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March 2, 2015

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MAR 02 2015

PUBLIC SERVICE COMMISSION

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Case No. 2012-00578

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of Kentucky Power Company's Annual Status Report regarding the Mitchell generating station. It is being filed in accordance with Ordering Paragraph 6 of the Commission's October 7, 2013 Order in the above matter.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Mark R. Overstreet

MRO
Enclosure
cc: Michael L. Kurtz
Jennifer B. Hans
Shannon Fisk
Joe F. Childers

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MAR 02 2015

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Application Of Kentucky Power Company For: (1) A Certificate Of Public Convenience And Necessity Authorizing The Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief	)	Case No. 2012-00578

MITCHELL GENERATING PLANT: MARCH 2, 2015 ANNUAL PERFORMANCE REPORT AND REPORT ON POTENTIAL IMPACTS OF FUTURE ENVIRONMENTAL REGULATIONS

Table of Contents

1) Introduction

Kentucky Power Company files this report in conformity with the Kentucky Public Service Commission's October 7, 2013 Order in Case No. 2012-00578. Portions of the required information are provided in the following attachments:

Attachment 1: Plant Performance Data

- i. Net Capacity Factor
- ii. Equivalent Forced Outage Rate ("EFOR")
- iii. Equivalent Availability Factor
- iv. Net Unit Heat Rate

Attachment 2: Unplanned System Outages

2) Mitchell Plant Performance

Attachment 1 to this report includes performance data for Mitchell Unit 1 (ML1) & Unit 2 (ML2). The performance of ML1 during 2014 was affected by turbine vibrations in January and February and a planned outage that occurred from October 11, 2014 to November 2, 2014. In the 10 days of October preceding the planned outage the unit experienced a forced outage and maintenance outage, resulting in a high calculated EFOR for the month of October which only represents that portion of the month when the unit was not in a planned outage.

Tube leaks in April impacted the performance of ML2 in 2014.

3) Mitchell Plant Unplanned System Outages

Attachment 2 to this report shows the unplanned outage events that occurred at ML1 & ML2 during the 2014 calendar year. ML1 experienced turbine vibrations in January and February resulting in multiple outages of relatively short duration prior to an outage in February to repair the turbine.

The list of outages includes both Forced Outages ("FO") and Maintenance Outages ("MO"). A FO is defined by the North American Electric Reliability Corporation ("NERC") as an outage event that requires the removal of a unit from service in the near term, or placing the unit in another outage state or a Reserve Shutdown state. This type of outage usually results from immediate mechanical/electrical/hydraulic control system trips or operator-initiated trips in response to unit alarms[1].

Within the classification of FO there are three types that differ as follows:

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[1] NERC GADS Generating Availability Data System Data Reporting Instructions, January 2012.

U1 - An automatic or manual immediate separation of a generating unit from the grid

U2 - An outage that requires removal from the grid within six hours of the event

U3 -An outage that can be postponed beyond six hours but that requires a unit to be removed from the in-service state before the end of the next weekend.

A MO is defined by NERC as an outage that can be deferred beyond the end of the next weekend, but requires that the unit be removed from service, placed in another outage state, or placed in a Reserve Shutdown state before the next Planned Outage.

4) Mitchell Plant Operations & Maintenance ("O&M") Expenses

The 2014 budgeted and actual O&M expenses for the Mitchell Plant, as well as the budgeted O&M expenses for 2015 are included in Table 1 below. The actual O&M expense in 2014 was approximately $4.2 million over the budgeted amount. This variance is largely due to an increase in cost for day-to-day operations and spending for forced outages.

The 2015 budgeted O&M expense of $30.4 million is approximately $6 million over 2014 actuals. This increase is driven primarily by a planned increase for scheduled outages in 2015.

Table 1

Mitchell Plant O&M Expense		
2014		2015
Actuals	Budget	Budget
$24,488,599	$20,468,529	$30,404,062

NOTES:

Totals reflect the 50% of Mitchell Plant owned by KPCo

5) Mitchell Plant Capital Investments

The 2014 actual and budgeted capital investments for the Mitchell Plant, as well as the forecasted capital spend for 2015 are included in Table 2.

In 2014, capital project spending at the Mitchell Plant was approximately $38.4 million, which was $6.1 million under the budgeted amount for the year. Actual costs were less than budgeted costs due to the construction of some major projects being shifted into 2015.

The decreased capital expenditures budgeted for 2015 are indicative of the completion of major environmental projects at the plant, which included dry fly ash conversion and landfill construction.

Table 2

Mitchell Plant Capital Investment		
2014		2015
Actuals	Budget	Budget
$38,440,850	$44,563,256	$18,152,553

NOTES:

Totals reflect the 50% of Mitchell Plant owned by KPCo

6) Discussion of Environmental Regulations and Potential Future Impacts

The Mitchell Plant has fully controlled units with respect to air emissions, meaning that they are equipped with Electrostatic Precipitators ("ESPs") for the removal of approximately 99% of particulate matter; Selective Catalytic Reduction ("SCR") systems for reduction of approximately 90% of nitrogen oxide ("NO_x") emissions; and flue gas desulfurization systems ("FGD") for reduction of sulfur dioxide ("SO_2") emissions by approximately 98%. These systems are instrumental in achieving compliance with air pollution control regulations as described below.

Mercury and Air Toxics Standards ("MATS")

The MATS Rule is federal regulation under the Clean Air Act that creates additional environmental requirements at coal- and oil-fired electric generating units for emissions of hazardous air pollutants ("HAPs"). It became effective February 16, 2012 and has a compliance date of April 16, 2015. The emission parameters regulated by this rule are: 1) mercury; 2) several non-mercury metals such as arsenic, lead, cadmium and selenium; 3) various acid gases including hydrochloric acid ("HCl"); and 4) many organic HAPs. The rule establishes stringent emission rate limits for mercury, filterable particulate matter ("PM") as a surrogate for all non-mercury toxic metals, and HCl as a surrogate for all acid gases. Alternative emission limits were also established for the individual non-mercury metals and for sulfur dioxide ("SO_2") (alternate to HCl) for generating units that have operating FGD systems. The rule regulates organic HAPs through work practice standards.

The installed Mitchell SCR and FGD systems achieve co-benefit removal of mercury from the flue gas while the ESPs remove particulate bound mercury and other particulate hazardous air pollutants. The FGD systems will allow the plant to meet the SO_2 alternate measurement for mitigation of acid gas emissions. These systems are expected to enable the Mitchell Plant to meet the emissions requirements of the MATS Rule.

Cross-State Air Pollution Rule ("CSAPR")

The CSAPR was created to serve as the replacement for the CAIR, and was initially proposed by the EPA in August 2010 as the Clean Air Transport Rule. The CSAPR addresses National

Ambient Air Quality Standards ("NAAQS") for ozone and particulate matter, and is focused on the reduction of emissions of SO_2 and NO_X from electric generating units in 28 eastern, southern and mid-western states—including Kentucky, Indiana and West Virginia.[2] Along with other requirements, the final CSAPR established state-specific annual emission "budgets" for SO_2 and annual and seasonal budgets for NO_X. Based on this budget, each emitting unit within affected states was allocated a specified number of NO_x and SO_2 allowances for the applicable compliance period, whether annual or ozone season. Allowance trading within and between states is allowed on a regional basis.

Phase I of the CSAPR was originally intended to go into effect in January, 2012. The program was delayed as a result of complicated and lengthy litigation. Much of that litigation has been resolved, and Phase 1 of the program took effect on January 1, 2015. The CSAPR Phase 2 emission budgets will be applicable beginning in 2017. The installed SCR and FGD systems' respective emission reductions of NO_x and SO_2 allowed the plant to operate in compliance with the Clean Air Interstate Rule, and will allow continued compliance with, and minimize the cost of, emission allowances associated with the Cross State Air Pollution Rule.

Clean Water Act ("316(b)") Rule

A final rule under Section 316(b) of the Clean Water Act was issued by EPA on August 15, 2014, with an effective date of October 14, 2014 affecting all existing power plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with a standard that addresses impingement of aquatic organisms on cooling water intake screens and requires site-specific studies to determine appropriate compliance measures to address entrainment of organisms in cooling water systems for those facilities withdrawing more than 125 million gallons per day. The overall goal of the rule is to decrease impacts on fish and other aquatic organisms from operation of cooling water systems. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats.

Facilities with existing closed cycle recirculating cooling systems, such as Mitchell, may not be required to make any technology changes. This determination would be made by the applicable state environmental agency during the plants' next National Pollutant Discharge Elimination System ("NPDES") permit renewal cycle. If additional capital investment is required, the amount is expected to be small compared to the cost that would be needed if the plant were not equipped with cooling towers.

Coal Combustion Residuals ("CCR") Rule

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[2] Final CSAPR issued by the USEPA on July 6, 2011 and published in the Federal Register on August 8, 2011.

EPA signed the final CCR Rule on December 19, 2014. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and will become effective six months from the date of its publication in the Federal Register (not yet published as of February 24, 2014). Preliminary review of this extensive rule indicates it is applicable to new and existing CCR landfills and CCR surface impoundments. It contains requirements for liner design criteria for new landfills, surface impoundment structural integrity requirements, CCR unit operating criteria, groundwater monitoring and corrective actions, closure and post-closure care, and recordkeeping, notification and internet posting obligations. EPA has not included a mandatory liner retrofit requirement for existing, unlined CCR surface impoundments, however operations must cease if groundwater monitoring data indicate there has been a release from the impoundment that exceeds applicable groundwater protections standards. Additional review and evaluation of this final rule is needed before its impacts to Kentucky Power operations can be fully determined.

It should be noted that the Mitchell Plant has completed a dry fly ash conversion and dry ash landfill construction to meet current permit requirements. These projects will also position the Mitchell Plant well for compliance with the CCR rulemaking.

Effluent Limitation Guidelines and Standards ("ELG")

EPA proposed an update to the ELG for the steam electric power generating category in the Federal Register on June 7, 2013. The proposed ELG would require more stringent controls on certain discharges from certain electric generating units, and will set technology-based limits for waste water discharges from power plants with a main focus on process and wastewater from FGD, fly ash sluice water, bottom ash sluice water and landfill/pond leachate.

Kentucky Power anticipates that wastewater treatment projects will be necessary at the Mitchell units and these have been considered as part of the respective long-term unit evaluations. The expected date for a final ELG rule is September 30, 2015. Similar to the effect on CCR compliance mentioned above, Mitchell Plant's dry fly ash conversion and dry ash landfill construction should position the plant well for compliance with the final ELG rulemaking.

National Ambient Air Quality Standards ("NAAQS")

The Clean Air Act requires EPA to establish and periodically review the NAAQS designed to protect public health and welfare. Several NAAQS have been recently revised or are under review, which could lead to more stringent SO2 and NOx limits. This includes the NAAQS for SO_2 (revised in 2010), NO_x (revised in 2010), fine particulate matter (revised in 2013), and ozone (expected to be revised in 2015).

The scope and timing of potential requirements is uncertain. However, because both units at the Mitchell Plant have already been retrofitted with SCR and FGD systems, the risk from more stringent SO_2 and NO_x limits is expected to be manageable.

Greenhouse Gas ("GHG") Regulations

EPA has been working on a regulatory program for greenhouse gas emissions from existing power plants since December 2010. On June 25, 2013, President Obama announced a climate action plan to address GHG emissions from all fossil-fired power plants which included a specific schedule for EPA to propose, finalize and implement greenhouse gas regulations. EPA issued proposed GHG New Source Performance Standards, referred to as the Clean Power Plan, for existing sources on June 2, 2014 and plans to finalize these guidelines during the summer of 2015.

As proposed, the guidelines are complex and rely on aggressive assumptions for coal plant heat rate improvements, redispatch of natural gas generation, and greater utilization of renewable energy and end-use energy efficiency to establish CO_2 target emissions levels for states. The proposed guidelines also include interim goals taking effect in 2020, and final targets becoming effective in 2030. Once the regulations are final, States will then be required to develop implementation plans for compliance on a regional basis, or be subject to a federal implementation plan. States will have from one to three years, depending on available deadline extensions, to submit their single-state or multi-state implementation plans.

The targets contained in the proposed guidelines result in CO_2 emission rate reductions for Kentucky of an average of 15% from 2020 – 2029, and 18% from 2030 and beyond (based on 2012 levels). However, the impact of these targets and the compliance schedule, within the context of a state-wide compliance plan, on the electric generating units at the Mitchell Plant is unclear at this time.

Mitchell 1

Net Maximum Capacity: 385

MONTH	FORCED OUTAGE RATE (%)	EQUIV FORCED OUTAGE RATE (%)	EQUIV AVAIL FACTOR (%)	NET CAPACITY FACTOR MWH (%)	HEAT RATE ACTUAL (BTU / KWH)
JAN 14	25.33	37.37	64.98	48.31	10,084
FEB 14	9.46	42.78	18.91	20.21	10,540
MAR 14	17.47	21.83	67.91	62.98	10,738
Q1 Total	19.89	31.73	51.65	44.61	10,616
APR 14	0.00	0.88	87.95	79.45	9,156
MAY 14	0.00	1.07	65.61	58.26	9,901
JUN 14	0.00	4.08	63.47	51.32	10,372
Q2 Total	0.00	1.86	72.27	62.96	9,718
JUL 14	4.55	7.70	86.96	67.86	9,992
AUG 14	0.00	4.67	94.39	79.16	10,190
SEP 14	0.00	3.90	95.41	80.90	10,419
Q3 Total	1.43	5.37	92.22	75.92	10,410
OCT 14	91.57	92.01	1.28	0.86	10,750
NOV 14	41.78	42.14	55.30	47.71	10,747
DEC 14	19.64	31.45	25.25	16.31	11,717
Q4 Total	42.32	45.42	26.99	21.35	10,997
YTD TOTAL	12.24	17.45	60.80	51.21	10,304

Mitchell 2

Net Maximum Capacity: 395

MONTH	FORCED OUTAGE RATE (%)	EQUIV FORCED OUTAGE RATE (%)	EQUIV AVAIL FACTOR (%)	NET CAPACITY FACTOR MWH (%)	HEAT RATE ACTUAL (BTU / KWH)
JAN 14	0.96	6.67	82.93	74.70	9,619
FEB 14	0.00	6.16	91.01	93.47	9,508
MAR 14	0.00	6.99	91.43	84.94	8,664
Q1 Total	0.30	6.62	88.37	84.07	9,362
APR 14	15.35	17.20	61.86	53.66	10,537
MAY 14	0.00	2.17	70.05	58.30	9,090
JUN 14	4.48	6.19	92.03	76.47	9,717
Q2 Total	6.44	8.33	74.60	62.76	9,750
JUL 14	0.00	0.83	98.01	81.21	9,643
AUG 14	9.86	10.58	66.68	51.99	9,891
SEP 14	11.18	11.99	85.84	69.80	9,295
Q3 Total	6.63	7.43	83.48	67.64	9,821
OCT 14	0.92	1.00	98.57	81.23	9,728
NOV 14	0.00	2.72	96.32	89.09	9,291
DEC 14	0.00	4.03	78.30	65.10	9,251
Q4 Total	0.33	2.51	91.01	78.36	9,432
YTD TOTAL	3.28	6.12	84.37	73.18	9,571

Mitchell Generating Plant
Unplanned Outages
2014

Kentucky Power Co.
01/01/2014 To 12/31/2014
Mitchell Unit 1

			HOURS OF DURATION		
Month	From	To	Unplanned	Event Type	Reason for Outage
January	12/30/13 10:30	1/4/14 20:52	92.87	U1	due to #5 turbine bearing possibly being wiped.
January	1/11/14 18:00	1/13/14 1:10	31.17	U1	Unit trip (suspected turbine vibration at this time)
January	1/15/14 18:52	1/16/14 1:43	6.85	U1	Turbine Vibration
January	1/21/14 6:40	1/21/14 17:04	10.4	U1	Turbine vibrations on #5, #6 and #7
January	1/22/2014 0:44	1/22/2014 16:00	15.27	SF	#1 turbine throttle valve failed
January	1/22/14 16:00	1/23/14 8:00	16	U1	Start-up steam u/a
January	1/23/14 21:56	1/23/14 23:45	1.82	U1	High Vibrations
February	2/5/14 16:32	2/5/14 21:52	5.33	U1	Turbine Vibration
February	2/6/14 9:15	2/7/14 0:00	14.75	U1	Tripped on turbine vibration
February	2/7/14 0:00	2/7/14 0:01	0.02	U1	Valve Repair Work
February	2/7/14 0:01	2/23/14 0:00	383.98	MO	Turbine Vibration Inspection and Repair
March	3/8/14 5:44	3/12/14 21:15	110.52	U1	Reheat Tube Leak
March	3/28/14 1:20	4/3/14 21:30	164.17	MO	Air Heater Wash
June	6/9/14 0:00	6/9/14 16:41	16.7	MO	Continue planned outage tube repairs in
June	6/13/14 5:11	6/14/14 16:47	35.6	MO	#12 ID Fan Hydraulic Leak Repairs
July	7/2/14 3:29	7/3/14 10:05	30.6	U1	External steam leak on main turbine
July	7/3/14 10:05	7/5/14 5:25	43.3	MO	Main steam line drain piping inspections
October	10/1/14 10:07	10/6/14 0:00	109.9	U2	Tube Leak
October	10/6/14 0:00	10/11/14 0:00	120.0	MO	Planned Outage preparation
November	11/4/14 16:31	11/11/14 17:47	169.27	U2	Tube Leak
November	11/12/2014 5:15	11/13/2014 5:15	24	SF	second reheat turbine valve
November	11/13/14 10:48	11/13/14 11:05	0.28	U1	Low Main Steam Temperature Trip
November	11/27/14 12:12	12/3/14 0:00	131.8	U2	Tube leak
December	12/3/14 0:00	12/22/14 22:25	478.42	MO	Tube Replacement Lower Right rear wall

Event Type	NERC Description
MO	Maintenance Outage - can be deferred beyond the end of the next weekend but must occur before the next planned outage
SF	Startup Failure - results when a unit is unable to synchronize within a specified startup time following an outage or reserve shutdown.
U1	Unplanned (Forced) Outage - requires immediate removal from service
U2	Unplanned (Forced) Outage - required removal from service within 6 hours
U3	Unplanned (Forced) Outage - can be postponed beyond 6 hours but requires removal from service before the end of the next weekend

Mitchell Generating Plant
Unplanned Outages
2014

Kentucky Power Co.
01/01/2014 To 12/31/2014
Mitchell Unit 2

			HOURS OF DURATION		
Month	**From**	**To**	**Unplanned**	**Event Type**	**Reason for Outage**
January	1/11/14 4:00	1/14/14 8:41	76.68	MO	Tube Leak
January	1/14/14 8:41	1/14/14 15:45	7.07	MO	Tube Leak
January	1/22/14 3:56	1/22/14 10:07	6.18	U2	Water Line Leak @ Feedpump
April	4/18/14 2:31	4/23/14 23:25	140.9	MO	Repair suspected tube leak in reheat section of boiler
April	4/26/14 18:04	4/30/14 6:00	83.93	U1	Tube leak
June	6/28/14 13:20	6/29/14 21:12	31.9	U1	Loss of 600V Kv buss. due to fault
August	8/11/14 8:03	8/19/14 6:15	190.2	MO	Economizer tube leak repairs
August	8/19/2014 13:30	8/20/2014 13:30	24	SF	Hydrolyzer condensate return line leak.
August	8/20/14 13:30	8/21/14 18:00	28.5	U1	Hydrolyzer condensate return line leak
September	9/21/14 3:40	9/24/14 10:30	78.8	U1	Exciter brush issues
September	9/24/14 23:04	9/24/14 23:23	0.3	U1	Unit needs to come off line to reset valves
October	10/23/14 7:00	10/23/14 13:49	6.8	U1	Control Valve Failed closed causing turbine vibration.
December	12/4/14 2:07	12/8/14 3:50	97.72	MO	Tube Leak Repairs

Event Type	NERC Description
MO	Maintenance Outage - can be deferred beyond the end of the next weekend but must occur before the next planned outage
SF	Startup Failure - results when a unit is unable to synchronize within a specified startup time following an outage or reserve shutdown.
U1	Unplanned (Forced) Outage - requires immediate removal from service
U2	Unplanned (Forced) Outage - required removal from service within 6 hours
U3	Unplanned (Forced) Outage - can be postponed beyond 6 hours but requires removal from service before the end of the next weekend