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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130198-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: PETITION FOR PRUDENCE DETERMINATION REGARDING NEW PIPELINE SYSTEM

DIRECT TESTIMONY & EXHIBITS OF:

JUAN E. ENJAMIO

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR PRUDENCE DETERMINATION

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Juan E. Enjamio. My business address is Florida Power & Light Company, 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL") as Supervisor of Integrated Analysis in the Resource Assessment & Planning Department ("RAP").

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Florida in 1979 with a Bachelor of Science degree in Electrical Engineering. I joined FPL in 1980 as a Distribution Engineer. Since my initial assignment in FPL, I have held positions as a Transmission System Planner, Power System Control Center Engineer, Bulk Power Markets Engineer, Supervisor of Transmission Planning and Supervisor of Supply and Demand Analysis. In 2004, I became Supervisor of Integrated Analysis – Resource Planning.

Q. Please describe your duties and responsibilities in your current position.

A. In my current position as Supervisor of Integrated Analysis, I am responsible for supervision and coordination of economic analysis of alternatives to meet FPL's resource needs and maintain system reliability.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits which are attached to my direct testimony:

JEE-1 Generation Resource Plans

JEE-2 Gas Price Forecasts

JEE-3 Financial Assumptions

JEE-4 Economic Results

JEE-5 Economic Results- Four Combinations

JEE-6 Economic Results- Gas Price Sensitivities

JEE-7 Economic Results of Non-Compliant Bid

JEE-8 Projection of Approximate Bill Impacts

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

A. The purpose of my testimony is twofold: first, to present FPL's projection of the amount of incremental natural gas transportation that will be needed to fuel FPL's generation fleet and how FPL made that determination, and, second, to present the results of the comparative economic evaluation of the gas transportation proposals received in response to FPL's Request for Proposals ("RFP"). Based upon the economic evaluation I present, I conclude that Combined Project 1 is the most cost-effective gas transportation alternative.

Q. Please summarize your testimony.

A. In 2002, FPL's energy generated from gas was 33.1% of total energy generated. In 2012, FPL's energy generated from gas was 72.6%, an increase of 119% since 2002. This dramatic increase in FPL's use of natural gas has been driven by recent economically driven decisions to meet the need for new generation capacity by building new highly efficient gas-burning combined cycle units as well as by modernizing many of FPL's old and inefficient steam units. FPL expects that its reliance on cost-effective natural gas-fired generation will continue in the near future. In fact, FPL plans to add 8,143 MW of additional gas-fired combined cycle units between 2013 and 2030.

FPL forecasts that the FPL system will require 405 million cubic feet per day ("MMcf/d") of incremental firm gas transportation capacity in 2017. This incremental need will grow to 575 MMcf/d in 2020 and 870 MMcf/d by 2030. As described further in the testimony of FPL witness Morley, these projections of incremental gas transportation needed were established using a risk-adjusted load forecast based upon historic differences between FPL's actual and forecasted summer peak and net energy for load. Use of this risk-adjusted load forecast increases the likelihood that FPL will have adequate gas transportation to meet its future requirements. The use of a risk-adjusted load forecast as a reserve measure for purposes of ensuring adequate gas supply is similar in concept to using a 20% reserve margin as is done for generation resource planning.

FPL issued an RFP to solicit bids to meet the projected future needs for additional gas transportation. The overall project is now known as the new

Pipeline System. The RFP requested separate bids for both an Upstream Pipeline Project and a Downstream Pipeline Project. After completing the evaluation of proposals, FPL adopted new terminology to further clarify the distinction between the two pipeline projects. For the purpose of this proceeding the Upstream Project and Downstream Project are identified as the "Northern Pipeline Project" and "Southern Pipeline Project," respectively. The RFP evaluation team reviewed the proposed alternatives and developed every possible combination of Northern and Southern Pipeline Projects ("Combined Projects"). Twelve such Combined Projects, which represent all combinations of four proposals for the Northern Pipeline Proposals and three proposals for the Southern Pipeline Project, were developed and forwarded to RAP which then conducted a blind (without knowledge of the bidders' identities) economic evaluation. The economics of these twelve Combined Projects were compared both under a Base Resource Plan and under a Four Year Nuclear Delay Resource Plan and are presented in Exhibit JEE-4.

Since the three proposals for the Southern Pipeline Project consisted of bids from the same company, the number of Combined Projects useful in the determination of the best Pipeline System alternative can be narrowed to four combinations. Each of these four Combined Projects includes one of the Northern Pipeline Project Proposals, paired with the best proposal for the Southern Pipeline Project. The comparison of these four Combined Projects shows that Combined Project 1 results in the lowest cost to FPL customers with CPVRR savings of $580 million, $937 million and $1,356 million CPVRR, respectively, when compared to the other three Northern Pipeline Project Proposals, under the Base Resource Plan. Similarly, Combined Project 1 results in CPVRR savings of $513 million, $919 million, and $1,289 million, respectively, when compared to the other three Northern Pipeline Project Proposals, under the Four Year Nuclear Delay Resource Plan. These results are presented in Exhibit JEE-5. Based on its large economic advantage, I conclude that Combined Project 1 is the best alternative to meet the future gas requirements of FPL's customers.

II. NEED FOR ADDITIONAL GAS TRANSPORTATION CAPACITY

Q. What has been the trend in FPL's historical use of natural gas?

A. In 2002, 33.1% of FPL's total energy generated was produced using natural gas. In 2012 the amount of FPL's total energy generated from gas was 72.6%, an increase of 119% since 2002.

Q. What has driven the increase in FPL's historical use of natural gas?

A. The dramatic increase in FPL's use of natural gas has been driven by recent economics-driven decisions to meet the need for new generation capacity by building new highly efficient gas-burning combined cycle units as well as by modernizing many of FPL's old and inefficient steam units. These decisions were reviewed and approved by the Commission. In total, 10,751 MW of new gas-fired units were added between 2002 and 2012.

Q. What benefits have FPL customers received from the addition of this highly efficient gas-fired generation capacity?

A. The addition of 10,751 MW of new highly efficient gas-fired generation capacity combined with generally low natural gas price over the last ten years have resulted in both significantly lower costs to our customers and a cleaner generation fleet with much lower air emissions. FPL has estimated that from 2001 to 2012 FPL customers have saved approximately $6 billion nominal due to lower fuel costs. These savings in lower fuel costs reflect the higher efficiency of FPL's generation fleet, the switch from higher cost oil to natural gas, as well as lower gas prices. In addition, the emission rates for FPL's fossil-fueled generation fleet have decreased dramatically as a result of the addition of these gas fired units. Since 2002, the emission rates for FPL's fossil-fueled generation fleet have declined 94% for SO_2, 81% for NO_2, and 31% for CO_2.

Q. Does FPL intend to bring additional gas-fired generation capacity into its fleet?

A. Yes. In addition to placing the Cape Canaveral Next Generation Clean Energy Center (1,210 MW) into service in April 2013, FPL has already obtained the Commission's approval to build an additional 2,489 MW of new combined cycle capacity: the Riviera Beach Next Generation Clean Energy Center (1,212 MW) will be in-service in 2014; and the Port Everglades Next Generation Clean Energy Center (1,277 MW) will be in-service in 2016. This new combined cycle capacity is needed to meet new load and to replace aging, less efficient, oil and gas fired generation capacity.

Moreover, after constructing the three units just described, as well as 2,200 MW of new nuclear unit capacity at Turkey Point in 2022 and 2023, FPL projects that it will need to add another 4,444 MW of generation by 2030. Total gas generation projected to be added between 2013 and 2030 totals 8,143 MW. Currently available information indicates that gas-fired combined cycle units will continue to be the least-cost, non-nuclear alternative for meeting that need.

Q Please address how FPL has assessed its need for 8,143 MW of gas-fired generation by 2030.

A. As part of its regular resource planning process, FPL assesses its future generation resource needs. In performing its assessment, FPL employs two reliability criteria: Loss of Load Probability ("LOLP") of 0.1 days per year and a 20% Reserve Margin. For many years now, the 20% Reserve Margin has been driving FPL's resource need determination. Under the 20% Reserve Margin approach, FPL projects the resources necessary to meet its forecasted peak load while accounting for the potential for load forecast error as well as for unplanned unit outages.

Once FPL's resource needs are assessed, then FPL performs an analysis to choose among available types of technologies to determine which combination of resources, including DSM, is most cost-effective. It is this process that FPL has used to determine that it will need to add 8,143 MW of gas-fired capacity between 2013 and 2030.

Q. Why does FPL believe that gas-fired generation will continue to be the generation of choice in the foreseeable future?

A. While FPL evaluates a wide variety of resource alternatives within its resource planning process, after the addition of the Turkey Point nuclear units, natural gas-fired generation continues to emerge as the most attractive non-nuclear generation resource choice. This is true for both economic and practical reasons.

Under current planning assumptions, natural gas-fired combined cycle units consistently emerge as the most cost-effective, non-nuclear generation option addition after the planned Turkey Point nuclear unit additions. FPL has significant experience with this technology, and it is projected to continue to have a lower overall cost than other fossil generation alternatives. Moreover, it enjoys a lower cost than renewable generation alternatives, including wind and solar.

From a practical perspective, there are other factors that limit the potential of adding other types of technologies to FPL's system. Even if coal were an economically superior option, which it is not, attempting to permit a coal plant in Florida is not practical or feasible in the foreseeable future. Plus, there is great uncertainty about the cost of greenhouse gas emission controls for new coal technologies. The State of Florida has had a policy in place for over thirty years discouraging reliance on oil-fired generation, and its costs and emissions also make it an impractical option. Analysis results clearly indicate that renewable options, such as wind and solar photovoltaics, are more expensive for FPL to build than combined cycle natural gas facilities and these renewable resources are treated as non-firm capacity options. Planning for additional nuclear development after Turkey Point units 6 and 7 is also impractical while these two nuclear units are under development. While additional nuclear capacity would improve fuel diversity and reduce FPL's reliance on natural gas, it would be challenging to finance on top of other on-going nuclear development, and it would present political challenges as well.

Q. What is FPL's current generation resource plan?

A. FPL's generation resource plan consists of the following generation resources:

- Cape Canaveral Next Generation Clean Energy Center (1,210 MW), placed in-service April 2013
- Riviera Beach Next Generation Clean Energy Center (1,212 MW), in-service June 2014
- Port Everglades Next Generation Clean Energy Center (1,277 MW), in-service June 2016
- Turkey Point 6 Nuclear Unit (1,100 MW) in-service June 2022
- Turkey Point 7 Nuclear Unit (1,100 MW) in-service June 2023

After the planned 2023 addition of Turkey Point 7, the resource plan currently projects that gas-fired combined cycle units will be used to meet reserve margin requirements. This resource plan is shown in Exhibit JEE-1.

Q. Does the addition of a third pipeline represent an unexpected cost to FPL's customers?

A. No. FPL's strategy to rely on gas-fired generation to meet most of its future generation needs has been based on the recognition that a significant amount of incremental gas transportation will be required over the foreseeable future. All of FPL's recent resource planning decisions, resulting from studies comparing gas generation options such as an analysis of unit retirements, unit modernizations and new combined cycle units, have reflected this assumption. The objective of FPL's RFP for pipeline capacity is to ensure that FPL secures the required amount of incremental gas transportation to meet this need at the lowest cost to its customers, while also enhancing the reliability of its gas supply network.

III. DETERMINATION OF THE AMOUNT OF INCREMENTAL GAS TRANSPORTATION CAPACITY

Q. Earlier you testified that FPL projects it will need an additional 8,143 MW of natural gas generation on its system between 2013 and 2030. How much natural gas transportation capacity would be needed for such generation?

A. Based on FPL's plans to meet future needs largely with those natural gas unit additions, the FPL system will require 405 MMcf/d of incremental firm gas transportation capacity in 2017. This incremental need will grow to 575 MMcf/d in 2020 and about 870 MMcf/d by 2030.

Q. Please explain how FPL developed these projections of incremental natural gas need.

A. In planning both its generation and transmission resources, FPL uses reliability criteria or standards to protect its customers against risks that could affect the reliability of their service. FPL followed a similar approach in assessing the amount of gas transportation capacity needed to meet projected load and unit fuel needs.

As I noted earlier, the reliability criterion that has been driving FPL's generation planning need in recent years has been the use of a 20% reserve margin. Planning to maintain a 20% reserve margin above projected peak load, as a minimum, protects customers from a host of potential contingencies: actual load in excess of forecasted load, unit outages, temporary unit de-ratings, lower-than-projected load reductions from DSM and transmission line outages being the primary risks. For instance, if at the time of system peak a 1,000 MW nuclear unit trips and hot weather results in an actual peak that is 1,500 MW higher than forecasted, having a reserve margin of at least 20% protects customers against service interruptions.

Similarly, when FPL conducts transmission planning, it also employs reliability protection measures. The planning for the adequacy of the electrical transmission system is based on the concept of stressing the system in order to assure its reliability. The need to provide sufficient electrical transmission capacity and redundancy to account for the loss of various components under stress conditions results in a system that is not only able to withstand facility outages but also has an implicit capacity to deal, from a transmission perspective, with higher than projected loads.

Just as FPL needs to have sufficient generation resources to provide an adequate reserve margin and a transmission system that can overcome multiple contingencies to assure customer reliability, FPL also needs to have natural gas transportation reserves available to meet customer needs even under unexpected conditions. It does customers little good to assure the reliability, of the generation resources if there is not similarly reliable gas transportation in place

FPL has chosen as its gas transportation reliability measure the use of an adjusted load forecast that quantifies the uncertainty of higher than forecasted levels of peak demand and energy in the future based upon the historic differences between forecasted and actual levels of peak demand and energy. This is the risk-adjusted forecast that has been prepared by FPL witness Morley.

Q. Has FPL historically employed such a reliability criterion to determine gas transportation capacity?

A. FPL has not previously applied a reliability reserve or other reliability criterion to determine gas transportation adequacy. However, FPL recognizes that its system now presents a unique challenge because of the recent increase in FPL's reliance on natural gas and gas transportation for electric generation. FPL is now the largest user of natural gas for generating electricity in the country. In most other areas where gas is a primary fuel for electric generation, gas is delivered through well connected networks that provide gas supply reliability both in terms of capacity and redundancy. Conversely, peninsular Florida primarily relies on just two pipelines from outside the state, with very limited connectivity between them. Even with the addition of the new Pipeline System, there will still be only three major pipeline systems into peninsular Florida, which will provide less optionality and redundancy than exists in other states with major reliance on gas as a power plant fuel.

Q. In the event that FPL found itself short of gas capacity due to high loads or other reasons could it reasonably rely on short term gas transportation purchases to meet the unexpected need?

A. No. In the past FPL has at times purchased gas transportation in the spot market. However, as explained in the testimony of FPL witnesses Forrest and Sexton, Florida's gas transportation infrastructure is almost completely utilized, and FPL cannot depend on spot gas transportation capacity being available in sufficient quantities when needed.

Q. Doesn't FPL have the ability to switch to oil operation in case of a gas interruption?

A. Yes, but only on a very limited basis. Most, but not all, of FPL's gas-fired combined cycle units have distillate oil backup capability for use in short-term, emergency situations limited to a few days of operation. As a result, this oil backup capability is insufficient to provide an adequate reserve in case of extended periods of high gas requirements due to high loads or outages of large units that are not gas-fired that would cause a need for substantially higher gas-fired electric output.

Q. Please elaborate on FPL's proposal to address the need for a reliability reserve in the evaluation of incremental gas transportation requirements.

A. FPL believes that the greatest risk of under-forecasting the actual future needs of gas transportation capacity relates to the potential for under-forecasting the load that FPL will have to serve. Therefore, it is reasonable to provide a reliability reserve in planning for gas transportation capacity based on using a higher, risk-adjusted load forecast for which the probability of the actual load being lower. The base case load forecast has a 50% probability of underestimating the load, and therefore will have a 50% probability of underestimating the system gas requirements. For purposes of determining its gas needs, FPL proposes to use a risk-adjusted load forecast that has a lower probability of underestimating the load.

As explained in the testimony of FPL witness Morley, the risk-adjusted load forecast that FPL proposes to use is designed to reflect the higher values of net energy for load and summer peak demands that may occur in the future given past forecasting variances. The risk-adjusted load projections are expected to have a 75% probability of being equal to or higher than the actual loads. It is important to point out that even when using this risk-adjusted load forecast, there will still be a 25% chance that actual loads will be higher than forecasted, so it is by no means an unduly aggressive view of what FPL's gas transportation needs might turn out to be. The annual summer peak loads projected under both the base case and the risk-adjusted load forecasts are shown in FPL witness Morley's Exhibit RM-4.

Q. Do you believe that the risk-adjusted load forecast as described above will provide an adequate reliability reserve for determining the need for incremental gas transportation?

A. Yes. When considering what the appropriate level of gas transportation reliability reserve should be, FPL looked at the 20% reserve margin level used for generation resource planning. This 20% generation reserve margin addresses the potential differences between actual and forecasted load, as well as other risks such as generation unit and transmission line outages. Instead of using a 20% gas transportation reserve margin, FPL proposes to base its gas transportation reserve margin on the use of the higher risk-adjusted load forecast, which primarily focuses on the potential load forecast variances. However, although the application of this higher load forecast, is primarily aimed at protecting FPL's customers from some higher than forecasted loads, the reserve margin thus created protects customers to some extent also from other gas supply risks such as pipeline and other gas supply interruptions. It should be noted, however, that FPL is being conservative in this approach because its methodology addresses some but not all, of the potential load forecast variances.

In her testimony, FPL witness Morley explains that the risk-adjusted load forecast is never higher than the base case forecast by more than 11.8%; on average the risk-adjusted forecast is about 9.8% higher than the base case forecast for the 2016 to 2025 period. See Exhibit RM-4 in the testimony of FPL witness Morley. FPL therefore concluded that the use of the risk-adjusted forecast results in a gas transportation margin which provides FPL's customers with a modest but reasonable level of insurance from potentially under-forecasted peak loads.

Q. FPL is proposing to use the risk-adjusted load forecast as well as building a third, geographically diverse pipeline to provide enhanced gas transportation reliability. Are both these measures of additional reliability necessary?

A. Yes. These two measures work effectively together to provide the necessary level of gas delivery reliability. Meeting the incremental gas transportation needs established with the use of the risk-adjusted load forecast without adding a third pipeline system would provide additional supply reliability by offering more protection from high peak loads, but would only provide very limited protection from the effects of losing a pipeline. Conversely, the construction of a third pipeline system without contracting for incremental capacity would provide protection against loss of pipe, but would not protect from higher gas needs resulting from loads that are higher than expected. For these reasons it is appropriate to add a third pipeline system, sized to accommodate the incremental gas transportation resulting from the use of the risk-adjusted forecast.

Q. What other assumptions, other than load forecast, did you use in the process of establishing the need for incremental gas transportation?

A. Other than the load forecast, all other major assumptions used in this process were consistent with the assumptions shown in FPL's 2013 Ten Year Power Plant Site Plan ("Site Plan").

Q. How was the impact of incremental DSM treated in the analysis of incremental gas transportation?

A. The assumptions and treatment of incremental DSM are the same as that shown and described in the Site Plan. For the period of 2013 to 2019, FPL's incremental additions of DSM are projected to average about 124 MW a year, consistent with the FPSC's direction in the last DSM Plan docket. For the period of 2020 to 2026, FPL assumed 100 MW of incremental DSM would be added every year. At present FPL's planning basis does not project further additions of incremental DSM beyond 2026. Consistent with FPL's normal practice, incremental DSM in 2013 through 2026 is not reflected in the load forecasts prepared by FPL witness Morley, but is later subtracted from the load forecast by RAP.

Q. Once you established the load forecast and other assumptions to be used, what procedure did you use to establish the need for incremental gas transportation capacity?

A. The P-MAREA production-costing model from P-Plus Corporation was used to determine the incremental need for gas transportation in the future. This model has been used by FPL for a number of years in fuel cost recovery proceedings as well as need proceedings before the Commission. The P-MAREA model simulates the operation of FPL's system on an hourly basis. The model captures variable costs (such as fuel, variable O&M and environmental compliance costs) in its production costing calculations, projects the annual emission levels associated with the resource plans, incorporates the effects of system transmission transfer limits on the dispatch of the generating units and recognizes existing and projected gas delivery constraints to the various plants in FPL's system. This model was used to establish the annual peak gas use requirements for the FPL system.

Q. How do FPL's current gas transportation requirements compare to its gas transportation requirements at the time FPL sought a determination of need for the Florida EnergySecure pipeline in 2009?

A. Under current assumptions, FPL projects an incremental need of approximately 870 MMcf/d of incremental gas transportation capacity by 2030 to support expected load growth and the addition of 8,143 MW of gas-dependent generation capacity by that year. This is a significant decrease from the projections utilized in the analysis for the Florida EnergySecure Line which, by 2030 forecasted a need for 1,625 MMcf/d of incremental gas transportation capacity to support 10,170 MW of new gas-dependent capacity.

IV. DESCRIPTION OF ECONOMIC ANALYSIS

Q. How did FPL determine which proposals would be included in the economic evaluation?

A. As described by FPL witness Stubblefield, the evaluation team reviewed all proposals submitted to FPL in response to the RFP and determined if these proposals met FPL's minimum requirements as stated in the RFP. All the proposals that met these minimum requirements were included in the economic evaluation.

Q. Did FPL perform separate economic evaluations, one for the Northern Pipeline Project and one for the Southern Pipeline Project?

A. No. FPL evaluates the economics of gas transportation proposals using production-cost simulations of its power supply system. To properly capture all economic effects in the simulation, FPL's model must include the costs and volumes of gas for combined Northern/Southern Pipeline Projects. As described by FPL witness Stubblefield, the RFP evaluation team developed several Combined Projects from the proposal alternatives, for economic evaluation. Each Combined Project consisted of one proposal for the Northern Pipeline Project and one proposal for the Southern Pipeline Project. All proposals that met FPL's minimum requirements were included in the development of the combinations; all combinations were then submitted to the comparative economic evaluation. Therefore, FPL's economic analysis evaluated twelve combinations of proposals for both the Northern and Southern Pipeline Projects.

Q. Did you know the identity of the bidders included in the initial economic evaluation?

A. No. In the initial economic evaluation that determined the most cost-effective combination of Projects, the RAP received a coded list of combinations in order to ensure objectivity and eliminate even the appearance of bias.

Subsequent economic evaluations of refined bids, which did not meaningfully change results, were performed with knowledge of the bidders' identities.

Q. Did FPL receive a proposal for a Southern Pipeline Project that was deemed non-compliant with the terms of the RFP?

A. Yes. FPL received one proposal for the Southern Pipeline Project which did not need the Minimum Requirements of the RFP as explained in the testimony of FPL witness Stubblefield. Nevertheless, FPL performed an economic analysis of this non-compliant proposal to provide a further reference point for evaluating the reasonableness of the gas transportation charges for the best of the compliant Southern Pipeline Project proposals. In this analysis, the non-compliant proposal was compared to the best Southern Pipeline Project proposal; both proposals were paired with the same, best proposal for the Northern Pipeline Project. It was determined that this non-compliant bid would be from $69 million to $105 million more expensive that the other proposal for the Southern Pipeline project and, therefore, the inclusion of this non-compliant proposal would not have changed the choice for the best Combined Project . These results are shown in Exhibit JEE-7.

Q. Which load forecast was used in the simulation models for the economic evaluation?

A. FPL based its simulation modeling used in the economic analysis on the risk-adjusted load forecast, which is the same forecast used to determine the need for incremental gas transportation capacity.

Q. Please describe the evaluation process used by FPL when determining which of the various combinations of proposals was the most cost-effective for its customers?

A. Step 1- EMT provided RAP a list identifying by alphanumeric code each Combined Project together with the information on each Combined Project required to perform the economic evaluation. The identity of the bidders was not disclosed to RAP in the initial evaluation. For each of the combinations to be evaluated, the following information was provided to RAP:

1. Volume and timing of gas transportation added.
2. Fixed costs for the pipeline combination, expressed both in dollars per MMBtu and annual costs ($ millions). These fixed costs are not a function of the volume of gas that flows through the pipeline.
3. Variable cost (commodity, fuel and transportation surcharges) of gas that would flow on the pipeline combination, expressed in $/MMBtu.

Step 2- RAP quantified the fuel and other variable costs for each combination. Each gas transportation combination resulted in slightly different variable costs. The P-MAREA production-costing model was used to determine the resulting difference in FPL's total system fuel and other variable costs.

Step 3- FPL aggregated all components of system cost and determined the CPVRR of each Combined Project.

This economic analysis was performed under two resource planning scenarios: the first scenario consisted of the resource plan previously described in this testimony ("Base Resource Plan") and the second scenario consisted of a plan which assumed a four year delay in the in-service dates of the Turkey Point 6 and 7 nuclear units ("Four Year Nuclear Delay Plan").

Q. Did FPL analyze the impact of fuel price sensitivities on the economic evaluation of the different proposals?

A. Yes. FPL performed a sensitivity analysis of the effects of low and high gas price forecasts on the results of the economic evaluation. This sensitivity analysis showed that the gas price forecast had a relatively low impact on the difference in CPVRR between the various Combined Projects. This result is consistent with expectations, because the great majority of the payments that FPL will make for gas transportation on the Northern and Southern Pipeline Projects are for fixed costs that are not dependent on fuel prices. Only the projected fuel cost for compression that is needed to move the gas through the pipelines is sensitive to fuel prices. The fuel price forecasts used are shown in Exhibit JEE-2.

Q. What financial assumptions did you use for this economic analysis?

A. Exhibit JEE-3 shows the long-term financial assumptions used in this economic analysis.

V. RESULTS OF THE ECONOMIC ANALYSIS

Q. What are the results of the economic analysis?

A. In the initial economic evaluation, it was determined that Combined Project 1 was the lowest cost project (i.e., it had the lowest CPVRR). Combined Project 1 consists of a proposal from Company 1 for the Northern Pipeline Project combined with a proposal from Company Aii for the Southern Pipeline Project. Without revealing the outcome of the economic analysis FPL then gave all eligible bidders the opportunity to improve their proposals. The economics of the twelve Combined Projects were updated with the revised information provided by the bidders. The updated economic analysis showed that Combined Project 1 remained the most cost-effective combination.

Under the Base Resource Plan, using the updated bidder information, the economic analysis shows that Combined Project 1 is the most economically beneficial alternative with an advantage ranging from $34 million to $1,397 million CPVRR when compared to all the other eleven Combined Projects. Under the Four Year Nuclear Delay Plan, using the updated bidder information, the economic analysis shows that Combined Project 1 is the most economically beneficial with an advantage ranging between $41 million and $1,347 million CPVRR over the other eleven Combined Projects. FPL Exhibit JEE-4 shows the economic results of each proposal combinations under the two different resource plans.

After the initial blind economic analysis, which resulted in the initial determination that Combined Project 1 was the best alternative was completed, the RAP economic analysis team learned that the three bids for the Southern Pipeline Project, identified as Ai, Aii, and Aiii, were three different proposals from the same company, with proposal Aii being the lowest cost of the three. A comparison of the four Northern Pipeline Projects combined with the best Southern Pipeline Project proposal (i.e., Aii) provides a direct comparison of the economics of the four proposals for the Northern Pipeline Project. In this comparison, Combined Project 1 had an economic advantage ranging from $580 million to $1,356 million CPVRR over the other three Combined Projects under the Base Resource Plan, and an economic advantage ranging from $513 million to $1,289 million CPVRR under the Four Year Nuclear Delay Resource Plan. FPL Exhibit JEE-5 shows the economic results of each of these four proposal combinations under the two different resource plans.

Q. What are the results of the fuel sensitivity analysis?

A. The economic analysis of the twelve Combined Projects for both low and high gas price scenarios, using the Base Resource Plan, confirmed that Combined Project 1 was the lowest cost option. Combined Project 1 was $676 million CPVRR lower than the next best option with the low gas price forecast, and $479 million CPVRR lower than the next best option with the high gas price forecast. These results are shown in Exhibit JEE-6.

Q. Did you develop projections of the estimated bill impact to FPL customers?

A. Yes. FPL developed projections of the approximate system bill impact comparing Combined Project 1 to Combined Projects 2, 3 and 4. As previously explained in this testimony, these four Combined Projects include the four different proposals for the Northern Pipeline Project paired with the same, lowest cost proposal for the Southern Pipeline Project. These bill impact projections were performed for both the Base Resource Plan and the Four Year Nuclear Delay Resource Plan. Exhibit JEE-8 shows the projections of these bill impacts, including the specific impact of the fixed gas transportation charges, for an average customer using a typical bill of 1,000 kWh per month.

Q. How do the transportation costs of the best Combined Project resulting from the current RFP compare to the transportation costs that were projected for the Florida EnergySecure Line?

A. For every year of the analysis period, the annual transportation cost of the best proposal resulting from the RFP (Combined Project 1) is lower than the annual transportation costs that were projected for the Florida Energy Secure Line in Docket No. 090172-EI. For example, the transportation cost for 2017, which is the first year of the new pipeline system, is \$2.02/MMBtu, which is \$0.24/MMBtu lower than the 2017 transportation cost for the Florida EnergySecure Line of \$2.26/MMBtu.

VI. CONCLUSION

Q. Is the combination of Northern and Southern Pipeline Projects described as Combined Project 1 the lowest cost gas transportation option available to FPL and FPL's customers?

A. Yes.

The comparison of the four Northern Pipeline Project proposals received in the FPL RFP, all paired with the same, best Southern Pipeline Project proposal, shows that Combined Project 1 results in the lowest cost to FPL customers with CPVRR savings of $580 million, $937 million and $1,356 million CPVRR when compared to the other three Northern Pipeline Project Proposals under the Base Resource Plan. Similarly, Combined Project 1 results in CPVRR savings of $513 million, $919 million, and $1,289 million when compared to the other three Northern Pipeline Project Proposals under the Four Year Nuclear Delay Resource Plan. Based on its economic advantage, I conclude that Combined Project 1 is the best alternative to meet the future gas requirements of FPL's customers.

Q. Are FPL's future gas transportation requirements effectively met by Combined Project 1?

A. Yes. After the addition of Turkey Point Units 6 and 7, natural gas will be FPL's major fuel source for the foreseeable future, and gas-fired generation capacity will continue to be a major part of FPL's future resource plan. As described by FPL witnesses Forrest and Sexton, the existing gas infrastructure in Florida will be inadequate to meet the long-term needs for gas transportation capacity to support the anticipated increase in gas generation, expected to as much as 8,143 MW of new gas-fired generation by 2030.

Does this conclude your direct testimony?

A. Yes.

Generation Resource Plans Utilized in the Analyses
Base Resource Plan

Year	Unit	Incremental MW added	Cumulative MW added	Gas dependent cumulative MW added	Generation Reserve Margin
2013	Cape Canaveral	1,210	1,210	1,210	28.0%
2014	Riviera Beach	1,212	2,422	2,422	28.5%
2015		0	2,422	2,422	31.2%
2016	PEEC	1,277	3,699	3,699	31.3%
2017		0	3,699	3,699	27.5%
2018		0	3,699	3,699	24.3%
2019		0	3,699	3,699	22.7%
2020		0	3,699	3,699	21.1%
2021		0	3,699	3,699	21.0%
2022	Turkey Point 6	1,100	4,799	3,699	23.5%
2023	Turkey Point 7	1,100	5,899	3,699	25.1%
2024		0	5,899	3,699	22.0%
2025	3x1 GFCC	1,269	7,168	4,968	23.3%
2026	Filler CC	635	7,803	5,603	21.8%
2027	Filler CC	635	8,438	6,238	21.1%
2028	Filler CC	635	9,073	6,873	20.6%
2029	Filler CC	635	9,708	7,508	20.4%
2030	Filler CC	635	10,343	8,143	20.3%

GFCC= greenfield combined cycle unit
Filler CC = smaller combined cycle units assumed after 2025

Generation Resource Plans Utilized in the Analyses
Four Year Nuclear Delay Resource Plan

Year	Unit	Incremental MW added	Cumulative MW added	Gas dependent cumulative MW added	Generation Reserve Margin
2013	Cape Canaveral	1,210	1,210	1,210	28.0%
2014	Riviera Beach	1,212	2,422	2,422	28.5%
2015		0	2,422	2,422	31.2%
2016	PEEC	1,277	3,699	3,699	31.3%
2017		0	3,699	3,699	27.5%
2018		0	3,699	3,699	24.3%
2019		0	3,699	3,699	22.7%
2020		0	3,699	3,699	21.1%
2021		0	3,699	3,699	21.0%
2022	3x1 GFCC	1,269	4,968	4,968	24.2%
2023		0	4,968	4,968	21.2%
2024	Filler CC	635	5,603	5,603	20.8%
2025	Filler CC	1,270	6,873	6,873	22.1%
2026	Turkey Point 6	1,100	7,973	6,873	22.5%
2027	Turkey Point 7	1,100	9,073	6,873	23.6%
2028		0	9,073	6,873	20.6%
2029	Filler CC	635	9,708	7,508	20.4%
2030	Filler CC	635	10,343	8,143	20.3%

GFCC= greenfield combined cycle unit
Filler CC = smaller combined cycle units assumed after 2024

Henry Hub
Price Forecast
$/MMbtu

	Medium Price	Low Price	High Price
2017	$4.82	$3.82	$5.82
2018	$5.62	$4.45	$6.79
2019	$6.15	$4.87	$7.43
2020	$6.67	$5.29	$8.06
2021	$7.06	$5.59	$8.53
2022	$7.36	$5.83	$8.89
2023	$7.97	$6.31	$9.63
2024	$8.33	$6.59	$10.06
2025	$8.68	$6.87	$10.48
2026	$8.99	$7.12	$10.86
2027	$9.30	$7.36	$11.23
2028	$9.61	$7.61	$11.61
2029	$9.93	$7.86	$11.99
2030	$10.22	$8.09	$12.34
2031	$10.65	$8.44	$12.87
2032	$11.07	$8.76	$13.37
2033	$11.50	$9.10	$13.89
2034	$11.94	$9.46	$14.43
2035	$12.41	$9.83	$14.99
2036	$12.89	$10.21	$15.57
2037	$13.39	$10.60	$16.17
2038	$13.91	$11.01	$16.80
2039	$14.45	$11.44	$17.45
2040	$15.01	$11.89	$18.13

COST OF CAPITAL

SOURCE	WEIGHT	LONG LIVE ASSETS COST	WTD COST	AFTER TAX
DEBT	40.38%	4.79%	1.93%	1.19%
PREFERRED	0.00%	0.00%	0.0%	0.0%
COMMON	59.62%	10.50%	6.26%	6.26%
TOTAL	100.0%	--	8.19%	7.45%

DISCOUNT RATE: 7.45%

Results of the Economic Analysis
Base Resource Plan
CPVRR thru 2057 (2013$)

Combined Project	Northern Pipeline Proposal	Southern Pipeline Proposal	Fixed Transportation Costs $ Million	Variable System Costs (fuel and other) $ Million	Total $ Million	Difference from Least Cost Combined Project 1 $ Million
1	1	Aii	$3,788	$117,336	$121,123	-
5	1	Ai	$3,804	$117,354	$121,158	$34
9	1	Aiii	$3,828	$117,336	$121,164	$41
4	4	Aii	$4,838	$116,866	$121,703	$580
12	4	Aiii	$4,878	$116,866	$121,744	$621
8	4	Ai	$4,854	$116,892	$121,746	$622
3	3	Aii	$4,809	$117,252	$122,061	$937
7	3	Ai	$4,825	$117,270	$122,096	$972
11	3	Aiii	$4,850	$117,252	$122,101	$978
2	2	Aii	$5,667	$116,813	$122,480	$1,356
6	2	Ai	$5,683	$116,836	$122,519	$1,395
10	2	Aiii	$5,708	$116,813	$122,520	$1,397

*System Variable Costs include all of FPL's system fuel costs, variable O&M, and cost of air emissions.

Results of the Economic Analysis
Four Year Nuclear Delay Resource Plan
CPVRR thru 2057 (2013$)

Combined Project	Northern Pipeline Proposal	Southern Pipeline Proposal	Fixed Transportation Costs $ Million	Variable System Costs (fuel and other) $ Million	Total $ Million	Difference from Least Cost Combined Project 1 $ Million
1	1	Aii	$3,922	$119,099	$123,021	-
5	1	Aiii	$3,963	$119,099	$123,061	$41
9	1	Ai	$3,952	$119,120	$123,072	$51
4	4	Aii	$4,919	$118,615	$123,534	$513
8	4	Aiii	$4,960	$118,615	$123,575	$554
12	4	Ai	$4,949	$118,646	$123,596	$575
3	3	Aii	$4,934	$119,005	$123,940	$919
7	3	Aiii	$4,975	$119,005	$123,980	$960
11	3	Ai	$4,965	$119,027	$123,992	$971
2	2	Aii	$5,737	$118,573	$124,310	$1,289
6	2	Aiii	$5,778	$118,573	$124,351	$1,330
10	2	Ai	$5,768	$118,600	$124,368	$1,347

*System Variable Costs include all of FPL's system fuel costs, variable O&M, and cost of air emissions.

Results of the Economic Analysis

Base Resource Plan

CPVRR thru 2057 (2013$)

Combined Project	Northern Pipeline Proposal	Southern Pipeline Proposal	Fixed Transportation Costs $ Million	Variable System Costs (fuel and other) $ Million	Total $ Million	Difference from Least Cost Combined Project 1 $ Million
1	1	Aii	$3,788	$117,336	$121,123	-
4	4	Aii	$4,838	$116,866	$121,703	$580
3	3	Aii	$4,809	$117,252	$122,061	$937
2	2	Aii	$5,667	$116,813	$122,480	$1,356

*System Variable Costs include all of FPL's system fuel costs, variable O&M, and cost of air emissions.

Results of the Economic Analysis
Four Year Nuclear Delay Resource Plan
CPVRR thru 2057 (2013$)

Combined Project	Northern Pipeline Proposal	Southern Pipeline Proposal	Fixed Transportation Costs $ Million	Variable System Costs (fuel and other) $ Million	Total $ Million	Difference from Least Cost Combined Project 1 $ Million
1	1	Aii	$3,922	$119,099	$123,021	-
4	4	Aii	$4,919	$118,615	$123,534	$513
3	3	Aii	$4,934	$119,005	$123,940	$919
2	2	Aii	$5,737	$118,573	$124,310	$1,289

*System Variable Costs include all of FPL's system fuel costs, variable O&M, and cost of air emissions.

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Economic Results - Four Combinations
Exhibit JEE-5, Page 2 of 2

Results of the Economic Analysis
Base Resource Plan
Gas Sensitivity- Low Commodity Price
CPVRR thru 2057 (2013$)

Combined Project	Northern Pipeline Proposal	Southern Pipeline Proposal	Fixed Transportation Costs $ Million	Variable System Costs (fuel and other) $ Million	Total $ Million	Difference from Least Cost Combined Project 1 $ Million
1	1	Aii	$3,788	$99,024	$102,811	-
4	4	Aii	$4,838	$98,649	$103,487	$676
3	3	Aii	$4,809	$98,956	$103,765	$954
2	2	Aii	$5,648	$98,679	$104,327	$1,516

*System Variable Costs include all of FPL's system fuel costs, variable O&M, and cost of air emissions.

Results of the Economic Analysis
Base Resource Plan
Gas Sensitivity- High Commodity Price
CPVRR thru 2057 (2013$)

Combined Project	Northern Pipeline Proposal	Southern Pipeline Proposal	Fixed Transportation Costs $ Million	Variable System Costs (fuel and other) $ Million	Total $ Million	Difference from Least Cost Combined Project 1 $ Million
1	1	Aii	$3,788	$135,306	$139,093	-
4	4	Aii	$4,838	$134,735	$139,573	$479
3	3	Aii	$4,809	$135,204	$140,013	$919
2	2	Aii	$5,648	$134,790	$140,437	$1,344

*System Variable Costs include all of FPL's system fuel costs, variable O&M, and cost of air emissions.

Results of the Economic Analysis
Non-Compliant Bid
CPVRR thru 2057 (2013$)

Base Resource Plan

Combined Project	Northern Pipeline Proposal	Southern Pipeline Proposal	Fixed Transportation Costs $ Million	Variable System Costs (fuel and other) $ Million	Total $ Million	Difference from Least Cost Combined Project 1 $ Million
1	1	Aii	$3,788	$117,336	$121,123	-
13	1	B	$3,839	$117,354	$121,193	$69

Four Year Nuclear Delay Resource Plan

Combined Project	Northern Pipeline Proposal	Southern Pipeline Proposal	Fixed Transportation Costs $ Million	Variable System Costs (fuel and other) $ Million	Total $ Million	Difference from Least Cost Combined Project 1 $ Million
1	1	Aii	$3,922	$119,099	$123,021	-
13	1	B	$4,008	$119,118	$123,126	$105

*System Variable Costs include all of FPL's system fuel costs, variable O&M, and cost of air emissions.

Projection of Approximate Bill Impacts:
Differential between Combined Project 1 and Combined Project 2
Base Resource Plan

Year	(1) Combined Project 1 Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	(2) Combined Project 1 Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	(3) Combined Project 2 Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	(4) Combined Project 2 Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	(5) =(3+4)-(1+2) Differential in total Annual Revenue Requirements ($millions, Nominal $)	(6) Projected Total Sales After DSM (GWh at the meter)	(7) =((5)x100)/(6) Differential in System Average Electric Rates (cents/kwh)	(8) =(7)x10 Differential in Customer Bill of 1,000 kwh ($)	(9) =(7)x12 Differential in Customer Bill of 1,200 kwh ($)
-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
2013	0	0	0	0	0	106,262	0.00	$0.00	$0.00
2014	0	0	3	-4	-1	111,474	0.00	-$0.01	-$0.01
2015	0	0	9	-18	-10	113,995	-0.01	-$0.08	-$0.10
2016	0	0	11	-92	-81	115,835	-0.07	-$0.70	-$0.84
2017	199	2,697	290	2,688	83	116,734	0.07	$0.71	$0.85
2018	294	4,572	431	4,557	122	117,850	0.10	$1.03	$1.24
2019	292	5,010	428	4,994	121	118,850	0.10	$1.02	$1.22
2020	359	5,533	542	5,508	158	120,208	0.13	$1.31	$1.58
2021	390	5,904	595	5,875	176	120,725	0.15	$1.46	$1.75
2022	388	5,980	593	5,951	176	121,846	0.14	$1.45	$1.73
2023	386	6,443	591	6,413	175	123,795	0.14	$1.41	$1.70
2024	384	6,785	590	6,753	173	126,196	0.14	$1.37	$1.65
2025	381	7,191	586	7,158	172	127,977	0.13	$1.34	$1.61
2026	379	7,672	584	7,637	170	130,049	0.13	$1.31	$1.57
2027	377	8,170	582	8,133	168	131,983	0.13	$1.27	$1.53
2028	435	8,589	611	8,551	138	134,261	0.10	$1.03	$1.24
2029	460	9,119	622	9,082	124	135,816	0.09	$0.92	$1.10
2030	458	9,693	620	9,654	122	137,560	0.09	$0.89	$1.07
2031	455	10,290	616	10,250	121	139,242	0.09	$0.87	$1.05
2032	454	11,215	616	11,172	119	141,370	0.08	$0.84	$1.01
2033	451	12,606	613	12,557	112	142,957	0.08	$0.79	$0.94
2034	450	13,463	612	13,410	108	144,556	0.07	$0.75	$0.90
2035	450	14,331	611	14,276	106	146,178	0.07	$0.73	$0.87
2036	450	15,917	612	15,856	101	147,821	0.07	$0.68	$0.82
2037	448	16,946	609	16,881	96	149,492	0.06	$0.64	$0.77
2038	447	18,084	609	18,016	93	151,186	0.06	$0.62	$0.74
2039	447	19,275	608	19,204	90	152,906	0.06	$0.59	$0.71
2040	447	20,346	609	20,272	88	154,650	0.06	$0.57	$0.68
2041	445	21,741	606	21,664	84	156,423	0.05	$0.54	$0.65
2042	368	23,241	606	23,160	157	158,224	0.10	$0.99	$1.19
2043	330	25,401	606	25,317	192	160,054	0.12	$1.20	$1.44
2044	330	27,344	607	27,253	185	161,913	0.11	$1.15	$1.37
2045	328	29,253	604	29,166	189	163,802	0.12	$1.15	$1.38
2046	328	30,745	603	30,648	179	165,722	0.11	$1.08	$1.29
2047	327	32,703	603	32,602	175	167,674	0.10	$1.04	$1.25
2048	327	34,868	603	34,763	171	169,658	0.10	$1.01	$1.21
2049	325	37,005	601	36,896	167	171,676	0.10	$0.97	$1.16
2050	325	39,697	600	39,583	162	173,729	0.09	$0.93	$1.12
2051	324	42,344	599	42,226	158	175,818	0.09	$0.90	$1.08
2052	324	44,920	600	44,798	154	177,943	0.09	$0.87	$1.04
2053	308	47,797	598	47,671	164	180,105	0.09	$0.91	$1.09
2054	300	50,836	597	50,705	167	182,294	0.09	$0.91	$1.10
2055	299	53,774	596	53,638	162	184,510	0.09	$0.88	$1.05
2056	299	57,011	597	56,870	157	186,752	0.08	$0.84	$1.01
2057	98	17,954	196	17,904	48	189,022	0.03	$0.25	$0.30
							Levelized Bill Impact	$0.74	$0.88

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1) and (3), are total fixed transportation costs for the combined project.

Projection of Approximate Bill Impacts: Differential between Combined Project 1 and Combined Project 3 Base Resource Plan

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Combined Project 1		Combined Project 3		=(3+4)-(1+2)		=((5)x100)/(6)	=(7)x10	=(7)x12
Year	Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	Differential in total Annual Revenue Requirements ($millions, Nominal $)	Projected Total Sales After DSM (GWh at the meter)	Differential in System Average Electric Rates (cents/kwh)	Differential in Customer Bill of 1,000 kwh ($)	Differential in Customer Bill of 1,200 kwh ($)
-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
2013	0	0	0	0	0	106,262	0.00	$0.00	$0.00
2014	0	0	0	0	0	111,474	0.00	$0.00	$0.00
2015	0	0	0	0	0	113,995	0.00	$0.00	$0.00
2016	0	0	0	0	0	115,835	0.00	$0.00	$0.00
2017	199	2,697	243	2,694	41	116,734	0.04	$0.36	$0.43
2018	294	4,572	361	4,567	61	117,850	0.05	$0.52	$0.62
2019	292	5,010	358	5,005	61	118,850	0.05	$0.52	$0.62
2020	359	5,533	448	5,531	87	120,208	0.07	$0.72	$0.86
2021	390	5,904	490	5,903	98	120,725	0.08	$0.81	$0.98
2022	388	5,980	487	5,980	99	121,846	0.08	$0.82	$0.98
2023	386	6,443	485	6,442	98	123,795	0.08	$0.79	$0.95
2024	384	6,785	484	6,784	99	126,196	0.08	$0.78	$0.94
2025	381	7,191	481	7,190	98	127,977	0.08	$0.77	$0.92
2026	379	7,672	478	7,671	98	130,049	0.08	$0.76	$0.91
2027	377	8,170	476	8,169	98	131,983	0.07	$0.75	$0.89
2028	435	8,589	528	8,583	87	134,261	0.07	$0.65	$0.78
2029	460	9,119	550	9,112	83	135,816	0.06	$0.61	$0.73
2030	458	9,693	548	9,686	83	137,560	0.06	$0.60	$0.72
2031	455	10,290	545	10,283	83	139,242	0.06	$0.60	$0.72
2032	454	11,215	544	11,207	82	141,370	0.06	$0.58	$0.70
2033	451	12,606	541	12,595	79	142,957	0.06	$0.55	$0.66
2034	450	13,463	540	13,451	78	144,556	0.05	$0.54	$0.65
2035	450	14,331	540	14,318	77	146,178	0.05	$0.53	$0.63
2036	450	15,917	540	15,902	75	147,821	0.05	$0.51	$0.61
2037	448	16,946	538	16,929	73	149,492	0.05	$0.49	$0.59
2038	447	18,084	537	18,067	73	151,186	0.05	$0.48	$0.58
2039	447	19,275	537	19,256	71	152,906	0.05	$0.46	$0.56
2040	447	20,346	537	20,327	71	154,650	0.05	$0.46	$0.55
2041	445	21,741	535	21,721	70	156,423	0.04	$0.45	$0.54
2042	368	23,241	535	23,219	145	158,224	0.09	$0.92	$1.10
2043	330	25,401	534	25,377	180	160,054	0.11	$1.13	$1.35
2044	330	27,344	535	27,319	180	161,913	0.11	$1.11	$1.33
2045	328	29,253	533	29,226	177	163,802	0.11	$1.08	$1.30
2046	328	30,745	532	30,717	176	165,722	0.11	$1.06	$1.28
2047	327	32,703	531	32,674	175	167,674	0.10	$1.05	$1.26
2048	327	34,868	532	34,837	175	169,658	0.10	$1.03	$1.24
2049	325	37,005	530	36,973	172	171,676	0.10	$1.00	$1.20
2050	325	39,697	529	39,664	171	173,729	0.10	$0.99	$1.18
2051	324	42,344	528	42,310	170	175,818	0.10	$0.97	$1.16
2052	324	44,920	529	44,884	169	177,943	0.09	$0.95	$1.14
2053	308	47,797	527	47,760	182	180,105	0.10	$1.01	$1.21
2054	300	50,836	526	50,798	188	182,294	0.10	$1.03	$1.24
2055	299	53,774	525	53,734	186	184,510	0.10	$1.01	$1.21
2056	299	57,011	526	56,970	186	186,752	0.10	$1.00	$1.19
2057	98	17,954	172	17,940	60	189,022	0.03	$0.32	$0.38
							Levelized Bill Impact	$0.50	$0.60

Notes. (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1) and (3), are total fixed transportation costs for the combined project.

Projection of Approximate Bill Impacts: Differential between Combined Project 1 and Combined Project 4 Base Resource Plan

Year	(1) Combined Project 1 Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	(2) Combined Project 1 Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	(3) Combined Project 4 Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	(4) Combined Project 4 Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	(5) =(3+4)-(1+2) Differential in total Annual Revenue Requirements ($millions, Nominal $)	(6) Projected Total Sales After DSM (GWh at the meter)	(7) =((5)x100)/(6) Differential in System Average Electric Rates (cents/kwh)	(8) =(7)x10 Differential in Customer Bill of 1,000 kwh ($)	(9) =(7)x12 Differential in Customer Bill of 1,200 kwh ($)
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2013	0	0	0	0	0	106,262	0.00	$0.00	$0.00
2014	0	0	0	0	0	111,474	0.00	$0.00	$0.00
2015	0	0	0	0	0	113,995	0.00	$0.00	$0.00
2016	0	0	0	0	0	115,835	0.00	$0.00	$0.00
2017	199	2,697	301	2,688	94	116,734	0.08	$0.80	$0.96
2018	294	4,572	447	4,556	137	117,850	0.12	$1.16	$1.39
2019	292	5,010	445	4,993	136	118,850	0.11	$1.14	$1.37
2020	359	5,533	453	5,509	70	120,208	0.06	$0.58	$0.70
2021	390	5,904	454	5,877	37	120,725	0.03	$0.31	$0.37
2022	388	5,980	453	5,952	38	121,846	0.03	$0.31	$0.37
2023	386	6,443	453	6,414	38	123,795	0.03	$0.31	$0.37
2024	384	6,785	453	6,755	38	126,196	0.03	$0.30	$0.36
2025	381	7,191	450	7,159	37	127,977	0.03	$0.29	$0.34
2026	379	7,672	449	7,639	37	130,049	0.03	$0.28	$0.34
2027	377	8,170	451	8,135	39	131,983	0.03	$0.30	$0.36
2028	435	8,589	497	8,548	21	134,261	0.02	$0.16	$0.19
2029	460	9,119	516	9,076	12	135,816	0.01	$0.09	$0.11
2030	458	9,693	515	9,648	11	137,560	0.01	$0.08	$0.10
2031	455	10,290	513	10,243	11	139,242	0.01	$0.08	$0.09
2032	454	11,215	517	11,165	13	141,370	0.01	$0.10	$0.11
2033	451	12,606	518	12,549	10	142,957	0.01	$0.07	$0.08
2034	450	13,463	518	13,402	7	144,556	0.00	$0.05	$0.06
2035	450	14,331	519	14,267	5	146,178	0.00	$0.04	$0.04
2036	450	15,917	521	15,848	2	147,821	0.00	$0.01	$0.01
2037	448	16,946	526	16,872	4	149,492	0.00	$0.02	$0.03
2038	447	18,084	529	18,007	5	151,186	0.00	$0.03	$0.04
2039	447	19,275	530	19,194	2	152,906	0.00	$0.01	$0.02
2040	447	20,346	532	20,262	1	154,650	0.00	$0.01	$0.01
2041	445	21,741	531	21,653	-2	156,423	0.00	-$0.02	-$0.02
2042	368	23,241	540	23,148	79	158,224	0.05	$0.50	$0.60
2043	330	25,401	545	25,300	114	160,054	0.07	$0.71	$0.85
2044	330	27,344	547	27,237	111	161,913	0.07	$0.68	$0.82
2045	328	29,253	547	29,132	98	163,802	0.06	$0.60	$0.71
2046	328	30,745	548	30,634	109	165,722	0.07	$0.66	$0.79
2047	327	32,703	559	32,587	116	167,674	0.07	$0.69	$0.83
2048	327	34,868	567	34,746	118	169,658	0.07	$0.70	$0.84
2049	325	37,005	566	36,879	116	171,676	0.07	$0.67	$0.81
2050	325	39,697	567	39,566	112	173,729	0.06	$0.65	$0.77
2051	324	42,344	568	42,209	109	175,818	0.06	$0.62	$0.75
2052	324	44,920	585	44,780	121	177,943	0.07	$0.68	$0.82
2053	308	47,797	592	47,652	139	180,105	0.08	$0.77	$0.93
2054	300	50,836	593	50,685	142	182,294	0.08	$0.78	$0.94
2055	299	53,774	594	53,616	138	184,510	0.07	$0.75	$0.90
2056	299	57,011	597	56,848	135	186,752	0.07	$0.73	$0.87
2057	98	17,954	196	17,897	40	189,022	0.02	$0.21	$0.26
							Levelized Bill Impact	$0.32	$0.39

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.

(2) The values presented in Columns (1) and (3), are total fixed transportation costs for the combined project.

Projection of Approximate Bill Impacts:
Differential between Combined Project 1 and Combined Project 2
Four Year Nuclear Delay Resource Plan

Year	(1) Combined Project 1 Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	(2) Combined Project 1 Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	(3) Combined Project 2 Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	(4) Combined Project 2 Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	(5) =(3+4)-(1+2) Differential in total Annual Revenue Requirements ($millions, Nominal $)	(6) Projected Total Sales After DSM (GWh at the meter)	(7) =((5)x100)/(6) Differential in System Average Electric Rates (cents/kwh)	(8) =(7)x10 Differential in Customer Bill of 1,000 kwh ($)	(9) =(7)x12 Differential in Customer Bill of 1,200 kwh ($)
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2013	0	0	0	0	0	106,262	0.00	$0.00	$0.00
2014	0	0	3	-4	-1	111,474	0.00	-$0.01	-$0.01
2015	0	0	9	-18	-10	113,995	-0.01	-$0.08	-$0.10
2016	0	0	11	-92	-81	115,835	-0.07	-$0.70	-$0.84
2017	199	2,697	290	2,688	83	116,734	0.07	$0.71	$0.85
2018	294	4,572	431	4,557	122	117,850	0.10	$1.03	$1.24
2019	292	5,010	428	4,994	121	118,850	0.10	$1.02	$1.22
2020	359	5,533	542	5,508	158	120,208	0.13	$1.31	$1.58
2021	390	5,904	595	5,875	176	120,725	0.15	$1.46	$1.75
2022	388	6,185	593	6,154	174	121,846	0.14	$1.43	$1.71
2023	386	7,261	591	7,228	172	123,795	0.14	$1.39	$1.67
2024	443	7,812	620	7,777	141	126,196	0.11	$1.12	$1.34
2025	469	8,210	630	8,175	126	127,977	0.10	$0.99	$1.18
2026	467	8,402	628	8,366	125	130,049	0.10	$0.96	$1.16
2027	465	8,365	626	8,329	125	131,983	0.09	$0.95	$1.14
2028	464	8,587	626	8,553	128	134,261	0.10	$0.95	$1.14
2029	460	9,122	622	9,085	124	135,816	0.09	$0.92	$1.10
2030	458	9,693	619	9,654	122	137,560	0.09	$0.89	$1.07
2031	455	10,290	616	10,250	121	139,242	0.09	$0.87	$1.05
2032	454	11,217	616	11,173	118	141,370	0.08	$0.83	$1.00
2033	451	12,607	613	12,558	112	142,957	0.08	$0.79	$0.94
2034	450	13,466	612	13,413	108	144,556	0.07	$0.75	$0.90
2035	450	14,331	611	14,275	105	146,178	0.07	$0.72	$0.86
2036	450	15,917	612	15,857	102	147,821	0.07	$0.69	$0.83
2037	448	16,946	609	16,881	96	149,492	0.06	$0.64	$0.77
2038	447	18,084	609	18,016	93	151,186	0.06	$0.62	$0.74
2039	446	19,276	608	19,205	90	152,906	0.06	$0.59	$0.71
2040	447	20,345	609	20,272	89	154,650	0.06	$0.57	$0.69
2041	445	21,741	606	21,664	84	156,423	0.05	$0.54	$0.65
2042	368	23,241	606	23,160	157	158,224	0.10	$0.99	$1.19
2043	330	25,402	606	25,319	192	160,054	0.12	$1.20	$1.44
2044	330	27,344	606	27,254	186	161,913	0.12	$1.15	$1.38
2045	328	29,253	604	29,166	189	163,802	0.12	$1.15	$1.38
2046	328	30,745	603	30,648	179	165,722	0.11	$1.08	$1.29
2047	327	32,704	602	32,603	175	167,674	0.10	$1.04	$1.25
2048	327	34,868	603	34,764	172	169,658	0.10	$1.02	$1.22
2049	311	37,007	601	36,898	181	171,676	0.11	$1.06	$1.27
2050	303	39,697	600	39,583	184	173,729	0.11	$1.06	$1.27
2051	302	42,344	599	42,227	181	175,818	0.10	$1.03	$1.23
2052	302	44,920	600	44,798	176	177,943	0.10	$0.99	$1.19
2053	300	47,798	598	47,672	172	180,105	0.10	$0.95	$1.14
2054	300	50,836	597	50,704	166	182,294	0.09	$0.91	$1.09
2055	299	53,775	596	53,638	161	184,510	0.09	$0.87	$1.04
2056	299	57,014	597	56,873	157	186,752	0.08	$0.84	$1.01
2057	98	17,954	196	17,904	48	189,022	0.03	$0.25	$0.30
							Levelized Bill Impact	$0.70	$0.84

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1) and (3), are total fixed transportation costs for the combined project.

Projection of Approximate Bill Impacts: Differential between Combined Project 1 and Combined Project 3 Four Year Nuclear Delay Resource Plan

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Combined Project 1		Combined Project 3		=(3+4)-(1+2)		=((5)x100)/(6)	=(7)x10	=(7)x12
Year	Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	Differential in total Annual Revenue Requirements ($millions, Nominal $)	Projected Total Sales After DSM (GWh at the meter)	Differential in System Average Electric Rates (cents/kwh)	Differential in Customer Bill of 1,000 kwh ($)	Differential in Customer Bill of 1,200 kwh ($)
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2013	0	0	0	0	0	106,262	0.00	$0.00	$0.00
2014	0	0	0	0	0	111,474	0.00	$0.00	$0.00
2015	0	0	0	0	0	113,995	0.00	$0.00	$0.00
2016	0	0	0	0	0	115,835	0.00	$0.00	$0.00
2017	199	2,697	243	2,694	41	116,734	0.04	$0.36	$0.43
2018	294	4,572	361	4,567	61	117,850	0.05	$0.52	$0.62
2019	292	5,010	358	5,005	61	118,850	0.05	$0.52	$0.62
2020	359	5,533	448	5,531	87	120,208	0.07	$0.72	$0.86
2021	390	5,904	490	5,903	98	120,725	0.08	$0.81	$0.98
2022	388	6,185	487	6,184	98	121,846	0.08	$0.81	$0.97
2023	386	7,261	485	7,260	98	123,795	0.08	$0.79	$0.95
2024	443	7,812	537	7,807	88	126,196	0.07	$0.70	$0.84
2025	469	8,210	559	8,204	84	127,977	0.07	$0.66	$0.79
2026	467	8,402	557	8,395	83	130,049	0.06	$0.64	$0.77
2027	465	8,365	555	8,358	83	131,983	0.06	$0.63	$0.76
2028	464	8,587	554	8,581	84	134,261	0.06	$0.63	$0.75
2029	460	9,122	550	9,115	83	135,816	0.06	$0.61	$0.73
2030	458	9,693	548	9,686	83	137,560	0.06	$0.60	$0.72
2031	455	10,290	545	10,283	83	139,242	0.06	$0.60	$0.72
2032	454	11,217	544	11,208	81	141,370	0.06	$0.58	$0.69
2033	451	12,607	541	12,596	79	142,957	0.06	$0.55	$0.66
2034	450	13,466	540	13,454	78	144,556	0.05	$0.54	$0.65
2035	450	14,331	540	14,318	77	146,178	0.05	$0.53	$0.63
2036	450	15,917	540	15,902	75	147,821	0.05	$0.51	$0.61
2037	448	16,946	538	16,929	73	149,492	0.05	$0.49	$0.59
2038	447	18,084	537	18,066	72	151,186	0.05	$0.48	$0.57
2039	446	19,276	537	19,258	72	152,906	0.05	$0.47	$0.57
2040	447	20,345	537	20,326	71	154,650	0.05	$0.46	$0.55
2041	445	21,741	535	21,721	70	156,423	0.04	$0.45	$0.54
2042	368	23,241	535	23,219	145	158,224	0.09	$0.92	$1.10
2043	330	25,402	534	25,378	180	160,054	0.11	$1.13	$1.35
2044	330	27,344	535	27,319	180	161,913	0.11	$1.11	$1.33
2045	328	29,253	533	29,226	177	163,802	0.11	$1.08	$1.30
2046	328	30,745	532	30,717	176	165,722	0.11	$1.06	$1.28
2047	327	32,704	531	32,674	174	167,674	0.10	$1.04	$1.25
2048	327	34,868	532	34,838	175	169,658	0.10	$1.03	$1.24
2049	311	37,007	530	36,975	187	171,676	0.11	$1.09	$1.31
2050	303	39,697	529	39,664	193	173,729	0.11	$1.11	$1.33
2051	302	42,344	528	42,310	192	175,818	0.11	$1.09	$1.31
2052	302	44,920	529	44,884	191	177,943	0.11	$1.07	$1.29
2053	300	47,798	527	47,761	189	180,105	0.11	$1.05	$1.26
2054	300	50,836	526	50,797	187	182,294	0.10	$1.03	$1.23
2055	299	53,775	525	53,735	186	184,510	0.10	$1.01	$1.21
2056	299	57,014	526	56,973	186	186,752	0.10	$1.00	$1.19
2057	98	17,954	172	17,940	60	189,022	0.03	$0.32	$0.38
							Levelized Bill Impact	$0.49	$0.58

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1) and (3), are total fixed transportation costs for the combined project.

Projection of Approximate Bill Impacts: Differential between Combined Project 1 and Combined Project 4 Four Year Nuclear Delay Resource Plan

Year	(1) Combined Project 1 Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	(2) Combined Project 1 Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	(3) Combined Project 4 Fixed Transportation Costs Annual Revenue Requirements ($millions, Nominal $)	(4) Combined Project 4 Variable System Costs Annual Revenue Requirements ($millions, Nominal $)	(5) =(3+4)-(1+2) Differential in total Annual Revenue Requirements ($millions, Nominal $)	(6) Projected Total Sales After DSM (GWh at the meter)	(7) =((5)x100)/(6) Differential in System Average Electric Rates (cents/kwh)	(8) =(7)x10 Differential in Customer Bill of 1,000 kwh ($)	(9) =(7)x12 Differential in Customer Bill of 1,200 kwh ($)
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2013	0	0	0	0	0	106,262	0.00	$0.00	$0.00
2014	0	0	0	0	0	111,474	0.00	$0.00	$0.00
2015	0	0	0	0	0	113,995	0.00	$0.00	$0.00
2016	0	0	0	0	0	115,835	0.00	$0.00	$0.00
2017	199	2,697	301	2,688	94	116,734	0.08	$0.80	$0.96
2018	294	4,572	447	4,556	137	117,850	0.12	$1.16	$1.39
2019	292	5,010	445	4,993	136	118,850	0.11	$1.14	$1.37
2020	359	5,533	453	5,509	70	120,208	0.06	$0.58	$0.70
2021	390	5,904	454	5,877	37	120,725	0.03	$0.31	$0.37
2022	388	6,185	453	6,156	37	121,846	0.03	$0.30	$0.36
2023	386	7,261	453	7,230	36	123,795	0.03	$0.29	$0.35
2024	443	7,812	494	7,774	12	126,196	0.01	$0.10	$0.12
2025	469	8,210	511	8,170	2	127,977	0.00	$0.02	$0.02
2026	467	8,402	510	8,360	1	130,049	0.00	$0.01	$0.01
2027	465	8,365	512	8,324	7	131,983	0.01	$0.05	$0.06
2028	464	8,587	514	8,547	11	134,261	0.01	$0.08	$0.10
2029	460	9,122	512	9,079	9	135,816	0.01	$0.06	$0.08
2030	458	9,693	511	9,648	8	137,560	0.01	$0.05	$0.07
2031	455	10,290	509	10,243	7	139,242	0.00	$0.05	$0.06
2032	454	11,217	513	11,166	9	141,370	0.01	$0.06	$0.07
2033	451	12,607	514	12,550	6	142,957	0.00	$0.04	$0.05
2034	450	13,466	514	13,405	3	144,556	0.00	$0.02	$0.03
2035	450	14,331	515	14,267	1	146,178	0.00	$0.01	$0.01
2036	450	15,917	517	15,848	-2	147,821	0.00	-$0.02	-$0.02
2037	448	16,946	522	16,872	0	149,492	0.00	$0.00	$0.00
2038	447	18,084	525	18,007	1	151,186	0.00	$0.01	$0.01
2039	446	19,276	526	19,195	-2	152,906	0.00	-$0.01	-$0.01
2040	447	20,345	528	20,261	-3	154,650	0.00	-$0.02	-$0.02
2041	445	21,741	527	21,653	-6	156,423	0.00	-$0.04	-$0.05
2042	368	23,241	536	23,148	75	158,224	0.05	$0.48	$0.57
2043	330	25,402	541	25,300	109	160,054	0.07	$0.68	$0.82
2044	330	27,344	544	27,239	108	161,913	0.07	$0.67	$0.80
2045	328	29,253	543	29,132	94	163,802	0.06	$0.57	$0.69
2046	328	30,745	544	30,634	105	165,722	0.06	$0.63	$0.76
2047	327	32,704	555	32,587	111	167,674	0.07	$0.66	$0.80
2048	327	34,868	563	34,748	116	169,658	0.07	$0.69	$0.82
2049	311	37,007	562	36,882	127	171,676	0.07	$0.74	$0.89
2050	303	39,697	563	39,566	130	173,729	0.07	$0.75	$0.90
2051	302	42,344	565	42,210	128	175,818	0.07	$0.73	$0.88
2052	302	44,920	581	44,780	139	177,943	0.08	$0.78	$0.94
2053	300	47,798	588	47,653	142	180,105	0.08	$0.79	$0.95
2054	300	50,836	589	50,684	137	182,294	0.08	$0.75	$0.90
2055	299	53,775	591	53,618	134	184,510	0.07	$0.73	$0.87
2056	299	57,014	594	56,851	132	186,752	0.07	$0.70	$0.85
2057	98	17,954	195	17,896	39	189,022	0.02	$0.21	$0.25
							Levelized Bill Impact	$0.29	$0.34

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.

(2) The values presented in Columns (1) and (3), are total fixed transportation costs for the combined project.