COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION TURBINE AT THE GREEN RIVER GENERATING STATION AND A SOLAR PHOTOVOLTAIC FACILITY AT THE E.W. BROWN GENERATING STATION	**)))))))))**	**CASE NO. 2014-00002**

<u>JOINT APPLICATION</u>

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively the "Companies" or "Applicants") pursuant to KRS 278.020, et seq. and 807 KAR 5:001, Sections 14 and 15(2), hereby jointly apply to the Public Service Commission ("Commission") for Certificates of Public Convenience and Necessity ("CPCN") for the construction of an approximately 700 MW net summer rating natural gas combined cycle combustion turbine facility at KU's Green River Generating Station in Muhlenberg County, Kentucky ("Green River NGCC"), including a 20-inch natural gas pipeline to serve that facility and an approximately 10 MW solar photovoltaic facility at KU's E.W. Brown Generating Station in Mercer County, Kentucky ("Brown Solar Facility"). In support of this Joint Application, the Companies state as follows:

1. <u>Address</u>. LG&E's full name and business address is Louisville Gas and Electric Company, 220 West Main Street, Louisville, Kentucky 40202. KU's full name and business address is Kentucky Utilities Company, One Quality Street, Lexington,

Kentucky 40507. The mailing address for both applicants is P.O. Box 32010, Louisville, Kentucky 40232. The Companies may be reached by electronic mail at the electronic mail addresses of their counsel set forth below.

2. Corporate Status and Articles of Incorporation. Certified copies of LG&E's and KU's current Articles of Incorporation are on file with the Commission in Case No. 2010-00204, *In the Matter of: Joint Application of PPL Corporation, E.ON AG, E.ON U.S. Investments Corp., E.ON U.S. LLC, Louisville and Gas Electric Company and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities*, which Articles were filed in that proceeding on May 28, 2010, and are incorporated by reference herein pursuant to 807 KAR 5:001, Section 14(2).

LG&E is incorporated in the Commonwealth of Kentucky and is in good corporate standing, as attested by the Certificate of Existence from the Kentucky Secretary of State attached hereto as Exhibit 1. LG&E was incorporated in Kentucky on July 2, 1913. KU is incorporated in the Commonwealth of Kentucky and the Commonwealth of Virginia and is in good corporate standing in both states, as attested by the Certificate of Existence from the Kentucky Secretary of State and the Certificate of Good Standing from the Virginia State Corporation Commission, which certificates are collectively attached hereto as Exhibit 2. KU was incorporated in Kentucky on August 17, 1912, and in Virginia on November 26, 1991.

3. Statement of Need (807 KAR 5:001, Section 15(2)(a)). As explained in Case No. 2011-00375,[1] the Companies determined that, in light of changing

[1] *In re the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the*

environmental regulations and the operating characteristics, age, and size of the coal-fired steam generating units at the Green River, Tyrone and Cane Run stations, those units should be retired. The combination of those retirements and the Companies' forecasted load resulted in the need to construct a new generation facility. In that case, the Commission authorized the construction of a new natural gas combined cycle combustion turbine at the Cane Rune Station and the purchase of natural gas generating facilities from Bluegrass Generation Company.

The construction at Cane Run has progressed very well and is on schedule to be in operation in 2015. However, the Federal Energy Regulatory Commission did not authorize the Bluegrass Generation Company purchase as presented, and, therefore, that purchase was not completed. As regulated utilities, the Companies have an obligation to serve all customers located in their service territories, and must be prepared to meet load growth in those areas. As explained in the testimony of David S. Sinclair, even with the addition of the new facility at Cane Run, the Companies' load forecast indicates a reserve margin capacity shortfall of 71 MW in 2016 which will grow to 367 MW by 2020 and 1,573 MW by 2035. Thus, the construction projects proposed in this case are essential for the Companies to provide reliable, low-cost power to their growing native loads. The following table reflects the growing capacity need through 2035.

	2015	2016	2017	2018	2019	2020	2025	2030	2035
Forecasted Peak Load	7,426	7,509	7,597	7,696	7,746	7,815	8,147	8,517	8,891
Energy Efficiency/DSM	(386)	(418)	(450)	(482)	(464)	(466)	(475)	(484)	(493)
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,673	8,034	8,398
Existing Resources[2]	7,814	7,796	7,796	7,796	7,796	7,796	7,796	7,796	7,796
Firm Purchases (OVEC)	152	152	152	152	152	152	152	152	152
Curtailable Demands	137	137	137	137	137	137	137	137	137
Total Supply	8,103	8,085	8,085	8,085	8,085	8,085	8,085	8,085	8,085
Reserve Margin ("RM")	15.1%	14.0%	13.1%	12.1%	11.0%	10.0%	5.4%	0.6%	-3.7%
RM Shortfall (17% RM)	(134)	(212)	(277)	(355)	(434)	(514)	(892)	(1,314)	(1,741)
RM Shortfall (15% RM)	7	(71)	(134)	(211)	(289)	(367)	(738)	(1,154)	(1,573)

To meet the needs reflected in the table, the Companies sent a request for proposals ("RFP") in September 2012 for electric energy and capacity to 165 potential suppliers. The Companies also began developing numerous self-build generation options. Twenty-nine companies responded to the RFP with 72 different proposals. The proposals included new build proposals and power purchase agreements from a broad spectrum of generation technologies. Consideration of the various proposals and the self-build options is described in great detail in the Resource Assessment the Companies prepared which is attached to Mr. Sinclair's direct testimony. As reflected in the Resource Assessment, the Companies considered all available options along with the impact of expected Demand Side Management programs while also considering the risks related to various load scenarios such as load growth, natural gas prices, and potential carbon regulations.

At the conclusion of this decision process, the Companies determined that the least-cost reasonable alternative for meeting customer needs is to construct an

[2] 'Existing Resources' reflects the retirement of Tyrone 3, Green River 3-4, and Cane Run 4-6 and the addition of Cane Run 7.

approximately 700 MW natural gas combined cycle combustion turbine at the Green River station and to construct an approximately 10 MW solar photovoltaic facility at the Brown station. A detailed description of the foregoing process is set forth in Mr. Sinclair's testimony and in the Resource Assessment attached to his testimony.

4. Permits from Public Authorities (807 KAR 5:001, Section 15(2)(b)). The Companies will be required to obtain certain environmental and construction-related permits associated with the construction of Green River NGCC and the Brown Solar Facility. The required permits and the process for obtaining those permits are discussed in the direct testimonies of Messrs. Voyles and Revlett, which accompany this Joint Application and are incorporated herein by reference. Copies of those permits will be filed with the Commission, as obtained, to the extent required by law or requested by the Commission. The permits described by Messrs. Voyles and Revlett are the only permits that will be necessary for the projects for which approval is sought in this case.

5. Location of Proposed Construction (807 KAR 5:001, Section 15(2)(c)). As previously stated, Green River NGCC will be located at KU's Green River Generating Station in Muhlenberg County, Kentucky. There are no like facilities in the vicinity of Green River NGCC and it is not anticipated that Green River NGCC will compete with any other public utilities, corporations or persons. The Brown Solar Facility will be located at KU's existing Brown Generating Station in Mercer County, Kentucky. There are no like facilities in the vicinity of the proposed solar facility and it is not anticipated that it will compete with any other public utilities, corporations or persons.

6. Manner of Proposed Construction (807 KAR 5:001, Section 15(2)(c)). As explained in detail in the direct testimony of Mr. Voyles, both the Green River NGCC

and the Brown Solar Facility will be constructed primarily through a self-build process. An engineering firm has been selected to perform engineering services, optimize design for the Companies' needs, support environmental permitting, and to assist the Companies in their procurement efforts. Construction for both projects is scheduled to begin soon after receipt of the CPCN and other required regulatory and environmental approvals. Completion of Green River NGCC is expected to occur no later than May 2018. In addition, a 20-inch natural gas pipeline approximately 11 miles in length will be constructed to supply natural gas to Green River NGCC. As described in Mr. Meiman's testimony, construction of the Brown Solar Facility must be completed no later than December 31, 2016 to take full advantage of available federal tax credits.

7. Maps and Plans, Specifications and Drawings (807 KAR 5:001, Section 15(2)(d)). The required maps and the conceptual plans, specification and drawings for Green River NGCC are attached collectively as Joint Application Exhibit 3. A map showing the gas pipeline that will serve Green River NGCC is attached as Joint Application Exhibit 4. The required maps and conceptual plans, specifications and drawings for Brown Solar Facility are attached collectively as Joint Application Exhibit 5.

8. Financing Plans (807 KAR 5:001, Section 15(2)(e)). The total projected capital cost for Green River NGCC, including the gas pipeline, is approximately $700 million. The total projected capital cost for the Brown Solar Facility is approximately $36 million. The Companies' proposed financing of such costs is discussed in the direct testimony of Mr. Staton, which accompanies this Joint Application and is incorporated herein by reference.

9. Estimated Cost of Operation (807 KAR 5:001, Section 15(2)(f)). The estimated annual cost of operation of the proposed construction projects is set forth in the direct testimony of Mr. Voyles, which accompanies this Joint Application and is incorporated herein by reference.

10. Ownership. Subject to the necessary approvals, KU will own 60% and LG&E will own 40% of Green River NGCC. KU will own 64% and LG&E will own 36% of Brown Solar Facility. Ownership of both facilities will comply with the Companies' Power Supply System Agreement dated October 9, 1997. The ownership allocation decisions are described in more detail in the testimony of Messrs. Thompson and Sinclair.

11. Testimony and Exhibits. A detailed statement of the facts establishing that the construction of Green River NGCC and the Brown Solar Facility are required by the public convenience and necessity, and otherwise supporting this Joint Application, is included in the direct testimony and exhibits of the Companies' witnesses:

- Paul W. Thompson, Chief Operating Officer;
- David S. Sinclair, Vice President, Energy Supply and Analysis;
- John N. Voyles, Jr., Vice President Transmission and Generation Services;
- Gary H. Revlett, Director, Environmental Affairs.
- Edwin R. Staton, Vice President, State Regulation and Rates; and
- Gregory J. Meiman, Director, Corporate Tax and Benefit Plan Compliance.

WHEREFORE, LG&E and KU respectfully request the Commission to issue an order granting the Companies (i) a Certificate of Public Convenience and Necessity for the construction of an approximately 700 MW net summer rating natural gas combined cycle combustion turbine at KU's Green River Generating Station, including a 20-inch natural gas pipeline, (ii) a Certificate of Public Convenience and Necessity for the construction of an approximately 10 MW solar photovoltaic facility at KU's Brown Generating Station, and (iii) for any and all other relief to which the Companies may appear entitled.

Dated: January 17, 2014

Respectfully submitted,

Allyson K. Sturgeon

Kendrick R. Riggs
Robert M. Watt, III
Lindsey W. Ingram III
Stoll Keenon Ogden, PLLC
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Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company

CERTIFICATE OF SERVICE

This is to certify that Louisville Gas and Electric Company and Kentucky Utilities Company's January 17, 2014 electronic filing is a true and accurate copy of the documents being filed in paper medium; that the electronic filing was transmitted to the Commission on January 17, 2014; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; that an original and one copy of the filing is being hand-delivered to the Commission on January 17, 2014; and that on January 17, 2014, electronic mail notification of the electronic filing will be provided to the following:

Dennis G. Howard II
Assistant Director
Office of the Attorney General
Office of Rate Intervention
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Allyson K. Sturgeon

Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company

Certificate of Existence from the Kentucky Secretary of State for Louisville Gas and Electric Company

Exhibit 1

Commonwealth of Kentucky
Alison Lundergan Grimes, Secretary of State

Alison Lundergan Grimes
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 146859
Visit https://app.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Alison Lundergan Grimes, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

LOUISVILLE GAS AND ELECTRIC COMPANY

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is July 2, 1913 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 9th day of January, 2014, in the 222nd year of the Commonwealth.

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
146859/0032196

Certificate of Existence from the Kentucky Secretary of State for Kentucky Utilities Company and the Certificate of Good Standing from the Virginia State Corporation Commission

Exhibit 2

Commonwealth of Kentucky
Alison Lundergan Grimes, Secretary of State

Alison Lundergan Grimes
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 146846
Visit https://app.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Alison Lundergan Grimes, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

KENTUCKY UTILITIES COMPANY

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is August 17, 1912 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 8th day of January, 2014, in the 222nd year of the Commonwealth.

Alison Lundergan Grimes

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
146846/0028494

Commonwealth of Virginia

State Corporation Commission

CERTIFICATE OF GOOD STANDING

I Certify the Following from the Records of the Commission:

That KENTUCKY UTILITIES COMPANY is duly incorporated under the law of the Commonwealth of Virginia;

That the date of its incorporation is November 26, 1991;

That the period of its duration is perpetual; and

That the corporation is in existence and in good standing in the Commonwealth of Virginia as of the date set forth below.

Nothing more is hereby certified.

STATE CORPORATION COMMISSION
VIRGINIA
SIC SEMPER TYRANNIS
1903

Signed and Sealed at Richmond on this Date:
January 8, 2014

Joel H. Peck

Joel H. Peck, Clerk of the Commission

CISECOM
Document Control Number: 1401086185

Maps and Plans, Specifications and Drawings for Green River NGCC

Exhibit 3

FACILITY LEGEND

1. COMBUSTION TURBINE
2. HEAT RECOVERY STEAM GENERATOR
3. STEAM TURBINE BUILDING
4. HRSG STACK
5. ADMINISTRATION/CONTROL BUILDING
6. GAS YARD
7. GAS COMPRESSOR BUILDING
8. CIRC. WATER CHEMICAL FEED BUILDING
9. EMERGENCY GENERATOR *
10. DEMIN WATER STORAGE TANK
11. EXISTING SUBSTATION
12. GSU TRANSFORMER
13. SWITCHYARD
14. COOLING TOWER
15. WAREHOUSE/MAINTENANCE SHOP
16. WATER TREATMENT BUILDING
17. WATER PRETREATMENT AREA
18. UNIT AUX TRANSFORMERS
19. SERVICE/FIRE WATER STORAGE TANK
20. FIRE PROTECTION PUMP HOUSE
21. AUXILIARY BOILER BUILDING

Revisions

A Project:
INTIAL ISSUE
HDR PROJECT #211611

Dwn: J_B 11/18/13
Chkd: AWS 11/18/13
Appd: MAW

FACILITY GRADE NOTES

BASE POWERBLOCK ELEVATION = 440' ASL
BASE WATER TREATMENT AREA ELEVATION = 445' ASL
BASE COOLING TOWER ELEVATION = 435' ASL
BASE SWITCHYARD ELEVATION = 440' ASL

EMISSION POINTS

EMISSION POINT No. (EPN)	NAME	SPCS NAD83 (FEET)	UTM ZONE 16 (METERS)	HEIGHT ABOVE GRADE (FEET)
1	HRSG 1 STACK	N2018929.0 E1240910.0	N4135367 E488954	180
2	HRSG 2 STACK	N2018775.0 E1241004.0	N4135321 E488983	180
3	COOLING TOWER CELL 1	N2019040.0 E1241092.0	N4135402 E489009	64
4	COOLING TOWER CELL 2	N2018981.0 E1241080.0	N4135384 E489005	64
5	COOLING TOWER CELL 3	N2019028.0 E1241147.0	N4135399 E489025	64
6	COOLING TOWER CELL 4	N2018970.0 E1241134.0	N4135381 E489022	64
7	COOLING TOWER CELL 5	N2019016.0 E1241201.0	N4135395 E489042	64
8	COOLING TOWER CELL 6	N2018958.0 E1241188.0	N435377 E489038	64
9	COOLING TOWER CELL 7	N2019004.0 E1241256.0	N4135392 E489059	64
10	COOLING TOWER CELL 8	N2018946.0 E1241243.0	N4135374 E489055	64
11	COOLING TOWER CELL 9	N2018992.0 E1241310.0	N4135388 E489075	64
12	COOLING TOWER CELL 10	N2018934.0 E1241297.0	N435371 E489072	64
13	COOLING TOWER CELL 11	N2018980.0 E1241364.0	N4135385 E489092	64
14	COOLING TOWER CELL 12	N2018922.0 E1241352.0	N4135367 E489088	64
15	AUXILIARY BOILER	N2018854.0 E1240603.0	N4135343 E488860	42
16	EMERGENCY DIESEL GENERATOR	N2019022.0 E1240889.0	N4135396 E488947	11
17	FUEL GAS HEATER	N2018819.0 E1241171.0	N4135335 E489034	10
18	DIESEL FIRE PUMP	N2019154.0 E1240553.0	N4135435 E488844	10

N

SITE ARRANGEMENT

SCALE: 1" = 200'-0"

200 100 0 200 400 600

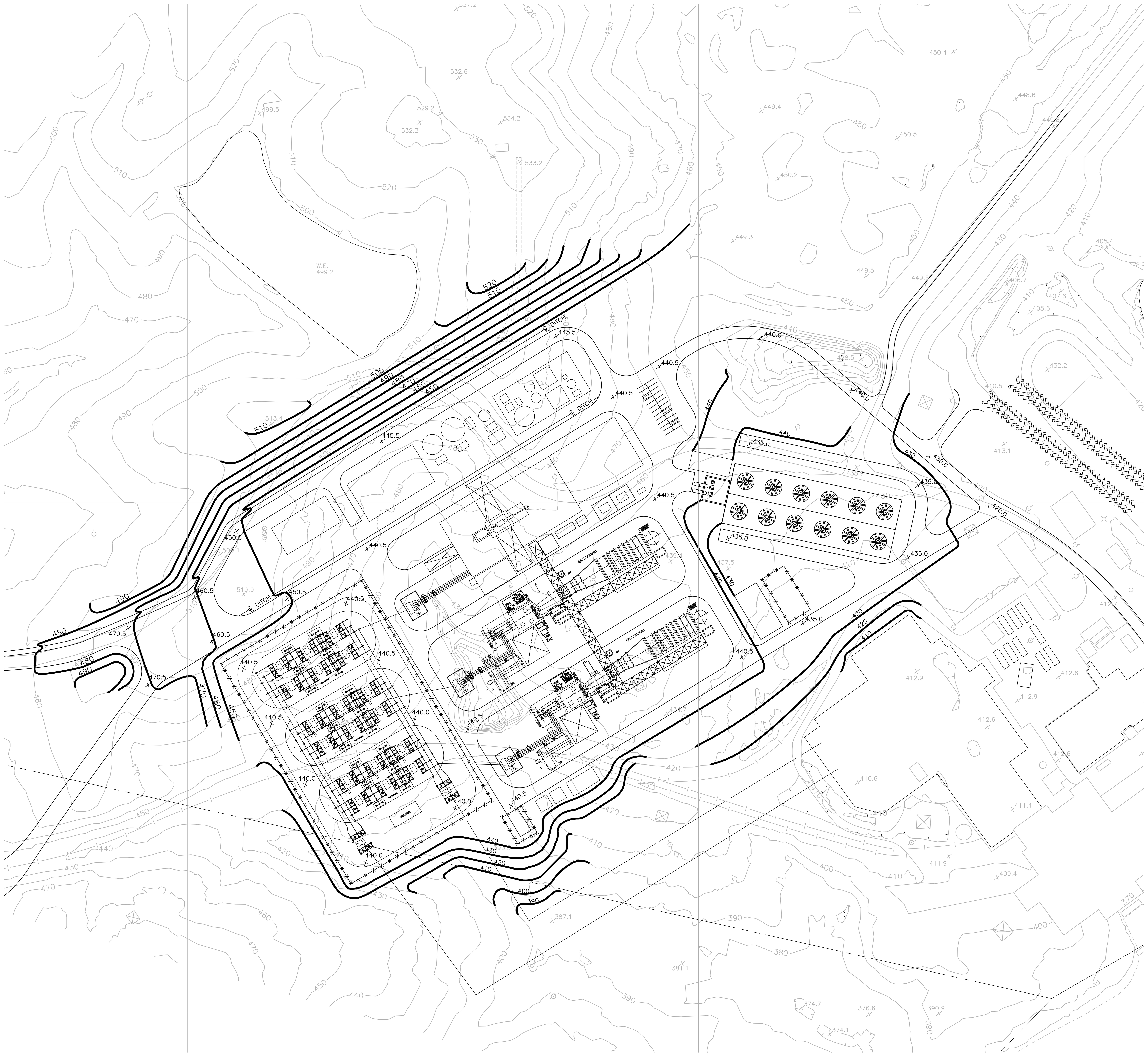
E 1243000

NOT TO BE USED FOR CONSTRUCTION

HDR Engineering, Inc.
PROJECT: 211611

Location and Unit: GREEN RIVER		LOUISVILLE GAS & ELECTRIC COMPANY, a PPL company — Generation Services	Drawn: J_B
Scale: AS NOTED	Contract No.		Checked: AWS
Engineering discipline: MECHANICAL	Drawing type: PLAN		Approved: MAW 15 NOV 13
Title: GREEN RIVER 5 NGCC EMISSION POINT LOCATION PLAN			Released for: REVIEW
			Alternate Drawing No: S2501
Originator: HDR ENGINEERING, INC.	Job or Project No: 211611	Drawing No: 211611-CGA-S2501	Rev. A

DMS Version 2.0



NOTES:
1. SLOPES ARE SHOWN AS 1H:1V FOR ROCK CUT AND 2H:1V FOR SOILS CUT AND SOILS FILL, TO BE ADJUSTED AS SPECIFIED IN THE GEOTECHNICAL REPORT.
2. POINT ELEVATIONS FOR ROADS ARE AT CENTERLINE.
3. MAXIMUM VERTICAL SLOPE OF 6% FOR ROADS.
4. FINAL GRADING PLAN TO PROVIDE SURFACE SLOPES OF UP TO 1% FOR SURFACE DRAINAGE TO DITCHES AND OR STORM DRAINS.

Revisions

A Project:
12/03/13
HDR PROJECT #211611
INITIAL ISSUE
Dwn: PVJ 12/03/13
Chkd: SMP
Appd: MAW

GRADING PLAN

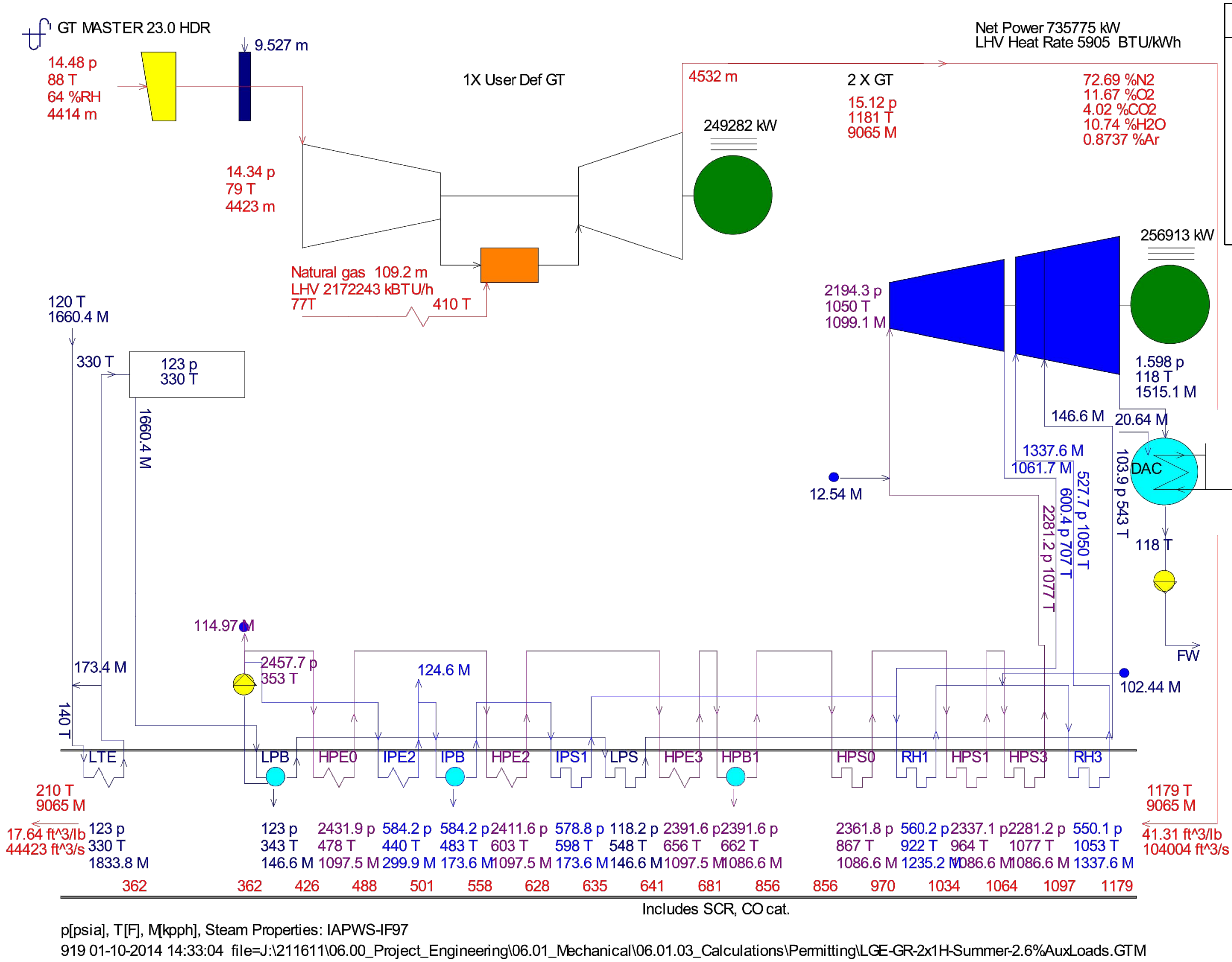
SCALE: 1" = 100'-0"

100 50 0 100 200 300

NOT TO BE USED FOR CONSTRUCTION

HDR Engineering, Inc. PROJECT: 211611	Location and Unit: GREEN RIVER	LG&E Generation Services LOUISVILLE GAS & ELECTRIC COMPANY a PPL company	Drawn: PVJ
	Scale: AS NOTED / Contract No.		Checked: MAW
	Engineering discipline: CIVIL / Drawing type: PLAN		Approved: SMP
	Title: GREEN RIVER GRADING PLAN		Released for: INITIAL ISSUE
			Alternate Drawing No:
	Originator: HDR ENGINEERING, INC.	Job or Project No:	Drawing No: SKC2001 Rev. A

DMS Version 2.0



PERFORMANCE SUMMARY

AMBIENT TEMPERATURE	88°F
RELATIVE HUMIDITY	64%
ELEVATION	440'
FUEL	NATURAL GAS
CT LOAD	2x100%
EVAP COOLER STATUS	ON
NET OUTPUT NEW AND CLEAN	735,775 kW
NET HEAT RATE (HHV) NEW AND CLEAN	6537 BTU/kWHR
NET OUTPUT WITH DEGRADATION	713,702 kW
NET HEAT RATE (HHV) WITH DEGRADATION	6710 BTU/kWHR

Revisions

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	01/10/2014	INITIAL ISSUE	DCW	CAZ		AWS	MAW

HDR Engineering, Inc.

Title

GREEN RIVER NGCC PROJECT
HEAT BALANCE DIAGRAM
2x1 ADVANCED CLASS CT-SUMMER DEGRADED

LG&E® Generation Services
LOUISVILLE GAS & ELECTRIC COMPANY
a PPL company

GR5

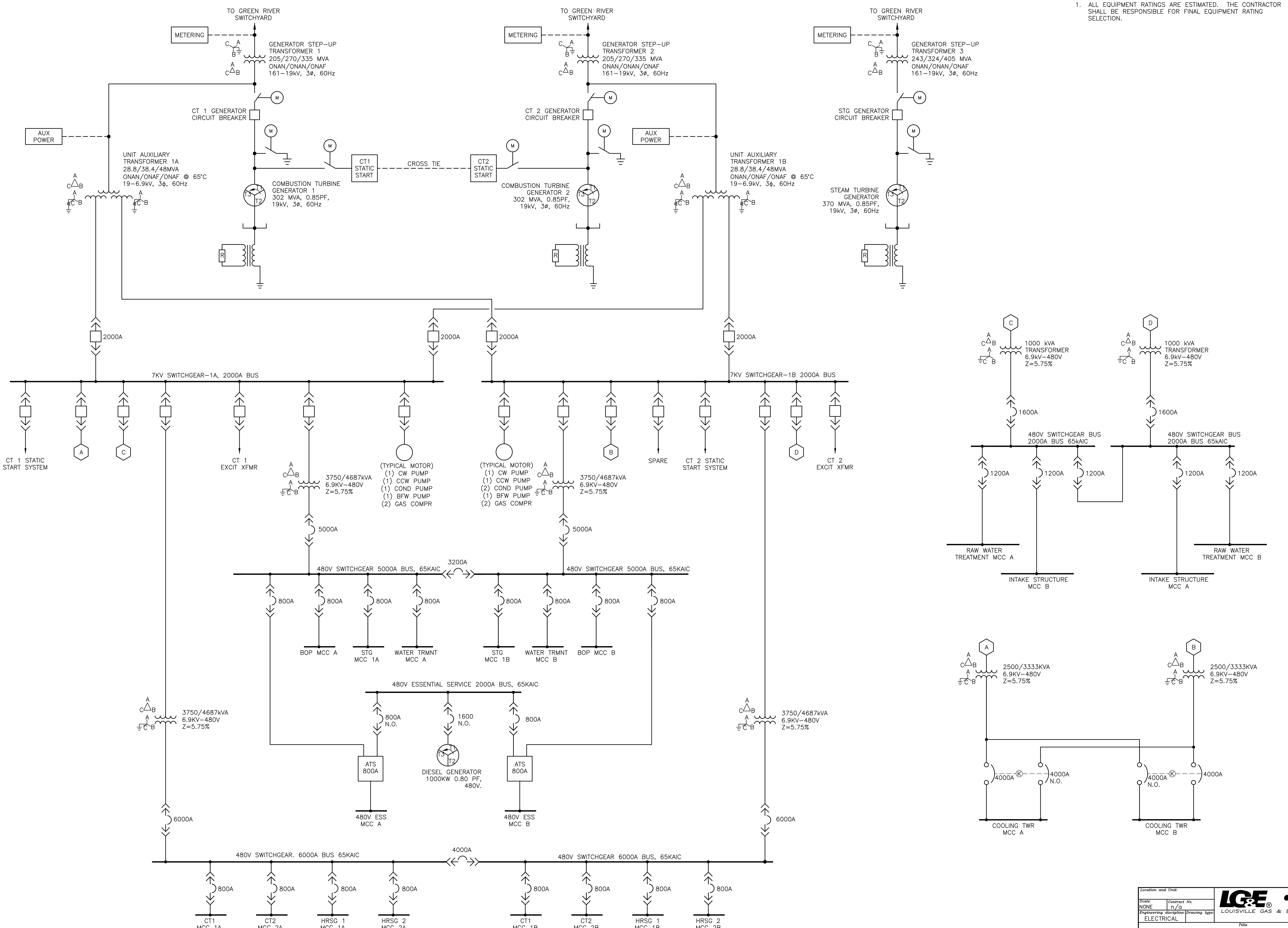
Scale	Drawn/Appd	Date	Drawing No.	
NONE	TEB/LGE	01/10/2014	0HB-M1001	A

DMS Version2.0

Revisions

A 14 OCT 2013 INITIAL ISSUE

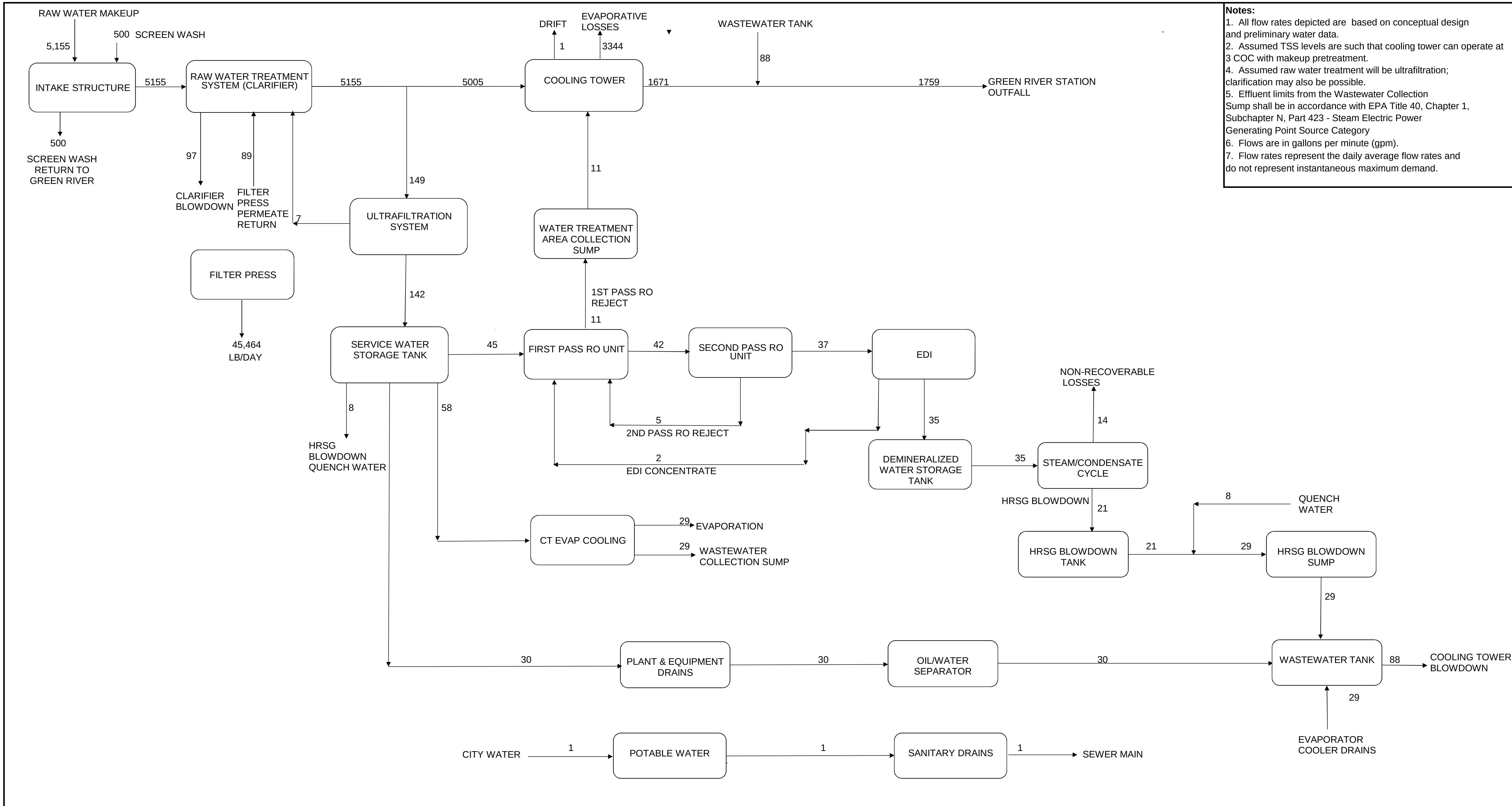
NOTES:
1. ALL EQUIPMENT RATINGS ARE ESTIMATED. THE CONTRACTOR SHALL BE RESPONSIBLE FOR FINAL EQUIPMENT RATING SELECTION.



NOT TO BE USED FOR CONSTRUCTION

Location and Unit:	LG&E LOUISVILLE GAS & ELECTRIC COMPANY Generation Services	Drawn: REB 01 JUL 13
Scale: NONE / Contract No. n/a		Checked:
Engineering discipline: ELECTRICAL / Drawing type:	Title: PROPOSED GREEN RIVER 2 x 1-ON-1 NGCC OVERALL ONE-LINE DIAGRAM	Approved:
		Released for:
		Alternate Drawing No: 0MP-E1004
Originator: HDR ENGINEERING	Job or Project No:	Drawing No: 211611-0MP-E1004 Rev:

DMS Version 2.0



Notes:
1. All flow rates depicted are based on conceptual design and preliminary water data.
2. Assumed TSS levels are such that cooling tower can operate at 3 COC with makeup pretreatment.
4. Assumed raw water treatment will be ultrafiltration; clarification may also be possible.
5. Effluent limits from the Wastewater Collection Sump shall be in accordance with EPA Title 40, Chapter 1, Subchapter N, Part 423 - Steam Electric Power Generating Point Source Category
6. Flows are in gallons per minute (gpm).
7. Flow rates represent the daily average flow rates and do not represent instantaneous maximum demand.

Heat Balance Case	1	Net Plant Output (MW)	690	Heat Rejection	Wet Tower
Configuration	2 on 1	Ambient Temperature	69°F	Cycle Blowdown	1.0%
Evaporative Coolers	On	Relative Humidity	85%	CT COC	3.0
Raw Water Makeup TSS	375 mg/l				

LG&E
GREEN RIVER 5 NGCC PROJECT
WATER MASS BALANCE

HDR | LG&E KU PPL companies

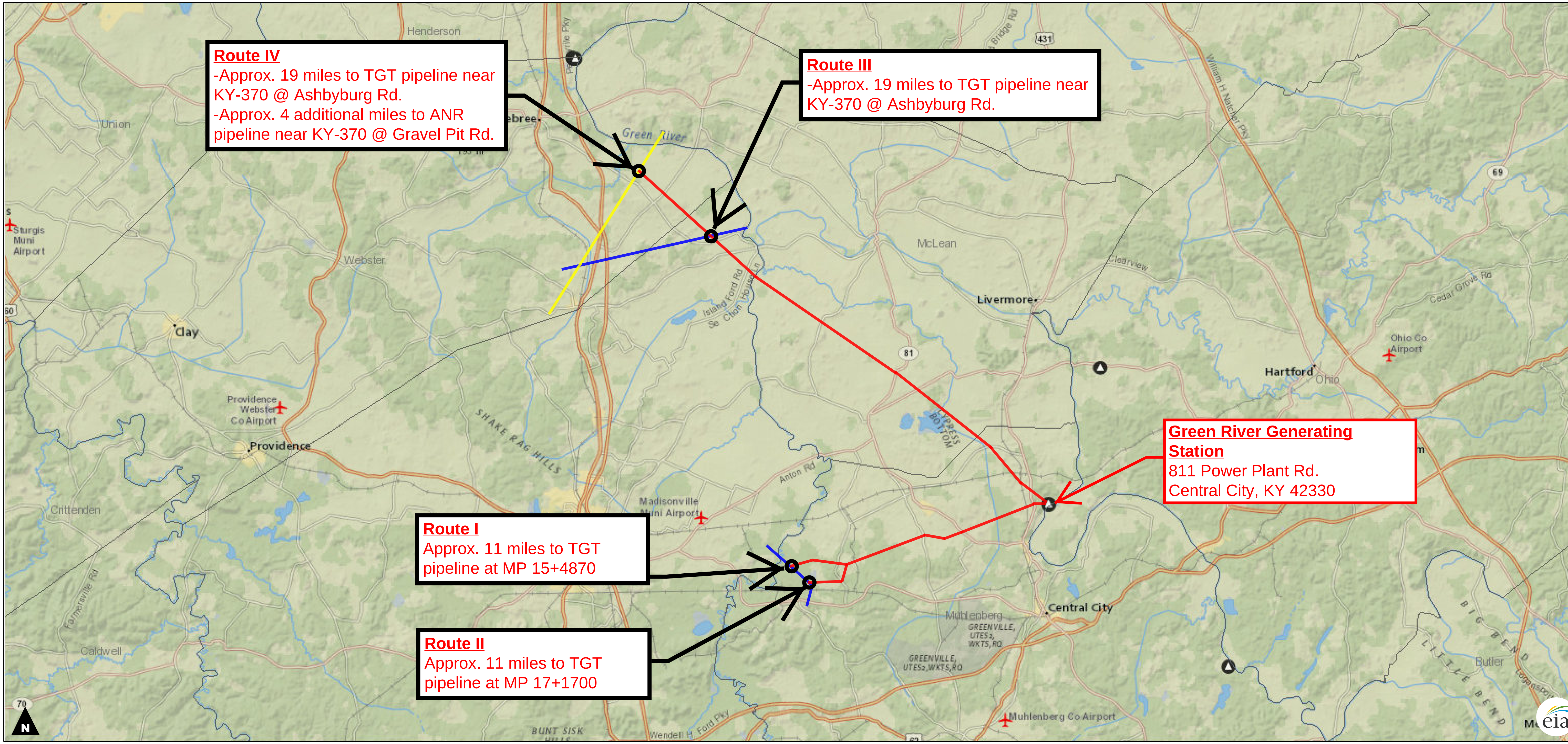
Engineer: BMP	Dwg: BMP 12/04/13	Scale	Draw/Approval	Date	Drawing Number	Rev
Check:	Ck. Date:				SH 1/1	A

Project Number

Map Showing Gas Pipeline for Green River NGCC

Exhibit 4

EXHIBIT 4 - Green River Combined Cycle Plant Pipeline Proposed Routes



National Geographic:National Geographic, Esri, DeLorme, NAVTEQ, UNEP-WCMC, USGS, NASA, ESA, METI, NRCAN, GEBCO, NOAA, iPC

0 1.5 3 6 Miles

- County Boundary
- Coal Power Plant
- **Texas Gas Transmission Pipeline**
- **ANR Transmission Pipeline**
- **Proposed GRCC Pipeline Route**
- **Proposed Tie-in Location**

Existing and proposed routes and distances are estimated from satellite imagery. They are not exact. Distances do not account for changes in elevation.

http://www.eia.gov/state/

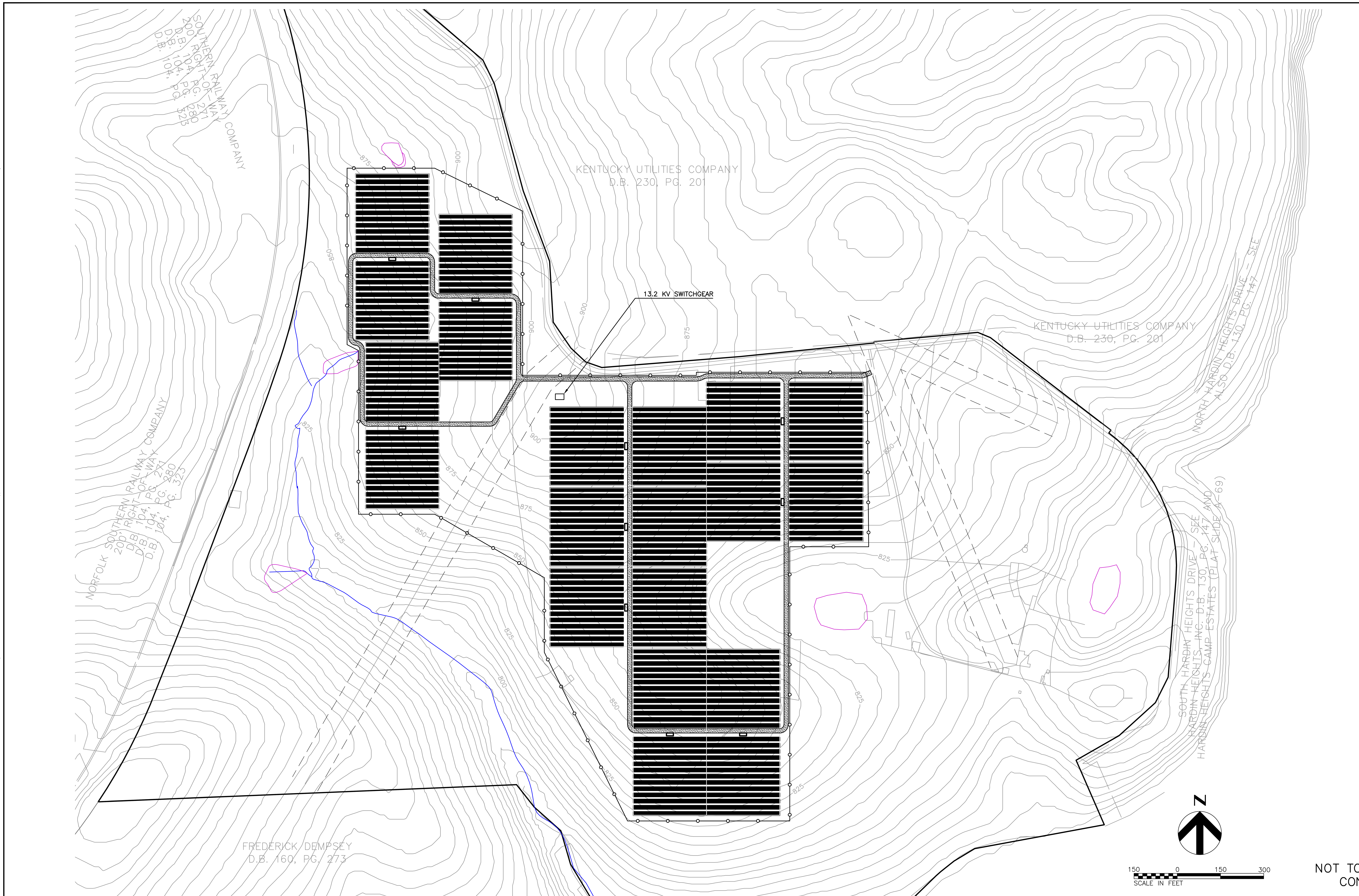
Maps and Plans, Specifications and Drawings for Brown Solar Facility

Exhibit 5

EW Brown 10MW PV Solar Siting

Figure 1

HDR
ONE COMPANY | Many Solutions



Revisions

A	05 DEC 2013 INITIAL ISSUE
B	
C	

NOT TO BE USED FOR CONSTRUCTION

FIXED-AXIS RACK	
TILT ANGLE	25°
GCR	0.60
AREA	49.7 ACRES
RACK (RBI)	TWO MODULES WIDTH IN PORTRAIT ORIENTATION

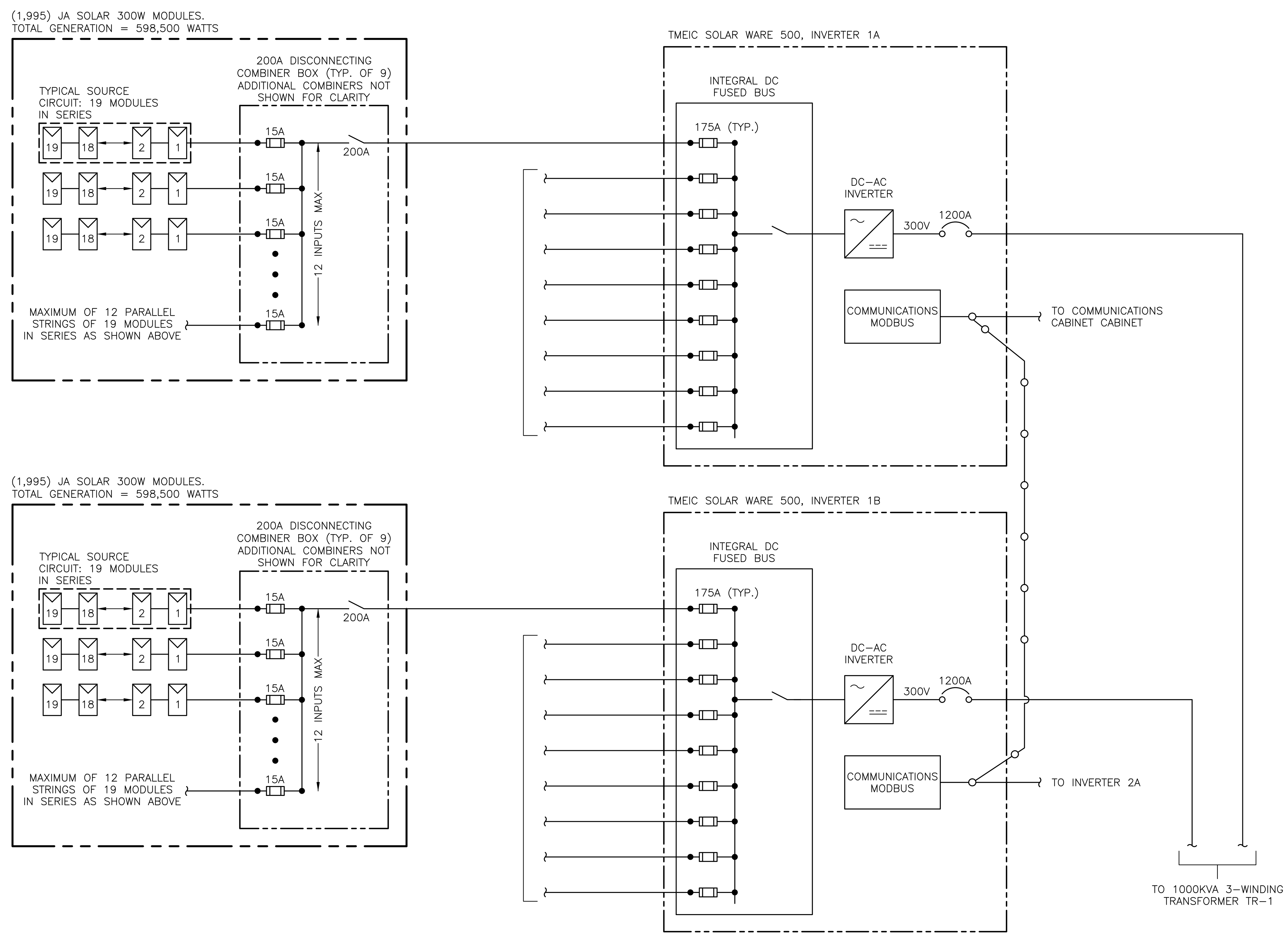
Location and Unit:	LG&E LOUISVILLE GAS & ELECTRIC COMPANY Generation Services	Drawn: AMG 12 DEC 13
Scale: 1" = 150' / Contract No. n/a		Checked:
Engineering discipline: CIVIL / Drawing type:		Approved:
Title: EW BROWN STATION SOLAR PV PROJECT SITE ARRANGEMENT - STANDARD EFFICIENCY CRYSTALLINE		Released for: -
		Alternate Drawing No: CGA-S1001
Originator: HDR ENGINEERING	Job or Project No: 221566	Drawing No: 221566-CGA-S1001 Rev.

DMS Version 2.0

Location and Unit:	LG&E Generation Services	Drawn: ADK 12/23/13
Scale: n/a Contract No. n/a	LOUISVILLE GAS & ELECTRIC COMPANY	Checked:
Engineering discipline: ELECTRICAL Drawing type:		Approved:
Title	EW BROWN STATION SOLAR PV PROJECT AC ONE-LINE DIAGRAM	Released for: –
		Alternate Drawing No: CMP-E1001
Originator: HDR ENGINEERING	Job or Project No: 221566	Drawing No: 221566-CMP-E1001 Rev:

DMS Version 2.0

TOTAL SYSTEM DESCRIPTION	
MODULE TYPE	JA SOLAR 300W
QUANTITY	39,900 MODULES
SYSTEM SIZE (DC)	12.0 MW DC
SYSTEM SIZE (AC)	10.0 MW AC
TILT ANGLE	25° FIXED
INVERTER	TMEIC 500kW (20 TOTAL)
TRANSFORMER	1000kVA (10 TOTAL)



Revisions

A 10 JAN 2014 INITIAL ISSUE

NOT TO BE USED FOR CONSTRUCTION

Location and Unit:	LG&E Generation Services LOUISVILLE GAS & ELECTRIC COMPANY		Drawn: ADK 12/23/13
Scale: n/a	Contract No. n/a		Checked:
Engineering discipline: ELECTRICAL	Drawing type:		Approved:
Title: EW BROWN STATION SOLAR PV PROJECT DC ONE–LINE DIAGRAM			Released for: –
			Alternate Drawing No: CMP–E1002
Originator: HDR ENGINEERING	Job or Project No: 221566	Drawing No: 221566–CMP–E1002	Rev:

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION TURBINE AT THE GREEN RIVER GENERATING STATION AND A SOLAR PHOTOVOLTAIC FACILITY AT THE E.W. BROWN GENERATING STATION	)))))))))	**CASE NO. 2014-00002**

DIRECT TESTIMONY OF
PAUL W. THOMPSON
CHIEF OPERATING OFFICER
KENTUCKY UTILITIES COMPANY
AND LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: January 17, 2014

Q. Please state your name, position and business address.

A. My name is Paul W. Thompson. I am the Chief Operating Officer for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E"). I am employed by LG&E and KU Services Company, which provides services to LG&E and KU (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I testified in LG&E's and KU's most recent general rate cases, Case Nos. 2012-00221 and 2012-00222, *In re the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates* and *In re the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*. I also testified in in Case No. 2011-00375, *In re the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky*. I testified in Case Nos. 2009-00548 and 2009-00549, *In re the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates* and *In re the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates* and I testified in LG&E's 2008 rate application, Case No. 2008-00252, *In re the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*, and

KU's 2008 rate application, Case No. 2008-00251, *In re the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*. Additionally, I testified in *In re the Matter of: The Application of Big Rivers Electric Corporation, E.ON U.S. LLC, Western Kentucky Energy Corp., and LG&E Energy Marketing Inc. for Approval of Transaction* in Case No. 2007-00455. I also filed testimony in the Commission's investigation of LG&E's and KU's membership in the Midwest Independent Transmission System Operator, Inc., *In the Matter of: Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, Case No. 2003-0266. I testified in LG&E's 2003 rate application, Case No. 2003-0433, *In re the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, and KU's 2003 rate application, Case No. 2003-0434, *In re the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*. Finally, I testified in the merger proceedings of LG&E and KU before the Kentucky Public Service Commission in Case No. 1997-0300, *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Merger under KRS 278.020.*

Q. What is the purpose of your testimony?

A. I will provide an overview of the Companies' plans to meet customer needs while at the same time complying with recently enacted and anticipated air quality regulations in the most cost-effective manner. I will introduce the other witnesses testifying in this case and I will describe the Companies' plan to construct new natural gas combined cycle facilities at Green River ("Green River NGCC") and a 10 MW solar photovoltaic facility at the E.W. Brown generating station ("Brown Solar Facility"). Finally, I will describe the Companies' plans for joint ownership of the Green River NGCC and the Brown Solar Facility and conclude by recommending that the Commission approve the Companies' Application and authorize the construction as proposed.

Q. Please identify the other witnesses offering direct testimony on behalf of the Companies in this case, and generally describe the subject matter of each such testimony.

A. The Companies are offering direct testimony from the following witnesses:

- David S. Sinclair - Mr. Sinclair will describe the process by which the Companies determined the least-cost method of meeting expected load while complying with changing environmental regulations, including a presentation of the Companies' Resource Assessment.
- John N. Voyles, Jr. - Mr. Voyles will describe the proposed construction of the Green River NGCC and the Brown Solar Facility.
- Gary H. Revlett – Mr. Revlett will discuss the relevant environmental regulations and permitting issues relating to the Green River NGCC and the Brown Solar Facility.
- Edwin R. Staton - Mr. Staton will discuss financing, joint participation, cost recovery and other regulatory approvals to be obtained.
- Gregory J. Meiman – Mr. Meiman will discuss the tax implications and benefits related to the construction of the Brown Solar Facility.

Q. Please describe the events that led to the Companies' decision to construct new generation facilities at Green River and Brown.

A. As described by Mr. Revlett, changing and more stringent environmental regulations have arrived. As I explained in Case No. 2011-00375, those new regulations presented the Companies with the decision either to install pollution control devices on most of their generation assets, or to retire those assets and replace them with different generation technology. In that case, we explained that the least-cost solution was to retire coal generating facilities at Green River, Tyrone and Cane Run and to construct natural gas generating facilities at Cane Run and to purchase natural gas facilities from Bluegrass Generation Company. The Commission authorized that construction and purchase and the construction at Cane Run has progressed very well. However, the Federal Energy Regulatory Commission did not authorize the purchase from Bluegrass Generation Company as presented. The inability to complete that purchase, combined with the Companies' forecasted load growth, require the Companies to augment their existing generation capacity. Therefore, as described in more detail by Mr. Sinclair, the Companies have concluded that constructing the Green River NGCC is a cost-effective and reasonable means of ensuring adequate generation capacity in the years to come. Furthermore, Mr. Sinclair also describes that constructing the Brown Solar Facility will allow the Companies to add a renewable resource with relatively minor impact to customer revenue requirements in the coming years. Both the Green River NGCC and Brown Solar Facility will broaden and further diversify the Companies' fuel supply sources and reduce future greenhouse gas emissions.

Q. Please describe the facilities to be constructed at Green River and Brown.

A. The Companies are proposing the construction of an approximately 700 MW net summer rating natural gas combined cycle unit at the existing KU site at Green River in Muhlenberg County, Kentucky. As described by Mr. Voyles, the estimated cost of constructing the new facilities at Green River is approximately $700 million. The Companies are further proposing the construction of a 10 MW solar photovoltaic facility at the existing E.W. Brown generating station in Mercer County, Kentucky. Based on conceptual design information, the estimated cost of construction of the new facilities at Brown is approximately $36 million.

Q. Why are the Companies proposing the construction of a solar facility?

A. The Companies believe it is prudent at this time to construct a facility to expand their renewable energy sources. A number of developments have enabled the Companies, for the first time, to present a feasible proposal to the Commission for a solar generation facility. The declining price of solar panels, available federal tax credits, and renewable energy certificates have helped create this opportunity. Additionally, the Companies have identified land they already own at Brown (it was acquired to provide a supply of cover soil for landfill purposes) which is suitable for solar panel installation after obtaining the cover soil. These developments, along with the increased likelihood of carbon constraints, have created a reasonable opportunity for the Companies to add a renewable source to their generation portfolio and gain the valuable experience that will result from constructing and operating that source. As stated above, the conceptual design cost of construction of the Brown Solar Facility is approximately $36 million which is comprised of approximately $26 million for solar generating system equipment, $3 million for site preparation work, and $7 million for owner’s costs.

Q. Describe the Companies’ most recent and planned construction of new generating units?

A. The Companies' most-recently completed base load generating unit is Trimble County Unit 2 which was placed in commercial operation in January 2011. In addition, the Companies are currently in the process of constructing a 640 MW NGCC at Cane Run, which is currently slated to begin commercial operation in the spring of 2015. The Green River station consists of a four-generating-unit, 263-megawatt coal-fired plant, which began commercial operation in 1950. Green River Units 1 and 2 were retired on January 1, 2002. Green River Units 3 and 4 are expected to be retired by early 2015, and will ultimately be replaced with a single and larger NGCC unit expected to begin commercial operation in 2018. The Brown Solar Facility will be added to the Companies' generation portfolio by the end of 2016.

Q. Given the current construction of a 640 MW generation facility at Cane Run, why are the Companies proposing an additional approximately 710 MW of facilities in this case?

A. The Companies have carefully studied and mapped out a plan to meet customer needs in the years ahead. Executing that plan requires the construction of the Green River NGCC and the Brown Solar Facility. As regulated utilities, the Companies have an obligation to serve all customers located in their service territories, and thus must be prepared to meet load growth in those areas. Mr. Sinclair's team has used state of the art modeling to develop the most reasonable and cost-effective method of meeting customers' energy needs. As he explains in his testimony, even with the addition of the new facility at Cane Run, the Companies' load forecast indicates a 2016 reserve margin capacity shortfall of 71 MW and 212 MW at 15% and 17% target reserve margins, respectively. Those shortfalls grow to 367 MW and 514 MW in 2020 at 15% and 17% target reserve margins, respectively, and, by 2035, the shortfalls will be

1,573 MW and 1,741 MW at 15% and 17% target reserve margins, respectively. Thus, the proposed construction projects are essential for the Companies to provide reliable, low-cost power to their customers over time.

Q. Did the Companies consider other options to meet the need for additional capacity and energy?

A. Yes. Mr. Sinclair testifies that the Companies issued a Request for Proposals ("RFP") and prepared a Resource Assessment to compare available options for meeting the projected needs of their customers. As explained in the Resource Assessment, the Companies received 72 proposals from 29 responding companies after sending out the RFP including new build and power purchase agreements. In addition, the Companies developed a number of "self-build" options under which the Companies would be responsible for constructing the new facilities at Green River. Those options were considered in the RFP process. In the final analysis, the Companies determined that the self-build construction proposal at Green River is the least reasonable cost option to enable the Companies to meet their needs for additional capacity and energy. Additionally, the Companies evaluated the feasibility of installing a solar facility. Interestingly, when the RFP process began, the cost of any sort of solar option was not economically competitive. However, based on recent information regarding the cost of solar panels and the ability to utilize the Companies' existing real property at the Brown Station for construction of a solar facility, the installed costs of a solar project became more viable. Given the increasing likelihood of carbon constraints, the ability to sell renewable energy credits, and the availability of federal tax credits if a solar facility is operational by the end of 2016, the Companies believe a solar facility will be a prudent fuel-diverse addition to the generation portfolio and will reduce future greenhouse gas emissions.

Q. Who will own the Green River NGCC and the Brown Solar Facility?

A. The Green River NGCC will be jointly owned by KU and LG&E. KU will own 60% and LG&E will own 40%. As for the Brown Solar Facility, it will also be jointly owned, with KU owning 64% and LG&E owning 36%. As explained in the Resource Assessment, those particular allocations are optimal when considering the production cost savings of the Green River NGCC and each company's individual energy and capacity needs.

Q. Please describe the effects on employment that will result from the retirement of Green River facilities and the addition of the Green River NGCC.

A. There are 41 people currently employed at Green River, many of whom will be employed elsewhere within the Companies when the existing Green River facilities are retired by early 2015. For those that are not reassigned, the Companies believe they will either retire or be offered severance packages. Once the Green River NGCC becomes operational in 2018, the Companies expect it will require approximately 45-50 employees. The operation of the Brown Solar Facility is expected to be staffed by current employees already located at Brown.

Q. Do you have a recommendation for the Commission?

A. Yes. It is my recommendation that the Commission grant the Companies' Application and approve the planned construction at Green River and Brown. That approval will allow the Companies to meet the demand of their customer bases in a least-cost manner while achieving compliance with environmental regulations.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is Chief Operating Officer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of January 2014.

(SEAL)
Notary Public

My Commission Expires:

SHERI L. GARDNER
Notary Public, State at Large, KY
My Commission expires Dec. 24, 2017
Notary ID # 501600

APPENDIX A

Paul W. Thompson

Chief Operating Officer
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

Industry Affiliations

Center for Applied Energy Research, Advisory Board Member
Electric Energy Inc., Board Member
Ohio Valley Electric Corporation, Board Member
Prior Affiliations:
FutureGen Industrial Alliance, Board Member and former Chairman of the Board

Civic Activities

Greater Louisville Inc. Board
Louisville Downtown Development Corporation Board, Chairman
Louisville Free Public Library Foundation Board, Advocacy Committee Chairman
Chairman, [2006 – 2012]
Chair, Annual Appeal 2002 & 2003
Co-Chair Annual Children's Reading Appeal 1999, 2000, & 2001
Jefferson County Public Education Foundation Board [2008 – 2013]
University of Kentucky College of Engineering, Project Lead The Way, Council Member [2007– 2012]
March of Dimes 1997 & 1998 - Honorary Chair
Habitat for Humanity - Representing LG&E as co-sponsor
Friends of the Waterfront Board 1998 – 2002
Leadership Louisville -- 1997-98

Education

University of Chicago, MBA in Finance and Accounting -- 1981
Massachusetts Institute of Technology (MIT), BS in Mechanical Engineering -- 1979

Previous Positions

Senior Vice President, Energy Services
1999 - 2012 LG&E Energy Marketing, Louisville, KY
1998 - 1999 – Group Vice President
Louisville Gas and Electric Company, Louisville, KY
1996 - 1999 – Vice President, Retail Electric Business
LG&E Energy Corp., Louisville, KY

1994 - 1996 (Sept.) – Vice President, Business Development
1994 - 1994 (July) – Louisville Gas & Electric Company, Louisville, KY
General Manager, Gas Operations
1991 - 1993 – Director, Business Development

Koch Industries Inc.

1990 - 1991 – Koch Membrane Systems, Boston, MA
National Sales Manager, Americas
1989 - 1990 – John Zink Company, Tulsa, OK
Vice President, International

Lone Star Technologies (a former Northwest Industries subsidiary)

1988 - 1989 – John Zink Company, Tulsa, OK
Vice Chairman
1986 - 1988 – Hydro-Sonic Systems, Dallas, TX
General Manager
1986 – 1986 (July) –- Ft. Collins Pipe, Dallas, TX, General Manager
1985 - 1986 – Lone Star Technologies, Dallas, TX, Assistant to Chairman
1980 - 1985 – Northwest Industries, Chicago, IL, Manager, Financial Planning

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY AND KENTUCKY	)	
UTILITIES COMPANY FOR A CERTIFICATE	)	
OF PUBLIC CONVENIENCE AND NECESSITY	)	
FOR THE CONSTRUCTION OF A COMBINED	)	
CYCLE COMBUSTION TURBINE AT THE	)	**CASE NO. 2014-00002**
GREEN RIVER GENERATING STATION AND	)	
A SOLAR PHOTOVOLTAIC FACILITY AT	)	
THE E.W. BROWN GENERATING STATION	)	

DIRECT TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
KENTUCKY UTILITIES COMPANY
AND LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: January 17, 2014

<u>Section 1 - Introduction and Overview</u>

Q. Please state your name, position, and business address.

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Please describe your job responsibilities.

A. I have four primary areas of responsibility: (i) fuel procurement (coal and natural gas) for the Companies' generating stations, (ii) real time dispatch optimization of the generating stations to meet the Companies' native load obligations, (iii) wholesale market activities, and (iv) sales and market analysis and generation planning. As pertains to this proceeding, the Sales Analysis and Forecasting group prepared the load forecast and the Generation Planning group performed the analysis of the alternative generation options to meet customers' future capacity and energy needs in a lowest-cost manner. Both of these were done under my direction.

Q. Have you previously testified before the Kentucky Public Service Commission ("the Commission")?

A. Yes. I previously testified before the Commission in the following cases:

- Case No. 2003-00266, *In the Matter of: Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator*;

- Case No. 2004-00507, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and a Site Compatibility Certificate for the Expansion of the Trimble County Generating Station*;
- Case No. 2011-00161, *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery By Environmental Surcharge* and Case No. 2011-00162, *In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery By Environmental Surcharge*;
- Case No. 2011-00375, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and a Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities From Bluegrass Generation Company, LLC in La Grange, Kentucky*; and
- Case No. 2012-00428, *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*.

Q. Are you sponsoring any exhibits?

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

Exhibit DSS-1 2013 Resource Assessment ("Resource Assessment") – an analysis of alternatives for meeting the Companies' future capacity and energy needs.

Exhibit DSS-2	Table of Peak Demand and Energy Requirements Before DSM (2012-2042)
Exhibit DSS-3	Table of DSM Impacts to Peak Demand and Energy Requirements (2012-2042)
Exhibit DSS-4	Table of Peak Demand and Energy Requirements After DSM (2000-2042)
Exhibit DSS-5	Table of Peak Demand and Energy Requirements After DSM – Comparison of 2013 LF and 2014 LF (2015-2042)

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the process by which the Companies reached the decision to construct a new approximately 700 MW 2x1 natural gas combined cycle ("NGCC") combustion turbine generating unit at KU's Green River Station ("Green River 2x1 NGCC unit") and to construct a 10 MW solar photovoltaic facility at the E.W. Brown Station ("Brown Solar Facility"). That decision was reached after an extensive process that considered: (1) the Companies' load forecast and the uncertainty associated with it; (2) the impact of the Companies' demand-side management ("DSM") programs on future generation resource needs; (3) the potential for future regulation of greenhouse gas ("GHG") emissions by the U.S. Environmental Protection Agency ("EPA"); (4) the issuance and evaluation of a Request for Proposals ("RFP") for capacity and energy to replace the retired generation facilities and meet future load growth; and (5) the uncertainty associated with future natural gas prices. My testimony also describes the methodology used to determine ownership shares for LG&E and KU for the proposed capacity additions. Finally, I will recommend to the Commission that it approve the proposed construction of the Green River 2x1 NGCC unit and the Brown Solar Facility.

<u>Section 2 – Forecast of Peak Demand and Energy Requirements</u>

Q. Please describe the Companies' load forecast process.

A. Each year, the Companies prepare a 30 year demand and energy forecast. The first part of the forecast process involves gathering and processing input data. The following are key inputs to the forecast process:

- Macroeconomic data
- Historical energy and customer data
- Weather data (20-year normal degree-day series)
- Other data including billing cycle forecasts, class-level electricity price series, and residential appliance shares and efficiencies.

Once the input data are prepared, these data are used to specify the forecast models. The forecasting approach is based on econometric modeling of sales by customer class, but also incorporates specific intelligence on the prospective energy needs of the Companies' largest customers. Sales for several large customers for both KU and LG&E are forecasted using their recent history and information provided by the customers to the Companies regarding their outlook. These customers are referred to as "Major Accounts." This process allows for market intelligence to be directly incorporated into the sales forecast.

The sales forecast is prepared for both LG&E and KU with the latter's forecast disaggregated into the three jurisdictions it serves: (1) retail sales in Kentucky, (2) retail sales in Virginia, and (3) wholesale sales to Kentucky municipalities. Both Companies' forecasts are disaggregated by customer class such as residential, commercial and industrial sales. The number of customers and use-per-customer for residential and commercial classes are forecasted with the product of the two comprising the sales forecast.[1]

This widely accepted approach can readily accommodate the influences of national, regional and local (service territory) drivers of utility sales. The modeling of residential and small commercial sales also incorporates elements of end-use forecasting – covering base load, heating and cooling components of sales – which recognize expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

Once complete, the Companies' sales forecasts are converted from a billed to calendar basis, adjusted for losses, and associated with hourly load profiles to create a forecast of hourly energy requirements. The resulting forecast of hourly energy requirements is used to generate the peak demand forecasts.[2]

Q. You stated that the Companies prepare a 30-year load forecast each year. When was the load forecast prepared that was used in preparing the Resource Assessment?

A. The load forecast for 2013 through 2042 that was used in preparing the Resource Assessment was completed in the summer of 2012 ("2013 LF"). This forecast was the basis for identifying the need for capacity beginning as soon as the summer of

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[1] A detailed description of the methodologies used to create the energy forecasts can be found in Volume II, Technical Appendix, pages 212-227 of the 2011 IRP, Case No. 2011-00140. The methodology has not materially changed since the 2011 IRP.

[2] A detailed description of the peak demand forecast methodology can be found in Volume II, Technical Appendix, pages 208 - 211 of the 2011 IRP, Case No. 2011-00140. The methodology has not materially changed since the 2011 IRP.

2015 which led to the Companies issuing an RFP for capacity and energy in September 2012.[3]

Q. Please describe the 2013 LF.

A. In the 2013 LF, the combined Companies' peak demand is forecasted to grow from 2012 through 2042 at a compound annual growth rate ("CAGR") of 1.2 percent. The combined Companies' energy requirements are forecasted to grow at a CAGR of 0.9%. Neither of these values includes the impact of any of the Companies' DSM programs. Table 1 shows values for peak demand and energy requirements forecasts for selected years.[4]

Table 1 – 2013 LF - Peak Demand and Energy Requirements (Before DSM Programs)

	2012	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Peak Demand (MW)[5]	6,970	7,426	7,815	8,147	8,517	8,891	9,261
Energy Requirements (GWh)[6]	35,076	36,748	38,184	39,847	41,768	43,657	45,683

Q. What are the main reasons that peak demand and energy requirements are forecasted to grow over the next 30 years?

A. The main drivers for the forecasted load growth over the next 30 years are increases in the number of customers and a growing economy, as reflected in forecasts of Kentucky Real Gross State Product ("RGSP") and Kentucky Total Non-Farm Employment ("Employment"). Long-term forecasts of RGSP and Employment are obtained from IHS Global Insight. Customer projections are based on projections

[3] On September 7, 2012, the Companies issued a RFP from parties wishing to sell capacity and energy for between 1 MW and 700 MW for a term to begin no earlier than January 1, 2015.

[4] Exhibit DSS-2 contains data for all years.

[5] Peak Demand data for 2012 reflects the actual value adjusted for estimated DSM impact. The Companies' all-time actual peak demand of 7,175 MW occurred on August 4, 2010.

[6] 2012 energy data is a weather-normalized estimated value.

from the Kentucky State Data Center for increases in the number of households and population within the service territories for each company. All of the major drivers are forecasted to grow over the next thirty years, which leads to growth in the energy requirements and peak demand.

Partially offsetting the impact of more customers and a larger economy is the effect of improving appliance efficiency and their adoption by customers. This impact is captured in the residential and small-commercial use per customer models. The energy efficiency of new appliances is based on the standards set forth in existing legislation and regulations, such as the 2007 Energy Independence and Security Act. The end-use models capture the efficiency gains over time as customers replace older, less efficient appliances with newer, more efficient appliances.

Industrial and large commercial customers are assumed to continue to make efficiency improvements as well. For example, major account representatives monitor the largest customers so that efficiency improvements at these locations are taken into account in the forecast process.

Q. Are KU's and LG&E's load forecasts expected to grow in a similar fashion over the long term?

A. Yes. LG&E's energy requirements are expected to have a CAGR of 1.0% through 2042 before the impact of DSM programs and KU's are expected to have a CAGR of 0.8% through 2042 before the impact of DSM programs.

Q. You stated that the information in Table 1 was before the impact of the Companies' DSM programs. Please describe the forecasted reductions to peak demand and energy requirements associated with those programs.

A. The Companies have a number of DSM programs that reduce the peak demand and energy usage of residential and commercial customers.[7] Table 2 shows the forecasted impact of these programs for selected years.[8]

Table 2 – 2013 LF - Peak Demand and Energy Reductions from DSM Programs

	2012[9]	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Peak Demand (MW)	114	386	466	475	484	493	502
Energy (GWh)	139	585	764	764	764	764	764

Q. Why does the impact of the Companies' DSM programs flatten out after 2020?

A. DSM programs have historically been presented to the Commission with a seven year program planning period. The last filing approved by the Commission was Case No. 2011-00134 on November 9, 2011 with the new programs starting January 1, 2012. Because of the seven year planning period, savings associated with all currently approved programs flatten out after 2018. Prior to the end of 2018, programs will be reevaluated and renewed where appropriate, taking market potentials, building codes, customer expectations, and energy efficient technologies into consideration.

Q. Does the lack of forecasted new DSM programs beyond 2018 mean that no increase in energy efficiency is forecasted beyond that year?

A. No. As I just stated, the Companies' load forecasting process captures increases in energy efficiency that customers will achieve on their own.

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[7] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New Demand-Side Management and Energy-Efficiency Programs, Case No. 2011-00134.*

[8] Exhibit DSS-3 contains data for all years.

[9] 2012 data are estimated values.

Q. What is the Companies' forecast of peak demand and energy requirements after including the impact of DSM programs?

A. Once DSM programs are included, the Companies' peak demand is forecasted to increase from 6,552 MW in 2012 (after adjusting for weather) to 7,350 MW by 2020. Similarly, energy is forecasted to grow from 34,937 GWh in 2012 (after adjusting for weather) to 37,421 GWh by 2020 after reductions for saving from DSM programs. Table 3 shows the forecasted values for peak demand and energy requirements after reductions for DSM programs in selected years.[10] The CAGR from 2012 through 2040 for the Combined Company peak after DSM is 1.0% and for Combined Company energy requirements after DSM is 0.9%. This is almost identical to the overall U.S. growth in electricity demand forecasted by the U.S. Energy Information Administration ("EIA").[11]

Table 3 – 2013 LF - Peak Demand and Energy Requirements (After DSM Programs)

	2012	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Peak Demand (MW)[12]	6,856	7,040	7,350	7,673	8,034	8,398	8,760
Energy Requirements (GWh)[13]	34,937	36,162	37,421	39,083	41,004	42,894	44,920

Q. I note that Exhibit DSS-4 shows the Companies' all-time peak demand was 7,175 MW in 2010 yet the forecasted peak demand does not approach that level until around 2017. Does this mean that the Companies have lost load in recent years?

[10] Exhibit DSS-4 contains data for all years.
[11] In the EIA's 2013 Annual Energy Outlook, the estimated CAGR for electricity use is 0.9% from 2011 to 2040. *See* http://www.eia.gov/forecasts/aeo/MT_electric.cfm#growth_elec.
[12] The Companies' all-time actual peak demand of 7,175 MW occurred on August 4, 2010.
[13] 2012 energy data is a weather-normalized actual value.

A. No. One cannot just look at changes in annual peak demand to understand load growth. Setting a new annual peak demand requires a number of conditions to occur during the middle of certain weeks in July and August: (i) much higher than normal maximum and minimum temperatures for a number of consecutive days over the entire service area; (ii) high humidity; and (iii) no afternoon thunderstorms. If these weather conditions occur over the weekend, during the week of July 4, only for a short period of time, etc., then a record peak load is not likely to occur. Obviously, these conditions do not occur every year. While we can calculate a "weather normalized" value for the annual peak, this estimate does not fully take into account all of the factors that lead to real life record peak demand conditions. While peak conditions have not materialized in July and August, the Companies have experienced new record monthly peak demands for six of the other eleven months (January, May, June, September, November, and December) since the August 2010 all-time peak demand. As recently as January 6, 2014 for hour ending 21:00, the Companies set a new all-time winter peak of 7,114 MW which exceeded the previous winter peak of 6,555 MW set in January 2009. The 7,114 MW peak represents the energy used during the hour; however load during that hour instantaneously exceeded this amount by over 100 MW according to 4-second interval data.

Given that (i) our customers used 7,175 MW in 2010; (ii) we have added customers since 2010; and (iii) we are forecasting the addition of more customers, the forecast of increasing summer peak demand is reasonable, even though the Companies may not set a peak demand record every year.

Q. Does the peak demand forecast include the potential impacts of more frequent extreme weather events due to climate change?

A. No. There are some climate scientists that believe that the frequency of extreme weather events will increase due to climate change. For example, the Intergovernmental Panel on Climate Change ("IPCC") asserts in a recent report, "*It is virtually certain that there will be more frequent hot and fewer cold temperature extremes over most land areas on daily and seasonal timescales as global mean temperatures increase. It is very likely that heat waves will occur with a higher frequency and duration. Occasional cold winter extremes will continue to occur*."[14] Additionally, according to Dr. John Holdren, the White House Science and Technology Advisor, we might expect more extreme cold weather events like the one experienced on January 6 and 7, 2014 as a result of global warming.[15] However, our peak load forecast is based on the average of extreme temperatures over the historical 20-year period. This same average temperature is used in all years of the peak forecast.

Q. You stated that the 2013 LF utilized in the development of the Resource Assessment had been prepared in the summer of 2012. Have the Companies completed another load forecast since then?

A. Yes. The Companies prepare a 30-year load forecast every year. The most recent one was completed in the summer of 2013 for 2014 through 2043 ("2014 LF").

Q. Are there any material differences between the 2013 LF and the 2014 LF?

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[14] "Climate Change 2013, The Physical Science Basis, Summary for Policymakers," IPCC, October 2013, p. 18. *See* http://www.climatechange2013.org/images/uploads/WGI_AR5_SPM_brochure.pdf.

[15] "The Polar Vortex Explained in 2 Minutes," Dr. J. Holdren, White House Office of Science and Technology Policy, January 8, 2014. *See* http://www.whitehouse.gov/photos-and-video/video/2014/01/08/polar-vortex-explained-2-minutes.

A. No. Table 4 compares the forecasts of peak demand and energy requirements (after DSM programs) from the 2014 LF and the 2013 LF.[16]

Table 4 – 2014 LF compared to the 2013 LF - Peak Demand and Energy Requirements (After DSM Programs)

	2015	2020	2025	2030	2035	2040
Peak Demand (MW)						
2014 LF	7,028	7,315	7,598	7,880	8,172	8,476
2013 LF	7,040	7,350	7,673	8,034	8,398	8,760
Difference (2014 minus 2013)	(12)	(35)	(75)	(154)	(226)	(284)
Energy (GWh)						
2014 LF	35,892	37,260	38,478	39,841	41,162	42,333
2013 LF	36,162	37,421	39,083	41,004	42,894	44,920
Difference (2014 minus 2013)	(270)	(160)	(605)	(1,163)	(1,732)	(2,586)

The differences between the two forecasts are primarily due to minor changes in anticipated growth rates for specific customer classes. The most significant sources of change between the two plans are a reduction in LG&E commercial sales growth partially offset by a slight increase in KU residential sales growth during this period. These changes are based on updated model inputs related to Kentucky economic forecasts and revised models.

Q. Why didn't the Companies utilize the 2014 LF to prepare the Resource Assessment?

A. In preparing the Resource Assessment, the Companies evaluated the various resource options under a range of load forecasts. The 2014 LF falls well within that range. Figures 1 and 2 show the 2013 LF Base, High, and Low scenarios along with the 2014 LF for both peak demand and energy requirements (both after adjusting for DSM programs). As one can see, the 2014 LF falls between the 2013 LF Base and

[16] Exhibit DSS-5 contains data for all years.

Low load scenarios for both peak demand and energy. The analytical work for the Resource Assessment began in December 2012 and continued through the summer of 2013. When the 2014 LF was completed and the differences between the 2013 LF and the 2014 LF turned out to be immaterial, it was decided that the quality of the decision related to the next generation resource would not be improved by replicating months of work with a slightly different baseline load forecast. Therefore, there was no need to explicitly include the 2014 LF in the Resource Assessment.

Figure 1 - 2013 LF Energy Requirements Scenarios and 2014 LF Baseline

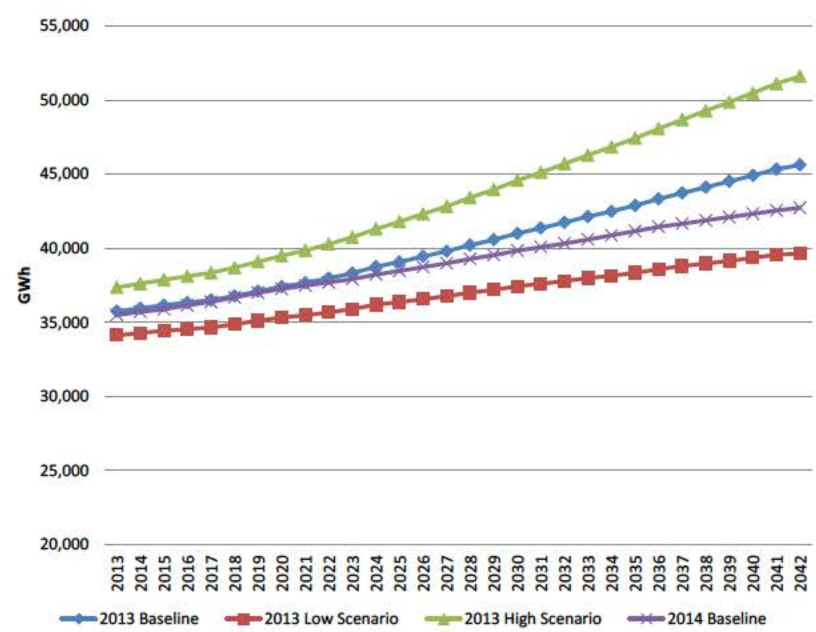
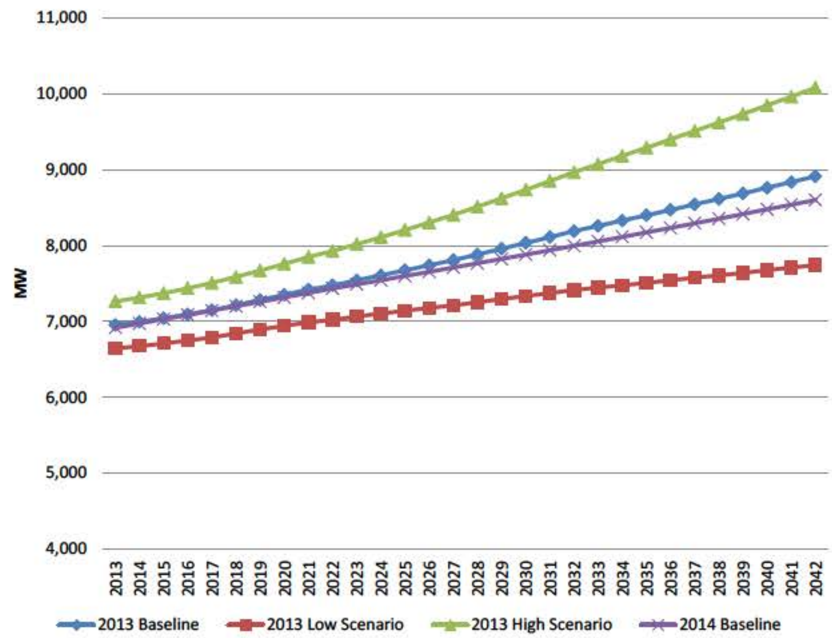


Figure 2 - 2013 LF Peak Demand Scenarios and 2014 LF Baseline



Q. How were the Low and High load energy requirements forecast scenarios created for the 2013 LF?

A. Historical weather-normalized sales were used to determine distributions around historical growth rates. These distributions were applied to the load forecast to create pessimistic (low growth) and optimistic (high growth) cases such that there is a 90% likelihood that the forecasted load will fall within this range.

Q. How do the Companies ensure their load forecasts are reasonable?

A. The Companies seek to ensure their load forecast is prepared using sound methods by people who are qualified professionals. There are three practices that the Companies employ to help produce the most reasonable forecast possible:

1. Build and rigorously test statistically and economically sound mathematical models of the load forecast variables;

2. Use quality forecasts of future macroeconomic events, both nationally and in the service territory, that influence the load forecast variables; and

3. Thoroughly review and analyze the model output to ensure the results make sense based on historical trends and the forecaster's own sense and understanding of long-term trends in electricity usage.

The end result is the best forecast that can be produced by experienced professionals using the best available methods, models, and data.

Q. In your professional opinion, is the 2013 LF a reasonable forecast that can be relied upon in the development of the Resource Assessment?

A. Yes. I have been involved in economic forecasting for 30 years and first began performing utility load forecasts in 1986. So I have prepared and reviewed many forecasts in my career. It is my opinion that the 2013 LF fully meets the criteria I just discussed and is a reasonable forecast upon which to base long-term generation resource decisions.

Section 3 – Need for Capacity and Energy and the Resource Assessment

Q. Based on the 2013 LF, when will the Companies need additional capacity?

A. After the 2013 LF was completed in the summer of 2012, it was determined that the Companies will need additional capacity and energy beginning perhaps as early as 2015 but certainly by 2016. Table 5 shows the Companies' forecasted reserve margin. As you can see, the Companies are expected to be at the minimum range of their target reserve margin (between 15% and 17%) in 2015. But by 2016 they are forecasted to be between 71 MW and 212 MW short of the target reserve margin.

This deficit is forecasted to grow by around 75 MW annually from 2016 through 2020 as load grows due to the reasons I just discussed.

Table 5 – LG&E/KU Resource Summary (MW, Summer, 2013 LF)

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Forecasted Peak Load	7,426	7,509	7,597	7,696	7,746	7,815	8,147	8,517	8,891
Energy Efficiency/DSM	(386)	(418)	(450)	(482)	(464)	(466)	(475)	(484)	(493)
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,673	8,034	8,398
Existing Resources[17]	7,814	7,796	7,796	7,796	7,796	7,796	7,796	7,796	7,796
Firm Purchases (OVEC)	152	152	152	152	152	152	152	152	152
Curtailable Load	137	137	137	137	137	137	137	137	137
Total Supply	8,103	8,085	8,085	8,085	8,085	8,085	8,085	8,085	8,085
Reserve Margin ("RM")	15.1%	14.0%	13.1%	12.1%	11.0%	10.0%	5.4%	0.6%	-3.7%
RM Shortfall (17% RM)*	(134)	(212)	(277)	(355)	(434)	(514)	(892)	(1,314)	(1,741)
RM Shortfall (15% RM)*	7	(71)	(134)	(211)	(289)	(367)	(738)	(1,154)	(1,573)

*Negative values reflect reserve margin shortfall.

Q. In May 2012, the Commission issued an order approving, among other things, a Certificate of Public Convenience and Necessity ("CPCN") for the purchase of Bluegrass Generation Company, L.L.C.'s ("Bluegrass Generation's") assets consisting of 495 MW of simple cycle combustion turbines ("SCCTs"). Did the Companies purchase these assets?

A. No. The Federal Energy Regulatory Commission ("FERC") placed conditions on the Companies' acquisition of LS Power's Bluegrass Generation assets that made it

[17] 'Existing Resources' reflects the retirement of Tyrone Unit 3, Green River Units 3 and 4, and Cane Run Units 4, 5, and 6 and the addition of Cane Run Unit 7.

uneconomical.[18,19] On June 18, 2012, the Companies informed the Commission of their decision not to proceed with the purchase of the Bluegrass Generation assets.[20]

Q. Has the Companies' need for additional generation resources changed since the Commission issued its order regarding the purchase of the Bluegrass Generation assets?

A. The Companies' need for additional generation resources has not materially changed since the Commission issued its order on the purchase of the Bluegrass Generation assets. By April of 2015, the Companies will have retired 797 MW of existing coal-fired capacity and, by May 2015, brought on-line Cane Run Unit 7, a 640 MW NGCC unit. As was demonstrated in Case No. 2011-00375 (the CPCN case for Cane Run Unit 7 and the Bluegrass Generation assets), had the Companies acquired the Bluegrass Generation assets, their next need for capacity and energy would have been in 2020.[21] Without the Bluegrass Generation assets, that need would have been accelerated to 2015, which is consistent with the Companies' current need for capacity, as shown in Table 6.

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[18] Bluegrass Generation is a Delaware limited liability company, and a wholly-owned subsidiary of Port River, LLC (Port River). Port River is a Delaware limited liability company owned by LS Power Equity Partners II, L.P. and indirectly owned by LS Power Equity Partners II PIE, L.P. and LS Power Partners II, L.P. Bluegrass Generation is an exempt wholesale generator and has received market-based rate authority from the FERC.

[19] *Order Conditionally Authorizing Disposition and Acquisition of Jurisdictional Facilities and Acquisition of Generating Facilities*, Docket No. EC12-29-000, May 4, 2012, 139 FERC ¶ 61,094. For the Order, *see* http://www.ferc.gov/EventCalendar/Files/20120504160345-EC12-29-000.pdf.

[20] Lonnie Bellar, Letter, June 18, 2012, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky*, Case No. 2011-00375. *See* http://psc.ky.gov/pscscf/Post%20Case%20Referenced%20Correspondence/2011%20cases/2011-00375/20120618_LG&E-KU_Letter%20Regarding%20Bluegrass%20Acquisition.pdf.

[21] Case No. 2011-00375, Rebuttal Testimony of David S. Sinclair, Rebuttal Testimony Exhibit DSS-3, February 3, 2012. *See* http://psc.ky.gov/PSCSCF/2011%20cases/2011-00375/20120203_LGE%20and%20KUs%20Rebuttal%20Testimony%20of%20David%20Sinclair.pdf.

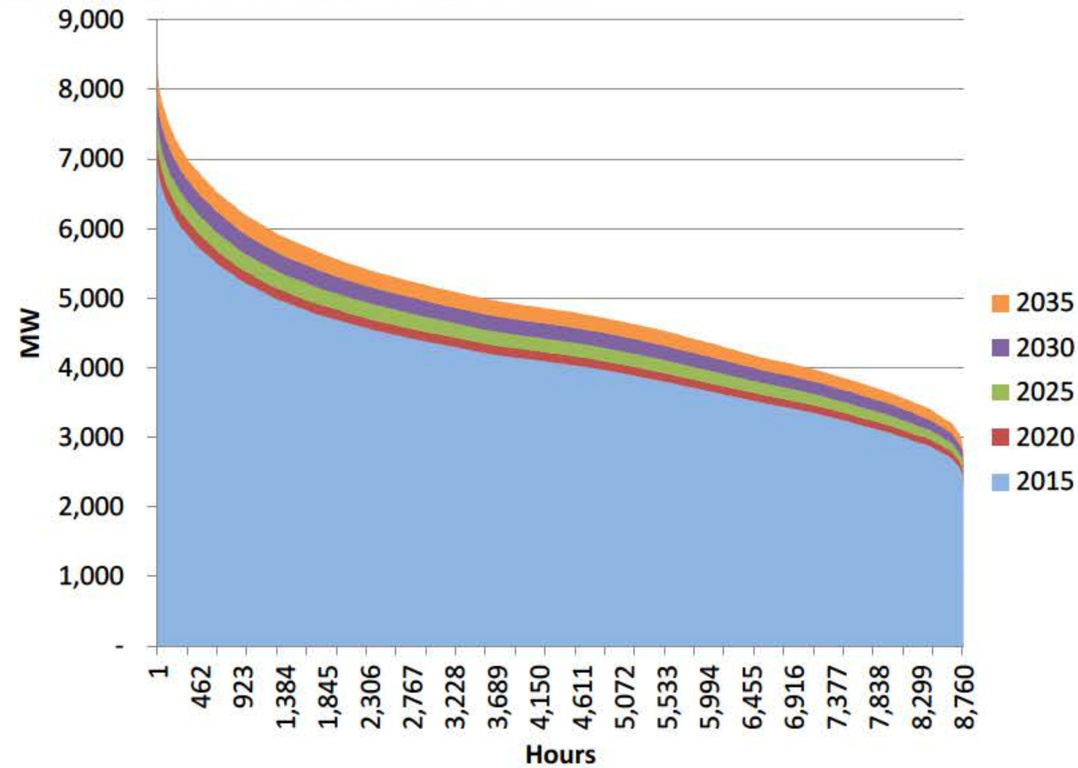
Table 6 – Resource Summary Comparison, 2013 and 2011 Resource Assessments

2013 Resource Assessment									
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,673	8,034	8,398
Total Supply	8,103	8,085	8,085	8,085	8,085	8,085	8,085	8,085	8,085
Reserve Margin	15.1%	14.0%	13.1%	12.1%	11.0%	10.0%	5.4%	0.6%	-3.7%
2011 Resource Assessment without Bluegrass Generation Assets									
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Net Peak Load	7,185	7,196	7,261	7,360	7,519	7,672	8,282	8,887	9,431
Total Supply	8,274	8,090	8,090	8,090	8,090	8,090	8,090	8,090	8,090
Reserve Margin	15.2%	12.4%	11.4%	9.9%	7.6%	5.4%	-2.3%	-9.0%	-14.2%

Q. The Companies' reserve margin measures their ability to meet the maximum hourly load. What about the ability to reliably and cost-effectively meet load in the other hours of the year?

A. As can be seen in Figure 3, the Companies' load is forecasted to grow across all hours in the year, even after adjusting for planned DSM programs. To reliably serve this load in a low-cost manner, the Companies must have a portfolio of generating assets that will allow: (i) scheduling of required plant maintenance; (ii) addressing unplanned unit outages; (iii) following load moment-to-moment; (iv) ramping of generation to match changes in load over the course of the day; (v) addressing transmission system constraints; (vi) meeting system voltage requirements; and (vii) providing various other grid reliability needs. It is vital that any new resources be evaluated over the course of all hours of the year and not just by their contribution to meeting the peak hour.

Figure 3 – Load Duration Curve (2013 LF)



Q. What actions did the Companies take to address the forecasted reserve margin deficits and the need for low-cost energy throughout the year?

A. Several actions were taken to address the forecasted reserve margin deficits and the need for low-cost energy. In September 2012 the Companies sent a RFP to 165 potential suppliers of capacity and energy, began developing numerous self-build generation options, and investigated potential new DSM programs.

Q. Please describe the responses the Companies received to the RFP.

A. Twenty-nine companies responded to the RFP with 72 proposals. The responses included new build proposals and power purchase agreements ("PPAs") from existing assets across a broad spectrum of generation technologies. Section 3 of the Resource Assessment describes the RFP responses in great detail.

Q. What self-build options did the Companies develop?

A. The Companies engaged an engineering firm to help identify potential self-build alternatives and the associated costs for each. As discussed in Section 3 of the Resource Assessment, the self-build options included new NGCC units (1x1 and 2x1), a greenfield solar photovoltaic facility, and uprates to existing simple cycle combustion turbines.

Q. Why was the Green River Station selected as the site for the NGCC unit self-build options?

A. The Green River Station was selected as the best site for any new NGCC units because of the planned retirement of Green River Units 3 and 4, both of which burn coal. Construction at an existing site will simplify the environmental permitting process as discussed by Mr. Revlett and allow the Companies to take some advantage of existing infrastructure as discussed by Mr. Voyles. Furthermore, as Mr. Voyles discussed, replacing the retiring generation at the Green River Station will reduce the need to rely more heavily on the transmission grid in the western part of the Companies' service area.

Q. Did the Companies consider any new DSM programs when it prepared the Resource Assessment?

A. Yes. As shown on Table 3 of the Resource Assessment, the Companies considered seven new DSM programs in evaluating potential means to meet future load. For purposes of the Resource Assessment analysis, it was assumed that a commercial new construction program might be a viable future DSM program. Therefore, the load forecast was reduced accordingly.

Q. In preparing the Resource Assessment, what risks did the Companies consider when they evaluated the various supply-side and demand-side resources?

A. The Resource Assessment seeks to identify the best resource(s) to reliably meet our customers' long-term (30 years) energy needs at the lowest reasonable cost. Because the future is uncertain, it is vital that a new resource is reliable and economically robust under a range of possible conditions. After careful consideration, the Companies identified three key risk elements as most critical for testing the robustness of possible resources: (i) load growth, (ii) natural gas prices, and (iii) potential CO_2 regulations.

Q. Please describe how load risk was evaluated in the Resource Assessment.

A. As I previously discussed, the Companies produce a Base, High, and Low load forecast each year. In the Resource Assessment, alternatives were evaluated using the Base and Low load forecast.

Q. Why did the Resource Assessment not consider a "High" load forecast in evaluating the alternative resources?

A. By not explicitly including a "High" load forecast as part of the Resource Assessment, the Companies were being conservative in their analysis of potential resource options. Any probability for load being greater than the Base load forecast would favor more capacity sooner. As discussed in the Resource Assessment, despite the fact that load could turn out to be greater than the Base forecast, this risk was not considered since having excess capacity and energy is often viewed as more costly than adding additional capacity should load turn out to be greater. Thus, the analysis focused only on the Base and Low load forecasts.[22] Furthermore, the Resource Assessment was prepared assuming no ability to make off-system sales. Therefore,

[22] See Resource Assessment, Section 4.1.1.

the ability to mitigate any short-term costs associated with capacity above the target reserve margin was not considered.

Q. How did the Resource Assessment consider the uncertainty associated with natural gas prices?

A. The Resource Assessment utilized Low, Mid, and High natural gas price forecasts based on forecasts from the EIA.[23] Resource alternatives were evaluated using each of these natural gas price forecasts.

Q. Why did the Resource Assessment only utilize alternative forecasts for natural gas prices and not coal prices?

A. First, natural gas prices have tended to be more volatile than coal prices, so capturing that potential volatility in the analysis is more critical as compared to the low volatility associated with coal prices. Second, pending EPA regulations on CO_2 emissions makes it uneconomical to consider building new coal plants, thus making natural gas the only viable fossil fuel for new plants. Therefore, it was important to focus on the uncertainty surrounding the production cost for new gas-fired generation.

Q. How did the Companies' model the uncertainty associated with possible CO_2 regulation?

A. President Obama has announced his intention of regulating CO_2 emissions from new and existing power plants.[24,25,26] Therefore, the Resource Assessment explicitly

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[23] See Resource Assessment, Section 4.1.2.

[24] "Setting the Stage for a Second Term," Time, December 19, 2012, R. Stengel et al. *See* http://poy.time.com/2012/12/19/setting-the-stage-for-a-second-term/.

[25] "Speech Gives Climate Goals Center Stage," R. Stevenson and J. Broder, The New York Times, January 21, 2013. *See* http://www.nytimes.com/2013/01/22/us/politics/climate-change-prominent-in-obamas-inaugural-address.html?_r=0.

considered this risk. Since the exact nature of future CO_2 regulations remains unknown, the Companies decided to utilize an approach that puts a price on each ton of CO_2 emitted. The assumption for future CO_2 prices and the timing for CO_2 regulation, should it occur, would be based on the "Mid" price forecast prepared by Synapse Energy Economics, Inc., a consulting firm that does a significant amount of work for various environmental groups such as the Sierra Club and Natural Resources Defense Council. While the likelihood of future CO_2 regulations has increased with the President's announcement, they are by no means assured and certainly their form and timing remains unknown. Therefore, the Resource Assessment also considered a "Zero" carbon scenario where there is never a price on future CO_2 emissions.

Q. You have previously testified that regulation of CO_2 was essentially "unknown and unknowable." Has your position changed?

A. Somewhat. As I said, the future remains highly uncertain regarding CO_2 regulation in the U.S. Many people believe that the Clean Air Act is not really suited for regulating CO_2 emissions and that new legislation is needed from Congress.[27,28] Given the current climate in Washington, it is hard to envision bipartisan support for GHG legislation. Second, court challenges continue related to past actions taken by EPA to regulate CO_2 emissions and threats of future litigation are being made should

[26] "Presidential Memorandum -- Power Sector Carbon Pollution Standards," The White House, Office of the Press Secretary, June 25, 2013. *See* http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[27] "Regulation of Greenhouse Gas Emissions Under the Clean Air Act," Business Roundtable Network, November 8, 2013. *See* http://businessroundtable.org/studies-and-reports/regulation-of-greenhouse-gas-emissions-under-the-clean-air-act.

[28] "NRDC Plan For Flexible EPA Climate NSPS Spurs Fear Of Market Distortion," C. Knight, Inside EPA, August 8, 2013. *See* http://insideepa.com/201308082443486/EPA-Daily-News/Daily-News/nrdc-plan-for-flexible-epa-climate-nsps-spurs-fear-of-market-distortion/menu-id-986 html.

EPA press ahead on regulations for existing power stations.[29] In this environment, much remains unknown about if, when, and how CO_2 might be regulated in the future. However, the Companies feel that enough is known that the risk of future CO_2 regulations should be part of a 30-year analysis related to the next generation resource and that a resource should be economically robust with or without future CO_2 regulations. I would add, however, that there is not enough known about the potential for CO_2 regulations to evaluate material changes to the Companies' existing generation fleet.

Q. How did the Companies model the uncertainty associated with load, natural gas prices, and CO_2 regulations?

A. In evaluating the various resource alternatives, the Companies combined the two load forecast scenarios, three natural gas price scenarios, and two CO_2 price scenarios into twelve unique scenarios.[30] As I previously mentioned, the Resource Assessment did not consider a "High" load forecast so the Base load forecast was weighted 80 percent and the Low load forecast was weighted 20 percent based on the statistical distribution associated with the Base load forecast. Each of the natural gas price forecasts was considered equally likely (0.333 each) as were the CO_2 price forecasts (0.5 each). Table 9 in Section 4.1.4 of the Resource Assessment shows the weight assigned to each of the twelve scenarios. Essentially, all six of the scenarios that involve the Base load forecast have a weight of 0.133 (0.8 load x 0.333 natural gas

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[29] "Whitfield: Attorneys General Confirm Overreach by Obama's EPA on Coal-Fired Power Plant Regulations," Energy & Commerce Committee, United States House of Representatives, September 13, 2013. *See* http://energycommerce house.gov/press-release/whitfield-attorneys-general-confirm-overreach-obamas-epa-coal-fired-power-plant-regulations.

[30] Twelve scenarios result from the product of 2 x 2 x 3 = 12 scenarios.

price x 0.5 CO_2 price) and all six of the scenarios that involve the Low load forecast have a weight of 0.033 (0.2 load x 0.333 natural gas price x 0.5 CO_2 price).

Q. Are the Companies suggesting that there is a 50 percent probability that there will be a price on CO_2 beginning in 2020?

A. Not really, but that is the weighting used in the Resource Assessment. The form CO_2 regulations could take under the Clean Air Act remains subject to much speculation and need not result in an explicit price per ton of CO_2 emitted as was assumed in the Resource Assessment. The recently released New Source Performance Standards for new generating plants use an emission rate approach that can be met by existing NGCC technology, thereby imposing no price per ton on CO_2 emissions for those units. Lacking any meaningful way to establish a weighting on the nature, timing, and cost of possible CO_2 regulations, the Companies felt it was best just to equally weight the "Zero" CO_2 price scenario and the Synapse "Mid" price scenario. I would point out that the Companies are recommending the construction of a NGCC unit and a solar facility, both of which become more economically attractive the greater the weight one places on future CO_2 emission costs.

Q. What did the results of the Resource Assessment show to be the most robust resource to reliably meet the future electricity needs of customers?

A. The Resource Assessment determined that the optimal plan for reliably meeting customers' long-term capacity and energy needs at the lowest reasonable cost would be to have an approximately 700 MW 2x1 NGCC unit in service by May 2018 at the Green River Station. Table 33 of the Resource Assessment demonstrates that building the Green River 2x1 NGCC unit to be in service by 2018 results in the lowest PVRR across all twelve scenarios and is the best choice when the major risks are evaluated individually.

Q. Are the Companies recommending any other resource addition besides the Green River 2x1 NGCC?

A. Yes. The Companies are also recommending construction of a 10 MW solar facility at the E.W. Brown Station. While the Brown Solar Facility is not a lowest reasonable cost resource absent REC prices greater than $57/REC, as can be seen in Tables 35, 36, and 37 in the Resource Assessment, the Companies are proposing to move forward with the project because (i) it is a prudent hedge against both GHG regulations and natural gas price risk; (ii) it will reduce the Companies' GHG emissions; (iii) it affords the Companies the opportunity gain operational experience with an intermittent renewable resource; and (iv) it does not materially add to revenue requirements over the next 30 years.

Q. How did the Companies' analysis of the solar facility evolve over time?

A. Given the potential for CO_2 regulations in the future and the declining cost of solar panels, the Companies believed it made sense to fully evaluate a utility scale solar project in the Resource Assessment. In the early stages of the analysis, the project was very unattractive due to the estimated cost of solar panels and the cost of land required for a 10 MW project (approximately 100 acres). However, from late 2012 (when conceptual self-build cost estimates were first developed) to late 2013, the estimated price of solar panels decreased from about $3.80 per watt to around $2.00 per watt and the Companies were able to identify an existing property with enough space to eliminate the land cost from the project. In September 2013, the Companies estimated that the solar project could be built for approximately $2,400/kW, which was consistent with information publicly available for other solar projects. At that cost, a 10 MW solar project would have reduced the weighted average PVRR of providing service to customers as shown in Table 34 of the Resource Assessment.

Based on these lower cost estimates, the Companies commissioned a conceptual siting study review at the E.W. Brown site in December 2013, resulting in a project cost range of $3,500/kW to $4,100/kW and an expected cost of approximately $3,600/kW. At these higher capital costs, the Brown Solar Facility will slightly increase incremental PVRR, absent REC prices in excess of $57, as shown in Tables 35, 36, and 37 in the Resource Assessment.

Q. Are there any other benefits of constructing the Green River 2x1 NGCC unit and the Brown Solar Facility that were not reflected in the Resource Assessment analysis?

A. Yes. After the Green River 2x1 NGCC unit is in service, the Companies' energy generated from natural gas will increase to between 20 and 30 percent, compared to approximately 10 to 20 percent prior to 2018. By increasing the natural gas capacity in the fleet and adding a solar facility, the Companies will increase their fuel diversity and reduce future GHG emissions.

Q. Given the uncertainty associated with CO_2 regulations in particular, did the Companies seek to defer the selection of a long-term resource?

A. Yes. The Companies received several short-term PPA responses in the RFP and evaluated them with an eye toward deferring a long-term resource. Section 4.5.2 of the Resource Assessment discusses the deferral analysis in detail. Table 27 in the Resource Assessment shows that a [redacted] had the potential to reduce

PVRR by $[redacted] million compared to constructing the Green River 2x1 NGCC unit by 2018 based on the weighted average of all twelve scenarios.

Q. If a [redacted] could potentially delay the need for a long-term resource by two years, why are the Companies recommending the construction of the Green River 2x1 NGCC unit to be in service by 2018?

A. When a PPA with [redacted] was identified as a potential resource, the Companies naturally conducted further due diligence on the financial strength of [redacted] and the reliability of the generating assets that would be supporting the PPA. This due diligence revealed that:

- [redacted] are in poor financial health and, given their [redacted] credit rating by Standard & Poor's, the estimated likelihood of default over the next six years is high. [redacted] financial condition is not expected to materially improve now that [redacted], and
- It is unclear whether the [redacted] that are the source of the capacity and energy for the proposed PPA will be capable of reliable operations [redacted].[31]

Appendix C in the Resource Assessment contains a detailed analysis of the financial and environmental risks associated with a potential PPA with [redacted].

[31] [redacted]

Given the relatively small potential savings of the [redacted] PPA compared to the potential reliability risks to the Companies' customers should [redacted] not be able to perform over the life of the PPA, it was decided not to proceed with further discussions with [redacted] Furthermore, it is one thing to enter into a PPA with a party that one believes to be financially sound, and whose assets are likely to perform over the term of the PPA at the time the deal is done, and then have circumstances change. However, as someone who has negotiated numerous PPAs over the years, it is my professional opinion that it could be unwise to knowingly enter into a transaction with a financially weak counterparty whose asset performance is questionable over the term of the contract.

Q. Other than a PPA with [redacted], were there any other resource alternatives across a range of scenarios that could defer the construction of the Green River 2x1 NGCC unit to be in service by 2018?

A. No. As shown in Table 33 of the Resource Assessment, constructing the Green River 2x1 NGCC unit so that it is in service by 2018 results in the lowest PVRR based on the weighting of all scenarios. However, as can be seen in Table 32 of the Resource Assessment, in the Mid and High natural gas price scenarios combined with the Mid CO_2 prices (a total of four scenarios), some deferral options have a somewhat lower PVRR than constructing the Green River 2x1 NGCC unit to be in service by 2018. If the future does not play out exactly as forecasted in these scenarios, attempting to delay the construction of the Green River 2x1 NGCC unit for only two years would result in higher revenue requirements. Constructing the Green River 2x1 NGCC unit to be in service by 2018 is clearly the most robust option for reliably and economically meeting the long-term energy needs of our customers when consideration is given to the totality of these future uncertainties.

Q. Why was [redacted] not the lowest-cost option in the most recent Resource Assessment when [redacted]?

A. There are two main reasons why [redacted] was not selected as a lowest-cost resource in the Resource Assessment – increasing risk of CO_2 regulations and the potential for lower future natural gas prices. In the prior Cane Run Unit 7 CPCN case, the Companies did not evaluate any scenarios that put a price on future CO_2 emissions, whereas the current Resource Assessment does. In a world with CO_2 costs, the lower CO_2 emissions from a NGCC unit compared to a SCCT unit more than offset the difference in capital costs. In Table 23 of the Resource Assessment, a comparison of the "[redacted]" with "[redacted]) shows that [redacted] is lower cost in four of the six Zero carbon scenarios (ranging from PVRR $[redacted] million to $[redacted] million with a weighted average of [redacted] million) but is significantly more expensive in all six Mid carbon price scenarios (ranging from PVRR $[redacted] million to [redacted] million with a weighted average of $[redacted] million). Furthermore, even in two of the Zero carbon scenarios, the PVRR of "[redacted] is favorable compared to "[redacted]" in both Low natural gas price cases by [redacted] million to $[redacted] million. With the growing risk of CO_2 regulations and the growth in U.S. natural gas reserves since the last CPCN case, constructing the Green River 2x1 NGCC unit has a greater potential to provide low-cost energy to our customers than does [redacted]

[redacted]) to the Companies' generation fleet. That is why the weighted average PVRR of "[redacted], [redacted]" is $[redacted] million favorable to "[redacted]" as shown in Table 19 of the Resource Assessment.

I would add that even if [redacted] had been determined to be a potentially lowest-cost resource, there is no indication that [redacted]. The Companies' [redacted] has already created reliability risks [redacted] that remain unresolved. The Companies should not further extend that risk into [redacted] by hoping [redacted]

Q. Based on Table 5, it appears that the Companies only need between 211 MW and 355 MW in 2018, yet they are proposing to construct the Green River 2x1 NGCC unit, at approximately 700 MW. Would it be better to build a smaller unit?

A. No. It is important to remember that the Green River 2x1 NGCC unit is likely to be used to serve load throughout the year, not just on hot summer peak days. One cannot just utilize reserve margin to understand the value of a resource's capacity to the system. To determine the value of both capacity and energy beginning in 2018, the Resource Assessment evaluated a 670 MW 2x1 NGCC unit and a smaller 332 MW 1x1 NGCC unit. As can be seen in Table 23 in the Resource Assessment, the larger "[redacted]" option is lower cost than the smaller "[redacted]" option in eleven of the twelve scenarios. Only in the Low load, High natural gas price and Zero CO_2 price scenario is a 1x1 NGCC unit lower cost (PVRR $[redacted] million) than a 2x1 NGCC unit. As shown in Table 19 of the Resource Assessment, constructing a 2x1 NGCC unit instead of a 1x1 NGCC unit reduces the weighted average PVRR across all scenarios by over $[redacted] million. This demonstrates that building a smaller unit to be in service by 2018 will only increase costs to customers over the long-term.

Q. Why did the Resource Assessment evaluate a 670 MW 2x1 NGCC unit as opposed to some other output rating?

A. In our analysis, we identified numerous NGCC turbines from various manufacturers in various configurations. Those various options ranged in capacity from approximately 600-780 MW. For economic modeling purposes to assess least reasonable cost, we modeled the 670 MW 2x1 turbine because it is near the midpoint of the capacity range.

<u>Section 4 – Potential for new DSM Programs</u>

Q. You previously testified that no new DSM programs are included in the 2013 LF after 2018. Have the Companies evaluated the potential for additional energy and demand savings that are achievable above and beyond the Companies' current activity?

A. Yes. The Companies recently filed an energy efficiency potential study[32] with the Commission and are filing concurrently with this CPCN application a Demand Side Management and Energy Efficiency Program Plan for new programs for the 2015-2018 time period. The study showed that a small amount of additional energy and demand savings can be achieved beyond the Companies' planned activity currently scheduled through 2018. The Companies' planned savings through 2018 average 200,000 MWh for the residential and commercial sectors. If the Companies continue to achieve annual savings at the planned rate, achievable discretionary electric energy efficiency potential will be exhausted in 2020.

Q: If the results of the energy efficiency potential study or the DSM filing were incorporated into the Resource Assessment, would they have altered the results?

A. No. All projected savings through 2018 were included in the supply-side planning analysis. The additional two years of potential achievable energy efficiency identified in the potential study at the current average rate of 200,000 MWh per year equates to additional savings potential of approximately 0.5% per year. Reducing the Base load forecast by this amount would result in load being greater than the Low load case. As can be seen in Table 33 of the Resource Assessment, constructing the Green River 2x1 NGCC unit by 2018 is the least cost option in the Low load cases.

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[32] In the Matter of: *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky*, Case No. 2011-00375, Order at 5 (May 3, 2012). *See* http://psc.ky.gov/PSCSCF/2011%20cases/2011-00375/20120503_PSC_ORDER.pdf.

Section 5 – Short-term Capacity Procurement

Q. You stated that the Companies are forecasted to have a reserve margin deficit in 2016 and 2017. What are the Companies doing to address capacity needs in those years?

A. First, if approved, the Brown Solar Facility will make a small contribution toward reducing the 2016 reserve margin deficit. Second, the Companies are pursuing negotiations for a short-term PPA to address capacity and energy needs in 2016 and 2017.

Section 6 – Ownership Share for the Green River 2x1 NGCC unit and the Brown Solar Facility

Q. What is the recommended ownership allocation between LG&E and KU for the Green River 2x1 NGCC unit and the Brown Solar Facility?

A. It is recommended that LG&E own 40 percent of the Green River 2x1 NGCC unit and 36 percent of the Brown Solar Facility and that KU own 60 percent of the Green River 2x1 NGCC unit and 64 percent of the Brown Solar Facility.

Q. How was this ownership allocation determined?

A. The ownership allocation for the Green River 2x1 NGCC unit was determined using the same methodology that was used to determine the ownership allocations for Trimble County Unit 2 ("TC2") and Cane Run Unit 7 ("CR7"). As is the case for TC2 and CR7, the Green River 2x1 NGCC unit is expected to provide a significant amount of energy savings to customers over its life; therefore, the ownership share was determined based on the forecasted energy savings to LG&E and KU, respectively. This method is discussed in more detail in Section 5.1 of the Resource Assessment.

For the Brown Solar Facility, the ownership share was determined based on LG&E's and KU's shares of forecasted load during daylight hours because that is when the Brown Solar Facility will be generating electricity.

<u>Section 7 – Summary and Recommendation</u>

Q. Please summarize why the Companies are proposing to construct the Green River 2x1 NGCC unit and the Brown Solar Facility.

A. The Companies are seeking to construct the Green River 2x1 NGCC unit and the Brown Solar Facility because they have a long-term need for additional reliable capacity and low-cost energy beginning as early as 2015. To identify the most robust resources to meet that need, the Companies sought proposals from the market and developed a number of self-build generation alternatives. The Companies then performed an extensive 11-month analysis of the various supply-side and demand-side alternatives to meet our customers' energy needs over the next 30 years, which is documented in the Resource Assessment. The end result of this process is that having the Green River 2x1 NGCC unit in service by May 2018 and the Brown Solar Facility in service by the end of 2016 proved to be the most robust options under a wide range of future customer load, natural gas prices, and CO_2 prices to reliably and economically meet our customers' future energy needs.

Q. What is your recommendation to the Commission?

A. Based on my testimony and the analyses performed under my direction and discussed in the Resource Assessment, it is my recommendation that the Commission should approve the Green River construction project and the E.W. Brown construction project to ensure adequate generating capacity and low-cost energy.

Q. Does this conclude your testimony?

A. Yes it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of January 2014.

Sheri L. Gardner (SEAL)
Notary Public

My Commission Expires:

SHERI L. GARDNER
Notary Public, State at Large, KY
My Commission expires Dec. 24, 2017
Notary ID # 501600

APPENDIX A

David S. Sinclair

Vice President, Energy Supply and Analysis
LG&E and KU Energy, LLC
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4653

Education

Arizona State University, M.B.A -1991
Arizona State University, M.S. in Economics – 1984
University of Missouri, Kansas City, B.A. in Economics - 1982

Professional Experience

LG&E and KU Energy, LLC
2008-present – Vice President, Energy Supply and Analysis
2000-2008 – Director, Energy Planning, Analysis and Forecasting

LG&E Energy Marketing, Louisville, Kentucky
1997-1999 – Director, Product Management
1997-1997 (4th Quarter) – Product Development Manager
1996-1996 – Risk Manager

LG&E Power Development, Fairfax Virginia
1994-1995 – Business Developer

Salt River Project, Tempe, Arizona
1992-1994 – Analyst, Corporate Planning Department

Arizona Public Service, Phoenix, Arizona
1989-1992 – Analyst, Financial Planning Department
1986-1989 – Analyst, Forecasts Department

State of Arizona, Phoenix, Arizona
1983-1986 – Economist, Arizona Department of Economic Security

Affiliations

Consensus Forecasting Group (2013-present) - nonpartisan group of economists that monitor Kentucky's revenues and the economy on behalf of the governor and legislature.

2013 Resource Assessment

PPL companies

Generation Planning & Analysis
December 2013

Table of Contents

List of Terms

2011 IRP	2011 Integrated Resource Plan
2013 LF	2013 Load Forecast
[redacted]	[redacted]
AEO	Annual Energy Outlook
[redacted]	[redacted]
CAGR	Compound annual growth rate
CCS	Carbon capture and sequestration
CNC	Commercial New Construction
The Companies	Louisville Gas and Electric Company and Kentucky Utilities Company
CR7	Cane Run 7
DSM	Demand-side management
EEI	Electric Energy Inc.
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FGD	Flue-gas desulfurization
[redacted]	[redacted]
GHG	Greenhouse gas
ILB-HS	Illinois Basin high-sulfur
IPCB	Illinois Pollution Control Board
KU	Kentucky Utilities Company
KY PSC	Kentucky Public Service Commission
LD	Limited Dispatch
LG&E	Louisville Gas and Electric Company
LGR	Long-term generic resource
NGCC	Natural gas combined-cycle
NPV	Net present value
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
PPA	Power purchase agreement
PV	Photovoltaic
PVRR	Present value revenue requirements
RECs	Renewable Energy Certificates
RFP	Request for Proposals
RGSP	Real Gross State Product
RM	Reserve margin
SCCT	Simple-cycle combustion turbine
SCR	Selective catalytic reduction
TC2	Trimble County 2

1 Executive Summary

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") are required to reliably meet the long-term electricity needs of their customers at the lowest reasonable cost. To accomplish this objective, the Companies utilize a range of generation technologies (coal, gas, and hydro) as well as various demand-side resources such as interruptible loads and demand-side management ("DSM") programs. Annually, the Companies evaluate the ability of their existing portfolio of demand-side and supply-side resources to reliably meet their long-term forecast of peak demand and energy requirements. When deficiencies are identified, the Companies will seek to acquire new resources from the market, construct new assets, and/or develop additional demand-side resources.

- **The Companies' generation fleet is in transition in order to comply with the U.S. Environmental Protection Agency's ("EPA's") emissions regulations.** In 2011, the Companies announced plans to retire 797 MW of coal-fired capacity by 2016. To offset this loss of energy and capacity, the Companies proposed to construct a 640 MW natural gas combined-cycle ("NGCC") unit, the construction of which is underway and on schedule. The Companies also planned to purchase the existing 495 MW LS Power Bluegrass facility, but terminated their agreement to do so after an unfavorable FERC ruling.

- **Additional capacity and energy is needed.** Without the Bluegrass facility, a resource adequacy analysis that was completed in the summer of 2012 indicated that the Companies would need additional resources beginning as early as 2015 to reliably serve customers' capacity and energy needs.

- **The Companies considered a variety of capacity and energy options**. To meet customers' long-term needs for capacity and energy, the Companies issued a request for proposals ("RFP") in September 2012 to 165 potential providers. Seventy-two responses were received, including power purchase agreements ("PPAs"), asset sale offers, and new asset development offers sourced from a variety of generation technologies (e.g., coal, natural gas, wind, biomass, and solar). In addition to the RFP responses, the Companies considered seven new demand-side management programs and developed five self-build alternatives, including new NGCC and solar photovoltaic ("PV") projects and uprates to existing simple-cycle combustion turbines.

- **The analysis of options considered multiple uncertainties**. The Companies' long-term resource decisions must be robust under a number of possible futures to ensure that customers' energy needs are reliably met at the lowest reasonable cost. Therefore, the Companies evaluated the RFP and self-build alternatives over a number of load, natural gas price, and CO_2 price scenarios. Given the long-term nature of the Companies' capacity and energy needs, the analysis of RFP responses and self-build alternatives focused on (i) finding the lowest reasonable cost long-term resource(s) and (ii) whether a short-term PPA could cost-effectively and reliably defer the need for the long-term resource(s).

The analysis concluded that building a 2x1 NGCC unit at the Green River station ("Green River 2x1") is the most robust alternative for reliably meeting customers' long-term capacity and energy needs. The long-term alternatives were evaluated over twelve scenarios:

- Over all scenarios, the Green River 2x1 alternative has the lowest weighted average revenue requirements.
- The Green River 2x1 alternative is least-cost in eight of the twelve scenarios.
- The downside risk associated with the Green River 2x1 alternative is small compared to other alternatives and only occurs if there are never restrictions on greenhouse gas ("GHG") emissions on existing coal units.

The Companies also determined that there was no short-term PPA that would defer the need for the Green River 2x1 unit. The Companies evaluated numerous short-term PPAs in an effort to cost-effectively and reliably defer the addition of the NGCC unit beyond 2018. No PPA can cost-effectively and reliably defer the Green River 2x1 unit beyond 2018.

Given the increasing likelihood of CO_2 constraints and the ability to sell Renewable Energy Certificates ("RECs"), the Companies also recommend building a 10 MW solar facility at the existing E.W. Brown station. The solar facility is a prudent hedge against both GHG regulations and natural gas price risk, it will reduce GHG emissions, it affords the Companies the opportunity to gain operational experience with a solar PV resource, and it does not materially add to revenue requirements over the next 30 years.

The ownership splits of the NGCC and solar facilities between LG&E and KU are very similar. As a baseload unit, the NGCC unit's ownership was calculated so that each company's ownership share matches its share of expected energy benefits. Ownership of the solar facility was based on each company's share of total energy during daylight hours:

- For the Green River NGCC unit, the optimal ownership split is 60% for KU and 40% for LG&E
- For the solar facility, the optimal ownership split is 64% for KU and 36% for LG&E.

In summary, based on the RFP and self-build analysis, the optimal plan for reliably meeting customers' long-term capacity and energy needs includes the following:

- Construct a 670 MW 2x1 NGCC unit in 2018 at the Green River station
- Construct a 10 MW solar project in 2016 at the E.W. Brown station.

Moving forward with the NGCC unit and a 10 MW solar PV facility will enable the Companies to economically and reliably serve customers' energy needs in an environment marked by uncertainty in load, natural gas prices, and GHG regulations.

2 Capacity and Energy Need

In 2011, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") announced plans to retire 797 MW of coal-fired capacity to comply with the U.S. Environmental Protection Agency's ("EPA's") National Ambient Air Quality Standards and Mercury and Air Toxics Standards. In February 2013, the Companies retired Tyrone 3 (71 MW); the five Cane Run and Green River coal units (726 MW) will be retired in 2015. To offset this loss of energy and capacity, the Companies proposed to construct a 640 MW natural gas combined-cycle ("NGCC") unit at their Cane Run site ("Cane Run 7") to be online in 2015 and purchase the existing LS Power Bluegrass facility in LaGrange, Kentucky (495 MW of simple-cycle combustion turbines ("SCCTs")).[1]

The construction of Cane Run 7 is underway and on schedule. However, the Companies were unable to purchase the Bluegrass facility after receiving an unfavorable Federal Energy Regulatory Commission ("FERC") ruling in May 2012.[2] To acquire the Bluegrass facility, the Companies needed authorization from FERC to complete the transaction under section 203 of the Federal Power Act. Therefore, in November 2011, the Companies and Bluegrass Generation Company, a subsidiary of LS Power, filed an application with FERC requesting authorization to complete the transaction. In its review of the application, FERC found that the proposed transaction resulted in significant screen failures in the horizontal market power analysis. As a result, FERC conditionally authorized the transaction, subject to the Companies proposing adequate mitigation to remedy the identified screen failures.

After reviewing the regulatory, operational, and economic impacts of the mitigation measures, the Companies determined that the mitigation measures were not acceptable because they would have resulted in higher costs to the Companies' customers. Therefore, in June 2012, the Companies terminated their agreement to purchase the Bluegrass facility.[3]

After the Companies prepared their 2013 Load Forecast ("2013 LF") in the summer of 2012, it was clear that additional resources would be required as early as 2015 to reliably serve customers' capacity and energy needs. Table 1 details the Companies' capacity supply/demand balance for the 2013 LF.[4] As demonstrated in the Companies' 2011 Integrated Resource Plan ("2011 IRP"), a 15 to 17 percent reserve margin (above peak load after adjusting for DSM) is required to ensure system reliability from a generation supply perspective.[5] With the planned changes to the Companies' generation portfolio and with 386 MW of demand reduction from DSM programs and 137 MW of curtailable load from curtailable service rider customers, the Companies will have a long-term need for capacity beginning

[1] See Case No. 2011-00375, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky* (Kentucky Public Service Commission ("KY PSC") May 3, 2012).

[2] Order Conditionally Authorizing Disposition and Acquisition of Jurisdictional Facilities and Acquisition of Generating Facilities, Docket No. EC12-29-000, May 4, 2012, 139 FERC ¶ 61,094. For the Order, see http://www.ferc.gov/EventCalendar/Files/20120504160345-EC12-29-000.pdf.

[3] On June 18, 2012, the Companies sent a letter to KY PSC informing them of the decision not to proceed with the Bluegrass acquisition.

[4] For purposes of calculating reserve margin, loads subject to the Companies' curtailable service rider are considered supply-side resources.

[5] See Case No. 2011-00140, *The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company* (KY PSC March 13, 2013).

perhaps as early as 2015, but definitely by 2016. The reserve margin deficit is forecasted to grow to over 1,500 MW in the next 20 years.

Table 1 – LG&E/KU Resource Summary (MW, Summer, 2013 LF)

	2015	2016	2017	2018	2019	2020	2025	2030	2035
Forecasted Peak Load	7,426	7,509	7,597	7,696	7,746	7,815	8,147	8,517	8,891
DSM	(386)	(418)	(450)	(482)	(464)	(466)	(475)	(484)	(493)
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,673	8,034	8,398
Existing Resources[6]	7,814	7,796	7,796	7,796	7,796	7,796	7,796	7,796	7,796
Firm Purchases (OVEC)	152	152	152	152	152	152	152	152	152
Curtailable Load	137	137	137	137	137	137	137	137	137
Total Supply	8,103	8,085	8,085	8,085	8,085	8,085	8,085	8,085	8,085
Reserve Margin ("RM")	15.1%	14.0%	13.1%	12.1%	11.0%	10.0%	5.4%	0.6%	-3.7%
RM Shortfall (17% RM) *	(134)	(212)	(277)	(355)	(434)	(514)	(892)	(1,314)	(1,741)
RM Shortfall (15% RM) *	7	(71)	(134)	(211)	(289)	(367)	(738)	(1,154)	(1,573)

*Negative values reflect reserve margin shortfalls.

While meeting customers' peak demand is critical, it is also vital to reliably serve their energy needs all year round at the lowest reasonable cost. As seen in Table 2, energy requirements are forecasted to grow by 8 TWh over the next 23 years even after reductions for DSM.[7] This translates into a compound annual growth rate ("CAGR") of 0.9 percent.

Table 2 – Energy Requirements (TWh, 2013 LF, After DSM)

	2012*	2015	2016	2017	2018	2019	2020	2025	2030	2035
Energy Requirements	34.9	36.2	36.3	36.5	36.8	37.1	37.4	39.1	41.0	42.9

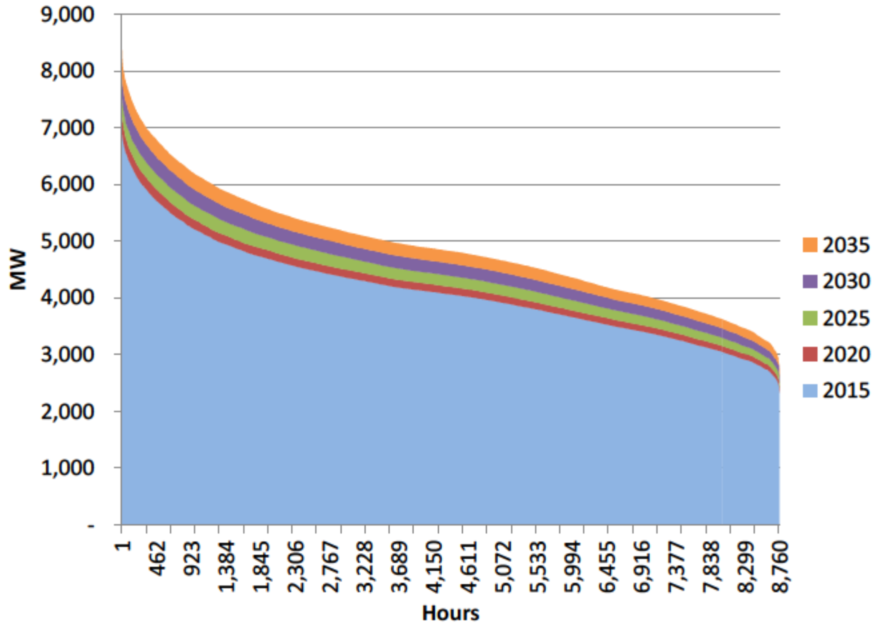
*Weather-normalized actual energy requirements.

The Companies' load duration curves for 2015, 2020, 2025, 2030, and 2035 are plotted in Figure 1. The load duration curve for a given year plots the Companies' hourly loads in descending order. The left-most point on each curve is the annual peak demand; the right-most portion of each curve reflects load levels in off-peak periods. The area under each curve represents customers' energy requirements for that year. As seen in Figure 1, energy requirements are expected to increase throughout all portions of the load duration curve, not just in the peak hours.

[6] 'Existing Resources' include Cane Run 7.

[7] Energy requirements represent the amount of generated energy needed to serve customers' energy needs, inclusive of transmission and distribution losses.

Figure 1 – Load Duration Curve (2013 LF)



3 RFP Responses, Self-Build Alternatives, and DSM Programs

To meet customers' long-term needs for capacity and energy, the Companies issued an RFP in September 2012 to 165 marketers, project developers, generation asset owners, and utilities.[8] The Companies requested proposals from parties with resources that would qualify as a Designated Network Resource for transmission purposes. The RFP did not limit responses to a particular set of fuels or generating technologies. The specified capacity range for the responses was broad: the RFP encouraged offers for firm summer and winter capacity ranging between 1 MW and 700 MW with the caveat that the Companies may procure more or less than 700 MW and may aggregate capacity and energy from multiple parties to meet their needs. The RFP cited the Companies' interest in both short- and long-term proposals.

Twenty-nine companies responded to the RFP with 72 proposals. The majority of RFP responses included power purchase agreements ("PPAs") and new asset development offers for gas-fired technologies. Coal, wind, biomass, and solar technologies were also included.

In addition to the RFP responses, the Companies developed five self-build alternatives and seven DSM programs. The self-build alternatives include new NGCC and solar photovoltaic ("PV") projects and projects to uprate existing simple-cycle combustion turbines. Because the EPA's original draft New Source Performance Standards ("NSPS") for GHG issued in March 2012 required new coal units to eventually be equipped with unproven and uneconomic carbon capture and sequestration ("CCS") technology, no self-build coal option was developed.[9]

The Green River station was considered the primary site in this analysis for the Companies' self-build NGCC alternatives due to the planned retirement of the Green River coal units as well as the reliability benefits associated with having generation in the western part of the state. The Green River station also affords good access to existing natural gas pipelines. If a new NGCC unit is constructed at the Green River station in 2018, the Companies would be able to offset the new unit's SO_2, NO_x, and particulate emissions with the retirement of the two remaining Green River coal units. Absent this offset, the Companies would likely be required to install additional emission control equipment on the new unit and the new unit would likely be subject to more stringent emission limits.

As more time elapses following the retirement of the Green River coal units, the ability to obtain an air permit for a new NGCC unit without operating constraints (e.g., annual start limitations) becomes more uncertain. Therefore, the analysis assumed that the Green River unit would be subject to operating constraints if it is commissioned after 2018.[10] In higher gas price scenarios, these operating constraints would likely increase fuel costs by limiting the Companies' ability to more frequently cycle the unit during lower load periods.

When the RFP analysis began, the Companies' conceptual self-build cost estimate for a greenfield 10 MW solar PV facility was approximately $4,600/kW. Among other things, this cost includes the cost of land for the project (approximately 100 acres) and the cost of solar panels. Over the last year, the cost of solar panels has decreased substantially. Furthermore, because the Companies already own land at the E.W. Brown station that is suitable for a solar project, the Companies can eliminate the cost of land

[8] A copy of the RFP is available on the Companies' website (http://www.lge-ku.com/rfp/default.asp).
[9] In September 2013, the EPA announced revised draft NSPS for coal that continue to require CCS.
[10] In this analysis, NGCC units commissioned after 2018 are limited to 120 starts per year.

by building at the E.W. Brown station. With these savings, the updated cost of the 10 MW solar PV project is much lower than the original greenfield solar cost estimates. The evolution of the cost estimate for the self-build 10 MW solar facility is discussed in detail in section 4.6.

The DSM programs that were considered in this analysis are summarized in Table 3. The Companies will be filing a DSM application in January 2014 that considered numerous DSM programs. The DSM programs in Table 3 are the most competitive programs that will not be included in the DSM filing.

Table 3 – DSM Programs

Program	**Summary**
Lighting	Residential electric customers who respond to a direct mailing would receive one LED light bulb in the mail at no cost.
Thermostat Rebates	Residential electric customers who purchase a programmable thermostat and have it installed at their residence would be eligible for a rebate of up to $125 for purchasing the thermostat and up to $75 for the cost of installation.
Windows & Doors	Residential electric customers who purchase and install Energy Star qualified exterior doors and windows would be eligible for a $100 rebate for each door and a $20 rebate for each window.
Manufactured Homes	Residential electric customers who purchase a new Energy Star manufactured home would be eligible for a $250 rebate.
Behavioral Thermostat Pilot	In this two-year pilot, a small number of residential electric customers would receive a thermostat with two-way communication capability. The thermostat would provide information on ways to reduce their energy usage.
Commercial New Construction	Commercial electric customers would be eligible for a rebate after new building construction. Rebates would be based on energy savings above code with bonuses for achieving LEED certification.
Automated Demand Response	Commercial electric customers would receive two-way communication devices that turn off equipment during peak times throughout the year. Customers would have capability to monitor real-time energy usage through software provided and receive incentives for participation.

Table 4 summarizes the number of RFP proposals and self-build alternatives. Several responses to the RFP included multiple proposals that refer to the same asset or asset portfolio. Table 5 shows the capacity proposed by the RFP respondents. A detailed summary of all proposals is included in *Appendix A – Detailed Summary of RFP Proposals, Self-Build Alternatives, and DSM Programs*.

Table 4 – Number of RFP Proposals and Self-Build Alternatives

Response Type	**Number of Proposals/ Alternatives**
RFP	**72**
Self-Build	**5**
NGCC	2
Solar	1
SCCT Uprate Projects	2
DSM Programs	**7**
Total	**84**

Table 5 – Capacity Proposed by RFP Respondents

Category	**Capacity (MW)**
Total	12,381
Coal	3,177
Gas	7,754
Renewable (Wind, Biomass, Solar)	550
Portfolio	900
Proposed	4,772
Existing	7,609
In-State	4,286
Out-of-State	8,095

4 RFP Analysis

4.1 Key Inputs and Uncertainties

The Companies' long-term resource decisions must be robust under a number of possible futures to ensure that customers' energy needs are reliably met at the lowest reasonable cost. While there are a number of uncertainties that could have some impact on the Companies' resource decisions, the uncertainties in native load (demand and energy), natural gas prices, and greenhouse gas ("GHG") regulations are the most important to consider when evaluating long-term generating resources. Therefore, the Companies evaluated the RFP and self-build alternatives over a number of load, natural gas price, and CO_2 price scenarios.

4.1.1 Load Forecast

The only reason for the Companies to acquire new supply-side or demand-side resources is to reliably meet customers' future energy needs at the lowest reasonable cost. Therefore, the forecast of future demand and energy is at the heart of any resource assessment. The volume of future load (demand and energy) is driven by future economic activity, the adoption rate of new and existing DSM programs, and the development of new electric end-uses (e.g., electric vehicles). The Companies' 2013 LF utilized the best information available to develop a reasonable long-term load forecast. As with any long-term forecast, the uncertainty associated with it tends to grow through time. Therefore, "High" and "Low" load forecasts were also developed.

Table 6 lists the three load forecast scenarios evaluated in this analysis. In Kentucky, energy consumption is correlated to the state's real gross state product ("RGSP"). According to IHS Global Insight, the Kentucky RGSP is expected to grow by an average of 2.0% per year between the years 2012 and 2042. According to the Energy Information Administration's ("EIA's") Annual Energy Outlook ("AEO") issued in 2013, annual electricity consumption on a national level is expected to grow at an average rate, from 2010 to 2040, of 0.7%, 0.8% and 0.6% for the Residential, Commercial and Industrial sectors, respectively.

Table 6 – Native Load Scenarios

Year	Energy Requirements (GWh)			Peak Demand (MW)		
	2013 LF	Low	High	2013 LF	Low	High
2013	35,748	34,341	37,155	6,952	6,674	7,230
2014	35,952	34,475	37,429	6,995	6,703	7,286
2015	36,162	34,606	37,719	7,040	6,734	7,347
2016	36,335	34,690	37,980	7,091	6,767	7,415
2017	36,503	34,766	38,240	7,147	6,805	7,490
2018	36,788	34,960	38,615	7,214	6,854	7,574
2019	37,101	35,173	39,030	7,282	6,902	7,661
2020	37,421	35,379	39,462	7,350	6,948	7,752
2021	37,669	35,504	39,835	7,418	6,991	7,845
2022	37,982	35,693	40,272	7,474	7,023	7,925
2023	38,323	35,899	40,746	7,540	7,063	8,017
2024	38,752	36,187	41,317	7,606	7,103	8,109
2025	39,083	36,355	41,811	7,673	7,137	8,208
2026	39,444	36,551	42,338	7,739	7,172	8,307
2027	39,806	36,743	42,869	7,806	7,206	8,406
2028	40,211	36,971	43,451	7,881	7,247	8,516
2029	40,582	37,159	44,005	7,957	7,287	8,627
2030	41,004	37,393	44,615	8,034	7,327	8,740
2031	41,364	37,559	45,169	8,111	7,366	8,857
2032	41,746	37,748	45,745	8,188	7,405	8,972
2033	42,140	37,943	46,337	8,257	7,436	9,078
2034	42,494	38,096	46,892	8,328	7,467	9,189
2035	42,894	38,300	47,488	8,398	7,500	9,296
2036	43,333	38,536	48,130	8,469	7,533	9,406
2037	43,740	38,737	48,744	8,541	7,565	9,517
2038	44,125	38,916	49,333	8,613	7,597	9,628
2039	44,518	39,101	49,936	8,685	7,630	9,741
2040	44,920	39,295	50,545	8,760	7,664	9,855
2041	45,338	39,503	51,173	8,834	7,699	9,970
2042	45,627	39,579	51,674	8,910	7,731	10,090

Energy and peak demand grow at similar rates in each of the three load scenarios. The Low load scenario was developed to assess each alternative in an environment where a significant portion of the Companies' load is lost. Compared to the 2013 LF scenario, peak demand in the Low load scenario is approximately 300 MWs lower in 2015; the first need for capacity and energy in the Low load scenario doesn't occur until 2023. The High load scenario was developed to assess each alternative in an environment where a significant amount of load is gained. Compared to the 2013 LF scenario, peak demand in the High load scenario is approximately 300 MWs higher in 2015.

In the High load scenario, the need for additional long-term resources is accelerated; therefore, resource plans that do not meet the Companies' reserve margin need in the High load scenario are not favored in the High load scenario. If the Companies plan to meet the 2013 LF, and actual load turns out to be higher than expected, the need to quickly add additional resources may exist. Alternatively, if actual load turns out to be lower than expected, the Companies will have excess capacity and energy for a period of time.

Because having excess capacity and energy is often viewed as more costly than quickly adding capacity and energy, the evaluation of the best resource expansion plan focused only on the 2013 LF and the Low load forecasts. Furthermore, the analysis assumed no ability to make off-system sales; therefore, the ability to mitigate any short-term costs associated with capacity above the target reserve margin was not considered.

For purposes of this Resource Assessment, the likelihood of the actual load turning out to be at or above the 2013 LF load forecast is assumed to be 80% while the likelihood of actual load turning out to be around the Low load forecasts is assumed to be 20%. These weightings are based on the statistical distributions assumed in developing the High and Low load forecasts.[11]

4.1.2 Natural Gas and Coal Prices

Because of EPA's proposed New Source Performance Standards ("NSPS") for GHG, natural gas has become the fuel of choice for new fossil generation. An abundance of natural gas supply resulting from advancements in natural gas drilling technologies has put downward pressure on prices and greatly improved the economics of NGCC technology. On the other hand, the impending nationwide retirement of coal units and the shift to NGCC units will increase the demand for natural gas and put upward pressure on prices. Additional upside price risk is associated with the possibility of regulations limiting the extraction of shale gas. To address this long-term natural gas price uncertainty, the Resource Assessment analysis considered three natural gas price scenarios.

The Henry Hub natural gas price scenarios considered in the analysis are listed in Table 7 along with the forecast of coal prices. Natural gas prices through 2033 are forecasted by the EIA as shown in their 2012 AEO.[12] Beyond 2033, the prices are extrapolated based on the rate of escalation prior to 2033.[13] For purposes of this Resource Assessment, the three natural gas price scenarios were assumed to be equally likely.

The coal prices in Table 7 are the forecasted Illinois Basin high-sulfur ("ILB-HS") mine-mouth coal prices for the Companies' open coal position. This forecast was used to develop the delivered coal prices used in the analysis. Through 2017, these coal prices are based on (i) market bid prices and (ii) a forecast developed by Wood Mackenzie (an energy and mining research and consulting firm) in the spring of

[11] The High and Low load scenarios were developed to be the 5th and 95th percentile in a normal distribution about the 2013 LF scenario. With this assumption, the likelihood of the 2013 LF scenario is 64% and the likelihoods of the High and Low load scenarios are each 18%. Because the High load scenario was ultimately ignored, the modeled likelihood for the 2013 LF scenario includes the likelihood of the High load scenario. The modeled likelihood for the 2013 LF scenario (80%) was computed by rounding the sum of the likelihoods for the 2013 LF and High load scenarios (82%) to the nearest 10 percent.

[12] The "Mid", "High", and "Low" case natural gas price forecasts are based on EIA's AEO 2012 "Reference," "Low Estimated Ultimate Recovery (EUR)," and "High Technically Recoverable Resource (TRR)" cases, respectively. For the EIA's AEO 2013 data tables, see http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=8-AEO2012&table=13-AEO2012&region=0-0&cases=ref2012-d020112c.

[13] The Mid and High gas price cases are escalated at the 2032-2033 growth rates in EIA's Reference and Low EUR forecasts, respectively. The Low gas price gas is escalated at the 2023-2033 CAGR.

2012.[14] In 2018-2033, these prices were escalated at the annual growth rates in the average coal price forecast from EIA's AEO 2012 Reference case. Beyond 2033, coal prices are extrapolated based on the price forecast's 2023-2033 CAGR.

Table 7 – Natural Gas and Coal Prices (Nominal $/mmBtu)

Year	Henry Hub Natural Gas Prices (Source: EIA)			Coal Prices (ILB-HS, Mine Mouth, Open Position)
	Low	Mid	High	
2013	3.22	4.24	4.40	1.95
2014	3.18	4.41	4.72	2.03
2015	3.32	4.62	4.94	2.23
2016	3.28	4.67	5.11	2.29
2017	3.31	4.79	5.32	2.41
2018	3.34	4.93	5.55	2.46
2019	3.41	5.16	5.86	2.51
2020	3.53	5.39	6.25	2.57
2021	3.67	5.77	6.78	2.67
2022	3.85	6.22	7.40	2.74
2023	4.07	6.58	7.95	2.82
2024	4.21	6.88	8.41	2.93
2025	4.40	7.23	8.91	3.03
2026	4.56	7.56	9.38	3.15
2027	4.79	7.93	9.91	3.25
2028	5.03	8.22	10.38	3.36
2029	5.15	8.57	10.78	3.49
2030	5.40	8.95	11.30	3.62
2031	5.61	9.35	11.03	3.76
2032	5.80	9.81	10.97	3.89
2033	6.11	10.19	11.62	3.99
2034	6.36	10.58	12.31	4.13
2035	6.63	10.99	13.04	4.27
2036	6.90	11.42	13.81	4.42
2037	7.19	11.86	14.63	4.58
2038	7.49	12.32	15.50	4.74
2039	7.80	12.80	16.41	4.91
2040	8.12	13.30	17.39	5.08
2041	8.46	13.81	18.42	5.26
2042	8.81	14.35	19.51	5.45

The level of natural gas prices determines the favorability of renewable technologies; as natural gas prices increase, the value of renewable technologies potentially increases. Furthermore, the relationship or "spread" between natural gas and coal prices is a key factor in comparing the value of

[14] The coal prices in 2013 and 2014 are based fully on the bid price curve. Prices in 2015 are 75% bid prices, 25% Wood Mackenzie. Prices in 2016 and 2017 are blended 50% bid/50% Wood Mackenzie and 25% bid/75% Wood Mackenzie, respectively.

existing or proposed natural gas alternatives to existing coal alternatives. With three natural gas price forecasts and one coal price forecast, this analysis considered three spreads between natural gas and coal prices. As a result, it was not necessary to develop more than one coal price forecast.

4.1.3 CO_2 Prices

Expectations for action on climate change are rising, including more stringent regulations for new and existing generating units.[15,16] Therefore, the Resource Assessment analysis was developed with this risk in mind. The reasonableness of this assumption was confirmed in July 2013 when the President ordered EPA to develop draft GHG regulations on existing generating units by June 2014.[17] Because the exact nature of future GHG regulations remains unknown, the Companies decided to utilize an approach that puts a price on each ton of CO_2 emitted. It was further decided that a reasonable assumption for future CO_2 prices and the timing for GHG regulation should it occur would be based on the "Mid" price forecast prepared by Synapse Energy Economics, Inc., a consulting firm that does a significant amount of work for various environmental groups such as the Sierra Club and Natural Resources Defense Council. While the risk of future GHG regulations has increased with the President's announcement, they are by no means assured. Therefore, the Resource Assessment also considered a "Zero" CO_2 scenario where there is never a price on future CO_2 emissions.

The CO_2 price scenarios considered in this analysis are listed in Table 8. CO_2 prices published by Synapse Energy Economics were used to develop the Mid CO_2 price forecast. Synapse published three forecasts (Low, Mid, High) starting in 2020 at $15, $20, and $30 per short ton in real 2012 dollars.[18] According to the Synapse report, the Synapse Mid CO_2 price forecast lies well within the range of "mid-case" forecasts used by utilities in resource planning over the past three years. The Synapse Mid forecast was converted into nominal dollars using an annual inflation rate of 1.8%.[19] The Synapse Mid forecast extended through 2040; after 2040, the real price forecast was extrapolated at the growth rate in $/short ton over the last ten years of the forecast ($2.25/ton). For purposes of this Resource Assessment, the Zero and Mid CO_2 price scenarios were assumed to be equally likely.

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[15] "Setting the Stage for a Second Term," Time, December 19, 2012, R. Stengel et al. *See* http://poy.time.com/2012/12/19/setting-the-stage-for-a-second-term/.

[16] "Speech Gives Climate Goals Center Stage," R. Stevenson and J. Broder, The New York Times, January 21, 2013. *See* http://www.nytimes.com/2013/01/22/us/politics/climate-change-prominent-in-obamas-inaugural-address.html?_r=0.

[17] "Presidential Memorandum -- Power Sector Carbon Pollution Standards," The White House, Office of the Press Secretary, June 25, 2013. See http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[18] See Synapse's "2012 Carbon Dioxide Price Forecast," October 4, 2012 at http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

[19] Synapse staff commented via email, "After 2012, we assumed 1.8% annual inflation (as measured by the GDP price deflator), to convert future nominal amounts to constant dollars."

Table 8 – CO_2 Price Scenarios (Source: Synapse Energy Economics, Inc.)

Year	CO_2 Price (Nominal $/short ton)	
	Zero	Mid
2013	-	-
2014	-	-
2015	-	-
2016	-	-
2017	-	-
2018	-	-
2019	-	-
2020	-	23
2021	-	26
2022	-	29
2023	-	33
2024	-	36
2025	-	39
2026	-	43
2027	-	47
2028	-	51
2029	-	55
2030	-	59
2031	-	63
2032	-	67
2033	-	72
2034	-	76
2035	-	81
2036	-	86
2037	-	91
2038	-	96
2039	-	102
2040	-	107
2041	-	113
2042	-	119

4.1.4 Summary of Scenarios

The load, natural gas price, and CO_2 price scenarios were combined to produce 12 scenarios for the analysis (see Table 9). Each gas and CO_2 price scenario was considered equally likely, but the likelihoods of the 2013 LF and the "Low" load forecasts were assumed to be 80% and 20%, respectively. For all scenarios, the analysis assumed the Companies had no access to energy from the market and made no off-system sales. These assumptions focus the analysis on finding the best resource for serving the Companies' native load and eliminate the need to speculate on future power prices.

Table 9 – Analysis Scenarios

Scenario	Native Load	Gas Price	CO_2 Price	Scenario Weight
1	2013 LF	Low	Zero	0.133[20]
2	2013 LF	Low	Mid	0.133
3	2013 LF	Mid	Zero	0.133
4	2013 LF	Mid	Mid	0.133
5	2013 LF	High	Zero	0.133
6	2013 LF	High	Mid	0.133
7	Low	Low	Zero	0.033
8	Low	Low	Mid	0.033
9	Low	Mid	Zero	0.033
10	Low	Mid	Mid	0.033
11	Low	High	Zero	0.033
12	Low	High	Mid	0.033

The top options from an initial screening analysis were evaluated under all 12 scenarios to identify the resource alternatives that were most robust. The resource alternatives that were considered robust were the resources that were competitive across all scenarios and had an attractive risk profile. The most robust resource (or combination of resources) is the best choice to reliably meet customers' long-term energy needs (whatever they may be) at the lowest reasonable cost (given all of the uncertainties).

4.1.5 Other Inputs

4.1.5.1 Long-Term Generic Resources

The RFP analysis was completed in four phases. The Phase 1 screening analysis grouped similar proposals and identified the proposals in each group with the lowest levelized cost. In Phases 2-4, each alternative was evaluated in the context of the Companies' generation portfolio over the 12 "load-gas price-CO_2 price" scenarios. For each alternative and scenario, the Companies developed a resource expansion plan consisting of multiple long-term generic resources ("LGRs"). An alternative's impact on the Companies' resource expansion plan must be considered in each scenario to properly evaluate the alternative. RFP or self-build alternatives with greater capacity may have higher initial costs but they will defer the need (and associated cost) of LGRs.

Table 10 lists the LGRs that were used to develop each resource expansion plan along with their capital and operating costs. For purposes of developing this Resource Assessment, a capacity rating of 670 MW was used for a 2x1 NGCC unit. However, 2x1 NGCC units can range from 600 MW to 800 MW depending upon the manufacturer and unit configuration.[21] All LGRs are assumed to be constructed at generic brownfield plant sites. Since the LGRs do not replace existing generation, they will likely be subject to more stringent emission limits. For purposes of this Resource Assessment, all NGCC LGR units were assumed to be limited to 120 starts (per gas turbine) per year.

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[20] The scenario weight for scenario 1 (0.133) is computed as the product of (i) the likelihood of the 2013 LF scenario (0.80), (ii) the likelihood of the Mid gas price scenario (0.33), and (iii) the likelihood of the Zero CO_2 price scenario (0.50).

[21] Similarly, the capacity of a 1x1 NGCC unit can range from approximately 300 MW to 400 MW.

Table 10 – Long-Term Generic Resources ($2018)

LGR	Capacity (MW)	Capital ($M)	Fixed O&M ($/MW-Yr)	Variable O&M ($/MWh)	Long-term Service Agreement	Start Fuel (mmBtu/start)
NGCC (1x1)	[redacted]					
NGCC (2x1)						
SCCT						

*In addition to this cost, a rotor replacement is assumed every 16 years at a cost of [redacted].

4.1.5.2 PPA Financing Costs

When rating agencies assess a utility's debt rating, they impute debt on the utility's balance sheet to reflect the fixed financial obligations associated with PPAs. As a result, when utilities enter into a PPA, they must increase the equity share of their capital structure to offset the imputed debt and maintain their debt rating.[22]

To calculate the amount of imputed debt, rating agencies compute the net present value ("NPV") of future fixed payments associated with the PPA (e.g., capacity payments) using a discount rate equivalent to the company's average cost of debt. Then, a risk factor is applied to reflect the benefits of regulatory or legislative cost recovery mechanisms. In the Companies' business environment, where regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs, a risk factor of 50% is applied to the NPV. This product is then multiplied by the utilities' target share of debt financing to calculate the amount of imputed debt associated with a PPA.[23] This process is consistent with the process used to address capitalization issues in the Companies' last rate case before the KPSC.

4.1.5.3 Transmission Capital Cost

A key consideration when evaluating a new resource is understanding the resource's impact on the Companies' transmission system. Transmission system upgrade costs are impacted by the size, timing, and location of resource alternatives. Transmission system upgrade costs were developed by the Companies using the same methodology that is used annually to develop the Companies' transmission expansion plan.

4.1.5.4 Financial Inputs

Table 11 lists the key financial inputs in the analysis.

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[22] A utility's debt rating is a function of its capital structure.

[23] A complete summary of the methodology Standard & Poor's uses to calculate imputed debt for U.S. utilities' PPAs is available at http://www.psc.utah.gov/utilities/electric/09docs/0903523/062309ExhibitE.pdf.

Table 11 – Key Financial Inputs

Input	Value
Analysis Period	2013-2042
Return on Equity	10.5%
Cost of Debt	3.75%
Capital Structure	
Debt	45.7%
Equity	54.3%
Tax Rate	38.9%
Revenue Requirement Discount Rate	6.75%

4.2 Analysis Overview

The analysis of RFP proposals was completed in four phases:

- The Phase 1 screening analysis grouped similar proposals and identified the proposals in each group with the lowest levelized cost. These proposals were evaluated in subsequent phases of the analysis in the context of the Companies' generation portfolio.
- The Phase 2 analysis evaluated the long-term resource proposals and self-build alternatives that passed the Phase 1 screening analysis to determine the best resource for meeting the Companies' long-term capacity and energy needs. Based on this analysis, the Companies' Green River 2x1 alternative was determined to be the best alternative for reliably meeting customers' long-term capacity and energy needs at the lowest reasonable cost.
- To further test the robustness of the Companies' Green River 2x1 alternative, the Phase 3 analysis evaluated numerous short-term PPAs in an effort to enhance the Companies' Green River 2x1 alternative and/or cost-effectively defer the addition of the Green River 2x1 NGCC unit beyond 2018. Based on this analysis, no PPA cost-effectively and reliably deferred the addition of the Green River 2x1 NGCC unit beyond 2018.
- In the Phase 3 analysis, the companies evaluated both a self-build 10 MW solar project and a proposal from [redacted] to [redacted]. Cost estimates for these projects were developed in 2012 when the RFP analysis began. Since that time, the price of solar panels has fallen significantly. The Phase 4 analysis revisited the analysis of the 10 MW solar PV project and determined that the project resulted in a small increase in revenue requirements and was most favorable in the Mid CO_2 and High natural gas price scenarios.

4.3 Phase 1 Screening Analysis

4.3.1 Methodology

For proposals with similar dispatch characteristics and contract terms, those with the lowest levelized cost will evaluate most favorably when combined with the Companies' existing generation portfolio. For this reason, in the Phase 1 screening analysis, similar proposals were first evaluated against each other. To identify the proposals in each group with the lowest levelized cost per MWh, the proposals were evaluated under three natural gas price scenarios and three operating scenarios. The proposals in the "limited dispatch" group were also evaluated over three different contract terms.[24] In total, the limited dispatch proposals were evaluated over 27 scenarios; the other proposals were evaluated over nine scenarios.

The Phase 1 screening analysis considered each proposal's capital and operating costs. Where applicable, the following costs were considered in the Phase 1 screening analysis:

1. Fuel/Energy Costs
2. Start Costs
3. Hourly Operating Cost
4. Variable O&M
5. Unit Capital Costs
6. Fixed O&M
7. Capacity Charge
8. Fixed Cost for Firm Transmission Service
9. Firm Gas Transportation Costs

The natural gas prices used in the analysis are based on the forecasts of Henry Hub prices in Table 7. Operating scenarios were defined by an assumed capacity factor and number of starts per year. The operating scenarios evaluated for each group are summarized in Table 12. Each natural gas price scenario, operating scenario, and term (for the limited dispatch group) was assumed to be equally likely in this analysis.

[24] The analysis considered contract terms of 5, 10, and 20 years. To evaluate a 5-year proposal over 20 years, for example, the costs of the 5-year proposal were extended to 20 years based on the escalation of costs over the 5-year period. Likewise, to evaluate a 20-year proposal over 5 years, the costs of the proposal beyond the 5-year period were simply ignored.

Table 12 – Phase 1 Screening Analysis Operating Scenarios

	Scenario 1		Scenario 2		Scenario 3	
Group	Capacity Factor	Number of Starts	Capacity Factor	Number of Starts	Capacity Factor	Number of Starts
NGCC (1X1), 5 Yr Term	85%	50	60%	100	40%	250
NGCC (1X1), Own	85%	50	60%	100	40%	250
NGCC (2X1), 10 Yr Term	85%	50	60%	100	40%	250
NGCC (2X1), 20 Yr Term	85%	50	60%	100	40%	250
NGCC (2X1), 5 Yr Term	85%	50	60%	100	40%	250
NGCC (2X1), Own	85%	50	60%	100	40%	250
Coal, 10 Yr Term	65%	5	50%	10	35%	20
Coal, 5 Yr Term	65%	5	50%	10	35%	20
Coal, Own	65%	5	50%	10	35%	20
DSM	100%	N/A	100%	N/A	100%	N/A
Limited Dispatch ("LD")						
Landfill Gas	75%	20	75%	20	75%	20
Firm Physical Energy	100%	N/A	100%	N/A	100%	N/A
Other LD Proposals	85%	5	85%	5	85%	5
SCCT, 20 Yr Term	1%	10	5%	50	10%	100
SCCT, 5 Yr Term	1%	10	5%	50	10%	100
SCCT, Own	1%	10	5%	50	10%	100
Solar, Own	15%	0	15%	0	15%	0
Wind	30%	0	30%	0	30%	0

4.3.2 Results

The proposals in each group with the lowest average levelized cost per MWh (across all scenarios) passed the Phase 1 screening analysis and were evaluated in subsequent phases of the analysis. These proposals are listed in Table 13. Forty-one proposals did not pass the Phase 1 screening analysis. A complete summary of results from the Phase 1 screening analysis is included in *Appendix B – Phase 1 Screening Analysis Results*.

Table 13 – Lowest Cost Responses from Phase 1 Screening Analysis

Group	Counterparty	Description
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	

4.4 Phase 2 – Long-Term Resource Alternatives

The Phase 2 analysis evaluated long-term RFP proposals and self-build alternatives to determine the best resource for meeting the long-term capacity and energy needs of the Companies' customers. When considering a new resource, it must be evaluated in the context of the Companies' generation portfolio and transmission system to understand the alternative's impact on:

- system production costs,
- resource expansion plans, and
- transmission system expansion plans.

All of these factors were considered in the Phase 2 analysis, in addition to the capital and operating costs considered in the Phase 1 screening analysis.

While the Companies' forecasted reserve margin drops below the lower limit of the target 15-17% range in 2016 (see Table 1), a new NGCC unit cannot be commissioned prior to 2018 given the time needed to develop, permit, and construct a new generating unit. Therefore, the Phase 2 analysis was completed in two iterations: the first iteration evaluated two-year PPAs (for 2016-2017) and the second iteration focused on long-term proposals for capacity and energy. In Iteration 2, proposals for new units (commissioned in 2018) were paired with the least-cost two-year PPAs from Iteration 1 to complete a full 30-year economic analysis.

Several proposals from [redacted] passed the Phase 1 screening analysis but were not considered in the Phase 2 analysis. For each of these proposals, [redacted] proposed [redacted]. After further discussions with [redacted], the Companies learned [redacted]. Furthermore, [redacted]. Therefore, the [redacted] proposals were not included in the Phase 2 analysis.

During this analysis, the Companies met with the RFP respondents that submitted the most economic short- and long-term alternatives to better understand their proposals and seek ways to improve them. This group of RFP respondents includes [redacted]. The information presented here reflects each party's best-and-final proposals.

4.4.1 Methodology

Beginning with the Phase 2 analysis, each alternative was evaluated using Strategist and PROSYM in the context of the Companies' generation portfolio over the 12 scenarios discussed in section 4.1.4.[25] For each "native load-gas price-CO_2 price" scenario, Strategist was used to develop a least-cost resource expansion plan for meeting the Companies' forecasted energy requirements from 2013 through 2042. Then, detailed production costs were computed for each scenario and associated expansion plan using PROSYM. To focus the analysis on finding the best resource for serving the Companies' native load and eliminate the need to speculate on future power prices, the analysis assumed the Companies had no access to energy from the market and made no off-system sales. The present value of revenue requirements ("PVRR") was computed for each scenario over a 30-year analysis period (2013-2042). Table 14 lists the costs included (where applicable) in the 30-year PVRR for each alternative and scenario.

[25] Strategist and PROSYM are software products from Ventyx, an ABB Company.

Table 14 – Summary of Costs Used to Calculate Revenue Requirements

	Resource Type			
Cost	**Existing**	**LGR**	**RFP**	**Self-Build**
Fuel/energy costs	X	X	X	X
Start costs	X	X	X	X
Hourly operating costs	X	X	X	X
Variable O&M	X	X	X	X
CO2 emissions costs	X	X	X	X
Unit capital costs	Fixed Costs Not Considered for Existing Assets*	X	X	X
Transmission system upgrade costs		X	X	X
Fixed O&M		X	X	X
Firm gas transportation		X	X	X
Fixed cost for firm transmission service		N/A	X	N/A
PPA capacity charge		N/A	X	N/A
PPA financing costs		N/A	X	N/A

*Because fixed costs for existing assets are not impacted by the alternatives evaluated, they were not considered in the analysis.

4.4.2 Iteration 1 – Analysis of Two-Year PPAs

As stated previously, new NGCC generation cannot be commissioned until 2018. To perform a complete 30-year economic analysis for proposals for new generation, the proposals must be paired with a two-year PPA (for 2016-2017) to meet the reserve margin shortfall that begins in 2016. The first iteration of the Phase 2 analysis evaluated two-year PPAs to determine which PPAs to pair with proposals for new generation. The Phase 2, Iteration 1 alternatives are listed in Table 15. All alternatives considered in Iteration 1 meet the Companies' capacity and energy needs in the 2013 LF scenario through 2017 (capacity and energy needs are shown in Table 1).[26] In Table 15, the "AltID" is a unique identifier for each alternative. In some cases, the "delivered MW" value is less than the capacity of the PPA due to transmission losses.

Table 15 – Two-Year PPAs (Phase 2, Iteration 1)

	AltID	Description	Delivered MW
1	C05D	[redacted]	[redacted]
2	C06F	[redacted]	[redacted]
3	C19I	[redacted]	[redacted]
4	C19J	[redacted]	[redacted]
5	C19N	[redacted]	[redacted]
6	C20G	[redacted]	[redacted]
7	C21E	[redacted]	[redacted]
8	C22F	[redacted]	[redacted]
9	C22G	[redacted]	[redacted]
10	C23D	[redacted]	[redacted]
11	C46F	[redacted]	[redacted]

[26] The options that passed the Phase 1 screening analysis and do not meet the Companies' capacity and energy needs in the 2013 LF scenario through 2017 were evaluated in Phase 3.

The Phase 2, Iteration 1 results are summarized in Table 16. All Iteration 1 alternatives have the same resource expansion plan from 2018 forward. Therefore, the PVRR differences in Table 16 are driven entirely by cost differences between the two-year PPAs. Based on these results, the [redacted] and the [redacted] are the least cost two-year PPAs.

Table 16 – Analysis of Two-Year PPAs Results, All Scenarios (Weighted Average PVRR 2013-2042, $M)

	AltID	Description	PVRR	Diff from Best
1	C22F	[redacted]		
2	C46F			
3	C22G			
4	C20G			
5	C05D			
6	C06F			
7	C19N			
8	C21E			
9	C19I			
10	C19J			
11	C23D			

For the [redacted] alternatives, a [redacted] must be completed to [redacted]. This cost negatively impacts the [redacted] alternatives.

4.4.3 Iteration 2 – Analysis of Long-Term Proposals

Phase 2, Iteration 2 evaluated the long-term proposals for meeting the Companies' capacity and energy needs. The proposals from [redacted] and the Companies' self-build alternatives (Green River 2x1 and Green River 1x1) involve new NGCC units; the remaining alternatives involve existing assets. Each of the new NGCC proposals was paired separately with the two-year [redacted] and the two-year [redacted].[27] The Phase 2, Iteration 2 alternatives are listed in Table 17. Where applicable, each alternative's "long name" includes the name of the respondent(s), the term of the proposal(s), whether the proposal is a PPA or asset sale, and the first year of the proposal.

[27] The proposals for existing assets did not require a short-term PPA to meet the reserve margin shortfall in 2016-2017.

Table 17 – Long-Term Alternatives (Phase 2, Iteration 2)

	Alt ID	Short Name	Long Name	2018 Delivered MWs
1	C46H	[redacted]	[redacted]	[redacted]
2	C46B	[redacted]	[redacted]	[redacted]
3	C07C	[redacted]	[redacted]	[redacted]
4	C22Z	[redacted]	[redacted]	[redacted]
5	C46J	[redacted]	[redacted]	[redacted]
6	C22V	[redacted]	[redacted]	[redacted]
7	C46K	[redacted]	[redacted]	[redacted]
8	C42E	[redacted]	[redacted]	[redacted]
9	C46L	[redacted]	[redacted]	[redacted]
10	C42D	[redacted]	[redacted]	[redacted]
11	C46I	[redacted]	[redacted]	[redacted]
12	C47W	[redacted]	[redacted]	[redacted]
13	C47T	[redacted]	[redacted]	[redacted]
14	C47U	[redacted]	[redacted]	[redacted]
15	C47V	[redacted]	[redacted]	[redacted]
16	C09A	[redacted]	[redacted]	[redacted]
17	C45F	[redacted]	[redacted]	[redacted]
18	C45B	[redacted]	[redacted]	[redacted]

One proposal from [redacted] was not directly evaluated in the Phase 2 analysis in the context of the Companies' generation portfolio. In this [redacted] proposal, [redacted] proposed to [redacted]. Because the Companies can build the same unit at the Green River site, the most direct approach for evaluating this proposal was to compare the capital and firm gas transportation costs for the [redacted] site to the same costs for the Green River site.[28] Capital costs include the cost of the unit as well as capital costs for transmission system upgrades and transmission networking costs. Table 18 summarizes the cost differences between the [redacted] and Green River sites.

Table 18 – Capital and Firm Gas Transportation Costs ([redacted] vs. Green River, PVRR 2013-2042, $M)

	[redacted]	Green River	Difference ([redacted] Less Green River)
Unit Capital	[redacted]	[redacted]	[redacted]
Transmission Capital			
System Upgrade Costs	[redacted]	[redacted]	[redacted]
Networking Costs	[redacted]	[redacted]	[redacted]
Firm Gas Transportation	[redacted]	[redacted]	[redacted]
Total Costs	[redacted]	[redacted]	[redacted]

[28] Because the comparison focuses on the same unit, the impact of the unit to the Companies' resource expansion plan and production costs are the same. For this reason, it is not necessary to evaluate the unit in Strategist or PROSYM in the context of the Companies' generation portfolio.

Compared to the Green River site, the [redacted] site has lower transmission system upgrade costs but higher transmission networking costs. [redacted] proposed to connect the [redacted] site to the Companies' transmission system via a single radial high voltage transmission line. The Companies do not believe this is prudent from a reliability perspective; each of the Companies' generating units are connected to the transmission system via multiple transmission lines. Furthermore, the Green River and [redacted] sites are located near different natural gas pipelines.[29] Firm gas transportation costs for the Green River site are expected to be lower than firm gas transportation costs for the [redacted] site. Based on the cost comparison in Table 18, the Green River site is the better site for a NGCC unit to be integrated into the LG&E/KU system.

Table 19 lists the weighted average PVRR over all scenarios for each alternative. Over all scenarios, the Green River 2x1 alternative is the least-cost alternative. The top alternatives include NGCC technologies. The [redacted] alternative is [redacted] million unfavorable to the Green River 2x1 alternative (over all scenarios).

Table 19 – Long-Term Resource Alternatives Results, All Scenarios (PVRR 2013-2042, $M)

Weighted Average – All Scenarios		
Rank – Alternative	**PVRR**	**Diff from Best**
[redacted]		

Table 20 lists the weighted average PVRR over the six Zero and six Mid CO_2 scenarios. The [redacted] and [redacted] alternatives are competitive only in the Zero CO_2 scenarios where the weighted average PVRR for the [redacted] alternative is [redacted] million favorable to the Green River 2x1 alternative and the weighted average PVRR for the [redacted] alternative is [redacted] million unfavorable to the Green River 2x1 alternative.

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[29] The Green River site is located near the Texas Gas pipeline; the [redacted] site is located near the [redacted].

Table 20 – Long-Term Resource Alternatives Results, CO_2 Price Scenarios (PVRR 2013-2042, $M)

Weighted Average – Zero CO_2 Scenarios			Weighted Average – Mid CO_2 Scenarios		
Rank – Alternative	PVRR	Diff from Best	Rank – Alternative	PVRR	Diff from Best
[redacted]					

The results of the Mid CO_2 scenarios demonstrate the significant amount of downside risk associated with the [redacted] and [redacted] alternatives. Compared to the least-cost Green River 2x1 alternative, the weighted average PVRRs for the [redacted] and [redacted] alternatives are unfavorable by [redacted] million and [redacted] million, respectively.

In a CO_2 constrained world, the efficiency of gas technologies is important. The improved heat rate of the Green River 2x1 alternative (compared to the [redacted] alternative) more than offsets the higher capital cost for the Green River 2x1 alternative. Provided the likelihood of the Mid CO_2 scenario exceeds three percent, the Green River 2x1 alternative is the least-cost alternative.[30]

Table 21 lists the weighted average PVRR for the long-term resource alternatives in the Mid, Low, and High gas price scenarios. The Green River 2x1 alternative is the least-cost alternative on average in any gas price scenario when considering the uncertainty surrounding load and greenhouse gas regulations. Not surprisingly, the [redacted] alternative performs best in the High gas scenarios but is still not lower cost than Green River 2x1 alternative because of the risk associated with future CO_2 costs.

[30] Compared to the [redacted] alternative, the Green River 2x1 alternative is [redacted] million favorable in the Mid CO_2 scenario and [redacted] million unfavorable in the Zero CO_2 scenario. Over all scenarios, the weighted average PVRR of the Green River 2x1 and [redacted] alternatives is the same if the likelihood of the Mid CO_2 scenario is approximately three percent ([redacted]/([redacted]+[redacted])=3.2%).

Table 21 – Long-Term Resource Alternatives Results, Natural Gas Price Scenarios (PVRR 2013-2042, $M)

Weighted Average – Low Gas Price Scenarios			Weighted Average – Mid Gas Price Scenarios			Weighted Average – High Gas Price Scenarios		
Rank-Alternative	PVRR	Diff from Best	Rank – Alternative	PVRR	Diff from Best	Rank – Alternative	PVRR	Diff from Best
[redacted]								

Table 22 lists the weighted average PVRR for the long-term resource alternatives in the 2013 LF and Low load scenarios. The ranking of alternatives in both load scenarios is similar to the ranking of alternatives over all 12 scenarios; the Green River 2x1 alternative is the least-cost alternative. Compared to the 2013 LF scenario, the margin between the Green River 2x1 alternative and the shorter-term PPAs is narrower in the Low load scenario. Even in the Low load scenario, the Green River 1x1 alternative (with roughly half the capacity of the Green River 2x1 alternative) is not least-cost.

Table 22 – Long-Term Resource Alternatives Results, Native Load Scenarios (PVRR 2013-2042, $M)

Weighted Average – 2013 LF Load Scenarios			Weighted Average – Low Load Scenarios		
Rank – Alternative	PVRR	Diff from Best	Rank – Alternative	PVRR	Diff from Best
[redacted]					

Table 23 lists the PVRR for the long-term resource alternatives in each of the twelve scenarios. The Green River 2x1 alternative is the least-cost alternative in all of the Mid CO_2 and Low gas scenarios (8 scenarios). Because of its relatively small size ([redacted]), the [redacted] alternative is also paired with the Green River 2x1 NGCC unit in 2018. When this alternative is considered, the Green River 2x1 alternative is the least-cost alternative in 9 of 12 scenarios.

Only when there is never a GHG limitation on existing coal units and gas prices are at or above the Mid gas scenario would the Green River 2x1 alternative be more expensive than other alternatives, regardless of load level. Not surprisingly, if future GHG regulations are assumed to have little impact on coal generation, the [redacted] alternative is the least-cost alternative provided future gas prices are at or above the Mid gas price forecast. The [redacted] alternative is least cost only in the "Zero CO_2-Mid gas-Low load" scenario where the efficiency of gas technologies is not as important and there is less need for energy-intensive resources due to lower load.

Table 23 – Long-Term Resource Alternatives Scenario Results ($M)

PVRR (2013-2042)												
CO_2 Price	**0C**	**0C**	**0C**	**0C**	**0C**	**0C**	**MC**	**MC**	**MC**	**MC**	**MC**	**MC**
Gas Price	**LG**	**LG**	**MG**	**MG**	**HG**	**HG**	**LG**	**LG**	**MG**	**MG**	**HG**	**HG**
Load	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**
[redacted]												
Difference from Least-Cost Alternative												
CO_2 Price	**0C**	**0C**	**0C**	**0C**	**0C**	**0C**	**MC**	**MC**	**MC**	**MC**	**MC**	**MC**
Gas Price	**LG**	**LG**	**MG**	**MG**	**HG**	**HG**	**LG**	**LG**	**MG**	**MG**	**HG**	**HG**
Load	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**
[redacted]												

Gas Price: Low (LG), Mid (MG), High (HG) CO_2 Price: Zero (0C), Mid (MC) Load: 2013 LF (BL), Low (LL)

The extreme downside risks associated with the [redacted] and [redacted] alternatives are also shown by the scenario results in Table 23. In the Mid CO_2 scenarios, the downside risk for the [redacted] alternative ranges from [redacted] million in the "Mid CO_2-High gas-Low load" scenario to [redacted] million in the "Mid CO_2-Low gas-2013 LF load" scenario. The 2011 Resource Assessment focused primarily on the Zero CO_2 and Mid gas scenarios. [redacted].

In the Mid CO_2 scenarios, the downside risk for the [redacted] alternative ranges from [redacted] million in the "Mid CO_2-High gas-Low load" scenario to [redacted] million in the "Mid CO_2-Low gas-Low load" scenario. Even if the Low load scenario is ignored (given the lower likelihood of the Low load scenario), the downside risk for the [redacted] alternative is still up to [redacted] million.

As mentioned previously, the Green River 2x1 alternative is more expensive than other alternatives only if there is never a GHG limitation on existing coal units and gas prices are at or above the Mid gas scenario. In the two "Zero CO_2-Low gas" scenarios, the Green River 2x1 alternative is more than [redacted] million favorable to the [redacted] alternative and approximately [redacted] million favorable to the [redacted] alternative. Across all Zero CO_2 scenarios, the Green River 2x1 alternative is only [redacted] million unfavorable to the [redacted] alternative and [redacted] million favorable to the [redacted] alternative (see Table 20). The downside risk associated with the Green River 2x1 alternative is small compared to these alternatives.

These results clearly show that the Green River 2x1 alternative is the most robust alternative for reliably meeting customers' long-term capacity and energy needs at the lowest reasonable cost:

1. The weighted average PVRR for the Green River 2x1 alternative is least-cost.
2. The Green River 2x1 alternative is least-cost in nine of the twelve scenarios evaluated.
3. The downside risk associated with the Green River 2x1 alternative is small compared to other alternatives and only occurs if there are never restrictions on GHG emissions on existing coal units.

Given the uncertainties around load, gas prices, and GHG regulations, the Green River 2x1 alternative is the most robust alternative for reliably meeting customers' long-term energy needs.

4.5 Phase 3 – Enhancements and Deferral Considerations

To further test the robustness of the Green River 2x1 alternative and its timing, the Companies evaluated numerous short-term PPAs in an effort to (i) enhance the Green River 2x1 alternative and/or (ii) cost-effectively and reliably defer the addition of the NGCC unit beyond 2018. The Phase 3 analysis was completed in two iterations:

1. The capacities of several proposals from the Phase 1 screening analysis are less than the average annual increase in the Companies' peak demand and – on a stand-alone basis – cannot meet the Companies' reserve margin need. Iteration 1 evaluated each of these proposals in combination with the Green River 2x1 alternative to determine whether a "small" proposal could further enhance the Green River 2x1 alternative.
2. Iteration 2 evaluated numerous short-term alternatives to determine whether the Green River 2x1 NGCC unit could be reliably and cost-effectively deferred beyond 2018.

4.5.1 Iteration 1 – Enhancements

The capacity of several proposals from the Phase 1 screening analysis is less than the average annual increase in the Companies' peak demand and – on a stand-alone basis – cannot meet the Companies' reserve margin need. Iteration 1 evaluated each of these proposals in combination with the least-cost Green River 2x1 alternative from Phase 2 (alternative C42D) to determine whether the addition of a "small" proposal could further enhance the Green River 2x1 alternative. The Iteration 1 alternatives are summarized in Table 24.

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Table 24 – Small Proposal Alternatives

	AltID	Short Name	Long Name	2018 Delivered MWs for Small Proposal[31]
1	C28A	[redacted]		
2	C28B			
3	C28C			
4	C28D			
5	C28E			
6	C28F			
7	C28G			
8	C28H			
9	C28I			
10	C28J			
11	C28K			
12	C28L			
13	C28M			
14	C28N			
15	C28O			
16	C28Q			

[31] Delivered MWs for the wind, solar, and DSM alternatives do not reflect the level of production at the time of the Companies' peak demand. Given the nature of the proposal, approximately 30% of the capacity for wind alternatives C28E and C28F is expected to be available at the time of the Companies' peak. Alternative C28G is a more traditional wind proposal, with approximately 10% of its capacity available at the time of peak. For the solar alternatives, 80-90% of their total capacity is typically available at the time of peak. The estimated demand reductions for the DSM programs increase over time. Most notably, the DSM automated demand response program is expected to reduce demand by 60 MW in 2021. None of the "small" proposals are large enough to defer the need for new generation in 2018.

The Phase 3, Iteration 1 results are summarized in Table 25 along with the results for alternative C42D, which is highlighted in gray. When a unit is added to a generation portfolio, production costs decrease. This favorable impact is offset by the small proposal's capital and fixed operating costs.[32] Only the DSM Commercial New Construction program reduces the total revenue requirements of the Green River 2x1 alternative.[33] The capital cost of the solar alternatives in Iteration 1 (alternatives C28H and C28I) is [redacted]/kW. At this price level, justification for solar projects is difficult.

Table 25 – Analysis of Small Proposal Alternatives Results, All Scenarios (Weighted Average PVRR 2013-2042, $M)

	AltID	Short Name	PVRR	Diff from Best
1	C28O	[redacted]		
2	C42D			
3	C28A			
4	C28M			
5	C28L			
6	C28N			
7	C28B			
8	C28K			
9	C28F			
10	C28H			
11	C28J			
12	C28C			
13	C28G			
14	C28E			
15	C28D			
16	C28I			
17	C28Q			

4.5.2 Iteration 2 – Deferral Considerations

Iteration 2 evaluated numerous short-term alternatives to determine whether the Green River 2x1 NGCC unit could be reliably and cost-effectively deferred beyond 2018. Iteration 2 considered the following types of alternatives:

1. Standard PPAs. Standard PPAs include short-term PPAs that – on a stand-alone basis – can defer the Green River 2x1 NGCC unit beyond 2018.
2. Combinations of "small" proposals. Iteration 2 considered two alternatives with combinations of the lower-cost "small" proposals from Iteration 1 as well as one alternative consisting of all DSM and renewable proposals.
3. "Staged" proposals. The capacity and energy for several of the short-term PPAs are sourced from multiple generating units. In the staged PPAs, the capacity of the PPA increases through the contract term to better match load growth, resulting in lower fixed costs for the deferral options. For example, the Phase 2 analysis considered a [redacted]

[32] The small proposals do not materially impact the transmission capital cost of the Green River 2x1 alternative.
[33] The estimated demand reduction for the DSM Commercial New Construction program increases from 1.7 MW in 2018 to 3.4 MW by 2021.

[redacted], while the Phase 3 analysis considers a [redacted].

During this analysis, the Companies discussed the terms of the “staged” PPAs with [redacted]. In some cases, these discussions resulted in improvements to the non-staged proposals. The information presented here reflects the parties’ best-and-final proposals.

The Iteration 2 alternatives are listed in Table 26. The year the Green River 2x1 NGCC unit is commissioned is listed in the alternative’s long and short name. All alternatives include the DSM Commercial New Construction (“CNC”) program because Iteration 1 demonstrated that it reduced the cost of the Green River 2x1 alternative.

Table 26 – PPAs That Could Defer Green River 2x1 NGCC Unit

	Alt ID	Short Name	Long Name
Standard PPAs			
1	C06_	[redacted]	[redacted]
2	C06C	[redacted]	[redacted]
3	C06D	[redacted]	[redacted]
4	C06E	[redacted]	[redacted]
5	C06G	[redacted]	[redacted]
6	C06H	[redacted]	[redacted]
7	C20C	[redacted]	[redacted]
8	C20D	[redacted]	[redacted]
9	C20E	[redacted]	[redacted]
10	C21B	[redacted]	[redacted]
11	C21C	[redacted]	[redacted]
12	C21D	[redacted]	[redacted]
13	C23B	[redacted]	[redacted]
14	C47N	[redacted]	[redacted]
15	C24A	[redacted]	[redacted]
16	C24B	[redacted]	[redacted]
17	C47P	[redacted]	[redacted]
18	C50G	[redacted]	[redacted]
19	C50E	[redacted]	[redacted]
20	C50A	[redacted]	[redacted]
21	C55B	[redacted]	[redacted]
22	C47R	[redacted]	[redacted]
23	C47S	[redacted]	[redacted]
24	C50D	[redacted]	[redacted]
25	C50F	[redacted]	[redacted]
26	C54A	[redacted]	[redacted]
27	C54E	[redacted]	[redacted]
28	C54F	[redacted]	[redacted]
29	C54G	[redacted]	[redacted]
30	C54H	[redacted]	[redacted]
31	C55E	[redacted]	[redacted]
32	C55F	[redacted]	[redacted]

	Alt ID	Short Name	Long Name
Standard PPAs			
33	C55G	[redacted]	
34	C56B		
Staged Proposals			
35	C50B	[redacted]	
36	C50C		
37	C54C		
38	C54D		
39	C55C		
40	C55D		
41	C56A		
42	C56C		
Small Proposals			
43	C30A	[redacted]	
44	C32A		
45	C35A		

Several RFP responses included either multiple proposals or a single proposal with flexible terms. For example, the response from [redacted] included multiple proposals, each referencing a different [redacted]. In the [redacted] proposal, the amount of capacity offered in the proposal was negotiable. For responses like these, Iteration 2 includes multiple alternatives.

Several alternatives in Iteration 2 include proposals that are variants of the original proposal. For example, if the term of a PPA was specified to start in 2015, Iteration 2 evaluates the proposal as specified, as well as a variation of the proposal that begins in 2016 (to coincide with the year the Companies' reserve margin drops below the target range). The objective in creating these variants was to evaluate the most likely candidates for deferring the Green River 2x1 NGCC unit beyond 2018.

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Table 27 lists the weighted average PVRR over all scenarios for each of the Iteration 2 alternatives. On average over all scenarios, the [redacted] (alternative C55D) cost-effectively defers the Green River 2x1 NGCC unit to 2020; this alternative reduces the weighted average PVRR of building in 2018 by [redacted] million. In the next seven tables, the least-cost 2018 Green River 2x1 option is highlighted in gray.

Table 27 – Analysis of Deferral Options Results, All Scenarios (PVRR 2013-2042, $M)

			Wtd Avg – All Scenarios	
	AltID	**Short Name**	**PVRR**	**Diff from Best**
1	C55D	[redacted]		
2	C55B	[redacted]		
3	C55G	[redacted]		
4	C55E	[redacted]		
5	C50A	[redacted]		
6	C55C	[redacted]		
7	C55F	[redacted]		
8	C50D	[redacted]		
9	C56C	[redacted]		
10	C56A	[redacted]		
11	C54A	[redacted]		
12	C30A	[redacted]		
13	C56B	[redacted]		
14	C54D	[redacted]		
15	C50B	[redacted]		
16	C54E	[redacted]		
17	C50C	[redacted]		
18	C06C	[redacted]		
19	C54C	[redacted]		
20	C54G	[redacted]		
21	C32A	[redacted]		
22	C54F	[redacted]		
23	C50E	[redacted]		
24	C20C	[redacted]		
25	C06G	[redacted]		
26	C50F	[redacted]		
27	C54H	[redacted]		
28	C47S	[redacted]		
29	C06_	[redacted]		
30	C50G	[redacted]		
31	C20D	[redacted]		
32	C21B	[redacted]		
33	C24A	[redacted]		
34	C24B	[redacted]		
35	C47P	[redacted]		
36	C21C	[redacted]		
37	C47R	[redacted]		
38	C06H	[redacted]		
39	C20E	[redacted]		
40	C23B	[redacted]		
41	C21D	[redacted]		
42	C06E	[redacted]		
43	C47N	[redacted]		
44	C06D	[redacted]		
45	C35A	[redacted]		

Table 28 lists the weighted average PVRR over the six Zero and six Mid CO_2 price scenarios. As mentioned previously, if the Green River unit is commissioned after 2018, the analysis assumes the Companies would not be able to offset the new unit's emissions with the retirement of the Green River coal units. Absent this offset, the new unit would likely be subject to additional operating constraints. Partly for this reason, deferral is not economic in the Zero carbon scenarios where operating flexibility for the NGCC unit is more important. In the Mid CO_2 scenarios, the most economic deferral alternative improves the weighted average PVRR of building in 2018 by [redacted] million.

Table 28 – Analysis of Deferral Options Results, CO_2 Price Scenarios (PVRR 2013-2042, $M)

	AltID	Short Name	Wtd Avg – Zero CO_2 PVRR	Wtd Avg – Zero CO_2 Diff from Best	Wtd Avg – Mid CO_2 PVRR	Wtd Avg – Mid CO_2 Diff from Best
1	C55D	[redacted]				
2	C55B	[redacted]				
3	C55G	[redacted]				
4	C55E	[redacted]				
5	C50A	[redacted]				
6	C55C	[redacted]				
7	C55F	[redacted]				
8	C50D	[redacted]				
9	C56C	[redacted]				
10	C56A	[redacted]				
11	C54A	[redacted]				
12	C30A	[redacted]				
13	C56B	[redacted]				
14	C54D	[redacted]				
15	C50B	[redacted]				
16	C54E	[redacted]				
17	C50C	[redacted]				
18	C06C	[redacted]				
19	C54C	[redacted]				
20	C54G	[redacted]				
21	C32A	[redacted]				
22	C54F	[redacted]				
23	C50E	[redacted]				
24	C20C	[redacted]				
25	C06G	[redacted]				
26	C50F	[redacted]				
27	C54H	[redacted]				
28	C47S	[redacted]				
29	C06_	[redacted]				
30	C50G	[redacted]				
31	C20D	[redacted]				
32	C21B	[redacted]				
33	C24A	[redacted]				
34	C24B	[redacted]				
35	C47P	[redacted]				
36	C21C	[redacted]				
37	C47R	[redacted]				
38	C06H	[redacted]				
39	C20E	[redacted]				
40	C23B	[redacted]				
41	C21D	[redacted]				
42	C06E	[redacted]				
43	C47N	[redacted]				
44	C06D	[redacted]				
45	C35A	[redacted]				

Table 29 lists the weighted average PVRR for the Iteration 2 alternatives in the Low, Mid, and High gas price scenarios. Deferring the commissioning of the Green River 2x1 NGCC unit to 2020 is economic in the Mid and High gas price scenarios. However, the deferral option is not economic in the Low gas price scenarios.

Table 29 – Analysis of Deferral Options Results, Natural Gas Price Scenarios (PVRR 2013-2042, $M)

			Wtd Avg – Low Gas Price Scenarios		Wtd Avg – Mid Gas Price Scenarios		Wtd Avg – High Gas Price Scenarios	
	AltID	**Short Name**	**PVRR**	**Diff from Best**	**PVRR**	**Diff from Best**	**PVRR**	**Diff from Best**
1	C55D	[redacted]						
2	C55G	[redacted]						
3	C55B	[redacted]						
4	C55C	[redacted]						
5	C55E	[redacted]						
6	C50A	[redacted]						
7	C55F	[redacted]						
8	C56C	[redacted]						
9	C56A	[redacted]						
10	C56B	[redacted]						
11	C54D	[redacted]						
12	C50D	[redacted]						
13	C30A	[redacted]						
14	C50C	[redacted]						
15	C50B	[redacted]						
16	C54A	[redacted]						
17	C54G	[redacted]						
18	C54C	[redacted]						
19	C32A	[redacted]						
20	C54E	[redacted]						
21	C06C	[redacted]						
22	C50F	[redacted]						
23	C50E	[redacted]						
24	C54F	[redacted]						
25	C20C	[redacted]						
26	C54H	[redacted]						
27	C06G	[redacted]						
28	C20D	[redacted]						
29	C50G	[redacted]						
30	C47S	[redacted]						
31	C47P	[redacted]						
32	C06_	[redacted]						
33	C24A	[redacted]						
34	C24B	[redacted]						
35	C20E	[redacted]						
36	C47R	[redacted]						
37	C21B	[redacted]						
38	C23B	[redacted]						
39	C06H	[redacted]						
40	C47N	[redacted]						
41	C21C	[redacted]						
42	C06E	[redacted]						
43	C21D	[redacted]						
44	C06D	[redacted]						
45	C35A	[redacted]						

Table 30 lists the weighted average PVRR for the Iteration 2 alternatives in the 2013 LF and Low load scenarios. Deferring the commissioning of the Green River 2x1 NGCC unit to 2020 is economic in both load forecast scenarios. Furthermore, the value of deferral is similar in both load scenarios ([redacted] million).

Table 30 – Analysis of Deferral Alternatives Results, Native Load Scenarios (PVRR 2013-2042, $M)

			Wtd Avg – 2013 LF Load Scenarios		Wtd Avg – Low Load Scenarios	
	AltID	Short Name	PVRR	Diff from Best	PVRR	Diff from Best
1	C55D	[redacted]				
2	C55B	[redacted]				
3	C55G	[redacted]				
4	C55E	[redacted]				
5	C55C	[redacted]				
6	C50A	[redacted]				
7	C55F	[redacted]				
8	C50D	[redacted]				
9	C56C	[redacted]				
10	C56A	[redacted]				
11	C30A	[redacted]				
12	C54A	[redacted]				
13	C56B	[redacted]				
14	C54D	[redacted]				
15	C50B	[redacted]				
16	C54E	[redacted]				
17	C50C	[redacted]				
18	C06C	[redacted]				
19	C54C	[redacted]				
20	C54G	[redacted]				
21	C32A	[redacted]				
22	C50E	[redacted]				
23	C54F	[redacted]				
24	C20C	[redacted]				
25	C06G	[redacted]				
26	C50F	[redacted]				
27	C54H	[redacted]				
28	C47S	[redacted]				
29	C06_	[redacted]				
30	C50G	[redacted]				
31	C20D	[redacted]				
32	C21B	[redacted]				
33	C24A	[redacted]				
34	C24B	[redacted]				
35	C47P	[redacted]				
36	C47R	[redacted]				
37	C21C	[redacted]				
38	C06H	[redacted]				
39	C20E	[redacted]				
40	C23B	[redacted]				
41	C21D	[redacted]				
42	C06E	[redacted]				
43	C47N	[redacted]				
44	C06D	[redacted]				
45	C35A	[redacted]				

Table 31 summarizes the difference in each of the 12 scenarios between each alternative's PVRR and the PVRR of the least-cost alternative. Over all scenarios, the weighted average PVRR impact of deferring the Green River 2x1 NGCC unit from 2018 to 2020 is [redacted] million. However, bringing the Green River 2x1 NGCC unit online by 2018 is the lowest cost option in 8 of the 12 scenarios considered.

Table 31 – Analysis of Deferral Alternatives Scenario Results (PVRR 2013-2042, $M)

Difference from Least-Cost Alternative												
CO_2 Price	**0C**	**0C**	**0C**	**0C**	**0C**	**0C**	**MC**	**MC**	**MC**	**MC**	**MC**	**MC**
Gas Price	**LG**	**LG**	**MG**	**MG**	**HG**	**HG**	**LG**	**LG**	**MG**	**MG**	**HG**	**HG**
Load	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**
[redacted]												

Gas Price: Low (LG), Mid (MG), High (HG) CO_2 Price: Zero (0C), Mid (MC) Load: 2013 LF (BL), Low (LL)

To further explore the deferral option, the Companies initiated further discussions with [redacted]. These discussions focused on [redacted]'s financial strength, credit risk, contractual uncertainties, and environmental risks that would be associated with a potential [redacted] PPA. This analysis revealed the following:

- [redacted] are in poor financial health. Given their [redacted] credit rating by Standard & Poor's, the estimated likelihood of default over the next six years is high. [redacted]'s financial condition is not expected to materially improve [redacted].
- It is unclear whether the [redacted] units referenced in the [redacted] PPA will be [redacted]

A complete summary of this analysis is included in *Appendix C –* [redacted] *Considerations*.

Should any of these risks materialize and result in [redacted] not being able to deliver energy, the ability to reliably serve customers would be jeopardized. Therefore, it was determined that the potential inability to reliably serve customers' load more than offsets the value in certain scenarios afforded by the proposal's ability to defer the addition of new generation beyond 2018.

Without the [redacted] proposals, the best plan for reliably meeting customers' long-term capacity and energy needs at the lowest reasonable cost remains commissioning a 2x1 NGCC unit at the Green River station by 2018. Table 32 lists the PVRR differences in each of the 12 scenarios for all but the [redacted] alternatives. The 2018 Green River 2x1 alternative is least-cost in all of the Zero CO_2 scenarios and the two Mid CO_2 scenarios with low gas prices. If the Companies knew that gas prices were going to be at or above the Mid gas price scenario, deferring the Green River unit would be least-cost. However, because there is no basis for weighting one gas price scenario more heavily than another scenario, deferring the Green River 2x1 NGCC unit is not least-cost.

Table 32 – Analysis of Deferral Alternatives Scenario Results – No AEM (PVRR 2013-2042, $M)

Difference from Least-Cost Alternative												
CO_2 Price	**0C**	**0C**	**0C**	**0C**	**0C**	**0C**	**MC**	**MC**	**MC**	**MC**	**MC**	**MC**
Gas Price	**LG**	**LG**	**MG**	**MG**	**HG**	**HG**	**LG**	**LG**	**MG**	**MG**	**HG**	**HG**
Load	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**
[redacted]												

Gas Price: Low (LG), Mid (MG), High (HG) CO_2 Price: Zero (0C), Mid (MC)   Load: 2013 LF (BL), Low (LL)
*The small proposals were originally paired with an [redacted]. Here, they are paired with a [redacted].

Table 33 lists the weighted average PVRR differences over all scenarios along with the weighted average PVRR for each set of CO_2, gas, and load scenarios. The 2018 Green River 2x1 alternative is the least-cost alternative over all scenarios and in each set of scenarios. Over all scenarios, the weighted average PVRR of the 2018 Green River 2x1 alternative is [redacted] million favorable to the least-cost deferral alternative (alternative C54D). Because no PPA can cost-effectively and reliably defer the addition of a 2x1 NGCC unit beyond 2018, the best plan for reliably meeting customers' long-term capacity and energy needs at the lowest reasonable cost remains constructing a 2x1 NGCC unit at the Green River station by 2018.

Table 33 – Analysis of Deferral Alternatives Results, Weighted Average Difference from Least-Cost Alternative – No AEM (PVRR 2013-2042, $M)

AltID	Short Name	All Scenarios	Zero CO_2	Mid CO_2	Low Gas	Mid Gas	High Gas	2013 LF Load	Low Load
C50A	[redacted]								
C50D	[redacted]								
C54A	[redacted]								
C54D	[redacted]								
C50B	[redacted]								
C54E	[redacted]								
C50C	[redacted]								
C06C	[redacted]								
C54C	[redacted]								
C54G	[redacted]								
C30B	[redacted]								
C54F	[redacted]								
C50E	[redacted]								
C20C	[redacted]								
C06G	[redacted]								
C50F	[redacted]								
C54H	[redacted]								
C32B	[redacted]								
C47S	[redacted]								
C06_	[redacted]								
C50G	[redacted]								
C20D	[redacted]								
C21B	[redacted]								
C24A	[redacted]								
C24B	[redacted]								
C47P	[redacted]								
C21C	[redacted]								
C47R	[redacted]								
C06H	[redacted]								
C20E	[redacted]								
C23B	[redacted]								
C21D	[redacted]								
C06E	[redacted]								
C47N	[redacted]								
C06D	[redacted]								
C35A	[redacted]								

*The small proposals were originally paired with an [redacted] PPA. Here, they are paired with a [redacted] PPA.

4.6 Phase 4 – Solar Considerations

In the Phase 3, Iteration 1 analysis, the Companies evaluated both a greenfield 10 MW solar photovoltaic ("PV") project and a proposal from [redacted] to [redacted]. HDR, an engineering consulting firm engaged by the Companies, estimated the cost of the greenfield solar facility to be approximately $4,600/kW. The cost of the proposal from [redacted] was approximately [redacted]/kW. When the RFP analysis began, neither of these projects was economic. However, during the analysis of RFP responses, Public Service Company of Colorado ("PSCC"), a subsidiary of Xcel Energy, proposed plans to purchase 170 MW of solar capacity through

PPAs from two solar facilities to be constructed.[34] Based on publicly available information in this filing, the implied installed costs of these solar facilities were much lower than either of the projects the Companies' were evaluating. A report from Electric Power Research Institute ("EPRI") also supported the view that solar panel costs were decreasing.

Based on this new information, the Companies updated their cost estimate for a 10 MW solar facility in September 2013. In the original conceptual self-build cost estimate developed by HDR, the cost of solar panels alone was approximately $3,800/kW. Based on the new information from EPRI, the cost of solar panels was assumed to be approximately $2,000/kW. In addition to the lower panel costs, the Companies already own land at the E.W. Brown station that is suitable for a solar project. With lower panel costs and available land, the total cost of the Companies' 10 MW solar project was reduced to approximately $2,400/kW.

As long as Kentucky does not have a renewable portfolio standard, the Companies would have the option to sell the Renewable Energy Certificates (RECs) that are created when the facility produces electricity.[35] Today, the market price in Ohio for solar RECs from Kentucky is $24-28 per REC. While the market price for solar RECs is more than $100 in New Jersey and Maryland, more than $200 in Massachusetts, and more than $400 in Washington D.C., solar RECs from Kentucky cannot currently be sold in these markets.

The Companies evaluated the 10 MW solar facility in combination with the Green River 2x1 alternative (alternative C50A) under three pricing scenarios for solar RECs. The results of this analysis are summarized in Table 34. The price for solar RECs in each of the three scenarios ($0, $16, and $26 per REC in 2016) was assumed to escalate at 2% per year.

Table 34 – Impact of 10 MW Solar Project ($2,400/kW Capital Cost, PVRR 2013-2042, $M)

AltID	Alternative (2016 Solar REC Price)	All Scenarios	Zero CO_2	Mid CO_2	Low Gas	Mid Gas	High Gas	2013 LF Load	Low Load
Weighted Average PVRR									
C50A	[redacted]								
C57A									
C57B									
C57C									
Difference from Green River 2x1 Alternative									
C57A	[redacted]								
C57B									
C57C									

At a capital cost of $2,400/kW, if the Companies do not sell the RECs, the solar facility's impact to the weighted average PVRR is unfavorable over all scenarios and in each subset of scenarios. At $16 per REC, there is no impact on PVRR over all scenarios. Furthermore, the PVRR impact is favorable or neutral in all but the Zero CO_2 and Low gas scenarios. At the current market price of $26 per REC, the

[34] For PSCC's "2013 All Source Solicitation 120 Day Report" September 10, 2013 filing, *see* http://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=240772&p_session_id=.

[35] One REC is created for every MWh that is produced.

PVRR impact is favorable over all scenarios by [redacted]. While there is no forward market for solar RECs beyond 2014, $26/REC is a reasonable price expectation given today's market for solar RECs and the diversity of renewable portfolio standards in the eastern states.

Based on these results, the Companies re-engaged HDR in December 2013 to perform a conceptual siting study review at the Brown site. Compared to the original cost estimate from HDR, the updated estimate reflected lower solar panel costs but higher site development costs. The new cost estimate ranged from approximately $3,500/kW to $4,100/kW, with an expected cost of approximately $3,600/kW ($1,000/kW lower than the original cost estimate). The PVRR impact of the 10 MW solar project is summarized at each of these capital cost levels in Table 35, Table 36, and Table 37.

Table 35 – Impact of 10 MW Solar Project ($3,500/kW Capital Cost, PVRR 2013-2042, $M)

AltID	Alternative (2016 Solar REC Price)	All Scenarios	Zero CO_2	Mid CO_2	Low Gas	Mid Gas	High Gas	2013 LF Load	Low Load
Weighted Average PVRR									
C50A	[redacted]								
C59A									
C59B									
C59C									
C59D									
Difference from Green River 2x1 Alternative									
C59A	[redacted]								
C59B									
C59C									
C59D									

Table 36 – Impact of 10 MW Solar Project ($3,600/kW Capital Cost, PVRR 2013-2042, $M)

AltID	Alternative (2016 Solar REC Price)	All Scenarios	Zero CO_2	Mid CO_2	Low Gas	Mid Gas	High Gas	2013 LF Load	Low Load
Weighted Average PVRR									
C50A	[redacted]								
C58A									
C58B									
C58C									
C58D									
Difference from Green River 2x1 Alternative									
C58A	[redacted]								
C58B									
C58C									
C58D									

Table 37 – Impact of 10 MW Solar Project ($4,100/kW Capital Cost, PVRR 2013-2042, $M)

AltID	Alternative (2016 Solar REC Price)	All Scenarios	Zero CO_2	Mid CO_2	Low Gas	Mid Gas	High Gas	2013 LF Load	Low Load
Weighted Average PVRR									
C50A	[redacted]								
C60A	[redacted]								
C60B	[redacted]								
C60C	[redacted]								
C60D	[redacted]								
Difference from Green River 2x1 Alternative									
C60A	[redacted]								
C60B	[redacted]								
C60C	[redacted]								
C60D	[redacted]								

Based on the higher capital costs from HDR's conceptual siting study review, the PVRR impact of the 10 MW solar facility would slightly increase PVRR. In order for the project to break-even, REC prices would need to be considerably higher than current pricing for Kentucky solar RECs; REC prices would need to range from $57 to $79 per REC, which is more in line with prices in New Jersey and Maryland.

To take advantage of federal investment tax credits for solar installations included in this analysis, the 10 MW solar project must be completed by December 31, 2016. Given this short timeline and despite the slightly unfavorable PVRR impact, the Companies are proposing to move forward with a formal solicitation of bids to construct a 10 MW solar facility at the Brown site. The solar facility is a prudent hedge against both GHG regulations and natural gas price risk, it will reduce GHG emissions, it affords the Companies the opportunity to gain operational experience with a solar PV resource, and it does not materially add to revenue requirements over the next 30 years.

4.7 Final Recommendation

Based on the RFP and self-build analysis, the optimal plan for reliably meeting customers' long-term capacity and energy needs is the following:

1. Construct a 670 MW 2x1 NGCC unit in 2018 at the Green River station.
2. Construct a 10 MW solar project in 2016 at the E.W. Brown station.

Moving forward with the NGCC unit and a 10 MW solar PV facility will enable the Companies to economically and reliably serve customers' energy needs in an environment marked by uncertainty in load, natural gas prices, and GHG regulations.

5 Utility Ownership Allocation

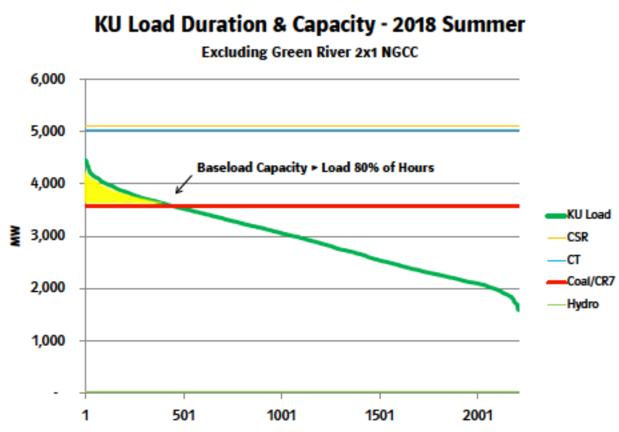
5.1 Background

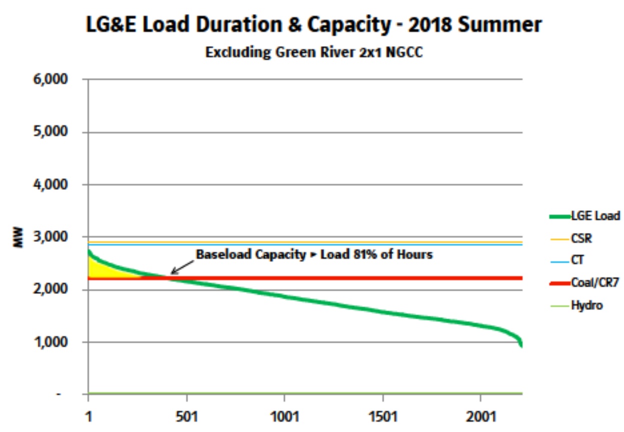
Since the merger of LG&E and KU, the Companies have commissioned eleven jointly-owned units: ten SCCTs at the Trimble County, E.W. Brown, and Paddy's Run stations and the Trimble County 2 coal unit ("TC2"). Cane Run 7 ("CR7") is on schedule to be commissioned in May 2015. An ownership ratio for the jointly-owned SCCTs was determined so that each utility's projected reserve margin was equalized in the in-service year. Because TC2 and CR7 were expected to provide significant energy savings to customers, their ownership splits were based on the expected energy benefits to each company. To determine these benefits, the production costs associated with the Companies' existing generation portfolio and 30-year least-cost expansion plan were compared to the production costs associated with the Companies' generation portfolio and a 30-year expansion plan that included only SCCTs. This "all-SCCT" expansion plan represented the least-cost expansion plan when only considering capacity needs. The overall least-cost plan included the proposed unit (either TC2 or CR7) and was expected to result in significant energy savings over the "all-SCCT" plan. Because each company was expected to benefit differently from constructing the proposed unit due to each company's unique load profile and existing generation mix, the ownership split for the proposed unit was determined based on each company's share of the net present value of production cost savings.

5.2 Energy and Capacity Needs

KU and LG&E have different load profiles and will have different levels of baseload capacity available to meet their individual energy needs. Figure 2 shows that KU's baseload capacity is expected to be greater than its 2018 summer load 80% of the time, while LG&E is expected to have sufficient baseload capacity in 81% of the summer hours. Both figures reflect each company's share of Cane Run 7. This data demonstrates that each company's need for summer capacity is similar.

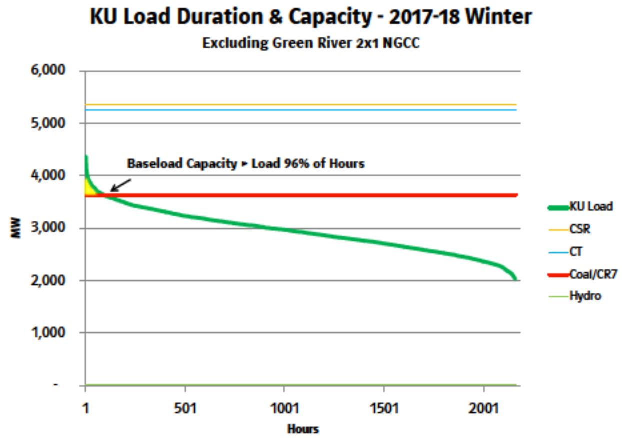
Figure 2 – KU and LG&E Summer Load Duration Curves

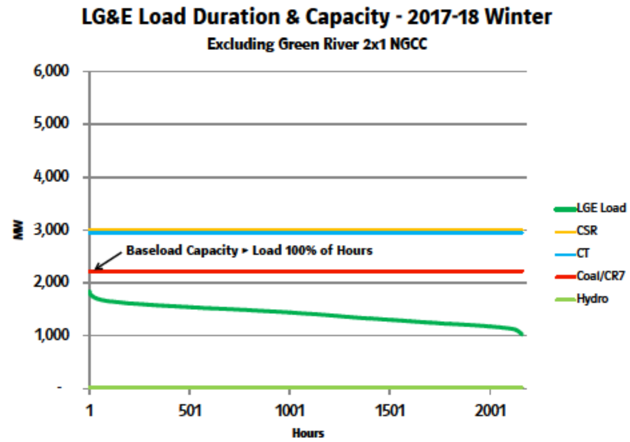




With the addition of Cane Run 7, KU and LG&E's need for winter capacity is also very similar. As seen in Figure 3, KU's winter baseload capacity is expected to be greater than its 2017-2018 winter load 96% of the time, while LG&E is expected to have sufficient baseload capacity in all winter hours.

Figure 3 – KU and LG&E Winter Load Duration Curves





5.3 Methodology

5.3.1 Green River 2x1 NGCC Unit

Depending on natural gas price levels and future GHG regulations, the Green River 2x1 NGCC unit is expected to operate at a 40-90% capacity factor, generating significant amounts of energy. For this reason, the Companies calculated their ownership using a method similar to the method used for TC2 and CR7 (see Section 5.1) so that each company's ownership share matches its share of the anticipated energy benefits.

5.3.2 10 MW Solar Project

The 10 MW solar project was allocated to each company based on its share of total energy during daylight hours. Because the number of daylight hours (and solar generation) varies by month, this analysis was based on each company's monthly forecast of energy.

5.4 Optimal Ownership

For a Green River 2x1 NGCC unit, the optimal ownership split is 60% for KU and 40% for LG&E. For the 10 MW solar project, the optimal ownership split is 64% for KU and 36% for LG&E. Both of these ownership splits are also close to the allocation of total energy between the Companies. KU's share of total energy is approximately 65%; LG&E's share is 35%.

6 Appendices

6.1 Appendix A – Detailed Summary of RFP Proposals, Self-Build Alternatives, and DSM Programs

Contract Description									Capital Cost	Fixed Costs (FCs, Expressed as $/MW at TIP)								Fuel/Energy Costs			Variable Costs									
									Per Bid	Per Bid				Additional Costs Incurred by LGE/KU ($2015)				Per Bid			Per Bid					Additional Costs Incurred by LGE/KU ($2015)				
Response	Counterparty	Class	Technology	Description	XM Interconnect Point (TIP)	Contract Start Date	Capacity @ TIP	Base Year for Counterparty Inputs	Asset Sale Price ($M)	FC #1 ($/MW-yr)	FC #1 Escalation	FC #2 ($/MW-yr)	FC #2 Escalation	LGE/KU Fixed XM Cost ($/MW-yr)	LGE/KU Firm Gas Transport ($/MW-yr)	Other LGE/KU Fixed O&M ($/MW-yr)	Fixed Cost Escalator	Unfired Heat Rate @ TIP (Btu/kWh)	Energy Price @ TIP ($/MWh)	Energy Price Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu or gallons)	Variable O&M ($/MWh)	Start Cost and VOM Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu)	Variable O&M ($/MWh)	Start Cost and VOM Escalator
1A	[redacted]																													
1B	[redacted]																													
1C	[redacted]																													
2	[redacted]																													
3	[redacted]																													
4A	[redacted]																													
4B	[redacted]																													
4C	[redacted]																													
5A	[redacted]																													
5B	[redacted]																													
5C	[redacted]																													
5D	[redacted]																													
5E	[redacted]																													
5F	[redacted]																													
6A	[redacted]																													
6B	[redacted]																													
7A	[redacted]																													
7B	[redacted]																													
7C	[redacted]																													
7D	[redacted]																													
7E	[redacted]																													
7F	[redacted]																													
7G	[redacted]																													
7H	[redacted]																													
7I	[redacted]																													
7J	[redacted]																													
8	[redacted]																													
9A	[redacted]																													
9B	[redacted]																													
10	[redacted]																													
11A	[redacted]																													
11B	[redacted]																													
11C	[redacted]																													
11D	[redacted]																													
11E	[redacted]																													
11F	[redacted]																													
12	[redacted]																													
13	[redacted]																													
14A	[redacted]																													
14B	[redacted]																													
15	[redacted]																													
16A	[redacted]																													
16B	[redacted]																													
16C	[redacted]																													
17	[redacted]																													
18A	[redacted]																													
18B	[redacted]																													
18C	[redacted]																													
19A	[redacted]																													
19B	[redacted]																													
19C	[redacted]																													
19D	[redacted]																													
19E	[redacted]																													
19F	[redacted]																													
20	[redacted]																													
21	[redacted]																													
22A	[redacted]																													
22B	[redacted]																													
22C	[redacted]																													
23	[redacted]																													
24A	[redacted]																													
24B	[redacted]																													
25	[redacted]																													
26	[redacted]																													
27A	[redacted]																													
27B	[redacted]																													
41A	[redacted]																													
41B	[redacted]																													
42	[redacted]																													
43A	[redacted]																													
43B	[redacted]																													
43C	[redacted]																													
29	LGE/KU	NGCC (1X1)_Own	NGCC (1x1), Siemens	Self-Build, 332 MW	Green River	6/1/2017	332	2018	437.9						21,080		2.00%	6,880								0	441	1,510	0.35	2.00%
33	LGE/KU	NGCC (2X1)_Own	NGCC (2x1), Siemens	Self-Build, 670.4 MW	Green River	6/1/2017	670	2018	650.4						21,080		2.00%	6,866								0	883	3,019	0.35	2.00%
35	LGE/KU	Solar_Own	Solar (PV Array)	Self-Build, 10 MW	Site TBD	1/1/2016	10	2015	46.3							10,185	2.00%												0.91	2.00%
37	LGE/KU	SCCT_Own	SCCT	Trimble CT Retrofit	Trimble County Station	4/1/2015	54	2015	108									10,139												
38	LGE/KU	SCCT_Own	Steam Augmentation	Steam Augmentation for Trimble CTs	Trimble County Station	4/1/2015	102	2015	108									9,969												
40A	LGE/KU	DSM	DSM	Lighting	LGE/KU System	1/1/2015	1	2015																						
40B	LGE/KU	DSM	DSM	Thermostat Rebates	LGE/KU System	1/1/2015	1	2015																						
40C	LGE/KU	DSM	DSM	Windows & Doors	LGE/KU System	1/1/2015	1	2015																						
40D	LGE/KU	DSM	DSM	Manufactured Homes	LGE/KU System	1/1/2015	1	2015																						
40E	LGE/KU	DSM	DSM	Behavioral Thermostat Pilot	LGE/KU System	1/1/2015	1	2015																						
40F	LGE/KU	DSM	DSM	Commercial New Construction	LGE/KU System	1/1/2015	1	2015																						
40G	LGE/KU	DSM	DSM	Automated Demand Response	LGE/KU System	1/1/2015	1	2015	127.1																					

6.2 Appendix B – Phase 1 Screening Analysis Results

Group	Counterparty	Description	Capital ($/kW)	Fixed O&M ($/MW-yr)	Energy Price ($/MWh)	Avg Levelized Cost ($/MWh)	Pass
[redacted]							✓ ✓

Note: With a few exceptions, the least-cost proposals in each Phase 1 screening group passed the Phase 1 screening analysis. These exceptions are discussed further on the following page.

With the following exceptions, the least-cost proposals in each Phase 1 screening group passed the Phase 1 screening analysis:

- The [redacted] from [redacted] for [redacted] did not pass the Phase 1 screening analysis because a similarly-sized [redacted] proposal from [redacted] was lower cost.
- The "NGCC (2X1)_5" group included proposals from two companies. The top option from each company passed the Phase 1 screening analysis.
- [redacted]
- The most competitive proposals from [redacted] were [redacted]. For this reason, the [redacted] from [redacted] did not pass the Phase 1 screening analysis.
- In the "Coal_Own" group, the [redacted] proposal from [redacted] is not a viable alternative given the short timeline for completing this transaction.

6.3 Appendix C – [redacted] Considerations (Prepared September 2013)

[redacted] is [redacted] of [redacted]. The capacity and energy referenced in the [redacted] proposal is sourced from [redacted]. [redacted]. Based on the Phase 3 results, the Companies' entered into contract discussions with [redacted]. Before finalizing PPA terms, the Companies evaluated the financial performance, credit exposure, contractual uncertainties, and environmental risks that would be associated with a potential [redacted] PPA. This analysis determined that these risks are substantial and more than offset the value afforded by the proposal's ability to defer the addition of new generation beyond 2018.

6.3.1 Financial Risk

[redacted], the [redacted] that [redacted], is in poor financial condition, primarily due to low current market prices for capacity and energy [redacted]. This poor financial condition greatly increases the risks of entering into a four year PPA that will not begin until 2016. This risk is further complicated by [redacted].

In a typical PPA, the buyer is concerned about the seller's performance should market prices become greater than the PPA price – the classic price majeure risk. In addition to the usual price risk, the Companies are concerned that the weak financial condition of [redacted] will worsen should low power prices continue. Normally, lower prices would decrease a buyer's risk in a PPA. However, in the proposed [redacted] transaction, lower prices may lead to the inability of [redacted] to properly maintain the [redacted] plant or force the station to shut down because it becomes uneconomic to continue operations. [redacted] financial instability poses a significant risk to the Companies over the life of a potential PPA and arguably outweighs the usual "price majeure" PPA risk. In other words, the Companies' risk increases if prices rise and also increases if prices remain the same or fall. This is not a desirable situation when contemplating entering into a PPA to ensure reliable service to customers.

Pertinent facts regarding [redacted] financial situation are as follows:

1. In [redacted].
2. According to the rating agencies, the highest expected credit rating (if rated) for [redacted].
   - S&P Global Corporate Average Cumulative default rates (1981-2012) for the 6 year future time horizon (now through 2019) is 48% for a [redacted] rating.
3. [redacted]
4. S&P simulated default scenarios contemplate a default by [redacted] in 2015 and a default by [redacted] in 2016 assuming natural gas prices remain low, higher than expected capital expenditures, and higher operational outages.

The Companies requested that [redacted] propose a credit arrangement that it felt would be appropriate for its PPA proposal. [redacted] responded with a typical PPA mark-to-market credit arrangement that would only address price risk. In fact, given the Companies' obligation to reliably serve their customers, there is no credit arrangement that can ensure [redacted] will be a reliable provider of power through 2019. The

Companies have never viewed a cash payment in the event of default as a substitute for physical reliability. Knowingly entering into a PPA of this term and volume with an entity in such poor financial condition could be deemed unwise should [redacted] fail to perform at some point in the future.

6.3.2 Contractual Risk

The Companies would not be contracting with the [redacted]. Instead, the Companies would be contracting with [redacted]. While this contract structure is [redacted], it impairs the Companies' ability to mitigate and manage plant operating issues as it would in a typical capacity PPA. The Companies' uncertainty is further increased because [redacted]. The issues that would be challenging to address in PPA negotiations are:

1. Enforcement of good utility practices for the operation and maintenance of the assets.
2. Ability to challenge potential force majeure claims at [redacted].
3. Ability to monitor plant maintenance and operations, particularly in light of [redacted].
4. Ability to force [redacted].
5. The uncertainty of the terms and conditions of [redacted].
6. A [redacted] and other credit risk issues as described above.

For these reasons, negotiating a PPA with an acceptable risk profile for the Companies seems unlikely. Thus, the Companies would likely be forced to accept a PPA which would leave it unfavorably exposed to the above mentioned issues should it pursue negotiations with [redacted].

6.3.3 Environmental Risk

The [redacted] plant lacks [redacted] and presently operates [redacted]

Furthermore, it is highly likely that the Companies would end up with most, if not all, of the financial and reliability risks associated with future environmental regulations and permits in a PPA with very little ability to control or manage such risks except to seek an alternative supplier. Given the [redacted], future environmental risk is considered significant. This environmental risk is further heightened because [redacted] weak financial condition makes it unlikely that it could raise the capital needed to install future controls.

6.3.4 Reliability Implications of an [redacted] Default

The Companies issued the RFP to acquire reliable capacity to serve the future needs of their customers. As discussed above, there are atypical and unacceptable circumstances (beyond the typical forced outage events) that could prevent [redacted] from delivering capacity and energy through 2019. Should [redacted] stop performing, the Companies' reserve margin would drop below their target range (15-17%) and increase their reliability risk (see Table 35). As the reserve margin shortfall increases due to forecasted load growth, the magnitude of the reliability risk associated with a failure of [redacted] to deliver under the PPA increases. As Table 35 indicates, the loss of a single 500 MW plant at near-peak conditions would put the Companies at risk of not meeting their NERC operating reserve obligations.

While every effort would be made to mitigate the risks of serving load reliably, the ability to contract for replacement capacity particularly in 2018 to 2019 is uncertain and would depend on market conditions and the availability of transmission capacity to access market power. It is unlikely that any self-build option would be a viable alternative over such a short time horizon given the time required to develop and build a new power plant.

Table 38 – Reserve Margin without [redacted] PPA (Based on 2014 Load Forecast)

	2016	2017	2018	2019
Reserve Capacity less Operating Reserves (328 MW)	681	630	535	498
Reserve Margin %	14.2%	13.4%	12.0%	11.4%
MW vs. 15%*	(53)	(113)	(217)	(263)

*Negative values denote reserve margin shortfalls.

6.3.5 Conclusion

The opportunity to enter into a PPA with [redacted] would appear to be economically attractive if [redacted] would deliver the contracted capacity and energy through 2019. However, any savings could quickly evaporate and significant reliability issues would ensue should the [redacted] plant not be able to operate at some point in the future. The poor financial condition of [redacted], the unusual PPA contract structure involving [redacted], and the environmental risks associated with [redacted] make reliance on the [redacted] PPA unreasonably risky. Furthermore, should [redacted] cease performing, the Companies would face material reliability challenges and limited ability to address them. For these reasons, the Companies eliminated the [redacted] PPA from further consideration in the RFP process.

6.4 Appendix D – NGCC and Solar Project Description

The following section summarizes the scope and cost of the proposed Green River 2x1 NGCC unit and the 10 MW solar PV facility.

6.4.1 Green River 2x1 NGCC Unit

6.4.1.1 Project Scope

The project scope includes all work necessary to construct a 670 MW net summer rating 2x1 NGCC unit with a fired heat rate of 6,940 Btu/kWh at Green River prior to May 1, 2018, including an 11 mile gas pipeline from Texas Gas to the Green River site.

H-class gas turbine technology provides the basis of an air permit application to be filed early in 2014, with the Kentucky Division for Air Quality (DAQ). This air permitting approach should allow for substitution of smaller F-class gas turbines if they prove to be lower cost. By utilizing the emissions from the existing Green River units 3 and 4 to be shut down, the new NGCC unit will be able to “net out” of the Prevention of Significant Deterioration permitting requirements for NO_x, SO_2, and PM. Receipt of all environmental permits necessary for construction is anticipated by early 2015. Significant delays of the permits required to commence construction will delay commercial operation beyond the best case required date of May 1, 2018.

HDR, an engineering consulting company, has been selected as the Owner’s Engineer to support the engineering efforts throughout 2013 to optimize the design of the NGCC unit, including environmental permitting. HDR is currently serving the Companies as Owner’s Engineer for Cane Run 7. HDR is also serving as Owner’s Engineer for Alliant Energy and Consumers Energy for their 2017 NGCC projects. HDR will assist the Companies in their procurement efforts in 2014. Based on the current plans, purchase orders for long lead time equipment are scheduled to be issued upon receipt of required regulatory and environmental approvals, consistent with a construction schedule to meet the planned May 1, 2018 commercial operations date.

EN Engineering will perform a route selection study for a gas pipeline to serve the Green River 2x1 NGCC unit. It is anticipated that the selected route will mostly be located along existing electric transmission rights of way. The cost estimated for a 20” diameter line, adequate to serve the planned 670 MW NGCC unit, is included in the overall cost estimate. The Companies’ Gas Engineering staff will manage the pipeline construction for the project. Construction of the pipeline is scheduled in 2017.

Texas Gas will likely provide interstate gas transportation for the Green River 2x1 NGCC unit. Texas Gas currently has firm transportation available in 2018 and has offered to provide service. The optimal transportation volume has not yet been determined, but the annual fixed cost component of the transportation is expected to range from $11 - $14 million plus a variable cost of $0.03/mmBtu and a fuel loss of 2.71%. The current offer by Texas Gas reflects the creation of a new service that does not at this time have a published maximum tariff rate. Based on previous agreements, however, it is reasonable to assume an annual discount of 27.5% from the maximum tariff rate or approximately $3.5 million annually. In addition, the offer includes:

- A minimum delivery pressure of 600 psig.
- Texas Gas’s commitment to pay for the capital expenditures incurred in the installation of a new meter station (estimated value of $2 million).

- An evergreen provision and contractual right of first refusal.

ANR Pipeline Company ("ANR") is also a potential supplier for the Green River 2x1 NGCC unit. Firm gas transportation is available on the ANR pipeline at approximately the same cost as Texas Gas. However, ANR's services are not as robust, and the distance between the Green River station and the ANR pipeline results in higher interconnect costs.

As required by the Companies' Open Access Transmission Tariff ("OATT"), a Large Generator Interconnection request was filed with TranServ on October 16, 2013. The System Impact Study results should be available by the end of 2014. While electric transmission upgrades are expected to be required, a transmission CCN application is not anticipated. Once a Large Generator Interconnection Agreement is signed in 2015, the Transmission Owner will be responsible for developing and constructing any necessary transmission system upgrades. Using methods and data consistent with the Companies' transmission planning process, the Companies' transmission staff conducted its own analysis of upgrades necessary for delivering energy from the Green River 2x1 NGCC unit to load. Transmission projects identified in the Companies' analysis include installation of a transformer, generator breakers, switches, line rating upgrades, and relocation of some transmission structures and conductors. The result of this analysis, including cost estimates, is a reasonable approximation of the transmission work expected.

6.4.1.2 Project Cost

Table 36 summarizes the project capital costs by year. The sum of nominal capital costs is expected to be $635.2 million for generation and $96.6 million for electric transmission upgrades.[36] No costs of decommissioning Green River units 3 and 4 are included in the estimate. The estimate includes contingency of approximately 10% of the expected EPC cost. The estimated project costs were determined in a site specific study dated March 29, 2013, assuming an Engineer, Procure & Construction contracting strategy is used. The estimate includes $10 million for capitalized spare parts.

Table 39 – Green River 2x1 NGCC Unit Capital Costs (Nominal Dollars, $M)

	2015	2016	2017	2018	Total
Generation	275.5	333.4	26.3	-	635.2
Transmission	10	30.2	46.4	10	96.6
Totals	285.5	363.6	72.7	10	731.8

The capital cost estimate is based on major equipment budgetary quotations and HDR's project database. Major equipment (gas turbine, heat recovery steam generator, and steam turbine) budgetary quotations from multiple suppliers were received in February 2013. HDR evaluated the budgetary quotes and compiled a Level I Conceptual Cost Estimate in March 2013. Major market shifts, such as an increased demand for natural gas or labor shortage due to environmental compliance projects, could cause the cost estimate to be exceeded.

[36] In 2018 dollars, the project capital costs are $650.4 million for generation and $99.9 million for electric transmission upgrades.

6.4.2 10 MW Solar PV Facility

6.4.2.1 Project Scope

The project scope includes all work necessary to construct a 10 MW solar PV facility at the E.W. Brown station prior to January 1, 2016.

The generation of a 10 MW solar PV facility has been modeled using the National Renewable Energy Laboratory's ("NREL's") PVWatts v.2 solar modeling program, which is an industry standard solar generation estimation tool. PVWatts was used for a central location within the Companies' service territory, which should be representative of the E.W. Brown site. The following additional solar PV system specifications were utilized based on the PVWatts evaluation of the E.W. Brown site:

- DC Rating: 12,701 kW
- DC to AC Conversion Efficiency Factor: 0.80
- AC Rating: 10,000 kW

The estimated land requirement for a 10 MW fixed array thin film PV facility is between 85 and 90 acres. This arrangement provides for adequate spacing between rows to avoid row-on-row shading, balance of plant system equipment such as inverter pads, and substation and maintenance access. The available land at the E.W. Brown site is approximately 150 acres, which allows for typical Kentucky topography.

6.4.2.2 Project Cost

The total installed cost of the 10 MW solar PV facility at the E.W. Brown site is estimated to be $36 million. Capital costs are representative of recent installations of similar sized solar facilities with thin film fixed panel technology and are de-escalated for anticipated reductions in capital cost.

Equipment pricing for major equipment, including the PV panels, inverters, switchgear, and the 69 kV substation, as well as recent equipment estimates from similar projects, were utilized in developing the estimated total project cost. These costs were then de-escalated for a 2016 operational date to reflect current pricing trends. Other assumptions and project scope included in the estimate is summarized as follows:

- Packaged 500 kW inverters serving 13.8 kV underground direct buried electric distribution collector system.
- Sales tax is included for non-production material.
- No permanent office or warehouse space is provided.
- 69 kV Transmission Interconnection (Single 10 MVA 13.8/69 kV transformer, two breaker loop feed 69 kV line interface).
- Owner's contingency of 10 percent of the total EPC project cost has been included within the project estimate.

Exhibit DSS-2: 2013 LF – Peak Demand and Energy Requirements Before DSM

	Peak Demand (MW)	Energy Requirements (GWh)
2012	6,970	35,076
2013	7,259	36,055
2014	7,338	36,396
2015	7,426	36,748
2016	7,509	37,014
2017	7,597	37,277
2018	7,696	37,658
2019	7,746	37,865
2020	7,815	38,184
2021	7,885	38,433
2022	7,943	38,746
2023	8,011	39,086
2024	8,079	39,516
2025	8,147	39,847
2026	8,216	40,208
2027	8,284	40,570
2028	8,361	40,975
2029	8,439	41,346
2030	8,517	41,768
2031	8,597	42,128
2032	8,676	42,510
2033	8,746	42,904
2034	8,819	43,258
2035	8,891	43,657
2036	8,964	44,097
2037	9,037	44,504
2038	9,111	44,888
2039	9,185	45,282
2040	9,261	45,683
2041	9,338	46,102
2042	9,416	46,390

Peak Demand data for 2012 reflects the actual value adjusted for estimated DSM impact.
Energy Requirements data for 2012 is a weather normalized estimated value.

Exhibit DSS-3: DSM Impacts to Peak Demand and Energy Requirements

	Peak Demand (MW)	Energy Requirements (GWh)
2012	114	139
2013	307	307
2014	344	444
2015	386	585
2016	418	679
2017	450	774
2018	482	870
2019	464	764
2020	466	764
2021	467	764
2022	469	764
2023	471	764
2024	473	764
2025	475	764
2026	476	764
2027	478	764
2028	480	764
2029	482	764
2030	484	764
2031	485	764
2032	487	764
2033	489	764
2034	491	764
2035	493	764
2036	494	764
2037	496	764
2038	498	764
2039	500	764
2040	502	764
2041	503	764
2042	505	764

Data for 2012 are estimated values.

Exhibit DSS-4: 2013 LF – Peak Demand and Energy Requirements After DSM

	Peak Demand (MW)	Energy Requirements (GWh)
2000	6,317	32,329
2001	6,221	31,781
2002	6,513	32,580
2003	6,393	33,424
2004	6,223	34,338
2005	6,833	34,893
2006	6,863	35,205
2007	7,132	35,831
2008	6,357	35,153
2009	6,555	33,922
2010	7,175	35,336
2011	6,756	34,515
2012	6,856	34,937
2013	6,952	35,748
2014	6,995	35,952
2015	7,040	36,162
2016	7,091	36,335
2017	7,147	36,503
2018	7,214	36,788
2019	7,282	37,101
2020	7,350	37,421
2021	7,418	37,669
2022	7,474	37,982
2023	7,540	38,323
2024	7,606	38,752
2025	7,673	39,083
2026	7,739	39,444
2027	7,806	39,806
2028	7,881	40,211
2029	7,957	40,582
2030	8,034	41,004
2031	8,111	41,364
2032	8,188	41,746
2033	8,257	42,140
2034	8,328	42,494
2035	8,398	42,894
2036	8,469	43,333
2037	8,541	43,740
2038	8,613	44,125
2039	8,685	44,518
2040	8,760	44,920
2041	8,834	45,338
2042	8,910	45,627

Peak Demand data for 2000-2012 are actual values.
Energy Requirements data for 2000-2012 are weather normalized actual values.

Exhibit DSS-5: Peak Demand and Energy Requirements After DSM – Comparison of 2013 LF and 2014 LF

	2013 LF Peak Demand (MW)	2013 LF Energy Requirements (GWh)	2014 LF Peak Demand (MW)	2014 LF Energy Requirements (GWh)
2015	7,040	36,162	7,028	35,892
2016	7,091	36,335	7,085	36,153
2017	7,147	36,503	7,142	36,383
2018	7,214	36,788	7,199	36,684
2019	7,282	37,101	7,257	36,998
2020	7,350	37,421	7,315	37,260
2021	7,418	37,669	7,374	37,479
2022	7,474	37,982	7,433	37,704
2023	7,540	38,323	7,488	37,922
2024	7,606	38,752	7,542	38,235
2025	7,673	39,083	7,598	38,478
2026	7,739	39,444	7,653	38,731
2027	7,806	39,806	7,709	38,990
2028	7,881	40,211	7,766	39,279
2029	7,957	40,582	7,822	39,543
2030	8,034	41,004	7,880	39,841
2031	8,111	41,364	7,937	40,084
2032	8,188	41,746	7,995	40,324
2033	8,257	42,140	8,054	40,596
2034	8,328	42,494	8,113	40,875
2035	8,398	42,894	8,172	41,162
2036	8,469	43,333	8,232	41,450
2037	8,541	43,740	8,292	41,663
2038	8,613	44,125	8,353	41,885
2039	8,685	44,518	8,414	42,111
2040	8,760	44,920	8,476	42,333
2041	8,834	45,338	8,538	42,556
2042	8,910	45,627	8,600	42,737

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY AND KENTUCKY	)	
UTILITIES COMPANY FOR CERTIFICATES	)	
OF PUBLIC CONVENIENCE AND NECESSITY	)	
FOR THE CONSTRUCTION OF A COMBINED	)	**CASE NO. 2014-00002**
CYCLE COMBUSTION TURBINE AT THE	)	
GREEN RIVER GENERATING STATION AND	)	
A SOLAR PHOTOVOLTAIC FACILITY AT THE	)	
E.W. BROWN GENERATING STATION	)	

DIRECT TESTIMONY OF
JOHN N. VOYLES, JR.
VICE PRESIDENT, TRANSMISSION AND GENERATION SERVICES
KENTUCKY UTILITIES COMPANY
AND LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: January 17, 2014

Q. Please state your name, position and business address.

A. My name is John N. Voyles, Jr. I am the Vice President of Transmission and Generation Services for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E"), and I am an employee of LG&E and KU Services Company, which provides services to LG&E and KU (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Please describe your job responsibilities.

A. I have 37 years of experience in the utility industry. In addition to oversight of the Transmission system, my current responsibilities include support of the generating fleet for both Companies with Generation Engineering and System Lab departments. I am also responsible for Project Engineering, the department that oversees large construction projects including generating stations, pollution control equipment, and on-site byproduct storage facilities. Prior to this assignment, I was the officer responsible for the generating fleet. Earlier in my career, I served as the corporate environmental director.

Q. Have you previously testified before this Commission?

A. Yes. I testified in Case No. 2011-00375, *In re the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine*

Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky. I testified in the Companies' 2009 environmental compliance plan cases (Case Nos. 2009-00197 (KU 2009 ECR Plan) and 2009-00198 (LG&E 2009 ECR Plan), and I also testified in the Companies' recent environmental cost surcharge cases, Case Nos. 2011-00161 (KU) and 2011-00162 (LG&E).

Q. What is the purpose of your testimony?

A. As discussed in Mr. Sinclair's and Mr. Revlett's testimonies, the Companies have concluded that the most cost-effective method of meeting customer needs while at the same time complying with the recently enacted and anticipated air quality regulations is to construct new natural gas combined cycle facilities at the Green River generating station ("Green River NGCC"). Furthermore, construction of a 10 MW solar photovoltaic facility at the E.W. Brown generating station ("Brown Solar Facility") will allow the Companies to add a renewable generation resource with relatively minor impact to customer revenue requirements in the coming years. My testimony will explain the details of the construction plans for the Green River NGCC and the Brown Solar Facility.

CONSTRUCTION AT GREEN RIVER

Q. Please describe the facilities the Companies propose to construct at Green River.

A. The Companies have proposed the construction of an approximately 700 megawatt net summer rating ("700 MW") natural gas combined cycle generating unit utilizing the latest advanced gas turbine technology at the Green River station. Conceptual and preliminary plans, specifications and drawings for Green River NGCC are attached as Joint Application Exhibit 3.

Q. Why have you described the Green River NGCC as an "approximately" 700 MW facility?

A. It has been our experience that different manufacturers of combustion turbines produce equipment with different capacity ratings and that actual capacity ratings can vary somewhat from what is stated as the equipment's name plate rating. Therefore, it is prudent for the Companies to allow for a reasonable amount of bid flexibility on output amount. Without that flexibility, it is possible that some turbine manufacturers whose turbines generate slightly more or less than 700 MW would be unable to submit a conforming bid without penalizing the efficiency of the unit offered in the bid. Such a result would work to the economic detriment of our customers. It should be noted that the Resource Assessment attached to Mr. Sinclair's testimony modeled a 670 MW NGCC. The Companies intend to capitalize on the market competitiveness and seek bids that are within a reasonable range of 700 MW, such as 10% above or below that capacity, to take advantage of the best bid among those that might be offered.

Q. Please explain the advantages of using an existing site for construction of the Green River NGCC.

A. The existing Green River site contains approximately 400 acres in Muhlenberg County along the Green River and is well-suited for the Green River NGCC. Using an existing site for the Green River NGCC will allow the Companies to utilize the river water intake and the Kentucky Pollutant Discharge Elimination System water discharge points. The Green River NGCC will utilize the transmission circuits already existing at Green River (subject to studies being performed by TranServ International ("TranServ")) in accordance with the Open Access Transmission Tariff

("OATT"). At this time, the Companies do not expect circumstances that would require new high voltage electric transmission lines for which transmission CPCNs from the Commission would be required, but this issue is being studied.

The use of the existing Green River site also minimizes development risk associated with air permitting. Although the Green River NGCC will still be required to obtain an air permit and to comply with all applicable environmental requirements, the utilization of the existing emissions of Green River units 3 and 4 (which will be retired in 2015) will allow the proposed unit to "net out" of the Prevention of Significant Deterioration air permitting process for nitrogen oxides ("NO_x"), sulfur dioxide ("SO_2"), and particulate matter ("PM") that would be required for a new "green field" site. Using the Green River site also minimizes the need to purchase additional property for the generation site (although approximately 120 acres will need to be purchased for siting setback requirements) and reduces additional costs related to site infrastructure for items such as utilities, security, communications, and the like.

Finally, constructing a new energy supply facility in Western Kentucky at Green River produces the ancillary benefit of more reliable energy supply for customers in Western Kentucky. Following the retirement of Green River 3 and 4, which are the Companies' only generation units in that part of their service territory, the Companies would have to rely more heavily on the transmission grid to transmit power to that area. Construction of the Green River NGCC (which will be a designated resource for the Companies) at the current Green River site reduces the need to rely more heavily on the transmission grid.

Q. Do the Companies currently operate any NGCC units?

A. No, but they are in the process of constructing the NGCC unit at Cane Run that was authorized by the Commission in Case No. 2011-00375 and it will be operational by May 2015. The Companies will incorporate the knowledge they have and are obtaining throughout the Cane Run NGCC effort. Moreover, the Companies are familiar with the technology involved with NGCC units. The Companies currently operate a fleet of advanced gas turbines and are familiar with the operation and maintenance requirements of gas turbines. The Companies' existing coal-fired steam fleet utilizes many steam turbines and heat-to-steam boilers. The operation and maintenance of the Green River NGCC steam turbine will be similar to the existing units. Although the heat recovery steam generator ("HRSG") can be compared to a boiler, it will have somewhat different O&M requirements. The Companies have visited, studied and received training on operating combined-cycle plants to understand construction and operating differences. Through collaborative funding from its members, including the Companies, the Electric Power Research Institute ("EPRI") has developed extensive recommendations on HRSG design to minimize maintenance issues. As with the Cane Run NGCC project, those EPRI recommendations are being reviewed and incorporated into the Green River NGCC technical specifications being developed by the Companies and our Owner's Engineer ("OE"), HDR. HDR has considerable NGCC experience and has served as the Companies' OE for Cane Run NGCC. In summary, the Companies have the necessary expertise to construct and operate Green River NGCC.

Q. Are there significant environmental benefits of using NGCC technology at Green River?

A. Yes. First, NGCC technology does not produce combustion by-products that would require the same landfill needs as coal-fired technology. Additionally, when compared to existing facilities at Green River, emission of PM and NO_X will be greatly reduced, while emissions of SO_2 will be all but eliminated. The reduction in SO_2 and NO_X emissions are also incorporated into meeting the Companies' requirements under the final Cross-State Air Pollution Rule allowance allocations.[1] We anticipate that the carbon dioxide emissions will be less than 1,000 pounds per MWh, which will comply with the Environmental Protection Agency's proposed greenhouse gas rule for new fossil-fuel-fired units.[2]

Q. Please describe the construction plans for Green River NGCC.

A. The Companies plan on constructing the unit so that it is operational prior to May 1, 2018. To the extent it becomes operational significantly after that date, the Companies are concerned that they will not be able to take full advantage of the emission "netting out" opportunities created by the retirements of Green River units 3 and 4, potentially adding costs to the unit. Thus, once regulatory approvals are obtained, the Companies will make every effort to construct and place the Green River NGCC into commercial operation prior to May 1, 2018. To that end, the Companies have already begun work on developing the specifications for the gas turbine, HRSG, steam turbine and the prime engineer, procure, and construct ("EPC") contract. The Companies plan to issue a Request for Quotations for the EPC contract in the second quarter of 2014.

[1] See the Direct Testimony of Gary H. Revlett for a discussion of the current status of the Cross State Air Pollution Rule.
[2] See the Direct Testimony of Gary H. Revlett for a discussion of the EPA's proposed greenhouse gas rule.

As described in Mr. Sinclair's testimony, the Companies have concluded that the lowest reasonable cost option for serving load and ensuring cost-effective environmental compliance is to self-build Green River NGCC. The self-build process will include an OE which will support our Project Engineering and Power Production staffs. As they did for the Cane Run NGCC project, the Companies have contracted with the engineering firm HDR to serve as the OE. HDR will also assist with design optimization, environmental permitting and procurement efforts. Once the EPC bids are received and analyzed, purchase orders for long lead time equipment can be authorized. With timely regulatory approval and receipt of the construction permits, completion of the Green River NGCC can meet the May 1, 2018 target commercial operation date.

Q. Please describe the construction timeline for the Green River NGCC.

A. Once the regulatory approvals are received, the construction process will begin. The critical time element for construction of the NGCC is the steam turbine. After the purchase order for the steam turbine is placed, manufacture requires approximately 20 months, with delivery three months later. Erection of the steam turbine typically requires eleven months. Startup, final testing and commissioning activities generally require two months with the end result being commercial operation. In total, the Companies estimate that it will take approximately 37 months from execution of the EPC contract until commercial operation, not considering time required for permitting and regulatory approvals. The Companies are preparing specifications and Requests for Quotations on equipment and construction packages so they can be in a position to execute the EPC contract soon after Commission approval and issuance of a final air permit by the Kentucky Department for Air Quality.

Q. Are there permits that will be required as part of the construction?

A. Yes. The environmental permits are discussed in Mr. Revlett's testimony. In addition, permits normally required for construction (plumbing, building, etc.) will be obtained at the appropriate time as necessary.

Q. Why are the Companies seeking a CPCN at this time?

A. The Companies are requesting a CPCN at this time so that they can ensure the cost-effectiveness of their plans in light of air quality standards, maximize the emission "netting out" opportunities, and position themselves to meet their obligation to reliably serve their customers in the years ahead. We recognize that it may take a number of months for approval of the CPCN and the necessary pre-construction environmental permits. We also know from experience that the large scope of the project will require an intensive process of qualifying suppliers, evaluation of bids and earnest negotiations. In light of the complexity of the construction project and the anticipated market impacts due to the EPA regulations, difficulties and resulting delays are possible. Taking all of that into account, in order to have Green River NGCC operational prior to May 1, 2018, we believe it is imperative to seek Commission approval at this time.

Q. Have the Companies performed any construction work for the Green River NGCC at this time?

A. No. However, as indicated previously, the Companies are proceeding with engineering, permitting, and bidding processes for the EPC contract. Unless entering into one or more of those contracts is necessary to ensure timely environmental compliance, address transmission system reliability concerns, or guard against significant market price increases or equipment delivery risks, the Companies will not enter into contracts prior to approval by this Commission. Should entering into contracts be necessary prior to final regulatory approvals, any such contracts will have cancellation clauses with specific deferment schedules contingent on receiving the necessary regulatory approvals (including the approval of this Commission).

Q. Will any natural gas transmission work have to be performed in connection with the Green River NGCC construction?

A. Yes. The Companies have contracted with EN Engineering, a route selection expert, to perform a route selection study for a gas pipeline to serve the Green River NGCC. The Companies anticipate an approximately 11-mile route mostly along existing electric transmission rights-of-way as depicted in Exhibit 4 to the Joint Application. Once the route is finalized, the Companies' Gas Engineering staff will manage the engineering and construction of that pipeline which is planned to be completed in 2017 to support test firing of the unit. Additionally, the Companies have had discussions with Texas Gas and ANR Pipeline Company about providing the interstate gas transportation necessary to supply the Green River NGCC and the meter station that will be necessary at the delivery point. Those discussions are ongoing.

Q. What are the expected construction costs of the Green River NGCC?

A. The project cost is expected to be approximately $700 million for generation, including the costs of the gas pipeline. From the Combined Cycle Feasibility Study Life Cycle Cost Analysis prepared by HDR, we have seen that the cost of combined cycle combustion turbines is approximately $1 million/MW. At $1 million/MW, the approximate cost would be $700 million. The Companies do not expect the price per MW to vary in any meaningful way if the successful bidder is slightly more or less than 700 MW. In the end, flexibility in the bidding marketplace will enable the Companies to choose the best solution for their customers.

Q. What will be the annual operating cost of the Green River NGCC?

A. In the Resource Assessment, fixed and variable operating and maintenance costs for the Green River NGCC are assumed to be $7.80/kW-year and $1.90/MWh, respectively.[3] These operating cost estimates are derived from the Combined Cycle Feasibility Study Life Cycle Cost Analysis prepared by HDR with input from Companies' Power Production organization. The Green River NGCC is expected to generate approximately 4,900 GWh per year beginning in 2018, resulting in an annual total fixed and non-fuel operating cost of approximately $14.5 million.

ELECTRIC TRANSMISSION CONSIDERATIONS

Q. How do the Companies plan to transmit power from the Green River NGCC to serve their load?

A. For power generated by the Green River NGCC, the Companies will utilize existing transmission infrastructure with modifications to the transmission facilities at or near the Green River station site that will be identified in the studies TranServ is conducting. At this time, those studies are not complete.

As a part of the Resource Assessment, the Companies' Transmission staff analyzed possible transmission modifications. That analysis, including cost estimates, attempts to identify the transmission work expected from the required TranServ study. Examples of some projects identified in the Companies' analysis

[3] These values are quoted in 2018 dollars. The fixed operating cost does not include the cost for firm gas delivery. The variable operating cost does not include start up fuel costs.

include installation of transformers, generator breakers, switches, line rating upgrades, and relocation of some transmission structures and conductors.

Q. What will these electric transmission modifications cost?

A. The estimated electric transmission cost of all projects which may be required in 2018 or earlier to support the Green River NGCC is approximately $100 million. It is important to note that this cost estimate continues to be refined as new information becomes available and further engineering is performed. Of course, to the extent Commission approval is required for any electric transmission work, timely application will be made.

CONSTRUCTION OF BROWN SOLAR FACILITY

Q. Why are the Companies proposing the construction of the 10 MW Brown Solar Facility?

A. As described by Messrs. Sinclair, Meiman and in the Resource Assessment, the recent decline in the price of solar panels, available federal tax credits and renewable energy certificates, and the fact that the Companies already own real property suitable for locating a solar photovoltaic facility of this size at the E.W. Brown generating station make the construction of a solar facility feasible. Given the increased likelihood of carbon constraints, the Companies believe the Brown Solar Facility will be a valuable addition to their generation portfolio and will provide experience with integrating an intermittent renewable energy supply source into the Companies' dispatching system.

Q. Please describe the proposed Brown Solar Facility.

A. The Companies propose construction of a solar facility at the Brown generating station in Mercer County, Kentucky capable of producing up to 10 MW at peak capacity under optimal conditions. The facility would include the installation of numerous fixed crystalline solar panels situated in a manner to capture the maximum amount of solar energy. That energy will then be transmitted to customers via the existing transmission and/or distribution infrastructure.

Q. Please describe the site upon which the Brown Solar Facility will be located.

A. The Companies acquired approximately 150 acres near the Brown Generation Station as a source for cover soils to be utilized in the landfill. The cover soils can be removed and the solar panel system installed on part of that acreage. The Companies plan to use suitable portions of the acreage on a South-facing incline which will be appropriately contoured to maximize the capture of solar energy. Conceptual and preliminary plans, specifications and drawings for the Brown Solar Facility are attached as Joint Application Exhibit 5.

Q. In addition to the advantage of existing ownership of sufficient acreage, are there transmission advantages to constructing the Brown Solar Facility at the Brown location?

A. Yes. The transmission and distribution infrastructure already in place at Brown means that the Companies do not anticipate any significant modifications or upgrades will be necessary to transmit power produced by the 10 MW solar facility. As with the Green River NGCC, the Companies will file as appropriate, an interconnect request with TranServ to identify what modifications, if any, will be required. However, at this time, the Companies expect that the existing transmission and distribution infrastructure at Brown will be adequate to handle the additional power.

Q. Please describe the construction plans, timeline and costs for the Brown Solar Facility.

A. The construction plans for the Brown Solar Facility are constrained by the need to have the facility operational no later than December 31, 2016. As explained by Mr. Meiman, that date is critical so that federal tax credits available for solar projects can be utilized. With that deadline in place, the Companies have contracted with HDR to develop a conceptual design. An OE for the project will be selected in early 2014 to develop detailed specifications for the site preparation requirements, solar panel systems and associated electrical inverter connections. We expect to take those specifications to the EPC marketplace thereafter. The total project cost is estimated to be approximately $36 million pending final site sizing and preparation, consisting of approximately $26 million for solar generating system equipment, $3 million for site preparation work, and $7 million for owner's costs.

Q. Will any construction permits be required?

A. No major construction permits are anticipated beyond the normal site runoff permits for site preparation. However, as described in testimony provided by Mr. Revlett, the final site layout and location could require some added water permits depending on the proximity to small runoff streams near the outer parts of the property.

Q. How much will it cost to operate the Brown Solar Facility on annual basis?

A. In the Resource Assessment, conceptual fixed and variable operating and maintenance costs for the Brown Solar Facility are assumed to be $12.50/kW-year and $0.80/MWh, respectively.[4] Based on these numbers, the annual total operating cost will be approximately $140,000.

Q. What is your recommendation to the Commission?

[4] These values are quoted in 2016 dollars.

A. I recommend that the Commission approve the Green River NGCC and Brown Solar Facility projects as cost-effective methods of ensuring adequate generating capacity while complying with current and proposed environmental laws. Further, as described above, the Companies need to move forward with the solutions proposed in this matter in a timely fashion.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY	)	
	)	**SS:**
COUNTY OF JEFFERSON	)	

The undersigned, **John N. Voyles, Jr.**, being duly sworn, deposes and says that he is Vice President, Transmission and Generation Services for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

John N. Voyles, Jr.

John N. Voyles, Jr.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of January 2014.

Sheri L. Gardner (SEAL)

Notary Public

My Commission Expires:

SHERI L. GARDNER
Notary Public, State at Large, KY
~~My Commission expires Dec. 24, 2017~~
Notary ID # 501600

APPENDIX A

John N. Voyles, Jr.

Vice President, Transmission and Generation Services
Louisville Gas and Electric Company and Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4762

Education

Rose-Hulman Institute of Technology, B.S. in Mechanical Engineering - 1976

Previous Positions

E.ON U.S. LLC

June 2008 - Present -Vice President, Transmission and Generation Services
2003 - 2008 -Vice President, Regulated Generation

LG&E Energy Corp.

February - May 2003 -- Director, Generation Services

Louisville Gas and Electric Company

1998 - 2003 -- General Manager, Cane Run, Ohio Falls and Combustion Turbines
1996 -1998 -- General Manager, Jefferson County Operations
1991 - 1995 -- Director, Environmental Excellence
1989 - 1991 -- Division Manager, Power Production, Mill Creek
1984 - 1989 -- Assistant Plant Manager, Mill Creek
1982 - 1984 -- Technical and Administrative Manager, Mill Creek
1976 - 1982 -- Mechanical Engineer

Professional Development

Emory Business School -- Management Development Program
Center for Creative Leadership (La Jolla, CA)
University of Louisville -The Effective Executive
Harvard Business School - Finance for the Non-Financial Manager
MIT - Leading Innovation & Growth: Managing the International Energy Co.

Board/Committee Memberships

Fund for the Arts - Board Member
Ohio Valley Electric Co. (OVEC) - Board member and Executive Committee member
Electric Energy, Inc. - Board member
Edison Electric Institute (EEI) - Committee member Energy Supply Executive Advisory Committee and the Environment Executive Advisory Committee
Electric Power Research Institute (EPRI) - Chairman, Research Advisory Committee

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY AND KENTUCKY	)	
UTILITIES COMPANY FOR CERTIFICATES	)	
OF PUBLIC CONVENIENCE AND NECESSITY	)	
FOR THE CONSTRUCTION OF A COMBINED	)	**CASE NO. 2014-00002**
CYCLE COMBUSTION TURBINE AT THE	)	
GREEN RIVER GENERATING STATION AND	)	
A SOLAR PHOTOVOLTAIC FACILITY AT THE	)	
E.W. BROWN GENERATING STATION	)	

DIRECT TESTIMONY OF
GARY H. REVLETT
DIRECTOR, ENVIRONMENTAL AFFAIRS
KENTUCKY UTILITIES COMPANY
AND LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: January 17, 2014

Q. Please state your name, position and business address.

A. My name is Gary H. Revlett. I am the Director of Environmental Affairs for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"). I am employed by LG&E and KU Services Company, which provides services to LG&E and KU (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I testified before the Commission in a number of proceedings. I testified most recently in the Companies' most recent application for a certificate of public convenience and necessity to build a natural gas combined cycle generating unit at the Cane Run Generating Station (Case No. 2011-00375).

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibit GHR-1: Chart of Permits.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to identify the environmental regulatory requirements applicable to the Companies' decision to construct a new natural gas combined cycle generating facility at Green River ("Green River NGCC") and to construct a 10 MW solar photovoltaic facility at the E.W. Brown generating station ("Brown Solar Facility"). More specifically, I will describe the Companies' need to comply with the regulations the U.S. Environmental Protection Agency promulgates under the federal Clean Air Act as amended ("CAAA"), including the proposed Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric

Utility Generating Units ("Proposed Greenhouse Gas Rule"). I will also provide updates to rules I have described in testimony in previous Commission proceedings, namely the Cross-State Air Pollution Rule ("CSAPR"), the Mercury and Air Toxics Standards ("MATS"), and the revised National Ambient Air Quality Standard ("NAAQS"). Finally, I will discuss environmental permitting and the status of the Companies' Site Assessment Reports.

Q. Please describe environmental regulation as it exists today.

A. Environmental compliance is and always has been an ongoing, everyday activity at our facilities and for our operations. The passage of the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act, and all subsequent amendments to and revisions of these and other environmental laws and regulations have significantly increased the Companies' environmental compliance obligations over time. There is a need for continuous investment in, and maintenance of, environmental pollution control equipment and facilities. The statutory goal for improvement of air quality has given rise to the stringent environmental regulations issued by the U.S. Environmental Protection Agency ("EPA").

Q. What environmental laws and regulations are applicable to the control of air emissions from fossil-fuel-fired generating stations?

A. Under the CAAA, the Companies are regulated by federal and state agencies. Equivalent regulatory authority at the state level is found in KRS Chapters 224 and 77. The EPA has granted Kentucky the functional responsibility for implementing the provisions of the CAAA through the State Implementation Plan process. All of the Companies' fossil-fuel-fired units in Kentucky except for those in Jefferson

County fall under the jurisdiction of the Kentucky Division for Air Quality ("KYDAQ") and must comply with regulations promulgated by the state agency, most notably in the form of the Title V permits KYDAQ has issued to the Companies' generating stations. Generating units located in Jefferson County are subject to regulation by the Louisville Metro Air Pollution Control District ("LMAPCD"), which is the primary air permitting authority for those facilities.

Q. Which air-emissions regulations affected the Companies' decision to construct the Green River NGCC and the Brown Solar Facility to meet their customers' needs?

A. The newest rule that affected the Companies' analysis is the Proposed Greenhouse Gas Rule, which will impose the first carbon-dioxide emissions restrictions on electric generating units in the United States. It applies only to new, not existing, electric generating units. As I describe further below, the proposed restrictions will effectively eliminate utilities' ability to build economical coal units in the foreseeable future, making NGCC the fossil-fuel technology of choice in situations where other non-coal-fired alternatives are not more economical. The other three EPA air-quality regulations that continue to affect the Companies' generating operations and planning decisions are the Clean Air Interstate Rule ("CAIR," which was reinstated after CSAPR was vacated), MATS, and the revised NAAQS for ozone and particulate matter.

<u>Proposed Greenhouse Gas Rule</u>

Q. Please describe the Proposed Greenhouse Gas Rule.

A. On April 13, 2012, under the authority of CAAA section 111, the EPA proposed a new source performance standard ("NSPS") to limit emissions of carbon dioxide ("CO_2") from new fossil-fuel-fired electric utility generating units, including, primarily, coal- and natural-gas-fired units.[1] The original proposal provided a single limit on CO_2 emissions for new fossil-fuel-fired electric utility generating units of all kinds: 1,000 lb CO_2/MWh.[2]

After receiving and reviewing more than 2.5 million comments on the proposed standard, the EPA chose to rescind its proposal and issue a new proposal, the Proposed Greenhouse Gas Rule, on September 20, 2013.[3] The new proposed rule provides different standards for coal-fired units (including integrated-gasification combined-cycle ("IGCC") units) and natural-gas-fired units, and further provides different standards for small and large natural-gas-fired units. The EPA based its proposed performance standard for coal-fired units on partial implementation of carbon capture and storage as the best system of emission reduction, which is the statutory benchmark for setting a new source performance standard. For such sources, the proposed standard is 1,100 lb CO_2/MWh.[4] For natural-gas-fired units, the EPA based its performance standards on modern, efficient NGCC technology as the best system of emission reduction. The proposed emission limits for those sources are 1,000 lb CO_2/MWh for large units and 1,100 lb CO_2/MWh for small units.[5] Natural-gas-fired units with heat input ratings greater than 850 MMBtu/hour, such as

[1] 77 FR 22392.
[2] *Id.*
[3] Available at: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.
[4] *Id.* at 15-16. The EPA has also proposed a standard as low as 1,050 lb CO_2/MWh for coal-fired units measured on an 84-month rolling average.
[5] *Id.* at 16.

the Green River NGCC, are considered large under the Proposed Greenhouse Gas Rule.[6]

The EPA has proposed to measure compliance with the proposed standards on a rolling 12-month basis by summing the hourly CO_2 emissions of a new generating unit for the applicable 12-month period and dividing it by the sum of the gross energy output of the generating unit for the same period.[7] There are no exceptions or exclusions for unit starts and stops; the total CO_2 output must be divided by the total energy output for each rolling 12-month period.[8]

Q. Why are the Companies taking into account a merely proposed standard like the Proposed Greenhouse Gas Rule when performing future-resource analyses?

A. There is every reason to believe the Proposed Greenhouse Gas Rule will become final in a form similar to its current form. President Obama directed the EPA to issue the Proposed Greenhouse Gas Rule by September 20, 2013, and to issue the final rule in a timely manner.[9] The EPA issued the Proposed Greenhouse Gas Rule on the deadline date, and has indicated it intends to finalize the rule by June 2014. Notably, the Proposed Greenhouse Gas Rule's standard for large natural-gas-fired units does not differ from the EPA's April 2012 proposed standard, and the small increases in the standards applicable to coal-fired units and small natural-gas-fired units—after receiving more than 2.5 million comments on the April 2012 proposal—reasonably indicate that EPA is unlikely to increase appreciably the proposed standards any further.

[6] *Id.* at 88.
[7] *Id.* at 89.
[8] *Id.* at 98.
[9] Presidential Memorandum -- Power Sector Carbon Pollution Standards (June 25, 2013). Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

Moreover, the Proposed Greenhouse Gas Rule is part of a larger effort by the President to reduce CO_2 emissions over time. In the same June 25, 2013 Presidential Memorandum he issued to the EPA concerning standards for new electric generating units, the President further directed the EPA to propose CO_2 emissions standards for existing generating units by June 1, 2014, with final standards to be issued by June 1, 2015.[10] The President made clear his belief that reducing CO_2 emissions is a pressing priority for his administration: "With every passing day, the urgency of addressing climate change intensifies. I made clear in my State of the Union address that my Administration is committed to reducing carbon pollution that causes climate change, preparing our communities for the consequences of climate change, and speeding the transition to more sustainable sources of energy."[11] It is therefore entirely reasonable to include the Proposed Greenhouse Gas Rule's restrictions, which apply only to new electric generating units, in the Companies' resource planning for future generating units.

Q. Has the EPA stated how it plans to regulate greenhouse-gas emissions from existing generating?

A. Not yet. As I stated above, the President has directed the EPA to propose CO_2 emission standards for existing electric generating units by June 1, 2014. The EPA has not yet indicated what it plans to include in its proposed standards.

Q. Will the Companies' proposed Green River NGCC comply with the Proposed Greenhouse Gas Rule?

[10] Presidential Memorandum -- Power Sector Carbon Pollution Standards (June 25, 2013). Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.
[11] *Id.*

A. Yes, it will. John N. Voyles discusses the Green River NGCC's emissions in greater detail in his testimony, but my understanding is that its CO_2 emissions will be less than 1,000 lb CO_2/MWh on average. This will comply with the Proposed Greenhouse Gas Rule.

Cross-State Air Pollution Rule

Q. What is the status of CSAPR?

A. On August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated CSAPR and temporarily reinstated the previously vacated Clean Air Interstate Rule ("CAIR"), which had required (and now again requires) significant reductions in sulfur dioxide ("SO_2") and nitrogen oxides ("NO_X") emissions in an attempt to bring a number of states and regions into compliance with the NAAQS for 2.5-micron particulate matter ("$PM_{2.5}$") and eight-hour ozone (smog).[12] (SO_2 is a precursor of $PM_{2.5}$, and NO_X is a precursor of $PM_{2.5}$ and ozone.) The Supreme Court heard oral argument in the case on December 10, 2013.[13]

Mercury and Air Toxics Standards

Q. What is the status of MATS?

A. MATS, which regulates emissions of mercury, particulate matter (as a surrogate for hazardous non-mercury metals), and hydrogen chloride from coal- and oil-fired electric generating units, became final on February 16, 2012.[14] Because MATS is a standard directed at coal- and oil-fired units, it does not apply to the Companies' proposed Green River NGCC or Brown Solar Facility.

[12] EME Homer City Generation, L.P. v. EPA, 696 F.3d 7 (D.C. Cir. 2012).
[13] *See* http://www.supremecourt.gov/Search.aspx?FileName=/docketfiles/12-1182.htm.
[14] 77 FR 9,304. Available at: http://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf.

National Ambient Air Quality Standards

Q. What is the status of the NAAQS?

A. The CAAA requires EPA to periodically review their national ambient air quality standards for the six primary pollutants to ensure that they are sufficiently stringent to protect human health and the environment. In the course of this process, EPA staff and a panel of technical experts review current studies and other available data and determine whether the stringency of existing standards should be increased.

The EPA revised its $PM_{2.5}$ standard on December 14, 2012 by reducing its annual standard from 0.15 $\mu g/M^3$ to 12 $\mu g/M^3$. The designation status associated with the new standard is currently under development, however, the area near the Green River facility is expected to be designated in attainment with the new standard.

EPA is currently reviewing its ozone NAAQS, but has not yet issued proposed rules for the standard. EPA has stated it intends to issue a revised ozone NAAQS by September 30, 2014,[15] however, due to the length of time EPA will need to develop technical comments, it appears the revision may not occur until 2015. The Green River facility area is designated "unclassifiable / attainment" with respect to the current 2008 standard of 0.075 ppm for an 8-hour average.

Q. Will the Green River NGCC comply with all applicable environmental regulations?

A. Yes. The Green River NGCC will meet all NAAQS standards, and will help the Companies comply with CAIR and CSAPR (or its successor regulation). As I noted above, the Green River NGCC will also comply with the Proposed Greenhouse Gas Rule.

[15] *See* http://www.epa.gov/airquality/ozonepollution/actions html.

The proposed new NGCC at Green River will have a cooling tower that will comply with all cooling water intake and discharge requirements. Finally, the Green River NGCC will not generate any combustion wastes requiring an on-site landfill for disposal, so it will not be subject to solid waste regulations.

Necessary Environmental Permits

Q. Which environmental permits will the Companies need to obtain before beginning to construct the Green River NGCC?

A. Before beginning construction, the Green River NGCC unit must receive an air construction permit from the KYDAQ. In addition to this construction permit, the Green River NGCC unit must also receive a Certificate of Public Convenience and Necessity and a Site Compatibility Certificate from the Kentucky Public Service Commission and submit an acceptable cumulative environmental assessment to the Kentucky Energy and Environment Cabinet.

Q. Are there other environmental permits that will be required before the Green River NGCC becomes operational?

A. Yes, there are several environmental permits that must be revised or updated prior to the commercial operation of the Green River NGCC, which I have listed in Exhibit GHR-1.

Q. What is the expected timeline for obtaining the necessary environmental permit to begin constructing the Green River NGCC?

A. The only environmental permit the Companies need to obtain before beginning to construct the Green River NGCC is a Title V air permit. The Companies expect to file an application for the permit by March 2014, and expect to receive the permit by March 2015.

Q. Will the Companies have to obtain any environmental permits in connection with the Brown Solar Facility?

A. It is dependent on the final site footprint. There will be no requirements for an air permit or water withdraw/discharge permit. However, there are some streams in the site area which could be impacted and require a permit from the U.S. Army Corps of Engineers.

Site Compatibility Certificates

Q. Are the Companies requesting that the Commission issue Site Compatibility Certificates for the Green River NGCC and the Brown Solar Facility?

A. Not at this time, though the Companies recognize the need to do so. The Companies have contracted with Cardno-ATC for the necessary Site Assessment Reports, which the Companies anticipate will be complete before April 2014. After the reports are complete, the Companies will apply to the Commission for the requisite Site Compatibility Certificates.

Q. Does this conclude your testimony?

A. Yes it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says he is the Director, Environmental Affairs for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gary H. Revlett

Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of January 2014.

Sheri L. Gardner (SEAL)
Notary Public

My Commission Expires:

SHERI L. GARDNER
Notary Public, State at Large, KY
My Commission expires Dec. 24, 2017
Notary ID # 501600

APPENDIX A

Gary H. Revlett
Director, Environmental Affairs
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4621

Education

University of Louisville, Ph.D. Analytical/Environmental Chemistry - May 1976

Murray State University, B.S. Chemistry - June 1971

OSHA Hazardous Waste Worker Training and 8-hour Refresher Courses

Previous Positions

E.ON U.S. Services Inc.

2006-2010 - Air Manager - Environmental Affairs

Tetra Tech EMI, Louisville, Kentucky

2005-2006 - Senior Air Quality Manager

Kenvirons, Inc., Frankfort, Kentucky

1994-2005 - Vice President and Treasurer
(Director of Air Services and Laboratory Services)

1985-1994 - Associate
(Manager of Testing and Air Services)

1978- 1984 - Senior Environmental Scientist
(Manager of Emission Testing and Air Modeling)

Kentucky Division of Pollution Control, Frankfort, KY

1976-1977 - Principal Chemist - Air Modeling Team

Green River Generating Station

Environmental Permitting and Regulatory Submittal Requirements for Natural Gas Combine-Cycle Plant (Unit 5)

Permit	Regulatory Agency	Regulated Activity	Authority	Status
Title V Operating Permit	KYDAQ	Operation of a major source of air pollution and pollution control equipment.	401 KAR 52:020	Permit application submitted on a 5 year cycle. Next application due date is February 28, 2018.
Acid Rain Permit	KYDAQ	Acid rain permit is required for >25MW combustion unit.	401 KAR 52:020 401 KAR 52:060 40 CFR Part 76	Permit application submitted with Title V renewal application. Next application due date is February 28, 2018.
CAIR Permit	KYDAQ	CAIR permit is required for all fossil fuel fired electric generating units > 25 MW	40 CFR 96.106, 206 & 306 401 KAR 52:020	With the initial Title V permit application.
Kentucky Pollutant Discharge Elimination System (KPDES) Permit	KYDOW	Discharge of process wastewater from an industrial or contaminated point source.	401 KAR 5:055 401 KAR 5:060	Amendment to existing application to be submitted. Permit renewal to include revision.
Spill Prevention, Control and Countermeasures (SPCC) Plan	KYDOW	Requirements to prevent the discharge of oil from non-transportation-related onshore and offshore facilities into or upon the navigable waters of the U.S. or adjoining shorelines.	40 CFR 112	Existing plan will be updated as needed during construction, unit start-up & operation.
Groundwater Protection Plan	KYDOW	Activities with the potential to contaminate groundwater.	401 KAR 5:037	Existing plan will be updated as needed during construction, unit start-up & operation.
Above Ground Storage Tank (AST) Permit	State Fire Marshall	Flammable, Combustible and Hazardous material storage vessel installations	815 KAR 10:060	To be submitted as necessary

<u>Agency Abbreviations:</u>

USEPA:	United States Environmental Protection Agency
KYDAQ:	Kentucky Division for Air Quality
KYDOW:	Kentucky Division of Water
KYPSC:	Kentucky Public Service Commission
KYEEC:	Kentucky Energy and Environment Cabinet

Permit	Regulatory Agency	Regulated Activity	Authority	Status
Permit to Dredge or Fill Streams, Creeks or Wetlands	USACE	The construction will be required to compile with requirements under a Section 404 permit or a Nationwide Permit No. 39 (Permit No. 12 for utility lines and pipelines	40 CFR Part 230 40 CFR Parts 320- 332	Permit application will be submitted in ??, 2014 and permit received prior to commencing construction.
Water Quality Certification	KYDOW	WQC permit application submitted to KYDOW if there will be a discharge of fill material into a stream or wetland or construction across or along.	401 KAR Chapter 9 & 10	Permit application will be submitted in ??, 2014 and permit received prior to commencing construction.
Archaeological Survey Permit	KY Heritage Council	Permit application to evaluate archeological impacts and requirements.	NHPA Section 106	Site assessment prior to commencing construction.
Endangered Species	KYDFW	Determination of impacts on endangered species and requirements.	50 CFR Parts 400 - 499	Site assessment prior to commencing construction.
Certificate of Public Convenience and Necessity for Construction of Utilities	KYPSC	Required for construction of utilities. A site compatibility certificate also must be obtained prior to commencing construction of facilities for electric generation capable of generating (in the aggregate) more than 10 MW. The site compatibility certificate requires submission of a site assessment report.	KRS 278.020 KRS 278.216 KRS 278.708	To Be Submitted in April, 2014.
Cumulative Environmental Assessment	KYEEC	Required before construction of a facility for the generation of electricity. This assessment will contain a description of project impact to environmental resources.	KRS 224.10-280	To Be Submitted in April, 2014.

Agency Abbreviations:

USEPA: United States Environmental Protection Agency
USACE: United States Army Corps of Engineers
KYDAQ: Kentucky Division for Air Quality
KYDOW: Kentucky Division of Water
KYPSC: Kentucky Public Service Commission
KYEEC: Kentucky Energy and Environment Cabinet
KYDFW: Kentucky Department of Fish and Wildlife

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY AND KENTUCKY	)	
UTILITIES COMPANY FOR CERTIFICATES	)	
OF PUBLIC CONVENIENCE AND NECESSITY	)	
FOR THE CONSTRUCTION OF A COMBINED	)	
CYCLE COMBUSTION TURBINE AT THE	)	**CASE NO. 2014-00002**
GREEN RIVER GENERATING STATION AND	)	
A SOLAR PHOTOVOLTAIC FACILITY AT THE	)	
E.W. BROWN GENERATING STATION	)	

DIRECT TESTIMONY OF
EDWIN R. "ED" STATON
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY
AND LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: January 17, 2014

Q. Please state your name, position and business address.

A. My name is Edwin R. "Ed" Staton. I am the Vice President, State Regulation and Rates for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E"). I am employed by LG&E and KU Services Company, which provides services to LG&E and KU (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I testified most recently before the Commission in the proceeding concerning consideration of the implementation of smart grid and smart meter technologies. *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 (January 28, 2013). I testified in East Kentucky Power Cooperative, Inc.'s application to join the PJM Interconnection, LLC as a full member. *In the Matter of: Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Transmission Certain Facilities to PJM Interconnection, LLC*, Case No. 2012-00169 (Oct. 1, 2012). I also testified in *In the Matter of: Application of Kentucky Utilities Company Concerning the Need To Obtain Certificates of Convenience and Necessity For the Construction of Temporary Transmission Facilities in Hardin County, Kentucky*, Case No. 2009-00325 (September 3, 2009).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss issues of cost, financing, joint participation, and other regulatory approvals relating to the Companies' plans to construct a new natural gas combined cycle generating facility at KU's Green River station ("Green River NGCC") and to construct a 10 MW solar photovoltaic facility at the E.W. Brown generating station ("Brown Solar Facility"). I will describe the Companies' position regarding rate recovery associated with the construction of the Green River NGCC and the Brown Solar Facility. I will conclude by recommending that the Commission approve the Companies' Application and authorize the construction as proposed.

Q. How much will it cost to build the Green River NGCC and how much will it cost to build the Brown Solar Facility?

A. As discussed in the testimony of John Voyles, the estimated cost of constructing the Green River NGCC is approximately $700 million which includes the cost of building a 20-inch natural gas transmission line to serve the new facilities. The cost to construct the Brown Solar Facility is approximately $36 million.

Q. As a result of constructing the Green River NGCC and the Brown Solar Facility, will there be additional electrical transmission costs?

A. Yes, the additional electrical transmission costs related to the Green River NGCC are discussed in John Voyles' testimony and in the Resource Assessment attached to David Sinclair's testimony. For the Brown Solar Facility, we do not anticipate that significant electrical transmission modifications will be necessary.

Q. How do the Companies plan to finance the Green River NGCC and the Brown Solar Facility construction costs?

A. The Companies expect to finance the costs of both projects with a combination of new debt and equity. The debt is expected to be a combination of short-term debt, in the form of commercial paper notes, loans from affiliates via the money pool, and/or bank loans. The mix of debt and equity used to finance the projects will be determined so as to allow the Companies to maintain their strong investment-grade credit ratings. The Companies will continue to evaluate financing alternatives as these projects progress and will seek the approval of the Commission pursuant to KRS 278.300 to the extent required.

Q. How will the costs of the projects be allocated between KU and LG&E?

A. As described in Paul Thompson's direct testimony, LG&E and KU will jointly own the Green River NGCC and the Brown Solar Facility. KU will own 60% and LG&E will own 40% of the Green River NGCC. As for the Brown Solar Facility, KU will own 64% and LG&E will own 36%. The costs of the two projects will be shared in accordance with those ownership percentages.

Q. Are there any other regulatory approvals or permits needed for the Green River NGCC project and the Brown Solar Facility project?

A. Yes. As discussed in the testimony of Messrs. Revlett and Voyles, the Companies will need certain environmental permits and possibly construction permits. At this time, the Companies do not believe that any Certificates of Public Convenience and Necessity ("CPCN") will be necessary for the electric transmission needs that will arise as a result of the construction of the Green River NGCC or the Brown Solar Facility. However, that issue is still being studied. To the extent Commission approval is required, the Companies will make timely application.

Additionally, the Companies are in the process of completing Site Assessment Reports for the Green River NGCC and the Brown Solar Facility. The Companies expect to request the Commission to issue Site Compatibility Certificates pursuant to KRS 278.216 after completion of those Site Assessment Reports in the second quarter of 2014.

Q. Why are the Companies not requesting a CPCN for any electric transmission facilities as part of this proceeding?

A. As mentioned above, the Companies are studying the issue of electric transmission needs in connection with the Green River NGCC, and, at this time, do not believe that electric transmission CPCNs will be required because we anticipate that any construction will be an ordinary extension of an existing system in the usual course of business. Additionally, there are significant differences associated with the timing of a Commission decision on the Application in this case and a Commission decision on an electric transmission CPCN case. KRS 278.020 places no specified deadline for a Commission decision in this case, but as Mr. Voyles states in his testimony, in order to place the Green River NGCC in service by May 1, 2018, the Engineering, Procurement and Construction Contract must be awarded by the first quarter of 2015. Electric transmission line CPCN cases, on the other hand, must be decided within no more than 120 days after an application is filed pursuant to KRS 278.020(8). Thus, if the Companies determine that an electric transmission line CPCN is necessary, it will be more administratively efficient to request it in a separate proceeding.

Q. Will the Companies need to construct a natural gas transmission line for the supply of gas to the Green River NGCC?

A. Yes. As described in John Voyles' testimony, an approximately 11-mile 20-inch gas transmission line will be necessary to serve the Green River NGCC. A route selection study will be performed and we anticipate that the route will be located primarily in existing rights of way for electric facilities.

Q. Are the Companies seeking to recover the costs associated with the Green River NGCC and the Brown Solar Facility at this time?

A. No. The Companies are not presently seeking cost recovery for these projects. However, the Companies do expect that they will seek cost recovery in future general rate cases.

Q. Do you have a recommendation for the Commission in this case?

A. Yes. It is my recommendation that the Commission grant the Companies' Application and approve the planned construction of the Green River NGCC and the Brown Solar Facility.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Edwin R. Staton**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Edwin R. Staton

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of January 2014.

(SEAL)
Notary Public

My Commission Expires:

SHERI L. GARDNER
Notary Public, State at Large, KY
My Commission expires Dec. 24, 2017
Notary ID # 501600

APPENDIX A

Edwin R. “Ed” Staton
Vice President, State Regulation and Rates
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky40202

Work History

Vice President, State Regulation and Rates, Kentucky Utilities Company and Louisville Gas and Electric Company, Louisville, Ky.

Vice President, Transmission –Kentucky Utilities Company and Louisville Gas and Electric Company, Louisville, Ky.

Director Transmission –LG&E and KU Services Company, Louisville, Ky

Director of Distribution Operations – Kentucky Utilities Company, Lexington, Ky.

Manager of Distribution Operations – Auburndale Operations Center, Louisville Gas & Electric Company

District Manager – Kentucky Utilities Co. - Elizabethtown, Ky.

Local Service Manager – Kentucky Utilities Co. – Eddyville, Ky.

Line Technician/Service Technician – Kentucky Utilities Co. – Morganfield, Ky.

Education

Diploma – Tates Creek High School, Lexington, Ky.

Associate Degree – Business Management, University of Kentucky – Henderson Community College, Henderson, Ky.

Bachelor of Science Degree – Business Administration (minor in Accounting), - University of Southern Indiana, Evansville, Indiana

Master of Business Administration – Western Kentucky University, Bowling Green, Ky.

Vocational Training

Kentucky Institute for Economic Development

Public Utilities Regulations Guide

Gas Distribution Operations – Institute of Gas Technology, Des Plains, Ill.

E.ON Academy - International Management Program – IMD (International Institute for Management Development), Lausanne, Switzerland

M.I.T. Sloan School of Management, Executive Program in Corporate Strategy, Boston, Mass.

Community Service

APPENDIX A

- President – Lyon Co. Chamber of Commerce 1996-1997
- Co-Chairman – Eddyville Industrial Foundation 1997-1998
- Board member – Elizabethtown Chamber of Commerce 2000
- Member – Larue Co. Industrial Foundation 1999-2003
- Member – Elizabethtown luncheon Rotary Club 1999-2000
- Member – Kentucky Industrial Development Council 1996-present
- Junior Achievement:
  Classroom instructor
  Coral Ridge Elementary School, Louisville, Ky. 2001-2002
- Board member – Junior Achievement of the Bluegrass 2007-present
- Junior Achievement:
  Classroom instructor
  Tates Creek Middle School, Lexington, Ky. 2008-present

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION TURBINE AT THE GREEN RIVER GENERATING STATION AND A SOLAR PHOTOVOLTAIC FACILITY AT THE E.W. BROWN GENERATING STATION	)))))))))	**CASE NO. 2014-00002**

DIRECT TESTIMONY OF
GREGORY J. MEIMAN
DIRECTOR OF CORPORATE TAX AND
BENEFIT PLAN COMPLIANCE
KENTUCKY UTILITIES COMPANY
AND LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: January 17, 2014

Q. Please state your name, position and business address.

A. My name is Gregory J. Meiman. I am the Director of Corporate Tax and Benefit Plan Compliance for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E"). I am employed by LG&E and KU Services Company, which provides services to LG&E and KU (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. No.

Q. What is the purpose of your testimony?

A. I will provide testimony regarding the potential tax credits and incentives for the proposed solar photovoltaic facility at the E.W. Brown generating station ("Brown Solar Facility").

Q. Could you explain the potential federal income tax credits available to the Companies for the Brown Solar Facility?

A. Yes. 26 U.S.C. Section 48(a) of the Internal Revenue Code provides a tax credit for a portion of the expenditures the Companies make in placing solar energy property in service. For this purpose, the expenditures for tangible property (excluding most buildings and their structural components) designed to use solar energy to produce electricity are eligible for the credit. Expenditures for solar photovoltaic panels are eligible for the tax credit.

Q. Are there any other requirements the Companies must meet to qualify for the federal tax credit?

A. Yes. Beyond meeting the above definition of solar energy property, there are effectively three additional conditions of qualification for the credit. The property must be constructed or acquired by the Companies. Also, once the solar property is placed in service, depreciation must be allowed. Finally, the solar property must meet any IRS mandated performance and quality standards that exist when the solar property is purchased.

Q. How is the federal credit calculated?

A. The credit is thirty percent (30%) of the Companies' qualifying cost of the solar energy property. To qualify for the credit, the solar energy property must be placed in service prior to 2017. We believe a very high percentage of the estimated cost for the Brown Solar Facility will be qualifying cost under the federal tax credit.

Q. Are there any further federal tax considerations to claiming the credit?

A. Yes. The depreciable basis of the solar energy property must be reduced by fifty percent (50%) of the credit.

Q. Is it likely that the Brown Solar Facility will qualify for the federal tax credit?

A. Yes. Given the nature of the project and the current timeline for completion it is likely that the Companies will qualify for the credit for qualifying expenditures under current law.

Q. Does the Commonwealth of Kentucky offer any tax credits or incentives for solar projects?

A. Yes. However, as explained below, the availability of state tax credits or incentives is very limited. The Kentucky Economic Development Finance Authority has been granted authority to negotiate incentives for solar and other energy projects. As outlined in KRS Chapter 154 - Subchapter 27, the incentive may cover up to fifty percent (50%) of the capital investment.

Q. What are the requirements for qualification for the Kentucky state incentives?

A. In order for a solar facility to qualify, it must represent a minimum capital investment of at least $1,000,000 and be able to generate at least 50 kilowatts of electricity for sale to an unrelated party such as the Companies' customers.

Q. In what form are the Kentucky state tax incentives made available to taxpayers?

A. The form of the incentive may include: (i) tax relief up to one hundred percent (100%) of the Kentucky state income tax arising from income earned by the project, (ii) sales and use tax refunds up to one hundred percent (100%) of tax paid on materials, machinery and equipment, used to construct the project, or (iii) a wage assessment of up to four percent (4%) of gross wages on associated employees whose jobs were created as a result of the project. Given the Companies' current income tax position, potential availability of other sales and use tax exemptions and the relatively limited wages associated with the solar project, the practical opportunities for use of the incentives may be limited or unavailable altogether.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Gregory J. Meiman**, being duly sworn, deposes and says that he is Director, Corporate Tax and Benefit Plan Compliance for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gregory J. Meiman
Gregory J. Meiman

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of January 2014.

Sheri L. Gardner (SEAL)
Notary Public

My Commission Expires:

SHERI L. GARDNER
Notary Public, State at Large, KY
My Commission expires Dec. 24, 2017
Notary ID # 501600

APPENDIX A

Gregory J. Meiman
Director, Corporate Tax
and Benefit Plan Compliance
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2562

Education

University of Louisville, Louis D. Brandeis School of Law, Juris Doctor, Louisville, Kentucky, 1986
University of Louisville, Bachelor of Science in Business Administration, Louisville, Kentucky, 1983

Positions Held

LG&E and KU Energy LLC, Louisville, Kentucky

Director, Corporate Tax and Benefit Plan Compliance	January 2013 – present
Senior Counsel and Executive Plans Specialist	2002 – 2012
Assistant General Counsel and Executive Plan Manager	2000 – 2001
Senior Counsel and Executive Plan Manager	1999 – 2000
Senior Corporate Attorney	1996 – 1999

Greenebaum Doll & McDonald PLLC, Louisville, Kentucky

Of Counsel	2001 – 2002

Providian Corporation, Louisville, Kentucky

Tax and Benefits Counsel	1988 – 1996

Welenken, Himmelfarb & Company, Louisville, Kentucky

Staff Accountant	1986 – 1988

Professional Memberships

Kentucky Bar Association
Kentucky Society of Certified Public Accountants
Certified Employee Benefits Specialist
Tax Executives Institute