Scott A. Goorland
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5633
(561) 691-7135 (Facsimile)
scott.goorland@fpl.com

July 18, 2014

Filed Electronically

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

RE: Docket No. 140001-EI

Dear Ms. Stauffer:

Enclosed for filing is a replacement version of Florida Power & Light Company's ("FPL's") petition for approval of gas reserve project costs through the fuel clause and supporting testimony and exhibits of Sam Forrest, Dr. Tim Taylor and Kim Ousdahl, which was filed on June 25, 2014. The replacement copy is substantively identical to the original filing, but corrects an issue with the redaction of confidential information in certain exhibits located in Document No. 03280-14 that FPL recently discovered. All of the confidential information in both the original and replacement versions is appropriately redacted, but in the original version the redaction could be circumvented by a particular set of electronic manipulations which cannot be applied to the replacement version. FPL asks that the Commission remove the original, June 25 version of the filing from its website and replace it with the enclosed replacement version.

Thank you for your assistance, and I apologize for the inconvenience.

Sincerely,

/s/ Scott A. Goorland

Scott A. Goorland

lrb

Enclosures

cc: Parties of record w/enclosures

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No. 140001-EI Filed: June 25, 2014

PETITION

Florida Power & Light Company ("FPL" or "Company") petitions the Florida Public Service Commission ("FPSC" or "Commission") for a determination that it is prudent for FPL to acquire an interest in a natural gas reserve project that will provide price stability and projected fuel savings for customers; and that the revenue requirements associated with investing in and operating the gas reserves are eligible for recovery through the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause"). FPL further requests that the Commission establish guidelines under which FPL could participate in future gas reserve projects and recover their costs through the Fuel Clause without prior Commission approval, subject to the Commission's established process for reviewing fuel-related transactions in Fuel Clause proceedings. The pre-filed direct testimonies and exhibits of FPL witnesses Sam Forrest, Dr. Tim Taylor, and Kim Ousdahl are being filed with this Petition and are incorporated herein by reference.

I. Introduction

1. FPL is a Florida corporation with headquarters at 700 Universe Boulevard, Juno Beach, Florida, 33408. FPL currently serves approximately 4.7 million retail customers throughout Florida. Its service area comprises about 27,650 square miles in 35 Florida counties.

Approximately nine million people live within the area FPL serves, which ranges from Nassau County in the north to Miami-Dade County in the south, and westward to Manatee County.

2. The names and addresses of FPL's representatives to receive communications regarding this docket are:

Kenneth A. Hoffman
Vice President, Regulatory Affairs
ken.hoffman@fpl.com
Florida Power & Light Company
215 S. Monroe Street, Ste 810
Tallahassee, FL 32301
(850) 521-3919
(850) 521-3939 (fax)

R. Wade Litchfield
Vice President and General Counsel
wade.litchfield@fpl.com
John T. Butler
Assistant General Counsel - Regulatory
john.butler@fpl.com
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
(561) 304-5639
(561) 691-7135 (fax)

3. This Petition is being filed consistent with Rule 28-106.201, Florida Administrative Code. The agency affected is the Florida Public Service Commission, located at 2540 Shumard Oak Boulevard, Tallahassee, FL 32399. This case does not involve reversal or modification of an agency decision or an agency's proposed action. Therefore, subparagraph (c) and portions of subparagraphs (e), (f) and (g) of subsection (2) of that rule are not applicable to this Petition. In compliance with subparagraph (d), FPL states that it is not known which, if any, of the issues of material fact set forth in the body of this Petition may be disputed by any others who may plan to participate in this proceeding. The discussion below demonstrates how the petitioner's substantial interests will be affected by the agency determination.

II. Summary of Request

4. In recent years, FPL has invested in clean, fuel efficient natural gas generation facilities, significantly reducing emissions compared to older, oil-fired generation. In addition, the improved efficiencies combined with the currently lower natural gas prices have helped FPL keep its customers' bills low. By significantly reducing the amount of fuel FPL uses to generate power, FPL's investments in natural gas power plants have saved customers more than $6.5 billion in fuel costs since 2001, and they will continue to provide customer savings for decades. Replacing 1960s-era generating units with the Cape Canaveral Next Generation Clean Energy Center, Riviera Beach Next Generation Clean Energy Center, and Port Everglades Next Generation Clean Energy Center (the "Modernization Projects") is an important extension of this strategy. The Commission has issued affirmative determinations of need for each of the Modernization Projects. Docket Nos. 080245-EI and 080246-EI, Order No. PSC-08-0591-FOF-EI (issued September 12, 2008); Docket No. 110309-EI, Order No. PSC-12-0187-FOF-EI (issued April 9, 2012).

5. As a consequence of these efforts to keep customers' bills low and reduce emissions, approximately 65% of the electricity that FPL supplies to customers comes from natural gas-fired generation. FPL currently supplies about 62% of all the electricity consumed in Florida. With such a large demand for natural gas, establishing a predictable, reliable, and low cost fuel supply is imperative for FPL and its customers.

6. With the Commission's approval, FPL has recently entered into contracts for gas transportation capacity on a new gas pipeline system. Docket No. 130198-EI, Order No. PSC-13-0505-PAA-EI (issued October 28, 2013). The new pipeline system's geographic diversity will improve the reliability and security of natural gas deliveries to market areas in Florida by

providing additional pipeline infrastructure to meet Florida's future natural gas needs, as well as provide a backup to Florida's existing pipeline infrastructure that will enable flexibility in the event of a loss or disruption of supply on that infrastructure.

7. With a growing fleet of low-emission, highly efficient natural gas-fired plants and contracts for reliable and diverse gas transportation in place, FPL now looks to continue its efforts to ensure a reliable and stable source of delivery of clean electricity for its customers at low and stable prices through investment in natural gas production from shale gas formations. In other words, FPL is looking for opportunities to acquire natural gas at production costs (as an investor), rather than at market prices (as a purchaser), in order to help insulate customers from the vagaries of the gas market.

8. FPL began its search for opportunities to invest in gas reserves by exploring options with its existing suppliers. FPL then explored options beyond existing suppliers, with suppliers who would be able to meet FPL's conditions. FPL specifically looked for shale areas and suppliers that could meet requirements such as production from well-established reserves, and in close proximity to existing gas transportation pipelines that could deliver the gas efficiently to FPL.

9. FPL's search for opportunities to invest in gas reserves has been hindered by the need to allow time for Commission review before making a binding commitment to invest. Due to the volatile, fluctuating nature of the market for gas reserves, most of the potential counterparties are not willing to wait for regulatory approval in order to execute an agreement. They have other more immediately available options to secure investment or partners in these projects and are not willing to subject themselves to market-price risk while awaiting regulatory approval. As a means to bridge this obstacle, USG Properties Woodford I, LLC ("USG"), an

affiliate of FPL, entered into a series of agreements on June 18, 2014 with PetroQuest Energy, Inc. ("PetroQuest") (collectively referred to as the "PetroQuest Agreement"), under which USG will pay a share of the costs for developing and operating natural gas production wells and will receive a portion of PetroQuest's working interest in those wells in the Woodford Shale Gas region (the "Woodford Gas Reserves Project," the "Woodford Project," or the "Project"). Both USG and FPL were involved in negotiating the terms of the PetroQuest Agreement. Subject to certain prerequisites and terms, FPL will be entitled to acquire USG's interest under the PetroQuest Agreement via an assignment.[1] FPL intends to take assignment of the USG interest upon a finding by this Commission that the Woodford Gas Reserves Project is prudent; and that FPL may recover the costs of the project through the Fuel Clause; otherwise, USG will continue to be the contracting party and retain the benefits and responsibilities thereof. An assignment of USG's interest to FPL would be made at USG's net book value in the interest, reflecting USG's payment to PetroQuest for drilling rights in the acreage in which USG had already earned an interest, increased by USG's investment in wells developed subsequent to the effective date of the PetroQuest Agreement, and less depletion, if any,[2] for the gas produced during USG's period of ownership.

10. The Woodford Gas Reserves Project offers FPL and its customers an excellent opportunity to obtain a portion of FPL's gas requirements at a stable, lower cost. By disassociating a portion of FPL's natural gas purchases from market prices that historically have

[1] For convenient reference, the Petition refers to FPL being assigned USG's interest in the Woodford Gas Reserves Project. In order to better accommodate the accounting and reporting for gas reserve transactions and provide maximum flexibility to minimize tax obligations, however, FPL intends to establish wholly-owned subsidiaries to hold the interest in that project and in any future gas reserve transactions. As further explained below, there would be no impact on customers compared to FPL's holding the gas reserve interests itself.

[2] "Depletion" is the equivalent to depreciation in accounting for investments in gas production wells. As explained further in the testimony of FPL witness Ousdahl, a well's depletion expense for a given period of time is measured by the units of gas produced during that period, divided by the estimated total production over the well's useful life.

been quite volatile and instead obtaining that gas at a stable cost of production, the Woodford Gas Reserves Project will help mitigate volatility in market prices and ensure more stable prices for the gas FPL burns in its power plants. The Woodford Gas Reserves Project is expected to produce significant volumes of gas over multiple decades, all of which would be provided at the cost of production rather than market prices. Those forecasted production costs are lower than FPL's forecasted natural gas market prices.

11. Ownership of interests in gas reserves such as the Woodford Gas Reserves Project thus would operate as a long-term physical hedge against market volatility. For a portion of its total consumption of natural gas to generate electricity for its customers, FPL would be able to lock in gas prices at production costs rather than relying on market prices. The gas reserves would provide additional price stabilization to FPL's existing financial hedging program in two respects. The existing program focuses on short-term transactions because of the cost and credit risks associated with long-term financial hedges, whereas the gas reserves would provide a hedge against market-price volatility over multiple decades. And the financial hedges on which the existing program relies have the effect of locking in the current view of future market prices; if the current view is that future prices will go up, then financial hedges can offer no protection against the expected increases. In contrast, FPL would obtain gas from its gas reserves at the same, stable cost of production regardless of whether future market prices are projected to increase.

12. The Woodford Gas Reserve Project also is projected to benefit FPL's customers by providing natural gas at a lower cost per MMBtu than would be incurred if the same amount of natural gas were purchased at market prices. FPL's revenue requirements for the Project are projected to be lower than the market price of natural gas on a dollars per MMBtu basis even in

the early years, and then far lower over the remaining 30 plus year life of the project as market prices for natural gas increase (as expected) while FPL's cost of production remains steady and low. FPL customers are expected to save approximately $107 million on a net present value ("NPV") basis over the life of the project, based on FPL's current forecast of natural gas prices.

13. FPL is seeking a Commission determination that investing in the Woodford Gas Reserves Project is prudent and that the revenue requirements associated with this investment may be recovered through the Fuel Clause. While there are multiple examples of utilities across the U.S. investing in gas reserves, the PetroQuest transaction will be FPL's first acquisition of gas reserve interests. Due to the size of the investment and the length of the commitments required, FPL believes it is appropriate to seek a prudence determination from the Commission before proceeding. FPL cannot justify undertaking such a sizable financial commitment without assurance that the Commission concurs. Recovery through the Fuel Clause is consistent with established Commission policy, because the Woodford Gas Reserves Project is reasonably projected to reduce fossil fuel costs, in comparison to purchasing an equivalent volume of natural gas at market prices, and the costs are not currently recognized in FPL's base rates. *See* Order No. 14546, Docket No. 850001-EI-B, dated July 8, 1985; Order No. PSC-11-0080-PAA-EI, Docket No. 100404-EI, dated January 31, 2011.

14. The Woodford Gas Reserves Project will be an important step in delivering lower and more stable natural gas prices for FPL's customers, but it is only one of a number of steps. As noted in FPL witness Forrest's testimony, FPL has undertaken multiple projects that have reduced fuel costs to FPL's customers. The next step available to FPL to lower and stabilize natural gas prices for customers is to explore other gas reserve investment opportunities. As noted earlier, however, most of the potential counterparties are not willing to wait for regulatory

approval in order to execute an agreement. FPL cannot depend on USG continuing to assume a transitional role in future transactions. USG is essentially providing FPL a "free option": if the Commission approves the Woodford Gas Reserves Project and the terms of an assignment, FPL can acquire the interest, but if the Commission declines such approval, then USG will retain the interest in the transaction. USG cannot be expected to continue tying up its capital in the future by offering these one-sided "free options."

15. In order to ensure that the benefits of potential future gas reserve projects can be secured for customers in a timely fashion, it is essential that a process be established so that FPL will be able to make decisions on the projects with confidence regarding their recoverability. To that end, FPL requests that the Commission approve guidelines for acquiring future gas reserve projects, such that FPL would be presumptively eligible to recover revenue requirements through the Fuel Clause for projects that meet the guidelines, subject to the usual review of the prudence of fuel-related transactions that the Commission conducts in Fuel Clause proceedings. The guidelines thus would function similar to the hedging guidelines that the Commission approved in Order No. PSC-08-0667-PAA-EI, issued on October 8, 2008 in Docket No. 080001-EI. Generally, FPL's proposed guidelines describe the parameters under which FPL would be able to transact on future gas reserve opportunities. They cover the scope of FPL's project participation as a percentage of average daily burn, as well as on an annual capital expenditure basis. They also describe how the deals will be evaluated against FPL's then current forecast of natural gas prices. Finally, the guidelines will discuss the nature and composition (percentage of methane versus natural gas liquids) of gas reserves that FPL can pursue. The proposed guidelines are contained in confidential Exhibit SF-9 to the pre-filed direct testimony of FPL witness Forrest.

16. The remainder of this Petition describes in greater detail the nature of FPL's request, the results of the economic evaluation that demonstrate the value of FPL's proposed investment in the Woodford Gas Reserve Project for customers, the basis for FPL's requested cost recovery through the Fuel Clause, the accounting treatment that will be applied to the Woodford Gas Reserve Project and future gas reserve projects, and FPL's proposed gas reserve project guidelines. Additional support for the Petition is contained in the pre-filed direct testimonies and exhibits of FPL witnesses Forrest, Taylor and Ousdahl.

III. FPL's Use of Natural Gas

17. FPL generated 67.4% of its total energy from natural gas in 2013. The contribution from natural gas is expected to be approximately 65% for the coming years, largely as a result of increased nuclear production through the recently completed nuclear uprate project. In 2013, FPL used approximately 550 billion cubic feet of natural gas, substantially more than any other investor-owned utility in the country. FPL's natural gas usage is expected to remain fairly constant over the next couple of years before beginning to grow again in 2016 and beyond.

18. FPL has a robust supply portfolio that includes more than 40 natural gas producers and marketers, firm transportation on five pipelines including three upstream pipelines that provide FPL access to on-shore shale gas supply in Texas and Louisiana, and 2.5 Bcf of firm natural gas storage. FPL delivers natural gas to its power plants on the Florida Gas Transmission ("FGT") pipeline and on the Gulfstream Natural Gas System ("Gulfstream") pipeline. With the Commission's recent approval for FPL to acquire firm transportation on both Sabal Trail Transmission ("Sabal Trail") and the Florida Southeast Connection ("FSC") pipelines, FPL is

well positioned to access both conventional on- and off-shore supply and unconventional on-shore shale supply.

19. FPL currently secures physical gas, months or several years in advance, with pricing formulas based on publicly available index postings. These pricing formulas are commonly used by industry participants; however, these formulas can result in a large degree of price volatility due to movements in the underlying natural gas and/or index postings. Because natural gas fuel costs are passed directly to FPL customers via the Fuel Clause, FPL customers are exposed to gas price volatility.

20. The market price of natural gas is volatile and is a large component of the price of electricity, so it can cause significant swings in customers' electric bills. The Commission has summarized the volatility of natural gas markets and the important role hedging activities can play to reduce the impact on customers as follows:

> Natural gas prices are volatile and are influenced by weather (winter and summer temperatures), industrial demand, power generation demand, the price of alternative fuels, and tropical storms and hurricanes. Global influences may begin to affect natural gas prices as future gas supply could become more dependent upon the import of liquefied natural gas (LNG). . . Given these circumstances, having hedging available as part of FPL's fuel procurement strategy is appropriate.

Docket No. 080001-EI, Order No. PSC-08-0667-PAA-EI, p. 10 (issued October 8, 2008).

21. Consistent with these guidelines, FPL currently engages in short term financial hedging activities, reported to and approved by the Commission each year, to reduce fuel price volatility and deliver greater price certainty to FPL's customers. FPL achieves this objective by financially hedging a portion of its projected gas consumption for the following year. FPL is not engaged in long-term financial hedging because it would likely have significant credit and collateral requirements that may not be in the best interest of FPL or its customers. A long-term

physical hedge could provide similar benefits without the credit and collateral concerns. As further discussed below, acquiring an interest in natural gas reserves and drilling operations would provide a long-term physical hedge.

IV. The Emerging Importance of Shale and Other Unconventional Gas Sources

22. Natural gas and other fossil fuels are formed from the decaying remains of plants and animals, mostly microscopic marine life, from millions of years ago. The pressure and temperatures deep within the earth's crust will impact the type of hydrocarbons that are formed. For example, deeper deposits with higher pressure and higher temperature favor the formation of lighter hydrocarbons (natural gas), while shallower deposits tend to contain heavier hydrocarbons that are in liquid form (e.g., oil). Historically, the most common formation that was drilled to extract natural gas has been what is characterized as "conventional." These are geologic deposits with naturally occurring pockets where natural gas collects and is trapped by an impervious layer of rock. Currently, however, the fastest growing source of natural gas is from unconventional formations. The most common unconventional formations are shale gas, tight gas, and coal-bed methane.

23. Shale formations are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas. Shale gas refers to natural gas that is trapped within shale formations which have little permeability and, therefore, cannot usually flow in commercial quantities without special drilling and completion techniques. Over the past decade, advancements in technology related to horizontal drilling and completion techniques have allowed access to large volumes of shale gas that were previously uneconomical to produce. The production of natural gas from shale formations has rejuvenated the natural gas industry in the United States which

contains some of the largest shale gas reserves in the world. Shale gas has been the fastest growing source of supply in the United States over the past 10 years and its emergence has pushed gas prices to historical lows.

24. Offshore natural gas production in the Gulf of Mexico has declined significantly and is projected to remain flat at the current reduced levels through 2040. Production in the Mobile Bay area, historically a major source of supply for FPL, also has declined steadily.

25. Shale gas production, by contrast, has been growing rapidly over the past few years and is projected to continue this rapid growth in the future. In 2000, shale gas provided only 1% of U.S. natural gas production; by 2010 it was more than 20% and the EIA predicts that by 2035, 50% of the United States' natural gas supply will come from shale gas. As a result of the focused investment in shale gas production, the cost of drilling and producing gas from shale formations has dropped dramatically, leading to lower natural gas pricing from shale gas formations such as Woodford, and an increase in the amount of economically recoverable gas reserves. This combination of lower prices and additional reserves mean that now is an excellent time to begin investing in gas reserves.

V. The Woodford Shale

26. The Woodford Shale lies underneath most of the state of Oklahoma and ranges from 50 feet up to 300 feet thick. The region of the Woodford Shale in the Arkoma Basin of southeastern Oklahoma, where the Area of Mutual Interest ("AMI") acreage with PetroQuest is located, covers approximately 2,900 square miles and lies between 6,000 feet and 13,000 feet beneath the surface. It is an organic-rich shale and is characterized as a low permeability rock

with relatively high porosity. The Woodford Shale in this region where the AMI acreage is located produces dry natural gas[3]. The first gas production from the Woodford Shale was recorded in 1939 from vertical wells. The first horizontal wells were drilled in 2004 and, today, with the advent of technological advances in horizontal drilling and completion methods, there are approximately 2,000 wells producing from the formation. Many oil companies like Devon Energy, Newfield Exploration, Chesapeake Energy, Antero Resources, Continental Resources, PetroQuest Energy, XTO Energy and others are actively drilling the Woodford Shale.

VI. FPL's Review of Shale Gas Production Opportunities

27. Recognizing the projected growth in the shale gas market, and the importance of shale gas as part of FPL's fuel supply portfolio, FPL began reviewing opportunities for acquiring an interest in the production of shale gas, which could provide both customer savings and price stability. FPL began by exploring options with its existing suppliers. FPL then explored options beyond existing suppliers, with producers who would be able to meet FPL's conditions. FPL had initial conversations with more than 25 counterparties. Of those, several were eliminated because they were not interested in a joint venture under the terms FPL required to ensure savings for FPL customers, or were unwilling to wait the time necessary for FPL to complete the regulatory process. FPL eventually exchanged data with the remaining counterparties.

28. Of the remaining options, FPL was able to determine that a few of the opportunities were uneconomic for customers based on engineering consultant reports, which

[3] "Dry gas" refers to natural gas that is predominantly methane, containing only small amounts of other, heavier hydrocarbons such as ethane, propane, butane, and pentane. These heavier hydrocarbons are commonly called natural gas liquids, or "NGLs". Natural gas containing significant fractions of NGLs is referred to as "wet gas".

indicated that estimated reserves for these counterparties were lower than what the counterparty had claimed, or that the projected capital expenditures would be higher than what the counterparty had claimed. FPL was ultimately able to make arrangements with PetroQuest to enter into a joint venture for investment in gas reserves and production.

VII. The PetroQuest Agreement

29. As a result of FPL's review of gas production options to reduce FPL's and its customers' exposure to natural gas market prices, on June 18, 2014 USG entered into the PetroQuest Agreement to invest directly in shale gas reserves and receive natural gas from the Woodford Shale region. The PetroQuest Agreement consists of several documents, including:

a. Drilling and Development Agreement ("DDA"): The DDA lays out the terms of development of future wells per the schedule established by PetroQuest. Included as an Exhibit to the DDA is a Form of Operating Agreement ("OA") that will govern the operation of the wells both during drilling and once they are completed and operational.

b. Tax Partnership Agreement ("TPA"): FPL will have a tax partnership agreement with PetroQuest that will allow FPL to expense, for tax purposes, Intangible Drilling Costs ("IDCs") incurred during drilling.

30. The DDA, OA, and TPA are included as Confidential Exhibits SF-4 and SF-5, respectively, to the testimony of FPL witness Forrest. In order to provide an opportunity for Commission review of the prudence of the transaction for FPL's customers, the PetroQuest

Agreement is structured such that USG may assign all of its rights and obligations under the Agreement to FPL.

31. PetroQuest is a well-known, highly regarded and publicly traded independent oil and natural gas company engaged in the acquisition, exploration, development, and production of oil and natural gas properties in the United States. PetroQuest has operations in Oklahoma, Texas, Louisiana, and the Gulf of Mexico. As of December 31, 2013, the company had approximately 48,000 developed net acres and an additional 59,000 undeveloped net acres in the Woodford Shale Gas region. PetroQuest has drilled over 120 wells in the Woodford Shale and has established itself as an efficient, low cost developer of natural gas reserves.

32. USG is currently engaged in the exploration and production of oil and natural gas in many regions of the U.S. USG has successfully participated in drilling programs in 12 different shale formations around the country and is a partner in more than 800 producing wells as a non-operating entity. This includes a successful joint venture with PetroQuest in the Woodford Shale Gas region. In order to facilitate a successful joint venture for FPL, FPL and USG worked together to negotiate the PetroQuest Agreement for the development of properties not currently being drilled under the joint venture. USG was willing to make accommodations to begin the drilling program with PetroQuest on a schedule mutually agreed to by the parties, effectively providing a no cost "bridge" for FPL to consummate the transaction. Upon a determination by the Commission that entering into the PetroQuest Agreement is prudent and that the associated costs may be recovered through the Fuel Clause, all of USG's working interests in these properties and its rights under the PetroQuest Agreement will be transferred to FPL at net book value. If the Commission determines not to approve the prudence and cost

recovery of the transaction for FPL, then USG simply would retain its interest and value in the PetroQuest Agreement.

33. The structure of the PetroQuest Agreement is consistent with common industry practice for contracting to purchase an interest in gas production and reflects the following:

a. PetroQuest will function as the operator for production within the AMI in the Woodford Shale region. The AMI is defined as 19 sections, within which there are 19 existing horizontal wells operated by PetroQuest. USG has been a partner in 17 of the existing wells. As noted above, FPL will have no rights and will not compensate USG for the existing wells located within the AMI. The PetroQuest Agreement contemplates that 38 additional horizontal well locations will be drilled in the AMI;

b. USG (FPL upon Commission approval) will pay PetroQuest a "carry" amount that reflects a percentage of PetroQuest's share to drill and complete each of the sections under a defined drilling program in the AMI, but may include additional wells in each section in order to economically optimize gas production. The "carry" is a common, industry-standard approach to compensating PetroQuest for the investment it made and risks it took previously in developing the Woodford Project;

c. In exchange, USG (FPL upon Commission approval) will receive a percentage of PetroQuest's working interest in the natural gas production from each well that is developed in the AMI; and,

d. Subject to participation in a minimum number of wells by the end of 2015, USG (FPL upon Commission approval) will retain the right to "non-consent"

to, or not participate in, future wells upon notice to PetroQuest. This will allow USG (and, ultimately, FPL) to review and analyze production data and operating costs for future wells to ensure that customers will benefit from any participation.

34. Upon the Commission's determination that the PetroQuest Agreement is prudent for FPL, and the costs recoverable through the Fuel Clause, USG will transfer its rights under the PetroQuest Agreement to FPL at USG's net book value in the interest, reflecting USG's payment to PetroQuest for drilling rights in the undeveloped acreage in which USG had already earned an interest, increased by USG's investment in wells developed subsequent to the effective date of the PetroQuest Agreement, and less depletion, if any, for the gas produced during USG's period of ownership.[4] In essence, FPL will be paying the market price for this transaction, as measured at the time of USG's initial purchase. USG will not be compensated for any gain that might occur as a result of market increases between the time of the initial purchase and the transfer to FPL, and it will not be compensated for providing FPL a "free option" to decide whether or not to take the transfer depending on the outcome of this proceeding.

35. The net book value at the time of purchase between USG and FPL is estimated to be approximately $68.4 million, assuming regulatory approval and transfer by January 1, 2015, and based on current assumptions as to the timing of the drilling program and resulting gas production as described by FPL witness Taylor. It is estimated that FPL will have a total capital expenditure of approximately $191 million under the PetroQuest Agreement.

[4] Some of the acreage described in the Woodford Project is already contained in a previous joint venture between USG and PetroQuest. As part of the DDA, USG and PetroQuest will reassign any overlapping acreage from the original joint venture to the new Woodford Project. A portion of FPL's payment to USG for the transfer will be to compensate USG for the net book value of the acreage from the previous joint venture that it transferred to FPL.

36. PetroQuest plans to begin drilling 14 wells before the end of 2014, approximately 37% of all the new wells planned for the Woodford Project. Of the 14 wells to be drilled in 2014, four will begin producing gas prior to the assumed January 1, 2015 assignment date to FPL while the remaining 10 wells will still be undergoing some level of completion prior to the first flow of gas. Thus, the great majority of gas from the planned wells will be for the benefit of FPL's customers if the Commission approves FPL's request by the end of 2014.

37. Once the PetroQuest Agreement is assigned to FPL, FPL will receive the rights to its share of the physical gas produced from the Woodford Project without any charge to FPL's customers separate from recovery of the revenue requirements associated with this proposed investment (*i.e.*, FPL will recover the cost of exploration and production instead of market pricing) plus applicable transportation and operating costs. Going forward, FPL would decide whether to participate in the development of new wells based on expected production costs, natural gas market price forecasts, and expected production volume. For each year during the drilling phase, FPL will provide the Commission in its annual Fuel Clause final true-up filing a report on its decisions related to the number of wells in which it participates. Additionally, FPL will report annually its costs and the volume of natural gas received during the life of the proposed investment in the Fuel Clause.

VIII. Economic Benefits of the Woodford Gas Reserve Project for FPL Customers

38. To perform an economic evaluation of this investment, FPL utilized its natural gas price forecast along with estimated natural gas production and projected costs for the Woodford Project that were developed by FPL witness Taylor. Dr. Taylor performed an internal analysis using industry accepted methods for forecasting. FPL also retained Forrest A. Garb &

Associates, a well-recognized external consultant, to provide an independent confirmatory analysis, which concluded that Dr. Taylor's analysis is a reasonable estimate of the volumes of gas to be expected from the drilling program. In fact, the results of the independent analysis are extremely close to Dr. Taylor's. The analysis shows that the Woodford Project is economically viable and commercially attractive, with robust reserves available with a high expectation of natural gas recovery, operated by an industry leader in this region.

39. FPL then determined the revenue requirements for the Project over its 30-plus year economic life. FPL's revenue requirements were converted to an estimated cost per MMBtu of natural gas, using the total expected gas production volumes. The results of FPL's economic evaluation are depicted graphically on Exhibit SF-7, which is attached to the testimony of FPL witness Forrest. A more detailed calculation is shown as Confidential Exhibit SF-8 to the testimony of FPL witness Forrest. The testimony of FPL witness Forrest addresses in greater detail the economic evaluation, as well as sensitivity analyses that FPL performed to evaluate the impact of a lower natural gas price forecast and/or less natural gas production from the Woodford Gas Reserve Project than is expected.

40. The economic benefit of the Woodford Gas Reserve Project for FPL's customers is clear – FPL will be able to procure natural gas at a lower and more stable cost per MMBtu than would otherwise be incurred if the same amount of natural gas were to be purchased at market prices. This holds true even in the event that natural gas market prices decline further from current forecasted prices or production from the Woodford Gas Reserves Project is lower than expected. The benefits will start immediately upon FPL taking assignment of the PetroQuest Agreement and then continue over the productive life of the Woodford Project wells. The revenue requirements associated with the project, on an NPV basis, are projected to be

approximately $107 million lower than the forecasted cost of the natural gas FPL would otherwise be required to purchase over the expected economic life of the project. FPL's revenue requirements are projected to be lower than the forecasted market price of natural gas on a dollars per MMBtu basis during the entire life of the project, with customers experiencing a majority of their savings early in the life of the Project.

IX. Benefits as a Long Term Physical Hedge

41. By disassociating a portion of FPL's natural gas purchases from volatile market prices, and instead obtaining a portion of its natural gas requirements at a stable, lower cost of production, this investment will allow the Company to replace a portion of its short-term financial hedging program for fuel purchases with, in effect, a long term physical hedge. At the same time, by procuring only a portion of FPL's gas requirements through investments in gas reserves, FPL maintains the flexibility to purchase lower priced gas in the market, if available, for the remainder of FPL's needs. This means that FPL customers can benefit should gas prices unexpectedly or temporarily fall. Moreover, if the market evolves in a way that places downward pressure on the forward market price for gas, FPL will be able to roll off the hedges in a relatively short period of time by natural attrition due to the accelerated production (and hence depletion) of the gas reserves that occurs in the first few years of their operation.

X. Request For Fuel Clause Recovery

42. FPL seeks to recover the investment and operating costs of the Woodford Project through the Fuel Clause. The recoverable costs would include the following types: exploration

expense, depletion expense, operating expenses, G&A, taxes, transportation costs and a return on the unrecovered investment, including working capital. These costs would be projected for each year based on the drilling plan and quantities of gas to be produced and then adjusted to reflect actual costs subsequently through the existing Fuel Clause true-up process.

43. As described above, the proposed investment will reduce the delivered price of fuel that would otherwise be expected to be recovered through the Fuel Clause. FPL will be securing needed natural gas at a lower cost on a dollars per MMBtu basis. Therefore, this is precisely the type of investment that qualifies for cost recovery through the Fuel Clause.

44. The Commission has well-established criteria for the recovery of costs through the Fuel Clause. By Order No. 14546, issued July 8, 1985, the Commission established that the following would be examined, on a case by case basis, for recovery:

> Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers.

In 2011, the Commission confirmed that such costs would be recoverable and further explained that "the appropriate policy going forward is to restrict capital project cost recovery through the Fuel Clause to projects that are 'fossil fuel-related' and that lower the delivered price, or input price, of fossil fuel." Docket No. 100404-EI, Order No. PSC-11-0080-PAA-EI, p. 10 (issued January 31, 2011).

45. Consistent with Order No. 14546, FPL has recovered costs through the Fuel Clause for several projects that generated fuel savings, such as costs for a gas pipeline lateral to the Martin Plant (Docket No. 930001-EI, Order No. PSC-93-1331-FOF-EI, issued September 13, 1993), rail cars to deliver coal to the Scherer Plant (Docket No. 950001-EI, Order No. PSC-95-1089-FOF-EI, issued September 5, 1995), and power plant equipment modifications to allow a

cheaper, low gravity fuel to be burned (Docket No. 970001-EI, Order No. PSC-97-0359-FOF-EI, issued March 31, 1997).

46. The proposed investment is fossil fuel-related and was not included in the establishment of FPL's base rates in Docket No. 120015-EI. It will also lower the delivered price of natural gas. As discussed above, the Project is estimated to save customers approximately $107 million on an NPV basis, compared to FPL's current projection of natural gas prices. Accordingly, FPL's investment in the Woodford Gas Reserves Project clearly and directly qualifies for cost recovery through the Fuel Clause as set forth in Order No. 14546. Finally, because there will be a measure of variation and uncertainty in the overall level of incurred costs that can be expected for gas reserve projects over time, cost recovery is more appropriate in the Fuel Clause, where the changes can be reflected in annual Fuel Clause factors.

XI. Accounting Treatment of Proposed Investment

47. FPL will establish a separate, wholly-owned direct subsidiary to hold FPL's interest in the Woodland Project, conduct its gas production activities and to transact the sale of the commodity to FPL utility for its customers at production costs. This structure will allow for the following benefits:

- Allow maximum flexibility to minimize state income tax obligations;
- Allow for the separation of Federal Energy Regulatory Commission ("FERC") electric chart of accounts for regulatory reporting purposes (FERC Form 1 requires the subsidiaries to be deconsolidated);
- Provide clearer definition and transparency for the investment and activities associated with gas reserve projects; and,

- Since costs associated with gas production will be recovered through the Fuel Clause, the separate legal entity facilitates segregation for ratemaking and earnings surveillance related to base rates.

48. FPL intends that the transfer from USG would be to the subsidiary rather than directly to FPL itself. The subsidiary will be fully consolidated with FPL for regulatory and financial reporting purposes. The assignment of USG's rights and obligations for ownership of the Woodford working interest and the relevant terms of that assignment are documented in an MOU between USG and FPL. A copy of this MOU is attached as Exhibit KO-1 to the testimony of FPL witness Ousdahl. As discussed above, this transfer will occur at net book value.

49. FPL will utilize the successful efforts method of accounting for the proposed joint venture investment in the Woodford Gas Reserves Project. There are generally four types of costs that are allowed to be included under the successful method of accounting: acquisition, exploration, development and production costs.

50. Under the successful method of accounting, depreciation is recorded in the form of "depletion," which is measured on a unit-of-production basis rather than on a remaining life or whole life basis. Depletion for a gas reserve investment plays the same role as depreciation would for an electric plant asset providing for recognition of the use of the asset in the financial statements and recovery of the asset in rates. FPL plans to aggregate its investments at a reservoir or field level because they share common geological structural features. In addition, reserve estimates must be updated on an annual basis for financial reporting purposes.

51. FPL will calculate the revenue requirements for the Project (*e.g.*, depletion, O&M, return on the investment) to be recovered through the Fuel Clause, using a projection for each year of the expected quantities and related costs. The first year in which costs associated

with the Woodford Project will be projected for recovery in the Fuel Clause is 2015. The 2015 Fuel Clause Projection filing will be made in August 2014. All of the costs will be retail jurisdictionalized along with all other fuel costs recoverable through the Fuel Clause; based on the percentage of retail kWh sales to total kWh sales. FPL will calculate the associated return on its capital invested in the Project in the same manner as it does with other clause related capital investments.

XII. Establishment of Guidelines for Future Gas Reserve Projects

52. To the extent the proposed investment in the PetroQuest transaction is approved by the Commission as prudent and recoverable through the Fuel Clause, FPL will be in a position to evaluate similar investment opportunities to achieve an expanded and continuing level of fuel cost savings and price stability for its customers. The PetroQuest transaction described herein is an example of just one agreement in a broad market. As similar investment opportunities to achieve additional fuel cost savings and price stability for its customers arise, it is imperative for FPL to be in a position to move quickly to take advantage of those opportunities.

53. Gas production in today's shale gas markets is a fast moving business. Counterparties are generally unwilling to wait for standard regulatory approval timing in order to execute an agreement. Counterparties are looking for a definitive start date to begin (or continue) their drilling program and cannot wait more than a month or two as market prices fluctuate. Additionally, without a certain end date to the regulatory approval process, counterparties are unable to appropriately manage their annual capital expenditures and drilling programs. These

organizations are developing drilling and capital expenditure programs and attempting to secure sources of funding.

54. FPL cannot depend on having USG or any other entity stand in until the regulatory review is completed. Furthermore, because of the volatile nature of the gas markets, the start date of a transaction can have significant impacts on the value as viewed by the counterparty, as well as the benefit to FPL's customers. A several month delay in executing an agreement in today's gas markets could result in millions of dollars of savings lost for FPL's customers.

55. In order to ensure that the benefits available to customers are able to be secured in a timely fashion, FPL requests that the Commission approve guidelines for gas reserve projects, such that FPL would be eligible to recover through the Fuel Clause the revenue requirements for future projects that meet those guidelines, subject to the usual review of the prudence of fuel-related transactions that the Commission conducts in Fuel Clause proceedings. Attached to the testimony of FPL witness Forrest as Confidential Exhibit SF-9 are FPL's proposed guidelines. Certain key provisions in the guidelines need to be kept confidential, because their disclosure would disadvantage FPL in negotiating with potential counterparties for future gas reserve projects, which in turn could reduce the fuel savings for FPL's customers.

56. The adoption of guidelines would be consistent with how the Commission has administered the fuel hedging programs for FPL and Florida's other investor-owned utilities. Similar to the hedging guidelines, the Commission could establish a framework whereby the company could enter into several transactions that are within a range of predetermined terms/guidelines. Also similar to the hedging guidelines, the Commission should acknowledge

that there are potential drilling/production risks with pursuing gas assets and as long as the transaction was within the guidelines it cannot be deemed imprudent based on the results.

57. By allowing FPL to move forward on future projects without the need for prior approval, the Commission would facilitate FPL's ability to take advantage of additional opportunities to achieve lower and more gas prices for customers, while maintaining the Commission's ability to review those projects in the same manner that it reviews other fuel-related transactions.

WHEREFORE, for the reasons set forth above and as more fully supported by the testimony filed with this Petition, FPL respectfully requests that the Commission determine that FPL's participation in the Woodford Gas Reserves Project is prudent and that the costs associated with the Woodford Gas Reserves Project are eligible for recovery through the Fuel Clause; and further requests that the Commission approve FPL's proposed guidelines under which FPL could participate in future gas reserve projects and recover their costs through the Fuel Clause without prior Commission approval, subject to the Commission's established process for reviewing fuel-related transactions in Fuel Clause proceedings. Furthermore, given the need to move expediently in order to capture benefits for customers as early as possible, FPL specifically requests that the Commission consider these three elements of FPL's approval request at the Commission's October 22-24 Fuel Clause hearing. FPL will cooperate in the accelerated processing of its request as required to meet that timetable, through means such as expediting responses to discovery requests or any other means available.

Respectfully submitted,

Charles A. Guyton
Gunster, Yoakley & Stewart, P.A.
Suite 601
215 South Monroe Street
Tallahassee, Florida 32301

R. Wade Litchfield
Vice President and General Counsel
wade.litchfield@fpl.com
John T. Butler
Assistant General Counsel – Regulatory
john.butler@fpl.com
Scott A. Goorland
Principal Attorney
scott.goorland@fpl.com
700 Universe Boulevard
Juno Beach, FL, 33408
(561) 304-5639

/s/ John T. Butler
John T. Butler
Florida Bar No. 283479

CERTIFICATE OF SERVICE
Docket No. 140001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service on this 25th day of June, 2014 to the following:

Martha F. Barrera, Esq.
Julia Gilcher, Esq.
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
mbarrera@psc.state.fl.us
jgilcher@psc.state.fl.us

Jon C. Moyle, Esq.
Moyle Law Firm, P.A.
118 N. Gadsden St.
Tallahassee, FL 32301
Counsel for FIPUG
jmoyle@moylelaw.com

Beth Keating, Esq.
Gunster Law Firm
Attorneys for FPUC
215 South Monroe St., Suite 601
Tallahassee, FL 32301-1804
bkeating@gunster.com

John T. Burnett, Esq.
Dianne M. Triplett, Esq.
Attorneys for DEF
299 First Avenue North
St. Petersburg, FL 33701
john.burnett@duke-energy.com
dianne.triplett@duke-energy.com

James D. Beasley, Esq.
J. Jeffrey Wahlen, Esq.
Ashley M. Daniels, Esq.
Ausley & McMullen
Attorneys for Tampa Electric
P.O. Box 391
Tallahassee, FL 32302
jbeasley@ausley.com
jwahlen@ausley.com
adaniels@ausley.com

Jeffrey A. Stone, Esq.
Russell A. Badders, Esq.
Steven R. Griffin, Esq.
Beggs & Lane
Attorneys for Gulf Power
P.O. Box 12950
Pensacola, FL 32591-2950
jas@beggslane.com
rab@beggslane.com
srg@beggslane.com

Robert Scheffel Wright, Esq.
John T. LaVia, III, Esq.
Gardner, Bist, Wiener, et al
Attorneys for Florida Retail Federation
1300 Thomaswood Drive
Tallahassee, FL 32308
schef@gbwlegal.com
jlavia@gbwlegal.com

James W. Brew, Esq.
F. Alvin Taylor, Esq.
Attorney for White Springs
Brickfield, Burchette, Ritts & Stone, P.C
1025 Thomas Jefferson Street, NW
Eighth Floor, West Tower
Washington, DC 20007-5201
jbrew@bbrslaw.com
ataylor@bbrslaw.com

J. R. Kelly, Esq.
Patricia Christensen, Esq.
Charles Rehwinkel, Esq.
Joseph A. McGlothlin, Esq.
Erik L. Sayler, Esq.
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399
kelly.jr@leg.state.fl.us
christensen.patty@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us
mcglothlin.joseph@leg.state.fl.us
sayler.erik@leg.state.fl.us

Michael Barrett
Division of Economic Regulation
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
mbarrett@psc.state.fl.us

By: __*/s/ John T. Butler*_____

John T. Butler
Fla. Bar No. 283479

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY'S

PETITION FOR PRUDENCE DETERMINATION

REGARDING ACQUISITION OF GAS RESERVES

DIRECT TESTIMONY OF SAM FORREST

DOCKET NO. 140001-EI

JUNE 25, 2014

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sam Forrest. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Vice President of the Energy Marketing and Trading ("EMT") Business Unit.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science in Electrical Engineering from Texas A&M University and a Masters of Business Administration from the University of Houston. Prior to being named Vice President of EMT for FPL in 2007, I was employed by Constellation Energy Commodities Group as Vice President, Origination. In this capacity, I was responsible for managing a team of power originators marketing structured electric power products in Texas, the Western United States, and Canada. Prior to my responsibilities in the West, I was responsible for Constellation's business development activities in the Southeast U.S.

Before joining Constellation, from 2001 to 2004, I held a variety of energy marketing and trading management positions at Duke Energy North America

("DENA"). Prior to DENA, I was employed by Entergy Power Marketing Corp. ("EPMC") in several positions of increasing responsibility, including Vice President – Power Marketing following EMPC's entry into a joint venture with Koch Energy Trading.

Prior to my entry into the energy sector, I was involved with a successful start-up organization in the automotive industry from 1996 to 1998. From 1987 to 1996, I worked for AlliedSignal Aerospace at the Johnson Space Center in Houston, Texas, in increasing roles of responsibility.

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

A. I am responsible for the overall direction and management of the EMT Business Unit, which handles FPL's short-term and long-term fuel management and operations. These fuels include natural gas, residual and distillate fuel oils, and coal. Additionally, EMT is responsible for FPL's fuel hedging program, long-term fuel transportation and storage contracts, power origination activities and short-term power trading and operations. EMT is an active participant in the short-term and long-term natural gas markets throughout the Southeastern United States.

Q. Are you sponsoring any exhibits in this case?

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

- SF-1 Map of FPL's Existing Natural Gas Transportation
- SF-2 Map of U.S. Natural Gas Transportation Pipelines

- SF-3 Map of U.S. Shale Gas and Oil Production Locations
- SF-4 Drilling and Development Agreement (confidential)
- SF-5 Tax Partnership Agreement (confidential)
- SF-6 PetroQuest Agreement Term Sheet (confidential)
- SF-7 PetroQuest Transaction Production Profile
- SF-8 Results of FPL's Economic Evaluation (confidential)
- SF-9 Proposed Transactional Guidelines (confidential)

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

A. My testimony supports FPL's primary requests in this proceeding. First, FPL is seeking a determination by the Florida Public Service Commission ("FPSC" or "Commission") that investing through a joint development agreement with PetroQuest Energy, Inc. ("PetroQuest") to develop gas reserves in the Woodford Shale region located in southeastern Oklahoma is prudent and that the revenue requirements associated with this investment may be recovered through the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause"). My testimony explains why such an investment would be appropriate and prudent for FPL, how it can be viewed as the next step in our overall strategy of securing reliable sources of natural gas at more stable prices for our customers, and why recovery through the Fuel Clause is both appropriate and necessary.

Additionally, FPL is requesting the Commission approve a set of guidelines for acquiring future gas reserve projects, such that FPL would be

presumptively eligible to recover revenue requirements through the Fuel Clause for projects that meet the guidelines, subject to the usual review of fuel-related transactions that the Commission conducts in Fuel Clause proceedings. My testimony explains why such guidelines are necessary if FPL is to continue to participate in this market and make further investments in gas reserve projects. In this regard, I also explain the limited role that an affiliate has agreed to play in helping to make the first project a possibility for FPL.

Q. Please provide a brief summary of your testimony.

A. FPL currently supplies 62% of the electricity consumed in Florida with approximately 65% of this coming from natural gas fired generation. This equates to FPL purchasing up to 600 billion cubic feet ("Bcf") of gas annually. With such a large demand for natural gas, establishing a predictable, reliable, and low cost fuel supply is imperative for FPL and its customers. Since 2002, FPL has had a hedging program in place to help dampen price volatility over the short run (approximately 12 to 24 months out) and has recently entered into Commission-approved contracts for gas transportation on a new, independently routed third pipeline system. FPL is looking to continue its efforts to ensure a reliable and stable source of delivery of clean electricity for its customers by investing in natural gas production.

The PetroQuest transaction provides FPL's customers with a source of physical gas supply that provides for stable pricing over the production term

of the project, thus mitigating volatility inherent in FPL's natural gas procurement. The agreement also establishes a source of supply that is low cost by comparison to FPL's forecast of natural gas prices. This investment is a real opportunity to capitalize on the advances that have been made in the exploration and drilling of shale gas reserves.

One of the keys to success in this market is being able to move quickly. Exploration and production companies typically are not willing to wait for a prospective investor to obtain regulatory approvals before a transaction becomes effective. The market is too active and drilling decisions need to be made quickly. To bridge this challenge in this first instance, NextEra Energy's Gas Infrastructure and Development ("GI") business unit, which has extensive experience in these kinds of joint ventures, has formed USG Properties Woodford I, LLC ("USG") to transact with PetroQuest and begin the drilling program (I will refer to USG and GI collectively as "USG"). USG is an affiliate of FPL and will assign the PetroQuest transaction to FPL upon approval by the Commission (as discussed by FPL witness Ousdahl, the assignee would be a wholly-owned, fully regulated FPL subsidiary, but for simplicity I will refer to FPL as the assignee). Otherwise, USG will retain the transaction for its own interest. While this arrangement serves the needs of FPL and its customers, in this instance, for purposes of framing the proposal and allowing the Commission to consider this initiative, it amounts to USG providing FPL's customers a free option to acquire the PetroQuest transaction.

Therefore, for FPL to engage in transactions of this nature in the future, FPL needs Commission approval of a framework for making gas reserve investments within which FPL would have reasonable assurance as to the prudence of those transactions.

Q. Please identify FPL's other witnesses in this proceeding and the areas they cover.

A. The following is a listing of FPL's other witnesses and the areas they cover:

- Dr. Tim Taylor, Chief Technology Officer, NextEra Energy Project Management, LLC - Gas Infrastructure & Development – Overview of the gas reserves market, valuation methodology used to value the PetroQuest transaction and results of valuation;
- Kim Ousdahl, Vice President, Controller & Chief Accounting Officer, FPL – Overview of gas reserve accounting and request for Fuel Clause recovery of the PetroQuest transaction.

II. SUMMARY OF FPL'S REQUEST

Q. What is FPL asking the Commission to determine in this proceeding?

A. FPL's petition asks the Commission to find that it is prudent for FPL to acquire an interest in a natural gas reserve project that will provide price stability and projected fuel savings for customers, and that the revenue requirements associated with investing in and operating the gas reserves are eligible for recovery through the Fuel Clause. FPL further requests that the

Commission establish guidelines under which FPL could participate in future gas reserve projects and recover the associated costs through the Fuel Clause without prior Commission approval, subject to the Commission's established process for reviewing fuel-related transactions in Fuel Clause proceedings.

Q. Why does FPL need the Commission to make a prudence determination with respect to the PetroQuest transaction?

A. While there are multiple utilities across the U.S. investing in gas reserves, the PetroQuest transaction will be FPL's first acquisition of gas reserve interests. Due to the size of the investment and the length of the commitments required, FPL believes it is appropriate to seek a prudence determination from the Commission before proceeding. FPL cannot justify undertaking such a sizable financial commitment without assurance that the Commission concurs.

Q. Is FPL's request to recover the gas reserve costs for the PetroQuest project through the Fuel Clause consistent with Commission precedent?

A. Yes. As a matter of policy and practice, the Commission may allow Fuel Clause Recovery of "fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers." Order No. 14546, Docket No. 850001-EI-B, issued on July 8, 1985. This policy was reiterated in Order No. PSC-11-0080-PAA-EI, Docket No. 100404-EI, issued on January 31, 2011, which provides that "the appropriate policy going forward is to restrict capital project cost recovery through the Fuel Clause to projects that are 'fossil fuel-related' and that lower

the delivered price, or input price, of fossil fuel." Consistent with Order No. 14546, FPL has recovered costs through the Fuel Clause for several projects that generated fuel savings, such as the Martin gas pipeline lateral project that was addressed in Order No. PSC-93-1331-FOF-EI. Similarly, it is appropriate to recover charges paid for gas reserves that result in fuel savings for customers. The application of the Commission's precedent to recovering gas reserve costs through the Fuel Clause, as well as the appropriate regulatory accounting for those costs in the Fuel Clause proceedings, are addressed in greater detail by FPL witness Ousdahl.

III. FPL'S USE OF NATURAL GAS

Q. Does FPL rely heavily on natural gas to fuel electric generation?

A. Yes. FPL generated 67.4% of its total energy from natural gas in 2013. This number will drop to approximately 65% going forward, as shown in FPL's most recent Ten Year Power Plant Site Plan ("TYSP"). This is largely a result of increased nuclear production through the recently completed nuclear uprate project. In 2013, FPL used approximately 550 Bcf of natural gas, substantially more than any other investor-owned utility in the country, according to the U.S. Energy Information Administration ("EIA"). As noted in its TYSP, FPL's natural gas usage is expected to remain fairly constant over the next couple of years before beginning to grow again in 2016 and beyond. With this continued emphasis on natural gas as its primary fuel, it is

important that FPL continue to diversify its fuel portfolio from a supply standpoint, as well as mitigate volatility and price risk associated with the supply of natural gas.

Q. Please describe the benefits of natural gas generation for Florida in general and specifically for FPL.

A. In recent years, FPL has invested in clean, fuel-efficient natural gas generation facilities, significantly reducing emissions compared to older, oil-fired generation. In addition, the improved efficiencies combined with the currently lower natural gas prices have helped FPL keep its customers' bills low. By significantly reducing the amount of fuel FPL uses to generate power, FPL's investments in natural gas power plants have saved customers more than $6.5 billion in fuel costs since 2001, and they will continue to provide customer savings for decades. Replacing 1960s-era generation units with Cape Canaveral Next Generation Clean Energy Center, Riviera Beach Next Generation Clean Energy Center and Port Everglades Next Generation Clean Energy Center (the "Modernization Projects") is an important extension of this strategy. These types of investments have helped reduce the annual amount of foreign oil consumed by FPL over the last decade by more than 99%. The emissions reductions, along with the significantly reduced costs, have benefited FPL's customers, as well as the rest of Florida.

Q. Please describe how FPL currently supplies the gas that is burned in its power plants.

A. FPL has a robust supply portfolio that includes more than 40 natural gas producers and marketers, firm transportation on five pipelines including three upstream pipelines that provide FPL access to on-shore shale gas supply in Texas and Louisiana, and 2.5 Bcf of firm natural gas storage. FPL delivers natural gas to its power plants on the Florida Gas Transmission ("FGT") pipeline and on the Gulfstream Natural Gas System ("Gulfstream") pipeline. With the Commission's recent approval for FPL to acquire firm transportation on both Sabal Trail Transmission ("Sabal Trail") and the Florida Southeast Connection ("FSC") pipelines, FPL is well positioned to provide access to both conventional on- and off-shore supply and unconventional on-shore shale supply. A map of FPL's transportation contracts has been included as Exhibit SF-1 to my testimony. Additionally, a map of the U.S. natural gas transportation system has been included as Exhibit SF-2.

Q. How does FPL currently mitigate the price risks inherent in acquiring the large volumes of natural gas needed for its power plants?

A. Price risk is defined as the risk of market fluctuations in natural gas prices. FPL currently secures physical gas, months or several years in advance, with pricing formulas based on publicly available index postings. These pricing formulas are commonly used by industry participants; however, these formulas can result in a large degree of price volatility due to movements in the underlying natural gas and/or index postings.

Today, FPL's method of mitigating price risk is its short-term hedging program, which is approved by the Commission. FPL's hedging objectives are to effectively execute a well-disciplined and independently monitored fuel hedging strategy to achieve the goal of fuel price stability (volatility minimization). FPL achieves this objective by financially hedging a portion of its projected gas consumption for the following year.

However, the current hedging program has three substantial limitations that could be addressed by investing in upstream production (such as gas reserves). First, the financial market typically does not have the liquidity - i.e., the volume of gas contracts available without driving up the price of gas - to provide fixed-price hedges over the 30 years or longer that gas can be produced from a portfolio of gas reserve projects. Second, during periods of rising market prices, financial hedges will also reflect rising costs whereas an ownership interest in gas production is better able to keep long-term costs low. Investing in gas production will enable FPL's customers to pay lower prices for gas supply purchases and serve as a low-cost alternative to financial hedges in a market of rising prices. Third, while FPL maintains a strong balance sheet, there are nonetheless limits on its ability to provide the credit support required for a long-term hedging program that provides meaningful protection against rising prices.

Q. Why doesn't FPL simply buy long-term, fixed-price gas?

A. There are significant practical constraints on contracting for long-term, fixed price physical supply. First, these types of contracts are not readily available, as gas suppliers typically only hedge on a shorter-term basis. Second, there is significant credit exposure to a counterparty that has sold at a fixed price. If the market rises after the sale is made, credit support is required to ensure the full value of the position is protected. This can often be problematic for the counterparty, which may not have access to the liquidity required to provide the required credit support. Conversely, FPL could be forced to provide significant credit support to the counterparty if the market price for gas falls, reducing FPL's liquidity and forcing FPL's customers to pay for the credit support. Not even a balance sheet as strong as FPL's is designed for this type of credit risk.

IV. OPPORTUNITIES FOR FPL IN GAS RESERVES

Q. Please describe the current production of natural gas in the U.S.

A. America is currently experiencing an energy boom that will continue for decades, according to the EIA. U.S. production of natural gas overall is projected to grow steadily, increasing 56% from 2012 to 2040. Demand also is expected to grow. In its *Annual Energy Outlook 2014*, EIA forecasts that natural gas will replace coal as the largest source of U.S. electricity by 2035.

Significantly, however, the areas from which natural gas is being produced are changing dramatically. Production from the Gulf of Mexico has declined significantly and is projected to remain flat at the current reduced levels through 2040. Production in the Mobile Bay area, historically a major source of supply for FPL, has also declined steadily. To address these declining reserves, significant efforts were undertaken by the gas industry to research drilling and completion techniques on shale gas formations. The result was improved drilling and well stimulation methods, which considerably increased the yield and recovery rate of natural gas from shale formations, previously thought uneconomic to drill. These improved drilling methods are now being applied in many parts of the U.S. The result has been a tremendous increase in natural gas production activity.

These enhancements in drilling and completion technology have led to a surge in recent years in natural gas production from unconventional sources of natural gas, primarily shale formations. U.S. shale production was 10.3 trillion cubic feet ("Tcf") in 2012, a jump of 21% over the previous year. The rapid increase in shale production is shown graphically in Exhibit TT-3 to FPL witness Taylor's testimony. In 2012, remaining proven U.S. shale reserves increased 276% from 2008 to 129.4 Tcf. In its *Annual Energy Outlook 2014*, the EIA increased its current estimate of technically recoverable shale gas reserves in the U.S. to 664 Tcf, which is enough to serve the entire U.S.'s needs for more than 25 years – from shale gas alone.

In 2000, shale gas provided only 1% of U.S. natural gas production; by 2010 it was more than 20% and the EIA predicts that by 2035, 50% of the natural gas supply in the United States will come from shale gas.

Q. Please describe shale gas and its impact on gas pricing in the U.S.

A. Shale formations are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas. Shale rock is highly porous, yet highly impermeable such that gas gets trapped in the formation. Shale gas refers to the gas that is trapped within the shale formations. A thorough discussion on this unconventional source of natural gas supply is provided in FPL witness Taylor's testimony.

As mentioned previously, shale gas production has been growing rapidly over the past few years and is projected to continue this rapid growth in the future. As a result of the focused investment in shale gas production, the cost of drilling and producing gas from shale has dropped dramatically, leading to lower natural gas pricing from shale gas formations, such as the Woodford Shale in Oklahoma, and an increase in the amount of economically recoverable gas reserves. This combination of lower prices and additional reserves means that now is an excellent time to begin investing in gas reserves.

Q. Why is FPL seeking to invest in gas production?

A. FPL purchases natural gas from more than 25 producers and much of this supply originates from unconventional sources of supply like shale gas. The

gas supply contracts are typically on a one-month to three-year term, and the prices are not fixed. As a result, the prices FPL pays for gas supply are subject to significant change based on market conditions. Natural gas fuel costs are recovered through the Fuel Clause, so FPL customers are directly exposed to gas price volatility.

Because the market price of natural gas is volatile and is a large component of the price of electricity, it can cause significant short- and long-term swings in customers' electric bills. Acquiring an interest in natural gas reserves and drilling operations would provide a longer-term physical hedge against future increases in natural gas costs for FPL's customers. Because the gas reserves are effectively delivering both physical supply and prices at or below FPL's current projections, they would partially supplant the need for financial hedges and allow FPL to reduce the amount of short-term financial hedges that it places. At the same time, by procuring only a portion of FPL's gas requirements through investments in gas reserves, FPL maintains the flexibility to purchase lower-priced gas in the market, if available, for the remainder of FPL's needs. This means that FPL customers can benefit should gas prices unexpectedly or temporarily fall, but will be partially protected by investment in gas reserves should prices rise over both the short- and long-term.

Q. Does FPL currently procure gas from unconventional supply sources, such as shale?

A. Yes. FPL estimates that roughly 70% of its natural gas supply portfolio is made up of shale gas, up significantly from just five years ago. These supply sources include shale formations in Texas, Louisiana, Oklahoma, and Arkansas, and also now include gas sourced from West Virginia, Ohio, and Pennsylvania. FPL will remain heavily dependent on this relatively new source of supply as shale production increases and traditional sources of supply like the Gulf of Mexico continue to decline. FPL recognized the projected growth in the shale gas market, combined with the importance of shale gas as a part of FPL's fuel supply portfolio, and initiated a review of opportunities to acquire an interest in the production of shale gas in order to provide customer savings and price stability. A map of the shale production areas in the U.S. is provided as Exhibit SF-3.

Q. Please describe FPL's review of gas reserve opportunities.

A. FPL began by exploring options with its existing suppliers, specifically looking for shale areas and suppliers that could meet requirements such as production from well-established reserves in close proximity to existing gas transportation pipelines that could deliver the gas efficiently to FPL. FPL then explored options beyond existing suppliers, with producers who would be able to meet FPL's conditions. FPL had initial conversations with more than 25 counterparties. Of those, several were eliminated because they were not interested in a joint venture under the terms FPL required to ensure

savings for FPL customers, or were unwilling to wait the time necessary for FPL to complete the regulatory process. FPL eventually exchanged data with the remaining counterparties, but determined that a few of the opportunities were uneconomic for customers based on engineering consultant reports, which indicated that estimated reserves for these counterparties were lower than what the counterparty had indicated, or that the projected capital expenditures would be higher than what the counterparty had indicated.

Q. Did FPL find a counterparty willing to wait for a final regulatory outcome to consummate a transaction?

A. No. While there were transactions that appeared to be economic, the six-month or more delay in the required regulatory review proved to be problematic. Counterparties are looking for a definitive start date to begin (or continue) their drilling program and cannot wait more than a month or two as market prices fluctuate. Additionally, without a certain end date to the regulatory approval process, counterparties are unable to appropriately manage their annual capital expenditures and drilling programs while attempting to secure sources of funding. Therefore, they were unwilling to take the market price risk of waiting for FPL to gain Commission approval, particularly as there are many other potential drilling partners available that can make commercial decisions more rapidly than FPL.

Q. Was FPL nonetheless able to make arrangements with a counterparty to enter a joint venture for investment in gas reserves and production?

A. In this initial instance, yes; however, as I will discuss later in my testimony, this was only with the assistance of an affiliate that FPL will not have available on a regular basis going forward. FPL has been able to reach an agreement with PetroQuest to invest directly in gas reserves and procure natural gas from the Woodford Shale Gas region (the "Woodford Project").

Q. Please provide an overview of PetroQuest, the counterparty for the Woodford Project.

A. PetroQuest is a well-known and highly regarded independent oil and natural gas company, engaged in the exploration, development, acquisition, and production of oil and natural gas properties in the United States. The company was founded in 1985 and is based in Lafayette, Louisiana. It is a publicly traded company under the symbol PQ, with 2013 revenues of $182 million and a market capitalization of approximately $438 million as of June 16, 2014.

PetroQuest has operations in Oklahoma, Texas, Louisiana, and the Gulf of Mexico. As of December 31, 2013, the company had approximately 48,000 developed net acres and an additional 59,000 undeveloped net acres in the Woodford Shale Gas region. It has proved reserves of approximately 302 Bcf-equivalent, with approximately 64% of this located in the Woodford Shale Gas region.

Q. How has FPL solved the regulatory delay problem for the Woodford Project?

A. USG, an affiliate of FPL, is currently engaged in the exploration and production of oil and natural gas in many regions of the U.S. USG has successfully participated in drilling programs in 12 different shale formations around the country and is a partner in more than 800 producing wells as a non-operating entity. This includes a successful joint venture with PetroQuest in the Woodford Shale Gas region. In order to facilitate a successful joint venture for FPL, FPL and USG worked together to negotiate an agreement with PetroQuest (the "PetroQuest Agreement") for the development of properties not currently being drilled under the joint venture. USG was willing to make accommodations to begin the drilling program with PetroQuest on a schedule mutually agreed to by the parties, effectively providing a no-cost "bridge" for FPL to consummate the transaction.

Upon a determination by the Commission that entering into the PetroQuest Agreement is prudent and that the associated costs may be recovered through the Fuel Clause, all of USG's working interests in these properties and its rights under the PetroQuest Agreement will be transferred to FPL at net book value. If the Commission determines not to approve the prudence and cost recovery of the transaction for FPL, then USG would simply retain its interest and value in the PetroQuest Agreement. Thus, USG is effectively providing a no-cost "bridge" for FPL to consummate the PetroQuest transaction.

Q. Can FPL plan on USG providing a "bridge" for future transactions?

A. No. The PetroQuest Agreement provides a unique opportunity in an area of the country where USG already has substantial experience with a known partner that has produced good operating results. The PetroQuest Agreement presents economics that are favorable to USG and is of a size that fits within its profile. However, this set of factors may not be present for future transactions, and FPL cannot rely upon it occurring again. USG has undertaken to "hand off" this project at net book value to FPL, should the Commission provide the relevant authorizations; however, this free option is, understandably, clearly not part of USG's ongoing business model. For this reason, and as I will discuss in detail later in my testimony, FPL is seeking approval of a framework for future transactions that allows FPL to enter transactions on a more expedited basis, consistent with the market timing and commercial terms that are characteristic of the gas drilling industry.

V. OVERVIEW OF THE WOODFORD PROJECT AGREEMENT

Q. Please provide an overview of the PetroQuest transaction with USG and FPL.

A. On June 18, 2014, USG entered into the PetroQuest Agreement to invest directly in shale gas reserves and receive natural gas from the Woodford Shale region. The PetroQuest Agreement consists of several documents, including:

a. Drilling and Development Agreement ("DDA"): The DDA lays out the terms of development of future wells per the schedule established by PetroQuest. The DDA is included as Confidential Exhibit SF-4. Included as an Exhibit to the DDA is a Form of Operating Agreement that will govern the operation of the wells both during drilling and once they are completed and operational.

b. Tax Partnership Agreement ("TPA"): FPL will have a tax partnership agreement with PetroQuest that will allow FPL to expense, for tax purposes, Intangible Drilling Costs ("IDCs") incurred during drilling. The IRS defines IDCs as capital costs related to items with no salvage value such as labor, fuel and transportation. This enhances the tax treatment for FPL and accordingly further improves the economics of the gas reserves for FPL's customers. The TPA is included as Confidential Exhibit SF-5.

In order to provide an opportunity for Commission review of the prudence of the transaction for FPL's customers, the PetroQuest Agreement is structured such that USG may assign all of its benefits and responsibilities under the Agreement to FPL.

Q. What is PetroQuest's financial incentive to bring in FPL as a non-operating investor for the Woodford Project?

A. The PetroQuest Agreement uses a common approach wherein FPL will be paying a higher percentage of the capital expenditures ("CapEx") than FPL receives as its share of output from a well. This increase in the CapEx share, which is referred to in the industry as the "carry," is meant to provide payment for an ownership interest in the leasehold and associated mineral rights currently owned by PetroQuest that are located in the area where the wells either exist or are to be drilled under the PetroQuest Agreement. Without acquiring the leasehold interest, FPL would not be entitled to any wells drilled or the associated production on this acreage. Additionally, the carry serves to compensate PetroQuest for acting as the operator and to reimburse it for previous expenses incurred and risks taken in purchasing the mineral rights, developing the acreage and enhancing the drilling and completion tactics that increase the productivity of future wells in that acreage. This allows firms such as PetroQuest to obtain capital to continue funding the planned drilling program while still receiving a benefit for the development efforts incurred to date. FPL's investment is defined as a "working interest" in the properties. A working interest is a well-established form of investment in oil and gas drilling operations in which the investor is directly responsible for a portion of the ongoing costs associated with exploration, drilling and production. The working interest owner also fully participates in the profits of the drilling

program, or in the case of the PetroQuest Agreement for FPL, a percentage of the physical gas.

Q. Is this "carry" arrangement common in the oil and gas industry?

A. Yes. As I indicated, the concept of non-operating working interest owners "carrying" the operator is standard throughout the oil and gas industry. While the specifics of the carry arrangements will vary depending on the needs of each set of agreeing parties, some common "carry" arrangements include one or more of the following elements:

- Increased share of all future CapEx paid by non-operating working interest owner to operator for a fixed share of the working interest. This structure will be used by FPL and PetroQuest.
- Upfront payment from non-operating working interest owner to operator followed by a proportional payment CapEx relative to working interest received.
- Increased share of future CapEx paid by non-operating working interest owner to operator until an agreed upon threshold for "total carry" has been met, followed by a proportional payment of CapEx relative to working interest received.

Each potential structure accomplishes the goal of reimbursing the operator for efforts undertaken to date in an arrangement that provides value to both the non-operating working interest owner and the operator. FPL's "carry" arrangement under the PetroQuest Agreement is of the first type listed above.

As mentioned previously, different structures can be employed based on the financing or cash flow needs of the parties, each effectively achieving the same value to each party. In the case of the PetroQuest Agreement, the first structure met both FPL's and PetroQuest's needs.

Q. Will FPL make a payment to USG related to USG's existing interest in the acreage associated with the PetroQuest Agreement?

A. Yes. As previously mentioned, USG has been in a joint venture with PetroQuest since 2010 for acreage in the Woodford Shale ("Original JV"). The acreage described in the Woodford Project is already contained in the Original JV between USG and PetroQuest. As part of the DDA, USG and PetroQuest will reassign acreage from the Original JV to the new Woodford Project. Assuming FPL receives Commission approval, FPL will have to compensate USG for drilling rights in the acreage in which USG had already earned an interest under the Original JV. Thereafter, USG will have no remaining economic or ownership interest in any of the proposed wells contained in the Woodford Project, and FPL will be entitled to the full working interest as described by the DDA.

Q. Please describe the PetroQuest Agreement in greater detail.

A. USG, as the initial party to the agreement, will begin the drilling program with PetroQuest. Upon approval from the Commission, FPL will take assignment from USG of their working interests and continue the drilling program with PetroQuest.

The structure of the PetroQuest Agreement is consistent with common industry practice for contracting to purchase an interest in gas production and reflects the following:

a. PetroQuest will function as the operator for production within an Area of Mutual Interest ("AMI") in the Woodford Shale region. The AMI is defined as 19 sections, within which there are 19 existing horizontal wells operated by PetroQuest. FPL witness Taylor describes the AMI in greater detail. Dr. Taylor also includes a map of the Woodford Shale and the AMI as Exhibits TT-5 and TT-6, respectively. USG has been a partner in 17 of the existing wells. As noted above, FPL will have no rights and will not compensate USG for the existing wells located within the AMI The PetroQuest Agreement contemplates that 38 additional horizontal well locations will be drilled in the AMI;

b. USG (FPL upon Commission approval) will pay PetroQuest a carry amount that reflects a percentage of PetroQuest's share to drill and complete each of the sections under a defined drilling program in the AMI, but may include additional wells in each section in order to economically optimize gas production;

c. In exchange, USG (FPL upon Commission approval) will receive a percentage of PetroQuest's working interest in the natural gas production from each well that is developed in the AMI; and

d. USG (FPL upon Commission approval) will retain the right to "non-consent" or not participate in the future wells upon notice to PetroQuest. This will allow USG (and, ultimately, FPL) to review and analyze production data and operating costs for each proposed well to ensure that customers will benefit from any participation. There is a minimum commitment to drill 15 wells by December 31, 2015. This minimum commitment is subject to PetroQuest meeting mutually agreed to targets on drilling costs, safety, and environmental compliance. The minimum commitment provision is meant to ensure PetroQuest that it will receive enough investment from USG/FPL to justify acquiring the necessary two drilling rigs and assembling the team needed to drill those wells.

It is estimated that FPL will have a total capital expenditure of approximately $191 million under the PetroQuest Agreement. A high-level term sheet providing a more detailed description of the PetroQuest Agreement is included as Confidential Exhibit SF-6 to my testimony.

Q. Does FPL expect that it will be able to meet the minimum commitment on the drilling schedule?

A. Yes. FPL fully expects to drill more than the minimum 15 wells if the drilling program is running properly, and as mentioned previously, the commitment only applies if PetroQuest meets the prescribed drilling cost, safety and environmental targets on wells that have been drilled. Per the current

schedule, PetroQuest plans to begin drilling 14 of the planned new wells before the end of 2014. USG intends to participate or non-consent for these new wells prior to assignment of the PetroQuest Agreement to FPL. It is assumed the first 14 wells will be consented to by USG prior to transfer to FPL, thus committing FPL to consent to just one more well prior to December 31, 2015. All 38 wells proposed are expected to begin flowing gas by the end of 2015.

Q. Please describe how the PetroQuest Agreement will be transferred from USG to FPL.

A. Upon the Commission's determination that the PetroQuest Agreement is prudent for FPL and the costs recoverable through the Fuel Clause, USG will transfer its working interest to FPL at net book value based on the capital invested by USG prior to the transfer, less the value of depletion of reserves. FPL witness Ousdahl will discuss the basis for the transfer price to FPL in more detail.

As mentioned previously, PetroQuest plans to begin drilling approximately 37% of the planned new wells before the end of 2014. Of the 14 wells to be drilled in 2014, only four will begin producing gas prior to the assumed January 1, 2015 assignment date to FPL. The remaining 10 wells will still be undergoing some level of completion prior to the first flow of gas. As a result, the great majority of gas from these wells will be for the benefit of FPL's customers if the Commission approves FPL's request by the end of

2014. Once the PetroQuest Agreement is assigned to FPL, FPL will receive the rights to its share of the physical gas produced from the Woodford Project without any charge to FPL's customers separate from recovery of the revenue requirements associated with this proposed investment (i.e., FPL will recover the cost of exploration and production instead of purchasing gas at market pricing), plus applicable transportation and operating costs, which are all taken into account in the calculation of customer savings presented later in my testimony. Going forward, FPL would decide whether to participate in the development of new wells in the Woodford Project based on expected production costs, natural gas market price forecasts, and expected production volume.

During the drilling phase, FPL will provide the Commission in its annual Fuel Clause final true-up filing a report on its decisions related to the number of wells in which it participates. Additionally, FPL will report annually its costs and the volume of natural gas received during the life of the proposed investment in the Fuel Clause. FPL witness Ousdahl will discuss accounting and reporting in more detail.

Q. What incremental services, functions and staffing will be required at FPL to manage gas reserves investments?

A. The primary areas of responsibility for the management of FPL gas reserves are accounting, technical services and business management. FPL, through an outsource provider experienced in oil and gas back office accounting, will

manage the billing reconciliation process with PetroQuest and process and report on the costs through the Fuel Clause. FPL will use industry standard joint interest billing software to track and reconcile all costs, royalties, taxes and fees from PetroQuest. Technical services will be provided by USG to FPL under established affiliate services terms. Technical services include reservoir engineering and operational guidance during the drilling and production phases. Business management will be handled within FPL's existing EMT business unit. Financial and operational decisions related to FPL's investments in gas reserves will be made by FPL. FPL proposes to include for recovery in the Fuel Clause any incremental costs that are incurred to manage these activities.

VI. ECONOMIC EVALUATION OF THE WOODFORD PROJECT

Q. How did FPL estimate the economic benefits of the transaction?

A. FPL utilized estimated natural gas production and projected costs provided by FPL witness Taylor. These inputs were applied to FPL's economic models containing current projections on fuel usage and market pricing to calculate FPL's revenue requirements needed to support the investment.

Q. Can you describe how the volume of expected gas production was estimated for FPL's prospective investment in the wells in the Woodford Project?

A. Yes. FPL witness Taylor performed what is referred to as an Estimated Ultimate Recovery ("EUR") analysis, which is described in detail in his testimony. Dr. Taylor utilized production data from the existing wells in the AMI to estimate the future volumes of natural gas reserves that can reasonably be expected to be recovered from the new wells.

Within any given section of the AMI, there are numerous working interest owners besides PetroQuest. Over the 19 sections of the AMI, PetroQuest and USG currently have on average 60% of the working interest jointly, meaning the other 40% is represented by other organizations or individuals. These other 40% working interest owners have varying rights to non-consent to future wells, meaning they have the right to decide whether to participate in the drilling of a respective well. If the other working interest owners non-consent to a well, FPL is permitted, but not required, to pay for their share of the drilling costs and receive their share of the well's output in return. For purposes of the evaluation, FPL has conservatively assumed that all working interest owners with such rights non-consent on all 38 proposed wells, such that FPL and PetroQuest would step into these other working interest owners' rights under the carry structure terms of the PetroQuest Agreement. This conservative assumption results in the highest level of projected capital

expenditure by FPL and the highest level of projected gas production for FPL. As a sensitivity to this base case, FPL also has calculated the estimated customer savings if all other working interest owners do consent. In this event, FPL will have an estimated capital expenditure of approximately $119 million under the PetroQuest Agreement. The results of the economic evaluation are presented later in my testimony.

Q. What steps has FPL taken to ensure that the estimate of production from the Woodford Project reasonable?

A. First of all, Dr. Taylor has extensive academic training, as well as many years of experience, in estimating gas reserves. Dr. Taylor's direct testimony describes his analysis in detail. In addition, FPL retained Forrest A. Garb & Associates, Inc. ("FGA"), to provide an independent, confirmatory analysis. FGA performed a formal reserve evaluation, which included an evaluation of reserves and future net revenues. FGA analyzed the existing wells in detail to determine their own type curves and reviewed the maps, operating expenses, CapEx, and development schedule. FGA concluded that Dr. Taylor's analysis is a reasonable estimate of the volumes of gas to be expected from the drilling program and, in fact, developed independent estimates which almost exactly coincide with Dr. Taylor's.

FPL intends to rely on FPL witness Taylor's expertise on a going-forward basis to evaluate its non-consent option under the PetroQuest Agreement.

Q. How did FPL determine the revenue requirements for FPL's interest in the Woodford Project?

A. Under the current drilling schedule, FPL's capital investment will be required in the first year after taking assignment, during which time the planned new natural gas wells will be drilled. Then, minimal production, processing and gathering costs will be incurred over the remaining 30-plus year economic life of the wells. The economic life of a well is determined by comparing the operating cost of a well to the market price of the natural gas. Production from a well remains economic when the value of the gas produced from the well is greater than the ongoing operating costs. The revenue requirements associated with FPL's investment reflect the assumption that FPL will invest in the development of all planned wells permitted by the PetroQuest Agreement.

To perform an economic evaluation of this investment, FPL's revenue requirements were converted to an estimated cost per MMBtu of natural gas, using the total expected gas production volumes provided by FPL witness Taylor. As shown on my Exhibit SF-7, that production is expected to be at its highest annual level during the first few years of the transaction and peak in the year 2016 at an average volume of approximately 46 million cubic feet ("MMcf") per day, decreasing to around 7 MMcf per day in 2030. This production curve closely aligns with the capital investment spend curve discussed above.

It is important to note that FPL's methodology for forecasting fuel prices has been reviewed and approved by the Commission as reasonable in a number of Commission dockets. See, e.g., Docket Nos. 110309, 130001-EI and 130009-EI. The results of FPL's economic evaluation are provided on the attached Confidential Exhibit SF-8.

Q. What assumptions did FPL make on the gas transportation needed to physically deliver the gas from the Woodford Project?

A. For purposes of the economic evaluation, FPL assumed it would procure firm transportation on an existing pipeline system to accept gas from the gathering system and deliver it to the Perryville Hub in Louisiana. From there, FPL would utilize its existing agreement on the Southeast Supply Header (see Exhibit SF-1) to move the gas into either FGT or Gulfstream for delivery into Florida. The costs associated with this incremental natural gas transportation are included in the economic evaluation included as Confidential Exhibit SF-8 and reflect a conservative approach to how this transaction would be managed.

Q. When would FPL's customers start to benefit from FPL's investment in the Woodford Project?

A. The benefits will start immediately upon FPL taking assignment of the PetroQuest Agreement with customer savings beginning in year one, and will continue over the productive life of the Woodford Project wells. The PetroQuest transaction is projected to be highly beneficial for FPL's customers, providing needed natural gas at a lower and more stable cost per

MMBtu than would otherwise be incurred if the same amount of natural gas were to be purchased at market prices.

Q. What are the estimated revenue requirement benefits for customers?

A. The revenue requirements associated with the project, on a cumulative net present value ("NPV") basis, are projected to be approximately $107 million lower than the cost of the natural gas FPL would otherwise be required to purchase over the expected economic life of the project. Further, as can be seen from the production profile in Exhibit SF-7, approximately half of the expected gas would be produced in the first seven years after taking assignment of the PetroQuest Agreement, resulting in $47 million in customer savings during that period. As was mentioned previously, FPL ran a sensitivity that assumed all other working interest owners consent to their participation in the PetroQuest Agreement drilling program. This results in customer savings of approximately $61 million on capital expenditures of $119 million.

In addition to the customer savings, it is also important that the proposed investment also will provide long-term price stability for a portion of FPL's natural gas needs. By disassociating a portion of FPL's natural gas purchases from volatile market prices, and instead obtaining a portion of its natural gas requirements at a stable, lower cost of production, this investment will allow the Company to replace a portion of its short-term financial hedging program for fuel purchases with, in effect, a longer-term physical hedge.

Q. Can you provide an example of how investment in gas reserves also provides price stability?

A. Yes. By way of simplified illustration, suppose that FPL procures 25% of its gas requirements from reserve projects at a stable, unit cost of production. Further suppose that the price of gas in Year 5 turns out to be $2.00 per MMBtu higher than the forward curve projected in Year 1. Without the investment in gas reserves, FPL's customers would have to pay the full additional $2.00 per MMBtu in Year 5, because FPL's short-term financial hedging program does not extend that far out in time. However, because FPL would be procuring 25% of its gas requirements on a cost-of-production basis that is independent of what the Year 5 market price turns out to be, FPL's customers would only pay $1.50 of this $2.00 per MMBtu increase in the Year 5 market price. This is a valuable form of longer-term volatility reduction that FPL simply cannot offer through its existing financial hedging program.

Q. How would the customer savings be affected by movements in forecasted gas prices or changes in the expected production from the wells?

A. FPL evaluated the impact to customers across assumed movements in gas prices and production levels. The gas price scenarios considered are consistent with what is included in the Company's annual TYSP filing. The base case for customer savings assumed the TYSP Base fuel cost forecast, with sensitivities to the High fuel cost forecast and the Low fuel cost forecast that reflect the same volatility factor of 21% used for the TYSP. Additionally,

the Base production levels for the project were varied to a High case, with estimated production being adjusted upwards by 10%, and a Low case, with estimated production being adjusted downwards by 10%. As discussed by FPL witness Taylor, the 10% adjustment figure is considered to be an industry standard for capturing the potential upside or downside case in production. A summary of the range of impacts on customer savings is shown below.

Sensitivity Cases for Customer Savings

	"Low Fuel"	"Base Fuel"	"High Fuel"
Low Production	($14.4 MM)	$72.6 MM	$159.5 MM
Base Production	$10.3 MM	**$106.9 MM**	$203.5 MM
High Production	$34.1 MM	$140.4 MM	$246.7 MM

As can be seen from this table, the Woodford Project is projected to generate fuel savings for FPL customers in all but one out of the nine analyzed cases, with the most likely case yielding savings of approximately $107 million on an NPV basis.

In the event lower market fuel prices were to materialize, as in the “Low Fuel” sensitivity cases, FPL’s customers would enjoy substantial reductions in their electric bills due to the reduced cost for gas that FPL would acquire at those lower market prices. By way of example, if the “Low Fuel – Low Production” scenario materialized, the lower price that FPL would be paying

on the 97% of its natural gas requirements that would not be provided under the PetroQuest Agreement would reduce FPL's typical 1000-kWh residential customer bill in 2016 by $4.93 per month. In contrast, the cost impact of the gas provided under the PetroQuest Agreement would only increase that monthly bill by $0.07, leaving a significant net reduction of $4.86 per month. In other words, in the event that natural gas prices turn out to be lower than projected, it would be a very positive circumstance for our customers.

Q. Is it appropriate to recover the costs of FPL's Woodford Project through the Fuel Clause?

A. Yes, as will be described in greater detail by FPL witness Ousdahl, it is appropriate to recover these costs through the Fuel Clause. The Woodford Project is eligible for Fuel Clause recovery under Item 10 of Order No. 14546 and subsequent decisions interpreting it, because it is reasonably projected to lower the delivered cost of fuel and the costs for the project are not recognized or anticipated in the cost levels used to determine current base rates.

VII. GUIDELINES FOR REGULATORY TREATMENT OF FUTURE GAS RESERVE AGREEMENTS

Q. Is FPL considering future potential opportunities to invest in gas reserves?

A. Yes. To the extent the proposed investment in the PetroQuest transaction is approved by the Commission as prudent and recoverable through the Fuel

Clause, FPL will be in a position to evaluate similar investment opportunities to achieve an expanded and continuing level of fuel cost savings and price stability for its customers. The PetroQuest transaction described herein is an example of just one agreement in a broad market.

Q. What types of projects will FPL pursue for future investments in gas reserves?

A. As further described in the testimony of FPL witness Taylor, there are a number of different classifications of reserves that are determined by current technological and economic conditions, and the distinction between proved, probable and possible reserves, as defined for reporting purposes, can be relatively small. Because producers typically own a mix of each category of reserves, the transactional opportunities would be substantially reduced if FPL were to pursue only those reserves labeled as Proved. This is demonstrated by the Woodford Project, where 25 of the proposed wells are characterized as Proved, while 13 are characterized as Probable. All of the proposed wells in the Woodford Project are in close proximity, so there is only a low chance of substantial differences in productivity among the wells regardless of their current classification.

Another dimension in the range of potential projects available in the market is the mix of hydrocarbons. FPL witness Taylor explains that production is characterized by a wide array of commodities, from methane to natural gas liquids ("NGLs") to oil. FPL will focus on the development of natural gas

resources to physically supply its power plants, but also understands the value of NGLs and oil and the real economic benefit in lowering the ultimate cost of natural gas from having those hydrocarbons present. Thus, while the Woodford Project produces dry gas, when analyzing future projects the value of NGLs and oil will be considered as well.

As mentioned previously, FPL currently has natural gas supply from sources which include shale formations in Texas, Louisiana, Oklahoma, and Arkansas, West Virginia, Ohio, and Pennsylvania. FPL will remain heavily dependent on these relatively new sources of supply as shale production increases and traditional sources of supply like the Gulf of Mexico continue to decline. In order to maintain a flexible and robust portfolio, FPL will pursue transactions that provide geographic diversity, such that it does not become too reliant on any one production area.

Finally, FPL believes it is important to pursue a portfolio of assets that maintains an economically beneficial stream of gas production for our customers. In order to accomplish this, a mix of all categories of reserves must be considered so as not to limit FPL's opportunities to deliver economic benefits for our customers. Additionally, considering a mix of natural gas and NGLs will be important as there is a real potential to "buy-down" the cost of gas with the presence of NGLs. FPL witness Taylor discusses NGLs in more detail in his testimony. Ultimately, a mix of different reserve types will help

provide for a steady flow of physical gas deliveries from natural gas production on favorable terms for FPL's customers.

Q. Are there constraints that limit FPL's ability to enter into future beneficial agreements for gas production similar to the PetroQuest Agreement?

A. Yes. As described earlier in my testimony, most counterparties to date have been unwilling to wait for standard regulatory approval timing in order to execute an agreement, and FPL cannot depend on having USG or any other entity "stand in" until the regulatory review process is completed and then to simply hand over the project at net book value. Moreover, because of the volatile nature of the gas markets, the start date of a transaction can have significant impacts on the value as viewed by the counterparty, as well as the benefit to FPL's customers.

Q. How does FPL propose to accommodate the need for prompt action on future gas reserve opportunities?

A. FPL is proposing a set of guidelines, which would provide a framework to allow FPL to consummate a transaction when an agreement has been reached that meets the guidelines, without having to wait on the normal several-month-long Commission approval process.

Q. Has FPL developed proposed guidelines within which FPL could make timely investment decisions on future gas reserve opportunities?

A. Yes. In order to ensure that the benefits available to customers can be secured in a timely fashion, FPL requests that the Commission approve guidelines for

gas reserve projects, such that FPL would be eligible to recover through the Fuel Clause the revenue requirements for future projects that meet those guidelines, subject to the usual review of the prudence of fuel-related transactions that the Commission conducts in Fuel Clause proceedings.

By allowing FPL to move forward on future projects without the need for prior approval, the Commission would facilitate FPL's ability to take advantage of additional opportunities to achieve lower and more stable gas prices for customers, while maintaining the Commission's ability to review those projects in the same manner that it reviews other fuel-related transactions.

Q. Would the adoption of guidelines be consistent with how the Commission has administered the short-term hedging programs?

A. Yes. Starting with a set of initial guidelines in 2002 and then expanding and refining those guidelines in 2008, the Commission has worked with FPL and the other investor-owned utilities to develop and implement both a process and substantive guidance for what should and should not be part of the short term hedging programs. This collaboration has been effective in giving the Commission a clear line of sight into the nature and extent of the utilities' planned short-term hedges, while at the same time giving the utilities comfort that they can execute on what are often very substantial financial positions without having their decisions second-guessed as market conditions unfold. Similar to the hedging guidelines, the Commission could establish a

framework whereby the company could enter into several transactions that are within a range of predetermined terms/guidelines. Also similar to the hedging guidelines, the Commission should acknowledge that there are potential drilling/production risks with pursuing gas assets and as long as the transaction was within the guidelines, it cannot be deemed imprudent based on the results.

Q. What are FPL's proposed guidelines?

A. FPL's proposed guidelines are attached as Confidential Exhibit SF-9. Certain key provisions in the guidelines need to be kept confidential, because their disclosure would disadvantage FPL in negotiating with potential counterparties for future gas reserve projects, which in turn could reduce the fuel savings for FPL's customers. Generally, the guidelines describe the parameters under which FPL will be able to transact on future gas reserve opportunities. They cover the scope of FPL's project participation as a percentage of average daily burn, as well as on an annual capital expenditure basis. They also describe how the deals will be evaluated against FPL's then-current forecast of natural gas prices. Finally, the guidelines will discuss the composition (percentage of methane versus NGLs of gas reserves that FPL can pursue).

Q. Are there other examples of industry participants establishing guidelines with their commissions for future transactions around gas reserves?

A. Yes. There are other industry examples which exist. For example, NorthWestern Energy included acquisition criteria for gas reserve properties

in its current (2012) Natural Gas Biennial Procurement Plan, as to which the Montana Public Service Commission commented favorably in May 2013. While each utility is different in terms of the mix of their fuel portfolio and every jurisdiction is unique in some way, there has been recognition that establishing a framework for future deals will help the utility to transact on a more expedited basis in ways that will benefit customers. Essentially, there are different specifics on the composition of reserves, but the same general ideas in terms of the benefits to customers and future gas prices.

VIII. CONCLUSION

Q. Please summarize why investing in gas reserves will benefit FPL's customers.

A. Fundamentally, investing in gas reserves is about delivering lower and more stable prices for the commodity that is by far the largest component in FPL's fuel bill: natural gas. The Woodford Project is projected to deliver approximately $107 million of customer savings on a net present value basis. This is an extremely attractive financial opportunity for our customers. While future transactions may not present the level of savings the Woodford Project does, the proposed guidelines will ensure that future gas reserve projects are also projected to deliver net savings.

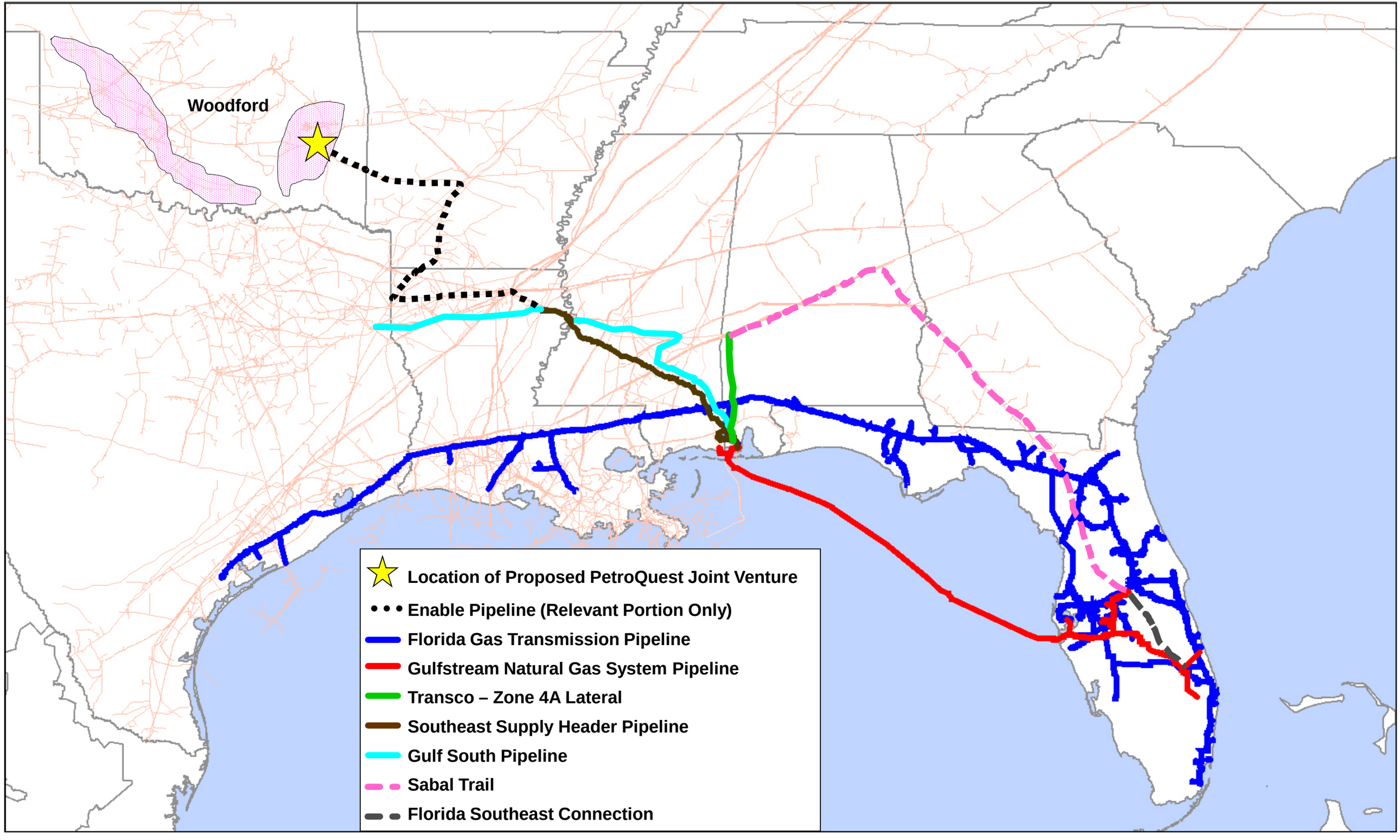
At the same time, gas reserve projects will help stabilize gas costs for our customers over a longer time frame than can be realistically achieved with FPL's existing financial hedging program. That program extends only 12 to 24 months into the future, with prohibitive costs and credit risks associated with extending it for a longer period of time. However, similar to the current hedging plan, the volatility in the fuel bill will be greatly reduced as additional reserves are added to the portfolio. The benefit of the gas reserves projects is that they will provide gas at a well-understood and predictable cost of production for decades and allow for longer-term volatility reduction without the potential collateral and liquidity issues of the current hedging program.

Finally, if market prices for gas were to fall and were expected to remain low in the future, FPL could quickly curtail customer exposure to gas reserve revenue requirements by simply non-consenting on any wells yet to be drilled in the Woodford Project and not continuing to invest in replacement gas reserve projects. Once these steps were taken, the rapid gas production and associated depletion in existing wells would reduce the remaining investment to a small fraction of its original value in just a few years. In short, gas reserve projects offer customers an unparalleled opportunity for substantial savings and certainty in the face of a volatile gas market.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit SF-1: Map of FPL's Existing Natural Gas Transportation



Map of FPL 's Existing Natural Gas Transportation, Exhibit SF-1, Page 1 of 1

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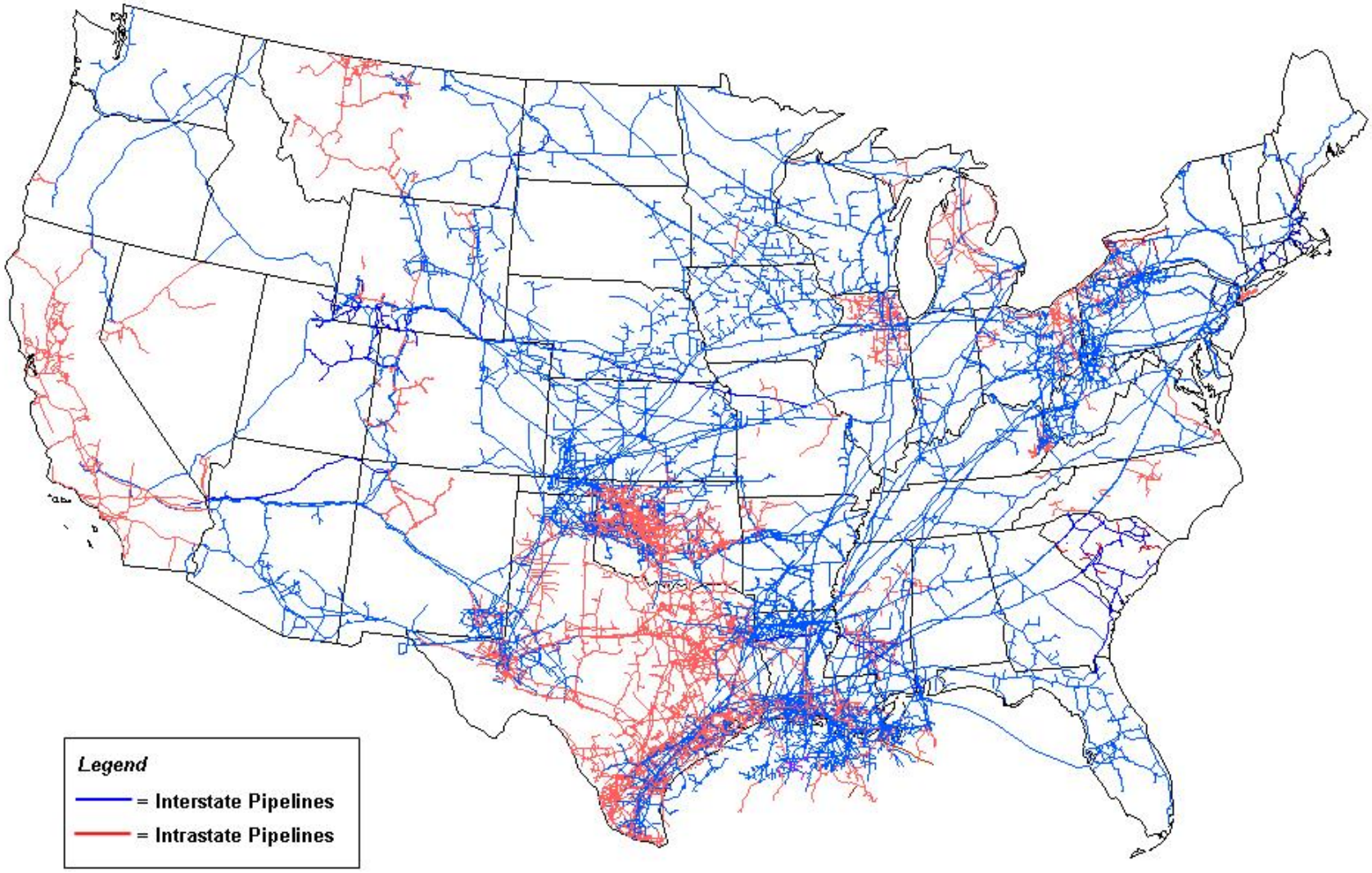
EXHIBIT SF-2: Map of U.S. Natural Gas Transportation Pipelines



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

EXHIBIT SF-3: Map of U.S. Shale Gas and Oil Production Locations

Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

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Map of U.S. Shale Gas and Oil Production Locations
Exhibit SF-3, Page 1 of 1

Exhibit SF-4
Drilling and Development Agreement
Pages 1 - 78
IS CONFIDENTIAL IN ITS ENTIRETY

Exhibit SF-5
Tax Partnership Agreement
Pages 1 - 19
IS CONFIDENTIAL IN ITS ENTIRETY

TERM SHEET
TO PURCHASE AND DEVELOP GAS RESERVES

This Term Sheet ("Term Sheet") sets forth below the principal terms and conditions of the sale and development of certain oil and gas interests by PetroQuest Energy, Inc.'s wholly-owned subsidiary, PetroQuest Energy, LLC ("Seller" or "PQ") to and with Florida Power and Light Company ("FPL") and USG Properties Woodford I, LLC ("USG"), (collectively "Buyer") in the Woodford Shale in Oklahoma ("Agreement").

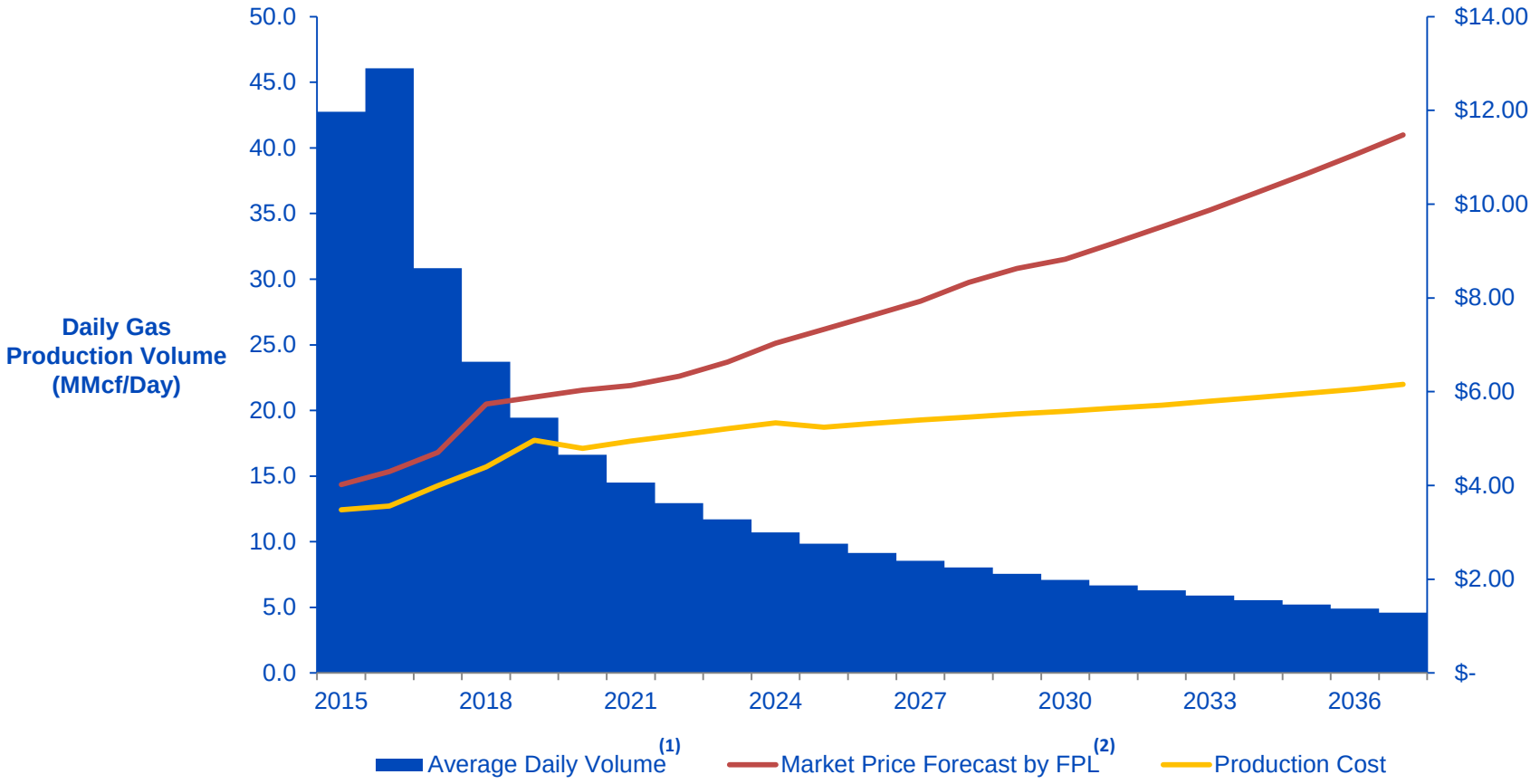
Counterparty:	USG is the initial transacting counterparty and would, subject to Florida Public Service Commission approval, transfer all of its rights and obligations under the Agreement along with its undivided Working Interest in the AMI, as outlined in the MOU between FPL and USG, to FPL or a wholly-owned FPL subsidiary at net book value which is estimated to be $68.4 million as of January 1, 2015. Seller is the contracting party as a Working Interest owner and the operator of the subject assets within the AMI. The Parties each own equal undivided Working Interests in and to the oil, gas or mineral leases and interests in the well to be drilled. USG may transfer all of its rights and obligations under the Agreement to FPL or any other affiliated third party.
Area of Mutual Interest:	The 19 sections of land identified by Seller in the Woodford Shale (hereinafter, Area of Mutual Interest or "AMI") which contains 19 existing flowing wells that will not be part of this transaction, and 38 wells to be drilled.
Development and Drilling Costs:	The drilling and completion of the remaining wells in the AMI shall commence in accordance with Seller's drilling schedule, which is incorporated in the final, definitive Agreement. Unless Buyer non-consents to participating in a section(s) as hereinafter set forth, Buyer agrees to pay [redacted] of the Party's combined Working Interest share of the costs to drill and complete each well and Buyer shall earn [redacted] of the Party's combined Working Interest.
Operator:	Seller is the Operator and shall provide Buyer with drilling, completion, and production data, including well logs and other acquired engineering data by well. Seller shall provide or contract for all appropriate equipment and services necessary to meet the drilling schedule. Buyer has the right to audit Seller data as it pertains to any development under the Agreement. Buyer shall pay operating expenses incurred by Seller to the extent chargeable under Applicable Operating Agreement related to Buyer's Working Interest share with no carry.

Lease Assignment:	Within 5 Business Days of the later of (i) Buyer's payment of its share of drilling costs (inclusive of the carried costs) set forth in an authorization for expenditure with respect to the estimated total drilling costs for a proposed well, or (ii) the spud date for such commitment well, the Parties shall execute, acknowledge and deliver an assignment from Seller to Buyer for a portion of the leased acreage and mineral rights in which the commitment well resides. Such assignments shall be made progressively on a well by well basis within each section.
Drilling Elections:	Buyer is committed to participate in drilling at least 15 wells in the AMI by December 31, 2015. Buyer may non-consent on a well-by-well basis, however, should Buyer fail to participate in at least 15 proposed wells by December 31, 2015, Buyer shall pay Seller [redacted] per well for each well short of the lesser of 15 wells or the number of wells proposed before December 31, 2015. This payment is waived in the event that: (i) Seller's average drilling costs exceeds [redacted] for the four wells immediately preceding the non-consented well; or (ii) Seller's operation of assets in the AMI is in material non-compliance with or material violation of a material Environmental or Safety Law. Should Buyer non-consent on a well, Buyer shall not pay any carry costs for that well and will not be entitled to output from that well. Buyer may non-consent on a well-by-well basis to any proposed wells after December 31, 2015 without penalty in accordance with the Applicable Operating Agreement. If Seller fails to commence drilling operations for a proposed well on or before one hundred twenty (120) days following Buyer's election (deemed or otherwise) whether or not to participate in such operations, then Seller shall resubmit a new well proposal to Buyer prior to conducting operations for such well.
Take In Kind Gas and Delivery:	Seller acknowledges that Buyer has the right under each Applicable Operating Agreement to take all (and not less than all) of its entitlement to gas production in kind, provided that any such election to take in kind must be made in writing not less than thirty (30) Days prior to the Day upon which Buyer will commence taking its share of production in kind.
Lease Accounting and Royalties:	Seller shall be responsible for all lease accounting and royalty issues of any kind on both Seller's and Buyer's share of production in accordance with the relevant lease provisions covering the lands developed under the Agreement, and Buyer would pay Seller for Buyer's portion of the royalty payments. All royalties due third parties with respect to gas delivered to Buyer shall be based on the value of gas applicable to the Delivery receipt point or on terms otherwise acceptable to Buyer.

Tax Benefit:	A tax-partnership mechanism has been put into place to assure Buyer's ability to deduct the IDC, including the "carried" portion, in proportion to Buyer's capital contributed.

AMI Procedures:	The AMI will be administered in accordance with the following provisions:
	• Buyer or Seller may lease or acquire AMI Interests from third parties that have a working interest in the AMI
	  o Such acquisition may occur due to a non-consent by the third party to a Seller proposed well in the AMI
	  o In the event of such third party non-consent, Buyer has the right but not the obligation to acquire the third party's interest in the well
	• In the event either Party enters into an agreement to acquire any AMI Interest including through a third party non-consent, then such Acquiring Party shall notify the other, Non-Acquiring Party in writing of such acquisition and offer the Non-Acquiring Party an opportunity to participate in that interest (Offered AMI interest)
	• The Non-Acquiring Party may elect to acquire its AMI Share in the Offered AMI Interest by notifying the Acquiring Party in writing within 15 days of notice
	  o The "AMI Share" of each Party is as follows:
	  ▪ PQ
	  ▪ USG/FPL [redacted]
	  o The "AMI Cost Share" of each Party is as follows:
	  ▪ PQ
	  ▪ USG/FPL [redacted]
	• If the Non-Acquiring Party does not elect to acquire its AMI Share of the Offered AMI Interest, then such Non-Acquiring Party shall have no further rights to the Offered AMI Interest and such Offered AMI Interest shall be excluded from this Agreement
	• If the AMI Interest covers contiguous lands both within and out of the AMI, the Acquiring Party shall only be obligated to offer the portion of the AMI Interest covering lands within the AMI to the Non-Acquiring Parties

PetroQuest Transaction Production Profile



(1) Based on estimates

(2) As of October 2013

Docket No. 140001-EI
PetroQuest Transaction Production Profile
Exhibit SF-7, Page 1 of 1

CONFIDENTIAL

Results of FPL's Economic Evaluation

A	B	C	D	E	F = C + D + E	G = F / B	H	I = B x (H-G)	J	K = I x J
Year	Annual Production (Bcf)	Operating Expenses ($MM)	Depreciation ($MM)	Return Rate[2] ($MM)	Revenue Requirement ($MM)	Effective Cost ($/MMBtu)	FPL Market Price Forecast ($/MMBtu)	Undiscounted Customer Savings ($MM)	FPL Discount Factor[3]	Discounted Customer Savings ($MM)
2015	15.6	[redacted]				$3.48	$4.02	$8.4	0.9302	$7.8
2016	16.8					$3.56	$4.30	$12.4	0.8649	$10.7
2017	11.3					$4.00	$4.70	$8.0	0.8043	$6.4
2018	8.7					$4.40	$5.74	$11.6	0.7480	$8.7
2019	7.1					$4.96	$5.89	$6.6	0.6956	$4.6
2020	6.1					$4.79	$6.03	$7.6	0.6468	$4.9
2021	5.3					$4.94	$6.13	$6.3	0.6015	$3.8
2022	4.7					$5.08	$6.33	$5.9	0.5594	$3.3
2023	4.3					$5.21	$6.63	$6.1	0.5202	$3.2
2024	3.9					$5.34	$7.03	$6.6	0.4837	$3.2
2025	3.6					$5.24	$7.33	$7.5	0.4498	$3.4
2026	3.3					$5.32	$7.63	$7.7	0.4183	$3.2
2027	3.1					$5.39	$7.93	$7.9	0.3890	$3.1
2028	2.9					$5.46	$8.33	$8.4	0.3617	$3.1
2029	2.8					$5.52	$8.63	$8.6	0.3364	$2.9
2030	2.6					$5.58	$8.83	$8.4	0.3129	$2.6
2031	2.4					$5.65	$9.17	$8.6	0.2910	$2.5
2032	2.3					$5.71	$9.52	$8.7	0.2705	$2.4
2033	2.2					$5.80	$9.88	$8.8	0.2516	$2.2
2034	2.0					$5.88	$10.26	$8.8	0.2340	$2.1
2035	1.9					$5.97	$10.65	$8.9	0.2176	$1.9
2036	1.8					$6.05	$11.06	$9.0	0.2023	$1.8
2037-65	23.1					$7.88	$17.16	$213.8	0.0894	$19.1
Totals[1]	**137.8**	**$323.2**	**$190.8**	**$195.5**	**$709.4**			**$394.7**		**$106.9**

Notes:

(1) Totals are for 2015-2065, an assumed 50 year project life. Totals may not add due to rounding.

(2) Return rate includes return on the assets and return of financing costs.

(3) Based on a discount rate of 7.5%, which reflects FPL's weighted average cost of capital.

Docket No. 140001-EI
Results of FPL's Economic Evaluation (Confidential)
Exhibit SF-8, Page 1 of 1

GAS RESERVES GUIDELINES

Florida Power and Light Company's ("FPL" or "the Company") goals in purchasing natural gas to supply its power plants are reliability, price stability and low cost. Participating in gas reserve projects through a joint development agreement is a form of long-term hedging that can be a valuable supplement to FPL's existing short-term hedging program.

The Florida Public Service Commission ("Commission") previously has found "that the purpose of hedging is to reduce the impact of volatility in the fuel adjustment charges paid by an IOU's customers, in the face of price volatility for the fuels (and fuel price-indexed purchased power energy costs) that the IOU must pay in order to provide electric service." Further, the Commission found the primary purpose of hedging is to "reduce the variability or volatility in fuel costs paid by customers over time." *(Order No. PSC-08-0667-PAA-EI, Attachment A, page 2)*

Because of the natural depletion rate of shale-based gas production, it is understood that FPL will need to continue pursuing new gas reserve project opportunities to compensate for declining production from existing projects, as well as to expand the percentage of FPL's gas requirements that are hedged long-term. Moreover, it is clear that market participants and potential counterparties expect and value the ability to respond to opportunities quickly. Accordingly, a successful market strategy requires an established framework within which FPL may negotiate and consummate transactions.

I. SCOPE OF GAS RESERVE PROJECT PARTICIPATION

- Gas reserve projects will help reduce the overall portfolio price volatility and supply risk. The transactions will lessen the impact to customers if gas prices spike or rise and stay high for an extended period of time. Even though each transaction individually will represent a very small percentage of the Company's supply portfolio, collectively these transactions would help dampen the effects of price volatility.
- Guideline I.A: Overall, the estimated aggregate output of all gas reserve projects will not exceed the following percentages of FPL's projected average daily natural gas burn:

Year	Maximum Volume as a Percentage of Average Daily Burn
2015	[redacted]
2016	
2017	

- Guideline I.B: FPL will provide an annual update to the three year window presented in Guideline I.A as part of its Risk Management Plan filed in early August each year with the Estimated/Actual Testimony filing.
- Guideline I.C: Because gas reserve transactions provide a hedging benefit for FPL and its customers, the estimated aggregate volumes of natural gas from all gas reserve transactions in each calendar year will be netted against the amounts that FPL forecasts

GAS RESERVES GUIDELINES

to hedge pursuant to FPL's annual Risk Management Plan. FPL will hedge the net amount as prescribed in the Risk Management Plan.

- Guideline I.D: FPL will not obligate itself to invest more than [redacted] in the aggregate on gas reserve projects over the course of any one calendar year.

II. CUSTOMER SAVINGS

- Investment in gas reserve projects can offer significant price stability for the volumes produced, while also providing customer savings in a market of rising gas prices. A benefit of a well-managed gas reserves investment program is secure low-cost natural gas for our customers for years into the future that delivers an expected pricing discount relative to the forward curve. Since typical wells produce for 40 to 60 years, gas production joint ventures can provide stable pricing for decades to come, thus helping to achieve the Commission's stated goal for hedging to reduce price volatility for customers.
- Transactions of this type can result in lost opportunities for savings in the fuel costs to be paid by customers if fuel prices actually settle at lower levels than at the time the gas reserves investments were made. However, since only a portion of FPL's fuel requirements is procured through gas reserves investments, FPL maintains the ability to purchase low priced fuel when the opportunity arises. Moreover, in some projects it may be possible to delay the drilling plan and/or reduce the production volume from existing wells in the event of unexpected price declines. Conversely, when fuel prices settle at higher levels than at the time the gas reserves investments were made, increased customer savings are a direct result of the gas production joint venture.
- Guideline II.A: Evaluation of the prudence of FPL's having entered into a new gas reserve project will be based on a showing that the project is estimated to generate savings for customers on a net present value basis, relying solely on information relative to these Guidelines available to FPL at the time the transaction was entered, including the use of an independent third party reserve engineering report and FPL's standard fuel price forecasting methodology.

III. SUPPLY DIVERSITY

- Gas reserve projects will provide beneficial geographic diversity of fuel supply. Catastrophic events, such as hurricanes, affect FPL's ability to procure and deliver fuel. Investments in multiple gas reserves across various regions will reduce the impact of a single event disrupting FPL's entire fuel supply.
- Gas reserve projects also will increase the diversity of FPL's supply from a physical perspective, as well as a financial one. The longer time frame of these investments

GAS RESERVES GUIDELINES

offers diversity when compared to the current financial and physical contract lengths in the existing hedging program.

- FPL intends over time to transact with a wide range of suppliers so as to minimize concentration of supply with any one producer. This will allow FPL to transact in multiple regions and will also provide for reduced credit exposure to any one entity.
- Guideline III.A: FPL will only enter into transactions for onshore gas reserve projects, located in areas with reserves that have a well-established history of gas production. Florida does not meet these criteria.
- Guideline III.B: Because one of the primary purposes of gas reserve projects is a physical source of supply to serve its substantial gas needs, FPL will only enter into a transaction if there is a transportation path available to deliver the gas produced from that project to FPL's service territory. Texas, Louisiana, Oklahoma, Arkansas, Mississippi, Alabama, West Virginia, Ohio, and Pennsylvania currently meet this criterion. FPL will make use of its transportation portfolio, along with considering new physical paths. The costs of any new transportation needed to deliver gas from a gas reserve project will be taken into consideration when analyzing the economics of that project.

IV. CHARACTERISTICS OF GAS RESERVES

- Natural gas production consists of a combination of hydrocarbons, which can include methane, natural gas liquids ("NGLs"), and oil. The composition of natural gas production varies region by region and within individual regions.
- FPL's natural gas plants burn primarily methane and can accommodate only a very small percentage of other hydrocarbons. However, there are active third party markets for purchase and sale of NGLs and oil.
- There are a range of designations for reserves denoting the degree of certainty that the predicted quantity of gas is commercially recoverable from the well under current conditions: Proved, Probable, and Possible. FPL's gas reserve portfolio would appropriately be comprised of a wide range of projects, including reserves that fall within each of those categories.
- Guideline IV.A: Although there is significant customer value in the production and sale of NGLs and oil, the purpose of FPL's gas reserves program is to provide a source of physical supply of natural gas to serve its power plants. For that reason, FPL will only enter into a transaction for a gas reserve project if the estimated output of the wells in the project contains at least [redacted] from methane by volume.
  - Guideline IV.B: All NGLs and oil produced from a gas reserve project will be sold at market prices and the resulting revenues will be credited to the Fuel Clause to offset the production costs for which customers are responsible, thus lowering the effective cost of natural gas. The projected revenues from NGLs and oil produced from a gas reserve project will be taken into consideration when analyzing the economics of that project.

GAS RESERVES GUIDELINES

Flexibility to respond to market opportunities is in the best interest of FPL and its customers. Therefore, it is understood that FPL may (i) propose modifications to these guidelines in the annual update provided pursuant to Guideline I.B above, and (ii) seek Fuel Clause recovery for a project that deviates from one or more of the guidelines upon a showing that the project nonetheless is expected to benefit FPL customers.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY'S

PETITION FOR PRUDENCE DETERMINATION

REGARDING ACQUISITION OF GAS RESERVES

DIRECT TESTIMONY OF DR. TIM TAYLOR

DOCKET NO. 140001-EI

JUNE 25, 2014

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tim Taylor. My business address is 601 Travis, Suite 1900, Houston, Texas, 77002.

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

A. I am employed by NextEra Energy Project Management, LLC, as the Chief Technology Officer of the Gas Infrastructure and Development business unit ("Gas Infrastructure").

Q. Please describe your educational background and professional experience.

A. I have been actively involved in the oil and gas industry for over 40 years. I hold Bachelor of Science, Masters of Science and PhD degrees in Petroleum Engineering from the University of Texas at Austin. I am a licensed professional engineer in the state of Texas.

I have been with Gas Infrastructure since August of 2012. Prior to that, I was Chief Operating Officer of Texas American Resources. I was also a Professor in the Petroleum and Geosystems Engineering Department at the University of Texas at Austin where I taught oil and gas reserve determination and economics and petrophysics. Prior to that, I was Chief Operating Officer of SOCO International, plc, an international oil and gas company. I have also served in various capacities with Snyder Oil Company and Gulf Oil Company

and was President and CEO of Taylor, Caudle & Associates, a consulting firm specializing in reserves and economics. Exhibit TT-1 is a copy of my resume.

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

A. As Chief Technology Officer, I am responsible for evaluating oil and gas acquisition opportunities, supporting operations in evaluating drilling and lease acquisition proposals from outside operating partners and maintaining internal reserves and economics database. I am responsible for preparing internal reserve estimates, using Securities and Exchange Commission ("SEC") and Society of Petroleum Engineers reserve definitions and guidelines.

Q. Are you sponsoring any exhibits in this case?

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

- TT-1 Resume of Dr. Timothy D. Taylor
- TT-2 Difference Between Conventional and Unconventional Natural Gas Deposits
- TT-3 Historic and Projected Growth of Shale Gas Volumes
- TT-4 "Behind-Pipe" Zones
- TT-5 Map of the Woodford Shale
- TT-6 Location Map of the PetroQuest Acreage
- TT-7 EUR Type Curve Map
- TT-8 Projected Drill Schedule Map
- TT-9 Volume Forecast for FPL (confidential)

- TT-10 Forrest A. Garb & Associates Report (confidential)

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

A. The purpose of my testimony is to:

(i) Provide an overview of the gas production industry as background for the proposed investment in gas reserves and the production of natural gas in the Woodford Shale region to meet a portion of Florida Power and Light Company's ("FPL") natural gas requirements (the "Woodford Gas Reserve Project," "Woodford Project" or the "Project");

(ii) Summarize the volumes of natural gas that can be recovered underneath the 19 sections (12,160 acres) in Pittsburg County, Oklahoma, operated by PetroQuest Energy, LLC ("PetroQuest") that comprise the Woodford Project;

(iii) Describe and support the analysis of the production rate at which these reserves can be recovered using the drilling schedule provided by PetroQuest;

(iv) Present the estimate of the total amount of gas that is expected to be economically recovered from the Woodford Project, referred to as the Estimated Ultimate Recovery ("EUR");

(v) Demonstrate the reasonableness of Project estimates in items ii, iii and iv above by comparing them to an independent, third party study; and,

(vi) Discuss the detailed monthly forecast of volumes of natural gas to be recovered from the Project and provided to USG Properties Woodford

I, LLC (I will refer to both this entity and Gas Infrastructure as "USG") and FPL.

Q. Please provide a brief summary of your testimony.

A. My testimony provides an overview of the geology and technology of the gas production industry relevant to the proposed Woodford Project, including a description of natural gas and other hydrocarbons, how they are formed, and how natural gas reserves are categorized. I provide an overview of the Woodford Shale, where the Woodford Project is located.

My testimony then examines the reserves recoverable from the wells and leases operated by PetroQuest that will be part of the Woodford Project. I discuss the economic analysis that determined the EUR of each existing or to be drilled well and the detailed monthly volume forecast of these reserves used for purposes of assessing the Project. This analysis consists of the following steps: (i) identification of the wells and leases being offered for sale by PetroQuest, (ii) confirmation that PetroQuest is the operator of record of the wells and leases being offered, (iii) attainment of records from PetroQuest relating to working and net revenue interest, historical operating costs, historical drilling and completion costs, historical production volumes from existing wells, (iv) construction of production type curves based on nearby well performance and on the specific producing wells in the acreage being offered, and (v) inclusion of this information, along with FPL's forecasted gas pricing, into an oil and gas reserves and economics software model, PHDWin,

from which gas volume forecasts were generated. A third-party engineering firm, Forrest A. Garb & Associates, Inc., was engaged by FPL to perform an independent analysis.

Based on the results of my analysis, I conclude that the Project is economically viable and commercially attractive. I have also provided the results of my analysis to FPL, which uses it as an input in projecting customer savings for the Project.

II. OVERVIEW OF THE GAS PRODUCTION INDUSTRY

Q. Please provide a brief description of natural gas and explain the difference between "wet" and "dry" natural gas.

A. Natural gas and other fossil fuels are hydrocarbons. Hydrocarbons are formed by the decaying remains of plants and animals, mostly microscopic marine life, from millions of years ago. The physical process in which this organic matter is converted into hydrocarbons is known as catagenesis, and it occurs deep within the earth's crust. The pressure and temperature at which catagenesis occurs will impact the type of hydrocarbons that are formed. For example, deeper deposits with higher pressure and higher temperature favor the formation of lighter hydrocarbons (natural gas), while shallower deposits tend to contain heavier hydrocarbons that are in liquid form (i.e., oil).

Natural gas primarily consists of methane, but other, heavier hydrocarbons such as ethane, propane, butane, and pentane may be present as well. These heavier hydrocarbons are commonly called natural gas liquids ("NGLs"). When natural gas contains predominantly methane, it is commonly referred to as "dry" gas. In reality, there is rarely pure, 100% methane even in "dry gas" formations, as small amounts of NGLs and other impurities are almost invariably present. Conversely, natural gas containing significant fractions of the other previously mentioned hydrocarbons, or NGLs, is commonly referred to as "wet" gas.

Upon extraction of wet gas from the well, the entire volume is sent through a processing facility to separate and capture the NGLs, thus transforming the "wet" gas into "dry" gas. NGLs collected during processing may require further processing or separate transport depending on their specific contents. As I will discuss below, there are markets for the NGLs; thus, the owner of a gas reserves project will realize value from the extraction and processing of NGLs as well as methane. The ratio of dry gas to NGLs is one of several factors in assessing the commercial viability of a formation. In addition to dry gas and NGLs, it is not uncommon for oil to also be produced simultaneously from the wells.

Q. Describe the gas that is used for purposes of generating electricity in power plants.

A. Natural gas-fired generation facilities run on pipeline quality dry gas, which is fed directly into the plant. "Pipeline quality" natural gas has specific characteristics for heat content, moisture and NGLs and typically requires a minimum of 85% methane. Pipelines maintain gas quality standards to ensure the uniformity and usability of the natural gas they transport so that their customers, including FPL, can operate gas-fired equipment safely and efficiently.

Q. What are the different types of underground formations that can contain natural gas?

A. Historically, the most common formation that was drilled to extract natural gas has been what is characterized as "conventional." These formations are geologic deposits characterized by naturally occurring pockets where natural gas collects and is trapped by an impervious layer of rock. This natural gas can be either "associated," which means it resides in conjunction with an oil deposit, or "non-associated," which means there is no oil associated with the gas deposit.

Currently, the fastest growing source of natural gas is from unconventional formations. The most common unconventional formations are shale gas, tight gas, and coal-bed methane. These formations are characterized by natural gas that is trapped in porous rocks that have little permeability and, therefore,

cannot usually flow in commercial quantities without special drilling and completion techniques.

The graphic provided in Exhibit TT-2, produced by the U.S. Energy Information Administration ("EIA"), illustrates the difference between conventional and unconventional natural gas deposits.

Q. How has unconventional shale gas affected the natural gas industry?

A. Advancements in technology related to horizontal drilling and completion techniques have created access to large deposits of shale gas that were previously uneconomical to produce. This has rejuvenated the natural gas industry in the United States, which contains some of the largest shale gas reserves in the world. Shale gas is the fastest growing source of supply in the United States over the past 10 years and its emergence has pushed gas prices to historical lows. Specifically, over that same time frame, the percentage of shale gas that contributed to domestic production grew from less than 5% to over 30% of total production. The graph provided in Exhibit TT-3, from the EIA, depicts the historic and projected growth of shale gas volumes.

Q. What is meant by the term "gas reserves"?

A. Gas reserves represent the quantity of gas than can be economically recovered from a reservoir (conventional or unconventional). Recoverable gas reserves do not typically equal 100% of the gas in the reservoir due to variations in rock quality, porosity, permeability, pressure, the number of wells and their drainage areas, economic considerations, and other factors. Estimated

volumes of gas reserves can change with advancements in technology that can reduce drilling and operating costs and changes in commodity pricing that make additional volumes of gas economically recoverable.

Q. What method typically is used to estimate the amount of gas that is physically recoverable from shale reserves?

A. The decline curve analysis method is the most reliable and commonly used method to estimate recoverable gas from shale reservoirs when abundant historical production data is available, as is the case for the Woodford Project.

Decline curve analysis is a reserve estimation method that uses the shape of the decline in historical production to forecast future volumes of gas by applying mathematical equations that describe the shape of the decline curve and the constantly changing rate of decline. These equations are hyperbolic in nature and this method is, by far, the most accurate in predicting future production when sufficient historical production is available. While actual performance can vary from estimates significantly for individual wells, decline curve analysis has proven very reliable and accurate in predicting the average performance for wells within a reserve. As will be discussed later in my testimony, decline curve analysis was used to forecast future reserves because there are many wells in the PetroQuest area with sufficient historical production to justify the application of this method. The results of the methodology are inserted into the economic model that determines the EUR of the reserves. I will discuss the EUR concept in greater detail below.

Q. Are gas reserves classified on attributes other than quantity?

A. Yes. In addition to quantifying the amount of gas reserves, companies also characterize the quality of reserves. In this context, "quality" refers to the likelihood, based on currently available information, that the full estimated reserve quantity can be economically produced. The industry uses as its frame of reference for classifying gas reserves three standard categories defined by the SEC for public company reporting.

- Proved reserves ("Proved") are those reserves with reasonable certainty (90% probability) that the predicted quantity of gas can be commercially recoverable under current technical, contractual, economic, and regulatory conditions. This reserve category can be further subdivided into three sub-categories.
    - Proved Developed Producing ("PDP") reserves are in currently operating wells that have reasonable certainty of continuing production.
    - Proved Developed Non-Producing ("PDNP") reserves are reserves that have been (i) drilled and completed but not yet producing due to pending pipeline connection, surface facilities or other factors that do not require substantial capital investment relative to drilling the well or, (ii) hydrocarbon bearing zones that are "behind pipe," which generally means productive zones up the wellbore from the primary completion zone (see Exhibit TT-4). These zones will be equipped for

production at some point in the future, typically after the currently producing zone is depleted.

- Proved Undeveloped ("PUD") reserves are in well locations in a proved area that require additional capital investment to drill and complete the well in order to extract the gas.

- Probable reserves ("Probable") are those reserves with some uncertainty (50% probability) that the predicted quantity can be commercially recoverable under current technical, contractual, economic, and regulatory conditions. These reserves may appear productive by analysis but are outside the areas defined as proved and lack definitive tests.
- Possible reserves ("Possible") are those reserves with high uncertainty (10% probability) that the predicted quantity can be commercially recoverable under current technical, contractual, economic, and regulatory conditions. These areas appear to contain hydrocarbons but are outside of the area assumed to be probable.

Q. Are projects and transactions involving gas reserves priced solely on the basis of the three levels of reserve categories in the SEC reporting requirements?

A. No. Projects and transactions involving gas reserves are priced on the basis of several factors, which I discuss in more detail below. But with regard to the quality of reserves, obviously there is a range of estimates anywhere from

below 10% to more than 90%. The actual estimate, not the SEC category, is typically used in pricing a transaction.

Q. Can there be substantial value in reserves that are classified as Probable and Possible?

A. Definitely. While Proved reserves provide more immediate certainty around production, there is substantial value in developing projects whose quality of reserve estimates also include Probable or Possible reserves. The distinction between the actual categorization of a reserve as Proved, versus Probable or Possible can be quite narrow and evolve over time. For instance, by SEC definition, a PUD location may be only one location away from an existing PDP well. In that instance, the next location away from the PUD location would be defined as Probable. When the PUD location is drilled, it immediately gets reclassified as a PDP well. Therefore, by definition, the adjacent Probable location automatically becomes a PUD location. So, by this example, we see that the SEC reserve classification applicable to a well can evolve simply by the normal course of developing a well field.

In many instances, it is necessary and/or desirable to drill Probable or Possible locations before they have been converted to PUD locations in order to take advantage of efficiencies in drilling rig utilization. In other words, if a surface location is capable of accommodating multiple wells, it would be inefficient to drill only the PUD locations, move the rig off to wait for production to be established in those wells, then move the rig back to that location to drill the

Probable or Possible locations. In other instances, it would make sense to drill Probable or Possible locations when there are no adjacent PUD locations, in order to extend the limits of the field based on geophysical interpretations of seismic data which would give a high level of confidence that the Probable wells would perform similarly to the PUD wells. Both of these scenarios apply to the Woodford Project, where we have three-dimensional seismic data that covers the entire Area of Mutual Interest ("AMI") for the Woodford Project.

By combining a thorough analysis of available technical data, project investors make informed decisions on investing in Probable and Possible reserves based on the economics of the project. Probable and Possible reserves represent the future growth of a project. As wells are drilled, these categories get converted to Proved reserves as described above. A typical gas reserve investment portfolio would appropriately be comprised of a wide range of projects, including reserves that fall within each of the major SEC categories of Proved, Probable and Possible.

Q. What are some of the factors that affect the commercial value of shale formations?

A. Broadly speaking, there are three main factors that determine the value of any natural gas resource in the marketplace: market value of the commodity, the amount and composition of the commodities that can be extracted, and the cost to extract that commodity. Two of these factors, amount and composition

of the commodities and cost to extract, will be specific to each shale region and can be evaluated more granularly.

Regarding the amount and composition of the commodities, each shale region contains a unique composition of hydrocarbons. In addition to natural gas and NGLs, it is possible for oil to coexist in the reservoir which would be produced along with the natural gas. The volume of NGLs extracted from wet gas varies according to its composition. When NGLs are present, both the NGL volumes and the resulting volumes of dry natural gas, after extraction of the NGLs, are projected and included in an economic analysis.

Regarding the cost of extracting the commodity, each unconventional resource has unique geologic or geographic characteristics that will affect economic value. A particular formation's depth, thickness, and rock type will affect the capital expenditures ("CapEx") required to drill and complete a well. In addition, there are ongoing operating expenditures ("OpEx") associated with the production of the natural gas.

Q. How does the presence of NGLs and/or oil affect the economics of a well?

A. As previously mentioned, NGLs commonly exist as a component of natural gas. Although NGLs and natural gas are extracted in conjunction with one another, NGLs have a different set of uses and hence a different market price. The largest uses of NGLs are in petrochemicals, gasoline components, and heating. Pricing for NGLs is closely correlated with the price of oil and NGLs

usually sell at a percentage of the price of crude oil. Based on current market pricing, NGLs are trading at a significant premium to natural gas on a unit equivalent basis. For this reason, many producers have focused their development efforts on formations that contain a higher concentration of NGLs. Said another way, the presence of NGLs in the volumes extracted from a well can effectively lower the per unit cost of the natural gas produced, as the increased value of NGLs relative to natural gas subsidizes the cost of producing the natural gas. Similar considerations apply if oil can be extracted from a well along with natural gas.

Q. Would it be appropriate for FPL to consider future projects in formations that contain NGLs and/or oil as well as dry gas?

A. Yes. While the Woodford Project is not anticipated to have economically significant quantities of NGLs or oil, each project opportunity should be evaluated on its economic merit. For example, because NGLs currently trade at a premium relative to natural gas, a wet gas project can be economically viable with lower natural gas production volumes than are needed to justify a dry gas project. With producers focusing on regions with higher ratios of NGLs to methane, FPL would be substantially limiting the opportunities with potential counterparties and may encounter difficulty in executing additional transactions until the gas price forecast has increased to make dry gas projects more economical. Moreover, the significant value in NGLs can lower the effective cost of the methane that is produced. So it would truly depend on the specifics of the project opportunity.

III. OVERVIEW OF WOODFORD SHALE

Q. Would you please provide a brief description of the Woodford Shale?

A. The Woodford Shale lies underneath most of the state of Oklahoma and ranges from 50 feet to 300 feet thick. The region of the Woodford Shale in the Arkoma Basin of southeastern Oklahoma, where the AMI acreage with PetroQuest is located, covers approximately 2,900 square miles and lies between 6,000 feet and 13,000 feet beneath the surface. The extent of this shale in this region is shown in Exhibit TT-5. It is an organic-rich shale of Devonian age that was deposited about 350 to 400 million years ago. It is characterized as a low permeability silica-rich shale rock with relatively high porosity. Porosity controls the amount of gas that can be stored in the rock and permeability controls the ability of the rock to allow fluid to flow through the pore spaces (i.e., a measure of the connectivity of the pores). The Woodford Shale in this region where the AMI acreage is located produces dry natural gas.

The oil and gas industry has long known the Woodford Shale to be the source rock for many of the conventional productive deposits. The first gas production from the Woodford Shale was recorded in 1939 from vertical wells. The first horizontal wells were drilled in 2004 and today, with the advent of technological advances in horizontal drilling and completion methods, there are approximately 2,000 wells producing from the formation.

Around 75% of those are horizontal wells. Many oil companies like Devon Energy, Newfield Exploration, Chesapeake Energy, Antero Resources, Continental Resources, PetroQuest Energy, XTO Energy and others are actively drilling the Woodford Shale.

Q. Please describe PetroQuest's involvement in the Woodford Shale and specifically in the AMI for the Woodford Project.

A. PetroQuest has drilled over 120 wells in the Woodford Shale and has established itself as an efficient, low cost developer of natural gas reserves. The production history from the wells in and around the AMI supports the application of the decline curve analysis method discussed earlier for the Woodford Project. The map shown in Exhibit TT-6 shows the 19 sections of the AMI being offered by PetroQuest. The horizontal lines within these sections represent individual horizontal wells that have been drilled in this area of Pittsburg County, Oklahoma. There are 19 horizontal Woodford wells within the AMI. USG has been a partner of PetroQuest in this area since 2010 and participated in drilling 17 of these wells, the other two having been drilled before the partnership was formed.

IV. ASSESSMENT OF WOODFORD PROJECT RESERVES

Q. Have you evaluated the gas reserves in the Woodford Project?

A. Yes. I estimated the future volumes of natural gas reserves that could reasonably be expected to be recovered from the wells to be drilled in the 19 sections and provided FPL with a monthly volume forecast.

Q. Why is it necessary to perform a reserve assessment for the Woodford Project?

A. The assessment of reserve projections is necessary to understand the future volumes of natural gas available in order for FPL to make its own assessment of the economic viability of the Woodford Project.

Q. How are reserves for the Woodford Project categorized for the purpose of the assessment?

A. There are 38 remaining horizontal well locations to be drilled in the AMI. Of these, 25 are in the PUD reserve category, meaning they are Proved reserves that have yet to be drilled but are supported by nearby producing wells. 13 of the locations are in the Probable reserve category. However, these locations are immediately adjacent to sections that have existing producing wells in the AMI. The distribution and performance of the existing wells gives us a high level of confidence that the Probable wells will perform similarly to the PUD wells.

Q. Please describe the reserve assessment that you performed for the Woodford Project.

A. My analysis consisted of the following steps:

(i) A performance analysis was conducted on the PDP wells in the AMI. The production data from these and other wells around the AMI were used in our decline curve analysis;

(ii) The result of the performance analysis indicated that there were differing levels of performance for the eastern area of the AMI versus the western area of the AMI. Therefore, for PUD and Probable reserves, two type curves were constructed, one for each area that matched the average performance from the nearby PDP wells;

(iii) These type curves were then applied to the remaining undrilled locations in each type curve area as shown in Exhibit TT-7. This exhibit also shows the EURs for each of the 19 existing wells and the EURs for the two type curves;

(iv) The PUD and Probable volume forecasts were fed into PHDWin, an industry oil and gas decline curve analysis and economic software program. A projected drilling schedule was applied according to the drilling schedule shown in Exhibit TT-8, assuming two rigs would be utilized to drill all of the wells in the AMI. Both rigs were assumed to begin drilling on September 1, 2014. The solid purple lines represent the horizontal laterals for the PUD locations and the dashed purple lines show the horizontal laterals for the Probable locations.

(v) An examination was conducted of PetroQuest's Lease Operating Statements, ("LOS") and USG's LOS from the wells in which USG and PetroQuest are partners in the AMI. These are industry-standard documents prepared by operating companies to capture their monthly operating costs, production taxes, transportation fees, and other costs. These costs were then fed into PHDWin along with FPL's natural gas price forecast supplied;

(vi) The resulting economic analysis determined the economic limit of the production from each well which, in turn, determined the EUR from each well; and

(vii) A detailed monthly forecast of the combined volumes of natural gas production was then provided to FPL.

This is an industry accepted method of reserve forecasting.

Q. What is the source of the inputs to your analysis?

A. The operating costs for the analysis were taken from the actual operating costs in PetroQuest's and USG's LOSs. The capital cost for the undrilled wells was provided by PetroQuest. Volume projections came from USG's decline curve analysis on PDP wells and from the type curve for PUD and Probable wells. The drilling schedule came from an internal USG analysis that I performed. All these items were deemed reasonable based on our experience in the area.

Q. What are the results of your analysis?

A. My analysis shows that the Woodford Project is economically viable. There are robust reserves available with a high expectation of natural gas recovery.

We determined the average EUR of the undrilled wells in the AMI to be 6.6 BCF/well. Relative to the projected costs for well development, these are economically attractive volumes. It was assumed that the transfer of ownership from USG to FPL would occur on January 1, 2015. Using the drilling schedule described earlier, we combined the production to be recovered from all wells subsequent to that date into one monthly volume forecast, as shown in Confidential Exhibit TT-9 and this forecast was provided to FPL.

Q. Did you also consider an outside consultant's reserve assessments in your analysis?

A. Yes. In addition to the internal analysis I performed for FPL of all of the reserves, FPL engaged an independent consulting firm to perform a third-party analysis. FPL chose Forrest A. Garb & Associates, Inc. ("FGA"), a trusted engineering firm with experience in the Woodford Shale. The FGA report is attached as Confidential Exhibit TT-10.

The average EUR from the FGA analysis of 6.62 BCF/well is extremely close to our internal estimate of 6.61 BCF/well and supports the conclusion that the reserves are economically viable at the levels we estimated.

Q. What is your overall conclusion regarding the Woodford Gas Reserve Project?

A. The Woodford Gas Reserve Project is an economically viable and commercially attractive natural gas recovery project, operated by an industry leader in this region.

Q. Does this conclude your direct testimony?

A. Yes.

Timothy (Tim) D. Taylor, PhD

work (713) 374-1503, *email* tim.taylor@nee.com

PROFESSIONAL EXPERIENCE

NextEra Energy Project Management, LLC, Houston, Texas Aug. 2012 – Present
Chief Technology Officer
Brought reserve function in-house and accomplished the first corporate SEC compliant reserve report working with third party consultants. Built internal LOS statements and documented oil, gas and ngl price differentials, yields, shrinks, BTU values, etc. Evaluate all incoming acquisition opportunities and capital redeployment strategies through divestitures. Support six internal operations groups in evaluating AFEs and acreage leasing. Work with operating partner companies on log interpretation, picking perforations, completion techniques, etc.

Independent Consultant Oct. 2011 – July 2012
Technical consultant to various oil and gas industry companies, primarily for PostRock Energy, a public oil and gas company headquartered in Oklahoma City. Brought reserve function in-house and managed the relationship with the third party reserve engineers resulting in increased Proved Developed Producing year-end reserves of 320,000 BO and 12 BCF. Organized and managed programs to lower operating costs in 2,800 wells, modified fracking techniques, identified secondary recovery potential in oil reservoirs, modified drilling schedules to focus on oil opportunities while preserving expiring gas acreage, established a true in-house reservoir engineering function, mentored young engineering staff, etc.

Texas American Resources Company, Austin, Texas 2008 – Oct. 2011
Chief Operating Officer / Executive Vice President / Director
Responsible for all aspects of operations and value enhancement, managing and optimizing four operated waterfloods and generating new business opportunities. Instrumental in forming three joint ventures for developing the Eagle Ford Shale play in S. Texas and in the recent divestiture of the company's DJ Basin assets for $150 MM. Guided drilling and workover programs in south, east and north Texas, Colorado and Wyoming. Responsible for development planning, strategic reserve category shifting to maximize Proved reserves and third party reserve reporting. Versed in vertical and horizontal drilling, secondary and enhanced oil recovery and hydraulic fracturing.

The University of Texas at Austin, Austin, Texas 2002 – 2008
Faculty member in the Petroleum and Geosystems Engineering Department.
Senior Lecturer / Program Coordinator
Taught application based courses focused on field development, project management, reserve determination, well and project economics, secondary and enhanced recovery, and petrophysics. Organized and led the effort to revitalize the recruiting program resulting in a 250% increase in undergraduate enrollment in four years while increasing student quality. Stayed active with industry companies and technology and taught numerous domestic and international petroleum engineering short courses.

Independent Consultant 2000 – 2002
President of Cox, Taylor, Bommer, LLC
Formed this petroleum engineering consulting company to help a group of friends in providing management and technical expertise to the oil and gas industry. (My involvement was not on a day-to-day basis as I was taking a break from the grind of international operations.

PROFESSIONAL EXPERIENCE *(Continued)*

Snyder Oil Corporation / SOCO International, plc 1990 - 2000
Engineering Manager / Acquisitions Manager / Chief Operating Officer - Joined Snyder Oil Corporation in 1990 as Engineering Manager responsible for building a new engineering department, performing in-house engineering and economic evaluations for SEC reporting, acquisitions and special project studies. Managed an annual 4,000 well evaluation program and provided engineering analysis and project planning for a 500+ well drilling program.

Vice President and Chief Operating Officer, SOCO International, plc - Instrumental in taking company public on the London Stock Exchange. Managed exploration and development projects in Russia, UK, Mongolia and Australia and served in a technical advisory role for projects in India, Australia, Yemen, Thailand and Vietnam, including evaluating all productive horizons for secondary and/or EOR potential.

Worked with financial advisors to successfully secure $100MM financing from the European Bank for Reconstruction and Development (EBRD) for our Russian Joint Venture, Permtex. Functioned as Country Manager for that project and brought production from zero to 6,000 Bbl./day in two years with 100% exports. Closely involved in all contract negotiations for all of SOCO International's projects. Served as President of an onshore UK subsidiary and streamlined the organization and operations in preparation for the sale of the asset.

Performed all economic and reserve evaluations company-wide and managed the third-party reserve reporting process for each country of operation.

Prior Experience
Taylor, Caudle & Associates, Inc. 1983 - 1990
President and Chief Executive Officer of this petroleum engineering consulting firm founded for the purpose of providing special field studies, secondary and enhanced oil recovery studies and reserves and economic evaluations for the petroleum industry. Successfully managed a large client base before selling the firm to join Snyder Oil Corporation.

Sipes, Williamson & Associates, Inc. 1980 - 1983
Manager of Enhanced Recovery for this Midland, Texas based petroleum engineering firm performing EOR studies and reserve and economic evaluations for the industry.

Gulf Oil Company 1972 - 1980
Served in various engineering capacities in the Gulf Coast and West Texas, the last of which was Chief Enhanced Recovery Engineer. Served on all technical committees for non-operated projects in which Gulf had a working interest.

Education
BS, MS and PhD degrees in Petroleum Engineering, all from The University of Texas at Austin.

Affiliations
Member of Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers and is a Registered Professional Engineer in the state of Texas.

Exhibit TT-2: Difference Between Conventional and Unconventional Natural Gas Deposits

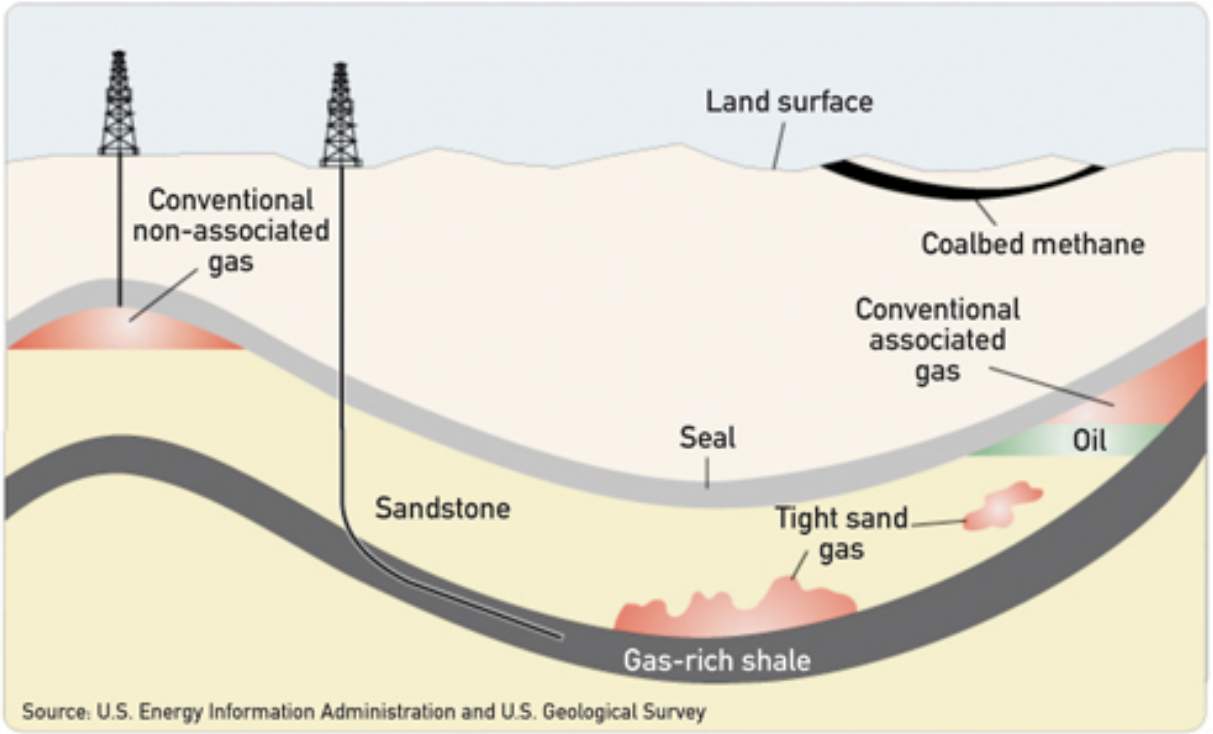
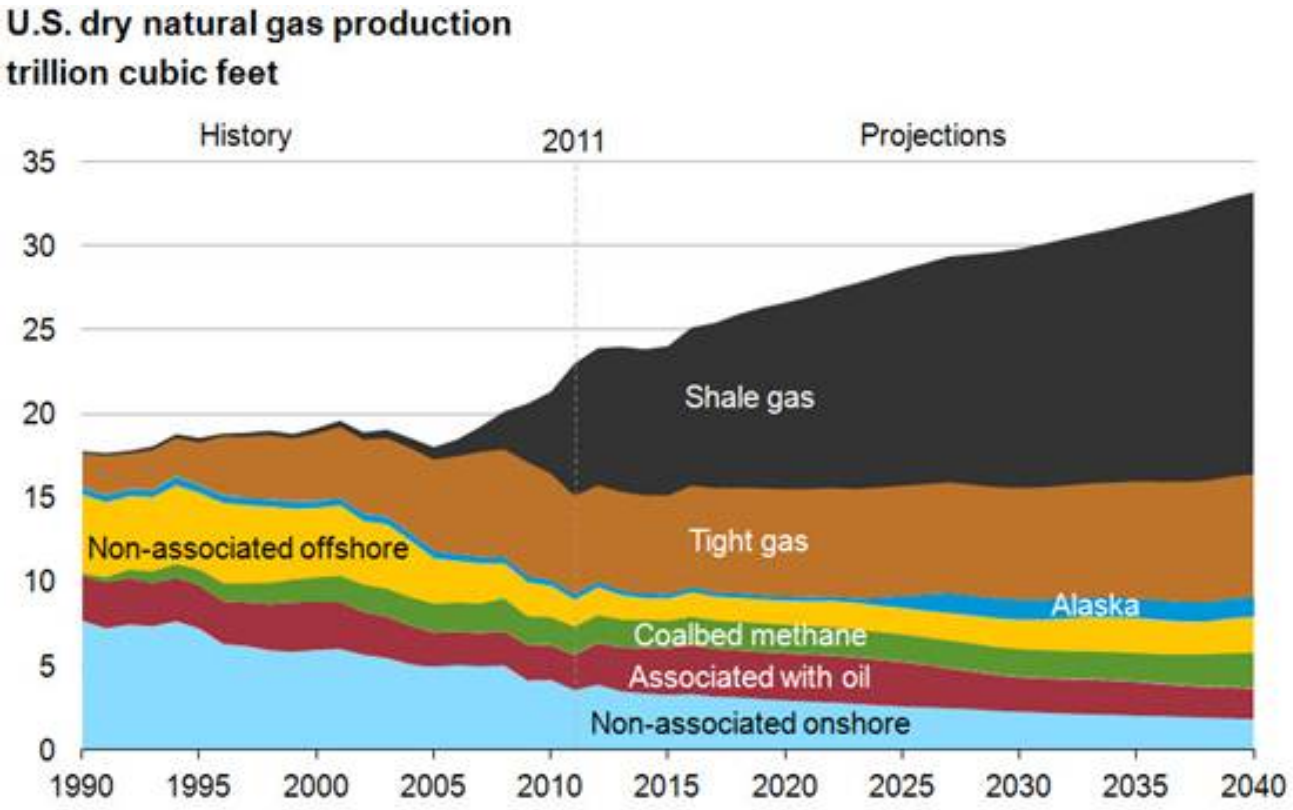
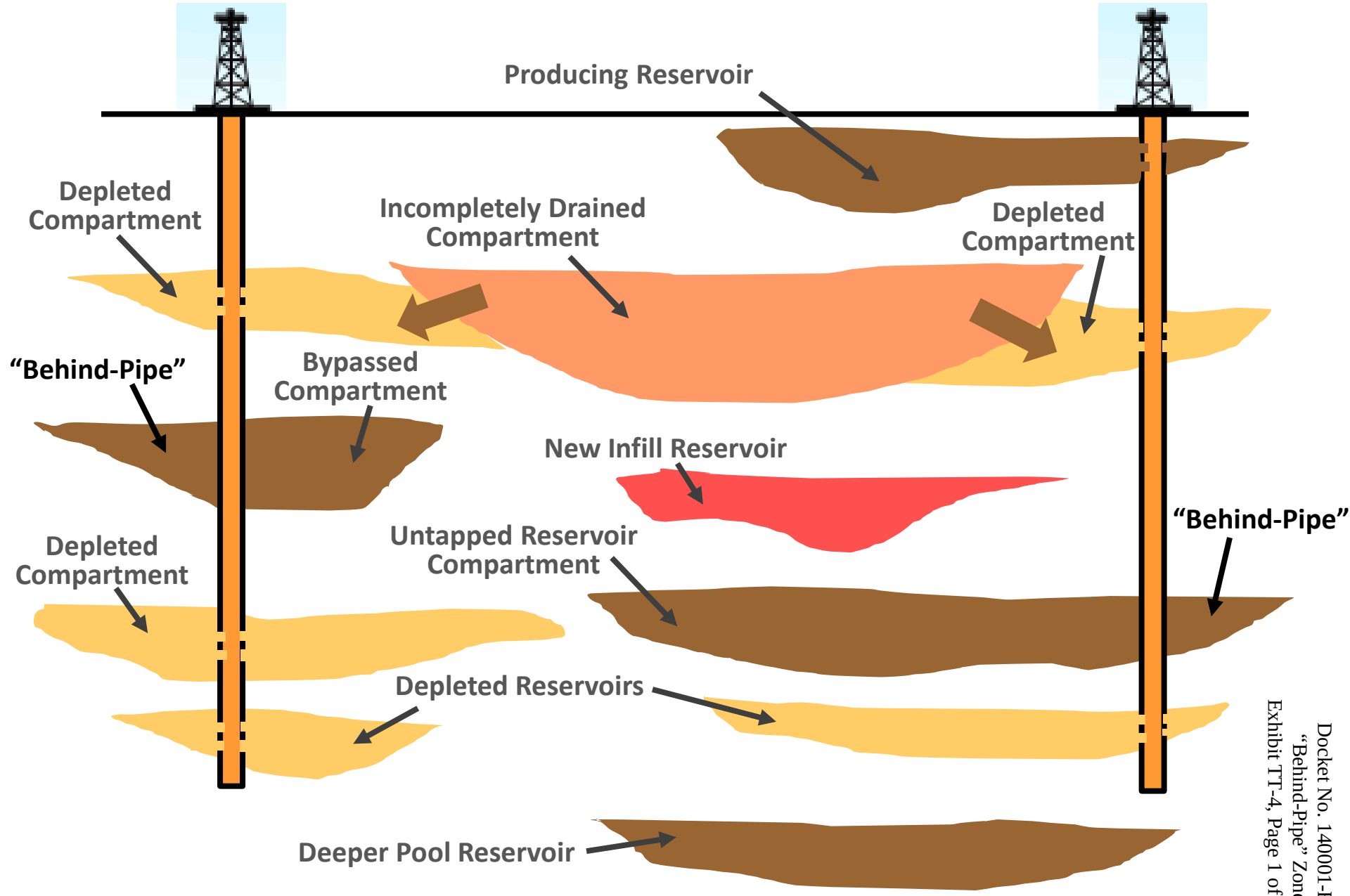


Exhibit TT-3: Historic and Projected Growth of Shale Gas Volumes



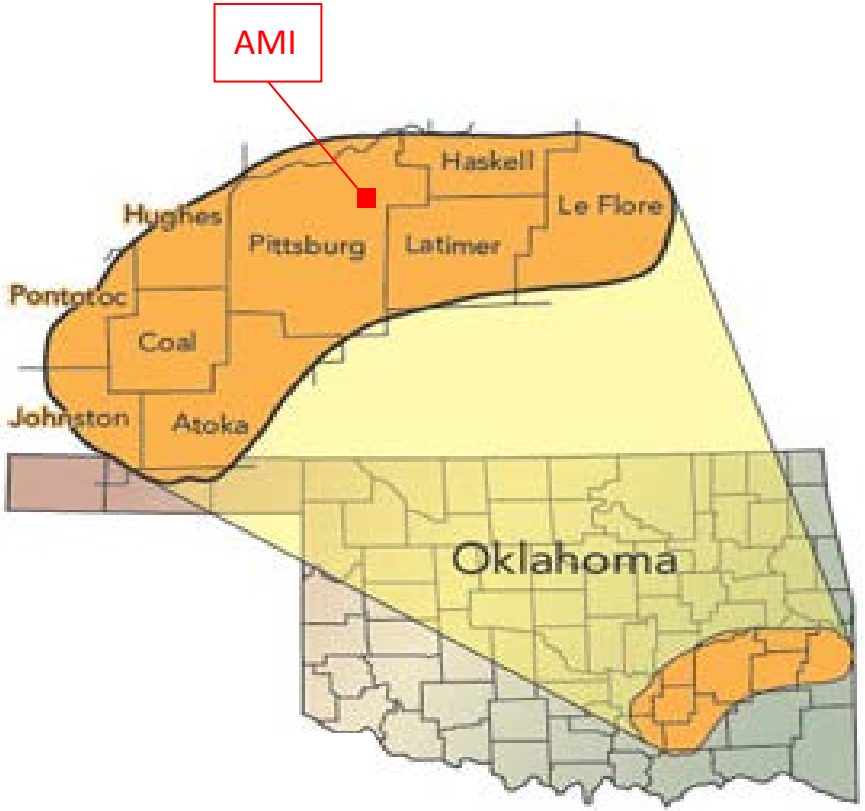
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2013 Early Release*

Exhibit TT-4: "Behind-Pipe" Zones



Docket No. 140001-EI
"Behind-Pipe" Zones
Exhibit TT-4, Page 1 of 1

Exhibit TT-5: Woodford Shale Area
Arkoma Basin



Docket No. 140001-EI
Map of the Woodford Shale
Exhibit TT-5, Page 1 of 1

Exhibit TT-6: Location Map of the PetroQuest Acreage

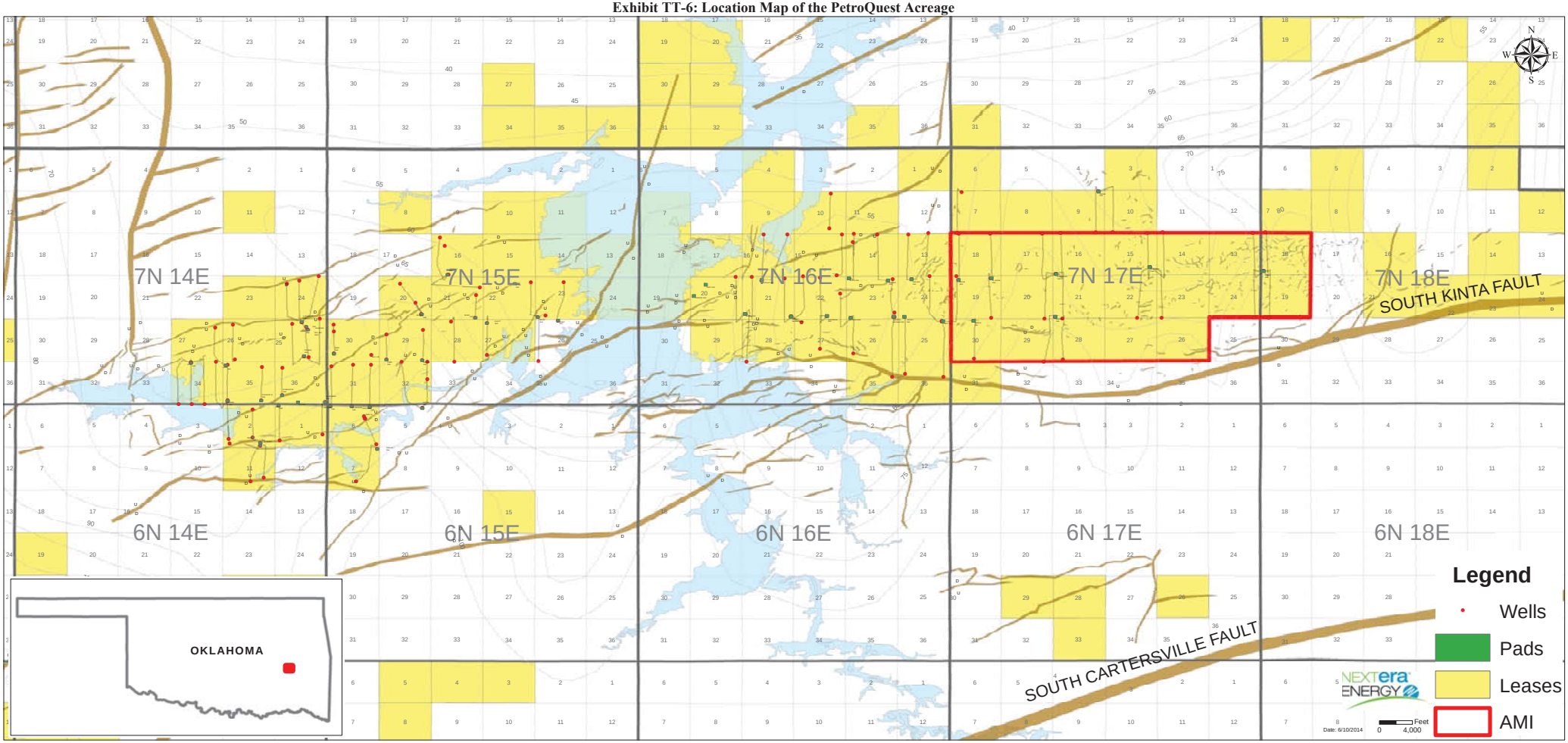


Exhibit TT-7: EUR Type Curve Map

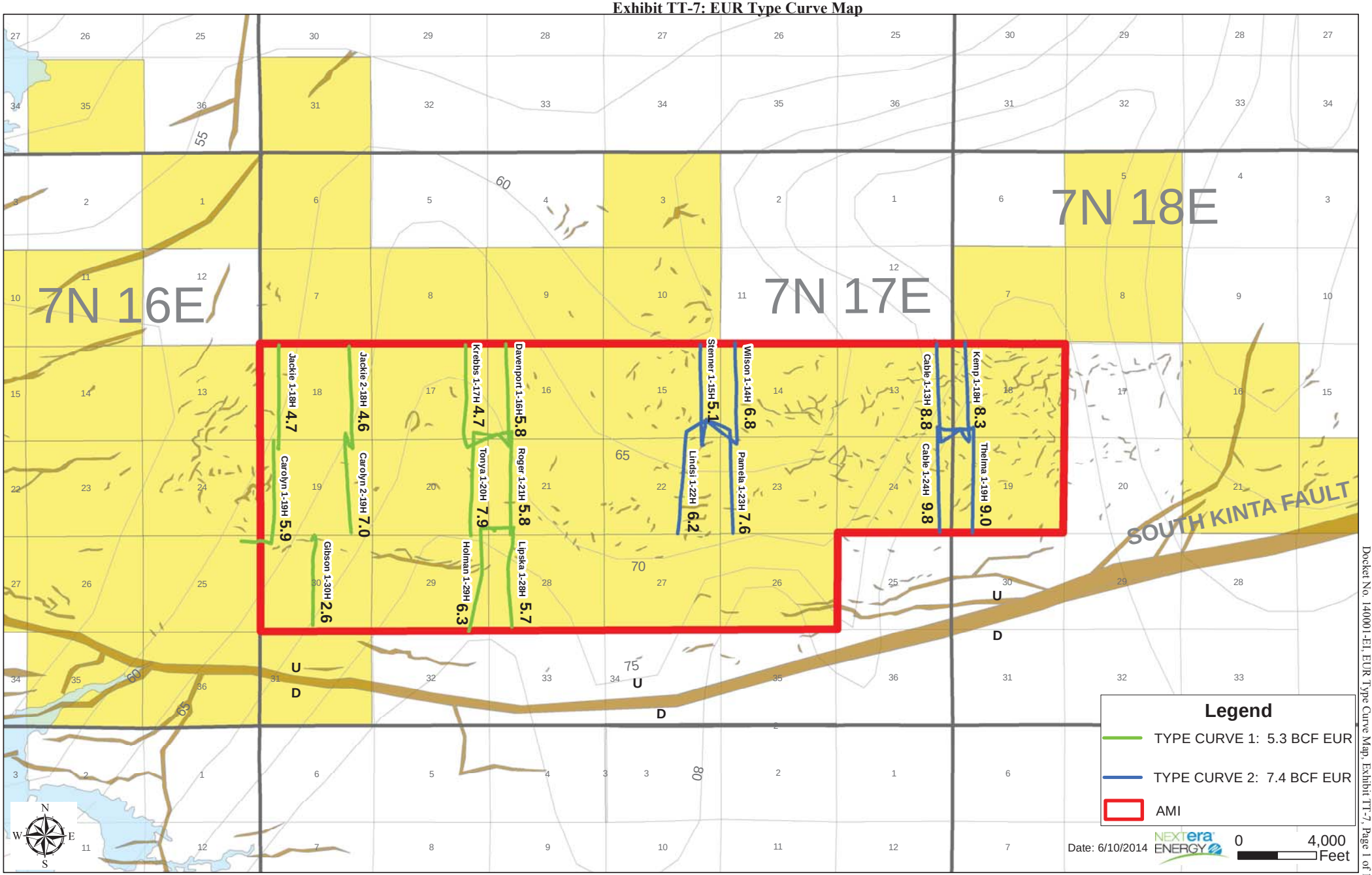
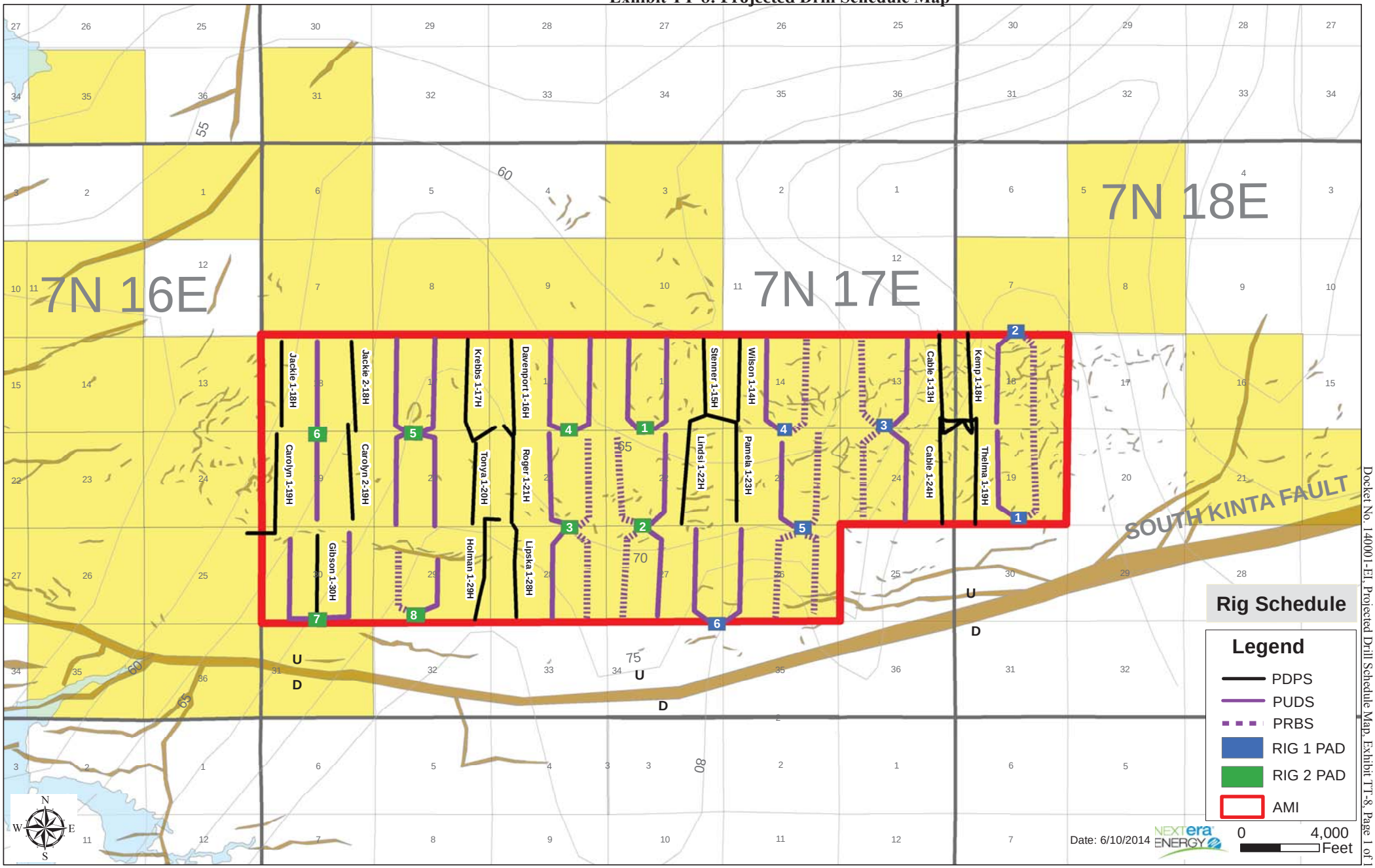


Exhibit TT-8: Projected Drill Schedule Map



Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2014	0.00	0.00							
7	8/1/2014	0.00	0.00							
8	9/1/2014	0.00	0.00							
9	10/1/2014	0.00	0.00							
10	11/1/2014	121.68	74.40							
11	12/1/2014	594.50	363.49							
12	1/1/2015	819.40	501.19							
13	2/1/2015	1,029.01	629.98							
14	3/1/2015	1,450.07	890.19							
15	4/1/2015	1,749.12	1,079.69							
16	5/1/2015	2,215.32	1,355.76							
17	6/1/2015	2,398.29	1,462.54							
18	7/1/2015	2,584.73	1,576.03							
19	8/1/2015	2,833.66	1,732.31							
20	9/1/2015	3,345.99	2,046.89							
21	10/1/2015	3,400.85	2,081.10							
22	11/1/2015	3,252.57	1,988.66							
23	12/1/2015	3,329.63	2,032.54							
24	1/1/2016	3,316.62	2,024.05							
25	2/1/2016	2,934.16	1,790.81							
26	3/1/2016	2,978.15	1,817.80							
27	4/1/2016	2,743.53	1,674.70							
28	5/1/2016	2,706.91	1,652.45							
29	6/1/2016	2,507.80	1,530.98							
30	7/1/2016	2,486.66	1,518.14							
31	8/1/2016	2,389.61	1,458.95							
32	9/1/2016	2,227.86	1,360.25							
33	10/1/2016	2,221.62	1,356.48							
34	11/1/2016	2,077.93	1,268.78							
35	12/1/2016	2,078.20	1,268.98							
36	1/1/2017	2,012.98	1,229.19							
37	2/1/2017	1,765.81	1,078.29							
38	3/1/2017	1,900.71	1,160.69							
39	4/1/2017	1,788.36	1,092.10							
40	5/1/2017	1,798.41	1,098.26							
41	6/1/2017	1,695.22	1,035.26							
42	7/1/2017	1,707.67	1,042.88							
43	8/1/2017	1,665.34	1,017.05							
44	9/1/2017	1,573.46	960.95							

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	10/1/2017	1,588.52	970.15							
7	11/1/2017	1,502.88	917.86							
8	12/1/2017	1,519.16	927.82							
9	1/1/2018	1,486.42	907.83							
10	2/1/2018	1,315.71	803.58							
11	3/1/2018	1,428.25	872.32							
12	4/1/2018	1,354.94	827.55							
13	5/1/2018	1,373.17	838.70							
14	6/1/2018	1,303.88	796.39							
15	7/1/2018	1,322.59	807.82							
16	8/1/2018	1,298.43	793.07							
17	9/1/2018	1,234.44	753.99							
18	10/1/2018	1,253.63	765.72							
19	11/1/2018	1,192.73	728.52							
20	12/1/2018	1,212.12	740.37							
21	1/1/2019	1,192.17	728.19							
22	2/1/2019	1,060.24	647.61							
23	3/1/2019	1,156.13	706.18							
24	4/1/2019	1,101.70	672.94							
25	5/1/2019	1,121.31	684.92							
26	6/1/2019	1,069.11	653.04							
27	7/1/2019	1,088.72	665.03							
28	8/1/2019	1,072.95	655.40							
29	9/1/2019	1,023.79	625.37							
30	10/1/2019	1,043.35	637.32							
31	11/1/2019	996.01	608.40							
32	12/1/2019	1,015.49	620.31							
33	1/1/2020	1,001.95	612.04							
34	2/1/2020	925.40	565.28							
35	3/1/2020	976.84	596.71							
36	4/1/2020	933.49	570.22							
37	5/1/2020	952.70	581.96							
38	6/1/2020	910.75	556.34							
39	7/1/2020	929.83	568.00							
40	8/1/2020	918.67	561.18							
41	9/1/2020	878.68	536.76							
42	10/1/2020	897.55	548.28							
43	11/1/2020	858.76	524.59							
44	12/1/2020	877.47	536.02							

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2021	867.64	530.02							
7	2/1/2021	775.42	473.69							
8	3/1/2021	849.58	518.99							
9	4/1/2021	813.45	496.92							
10	5/1/2021	831.76	508.11							
11	6/1/2021	796.61	486.63							
12	7/1/2021	814.75	497.72							
13	8/1/2021	806.39	492.61							
14	9/1/2021	772.60	471.97							
15	10/1/2021	790.49	482.90							
16	11/1/2021	757.54	462.77							
17	12/1/2021	775.26	473.60							
18	1/1/2022	767.77	469.02							
19	2/1/2022	687.16	419.78							
20	3/1/2022	753.94	460.58							
21	4/1/2022	722.90	441.62							
22	5/1/2022	740.20	452.19							
23	6/1/2022	709.88	433.66							
24	7/1/2022	727.01	444.13							
25	8/1/2022	720.50	440.15							
26	9/1/2022	691.18	422.24							
27	10/1/2022	708.06	432.55							
28	11/1/2022	679.37	415.03							
29	12/1/2022	696.08	425.24							
30	1/1/2023	690.16	421.62							
31	2/1/2023	618.38	377.77							
32	3/1/2023	679.20	414.93							
33	4/1/2023	651.95	398.28							
34	5/1/2023	668.26	408.25							
35	6/1/2023	641.55	391.93							
36	7/1/2023	657.70	401.80							
37	8/1/2023	652.48	398.61							
38	9/1/2023	626.54	382.76							
39	10/1/2023	642.46	392.49							
40	11/1/2023	617.01	376.94							
41	12/1/2023	632.77	386.57							
42	1/1/2024	627.97	383.64							
43	2/1/2024	583.18	356.27							
44	3/1/2024	618.90	378.10							

Woodford Project Grand Total
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2024	594.58	363.24	[redacted]						
5/1/2024	609.97	372.64							
6/1/2024	586.08	358.04							
7/1/2024	601.32	367.36							
8/1/2024	597.03	364.74							
9/1/2024	573.74	350.51							
10/1/2024	588.77	359.69							
11/1/2024	565.88	345.71							
12/1/2024	580.77	354.80							
1/1/2025	576.79	352.37							
2/1/2025	517.60	316.21							
3/1/2025	569.38	347.85							
4/1/2025	547.39	334.41							
5/1/2025	561.94	343.30							
6/1/2025	540.29	330.08							
7/1/2025	554.71	338.89							
8/1/2025	551.11	336.69							
9/1/2025	529.96	323.76							
10/1/2025	544.18	332.45							
11/1/2025	523.34	319.72							
12/1/2025	537.44	328.34							
1/1/2026	534.08	326.29							
2/1/2026	479.55	292.97							
3/1/2026	527.82	322.46							
4/1/2026	507.72	310.18							
5/1/2026	521.51	318.61							
6/1/2026	501.70	306.50							
7/1/2026	515.37	314.86							
8/1/2026	512.31	312.99							
9/1/2026	492.91	301.13							
10/1/2026	506.40	309.38							
11/1/2026	487.26	297.69							
12/1/2026	500.64	305.86							
1/1/2027	497.77	304.11							
2/1/2027	447.16	273.19							
3/1/2027	492.40	300.83							
4/1/2027	473.88	289.51							
5/1/2027	486.99	297.52							
6/1/2027	468.70	286.35							

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2027	481.70	294.29							
7	8/1/2027	479.06	292.67							
8	9/1/2027	461.12	281.72							
9	10/1/2027	473.95	289.56							
10	11/1/2027	456.24	278.73							
11	12/1/2027	468.96	286.51							
12	1/1/2028	466.46	284.98							
13	2/1/2028	434.12	265.22							
14	3/1/2028	461.68	282.06							
15	4/1/2028	444.47	271.54							
16	5/1/2028	456.90	279.14							
17	6/1/2028	439.88	268.74							
18	7/1/2028	452.19	276.26							
19	8/1/2028	449.82	274.82							
20	9/1/2028	433.07	264.58							
21	10/1/2028	445.20	271.99							
22	11/1/2028	428.61	261.86							
23	12/1/2028	440.62	269.19							
24	1/1/2029	438.31	267.78							
25	2/1/2029	393.92	240.66							
26	3/1/2029	433.95	265.12							
27	4/1/2029	417.79	255.24							
28	5/1/2029	429.49	262.39							
29	6/1/2029	413.49	252.62							
30	7/1/2029	425.08	259.70							
31	8/1/2029	422.85	258.34							
32	9/1/2029	407.10	248.71							
33	10/1/2029	418.50	255.68							
34	11/1/2029	402.91	246.16							
35	12/1/2029	414.20	253.05							
36	1/1/2030	412.03	251.73							
37	2/1/2030	370.30	226.23							
38	3/1/2030	407.93	249.22							
39	4/1/2030	392.74	239.94							
40	5/1/2030	403.74	246.66							
41	6/1/2030	388.70	237.47							
42	7/1/2030	399.59	244.12							
43	8/1/2030	397.49	242.85							
44	9/1/2030	382.69	233.80							

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
4										
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	10/1/2030	393.41	240.35							
7	11/1/2030	378.76	231.40							
8	12/1/2030	389.36	237.88							
9	1/1/2031	387.32	236.63							
10	2/1/2031	348.10	212.67							
11	3/1/2031	383.47	234.28							
12	4/1/2031	369.19	225.55							
13	5/1/2031	379.53	231.87							
14	6/1/2031	365.39	223.23							
15	7/1/2031	375.63	229.49							
16	8/1/2031	373.66	228.28							
17	9/1/2031	359.74	219.78							
18	10/1/2031	369.82	225.94							
19	11/1/2031	356.05	217.52							
20	12/1/2031	366.02	223.62							
21	1/1/2032	364.10	222.44							
22	2/1/2032	338.88	207.04							
23	3/1/2032	360.42	220.19							
24	4/1/2032	346.99	211.99							
25	5/1/2032	356.71	217.93							
26	6/1/2032	343.43	209.81							
27	7/1/2032	353.05	215.69							
28	8/1/2032	351.20	214.56							
29	9/1/2032	338.12	206.57							
30	10/1/2032	347.59	212.35							
31	11/1/2032	334.64	204.45							
32	12/1/2032	344.01	210.17							
33	1/1/2033	342.21	209.07							
34	2/1/2033	307.55	187.90							
35	3/1/2033	338.81	206.99							
36	4/1/2033	326.19	199.28							
37	5/1/2033	335.32	204.86							
38	6/1/2033	322.84	197.23							
39	7/1/2033	331.88	202.76							
40	8/1/2033	330.14	201.70							
41	9/1/2033	317.84	194.18							
42	10/1/2033	326.74	199.62							
43	11/1/2033	314.57	192.19							
44	12/1/2033	323.39	197.57							

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2034	321.69	196.53							
7	2/1/2034	289.11	176.63							
8	3/1/2034	318.49	194.58							
9	4/1/2034	306.63	187.33							
10	5/1/2034	315.22	192.58							
11	6/1/2034	303.48	185.41							
12	7/1/2034	311.98	190.60							
13	8/1/2034	310.34	189.60							
14	9/1/2034	298.78	182.54							
15	10/1/2034	307.15	187.65							
16	11/1/2034	295.71	180.66							
17	12/1/2034	304.00	185.72							
18	1/1/2035	302.40	184.75							
19	2/1/2035	271.78	166.04							
20	3/1/2035	299.40	182.91							
21	4/1/2035	288.24	176.10							
22	5/1/2035	296.32	181.03							
23	6/1/2035	285.28	174.29							
24	7/1/2035	293.27	179.17							
25	8/1/2035	291.74	178.23							
26	9/1/2035	280.87	171.59							
27	10/1/2035	288.74	176.40							
28	11/1/2035	277.98	169.83							
29	12/1/2035	285.77	174.59							
30	1/1/2036	284.27	173.67							
31	2/1/2036	264.58	161.64							
32	3/1/2036	281.40	171.92							
33	4/1/2036	270.92	165.51							
34	5/1/2036	278.50	170.15							
35	6/1/2036	268.13	163.81							
36	7/1/2036	275.64	168.40							
37	8/1/2036	274.20	167.52							
38	9/1/2036	263.98	161.28							
39	10/1/2036	271.38	165.80							
40	11/1/2036	261.27	159.62							
41	12/1/2036	268.59	164.09							
42	1/1/2037	267.18	163.23							
43	2/1/2037	240.12	146.70							
44	3/1/2037	264.52	161.61							

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	4/1/2037	254.67	155.59							
7	5/1/2037	261.80	159.95							
8	6/1/2037	252.05	153.99							
9	7/1/2037	259.11	158.30							
10	8/1/2037	257.76	157.47							
11	9/1/2037	248.16	151.61							
12	10/1/2037	255.11	155.85							
13	11/1/2037	245.60	150.05							
14	12/1/2037	252.48	154.25							
15	1/1/2038	251.16	153.44							
16	2/1/2038	225.72	137.90							
17	3/1/2038	248.66	151.92							
18	4/1/2038	239.40	146.26							
19	5/1/2038	246.11	150.36							
20	6/1/2038	236.94	144.76							
21	7/1/2038	243.58	148.81							
22	8/1/2038	242.30	148.03							
23	9/1/2038	233.28	142.52							
24	10/1/2038	239.81	146.51							
25	11/1/2038	230.88	141.05							
26	12/1/2038	237.34	145.00							
27	1/1/2039	236.10	144.24							
28	2/1/2039	212.19	129.64							
29	3/1/2039	233.75	142.81							
30	4/1/2039	225.05	137.49							
31	5/1/2039	231.35	141.34							
32	6/1/2039	222.73	136.08							
33	7/1/2039	228.97	139.89							
34	8/1/2039	227.77	139.16							
35	9/1/2039	219.29	133.97							
36	10/1/2039	225.43	137.72							
37	11/1/2039	217.03	132.60							
38	12/1/2039	223.11	136.31							
39	1/1/2040	221.94	135.59							
40	2/1/2040	206.57	126.20							
41	3/1/2040	219.70	134.22							
42	4/1/2040	211.52	129.22							
43	5/1/2040	217.44	132.84							
44	6/1/2040	209.34	127.90							

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2040	215.21	131.48							
7	8/1/2040	214.08	130.79							
8	9/1/2040	206.11	125.92							
9	10/1/2040	211.88	129.44							
10	11/1/2040	203.99	124.62							
11	12/1/2040	209.70	128.11							
12	1/1/2041	208.60	127.44							
13	2/1/2041	187.47	114.54							
14	3/1/2041	206.53	126.18							
15	4/1/2041	198.83	121.48							
16	5/1/2041	204.40	124.88							
17	6/1/2041	196.79	120.23							
18	7/1/2041	202.30	123.59							
19	8/1/2041	201.24	122.95							
20	9/1/2041	193.75	118.37							
21	10/1/2041	199.17	121.68							
22	11/1/2041	191.76	117.15							
23	12/1/2041	197.13	120.43							
24	1/1/2042	196.09	119.80							
25	2/1/2042	176.23	107.67							
26	3/1/2042	194.14	118.61							
27	4/1/2042	186.91	114.19							
28	5/1/2042	192.15	117.39							
29	6/1/2042	184.99	113.02							
30	7/1/2042	190.17	116.18							
31	8/1/2042	189.18	115.58							
32	9/1/2042	182.13	111.27							
33	10/1/2042	187.23	114.39							
34	11/1/2042	180.26	110.13							
35	12/1/2042	185.31	113.21							
36	1/1/2043	184.34	112.62							
37	2/1/2043	165.67	101.21							
38	3/1/2043	182.50	111.50							
39	4/1/2043	175.70	107.35							
40	5/1/2043	180.63	110.35							
41	6/1/2043	173.90	106.24							
42	7/1/2043	178.77	109.22							
43	8/1/2043	177.83	108.65							
44	9/1/2043	171.21	104.60							

Woodford Project Grand Total
Monthly Cash Flows

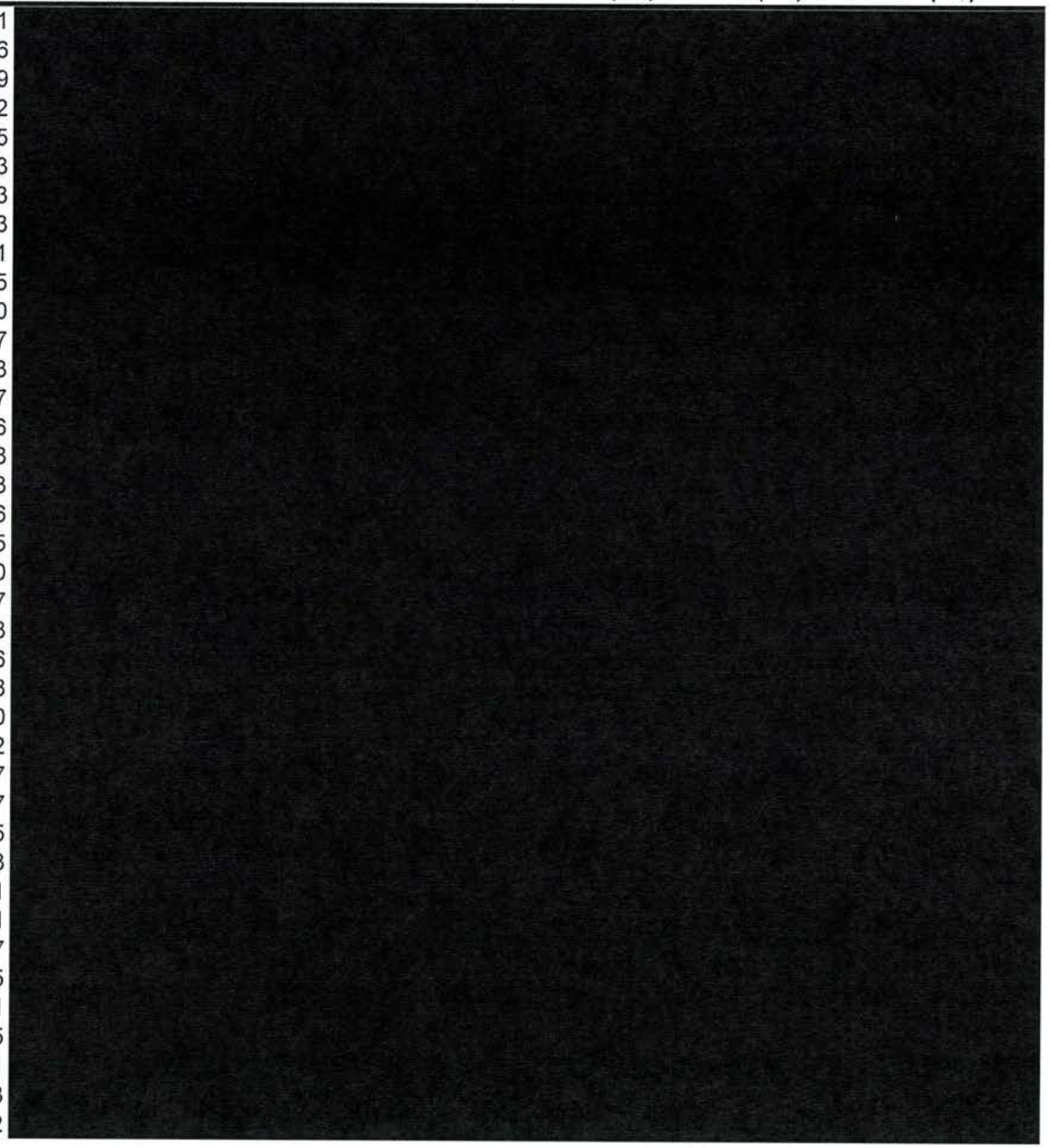
A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2043	176.00	107.53							
11/1/2043	169.45	103.52							
12/1/2043	174.20	106.42							
1/1/2044	173.28	105.87							
2/1/2044	161.28	98.53							
3/1/2044	171.53	104.80							
4/1/2044	165.14	100.89							
5/1/2044	169.77	103.72							
6/1/2044	163.44	99.85							
7/1/2044	168.02	102.65							
8/1/2044	167.14	102.11							
9/1/2044	160.92	98.31							
10/1/2044	165.42	101.06							
11/1/2044	159.26	97.30							
12/1/2044	163.72	100.02							
1/1/2045	162.87	99.50							
2/1/2045	146.37	89.42							
3/1/2045	161.25	98.51							
4/1/2045	155.24	94.84							
5/1/2045	159.59	97.50							
6/1/2045	153.64	93.87							
7/1/2045	157.95	96.50							
8/1/2045	157.12	95.99							
9/1/2045	151.27	92.42							
10/1/2045	155.50	95.00							
11/1/2045	149.71	91.47							
12/1/2045	153.91	94.03							
1/1/2046	153.10	93.53							
2/1/2046	137.59	84.06							
3/1/2046	151.58	92.60							
4/1/2046	145.93	89.16							
5/1/2046	150.02	91.65							
6/1/2046	144.43	88.24							
7/1/2046	148.48	90.71							
8/1/2046	147.70	90.24							
9/1/2046	142.20	86.87							
10/1/2046	146.18	89.31							
11/1/2046	140.74	85.98							
12/1/2046	144.68	88.39							

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2047	143.92	87.93							
7	2/1/2047	129.34	79.02							
8	3/1/2047	142.49	87.05							
9	4/1/2047	137.18	83.81							
10	5/1/2047	141.02	86.16							
11	6/1/2047	135.77	82.95							
12	7/1/2047	139.57	85.27							
13	8/1/2047	138.84	84.82							
14	9/1/2047	133.67	81.67							
15	10/1/2047	137.42	83.95							
16	11/1/2047	132.30	80.83							
17	12/1/2047	136.00	83.09							
18	1/1/2048	135.29	82.65							
19	2/1/2048	125.92	76.93							
20	3/1/2048	133.92	81.82							
21	4/1/2048	128.93	78.77							
22	5/1/2048	132.55	80.98							
23	6/1/2048	127.61	77.96							
24	7/1/2048	131.18	80.14							
25	8/1/2048	130.50	79.73							
26	9/1/2048	125.64	76.76							
27	10/1/2048	129.15	78.91							
28	11/1/2048	124.34	75.97							
29	12/1/2048	127.83	78.09							
30	1/1/2049	127.16	77.69							
31	2/1/2049	114.28	69.82							
32	3/1/2049	125.89	76.91							
33	4/1/2049	121.20	74.05							
34	5/1/2049	124.60	76.12							
35	6/1/2049	119.96	73.29							
36	7/1/2049	123.32	75.34							
37	8/1/2049	122.67	74.94							
38	9/1/2049	118.10	72.15							
39	10/1/2049	121.41	74.17							
40	11/1/2049	116.89	71.41							
41	12/1/2049	120.16	73.41							
42	1/1/2050	119.53	73.03							
43	2/1/2050	107.43	65.63							
44	3/1/2050	118.34	72.30							

Woodford Project Grand Total
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2050	113.94	69.61							
5/1/2050	117.13	71.56							
6/1/2050	112.76	68.89							
7/1/2050	115.92	70.82							
8/1/2050	115.32	70.45							
9/1/2050	111.02	67.83							
10/1/2050	114.13	69.73							
11/1/2050	109.88	67.13							
12/1/2050	112.96	69.01							
1/1/2051	112.37	68.65							
2/1/2051	100.99	61.70							
3/1/2051	111.25	67.97							
4/1/2051	107.10	65.43							
5/1/2051	110.10	67.27							
6/1/2051	106.00	64.76							
7/1/2051	108.97	66.58							
8/1/2051	108.40	66.23							
9/1/2051	104.36	63.76							
10/1/2051	107.29	65.55							
11/1/2051	103.29	63.10							
12/1/2051	106.18	64.87							
1/1/2052	105.63	64.53							
2/1/2052	98.31	60.06							
3/1/2052	104.56	63.88							
4/1/2052	100.67	61.50							
5/1/2052	103.48	63.22							
6/1/2052	99.63	60.87							
7/1/2052	102.42	62.57							
8/1/2052	101.88	62.25							
9/1/2052	98.09	59.93							
10/1/2052	100.84	61.61							
11/1/2052	97.08	59.31							
12/1/2052	99.80	60.97							
1/1/2053	99.28	60.65							
2/1/2053	89.22	54.51							
3/1/2053	98.29	60.05							
4/1/2053	94.63	57.81							
5/1/2053	97.28	59.43							
6/1/2053	93.66	57.22							



Woodford Project Grand Total
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2053	96.28	58.82							
8/1/2053	95.78	58.51							
9/1/2053	92.21	56.33							
10/1/2053	94.79	57.91							
11/1/2053	91.26	55.75							
12/1/2053	93.82	57.32							
1/1/2054	93.32	57.02							
2/1/2054	83.87	51.24							
3/1/2054	92.40	56.45							
4/1/2054	88.96	54.35							
5/1/2054	91.45	55.87							
6/1/2054	88.04	53.79							
7/1/2054	90.51	55.29							
8/1/2054	90.03	55.00							
9/1/2054	86.68	52.96							
10/1/2054	89.11	54.44							
11/1/2054	85.79	52.41							
12/1/2054	88.19	53.88							
1/1/2055	87.73	53.60							
2/1/2055	78.84	48.17							
3/1/2055	86.86	53.06							
4/1/2055	83.62	51.09							
5/1/2055	85.96	52.52							
6/1/2055	82.76	50.56							
7/1/2055	85.08	51.98							
8/1/2055	84.63	51.71							
9/1/2055	81.48	49.78							
10/1/2055	83.76	51.18							
11/1/2055	80.64	49.27							
12/1/2055	82.90	50.65							
1/1/2056	82.47	50.38							
2/1/2056	76.76	46.89							
3/1/2056	81.63	49.87							
4/1/2056	78.59	48.02							
5/1/2056	80.80	49.36							
6/1/2056	77.79	47.52							
7/1/2056	79.96	48.85							
8/1/2056	79.55	48.60							
9/1/2056	76.58	46.79							

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	10/1/2056	78.73	48.10							
7	11/1/2056	75.80	46.31							
8	12/1/2056	77.92	47.60							
9	1/1/2057	77.51	47.35							
10	2/1/2057	69.66	42.56							
11	3/1/2057	76.74	46.88							
12	4/1/2057	73.88	45.14							
13	5/1/2057	75.95	46.40							
14	6/1/2057	73.12	44.67							
15	7/1/2057	75.17	45.92							
16	8/1/2057	74.78	45.68							
17	9/1/2057	71.99	43.98							
18	10/1/2057	74.01	45.21							
19	11/1/2057	71.25	43.53							
20	12/1/2057	73.25	44.75							
21	1/1/2058	72.86	44.52							
22	2/1/2058	65.48	40.01							
23	3/1/2058	72.14	44.07							
24	4/1/2058	69.45	42.43							
25	5/1/2058	71.40	43.62							
26	6/1/2058	68.74	41.99							
27	7/1/2058	70.66	43.17							
28	8/1/2058	70.29	42.94							
29	9/1/2058	67.67	41.35							
30	10/1/2058	69.57	42.50							
31	11/1/2058	66.98	40.92							
32	12/1/2058	68.85	42.07							
33	1/1/2059	68.49	41.85							
34	2/1/2059	61.56	37.61							
35	3/1/2059	67.81	41.43							
36	4/1/2059	65.29	39.89							
37	5/1/2059	67.12	41.00							
38	6/1/2059	64.62	39.48							
39	7/1/2059	66.43	40.58							
40	8/1/2059	66.08	40.37							
41	9/1/2059	63.62	38.87							
42	10/1/2059	65.40	39.95							
43	11/1/2059	62.96	38.47							
44	12/1/2059	64.73	39.54							

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2060	64.39	39.34							
7	2/1/2060	59.93	36.61							
8	3/1/2060	63.74	38.94							
9	4/1/2060	61.36	37.49							
10	5/1/2060	63.08	38.54							
11	6/1/2060	60.73	37.10							
12	7/1/2060	62.43	38.14							
13	8/1/2060	62.11	37.94							
14	9/1/2060	59.79	36.53							
15	10/1/2060	61.47	37.55							
16	11/1/2060	59.18	36.15							
17	12/1/2060	60.84	37.17							
18	1/1/2061	60.52	36.97							
19	2/1/2061	54.39	33.23							
20	3/1/2061	59.91	36.60							
21	4/1/2061	57.68	35.24							
22	5/1/2061	59.30	36.23							
23	6/1/2061	57.09	34.88							
24	7/1/2061	58.69	35.86							
25	8/1/2061	58.38	35.67							
26	9/1/2061	56.21	34.34							
27	10/1/2061	57.78	35.30							
28	11/1/2061	55.63	33.99							
29	12/1/2061	57.19	34.94							
30	1/1/2062	56.89	34.76							
31	2/1/2062	51.13	31.24							
32	3/1/2062	56.32	34.41							
33	4/1/2062	54.22	33.13							
34	5/1/2062	55.74	34.06							
35	6/1/2062	53.67	32.79							
36	7/1/2062	55.17	33.71							
37	8/1/2062	54.88	33.53							
38	9/1/2062	52.84	32.28							
39	10/1/2062	54.32	33.18							
40	11/1/2062	52.29	31.95							
41	12/1/2062	53.76	32.84							
42	1/1/2063	53.48	32.67							
43	2/1/2063	48.06	29.36							
44	3/1/2063	52.95	32.35							

Woodford Project Grand Total
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2063	50.97	31.14	[redacted]						
5/1/2063	52.40	32.01							
6/1/2063	50.45	30.82							
7/1/2063	51.86	31.68							
8/1/2063	51.59	31.52							
9/1/2063	49.67	30.34							
10/1/2063	51.06	31.19							
11/1/2063	49.16	30.03							
12/1/2063	50.54	30.87							
1/1/2064	291.40	178.03							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2014	0.00	0.00							
7	8/1/2014	0.00	0.00							
8	9/1/2014	0.00	0.00							
9	10/1/2014	0.00	0.00							
10	11/1/2014	91.26	55.04							
11	12/1/2014	445.87	268.89							
12	1/1/2015	545.91	330.46							
13	2/1/2015	628.59	381.88							
14	3/1/2015	842.94	515.06							
15	4/1/2015	981.39	605.90							
16	5/1/2015	1,211.51	742.02							
17	6/1/2015	1,368.65	833.58							
18	7/1/2015	1,458.51	885.79							
19	8/1/2015	1,466.04	889.66							
20	9/1/2015	2,110.39	1,285.61							
21	10/1/2015	2,202.17	1,342.59							
22	11/1/2015	2,158.45	1,314.59							
23	12/1/2015	2,252.39	1,368.95							
24	1/1/2016	2,203.99	1,339.54							
25	2/1/2016	1,945.23	1,182.37							
26	3/1/2016	1,970.33	1,197.71							
27	4/1/2016	1,811.74	1,101.38							
28	5/1/2016	1,784.64	1,084.96							
29	6/1/2016	1,650.96	1,003.74							
30	7/1/2016	1,634.90	994.01							
31	8/1/2016	1,569.20	954.11							
32	9/1/2016	1,461.42	888.61							
33	10/1/2016	1,455.91	885.29							
34	11/1/2016	1,360.54	827.31							
35	12/1/2016	1,359.60	826.77							
36	1/1/2017	1,315.93	800.23							
37	2/1/2017	1,153.58	701.52							
38	3/1/2017	1,240.93	754.65							
39	4/1/2017	1,166.88	709.63							
40	5/1/2017	1,172.79	713.24							
41	6/1/2017	1,104.91	671.97							
42	7/1/2017	1,112.49	676.59							
43	8/1/2017	1,084.41	659.52							
44	9/1/2017	1,024.14	622.88							

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Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	10/1/2017	1,033.52	628.59							
7	11/1/2017	977.43	594.48							
8	12/1/2017	987.66	600.71							
9	1/1/2018	966.05	587.57							
10	2/1/2018	854.83	519.93							
11	3/1/2018	927.67	564.24							
12	4/1/2018	879.80	535.13							
13	5/1/2018	891.39	542.18							
14	6/1/2018	846.19	514.70							
15	7/1/2018	858.12	521.95							
16	8/1/2018	842.24	512.30							
17	9/1/2018	800.55	486.94							
18	10/1/2018	812.81	494.41							
19	11/1/2018	773.17	470.29							
20	12/1/2018	785.58	477.85							
21	1/1/2019	772.49	469.89							
22	2/1/2019	686.88	417.82							
23	3/1/2019	748.88	455.53							
24	4/1/2019	713.50	434.01							
25	5/1/2019	726.08	441.67							
26	6/1/2019	692.17	421.04							
27	7/1/2019	704.76	428.70							
28	8/1/2019	694.45	422.43							
29	9/1/2019	662.54	403.02							
30	10/1/2019	675.10	410.66							
31	11/1/2019	644.38	391.98							
32	12/1/2019	656.90	399.60							
33	1/1/2020	648.06	394.22							
34	2/1/2020	598.48	364.06							
35	3/1/2020	631.68	384.26							
36	4/1/2020	603.57	367.16							
37	5/1/2020	615.93	374.68							
38	6/1/2020	588.75	358.15							
39	7/1/2020	601.02	365.61							
40	8/1/2020	593.75	361.19							
41	9/1/2020	567.85	345.44							
42	10/1/2020	579.98	352.82							
43	11/1/2020	554.87	337.54							
44	12/1/2020	566.90	344.87							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2021	560.50	340.97							
7	2/1/2021	500.89	304.71							
8	3/1/2021	548.75	333.83							
9	4/1/2021	525.38	319.61							
10	5/1/2021	537.16	326.78							
11	6/1/2021	514.42	312.94							
12	7/1/2021	526.09	320.05							
13	8/1/2021	520.66	316.74							
14	9/1/2021	498.81	303.45							
15	10/1/2021	510.32	310.45							
16	11/1/2021	489.02	297.49							
17	12/1/2021	500.43	304.43							
18	1/1/2022	495.56	301.47							
19	2/1/2022	443.50	269.80							
20	3/1/2022	486.57	296.01							
21	4/1/2022	466.52	283.81							
22	5/1/2022	477.65	290.58							
23	6/1/2022	458.06	278.66							
24	7/1/2022	469.08	285.37							
25	8/1/2022	464.86	282.80							
26	9/1/2022	445.92	271.28							
27	10/1/2022	456.78	277.89							
28	11/1/2022	438.25	266.62							
29	12/1/2022	449.01	273.16							
30	1/1/2023	445.17	270.83							
31	2/1/2023	398.85	242.65							
32	3/1/2023	438.06	266.50							
33	4/1/2023	420.47	255.80							
34	5/1/2023	430.97	262.19							
35	6/1/2023	413.72	251.70							
36	7/1/2023	424.12	258.02							
37	8/1/2023	420.73	255.96							
38	9/1/2023	403.99	245.78							
39	10/1/2023	414.24	252.01							
40	11/1/2023	397.81	242.02							
41	12/1/2023	407.96	248.19							
42	1/1/2024	404.85	246.30							
43	2/1/2024	375.96	228.72							
44	3/1/2024	398.97	242.72							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	4/1/2024	383.28	233.18							
7	5/1/2024	393.19	239.21							
8	6/1/2024	377.77	229.83							
9	7/1/2024	387.59	235.80							
10	8/1/2024	384.81	234.11							
11	9/1/2024	369.79	224.97							
12	10/1/2024	379.46	230.86							
13	11/1/2024	364.69	221.87							
14	12/1/2024	374.28	227.70							
15	1/1/2025	371.70	226.13							
16	2/1/2025	333.55	202.92							
17	3/1/2025	366.91	223.22							
18	4/1/2025	352.72	214.59							
19	5/1/2025	362.09	220.29							
20	6/1/2025	348.13	211.79							
21	7/1/2025	357.41	217.44							
22	8/1/2025	355.08	216.03							
23	9/1/2025	341.44	207.73							
24	10/1/2025	350.60	213.30							
25	11/1/2025	337.16	205.12							
26	12/1/2025	346.24	210.64							
27	1/1/2026	344.06	209.32							
28	2/1/2026	308.93	187.95							
29	3/1/2026	340.01	206.86							
30	4/1/2026	327.06	198.98							
31	5/1/2026	335.94	204.38							
32	6/1/2026	323.16	196.61							
33	7/1/2026	331.96	201.96							
34	8/1/2026	329.98	200.76							
35	9/1/2026	317.48	193.15							
36	10/1/2026	326.16	198.43							
37	11/1/2026	313.83	190.93							
38	12/1/2026	322.44	196.17							
39	1/1/2027	320.58	195.04							
40	2/1/2027	287.98	175.21							
41	3/1/2027	317.11	192.93							
42	4/1/2027	305.18	185.67							
43	5/1/2027	313.61	190.80							
44	6/1/2027	301.83	183.63							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2027	310.19	188.72							
7	8/1/2027	308.49	187.68							
8	9/1/2027	296.93	180.65							
9	10/1/2027	305.19	185.67							
10	11/1/2027	293.77	178.73							
11	12/1/2027	301.96	183.71							
12	1/1/2028	300.34	182.73							
13	2/1/2028	279.52	170.06							
14	3/1/2028	297.26	180.85							
15	4/1/2028	286.17	174.11							
16	5/1/2028	294.18	178.98							
17	6/1/2028	283.21	172.31							
18	7/1/2028	291.14	177.13							
19	8/1/2028	289.61	176.20							
20	9/1/2028	278.83	169.64							
21	10/1/2028	286.64	174.39							
22	11/1/2028	275.96	167.89							
23	12/1/2028	283.69	172.60							
24	1/1/2029	282.20	171.69							
25	2/1/2029	253.62	154.30							
26	3/1/2029	279.40	169.98							
27	4/1/2029	268.99	163.65							
28	5/1/2029	276.52	168.24							
29	6/1/2029	266.22	161.97							
30	7/1/2029	273.68	166.51							
31	8/1/2029	272.25	165.63							
32	9/1/2029	262.11	159.47							
33	10/1/2029	269.45	163.93							
34	11/1/2029	259.41	157.83							
35	12/1/2029	266.68	162.25							
36	1/1/2030	265.28	161.40							
37	2/1/2030	238.42	145.05							
38	3/1/2030	262.64	159.79							
39	4/1/2030	252.86	153.84							
40	5/1/2030	259.94	158.15							
41	6/1/2030	250.26	152.26							
42	7/1/2030	257.27	156.52							
43	8/1/2030	255.92	155.70							
44	9/1/2030	246.39	149.90							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	10/1/2030	253.29	154.10							
7	11/1/2030	243.86	148.36							
8	12/1/2030	250.69	152.52							
9	1/1/2031	249.38	151.72							
10	2/1/2031	224.12	136.35							
11	3/1/2031	246.90	150.21							
12	4/1/2031	237.70	144.62							
13	5/1/2031	244.36	148.67							
14	6/1/2031	235.26	143.13							
15	7/1/2031	241.85	147.14							
16	8/1/2031	240.58	146.37							
17	9/1/2031	231.62	140.92							
18	10/1/2031	238.11	144.86							
19	11/1/2031	229.24	139.47							
20	12/1/2031	235.66	143.37							
21	1/1/2032	234.42	142.62							
22	2/1/2032	218.19	132.74							
23	3/1/2032	232.05	141.18							
24	4/1/2032	223.41	135.92							
25	5/1/2032	229.67	139.73							
26	6/1/2032	221.11	134.52							
27	7/1/2032	227.31	138.29							
28	8/1/2032	226.12	137.57							
29	9/1/2032	217.69	132.44							
30	10/1/2032	223.79	136.15							
31	11/1/2032	215.46	131.08							
32	12/1/2032	221.49	134.75							
33	1/1/2033	220.33	134.05							
34	2/1/2033	198.02	120.47							
35	3/1/2033	218.14	132.71							
36	4/1/2033	210.01	127.77							
37	5/1/2033	215.90	131.35							
38	6/1/2033	207.85	126.46							
39	7/1/2033	213.68	130.00							
40	8/1/2033	212.56	129.32							
41	9/1/2033	204.64	124.50							
42	10/1/2033	210.37	127.99							
43	11/1/2033	202.54	123.22							
44	12/1/2033	208.21	126.67							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2034	207.12	126.01							
7	2/1/2034	186.14	113.25							
8	3/1/2034	205.06	124.76							
9	4/1/2034	197.42	120.11							
10	5/1/2034	202.95	123.47							
11	6/1/2034	195.39	118.88							
12	7/1/2034	200.86	122.21							
13	8/1/2034	199.81	121.57							
14	9/1/2034	192.37	117.04							
15	10/1/2034	197.76	120.32							
16	11/1/2034	190.39	115.83							
17	12/1/2034	195.73	119.08							
18	1/1/2035	194.70	118.45							
19	2/1/2035	174.98	106.46							
20	3/1/2035	192.76	117.28							
21	4/1/2035	185.58	112.91							
22	5/1/2035	190.78	116.07							
23	6/1/2035	183.68	111.75							
24	7/1/2035	188.82	114.88							
25	8/1/2035	187.83	114.28							
26	9/1/2035	180.84	110.02							
27	10/1/2035	185.90	113.10							
28	11/1/2035	178.98	108.89							
29	12/1/2035	183.99	111.94							
30	1/1/2036	183.03	111.35							
31	2/1/2036	170.35	103.64							
32	3/1/2036	181.17	110.23							
33	4/1/2036	174.43	106.12							
34	5/1/2036	179.31	109.09							
35	6/1/2036	172.63	105.03							
36	7/1/2036	177.47	107.97							
37	8/1/2036	176.54	107.41							
38	9/1/2036	169.96	103.41							
39	10/1/2036	174.72	106.30							
40	11/1/2036	168.22	102.34							
41	12/1/2036	172.93	105.21							
42	1/1/2037	172.02	104.66							
43	2/1/2037	154.60	94.06							
44	3/1/2037	170.31	103.62							

Woodford Project PUD
Monthly Cash Flows

CONFIDENTIAL

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	4/1/2037	163.97	99.76							
7	5/1/2037	168.56	102.55							
8	6/1/2037	162.28	98.73							
9	7/1/2037	166.83	101.50							
10	8/1/2037	165.95	100.97							
11	9/1/2037	159.77	97.21							
12	10/1/2037	164.25	99.93							
13	11/1/2037	158.13	96.21							
14	12/1/2037	162.56	98.90							
15	1/1/2038	161.71	98.38							
16	2/1/2038	145.33	88.42							
17	3/1/2038	160.10	97.40							
18	4/1/2038	154.14	93.78							
19	5/1/2038	158.45	96.40							
20	6/1/2038	152.55	92.81							
21	7/1/2038	156.82	95.41							
22	8/1/2038	156.00	94.91							
23	9/1/2038	150.19	91.38							
24	10/1/2038	154.40	93.94							
25	11/1/2038	148.65	90.44							
26	12/1/2038	152.81	92.97							
27	1/1/2039	152.01	92.48							
28	2/1/2039	136.62	83.12							
29	3/1/2039	150.50	91.56							
30	4/1/2039	144.89	88.15							
31	5/1/2039	148.95	90.62							
32	6/1/2039	143.40	87.25							
33	7/1/2039	147.42	89.69							
34	8/1/2039	146.65	89.22							
35	9/1/2039	141.19	85.90							
36	10/1/2039	145.14	88.30							
37	11/1/2039	139.74	85.01							
38	12/1/2039	143.65	87.40							
39	1/1/2040	142.90	86.94							
40	2/1/2040	133.00	80.92							
41	3/1/2040	141.45	86.06							
42	4/1/2040	136.18	82.85							
43	5/1/2040	140.00	85.17							
44	6/1/2040	134.78	82.00							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2040	138.56	84.30							
7	8/1/2040	137.83	83.86							
8	9/1/2040	132.70	80.73							
9	10/1/2040	136.42	82.99							
10	11/1/2040	131.33	79.90							
11	12/1/2040	135.01	82.14							
12	1/1/2041	134.31	81.71							
13	2/1/2041	120.70	73.44							
14	3/1/2041	132.97	80.90							
15	4/1/2041	128.02	77.89							
16	5/1/2041	131.60	80.07							
17	6/1/2041	126.70	77.08							
18	7/1/2041	130.25	79.24							
19	8/1/2041	129.57	78.83							
20	9/1/2041	124.74	75.89							
21	10/1/2041	128.24	78.02							
22	11/1/2041	123.46	75.11							
23	12/1/2041	126.92	77.22							
24	1/1/2042	126.25	76.81							
25	2/1/2042	113.47	69.03							
26	3/1/2042	125.00	76.05							
27	4/1/2042	120.34	73.22							
28	5/1/2042	123.71	75.27							
29	6/1/2042	119.10	72.46							
30	7/1/2042	122.44	74.49							
31	8/1/2042	121.80	74.10							
32	9/1/2042	117.26	71.34							
33	10/1/2042	120.55	73.34							
34	11/1/2042	116.06	70.61							
35	12/1/2042	119.31	72.59							
36	1/1/2043	118.68	72.21							
37	2/1/2043	106.66	64.89							
38	3/1/2043	117.50	71.49							
39	4/1/2043	113.13	68.83							
40	5/1/2043	116.29	70.75							
41	6/1/2043	111.96	68.12							
42	7/1/2043	115.10	70.03							
43	8/1/2043	114.50	69.66							
44	9/1/2043	110.23	67.06							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
4		Gas Gross	Gas Net	Gas Price	Oil & Gas Rev. Net	Costs Net	Taxes Net	Invest. Net	NonDisc. CF Annual	Cum Disc. CF Annual
5	Year	(MMcf)	(MMcf)	($/Mcf)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
6	10/1/2043	113.32	68.94							
7	11/1/2043	109.10	66.38							
8	12/1/2043	112.15	68.23							
9	1/1/2044	111.57	67.88							
10	2/1/2044	103.84	63.18							
11	3/1/2044	110.44	67.19							
12	4/1/2044	106.33	64.69							
13	5/1/2044	109.30	66.50							
14	6/1/2044	105.23	64.02							
15	7/1/2044	108.18	65.82							
16	8/1/2044	107.61	65.47							
17	9/1/2044	103.60	63.03							
18	10/1/2044	106.51	64.80							
19	11/1/2044	102.54	62.38							
20	12/1/2044	105.41	64.13							
21	1/1/2045	104.86	63.80							
22	2/1/2045	94.24	57.33							
23	3/1/2045	103.82	63.16							
24	4/1/2045	99.95	60.81							
25	5/1/2045	102.75	62.51							
26	6/1/2045	98.92	60.18							
27	7/1/2045	101.69	61.87							
28	8/1/2045	101.16	61.55							
29	9/1/2045	97.39	59.25							
30	10/1/2045	100.12	60.91							
31	11/1/2045	96.39	58.64							
32	12/1/2045	99.09	60.29							
33	1/1/2046	98.57	59.97							
34	2/1/2046	88.59	53.90							
35	3/1/2046	97.59	59.37							
36	4/1/2046	93.96	57.16							
37	5/1/2046	96.59	58.76							
38	6/1/2046	92.99	56.58							
39	7/1/2046	95.60	58.16							
40	8/1/2046	95.09	57.86							
41	9/1/2046	91.55	55.70							
42	10/1/2046	94.12	57.26							
43	11/1/2046	90.61	55.13							
44	12/1/2046	93.15	56.67							

Woodford Project PUD
Monthly Cash Flows

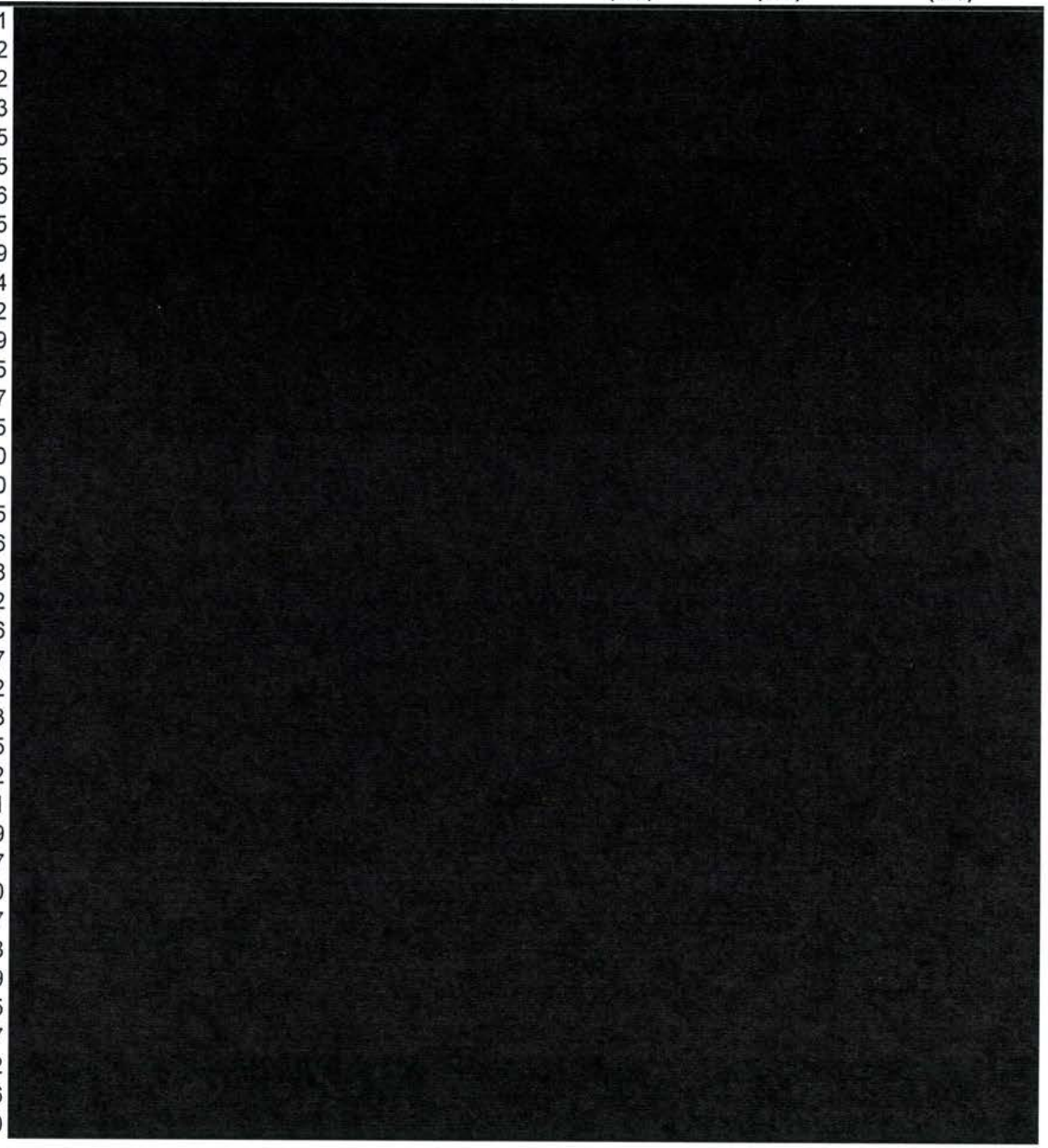
	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2047	92.66	56.37							
7	2/1/2047	83.28	50.67							
8	3/1/2047	91.74	55.81							
9	4/1/2047	88.32	53.74							
10	5/1/2047	90.80	55.24							
11	6/1/2047	87.42	53.18							
12	7/1/2047	89.86	54.67							
13	8/1/2047	89.39	54.39							
14	9/1/2047	86.06	52.36							
15	10/1/2047	88.47	53.83							
16	11/1/2047	85.18	51.82							
17	12/1/2047	87.56	53.27							
18	1/1/2048	87.11	52.99							
19	2/1/2048	81.07	49.32							
20	3/1/2048	86.22	52.46							
21	4/1/2048	83.01	50.50							
22	5/1/2048	85.34	51.92							
23	6/1/2048	82.16	49.99							
24	7/1/2048	84.46	51.39							
25	8/1/2048	84.02	51.12							
26	9/1/2048	80.89	49.21							
27	10/1/2048	83.15	50.59							
28	11/1/2048	80.06	48.71							
29	12/1/2048	82.30	50.07							
30	1/1/2049	81.87	49.81							
31	2/1/2049	73.58	44.76							
32	3/1/2049	81.05	49.31							
33	4/1/2049	78.04	47.48							
34	5/1/2049	80.22	48.81							
35	6/1/2049	77.23	46.99							
36	7/1/2049	79.40	48.30							
37	8/1/2049	78.98	48.05							
38	9/1/2049	76.04	46.26							
39	10/1/2049	78.17	47.56							
40	11/1/2049	75.26	45.79							
41	12/1/2049	77.37	47.07							
42	1/1/2050	76.96	46.82							
43	2/1/2050	69.17	42.08							
44	3/1/2050	76.19	46.36							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
4										
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	4/1/2050	73.36	44.63	[redacted]						
7	5/1/2050	75.41	45.88							
8	6/1/2050	72.60	44.17							
9	7/1/2050	74.64	45.41							
10	8/1/2050	74.25	45.17							
11	9/1/2050	71.48	43.49							
12	10/1/2050	73.48	44.71							
13	11/1/2050	70.74	43.04							
14	12/1/2050	72.73	44.25							
15	1/1/2051	72.35	44.01							
16	2/1/2051	65.02	39.56							
17	3/1/2051	71.63	43.58							
18	4/1/2051	68.96	41.95							
19	5/1/2051	70.89	43.13							
20	6/1/2051	68.25	41.52							
21	7/1/2051	70.16	42.69							
22	8/1/2051	69.79	42.46							
23	9/1/2051	67.19	40.88							
24	10/1/2051	69.08	42.03							
25	11/1/2051	66.50	40.46							
26	12/1/2051	68.37	41.59							
27	1/1/2052	68.01	41.38							
28	2/1/2052	63.30	38.51							
29	3/1/2052	67.32	40.96							
30	4/1/2052	64.81	39.43							
31	5/1/2052	66.63	40.54							
32	6/1/2052	64.15	39.03							
33	7/1/2052	65.94	40.12							
34	8/1/2052	65.60	39.91							
35	9/1/2052	63.15	38.42							
36	10/1/2052	64.92	39.50							
37	11/1/2052	62.50	38.03							
38	12/1/2052	64.26	39.09							
39	1/1/2053	63.92	38.89							
40	2/1/2053	57.45	34.95							
41	3/1/2053	63.28	38.50							
42	4/1/2053	60.93	37.07							
43	5/1/2053	62.63	38.11							
44	6/1/2053	60.30	36.69							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2053	61.99	37.71							
7	8/1/2053	61.66	37.52							
8	9/1/2053	59.37	36.12							
9	10/1/2053	61.03	37.13							
10	11/1/2053	58.76	35.75							
11	12/1/2053	60.40	36.75							
12	1/1/2054	60.09	36.56							
13	2/1/2054	54.00	32.85							
14	3/1/2054	59.49	36.19							
15	4/1/2054	57.27	34.84							
16	5/1/2054	58.88	35.82							
17	6/1/2054	56.68	34.49							
18	7/1/2054	58.27	35.45							
19	8/1/2054	57.97	35.27							
20	9/1/2054	55.81	33.95							
21	10/1/2054	57.37	34.90							
22	11/1/2054	55.23	33.60							
23	12/1/2054	56.78	34.55							
24	1/1/2055	56.48	34.36							
25	2/1/2055	50.76	30.88							
26	3/1/2055	55.92	34.02							
27	4/1/2055	53.84	32.76							
28	5/1/2055	55.35	33.67							
29	6/1/2055	53.29	32.42							
30	7/1/2055	54.78	33.33							
31	8/1/2055	54.49	33.15							
32	9/1/2055	52.46	31.92							
33	10/1/2055	53.93	32.81							
34	11/1/2055	51.92	31.59							
35	12/1/2055	53.38	32.47							
36	1/1/2056	53.10	32.30							
37	2/1/2056	49.42	30.07							
38	3/1/2056	52.56	31.98							
39	4/1/2056	50.60	30.79							
40	5/1/2056	52.02	31.65							
41	6/1/2056	50.08	30.47							
42	7/1/2056	51.48	31.32							
43	8/1/2056	51.22	31.16							
44	9/1/2056	49.31	30.00							



Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	10/1/2056	50.69	30.84							
7	11/1/2056	48.80	29.69							
8	12/1/2056	50.17	30.52							
9	1/1/2057	49.90	30.36							
10	2/1/2057	44.85	27.29							
11	3/1/2057	49.41	30.06							
12	4/1/2057	47.57	28.94							
13	5/1/2057	48.90	29.75							
14	6/1/2057	47.08	28.64							
15	7/1/2057	48.40	29.45							
16	8/1/2057	48.14	29.29							
17	9/1/2057	46.35	28.20							
18	10/1/2057	47.65	28.99							
19	11/1/2057	45.87	27.91							
20	12/1/2057	47.16	28.69							
21	1/1/2058	46.91	28.54							
22	2/1/2058	42.16	25.65							
23	3/1/2058	46.45	28.26							
24	4/1/2058	44.72	27.21							
25	5/1/2058	45.97	27.97							
26	6/1/2058	44.26	26.93							
27	7/1/2058	45.50	27.68							
28	8/1/2058	45.26	27.53							
29	9/1/2058	43.57	26.51							
30	10/1/2058	44.79	27.25							
31	11/1/2058	43.12	26.24							
32	12/1/2058	44.33	26.97							
33	1/1/2059	44.10	26.83							
34	2/1/2059	39.63	24.11							
35	3/1/2059	43.66	26.56							
36	4/1/2059	42.03	25.57							
37	5/1/2059	43.21	26.29							
38	6/1/2059	41.60	25.31							
39	7/1/2059	42.77	26.02							
40	8/1/2059	42.54	25.88							
41	9/1/2059	40.96	24.92							
42	10/1/2059	42.11	25.62							
43	11/1/2059	40.54	24.66							
44	12/1/2059	41.67	25.35							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
4		Gas Gross	Gas Net	Gas Price	Oil & Gas Rev. Net	Costs Net	Taxes Net	Invest. Net	NonDisc. CF Annual	Cum Disc. CF Annual
5	Year	(MMcf)	(MMcf)	($/Mcf)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
6	1/1/2060	41.46	25.22							
7	2/1/2060	38.58	23.47							
8	3/1/2060	41.04	24.97							
9	4/1/2060	39.51	24.04							
10	5/1/2060	40.61	24.71							
11	6/1/2060	39.10	23.79							
12	7/1/2060	40.20	24.46							
13	8/1/2060	39.99	24.33							
14	9/1/2060	38.50	23.42							
15	10/1/2060	39.58	24.08							
16	11/1/2060	38.10	23.18							
17	12/1/2060	39.17	23.83							
18	1/1/2061	38.96	23.70							
19	2/1/2061	35.02	21.30							
20	3/1/2061	38.58	23.47							
21	4/1/2061	37.14	22.60							
22	5/1/2061	38.18	23.23							
23	6/1/2061	36.76	22.36							
24	7/1/2061	37.79	22.99							
25	8/1/2061	37.59	22.87							
26	9/1/2061	36.19	22.02							
27	10/1/2061	37.20	22.63							
28	11/1/2061	35.82	21.79							
29	12/1/2061	36.82	22.40							
30	1/1/2062	36.63	22.28							
31	2/1/2062	32.92	20.03							
32	3/1/2062	36.26	22.06							
33	4/1/2062	34.91	21.24							
34	5/1/2062	35.89	21.84							
35	6/1/2062	34.55	21.02							
36	7/1/2062	35.52	21.61							
37	8/1/2062	35.33	21.50							
38	9/1/2062	34.02	20.70							
39	10/1/2062	34.97	21.28							
40	11/1/2062	33.67	20.48							
41	12/1/2062	34.61	21.06							
42	1/1/2063	34.43	20.95							
43	2/1/2063	30.94	18.83							
44	3/1/2063	34.09	20.74							

Woodford Project PUD
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	4/1/2063	32.82	19.97							
7	5/1/2063	33.74	20.53							
8	6/1/2063	32.48	19.76							
9	7/1/2063	33.39	20.31							
10	8/1/2063	33.22	20.21							
11	9/1/2063	31.98	19.46							
12	10/1/2063	32.87	20.00							
13	11/1/2063	31.65	19.26							
14	12/1/2063	32.54	19.80							
15	1/1/2064	187.61	114.14							

Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2014	0.00	0.00							
8/1/2014	0.00	0.00							
9/1/2014	0.00	0.00							
10/1/2014	0.00	0.00							
11/1/2014	30.42	19.36							
12/1/2014	148.62	94.60							
1/1/2015	273.49	170.73							
2/1/2015	400.41	248.10							
3/1/2015	607.14	375.12							
4/1/2015	767.74	473.79							
5/1/2015	1,003.80	613.74							
6/1/2015	1,029.64	628.96							
7/1/2015	1,126.22	690.24							
8/1/2015	1,367.62	842.65							
9/1/2015	1,235.60	761.27							
10/1/2015	1,198.69	738.51							
11/1/2015	1,094.12	674.07							
12/1/2015	1,077.24	663.59							
1/1/2016	1,112.62	684.51							
2/1/2016	988.93	608.44							
3/1/2016	1,007.83	620.09							
4/1/2016	931.78	573.32							
5/1/2016	922.27	567.49							
6/1/2016	856.85	527.24							
7/1/2016	851.77	524.13							
8/1/2016	820.41	504.84							
9/1/2016	766.44	471.64							
10/1/2016	765.71	471.20							
11/1/2016	717.39	441.47							
12/1/2016	718.60	442.22							
1/1/2017	697.05	428.96							
2/1/2017	612.24	376.77							
3/1/2017	659.78	406.03							
4/1/2017	621.48	382.47							
5/1/2017	625.63	385.02							
6/1/2017	590.30	363.29							
7/1/2017	595.18	366.29							
8/1/2017	580.93	357.53							
9/1/2017	549.32	338.07							

Woodford Project PROB
Monthly Cash Flows

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Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2017	554.99	341.57							
11/1/2017	525.45	323.38							
12/1/2017	531.49	327.11							
1/1/2018	520.37	320.26							
2/1/2018	460.88	283.65							
3/1/2018	500.57	308.08							
4/1/2018	475.13	292.43							
5/1/2018	481.77	296.51							
6/1/2018	457.69	281.69							
7/1/2018	464.47	285.87							
8/1/2018	456.19	280.77							
9/1/2018	433.89	267.05							
10/1/2018	440.82	271.31							
11/1/2018	419.56	258.23							
12/1/2018	426.54	262.53							
1/1/2019	419.67	258.30							
2/1/2019	373.35	229.79							
3/1/2019	407.25	250.65							
4/1/2019	388.20	238.93							
5/1/2019	395.23	243.26							
6/1/2019	376.94	232.00							
7/1/2019	383.96	236.32							
8/1/2019	378.50	232.96							
9/1/2019	361.26	222.35							
10/1/2019	368.25	226.65							
11/1/2019	351.62	216.42							
12/1/2019	358.59	220.71							
1/1/2020	353.89	217.82							
2/1/2020	326.92	201.22							
3/1/2020	345.17	212.45							
4/1/2020	329.91	203.06							
5/1/2020	336.77	207.28							
6/1/2020	322.01	198.20							
7/1/2020	328.81	202.39							
8/1/2020	324.93	199.99							
9/1/2020	310.84	191.32							
10/1/2020	317.57	195.46							
11/1/2020	303.89	187.05							
12/1/2020	310.56	191.15							

Woodford Project PROB
Monthly Cash Flows

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Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2021	307.13	189.04	[redacted]						
2/1/2021	274.53	168.98							
3/1/2021	300.83	185.16							
4/1/2021	288.08	177.32							
5/1/2021	294.60	181.33							
6/1/2021	282.19	173.69							
7/1/2021	288.66	177.67							
8/1/2021	285.73	175.87							
9/1/2021	273.79	168.52							
10/1/2021	280.17	172.45							
11/1/2021	268.52	165.28							
12/1/2021	274.84	169.17							
1/1/2022	272.21	167.55							
2/1/2022	243.66	149.98							
3/1/2022	267.37	164.57							
4/1/2022	256.39	157.81							
5/1/2022	262.55	161.61							
6/1/2022	251.82	155.00							
7/1/2022	257.92	158.76							
8/1/2022	255.64	157.35							
9/1/2022	245.26	150.96							
10/1/2022	251.27	154.66							
11/1/2022	241.11	148.41							
12/1/2022	247.07	152.08							
1/1/2023	244.99	150.80							
2/1/2023	219.53	135.12							
3/1/2023	241.14	148.43							
4/1/2023	231.48	142.48							
5/1/2023	237.29	146.06							
6/1/2023	227.83	140.23							
7/1/2023	233.58	143.78							
8/1/2023	231.74	142.64							
9/1/2023	222.55	136.98							
10/1/2023	228.22	140.47							
11/1/2023	219.19	134.92							
12/1/2023	224.81	138.38							
1/1/2024	223.12	137.34							
2/1/2024	207.22	127.55							
3/1/2024	219.93	135.37							

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Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2024	211.30	130.06							
5/1/2024	216.78	133.44							
6/1/2024	208.30	128.22							
7/1/2024	213.73	131.56							
8/1/2024	212.22	130.63							
9/1/2024	203.96	125.54							
10/1/2024	209.31	128.84							
11/1/2024	201.18	123.84							
12/1/2024	206.49	127.10							
1/1/2025	205.09	126.24							
2/1/2025	184.05	113.29							
3/1/2025	202.47	124.63							
4/1/2025	194.66	119.82							
5/1/2025	199.85	123.01							
6/1/2025	192.16	118.28							
7/1/2025	197.30	121.44							
8/1/2025	196.03	120.66							
9/1/2025	188.51	116.04							
10/1/2025	193.58	119.16							
11/1/2025	186.18	114.60							
12/1/2025	191.20	117.69							
1/1/2026	190.02	116.96							
2/1/2026	170.62	105.03							
3/1/2026	187.81	115.60							
4/1/2026	180.66	111.21							
5/1/2026	185.58	114.23							
6/1/2026	178.54	109.90							
7/1/2026	183.41	112.90							
8/1/2026	182.33	112.23							
9/1/2026	175.43	107.98							
10/1/2026	180.24	110.94							
11/1/2026	173.43	106.76							
12/1/2026	178.20	109.69							
1/1/2027	177.19	109.07							
2/1/2027	159.18	97.98							
3/1/2027	175.29	107.90							
4/1/2027	168.70	103.84							
5/1/2027	173.38	106.72							
6/1/2027	166.87	102.72							

Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2027	171.50	105.57							
8/1/2027	170.57	104.99							
9/1/2027	164.19	101.07							
10/1/2027	168.77	103.88							
11/1/2027	162.46	100.00							
12/1/2027	167.00	102.80							
1/1/2028	166.11	102.25							
2/1/2028	154.60	95.16							
3/1/2028	164.42	101.21							
4/1/2028	158.30	97.44							
5/1/2028	162.73	100.17							
6/1/2028	156.67	96.43							
7/1/2028	161.05	99.13							
8/1/2028	160.21	98.61							
9/1/2028	154.24	94.94							
10/1/2028	158.56	97.60							
11/1/2028	152.65	93.97							
12/1/2028	156.93	96.60							
1/1/2029	156.11	96.09							
2/1/2029	140.30	86.36							
3/1/2029	154.56	95.14							
4/1/2029	148.80	91.59							
5/1/2029	152.97	94.16							
6/1/2029	147.27	90.65							
7/1/2029	151.39	93.19							
8/1/2029	150.60	92.70							
9/1/2029	144.99	89.25							
10/1/2029	149.05	91.75							
11/1/2029	143.50	88.33							
12/1/2029	147.52	90.81							
1/1/2030	146.75	90.33							
2/1/2030	131.89	81.18							
3/1/2030	145.29	89.43							
4/1/2030	139.88	86.10							
5/1/2030	143.79	88.51							
6/1/2030	138.44	85.22							
7/1/2030	142.32	87.60							
8/1/2030	141.57	87.14							
9/1/2030	136.30	83.90							

Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2030	140.12	86.25							
11/1/2030	134.90	83.03							
12/1/2030	138.67	85.36							
1/1/2031	137.95	84.91							
2/1/2031	123.98	76.31							
3/1/2031	136.58	84.07							
4/1/2031	131.49	80.94							
5/1/2031	135.17	83.20							
6/1/2031	130.14	80.11							
7/1/2031	133.78	82.35							
8/1/2031	133.08	81.92							
9/1/2031	128.13	78.87							
10/1/2031	131.71	81.08							
11/1/2031	126.81	78.06							
12/1/2031	130.36	80.24							
1/1/2032	129.68	79.82							
2/1/2032	120.70	74.29							
3/1/2032	128.37	79.01							
4/1/2032	123.58	76.07							
5/1/2032	127.05	78.20							
6/1/2032	122.31	75.29							
7/1/2032	125.74	77.40							
8/1/2032	125.08	76.99							
9/1/2032	120.42	74.13							
10/1/2032	123.80	76.20							
11/1/2032	119.18	73.36							
12/1/2032	122.52	75.42							
1/1/2033	121.88	75.02							
2/1/2033	109.54	67.42							
3/1/2033	120.67	74.28							
4/1/2033	116.17	71.51							
5/1/2033	119.43	73.51							
6/1/2033	114.98	70.78							
7/1/2033	118.20	72.76							
8/1/2033	117.58	72.38							
9/1/2033	113.20	69.68							
10/1/2033	116.37	71.63							
11/1/2033	112.04	68.96							
12/1/2033	115.18	70.90							

Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2034	114.57	70.52	[redacted]						
2/1/2034	102.97	63.38							
3/1/2034	113.43	69.82							
4/1/2034	109.21	67.22							
5/1/2034	112.27	69.11							
6/1/2034	108.09	66.53							
7/1/2034	111.11	68.40							
8/1/2034	110.53	68.04							
9/1/2034	106.41	65.50							
10/1/2034	109.39	67.34							
11/1/2034	105.32	64.83							
12/1/2034	108.27	66.65							
1/1/2035	107.70	66.30							
2/1/2035	96.80	59.58							
3/1/2035	106.63	65.64							
4/1/2035	102.66	63.19							
5/1/2035	105.54	64.96							
6/1/2035	101.61	62.54							
7/1/2035	104.45	64.29							
8/1/2035	103.90	63.96							
9/1/2035	100.03	61.58							
10/1/2035	102.84	63.30							
11/1/2035	99.01	60.94							
12/1/2035	101.78	62.65							
1/1/2036	101.25	62.32							
2/1/2036	94.23	58.00							
3/1/2036	100.22	61.69							
4/1/2036	96.49	59.39							
5/1/2036	99.19	61.06							
6/1/2036	95.50	58.78							
7/1/2036	98.17	60.43							
8/1/2036	97.66	60.11							
9/1/2036	94.02	57.87							
10/1/2036	96.65	59.49							
11/1/2036	93.05	57.28							
12/1/2036	95.66	58.88							
1/1/2037	95.16	58.57							
2/1/2037	85.52	52.64							
3/1/2037	94.21	57.99							

Woodford Project PROB
Monthly Cash Flows

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Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2037	90.70	55.83							
5/1/2037	93.24	57.40							
6/1/2037	89.77	55.26							
7/1/2037	92.28	56.81							
8/1/2037	91.80	56.51							
9/1/2037	88.38	54.40							
10/1/2037	90.86	55.93							
11/1/2037	87.47	53.84							
12/1/2037	89.92	55.35							
1/1/2038	89.45	55.06							
2/1/2038	80.39	49.49							
3/1/2038	88.56	54.51							
4/1/2038	85.26	52.48							
5/1/2038	87.65	53.95							
6/1/2038	84.39	51.94							
7/1/2038	86.75	53.40							
8/1/2038	86.30	53.12							
9/1/2038	83.08	51.14							
10/1/2038	85.41	52.57							
11/1/2038	82.23	50.62							
12/1/2038	84.53	52.03							
1/1/2039	84.09	51.76							
2/1/2039	75.57	46.52							
3/1/2039	83.25	51.25							
4/1/2039	80.15	49.34							
5/1/2039	82.40	50.72							
6/1/2039	79.33	48.83							
7/1/2039	81.55	50.20							
8/1/2039	81.12	49.93							
9/1/2039	78.10	48.07							
10/1/2039	80.29	49.42							
11/1/2039	77.30	47.58							
12/1/2039	79.46	48.91							
1/1/2040	79.05	48.66							
2/1/2040	73.57	45.29							
3/1/2040	78.25	48.16							
4/1/2040	75.33	46.37							
5/1/2040	77.44	47.67							
6/1/2040	74.56	45.89							

Woodford Project PROB
Monthly Cash Flows

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Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2040	76.65	47.18							
8/1/2040	76.25	46.93							
9/1/2040	73.41	45.18							
10/1/2040	75.46	46.45							
11/1/2040	72.65	44.72							
12/1/2040	74.69	45.97							
1/1/2041	74.29	45.73							
2/1/2041	66.77	41.10							
3/1/2041	73.56	45.28							
4/1/2041	70.82	43.59							
5/1/2041	72.80	44.81							
6/1/2041	70.09	43.14							
7/1/2041	72.05	44.35							
8/1/2041	71.67	44.12							
9/1/2041	69.00	42.48							
10/1/2041	70.94	43.66							
11/1/2041	68.30	42.04							
12/1/2041	70.21	43.22							
1/1/2042	69.84	42.99							
2/1/2042	62.77	38.64							
3/1/2042	69.15	42.56							
4/1/2042	66.57	40.98							
5/1/2042	68.43	42.12							
6/1/2042	65.89	40.56							
7/1/2042	67.73	41.69							
8/1/2042	67.38	41.47							
9/1/2042	64.87	39.93							
10/1/2042	66.68	41.05							
11/1/2042	64.20	39.52							
12/1/2042	66.00	40.62							
1/1/2043	65.65	40.41							
2/1/2043	59.00	36.32							
3/1/2043	65.00	40.01							
4/1/2043	62.58	38.52							
5/1/2043	64.33	39.60							
6/1/2043	61.94	38.12							
7/1/2043	63.67	39.19							
8/1/2043	63.34	38.99							
9/1/2043	60.98	37.53							

Woodford Project PROB
Monthly Cash Flows

CONFIDENTIAL

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2043	62.69	38.59							
11/1/2043	60.35	37.15							
12/1/2043	62.04	38.19							
1/1/2044	61.72	37.99							
2/1/2044	57.44	35.36							
3/1/2044	61.09	37.60							
4/1/2044	58.82	36.20							
5/1/2044	60.46	37.22							
6/1/2044	58.21	35.83							
7/1/2044	59.84	36.84							
8/1/2044	59.53	36.64							
9/1/2044	57.31	35.28							
10/1/2044	58.92	36.27							
11/1/2044	56.72	34.92							
12/1/2044	58.31	35.89							
1/1/2045	58.01	35.70							
2/1/2045	52.13	32.09							
3/1/2045	57.43	35.35							
4/1/2045	55.29	34.03							
5/1/2045	56.84	34.99							
6/1/2045	54.72	33.68							
7/1/2045	56.25	34.63							
8/1/2045	55.96	34.45							
9/1/2045	53.88	33.16							
10/1/2045	55.38	34.09							
11/1/2045	53.32	32.82							
12/1/2045	54.81	33.74							
1/1/2046	54.53	33.56							
2/1/2046	49.01	30.16							
3/1/2046	53.99	33.23							
4/1/2046	51.97	31.99							
5/1/2046	53.43	32.89							
6/1/2046	51.44	31.66							
7/1/2046	52.88	32.55							
8/1/2046	52.60	32.38							
9/1/2046	50.64	31.17							
10/1/2046	52.06	32.05							
11/1/2046	50.12	30.85							
12/1/2046	51.53	31.72							

Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2047	51.26	31.55							
2/1/2047	46.07	28.36							
3/1/2047	50.75	31.24							
4/1/2047	48.86	30.07							
5/1/2047	50.23	30.92							
6/1/2047	48.36	29.77							
7/1/2047	49.71	30.60							
8/1/2047	49.45	30.44							
9/1/2047	47.61	29.30							
10/1/2047	48.94	30.13							
11/1/2047	47.12	29.00							
12/1/2047	48.44	29.82							
1/1/2048	48.18	29.66							
2/1/2048	44.85	27.61							
3/1/2048	47.70	29.36							
4/1/2048	45.92	28.27							
5/1/2048	47.21	29.06							
6/1/2048	45.45	27.98							
7/1/2048	46.72	28.76							
8/1/2048	46.48	28.61							
9/1/2048	44.75	27.54							
10/1/2048	46.00	28.31							
11/1/2048	44.29	27.26							
12/1/2048	45.53	28.02							
1/1/2049	45.29	27.88							
2/1/2049	40.70	25.05							
3/1/2049	44.84	27.60							
4/1/2049	43.17	26.57							
5/1/2049	44.38	27.32							
6/1/2049	42.72	26.30							
7/1/2049	43.92	27.03							
8/1/2049	43.69	26.89							
9/1/2049	42.06	25.89							
10/1/2049	43.24	26.62							
11/1/2049	41.63	25.63							
12/1/2049	42.80	26.34							
1/1/2050	42.57	26.21							
2/1/2050	38.26	23.55							
3/1/2050	42.15	25.94							

Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2050	40.58	24.98							
5/1/2050	41.72	25.68							
6/1/2050	40.16	24.72							
7/1/2050	41.29	25.41							
8/1/2050	41.07	25.28							
9/1/2050	39.54	24.34							
10/1/2050	40.65	25.02							
11/1/2050	39.13	24.09							
12/1/2050	40.23	24.76							
1/1/2051	40.02	24.63							
2/1/2051	35.97	22.14							
3/1/2051	39.62	24.39							
4/1/2051	38.15	23.48							
5/1/2051	39.21	24.14							
6/1/2051	37.75	23.24							
7/1/2051	38.81	23.89							
8/1/2051	38.61	23.76							
9/1/2051	37.17	22.88							
10/1/2051	38.21	23.52							
11/1/2051	36.79	22.64							
12/1/2051	37.82	23.28							
1/1/2052	37.62	23.16							
2/1/2052	35.01	21.55							
3/1/2052	37.24	22.92							
4/1/2052	35.85	22.07							
5/1/2052	36.86	22.69							
6/1/2052	35.48	21.84							
7/1/2052	36.48	22.45							
8/1/2052	36.29	22.34							
9/1/2052	34.94	21.50							
10/1/2052	35.91	22.11							
11/1/2052	34.58	21.28							
12/1/2052	35.54	21.88							
1/1/2053	35.36	21.76							
2/1/2053	31.78	19.56							
3/1/2053	35.01	21.55							
4/1/2053	33.70	20.75							
5/1/2053	34.65	21.33							
6/1/2053	33.36	20.53							

Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2053	34.29	21.11							
8/1/2053	34.11	21.00							
9/1/2053	32.84	20.21							
10/1/2053	33.76	20.78							
11/1/2053	32.50	20.01							
12/1/2053	33.41	20.57							
1/1/2054	33.24	20.46							
2/1/2054	29.87	18.39							
3/1/2054	32.91	20.26							
4/1/2054	31.68	19.50							
5/1/2054	32.57	20.05							
6/1/2054	31.36	19.30							
7/1/2054	32.23	19.84							
8/1/2054	32.07	19.74							
9/1/2054	30.87	19.00							
10/1/2054	31.74	19.53							
11/1/2054	30.55	18.81							
12/1/2054	31.41	19.33							
1/1/2055	31.25	19.23							
2/1/2055	28.08	17.29							
3/1/2055	30.93	19.04							
4/1/2055	29.78	18.33							
5/1/2055	30.62	18.85							
6/1/2055	29.48	18.14							
7/1/2055	30.30	18.65							
8/1/2055	30.14	18.55							
9/1/2055	29.02	17.86							
10/1/2055	29.83	18.36							
11/1/2055	28.72	17.68							
12/1/2055	29.53	18.17							
1/1/2056	29.37	18.08							
2/1/2056	27.34	16.83							
3/1/2056	29.07	17.90							
4/1/2056	27.99	17.23							
5/1/2056	28.78	17.71							
6/1/2056	27.70	17.05							
7/1/2056	28.48	17.53							
8/1/2056	28.33	17.44							
9/1/2056	27.28	16.79							

Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2056	28.04	17.26	[redacted]						
11/1/2056	27.00	16.62							
12/1/2056	27.75	17.08							
1/1/2057	27.61	16.99							
2/1/2057	24.81	15.27							
3/1/2057	27.33	16.82							
4/1/2057	26.31	16.20							
5/1/2057	27.05	16.65							
6/1/2057	26.04	16.03							
7/1/2057	26.77	16.48							
8/1/2057	26.63	16.39							
9/1/2057	25.64	15.78							
10/1/2057	26.36	16.22							
11/1/2057	25.38	15.62							
12/1/2057	26.09	16.06							
1/1/2058	25.95	15.97							
2/1/2058	23.32	14.36							
3/1/2058	25.69	15.81							
4/1/2058	24.74	15.23							
5/1/2058	25.43	15.65							
6/1/2058	24.48	15.07							
7/1/2058	25.17	15.49							
8/1/2058	25.04	15.41							
9/1/2058	24.10	14.84							
10/1/2058	24.78	15.25							
11/1/2058	23.86	14.68							
12/1/2058	24.52	15.10							
1/1/2059	24.39	15.02							
2/1/2059	21.92	13.50							
3/1/2059	24.15	14.87							
4/1/2059	23.25	14.31							
5/1/2059	23.90	14.71							
6/1/2059	23.01	14.17							
7/1/2059	23.66	14.56							
8/1/2059	23.53	14.49							
9/1/2059	22.66	13.95							
10/1/2059	23.29	14.34							
11/1/2059	22.42	13.80							
12/1/2059	23.05	14.19							

Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2060	22.93	14.12							
2/1/2060	21.34	13.14							
3/1/2060	22.70	13.97							
4/1/2060	21.85	13.45							
5/1/2060	22.47	13.83							
6/1/2060	21.63	13.31							
7/1/2060	22.24	13.69							
8/1/2060	22.12	13.62							
9/1/2060	21.30	13.11							
10/1/2060	21.89	13.48							
11/1/2060	21.08	12.97							
12/1/2060	21.67	13.34							
1/1/2061	21.55	13.27							
2/1/2061	19.37	11.92							
3/1/2061	21.34	13.14							
4/1/2061	20.54	12.65							
5/1/2061	21.12	13.00							
6/1/2061	20.33	12.52							
7/1/2061	20.90	12.87							
8/1/2061	20.79	12.80							
9/1/2061	20.02	12.32							
10/1/2061	20.58	12.67							
11/1/2061	19.81	12.20							
12/1/2061	20.37	12.54							
1/1/2062	20.26	12.47							
2/1/2062	18.21	11.21							
3/1/2062	20.06	12.35							
4/1/2062	19.31	11.89							
5/1/2062	19.85	12.22							
6/1/2062	19.11	11.77							
7/1/2062	19.65	12.09							
8/1/2062	19.55	12.03							
9/1/2062	18.82	11.58							
10/1/2062	19.35	11.91							
11/1/2062	18.62	11.46							
12/1/2062	19.15	11.79							
1/1/2063	19.05	11.72							
2/1/2063	17.12	10.54							
3/1/2063	18.86	11.61							

Woodford Project PROB
Monthly Cash Flows

CONFIDENTIAL

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2063	18.15	11.17	[redacted]						
5/1/2063	18.66	11.49							
6/1/2063	17.97	11.06							
7/1/2063	18.47	11.37							
8/1/2063	18.37	11.31							
9/1/2063	17.69	10.89							
10/1/2063	18.19	11.19							
11/1/2063	17.51	10.78							
12/1/2063	18.00	11.08							
1/1/2064	103.78	63.88							

Exhibit TT-10
Forrest A. Garb & Associates Report
Pages 1 - 30
IS CONFIDENTIAL IN ITS ENTIRETY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY'S

PETITION FOR PRUDENCE DETERMINATION

REGARDING ACQUISITION OF GAS RESERVES

DIRECT TESTIMONY OF KIM OUSDAHL

DOCKET NO. 140001-EI

JUNE 25, 2014

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kim Ousdahl, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Vice President, Controller and Chief Accounting Officer.

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

A. I am responsible for financial accounting, as well as internal and external financial reporting for FPL. In these roles, I am responsible for ensuring that the Company's financial reporting complies with requirements of Generally Accepted Accounting Principles ("GAAP") and multi-jurisdictional regulatory accounting requirements.

Q. Please describe your educational background and professional experience.

A. I graduated from Kansas State University in 1979 with a Bachelor of Science Degree in Business Administration, majoring in Accounting. I am a Certified Public Accountant ("CPA") licensed in the State of Texas and a member of the American Institute of CPAs, the Texas Society of CPAs and the Florida Institute of CPAs.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- KO-1-- Memorandum of Understanding ("MOU")
- KO-2 -- Estimated Transfer Price Calculation
- KO-3 -- Purchase Accounting Entry (Estimated)
- KO-4 -- Example Joint Interest Billing Statement ("JIB")
- KO-5 -- Year One Proforma Financial Statements
- KO-6 -- Sample of Supplemental Schedule Fuel Projection Filing
- KO-7 -- Condensed Chart of Accounts

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the appropriate accounting and regulatory treatment associated with FPL's proposed investment in the gas reserves and production of natural gas in the Woodford Shale region to meet a portion of FPL's natural gas requirements (the "Woodford Project" or "the Project"). This accounting and ratemaking treatment is not only appropriate for this specific investment, but also would be used for future gas reserve investments made consistent with this strategy. Specifically, my testimony addresses the following:

1. Overview of the Woodford Project;
2. Accounting for the transfer of interests to FPL from USG Properties Woodford I, LLC ("USG"), an affiliate that initially will invest in the

Project in order to accommodate the time required for Florida Public Service Commission ("FPSC" or "Commission") approval;

3. Description of the specialized accounting that will apply to the Project and any subsequent gas reserve investments, and the internal controls that will be in place to ensure appropriate financial reporting and ratemaking; and lastly,

4. Regulatory reporting, ratemaking and recovery of investment through the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause").

Q. Please summarize your testimony.

A. As described by FPL witness Forrest, investment in the Woodford Project will provide significant benefits for FPL's customers. Given FPL's projected natural gas prices, this investment will lower the delivered price and decrease the price volatility for natural gas that customers pay through the Fuel Clause. As such, recovery through the Fuel Clause of costs for the Project (and for other gas reserve projects that deliver similar benefits) is appropriate and consistent with Commission precedent.

Upon Commission approval of Fuel Clause recovery, USG will transfer the Woodford Project to a wholly-owned subsidiary of FPL (as yet unnamed but referred to herein as "GRCO") at net book value. USG will not gain from this transfer, and FPL will be put essentially in the position of initial purchaser. Use of a subsidiary will provide benefits to FPL's customers, including

flexibility to minimize state income tax obligations. The use of a subsidiary will not increase costs to FPL customers; in fact, it could lower customer costs to the extent that it minimizes state income taxes. To simplify the references in my testimony, I will refer just to FPL as the acquiring party except where specific, separate reference to GRCO is required.

Accounting for the costs of gas reserve projects is specialized, but standardized across the industry. Initially, FPL intends to use one of the several well-established third party providers of accounting and recordkeeping services in order to maintain oversight and control over the accounting for the Woodford Project and any other gas reserve projects consistent with FPL's role as a non-operator. As it gains experience with the accounting over time, FPL will evaluate if it can cost-effectively staff the function in-house.

II. OVERVIEW OF THE WOODFORD PROJECT

Q. Please describe the assets that FPL is proposing to acquire.

A. As described in greater detail by FPL witness Forrest, USG has entered into a series of agreements with PetroQuest Energy, Inc. ("PetroQuest") under which USG will pay a share of the costs for developing and operating natural gas production wells in the Woodford Project and will receive a portion of PetroQuest's working interest in those wells. For convenience, I will refer to

these agreements collectively as the PetroQuest Agreement. USG is the initial transacting counterparty with PetroQuest but, upon a Commission determination that FPL's investment in the Woodford Project is prudent and may be recovered through the Fuel Clause, USG will assign all of its rights and obligations under the PetroQuest Agreement to FPL. Upon assignment, USG would convey its interests and obligations to FPL, including the obligation to pay specified percentages of drilling costs for new wells and production costs for the producing wells as described in FPL witness Forrest's Confidential Exhibit SF-6.

PetroQuest, USG and other third parties have working interests in proved, developed producing ("PDP"), proved undeveloped ("PUD") and probable wells located within the Area of Mutual Interest ("AMI") in the Woodford Shale region. As a part of the new PetroQuest Agreement, additional capital investment will be required to support the drilling and development plan contemplated by that agreement. That plan calls for the drilling of additional wells before the end of 2014. Depending upon the timing of FPSC approval and the ultimate drilling program results, a portion of those new wells will have already been drilled and producing while USG holds the interests. USG would pay its share of the drilling costs specified in the PetroQuest Agreement and those costs would be included in the amount FPL pays USG at time of transfer. FPL and USG currently estimate that USG's net book value for

drilling performed from the effective date of the PetroQuest Agreement until the time of the transfer will be approximately $58.2 million, assuming a transfer date January 1, 2015. After transfer to FPL, and assuming that (i) FPL consents to all remaining wells that PetroQuest plans to drill with (ii) the remaining interest-holders in the AMI not consenting, the payments to PetroQuest for drilling costs are estimated to be approximately $122.4 million for the additional wells. This represents FPL's maximum estimated participation in the drilling program, which is presented in order to provide a conservative view of FPL's potential financial commitments under the PetroQuest Agreement.

Q. What other costs will FPL incur to step into USG's ownership interest in the Woodford Project when it is transferred?

A. As described by FPL witness Forrest, USG has been a joint venture ("JV") partner with PetroQuest since 2010 for acreage in the Woodford Shale ("Original JV"). A portion of the acreage contained in the Woodford Project was subject to the Original JV between USG and PetroQuest (the "Woodford Project Acreage"). As part of the new Drilling and Development Agreement ("DDA"), USG and PetroQuest assigned portions of the Woodford Project Acreage from the Original JV to the new Woodford Project. Because of USG's existing interests in the Woodford Project Acreage under the original JV, there was no need for USG to pay PetroQuest for its interest in that acreage as part of the Woodford Project. Under the Original JV, however,

USG paid PetroQuest a carry in order to earn its interest in the Woodford Project Acreage. It is therefore necessary for FPL – which has no existing interest in the Woodford Project Acreage – to compensate USG for the carry that was incurred in order to earn acreage. The cost of earned acreage of approximately $10.2 million will be incurred by FPL at the date of transfer from USG to FPL.

Q. Does FPL intend to hold its interest in the Woodford Project directly or through a subsidiary?

A. FPL intends to establish a wholly-owned direct subsidiary, which I refer to as GRCO, to hold FPL's interest in the Woodford Project.

Q. Why is FPL proposing to establish a subsidiary?

A. There are a number of benefits associated with the proposed legal structure. This structure will:

1. Allow maximum flexibility to minimize state tax obligations;
2. Allow for the separation of Federal Energy Regulatory Commission ("FERC") electric chart of accounts for regulatory reporting purposes (FERC Form 1 requires the subsidiaries to be deconsolidated); and
3. Provide clearer definition and transparency for the investment and activities associated with gas reserve projects.

Because costs associated with gas production will be recovered through the Fuel Clause, the separate legal entity facilitates segregation for ratemaking

and earnings surveillance related to base rates much as we do today for our trust fund investments associated with the storm and decommissioning funds.

Q. Has FPL previously used separate legal entities for regulated operations?

A. Yes. Currently, FPL has two primary wholly-owned subsidiaries which are included in its regulated operations for ratemaking purposes. The first is KPB which was initially formed to minimize certain state tax obligations and holds FPL's storm and decommissioning trust fund investments. The second is FPL Recovery Funding, LLC ("FREC") which serves as the securitization entity established to finance FPL's storm losses in 2007. These entities are fully regulated by the Commission.

Q. Will the use of a subsidiary result in higher costs for FPL's customers?

A. No. FPL will be charged only the actual costs and regulated return on the gas reserve assets that the subsidiary holds. These costs are what FPL proposes to recover through the Fuel Clause. If anything, the use of a subsidiary may reduce the amount paid by FPL customers because of the greater flexibility it will provide to minimize state income tax obligations.

III. ACCOUNTING FOR PROJECT TRANSFER

Q. Why is it necessary for USG to initially enter into the PetroQuest Agreement for the Woodford Project and then subsequently transfer that interest to FPL?

A. As discussed in the testimony of FPL witness Forrest, USG is providing a no-cost "bridge" that allows for the PetroQuest transaction to proceed while FPL seeks Commission approval.

Please note that as I explained above, FPL intends to hold the Woodford Project in GRCO and any future gas reserve projects in other wholly-owned subsidiaries rather than directly in FPL. Accordingly, FPL intends that the transfer from USG would be to GRCO rather than FPL.

Q. Please describe the terms on which the Woodford Project will be transferred from USG to GRCO upon Commission approval.

A. The assignment of USG's rights and obligations for ownership of the Woodford working interest and the relevant terms of that assignment are documented in a MOU between USG and FPL. A copy of this MOU is attached as Exhibit KO-1. The MOU calls for the transfer of the investment from USG to GRCO to be executed at net book value, which is the approach generally used for transfers between affiliates under GAAP.[1] The net book

[1] Accounting Standards Codification 805 ("ASC 805") – Business Combinations

value will be comprised of two parts. First, the amounts associated with the capital investment that USG has made since the effective date of the PetroQuest Agreement, less the depletion (if any); which is the cost associated with the percentage of gas extracted from the wells while it held the investment. The net book value for those interests at the time of purchase between USG and GRCO is estimated to be approximately $58.2 million assuming regulatory approval and transfer by January 1, 2015, and based on current assumptions as to the timing of the drilling program and resulting gas production as described by FPL witness Taylor.

Second, the net book value associated with the earned acreage previously incurred by USG under the Original JV must be calculated. Determining the appropriate price for the transfer of the Woodford Project earned acreage to FPL necessitates an allocation of net book value because USG will not be transferring all of its interests in the Woodford Project Acreage. There are currently producing wells drilled subject to the Original JV on the Woodford Project Acreage that USG will be retaining. A portion of the carry that USG has paid to PetroQuest is attributable to earning USG's interest in those wells, while the remainder of the carry is attributable to earning its interest in undeveloped acreage to be drilled in the Woodford Project Acreage which is to be assigned to FPL.

USG and FPL have agreed on the terms of an allocation of the carry paid by USG between the existing producing wells and the remaining, as-yet-undeveloped interests in the Woodford Project Acreage. Essentially, the carry is allocated among three categories of properties in the Woodford Project Acreage: the existing PDP wells, future wells that are presently categorized as PUD wells, and probable wells. The carry is allocated among those three categories based on the number of wells of each type, existing and planned, for each section of the Woodford Project Acreage. The carry allocated to the first two categories is reduced by the depletion that USG has recorded for the proved portions of the Woodford Project Acreage prior to the transfer from the Original JV to the Woodford Project. FPL would pay the share of the carry borne to earn acreage for the latter two categories, totaling $10.2 million, representing the Woodford Project Acreage that will be assigned to FPL. In contrast, FPL would not be responsible for paying the carry allocated to the PDP wells, because those wells are not being assigned to FPL.

Q. Is this calculation of earned acreage to be paid USG reasonable?

A. Yes. The cost of USG's interests in the Woodford Project Acreage is directly related to the actual and anticipated future gas production. The gas production is, in turn, directly related to the number of wells that are and will be drilled in the Woodford Project Acreage. Finally, the allocation of the carry is directly related to how many existing and future wells each party will have in the Woodford Project Acreage. Thus, there is a direct correlation between each

party's interests and the portion of the carry for which it is responsible. In order to ensure that the cost paid by FPL to USG is equal to that carry directly incurred for earned acreage in the assigned properties, FPL will engage an independent accounting firm to perform agreed upon procedures in order to agree the amounts contained in the calculation for carry paid and depletion recorded to the contractual obligations and the USG books and records through the effective date of the new PetroQuest Agreement. Any differences noted in the final report including the roll forward of depletion through effective date, will be adjusted in the true-up process for costs recovered in the Fuel Clause. Exhibit KO-2 shows the estimated combined transfer price.

Q. Please explain why the transfer price is appropriate.

A. Ordinarily, Florida Administrative Code Rule 25-6.1351 (the "Affiliate Rule") governs affiliate transactions. However, subsection (1) of that rule provides that it is not applicable to affiliate transactions for the purchase of fuel and related transportation services that are subject to Commission review and approval in cost recovery proceedings. The Project is directly related to the supply of fuel, and FPL is seeking approval to recover Project costs in the Fuel Clause. Therefore, the Affiliate Rule does not apply to the Project.

Transfer "at cost" puts FPL in the same position it would have been if it could have transacted for this investment on its own with PetroQuest, an

independent third-party seller. In essence, FPL will be paying the market price for this transaction, as measured at the time of USG's initial purchase.

Transfer on these terms is actually quite generous to FPL and its customers. USG will not be compensated for any gain that might occur as a result of market increases between the time of the initial purchase and the transfer to FPL, and it will not be compensated for providing FPL a "free option" to take the transfer or not depending on the outcome of this proceeding. Finally, I should note that transfer of the Project to GRCO at net book value is consistent with GAAP, which requires transfers between entities under common control to be conducted at cost.

Q. What are the acquisition accounting entries that you expect to record for acquisition of the Woodford Project?

A. Exhibit KO-3 provides the acquisition accounting entry to be recorded by GRCO that will be required upon the purchase of these assets from USG, assuming the current drilling plan and projected capital expenditures with that plan, and a January 1, 2015 transfer date.

IV. POST-TRANSFER ACCOUNTING AND INTERNAL CONTROLS

Q. What is the source(s) of accounting guidance that will be followed by FPL once the Project is transferred?

A. Upon transfer, FPL will be subject to ASC 932 Accounting for Oil and Gas Exploration and ASC 980 (formerly known as FAS 71) Accounting for the Effects of Certain Types of Regulation. Accounting for oil and gas production is a highly specialized and unique form of energy accounting. Neither the FERC Electric nor Natural Gas chart(s) of accounts is consistent with the standard accounting utilized in the oil and gas production industry. As a Securities and Exchange Commission ("SEC") registrant, it will be important for FPL and its subsidiary to account for these activities consistent with SEC requirements.

Q. Please describe the accounting method that FPL will follow to record activities related to these investments.

A. FPL will use successful efforts accounting, the method preferred by the SEC.

Q. Please describe the types of costs that will be incurred and how they are recorded under the successful efforts method.

A. There are generally four different types of costs that are recorded under the successful efforts method:

1. Acquisition Costs – Costs incurred to acquire rights to explore, produce, and develop natural gas, and expenses relating to the right to

extract natural gas from a property not owned by the company, which are capitalized when incurred;

2. Exploration Costs – Includes various types of activities:

   a. Costs relating to the collection and analysis of geophysical and seismic data involved in the initial review of a specific site and used at a future date to determine whether or not to drill at that location, which are expensed in the period in which incurred;

   b. Costs to ready a site prior to the installation of drilling equipment, which are expensed in the period in which incurred; and

   c. Costs to install and operate drilling equipment, which are capitalized if the reserve is proven to produce hydrocarbons and typically expensed in the period incurred if the effort is unsuccessful. These costs are further segregated into tangible and intangible drilling costs; with tangible costs including the equipment itself and the intangibles primarily associated with the labor cost incurred to conduct the drilling.

3. Development Costs – Costs to prepare a site with proven reserves for production, which are capitalized when incurred; and

4. Production Costs – Costs incurred to extract natural gas from the reserves, which are expensed in the period in which incurred.

The operator will provide FPL a joint interest billing statement ("JIB") each month reflecting the gross costs incurred and net costs to be remitted detailed by transaction type and activity cost incurred. This is the principal source document commonly used in this industry to provide to non-operators each month details concerning the activities performed and the costs incurred by well and by cost type. A sample JIB is attached as Exhibit KO-4.

Q. What form of depreciation is used for capital investments under the successful efforts method?

A. As with any utility plant investment, the Company and its regulated subsidiaries record depreciation representing the "return of" the investment as it is consumed over its economic life. In the case of gas and oil production accounting, depreciation is recorded in the form of "depletion," which is measured on a unit-of-production basis rather than on a remaining life or whole life basis. Depletion for a gas reserve investment plays the same role as depreciation would for an electric plant asset providing for recognition of the use of the asset in the financial statements and in rates. As permitted under ASC 932, for depletion purposes FPL plans to aggregate its investments at a reservoir or field level because they share common geological structural features. This will help simplify the depletion accounting.

Q. Do reserve estimates have to be updated periodically for the purpose of the depletion calculation?

A. Yes. Reserve estimates must be updated on an annual basis for financial reporting purposes. The reserve estimate reports that the Company will be relying on will be provided by third party reserve engineers. These reports will be used to determine the subsequent year's depletion expense.

Q. Please describe the internal controls that will be in place to ensure FPL's financial reporting and ratemaking will be compliant with all requirements.

A. A non-operator such as FPL that invests in gas reserve projects is reliant on the operator for both commercial operation and the resulting financial effects. Standard industry practice includes measures that substantially protect the non-operator interests. FPL will actively control its participation in the drilling program as managed by PetroQuest, will receive detailed transactional monthly invoices for all costs (JIBs) and will retain audit rights over the resulting costs of production as codified in the PetroQuest Agreement.

There will be other measures of internal control that will ensure proper billing and sharing of the expenditures. First, an authorization for expenditure ("AFE") provides consent to drill and memorializes that consent and the planned costs associated with that drilling activity. This document is signed and authorized by the non-operator, typically before drilling commences to

signify its participation and supports any prepayments required consistent with the PetroQuest Agreement. Second, on a monthly basis PetroQuest will send FPL a JIB. As outlined in the PetroQuest Agreement, FPL (through GRCO) would have the right to audit PetroQuest JIBs and will be reimbursed for any inaccurate or inappropriate billings. Sarbanes-Oxley ("SOX") processes will be developed to the extent appropriate to memorialize the processes and related key controls designed to ensure compliance with financial reporting requirements. Lastly, FPL's external auditors will conduct substantive controls testing around these transactions to the extent necessary as a part of its overall external audit.

Q. How does FPL envision implementing the accounting, reporting and ratemaking functions associated with investments in gas reserves?

A. Although this accounting is very specialized, utilizing a unique chart of accounts and specialized financial systems, it is highly standardized. There are numerous mid-sized entities that invest in oil and gas production for which it is cost effective to rely on third parties to perform the specialized accounting and reporting. These third party providers have the proper systems and experience to deliver the full scope of back-office services necessary to effectively participate as a non-operator in oil and gas production. At the outset, FPL intends to contract with an experienced firm specializing in oil and gas back-office outsourcing. The use of outsourcing will provide for

scalability as FPL continues to pursue investments. The activities we expect to outsource initially could include:

* JIB accounting
* Maintenance of general ledger and production of financial statements
* Production allocation and reporting
* Joint Venture compliance reviews/audits
* Support for external financial audits
* Electronic filings with state, federal or other regulatory tax agencies
* Payments to royalty owners
* Escheat reporting

As it gains experience with the accounting, reporting and ratemaking functions over time, FPL will evaluate which of those functions it can cost-effectively staff in-house.

V. COST RECOVERY AND REGULATORY REPORTING

Q. How does FPL propose to recover the costs of the Woodford Project and any future gas reserve projects?

A. FPL seeks to recover all costs associated with gas reserve projects through the Fuel Clause.

Q. Why is Fuel Clause recovery appropriate?

A. Item 10 of FPSC Docket No. 850001-EI-B, Order No. 14546 provides that Fuel Clause recovery is appropriate for projects that are intended to lower the delivered price of fuel when those costs were "not recognized or anticipated in the cost levels used to determine current base rates." The Commission recently reiterated its support for recovering through the Fuel Clause costs associated with projects that reduce the delivered price of fuel in Order No. PSC-11-0080-PAA-EI: "We find that the appropriate interpretation of this section of Order No. 14546 is that capital projects eligible for cost recovery through the Fuel Clause should produce fuel savings based on lowering the delivered price of fossil fuel, or otherwise result in burning lower price fuel at the plant." The Commission confirmed that such costs would be recoverable and further explained that "the appropriate policy going forward is to restrict capital project cost recovery through the Fuel Clause to projects that are 'fossil fuel-related' and that lower the delivered price, or input price, of fossil fuel". The Commission has permitted FPL to recover costs for capital projects through the Fuel Clause on several occasions previously, including costs for a gas pipeline lateral to the Martin Plant (Order No. PSC-93-1331-FOF-EI), rail cars to deliver coal to the Scherer Plant (Order No. PSC-95-1089-FOF-EI), and power plant equipment modifications to allow a cheaper, low-gravity fuel to be burned (Order No. PSC-97-0359-FOF-EI).

The Woodford Project clearly and directly meets the test for Fuel Clause recovery set forth in Order No. 14546. The Project is intended to lower the delivered price of natural gas that FPL burns in its generating units. As discussed in FPL witness Forrest's testimony, the Project is estimated to result in savings to customers compared to FPL's current projection of natural gas prices. Moreover, there was neither recognition nor anticipation of gas reserve project costs in the 2013 test year that formed the basis for FPL's current base rates.

FPL's proposed investment in the Woodford Project is even more directly related to lowering fuel prices than the projects mentioned above that have been previously approved for Fuel Clause recovery. This investment is solely intended to secure natural gas for the operation of FPL's generating plants. It is therefore, no different in substance than the natural gas costs paid to third parties to buy gas at market prices, all of which are currently recovered in the Fuel Clause.

Finally, because there will be a measure of variation and uncertainty in the overall level of incurred costs that can be expected for gas reserve projects over time, cost recovery is more appropriate in the Fuel Clause, where the changes can be reflected in annual Fuel Clause factors. For example, as FPL witness Forrest discusses in his testimony, a substantial portion of the ultimate

output from a well is expected to occur in the early years of production, after which time production will decline due to depletion. Thus, the absolute dollar amount of the revenue requirements for the well (which is what would be built into a base rate test year) would decline substantially over time.

Q. Please describe the types of costs that FPL proposes to recover through the Fuel Clause for the Woodford Project and any future gas reserve projects.

A. All of the investment and operating costs of GRCO would be included for recovery in the Fuel Clause by FPL. The recoverable costs would include the following types: exploration expense, depletion expense, operating expenses, G&A, taxes, transportation costs and a return on the unrecovered investment, including working capital. These costs would be projected for each year based on the drilling plan and quantities of gas to be produced and then adjusted to reflect actual costs subsequently through the existing Fuel Clause true-up process. This approach is consistent with the recovery of capital investment in environmental compliance projects through the Environmental Cost Recovery Clause.

Q. How would the monthly transactions to reflect the sale of gas from GRCO to FPL be recorded?

A. The revenue requirement from the costs incurred by GRCO to acquire, drill, produce and transport the natural gas from the well to FPL's generating plants would be calculated each month. That amount would be recorded in an

intercompany billing by GRCO to FPL. On FPL's books, the charge would be recorded as fuel expense for that month.

Q. How are these costs going to be reflected in the Fuel Clause?

A. Exhibit KO-5 to this testimony reflects proposed proforma financial statements that would form the basis for the revenue requirements calculation to be used in the clause filing for the first year of operations. Exhibit KO-6 reflects a sample Fuel Projection Filing with all the components that FPL is seeking to recover through the Fuel Clause. All of the costs will be retail jurisdictionalized along with all other fuel costs recoverable through the Fuel Clause, based on the percentage of retail kWh sales to total kWh sales.

Q. What will be the first period in which these costs will be reflected in the Fuel Clause?

A. The first year in which costs associated with the gas reserves project will be introduced is expected to be in the filing of 2015 projected fuel costs, which will be made in August 2014. FPL has developed a projection of costs to be incurred for the Woodford Project in 2015 using its best estimate of the costs associated with the transfer from USG and the expected drilling and production activities for which GRCO will be responsible during the remainder of that year. These 2015 estimates will be updated in the actual/estimated true-up filing (August 2015) and ultimately replaced with actual costs in the final true-up filing (March 2016).

Q. Will the Commission have the opportunity to audit the gas reserve costs that FPL recovers through the Fuel Clause?

A. Yes. The FPSC auditors, upon request, will be provided all information necessary to review charges associated with these recoveries annually in the fuel audit. They will have full access to FPL's and GRCO's books and records containing all transactions recorded from the JIBs.

Q. How will FPL calculate the return associated with gas reserve investments?

A. As with any utility capital investment recovered through the adjustment clauses, FPL will calculate the return associated with it in accordance with FPSC Order No. PSC-12-0425-PAA-EU. FPL updates annually its capital structure components (i.e. debt and equity rates) used to calculate the return on clause investments, based on the May Earnings Surveillance Reports ("ESR") results. The same methodology should be followed for the purpose of this investment.

Q. Will gas reserve investments be reflected in FPL's Earnings Surveillance Report filings?

A. No. Consistent with FPL's practice for all investments earning their own return through an adjustment clause, the investment in the gas reserves, net of depletion, will be removed from FPL's rate base in the ESR and all revenues and expenses will be eliminated from net operating income.

Q. What FERC accounts will FPL utilize to record natural gas activities and costs associated with the Project?

A. FPL intends to use the industry standard chart of accounts to record all costs associated with the investment at the subsidiary level. This condensed chart of accounts is included as Exhibit KO-7 with the subsidiary accounts reflected on the left hand side. It is important to be consistent with the industry practice to facilitate ease of electronic mapping of the JIBs and to facilitate use of third party support. Any audit of the transactions will be done at the transactional level using the industry chart of accounts contained herein. On the right hand side of that exhibit, we have provided a view of the high level mapping to the FERC natural gas chart of accounts that we intend to use for summary level financial statement reporting for consolidated FPL.

Q. Does this conclude your direct testimony?

A. Yes.

MEMORANDUM OF UNDERSTANDING

This MEMORANDUM OF UNDERSTANDING ("MOU") has been prepared to document the understanding between USG Energy Gas Producer Holdings, LLC, Delaware limited liability company ("USG") and Florida Power & Light Company ("FPL") with respect to the matters set forth herein below.

A. On June 18, 2014 (the "Closing Date"), PetroQuest Energy, L.L.C., a Louisiana limited liability company ("PQ") and USG Properties Woodford 1, LLC, a Delaware limited liability company ("USG Woodford" a wholly-owned subsidiary of USG), entered into a Drilling and Development Agreement (the "DDA" and together with the exhibits and schedules thereto and all ancillary documents, the "Project Documents") pursuant to which USG Woodford acquired certain rights and obligations to participate as a non-operating, working interest owner in the oil and gas leases, oil, gas and mineral leases, mineral servitudes, subleases and other leaseholds, royalties, overriding royalties, net profits interests, carried interests, mineral fee interests, farmout rights and operating rights with respect to a drilling program for future wells to be drilled by PQ within the Woodford Shale located in Pittsburg County, Oklahoma (the "Project").

B. The DDA requires that, beginning on the Closing Date, PQ will begin to execute the drilling plan as agreed with USG Woodford. That plan contemplates the Project having fourteen (14) wells in some stage of development, including four (4) actively producing wells, before December 31, 2014.

C. USG owns existing interests in the Project acreage under a 2010 joint venture between WSGP Gas Producing, LLC, a subsidiary of USG, and PQ (the "Original JV"). Under the Original JV, USG paid PQ a carry in order to earn its interest in the Project acreage. From the earliest negotiations of the Project Documents, it has been contemplated that FPL would acquire USG Woodford's rights, obligations and liabilities with respect to the Project. To that end, FPL and USG sought, analyzed, performed due diligence on the Project, and negotiated the Project Documents collectively. Each company has independently approved the Project, on the basis that each company was willing to assume for itself all of the rights, obligations, and liabilities of the Project as of the Closing Date and the potential rights, obligations, and liabilities of the Project that may arise in the future. Each party has engaged and paid for third party consultants including external legal counsel for the purposes of due diligence, and negotiations in the Project.

D. FPL determined, and USG Woodford agreed, that FPL would not acquire the Project unless and until the Florida Public Service Commission ("FPSC") confirms that acquisition of the Project is prudent and that the costs for the Project are eligible for recovery through the Fuel and Purchased Power Cost Recovery Clause ("FPSC Approval").

E. USG Woodford is acquiring the Project on the Closing Date with the understanding and agreement that, upon FPSC Approval, FPL intends to acquire the Project from USG Woodford on the following terms:

a. Within 30 days following FPSC Approval, USG Woodford shall assign all of its rights, obligations and liabilities with respect to the Project and the Project Documents to either FPL or to a subsidiary established by FPL to hold the Project ("Assignee").

b. In accordance with the terms of the DDA, USG Woodford shall be relieved of all of its direct obligations and liabilities with respect to the contracts and asset ownership, and Assignee shall assume all of USG Woodford's obligations and liabilities with respect to the Project Documents and asset ownership, upon such transfer and assignment.

c. Such transfer to FPL shall be made at USG Woodford's net book value for the Project at the time of transfer, calculated as the sum of:

i. the net book value of any new producing wells (the new "PDP") determined using the capital investment made by USG Woodford after the Closing Date less the cost associated with the percentage of gas extracted from the new wells drilled prior to transfer to FPL (otherwise known as "Depletion"). The net book value calculation is depicted as follows: Capital Expenditures made by USG Woodford up to the time of transfer x (1 - Production/Estimated Ultimate Recovery); and

ii. the net book value of the undeveloped interests, calculated as the carry less any depletion allocated among the following three categories of properties in the Project as of May 31, 2014 (the most current information available on the Closing Date): (1) the existing PDP wells (not to be transferred to FPL), (2) future wells that are categorized as proven undeveloped ("PUD") wells, and (3) probable wells ("PROB"). The carry is allocated among these three categories based on the number of wells of each type, existing and planned, for each section of the Project as of the Closing Date. FPL shall pay the share of the carry borne to earn acreage for the latter two categories, PUD and PROB, less any depletion applied to those categories, representing the Project acreage that will be assigned to FPL.

d. All revenues, expenses, working capital assets, and liabilities that accrue with respect to the Project at date of transfer shall be reflected as adjustments to the net book value; provided, however, that USG Woodford shall bear all of the costs and is entitled to all benefits resulting from any hedges put in place by USG Woodford for gas extracted from the wells. FPL will bear all incremental transfer costs.

F. It is the intent of this MOU that USG Woodford will not gain from the transfer of the Project, and that FPL will be put essentially in the position of USG Woodford as the initial purchaser of the Project.

G. USG and FPL understand that the Project Documents and terms of the Project are confidential and subject to confidentiality and non-disclosure restrictions provided for in the Project Documents.

IN WITNESS HEREOF, the parties hereto have executed this MOU.

USG Energy Gas Producer Holdings, LLC

By: _____

Name: Lawrence A. Wall, Jr.

Title: President

Date: JUNE 24, 2014

Florida Power & Light Company

By: _____

Name: Sam Forrest

Title: Vice President Energy Marketing and Trading

Date: JUNE 24, 2014

Gas Reserves Company
ESTIMATED TRANSFER PRICE CALCULATION
Assuming transfer date of January 1, 2015

Line No.	Item Description	Balance
1	Earned Acreage at May 31, 2014	$ 10,205,471
2	Cumulative capital expenditures made through 2014	58,240,800
3	**Net Book Value**	**$ 68,446,271**

Gas Reserves Company
Gas Reserves Acquisition - Estimated Purchase Accounting Entry

Line No.	GL Account	Entry Description	Debit	Credit
1	211	Unproved Property Acquisition Costs	$ 23,005,091	
2	221	Proved Property Acquisition Costs	45,441,180	
3	101	Cash		$ 68,446,271
4			$ 68,446,271	$ 68,446,271
5				
7		To record gas reserve acquisition from USG.		
8				
9	**Note:**			
10	Detail of entries for Accounts 211 and 221 shown above			

11		DRILLING COSTS	ACREAGE INTEREST	Total
12	Proved	$ 41,274,000	$ 4,167,180	$ 45,441,180
13	Probable	16,966,800	6,038,291	23,005,091
14		$ 58,240,800	$ 10,205,471	$ 68,446,271

Joint Interest Billing - Example

BIG OIL USA, INC.
P.O. BOX 12345, DENTON, TX 76201

COUNTRY SERVICE COMPANY (a)
15467 EAST 107TH AVENUE
HOUSTON, TX 77046

INVOICE NO.: 1023174
INVOICE DATE: MAY 24, 2010
TERM: NET 30 UPON RECEIPT
MONTH: APRIL 2010
PROPERTY: N. MOORE LEASE

Summary Statement and Invoice			
Owner No.	**Owner Name**	**Working Interest**	**Amount**
1123500	ABC OIL	.0447897	$ 24,033.14
1118600	CORONADO HILLS PARTNERS	.0635633	34,106.62
5117300	COUGAR PETROLEUM	.0153747	8,249.72
2954800	WILL B. SMITH	.0226632	12,160.56
1431400 - (a)	COUNTRY SERVICE COMPANY	.0547563 - (a)	29,380.99
0488500	J.B. JONES	.0258106	13,849.38
8224400	BDF OIL & GAS	.3833124	205,676.74
0000001	BIG OIL USA, INC.	.3897298	209,120.16
		1.0000000	
Total Current Period Charges to Joint Account			$536,577.31
TO INVOICE YOU FOR:			
Drilling and Development Charges - **See Page 2** $531,491.65*0.0547563 = $29,102.52			$ 29,102.52
Lease Operating Expenses - **See Page 3** - $5,085.66*0.0547563 = $278.47			278.47
Total Current Period Charges			29,380.99
Previous Balance Carried Forward			
Total Due			$ 29,380.99

REMITTANCE INSTRUCTIONS
Please reference the above invoice number and mail payment to:
Big Oil USA, Inc.
P.O. Box 12345
Denton, TX 76201

Joint Interest Billing - Example

BIG OIL USA, INC.
P.O. BOX 12345, DENTON, TX 76201

COUNTRY SERVICE COMPANY
15467 EAST 107 AVENUE
HOUSTON, TX 77046
PROPERTY: N. Moore Lease
WEILL: N. Moore #2

INVOICE NO.: 1023174
INVOICE DATE: MAY 24, 2010
TERM: NET 30 UPON RECEIPT
MONTH: APRIL 2010
AFE No.: 102

Drilling and Development Charges			
S/L	Description	Amount	Total
104	Tubing	$ 147,780.21	
105	Wellhead Assembly	764.88	
115	Misc. Non-Cont. Surface Well Material	684.79	
122	Production & Other Lease Facilities	14,111.02	
133	Installation Cost	4,245.70	
244	Permits, Shite Prep & Clean-up	8,638.74	
248	Other Contract Services	116.25	
249	Contract Drilling	301,903.89	
251	Direct Supervision	7,870.42	
255	Bits	(1,297.06)	
267	Equipment Rentals	3,449.50	
268	Small Tools & Supplies	206.90	
269	Transportation Land	6,156.29	
273	Communications	177.66	
275	Testing, Drafting & Inspection	22,083.03	
277	Perforating	8,280.20	
280	Drilling Overhead Charge	5,000.00	
283	Loss & Damage	1,319.23	
	Total Drilling and Development Charges	$	531,491.65

Joint Interest Billing - Example

BIG OIL USA, INC.
P.O. BOX 12345, DENTON, TX 76201

COUNTRY SERVICE COMPANY
15467 EAST 107TH AVENUE
HOUSTON, TX 77046
PROPERTY: N. Moore Lease
WELL: N. Moore #1

INVOICE NO.: 1023174
INVOICE DATE: MAY 24, 2010
TERM: NET 30 UPON RECEIPT
MONTH: APRIL 2010
AFE No.: N/A

Lease Operating Expense			
S/L	Description	Amount	Total
120	Contract Labor	$2,903.61	
121	Rig Services	406.71	
125	Gas Handling	6.81	
128	Salt Water Disposal	375.75	
140	Chemicals	44.72	
141	Small Tolls & Supplies	55.34	
143	Automotive Expense	198.36	
170	Telephone & Telegraph	53.50	
180	Employee Travel & Gen Exp	68.13	
800	General Services	112.08	
824	Area Expense	510.65	
880	Production Overhead	350.00	
	Total Lease Operating Expense		$5,085.66

Gas Reserves Company
Income Statement
Twelve Months Ended December 31, 2015

Line No.	Account No. [1]	Account Description		
1		**Revenues**		
2	602	Gas Revenues	$	52,473,402
3				
4		**Expenses**		
5	710	Lease Operating Expenses	$	18,455,962
6	725	DD&A		20,744,130
7	900	G&A Expenses		300,000
8	920	Interest expense		2,110,880
9	940	Income Tax Provision		4,225,485
10				
11				
12		**Net Income**	$	6,636,945

[1] Accounts refer to industry standard accounts. Refer to KO-7

Gas Reserves Company
At Year End 12/31/2015
Balance Sheet

Line No.	Account No. [6]	Account Description	Day 1 Balance Sheet Total	2015 Activity	Distribution to Parent @ YE [4] [5]	BS - YE 12/31/2015 Year End Balance Total
1	**Current Assets**					
2	101	Cash	$ -	$ 31,606,560	$ (27,381,075)	$ 4,225,485
3	221/231/233	Gas Reserves Investment	68,446,271	122,321,700		190,767,971
4	226/232/234	Accumulated Amortization	-	(20,744,130)		(20,744,130)
5	127	Accrued Receivables (Income Taxes)	-	28,119,267 [1]		28,119,267
6		**Totals Assets**	$ 68,446,271			**$ 202,368,592**
7	**Current Liabilities**					
8	401	Payable Intercompany Debt [2]	$ (27,652,293)	$ (49,417,967)	$ 8,380,629	$ (68,689,631)
9	420	Deferred Income Taxes [3]	-	(32,344,752)		(32,344,752)
10	501	Common Stock (Paid in Capital) [2]	(40,793,978)	(72,903,733)	19,000,446	(94,697,265)
11	525	Retained Earnings		(6,636,945)		(6,636,945)
12		**Totals Liabilities**	$ (68,446,271)			**$ (202,368,592)**
13						
14	**Notes:**					

[1] To calculate Income Tax Receivable:

Depletion	$ 20,744,130
Current IT	4,225,485
Current year - after tax income	6,636,945
Tax Depreciation Expense	(103,892,593)
Subtotal	(72,286,033)
Income Tax Receivable@ 38.9%	$ (28,119,267)

For first year of operations GRCO will incurr a loss for income tax purposes due to the deduction for tax purposes of drilling costs. This will be utilized by the parent company on their consolidated income tax calculation.

[2] The subsidiary capital structure will be based on the debt and equity ratios of FPL.

[3] To calculate DTL:

Depletion	$ 20,744,130
Tax Depreciation Expense	(103,892,593)
Subtotal	(83,148,463)
DTL @ 38.9%	$ (32,344,752)

For first year of operations GRCO will record a deferred income tax liability applicable to the deduction for tax purposes of the drilling and depletion costs.

[4] Components of distribution made to parent:

Depletion	$ (20,744,130)
Retained Earnings	(6,636,945)
	$ (27,381,075)

[5] Cash to parent - Repayment of:

Payable Intercompany Debt	$ 8,380,629
Common Stock	19,000,446
	$ 27,381,075

Represents the distribution to parent of the cash generated by the subsidiary during its first year of operations.

[6] Accounts refer to industry standard accounts. Refer to KO-7

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through December 2015 - SAMPLE SUPPLEMENTAL SCHEDULE

Supplemental Schedule - Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	January ESTIMATED	February ESTIMATED	March ESTIMATED	April ESTIMATED	May ESTIMATED	June ESTIMATED	**Six Month Amount**
1.	Investments								
	a. Capital addition		$5,045,400	$19,260,000	$14,214,600	$19,260,000	$5,045,400	$19,260,000	$82,085,400
2.	Gas Reserve Investment / DD&A Base (A)	$68,446,271	73,491,671	92,751,671	106,966,271	126,226,271	131,271,671	150,531,671	n/a
3.	Less: Accumulated Depletion Reserve	$0	377,307	971,330	1,901,685	3,106,386	4,682,419	6,426,341	n/a
									n/a
4.	Net Investment (Lines 2 - 3)	$68,446,271	$73,114,364	$91,780,341	$105,064,586	$123,119,885	$126,589,252	$144,105,330	n/a
5.	Average Rate Base (D)		70,780,318	82,447,352	98,422,463	114,092,236	124,854,569	135,347,291	n/a
6.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		475,248	553,585	660,848	766,061	838,324	908,776	4,202,842
	b. Debt Component (Line 5 x debt rate x 1/12) (C)		92,354	107,577	128,422	148,868	162,910	176,601	816,732
	Subtotal (Debt & Equity Return)		567,602	661,162	789,270	914,929	1,001,234	1,085,377	
7.	Investment and Operating Expenses								
	a. Transportation Costs		416,920	524,058	740,515	898,160	1,127,811	1,216,633	4,924,097
	b. Depletion		377,307	594,024	930,354	1,204,701	1,576,033	1,743,922	6,426,341
	c. Lease Operating Expenses (LOE)		47,592	103,946	121,077	169,423	201,640	240,162	883,839
	d. Taxes (Ad-Valorem, Severance & Franchise)		80,128	80,128	80,128	80,128	80,128	80,128	480,766
	e. G&A		25,000	25,000	25,000	25,000	25,000	25,000	150,000
8.	Total System Recoverable Expenses (Lines 6 & 7a-e)		$1,514,548	$1,988,317	$2,686,343	$3,292,341	$4,011,846	$4,391,222	$17,884,617

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) For purposes of this example the gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.9230% based on the May 2013 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) For purposes of this example the debt component is 1.5658% based on the May 2013 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

(D) Simplified example omits the working capital items that would be included in the actual clause filings.

Totals may not add due to rounding.

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through December 2015 - SAMPLE SUPPLEMENTAL SCHEDULE

Supplemental Schedule - Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	July ESTIMATED	August ESTIMATED	September ESTIMATED	October ESTIMATED	November ESTIMATED	December ESTIMATED	**Twelve Month Amount**
1.	Investments								
	a. Capital addition		$16,276,500	$9,630,000	$2,522,700	$8,368,650	$3,438,450	$0	$122,321,700
2.	Gas Reserve Investment / DD&A Base (A)	$150,531,671	166,808,171	176,438,171	178,960,871	187,329,521	190,767,971	190,767,971	n/a
3.	Less: Accumulated Depletion Reserve	$6,426,341	8,323,765	10,424,370	12,999,989	15,630,310	18,154,600	20,744,130	n/a
									n/a
4.	Net Investment (Lines 2 - 3)	$144,105,330	$158,484,406	$166,013,801	$165,960,882	$171,699,211	$172,613,371	$170,023,841	n/a
5.	Average Rate Base (D)		151,294,868	162,249,103	165,987,341	168,830,047	172,156,291	171,318,606	n/a
6.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,015,855	1,089,406	1,114,506	1,133,593	1,155,927	1,150,302	10,862,430
	b. Debt Component (Line 5 x debt rate x 1/12) (C)		197,410	211,703	216,580	220,289	224,630	223,537	2,110,880
	Subtotal (Debt & Equity Return)		1,213,264	1,301,108	1,331,086	1,353,882	1,380,556	1,373,839	
7.	Investment and Operating Expenses								
	a. Transportation Costs		1,311,045	1,441,048	1,702,735	1,731,192	1,654,296	1,690,799	14,455,211
	b. Depletion		1,897,425	2,100,605	2,575,618	2,630,321	2,524,290	2,589,531	20,744,130
	c. Lease Operating Expenses (LOE)		218,151	349,126	391,672	397,235	413,250	385,946	3,039,218
	d. Taxes (Ad-Valorem, Severance & Franchise)		80,128	80,128	80,128	80,128	80,128	80,128	961,533
	e. G&A		25,000	25,000	25,000	25,000	25,000	25,000	300,000
8.	Total System Recoverable Expenses (Lines 6 & 7a-e)		$4,745,012	$5,297,014	$6,106,239	$6,217,758	$6,077,520	$6,145,242	$52,473,402

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) For purposes of this example the gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.9230% based on the May 2013 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) For purposes of this example the debt component is 1.5658% based on the May 2013 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

(D) Simplified example omits the working capital items that would be included in the actual clause filings.

Totals may not add due to rounding.

Condensed Chart of Accounts

Condensed Chart of Accounts				
Gas Reserve Company (GRCO)			**Florida Power & Light (FPL) - FERC Gas**	
Current Assets			**Current Assets**	
101	Cash		131	Cash
120	AR-Oil & Gas Sales		143	Other Accounts Receivable
121	AR-Gas Imbalances			"
123	AR-Joint Interest Billings			"
126	AR-Other			"
127	Accrued Receivables		173	Accrued Utility Revenues
129	Allowance for Doubtful Accounts		144	Accumulated Provision for Uncollectible Accounts
130	Inventory-Oil		151	Fuel Stock
131	Inventory-Gas			"
132	Inventory-Supplies		154	Plant Materials and Operating Supplies
140	Prepaid Expenses		165	Prepayments
Gas Property			**Gas Property**	
211	Unproved Property Acquisition Costs		105.1	Production Properties Held for Future Use
219	Impairment Allowance			"
221	Proved Property Acquisition Costs		101	Gas Plant in Service
226	Accum. Amortization of #221		111	Accumulated Provision for Amortization and Depletion of Gas Utility Plant
230	Asset Retirement Costs		101	Gas Plant in Service
231	Proved Properties-Intangibles		111	Accumulated Provision for Amortization and Depletion of Gas Utility Plant
232	Accum. Amortization of #231			"
233	Tangible Costs, of Wells & Development Costs		101	Gas Plant in Service
234	Accum. Amortization of #233		111	Accumulated Provision for Amortization and Depletion of Gas Utility Plant
235	Accum., Amortization of #230			"
241	WIP-Intangibles		107	Construction Work in Progress - Gas
243	WIP-Tangibles			"
290	Deferred Tax Asset		190	Accumulated Deferred Income Taxes
Current Liabilities			**Current Liabilities**	
301	Vouchers Payable		232	Accounts Payable
302	Revenue Distributions Payable			"
306	Gas Imbalance Payables			"
307	Accrued Liabilities		242	Miscellaneous Current and Accrued Liabilities
320	Production Taxes Payable			"
330	Income Taxes Payable			"
335	Other Current Liabilities			"
360	Revenue Clearing			"
361	Billings Clearing			"
Long Term Liabilities			**Long Term Liabilities**	
401	Notes Payable		231	Notes Payable
410	Asset Retirement Obligation (ARO)		230	Asset Retirement Obligation
Deferred Income Taxes			**Deferred Income Taxes**	
420	Deferred Income Taxes		281-283	Accumulated Deferred Income Taxes
Stockholder's Equity			**Stockholder's Equity**	
501	Common Stock		201	Common Stock
525	Retained Earnings		216	Unappropriated Retained Earnings
Revenues			**Revenues**	
602	Gas Revenues		400	Operating Revenues
603	NGL Revenues			"
Expenses			**Expenses**	
701	Marketing Expenses		401	Operation Expense
710	Lease Operating Expenses			"
725	Depreciation, Depletion & Amortization		405-405	Amortization and Depletion of Producing Natural Gas Land and Land Rights
735	Amortization of Capitalized ARO		403	Depreciation Expense
761	Provision for Impairment of Oil & Gas Properties			
800	Exploration Expenses		401	Operation Expense
900	G&A Expenses			"
920	Interest Expense		427	Interest on Long-term Debt
924	Accretion Cost on Asset Retirement Obligations		403	Depreciation Expense
940	Income Tax Provision		409.1	Income Taxes, Utility Operating Income