives

As discussed in Section 13.0 of this Application, JEA has evaluated several supply-side technologies, either as alternatives to the GEC combined cycle conversion or as capacity resource options for installation following the proposed combined cycle conversion. As part of that analysis, JEA evaluated renewable technologies, conventional technologies, and emerging technologies. Based on the results of production cost modeling of multiple economic scenarios, JEA identified the GEC combined cycle conversion as the most cost-effective alternative to meet the need for additional capacity.

Although not subject to the Commission's "Bid Rule," JEA has issued numerous requests for proposals (RFP). The evaluations of the RFP responses indicated that none of the responses would be a cost-effective alternative to the GEC combined cycle conversion. As a result of these RFPs and other initiatives, JEA is evaluating renewable projects that may eventually be integrated into JEA's generating system.

1.7 Analysis of Non-Generating (Demand-Side) Alternatives

JEA's 2005 Demand-Side Management (DSM) plan was approved by the FPSC on September 1, 2004. Upon reviewing the plan, the FPSC determined that there were no cost-effective conservation measures available for use by JEA, so the FPSC established and approved zero DSM and conservation goals for JEA's residential and commercial/industrial sectors through 2014 (Docket No. 040030-EG). Nevertheless, JEA has voluntarily continued its historical programs, because it had determined that these programs were in the overall best interest of its customers.

Furthermore, in June 2006, JEA contracted with Summit Blue Consulting, LLC (Summit Blue), an independent firm that specializes in DSM program evaluation and development, to identify potential DSM programs for JEA. As part of this effort, Summit Blue and JEA developed an aggressive DSM portfolio that has been approved and funded by JEA's Board. Even with the energy and demand savings projected for the new DSM portfolio, however, the Greenland Energy Center combined cycle conversion is still needed to meet JEA's capacity requirements.

1.8 Integrated Fuel and CO_2 Emissions Allowance Cost Projections

Although no carbon dioxide (CO_2) regulatory programs have been adopted, in light of continuing discussion of potential CO_2 regulation, this Application presents additional economic analyses that incorporate a range of CO_2 emissions allowance cost estimates, and associated fuel forecasts, developed by the U.S. Department of Energy's Energy Information Agency (EIA). These analyses demonstrate that the GEC combined

cycle conversion is JEA's most cost-effective alternative, even assuming a carbon-regulated environment and a range of costs associated with CO_2 emissions allowances.

Fuel and emissions allowance costs are interrelated. Therefore, fuel and CO_2 emissions allowance cost projections included in this Application are fully integrated. That is, the EIA price projections consider fuel supply and demand in tandem with potential CO_2 emissions allowance costs, along with numerous other market influences, to develop fully integrated fuel and CO_2 emissions allowance cost projections.

1.9 Most Cost-Effective Alternative

After extensive economic comparisons to other generating unit and nongeneration alternatives, the GEC combined cycle conversion was determined to be the most cost-effective alternative to meet JEA's needs. Under the reference case, the expansion plan with the GEC is approximately $122.6 million lower in cumulative present worth costs (CPWC) than the plan without the GEC combined cycle conversion.

1.10 Adverse Consequences If the GEC is Not Built

Delaying the conversion of GEC would result in reduced reliability and higher costs to JEA's customers. If the proposed combined cycle conversion is delayed, JEA's summer reserve margin will fall to 9.6 percent in 2012, which is 167 MW below JEA's 15 percent reserve margin criterion. The impact of delaying the conversion of GEC to combined cycle configuration by 1 year (to 2013) and instead installing alternative capacity to maintain reserve margin requirements in the summer of 2012 would be an increase in CPWC of approximately $36.7 million.

The capacity deficit in the summer of 2012 represents a significant portion of the capacity that will be provided by the conversion of GEC to combined cycle. With a reserve margin below 15 percent in 2012, JEA's system will be exposed to decreased reliability and increased costs if the GEC combined cycle conversion is delayed and no additional generating capacity is installed in its place.

1.11 Conclusion

The proposed GEC combined cycle conversion will ensure that JEA has an adequate supply of power to serve its customers' needs at a reasonable cost. The detailed economic analyses presented in this Need for Power Application demonstrate that the GEC combined cycle conversion is the most cost-effective alternative to meet JEA's power supply needs. The addition of cost-effective natural gas generation will further diversify JEA's fuel mix. The project will also enhance fuel diversity and supply reliability by utilizing multiple natural gas supply options. JEA already utilizes

reasonably available DSM programs and renewable resources. Even with potential demand and energy reductions that could be achieved from additional conservation and renewable energy initiatives, the GEC combined cycle conversion is the least-cost alternative to reliably meet JEA's power supply needs.

2.0 Introduction

This Application demonstrates the need for the GEC combined cycle conversion under Section 403.519 Florida Statutes. The GEC facility will consist of two simple cycle 7FA combustion turbine units that are currently under development for commercial operation in 2010 and are proposed to be converted to a 2x1 combined cycle configuration by June 2012.

Section 3.0 provides a description of JEA and its existing facilities. This general overview of the system includes JEA's generating plants and electric bulk systems, existing purchase power agreements (PPAs), JEA's involvement with The Energy Authority (TEA), existing power sales agreements, unit retirements anticipated during the planning horizon, operating and spinning reserve requirements, JEA's Clean Power Program, and JEA's transmission system.

Section 4.0 provides the economic parameters and assumptions used throughout the Application.

Section 5.0 presents the JEA load forecast, which indicates the continued load growth that necessitates the GEC combined cycle conversion.

Section 6.0 demonstrates the availability of natural gas to provide a reliable fuel supply for the GEC, thus maintaining the integrity and reliability of JEA's system.

Section 7.0 presents the fuel price projections used in the economic evaluations. The fuel price projections are based on the US Department of Energy's Energy Information Administration's Annual Energy Outlook 2008 (AEO2008) projections and also include projections of CO_2 emissions allowance prices.

Section 8.0 discusses the available natural gas transportation system to serve the GEC and demonstrates that the natural gas transportation system will provide reliable delivery of natural gas to the GEC site.

Section 9.0 describes the GEC combined cycle conversion and provides the capital cost estimate, operating cost estimates, and estimated performance parameters for the combined cycle. Section 9.0 demonstrates that the GEC combined cycle will be designed and constructed so that it will operate reliably and efficiently and maintain the integrity of JEA's system.

Section 10.0 describes the evaluations conducted to demonstrate that interconnection of the GEC combined cycle conversion will not have an adverse impact on the transmission system. The Florida Regional Reliability Council (FRCC) has approved the interconnection of GEC combined cycle to the transmission system.

Section 11.0 discusses the reliability criteria used by JEA.

Section 12.0 demonstrates JEA's need for additional capacity by applying the 15 percent reserve margin to JEA's load forecast and comparing the capacity requirements to JEA's existing generating resources.

Section 13.0 describes the conventional and emerging generating unit alternatives that were compared to the GEC combined cycle conversion and used in expansion plans to provide JEA's capacity needs beyond those supplied by the GEC combined cycle conversion.

Section 14.0 describes JEA's Request for Proposals (RFP) process to identify renewable (wind and solar) resources that may be available, and demonstrates that JEA is utilizing available renewable energy sources and technologies to the extent reasonably available.

Section 15.0 describes JEA's existing conservation and demand-side management (DSM) programs and discusses the expanded DSM portfolio being developed by JEA.

Section 16.0 describes the methodology used to evaluate the cost-effectiveness of the GEC combined cycle conversion.

Section 17.0 presents the results of the economic analyses conducted. These analyses demonstrate that the GEC combined cycle conversion is JEA's least-cost alternative under a wide range of scenarios. The GEC combined cycle conversion is JEA's least-cost alternative, even with the addition of renewables and conservation and DSM.

Section 18.0 presents the cost and reliability impacts of delaying the GEC combined cycle conversion.

Section 19.0 demonstrates that JEA can readily finance the addition of the GEC combined cycle conversion.

4.0 Economic Parameters

This section presents the economic parameters and methodology used to evaluate the economics of the GEC combined cycle conversion as part of JEA's least-cost expansion plan to satisfy forecast capacity requirements throughout the 20 year evaluation period.

4.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed operations and maintenance (O&M) escalation rate, and nonfuel variable O&M escalation rate are each assumed to be 2.5 percent.

4.2 Municipal Bond Interest Rate

The tax exempt municipal bond interest rate is assumed to be 5.0 percent.

4.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax exempt municipal bond interest rate of 5.0 percent.

4.4 Interest During Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 5.0 percent.

4.5 Levelized Fixed Charge Rate

The fixed charge rate, or FCR, represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year FCR.

Different generating technologies are assumed to have different economic lives and, therefore, different financing terms. Simple cycle combustion turbines are assumed to have a 20 year financing term, while natural gas fired combined cycle units are assumed to be financed over 25 years. Given the various economic lives and corresponding financing terms, different levelized FCRs were developed. All levelized FCR calculations assume the 5.0 percent tax exempt municipal bond interest rate, a 2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost,

and a debt service reserve fund equal to 100 percent of the average annual debt service requirement earning interest at an interest rate equal to the bond interest rate of 5.0 percent. The resulting 20 year FCR is 8.972 percent, and the 25 year FCR is 7.915 percent.

11.0 Reliability Criteria

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand and to maintain an additional margin of capacity should unforeseen events result in higher system demand and/or lower than anticipated availability of capacity. This section discusses the reliability criteria used by JEA.

11.1 Reserve Sharing Requirements

Section 25-6.035 of the Florida Administration Code (FAC) requires that Florida utilities maintain a minimum 15 percent planned reserve margin for purposes of equitable sharing of energy reserves. The investor owned utilities in the State of Florida have entered into a stipulation to maintain 20 percent reserve margins, while the municipal utilities in the State generally maintain reserve margins of no less than 15 percent.

11.2 Reserve Margin Requirements

JEA uses a minimum 15 percent reserve margin in both the summer and the winter. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. JEA plans to maintain its seasonal reserve margins for firm load obligations (reflecting the load reductions associated with interruptible and curtailable loads). The reserve margin is calculated as follows:

$$\frac{\text{System Net Capacity - System Firm Peak Demand (After Interruptible/Curtailable Load)}}{\text{System Firm Peak Demand (After Interruptible/Curtailable Load)}}$$

11.2.1 Demand Response Considerations

Special consideration needs to be given to the portion of planned reserve requirements that can be covered by demand response (DR). Because DR grows as a portion of planned reserves, the frequency that DR is exercised increases. Depending upon the nature of the DR, increased frequency of its use can result in customer dissatisfaction, even to the extent that they leave the DR program, which can further exasperate reserve issues. Progress Energy Florida encountered this situation a few years ago, when many customers left their direct load control program.

JEA recently completed a review of its Planning Reserve Policy and determined that up 7.5 percent of JEA's forecast firm demand (half of its planning reserve margin) can be met by demand response programs. As a point of comparison, the FRCC's *2008 Summer Assessment* indicated that on a statewide basis, load management and

interruptible loads were expected to account for approximately 6.6 percent of the FRCC Region's 2008 summer firm peak demand. JEA's Planning Reserve Policy regarding non-firm load (i.e., demand response) is consistent with the non-firm load proportion of the firm peak demand for the FRCC Region as a whole.

11.2.2 Renewable Considerations

The inclusion of significant amounts of renewable energy that are neither dispatchable nor controllable may impact system reliability. Solar and wind are primary examples of this type of renewable resources. Currently, JEA is not anticipating adding wind capacity to its system, but is actively pursuing the addition of solar PV capacity. As the amount of capacity that JEA receives from renewable resources that are neither dispatchable nor controllable increases, the associated impact on system reliability will need to be evaluated.

12.0 Capacity Requirements

JEA adheres to a minimum 15 percent reserve margin in both the summer and winter seasons. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. JEA plans to maintain this 15 percent reserve margin only for firm load obligations. Interruptible load and curtailable load are considered in developing projections of firm peak demand for which the 15 percent reserve margin is calculated.

To determine JEA's need for capacity, a forecast of system peak demand was developed for the summer and winter seasons and was compared against net system capacity. The forecast system peak demand through 2027 is presented in Section 5.0. The net system capacity includes existing generation resources, existing system purchases, system sales, firm capacity additions, and planned unit retirements. JEA's existing system, including PPAs, planned unit retirements, and planned unit additions, are discussed in Section 3.0. Relevant changes to JEA's existing system that impact the future capacity requirements presented in this section are summarized as follows:

- JD Kennedy Unit 3 is assumed to be retired in March 2009.
- Planned unit additions include JD Kennedy CT 8 in 2009 and the two GEC simple cycle combustion turbines in 2010.
- Existing purchases include 207 MW from Southern Company through May 31, 2010, and winter purchases from Constellation in 2008 through 2010.
- For purposes of this Application, summer purchases have been added in 2008 through 2011 to maintain reserve margin requirements prior to the time of the Greenland Energy Center combined cycle conversion.
- Existing sales include 383 MW (winter) and 376 MW (summer) from the SJRPP units to FPL. Based on the terms and conditions of the sales agreement the total amount of energy that FPL can take under the agreement is limited. For the purpose of modeling in this Application, the term of the FPL-SJRPP sale is assumed to end on March 31, 2016.

The reliability levels for the summer base case and the winter base case (based on the changes to JEA's available generating capacity described above) are presented in Tables 12-1 and 12-2, respectively. The tables show that JEA's capacity will fall below its required 15 percent reserve margin in the summer of 2012. At that time, JEA's reserve margin decreases to 9.6 percent, or 167 MW below the level required to maintain the 15 percent reserve margin (including reducing the level of firm load by the impact of interruptible and curtailable loads). The deficit continues to increase and by the summer

of 2015 the reserve margin is 3.0 percent, or 393 MW below the capacity required to maintain the 15 percent reserve margin (including reducing the level of firm load by the impact of interruptible and curtailable loads). The summer reserve margin increases in the summer of 2016 because of the projected end of the SJRPP sale to FPL; however, the reserve margin is still below the capacity required to maintain the 15 percent required reserve margin.

In the winter of 2012/13, JEA's reserve margin decreases to 12.7 percent, or 77 MW below the capacity required to maintain the 15 percent reserve margin (including reducing the level of firm load by the impact of interruptible and curtailable loads). The deficit continues to increase and by the winter of 2015/16 the reserve margin is 5.4 percent, or 342 MW below the capacity required to maintain the 15 percent reserve margin (including reducing the level of firm load by the impact of interruptible and curtailable loads). The winter reserve margin increases in the winter of 2016/17 because of the projected end of the SJRPP sale to FPL; however, the reserve margin is still below the capacity required to maintain the 15 percent required reserve margin.

Table 12-1
Projected Reliability Levels – Summer/Base Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.5%	(176)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,007	2,890	9.9%	14.4%	(152)	(18)
2010	3,367	9	(376)	(51)	434	3,383	3,072	2,955	10.1%	14.5%	(150)	(16)
2011	3,367	9	(376)	(51)	434	3,383	3,138	3,021	7.8%	12.0%	(226)	(91)
2012	3,367	9	(376)	(51)	434	3,383	3,204	3,087	5.6%	9.6%	(301)	(167)
2013	3,367	9	(376)	(51)	434	3,383	3,269	3,152	3.5%	7.3%	(377)	(242)
2014	3,367	9	(376)	(51)	434	3,383	3,335	3,218	1.4%	5.1%	(452)	(317)
2015	3,367	9	(376)	(51)	434	3,383	3,400	3,283	-0.5%	3.0%	(527)	(393)
2016	3,367	9	0	(51)	434	3,759	3,466	3,349	8.5%	12.3%	(227)	(92)
2017	3,367	9	0	(51)	434	3,759	3,531	3,414	6.4%	10.1%	(302)	(167)
2018	3,367	0	0	(51)	434	3,750	3,597	3,480	4.3%	7.8%	(386)	(252)
2019	3,367	0	0	(51)	434	3,750	3,662	3,545	2.4%	5.8%	(462)	(327)
2020	3,367	0	0	(51)	434	3,750	3,728	3,611	0.6%	3.9%	(537)	(403)
2021	3,367	0	0	(51)	434	3,750	3,794	3,677	-1.1%	2.0%	(613)	(478)
2022	3,367	0	0	(51)	434	3,750	3,859	3,742	-2.8%	0.2%	(688)	(553)
2023	3,367	0	0	(51)	434	3,750	3,925	3,808	-4.5%	-1.5%	(763)	(629)
2024	3,367	0	0	(51)	434	3,750	3,990	3,873	-6.0%	-3.2%	(839)	(704)
2025	3,367	0	0	(51)	434	3,750	4,056	3,939	-7.5%	-4.8%	(914)	(780)
2026	3,367	0	0	(51)	434	3,750	4,121	4,004	-9.0%	-6.4%	(990)	(855)
2027	3,367	0	0	(51)	434	3,750	4,187	4,070	-10.4%	-7.9%	(1,065)	(930)

[1] Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2010.

Table 12-2
Projected Reliability Levels – Winter/Base Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2007/08	3,621	291	(383)	0	0	3,529	3,079	2,946	14.6%	19.8%	(11)	142
2008/09	3,621	366	(383)	0	0	3,604	3,155	3,022	14.2%	19.3%	(24)	129
2009/10	3,621	366	(383)	(63)	191	3,733	3,232	3,099	15.5%	20.4%	16	169
2010/11	3,621	9	(383)	(63)	567	3,751	3,309	3,176	13.4%	18.1%	(54)	99
2011/12	3,621	9	(383)	(63)	567	3,751	3,386	3,253	10.8%	15.3%	(142)	11
2012/13	3,621	9	(383)	(63)	567	3,751	3,462	3,329	8.3%	12.7%	(230)	(77)
2013/14	3,621	9	(383)	(63)	567	3,751	3,539	3,406	6.0%	10.1%	(319)	(166)
2014/15	3,621	9	(383)	(63)	567	3,751	3,616	3,483	3.7%	7.7%	(407)	(254)
2015/16	3,621	9	(383)	(63)	567	3,751	3,693	3,560	1.6%	5.4%	(495)	(342)
2016/17	3,621	9	0	(63)	567	4,134	3,770	3,637	9.7%	13.7%	(201)	(48)
2017/18	3,621	0	0	(63)	567	4,125	3,846	3,713	7.3%	11.1%	(298)	(145)
2018/19	3,621	0	0	(63)	567	4,125	3,923	3,790	5.2%	8.8%	(386)	(233)
2019/20	3,621	0	0	(63)	567	4,125	4,000	3,867	3.1%	6.7%	(474)	(321)
2020/21	3,621	0	0	(63)	567	4,125	4,077	3,944	1.2%	4.6%	(563)	(410)
2021/22	3,621	0	0	(63)	567	4,125	4,153	4,020	-0.7%	2.6%	(651)	(498)
2022/23	3,621	0	0	(63)	567	4,125	4,230	4,097	-2.5%	0.7%	(739)	(586)
2023/24	3,621	0	0	(63)	567	4,125	4,307	4,174	-4.2%	-1.2%	(828)	(675)
2024/25	3,621	0	0	(63)	567	4,125	4,384	4,251	-5.9%	-2.9%	(916)	(763)
2025/26	3,621	0	0	(63)	567	4,125	4,461	4,328	-7.5%	-4.7%	(1,004)	(851)
2026/27	3,621	0	0	(63)	567	4,125	4,537	4,404	-9.1%	-6.3%	(1,092)	(940)

[1] Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2010.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. D80614EM EXHIBIT 28
COMPANY JEA (Direct)
WITNESS Bradley E. Kushner (BEK-1)
DATE 02/12/09

Utility System Planning, Production Costing, Economic Analysis, and Demand-Side Management

Resume of
Bradley E. Kushner
Black & Veatch

Mr. Kushner is responsible for production costing associated with utility system expansion planning, as well as feasibility studies and economic analysis, and demand-side management evaluation. He has also been involved in the issuance and evaluation of requests for proposals (RFPs) and portfolio evaluations. Mr. Kushner has also presented expert testimony and prepared other experts for testimony related to determination of need proceedings, and has also testified under cross examination by intervening parties.

Education
Bachelors, Mechanical Engineering, University of Missouri at Columbia, 2000

Total Years Experience
8

Joined Black & Veatch
2000

Representative Project Experience

Cane Island 4 Need for Power Application, Florida Municipal Power Agency, Orlando, Fla

2008
As Study Manager, Mr. Kushner provided production costing, economic analysis and various other support to facilitate the completion and filing of the Cane Island 4 Need for Power Application (NFP). His work also included preparation of testimony related to the project to the Florida Public Service Commission (FPSC). The NFP provides a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements. The analysis considered self-build and purchase-power alternatives, including renewable energy technologies, and demand-side management. The FPSC approved the Cane Island 4 NFP in August 2008.

Valuation of Generating Unit Portfolio; Confidential Client
2007 - 2008
Study Manager. Oversee modeling and evaluation of purchase power contracts related to Client's portfolio of generation assets throughout North America. The purchase power contracts were modeled to assess a monetary value to be used as guidance for valuation of an overall generation portfolio. The portfolio of assets and associated purchase power contracts was evaluated using more than 50 models. Mr. Kushner was involved in the modeling of the contracts as well as quality assurance/quality control related to the entire portfolio prior to delivering evaluations to Client.

Characterization and Selection of Nuclear Generating Technologies; AmerenUE; Missouri
2007 - 2008

Project Analysis Engineer. Provide assistance in characterizing and screening of various nuclear generating technologies for consideration by AmerenUE. The nuclear technology selected for further evaluation will be evaluated as part of Client's Integrated Resource Plan (IRP) study. The characterization included consideration of provisions of the Energy Policy Act of 2005 related to new qualifying nuclear plant capacity as well as relative comparisons of competing nuclear generating technologies. Client deliverables included two separate presentations to AmerenUE's Stakeholders.

Supply-Side Technologies Characterization; Tampa Electric Company; Tampa, Florida
2007
Study Manager. Provide cost and performance estimates for various renewable, conventional, and other generating technologies for client consideration in support of their determination of need filing. Technologies considered approximately 20 renewable technologies (including biomass, biogas, waste-to-energy, wind, solar, geothermal, hydroelectric, and ocean energy), 6 conventional technologies (including simple and combined cycles), and 2 emerging technologies (including nuclear). Also considered advanced, energy storage, and distributed generation technologies.

Power Supply Study; Western Farmers Electric Cooperative; Anadarko, Oklahoma
2006 - 2008
Study Manager. Provide production costing, economic analysis, and various other support to facilitate completion of the Western Farmers Electric Cooperative (WFEC) Power Supply Study. The WFEC Power Supply Study is an update to previous capacity planning studies which evaluates the economics of various supply-side alternatives to satisfy forecast capacity requirements.

Integrated Resource Plan; Village of Rockville Centre, New York
2006 – 2007
Study Manager. Analysis related to and preparation of the Village of Rockville Centre (RVC) Integrated Resource Plan (IRP). The IRP included consideration of RVC's existing generating system and strategic planning to satisfy forecasted system requirements. The strategic planning process included consideration of conventional supply-side options, interaction with the purchase power market, demand-side management measures, renewable supply-side alternatives, and possible future environmental impacts.

Taylor Energy Center Need for Power Application; Various Clients, Florida
2005 - 2007
Study Manager. Provided production costing, economic analysis, and various other support to facilitate completion and filing of the Taylor Energy Center (TEC) Need for Power Application (NFP). Also included preparation of testimony related to the project to the Florida Public Service Commission (FPSC). The NFP provided a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the four separate utilities participating in the project. The analysis considered self-build and purchase power alternatives.

Integrated Resource Plan; City of Tallahassee; Tallahassee, Florida
2004 - 2007
Study Manager. Analysis related to and preparation of the City of Tallahassee's (the City's) Integrated Resource Plan (IRP). The IRP included consideration of the City's existing generating system and strategic planning to satisfy forecasted system requirements. The strategic planning process included consideration of conventional supply-side options, demand-side management measures, renewable supply-side alternatives, and possible future environmental impacts.

Integrated Resource Plan; Brazos Electric Power Cooperative, Texas
2005 - 2006
Project Analysis Engineer. Provided assistance to Brazos Electric Power Cooperative (Brazos) in developing their Integrated Resource Plan (IRP). Included drafting a request for power supply proposals (RFP), analysis of responses to the RFP, review of Brazos production costing analysis, and documentation of final report. The IRP provided strategic direction to Brazos, which is currently experiencing and is forecast to continue to experience robust system growth.

Stanton Energy Center Unit B Need for Power Application; Orlando Utilities Commission; Orlando, Florida
2005 - 2006
Study Manager. Provided production costing, economic analysis, and various other support to facilitate completion and filing of the Stanton Energy Center Unit B (Stanton B) Need for Power Application (NFP). Also included preparation of testimony related to the project to the Florida Public Service Commission (FPSC). The NFP provides a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the Orlando Utilities Commission. The FPSC approved the Stanton B NFP Application in May 2006, which represents the first coal-fired power plant approved in the State of Florida since 1991.

RFP Issuance and Evaluation; Western Farmers Electric Cooperative; Anadarko, Oklahoma
2002 - 2006
Project Analysis Engineer. Coordinated with Western Farmers Electric Cooperative (WFEC) to draft, issue, and evaluate a capacity solicitation (RFP) to secure forecast capacity requirements in the most cost-effective and reliable manner. The RFP process was undertaken through coordination with Rural Utilities Services (RUS) in an effort to obtain low-cost RUS project financing. Involved evaluation of numerous conventional as well as renewable technology proposals and culminated in the issuance of a short-list and presentation to WFEC Board of Directors.

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2006
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Ten-Year Site Plan, FRCC Forms, EIA-860 and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2006
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2006 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. The EIA-860 collects data related to the specific utility's existing and planned generating units. The Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

RFP Issuance and Evaluation; City of Columbia, Water & Light Department; Columbia, Missouri
2005 - 2006
Study Manager. Coordinated with the City of Columbia, Water & Light Department (the City) to draft, issue, and evaluate a capacity solicitation (RFP) to secure forecast capacity requirements in most cost-effective and reliable manner. Involved evaluation of numerous conventional capacity options under consideration by the City, as well as options proposed by respondents to the RFP. Included continuous communication with City staff as well as presentations to the City's planning committee.

Treasure Coast Energy Center Need for Power Application; Florida Municipal Power Agency; Orlando, Florida
2004 - 2005
Project Analysis Engineer. Provided production costing, economic analysis, and various other support to facilitate completion and filing of the Florida Municipal Power Agency's (FMPA) Need for Power Application (NFP). Also provided testimony related to the project to the Florida Public Service Commission (FPSC). The NFP provides a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements. The analysis performed for FMPA considered self-build and purchase power alternatives. The NFP Application was approved by the FPSC in July, 2005, representing a critical step in the permitting and licensing process in the State of Florida.

Stock Island Combustion Turbine Evaluation; Florida Municipal Power Agency; Orlando, Florida
2004 - 2005
Project Analysis Engineer. Performed production costing and economic analysis to determine the most cost-effective capacity additions to be located at the Stock Island site. The analysis considered two different generating units from specific manufacturers, who responded to FMPA's request for bids.

Generation Expansion Study; Oman
2005
Project Analysis Engineer. Performed production costing and economic analysis to determine the most cost-effective capacity additions to satisfy forecast capacity requirements in the Country of Oman. The analysis considered seven different generating technologies.

Integrated Resource Plan; Golden Valley Electric Association; Fairbanks, Alaska
2005
Project Analysis Engineer. Economic analysis in support of the Golden Valley Electric Association's (GVEA) Integrated Resource Plan (IRP). The IRP provided GVEA with recommendations of capacity additions which will satisfy forecasted capacity requirements in the most cost-effective manner.

Ten-Year Site Plan and FRCC Forms; Florida Municipal Power Agency; Orlando, Florida
2005
Engineering Manager. Provided assistance and support to the Florida Municipal Power Agency (FMPA) related to its 2005 Ten-Year Site Plan and subsequent submission to the Florida Public Service Commission

(FPSC). Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC.

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2005
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Ten-Year Site Plan, FRCC Forms, EIA-860 and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2005
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2005 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. The EIA-860 collects data related to the specific utility's existing and planned generating units. The Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Due Diligence and Economic Analysis; Dairyland Power Cooperative; La Crosse, Wisconsin
2003-2005
Project Analysis Engineer. Performed due diligence review of the power supply planning efforts undertaken by Dairyland Power Cooperative (DPC). Included development of numerous capacity expansion plans and associated system production costing. Analysis was done in compliance with the requirements of the Rural Utilities Services (RUS) to potentially obtain low-cost RUS project financing. Also included was a presentation of the study's findings to the DPC Board of Directors. Following the issuance of a request for proposals (RFP) for capacity supplies, Black & Veatch was released to perform additional production costing and evaluations of the bids and self-build options was completed, with the results presented to DPC project personnel as well as RUS staff.

Numeric Conservation Goals Filing; JEA; Jacksonville, Florida
2004
Project Analysis Engineer. Analysis related to and preparation of the JEA 2004 Petition for Approval of Numeric Conservation Goals, as required by the Florida Public Service Commission (FPSC). The submittal included analysis of numerous demand-side management (DSM) measures to be considered by JEA in order to determine their cost-effectiveness. The process is required to be completed by JEA every five years, culminating in the eventual determination by the FPSC of the conservation goals JEA must satisfy each year.

Numeric Conservation Goals Filing; Orlando Utilities Commission; Orlando, Florida
2004
Project Analysis Engineer. Analysis related to and preparation of the Orlando Utilities Commission (OUC) 2004 Petition for Approval of Numeric Conservation Goals, as required by the Florida Public Service Commission (FPSC). The submittal included analysis of numerous demand-side management (DSM) measures to be considered by OUC in order to determine their cost-effectiveness. The process is required to be completed by OUC every five years, culminating in the eventual determination by the FPSC of the conservation goals OUC must satisfy each year.

Site Selection Study; Florida Municipal Power Agency; Orlando, Florida
2004
Project Analysis Engineer. Coordination and preparation of a site selection study related to the potential construction of a new combined cycle unit to be installed by the Florida Municipal Power Agency.

Ten-Year Site Plan; Florida Municipal Power Agency; Orlando, Florida
2004
Engineering Manager. Provided assistance and support to the Florida Municipal Power Agency (FMPA) related to its 2004 Ten-Year Site Plan and subsequent submission to the Florida Public Service Commission (FPSC).

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2004
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Ten-Year Site Plan, FRCC Forms, and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2004
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2004 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Also included follow-up response to FPSC inquiries and preparation of presentation to FPSC staff. Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Due Diligence; City Utilities; Springfield, Missouri
2003
Project Analysis Engineer. Due diligence and economic analysis to determine the most cost-effective capacity additions to satisfy forecasted system requirements for City Utilities – Springfield. Two options were considered, consisting of constructing a second unit at an existing site and an independent developer's proposed construction of a unit at a new site.

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2003
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Participation Agreement; Kissimmee Utility Authority; Orlando, Florida
2003
Engineering Manager. Development of a Participation Agreement between client (KUA) and another Florida utility governing ownership, construction, and operation of a new generating unit at a KUA site. Included meetings and coordination with clients and incorporation of various requirements to sufficiently complete the Agreement.

Ten-Year Site Plan, FRCC Forms, and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2003
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2003 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Also included follow-up response to FPSC inquiries and preparation of

presentation to FPSC staff. Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Capacity Planning Study; Western Farmers Electric Cooperative; Anadarko, Oklahoma
2001 - 2002
Project Analysis Engineer. Production costing and economic analysis to determine WFEC's most cost-effective expansion options to meet forecast capacity requirements. The capacity planning study was performed in support of the RFP issuance described above.

Feasibility Study; Kissimmee Utility Authority; Kissimmee, Florida
2002
Engineering Manager. Assisted in coordination and preparation of a preliminary study to evaluate the feasibility of constructing a new generating unit at an existing Kissimmee Utility Authority site.

Ten-Year Site Plan, FRCC Forms, and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2002
Project Analysis Engineer. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2002 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Also included follow-up response to FPSC inquiries and preparation of presentation to FPSC staff. Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Capacity Planning Study; Braintree Electric Light Department; Braintree, Massachusetts
2002
Project Analysis Engineer. Production costing and economic analysis to determine Braintree Electric Light Department's most cost-effective expansion options to meet forecast capacity requirements.

Integrated Resource Plan; City of Tallahassee; Tallahassee, Florida
2001-2002

Project Analysis Engineer. Assisted in completion of the City of Tallahassee's Integrated Resource Plan (IRP), including evaluation of the City's demand-side management program alternatives.

Capacity Planning Study; Basin Electric Power Cooperative; Bismarck, North Dakota
2001
Project Analysis Engineer. Production costing and economic analysis necessary to provide Basin Electric Power Cooperative with recommendations as to which capacity additions would be most cost-effective to satisfy system requirements.

Ten-Year Site Plan; Lakeland Electric; Lakeland, Florida
2001
Project Analysis Engineer. Assisted in completion of Lakeland Electric's 2001 Ten-Year Site Plan, including consideration of Lakeland's capacity addition options.

Ten-Year Site Plan; Orlando Utilities Commission; Orlando, Florida
2001
Project Analysis Engineer. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2001 Ten-Year Site Plan and submit to the Florida Public Service Commission. Also included follow-up response to FPSC inquiries and preparation of presentation to FPSC staff.

Need for Power Application; Various Clients; Florida
2001
Project Analysis Engineer. Production costing and economic analysis required in support of determination of most cost-effective expansion options to meet the individual needs of the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency. Also included preparation of corresponding application to be presented to the Florida Public Service Commission, as well as written testimony in support thereof.

Table 1
CPWC Summaries for Scenario 1
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	10,944,111	11,076,282	132,171
High Fuel	11,445,988	11,531,656	85,668
Low Fuel	10,388,848	10,475,006	86,158
High Load	12,622,952	12,706,975	84,023
Low Load	9,982,509	10,071,060	88,551
High Capital Cost	11,054,207	11,183,726	129,519
Regulated CO_2	15,748,964	15,923,219	174,255
High Fuel with Regulated CO_2	16,584,764	16,721,907	137,143
High Regulated CO_2	23,736,690	24,092,564	355,874

Table 2
CPWC Summaries for Scenario 2
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	11,116,856	11,211,133	94,277
Regulated CO_2	15,881,845	16,030,780	148,935

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Table 3
CPWC Summaries for Scenario 3
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	10,702,856	10,837,724	134,869
Regulated CO_2	15,480,656	15,666,889	186,234

Table 4
CPWC Summaries for Scenario 4
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	10,886,730	10,957,378	70,648
Regulated CO_2	15,623,821	15,750,540	126,719

Table 5
CPWC Summaries for High Interest Rate Cases
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2013	CPWC of Expansion Plan *Without GEC* Conversion in 2013	CPWC Savings for Expansion Plan with GEC Conversion in 2013
Reference Case-Scenario 1	9,281,091	9,302,643	21,552
Reference Case-Scenario 3	9,079,388	9,097,998	18,610

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DATE 02/12/09

7.0 Fuel and CO_2 Emissions Allowance Price Projections

This section discusses the methodology used to develop projections for the prices of natural gas, distillate and residual fuel oils, and coal specific to the FRCC region that is considered in this Application. In addition to the reference case price projections, high and low price projections have been developed. The analyses presented throughout this Application also consider projections of emissions allowance prices. Development of emissions allowance price projections are also presented in this section.

7.1 Importance of Fully Integrated Fuel and Emissions Allowance Price Projections

The fuel and emissions allowance price projections considered throughout this Application (whether for the reference case, high case, low case, or the case in which existing and potential new emissions such as carbon dioxide, or CO_2, are treated as regulated emissions) represent fully integrated forecasts. That is, fuel price supply and demand are considered in tandem with potential costs associated with regulation of various emissions, along with numerous other market influences to develop fully integrated projections of fuel and emissions allowance prices. This is important for all scenarios considered, but especially so when considering the potential impacts associated with acquiring any allowances for existent regulated emissions and considering the potential impacts of the regulation of CO_2.

Regulations of emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and mercury (Hg) are reflected in each fuel price projection considered throughout this Application. While there is currently no State or Federal regulation of CO_2 emissions, several bills to regulate emissions of CO_2 (and other GHGs) have been proposed to the 110th US Congress. As such, this Application considers potential regulation of CO_2 emissions as outlined in Sections 7.7 and 7.8.

7.2 Description of 2008 US Energy Information Administration Annual Energy Outlook Reference Case

The fuel price projections for natural gas, fuel oil, and coal used in this Application were developed based on those included in the US EIA Annual Energy AEO2008. AEO2008 presents projections of energy supply, demand, and prices through 2030. The projections presented within AEO2008 are based on results from the EIA's NEMS. NEMS is a computer based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of

energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics. The discussion of the fuel price projections presented within this section is intended to be an overview of the AEO2008 and, therefore, focuses on the more salient aspects of AEO2008 and elaborates on relevant conclusions and projections. The AEO2008 in its entirety can be found at http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2008).pdf, while documentation on NEMS can be found at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model%20documentation.

7.2.1 Consideration of State and Federal Legislation and Regulations in AEO2008

Analyses developed by the EIA are required to be policy-neutral. Therefore, the projections in AEO2008 generally are based on Federal and State laws and regulations in effect on or before December 31, 2007 (with few exceptions). As stated in AEO2008, the potential impacts of pending or proposed legislation, regulations, and standards – or of sections of legislation that have been enacted but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself – are not reflected in the projections.

AEO2008 considered the potential impacts of both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), although both rules were recently vacated by the District of Columbia Circuit Court of Appeals. The vacatur of CAIR happened during publication of the AEO2008 (July 11, 2008) while CAMR was vacated too late for EIA to remove the CAMR provisions from its analysis. CAIR was adopted to limit emissions of SO_2 and NO_x from power plants in 29 states and the District of Columbia, while CAMR was adopted to limit emissions of Hg from power plants throughout the United States. Both CAIR and CAMR are represented as regional cap-and-trade programs in AEO2008, because the document was developed prior to final decisions being made regarding the structure of state programs and participation in regional trading programs contemplated in CAIR and CAMR.

In light of the recent vacatur of CAIR and CAMR, the economic analyses presented in Section 17.0 do not include costs for SO_2 or NO_x allowances under CAIR or Hg allowances under CAMR. In any event, CAIR and CAMR allowance costs would not have been significant for the proposed combined cycle unit due to the inherently low SO_2, NO_x and Hg emission rates associated with natural gas-fired generation, particularly as compared to other fuel types.

7.3 AEO2008 Reference Case FRCC Natural Gas, Fuel Oil, and Coal Price Projections

The AEO2008 Reference Case forecast prices for natural gas and fuel oil delivered to the FRCC region are presented in Table 7-1[1]. Forecasts of prices for High Sulfur Eastern Interior and Powder River Basin (PRB) coal delivered to the Georgia/Florida region are presented in Table 7-2[2]. The fuel price projections shown in Tables 7-1 and 7-2 are presented in constant 2006 dollars per MBtu. For the economic analysis presented in Section 19.0 of this Application, the fuel price projections were converted from those shown in Tables 7-1 and 7-2 to nominal dollars per MBtu by applying the 2.5 percent general inflation rate.

The natural gas price projections presented in Table 7-1 represent the AEO2008 projections for delivered natural gas to the FRCC region and do not include any usage charges or any other costs for firm or interruptible intrastate natural gas transportation. Discussion of how such costs were considered and factored into the economic analysis is presented in Section 19 of this Application.

Table 7-2 only presents forecast prices for coal delivered to the Georgia/Florida region from the Eastern Interior and PRB coal production region. Although the EIA provided forecast prices for coals from other production regions, this Application only considers coal delivered from the Eastern Interior and the PRB. The analyses presented throughout this Application assumes that PRB coal will continue to be burned in the existing Scherer plant, while Eastern Interior coal is assumed to be burned in the existing SJRPP and Northside units.

Although SJRPP and Northside have historically utilized coal from international sources (including Latin America), the characteristics of Eastern Interior coal are relatively comparable to the characteristics of the Latin American coal that has been used in the SJRPP and Northside units. AEO2008 does not include projections of the price of international coal for delivery to the United States. Given the similarities in coal characteristics and the capability of the SJRPP and Northside units to burn Eastern Interior coal, consideration of Eastern Interior coal is appropriate for the comparative economic analyses presented throughout this Application.

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[1] Regional fuel price projections, such as those shown in Table 7-1 for FRCC, are not included in the AEO2008 report itself, but are available on the EIA Web site as *Supplemental Tables* (http://www.eia.doe.gov/oiaf/aeo/supplement/supref.html). The FRCC fuel price projections corresponding to the AEO2008, from which the data in Table 7-1 were extracted, are presented in Supplemental Table 69.

[2] Supplemental Table 69 to the AEO2008, referenced previously, only presents forecasts of prices for coal delivered to the FRCC region on a composite basis (i.e., a single coal price forecast, with no differentiation between coal type/production region). EIA was able to provide forecast prices for coal delivered to the Georgia/Florida region from various coal production regions upon request. These projections are factored into the overall modeling and analysis used to generate the coal price projections shown in Supplemental Table 69 to the AEO2008.

Table 7-1
Annual Energy Outlook 2008 Reference Case Price Projections
Forecast of Natural Gas and Fuel Oil Delivered to the
Florida Reliability Coordinating Council Boundary[1]

Year	Natural Gas (2006 $/MBtu) [2]	Distillate Fuel Oil (2006 $/MBtu) [3]	Residual Fuel Oil (2006 $/MBtu)
2008	7.53	17.05	10.08
2009	7.83	14.50	11.13
2010	7.44	13.83	10.33
2011	7.17	13.13	9.78
2012	7.23	12.43	9.14
2013	6.88	11.73	8.61
2014	6.64	11.45	8.36
2015	6.47	10.88	7.80
2016	6.40	10.45	7.36
2017	6.41	10.46	7.35
2018	6.46	10.60	7.46
2019	6.51	10.75	7.60
2020	6.42	10.86	7.70
2021	6.31	10.96	7.80
2022	6.44	11.07	7.87
2023	6.49	11.27	8.04
2014	6.60	11.50	8.23
2025	6.73	11.72	8.40
2026	6.78	11.95	8.57
2027	6.87	12.13	8.60
2028	7.09	12.35	8.78
2029	7.17	12.60	8.87
2030	7.30	12.83	9.04

[1] Based on data presented in Supplemental Table 69 to the AEO2008 Reference Case.
[2] Natural gas price projections do not include usage charges or firm or interruptible transportation charges within the State. These costs are accounted for in the economic analysis as discussed in Section 16.0 of this Application.
[3] Distillate fuel oil price projections reflect the "nonroad, locomotive, and marine" (NRLM) diesel regulation finalized in May 2004, which requires sulfur content for all NRLM diesel fuel produced by refiners to be reduced to 500 parts per million (ppm) starting mid-2007. NRLM also establishes a new ultra-low sulfur diesel (ULSD) limit of 15 ppm for nonroad diesel by mid-2010.

Table 7-2
Annual Energy Outlook 2008 Reference Case Price Projections
Forecast of High Sulfur Eastern Interior and
Low Sulfur Powder River Basin Coal Delivered to the Georgia/Florida Region[1]

Year	High Sulfur Eastern Interior (2.64 lb S/MBtu) (2006 $/MBtu)	Low Sulfur Powder River Basin (0.35 lb S/MBtu) (2006 $/MBtu)
2008	2.27	1.88
2009	2.38	1.97
2010	2.49	2.07
2011	2.52	2.08
2012	2.53	2.05
2013	2.52	2.06
2014	2.53	2.06
2015	2.51	2.05
2016	2.52	2.04
2017	2.52	2.04
2018	2.50	2.05
2019	2.52	2.07
2020	2.51	2.08
2021	2.51	2.08
2022	2.54	2.09
2023	2.55	2.10
2014	2.57	2.11
2025	2.59	2.12
2026	N/A	2.13
2027	N/A	2.14
2028	N/A	2.16
2029	N/A	2.17
2030	N/A	2.18

(1) Based on data received directly from the EIA.

7.4 AEO2008 High and Low Price Case Natural Gas, Fuel Oil, and Coal Price Projections

The AEO2008 includes various cases in addition to the reference case. Each of these cases incorporates various changes to the reference case assumptions. Of the various cases considered by the EIA as part of AEO2008, two cases have been carried forward to the analyses considered in this Application in addition to the reference case – the High Price Case and the Low Price Case. Both the High Price Case and the Low

Price Case rely on assumptions consistent with the reference case with the exception of assumptions related to crude oil and natural gas resources. The High Price Case reflects more pessimistic assumptions related to these resources while the Low Price Case reflects more optimistic assumptions. Both the High Price and Low Price cases are fully integrated NEMS simulations, consistent with the reference case.

The natural gas, fuel oil, and coal price projections corresponding to the AEO2008 High Price Case are presented in Table 7-3. For comparison purposes, the AEO2008 Reference Case price projections for natural gas, fuel oil, and coal are also presented in Table 7-3. Figures 7-1 through 7-4 present graphical comparisons of the High Price Case and Reference Case price projections shown in Table 7-3.

The natural gas, fuel oil, and coal price projections corresponding to the AEO2008 Low Price Case are presented in Table 7-4. For comparison purposes, the AEO2008 Reference Case price projections for natural gas, fuel oil, and coal are also presented in Table 7-4. Figures 7-5 through 7-8 present graphical comparisons of the Low Price Case and Reference Case price projections shown in Table 7-4.

The price projections in Tables 7-3 and 7-4 (and corresponding Figures 7-1 through 7-8) are not specific to the FRCC region. The following section discusses the methodology used to develop high and low fuel price projections specific to FRCC.

7.5 FRCC High and Low Fuel Price Projections

As discussed in Section 7.4, AEO2008 included High Price Case and Low Price Case fuel price projections. Both the High and Low Price case projections were developed on a national basis and are, therefore, not specific to the FRCC region. Adjustments were made to the High Price Case and Low Price Case natural gas, fuel oil, and coal price projections in order to develop high and low fuel price projections specific to the FRCC region. The following subsections discuss the methodology used to develop the FRCC-specific high and low fuel price projections and present the resulting annual natural gas, fuel oil, and coal price projections. Consideration of any additional intrastate transportation costs is discussed in Section 16.0.

7.5.1 High Fuel Price Projections for FRCC

7.5.1.1 High Natural Gas Prices. In order to develop natural gas price projections for the FRCC region based on the AEO2008 High Price Case, the AEO2008 Reference Case natural gas price projections were analyzed to determine the annual differential between the FRCC-specific natural gas price projections presented in Table 7-1 and the Reference Case Henry Hub natural gas price projections presented in Table 7-3. The annual transportation differentials between natural gas delivered to the FRCC region and

Table 7-3
Natural Gas, Fuel Oil, and Coal Price Projections
AEO2008 High Price Case and AEO2008 Reference Case

Year	Natural Gas - Henry Hub (2006$/MBtu)		Fuel Oil - Electric Power (2006 cents/gallon)				Coal - Average Minemouth (2006$/MBtu)	
			Distillate		Residual			
	High Price Case	Reference Case	High Price Case	Reference Case	High Price Case	Reference Case	High Price Case	Reference Case
2008	7.23	7.23	240.7	240.7	157.2	157.2	1.28	1.28
2009	7.40	7.35	204.3	197.6	148.5	149.3	1.29	1.29
2010	7.28	6.90	203.1	189.0	146.6	141.5	1.28	1.28
2011	7.00	6.56	206.0	179.2	148.9	134.2	1.26	1.25
2012	7.01	6.37	209.4	169.1	155.5	127.5	1.25	1.22
2013	6.92	6.16	211.4	159.8	156.9	121.8	1.23	1.20
2014	6.85	5.99	217.1	156.1	161.2	117.9	1.22	1.18
2015	6.92	5.87	221.6	148.0	164.6	110.9	1.20	1.17
2016	7.02	5.82	226.5	142.3	168.6	105.2	1.21	1.16
2017	7.12	5.89	234.7	142.5	175.3	105.5	1.19	1.15
2018	7.16	5.97	242.5	144.5	179.9	107.7	1.19	1.14
2019	7.24	6.05	248.1	146.6	184.7	110.1	1.19	1.14
2020	7.08	5.95	254.3	148.3	190.5	112.3	1.20	1.14
2021	6.95	5.82	261.6	149.8	197.9	114.2	1.20	1.14
2022	7.01	5.95	264.3	151.6	201.5	115.7	1.21	1.15
2023	7.10	6.08	266.7	154.5	204.3	118.5	1.21	1.15
2024	7.28	6.25	269.3	157.9	208.3	121.1	1.21	1.16
2025	7.39	6.39	266.9	160.8	206.9	123.4	1.22	1.16
2026	7.64	6.56	268.7	164.4	210.7	126.4	1.22	1.16
2027	7.94	6.61	272.7	167.0	214.5	128.1	1.23	1.17
2028	8.19	6.86	277.7	169.9	218.4	131.0	1.25	1.18
2029	8.33	7.06	281.9	173.4	221.8	133.1	1.25	1.18
2030	8.43	7.22	286.5	176.2	226.6	135.3	1.28	1.19

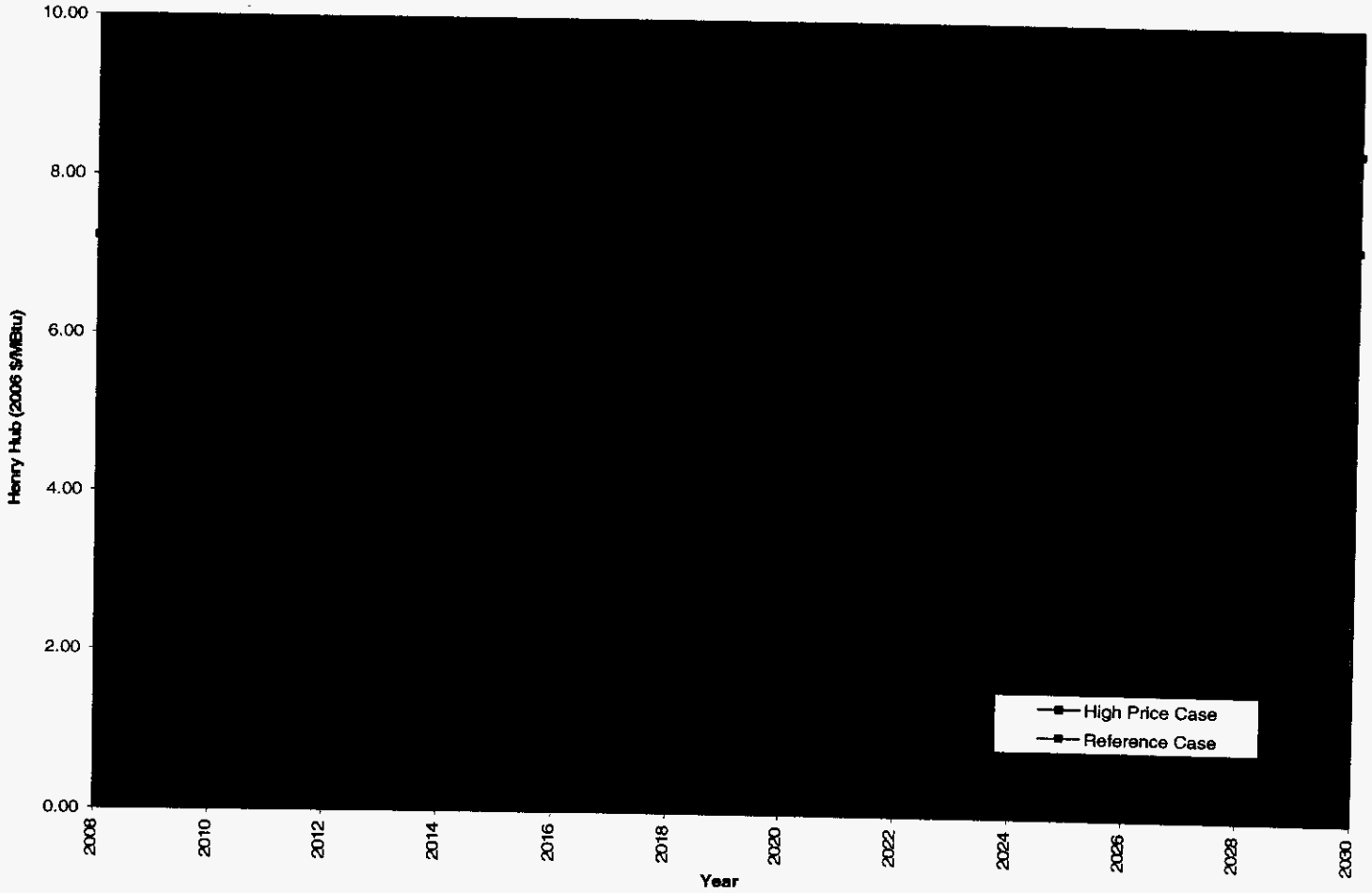

Figure 7-1
Comparison of Natural Gas Price Projections
AEO2008 High Price Case and AEO2008 Reference Case

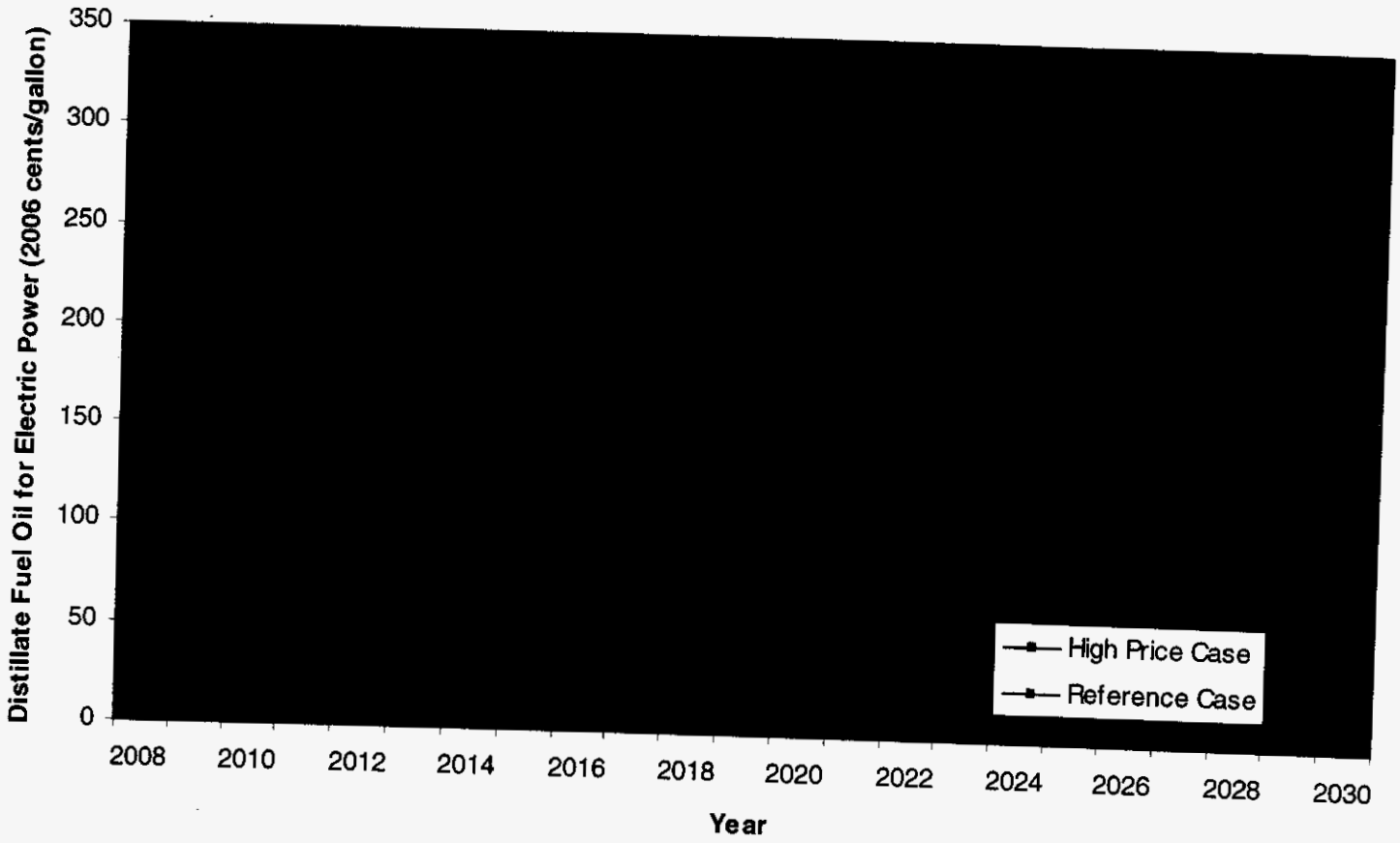

Figure 7-2
Comparison of Distillate Fuel Oil Price Projections
AEO2008 High Price Case and AEO2008 Reference Case

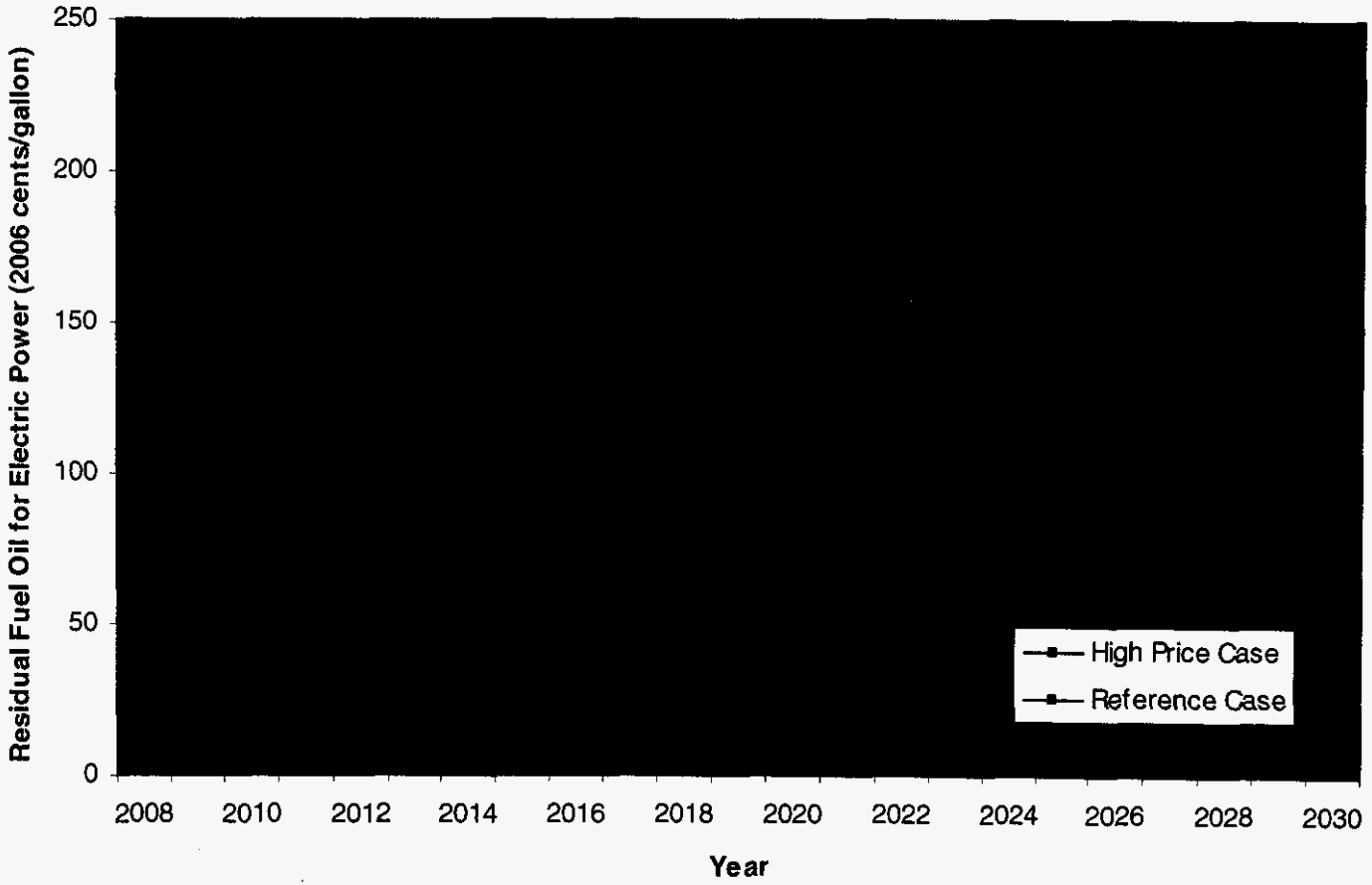

Figure 7-3
Comparison of Residual Fuel Oil Price Projections
AEO2008 High Price Case and AEO2008 Reference Case

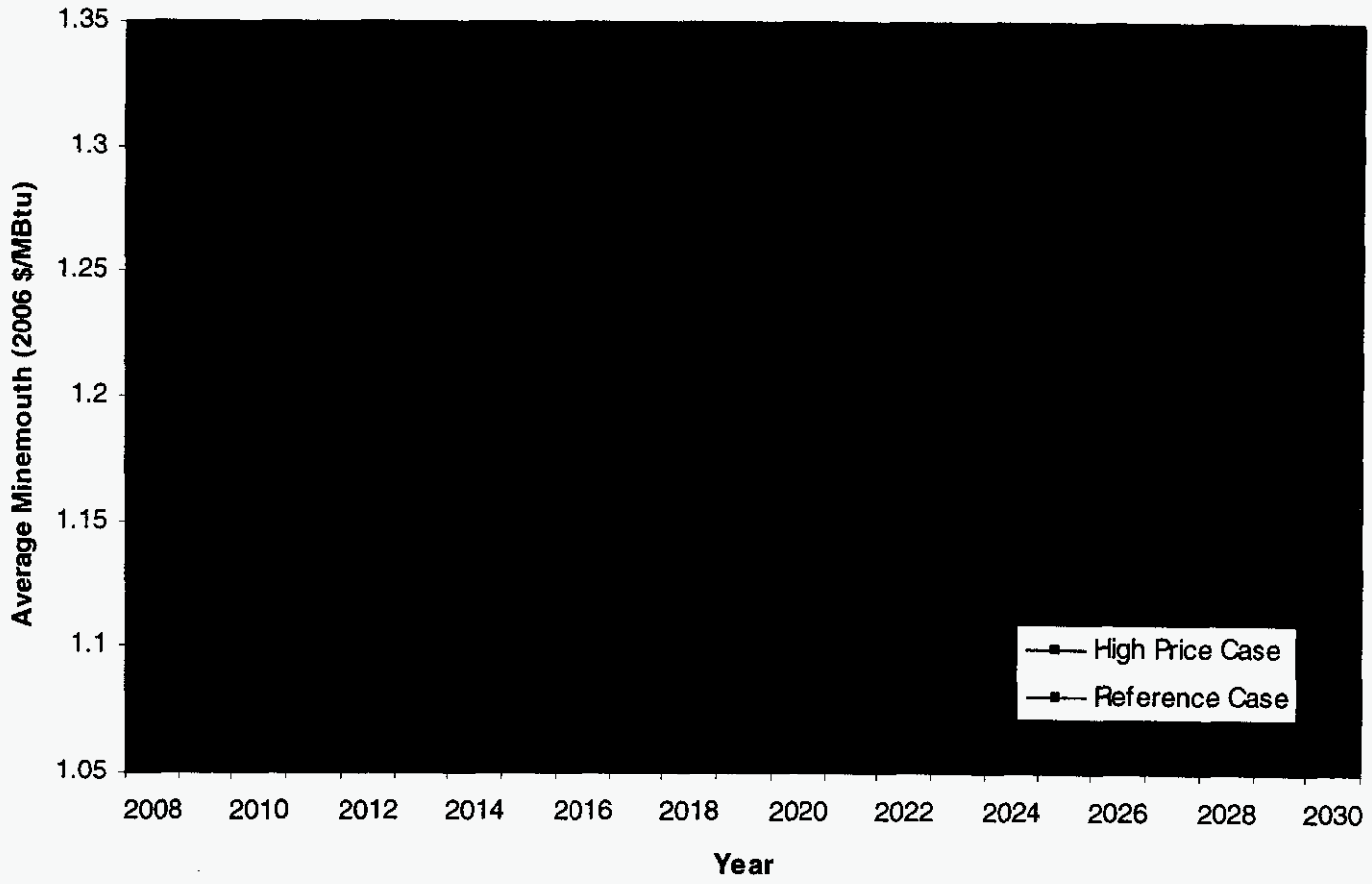

Figure 7-4
Comparison of Coal Price Projections
AEO2008 High Price Case and AEO2008 Reference Case

Table 7-4
Natural Gas, Fuel Oil, and Coal Price Projections
AEO2008 Low Price Case and AEO2008 Reference Case

Year	Natural Gas - Henry Hub (2006$/MBtu)		Fuel Oil - Electric Power (2006 cents/gallon)				Coal - Average Minemouth (2006$/MBtu)	
			Distillate		Residual			
	Low Price Case	Reference Case	Low Price Case	Reference Case	Low Price Case	Reference Case	Low Price Case	Reference Case
2008	7.23	7.23	240.7	240.7	157.2	157.2	1.28	1.28
2009	7.22	7.35	198.6	197.6	148.6	149.3	1.28	1.29
2010	6.61	6.90	178.6	189.0	132.8	141.5	1.27	1.28
2011	6.20	6.56	164.7	179.2	120.7	134.2	1.24	1.25
2012	5.92	6.37	150.5	169.1	110.9	127.5	1.21	1.22
2013	5.60	6.16	136.9	159.8	98.7	121.8	1.18	1.20
2014	5.34	5.99	123.6	156.1	86.4	117.9	1.17	1.18
2015	5.05	5.87	110.8	148.0	76.2	110.9	1.14	1.17
2016	4.83	5.82	98.0	142.3	66.0	105.2	1.12	1.16
2017	4.90	5.89	97.9	142.5	65.9	105.5	1.11	1.15
2018	4.97	5.97	97.3	144.5	65.5	107.7	1.09	1.14
2019	5.08	6.05	97.7	146.6	66.0	110.1	1.09	1.14
2020	5.01	5.95	98.1	148.3	66.4	112.3	1.09	1.14
2021	4.91	5.82	98.5	149.8	67.6	114.2	1.08	1.14
2022	4.99	5.95	98.8	151.6	67.8	115.7	1.08	1.15
2023	5.17	6.08	99.3	154.5	68.6	118.5	1.08	1.15
2024	5.30	6.25	100.0	157.9	70.4	121.1	1.08	1.16
2025	5.42	6.39	101.1	160.8	71.3	123.4	1.09	1.16
2026	5.55	6.56	102.5	164.4	72.0	126.4	1.10	1.16
2027	5.65	6.61	105.2	167.0	72.9	128.1	1.10	1.17
2028	5.78	6.86	108.4	169.9	74.3	131.0	1.11	1.18
2029	5.86	7.06	109.8	173.4	75.4	133.1	1.11	1.18
2030	6.00	7.22	111.2	176.2	76.1	135.3	1.12	1.19

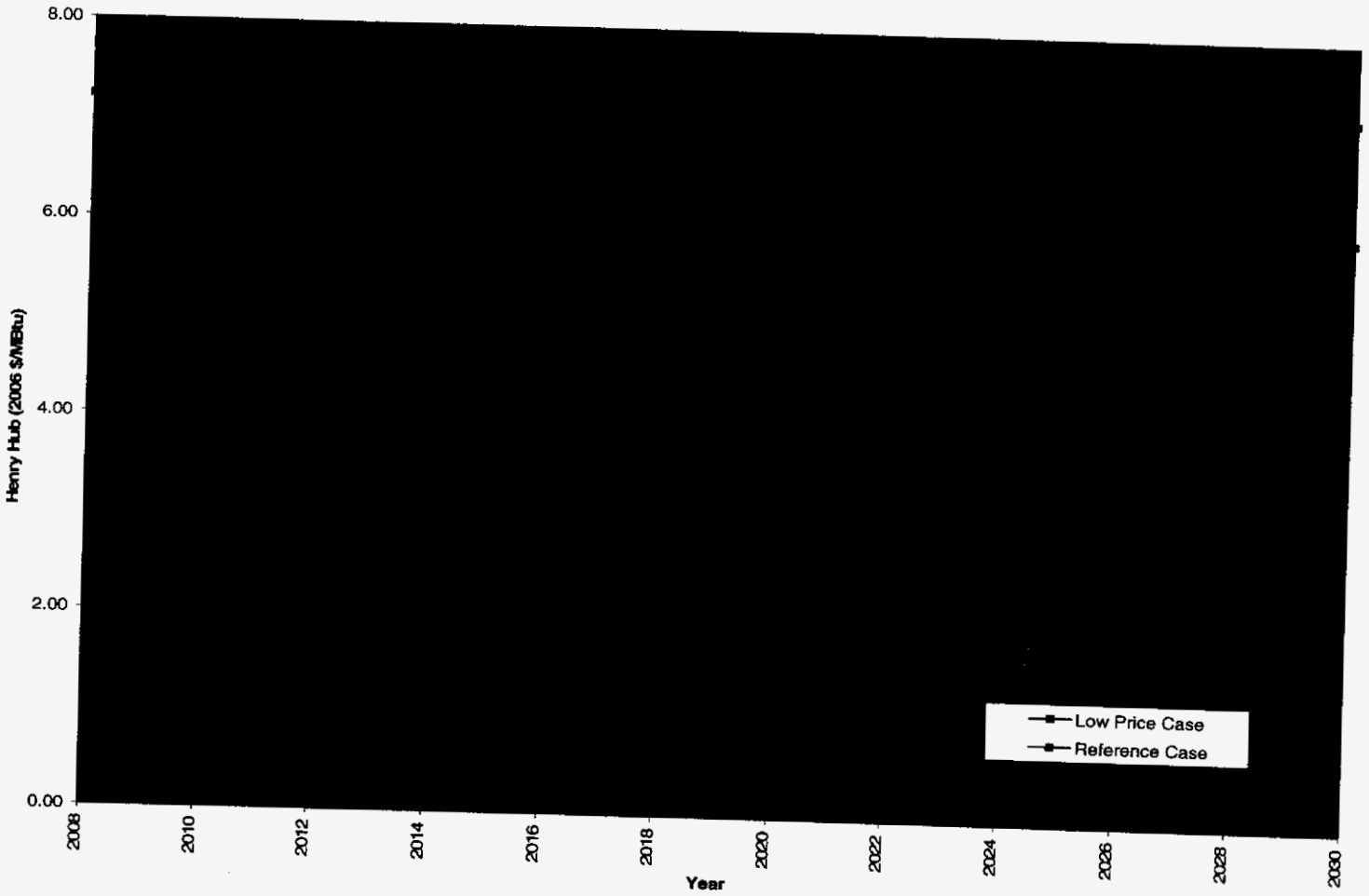

Figure 7-5
Comparison of Natural Gas Price Projections
AEO2008 Low Price Case and AEO2008 Reference Case

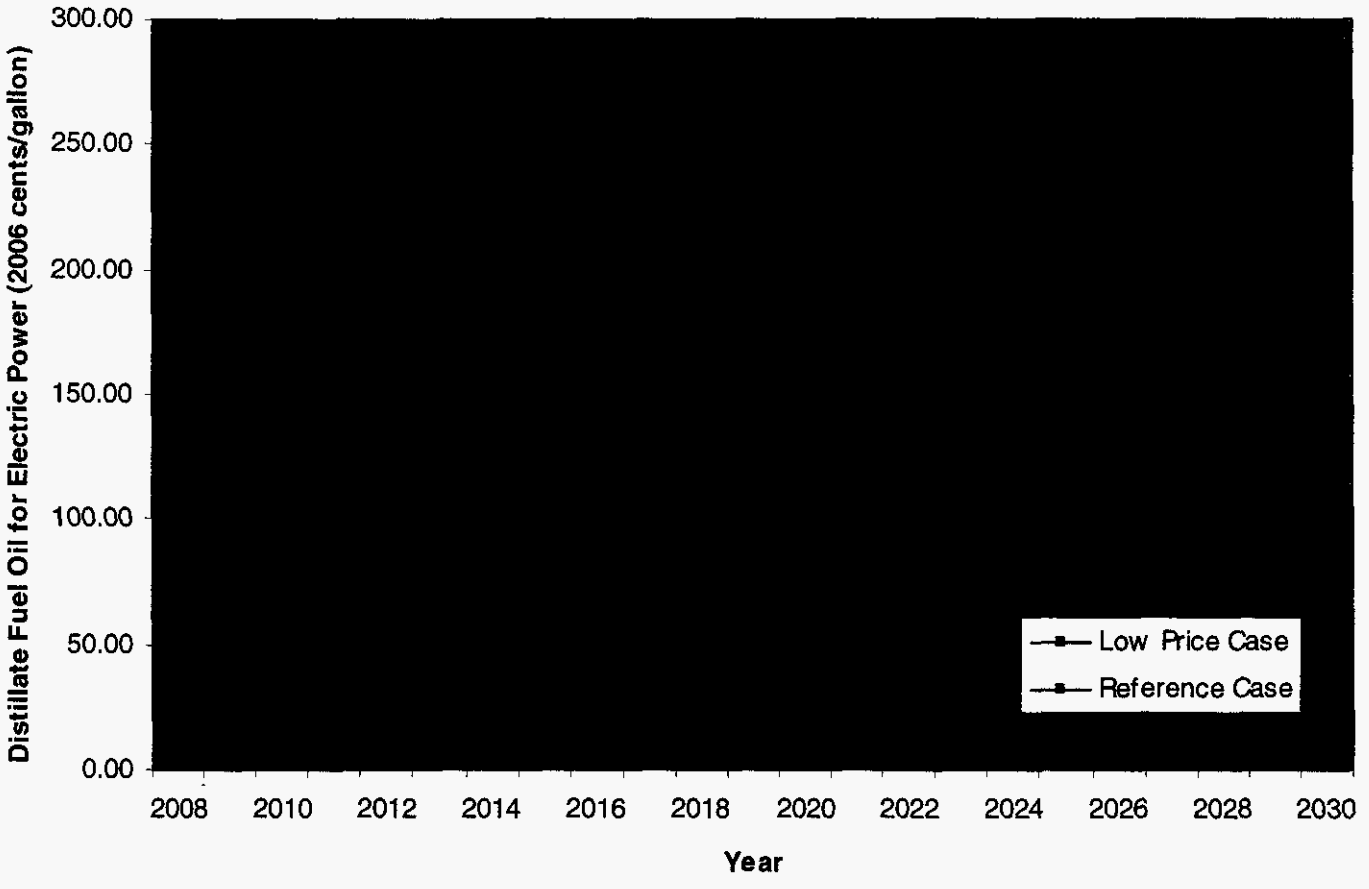

Figure 7-6
Comparison of Distillate Fuel Oil Price Projections
AEO2008 Low Price Case and AEO2008 Reference Case

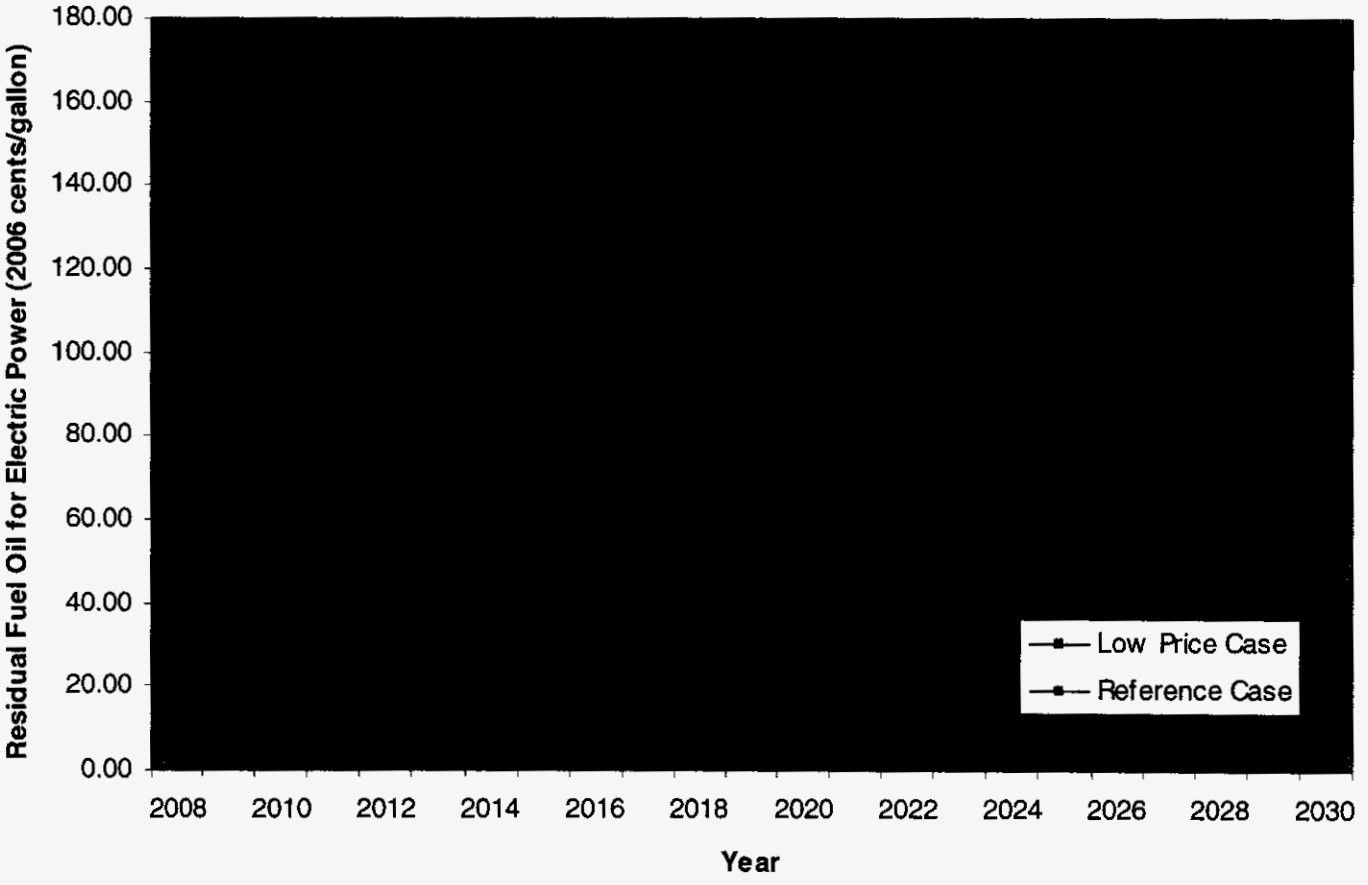

Figure 7-7
Comparison of Residual Fuel Oil Price Projections
AEO2008 Low Price Case and AEO2008 Reference Case

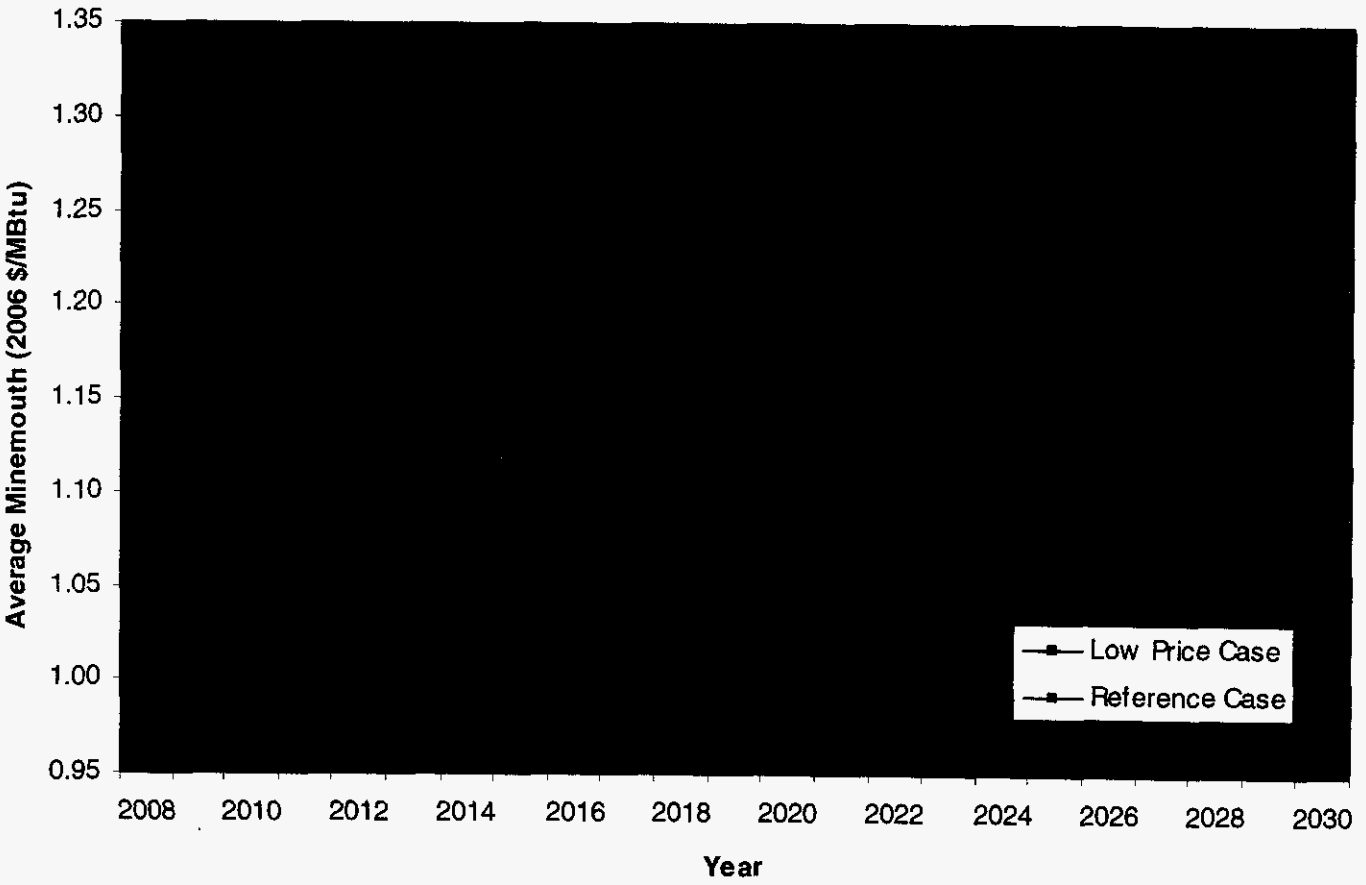

Figure 7-8
Comparison of Coal Price Projections
AEO2008 Low Price Case and AEO2008 Reference Case

natural gas at Henry Hub derived from the reference case were held constant and added to the AEO2008 High Price Case Henry Hub natural gas price projections shown in Table 7-3. The resulting high natural gas price projections specific to the FRCC region are presented in Table 7-5.

7.5.1.2 High Distillate and Residual Fuel Oil Prices. High price projections for distillate and residual fuel oil specific to the FRCC region were developed by first converting the AEO2008 High Price and AEO2008 Reference Case projections presented in Table 7-3 from cents per gallon to dollars per MBtu. The conversions were made by using the heat contents for distillate (138,690 Btu per gallon) and residual (149,690 Btu per gallon) used by the EIA. The annual transportation differentials for distillate and residual fuel oil between the AEO2008 Reference Case for the FRCC region (presented in Table 7-1) and for electric power usage in the United States as a whole (presented in Table 7-3) were determined. These annual transportation differentials for distillate and residual fuel oil were added to the AEO2008 High Price Case projections shown in Table 7-3 (after being converted to dollars per MBtu using the heat contents referenced previously). The resulting high distillate and residual fuel oil price projections specific to the FRCC region are presented in Table 7-5.

7.5.1.3 High Eastern Interior and Powder River Basin Coal Prices

The AEO2008 Reference Case Eastern Interior and PRB minemouth coal prices (annual dollars per ton)[3] were divided by the respective heat content of the coal from these regions (MBtu per ton)[4] resulting in reference case minemouth prices specific to Eastern Interior and PRB coal on a dollar per MBtu basis.

The AEO2008 Reference Case average minemouth coal prices for the United States were subtracted from the AEO2008 High Case average minemouth coal prices for the United States (each of which are presented in Table 7-3) to give an annual differential from the Reference Case to the High Case average US minemouth coal prices. This annual differential was applied to the reference case minemouth prices specific to Eastern Interior and PRB described above to yield annual high case minemouth prices specific to Eastern Interior and PRB coal on a dollar per MBtu basis.

An annual delivery adder (dollar per MBtu basis) to represent the cost for delivering Eastern Interior and PRB coal from the minemouth to the FRCC region was calculated by taking the difference between the annual reference case Eastern Interior and PRB minemouth prices and the AEO2008 Reference Case Eastern Interior and PRB coal prices delivered to the FRCC Region. This annual delivery adder was applied to the high case Eastern Interior and PRB coal minemouth prices resulting in the high price case

[3] http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_113.xls
[4] Table 71, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/coal.pdf

projections for Eastern Interior and PRB coal delivered to the FRCC region, which are presented in Table 7-5.

7.5.2 Low Fuel Price Projections for FRCC

7.5.2.1 Low Natural Gas Prices. In order to develop natural gas price projections for the FRCC region based on the AEO2008 Low Price Case, the AEO2008 Reference Case natural gas price projections were analyzed to determine the annual differential between the FRCC-specific natural gas price projections presented in Table 7-1 and the Reference Case Henry Hub natural gas price projections presented in Table 7-4. The annual transportation differentials between natural gas delivered to the FRCC region and natural gas at Henry Hub derived from the reference case were held constant and added to the AEO2008 Low Price Case Henry Hub natural gas price projections shown in Table 7-4. The resulting low natural gas price projections specific to the FRCC region are presented in Table 7-6.

7.5.2.2 Low Distillate and Residual Fuel Oil Prices. Low price projections for distillate and residual fuel oil specific to the FRCC region were developed by first converting the AEO2008 Low Price and AEO2008 Reference Case projections presented in Table 7-4 from cents per gallon to dollars per MBtu. The conversions were made by using the heat contents for distillate (138,690 Btu per gallon) and residual (149,690 Btu per gallon) used by the EIA. The annual transportation differentials for distillate and residual fuel oil between the AEO2008 Reference Case for the FRCC region (presented in Table 7-1) and for electric power usage in the United States as a whole (presented in Table 7-4) were determined. These annual transportation differentials for distillate and residual fuel oil were added to the AEO2008 Low Price Case projections shown in Table 7-4 (after being converted to dollars per MBtu using the heat contents referenced previously). The resulting low distillate and residual fuel oil price projections specific to the FRCC region are presented in Table 7-6.

7.5.2.3 Low Eastern Interior and Powder River Basin Coal Prices. The AEO2008 Reference Case Eastern Interior and PRB minemouth coal prices (annual dollars per ton)[5] were divided by the respective heat content of the coal from these regions (MBtu per ton)[6] resulting in reference case minemouth prices specific to Eastern Interior and PRB coal on a dollar per MBtu basis.

[5] http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_113.xls
[6] Table 71, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/coal.pdf

Table 7-5
Annual Energy Outlook 2008 High Case Price Projections
Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council[1]

Year	Natural Gas (2006$/MBtu)[2]	Distillate Fuel Oil (2006$/MBtu)	Residual Fuel Oil (2006$/MBtu)	High Sulfur Eastern Interior (2.64 lb S/MBtu) (2006$/MBtu)	Low Sulfur Powder River Basin (0.35 lb S/MBtu) (2006$/MBtu)
2008	7.53	17.05	10.08	1.89	2.27
2009	7.88	14.98	11.07	1.97	2.38
2010	7.81	14.85	10.67	2.07	2.49
2011	7.61	15.06	10.76	2.10	2.54
2012	7.86	15.33	11.02	2.08	2.55
2013	7.65	15.45	10.96	2.08	2.55
2014	7.50	15.85	11.26	2.09	2.56
2015	7.53	16.18	11.39	2.08	2.55
2016	7.60	16.52	11.59	2.08	2.56
2017	7.64	17.11	12.01	2.09	2.57
2018	7.65	17.67	12.29	2.10	2.55
2019	7.70	18.06	12.59	2.12	2.57
2020	7.55	18.50	12.92	2.14	2.57
2021	7.44	19.03	13.39	2.14	2.57
2022	7.49	19.20	13.60	2.15	2.60
2023	7.50	19.36	13.77	2.16	2.61
2024	7.63	19.53	14.05	2.16	2.63
2025	7.74	19.37	13.97	2.18	2.65
2026	7.86	19.47	14.21	2.19	2.67
2027	8.20	19.76	14.38	2.21	2.70
2028	8.41	20.13	14.62	2.23	2.73
2029	8.44	20.43	14.80	2.24	2.76
2030	8.51	20.78	15.13	2.27	2.80

[1] Based on data presented in Supplemental Table 69 (Reference Case), Table 12 (Reference Case), Table 12 (High Price Case), Table 13 (Reference Case), Table 13 (High Price Case), Table 15 (Reference Case), and Table 15 (High Price Case) in the AEO2008.

[2] Natural gas price projections do not include usage charges or intrastate firm or interruptible transportation charges. These costs are accounted for in the economic analysis as discussed in Section 16.0 of this Application.

Table 7-6
Annual Energy Outlook 2008 Low Case Price Projections
Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council[1]

Year	Natural Gas (2006$/MBtu)[2]	Distillate Fuel Oil (2006$/MBtu)	Residual Fuel Oil (2006$/MBtu)	High Sulfur Eastern Interior (2.64 lb S/MBtu) (2006$/MBtu)	Low Sulfur Powder River Basin (0.35 lb S/MBtu) (2006$/MBtu)
2008	7.53	17.05	10.08	1.89	2.27
2009	7.69	14.57	11.08	1.97	2.38
2010	7.15	13.08	9.75	2.07	2.48
2011	6.81	12.08	8.88	2.10	2.51
2012	6.78	11.09	8.04	2.08	2.51
2013	6.33	10.08	7.07	2.08	2.51
2014	5.99	9.10	6.26	2.09	2.51
2015	5.66	8.20	5.48	2.08	2.48
2016	5.41	7.25	4.74	2.08	2.47
2017	5.42	7.25	4.70	2.09	2.48
2018	5.45	7.20	4.64	2.10	2.45
2019	5.54	7.22	4.66	2.12	2.46
2020	5.48	7.24	4.63	2.14	2.46
2021	5.41	7.26	4.69	2.14	2.45
2022	5.47	7.27	4.66	2.15	2.47
2023	5.57	7.29	4.70	2.16	2.48
2024	5.66	7.33	4.84	2.16	2.50
2025	5.76	7.41	4.91	2.18	2.52
2026	5.77	7.49	4.95	2.19	2.55
2027	5.92	7.68	4.91	2.21	2.57
2028	6.00	7.92	5.00	2.23	2.59
2029	5.97	8.02	5.01	2.24	2.62
2030	6.08	8.15	5.08	2.27	2.64

[1] Based on data presented in Supplemental Table 69 (Reference Case), Table 12 (Reference Case), Table 12 (Low Case), Table 13 (Reference Case), Table 13 (Low Price Case), Table 15 (Reference Case), and Table 15 (Low Price Case) in the AEO2008.

[2] Natural gas price projections do not include any usage charges of intrastate firm or interruptible transportation charges. These costs are accounted for in the economic analysis as discussed in Section 16.0 of this Application.

The AEO2008 Low Case average minemouth coal prices for the United States were subtracted from the AEO2008 Reference Case average minemouth coal prices for the United States (each of which are presented in Table 7-3) to give an annual differential from the Reference Case to the Low Case average US minemouth coal prices. This annual differential was applied to the reference case minemouth prices specific to Eastern Interior and PRB described above to yield annual low case minemouth prices specific to Eastern Interior and PRB coal on a dollar per MBtu basis.

An annual delivery adder (dollar per MBtu basis) to represent the cost for delivering Eastern Interior and PRB coal from the minemouth to the FRCC region was calculated by taking the difference between the annual reference case Eastern Interior and PRB minemouth prices and the AEO2008 Reference Case Eastern Interior and PRB coal prices delivered to the FRCC region. This annual delivery adder was applied to the low case Eastern Interior and PRB coal minemouth prices resulting in the low price case projections for Eastern Interior and PRB coal delivered to the FRCC region, which are presented in Table 7-6.

7.6 EIA Analysis of Senate Bill 2191

Several bills to regulate emissions of GHGs (including CO_2, methane, NO_x, and fluorinated gas) have been proposed to the 110th US Congress. In response to a request from Senators Joseph Lieberman and John Warner, the US EIA developed an analysis entitled *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner ClimateSecurity Act of 2007*, which was published in April 2008. The following subsections discuss this analysis and summarize the conclusions EIA arrived at regarding projected CO_2 emission allowance prices and associated impacts to the price of natural gas.

As of the date that this Application was prepared, *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007* was one of three published analyses by the EIA of proposed legislation to regulate CO_2. The other two analyses were published by the EIA in January 2008 and April 2007, titled *Energy Market and Economic Impacts of S.1766, the Low Carbon Economy Act of 2007*, and *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007*, respectively. The CO_2 emission allowance prices and corresponding natural gas price projections presented in the EIA's analysis of S.2191 are higher than those presented in the EIA's analysis of S.1766 and the EIA's analysis of S.280, and the price projections presented in S.2191 utilize the most advanced forecasting models. Therefore, the EIA's analysis of S. 2191 was selected for consideration in this Application.

7.6.1 Overview of the Proposed Climate Security Act of 2007 (S.2191)

The *Climate Security Act of 2007* was introduced to the 110th US Congress as S.2191 on October 18, 2007, by Senators Lieberman (for himself, Senator Warner, Senator Harkin, Senator Coleman, Senator Dole, Senator Collins, Senator Cardin, Senator Klobuchar, and Senator Casey). The legislative intent of S.2191 is as follows:

> **(1)To establish the core of a federal program that will reduce United States greenhouse gas emissions substantially enough between 2007 and 2050 to avert the catastrophic impacts of global climate change; and (2) to accomplish that purpose while preserving robust growth in the United States economy, creating new jobs, and avoiding the imposition of hardship on United States citizens.**

As proposed, S.2191 would place a declining cap on US emissions of five primary GHGs (CO_2, methane, NO_x, sulfur hexafluoride, and perfluorocarbons - which the bill denotes as type I GHGs) and on US emissions of the sixth primary GHG (hydrofluorocarbons - which the bill denotes as Type II GHG) .

The annual GHG emission targets set forth in S.2191, measured in units of CO_2 equivalents, are summarized below. According to the EIA, The Title I caps decline gradually from 5,775 million metric tons (mmt) CO_2-equivalent in 2012 (7 percent below 2006 emission levels), to 3,860 mmt in 2030 (39 percent below 2006 levels), and 1,732 mmt in 2050 (72 percent below 2006 levels).

- For calendar years beginning after 2011 – 5,775 mmt, reduced by the amount of emissions of GHG in calendar year 2012 from noncovered entities.
- For calendar years beginning after 2029 – 3,860 mmt, reduced by the amount of emissions of GHG in calendar year 2030 from noncovered entities.
- For calendar years beginning after 2049 – 1,732 mmt, reduced by the amount of emissions of GHG in each such calendar year from noncovered entities.

Under S.2191, individual covered entities must submit allowances equal to their emissions, but their CO_2 emissions are not otherwise limited. Entities could buy and sell allowances, or bank allowances for future use. Under limited conditions, covered entities could also borrow allowance credits against future emissions reductions. Additionally, there are various alternative means of compliance including the following:

- Submitting tradable allowances from another nation's market in GHG emissions.
- Submitting a registered net increase in sequestration.
- Submitting a GHG emissions reduction (other than a registered net increase in sequestration).

- Submitting credits related to assisting developing countries achieve sustainable development and contribute to reducing their GHG emissions.

7.6.2 EIA Analysis of S.2191 – Overview and Summary of Results[7]

In developing its analysis of S.2191, EIA ran each of the policy cases described below through its integrated NEMS program. NEMS is developed and maintained by the EIA's Office of Integrated Analysis and Forecasting to provide projections of domestic energy-economy markets in the long term and perform policy analyses requested by decision makers in various US government agencies (including the White House, Congress, and offices within the US Department of Energy, among others). NEMS is the modeling tool used by EIA in developing its AEO2008. For the S.2191 analysis EIA made adjustments to the AEO2008 Reference Case that are delineated in Appendix C of the *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007.* The adjustments encompass assumptions related to the treatment of ethanol and biodiesel, offshore wind technology, corn and biomass feedstock, interregional transmission cost structure, and biomass electricity generation.

The use of NEMS allows for a fully integrated analysis of potential GHG emission allowance prices and energy demand. As stated in EIA's analysis of S.2191:

> **NEMS endogenously calculates changes in energy-related CO_2 emissions in the analysis cases. The cost of using each fossil fuel includes the costs associated with the GHG allowances needed to cover the emissions produced when they are used. The adjustments influence energy demand and energy-related CO_2 emissions. The GHG allowance price also determines the reductions in the emissions of other GHGs and from international offsets based on abatement cost relationship. With emission allowance banking, NEMS solves for the time path of permit prices such that cumulative emissions match the cumulative emissions target without requiring allowance borrowing and with price escalation consistent with the average cost of capital to the electric power sector.**

The EIA analysis of S.2191 includes several various policy cases and projections of associated CO_2 emissions allowance prices. The policy cases considered by EIA in the analysis of S.2191 are described as follows:

- **S.2191 Core Case** – represents the primary policy case.
- **S.2191 No International Offsets Case** – assumes offsets from international sources are not available.

[7] Refer to *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007* for additional detail regarding the various policy cases and the analysis as a whole.

- **S.2191 High Cost Case** – is similar to the S.2191 Core Case except that the costs of nuclear, coal with carbon capture and sequestration (CCS), and biomass generating technologies are assumed to be 50 percent higher than in the Core Case.
- **S. 2191 Limited Alternatives Case** – represents an environment where the deployment of key technologies, including nuclear, fossil with CCS, and various renewables, is held to their reference case level through 2030, as are imports of LNG.
- **S. 2191 Limited/No International Case** – combines the assumptions from the S. 2191 Limited Alternatives and S. 2191 No International Offset Cases.

The following tables and figures summarize results of the evaluations of the five policy cases considered by EIA in its analysis of S.2191. Tables 7-7 through 7-10 present projections of annual natural gas, distillate fuel oil, residual fuel oil, and coal prices, respectively, for use in the electric power sector for each of the five policy cases, as well as the corresponding annual price projections presented in the AEO2008 Reference Case. The annual natural gas price projections are presented in constant 2006 dollars per mcf, the distillate and residual fuel oil prices are presented in constant 2006 cents per gallon, and the annual coal price projections are presented in constant 2006 dollars per MBtu. Annual natural gas and coal price projections are presented beginning in 2012, which is the initial year of CO_2 emissions regulations contemplated in S.2191. It is important to note that the price projections for the five policy cases presented in Tables 7-7 through 7-10 include the cost of CO_2 emission allowances, while no such costs are included in the annual price projections for the AEO2008 Reference Case. Table 7-11 presents projections of annual CO_2 emissions allowance prices for each of the five policy cases, in constant 2006 dollars per metric ton CO_2 equivalent, beginning in 2012. Figure 7-9 through Figure 7-13 present graphical depictions of the data in Tables 7-7 through 7-112, respectively. Analysis of Tables 7-7 through 7-11 (supplemented by Figures 7-9 through 7-13) shows that projected impacts on natural gas prices and corresponding CO_2 emission allowance price projections differ depending upon the policy cases considered in the EIA analysis of S.2191.

Table 7-7
Natural Gas Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 $/mcf – Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

Year	AEO 2008 Reference Case	S. 2191 Core	S. 2191 High Cost	S.2191 Limited Alternatives	S. 2191 No International Offsets	S. 2191 Limited No International Offsets
2012	$6.67	$7.52	$7.75	$7.95	$9.60	$10.09
2013	$6.42	$7.36	$7.57	$7.81	$9.19	$9.39
2014	$6.23	$7.27	$7.52	$7.81	$9.05	$9.54
2015	$6.10	$7.21	$7.49	$7.81	$9.02	$9.73
2016	$6.05	$7.16	$7.53	$7.92	$8.84	$10.08
2017	$6.10	$7.23	$7.70	$8.16	$8.60	$10.43
2018	$6.15	$7.33	$7.93	$8.47	$8.33	$10.77
2019	$6.21	$7.48	$8.16	$8.86	$8.10	$11.28
2020	$6.11	$7.52	$8.30	$9.04	$8.06	$11.68
2021	$5.97	$7.49	$8.45	$9.27	$8.09	$12.05
2022	$6.09	$7.66	$8.73	$9.65	$8.32	$12.66
2023	$6.18	$7.88	$9.03	$10.07	$8.62	$13.27
2024	$6.31	$8.09	$9.32	$10.50	$8.85	$13.78
2025	$6.44	$8.25	$9.61	$10.94	$9.13	$14.23
2026	$6.56	$8.48	$10.00	$11.51	$9.47	$14.96
2027	$6.62	$8.76	$10.38	$12.01	$9.91	$15.66
2028	$6.85	$9.07	$10.79	$12.58	$10.45	$16.41
2029	$6.99	$9.51	$11.21	$13.26	$11.02	$17.31
2030	$7.13	$9.95	$11.75	$13.95	$11.64	$18.24

Table 7-8

Distillate Fuel Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 Cents/Gallon – Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

Year	AEO 2008 Reference Case	S. 2191 Core	S. 2191 High Cost	S.2191 Limited Alternatives	S. 2191 No International Offsets	S. 2191 Limited No International Offsets
2012	169.06	185.57	190.03	192.94	216.40	218.59
2013	159.80	177.63	182.62	186.05	205.23	205.86
2014	156.14	173.53	179.13	182.80	199.66	202.46
2015	148.02	166.79	172.73	177.03	194.61	199.33
2016	142.27	162.32	168.72	173.89	188.13	197.97
2017	142.47	164.66	171.34	176.54	185.24	202.81
2018	144.46	169.39	176.08	181.69	184.58	209.65
2019	146.65	172.73	179.97	185.85	184.37	216.29
2020	148.32	175.76	184.14	191.02	186.77	223.94
2021	149.79	179.63	188.64	196.69	191.43	231.44
2022	151.59	184.25	193.47	202.40	196.34	239.16
2023	154.47	188.68	199.16	207.64	202.78	248.09
2024	157.92	194.45	204.81	214.11	208.44	257.93
2025	160.77	198.69	210.26	221.31	215.51	265.87
2026	164.44	204.90	216.37	227.84	224.12	276.04
2027	166.97	212.07	223.84	235.50	231.97	287.03
2028	169.89	219.08	231.84	243.78	241.83	299.27
2029	173.43	227.82	239.29	251.80	250.97	311.27
2030	176.22	236.82	247.24	261.44	261.07	324.78

Table 7-9
Residual Fuel Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 Cents/Gallon – Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

Year	AEO 2008 Reference Case	S. 2191 Core	S. 2191 High Cost	S.2191 Limited Alternatives	S. 2191 No International Offsets	S. 2191 Limited No International Offsets
2012	127.47	145.08	150.05	154.40	182.69	180.81
2013	121.77	144.11	148.57	151.86	172.83	172.20
2014	117.85	143.57	149.37	154.00	171.59	170.48
2015	110.86	138.88	145.01	150.18	168.06	169.08
2016	105.19	134.59	141.34	146.68	163.68	171.19
2017	105.50	138.68	146.02	150.73	161.01	178.65
2018	107.69	143.97	151.74	157.21	161.71	187.08
2019	110.05	150.62	157.86	164.61	163.47	194.73
2020	112.32	154.69	161.71	168.81	166.39	202.56
2021	114.21	161.09	167.52	175.39	173.15	210.39
2022	115.70	161.76	171.69	180.90	176.61	220.42
2023	118.46	168.59	177.10	187.53	183.60	232.15
2024	121.14	175.47	184.35	196.16	190.33	243.21
2025	123.44	180.75	190.87	203.72	197.92	253.68
2026	126.36	187.12	197.13	210.23	206.04	264.74
2027	128.13	193.89	206.09	220.02	213.77	278.11
2028	130.99	201.69	215.09	227.89	222.73	292.77
2029	133.09	209.34	222.18	235.62	232.85	305.70
2030	135.33	218.13	234.40	248.32	246.59	319.67

Table 7-10
Coal Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 $/MBtu – Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

Year	AEO 2008 Reference Case	S. 2191 Core	S. 2191 High Cost	S.2191 Limited Alternatives	S. 2191 No International Offsets	S. 2191 Limited No International Offsets
2012	$1.78	$3.39	$3.82	$4.18	$6.35	$6.61
2013	$1.76	$3.47	$3.93	$4.32	$6.16	$6.21
2014	$1.75	$3.58	$4.08	$4.48	$6.21	$6.42
2015	$1.74	$3.69	$4.22	$4.66	$6.29	$6.74
2016	$1.72	$3.82	$4.39	$4.85	$6.21	$7.10
2017	$1.72	$3.97	$4.58	$5.07	$5.95	$7.47
2018	$1.71	$4.13	$4.78	$5.30	$5.66	$7.88
2019	$1.71	$4.31	$5.01	$5.54	$5.41	$8.33
2020	$1.72	$4.49	$5.24	$5.83	$5.51	$8.81
2021	$1.72	$4.67	$5.49	$6.13	$5.77	$9.32
2022	$1.72	$4.88	$5.77	$6.46	$6.07	$9.85
2023	$1.73	$5.11	$6.07	$6.81	$6.37	$10.46
2024	$1.73	$5.34	$6.39	$7.17	$6.71	$11.11
2025	$1.74	$5.60	$6.73	$7.60	$7.06	$11.81
2026	$1.74	$5.87	$7.11	$8.02	$7.47	$12.55
2027	$1.75	$6.15	$7.51	$8.47	$7.90	$13.34
2028	$1.76	$6.46	$7.94	$8.96	$8.38	$14.21
2029	$1.77	$6.82	$8.41	$9.50	$8.87	$15.11
2030	$1.78	$7.21	$8.91	$10.07	$9.40	$16.11

Table 7-11
CO_2 Emission Allowance Price Projections from EIA Analysis of S.2191
(2006 $/Metric Ton CO_2 Equivalent)

Year	S. 2191 Core	S. 2191 High Cost	S.2191 Limited Alternatives	S. 2191 No International Offsets	S. 2191 Limited No International Offsets
2012	$16.88	$21.47	$25.05	$48.47	$50.62
2013	$18.13	$23.06	$26.90	$46.77	$47.25
2014	$19.47	$24.77	$28.89	$47.75	$49.84
2015	$20.91	$26.60	$31.03	$48.83	$53.53
2016	$22.46	$28.57	$33.32	$48.23	$57.49
2017	$24.12	$30.68	$35.79	$45.54	$61.75
2018	$25.90	$32.95	$38.44	$42.65	$66.32
2019	$27.82	$35.39	$41.28	$40.27	$71.23
2020	$29.88	$38.01	$44.34	$41.53	$76.50
2021	$32.09	$40.82	$47.62	$44.60	$82.16
2022	$34.46	$43.84	$51.14	$47.91	$88.24
2023	$37.01	$47.09	$54.93	$51.45	$94.77
2024	$39.75	$50.57	$58.99	$55.26	$101.78
2025	$42.69	$54.31	$63.36	$59.35	$109.31
2026	$45.85	$58.33	$68.05	$63.74	$117.40
2027	$49.24	$62.65	$73.08	$68.46	$126.09
2028	$52.89	$67.28	$78.49	$73.52	$135.42
2029	$56.80	$72.26	$84.30	$78.96	$145.44
2030	$61.01	$77.61	$90.54	$84.81	$156.20

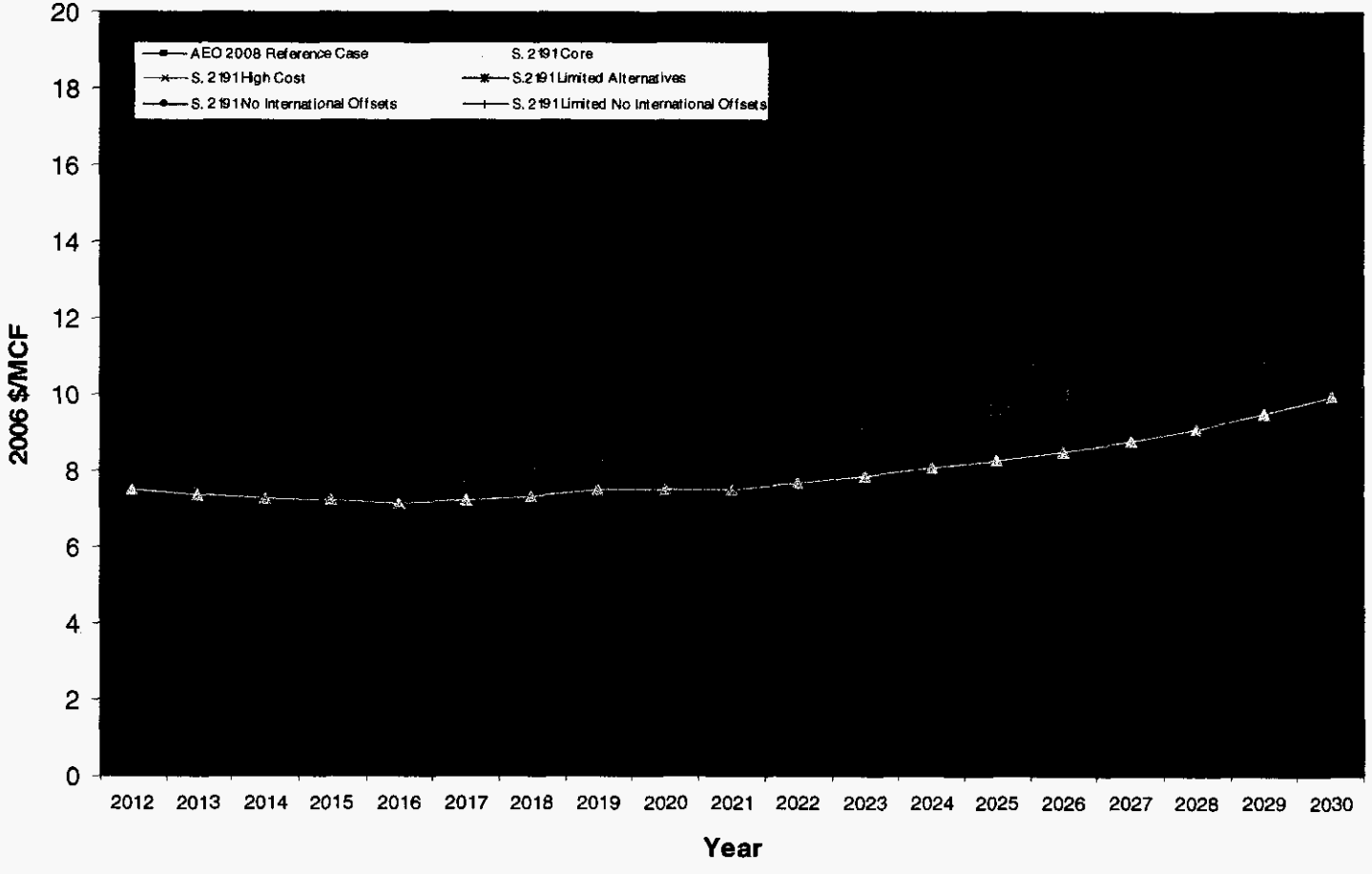

Figure 7-9
Natural Gas Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 $/mcf – Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

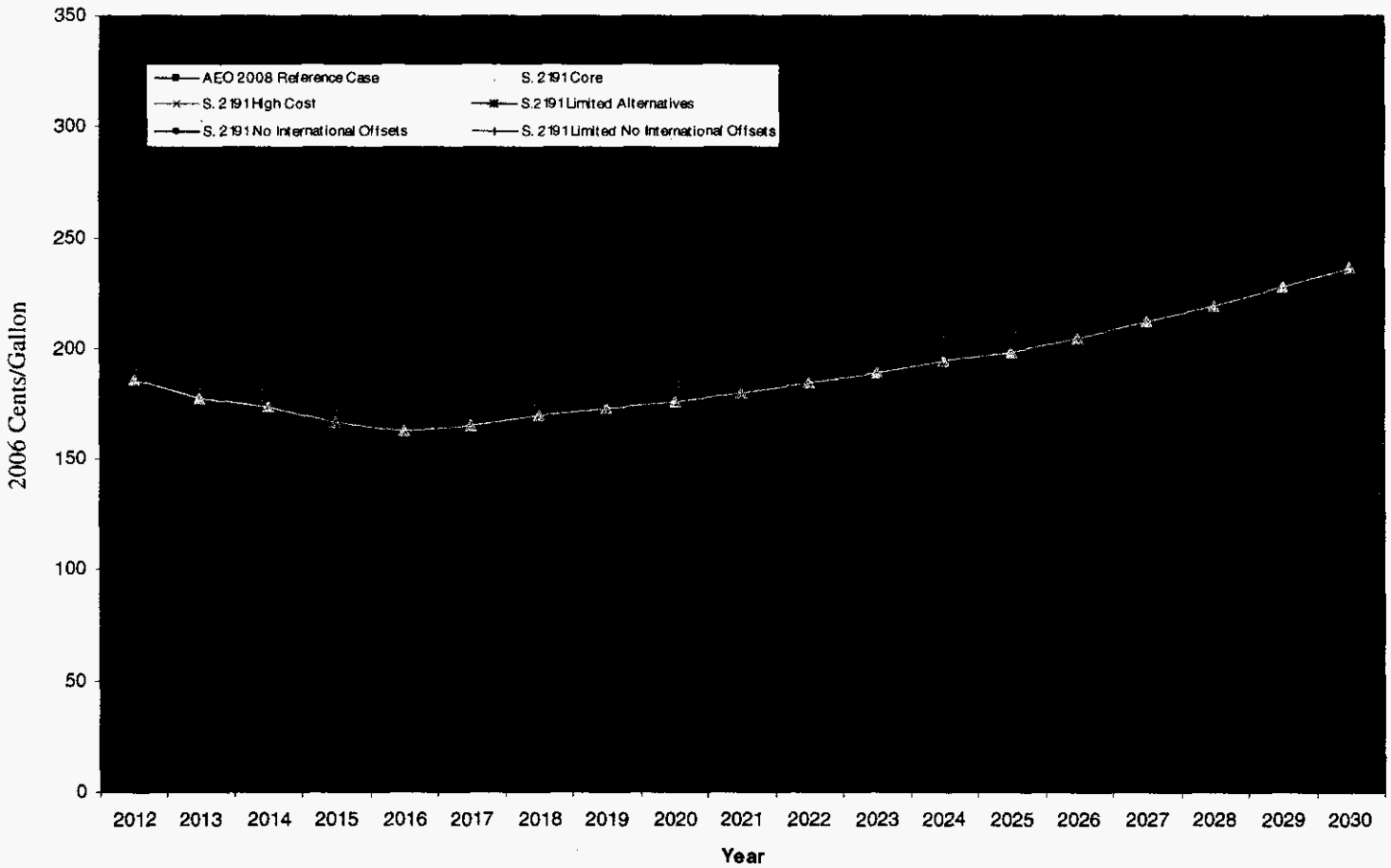

Figure 7-10
Distillate Fuel Oil Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 Cents/Gallon– Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

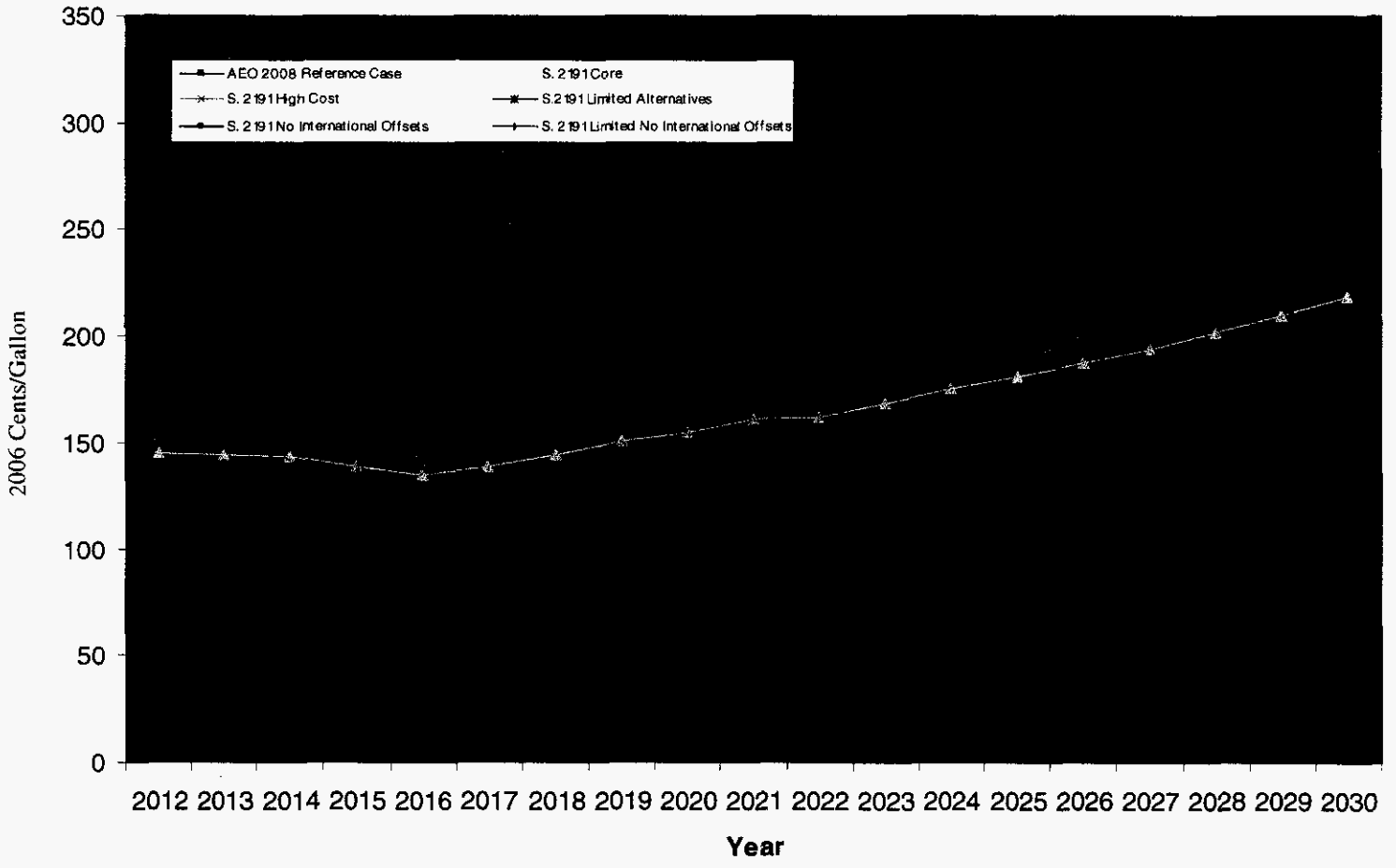

Figure 7-11
Residual Fuel Oil Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 Cents/Gallon– Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

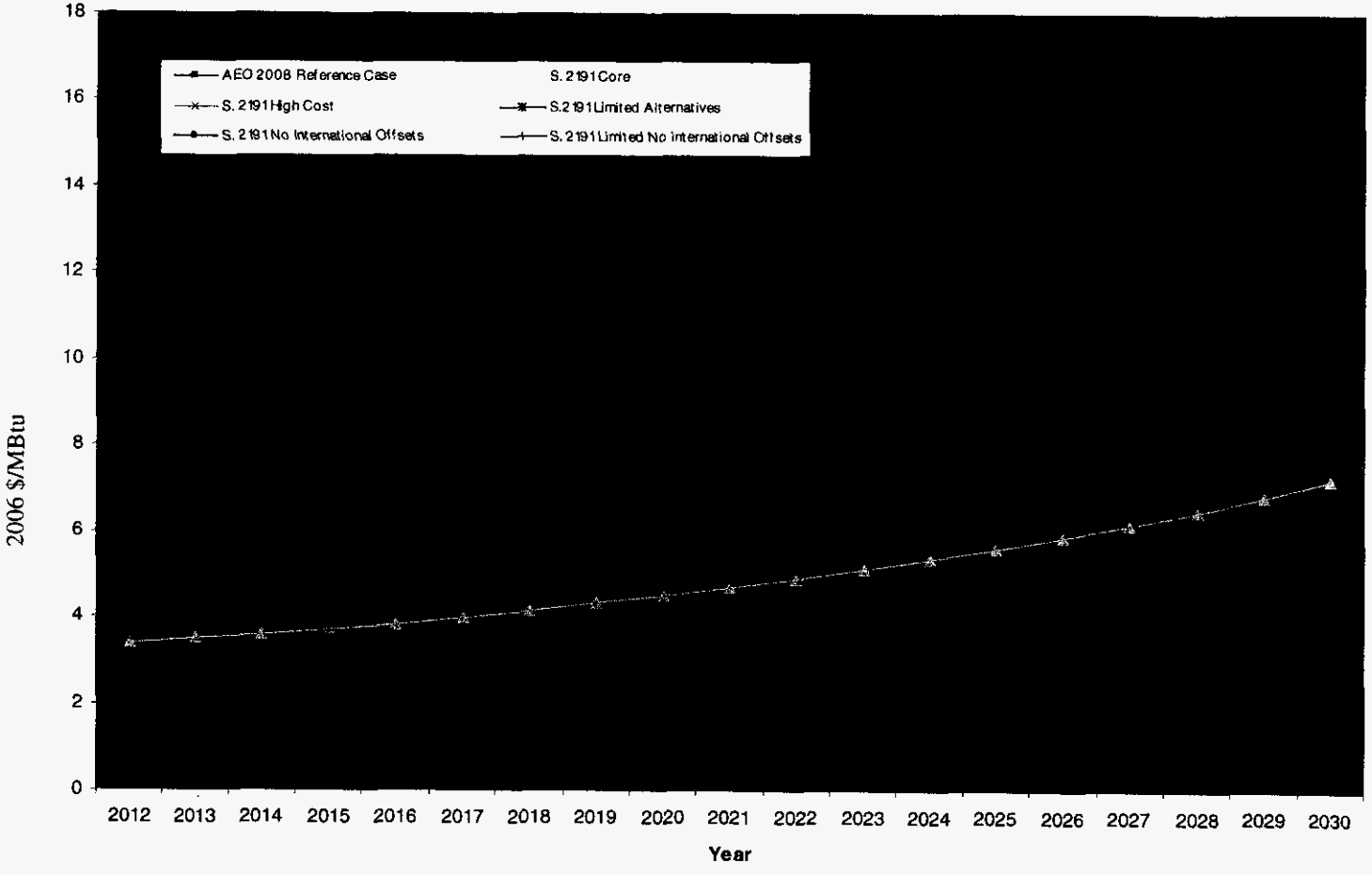

Figure 7-12
Coal Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 $/MBtu– Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

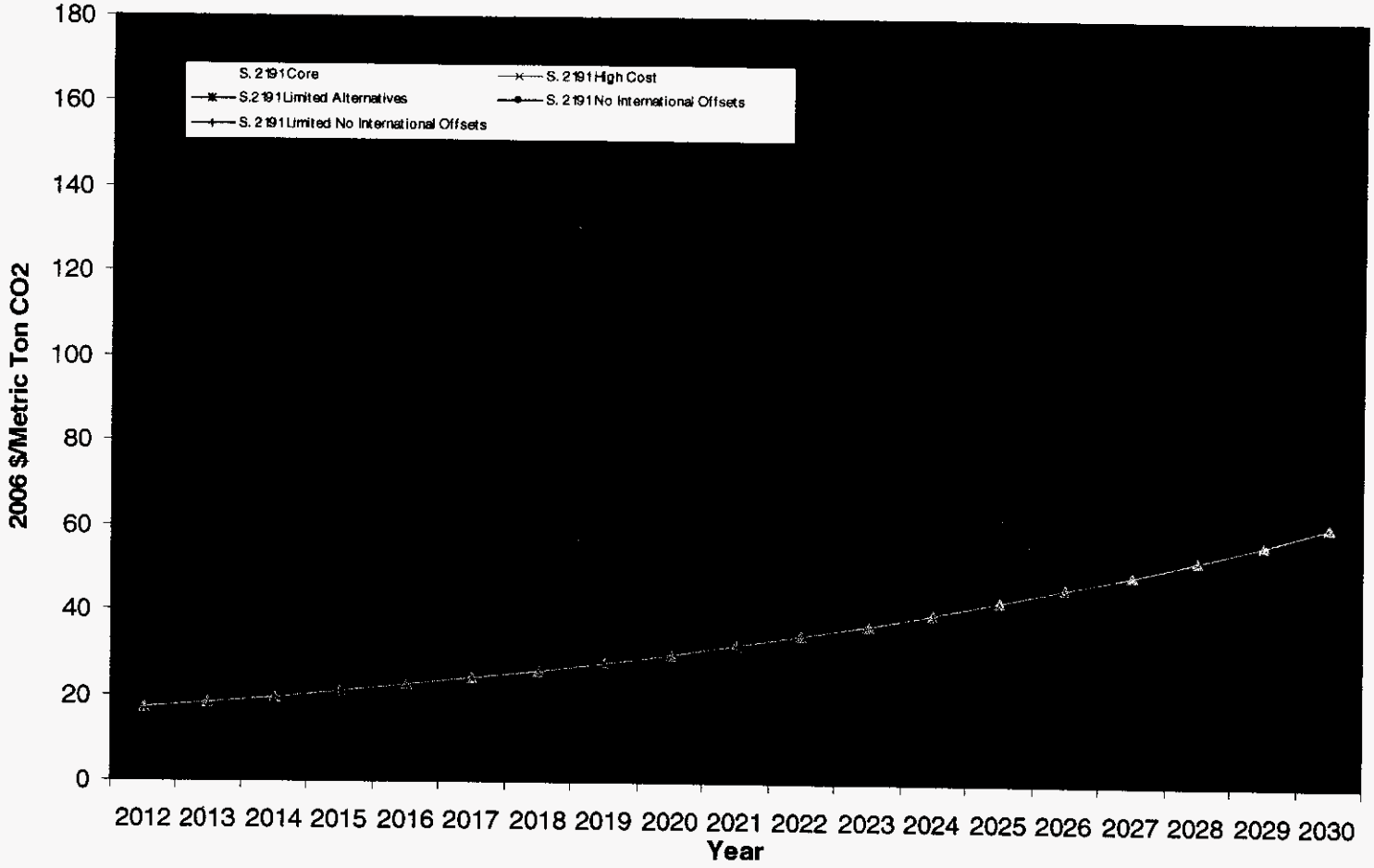

Figure 7-13
CO_2 Emission Allowance Price Projections from EIA Analysis of S.2191 (2006 $/Metric Ton CO_2 Equivalent)

7.7 Consideration of EIA Analysis of Senate Bill 2191

As discussed in Section 7.6, the *Climate Security Act of 2007* was introduced to the 110th US Congress as S.2191 on October 18, 2007, by Senators Lieberman (for himself, Senator Warner, Senator Harkin, Senator Coleman, Senator Dole, Senator Collins, Senator Cardin, Senator Klobuchar, and Senator Casey). The EIA's analysis of S.2191 included projections of natural gas, fuel oil, and coal prices, along with projected prices for emissions of CO_2, for five various policy cases involving different assumptions related to the structure of how S.2191 may be implemented if ultimately enacted by Congress. The fuel price projections, as well as the CO_2 emissions allowance price projections, for each of the five policy cases are presented throughout Section 7.6. The EIA's consideration of S.2191 Core Case as being representative of the primary policy case resulted in the selection of the S.2191 Core Case for further analysis in this Application.

The natural gas, fuel oil, and coal price projections for the S.2191 Core Case presented in Section 7.6 include the annual costs of CO_2 emissions allowance prices, consistent with the presentation of data in EIA's analysis of S.2191. Table 7-12 presents the natural gas, fuel oil, and coal price projections from the S.2191 Core Case excluding the annual costs of CO_2 emissions allowance prices as projected by the EIA.

Also presented in Table 7-12 are projections of natural gas, fuel oil, and coal prices including the EIA's projected annual costs of CO_2 emissions allowances for the S.2191 Core Case. It should be noted that these natural gas and fuel oil price projections differ from those presented in Section 7.6 as the natural gas, fuel oil, and coal prices presented in Table 7-12 are in constant 2006 dollars per MBtu, while those presented in Section 7.6 are presented in constant 2006 dollars per mcf for natural gas and constant 2006 cents per gallon for fuel oil.

Table 7-12
S. 2191 Core Case Natural Gas, Fuel Oil, and Coal Price Projections
Compared to Non-Adjusted Fuel Price Forecasts (2006 $/MBtu)

Year	Natural Gas		Distillate Fuel Oil		Residual Fuel Oil		Coal	
	Including Costs of CO_2 Emission Allowances	Excluding Costs of CO_2 Emission Allowances	Including Costs of CO_2 Emission Allowances	Excluding Costs of CO_2 Emission Allowances	Including Costs of CO_2 Emission Allowances	Excluding Costs of CO_2 Emission Allowances	Including Costs of CO_2 Emission Allowances	Excluding Costs of CO_2 Emission Allowances
2012	7.31	6.30	13.38	12.15	9.69	8.36	3.39	1.78
2013	7.16	6.07	12.81	11.48	9.63	8.20	3.47	1.75
2014	7.07	5.90	12.51	11.09	9.59	8.06	3.58	1.73
2015	7.01	5.76	12.03	10.50	9.28	7.63	3.69	1.71
2016	6.96	5.61	11.70	10.06	8.99	7.22	3.82	1.69
2017	7.03	5.57	11.87	10.11	9.26	7.36	3.97	1.68
2018	7.13	5.56	12.21	10.32	9.62	7.58	4.13	1.67
2019	7.28	5.58	12.45	10.42	10.06	7.87	4.31	1.67
2020	7.31	5.49	12.67	10.49	10.33	7.98	4.49	1.66
2021	7.29	5.32	12.95	10.60	10.76	8.23	4.67	1.63
2022	7.45	5.34	13.28	10.76	10.81	8.09	4.88	1.61
2023	7.66	5.38	13.60	10.90	11.26	8.35	5.11	1.60
2024	7.87	5.41	14.02	11.11	11.72	8.59	5.34	1.58
2025	8.03	5.37	14.33	11.20	12.08	8.71	5.60	1.55
2026	8.25	5.37	14.77	11.42	12.50	8.89	5.87	1.53
2027	8.52	5.42	15.29	11.69	12.95	9.07	6.15	1.48
2028	8.83	5.47	15.80	11.93	13.47	9.31	6.46	1.45
2029	9.25	5.63	16.43	12.27	13.98	9.51	6.82	1.43
2030	9.68	5.77	17.08	12.61	14.57	9.76	7.21	1.41

7.7.1 S.2191 Core Case Fuel Prices Delivered to the FRCC Region

Projections of natural gas, fuel oil, and coal prices to the FRCC region considering the potential impacts of CO_2 regulations, consistent with the EIA S.2191 Core Case, were developed for analysis in this Application. In order to develop such fuel price forecasts for natural gas and fuel oil, the AEO2008 Reference Case fuel prices delivered to the US electric power sector were analyzed and compared to the corresponding S.2191 Core Case fuel price projections presented in Table 7-12 (excluding the costs of CO_2 emissions allowances, which are accounted for elsewhere in the economic analysis included in this Application). Annual absolute differentials between the AEO2008 Reference Case fuel price projections and corresponding fuel price projections from the S. 2191 Core Case were calculated for natural gas, distillate and residual fuel oil. The annual absolute differentials were applied to the natural gas, distillate and residual fuel oil price projections for the FRCC Region shown in Tables 7-1 and 7-2 to develop projections of fuel prices delivered to the FRCC region that reflect the potential impact of S.2191 related to regulation of emissions of CO_2 (consistent with the EIA S.2191 Core Case). A similar method to calculate the impact of S.2191 on coal price projections was utilized. The only variation in the calculation is that the AEO2008 Reference Case fuel price projections for coal and the S.2191 Core Case price projections for coal were applied to both the Eastern Interior coal and the PRB coal. The AEO2008 Reference Case price projections for coal and the S.2191 Core Case price projections for coal were utilized as an average coal price indicator and, therefore, applied to both regions without differentiation. The resulting projections of fuel prices for 2012 through 2030, in constant 2006 dollars per MBtu, specific to the FRCC region are presented in Table 7-13. Prior to 2012, the natural gas, fuel oil, and coal price projections presented in Tables 7-1 and 7-2 remain unaffected as the analysis assumes that CO_2 regulations will begin in 2012.

Table 7-13
Forecast of Fuel Prices Delivered to FRCC Considering
Potential Impact of S.2191 (EIA S.2191 Core Case)
(2006 $/MBtu)

Year	Natural Gas	Distillate Fuel Oil	Residual Fuel Oil	High Sulfur Eastern Interior (2.64 lb S/MBtu)	Low Sulfur Powder River Basin (0.35 lb S/MBtu)
2012	$7.04	$12.39	$8.99	$2.53	$2.05
2013	$6.70	$11.69	$8.67	$2.52	$2.05
2014	$6.48	$11.28	$8.54	$2.51	$2.04
2015	$6.29	$10.70	$8.02	$2.48	$2.02
2016	$6.13	$10.25	$7.55	$2.48	$2.01
2017	$6.04	$10.30	$7.67	$2.48	$2.00
2018	$6.03	$10.50	$7.84	$2.46	$2.01
2019	$6.05	$10.60	$8.12	$2.47	$2.03
2020	$5.96	$10.65	$8.18	$2.45	$2.02
2021	$5.83	$10.76	$8.40	$2.41	$1.99
2022	$5.86	$10.90	$8.23	$2.43	$1.98
2023	$5.85	$11.03	$8.47	$2.42	$1.97
2024	$5.87	$11.23	$8.73	$2.41	$1.96
2025	$5.84	$11.33	$8.86	$2.41	$1.93
2026	$5.77	$11.51	$9.02	$2.41	$1.92
2027	$5.85	$11.78	$9.11	$2.41	$1.87
2028	$5.90	$12.03	$9.34	$2.41	$1.85
2029	$6.00	$12.37	$9.49	$2.41	$1.83
2030	$6.14	$12.74	$9.76	$2.41	$1.81

7.7.2 Carbon Dioxide Emissions Allowance Prices

EIA's projected CO_2 emission allowance prices corresponding to the S.2191 Core Case are presented in Table 7-14. EIA developed its projections of CO_2 emissions allowance prices in constant 2006 dollars per metric ton, which are shown in the second column of Table 7-14 and match those presented previously in Section 7.6 (Table 7-11). The annual CO_2 emission allowance price projections in constant 2006 dollars per short ton are shown in the third column of Table 7-14.

Table 7-14
Projected CO_2 Emission Allowance Prices
EIA S.2191 Core Case

Year	2006$/Metric Ton	2006$/Short Ton
2012	16.88	15.31
2013	18.13	16.44
2014	19.47	17.66
2015	20.91	18.97
2016	22.46	20.37
2017	24.12	21.88
2018	25.90	23.50
2019	27.82	25.24
2020	29.88	27.10
2021	32.09	29.11
2022	34.46	31.26
2023	37.01	33.58
2024	39.75	36.06
2025	42.69	38.73
2026	45.85	41.60
2027	49.24	44.67
2028	52.89	47.98
2029	56.80	51.53
2030	61.01	55.34

13.0 Supply-Side Alternatives

This section presents the conventional and emerging supply-side technologies that were considered by JEA. Estimated performance characteristics, emissions profiles, capital and operating costs, availability, and construction schedules are presented.

13.1 Conventional and Emerging Technologies

The conventional and emerging generating options that were evaluated as potential sources of future capacity for JEA are discussed in this section. In addition to a general description, a summary of projected performance, emissions, capital cost, O&M costs, construction schedules, scheduled maintenance requirements, and forced outage rates have been developed for each option.

Cost and performance estimates have been developed for several conventional self-build generation technologies that are proven, commercially available, and widely used in the power industry. Additionally, cost and performance estimates were developed for the LMS100 simple cycle combustion turbine, which may be considered an emerging technology. An emerging technology is a technology that cannot be considered conventional for various reasons, as discussed further in this section.

Although the combustion turbines and the combined cycle alternatives discussed herein assume a specific manufacturer (GE) and specific models (e.g., aeroderivative and frame combustion turbines), doing so is not intended to limit the alternatives considered solely to GE models. Rather, such assumptions were made to provide indicative cost, output, and performance data. Several manufacturers offer similar generating technologies with similar attributes, and the data presented in this analysis should be considered indicative of comparable technologies across a wide array of manufacturers.

Building additional coal or nuclear generation by 2012 is not feasible due to permitting constraints and construction lead times, and therefore.solid fuel generating facilities have not been included as generating unit alternatives. In addition, nuclear units are not included beyond the potential opportunities to participate in future nuclear generating units (as described in Section 16.4) because of the large size of the nuclear units and the need to have another entity develop and manage the projects.

The capital cost estimates developed include both direct and indirect costs. An allowance for possible general owner's cost items, as summarized in Table 13-1, has been included in the cost estimates.

Table 13-1
Possible Owner's Costs

Project Development

- Site selection study
- Land purchase/rezoning for Greenfield sites
- Transmission/gas pipeline right-of-way
- Road modifications/upgrades
- Demolition
- Environmental permitting/offsets
- Public relations/community development
- Legal assistance
- Provision of project management

Spare Parts and Plant Equipment

- Combustion turbine materials, gas compressors, supplies, and parts
- Steam turbine materials, supplies, and parts
- HRSG materials, supplies, and parts
- BOP equipment/tools
- Rolling stock
- Plant furnishing and supplies

Plant Startup/Construction Support

- Owner's site mobilization
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals and reagents
- Consumables
- Cost of natural gas not recovered in power sales
- Auxiliary power purchases
- Acceptance testing
- Construction all-risk insurance

Owner's Contingency

- Owner's uncertainty and costs pending final negotiation
- Unidentified project scope increases
- Unidentified project requirements
- Costs pending final agreements (i.e., interconnection contract costs)

Owner's Project Management

- Preparation of bid documents and the selection of contractors and suppliers
- Performance of engineering due diligence
- Provision of personnel for site construction management

Taxes/Advisory Fees/Legal

- Taxes
- Market and environmental consultants
- Owner's legal expenses
- Interconnect agreements
- Contracts (procurement and construction)
- Property

Utility Interconnections

- Natural gas service
- Natural gas system upgrades
- Electrical transmission
- Water supply
- Wastewater/sewer

Financing (included in fixed charge rate, but not in direct capital cost)

- Financial advisor, lender's legal, market analyst, and engineer
- Loan administration and commitment fees
- Debt service reserve fund

13.1.1 Generating Alternatives Assumptions

13.1.1.1 General Capital Cost Assumptions. Unless otherwise discussed for each site, the following general assumptions were applied in developing the cost and performance estimates:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, laydown, and staging.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be preengineered unless otherwise specified.
- Construction power is available at the boundary of the site(s).
- The LMS100 is assumed to have standard SCR. The LM6000 and 7FA simple cycle combustion turbines will have hot SCR. Except for the LMS100, the simple cycle units will not include a CO catalyst, but will have a spool piece for future installation.
- GE 7FA combined cycle plants will include SCR and space for a potential CO catalyst to reduce emissions.
- Standard sound enclosures will be included for the combustion turbines.
- Natural gas pressure is assumed to be adequate for the 7FA simple and combined cycle alternatives. Gas compressors will be included for the LM6000 and LMS100 aeroderivative combustion turbines. A regulating and metering station is assumed to be part of the owner's cost for each alternative.
- Demineralized water will be supplied by a demineralized water treatment system for the combined cycle option.
- The LMS100 and the combined cycle alternatives will utilize cooling towers. Groundwater or treated sewage effluent will be used as cooling water.
- The LMS100 has an intercooled compressor and will not utilize inlet cooling. The LM6000 will include the SPRINT option and will also include inlet chillers. The GE 7FA combined cycle will utilize evaporative coolers.
- Field erected service/fire water storage tanks are included.

13.1.1.2 Fuel Assumptions.

- Fuel gas is 100 percent methane with 0.2 grain of sulfur per 100 standard cubic feet (scf), with a heat content of 21,515 Btu/lb, lower heating value (LHV).

13.1.1.3 Direct Cost Assumptions.

- Total direct capital costs are expressed in 2008 dollars unless otherwise noted.
- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on an EPC contracting philosophy.
- Spare parts for startup are included. Initial inventory of spare parts for use during operation is included in the owner's costs.
- Permitting and licensing are included in the owner's costs.

13.1.1.4 Indirect Cost Assumptions. The following items are assumed in the capital cost estimate:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.
- Interest during construction and financing fees will be accounted for separately in the economic evaluation and, therefore, are not included in the capital cost or owner's cost estimates.

13.1.1.5 Meteorological Conditions. An average annual temperature and relative humidity of 70° F and 72 percent, respectively, were used for developing performance estimates for use in production cost modeling. Additionally, a winter temperature of 24° F (relative humidity of 91.9 percent) and a summer temperature of 98° F (relative humidity of 54.9 percent) were used to develop seasonal performance estimates.

13.1.1.6 Performance Degradation. Power plant output and heat rate performance will degrade with hours of operation because of factors such as blade wear, erosion, corrosion, and increased tube leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance when compared to the unit's new and clean performance. The degradation that cannot be recovered is referred to herein as nonrecoverable degradation, and estimates have been developed to capture its impacts. Nonrecoverable degradation will vary from unit to unit, so specific nonrecoverable output and heat rate factors have been developed and are presented in Table 13-2. The degradation percentages are applied one time to the new and clean performance data, and reflect lifetime aggregate nonrecoverable degradation.

Table 13-2
Nonrecoverable Degradation Factors

Unit Description	Degradation Factor	
	Output (%)	Heat Rate (%)
GE LM6000 Simple Cycle	3.2	1.75
GE LMS100 Simple Cycle	3.2	1.75
GE 7FA Simple Cycle	3.2	1.75
GE 1x1 7FA Combined Cycle	2.7	1.50

13.1.2 Future Sites

The generating unit alternatives considered throughout this Application (excluding the conversion of the Greenland Energy Center to combined cycle operation) were developed on a greenfield site basis.

13.1.3 Simple Cycle Combustion Turbine Alternatives

Combustion turbine generators are sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A simple cycle combustion turbine generates power by compressing ambient air and then heating the pressurized air to approximately 2,000° F or more, by burning oil or natural gas, with the hot gases then expanding through a turbine. The turbine drives both the compressor and

an electric generator. A typical combustion turbine would convert 30 to 35 percent of the fuel to electric power. A substantial portion of the fuel energy is wasted in the form of hot gases (typically 900° F to 1,100° F) exiting the turbine exhaust. When the combustion turbine is used to generate power and no energy is captured and utilized from the hot exhaust gases, the power cycle is referred to as a "simple cycle" power plant.

Combustion turbines are mass flow devices, and their performance changes with changes in the ambient conditions at which the unit operates. Generally speaking, as temperatures increase, combustion turbine output and efficiency decrease because of the lower density of the air. To lessen the impact of this negative characteristic, most of the newer combustion turbine-based power plants often include inlet air cooling systems to boost plant performance at higher ambient temperatures.

Combustion turbine pollutant emission rates are typically higher on a part per million (ppm) basis at part load operation than at full load. This limitation has an effect on how much plant output can be decreased without exceeding pollutant emissions limits. In general, combustion turbines can operate at a minimum load of about 50 percent of the unit's full load capacity while maintaining emission levels within required limits.

Advantages of simple cycle combustion turbine projects include low capital costs, short design and construction schedules, and the availability of units across a wide range of capacities. Combustion turbine technology also provides rapid startup and modularity for ease of maintenance.

The primary drawback of combustion turbines is that, due to the cost of natural gas and fuel oil, the variable cost per MWh of operation is high compared to other conventional technologies. As a result, simple cycle combustion turbines are often the technology of choice for meeting peak loads in the power industry, but are not usually economical for baseload or intermediate service.

Two different commercially proven combustion turbine sizes were evaluated, as well as the LMS100 (which, as described later in this section, is a relatively new design with limited hours of demonstrated operation). The GE LM6000 has a nominal output in the range of 50 MW at International Organization for Standardization (ISO) conditions with the SPRINT™ design feature included. The GE 7FA has a nominal output of about 170 MW at ISO conditions.

13.1.3.1 GE SPRINT LM6000 Combustion Turbine. The GE SPRINT LM6000 was selected as a potential simple cycle alternative because of its modular design, efficiency, and size. It is a two-shaft gas turbine engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine.

The LM6000 consists of a five-stage low-pressure compressor (LPC); a 14-stage, variable geometry, high-pressure compressor (HPC); an annular combustor; a two-stage, air-cooled, high-pressure turbine (HPT); a five-stage, low-pressure turbine (LPT); and an accessory drive gearbox. The LM6000 has two concentric rotor shafts, with the LPC and LPT assembled on one shaft, forming the LP rotor. The HPC and HPT are assembled on the other shaft, forming the HP rotor.

The LM6000 uses the LPT to power the output shaft. The LM6000 design permits direct coupling to 3,600 rpm generators for 60 hertz power generation. The gas turbine drives its generator through a flexible, dry type coupling connected to the front, or "cold" end, of the LPC shaft. The LM6000 gas turbine generator set has the following attributes:

- Full power in approximately 10 minutes.
- Cycling or peaking operation.
- Synchronous condenser capability.
- Compact, modular design.
- More than 5 million operating hours.
- More than 450 turbines sold.
- LM6000 SPRINT™ spray intercooling for power boost.
- Dual fuel capability.

The capital cost estimate was derived utilizing GE's Next-Gen package for the LM6000. This package includes more factory assembly, resulting in less construction time. Table 13-3 presents the operating characteristics of the LM6000 SPRINT combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent) and a summer temperature of 98° F (relative humidity of 54.9 percent), and annual average temperature conditions (70° F with a relative humidity of 72 percent). High temperature SCR would be used to control NO_x to 2 ppmvd while operating on natural gas. Table 13-4 presents estimated emissions for the LM6000.

13.1.3.2 GE 7FA Combustion Turbine. The GE 7FA combustion turbine, originally introduced in 1986, is the result of a multi-year development program using technology advanced by GE Aircraft Engines and GE's Corporate Research and Development Center. The development program facilitated the application of technologies such as advanced bucket cooling techniques, compressor aerodynamic design, and new alloys for F class gas turbines, enabling these machines to attain higher firing temperatures (2,400° F) than previous generating units.

Table 13-3
GE LM6000 PC SPRINT Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (Full Load)	47.4	9,637
Summer (Full Load)	46.2	10,171
Average (Full Load)	47.3	9,933
Average (75% Load)	26.5	11,304
Average (50% Load)	17.5	13,444

[1]Net capacity and net plant heat rate include degradation factors, inlet chilling is considered on full load cases above 60° F, and performance is preliminary.

Table 13-4
GE LM6000 PC SPRINT Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	29
CO, lb/MBtu	0.0648

[1]Emissions are at full load at 70° F, reflect operation on natural gas, and include the effects of SCR.

The GE 7FA combustion turbines have an 18-stage compressor and a 3-stage turbine and feature cold-end drive and axial exhaust, which is beneficial for combined cycle arrangements. With reduced cycle time for installation and startup, the GE 7FA can be installed relatively quickly. The packaging concept of the GE 7FA features consolidated skid-mounted components, controls, and accessories, which reduce piping, wiring, and other onsite interconnection work.

The GE 7FA combustion turbine has also exhibited outstanding environmental characteristics. Because of the higher specific output of these machines, smaller amounts of NO_x and CO are emitted per unit of power produced for the same exhaust concentrations as other generating technologies. GE 7FA turbines have accumulated more than 900,000 operating hours using dry low NO_x burners, which will be part of the NO_x control strategy when operating on natural gas.

Table 13-5 presents the operating characteristics of the GE 7FA combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). The 7FA will utilize dry low NO_x combustors and SCR to control NO_x to 2 ppmvd on natural gas. Table 13-6 presents estimated emissions for the 7FA.

Table 13-5
GE 7FA Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (Full Load)	187.9	11,009
Summer (Full Load)	142.1	11,241
Average (Full Load)	157.6	10,888
Average (75% Load)	125.9	11,610
Average (50% Load)	78.3	14,327

[1]Net capacity and net plant heat rate include degradation factors and performance is preliminary.

Table 13-6 GE 7FA Estimated Emissions[1]	
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165

[1]Emissions are at full load at 70° F and include the effects of SCR and dry low NO_x combustors.

13.1.3.3 GE LMS100 Combustion Turbine. The GE LMS100 is a new combustion turbine; the first LMS100 began commercial operation in July 2006. At the time this Application was prepared, only about half a dozen LMS100 units had been ordered from GE. After the reliability of the LMS100 has been successfully demonstrated, it will likely replace the use of two-unit blocks of LM6000s in the future.

The LMS100 is currently the most efficient simple cycle gas turbine in the world. In simple cycle mode, the LMS100 has an efficiency of 46 percent, which is 10 percent greater than the LM6000. It has a high part-load efficiency, cycling capability (without increased maintenance cost), better performance at high ambient temperatures, modular design (minimizing maintenance costs), the ability to achieve full power from a cold start in 10 minutes, and is expected to have high availability, though this availability must be commercially demonstrated before the LMS100 can be considered a conventional alternative.

The LMS100 is an aeroderivative turbine and has many of the same characteristics of the LM6000. The former uses off-engine intercooling within the turbine's compressor section to increase its efficiency. The process of cooling the air optimizes the performance of the turbine and increases output efficiency. At 50 percent turndown, the part-load efficiency of the LMS100 is 40 percent, which is a greater efficiency than most simple cycle combustion turbines at full load.

There are two main differences between the LM6000 and the LMS100. The LM6000 uses the SPRINT intercooling system to cool the compressor with a micro-mist of water, while the LMS100 cools the compressor air with an external heat exchanger

after the first stage of compression. Unlike the LM6000, which has a HP turbine and a power turbine, the LMS100 has an additional IP turbine to increase output efficiency.

As a packaged unit, the LMS100 consists of a 6FA turbine compressor, which outputs compressed air to the intercooling system. The intercooling system cools the air, which is then compressed in a second compressor to a high pressure, heated with combusted fuel, and then used to drive the two-stage IP/HP turbine described above. The exhaust stream is then used to drive a five-stage power turbine. Exhaust gases are at a temperature of less than 800° F, which allows the use of a standard SCR system for NO_x control.

Table 13-7 presents the operating characteristics of the LMS100 combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). Standard SCR will be used to control NO_x to 2 ppmvd while operating on natural gas. Table 13-8 presents estimated emissions for the LMS100.

Table 13-7
GE LMS100 Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (Full Load)	95.6	8,961
Summer (Full Load)	86.4	9,360
Average (Full Load)	96.5	9,095
Average (75% Load)	72.1	9,543
Average (50% Load)	47.8	10,609

[1]Net capacity and full load net plant heat rate include degradation factors, evaporative cooling is not considered, and performance is preliminary.

Table 13-8 GE LMS100 Estimated Emissions[1]	
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/TBtu	N/A
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	11.4
CO, lb/MBtu	0.025
[1]Emissions are at full load at 70° F and include the effects of SCR and CO catalyst.	

13.1.3.4 GE 7FA 1x1 Combined Cycle. Combined cycle power plants use one or more CTGs and one or more STGs to produce energy. Combined cycle power plants operate according to a combination of both the Brayton and Rankine thermodynamic power cycles. HP steam is produced when the hot exhaust gas from the CTG is passed through an HRSG. The HP steam is then expanded through a steam turbine, which spins an electric generator. It is assumed that duct firing will be used in the combined cycle option.

Combined cycle configurations have several advantages over simple cycle combustion turbines. Advantages include increased efficiency and potentially greater operating flexibility if duct burners are used. Disadvantages of combined cycles relative to simple cycles include a small reduction in plant reliability and an increase in the overall staffing and maintenance requirements because of added plant complexity.

The 1x1 combined cycle generating unit includes one GE 7FA CTG, one HRSG, and one STG and will include evaporative cooling. The HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, three-pressure, reheat unit with supplemental duct firing to maintain full steam turbine generator load at all ambient conditions. SCR and dry low NO_x burners will be included to control NO_x to 2 ppmvd, and space for a CO catalyst will be included.

The steam turbine is expected to be a tandem-compound, single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one HP section, one IP section, and a two-flow LP section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring, and control

systems are included. A single synchronous generator is included, which will be direct coupled to the steam turbine. The STG will be located outdoors, with a building provided for the major auxiliary electrical power equipment.

Table 13-9 presents the operating characteristics of the GE 1x1 7FA combined cycle at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). Table 13-10 presents estimated emissions for the 1x1 7FA combined cycle.

13.1.4 Capital Costs, O&M Costs, Schedule, and Maintenance Summary

The capital costs, O&M costs, schedule, forced outage, and maintenance estimates for the generating alternatives are summarized in Table 13-11. All costs are provided in 2008 dollars unless otherwise noted. The EPC cost includes engineering, procurement, construction, and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. The assumed owner's cost allowance is representative of typical owner's costs as outlined in Table 13-1, exclusive of escalation, financing fees, and interest during construction, which will be accounted for separately in the economic analyses.

Fixed and nonfuel variable O&M costs are also provided in 2008 dollars. Fixed costs include labor, maintenance, and other fixed expenses excluding backup power, property taxes, and insurance. Nonfuel variable costs include outage maintenance, consumables, and replacements dependent on unit operation. Construction schedules are indicative of typical construction durations for the alternative technology and plant size. Actual costs and schedules will vary from the preliminary estimates provided in Table 13-11.

The scheduled and forced outage assumptions for the generating alternatives are also presented in Table 13-11.

Table 13-9
GE 1x1 7FA Combined Cycle Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (Full Load with Duct Firing)	329.8	7,435
Summer (Full Load with Duct Firing)	299.6	7,445
Average (Full Load with Duct Firing)	307.2	7,420
Average (Full Load without Duct Firing)	247.0	6,969
Average (75% Load)	192.1	7,289
Average (50% Load)	141.0	7,923

[1]Net capacity and net plant heat rate include degradation factors, evaporative cooling is considered at full load cases above 60° F, and performance is preliminary.

Table 13-10
GE 1x1 7FA Combined Cycle Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165

[1]Emissions are at full load at 70° F and include the effects of SCR and dry low NO_x combustors.

Table 13-11
Capital Costs, O&M Costs, and Schedules for the Generating Alternatives
(All Costs in 2008 Dollars)

Supply Alternative	Capital Costs			Total Cost ($/kW) at 70° F	Fixed O&M ($/kW-yr)	Nonfuel Variable O&M ($/MWh)	Construction Schedule (months)	Scheduled Maintenance (days)	Forced Outage (percent)
	EPC Cost ($millions)[1]	Owner's Cost ($millions)[1]	Total Cost ($millions)[1]						
GE LM6000 SC	57.6	14.4	72.0	1,522.9	26.47	3.64	10	10	2.0
GE LMS100 SC	90.1	22.5	112.6	1,166.7	13.45	3.29	12	10	2.0
GE 7FA SC	110.3	27.6	137.9	861.9	8.41	15.57	12	10	2.0
1x1 GE 7FA CC	287.0	62.3	349.3	1,136.9	4.56	3.30	22	14	2.0

[1] Estimated capital costs are presented in overnight 2008 dollars and do not include interest during construction.

14.0 Renewable Energy and Clean Power

JEA recognizes the importance of integrating renewable energy into its power supply portfolio. JEA has pursued several clean power initiatives and is in the process of evaluating potential new renewable energy resources. The remainder of this section discusses JEA's clean power portfolio (including JEA's existing renewable energy resources), and potential new renewable energy resources being evaluated by JEA.

14.1 JEA Clean Power Portfolio

Since 1999, JEA has been working closely with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups to establish a process to maintain an action plan entitled *Clean Power Action Plan.* The Clean Power Action Plan establishes an Advisory Panel that is comprised of participants from the Jacksonville community, including representatives from the Sierra Club, ALA, and the newest member, the City of Jacksonville Environmental Protection Board. These local members provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program. Although the Clean Power Action Plan does not speak directly to CO_2 emissions, projects undertaken by JEA pursuant to the Plan have reduced JEA's CO_2 emissions.

JEA has implemented several projects as part of the Clean Power Action Plan, including installation of clean power systems, purchase power agreements, legislative and public education activities, and research into and development of clean power technologies. In particular, JEA has conducted a number of generation efficiency improvements, such as turbine upgrades, which increase the output of generating units without increasing the amount of fuel burned or the amount of CO_2 emitted. These particular projects are described later in this section.

14.1.1 Renewable Energy

In 2005, JEA received a Sierra Club Clean Power Award for its voluntary commitment to increasing the use of solar, wind, and other renewable or green power sources. Since that time, JEA has implemented new renewable energy projects and continues to explore additional opportunities to increase its utilization of renewable energy. As further discussed below, JEA's existing renewable energy sources include installation of solar PV, solar thermal, landfill and wastewater treatment biogas capacity, and wind.

14.1.1.1 Solar Energy. JEA has installed 35 solar PV systems, totaling 220 kW, on all of the public high schools in Duval County, as well as many of JEA's facilities, and

the Jacksonville International Airport (one of the largest solar PV systems in the Southeast). To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in early 2002. This program provided cash incentives for customers to install solar PV and solar thermal systems on their homes or businesses.

JEA provided customer incentives for more than 25 solar PV systems (for a total of 98 kW) until January 2005, when the PV incentive was discontinued in favor of the solar water heating program discussed below, which provides more cost effective CO_2 reduction. In addition to the PV incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems. JEA also offers incentives for the installation of solar hot water heaters. To date, the program has resulted in over 500 incentives, or approximately 1.6 MW of capacity savings.

14.1.1.2 Landfill Gas and Biogas. Since 1997, JEA has owned and operated internal combustion engine generators fueled by landfill gas produced by the City of Jacksonville's Girvin Road landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, landfill gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility. The facility uses biogas produced by the wastewater treatment plant to fuel the 800 kW generator. JEA has received approximately 1,500 kW of landfill gas from the North Landfill, where it is used to generate power at Northside Unit 3.

In 2006, JEA signed a purchase power agreement with Landfill Energy Systems to obtain energy from a 9.6 MW landfill gas-to-energy facility at the Trail Ridge Landfill in Jacksonville. Once completed, the facility will be one of the largest landfill gas-to-energy facilities in the Southeast, providing enough renewable energy to supply electricity to approximately 2,275 homes. The projected date of completion for the facility is late 2008.

14.1.1.3 Wind. As part of its ongoing effort to utilize more sources of renewable energy, in 2005 JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits associated with this green power project. Under the wind generation agreement, JEA has agreed to purchase 10 MW of capacity from NPPD's wind generation facility for a 20 year period. In turn, NPPD will buy back the energy at specified on/off peak charges. JEA retains the rights to the environmental attributes (renewable energy credits, or RECs) and will sell the RECs unless JEA needs them to meet state or federal environmental requirements.

14.1.1.4 Biomass. JEA has issued several RFPs for renewable energy resources. The only bids that JEA has received that were cost effective were for the Trail Ridge Landfill

project (discussed previously) and a yard waste power project proposed by Evergreen. JEA attempted to negotiate a purchase power agreement with Evergreen, but the parties were unable to reach agreement on issues surrounding the yard waste fuel source, prompting JEA, in agreement with the City of Jacksonville, to suspend negotiations. JEA will continue to work with the City of Jacksonville and potential third party developers to establish a yard waste biomass project that will be beneficial to both JEA customers and the residents of Jacksonville.

In a continuing effort to obtain cost effective biomass generation, JEA is conducting a detailed feasibility study of both self-build stand-alone biomass units and the co-firing of biomass in Northside 1 and 2. The JEA self-build projects would not be eligible for the tax advantages afforded to developers, but would take advantage of JEA's low cost tax exempt financing. Northside 1 and 2 are two of JEA's least cost units, and therefore any decreases in reliability due to the co-firing alternative for Northside 1 and 2 would result in significant increases in costs to JEA's customers due to the higher costs of replacement power.

JEA also periodically receives unsolicited offers for biomass and other renewable generation. JEA evaluates the feasible unsolicited offers, but has been unable to successfully execute a contract for cost-effective biomass or other renewable generation. One notable example is the 70 MW biomass project burning E-grass that JEA executed in 2002 with Biomass Investment Group, Inc. (BIG). Even though JEA executed the purchase power agreement, BIG has not implemented the project.

14.1.1.5 Ongoing Research Efforts. Many of Florida's renewable resources, such as offshore wind, tidal, and energy crops, have potential and need additional research and development before they can become large-scale technologies. JEA's renewable energy research efforts have focused on the development of technologies through a partnership with the UNF. The following projects are currently in progress:

- JEA is working with the UNF to quantify the winter peak reductions of solar hot water systems.
- UNF, along with the University of Florida, is evaluating the effect of biodiesel fuel in a pilot-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.
- UNF is evaluating the tidal hydro-electric potential for North Florida, particularly in the Intracoastal Waterway.
- UNF is in the preliminary stage of evaluating fuel cell technology utilizing methane produced at JEA's Buckman Wastewater Treatment Facility.

- JEA, UNF, and other Florida municipal utilities have partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for wind development in Florida.
- JEA is providing solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15 acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3 year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.
- JEA is evaluating the use of biofuels such as fats, oils and greases for potential use in solid fuel units.

14.1.2 Generation Efficiency and New Natural Gas Generation

Since the late 1990s, JEA has been modernizing their natural gas/oil fleet of generating units by replacing less efficient steam units and less efficient combustion turbines with a more efficient combined cycle unit and more efficient combustion turbines. Natural gas emits approximately 70 percent of the CO_2 of No. 6 oil on a fuel basis. This program, coupled with the much greater efficiency of a combined cycle unit compared to No. 6 oil steam units and less efficient combustion turbines, results in significant reduction of CO_2 on a per MWh basis.

14.1.2.1 Prior and Ongoing Projects. As a result of its system efficiency improvement efforts, JEA has retired the following units:

- Kennedy Steam Unit 8--43 MW Summer Heavy Oil/Natural Gas.
- Kennedy Steam Unit 9--43 MW Summer Natural Gas/Heavy Oil.
- Kennedy Steam Unit 10--97 MW Summer Natural Gas/Heavy Oil.
- Kennedy Combustion Turbine Unit 4--51 MW Summer No. 2 Oil.
- Kennedy Combustion Turbine Unit 5--51 MW Summer No. 2 Oil.
- Southside Steam Unit 4--67 MW Summer Natural Gas/Heavy Oil.
- Southside Steam Unit 5--142 MW Summer Natural Gas/Heavy Oil.

The retirement of these units and their replacement with an efficient combined cycle and efficient simple cycle combustion turbines significantly reduces CO_2 emissions. JEA's replacement units include Brandy Branch Unit 1, a 7FA simple cycle combustion turbine, Brandy Branch Combined Cycle, a 2x1 7FA combined cycle, and Kennedy 7, a 7FA simple cycle combustion turbine. These units all burn natural gas as their primary fuel with ultra low sulfur diesel as a backup fuel.

JEA also is installing Kennedy Combustion Turbine Unit 8, which is an efficient 7FA simple cycle combustion turbine designed to burn natural gas as its primary fuel and

ultra low sulfur diesel as a backup. Kennedy Combustion Turbine Unit 3, an inefficient diesel fired unit, will be retired with the installation of Kennedy Combustion Turbine Unit 8 further increasing the efficiency of JEA's generating fleet. Commercial operation of Kennedy Combustion Turbine Unit 8 is scheduled for March 2009.

14.1.2.2 Greenland Energy Center. JEA is in the process of permitting the installation of Greenland Units 1 and 2, which will be efficient 7FA simple cycle combustion turbines designed to burn natural gas as their primary fuel with ultra low sulfur oil as backup. The installation of Greenland Units 1 and 2 further increases the efficiency of JEA's natural gas fueled generating fleet.

The conversion of Greenland Units 1 and 2 to combined cycle is a key part of JEA's generating unit efficiency improvement program. The combined cycle conversion allows the output of the GEC to increase over 60 percent without any increase in CO_2 emissions when compared to the simple cycle combustion turbines. The conversion of the Greenland combustion turbines to combined cycle, along with the Brandy Branch combined cycle, allows JEA to generate a large amount of energy with natural gas with its attendant lower CO_2 emissions per unit of electrical output.

The Greenland combined cycle project replaces capacity and energy that JEA planned to receive as its share in the suspended Taylor Energy Center Supercritical Pulverized Coal Unit. Replacing JEA's share of Taylor Energy Center capacity with capacity and energy from the Greenland combined cycle reduces JEA's CO_2 emissions by more than 1 million tons per year from what would have been emitted by JEA's share of Taylor Energy Center.

14.2 History of JEA RFPs for Renewable Energy

As discussed previously in this section, JEA has issued several RFPs for renewable energy sources. The following discussion summarizes the renewable energy RFP processes undertaken by JEA.

14.2.1 2004 RFP for Renewable Energy Generation

In February 2004, JEA issued a RFP for Renewable Energy Generation for 1 MW to 300 MW. The RFP covered projects for all renewable energy resources that resulted in energy being delivered to JEA's service territory. JEA received 13 acceptable responses with capacities between 1 MW and 50 MW. Several of the projects competed for the same fuel - four proposed the City of Jacksonville yard waste as fuel and three proposed the Trail Ridge landfill gas for fuel. The remaining projects were two existing biomass facilities, a proposed biomass facility in Southeast Georgia, a proposed addition to a biomass facility in west Florida, a solar PV and a wind project. Proposals were scored

based on JEA's technical and pricing criteria. The technical criteria consisted of company experience, financial capabilities, team member qualifications, impact of the project on the environment, age and location of the facility, community support and size of the project.

The pricing proposals were evaluated by calculating an incremental cost for each proposal on the basis of all-in cost in nominal 2004 dollars. This evaluation involves calculating an annual busbar cost ($/MWh) for the project using the proposed energy, capacity, and transmission wheeling costs, if applicable. Annual avoided fuel, capacity, and O&M costs were calculated. Avoided fuel expenses were calculated by modeling the proposed project as a must-run unit in JEA's production cost model. The model generates a fuel cost or savings using the proposed project in the production cost model versus JEA's base case (i.e., JEA's planned dispatch of generation units without the renewable energy project). The avoided costs for capacity, fixed, and variable O&M were based on the then-current JEA planning estimates for a natural gas fired combustion turbine. The renewable projects were given avoided capacity credit for each year even though they may not avoid capacity from being constructed given the small size of some of the proposed projects. The renewable project also receives a sulfur dioxide (SO_2) reduction credit for the SO_2 avoided by the project. The net cost (or benefit) to JEA over 10 years was calculated by adding the busbar costs, the avoided costs, and the SO_2 credit. Incremental costs for the 13 projects ranged from $6/MWh below to $285/MWh above the base case and a $5 million net savings to $103 million net additional cost to JEA over 10 years.

A final score was calculated for all proposals and Landfill Energy Systems and Evergreen Paper and Energy received the top scores. JEA entered into negotiations with Landfill Energy Systems (9.6 MW) on the Trail Ridge landfill gas and signed a PPA in May 2006. The project is expected to be operational by late 2008. JEA started negotiations with Evergreen Paper and Energy (13 MW using the City's yard waste) but these negotiations were cancelled by JEA in July 2007 after consultation with the City of Jacksonville on the City of Jacksonville-Evergreen yard waste fuel contract. The City of Jacksonville concluded that Evergreen, after several years of negotiation, had failed to deliver an executed contract and the bonding requirement. In addition, Evergreen had not prepared the site to take the yard waste within the timeframe proposed by the City of Jacksonville.

14.2.2 2007 RFP for Renewable Energy Generation

In 2007, JEA decided to again issue a request for renewable energy proposals. In order to allow more creativity and flexibility in the solicitation process, JEA started the

process by soliciting letters of interest from companies interested in developing renewable energy projects for JEA. The solicitation was widely distributed, encouraged creativity in power purchase structures, included all renewable energy resources, and allowed project sizes up to 300 MW. Of the 19 responses received, 13 were for biomass projects, and the remaining were tidal, landfill gas, and digester gas projects as discussed below:

One of the projects was proposed by Trail Ridge LLC to generate energy from an additional 9.6 MW of landfill gas at the Trail Ridge landfill. JEA and Trail Ridge LLC continue to evaluate this proposal.

Two of the projects proposed a landfill gas technology but did not identify the landfill gas site that would be used. Since JEA was in negotiations with Trail Ridge LLC on the Trail Ridge landfill, JEA did not believe there was additional landfill opportunities in the JEA service area and did not pursue these technology-only proposals.

One letter of interest was from another Florida municipal utility indicating their interest in working with JEA on development of joint renewable energy projects. Specific projects were not mentioned. Because of the large size and risk of some renewable energy projects, JEA may consider working with other Florida utilities to develop joint projects similar to how several fossil fuel plants have been developed.

One letter of interest was an anaerobic digester using agricultural waste (1 MW). JEA was interested in pursuing this project but further discussion with the developer indicated that a fuel source had not been identified. JEA invited the proposer to contact JEA to begin project negotiations when a fuel source and location had been identified. The proposer has not contacted JEA since the initial discussion.

The final project was a 100 kW tidal demonstration project in the Intracoastal Waterway. JEA started negotiations with Integral Aqua Systems (IAS) on a PPA. However, the capital investor withdrew from this project in May 2007 and IAS has not been able to restructure the project although they did test a prototype hydro turbine in the Intracoastal Waterway in August 2007.

Because of the numerous biomass proposals that were received from the Letter of Interest, JEA issued a RFP for the biomass respondents on August 13, 2007. Proposals were due on September 21, 2007 (extended to September 28, 2007). JEA received four acceptable proposals and rejected five proposals because they did not meet the screening criteria. As part of the screening criteria, JEA required the respondents to complete all the RFP sections, propose a renewable energy resource, use proven technology, and have an availability factor of at least 85 percent. The availability factor is the percent of time a unit is capable of service if adequate resources are available. This factor is used in the purchase contracts as a default mechanism to ensure that the facility is capable of

operation during the terms of the contract. Of the five rejected projects, three did not meet the mandatory requirements of the RFP and two of the projects were not received by the due date.

The remaining four acceptable proposals, ranging from 9 MW to 120 MW, were scored based on JEA's technical and pricing scoring criteria. These proposals were evaluated on the following technical aspects: technical viability, fuel availability and security, team experience, financial stability, project financing, site control, and performance guarantees. Each of the four projects proposed viable technology and demonstrated team experience with utility-scale generation projects. However, none of the projects (with the exception of one project which was an existing operating biomass facility) could demonstrate a commitment on the fuel source or site nor did they demonstrate project financing by providing commitment letters from third-party institutions.

The pricing proposals were evaluated by calculating an incremental cost for each proposal on the basis of all-in cost in nominal 2007 dollars. The incremental cost is the difference between the project's cost of power relative to JEA's existing system and base case plan. The avoided unit was a new natural gas-fired combustion turbine and the process is similar to the pricing evaluation used in the 2004 RFP process and described previously in this section. In addition, biomass projects were given credit for reductions in sulfur dioxide and carbon credits. Incremental costs for the four projects ranged from $10/MWh to $59/MWh above base case and $51 million to $306 million in net additional cost to JEA over 20 years.

JEA chose not to negotiate with any of the proposers because of the high costs and the inability of the proposers to demonstrate fuel or site availability or project financing.

14.3 Renewable Energy (Solar and Wind) RFP

Most recently, JEA issued a RFP for renewable energy, in particular solar and wind resources (Solar and Wind RFP), on March 17, 2008. Responses to the RFP were due on May 16, 2008. The RFP requested projects greater than 1 MW that generate electricity from solar (including PV or thermal electric) or wind. Solar projects greater than 250 kW at a JEA commercial customer's site were also included if the aggregate installation is greater than 1 MW. The RFP also requested proposals for solar PV equipment (panels and inverters) for installation by JEA. These proposals were scored on technical and economic factors very similar to the 2004 and 2007 RFP processes.

14.3.1 Summary of RFP Responses

JEA received ten solar PV proposals and two proposals for solar PV panels (equipment purchase only). JEA did not receive any proposals for solar thermal electric or wind projects. Of the ten solar PV proposals received, eight were for ground-mounted systems from 8 MW to 12 MW in size and two were for distributed roof-top mounted systems from 2 MW to 4 MW in total size. All proposals submitted were for projects to be developed in the JEA service area.

14.3.2 Solar and Wind RFP Response Evaluation Process

The proposals were all scored based on JEA's technical and pricing factors. The technical areas, which were scored on a point scale of 1-10, evaluated the company qualifications, the technical project, and the readiness of the project. Specifically, these factors included: qualifications of the company, financial strength, technical feasibility, ease of interconnection, barriers to project site, other ancillary benefits of the project, level of development of financing plan, level of project development completed, status of major equipment, interconnection design maturity, level of resource assessment performed, level of site control, level of site infrastructure, status of obtaining permits, and project schedule. Questions were submitted to all Bidders and responses were due on June 13, 2008. Projects were ranked based on the technical score. MMA Renewable Ventures, Sun Power, and Rocky Mountain Energy Group submitted the top three technical scoring projects.

The pricing proposals were first evaluated based on their levelized price with levelized costs ranging from approximately $186/MWh to approximately $343/MWh. All of the solar proposals reflect the assumed extension of the benefits of the existing Solar Incentive Tax Credits. Finally, the pricing proposals were evaluated by calculating an incremental cost for each proposal on the basis of all-in cost in nominal 2008 dollars. The incremental cost is the difference between the project's cost of power relative to JEA's existing system and base case plan, with the GEC combined cycle conversion representing the avoided unit. The incremental costs of the proposals ranged from approximately $10/MWh to approximately $150/MWh over a 20 year period. JEA is pursuing negotiations with the company that provided the lowest cost solar PV proposal. That proposal has been carried forward to the detailed economic evaluations as described in Section 17.0 of this Application.

16.0 Evaluation Methodology

Detailed economic analyses were performed to evaluate the economics of the GEC combined cycle conversion as part of JEA's least-cost expansion plan to satisfy forecast capacity requirements throughout the 20 year evaluation period considered in this Application. This section discusses the evaluation methodology used in the economic analyses. The results of the analyses are presented in Section 17.0.

16.1 Expansion Planning Simulation

Optimal generation expansion planning and production cost modeling was performed using STRATEGIST, a computer software system licensed through Ventyx (which recently acquired NewEnergy Associates, LLC, the original developer of STRATEGIST). STRATEGIST is a proven and effective modeling program for optimal generation expansion planning and production cost modeling. According to Ventyx, over 50 utilities now use STRATEGIST for integrated corporate strategic planning, including least-cost expansion planning.

STRATEGIST includes an automatic expansion planning module that can determine the optimal balanced demand and supply plan for a utility system under a prescribed set of constraints and assumptions. STRATEGIST evaluates all combinations of generating unit alternatives and purchase power options in conjunction with existing capacity resources to satisfy forecast capacity requirements while maintaining user-defined reliability criteria. STRATEGIST simulates the hourly operation of a utility system to determine the cost and reliability effects of adding resources to the system or modifying the load through DSM programs. The simulation of the utility system operation is accomplished using dynamic programming, a mathematical technique useful for making a sequence of interrelated decisions for determining the combination of decisions that optimizes the desired outcome. In this Application, all expansion plans were analyzed over a 20 year period from 2008 through 2027.

16.2 Fuel and CO_2 Emissions Allowance Price Forecasts

Section 7.0 presents the fuel and CO_2 emissions allowance price forecasts used throughout this Application, including price forecasts for various sensitivity cases. The fuel and CO_2 emissions allowance price forecasts presented in Section 7.0 were developed in constant 2006 dollars. For purposes of the economic analyses presented throughout this Application, the constant 2006 dollars price projections were converted to nominal dollars using the 2.5 percent general inflation rate discussed in Section 4.0.

For sensitivity analyses that consider the potential regulation of emissions of CO_2, the emissions rates for every existing generating resource, as well as new capacity additions being considered, were included in the dispatching decisions made by STRATEGIST. Because each generating unit, whether existing or being considered as a supply-side alternative, has a unique emissions profile, the annual emissions allowance costs vary for each unit. Including emissions allowance costs in this manner allows the analysis to take into consideration the "all-in" production costs for each unit, including fuel costs, nonfuel variable costs, and costs associated with emissions of CO_2.

16.3 Firm Natural Gas Transportation Costs

As discussed in Section 8.0, the GEC site will receive natural gas from both Southern Natural Gas and Florida Gas Transmission Company through the SeaCoast Pipeline to the GEC Lateral for delivery to GEC. JEA is expected to have sufficient firm natural gas transportation capacity to reliably serve its natural gas fired generating units, including the GEC combined cycle, based on current contractual capacity as well as planned future increases to firm natural gas transportation capacity. For the 1x1 7FA combined cycle alternative, the economic analysis assumed 37,990 MBtu/day of incremental firm natural gas transportation capacity at $1.28/MBtu. Firm natural gas transportation for simple cycle combustion turbine alternatives is not included; however, Interruptible Transportation Service at the tariff rate of $0.598/MBtu is included for simple cycle combustion turbine alternatives.

16.4 New Nuclear Generating Units

In March 2008, the JEA Board of Directors approved the pursuit of nuclear energy partnerships with the goal of providing 10 percent of JEA's energy requirements from nuclear sources. Adding power from nuclear sources to JEA's portfolio is part of a resource strategy resulting in less dependence upon fossil fuels and a reduction in CO_2 emissions.

In June 2008, JEA entered into a PPA with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4, which are proposed new nuclear units to be constructed at the existing Plant Vogtle. Under this PPA, JEA will be entitled to a total of 206 MW of firm capacity from the proposed units. After accounting for transmission losses, JEA is anticipated to receive a total of 200 MW of net firm capacity from the proposed units. For purposes of the analyses presented throughout this Application, it has been assumed that 100 MW (net) of capacity is available to JEA beginning January 1, 2016 from Vogtle Unit 3, and an additional 100 MW (net) is available to JEA beginning January 1, 2017 from Vogtle Unit 4. The

costs associated with this PPA are confidential, and although the costs have been included in the analyses they are not presented separately in order to maintain confidentiality.

16.5 DSM Portfolio

As discussed in Section 15.0, JEA has developed a DSM portfolio consisting of new programs which address all customer classes. The projected annual seasonal demand reductions, net energy for load reductions, and costs for each program included in JEA's new DSM portfolio are summarized in Subsection 15.2.6. Several of the economic evaluations summarized in Section 17.0 include analysis of various scenarios that reflect the demand and energy savings, as well as corresponding annual costs, for the new DSM portfolio.

In order to accurately reflect the on-peak seasonal demand reductions projected to result from the energy efficiency programs included in JEA's new DSM portfolio in the economic evaluations discussed in Section 17.0, adjustments were made to the demand reductions presented in Tables 15-8 and 15-9 to account for meteorological data specific to the Jacksonville area.

16.6 Cumulative Present Worth Cost Analysis

Economic comparisons between competing expansion plans were developed on a CPWC basis. The CPWC calculation accounts for annual system costs (fuel, energy, and nonfuel variable O&M for existing resources and new unit additions, as well as fixed O&M and levelized capital costs for new unit additions) for each year of the expansion planning period and discounts each back to 2008 using the 5.0 percent present worth discount rate discussed in Section 4.0. These annual present-worth costs were then totaled over the 2008 through 2027 period to calculate the total CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various expansion plans, and the plan with the lowest CPWC is considered the least-cost expansion plan for any given case considered.

17.0 Economic Evaluation

Detailed economic analyses were performed to evaluate the cost-effectiveness of the GEC combined cycle conversion to help satisfy forecast capacity and energy requirements. Numerous evaluations were conducted in order to consider reference case fuel price and load forecasts as well as sensitivity cases related to fuel prices, load forecasts, capital costs, and regulation of CO_2 emissions. Additionally, the cost-effectiveness of the GEC combined cycle conversion was evaluated under several scenarios involving new renewable energy resources that may be available to JEA and reductions in coincident peak demand resulting from the implementation of the new DSM portfolio, both of which have been described in previous sections of this Application. The remainder of this section describes each of the scenarios evaluated and presents the corresponding CPWC for expansion plans with and without the GEC combined cycle conversion in June 2012.

The economic analyses described herein compare the economics of the least-cost expansion plan including the GEC combined cycle conversion in June 2012 versus the economics of the least-cost expansion plan that does not include the conversion in June 2012. For comparison purposes, the GEC combined cycle conversion in June 2012 was treated as a committed resource, and the optimal expansion model, STRATEGIST, was allowed to select among the supply-side alternatives presented in Section 13.0 to develop the least-cost expansion plan to meet capacity requirements beyond 2012. For cases in which the GEC combined cycle conversion was not treated as a committed resource in 2012, STRATEGIST was allowed to select among the same supply-side alternatives presented in Section 13.0 to meet capacity requirements.

17.1 Overview of Evaluation Scenarios

The economics of the GEC combined cycle conversion were considered for several cases among four distinct scenarios as outlined below. The results of the economic analyses for each case considered for each scenario are presented in subsequent subsections.

17.1.1 Scenario 1 – Conventional Expansion Scenario

The *Conventional Expansion Scenario* considers the addition of only conventional (fossil fueled) generating resources, with the exception of the new nuclear generating resources discussed in Section 16.4. As described previously in this section, the economics of an expansion plan including the GEC combined cycle conversion as a committed resource in June 2012 were evaluated against the economics of an expansion

plan that does not include the GEC combined cycle conversion. The Scenario 1 evaluations were performed for several sensitivity cases described as follows.

17.1.1.1 Reference Case. The *Reference Case* considers the reference case fuel price projections included in Section 7.3 and base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in the reference case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.2 High Fuel Price Case. The *High Fuel Price Case* considers the high fuel price projections presented in Section 7.5. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.3 Low Fuel Price Case. The *Low Fuel Price Case* considers the low fuel price projections presented in Section 7.5. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.4 High Load Case. The *High Load Case* considers the high load forecast presented in Section 5.0. Fuel price projections used in this case correspond to the reference case projections included in Section 7.3. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.5 Low Load Case. The *Low Load Case* considers the low load forecast presented in Section 5.0. Fuel price projections used in this case correspond to the reference case projections included in Section 7.3. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.6 High Capital Case. The *High Capital Case* reflects an increase of 20 percent in the capital cost of the GEC combined cycle conversion presented in Section 9.3 as well as the capital costs of all other generating unit alternatives presented in Section 13.0. Fuel price projections used in this case correspond to the reference case projections included in Section 7.3. The base case load forecast presented in Section 5.0 was used in the high capital cost case.

17.1.1.7 Regulated CO_2 Case. The *Regulated CO_2 Case* considers the fuel and CO_2 emissions allowance price projections corresponding to the EIA's analysis of S.2191 as presented in Section 7.8. The CO_2 emissions allowance prices used in this case correspond to the *S.2191 Core* analysis. Capacity requirements used in this case

correspond to the base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.8 High Fuel with Regulated CO_2 Case. The *High Fuel with Regulated CO_2 Case* considers the high fuel price projections in Section 7.5 and also considers the CO_2 emissions allowance price projections corresponding to the EIA's analysis of S.2191. The CO_2 emissions allowance prices used in this case correspond to the *S.2191 Core* analysis. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.9 High Regulated CO_2 Case. The *High Regulated CO_2 Case* considers CO_2 emissions allowance price projections based on the EIA's analysis of S.2191. The CO_2 emissions allowance price projections used in the *High Regulated CO_2 Case* correspond to the EIA's *S.2191 Limited Offsets/No International Case.* This analysis was selected because the resulting CO_2 emissions allowance prices are the highest of the S.2191 scenarios evaluated by the EIA.

The EIA analysis of S.2191 presented CO_2 emissions allowance price projections in 2006 dollars per metric ton beginning in 2012 and extending through 2030. For analysis purposes, the 2006 dollars per metric ton price projections were converted to 2006 dollars per short ton. These prices were then converted to nominal dollars using the 2.5 percent general inflation rate presented in Section 4.1. The resulting CO_2 emissions allowance price projections for 2012 through 2027 that were used in the *High Regulated CO_2 Case* are presented in Table 17-1. For comparison purposes, Table 17-1 also presents the CO_2 emissions allowance price projections used in the *Regulated CO_2 Case*, which were based on the EIA S.2191 Core case projections presented in Section 7.8. The fuel prices for this case correspond to the fuel prices presented in the EIA's *S.2191 Limited Offsets/No International Case.*

This scenario provides an indication of the potential effect of a higher-cost CO_2 regulatory regime than that assumed in the *Regulated CO_2 Case* described above. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

Table 17-1
Projected CO_2 Emission Allowance Prices
EIA S.2191 Limited Offsets/ No International Scenario and
EIA S.2191 Core
(Nominal $/Ton)

Year	Limited Offsets/ No International	Core
2012	53.26	17.75
2013	50.95	19.54
2014	55.09	21.52
2015	60.65	23.69
2016	66.77	26.08
2017	73.50	28.71
2018	80.91	31.60
2019	89.07	34.79
2020	98.06	38.29
2021	107.94	42.16
2022	118.83	46.41
2023	130.81	51.10
2024	144.01	56.24
2025	158.53	61.92
2026	174.52	68.17
2027	192.12	75.03

17.1.2 Scenario 2 – Renewable Expansion Scenario

The *Renewable Expansion Scenario* considers the addition of the new renewable energy resources being considered by JEA (including biomass and solar PV) as discussed in Section 14.0 in addition to conventional generating resources and the new nuclear generating resources. As with Scenario 1, the *Renewables Expansion Scenario* evaluates the economics of an expansion plan including the GEC combined cycle conversion as a committed resource in June 2012 against the economics of an expansion plan that does not include the GEC combined cycle conversion. Scenario 2 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Subsection 17.1.1.

The *Renewables Expansion Scenario* assumes the installation of a 35 MW biomass unit with a commercial operation date of January 1, 2012 and the installation of 5 MW and 10 MW of solar photovoltaics with commercial operation dates of January 1, 2010 and July 1, 2010, respectively. The characteristics of these renewable resources are more fully described in Section 14.0.

17.1.3 Scenario 3 – DSM Expansion Scenario

The *DSM Expansion Scenario* considers the addition of the new DSM portfolio being evaluated by JEA as discussed in Section 15.2 in addition to conventional generating resources and the new nuclear generating resources. Existing conservation and DSM programs as discussed in Section 15.1 are embedded in JEA's base case load forecast. As with Scenario 1, the *DSM Expansion Scenario* evaluates the economics of an expansion plan including the GEC combined cycle conversion as a committed resource in June 2012 against the economics of an expansion plan that does not include the GEC combined cycle conversion. Scenario 3 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Section 17.1.1.

As presented in Section 12.0, JEA's 2012 summer capacity requirements are 167 MW. With the *DSM Expansion Scenario*, JEA's 2012 summer capacity requirements are reduced to 41 MW.

17.1.4 Scenario 4 – Renewables and DSM Expansion Scenario

The *Renewables and DSM Expansion Scenario* considers the addition of both the new renewable energy resources and the new DSM portfolio being evaluated (as considered in Scenarios 3 and 4, respectively) in addition to conventional generating resources and the new nuclear generating resources. As with the other scenarios, the *Renewables and DSM Expansion Scenario* evaluates the economics of an expansion plan including the GEC combined cycle conversion as a committed resource in June 2012 against the economics of an expansion plan that does not include the GEC combined cycle conversion. Scenario 4 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Subsection 17.1.1.

17.2 Results of the Economic Evaluations

CPWC evaluations were performed for the various scenarios and cases within each of the scenarios as discussed previously. The CPWC associated with each of the expansion plans for each of the cases and scenarios are presented in this section.

17.2.1 CPWC Results of Scenario 1 Evaluations

The results of the CPWC evaluations for Scenario 1 are presented in Table 17-2. Analysis of the CPWC associated with each of the cases presented in Table 17-2 indicates that expansion plans including the GEC combined cycle conversion in June 2012 are the most cost-effective expansion plans for all cases considered.

17.2.2 CPWC Results of Scenario 2 Evaluations

The results of the CPWC evaluations for Scenario 2 are presented in Table 17-3. Analysis of the CPWC associated with both of the cases presented in Table 17-3 indicates that expansion plans including the new renewable resources being considered by JEA as well as the GEC combined cycle conversion in June 2012 are the most cost-effective expansion plans for the two cases considered.

17.2.3 CPWC Results of Scenario 3 Evaluations

The results of the CPWC evaluations for Scenario 3 are presented in Table 17-4. Analysis of the CPWC associated with both of the cases presented in Table 17-4 indicates that expansion plans including the new DSM portfolio being considered by JEA as well as the GEC combined cycle conversion in June 2012 are the most cost-effective expansion plans for the two cases considered.

17.2.4 CPWC Results of Scenario 4 Evaluations

The results of the CPWC evaluations for Scenario 4 are presented in Table 17-5. Analysis of the CPWC associated with both of the cases presented in Table 17-5 indicates that expansion plans including the new renewable resources and DSM portfolio being considered by JEA as well as the GEC combined cycle conversion in June 2012 are the most cost-effective expansion plans for the two cases considered.

17.3 Conclusions

The CPWC results summarized throughout this section demonstrate that the addition GEC combined cycle conversion in June 2012 is included in the least cost expansion plan for each of the different scenarios and cases evaluated. When combined with both the new renewable resources and the new DSM portfolio being considered by JEA, the GEC combined cycle conversion provides the most cost-effective resource addition to the JEA system to serve its forecast capacity requirements.

Table 17-2
CPWC Summaries for Scenario 1
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	11,054,686	11,177,317	122,631
High Fuel	11,528,352	11,637,336	108,984
Low Fuel	10,501,774	10,598,528	96,754
High Load	12,495,350	12,638,740	143,390
Low Load	10,001,095	10,058,137	57,042
High Capital Cost	11,183,032	11,295,586	112,554
Regulated CO_2	15,861,139	16,028,653	167,514
High Fuel with Regulated CO_2	16,681,496	16,840,280	158,784
High Regulated CO_2	23,814,086	24,215,124	401,038

Table 17-3
CPWC Summaries for Scenario 2
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	11,228,052	11,345,073	117,021
Regulated CO_2	15,999,936	16,154,956	155,020

Table 17-4
CPWC Summaries for Scenario 3
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	10,803,625	10,938,494	134,869
Regulated CO_2	15,581,425	15,767,659	186,234

Table 17-5
CPWC Summaries for Scenario 4
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	10,987,500	11,058,147	70,648
Regulated CO_2	15,724,591	15,851,309	126,719

18.0 Consequences of Delay

As demonstrated by the economic evaluations presented in this Application, the GEC combined cycle conversion in 2012 represents the most cost-effective alternative to satisfy JEA's forecast capacity requirements and continue to reliably serve its customers. The consequences of delaying the commercial operation of the GEC combined cycle conversion are significant from an economic and reliability standpoint for JEA. This section describes the negative consequences of delaying the GEC combined cycle conversion.

18.1 Economic Consequences

If the commercial operation of the GEC combined cycle conversion is delayed, JEA would be required to replace the capacity and energy that would otherwise be provided by a new, efficient combined cycle generating unit. The economic consequence of a one year delay in the commercial operation of the GEC combined cycle conversion (from June 2012 until June 2013) is approximately $36.7 million in CPWC, based on *Reference Case* assumptions.

18.2 Reliability Consequences

As shown in Section 12.0, JEA will require a significant amount of capacity in the summer of 2012 to maintain its reserve margin requirements. If the conversion of GEC to combined cycle is delayed and no additional generating capacity is installed to meet JEA's forecast capacity requirements by 2012, JEA's summer reserve margin will fall to approximately 9.6 percent (or 167 MW less than JEA's 15 percent reserve margin criterion) in 2012. The capacity deficit in the summer of 2012 represents a significant portion of the capacity that will be provided by the conversion of GEC to combined cycle. With a reserve margin below 15 percent in 2012, JEA's system will be exposed to decreased reliability and increased costs.