COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION OF KENTUCKY UTILITIES	**)**	
COMPANY'S AND LOUISVILLE GAS &	**)**	
ELECTRIC COMPANY'S RESPECTIVE NEED	**)**	**CASE NO. 2015-00194**
FOR AND COST OF MULTIPHASE	**)**	
LANDFILLS AT THE TRIMBLE COUNTY AND	**)**	
GHENT GENERATING STATIONS	**)**	

PRE-FILED DIRECT

TESTIMONY OF

JOHN W. WALTERS, JR.

ON BEHALF OF

STERLING VENTURES, LLC

<u>REDACTED</u>

AUGUST 6, 2015

VERIFIED DIRECT TESTIMONY OF JOHN W. WALTERS, JR.
ON BEHALF OF
STERLING VENTURES, LLC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John W. Walters, Jr. My business address is 376 South Broadway, Lexington, Kentucky 40508.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am the General Counsel and CFO of Sterling Ventures, LLC ("Sterling"), which is a business engaged in the mining of limestone. It was founded in 1995 and is based in Lexington, Kentucky with its activities currently focused on operating an underground limestone mine in Gallatin County, Kentucky. A statement of my education and work experience is attached to this testimony as Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. On May 20, 2015, I filed a complaint before the Commission on behalf of Sterling wherein my company challenged Kentucky Utilities Company's Certificate of Public Convenience and Necessity ("CPCN") to (i) build the first phase of a coal combustion residuals ("CCR") landfill at the Trimble County Generating Station ("Trimble Landfill") and (ii) fully recover the cost of the first phase of a CCR landfill at the Ghent Generating Station ("Ghent Landfill") through the environmental cost recovery mechanism ("ECR"). In sum, the complaint clearly demonstrates that the Trimble Landfill is no longer in the best interest of the KU's ratepayers because it is not necessary; and, it is unjust, unreasonable, and improper. In addition, the complaint unequivocally demonstrates that the Ghent Landfill is not the least cost alternative for the Companies; thus, the costs associated with the landfill should be capped under the ECR. My testimony is filed in support of the complaint.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION")?

No, I have not.

Q. HOW DID STERLING VENTURES FIRST BECOME INVOLVED IN KENTUCKY UTILITIES COMPANY'S ("KU") ISSUES IN DEALING WITH COAL COMBUSTION RESIDUALS?

A. In 2010, KU approached Sterling about the possibility of using Sterling's mine in connection with KU's plans to increase the capacity of Ghent's gypsum stack. The gypsum stack was reaching capacity and KU was interested in excavating 1.5 million tons of gypsum from the stack and placing the gypsum into Sterling's underground limestone mine. In connection with those discussions, KU provided Sterling with the information necessary for Sterling to obtain a beneficial reuse permit from the Ky. Division of Solid Waste to place Ghent's gypsum in Sterling's mine. In January of 2011, Paul Puckett of KU/LG&E's environmental group visited Sterling to investigate the suitability of the mine as a repository for Ghent gypsum.

Q. WHAT WAS THE BENEFICIAL REUSE ON WHICH THAT PERMIT WAS BASED?

A. At the time Sterling had just opened a third mining level approximately 650 feet underground in order to mine high calcium limestone for a lime kiln that is located on Sterling's property. Sterling was looking for a cost effective and efficient method to fill up air voids in mined out areas in the upper two levels of the mine to increase airflow through the working areas of the mine on the first and second levels and down through the third level.

Q. AFTER MR. PUCKETT VISITED THE MINE, WAS THERE ANY INDICATION THAT MR. PUCKETT THOUGHT THE MINE WAS UNSUITABLE TO RECEIVE CCR FROM GHENT?

A. No. In fact, contract negotiations to use Sterling's mine in connection with the plan to increase the Ghent stacking capacity continued through August 2011.

Q. DID STERLING ENTER INTO AN AGREEMENT WITH KU IN CONNECTION WITH REMOVING GYPSUM FROM THE GHENT GYPSUM STACK?

A. No. Sterling's understanding from KU was that the price proposed to reimburse Sterling for the material handling cost to remove, transport and place the gypsum in its mine was too high and therefore no contract resulted from those discussions.

Q. HOW DID STERLING BECOME INVOLVED IN A REVIEW OF THE GHENT COUNTY LANDFILL?

A. In connection with the discussions on removing gypsum from Ghent's stacking facility, Sterling became aware that Ghent was planning to spend approximately $205 million on a new CCR landfill project. Because of the substantial up–front cost to build the landfill, I thought it may be less expensive for KU to pay Sterling for the material handling cost of getting the gypsum from Ghent into Sterling's underground mine than it would be to place the gypsum in the new Ghent CCR landfill. As a result, I began analyzing the material handling cost that would be required to move the gypsum from Ghent to Sterling's mine, as well as the cost that KU would incur to build and operate the new CCR landfill.

Q. HOW DID YOU CONDUCT YOUR ANALYSIS?

A. I first reviewed all of the documents filed with the Commission in Case No. 2009-00197 - KU's Application for the CPCN for the Ghent CCR landfill. I was looking for details of the capital cost and operating cost of the proposed landfill. I discovered that KU had provided a detailed cost breakdown of each component of the capital cost of the Ghent landfill, and the specific cost of each of the operating and maintenance expenses. This breakdown included detailed cost components of the Ghent landfill that related specifically to placing gypsum and placing ash in the landfill.

Q. WHY WAS THE BREAKDOWN OF CAPITAL AND OPERATING COST BETWEEN GYPSUM AND ASH IMPORTANT IN YOUR INITIAL INVESTIGATION?

A. At the time, there were questions concerning whether coal ash could be possibly classified as a hazardous waste, and Sterling was not interested in coal ash going into its mine if the ash would later be classified as hazardous.

Q. WHAT WAS THE NEXT STEP FOLLOWING THE IDENTIFICATION OF THE BREAKDOWN OF SPECIFIC CAPITAL AND OPERATING COST OF THE PROPOSED GHENT LANDFILL?

A. I also discovered that KU had prepared for the Commission's review an analysis of the impact of each project in Case No. 2009-00197 on the ECR surcharge to its residential customers' monthly bills for the years 2010 through 2014. The starting point of that billing impact computation was a determination of the annual revenue requirements necessary to recover the cost of each project, including the Ghent Landfill. Specifically with respect to Ghent, KU calculated the annual revenue requirements for Phase I of the Ghent landfill for the years 2009 through 2018 (See Appendix B to this testimony- Revenue Requirements Summary, Ghent Landfill Phase I). I also discovered in my review of Case No. 2009-00197 that the Companies' preferred method of choosing between project alternatives was to compare the projects based upon the present value of the annual revenue requirements (PVRR) of each project, and then determine which project had the least cost based upon the comparative present value calculation.

Q. HOW DID YOU USE THIS INFORMATION?

A. As shown in Appendix B, KU only provided the Commission with the annual revenue requirements for Phase I of the proposed Ghent landfill for the years 2009 through 2018. Using the same format as Appendix B, and the assumptions that KU disclosed as the inputs for the calculation of the annual revenue requirements (book and tax deprecation, inflation, etc.), I created a spreadsheet to calculate the annual revenue requirements for each year from 2019 through the stated end of life of the Ghent Landfill project. I then applied the present value discount rate used in the CPCN application case to the annual revenue requirements to determine the present value of the revenue requirements of the proposed Ghent Landfill.

I then modified the spreadsheet to calculate the present value of the annual revenue requirements of the material handling cost to move the gypsum into Sterling's mine. I then eliminated the gypsum specific capital and operating cost from the Ghent Landfill revenue requirement projection, and compared the two resulting scenarios from a least cost present value prospective.

Q. WHAT WAS YOUR CONCLUSION?

A. That by eliminating $53,110,000 in gypsum specific capital costs, and $9,569,527 in annual operating and maintenance costs specifically related to gypsum disposal in the Ghent Landfill, KU could save a substantial amount of money by sending the gypsum to Sterling rather than putting it into the Ghent Landfill.

Q. AFTER YOUR ANALYSIS, HOW DID YOU PROCEED?

A. I sent a proposal to KU outlining the PVRR justification for only building the coal ash infrastructure components of the Ghent CCR Treatment Facility, not building the gypsum components, and sending the net CCR to Sterling for beneficial reuse in the mine. However, KU responded that Sterling's proposal to eliminate the capital cost of the gypsum infrastructure portion of the Ghent landfill was not the least cost alternative. Although Sterling attempted to have substantive discussions with KU concerning the proposal, none occurred.

Q. HAVE YOU SINCE LEARNED HOW KU DETERMINED THAT YOUR PROPOSAL WAS NOT THE LEAST COST ALTERNATIVE?

A. Yes. The Companies' Confidential Response to Sterling's data request SV 1-17 indicates that KU ran the PVRR comparison <u>without</u> eliminating the $53,110,000 of gypsum specific capital costs, and compared the Sterling proposal based on an evaluation of whether there would be savings from sending gypsum off-site to Sterling <u>after</u> building all of the gypsum specific infrastructure.

Q. DID KU CALCULATE THE ANNUAL REVENUE REQUIREMENTS FOR THE GHENT LANDFILL AFTER 2014 IN THE FORMAT OF APPENDIX B?

A. No. KU apparently used the Capital Expenditure Recovery module of Strategist, a proprietary computer model to calculate the annual revenue requirements for the period 2009 through 2058 (See CONFIDENTIAL Appendix C - Annual Revenue Requirements Case 37 – the preferred lowest cost alternative, which was then presented as KU Project 30).

Q. HOW DID THE ANNUAL REVENUE REQUIREMENTS PRESENTED IN APPENDIX B COMPARE TO THE ANNUAL REVENUE REQUIREMENTS PRESENTED IN APPENDIX C?

A. The calculations of the annual revenue requirements for years 2009 through 2018 disclosed to the public in Appendix B and used as the basis for showing the projected ECR impact on ratepayers' monthly bills was [redacted].

The projected O&M costs in both Appendices B and C were [redacted]. The capital portion of the annual revenue requirement in Appendix B was $25,435,565 (rate of return on environmental rate base of $20,543,486 plus depreciation of $5,110,443). The capital portion of the annual revenue requirement in Appendix C however was $[redacted] – a difference of almost [redacted]%.

Q. DO YOU HAVE AN OPINION ON WHAT HAS CAUSED THIS LARGE DISCREPANCY?

A. I do not have the actual Strategist report showing the inputs into Strategist that would have been the basis of each year's annual revenue requirements in Appendix C. However, I believe that using a shorter depreciation/cost recovery period in the PVRR calculation shown in Appendix C caused the difference between the annual revenue requirements shown in Appendix C versus the annual revenue requirements shown in Appendix B.

The calculation of the annual revenue requirements of Project 30 in Appendix B was based upon the Commission's approved straight-line depreciation/recovery period of 2.79% annually, with an accelerated tax depreciation period based upon the 20-year MACRS rate. I have not been able to determine whether KU is using the approved depreciation/cost recovery period using the 2.79% rate, or a shortened depreciation/cost recovery period in the true-up calculations of the ECR Surcharge. However, if KU is using the shorter depreciation/cost recovery period, and Appendix C is the correct representation of the annual revenue requirements, my calculations of PVRR cost savings from not building the gypsum infrastructure in the Ghent Landfill project would have increased.

Q. SHOULD THE ANNUAL REVENUE REQUIREMENTS PROVIDED TO THE PUBLIC IN APPENDIX B MATCH THE CONFIDENTIAL APPENDIX C ANNUAL REVENUE REQUIREMENTS CALCULATED USING STRATEGIST FOR THE YEARS 2009 THROUGH 2018?

A. Substantially, yes. There would not have been an exact match, but the difference should have been immaterial, not the [redacted]% difference between the capital portion of Appendices B and C. For example, in a recent PVRR alternatives case before the Colorado Public Utilities Commission, the Public Service Company of Colorado ("PSCC") (a subsidiary of Xcel Energy, Inc.) requested a CPCN to acquire certain generation facilities. In connection with that application, PSCC prepared a PVRR comparative analysis of the revenue requirements of the acquisition/non-acquisition alternative using both a spreadsheet model, as well as a model using Strategist.[1] The difference between the spreadsheet analysis of the present value of the revenue requirements in the spreadsheet was within 2% of the Strategist present value calculation. ($61 million as compared to $62 million.[2])

[1] See Appendix D: Direct Testimony of James F Hill: *In The Matter Of The Application Of Public Service Company Of Colorado For Approval Of The Acquisition Of The Brush 1, 3, And 4 Generation Facilities And, In Connection Therewith, The Grant Of Certificates Of Public Convenience And Necessity If Required And The Approval Of Cost Recovery Through A General Rate Schedule Adjustment* Proceeding No.12A-782E
[2] *Id*. at 14

Q. WHY DID PSCC PREPARE A SPREADSHEET COMPUTATION OF THE PRESENT VALUE OF THE ANNUAL REVENUE REQUIREMENTS OF THE TWO ALTERNATIVES IN ADDITION TO THE STRATEGIST COMPUTATION?

A. Mr. Hill, who testified on behalf of PSCC, stated that "[t]he benefit of the spreadsheet analysis is that it is more transparent and easier to review compared to the Strategist modeling analysis."[3]

Q. HOW DIFFICULT WOULD IT BE FOR KU TO PROJECT THE ANNUAL REVENUE REQUIREMENTS OF THE GHENT OR TRIMBLE LANDFILLS IN THE FORMAT OF APPENDIX B FOR THE COMPARATIVE ANALYSIS PERIOD?

A. It should be very easy. KU knows the projected dates of the capital cash requirements and the amount of the operating and maintenance cost based upon a stated volume of CCR. The Appendix B format of showing the projected annual revenue requirements is clear, concise, and straightforward. The present value of those annual revenue requirements is a mathematical calculation easily done in an excel spreadsheet.

Q. WHAT WERE THE PROJECTED SAVINGS TO KU'S RATEPAYERS IF KU DID NOT BUILD THE GYPSUM COMPONENTS OF THE GHENT LANDFILL, AND INSTEAD TRANSFERRED ALL OF ITS NET GYPSUM FOR BENEFICIAL REUSE TO STERLING'S MINE?

A. Attached to Sterling's Complaint in this case as Exhibit G is the comparative PVRR analysis of Sterling's proposal to Ghent. Even without considering the PVRR savings from delaying Phase II of the Ghent Landfill, and eliminating Phase III, the PVRR savings for using Sterling's mine versus the Ghent Landfill for gypsum would have been approximately $41

[3] *Id*. at 4-5

million.[4] Delaying the construction of Phases II and III (projected at the time to cost another $157.4 million) would have dramatically increased the PVRR savings.

Q. LOGISTICALLY, HOW WOULD STERLING'S GHENT PROPOSAL HAVE WORKED?

A. Sterling was proposing that gypsum continue to be placed in Ghent's gypsum stacking facility for dewatering. The gypsum would have been excavated and loaded into trucks for delivery to Sterling's mine, where it would have been dumped directly into the underground mine via a shaft. The material would then be moved to strategically fill air voids in mined out areas of the mine in order to maximize airflow through the mine.

Q. THERE WAS AN ACCIDENT IN 2012 THAT RESULTED IN A TEMPORARY SHUTDOWN OF STERLING'S MINE. WOULD THAT HAVE RESULTED IN A PROBLEM FOR THE OPERATION OF THE GHENT POWER PLANT WITH RESPECT TO DEALING WITH NET GYPSUM PRODUCTION?

A. No. Access to the underground portion of Sterling's mine was limited for approximately one month, which equates to 67,000 cubic yards of gypsum. The gypsum stacking facility had, and continues to have, enough storage capacity that it would have been able to handle the temporary shutdown of the mine. In addition, Sterling could have trucked the gypsum from the gypsum stack to the Ghent Landfill and incurred the cost to compact the gypsum in the landfill. It is important to understand that Sterling's proposal for Ghent did not stop the construction of the Ghent landfill, but only the portion of the treatment facility and equipment connected to gypsum disposal.

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[4] *See* Exhibit G of Sterling's Complaint.

Q. HOW COMMON IS AN EXTENDED SHUT DOWN OF AN UNDERGROUND LIMESTONE MINE AS A RESULT OF AN ACCIDENT OR OTHERWISE?

A. It is extremely rare for any working mine to be unexpectedly closed for more than a day or two in any one year as a result of accidents, unexpected events or otherwise. For example, Lexington Quarry Company in Nicholasville, Kentucky, a sister underground limestone mine to Sterling, has never closed because of an accident or any other involuntary event in over 40 years of operation.

Q. HOW DID STERLING BECOME INVOLVED IN THE REVIEW OF THE TRIMBLE COUNTY LANDFILL?

A. In the summer of 2014, Eric Somerville from Region 4 of the EPA, called Sterling to ask about whether KU/LG&E had contacted Sterling about using Sterling's mine and its beneficial reuse permit as an alternative to the Trimble Landfill. I talked to Mr. Somerville and told him that KU/LG&E had not contacted Sterling, but that in my opinion, the distance between Sterling and Trimble County, and relatively low cost of the first phase of the Trimble landfill, would not justify the material handling cost that would be necessary to move the material from Trimble into Sterling's mine.

However, after Mr. Somerville's call, I looked again at KU/LG&E's proposal for the Trimble landfill. In that review, I discovered information in KU/LG&E's 2014 Rate Application that the cost of the first phase of the landfill had increased by over 400%, which could make the option of beneficially reusing Trimble's CCR in Sterling's mine economical. I subsequently learned that Region 4 of the EPA had questioned whether KU/LG&E had prepared a complete and thorough investigation of the potential alternatives to the proposed Trimble landfill as required before a Clean Water Act 404 Permit can be issued, and specifically had highlighted the omission of Sterling's underground mine as a possible alternative to the landfill.

I then emailed Scott Straight and asked if he was interested in talking to Sterling about the possibility of using the mine as an alternative to the Trimble landfill proposal. Mr. Straight responded that KU/LG&E was interested in exploring the option and sent preliminary questions in order to get the process of reviewing the alternative started.

In early December, Sterling learned that an industrial property on the edge of Warsaw was available and could be used to build a barge unloading facility. I contacted Scott Straight about this development, but was unable to arrange a meeting with LG&E/KU to explore the Warsaw barge facility option.

I next learned in February 2015 that KU/LG&E had submitted a Supplement to Alternatives Analysis (the "SAA") to the Corps of Engineers, in response to deficiencies in the Companies' 404 Clean Water act permit application, one of which was the omission of Sterling's mine as an alternative to the proposed Trimble County Landfill. In addressing the omission of Sterling's mine as an alternative, SAA included an analysis of building two barge facilities to transport gypsum between Trimble County and Sterling. One of the proposed barge facilities was at the Trimble County and the other on property next to Steele Bottom Road near the Sterling mine (the "Steel Bottom Barge Facility"). However, there were significant cost and logistical hurdles to building the Steel Bottom Barge Facility.

Assuming that KU/LG&E would not have submitted the option of transporting CCR from a new barge facility at Trimble to the Steel Bottom Barge Facility if it was not technically or logistically feasible, I began reviewing the option of barging the CCR from the proposed Trimble on-load barge facility to a new off-load barge facility located at the Warsaw property.

Exhibits S, U, V and W of Sterling's Complaint are the results of my review based upon a comparative PVRR analysis of building the Trimble Landfill versus the option to barge CCR to Sterling's mine for beneficial use.

Q. CAN YOU FIRST EXPLAIN THE DIFFERENCES BETWEEN EXHIBITS S, U, V AND W OF STERLING'S COMPLAINT?

A. Yes. The KU/LG&E proposal for the Trimble Landfill includes the construction of both a CCR treatment and transport facility and the landfill itself. The CCR treatment portion of the facility conditions the CCR for disposal in the landfill, and the transport portion includes conveyors and roads to the landfill. Exhibit S assumes that the CCR treatment and transport facility is not necessary to transport materials by barge from Trimble County to Sterling. Exhibits U, V and W assume that KU/LG&E will build the CCR treatment infrastructure, but not the transport portion of the facility.

Q. DO YOU BELIEVE THAT THE CCR TREATMENT AND TRANSPORT FACILITY IS NECESSARY?

A. Unfortunately, KU/LG&E has not been willing to sit down with Sterling outside of this proceeding to substantively explore the potential capital and operational savings that could result from specifically designing a CCR treatment option that would take advantage of the opportunity of beneficially using CCR in Sterling's mine. Without that cooperation, Sterling cannot now say whether all or any portion of the CCR treatment facility is necessary, or the cost of the "treatment" portion of that facility is reasonable or unreasonable as compared to other alternatives. Sterling does not believe however that the landfill itself or the "transport" portion of the CCR treatment facility (haul roads, conveyors, trucks, conveyor-to-truck transfer station) is necessary based on the projected material handling cost of moving the materials to Sterling's mine for beneficial use.

If you look at Row 9, Column 12/31/2017, of Exhibit S, versus the same cell in Exhibits U, V and W, you will see the addition of $152,300,000 in capital cost, which is the cost of the Treatment facility as reflected in documents provided to the Commission in the 2014 LG&E/KU Rate cases (See Exhibit T of Sterling's Complaint).

Q. WHAT ARE THE DIFFERENCES BETWEEN EXHIBITS U, V, AND W?

A. Exhibits U, V and W each assume different amounts of net CCR would be disposed of at the Trimble landfill. Exhibit U assumes 637,000 cubic yards of CCR will either be placed in the Trimble landfill or moved to Sterling's mine for beneficial use, which is the 30% beneficial use assumption KU/LG&E used in evaluating the disposal alternatives in the Supplement to Alternatives Analysis file with the Corps of Engineers (See Exhibit P to Sterling's Complaint at 40 of 183)

Exhibits V and W rely on the two CCR Adaptive Reuse Scenarios that Region 4 of the EPA calculated after direct personal communications between the EPA and representatives of LG&E/KU on December 8, 2011. According to the EPA, LG&E/KU expected to beneficially reuse up to 93% of gypsum, and 75% of fly ash and bottom ash production (see Exhibit L of Sterling's Complaint, Table 2 to letter dated April 25, 2012). Exhibit V assumes 416,709 cubic yards of CCR left for disposal after beneficial use, which is Adaptive Reuse Scenario #1 in the referenced Corps letter. Exhibit W assumes 153,109 cubic yards remaining for landfill disposal, which is Adaptive Reuse Scenario #2 in the Corps letter.

Q. STERLING'S COMPLAINT DETAILS THE INPUTS, ASSUMPTIONS, AND CONCLUSIONS FROM YOUR COMPARATIVE PVRR ANALYSIS OF THE

OPTION OF BUILDING AND OPERATING THE TRIMBLE LANDFILL VERSUS MOVING THE MATERIALS TO STERLING'S MINE FOR BENEFICIAL USE. DO YOU HAVE ANY ADDITIONAL COMMENTS TO MAKE REGARDING THE INFORMATION PRESENTED IN THE COMPLAINT?

A. Only with respect to comments made by Mr. Conroy at the July 29, 2015 Informal Conference regarding using the format of Appendix B in calculating the present value of the revenue requirements. According to Mr. Conroy, the "Revenue Requirements" spreadsheet format shown in Appendix B was used in calculating the impact on customer billing from the ECR mechanism associated with the proposal to build the Ghent landfill, and does not represent the PVRR analysis of comparative projects.

First, there should be no issue that the annual revenue requirements of an environmental project would be the total annual ECR charges to be billed to the ratepayers in order to recover all of the approved cost of that project. Once determined, based on a defined set of assumptions, the calculated amount of a specific year's annual revenue requirement should be a static number. That projected annual revenue can then be used to calculate the increase in the amount of the ECR that will be billed to a ratepayer for the project in that year, as well as used in calculating the present value of the project for comparative purposes. The present value of the annual revenue requirements (PVRR) is simply the sum of all of the projected annual revenue requirements over the life of the project, discounted to present day dollars to reflect the time value of money.

Mr. Conroy's comments would give the impression that the calculation of the annual revenue requirement for any one year would be different based upon whether that year's revenue requirement would be used as the basis for determining the impact on a ratepayer bill, or whether that year's revenue requirement would be included in the present value calculation of all project years for comparative purposes. That should not be the case. Once the annual revenue requirement is calculated based on a set of criteria, that amount would not change depending on its use as part of a present value calculation, or in determining the ECR charge to the ratepayers.

Q. HAS LG&E/KU DONE A COMPARATIVE PVRR CALCULATION COMPARING BUILDING THE TRIMBLE LANDFILL VERSUS SENDING THE CCR TO STERLING FOR BENEFICIAL REUSE?

A. Yes. LG&E/KU has done a PVRR comparative calculation using a modeling spreadsheet (which I have been lead to believe is from the "Strategist" program). The Companies provided the spreadsheet to Sterling in the Companies' Confidential Response to Question No. 14 of Sterling Venture's First Request for Information dated July 2, 2015.[5] However, the Strategist PVRR comparative calculation was not prepared using the Warsaw barge site for the barge unloading facility referred to earlier, but rather the Steel Bottom Barge Facility.

Q. HAVE YOU REVIEWED THE STRATEGIST PVRR COMPARATIVE EVALUATION?

A. Yes. Strategist was [redacted]

[5]SV1-14\CCR\Support\20141104_OriginallyProposedLandfillLifeandPhases_TCCCR0002D14\20141104_OriginallyProposedLandfillLifeandPhases_TCCCR0002D14

[redacted]

Q. ARE THERE ANY OF THE VARIABLE TOGGLED INPUTS THAT YOU BELIEVE SHOULD BE EXCLUDED IN THE PVRR COMPARATIVE ANALYSIS OF SCENARIOS 1 AND 2?

A. [redacted]

Q. ARE THERE OTHER CHANGES THAT YOU BELIEVE SHOULD BE MADE TO THE INPUTS THE STRATEGIST PVRR MODEL?

A. [redacted]

It is difficult to understand the rationale or logic behind this assumption given that information the Companies produced in Response to Question No. 21 of Sterling Venture's First

Request for Information indicate that total CCR utilization is expected to increase by 48% between and 2033, not [redacted]

Q. IS IT POSSIBLE TO MODIFY THE STRATEGIST PVRR COMPARATIVE ANALYSIS DONE BY THE COMPANIES TO REFLECT THE CAPITAL AND OPERATING COST FOR BUILDING AND OPERATING THE WARSAW BARGE UNLOADING FACILITY VERSUS THE BARGE UNLOAD FACILITY AND OPERATIONS INCLUDED IN THE SUPPLEMENT TO ALTERNATIVES ANALYSIS?

A. [redacted]

[redacted]

Q. WHAT WERE THE RESULTS OF THOSE CHANGES?

A. In every possible scenario, the PVRR of the Warsaw Barge facility alternative is the least cost alternative as compared to building and operating the Trimble landfill.

All Years	BENEFICIAL REUSE			
	YES		NO	
Fuel Burn (2018 Tons)	**Trimble Landfill**	**Sterling Mine**	**Trimble Landfill**	**Sterling Mine**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The PVRR savings from using the Warsaw barge alternative versus building and operating the Trimble Landfill varies between a low of [redacted] However, as previously discussed, assuming 908,000 cubic yards of production for 37 years with no beneficial reuse is illogical.

The Low Fuel Burn toggle is more realistically considered as a method of determining the effect of increased beneficial reuse rather than a reduction of production. In order to meet the $[redacted] PVRR savings, beneficial reuse would have to increase to approximately 50% of CCR production under the 2015 Plan and 60% of the full 908,000 cubic yards.

For reference as to a reasonable assumption as to future beneficial reuse, the following chart details the actual production tons and beneficial reuse tons of CCR between 2010 and 2015 (annualized) at Trimble County.

Year	CCR Production	Beneficial Reuse	Net CCR to Landfill
2010	471,950	198,988	272,962
2011	834,197	157,528	676,669
2012	803,931	185,436	618,495
2013	818,636	260,802	557,834
2014	781,942	264,974	516,968
2015*	897,562	246,766	650,796

*Annualized

Q. THE COMPANIES HAVE CLAIMED THAT STERLING'S PROPOSED BENEFICIAL USE OF TRIMBLE COUNTY'S CCR FOR VENTILATION PURPOSES IN STERLING'S MINE IS NOT ALLOWED UNDER THE NEW CCR REGULATIONS. DO YOU AGREE?

A. No. Sterling disagrees with KU and LG&E's assessment of the impact of the new CCR regulations on the ability of Sterling to beneficially use CCR in its underground mine.

In connection with Sterling's original Application for the Beneficial Reuse Permit in 2010, Todd Hendricks, KDSW's geologist, and Robin Green, KDSW's Permit Administration Supervisor, visited Sterling's mine and confirmed that CCR placed in the mine would have no contact with surface water, no contact with ground water, no contact with soils, no fugitive dust emissions and no leachate to monitor.

Sterling has had a number of phone conversations with Mr. Hendricks since the publication of the EPA final CCR regulation and also meet with Ms. Greene and Mr. Hendricks in June of this year to confirm that KDWM believed that the new CCR regulations would not affect Sterling's ability to beneficially reuse CCR in its limestone mine.

As shown in the following analysis of the new regulations, the proposed use of CCR in the underground mine meets the conditions to qualify as beneficial use outlined in the new CCR regulations (40 CFR §257.53.)

(1) <u>The CCR must provide a functional benefit</u>.

Eliminating air voids in the mine provides the functional benefit of effectively and efficiently directing air to working areas of the mine.

(2) <u>The CCR must substitute for the use of a virgin material, conserving natural resources that would otherwise need to be obtained through practices, such as extraction</u>.

The CCR substitutes for concrete, steel and other materials used to construct air stoppings in the mine, as well as substantially reducing the amount of electricity required to run ventilation fans to move air in the mine, thereby reducing the environmental consequences of additional electric generation.

(3) <u>The use of the CCR must meet relevant product specifications, regulatory standards or design standards when available, and when such standards are not available, the CCR is not used in excess quantities</u>.

There are no product specifications relevant to Sterling's beneficial use of CCR. Sterling's requirement to maintain an active mining operation prevents excess quantities of CCR beyond what is necessary to fill voids in mined out, abandoned areas of the mine.

(4) When unencapsulated use of CCR involving placement on the land of 12,400 tons or more in non-roadway applications, the user must demonstrate and keep records, and provide such documentation upon request, that environmental releases to groundwater, surface water, soil and air are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use.

Given the geology of the mine and the strata between the surface and the mining levels, once the CCR is placed in the mine, there will be no environmental contact possible with groundwater, surface water, soil or air.

With respect to the first beneficial use criteria above - functional benefit - the preamble of the new CCR regulations as published in the Federal Register provides that: "To the extent that a state regulatory program has determined that a particular use provides a functional benefit, this may serve as evidence that this criteria has been met."[6].

In addition, with respect to the second beneficial reuse criteria above, the preamble also notes that: "Here as well, potential users of CCR may choose to rely on a state determination to provide evidence that this criterion has been met."[7]

The obvious intent of the EPA was to have the applicable state regulatory agencies be a critical component of the determination of qualifying beneficial reuse. KDSW assured Sterling that the new CCR regulations would have no effect on Sterling's Beneficial Reuse Permit.

[6] *Federal Register*/Vol. 80, No. 74 / Friday, April 17, 2015 / Rules and Regulations at 21349.
[7] *Id.*

Courts will defer to the state drafting the terms of an environmental permit in resolving questions of ambiguity. *Natural Res. Def. Council, Inc. v. Texaco Ref. & Mktg., Inc.*, 20 F. Supp. 2d 700, 709 (D. Del. 1998) ("In construing a permit provision, the Court should defer to the interpretation of the agency charged with enforcement of the terms."); *see also Cal. Pub. Interest Research Grp. v. Shell Oil Co.,* 840 F. Supp. 712, 716 (N.D. Cal. 1993) (An NPDES permit "is a legally enforceable rule drafted by a regulatory agency. As such, it is akin to any agency regulation or rule.") *and California Pub. Interest Research Group v. Shell Oil Co., 840 F. Supp. 712, 716 (N.D. Cal.1993)* ("In construing NPDES permits, courts often defer to the agency that drafted the permit, consistent with established rules of statutory construction that give deference to agency interpretations where they are reasonable.").

The above cases deal with permits issued by states with authorization under the National Pollutant Discharge Elimination System (NPDES) permit program, which controls water pollution by regulating point sources that discharge pollutants into waters of the United States. The NPDES program's purpose, authorization and enforcement structure is substantially similar to that created by the EPA under the new CCR regulations.

Given that the new CCR regulations specifically look to the states issuing beneficial use permits as evidence of compliance with the beneficial use requirements, and the courts defer to a state's technical expertise and interpretations of permit conditions, Sterling is confident in a KDWM determination that Sterling's can modify its existing beneficial Reuse Permit to allow the beneficial use of CCR from Trimble County.

Q. WHAT IS STERLING'S PROPOSAL TO DEAL WITH REMOVING CCR FROM TRIMBLE COUNTY IN THE EVENT THAT THERE IS A TEMPORARY SHUTDOWN

OF STERLING'S MINE OR STOPPAGE OF BARGE TRAFFIC ON THE OHIO RIVER BETWEEN TRIMBLE COUNTY AND THE WARSAW BARGE FACILITY?

A. There are several options to avoid any temporary interruption that would cause a potential backup of CCR at Trimble in excess of the onsite capacity in empty barges and silos at the Trimble CCR treatment facility.

The first is the new gypsum pond at Trimble County, which the Companies designed constructed with a liner to meet the new CCR regulations. Sterling would truck and compact if necessary, CCR from the truck loading station in the CCR treatment facility to the gypsum pond. Gypsum from the gypsum pond could be periodically excavated and moved to Sterling if the gypsum pond begins approaching capacity.

The second option would be for Sterling to truck the CCR from Trimble County to Ghent and place it in the Ghent landfill. Sterling would reimburse the Companies the cost of compacting the CCR in the Ghent landfill. This is also the alternative identified by the Companies in the event that the CWA 404 permit approval from the Corps of Engineers for the Trimble Landfill is rejected or delayed. In the event of a catastrophic geologic event that somehow permanently shut down Sterling's mine and did not affect Trimble County, Sterling would agree to truck gypsum from Trimble County to Ghent until Trimble County could build a new on-site landfill and would reimburse Ghent for the cost of compacting the CCR in the Ghent Landfill.

Ghent's current production of CCR is lower than planned, and current beneficial use is higher than anticipated. As a result, substantial excess capacity is being created in the Ghent landfill over the projected annual capacity needs. KU projected, planned, and constructed the Ghent Landfill based upon a net capacity requirement of 1,528,000 cubic yards per year after beneficial reuse. Based on 2014 and 2015 (annualized) alone, the Ghent facility already has 1,320,961 more cubic yards available in Phase I than projected.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION IN THIS PROCEEDING?

A. KU and LG&E's plan to deal with CCR at two facilities located 35 miles apart by river, and 28 miles by road, is to construct two massive landfill projects that together cost over $1 Billion. The first phases alone of the Trimble County and Ghent landfill projects are projected to cost $770 million. As history has proven, both landfills were planned and designed based upon an illogical and imprudent assumption - that each generating plant will produce, over their lifetime, the maximum amount of CCR possible, with no beneficial reuse. Indeed, the Companies' data shows that actual CCR capacity requirements, after beneficial reuse, at both facilities, are substantially less than assumed maximum capacity. In addition, information provided by the Companies indicates that beneficial reuse of CCR is expect to grow by 48% over the next 20 years, not fall to zero.

The result is two plants, close in proximity, that have planned landfill infrastructure well in excess of each plants' actual historical needs, and well in excess of a reasoned and prudent assumption of future needs. Illogical, imprudent and unreasonable assumptions of maximum CCR generation and no beneficial will unnecessarily cost ratepayers millions of dollars.

The Companies have the opportunity to substantially reduce ECR surcharges by utilizing Sterling Ventures' proposal to beneficially reuse Trimble's County's CCR in Sterling's mine. If by rare and remote chance that access to the mine is temporarily unavailable, Trimble has the ability to place CCR in the Ghent Landfill. The opportunity to utilize the combined CCR capacity of Sterling's limestone mine, and the available capacity in Ghent's new CCR landfill, if needed, results in the proposed Trimble landfill not serving the public convenience, in addition to being unnecessary, wasteful, duplicative, unjust, unreasonable, and improper..

To take full advantage of the opportunity to use Sterling's mine in conjunction with available capacity at the Ghent Landfill, the Companies have stated that Trimble County must build an on-site CCR treatment facility. Sterling has not had the time nor opportunity in this proceeding to review in any substantive manner the Companies' claims as to the need for a CCR treatment facility, or to substantively discuss any potential less expensive alternatives that could more efficiently utilize the combined capacity of Sterling' mine and the Ghent landfill. Therefore, Sterling takes no position with respect to the Companies' claimed need for the Trimble CCR treatment facility.

However, Sterling does recommend that the Commission revoke the CPCN previously granted to the Companies to (i) build a CCR landfill at Trimble County, and (ii) build any associated CCR transport facilities to move CCR from a CCR treatment facility to the landfill.

Q. DOES THIS CONCLUDE YOUR PRE-FILLED DIRECT TESTIMONY?

A. Yes.

APPENDIX A

John W. Walters, Jr.
General Counsel/Chief Financial Officer

Sterling Ventures, LLC

376 South Broadway

Lexington, Kentucky 40508

(859) 259-9600

Previous Positions

Grasch Walters Cowan, PLLC
Attorney May 1998 – September 2000

Stoll Keenon Park
Attorney August 1986 – May 1998

Island Creek Coal Company, Lexington Kentucky
Accountant, Tax Department May 1992 - August 1993

Aronson Greene Fisher & Co., Bethesda, Maryland
Accountant, Small Business Department September 1979 - April 1992

Professional/Trade Memberships

Kentucky Bar Association
Certified Public Accountant, Virginia 1981-1983
Certified Public Accountant, Kentucky 1983-1989

Education

Juris Doctor
University of Kentucky - May 1986

Bachelor of Science Business Administration – Accounting
University of Kentucky - May 1979

1

Kentucky Utilities Company
Environmental Cost Recovery Surcharge Summary

	2010	2011	2012	2013	2014
Total E(m) - ($000)	$21,573	$43,140	$61,826	$95,090	$96,261
12 Month Average Jurisdictional Ratio	81.91%	81.91%	81.91%	81.91%	81.91%
Jurisdictional E(m) - ($000)	$17,670	$35,334	$50,639	$77,884	$78,843
Forecasted Jurisdictional R(m) - (million)	1,237	1,314	1,379	1,450	1,515
Incremental MESF	1.43%	2.69%	3.67%	5.37%	5.21%
Residential Customer Impact					
Monthly bill (1,000 kWh per month)	$0.99	$1.87	$2.55	$3.73	$3.61

Incremental O&M

LG&E

Project 18	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
TC2 AQS O&M	0	1,328,398	2,078,421	2,457,617	2,631,751	2,702,173	2,767,171	2,834,519	2,917,621	2,972,968
Project 22										
Cane Run Landfill - Phase I	20,352	21,573	22,868	24,240	25,694	27,236	28,870	30,602	32,438	34,384
Project 23										
TC Ash Treatment Basin (BAP/Gypsum)	0	0	0	0	0	0	0	0	0	0
Project 24										
TC CCP Storage (Landfill)	0	0	0	0	967,296	1,025,334	1,086,854	1,152,065	1,221,189	1,294,460
Project 25										
Beneficial Reuse	0	6,781,867	4,044,649	4,243,433	4,769,138	5,428,541	5,610,358	6,106,637	6,456,655	6,768,993
Total-LGE	20,352	1,349,971	2,101,288	2,481,857	3,624,741	3,754,743	3,882,894	4,017,185	4,171,247	4,301,812

KU

Project 23	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
TC2 AQS O&M	0	5,663,169	8,860,636	10,477,210	11,219,570	11,519,791	11,796,886	12,084,001	12,438,277	12,674,231
Project 28										
Brown 3	0	0	0	649,267	3,122,809	3,193,154	3,239,641	3,335,614	3,463,706	3,572,886
Project 29										
Brown Ash Treatment Basin - Phase II	0	0	0	0	0	0	0	0	0	0
Project 30										
Ghent Landfill - Phase I	84,800	121,349	128,630	136,348	19,003,308	20,143,507	21,352,117	22,633,244	23,991,239	25,430,713
Project 31										
TC Ash Treatment Basin (BAP/Gypsum)	0	0	0	0	0	0	0	0	0	0
Project 32										
TC CCP Storage (Landfill)	0	0	0	0	892,889	946,462	1,003,249	1,063,444	1,127,251	1,194,886
Project 33										
Beneficial Reuse	50,000	4,181,968	4,423,023	1,788,885	592,869	613,321	635,000	657,980	682,339	708,159
Total-KU	84,800	5,784,518	8,989,266	11,262,825	34,238,576	35,802,914	37,391,894	39,116,304	41,020,473	42,872,716

Revenue Requirements Summary
2009 Amended Plan - KU

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Project 30	**Ghent Landfill - Phase I**										
	Revenue Requirement										
	Eligible Plant	4,321,671	46,478,848	105,485,803	177,577,356	191,133,918	201,941,953	202,578,976	203,254,220	203,969,979	203,969,979
	Less: Retired Plant	-	-	-	-	-	-	-	-	-	-
	Less: Accumulated Depreciation	-	-	-	-	(5,110,443)	(10,744,624)	(16,396,577)	(22,067,370)	(27,758,132)	(33,448,895)
	Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-	-	-	-
	Less: Deferred Tax Balance	-	-	-	-	(732,114)	(3,915,287)	(6,717,731)	(9,167,825)	(11,289,716)	(13,100,909)
	Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-	-	-	-
	Environmental Compliance Rate Base	4,321,671	46,478,848	105,485,803	177,577,356	185,291,361	187,282,042	179,464,668	172,019,025	164,922,131	157,420,175
	Rate of return	11.12%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%
		$ 480,509	$ 5,098,393	$ 11,571,030	$ 19,478,952	$ 20,325,122	$ 20,543,486	$ 19,685,976	$ 18,869,243	$ 18,090,765	$ 17,267,855
	Operating expenses	84,800	121,349	128,630	136,348	19,003,308	20,143,507	21,352,117	22,633,244	23,991,239	25,430,713
	Annual Depreciation expense	-	-	-	-	5,110,443	5,634,180	5,651,953	5,670,793	5,690,762	5,690,762
	Less depreciation on retired plant	-	-	-	-	-	-	-	-	-	-
	Annual Property Tax expense	-	6,483	69,718	158,229	266,366	279,035	286,796	279,274	271,780	264,318
	Total OE	$ 84,800	$ 127,832	$ 198,348	$ 294,577	$ 24,380,117	$ 26,056,723	$ 27,290,866	$ 28,583,310	$ 29,953,782	$ 31,385,793
	Total E(m)	565,309	5,226,225	11,769,378	19,773,528	44,705,239	46,600,208	46,976,843	47,452,553	48,044,547	48,653,648

Revenue Requirements
Project 30 - KU

					January					
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
In-Service					1	2	3	4	5	6
Ghent 4										
Capital Expenditures - Project 30 - Ghent Landfill - Phase I	$ 4,321,671	$ 42,157,177	$ 59,006,955	$ 72,091,553	$ 13,556,562	$ 10,808,035	$ 637,023	$ 675,244	$ 715,759	$ -
Accumulated Expenditures	$ 4,321,671	$ 46,478,848	$ 105,485,803	$ 177,577,356	$ 191,133,918	$ 201,941,953	$ 202,578,976	$ 203,254,220	$ 203,969,979	$ 203,969,979
Book Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	2.790%	2.790%	2.790%	2.790%	2.790%	2.790%
Tax Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
Income tax rate	36.70%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%
Deferred Tax Balance	-	-	-	-	732,114	3,915,287	6,717,731	9,167,825	11,289,716	13,100,909
Book Accumulated Depreciation Balance	-	-	-	-	5,110,443	10,744,624	16,396,577	22,067,370	27,758,132	33,448,895
Unrecovered Investment -- Book	4,321,671	46,478,848	105,485,803	177,577,356	191,133,918	201,941,953	202,578,976	203,254,220	203,969,979	203,969,979
Book Depreciation	-	-	-	-	5,110,443	5,634,180	5,651,953	5,670,793	5,690,762	5,690,762
Unrecovered Investment -- Tax total	4,321,671	46,478,848	105,485,803	177,577,356	191,133,918	201,941,953	202,578,976	203,254,220	203,969,979	203,969,979
Tax Depreciation	-	-	-	-	7,167,522	14,578,190	13,526,198	12,555,013	11,652,805	10,779,813
Allowed Rate of Return	11.12%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%
Book Depreciation expense total	-	-	-	-	5,110,443	5,634,180	5,651,953	5,670,793	5,690,762	5,690,762
Tax Depreciation expense total	-	-	-	-	7,167,522	14,578,190	13,526,198	12,555,013	11,652,805	10,779,813
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Balance	-	-	-	-	732,114	3,183,173	2,802,444	2,450,094	2,121,891	1,811,193
Revenue Recovery on Capital Expenditure to date										
Eligible Plant, cumulative capital expenditures	4,321,671	46,478,848	105,485,803	177,577,356	191,133,918	201,941,953	202,578,976	203,254,220	203,969,979	203,969,979
Less: Retired Plant	-	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	-	-	(5,110,443)	(10,744,624)	(16,396,577)	(22,067,370)	(27,758,132)	(33,448,895)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	-	-	(732,114)	(3,915,287)	(6,717,731)	(9,167,825)	(11,289,716)	(13,100,909)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	4,321,671	46,478,848	105,485,803	177,577,356	185,291,361	187,282,042	179,464,668	172,019,025	164,922,131	157,420,175
Rate of return	11.12%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%	10.97%
Return on Environmental Compliance Rate Base	$ 480,509	$ 5,098,393	$ 11,571,030	$ 19,478,952	$ 20,325,122	$ 20,543,486	$ 19,685,976	$ 18,869,243	$ 18,090,765	$ 17,267,855
Operating Expenses	84,800	121,349	128,630	136,348	19,003,308	20,143,507	21,352,117	22,633,244	23,991,239	25,430,713
Annual Depreciation expense	-	-	-	-	5,110,443	5,634,180	5,651,953	5,670,793	5,690,762	5,690,762
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	-	6,483	69,718	158,229	266,366	279,035	286,796	279,274	271,780	264,318
Total OE	$ 84,800	$ 127,832	$ 198,348	$ 294,577	$ 24,380,117	$ 26,056,723	$ 27,290,866	$ 28,583,310	$ 29,953,782	$ 31,385,793
Total E(m) - Project	565,309	5,226,225	11,769,378	19,773,528	44,705,239	46,600,208	46,976,843	47,452,553	48,044,547	48,653,648

CONFIDENTIAL INFORMATION

$ thousands

Case **37** **1 landfill**

	Annual Revenue Requirements									
	Capital						O&M			Total
	Phase1	*Phase2*	*Phase3*	*Phase4*	*Transmission*	**Total Capital**	*Non-Power*	*Power*	*Trans Ash*	**Total O&M**
[redacted]										

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE ACQUISITION OF THE BRUSH 1, 3, and 4 GENERATION FACILITIES AND, IN CONNECTION THEREWITH, THE GRANT OF CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY IF REQUIRED AND THE APPROVAL OF COST RECOVERY THROUGH A GENERAL RATE SCHEDULE ADJUSTMENT	)))))))))	DOCKET NO. 12A-____E

DIRECT TESTIMONY AND EXHIBITS OF JAMES F. HILL

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

JULY 5, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE ACQUISITION OF THE BRUSH 1, 3, and 4 GENERATION FACILITIES AND, IN CONNECTION THEREWITH, THE GRANT OF CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY IF REQUIRED AND THE APPROVAL OF COST RECOVERY THROUGH A GENERAL RATE SCHEDULE ADJUSTMENT	)))))))))	DOCKET NO. 12A-____E

DIRECT TESTIMONY AND EXHIBITS OF JAMES F. HILL

INDEX

SECTION **PAGE**

Appendix D

LIST OF EXHIBITS

Exhibit No. JFH-1	Details of strategist analysis
Exhibit No. JFH-2	Review of 35 transactions

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE ACQUISITION OF THE BRUSH 1, 3, and 4 GENERATION FACILITIES AND, IN CONNECTION THEREWITH, THE GRANT OF CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY IF REQUIRED AND THE APPROVAL OF COST RECOVERY THROUGH A GENERAL RATE SCHEDULE ADJUSTMENT)	**DOCKET NO. 12A-____E**

DIRECT TESTIMONY AND EXHIBITS OF JAMES F. HILL

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. James F. Hill. 1800 Larimer Street, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc., the service company subsidiary of Xcel Energy Inc., the registered public utility holding company parent of Public Service Company of Colorado ("Public Service", or "Company"). My title is Director, Resource Planning and Acquisition.

Q ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Public Service Company of Colorado ("Public Service", "PSCo", or "Company").

Q. HAVE YOU INCLUDED A DESCRIPTION OF YOUR QUALIFICATIONS, DUTIES AND RESPONSIBILITIES?

A. Yes. A description of my qualifications, duties and responsibilities is included as Attachment A.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is 1) to describe why the Brush Units 1, 3 and 4 are valuable additions to Public Service's overall generation portfolio, and 2) to show the net present value of benefits to customers associated with the proposed acquisition of the Brush units.

II. VALUE OF THE BRUSH GENERATION CAPACITY

Q. WILL THE BRUSH GENERATION UNITS HELP MEET A PORTION OF THE FUTURE NEED FOR ADDITIONAL POWER SUPPLIES?

A. Yes. As explained in the Second Supplemental Direct testimony filed in the 2011 Electric Resource Plan ("2011 ERP"), the Company is now showing an increase in our demand forecast and as a result an increase in or projected need for additional capacity in the 2011 ERP. Table JFH-1 shows how the Brush assets would serve approximately 78 MW of the Company's most current projection of summer generation capacity need in 2017 and 2018. The capacity need shown on row D of Table JFH-1 reflects the combined effect of 1) our proposal to replace Arapahoe 4 with a new PPA with Southwest Generation's Arapahoe 567 facility, 2) the recent approval of the 150 MW PacifiCorp Energy Exchange Agreement which act to replace the 176 MW LTPSA (Docket No. 12A-256E) and 3) the impact of increased demand as reflected in our most recent load forecast.

This updated load forecast is being presented to the Commission in Docket No. 11A-869E, our 2011 ERP proceeding, through second supplemental direct testimony filed by myself and Ms. Jannell Marks.

Table JFH-1: Summary Capacity Need Assessment (MW)*

Row		2012	2013	2014	2015	2016	2017	2018
A	Existing Generation	7,662	7,485	7,398	7,345	7,374	7,207	7,024
B	Firm Obligation Load	5,994	6,071	6,107	6,173	6,251	6,309	6,368
C	Planning Reserve Margin	1,017	1,030	1,035	1,046	1,059	1,068	1,078
(B+C)-A	**Capacity Need**	**(651)**	**(384)**	**(256)**	**(126)**	**(65)**	**171**	**422**

D	Impact of Brush 1,3,4 Purchase on Existing Generation						78	78

Row		2012	2013	2014	2015	2016	2017	2018
E=A+D	Existing Generation	7,662	7,485	7,398	7,345	7,374	7,285	7,102
F	Firm Obligation Load	5,994	6,071	6,107	6,173	6,251	6,309	6,368
G	Planning Reserve Margin	1,017	1,030	1,035	1,046	1,059	1,068	1,078
(F+G)-E	**Capacity Need**	**(651)**	**(384)**	**(256)**	**(126)**	**(65)**	**93**	**345**

Row F in the bottom half of Table JFH-1 reflects how the addition of the Brush units 1,3 and 4 from row E will add to the total amount of firm generation capacity on the Public Service system [1]. The net effect of all the changes discussed above, including the proposed acquisition of Brush 1, 3, and 4, is a modest <u>increase</u> in the Company's projected need for additional generation capacity of 34 MW in 2017 and 52 MW in 2018 compared to the projection originally filed in the 2011 ERP (Docket No. 11A-869E). The effect of these increases is that the 2017 need increased from 59 MW to 93 MW and the 2018 need increased from 292 MW to 345 MW. Thus, even with Commission approval of the Company's proposed acquisition of the Brush 1, 3, and 4 units as requested herein, the Company is projecting that it will seek to acquire more resources through the

[1]Public Service currently purchases the capacity of Brush 4 through a PPA that does not expire until September 2022. As a result, the purchase of the Brush 4 unit does not impact the capacity need in either 2017 or 2018.

Phase 2 competitive solicitation process than we initially projected when we filed our 2011 ERP.

Q. ARE THERE OTHER BENEFITS TO OWNING THE BRUSH UNITS?

A. Yes, in addition to helping to serve a portion of the Company's projected need for additional generation capacity in 2017 and 2018, Brush unit 3 can be started and brought to full load within 30 minutes. This type of 30-minute capable generation is helpful to Public Service Company's system operators in integrating wind generation onto the system. A discussion of the Company's 30-Minute Wind Reserve Guideline is included in the Attachment 2.14-1 "2011 Wind Limits Study" of Volume II of Public Services 2011 ERP.

III. ANALYSES OF BRUSH OWNERSHIP

Q. HOW DID YOU ANALYZE WHETHER OWNING BRUSH POWER LLC WOULD BE BETTER THAN CONTINUING WITH THE CURRENT PPAS?

A. I performed two different analyses on the costs associated with owning the Brush units versus continued PPAs with the units.

a) Spreadsheet analysis: The spreadsheet analysis compares the Net Present Value of Revenue Requirements ("PVRR") of continuing with the PPAs to the PVRR assuming ownership of the assets as proposed in this filing. Since the Brush units operate on the Public Service system in a peaking role they generate a relatively small amount of energy over the year. As a result, the spreadsheet analysis focuses on a comparison of only the fixed cost of capacity between the two options (PPA vs. own). The benefit of the spreadsheet analysis is that it is more transparent and easier to review compared to the Strategist modeling analysis.

b) <u>Strategist Analysis:</u> A similar comparison to that performed in the spreadsheet analysis was completed using the Strategist model. Unlike the spreadsheet analysis however, the Strategist analysis included the additional effects of how the Brush units operate within the Public Service electric supply system and therefore provides a more comprehensive system wide assessment of how purchasing the Brush units can provide value to customers. The analysis was performed using the same modeling assumptions and methodology as those used in preparing the various alternative plans presented in our 2011 ERP with the following updates[2]:

1) Updates to the load forecast
2) Updates to gas and market prices
3) PacifiCorp Exchange Agreement Extension
4) Retirement of Arapahoe 4 at the end of 2013
5) New PPA with Southwest Generation Arapahoe 567 for 2014-2023.

Q. WHAT ARE THE COSTS OF CONTINUING TO ACQUIRE POWER FROM BRUSH THROUGH THE EXISTING PPAS?

A. The costs incurred under the PPAs include:

a) Capacity payments (in $/kw-mo) adjusted by a Capacity Adjustment Factor that is based on the availability of unit generation capacity during a 12 month

[2] These updates are described in detail in Jim Hill's Second Supplemental Direct Testimony to the 2011 ERP filed concurrently with this filing.

rolling average (e.g. the available capacity during the summer is less than the available capacity during the winter)

b) Dispatchability payments (in $/kw-mo) adjusted by a Dispatchability Adjustment Factor

c) Tolling payments (in $/MWh) paid when the facility operates

d) Start payments (in $/turbine-start) paid each time a combustion turbine is started by Public Service

e) Fuel expenses

The capacity and dispatchability payments noted above were developed by the Purchase Power group within Xcel Energy based on the actual terms of the existing Brush PPAs. Total tolling and start payments were estimated using the Strategist model (for use in the Strategist analysis but not the spreadsheet analysis). Since the PPAs are tolling agreements, Public Service pays for and provides the fuel required to operate the units. Fuel was also estimated using the Strategist model (for use in the Strategist analysis but not the spreadsheet analysis).

Q. WHAT ARE THE COSTS OF OWNING THE BRUSH UNITS?

A. The costs of owning the Brush units include:

a) The purchase price which is recovered over the remaining life of the facilities.

b) Fixed Operation and Maintenance (FOM) expenses which primarily consist of the cost of labor and overhead to operate the facility. They also include other fixed expenses such as fixed contracts for water.

c) Ongoing Capital Expenditures

d) Variable Operating and Maintenance Expenses (VOM)

e) Fuel expenses

Estimates of the FOM, Ongoing Capital Expenditures and VOM over the remaining life of the units were developed by Public Service's Energy Supply group based on historical cost and historical operation of the units. Company witness Mr. George Hess explains how the O&M forecasts were developed in more detail. Fuel expenses and total VOM were estimated using the Strategist model.

Q. WHAT TOTAL USEFUL LIVES WERE USED FOR THE BRUSH UNITS IN YOUR ANALYSIS?

A. As presented in Company witness Ms. Lisa Perkett's testimony, the estimated total useful life of each Brush unit is 45 years. This results in retirement dates of 2034 for Brush 1, 2043 for Brush 3 and 2046 for Brush 4.[3]

IV. SPREADSHEET ANALYSIS

Q. PLEASE EXPLAIN HOW THE SPREADSHEET ANALYSIS WAS COMPLETED?

A. The spreadsheet analysis involves a direct comparison of the costs of the existing PPAs versus the cost of ownership. This analysis relies on Company witness Ms. Deborah Blair's annual revenue requirement projections associated with owning and operating the three Brush units and compares these costs of ownership with the total annual costs of purchasing power from the facilities

[3] Retirement dates listed are end of year. E.g. Brush 1 is retired at the end of 2034.

through PPAs. The delta between these two streams of annual costs were calculated then discounted back to year 2012 to arrive at a PVRR savings value for the ownership case.

Q. THE PPA FOR BRUSH 1, 3 EXPIRES IN 2017 BUT THE RETIREMENT DATES FOR THOSE UNITS IS 2034 FOR BRUSH 1 AND 2043 FOR BRUSH 3. SIMILARLY, THE BRUSH 4 PPA EXPIRES IN 2022 BUT THE RETIREMENT DATE IS 2046. DO THE DIFFERENCES IN PPA TERMS AND RETIREMENT DATES IMPACT THE ANALYSIS?

A. Yes. To get an apples-to-apples comparison between PPA versus ownership, it is important that the two cases be compared over equal lives. One approach for achieving equal lives in the analysis is to compare the annual cost of the PPAs with the annual cost of ownership over the remaining term of the existing PPAs. That is, compare the Brush 1, 3 PPA with Brush 1, 3 ownership for years 2013-2017 and compare the Brush 4 PPA with Brush 4 ownership for years 2013-2022. Table JFH-2 contains the results of this comparison and concludes that over the life of the existing PPA terms, owning the Brush units would provide a present value savings to customers of about $12 million. Also note is that savings will begin in the first year Public Service owns the units.

Table JFH-2: Savings of Owning vs. PPA over remaining PPA Term

	Savings of Owning vs. PPA		
	Brush 1,3 ($000)	Brush 4 ($000)	Total ($000)
2013	$814	$26	$840
2014	$1,041	$369	$1,410
2015	$1,245	$733	$1,979
2016	$1,497	$671	$2,168
2017	$548	$1,311	$1,859
2018	$0	$1,562	$1,562
2019	$0	$1,799	$1,799
2020	$0	$2,024	$2,024
2021	$0	$2,220	$2,220
2022	$0	$1,057	$1,057
PVRR	**$4,152**	**$7,203**	**$11,355**

Q. DOES A COMPARISON OF THE COSTS OF OWNERSHIP WITH THE COSTS OF PPAS OVER THE REMAINING PPA TERMS PROVIDE USEFUL INSIGHT AS TO THE COST EFFECTIVENESS OF OWNERSHIP?

A. Yes. This shorter term comparison is useful in understanding the economics of the deal in the early years based on known costs of the two options (PPA vs. Ownership). To get a more complete picture of the value of ownership however it is necessary to examine the economics of the deal over the entire remaining life of the assets. Since the existing PPAs expire before the end of the Brush assets remaining useful lives, this longer term analysis requires that an assumption be made about how future PPAs from the Brush units will be priced over time. Two different market based representations of the cost of future PPAs with the Brush units were developed using generic combustion turbine cost information that was filed in the 2011 ERP. In addition, another future PPA pricing case was developed to serve as a bounding reference case. I refer to all three of these future PPA pricing representations as the “PPA Tails” from here forward.

Q. HOW DID YOU DEVELOP THE MARKET BASED PPA TAIL REPRESENTATIONS AND THE BOUNDING CASE PPA TAILS?

A. One of the market based PPA tails was priced based on the cost to construct a RAP[4] combustion turbine and the other market based PPA tail was based on the cost to construct a greenfield combustion turbine[5]. The third PPA tail was developed simply by taking the pricing in the last year of the existing Brush PPAs and holding that price flat over the remaining useful lives of the units. This bounding case is not intended to represent realistic future PPA pricing but rather was provided to serve as a "worst case" look as to whether the $75 million cost to own the units will bring value to customers over time even under unrealistically low future PPA pricing assumptions. Table JFH-3 summarizes the cases that were included in the spreadsheet analysis.

Table JFH-3: Brush Cases Analyzed

	Case 1	Case 2	Case 3	Case 4
Ownership or PPA =>	Ownership	Existing PPA	Existing PPA	Existing PPA
PPA Tail Pricing =>	----	Flat Tail	2011 ERP RAP CT	2011 ERP Greenfield CT

Q. WHAT WERE THE RESULTS OF THE SPREADSHEET ANALYSIS?

[4] RAP refers to Resource Acquisition Period in the PSCo 2011 ERP. A RAP combustion turbine is priced at the midpoint of brownfield and greenfield estimates. See Section 2.8 of the PSCo 2011 ERP for details on the prices of the combustion turbines.

[5] See Section 2.8 of the PSCo 2011 ERP for details on the Greenfield combustion turbine pricing.

A. The spreadsheet analysis showed that ownership of the Brush units would produce a range of customer savings from $47 million (PVRR) up to $93 million (PVRR). Table JFH-4 includes the results of the spreadsheet analysis.

Table JFH-4: Brush Ownership Cost vs. PPA Cost

	Case 1	Case 2	Case 3	Case 4
Ownership or PPA =>	Ownership	Existing PPA	Existing PPA	Existing PPA
PPA Tail Pricing =>	----	Flat Tail	2011 ERP RAP CT	2011 ERP Greenfield CT
PVRR ($M) =>	$135	$182	$197	$228
Savings of Ownership PVRR ($M) =>	**---**	**$46**	**$61**	**$92**

Table JFH-4 shows that all three PPA cases (cases 2, 3, and 4) are more expensive than owning the Brush units (case 1). The case with PPA tail extensions derived by holding the last year of the current PPA pricing flat ("Flat Tail") is Case 2 and shows that owning the Brush units is estimated to save about $46 million over the 2013-2050 time period compared to continuing with PPAs even at the unrealistic flat future pricing assumption. Cases 3 and 4 use the two market based PPA tail pricing approaches discussed above, with the Case 3 PPA tail pricing based on a RAP combustion turbine and the Case 4 PPA tail pricing based on the more expensive generic Greenfield CT. The estimated savings of owning the Brush units is about $61 million and $92 million respectively compared to continuing with PPAs.

Q. THE PVRR RESULTS FROM TABLE JFH-4 SHOW THAT OVER THEIR REMAINING USEFUL LIVES PURCHASING THE BRUSH UNITS IS MORE ECONOMIC THAN CONTINUING WITH PPAS. HAVE YOU ANALYZED WHEN THESE SAVINGS WILL BEGIN FLOWING TO CUSTOMERS?

A. Yes. Customers will begin seeing savings in the first year after purchasing the Brush units. Figure JFH-1 shows the annual fixed costs for each of the four cases included in the spreadsheet analysis. The term “fixed costs” is used to describe the cost that would be incurred by Public Service in order to have control of the capacity of the Brush units (either via PPA or ownership) regardless of how much the units are operated. For the case where Public Service were to own these units, fixed costs would include depreciation, taxes, and earnings on the $75 million price to buy the units, O&M costs for items such as plant staffing and plant maintenance, and future capital expenditures needed to maintain the units. Fixed costs for the cases where Public Service were to continue with PPAs from these units would include capacity payments and dispatchability payments that the owners of Brush collect under the existing PPAs as well as the capacity price assumptions for future PPA pricing (PPA tails).

Figure JFH-1: Annual Fixed Costs of Brush Cases

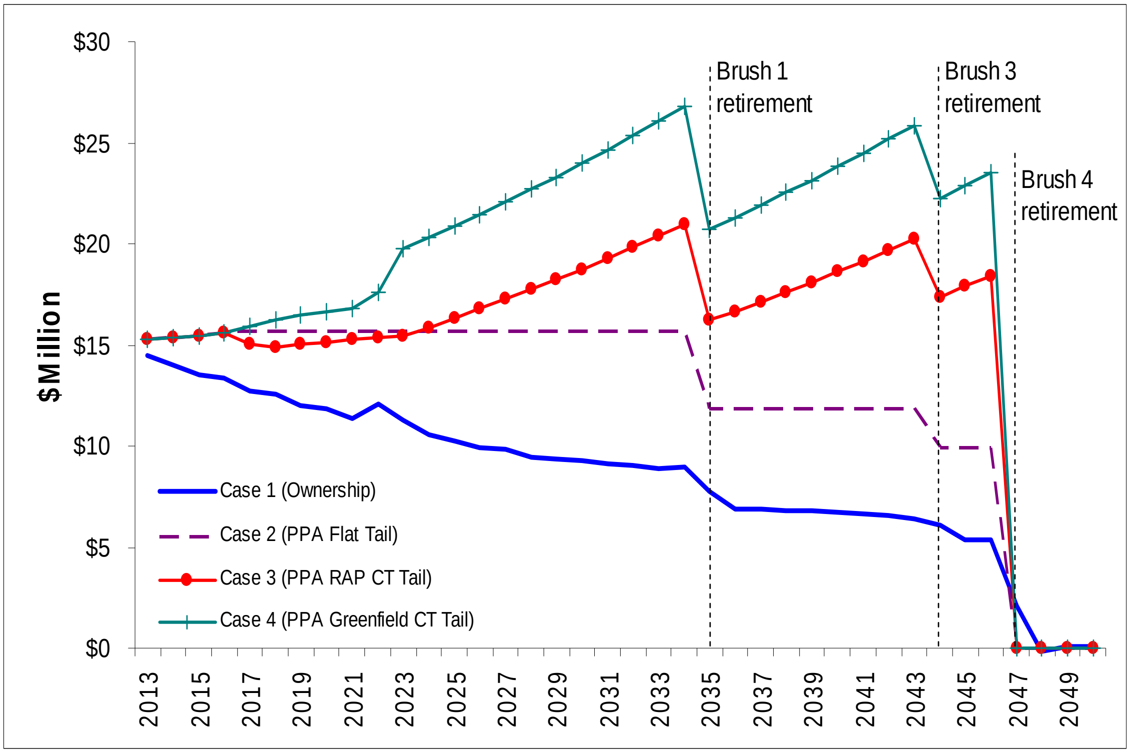

Figure JFH-1 illustrates how the spreadsheet analysis of fixed costs shows that customers will start saving money the first year of ownership and the savings should continue to accrue through the remaining lives of the Brush units.

V. <u>STRATEGIST ANALYSIS</u>

Q. YOU STATED THAT YOU ALSO COMPLETED A STRATEGIST ANALYSIS OF BRUSH OWNERSHIP VERSUS PPAS. CAN YOU BRIEFLY DISCUSS THAT ANALYSIS?

A. Yes. This Strategist analysis was very similar to the spreadsheet analysis for years 2012-2022 in that it compared known costs for continues PPAs with Brush 1,3, and 4 with known costs of owning those assets. The Strategist analysis however differed from that of the spreadsheet analysis in how it addressed the years after the current Brush PPA's expire. The difference between the two analysis lies mainly with the methodology of representing a price for either future PPAs with the Brush units (as was done in the spreadsheet analysis) or a cost to replace the Brush capacity from the market (as was done in the Strategist analysis). In the spreadsheet analysis, it was assumed that in years beyond the current Brush PPA terms that Brush 1, 3, and 4 units would continue to operate under PPA's for the remainder of their useful lives at the same MW capacity, heat rates, VOM, etc, but with different fixed costs (represented in the three different PPA tails). In contrast, the Strategist analysis did not continue to operate the Brush units but rather retired Brush units 1, 3 in 2017 and Brush 4 in 2022 from operation and allowed the model the discretion to determine when to replace the retired MWs of the Brush units with generic CT resources in order to maintain a 16.3% reserve margin. These generic CT resources used by Strategist to replace the retired Brush capacity were represented at their MW capacity, heat rates, VOM, costs etc which differed from those of the Brush units.

Q. WHAT WERE THE RESULTS OF THE STRATEGIST ANALYSIS OF BRUSH OWNERSHIP?

A. The results of the Strategist modeling analysis show that owning the Brush units would save about $61 million (PVRR) over continued PPAs. This result is the same as the "2011 ERP RAP CT" results from the simpler spreadsheet analysis ($62 million). Details regarding the Strategist analysis are contained in Exhibit JFH-1.

Q. ARE THERE OTHER MEASURES THAT CAN BE USED TO GAUGE WHETHER THE $75 MILLION PURCHASE PRICE FOR BRUSH 1, 3 AND 4 IS A GOOD DEAL FOR CUSTOMERS?

A. Yes. The transaction will result in the addition of 237 MW (237,000 kW) of generating capacity for $75 million for an overall cost of generation of about $316/kW. This capacity cost compares favorably with information we were able to obtain from publicly available sources identifying what others have paid for combustion turbine and combined cycle generating capacity from 2008 to the present. The Company's Business Development group was able to gather data from public sources such as SNL Financial, the Wall Street Journal, Energy Central, SEC filings, and internet searches of buyer's and seller's web sites for seven transactions involving the purchase of combustion turbines with a mean selling price of $419/kW and a median price of $410/kW, and twenty eight transactions involving the purchase of combined cycles with a mean selling price of $525/kW and a median price of $479/kW. Of the 35 transactions we reviewed, only two had a lower cost/kW ($204/kW and $294/kW) than the Brush purchase we are proposing. Exhibit JFH-2 contains information on these 35 transactions.

Q. PLEASE CONCLUDE THE RESULTS OF YOUR ANALYSES.

A. Purchasing the Brush 1, 3 and Brush 4 assets will provide inexpensive capacity to Public Service. Purchasing the assets is less expensive than continuing the PPAs and will continue to provide cost effective capacity through their remaining useful lives.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Attachment A

James F. Hill

Statement of Qualifications

I graduated from Colorado State University in 1983 with a Bachelor of Science degree in Natural Resource Management and in 1995 from the University of Colorado with a Bachelor of Science degree in Mechanical Engineering.

I have been employed by Public Service Company of Colorado, New Century Services, Inc., and now Xcel Energies Services Inc. for 28 years. I began my employment in 1984 at Public Service Company of Colorado's Fort St. Vrain Nuclear Generating Station in the Technical Services and Licensing Department. In August 1992, I joined Public Service Company of Colorado's System Planning Department where I performed resource planning functions, as a Planning Engineer, a Senior Resource Planning Analyst, Manager of Resource Planning and Bidding and now Director of Resource Planning and Bidding with a focus on Public Service Company of Colorado.

As the Director of the Resource Planning and Bidding Group, I have responsibility for overseeing the Company competitive resource acquisition processes as well as the various technical analyses on the resource options that are available to Xcel Energy's operating companies for meeting customer demand.

I have testified before the Colorado Public Utilities Commission regarding electric resource planning issues in numerous dockets.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION OF KENTUCKY UTILITIES)
COMPANY'S AND LOUISVILLE GAS &)
ELECTRIC COMPANY'S RESPECTIVE NEED) CASE NO. 2015-00194
FOR AND COST OF MULTIPHASE)
LANDFILLS AT THE TRIMBLE COUNTY AND)
GHENT GENERATING STATIONS)

AFFIDAVIT OF JOHN W. WALTERS, JR.

Commonwealth of Kentucky)
City of Lexington)

John W. Walters, Jr., having been first duly sworn, states as following: The prepared Pre-Filed Direct Testimony and Schedules attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further Affiant saith not.

John W. Walters, Jr.

SUBSCRIBED AND SWORN to before me this 6TH day of August, 2015.

Notary Public

My Commission expires: 1/31/19

My Commission ID#: 524812