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**COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION**

JUL 06 2007

**PUBLIC SERVICE
COMMISSION**

IN THE MATTER OF GENERAL ADJUSTMENT OF)
ELECTRIC RATES OF EAST KENTUCKY POWER)
COOPERATIVE, INC.) CASE NO. 2006-00472
)
)

Direct Testimony of Kevin C. Higgins

on behalf of

Kentucky Industrial Utility Consumers

June 27, 2007

1 **DIRECT TESTIMONY OF KEVIN C. HIGGINS**

2

3 **Introduction**

4 **Q. Please state your name and business address.**

5 A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah,
6 84111.

7 **Q. By whom are you employed and in what capacity?**

8 A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies
9 is a private consulting firm specializing in economic and policy analysis
10 applicable to energy production, transportation, and consumption.

11 **Q. On whose behalf are you testifying in this proceeding?**

12 A. My testimony is being sponsored by Kentucky Industrial Utility
13 Customers, Inc. ("KIUC"), which includes Gallatin Steel Company ("Gallatin
14 Steel"), AGC Automotive, and Air Liquide.

15 **Q. Please describe your professional experience and qualifications.**

16 A. My academic background is in economics, and I have completed all
17 coursework and field examinations toward a Ph.D. in Economics at the University
18 of Utah. In addition, I have served on the adjunct faculties of both the University
19 of Utah and Westminster College, where I taught undergraduate and graduate
20 courses in economics. I joined Energy Strategies in 1995, where I assist private
21 and public sector clients in the areas of energy-related economic and policy
22 analysis, including evaluation of electric and gas utility rate matters.

1 Prior to joining Energy Strategies, I held policy positions in state and local
2 government. From 1983 to 1990, I was economist, then assistant director, for the
3 Utah Energy Office, where I helped develop and implement state energy policy.
4 From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County
5 Commission, where I was responsible for development and implementation of a
6 broad spectrum of public policy at the local government level.

7 **Q. Have you testified previously before this Commission?**

8 A. Yes. I filed direct testimony in the Union Light, Heat and Power Company
9 general rate case, Case No. 2006-00172.

10 **Q. Have you testified previously before any state utility regulatory**
11 **commissions?**

12 A. Yes. I have testified in over seventy proceedings on the subjects of utility
13 rates and regulatory policy before state utility regulators in Alaska, Arizona,
14 Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Michigan,
15 Missouri, Minnesota, Nevada, New York, Ohio, Oklahoma, Oregon,
16 Pennsylvania, South Carolina, Utah, Washington, Virginia, West Virginia, and
17 Wyoming.

18 A more detailed description of my qualifications is contained in
19 Attachment "A" appended to this direct testimony.

20

21 **Overview and Conclusions**

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

1 A. My testimony addresses the appropriate basis for apportioning among
2 customer classes any revenue requirement increase that may be awarded by the
3 Commission in this proceeding. In addition, my testimony provides an adjustment
4 to EKPC's cost-of-service study to more properly reflect the allocation of
5 production costs to interruptible load.

6 **Q. What conclusions and recommendations are presented in your testimony?**

7 A. I recommend that the Commission reject EKPC's proposal to apportion its
8 requested revenue requirement increase on the basis of the total base revenues
9 currently recovered from each rate class. Fifty percent of the base revenues that
10 EKPC uses as the basis for spreading the proposed rate increase among customer
11 classes is comprised of fuel and purchased power costs. Yet, the revenue
12 deficiency that is driving EKPC's need for a rate increase is largely unrelated to
13 fuel and purchased power costs; instead, it is driven by EKPC's need to build
14 equity, which is a component of fixed cost recovery. Given that the underlying
15 rationale for the requested rate increase is almost entirely related to fixed cost
16 recovery, I recommend that any revenue increase be apportioned on the basis of
17 each class's demand-related revenues.

18 In addition, I recommend that the revenue apportionment for Gallatin
19 Steel be determined separately from the other special contract customers, rather
20 than by deriving a single rate change that would apply to the entire special
21 contract group, as proposed by EKPC. For purposes of revenue apportionment, it
22 is appropriate to consider Gallatin Steel separately from the other special
23 contracts given its size and unique load characteristics. Alternatively, the revenue

1 increase for the special contract customers should be separately determined on an
2 individual customer basis. A customer specific apportionment would better
3 capture the specific cost characteristics of each individual contract.

4 With respect to class cost-of-service, I support EKPC's use of the Average
5 and Excess Demand method, but I have determined that EKPC's analysis does not
6 correctly allocate the costs of Gallatin Steel's interruptible load. I recommend an
7 adjustment to the calculation to better reflect the treatment of interruptible load as
8 discussed in the NARUC Manual. Even though EKPC's allocation approach has
9 no impact on the revenues apportioned to Gallatin Steel in this proceeding, I
10 believe it is important to raise this issue now so that it is properly addressed in
11 future proceedings. My corrected Average and Excess cost-of-service study
12 shows that Gallatin Steel is paying \$950,000 above cost-of-service. The
13 interruptible credit in the Gallatin contract should therefore be increased by
14 \$950,000.

15
16 **Revenue Apportionment**

17 **Q. What has EKPC proposed as the basis for apportioning among customer**
18 **classes any rate increase that is awarded in this proceeding?**

19 **A.** As discussed in the direct testimony of William A. Bosta, EKPC is
20 proposing to apportion its requested revenue requirement increase on the basis of
21 the total base revenues currently recovered from each rate class. Mr. Bosta
22 describes this as a "proportion of revenue" rate design approach. He explains that

1 due to EKPC's need for "immediate" rate relief, it did not embark on a significant
2 effort to alter the existing rate design in this case.

3 **Q. How did EKPC calculate the proposed revenue increase for each customer**
4 **class?**

5 A. To determine the revenue apportionment, or rate spread, EKPC first
6 removed "buy-through" revenues, and then eliminated the revenue for those rate
7 categories for which no revenue increase was being requested – substation charges
8 (Load Center), Metering Charges, and the TGP contract. Next, EKPC determined
9 the proportion of existing base revenue recovered from each major rate class – the
10 "E" loads (80.05%), the "B" and "C" industrial loads (9.39%), and Special
11 Contracts (10.56%). EKPC then apportioned its proposed rate increase on the
12 basis of the resulting percentages, i.e., 80.05% for "E" loads, 9.39% for the "B"
13 and "C" industrial loads, and 10.56% Special Contracts.¹

14 **Q. What is your assessment of EKPC's recommended approach to revenue**
15 **apportionment?**

16 A. I recommend against adoption of EKPC's recommended revenue
17 apportionment method. Half of the base revenues that EKPC uses as the basis for
18 spreading the proposed rate increase among customer classes is comprised of fuel
19 and purchased power costs. Yet, the revenue deficiency that is driving EKPC's
20 need for a rate increase is largely unrelated to fuel and purchased power costs;
21 instead, it is driven by EKPC's need to build equity, which is a component of
22 fixed cost recovery. Given this fact, the inclusion of fuel and purchased power

¹ Direct testimony of William A. Bosta, p. 8.

1 costs in the derivation of the revenue apportionment violates the ratemaking
2 principle of assigning cost responsibility on the basis of cost causation.

3 EKPC's approach overstates the cost responsibility for those rate classes
4 whose energy-related revenues in relation to their demand-related revenues are
5 above the system average. These customers already pay for the full recovery of
6 their (relatively high) fuel and purchased power usage in their energy charges and
7 through the fuel adjustment clause ("FAC"). Including fuel and purchased power
8 costs (again) in the calculation of the apportionment of the requested rate increase
9 causes fuel and purchase power costs to be over-weighted in the determination of
10 class cost responsibility, unreasonably distorting the results.

11 **Q. What is your basis for concluding that EKPC's requested base revenue**
12 **increase is primarily a request for increased fixed cost recovery?**

13 A. It is clear from EKPC's filing that its primary objective in seeking to
14 increase rates is to build equity – and the request to build equity is a request for
15 increased fixed cost recovery.

16 One of the stated purposes of EKPC witness David G. Eames' testimony is
17 to describe EKPC's need for additional equity. Mr. Eames testifies that EKPC's
18 equity as a percentage of its assets has fallen from 13.71% at end of 2002 to just
19 4.87% at the end of the test year ending September 30, 2006. He further testifies
20 that:

21 A strong equity position is necessary for EKPC to meet its mortgage
22 covenants and to be able to obtain future financing. EKPC expects the
23 need for credit facility financing through 2019 for its capital expansion
24 program. Having the appropriate amount of equity will significantly reduce
25 the cost of future borrowings.²

² Direct testimony of David G. Eames, p. 5, lines 4-8.

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Mr. Eames also points out that EKPC would violate its \$650 million credit agreement with sixteen financial institutions if EKPC's equity were to fall below \$90 million as of the last day of any calendar year between 2005 and 2007. He further testifies that on September 30, 2006, members' equity stood at \$92 million.

EKPC's desire to increase its equity is a function of the Cooperative's existing asset valuation as well as the Cooperative's need to attract capital to meet future investment requirements. Both considerations are inherently related to EKPC's fixed assets – current and future. If EKPC's rates are increased to allow EKPC to attain a higher equity-to-asset ratio, the added revenue would constitute increased fixed cost recovery.

Q. But doesn't EKPC's filing also focus on increasing the Times-Interest-Earned Ratio ("TIER")?

A. Yes, the TIER is the standard benchmark for setting rates for electric cooperatives. But in seeking approval to set rates based on a TIER of 1.35, EKPC is seeking to earn a level of net income that will allow the Cooperative to meet its objective of increasing its equity.

Q. Can a cooperative's need for additional equity occur due to under-recovery of fuel and purchased power costs?

A. This can occur if base rates do not recover the cost of fuel and purchased power and the cooperative does not have a fuel adjustment clause. But in the case of EKPC, the FAC allows the cooperative to fully recover its fuel and purchased

1 power expenses to the extent such expenses are not the result of forced outages. In
2 EKPC’s rate increase request of \$43.4 million, \$4.6 million, or 10.6%, is related
3 to recovery of projected forced outage replacement costs. The balance of the
4 requested rate increase is unrelated to fuel and purchased power costs. This
5 remaining 89.4% of the requested rate increase is a request for increased fixed
6 cost recovery.

7 **Q. Are there other indications in EKPC’s filing that its rate increase request is**
8 **driven by fixed costs?**

9 A. Yes. EKPC proposes to recover its requested revenue increase for service
10 to “B” and “C” customers, as well as Special Contract customers, via an increase
11 in the demand charges levied for service to these classes – with no increase in the
12 energy charges. As explained by Mr. Bosta: “[T]his case is geared to improving
13 EKPC’s equity and TIER level and the increase in cost is more oriented to
14 demand-related costs.”³ I agree with Mr. Bosta on this point, and this principle
15 should be reflected in the apportionment of class cost responsibility.

16 **Q. What alternative do you propose for apportioning any revenue increase**
17 **awarded in this case?**

18 A. Given that the underlying rationale for the requested rate increase is
19 almost entirely related to fixed cost recovery, I recommend that any revenue
20 increase be apportioned on the basis of each class’s demand-related revenues.⁴
21 Such an approach would result in a better alignment of revenue recovery and cost

³ Direct testimony of William A. Bosta, p. 9, lines 19-21.

⁴ Another reasonable alternative would be to apportion any revenue increase on the basis of each class’s non-fuel-and-purchased-power-related revenues. This is conceptually similar to an allocation based on

1 causation than the EKPC’s “proportion of revenue” approach, which includes fuel
2 and purchased power costs. It would also meet EKPC’s objective of making a
3 “streamlined” determination of revenue apportionment and avoiding a major rate
4 re-design in this proceeding.

5 In addition, I recommend that the revenue requirement for special
6 contracts be apportioned to Gallatin Steel separately while aggregating the
7 remaining Special Contracts into a single group for apportionment purposes.⁵
8 Gallatin Steel is the single largest Special Contract customer, and the terms of its
9 service are unique in that a very large proportion of its load is interruptible. These
10 special circumstances warrant a stand-alone revenue apportionment for this
11 customer.

12 **Q. Has EKPC expressed a position with respect to your proposal to apportion**
13 **any revenue requirement increase on the basis of demand-related revenues?**

14 A. Yes. Mr. Bosta put forward a position in EKPC’s Response to KIUC 1.1.
15 While Mr. Bosta maintains that EKPC’s filed apportionment approach is
16 reasonable, Mr. Bosta “agrees that the overall rate increase is more oriented to
17 demand-related cost and that an apportionment of the increase on the basis of
18 demand-related revenue or non-fuel revenue would be another way to reasonably
19 apportion the increase.”

20 **Q. Why do you believe it is preferable for any revenue increase for Gallatin**
21 **Steel to be apportioned separately for the other special contracts?**

demand-related revenues, but the allocation would include non-fuel-and-purchased power-related energy charge revenues.

1 A. A special contract may have terms that reflect the unique nature of the
2 service being provided to a customer – and the apportionment of any revenue
3 increase should reflect each contract customer’s unique circumstances. For
4 example, most of the service to Gallatin Steel is interruptible, and as a result,
5 Gallatin Steel takes service under three different demand charges – one for firm
6 service, another for interruptions on ninety minutes notice, and a third for
7 interruptions on ten minutes notice. These three demand charges were negotiated
8 by the customer, EKPC, and the relevant distribution cooperative (Owen), and
9 were subsequently approved by the Commission. The differentials between these
10 demand charges represent the most reasonable measure of the differences in the
11 level of service received by Gallatin Steel. To the extent that Gallatin Steel
12 receives a rate increase to recover increased fixed costs for EKPC, the increase
13 should be proportionate to the revenues associated with these three levels of
14 demand charges, so as to best reflect the type of service provided to this customer.
15 This can be accomplished with a separate Gallatin-specific apportionment.

16 **Q. Would your recommended special contract apportionment produce the same**
17 **total apportionment to Special Contract customers as a group as would an**
18 **aggregate apportionment to the Special Contract class, such as that proposed**
19 **by EKPC?**

20 A. Yes. A Gallatin-specific apportionment within the Special Contract class
21 would not change the apportionment to Special Contracts as a class, nor would it
22 affect the apportionment to the other rate classes.

⁵ The TGP contract is not proposed to receive a rate increase. According to EKPC Response to KIUC 1.3, “Due to the nature of the elements that comprise the [TGP] contracts, there is no specific provision in the

1 **Q. What is the revenue increase by class that results from your recommended**
 2 **apportionment method if EKPC's requested revenue increase of \$43.4**
 3 **million is adopted?**

4 A. These results are presented in Table KCH-1. The derivation of these
 5 figures is shown in Exhibit KCH-1.

6 **Table KCH-1**

7
 8 **KIUC Apportionment of Revenue Increase if EKPC-Recommended**
 9 **\$43.4 Million Revenue Increase Is Adopted**

10

11 <u>Customer Class</u>	<u>% of Demand Rev.</u>	<u>Revenue Increase</u>
12 B & C Industrial	8.65%	\$ 3,751,395
13 Bundled Contracts	3.58%	\$ 1,552,600
14 Gallatin Steel	3.34%	\$ 1,448,515
15 Schedule E	84.43%	\$36,616,216
16		
17 TOTAL	100.00%	\$43,368,727
18		
19		

20 **Q. What is the revenue increase by class that results from your recommended**
 21 **apportionment method if KIUC's requested revenue increase of \$19.0 million**
 22 **is adopted?**

23 A. These results are presented in Table KCH-2. The derivation of these
 24 figures is shown in Exhibit KCH-2.

25 **Table KCH-2**

26
 27 **KIUC Apportionment of Revenue Increase if KIUC-Recommended**
 28 **\$19.0 Million Revenue Increase Is Adopted**

29

30 <u>Customer Class</u>	<u>% of Demand Rev.</u>	<u>Revenue Increase</u>
31 B & C Industrial	8.65%	\$ 1,643,500
32 Bundled Contracts	3.58%	\$ 680,200
33 Gallatin Steel	3.34%	\$ 634,600
34		

contracts that permit a general rate increase.

1	Schedule E	84.43%	\$16,041,700
2			
3	TOTAL	100.00%	\$19,000,000
4			
5			

6 **Q. Is there an alternative to your proposal to treat Gallatin separately from the**
7 **other special contracts and EKPC’s proposal to aggregate all Special**
8 **Contracts into a single apportionment?**

9 A. Yes. An alternative would be to apportion the revenue increase to each
10 special contract separately for apportionment purposes. Apportioning their
11 respective revenue increase responsibilities on an individual customer basis would
12 better capture the specific cost characteristics of each individual contract than
13 would occur by determining a “one-size-fits-all” rate change for Special Contracts
14 as a whole as proposed by EKPC. Like the Gallatin-specific apportionment
15 proposal, this customer-specific apportionment within the Special Contract class
16 would not change the apportionment to Special Contracts as a class, nor would it
17 affect the apportionment to the other rate classes

18 **Q. Have you calculated the revenue apportionment by class that would result if**
19 **the variant of your recommendation (apportioning the revenue increase**
20 **based on class non-fuel-and-purchased-power-related revenues) discussed in**
21 **Footnote 4 is adopted?**

22 A. Yes. These calculations are shown in Exhibit KCH-3.

23 **Q. Please summarize your recommended revenue apportionment for this**
24 **proceeding.**

1 A. Given that the underlying rationale for the requested rate increase is
2 almost entirely related to fixed cost recovery, I recommend that any revenue
3 increase be apportioned on the basis of each class's demand-related revenues.
4 In addition, I recommend that the revenue apportionment for Gallatin Steel be
5 determined separately from the other special contract customers, rather than by
6 deriving a single rate change that would apply to the entire special contract group,
7 as proposed by EKPC. If EKPC's recommended rate increase is approved, my
8 recommended revenue apportionment is shown in Table KCH-1. If KIUC's
9 recommended rate increase is approved, my recommended revenue apportionment
10 is shown in Table KCH-2.

11

12 **Class Cost-of-Service Study**

13 **Q. What is the role of the class cost-of-service study performed by EKPC in this**
14 **proceeding?**

15 A. EKPC's class cost-of-service study is presented for informational purposes
16 only. It plays no role in EKPC's proposed apportionment of its requested revenue
17 increase.

18 **Q. Do you disagree with the purely informational role assigned to the class cost-**
19 **of-service study by EKPC in this proceeding?**

20 A. No. For the purposes of this proceeding I believe it is reasonable to
21 apportion any revenue increase based on demand-related revenues, as I discussed
22 in the preceding section. Consequently, it is appropriate to view the class cost-of-
23 service analysis solely for information purposes at this time.

1 **Q. Even though the class cost-of-service study is presented just for informational**
2 **purposes, do you have any disagreements with the calculation performed by**
3 **EKPC?**

4 A. Yes. In my opinion, EKPC's analysis does not correctly allocate the costs
5 of Gallatin Steel's interruptible load. Even though EKPC's allocation approach
6 has no impact on the revenues apportioned to Gallatin Steel in this proceeding, I
7 believe it is important to raise this issue now so that it is properly addressed in
8 future proceedings and because it impacts the proper level of Gallatin's
9 interruptible credit.

10 **Q. What cost-of-service methodology does EKPC utilize in this proceeding?**

11 A. EKPC uses the Average and Excess Demand method. This method is
12 generally well accepted, and in my view, it is based on sound reasoning, although
13 particular care must be taken when applying this method to interruptible loads.

14 **Q. Please generally describe the Average and Excess Demand method.**

15 A. The Average and Excess Demand method is described in the Electric
16 Utility Cost Allocation Manual published by the National Association of
17 Regulatory Utility Commissioners ("NARUC Manual"). As the name suggests,
18 the Average and Excess Demand method allocates costs on two bases: average
19 demand and excess demand. Average demand is simply annual energy
20 consumption divided by the number of hours in the year. This portion of the
21 allocation is akin to a "base load allocation" in that it allocates that portion of
22 system generating capacity that would be needed if all customers used energy at a
23 constant 100 percent load factor.

1 The second component, excess demand, is equal to each class’s non-
2 coincident peak (“NCP”) demand minus its average demand. This component
3 measures each class’s contribution to generation costs based on the class’s
4 individual peak demand above its average demand. This measure attempts to
5 capture each class’s need for generating capacity that is attributable to load shape
6 – i.e., demand for capacity beyond that needed for provision of 100-percent-load-
7 factor service.

8 **Q. Does the NARUC Manual call attention to the need for special treatment of**
9 **interruptible load when using the Average and Excess Demand method?**

10 A. Yes, it does. Specifically, the NARUC Manual states:

11 The second component of each class’s allocation factor is called the
12 “excess demand factor.” It is the proportion of the difference between the
13 sum of all classes’ non-coincident peaks and the system average demand.
14 The difference may be negative for curtailable rate classes. [Emphasis
15 added.]⁶
16

17 **Q. What does the underlined sentence in the above excerpt from the NARUC**
18 **Manual mean?**

19 A. The underlined sentence means that the excess demand factor applied to
20 an interruptible rate class may be negative, reducing the allocation of costs to this
21 class. This reduction occurs because load that is contractually interruptible can be
22 treated as a resource during periods of peak demand or system constraints,
23 permitting the utility to meet its firm load requirements with fewer generating
24 resources. The ability to use interruptible load in this way provides cost savings to

⁶ NARUC Manual (1992), p. 49.

1 the system. A negative excess demand allocation factor occurs when an
2 interruptible class's firm demand is less than its average demand.

3 **Q. Please explain.**

4 A. Recall that excess demand is measured as that portion of class NCP that is
5 greater than (or in "excess of") average class demand. It follows from the
6 underlined passage in the NARUC Manual that the relevant portion of class NCP
7 that must be considered in measuring excess demand is the firm – or non-
8 curtailable – portion of the class's NCP. This is because the curtailable portion of
9 class NCP is not contributing to the need for additional system capacity and thus
10 should not be used to allocate capacity costs. Indeed, the curtailable portion of the
11 class NCP allows system load to be served with less system generating capacity.
12 The upshot is that the curtailable portion of the class's NCP should be subtracted
13 from the total class NCP when determining excess demand. Algebraically, then, if
14 the curtailable load is greater than the difference between total class NCP and
15 average class demand, the excess demand factor will be negative, as indicated in
16 the NARUC Manual. Mathematically, this will occur if firm class demand is less
17 than average class demand.⁷

18 **Q. Can you illustrate this point with a simple example?**

19 A. Yes. In fact, we can use Gallatin Steel's load to illustrate this point.
20 EKPC's cost-of-service study treats Gallatin Steel (appropriately) as a stand-alone
21 class. In the test period, Gallatin Steel had an average demand of 118 MW and an
22 NCP of 171 MW. Even though Gallatin Steel's firm load is only 15 MW, let us

⁷ The negative excess demand will be equal to class firm demand (as a component of class NCP) minus average class demand.

1 assume for the moment that all of Gallatin Steel's demand is firm. In such a
2 situation, Gallatin Steel's excess demand would be equal to its NCP (=Firm
3 Demand) – Average demand = 171 MM – 118 MW = 53 MW.

4 Now, let us assume that Gallatin Steel's firm demand is 130 MW. In this
5 case, to properly determine excess demand, Gallatin Steel's NCP would have to
6 be adjusted by removing its curtailable load, such that only its firm demand
7 remained. Therefore, Gallatin Steel's excess demand would equal Firm Demand –
8 Average Demand = 130 MW – 118 MW = 12 MW. This example shows that
9 with 41 MW of curtailable load (i.e., 171 MW of total NCP minus 130 MW of
10 firm load), Gallatin Steel's excess demand would be reduced relative to the first
11 example, but its excess demand would still have a positive sign, as its firm load
12 would exceed its average demand (i.e., it would still have positive "excess"
13 demand).

14 Now let us consider a third case, in which Gallatin Steel's firm demand
15 was coincidentally equal to its average demand of 118 MW. In this case, Gallatin
16 Steel's excess demand would equal 118 MW – 118 MW = 0 MW, as it would
17 have no firm load in excess of its average demand.

18 Finally, let us consider the actual firm load for Gallatin Steel, which is just
19 15 MW. In this case, we have an excess demand equal to 15 MW – 118 MW =
20 (103) MW, which is the negative excess demand case referenced in the NARUC
21 Manual.

22 **Q. How has EKPC treated Gallatin Steel's interruptible load in its cost-of-**
23 **service study?**

1 A. EKPC’s cost-of-service study recognizes that Gallatin Steel has
2 interruptible load, but the adjustment made in the study is not consistent with the
3 NARUC Manual. Rather than subtract Gallatin Steel’s curtailable load from its
4 NCP, EKPC simply sets Gallatin Steel’s excess demand equal to its firm load of
5 15 MW. This ad hoc adjustment overlooks the fact that a customer’s firm load is
6 “first in” to its total load at any given time; that is, 15 MW of firm load is not
7 excess to 118 MW of average demand – it is subsumed within it.

8 EKPC’s approach of setting excess demand equal to the customer’s firm
9 demand is clearly inconsistent with the NARUC Manual in that the excess
10 demand for an interruptible class could never be negative under such EKCP’s
11 approach. In fact, applying EKPC’s approach to the example of 130 MW of firm
12 demand discussed above would produce a clearly absurd result: it would result in
13 130 MW of excess demand – which, when combined with Gallatin Steel’s
14 average demand would exceed Gallatin Steel’s NCP. In other words, EKPC’s
15 method applied to 130 MW of firm demand would create an interruptible service
16 penalty, demonstrating that its approach to treating interruptible load is not
17 reasonable.

18 **Q. Have you queried EKPC regarding this issue in discovery?**

19 A. Yes. When queried regarding its treatment of interruptible load in the cost-
20 of-service study, EKPC responded that its approach was based on “informed
21 judgment”.⁸ When queried regarding the potentially absurd results that would
22 obtain from EKCP’s approach if Gallatin Steel’s firm load happened to be
23 substantially greater than 15 MW (e.g., 80 MW), EKPC responded that it would

1 ensure reasonable results through exercise of “reasonable judgment.”⁹ I interpret
2 this response to mean that EKPC would change its method of accounting for
3 interruptible load if the amount of interruptible load happened to be much greater
4 than 15 MW. This reinforces the notion that its treatment of Gallatin Steel’s
5 interruptible load is ad hoc, rather than based on a consistent set of cost-of-service
6 principles.

7 **Q. Has EKPC expressed a view on your recommended approach?**

8 A. In data responses, EKPC indicated it would never recognize a negative
9 excess demand for an interruptible customer, contrary to the prescription in the
10 NARUC Manual. For example, in EKPC Response to KIUC 1.9, EKPC states that
11 it believes that the allocation for a 100% interruptible customer should not be
12 lower the average demand allocator – which is another way of saying that the
13 excess demand allocator can never be negative. This statement also implies that
14 EKCP believes a 100%-load-factor firm customer and a 100% interruptible
15 customer should receive the same cost allocation.¹⁰ This position strikes me as
16 inherently unreasonable.

17 EKPC also attempted to show that applying my recommended approach to
18 Gallatin Steel, or to a 100-per-cent interruptible customer, would produce
19 allocations that are too low. However, in making this demonstration, EKPC failed
20 to adjust its system “adjusted excess demand” to reflect the removal of the
21 curtailable load. Consequently, the example it provided in its Response to KIUC

⁸ EKPC Response to KIUC 1.6.

⁹ EKPC Response to KIUC 1.7.

¹⁰ The allocation for a 100%-load-factor firm customer is based solely on the average demand allocator, as its excess demand is zero, a point to which EKPC agrees. See EKPC Response to KIUC 1.6(a).

1 1.9(e) produces a much lower allocation to Gallatin Steel than does my
2 calculation, which is presented below. Similarly, if EKCP had made this
3 adjustment to its calculation of a 100-percent-interruptible customer, the resulting
4 allocation would not be negative, as EKPC claims in its data response.

5 **Q. Have you re-calculated EKPC's cost-of-service study using the treatment of**
6 **interruptible load that you have discussed above?**

7 A. Yes. The results of my analysis – and a comparison to EKPC's results –
8 are shown in Exhibit KCH-4. These results show that Gallatin Steel's current rates
9 are providing a revenue sufficiency in excess of \$950 thousand per year.

10 **Q. What is the implication of this \$950 revenue sufficiency?**

11 A. This \$950 thousand revenue sufficiency implies that Gallatin Steel is
12 currently overpaying for its electric service. One way to eliminate this
13 overpayment would be to increase Gallatin's interruptible credit until the \$950
14 thousand sufficiency is eliminated. I recommend that this increase in the Gallatin
15 interruptible credit be made in this case. Such a change would slightly increase
16 EKPC's overall revenue deficiency from \$43.4 million to \$44.3 million.

17 **Q. Does this conclude your direct testimony?**

18 A. Yes, it does.

**KIUC Revenue Allocation to Major Classes & Rate Design
Using Current Demand Revenue at EKPC's Recommended \$43.4 Million Increase**

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
I.	Test Year Base Rate Revenue	Energy	Demand	Total						
1	Total Test Yr. Existing Revenue Including Buy-Through	\$ 368,343,135	\$ 143,682,168	\$ 512,025,304						
2	Less Buy Through Revenue	\$ (1,356,273)	\$ -	\$ (1,356,273)						
3	Total Test Yr. Existing Revenue Excluding Buy-Through	\$ 366,986,862	\$ 143,682,168	\$ 510,669,031						
4	Load Center Rev. - Substation Charges	\$ -	\$ (10,219,764)	\$ (10,219,764)						
5	Metering Point Charges	\$ -	\$ (433,500)	\$ (433,500)						
6	TGP Contract	\$ (8,857,116)	\$ (806,531)	\$ (9,663,647)						
7	Net Revenue	\$ 358,129,747	\$ 132,222,373	\$ 490,352,120						

Rate categories for which no increase being sought

Line No.	II. Base Revenue	% of Base Demand Revenue Total	Allocate to Class	% Change from Current Demand Revenue	% Change from Current Total Revenue	Billing kW	\$/kW
10	Proposed Revenue Increase		\$ 43,368,727	32.80%	8.84%		
11	Rate B						
12	Rate B - Inter						
13	Rate C						
14	Bundled Contracts (Inland Electric, AGC & Inland Steam)						
15	Gallatin						
16	Special Contract Total						
17	III. Energy Adder to "E" Rate						
18	Total Revenue Increase		\$ 43,368,727				
19	B & C		\$ (3,751,395)				
20	Special Contract		\$ (3,001,116)				
21	Amount Remaining to "E"		\$ 36,616,216	32.80%	9.33%	9,181,636,048	\$ 0.00399

"E" Billing kWh \$/kWh

**KIUC Revenue Allocation to Major Classes & Rate Design
Using Current Demand Revenue at KIUC's Recommended \$19.0 Million Increase**

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
I.	Test Year Base Rate Revenue									
1	Total Test Yr. Existing Revenue Including Buy-Through	Energy	Demand	Total						
2	Less Buy Through Revenue	\$ 368,343,135	\$ 143,682,168	\$ 512,025,304						
3	Total Test Yr. Existing Revenue Excluding Buy-Through	\$ (1,356,273)	\$ -	\$ (1,356,273)						
4		\$ 366,986,862	\$ 143,682,168	\$ 510,669,031						
5	Load Center Rev. - Substation Charges	\$ -	\$ (10,219,764)	\$ (10,219,764)						
6	Metering Point Charges	\$ -	\$ (433,500)	\$ (433,500)						
7	TGP Contract	\$ (8,857,116)	\$ (806,531)	\$ (9,663,647)						
8	Net Revenue	\$ 358,129,747	\$ 132,222,373	\$ 490,352,120						
II.	Base Revenue									
10	Proposed Revenue Increase					\$ 19,000,000	14.37%			
11	Rate B	Energy	Demand	Total						
12	Rate B - Inter	\$ 19,944,370	\$ 6,676,264	\$ 26,620,634						
13	Rate C	\$ 2,874,370	\$ 546,551	\$ 3,420,921						
		\$ 11,768,844	\$ 4,218,721	\$ 15,987,564						
		\$ 34,587,585	\$ 11,441,535	\$ 46,029,120	8.65%	\$ 1,643,500	14.36%	3.57%	2,138,666	\$ 0.77
14	Bundled Contracts (Inland Electric, AGC & Inland Steam)	\$ 16,166,156	\$ 4,739,161	\$ 20,905,316	3.58%	\$ 680,200	14.35%	3.25%	1,060,389	\$ 0.64
15	Gallatin	\$ 26,455,869	\$ 4,414,903	\$ 30,870,772	3.34%	\$ 634,600	14.37%	2.06%	1,942,343	\$ 0.33
16	Special Contract Total	\$ 42,622,025	\$ 9,154,063	\$ 51,776,088	6.92%	\$ 1,314,800	14.36%	2.54%	3,002,732	\$ 0.44
III.	Energy Adder to "E" Rate									
17	Total Revenue Increase					\$ 19,000,000				
18	B & C					\$ (1,643,500)				
19	Special Contract					\$ (1,314,800)				
20	Amount Remaining to "E"					\$ 16,041,700	14.37%	4.09%	9,181,636,048	\$ 0.00175

"E" Billing kWh \$/kWh

**KIUC Revenue Allocation to Major Classes & Rate Design
Using Current Non-Fuel Revenue at EKPC's Recommended \$43.4 Million Increase**

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
I.	Test Year Base Rate Revenue									
1	Total Test Yr. Existing Revenue Including Buy-Through	Fuel	Non-Fuel	Total						
2	Less Buy Through Revenue	\$ 250,055,979	\$ 261,969,325	\$ 512,025,304						
3	Total Test Yr. Existing Revenue Excluding Buy-Through	\$ (1,356,273)	\$ -	\$ (1,356,273)						
4	Load Center Rev. - Substation Charges	\$ 248,699,706	\$ 261,969,325	\$ 510,669,031						
5	Metering Point Charges	\$ -	\$ (10,219,764)	\$ (10,219,764)						
6	TGP Contract	\$ -	\$ (433,500)	\$ (433,500)						
7	Net Revenue	\$ (3,153,457)	\$ (6,510,190)	\$ (9,663,647)						
8		\$ 245,546,249	\$ 244,805,871	\$ 490,352,120						

Rate categories for which no increase being sought

Line No.	II. Base Revenue	% of Base Non-Fuel Revenue Total	Allocate to Class	% Change from Current Non-Fuel Revenue	% Change from Current Total Revenue	Billing kW	\$/kWh
10	Proposed Revenue Increase		\$ 43,368,727	17.72%	8.84%		
11	Rate B	Fuel	Non-Fuel	Total			
12	Rate B - Inter	\$ 14,780,366	\$ 11,840,268	\$ 26,620,634			
13	Rate C	\$ 2,130,137	\$ 1,290,784	\$ 3,420,921			
		\$ 8,721,650	\$ 7,265,914	\$ 15,987,564			
		\$ 25,632,153	\$ 20,396,966	\$ 46,029,120	8.33%	\$ 3,612,615	17.71%
					7.85%	2,138,666	\$ 1.69
14	Bundled Contracts (Inland Electric, AGC & Inland Steam)	\$ 13,040,264	\$ 7,865,053	\$ 20,905,316	3.21%	\$ 1,392,136	17.70%
15	Gallatin	\$ 20,945,702	\$ 9,925,070	\$ 30,870,772	4.05%	\$ 1,756,433	17.70%
16	Special Contract Total	\$ 33,985,966	\$ 17,790,123	\$ 51,776,088	7.26%	\$ 3,148,570	17.70%
17	Energy Adder to "E" Rate		\$ 3,148,570				
19	Total Revenue Increase		\$ 43,368,727				
20	B & C		\$ (3,612,615)				
21	Special Contract		\$ (3,148,570)				
22	Amount Remaining to "E"		\$ 36,607,542	17.72%	9.33%	9,181,636,048	\$ 0.00399

**KIUC Revenue Allocation to Major Classes & Rate Design
Using Current Non-Fuel Revenue at KIUC's Recommended \$19.0 Million Increase**

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
I.	Test Year Base Rate Revenue									
2	Total Test Yr. Existing Revenue Including Buy-Through	Fuel	Non-Fuel	Total						
3	Less Buy Through Revenue	\$ 250,055,979	\$ 261,969,325	\$ 512,025,304						
4	Total Test Yr. Existing Revenue Excluding Buy-Through	\$ (1,356,273)	\$ -	\$ (1,356,273)						
5	Load Center Rev. - Substation Charges	\$ -	\$ (10,219,764)	\$ (10,219,764)						
6	Metering Point Charges	\$ -	\$ (433,500)	\$ (433,500)						
7	TGP Contract	\$ (3,153,457)	\$ (6,510,190)	\$ (9,663,647)						
8	Net Revenue	\$ 245,546,249	\$ 244,805,871	\$ 490,352,120						
II.	Base Revenue									
10	Proposed Revenue Increase					\$ 19,000,000	7.76%			3.87%
11	Rate B	Fuel	Non-Fuel	Total						
12	Rate B - Inter	\$ 14,780,366	\$ 11,840,268	\$ 26,620,634						
13	Rate C	\$ 2,130,137	\$ 1,290,784	\$ 3,420,921						
		\$ 8,721,650	\$ 7,265,914	\$ 15,987,564						
		\$ 25,632,153	\$ 20,396,966	\$ 46,029,120	8.33%	\$ 1,582,700	7.76%		2,138,666	\$ 0.74
14	Bundled Contracts (Inland Electric, AGC & Inland Steam)	\$ 13,040,264	\$ 7,865,053	\$ 20,905,316	3.21%	\$ 609,900	7.75%		1,060,389	\$ 0.58
15	Gallatin	\$ 20,945,702	\$ 9,925,070	\$ 30,870,772	4.05%	\$ 769,500	7.75%		1,942,343	\$ 0.40
16	Special Contract Total	\$ 33,985,966	\$ 17,790,123	\$ 51,776,088	7.26%	\$ 1,379,400	7.75%		3,002,732	\$ 0.46
17	III. Energy Adder to "E" Rate									
19	Total Revenue Increase					\$ 19,000,000				
20	B & C					\$ (1,582,700)				
21	Special Contract					\$ (1,379,400)				
22	Amount Remaining to "E"					\$ 16,037,900	7.76%		9,181,636,048	\$ 0.00175

Rate categories for which no increase being sought

% of Base Non-Fuel Revenue Total	Allocate to Class	% Change from Current Non-Fuel Revenue	% Change from Current Total Revenue	Billing kW	\$/kW
\$ 19,000,000		7.76%	3.87%		
\$ 1,582,700		7.76%	3.44%	2,138,666	\$ 0.74
\$ 609,900		7.75%	2.92%	1,060,389	\$ 0.58
\$ 769,500		7.75%	2.49%	1,942,343	\$ 0.40
\$ 1,379,400		7.75%	2.66%	3,002,732	\$ 0.46
"E" Billing kWh					\$/kW

**Class Cost of Service Results at EKPC's Requested \$43.4 Million Increase
As Modified for Gallatin Steel (GS) Interruptible Load in Average and Excess Allocation Factor Development**

Line No.	(a) Description	(b) Allocation Factor	(c) Total	(d) E	(e) B	(f) C	(g) Inland Electric	(h) Inland Steam	(i) Gallatin	(j) TGP	(k) AGC
1	Production Demand	AED-PROD-GS	176,421,916	156,415,671	8,097,766	4,410,548	1,993,568	0	1,464,302	2,469,907	1,570,155
2	Production Demand	DA - Inland Steam	2,480,062	0	0	0	0	2,480,062	0	0	0
3	Transmission Demand	AED-TRANS	52,884,750	47,036,915	2,328,326	1,274,836	567,986	0	480,828	739,893	455,966
4	Transmission Demand	DA - Gallatin	1,457,679	0	0	0	0	0	1,457,679	0	0
5	Total Demand-Related		233,244,407	203,452,586	10,426,091	5,685,384	2,561,554	2,480,062	3,402,809	3,209,800	2,026,121
6	Energy	ENERGY	429,818,429	333,070,546	30,293,375	15,623,912	7,998,298	0	37,522,006	0	5,310,292
7	Energy	DA - TGP	8,857,114	0	0	0	0	0	0	8,857,114	0
8	Energy	DA - Inland Steam	7,821,334	0	0	0	0	7,821,334	0	0	0
9	Total Energy-Related		446,496,877	333,070,546	30,293,375	15,623,912	7,998,298	7,821,334	37,522,006	8,857,114	5,310,292
10	Distribution	DISTRIBUTION	16,932,853	16,932,853	0	0	0	0	0	0	0
11	Services	SERVICES	7,297,806	5,455,847	496,219	255,927	131,016	164,651	614,627	92,535	86,985
12	Other	NA	0	0	0	0	0	0	0	0	0
13	Total Cost		703,971,943	558,911,831	41,215,686	21,565,223	10,690,868	10,466,047	41,539,442	12,159,449	7,423,398
14	Revenue from Rates		500,015,765	392,546,911	30,041,555	15,987,564	7,391,355	8,554,161	30,870,772	9,663,647	4,959,800
15	Other Revenue		160,587,453	126,163,533	9,832,178	5,131,252	2,556,806	3,035,338	11,619,396	546,565	1,702,385
16	Total Present Revenue		660,603,218	518,710,444	39,873,733	21,118,816	9,948,161	11,589,499	42,490,168	10,210,212	6,662,185
17	Sufficiency/(Deficiency)		(43,368,725)	(40,201,387)	(1,341,953)	(446,407)	(742,707)	1,123,452	(950,726)	(1,949,237)	(761,213)
18	Percent Increase Required		8.67%	10.24%	4.47%	2.79%	10.05%	-13.13%	-3.08%	20.17%	15.35%

**Class Cost of Service Results at EKPC's Requested \$43.4 Million Increase
As Presented by EKPC**

Line No.	(a) Description	(b) Allocation Factor	(c) Total	(d) E	(e) B	(f) C	(g) Inland Electric	(h) Inland Steam	(i) Gallatin	(j) TGP	(k) AGC
19	Production Demand	AED-PROD-EKPC	176,421,916	149,833,918	7,660,225	4,177,254	1,879,411	0	9,017,821	2,364,123	1,489,163
20	Production Demand	DA - Inland Steam	2,480,062	0	0	0	0	2,480,062	0	0	0
21	Transmission Demand	AED-TRANS	52,884,750	47,036,915	2,328,326	1,274,836	567,986	0	480,828	739,893	455,966
22	Transmission Demand	DA - Gallatin	1,457,679	0	0	0	0	0	1,457,679	0	0
23	Total Demand-Related		233,244,407	196,870,833	9,988,551	5,452,090	2,447,397	2,480,062	10,956,328	3,104,017	1,945,129
24	Energy	ENERGY	429,818,429	333,070,546	30,293,375	15,623,912	7,998,298	0	37,522,006	0	5,310,292
25	Energy	DA - TGP	8,857,114	0	0	0	0	0	0	8,857,114	0
26	Energy	DA - Inland Steam	7,821,334	0	0	0	0	7,821,334	0	0	0
27	Total Energy-Related		446,496,877	333,070,546	30,293,375	15,623,912	7,998,298	7,821,334	37,522,006	8,857,114	5,310,292
28	Distribution	DISTRIBUTION	16,932,853	16,932,853	0	0	0	0	0	0	0
29	Services	SERVICES	7,297,806	5,455,847	496,219	255,927	131,016	164,651	614,627	92,535	86,985
30	Other	NA	0	0	0	0	0	0	0	0	0
31	Total Cost		703,971,943	552,330,079	40,778,145	21,331,929	10,576,711	10,466,047	49,092,961	12,053,665	7,342,406
32	Revenue from Rates		500,015,765	392,546,911	30,041,555	15,987,564	7,391,355	8,554,161	30,870,772	9,663,647	4,959,800
33	Other Revenue		160,587,453	126,163,533	9,832,178	5,131,252	2,556,806	3,035,338	11,619,396	546,565	1,702,385
34	Total Present Revenue		660,603,218	518,710,444	39,873,733	21,118,816	9,948,161	11,589,499	42,490,168	10,210,212	6,662,185
35	Sufficiency/(Deficiency)		(43,368,725)	(33,615,635)	(904,412)	(213,113)	(628,550)	1,123,452	(6,602,793)	(1,843,453)	(680,221)
36	Percent Increase Required		8.67%	8.56%	3.01%	1.33%	8.50%	-13.13%	21.39%	19.08%	13.71%

Data Source: EKPC Application Exhibit S