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Witness: Burton L. Crawford
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2012-0174

REBUTTAL TESTIMONY

OF

BURTON L. CRAWFORD

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

**Kansas City, Missouri
September 2012**

REBUTTAL TESTIMONY

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BURTON L. CRAWFORD

Case No. ER-2012-0174

1 **Q: Please state your name and business address.**

2 A: My name is Burton L. Crawford. My business address is 1200 Main, Kansas City,
3 Missouri 64105.

4 **Q: Are you the same Burton L. Crawford who pre-filed Direct Testimony in this**
5 **matter?**

6 A: Yes, I am.

7 **Q: What is the purpose of your Rebuttal Testimony?**

8 A: The purpose of my testimony is to rebut fuel model and off-system sales related issues in
9 the Missouri Public Service Commission (“MPSC” or “Commission”) Staff’s (“Staff”)
10 Revenue Requirement/Cost of Service report (“Staff Report”); issues related to off-
11 system sales adjustments in the Direct Testimony of Greg R. Meyer on behalf of
12 Missouri Industrial Energy Consumers (“MIEC”) and Midwest Energy Consumers Group
13 (“MECG”); off-system sales model derate issues presented in the Direct Testimony of
14 Nicholas L. Phillips on behalf of MIEC and MECG; and resource planning related issues
15 raised in the Direct Testimony of Bruce E. Biewald on behalf of the Sierra Club.

16 A. **Fuel and Purchased Power**

17 **Q: Do you have any issues with the Staff’s fuel and purchased power modeling efforts?**

18 A: Yes. There are at least four issues that should be addressed at true-up. These are related
19 to the treatment of firm contract sales, the treatment of new wind resources, the treatment

1 of non-asset based wholesale transactions and the treatment of the equivalent forced
2 outage rate (“EFOR”) at Hawthorn Unit 5.

3 **Q: Do you disagree with the Staff’s computation of firm off-system sales revenues?**

4 A: Yes. As Staff’s direct case is structured, they have essentially double counted wholesale
5 sales to the Kansas Municipal Energy Agency (“KMEA”).

6 Kansas City Power & Light Company (“KCP&L” or the “Company”) had a
7 contract for load following energy service with KMEA that expired May 31, 2012. The
8 contract was extended to November 30, 2012. As of December 1, 2012, KMEA will
9 participate in Southwest Power Pool’s (“SPP”) Energy Imbalance Services (“EIS”) market and will no longer require this service to be provided by KCP&L. Since this
10 contract will no longer be in effect at the time new rates go into effect in this case, the
11 Company’s estimation of the non-firm off-system sales margin was computed assuming
12 that this load would not be served by KCP&L. The energy that formerly went to serve
13 KMEA load was allowed to be sold in the off-system sales market.

14
15 Since Staff accepted the Company’s estimate of non-firm off-system sales margin
16 that includes energy that would have formerly been sold to KMEA and explicitly
17 includes the KMEA sales in their cost of service, they have effectively double counted
18 these wholesale sales. Staff should remove the KMEA firm contract sales from their cost
19 of service model.

20 However, if the Commission determines that it is appropriate to include this load
21 in the firm off-system sales, the non-firm off-system sales margin would need to be
22 reduced to recognize the reduction in energy available for sale in the non-firm market.

1 Also, the basis of the firm off-system sales energy that Staff included in its fuel
2 modeling and the related revenues in its Cost of Service Model is not clear to the
3 Company. KCP&L will attempt to resolve this uncertainty with the Staff prior to true-up.

4 **Q: Do you disagree with the Staff's Cost of Service modeling regarding the Company's**
5 **2012 wind additions?**

6 A: Yes. Staff did not include the generation or the cost of the new wind resources under
7 purchased power agreements (Cimarron and Spearville 3) that began delivering energy to
8 KCP&L earlier this year. These resources have been included in the Company's cost of
9 service modeling for retail and firm wholesale obligations and in the NorthBridge
10 estimate of non-firm off-system sales margins. Staff has indicated that these resources
11 will be included in its true-up case.

12 **Q: Do you take issue with the Staff's Cost of Service modeling regarding the treatment**
13 **of non-asset based wholesale transactions?**

14 A: Yes. The Staff Report at page 90 proposes to include the margins from non-asset based
15 wholesale transactions in the Company's retail cost of service. Such transactions should
16 not be included.

17 **Q: What are non-asset based wholesale transactions?**

18 A: Non-asset based wholesale transactions are wholesale market purchases and sales that do
19 not involve the utility's generation or transmission assets and are outside the SPP
20 footprint. For example, purchases and offsetting sales of energy within the Midwest
21 Independent Transmission System Operator, Inc. ("MISO") or PJM Interconnection LLC
22 ("PJM") systems would be considered a non-asset based transaction.

1 **Q: Why does the Company propose to exclude such transactions from its retail cost of**
2 **service?**

3 A: This activity does not involve KCP&L's regulated generation and transmission assets and
4 is not directly related to the provision of retail electric service in Missouri. As such, the
5 risks and rewards of such activity should not be included in the regulated business.

6 **Q: How does the Kansas Corporation Commission ("KCC") handle such non-asset**
7 **based wholesale activity?**

8 A: The KCC explicitly excludes these transactions from the regulated cost of service.

9 **Q: Does KCP&L propose that costs associated with non-asset based transactions**
10 **should also not be included in the cost to serve its retail customers?**

11 A: Yes. The true-up in this case will not include any such costs.

12 **Q: Please describe your concern with Staff's treatment of Hawthorn Unit 5.**

13 A: According to Staff Report at pages 127-135, Staff has adjusted the historical EFOR for
14 outages and derates related to the Hawthorn 5 Selective Catalytic Reduction ("SCR")
15 system and the Hawthorn 5 step-up transformer. These adjustments are not appropriate.

16 **Q: Why are Staff's Hawthorn 5 adjustments not appropriate?**

17 A: Staff has selectively removed events from the seven-year history of Hawthorn 5 which
18 results in a modeled EFOR that does not represent KCP&L's actual experience with this
19 plant. Consequently, Staff's analysis results in an artificially high level of availability for
20 the plant, inconsistent with what has occurred over the past seven years, which may lead
21 to an understatement of costs to serve retail customers.

22 Actual plant EFOR can vary greatly from year to year. As such, it is reasonable
23 to use a long-term average of plant performance when normalizing fuel and purchased

1 power expenses. While one could claim that any single event is unusual in nature and
2 should be eliminated from the averaging process, the nature of plant performance is such
3 that events do occur that may not happen ever again in the life of the plant. In other
4 words, “normalizing out” one-time events or focusing on the performance of a particular
5 piece of equipment can easily result in understating expected performance since
6 abnormal events can and will occur.

7 While incidents do occur that can take a unit off-line for an extended period of
8 time, there are also periods of exceptional, sustained performance where a unit remains
9 on-line for an extended period of time. Hawthorn 5 is an excellent example. While Staff
10 has removed events that have derated or taken the unit out of service, it has not
11 normalized out the fact that Hawthorn 5 had an all-time record run during this seven year
12 period. During 2009-2010, Hawthorn 5 experienced a record-breaking 186-day
13 continuous run. This was the plant’s longest run since at least 1990. Staff has not
14 normalized out this unusual event from Hawthorn 5’s seven-year history.

15 The bottom line is that coal plant availability can vary greatly year-to-year based
16 on any number of events. While there may be a rare and unusual event that supports an
17 adjustment, difficulties with an SCR and a transformer are not such events, and do not
18 justify Staff’s adjustment.

19 **B. Off-System Sales Adjustments**

20 **Q: Please briefly describe the off-system sales adjustment issues you will be addressing.**

21 A: I will address the off-system sales adjustments proposed in the Direct Testimonies of Mr.
22 Greg R. Meyer and Mr. Nicholas L. Phillips, representing MIEC and MECG. These

1 adjustments include SPP line loss charges, SPP Revenue Neutrality Uplift (“RNU”),
2 Purchases for Resale, plant derate assumptions, and the Iatan 2 EFOR.

3 **Q: Has Mr. Meyer failed to recognize prudently incurred costs related to KCP&L’s**
4 **off-system sales transactions?**

5 A: Yes. Mr. Meyer proposes to disallow costs associated with the SPP Line Loss Charges
6 and Purchases for Resale. Failure to recognize these costs results in understating
7 KCP&L’s cost to serve its retail customers.

8 **1. SPP Line Loss Charges**

9 **Q: Please describe the SPP Line Loss Charges that Mr. Meyer proposes to disallow.**

10 A: As described in my Direct Testimony, SPP Line Loss Charges are assessed by SPP on
11 off-system sales made by KCP&L, as well as other SPP transmission customers. SPP
12 uses the revenue from these Line Loss Charges to compensate SPP transmission owners
13 for the loss of energy that occurs when transmitting energy through the transmission
14 network.

15 **Q: Are these SPP Line Loss Charges to KCP&L a result of KCP&L’s membership in**
16 **the SPP regional transmission organization (“RTO”)?**

17 A: Yes. These line loss charges are assessed to KCP&L and other SPP transmission
18 customers.

19 **Q: Does KCP&L have any control over incurring these costs?**

20 A: No. To the extent that KCP&L makes off-system sales subject to these charges, these
21 Line Loss Charges will be assessed by SPP per the Federal Energy Regulatory
22 Commission (“FERC”)-approved SPP regional transmission tariff.

1 **Q: Is it appropriate to include SPP Line Loss Charges in the costs to serve KCP&L's**
2 **retail customers?**

3 A: Yes. KCP&L's retail customers receive the net benefits of KCP&L's off-system sales
4 and should therefore incur all costs associated with making these sales. The Staff Report
5 at page 90 agrees with KCP&L's proposal, which is consistent with the Commission's
6 decision to allow such costs in the Company's last rate case, as discussed in the Report
7 and Order at page 140, Case No. ER-2010-0355.

8 **Q: What is the basis for the amount of SPP Line Loss Charges KCP&L proposed in**
9 **this case?**

10 A: KCP&L included SPP Line Loss Charges based on the actual net SPP line loss expense
11 incurred by KCP&L for the 12-month period ending November 2011. KCP&L plans to
12 include the actual net SPP Line Loss Charges for the prior 12 months as of August 31,
13 2012, the true-up date in this case, as an expense in determining the off-system sales
14 margin.

15 **Q: Why does Mr. Meyer propose to disallow SPP Line Loss Charges incurred by**
16 **KCP&L?**

17 A: Mr. Meyer proposes to disallow the SPP Line Loss Charges because the model used by
18 Mr. Schnitzer to estimate KCP&L's off-system sales margins does not specifically
19 identify sales made outside the SPP system. In his Direct Testimony at page 20, Mr.
20 Meyer concludes that KCP&L "fails to recognize the higher sales price for those sales."

21 **Q: Do you agree with this logic?**

22 A: No. If KCP&L failed to recognize any actual higher sales prices from sales made outside
23 the SPP system, it would have been appropriate to exclude the higher cost associated with

1 making these sales. However, KCP&L recognizes these sales made outside the SPP
2 system and KCP&L's retail customers directly benefit from these sales. The off-system
3 sales tracker that KCP&L has had in place for several years fully reflects the benefit of
4 these sales and, therefore, KCP&L's retail customers should incur the costs associated
5 with making these sales.

6 **Q: Mr. Meyer's premise appears to be that sales made outside the SPP footprint**
7 **receive a premium above those made in the SPP footprint correct. Is this premise**
8 **correct?**

9 A: No. For at least two reasons, sales outside of SPP are not necessarily made at a premium
10 over sales made within SPP. First, in order to facilitate off-system sales, KCP&L has
11 secured long-term firm transmission paths that exit SPP. These paths come at a fixed
12 price. If the fixed cost of these paths was included in the price of a sale, KCP&L would
13 risk losing sales to lower offers. In other words, the cost of transmission on these paths is
14 a sunk cost and should not typically be considered in pricing a potential off-system sale.
15 Second, there are times when KCP&L has more energy to sell than can be sold within the
16 SPP footprint and in order to continue making economic sales, it must look outside the
17 SPP footprint. These sales are generally made at lower prices than sales made in the SPP
18 footprint. So in actual practice, sales made outside the SPP footprint are generally at a
19 lower price than sales made within the SPP footprint. Therefore, if any adjustments were
20 to be made to the off-system sales estimated by KCP&L witness Mr. Schnitzer, it should
21 be to decrease margins to account for the lower average price of sales made outside the
22 SPP footprint.

1 **Q: Do you have support for your position that sales made outside the SPP footprint are**
2 **generally made at lower prices to sales made inside the SPP footprint?**

3 A: Yes. The KCP&L FERC Form 1 provides off-system sales information by counter party.
4 An analysis of KCP&L's 2011 FERC Form 1 shows that the average sales price to
5 entities outside the SPP footprint is more than \$5.00/MWh below the price of sales made
6 to entities within the SPP footprint.

7 **2. SPP Revenue Neutrality Uplift**

8 **Q: Please explain Mr. Meyer's proposed treatment of the SPP RNU charges.**

9 A: Mr. Meyer at page 26 of his Direct Testimony proposes to treat these charges as a fuel
10 expense.

11 **Q: Are RNU charges a fuel expense?**

12 A: No. They are the net charges from SPP related to over-collection and under-collection of
13 revenue related to wholesale sales and purchases through the SPP energy imbalance
14 market.

15 **Q: What is KCP&L's proposal for RNU treatment?**

16 A: KCP&L proposes to include these as part of the off-system sales margin calculation.

17 **Q: Why is KCP&L's proposed treatment appropriate?**

18 A: KCP&L incurs these charges and credits due to its participation in the SPP EIS market.
19 The charges and credits are recorded as wholesale purchases and sales. The Staff Report
20 at page 90 agrees with KCP&L's proposal, which is consistent with the Commission's
21 decision in the last rate case, as noted in the Report and Order at pages 140-141, Case No.
22 ER-2010-0355.

1 **3. Purchases for Resale**

2 **Q: Why does Mr. Meyer propose that Purchase for Resale be disallowed from**
3 **KCP&L's cost of service?**

4 A: Essentially, Mr. Meyer proposes to disallow Purchase for Resale on the grounds that
5 benefits associated with these transactions are not reflected in KCP&L's cost of service,

6 **Q: Are the benefits associated with these transactions reflected in the actual costs to**
7 **KCP&L's retail customers and if so, how?**

8 A: Yes. The benefits described in Mr. Meyer's Direct Testimony at pages 22-23 currently
9 flow back to retail customers through the off-system sales margin tracking process and
10 will continue to do so under the Company's proposal in this case. KCP&L's Post
11 Analysis program (the program used to calculate KCP&L's actual off-system margins)
12 determines the actual benefits from these transactions, and as such the actual off-system
13 sales margins reflect this benefit. These are known as Block Price Adjustments.

14 **Q: Are these Block Price Adjustments included in the Company's Direct Case?**

15 A: No. While these adjustments flow through the off-system sales margin tracking process,
16 they were not in the Company's cost of service. However, they will be included in the
17 Company's cost of service in the true-up case.

18 **Q: Has Mr. Meyer offered other reasons for disallowing Purchases for Resale from**
19 **KCP&L's cost of service?**

20 A: Yes. He states at page 24 of his Direct Testimony that derates and forced outages can
21 result in purchase for resale transactions, and asserts that since KCP&L models
22 generation derates and forced outages in its production cost modeling, these costs may
23 already be accounted for.

1 **Q: Have these Purchases for Resale costs related to derates and forced outages been**
2 **included in KCP&L's production cost modeling?**

3 A: No. When a generation derate or forced outage is simulated in KCP&L's production cost
4 modeling, the energy that would have been available to make an off-system sale is no
5 longer available and no sale is made. What happens in actual practice is that KCP&L
6 may have an off-system sale in place at the time of a derate or forced outage which
7 results in a purchase needed to fill the sale. It is exactly this difference between the
8 production cost modeling and actual operating practice that KCP&L is accounting for
9 with the Purchases for Resale adjustment. Without this adjustment, purchased power
10 costs would be understated since the production cost models used by both KCP&L and
11 Staff cannot reflect these transactions.

12 **Q: What is the Staff's position in regard to purchases for resale?**

13 A: Staff agrees that these are legitimate costs that should be included in the Company's cost
14 of service, and has included them in its cost of service in this case, as noted in the Staff
15 Report at page 90.

16 **4. Iatan 2 Equivalent Forced Outage Rate**

17 **Q: Do you have any comment concerning Mr. Nicholas Phillips recommendation**
18 **concerning Iatan 2 EFOR assumptions?**

19 A: Yes. KCP&L agrees that the Iatan 2 EFOR needs to be reduced and will do so in its true-
20 up filing in this case. KCP&L will use an average of the monthly EFOR's for Iatan 2
21 starting November 2010 through August 2012.

1 C. **Off-System Sales Model Derates**

2 **Q: Please briefly describe Mr. Nicholas Phillips' concern with KCP&L's treatment of**
3 **coal plant derates used in the NorthBridge off-system sales analysis?**

4 A: Mr. Phillips in his Direct Testimony at page 15 questioned the Company's use of what he
5 termed "planned generator deratings." As such, he has not included the KCP&L
6 assumptions in his off-system sales analysis.

7 **Q: What do these derates represent?**

8 A: In addition to lost generation due to forced outages and forced derates which are included
9 in the EFOR values, KCP&L also experiences lost generation due to 1) planned outages
10 (other than those scheduled months or years in advance which KCP&L includes in its
11 normalized maintenance schedules), 2) transmission congestion, and 3) inefficiencies in
12 the wholesale market. The derates included in the NorthBridge off-system sales model
13 represent this lost generation.

14 **Q: How has the Company determined these derates?**

15 A: On a routine basis, the Company reports coal plant availability information to the North
16 American Electric Reliability Corporation ("NERC"). This is done through the
17 Generating Availability Data System ("GADS"). The Company's reported data is used
18 to calculate the derates due to events that are not part of the regular maintenance schedule
19 or included in the EFOR.

20 GADS events are categorized into 15 event codes. These codes describe the
21 nature of the event that is impacting the availability of the unit. These codes cover events
22 that range from a complete unit forced outage or scheduled overnight maintenance, to

1 fully planned maintenance outages. The event “states” shown in Schedule BLC-13 are
2 from the NERC GADS Data Reporting Instructions manual.

3 The Company simulates lost capacity due to forced and planned events using
4 three assumptions that must work together. The first is the EFOR assumption that
5 accounts for unit states D1, D2, D3, U1, U2, U3 and SF. The second is the planned
6 maintenance schedule which accounts for states PO and PE. The third assumption covers
7 the remaining states, D4, DM, PD, DP, MO and ME. This third set is what KCP&L
8 includes as part of its derate assumptions.

9 **Q: Please describe the transmission congestion component of the KCP&L derived**
10 **derates.**

11 A: As part of the current SPP EIS market, SPP posts Locational Imbalance Prices (“LIP”)
12 for each generator every 5 minutes. The LIP is the price signal from SPP to the owner of
13 generation. SPP pays the generation owner for any energy generated above their
14 scheduled output at the LIP.

15 When a transmission constraint occurs, generators that are negatively impacting
16 the constraint will see their LIP reduced. The LIP may even go negative. This is the
17 market signal from SPP to the generators negatively impacting the transmission
18 constraint to reduce their generation. Based on historic LIP prices, the Company
19 allocates a portion of the derate energy estimate to individual plants.

20 **Q: Please describe the wholesale market inefficiency component of the KCP&L**
21 **determined derates?**

22 A: In brief, due to the lack of a centralized day-ahead and real-time spot market, most
23 wholesale energy market transactions in the current SPP EIS market are done on a

1 bilateral basis. Production cost models such as MIDASTM or RealTime do not directly
2 account for inefficiencies inherent in these markets. In order to simulate market
3 inefficiencies, KCP&L includes derates in its production cost modeling.

4 **Q: Are these the same inefficiencies as described in the Direct Testimony of Mr.**
5 **Nicholas Phillips at pages 10-12?**

6 A: I believe so.

7 **Q: How did Mr. Phillips account for these inefficiencies in his RealTime simulations of**
8 **the KCP&L system?**

9 A: Mr. Phillips applied a hurdle rate to account for these inefficiencies.

10 **Q: Is the application of a hurdle rate a reasonable method to account for such**
11 **inefficiencies?**

12 A: Yes. It has the effect of reducing generation levels to account for the differences between
13 the perfect dispatch that occurs in modeling and actual operations.

14 **Q: Did KCP&L apply a hurdle rate in its fuel cost modeling in this case?**

15 A: No. Instead of a hurdle rate, KCP&L represented inefficient market operations through
16 the application of derates. It's simply another modeling technique to adjust a production
17 cost model to reflect differences between the perfect dispatch that occurs in modeling and
18 actual operations.

19 **Q: Were the derates KCP&L supplied to NorthBridge for use in its off-system sales**
20 **analysis applied in KCP&L's MIDASTM model when determining the normalized**
21 **fuel and purchased power costs for native load?**

22 A: Yes, they were.

1 **D. Resource Planning – La Cygne and Montrose**

2 **Q: Do you disagree with Sierra Club witness Mr. Bruce E. Biewald’s key conclusions?**

3 A: Yes. Mr. Biewald in his Direct Testimony at page 3 concludes that “there has been no
4 formal transparent process in Missouri in which KCP&L has demonstrated, or even
5 attempted to demonstrate, that it is conducting prudent planning with regard to its large
6 retrofit investment in La Cygne and Montrose.” This is incorrect. There is a formal and
7 transparent integrated resource planning process in Missouri where KCP&L has
8 demonstrated it is conducting prudent planning for the retrofit investments currently
9 underway at La Cygne and has evaluated potential retrofits at Montrose. The process is
10 underway in KCP&L’s current Integrated Resource Plan (“IRP”) case before the MPSC.

11 **Q: Do you take issue with Mr. Biewald’s recommendations to the Commission?**

12 A: Yes. Mr. Biewald recommends at page 4 of his Direct Testimony that the MPSC “insist”
13 on a prudent and proper planning process for La Cygne and Montrose projects. There is
14 no need in the context of this rate case to insist on such a process. However, this process
15 has already been well established by the Commission through its currently effective and
16 comprehensive Electric Utility Resource Planning rules found at 4 CSR 240-22.

17 Mr. Biewald also recommends that the MPSC “make it clear” to KCP&L that
18 investments in La Cygne and Montrose must be justified on economic terms or be subject
19 to disallowance. This is unnecessary since KCP&L is fully aware that any investments
20 that it may make are reviewed by the Commission and subject to disallowance should the
21 Commission find such investments to be imprudent.

22 **Q: Does that conclude your testimony?**

23 A: Yes, it does.

NERC GADS Unit States Diagram

