MEMORANDUM OF UNDERSTANDING AND AGREEMENT
REGARDING ALTERNATE POWER SOURCES

This Memorandum of Understanding and Agreement (**"MOU&A"**) is entered into and effective as of this 23 day of [July], 2015, by and between East Kentucky Power Cooperative, Inc. (**"EKPC"**), and each of the following Member Distribution Cooperatives (also referred to herein as **"Owner Member"**):

Member Distribution Cooperatives

Big Sandy Rural Electric Cooperative Corporation
Blue Grass Energy Cooperative Corporation
Clark Energy Cooperative, Inc.
Cumberland Valley Electric
Farmers Rural Electric Cooperative Corporation
Fleming-Mason Energy Cooperative
Grayson Rural Electric Cooperative Corporation
Inter-County Energy Cooperative Corporation
Jackson Energy Cooperative Corporation
Licking Valley Rural Electric Cooperative Corporation
Nolin Rural Electric Cooperative Corporation
Owen Electric Cooperative, Inc.
Salt River Electric Cooperative Corporation
Shelby Energy Cooperative, Inc.
South Kentucky Rural Electric Cooperative Corporation
Taylor County Rural Electric Cooperative Corporation

Factual Recitals

0.1 Each Owner Member is an electric cooperative, organized under the laws of the State of Kentucky, engaged in the business of supplying and distributing electric power and energy to its members within a certain service area, for which business the Owner Member operates an electric distribution system, among other operations.

0.2 EKPC is a generation and transmission cooperative corporation, organized under the laws of the State of Kentucky, which is owned by its Owner Members, which are certain electric cooperatives operating in the State of Kentucky (**"Owner Members"**).

0.3 EKPC and each Owner Member are parties to a Wholesale Power Contract, dated October 1, 1964, as amended, pursuant to which (among other things) EKPC sells and delivers to that Owner Member, and that Owner Member purchases and receives, electric power and energy

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required for the operation of the Owner Member's electric system. Such Wholesale Power Contracts are identical in all material respects, except for the identification of the respective Owner Member that is a party to each such agreement. A reference herein to **"Wholesale Power Contract"** refers to each and every such agreement.

0.4 As of October 23, 2003, each Wholesale Power Contract was amended by the execution of that certain amendment designated and known as **"Amendment No. 3"** thereto, to provide, among other things, for the obtaining by the subject Owner Member of electric power and energy from sources other than EKPC for use in operating the Owner Member's electric system, subject to certain limitation and required procedures set forth therein. Except for the identification of the respective Owner Member that is a party to each such Amendment No. 3, all of such amendments are identical. A reference herein to **"Amendment No. 3"** refers to each and every such amendment.

0.5 EKPC and certain Owner Members have, in the past, disagreed on the interpretation of some provisions of Amendment No. 3 and, therefore, to the Wholesale Power Contract as amended thereby.

0.6 The Owner Members each have a keen interest in pursuing or investigating opportunities to develop or otherwise obtain and use sources of electric power and energy other than EKPC. Such non-EKPC sources are hereinafter referred to as **"Alternate Sources"** and further defined in Section 2(A) below.

0.7 EKPC and each Owner Member each desire to avoid litigation over the provisions of the Wholesale Power Contract that pertain to Alternate Sources, and thereby avoid the costs and uncertainty of such litigation.

NOW THEREFORE, in consideration of the mutual covenants, understandings, and undertakings set forth herein, each of the Owner Members and EKPC, agree as follows:

<u>Understandings, Stipulations, and Agreements</u>

1. <u>Term</u>

(A) This MOU&A shall become effective on the date first written above and shall continue in effect until the termination of the Wholesale Power Contract. If the Wholesale Power Contract between EKPC and one of the Owner Members terminates before the other Wholesale Power Contracts, then this MOU&A shall terminate with respect to that Owner Member, but shall remain in effect with respect to the other Owner Members.

2. <u>Scope</u>

(A) The purpose of this MOU&A is to memorialize EKPC's and the Owner Members' mutually agreed interpretation of Amendment No. 3 with respect to Alternate Sources. Except as provided in Section 2(B), an **"Alternate Source"** is any generating resource that is owned (directly or indirectly, in whole or in part) or controlled (directly or indirectly, in whole or in part) by an Owner Member, regardless of whether the resource is connected to the Owner

Member's distribution system, or any power purchase arrangement under which an Owner Member purchases capacity or energy (or both), if such generating resource or power purchase arrangement is used to serve any portion of the Owner Member's load.

(B) A generating resource that meets the definition of a "Behind the Meter Source" as set forth in Section 4(A)(v)(a) that is used by a Member solely to provide energy to serve interruptible retail load during times when service for such load through PJM has been interrupted pursuant to the load's participation in PJM's demand response program will not be considered an "Alternate Source" subject to the requirements of this MOU&A. If an Owner Member desires to use such a generating resource at any other time, the Owner Member must comply with the requirements of this MOU&A with respect to that generating resource.

(C) Nothing in this MOU&A is intended to modify any of the express provisions of Amendment No. 3. During the term of this MOU&A, neither EKPC nor any Owner Member shall assert that this MOU&A is invalid for the reason that it is contrary to or inconsistent with the Wholesale Power Contract. In the event of an actual conflict between the Wholesale Power Contract, as amended, including by Amendment No. 3, and this MOU&A, the Wholesale Power Contract, as amended, including by Amendment No. 3, shall control.

3. Maximum Permissible Demand Reduction.

(A) The maximum demand reduction that an Owner Member can obtain through the use of Alternate Sources shall be determined as follows:

(i) All demand measurements, whether of EKPC aggregate demand or an Owner Member's demand, called for in this Section 3 shall be measured in megawatts in 15-minute intervals and shall be adjusted to include any interruptible load that was interrupted at the time of measurement.

(ii) If in connection with its acquisition of new service territory the Owner Member provides evidence to EKPC and the RUS in the related acquisition agreement that the acquired service territory must continue to be served by the current power supplier as a condition of the acquisition, the acquired service territory may be supplied by such current power supplier for so long as is required under the terms of such acquisition agreement. Until such supply from the current power supplier is terminated, the load of such acquired service territory shall not be included in the calculations of the 5% and 15% limitations set forth below in this Section 3 applicable to the Owner Member that acquired the service territory or any other Owner Member. From and after the termination of such supply from the current power supplier, the load of such acquired service territory (including such load during the three (3) twelve-month (12-month) periods immediately preceding the date of termination of such supply from the current power supplier) shall be included in calculations of the 5% and 15% limitations set forth below in this Section 3 applicable to the Owner Member or any Other Member.

(iii) If, at the time the Owner Member submits an election notice pursuant to Section 4, the aggregate amount of all Owner Members' loads being served with Alternate Sources (including the load proposed to be served by the Owner Member's new Alternate Source) would be less than two and one half percent (2.5%) of the rolling average of EKPC's coincident peak demand for the single calendar month with the highest peak demand occurring during each of the three (3) twelve-month (12-month) periods immediately preceding the date the Owner Member delivers such election notice, the Owner Member's aggregate demand reduction from Alternate Sources (including the demand reduction from the proposed new Alternate Source) may not exceed 15% of the rolling average of the Owner Member's coincident peak demand for the single calendar month with the highest average peak demand occurring during each of the three (3) twelve-month (12-month) periods immediately preceding the date the Owner Member delivers such election notice. If this 15% threshold would be exceeded, the Alternate Source shall not be permitted unless the load proposed to be served by it is reduced such that this 15% threshold is not exceeded.

(iv) If, at the time the Owner Member submits an election notice pursuant to Section 4, the aggregate amount of all Owner Members' loads being served with Alternate Sources (including the load proposed to be served by the Owner Member's new Alternate Source) would be equal to or greater than two and one half percent (2.5%) of the rolling average of EKPC's coincident peak demand for the single calendar month with the highest peak demand occurring during each of the three (3) twelve-month (12-month) periods immediately preceding the date the Owner Member delivers such election notice, the Owner Member's aggregate demand reduction from Alternate Sources (including the demand reduction from the proposed new Alternate Source) may not exceed five percent (5%) of the rolling average of the Owner Member's coincident peak demand for the single calendar month with the highest average peak demand occurring during each of the three (3) twelve-month (12-month) periods immediately preceding the date the Owner Member delivers such election notice. If this five percent (5%) threshold would be exceeded, the Alternate Source shall not be permitted unless the load proposed to be served by it is reduced such that this five percent (5%) threshold is not exceeded.

(v) If, at the time the Owner Member submits an election notice pursuant to Section 4, the aggregate amount of all Owner Members' loads being served with Alternate Sources (including the load proposed to be served by the Owner Member's new Alternate Source) would be greater than five percent (5%) of the rolling average of EKPC's coincident peak demand for the single calendar month with the highest peak demand occurring during each of the three (3) twelve-month (12-month) periods immediately preceding the date the Owner Member delivers such election notice, the

Alternate Source shall not be permitted unless the load proposed to be served by it is reduced such that this five percent (5%) threshold is not exceeded.

(vi) The term of any Alternate Source (inclusive of any renewal options), whether the Alternate Source is a generating facility owned or controlled by the Owner Member or a contract with a third party, shall not exceed twenty (20) years.

(a) Any Alternate Source that is a contract in effect at the time when the 2.5% threshold defined in Section 3(A)(iii) is reached will be honored for the remaining term of the contract (without exercise of any renewal option). However, if at the end of the existing contract's term that was in effect when the 2.5% threshold was reached, the 2.5% threshold continues to be reached or is exceeded, and the Owner Member's aggregate amount of Alternate Source elections then exceeds the 5% threshold defined in Section 3(A)(iv), then the Alternate Source contract may not be renewed unless the Owner Member reduces the aggregate amount of the Owner Member's load served by Alternate Sources such that the aggregate amount of the Owner Member's load served by Alternate Sources (taking into account the renewal of the contract) does not exceed the 5% threshold set forth in Section 3(A)(iv). The Owner Member may meet this requirement by using demand reduction available to another Owner Member, in accordance with Section 3(B).

(b) Any Alternate Source that is a generating facility owned or controlled by the Owner Member that is in effect when the 2.5% threshold defined in Section 3(A)(iii) is reached will be honored for the remaining term of the Alternate Source as set forth in the notice provided under Section 4(A).

(B) Demand reduction available to one Owner Member may be used by another Owner Member if those two Owner Members so agree; provided, however, that in no event may a new Alternate Source proposed by an Owner Member in an election notice pursuant to Section 4 be approved if:

(i) the aggregate amount of all Owner Members' loads being served with Alternate Sources (including the load proposed to be served by the Owner Member's new Alternate Source) would be greater than five percent (5%) of the rolling average of EKPC's coincident peak demand for the single calendar month with the highest peak demand occurring during each of the three (3) twelve-month (12-month) periods immediately preceding the date the Owner Member delivers such election notice; or

(ii) the aggregate amount of the Owner Member's load being served by Alternate Sources (including the load proposed to be served by the Owner Member's new Alternate Source) would be greater than fifteen percent (15%) of the rolling average of the Owner Member's coincident peak demand for the single calendar month with the highest average peak demand occurring during each of the three (3) twelve-month (12-month) periods immediately preceding such notice.

4. Alternate Source Notices

(A) In order for an Owner Member to reduce its purchases from EKPC by using electric power and energy from an Alternate Source, that Owner Member shall have provided EKPC with prior written notice of such reduction in accordance with the procedures and requirements set forth herein. Each such notice hereunder (an **"Alternate Source Notice"**) shall set forth the following information regarding the subject Alternate Source:

(i) the term during which the Alternate Source will be used to reduce the Owner Member's purchases from EKPC under the Wholesale Power Contract, including the date on which such use will begin, and the length of time during which such use will continue, which length may not exceed 20 years (including any renewal options for an Alternate Source that is a contract with a third party);

(ii) the maximum electrical capacity, in kW, to be available from the Alternate Source and the corresponding amount of reduction in demands to be served by EKPC as a result of the use of the Alternate Source, appropriately taking into account expected losses, if any;

(iii) a general description of the nature of the Alternate Source and the primary generating facilities from which the subject electric power and energy will be produced;

(iv) the approximate, expected pattern of use or dispatching of the Alternate Source and the corresponding pattern of hourly reductions in energy to be purchased by the Owner Member from EKPC; and

(v) a designation of whether the Alternate Source will be:

(a) interconnected to the Owner Member's distribution system (and not to any transmission system) and will not produce energy in any hour in excess of the Owner Member's load at the Related EKPC Point of Delivery. Such Alternate Sources are referred to in this MOU&A as **"Behind the Meter Sources"**. The **"Related EKPC Point of Delivery"** with respect to any Alternate Source is the point of delivery under the Owner Member's Wholesale

Power Contract through which energy purchased from EKPC would be used to serve the load served by the Alternate Source if the Alternate Source did not exist;

(b) interconnected or delivered to EKPC's or another entity's transmission system; or

(c) interconnected to the Owner Member's distribution system and will produce energy that exceeds the Owner Member's load at the Related EKPC Point of Delivery.

(B) Except as provided in Section 4(C) below, each Alternate Source Notice shall be provided to EKPC in writing at least eighteen (18) months prior to the date on which the use of the subject Alternate Source is to begin.

(C) For each Alternate Source having a noticed demand reduction of 5,000 kW or less, the required prior written notice may be provided to EKPC up to, but not later than ninety (90) days prior to the date on which the Owner Member intends to begin using that Alternate Source.

(D) An Owner Member may change or cancel an Alternate Source Notice only by providing to EKPC prior written notice of such change or cancellation, as follows: If after three years of operation an Alternate Source has a three-year rolling average peak capacity less than the maximum capacity set forth in the initial Alternate Source Notice, the Owner Member may reduce the maximum capacity of such Alternate Source by providing written notice to EKPC. Any such reduction shall not change the term or other characteristics of the Alternate Source. Ninety (90) days' prior written notice of any other change or any cancellation shall be required for an Alternate Source having an associated demand reduction of 5,000 kW or less. Otherwise, eighteen (18) months' prior written notice to EKPC of a change or cancellation shall be required. If any change is made to the demand reduction amount of an Alternate Source, the thresholds provided in Section 3 will be re-calculated as of the date the notice of change is submitted.

(E) If the Owner Member does not implement an Alternate Source within six (6) months after the date set forth in its notice for commencement of deliveries from the Alternate Source, the Owner Member may not implement the Alternate Source without re-submitting the notice required under this Section 4 and such notice shall be subject to re-calculation of the thresholds provided in Section 3 as of the date of such re-submitted notice. During the six (6) month period described in this Section (E), EKPC shall continue to serve the load intended to be served by the Alternate Source through sales of power and energy to the Owner Member under its Wholesale Power Contract.

5. Development and Use of Alternate Sources

(A) During the noticed term of use of that Alternate Source, it shall be the responsibility of the Owner Member to use commercially reasonable efforts to develop or otherwise acquire the subject Alternate Source so that such source may be used to supply a portion of the Owner Member's requirements beginning on the noticed date. EKPC shall use commercially reasonable efforts to cooperate with and assist the Owner Member in its development or acquisition; provided that EKPC shall not be required to make out-of-pocket expenditures or provide or facilitate financing for any Alternate Source.

(B) Except as otherwise agreed to by EKPC and an Owner Member, the owning Owner Member shall use commercially reasonable efforts to operate, maintain, and dispatch the facilities comprising each of its Alternate Sources (or to cause such operation, maintenance, and dispatching) so as to reduce the maximum electrical demand placed on EKPC's system by the corresponding noticed demand reduction.

(C) With respect to each noticed Alternate Source of an Owner Member, the obligations set forth in the foregoing two paragraphs shall continue until the end of the noticed term of the Alternate Source; provided, however, that such term may be shortened or lengthened at any time by the Owner Member by providing to EKPC prior written notice of such change, as follows: For each such change, ninety (90) days' prior written notice of such change shall be required for an Alternate Source having an associated demand reduction of 5,000 kW or less. Otherwise, eighteen (18) months' prior written notice to EKPC of such change shall be required.

(D) Other requirements for Behind the Meter Sources are as follows:

(i) To the extent that the Alternate Source does not deliver capacity or energy sufficient to serve the actual load of the Owner Member intended to be served by the Alternate Source, EKPC will charge the Owner Member for capacity and energy at the rates for electric service provided under the Wholesale Power Contract.

(ii) The Owner Member must provide to EKPC information regarding the expected generation from the Behind the Meter Source, including planned and unplanned outages, as needed by EKPC so that EKPC can include such information in its schedules of load submitted to PJM and minimize to the extent reasonably practicable any PJM penalties for deviations in load attributable to differences between the estimated and actual generation from the Behind the Meter Source.

(iii) The Alternate Sources will be metered with revenue class meters.

(E) Other requirements for Alternate Sources interconnected or delivered to EKPC's or another entity's transmission system are as follows:

(i) To the extent that the Alternate Source does not deliver capacity or energy sufficient to serve the actual load of the Owner Member intended to be served by the Alternate Source, EKPC will charge the Owner Member for capacity and energy as provided in this MOU&A, and not at the rates for electric service provided under the Wholesale Power Contract. EKPC will purchase amounts of replacement capacity and energy based on the historical amounts of capacity and energy provided by the Alternate Source.

(ii) The Owner Member must provide to EKPC a day-ahead schedule of generation. EKPC will work with the Owner Member to develop the day-ahead schedule.

(iii) The day-ahead schedule of load to be served by the Alternate Source will be deemed to equal the day-ahead generation schedule of the Alternate Source.

(iv) EKPC will pass through to the Owner Member all revenues, credits and charges from PJM associated with the Alternate Source, including without limitation PJM day-ahead and real-time energy market revenues, charges and credits, PJM capacity market revenues, charges and credits, PJM operating reserve revenues, credits and charges, and PJM operating services necessary to serve the load served by the Alternate Source (i.e. capacity, energy, ancillary services (including operating reserves), NITS transmission, RTEP, etc.).

(v) The Alternate Sources will be metered with revenue class meters.

(vi) The Owner Member will pay an administrative fee to EKPC to cover the increased operation and administrative costs.

(vii) PJM market participant activities for the Alternate Source and related load will be managed by EKPC or EKPC's agent. The Owner Member shall pay EKPC a non-discriminatory, cost-based fee for such PJM market participant services, which shall be performed in accordance with good utility practices. Any dispute regarding such fee shall be submitted to the Kentucky Public Service Commission for a determination of the appropriate fee.

(F) Other requirements for Alternate Sources interconnected to an Owner Member's distribution system that produce energy that exceeds the Owner Member's load at the Related EKPC Point of Delivery shall be developed based on the requirements set forth above in Sections 5(D) and 5(E).

6. Other Matters.

(A) EKPC shall not be entitled to charge any Owner Member for so-called "stranded costs" related to the Owner Member's implementation of its rights to use Alternate Sources. As a result, to the extent that an Owner Member's use of Alternate Sources reduces its billing demands under EKPC's rates under the Wholesale Power Contract as in effect from time to time, EKPC shall not be entitled to charge any special rate or charge to the Owner Member attributable to such billing demand reduction. EKPC will, however, be entitled to continue to set its rates for all Owner Members under the Wholesale Power Contracts to produce revenues that are sufficient to cover all of its costs, in accordance with the Wholesale Power Contracts.

(B) EKPC covenants and agrees to revise or rescind existing Board Policies so that its Board Policies are consistent with this MOU&A.

(C) This Agreement may be executed in counterpart, which shall be deemed an original, but all of which together shall constitute one and the same instrument.

[Signature pages have been intentionally omitted for filing economy]

Dennis Holt
Interim CEO
Phone (606) 678-4121

South Kentucky RECC
A Touchstone Energy Cooperative

200 Electric Avenue
P.O. Box 910
Somerset KY 42502

November 28, 2017

Mr. Anthony S. Campbell
President and Chief Executive Officer
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P.O. Box 707
Winchester, Kentucky 40392-0707

Dear Mr. Campbell,

Pursuant to the provisions of Amendment No. 3 to the Wholesale Power Contract between East Kentucky Power Cooperative, Inc. ("EKPC"), and South Kentucky Rural Electric Cooperative Corporation ("South Kentucky") dated November 13, 2003 ("Amendment 3"), and the Memorandum of Understanding and Agreement Regarding Alternate Power Sources, between EKPC and the 16 Owner Members of EKPC including South Kentucky, dated July 15, 2015 ("MOU"), South Kentucky does hereby provide the following notice of its election to reduce its purchases of electric power from EKPC and replace same with electric power furnished from an Alternate Source.

According to the provisions of Section 4(A) of the MOU there are five (5) primary procedures and requirements for the content of this notice; in compliance with these provisions, South Kentucky provides the required information with respect to its Alternate Source election immediately following each listed item.

(i) *the term during which the Alternate Source will be used to reduce the Owner Member's purchases from EKPC under the Wholesale Power Contract, including the date on which such use will begin, and the length of time during which such use will continue, which length may not exceed 20 years (including any renewal options for an Alternate Source that is a contract with a third party)*

The Alternate Source (which is further described below) will be used to supply 58 MW's of South Kentucky's power requirements outside of and separate from the Wholesale Power contract between South Kentucky RECC and East Kentucky Power Cooperative for a term of 20 years commencing at 12:00 a.m. (EST) on June 1, 2019.

(ii) *the maximum electrical capacity, in kW, to be available from the Alternate Source and the corresponding amount of reduction in demands to be served by*

EKPC as a result of the use of the Alternate Source, appropriately taking into account expected losses, if any

The maximum electrical capacity to be available from the Alternate Source, and the corresponding amount of reduction in demands to be served by EKPC as a result of the use of the Alternate Source, is 58,000 kW.

(iii) *a general description of the nature of the Alternate Source and the primary generating facilities from which the subject electric power and energy will be produced*

The Alternate Source shall be in the form of South Kentucky RECC becoming a PJM member and purchasing energy, capacity, transmission and services required by PJM policies from the PJM market.

(iv) *the approximate, expected pattern of use or dispatching of the Alternate Source and the corresponding pattern of hourly reductions in energy to be purchased by the Owner Member from EKPC*

The Alternate Source will supply the 58,000 KW of energy all hours of each year of the 20 year term, by purchasing same from the PJM wholesale market.

(v) *a designation of whether the Alternate Source will be:*

(a) *interconnected to the Owner Member's distribution system (and not to any transmission system) and will not produce energy in any hour in excess of the Owner Member's load at the Related EKPC Point of Delivery. Such Alternate Sources are referred to in this MOU&A as "Behind the Meter Sources". The "Related EKPC Point of Delivery" with respect to any Alternate Source is the point of delivery under the Owner Member's Wholesale Power Contract through which energy purchased from EKPC would be used to serve the load served by the Alternate Source if the Alternate Source did not exist;*

(b) *interconnected or delivered to EKPC's or another entity's transmission system; or*

(c) *interconnected to the Owner Member's distribution system and will produce energy that exceeds the Owner Member's load at the Related EKPC Point of Delivery.*

The Alternate Source will be: (b) interconnected or delivered to EKPC's or another entity's transmission system.

South Kentucky remains proud to be an Owner-Member of EKPC and looks forward to working with its leadership and others in effectuating the terms of the Wholesale Power Agreement, as amended, and the MOU.

I appreciate your time and attention to this matter, and please do not hesitate to contact me with any questions or concerns.

Sincerely Yours,

Dennis Holt

Dennis Holt
Interim President and
Chief Executive Officer
South Kentucky Rural
Electric Cooperative Corporation

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Witness: Carter Babbit

South Kentucky Rural Electric Cooperative Corporation
Case No. 2018-00050
Commission Staff's First Request for Information

5. Refer to the MOU, paragraph 4(A)(iii), regarding a general description of the nature of the alternate source of electric power. Also, refer to the Application, Exhibit 4, Written Notice to EKPC ("Notice to EKPC"), page 2, section (iii).

a. State whether the Alternate Source is one specific generating unit, or whether the Alternate Source could be any unit in the PJM market.

b. If the Alternate Source is one specific generating unit, provide the following:

i. Name and location of the unit;
ii. Owner of the unit;
iii. Nameplate capacity of the unit;
iv. Primary fuel source used for generation at the unit;
v. Commission date of the unit; and
vi. Forced outage rate of the unit, if operational.

c. If the Alternate Source could be from any unit in the PJM market, state whether South Kentucky will be required, as part of joining PJM, to choose between becoming a FAR entity or a RPM entity.

Response:

a. The Alternate Source is not tied to a specific generating unit or units within PJM.

b. Not Applicable.

c. South Kentucky is not purchasing capacity as part of the Alternate Source designation. South Kentucky will be an RPM entity, paying PJM for capacity it procures for the system through the capacity auctions (with price uncertainty for that capacity mitigated through the capacity hedge).

Witness: Carter Babbit

Response:

Note that the provision referenced in the question is not applicable to the transactions under the agreement.

a. The Alternate Source is not tied to, or contingent upon, any specific generation unit(s) or that any specific generation unit(s) be operating or operational.

b. See a. above.

c. See a. above.

d. This question is not applicable based on a. above.

e. The situation described would not impact the delivery obligation of Morgan Stanley for the Alternate Source and, as such, the financial implications of such an event were not considered as part of the analysis that led to the Alternate Source selection. Any amount to be paid to EKPC by South Kentucky would be based on EKPC's capacity and energy costs as stated in the MOU Section 5 E (i), page 8.

Witness: Dennis Holt

South Kentucky Rural Electric Cooperative Corporation
Case No. 2018-00050
Distribution Cooperatives' First Request for Information

23. Please state South Kentucky's load factor for 2017. Please provide all assumptions, calculations, workpapers and supporting Documents used in this computation, including but not limited to any Documents in electronic Excel spreadsheet format with all formulas intact and unprotected, and with all columns and rows accessible.

Response:

The load factor for 2017 was 41.17%. See Attachment DISTCOOP#23.

South KY RECC

Load Factor

KWH purchased / (annual peak KW X 8,760 hours per year)

KWH purchased	1,274,648,341
annual peak KW	353,436
hours per year	8,760

Load Factor =	41.17%

807 KAR 5:058. Integrated resource planning by electric utilities.

RELATES TO: KRS Chapter 278
STATUTORY AUTHORITY: KRS 278.040(3), 278.230(3)
NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.040(3) provides that the commission may adopt reasonable administrative regulations to implement the provisions of KRS Chapter 278. This administrative regulation prescribes rules for regular reporting and commission review of load forecasts and resource plans of the state's electric utilities to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers within their service areas, and satisfy all related state and federal laws and regulations.

Section 1. General Provisions. (1) This administrative regulation shall apply to electric utilities under commission jurisdiction except a distribution company with less than $10,000,000 annual revenue or a distribution cooperative organized under KRS Chapter 279.

(2) Each electric utility shall file triennially with the commission an integrated resource plan. The plan shall include historical and projected demand, resource, and financial data, and other operating performance and system information, and shall discuss the facts, assumptions, and conclusions, upon which the plan is based and the actions it proposes.

(3) Each electric utility shall file ten (10) bound copies and one (1) unbound, reproducible copy of its integrated resource plan with the commission.

Section 2. Filing Schedule. (1) Each electric utility shall file its integrated resource plan according to a staggered schedule which provides for the filing of integrated resource plans one (1) every six (6) months beginning nine (9) months from the effective date of this administrative regulation.

(a) The integrated resource plans shall be filed at the specified times following the effective date of this administrative regulation:

1. Kentucky Utilities Company shall file nine (9) months from the effective date;
2. Kentucky Power Company shall file fifteen (15) months from the effective date;
3. East Kentucky Power Cooperative, Inc. shall file twenty-one (21) months from the effective date;
4. The Union Light, Heat & Power Company shall file twenty-seven (27) months from the effective date;
5. Big Rivers Electric Corporation shall file thirty-three (33) months from the effective date; and
6. Louisville Gas & Electric Company shall file thirty-nine (39) months from the effective date.

(b) The schedule shall provide at such time as all electric utilities have filed integrated resource plans, the sequence shall repeat.

(c) The schedule shall remain in effect until changed by the commission on its own motion or on motion of one (1) or more electric utilities for good cause shown. Good cause may include a change in a utility's financial or resource conditions.

(d) If any filing date falls on a weekend or holiday, the plan shall be submitted on the first business day following the scheduled filing date.

(2) Immediately upon filing of an integrated resource plan, each utility shall provide notice to intervenors in its last integrated resource plan review proceeding, that its plan has been filed and is available from the utility upon request.

(3) Upon receipt of a utility's integrated resource plan, the commission shall establish a review schedule which may include interrogatories, comments, informal conferences, and staff reports.

Section 3. Waiver. A utility may file a motion requesting a waiver of specific provisions of this administrative regulation. Any request shall be made no later than ninety (90) days prior to the date established for filing the integrated resource plan. The commission shall rule on the request within thirty (30) days. The motion shall clearly identify the provision from which the utility seeks a waiver and provide justification for the requested relief which shall include an estimate of costs and benefits of compliance with the specific provision. Notice shall be given in the manner provided in Section 2(2) of this administrative regulation.

Section 4. Format. (1) The integrated resource plan shall be clearly and concisely organized so that it is evident to the commission that the utility has complied with reporting requirements described in subsequent sections.

(2) Each plan filed shall identify the individuals responsible for its preparation, who shall be available to respond to inquiries during the commission's review of the plan.

Section 5. Plan Summary. The plan shall contain a summary which discusses the utility's projected load growth and the resources planned to meet that growth. The summary shall include at a minimum:

(1) Description of the utility, its customers, service territory, current facilities, and planning objectives;
(2) Description of models, methods, data, and key assumptions used to develop the results contained in the plan;
(3) Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts;
(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities;
(5) Steps to be taken during the next three (3) years to implement the plan;
(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.

Section 6. Significant Changes. All integrated resource plans shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and

NUCOR EXHIBIT 2

tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate changes.

Section 7. Load Forecasts. The plan shall include historical and forecasted information regarding loads.

(1) The information shall be provided for the total system and, where available, disaggregated by the following customer classes:

(a) Residential heating;

(b) Residential nonheating;

(c) Total residential (total of paragraphs (a) and (b) of this subsection);

(d) Commercial;

(e) Industrial;

(f) Sales for resale;

(g) Utility use and other.

The utility shall also provide data at any greater level of disaggregation available.

(2) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year:

(a) Average annual number of customers by class as defined in subsection (1) of this section;

(b) Recorded and weather-normalized annual energy sales and generation for the system, and sales disaggregated by class as defined in subsection (1) of this section;

(c) Recorded and weather-normalized coincident peak demand in summer and winter for the system;

(d) Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments;

(e) Total energy sales and coincident peak demand to retail and wholesale customers for which service is provided under an interruptible or curtailable contract or tariff or under some other nonfirm basis;

(f) Annual energy losses for the system;

(g) Identification and description of existing demand-side programs and an estimate of their impact on utility sales and coincident peak demands including utility or government sponsored conservation and load management programs;

(h) Any other data or exhibits, such as load duration curves or average energy usage per customer, which illustrate historical changes in load or load characteristics.

(3) For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.

(4) The following information shall be filed for each forecast:

(a) Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section;

(b) Summer and winter coincident peak demand for the system;

(c) If available for the first two (2) years of the forecast, monthly forecasts of energy sales and generation for the system and disaggregated by class as defined in subsection (1) of this section and system peak demand;

(d) The impact of existing and continuing demand-side programs on both energy sales and system peak demands, including utility and government sponsored conservation and load management programs;

(e) Any other data or exhibits which illustrate projected changes in load or load characteristics.

(5) The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company:

(a) For the base year and the four (4) years preceding the base year:

1. Recorded and weather normalized annual energy sales and generation;

2. Recorded and weather-normalized coincident peak demand in summer and winter.

(b) For each of the fifteen (15) years succeeding the base year:

1. Forecasted annual energy sales and generation;

2. Forecasted summer and winter coincident peak demand.

(6) A utility shall file all updates of load forecasts with the commission when they are adopted by the utility.

(7) The plan shall include a complete description and discussion of:

(a) All data sets used in producing the forecasts;

(b) Key assumptions and judgments used in producing forecasts and determining their reasonableness;

(c) The general methodological approach taken to load forecasting (for example, econometric, or structural) and the model design, model specification, and estimation of key model parameters (for example, price elasticities of demand or average energy usage per type of appliance);

(d) The utility's treatment and assessment of load forecast uncertainty;

(e) The extent to which the utility's load forecasting methods and models explicitly address and incorporate the following factors:
1. Changes in prices of electricity and prices of competing fuels;
2. Changes in population and economic conditions in the utility's service territory and general region;
3. Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels; and
4. Continuation of existing company and government sponsored conservation and load management or other demand-side programs.
(f) Research and development efforts underway or planned to improve performance, efficiency, or capabilities of the utility's load forecasting methods; and
(g) Description of and schedule for efforts underway or planned to develop end-use load and market data for analyzing demand-side resource options including load research and market research studies, customer appliance saturation studies, and conservation and load management program pilot or demonstration projects.
Technical discussions, descriptions, and supporting documentation shall be contained in a technical appendix.

Section 8. Resource Assessment and Acquisition Plan. (1) The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.
(2) The utility shall describe and discuss all options considered for inclusion in the plan including:
(a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;
(b) Conservation and load management or other demand-side programs not already in place;
(c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and
(d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.
(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs.
(a) A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.
(b) A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility:
1. Plant name;
2. Unit number(s);
3. Existing or proposed location;
4. Status (existing, planned, under construction, etc.);
5. Actual or projected commercial operation date;
6. Type of facility;
7. Net dependable capability, summer and winter;
8. Entitlement if jointly owned or unit purchase;
9. Primary and secondary fuel types, by unit;
10. Fuel storage capacity;
11. Scheduled upgrades, deratings, and retirement dates;
12. Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the fifteen (15) forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars.
a. Capacity and availability factors;
b. Anticipated annual average heat rate;
c. Costs of fuel(s) per millions of British thermal units (MMBtu);
d. Estimate of capital costs for planned units (total and per kilowatt of rated capacity);
e. Variable and fixed operating and maintenance costs;
f. Capital and operating and maintenance cost escalation factors;
g. Projected average variable and total electricity production costs (in cents per kilowatt-hour).
(c) Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan.
(d) Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.
(e) For each existing and new conservation and load management or other demand-side programs included in the plan:
1. Targeted classes and end-uses;
2. Expected duration of the program;

3. Projected energy changes by season, and summer and winter peak demand changes;
4. Projected cost, including any incentive payments and program administrative costs; and
5. Projected cost savings, including savings in utility's generation, transmission and distribution costs.

(4) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast:

(a) On total resource capacity available at the winter and summer peak:
1. Forecast peak load;
2. Capacity from existing resources before consideration of retirements;
3. Capacity from planned utility-owned generating plant capacity additions;
4. Capacity available from firm purchases from other utilities;
5. Capacity available from firm purchases from nonutility sources of generation;
6. Reductions or increases in peak demand from new conservation and load management or other demand-side programs;
7. Committed capacity sales to wholesale customers coincident with peak;
8. Planned retirements;
9. Reserve requirements;
10. Capacity excess or deficit;
11. Capacity or reserve margin.

(b) On planned annual generation:
1. Total forecast firm energy requirements;
2. Energy from existing and planned utility generating resources disaggregated by primary fuel type;
3. Energy from firm purchases from other utilities;
4. Energy from firm purchases from nonutility sources of generation; and
5. Reductions or increases in energy from new conservation and load management or other demand-side programs;

(c) For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.

(5) The resource assessment and acquisition plan shall include a description and discussion of:

(a) General methodological approach, models, data sets, and information used by the company;

(b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;

(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan;

(d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;

(e) Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;

(f) Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment; and

(g) Consideration given by the utility to market forces and competition in the development of the plan.

Technical discussion, descriptions and supporting documentation shall be contained in a technical appendix.

Section 9. Financial Information. The integrated resource plan shall, at a minimum, include and discuss the following financial information:

(1) Present (base year) value of revenue requirements stated in dollar terms;
(2) Discount rate used in present value calculations;
(3) Nominal and real revenue requirements by year; and
(4) Average system rates (revenues per kilowatt hour) by year.

Section 10. Notice. Each utility which files an integrated resource plan shall publish, in a form prescribed by the commission, notice of its filing in a newspaper of general circulation in the utility's service area. The notice shall be published not more than thirty (30) days after the filing date of the report.

Section 11. Procedures for Review of the Integrated Resource Plan. (1) Upon receipt of a utility's integrated resource plan, the commission shall develop a procedural schedule which allows for submission of written interrogatories to the utility by staff and intervenors, written comments by staff and intervenors, and responses to interrogatories and comments by the utility.

(2) The commission may convene conferences to discuss the filed plan and all other matters relative to review of the plan.

(3) Based upon its review of a utility's plan and all related information, the commission staff shall issue a report summarizing its review and offering suggestions and recommendations to the

utility for subsequent filings.

(4) A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing. (17 Ky.R. 1289; Am. 1720; eff. 12-18-90; 21 Ky.R. 2799; 22 Ky.R. 287; eff. 7-21-95.)

Kentucky Public Service Commission

Staff Report on the

2015 Integrated Resource Plan

of East Kentucky Power Cooperative, Inc.

Case No. 2015-00134

April 2016

- Work with federal and state stakeholders to ensure the economic vitality of EKPC's existing and future resources to meet the challenges and opportunities in complying with current and proposed environmental regulations.[6]

EKPC's total energy requirements are expected to increase by 1.4 percent per year from 2015-2034.[7] Winter peak demand is expected to increase by 1.0 percent and summer peak demand is expected to increase by 1.5 percent for the same period.[8] EKPC's annual load factor is projected to grow from 48 percent to 51 percent, which reflects the historical average.[9] With the acquisition of Bluegrass, EKPC does not plan on adding any additional resources to serve projected load until 2026.[10]

EKPC's adjusted winter peak is expected to increase from 3,207 to 3,651 MW from 2015 to 2029, for an annual growth rate of 1.0 percent.[11] Its adjusted summer peak is expected to increase from 2,334 to 2,885 MW over the same period, for a growth rate of 1.5 percent.[12] Its total energy requirements are projected to increase from 13,368,393 Megawatt-hours ("MWh") in 2015 to 16,454,469 MWh in 2029, for an annual growth rate of 1.4 percent.[13]

The IRP was developed based on a minimum reserve margin of 3.0 percent over EKPC's summer peak.[14] Through its existing DSM programs, EKPC expects a reduction in winter peak demand of approximately 238.6 MW by 2029.[15] If all of the new DSM programs are implemented, EKPC forecasts an incremental potential winter peak reduction of 137.4 MW by 2029.[16]

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[6] *Id.*

[7] *Id.* at 35.

[8] *Id.*

[9] *Id.*

[10] EKPC's Response to Staff's Third Request, Item 5.

[11] IRP at 37.

[12] *Id.*

[13] IRP at 36 and 40.

[14] *Id.* at 174. EKPC does not currently have a reserve requirement for the winter peak season. *See* EKPC's Response to Commission Staff's First Request ("Staff's First Request"), Item 39.b.

[15] *See Integrated Resource Plan Technical Appendix, Volume 2, Demand Side Management* ("DSM App."), at DSM-16.

[16] *Id.* at DSM-17.

SECTION 4

SUPPLY-SIDE RESOURCES AND ENVIRONMENTAL COMPLIANCE

INTRODUCTION

This section summarizes, reviews, and comments on EKPC's evaluation of existing and future supply-side resources. It also includes discussion on various aspects of EKPC's environmental compliance planning.

EXISTING CAPACITY

EKPC, at the time of filing this IRP, owned 35 generating units located at nine sites with a combined 2,671 MW of summer capacity.[113] The generating fuel sources include natural and landfill gas along with coal. Shortly after the filing of this case, EKPC notified the Commission of its intent to acquire through a facility purchase three natural gas-fired simple cycle combustion turbines, to assist it in meeting its winter load, located in Oldham County. In December 2015, the Commission approved EKPC's application for the purchase of the existing generating facilities of Bluegrass Generation Company, LLC, located in Oldham County, Kentucky.[114] The addition of three natural gas-fired simple cycle combustion turbines added 594 MW of capacity to EKPC's generation portfolio.[115]

EKPC's first power plants were coal-fired plants built at the Dale Station in Clark County. Units 1 and 2, rated at 23 MWs each, were constructed in 1954. The next two plants, each rated at 75 MWs, began operation in 1957 and 1960. Since the last IRP, EKPC retired the first two units in April 2015 and Units 3 and 4 are scheduled for retirement in April 2016.[116]

In 1965 EKPC constructed a 116 MW unit at the Cooper Station near Somerset, Kentucky and followed it four years later with construction of a 225 MW unit. Both of these plants are conventional coal-fired generating units. Unit 2 was retrofitted in 2012 with pollution control equipment to comply with the Mercury and Air Toxics Standards ("MATS") rule. EKPC also studied least-cost alternatives to bring Unit 1 in compliance with the MATS rule. After extensive analysis, EKPC determined that the Unit 2 pollution control equipment was robust enough to meet air emission regulations for the combined

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[113] As a member of PJM, EKPC plans its capacity resources based upon its obligation coincident to PJM's regional peak summer load and reports capacity as summer capacity.

[114] *See* Case No. 2015-00267, *East Kentucky Power Cooperative, Inc.* (Ky. PSC Dec. 1, 2015).

[115] 198 MW output from Unit 3 is committed to Louisville Gas &Electric Company and Kentucky Utilities Company ("LG&E/KU") through April 30, 2019, when it will transfer the EKPC system.

[116] IRP at 81, Table 8.(3)(b(1-11)-1).

As a result of becoming a PJM member in 2013, EKPC's projected future needs are based on summer peak loads. While this holds true for the PJM requirement, EKPC has an obligation to economically meet its members' winter peak load.[125] Prior to joining PJM in 2013, EKPC was already short on capacity to meet its winter load. EKPC assumed, based on historical price duration curves and PJM market operations, that upon joining PJM, it could rely on PJM's capacity markets to economically supply this capacity shortage. The uncharacteristically cold temperatures in January 2014 and February 2015 changed the cost and availability of energy in PJM markets significantly and permanently, driving EKPC's need to develop a hedging position.[126] EKPC decided with the economic variability of the PJM markets, that its Member Cooperatives were better served if EKPC secured an energy hedge.

EKPC's power plan objective is to develop an economic, reliable plan, while simultaneously mitigating operational and financial risks.[127] A recommended plan of action for EKPC is to compare PPA costs against other power supply alternatives identified in its RFP process. In the summer of 2014, EKPC refreshed a July 2012 released RFP and evaluated the updated responses.[128] As a result, in the winter of 2014-2015, EKPC purchased 200 MWs through a third party PPA. The PPA provided immediate relief from market prices for EKPC, yet EKPC preferred a more permanent solution. After much internal and external consulting analysis, EKPC purchased Bluegrass as a direct result of this process.[129]

EKPC's projected capacity additions and reserve needs for 2015–2029 are shown in the table below. Included in the projected capacity are 170 MWs from SEPA, the impact of existing and new DSM programs, and the addition of Bluegrass.[130]

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[125] *Id.* at 20.

[126] *Id.* at 30.

[127] *Id.* at 5.

[128] *Id.* at 30.

[129] EKPC's Response to Commission Staff's Second Request for Information ("Staff's Second Request"), Item 4.

[130] EKPC's Response to Staff's Third Request, Item 5.

Projected Capacity (MWs)

Year	Other Cap.	Peaking/Int. Capacity		Total Capacity		3% Reserves		Reserve Margin %	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum
2015				3276	2922	0	70	2	22
2016		396	330	3572	3002	0	70	11	24
2017				3322	3002	0	71	3	23
2018				3322	3002	0	72	2	22
2019			165	3322	3167	0	72	2	28
2020		198		3520	3167	0	73	8	27
2021				3520	3167	0	74	8	25
2022				3520	3167	0	74	8	24
2023				3520	3167	0	75	7	23
2024				3520	3167	0	76	7	21
2025				3520	3167	0	77	6	20
2026	50			3570	3217	0	78	7	20
2027				3570	3217	0	79	6	18
2028	50			3620	3267	0	80	7	19
2029	50			3670	3317	0	81	7	19

EKPC's generation expansion plan includes no additions during the planning period.[131]

RELIABILITY CRITERIA AND RESERVE MARGIN

EKPC's mission is to provide reliable, affordable energy and services to its 16 Member Cooperatives. EKPC is a member of the Southeastern Reliability Corporation ("SERC").[132] As a member it takes advantage of SERC's ability to resolve reliability issues, act as a liaison for disputes, administer a regional compliance and enforcement program, and establish reliability standards.

To provide reliable service, EKPC requires a margin of power above the projected peak demand. This reserve margin is necessary to account for operational reserves plus uncertainties in the projected load and weather fluctuations. Historically, EKPC planned capacity to meet its winter peak load plus a 12 percent reserve margin. Currently, as a member of PJM, EKPC plans its capacity resource requirements as

[131] IRP at 125.

[132] IRP at 2. SERC serves as a regional entity with delegated authority from the North American Reliability Corporation ("NERC") for the purpose of proposing and enforcing reliability standards in all of portions of 16 central and southeastern states.

defined by PJM's summer peak plus its ability to economically meet its own winter load projections.[133] PJM reserve requirements are based on a contribution to PJM's summer system peak, and due largely to load diversity, EKPC will be required to maintain a planning reserve requirement of slightly less than three percent of EKPC's summer load which equates to reserving roughly 70 MWs during the summer season only.

NERC requires that utilities have swift access to sufficient power to overcome the loss of a generation source. The power can be self-supplied or as is more common, available through a Regional Transmission Organization ("RTO") or in partnership with neighboring utilities. EKPC will rely upon PJM for this service.

SUPPLY-SIDE EVALUATION

EKPC evaluates power supply options as demand evolves, reviewing among other things the reliability and cost of the source. In assessing future resources, needs are evaluated on a present worth of revenue requirement and a cash-flow basis.

EKPC selected the RTSim model from SimTec, Inc. to develop its resource plan.[134] The model replicates EKPC's system and supplies projected customer loads using a statistical range of inputs created from actual EKPC load forecasts. With the EKPC system loaded in the model, it runs more than five hundred input iterations during the statistical load simulations.[135]

RTSim's Resource Optimizer is then used to determine EKPC's ideal plan. The Resource Optimizer uses alternative resource plans to determine the best plan. The optimizer examines data from the production cost model simulation, using future units as resource alternatives. Since the basic RTSim model is used by the optimizer, the same data and detailed analysis used in the initial runs are used in the optimized run, the difference being that future units are set as resource alternatives and are given a potential future commercial operation date. The future units include combined cycle peaking and intermediate units, unit power purchases, peaking combustion turbines, and market power purchases.[136] The resource optimizer can simulate thousands of potential resource combinations to determine the least cost plans. The optimizer selects the lowest cost plans from the present value of total production cost and annual fixed costs of future alternatives. Plans are then tailored to meet certain criteria, and the present value of each plan is compared to remaining at status quo.

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[133] IRP at 174.

[134] *Id.* at 164

[135] *Id.* at 165.

[136] *Id.* at 166.

In the 2015 IRP, EKPC simulated 2,500 expansion plans, each with five iterations. The iterations varied fuels, forced outages, loads, and market prices to come up with the five lowest cost plans, which were reviewed alongside recent experience to determine each plan's feasibility.[137]

Resource Optimizer Plan Summary (MWs) [138]

Year	Type	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	FINAL MW
2015	Seasonal				100		
2016	Base Seasonal	150	200	200	100	100 200	**150**
2017	Base Seasonal	250	50	100	100 50		**250**
2018	RE PPA Seasonal		50	50		50	
2019	Seasonal		100				
2020	RE PPA Seasonal			50 100			
2021	RE PPA			50	50	100	
2022							
2023							
2024							
2025	Base				50	50	
2026	RE PPA	50	50				**50**
2027	RE PPA				50		
2028	RE PPA	50	50			50	**50**
2029	RE PPA	50	50	50	50		**50**

The above five plans were reviewed and the result is a robust simulation of a variety of load and market conditions. Risk analysis is incorporated into the simulation.[139] EKPC's generation expansion plan does not include new additions during the planning period.

ENVIRONMENTAL COMPLIANCE

EKPC stated it has reviewed current and pending environmental regulations extensively in its report and discusses the potential CPP which regulates a maximum CO_2 emissions rate. EKPC states that it is reviewing all of its options to meet this rate. Kentucky has the option to develop its own State Implementation Plan ("SIP") to meet

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[137] *Id.* at 170.

[138] *Id.* at 172, Table 8.(5)(a)-2.

[139] *Id.* at 173.

peaking, gas-fired technologies; two intermediate/peaking gas-fired technologies; five power purchases from the market and four emission free power purchase options.

PLAN OPTIMIZATION

The Resource Optimizer simulates potential new resources in operation with the system's existing resources in order to determine the optimum expansion plan. In the development of this IRP, EKPC had the Resource Optimizer simulate 2,500 different expansion plans with five iterations of each plan for the 15-year period 2015-2029. Each of the iterations varies inputs such as loads, fuel prices, market prices, and forced outages. The results of the Resource Optimizer runs produced the five lowest-cost plans, which were the plans included in the IRP.[210]

In the original optimization plan, each of the five lowest-cost plans included some combination of peaking power and PPA emission free additions, with variations on the timing and size of the additions.[211] Through the planning period, EKPC's total anticipated capacity additions over the 15-year was 550 MW with 150 MW of peaking /intermediated capacity added in 2016 and 250 MW of peaking/intermediate capacity in 2017. The other capacity is composed of 50 MW of renewable PPA each year in 2026, 2028 and 2029.

Due to the Commission's approval of EKPC's proposed acquisition of Bluegrass on December 1, 2015, which added 396 MW of capacity in 2016 and 198 MW of capacity in 2020, the Company will not need additional capacity until 2026.[212] In 2026, 2028 and 2029, EKPC plans on adding a renewable PPA of 50 MW in each of those years.[213] With the anticipation of increasing market prices for capacity and energy, DSM will become more cost-effective, possibly decreasing or eliminating the need for additional capacity in the latter years of the planning period.

DISCUSSION OF REASONABLENESS

EKPC's integration process reflects the recognition of DSM impacts on the need for future capacity additions. It captures the effects of changing environmental rules as well. Staff commends EKPC for its efforts to acquire Bluegrass at a very reasonable cost and procuring long term capacity that will aid in avoiding the risks associated with procuring capacity and energy from the market.

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[210] IRP at 171.

[211] *Id.* The plans with the annual PPA and emission free PPAs were the three highest-cost plans.

[212] EKPC's Response to Staff's Third Request, Item 5.

[213] *Id.* and IRP at 169.

Witness: Dennis Holt

South Kentucky Rural Electric Cooperative Corporation
Case No. 2018-00050
Nucor Steel Gallatin's First Request for Information

6. Under the November 13, 2003 Amendment No. 3 and the July 23, 2015 Memorandum of Understanding, for the most recent year where data is available, what is the maximum amount of MW (capacity) that can be purchased from Alternative Sources by South Kentucky?

Response:

According to EKPC's calculations given in a PowerPoint presentation dated February 13, 2018 ("EKPC Presentation"), the maximum capacity available for South Kentucky to purchase from Alternate Sources is 61.9 MW, less the 58 MW that were included in the notice dated November 28, 2017. See Attachment NUCOR#6.

NUCOR EXHIBIT 3

EKPC 5% Limit

Owner-Member Cooperative	EKPC CP (MW) for Month of Feb 2015-Jan 2016	Feb 2016-Jan 2017	Feb 2017-Jan 2018	Average	5% Limit
Big Sandy	89.5	56.9	74.3	73.6	3.7
Blue Grass	410.9	324.4	382.2	372.5	18.6
Clark	154.0	113.6	139.4	135.7	6.8
Cumberland Valley	158.3	109.6	141.3	136.4	6.8
Farmers	136.4	115.9	138.4	130.2	6.5
Fleming Mason	196.9	166.9	189.1	184.3	9.2
Grayson	85.2	57.6	72.7	71.9	3.6
Inter-County	171.1	134.1	158.6	154.6	7.7
Jackson	325.6	230.2	293.6	283.2	14.2
Licking Valley	88.6	58.7	75.0	74.1	3.7
Nolin	211.1	199.1	215.5	208.6	10.4
Owen	347.4	350.7	423.8	374.0	18.7
Salt River	314.4	262.0	306.4	294.3	14.7
Shelby	120.5	99.6	113.9	111.3	5.6
South Kentucky	458.9	353.4	426.2	412.9	20.6
Taylor	159.4	139.1	157.0	151.8	7.6
Total	3,428.1	2,771.8	3,307.4	3,169.1	158.5

A3 Allotments, Based on Data Through January 2018

Owner-Member Cooperative	Owner-Member Peak (MW) Feb 2015-Jan 2016	Feb 2016-Jan 2017	Feb 2017-Jan 2018	Average	5% Election	15% Election
Big Sandy	89.5	58.8	74.3	74.2	3.7	11.1
Blue Grass	410.9	324.4	383.2	372.8	18.6	55.9
Clark	154.0	113.6	140.1	135.9	6.8	20.4
Cumberland Valley	158.3	110.0	141.3	136.5	6.8	20.5
Farmers	136.8	115.9	138.4	130.3	6.5	19.6
Fleming Mason	198.0	179.7	189.1	188.9	9.4	28.3
Grayson	85.2	58.3	72.7	72.1	3.6	10.8
Inter-County	171.1	134.4	158.6	154.7	7.7	23.2
Jackson	327.7	232.2	293.6	284.5	14.2	42.7
Licking Valley	88.6	60.6	76.6	75.3	3.8	11.3
Nolin	230.4	199.1	216.1	215.2	10.8	32.3
Owen	430.9	401.5	447.5	426.6	21.3	64.0
Salt River	316.1	262.0	306.4	294.8	14.7	44.2
Shelby	120.5	101.6	113.9	112.0	5.6	16.8
South Kentucky	458.9	353.4	426.2	412.9	20.6	61.9
Taylor	160.2	139.1	157.0	152.1	7.6	22.8
Total	3,537.0	2,844.5	3,335.0	3,238.8	161.9	

A3 Balances as of January 2018

Owner-Member Cooperative	Allocation %	Allocation MW	5% Balance MW	Pro-rata Share of Balance MW
Big Sandy	5%	3.7	3.7	1.8
Blue Grass	5%	18.6	18.6	9.2
Clark	5%	6.8	6.8	3.4
Cumberland Valley	5%	6.8	6.8	3.4
*Farmers**	*5%*	*6.5*	*1.9*	1.0
*Fleming Mason**	*5%*	*9.4*	*8.0*	4.0
Grayson	5%	3.6	3.6	1.8
Inter-County	5%	7.7	7.7	3.8
*Jackson**	*5%*	*14.2*	*0.1*	0.1
*Licking Valley**	*5%*	*3.8*	*3.5*	1.7
Nolin	5%	10.8	10.8	5.3
*Owen**	*5%*	*21.3*	*0.0*	0.0
*Salt River**	*5%*	*14.7*	*0.0*	0.0
Shelby	5%	5.6	5.6	2.8
*South Kentucky**	*15%*	*61.9*	*3.9*	1.9
Taylor	5%	7.6	7.6	3.8
Total			88.8	44.1

** indicates project in place or in process.*

Noticed Projects

Owner-Member	Project	Notice Given	MW	Delivery
Jackson	Irvine LFGTE		1.6	10/2013
Jackson	Dupree Energy Sys		1.0	3/2015
Farmers	Federal Mogul DG		3.6	2005
Farmers	Glasgow LFGTE		1.0	11/2015
Salt River	Lock 7		2.0	2013
Owen	Owen Office		2.0	2016
South Kentucky	PJM/Market	12/2018	58.0	6/2019
Salt River	PJM/Market	2/2018	12.7	9/2019
Owen	PJM/Market	2/2018	19.3	9/2019
Fleming-Mason	LFG PPA	2/2018	1.4	10/2018
Licking Valley	Solar Installation	2/2018	0.3	5/2018
Jackson	Lock 12	2/2018	1.7	12/2018
Jackson	Lock 14	2/2018	1.7	12/2019
Jackson	PJM/Market	2/2018	8.0	9/2019

Total Projects 114.4
Not to Exceed 158.5 MW
Remaining 44.1

Total projects MW cannot exceed 5% of the 3 year average of EKPC CP, which is currently 158.5 MW.

Feb 2015-Jan 2016 Peak Occurred Feb 2015
Feb 2016-Jan 2017 Peak Occurred Jan 2017
Feb 2017-Jan 2018 Peak Occurred Jan 2018

C:\Users\dennish\AppData\Local\Microsoft\Windows\INetCache\Content.Outlook\51OUJVZY\Amendment 3 Allotment Jan 2018 for distribution

	Noticed Projects (MW)	Three-Year Average Peak Demand (MW)	A3 Projects As of 2/2018 As Percent of Member Three-Year Average Peak Demand
Jackson	1.6	284.5	0.56%
Jackson	1.0	284.5	0.35%
Farmers	3.6	130.3	2.76%
Farmers	1.0	130.3	0.76%
Salt River	2.0	294.8	0.67%
Owen	2.0	426.6	0.46%
South Kentucky	58.0	412.9	14.05%
Salt River	12.7	294.8	4.30%
Owen	19.3	426.6	4.52%
Fleming-Mason	1.4	188.9	0.74%
Licking Valley	0.3	75.3	0.39%
Jackson	1.7	284.5	0.59%
Jackson	1.7	284.5	0.59%
Jackson	8.0	284.5	2.81%
	114.3		

Remaining A3 Balance is 44.1 MW (158.5 - 114.3); Going Forward No Member Can Take More Than 5% Because More Than 2.5% of EKPC Three-Year Average Peak Demand (79.25 MW) is Taken

Witness: Dennis Holt & Michelle Herrman

South Kentucky Rural Electric Cooperative Corporation
Case No. 2018-00050
Commission Staff's First Request for Information

18. Refer to the Holt Testimony, page 14, regarding potential risks arising from the proposed transaction. Also, refer to the Direct Testimony of Michelle Herrman, page 15. Describe all risks South Kentucky has identified related to the transactions, and how South Kentucky plans to mitigate each of those risks.

Response:

South Kentucky identified the following possible risks of the proposed transaction:

a. Risk: Market price decline on energy during the term of the proposed transaction and South Kentucky's inability to re-price the proposed transaction to reflect a lower market price.

   Mitigation plans: The resulting blending of the contract price and EKPC's current and forecasted prices are believed to result in a lower price than would be recognized if South Kentucky's energy was sourced solely from EKPC. EKPC's prices are not expected to fall to a level below its current contract price for energy under this contract agreement. Thus, the transaction itself is intended to mitigate risk.

b. Risk: Changes within PJM in regard to new potential capacity and energy rules that could impact the overall value to be realized from the proposed transaction.

   Mitigation plans: South Kentucky recognizes that it is currently facing the same risks whether it is a direct participant in PJM or a participant in PJM as a member owner of EKPC. In any event, South Kentucky expects to participate in PJM through its agent EKPC to mitigate potential impacts resulting from changes in rules.

c. Risk: Changes in laws or regulations; for example, changes in environmental law applicable to PJM, as well as all its participants that could impact the overall value to be realized from the proposed transaction.

NUCOR EXHIBIT 4

Mitigation plans: South Kentucky recognizes that it faces the same or essentially similar risks whether it purchases power from Morgan Stanley, EKPC or any other energy provider, and no specific risk mitigation avenues are available here outside of activities before lawmakers and agencies as pursued in the normal course.

d. Risk: Variability in capacity pricing associated with the capacity hedge risk, to the extent that the final zonal price in PJM settles at a value higher than the Floating Price (*i.e.*, the BRA Resource Clearing price).

Mitigation plans: There is variability in capacity pricing under the current structure of supplemental auctions. However, the capacity cost accounts for only a small portion of cost under this contract, 11-13 percent. The variability in capacity costs would likely impact EKPC's costs as well.

e. Risk: Lack of PSC approval.

Mitigation Plans: South Kentucky intends to demonstrate through this proceeding that its decision to execute the proposed transaction with Morgan Stanley is in the best interest of its members, as it will provide for a lower-cost and more diversified supply than currently in place. As noted in the response to question 8, South Kentucky already has given notice consistent with Amendment 3 and the MOU; accordingly, denial of this petition would require further actions by South Kentucky to ensure that it has an Alternate Source in place during the period it is obligated to have such supply in place.

f. Risk: Failure of Morgan Stanley to perform under the proposed transaction and make good on its collateral obligations to make South Kentucky whole on the difference in price between the cost of energy under the proposed transaction and the cost of replacement power.

Mitigation Plans: The proposed transaction provides for collateral to be provided as part of South Kentucky's agreement with Morgan Stanley. See Exhibit 6 of South Kentucky's Application in this proceeding. The collateral requirement protects South Kentucky's interests if Morgan Stanley were not to perform. Additionally, this risk is mitigated by South Kentucky's participation in PJM. Since the energy and capacity are not being provided from specific generating units, but rather by the PJM market resources, South Kentucky would have the ability to purchase from the PJM market with relative ease in the event that Morgan Stanley does not perform. South Kentucky has no such protections from EKPC if they were to fail to perform.

g. Risk: Cost risks associated with South Kentucky's collateral obligations under the proposed transaction.

Mitigation Plans: South Kentucky's collateral requirements are impacted by the threshold amount utilized in the collateral calculation. (See Paragraph 10. I. A. to the Collateral Annex.) Correspondingly, the threshold amount is impacted by its ability to maintain a TIER Ratio above a high average TIER Ratio of 1.25 using two of the last three calendar years; and its ability to maintain a DSC Ratio above a high average DSC Ratio of 1.25 using two of the last three calendar years. This requirement, however, is no more stringent than what is currently in place with current lenders. In situations where we maintain the ratios above the requirement described above, the threshold amounts reduce South Kentucky's collateral needs and the costs associated with its collateral obligations are expected to be immaterial. In the event that there is pressure on the ratio outcomes, South Kentucky recognizes that it will need to improve these ratio outcomes.

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EAST KENTUCKY POWER COOPERATIVE, INC.
OF
WINCHESTER, KENTUCKY

Rates, Rules and Regulations for Furnishing

Wholesale Power Service

at

Various Locations to

Rural Electric Cooperative Members

Throughout Kentucky

Public Service Commission
of Kentucky

KENTUCKY
PUBLIC SERVICE COMMISSION
Gwen R. Pinson
Executive Director
Gwen R. Pinson
EFFECTIVE
11/2/2017
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

DATE OF ISSUE: October 2, 2017

DATE EFFECTIVE: November 2, 2017

ISSUED BY: Anthony S. Campbell
Anthony S. Campbell,
President and Chief Executive Officer

Rate E T

Availability

Available to all cooperative associations which are or shall be owner-members of EKPC. The electric power and energy furnished hereunder shall be separately metered for each point of delivery. T

Applicability

Applicable to all power usage at the load center not subject to the provisions of Rate A, Rate B, Rate C, or Rate G of this tariff. T T

Monthly Rate - Per Load Center

An owner-member may select either Option 1 or Option 2 of this section of the tariff to apply to all load centers. The owner-member must remain on a selected option for at least one (1) year and may change options, no more often than every twelve (12) months, after giving a minimum notice of two (2) months. T T

	Option 1	Option 2
Demand Charge per kW of Billing Demand	$7.99	$6.02
Energy Charge per kWh		
On-Peak kWh	$ .042752	$ .050899
Off-Peak kWh	$ .042174	$ .042174

On-peak and off-peak hours are provided below:

Months	On-Peak Hours - EPT	Off-Peak Hours – EPT
October through April	7:00 a.m. to 12:00 noon	12:00 noon to 5:00 p.m.
	5:00 p.m. to 10:00 p.m.	10:00 p.m. to 7:00 a.m.
May through September	10:00 a.m. to 10:00 p.m.	10:00 p.m. to 10:00 a.m.

DATE OF ISSUE: October 2, 2017

DATE EFFECTIVE: Service rendered on and after November 2, 2017

ISSUED BY: Anthony S. Campbell

Anthony S. Campbell,
President and Chief Executive Officer

Issued by authority of an Order of the Public Service Commission of Kentucky in Case No. 2017-00002 dated August 7, 2017.

KENTUCKY
PUBLIC SERVICE COMMISSION
Gwen R. Pinson
Executive Director
Gwen R. Pinson
EFFECTIVE
11/2/2017
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Rate E (continued) T

Billing Demand

The billing demand (kilowatt demand) is based on EKPC's system peak demand (coincident peak) which is the highest average rate at which energy is used during any fifteen (15)-minute interval in the below listed hours for each month and adjusted for power factor as provided herein:

Months	Hours Applicable for Demand Billing – EPT
October through April	7:00 a.m. to 12:00 noon
	5:00 p.m. to 10:00 p.m.
May through September	10:00 a.m. to 10:00 p.m.

Billing demand applicable to this rate is equal to the load center's contribution to EKPC's system peak demand minus the actual demands of Rate A, Rate B, and Rate C participants coincident with EKPC's system peak demand. T T

Billing Energy

Billing energy applicable to this rate is equal to the total energy provided at the load center minus the actual energy provided to Rate A, Rate B, and Rate C participants. T T

DATE OF ISSUE: October 2, 2017

DATE EFFECTIVE: Service rendered on and after November 2, 2017

ISSUED BY: Anthony S. Campbell,
President and Chief Executive Officer

KENTUCKY
PUBLIC SERVICE COMMISSION
Gwen R. Pinson
Executive Director
EFFECTIVE
11/2/2017
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

EKPC 2017 Fuel Costs

January	0.02616
February	0.02275
March	0.02528
April	0.02482
May	0.02509
June	0.02361
July	0.02484
August	0.02310
September	0.02509
October	0.02448
November	0.02545
December	0.02664
Average	**0.02478**

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Company		EAST KENTUCKY POWER COOPERATIVE				
		FUEL ADJUSTMENT CLAUSE SCHEDULE				
Month Ended		DECEMBER 2017				
					FAC Factor*	
Fuel Fm (Fuel Cost Schedule)		34,525,397				
	=		=	(+)	$0.02664	
Sales Sm (Sales Schedule)		1,296,194,676				
Fuel (Fb)		$25,538,552				
	=		=	(-)	$0.02776	
Sales (Sb)		919,982,171				
					($0.00112)	

Effective Date for Billing FEBRUARY 2017

Submitted by Michelle K. Carpenter

(Signature) MICHELLE K. CARPENTER, CPA

Title CONTROLLER

Date Submitted JANUARY 19, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

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COMMISSION

Company: EAST KENTUCKY POWER COOPERATIVE

FUEL ADJUSTMENT CLAUSE SCHEDULE

Month Ended: NOVEMBER 2017

						FAC Factor*
Fuel Fm (Fuel Cost Schedule) / Sales Sm (Sales Schedule)	=	25,398,205 / 998,000,640	=	(+)		$0.02545
Fuel (Fb) / Sales (Sb)	=	$25,538,552 / 919,982,171	=	(-)		$0.02776
						($0.00231)

Effective Date for Billing: JANUARY 2017

Submitted by: Michelle K. Carpenter (Signature) MICHELLE K. CARPENTER, CPA

Title: CONTROLLER

Date Submitted: DECEMBER 20, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

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Company EAST KENTUCKY POWER COOPERATIVE

FUEL ADJUSTMENT CLAUSE SCHEDULE

Month Ended OCTOBER 2017

					FAC Factor*
Fuel Fm (Fuel Cost Schedule) / Sales Sm (Sales Schedule)	=	22,116,132 / 903,260,380	=	(+)	$0.02448
Fuel (Fb) / Sales (Sb)	=	$25,538,552 / 919,982,171	=	(-)	$0.02776
					($0.00328)

Effective Date for Billing DECEMBER 2017

Submitted by Michelle K. Carpenter (Signature) MICHELLE K. CARPENTER, CPA

Title CONTROLLER

Date Submitted NOVEMBER 20, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

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OCT 20 2017

PUBLIC SERVICE COMMISSION

OCT 23 2017

Company EAST KENTUCKY POWER COOPERATIVE

FUEL ADJUSTMENT CLAUSE SCHEDULE

Month Ended SEPTEMBER 2017

						FAC Factor*
Fuel Fm (Fuel Cost Schedule) / Sales Sm (Sales Schedule)	=	22,580,855 / 900,021,762	=	(+)		$0.02509
Fuel (Fb) / Sales (Sb)	=	$25,538,552 / 919,982,171	=	(-)		$0.02776
						($0.00267)

Effective Date for Billing NOVEMBER 2017

Submitted by Michelle K. Carpenter

(Signature) MICHELLE K. CARPENTER, CPA

Title CONTROLLER

Date Submitted OCTOBER 20, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

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SEP 20 2017

PUBLIC SERVICE COMMISSION

Company: EAST KENTUCKY POWER COOPERATIVE

FUEL ADJUSTMENT CLAUSE SCHEDULE

Month Ended: AUGUST 2017

					FAC Factor*
Fuel Fm (Fuel Cost Schedule) / Sales Sm (Sales Schedule)	=	24,425,142 / 1,057,217,273	=	(+)	$0.02310
Fuel (Fb) / Sales (Sb)	=	$33,087,730 / 1,097,928,848	=	(-)	$0.03014
					($0.00704)

Effective Date for Billing: OCTOBER 2017

Submitted by: Michelle K. Carpenter (Signature) MICHELLE K. CARPENTER, CPA

Title: CONTROLLER

Date Submitted: SEPTEMBER 20, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

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Company EAST KENTUCKY POWER COOPERATIVE

FUEL ADJUSTMENT CLAUSE SCHEDULE

Month Ended JULY 2017

						FAC Factor*
Fuel Fm (Fuel Cost Schedule) / Sales Sm (Sales Schedule)	=	28,417,688 / 1,144,230,174	=	(+)		$0.02484
Fuel (Fb) / Sales (Sb)	=	$33,087,730 / 1,097,928,848	=	(-)		$0.03014
						($0.00530)

Effective Date for Billing SEPTEMBER 2017

Submitted by Michelle K. Carpenter

(Signature) MICHELLE K. CARPENTER, CPA

Title CONTROLLER

Date Submitted AUGUST 18, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

Company EAST KENTUCKY POWER COOPERATIVE

FUEL ADJUSTMENT CLAUSE SCHEDULE

Month Ended JUNE 2017

					FAC Factor*
Fuel Fm (Fuel Cost Schedule) / Sales Sm (Sales Schedule)	=	23,559,503 / 997,714,387	=	(+)	$0.02361
Fuel (Fb) / Sales (Sb)	=	$33,087,730 / 1,097,928,848	=	(-)	$0.03014
					($0.00653)

Effective Date for Billing AUGUST 2017

Submitted by Michelle K. Carpenter

(Signature) MICHELLE K. CARPENTER, CPA

Title CONTROLLER

Date Submitted JULY 20, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

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JUN 20 2017

PUBLIC SERVICE COMMISSION

JUN 21 2017

Company	EAST KENTUCKY POWER COOPERATIVE

FUEL ADJUSTMENT CLAUSE SCHEDULE

Month Ended		MAY 2017			
					FAC Factor*
Fuel Fm (Fuel Cost Schedule) / Sales Sm (Sales Schedule)	=	23,045,237 / 918,647,642	=	(+)	$0.02509
Fuel (Fb) / Sales (Sb)	=	$33,087,730 / 1,097,928,848	=	(-)	$0.03014
					($0.00505)

Effective Date for Billing	JULY 2017
Submitted by (Signature)	Michelle K. Carpenter MICHELLE K. CARPENTER, CPA
Title	CONTROLLER
Date Submitted	JUNE 20, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

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MAY 19 2017
PUBLIC SERVICE COMMISSION

Company EAST KENTUCKY POWER COOPERATIVE

FUEL ADJUSTMENT CLAUSE SCHEDULE

Month Ended APRIL 2017

						FAC Factor*
Fuel Fm (Fuel Cost Schedule)		21,237,091				
	=		=	(+)		$0.02482
Sales Sm (Sales Schedule)		855,652,816				
Fuel (Fb)		$33,087,730				
	=		=	(-)		$0.03014
Sales (Sb)		1,097,928,848				
						($0.00532)

CHECKED
Public Service Commission
MAY 30 2017
By
FINANCIAL ANALYSIS DIVISION

MAY 23 2017

Effective Date for Billing JUNE 2017

Submitted by Michelle K. Carpenter

(Signature) MICHELLE K. CARPENTER, CPA

Title CONTROLLER

Date Submitted MAY 19, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

FA

Company EAST KENTUCKY POWER COOPERATIVE

FUEL ADJUSTMENT CLAUSE SCHEDULE

Month Ended MARCH 2017

					FAC Factor*
Fuel Fm (Fuel Cost Schedule) / Sales Sm (Sales Schedule)	=	26,381,697 / 1,043,768,098	=	(+)	$0.02528
Fuel (Fb) / Sales (Sb)	=	$33,087,730 / 1,097,928,848	=	(-)	$0.03014
					($0.00486)

Effective Date for Billing MAY 2017

Submitted by Michelle K. Carpenter

(Signature) MICHELLE K. CARPENTER, CPA

Title CONTROLLER

Date Submitted APRIL 20, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

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MAR 20 2017
PUBLIC SERVICE
COMMISSION

Company: EAST KENTUCKY POWER COOPERATIVE

FUEL ADJUSTMENT CLAUSE SCHEDULE

Month Ended: FEBRUARY 2017

					FAC Factor*
Fuel Fm (Fuel Cost Schedule) / Sales Sm (Sales Schedule)	=	22,024,059 / 968,121,799	=	(+)	$0.02275
Fuel (Fb) / Sales (Sb)	=	$33,087,730 / 1,097,928,848	=	(-)	$0.03014
					($0.00739)

Effective Date for Billing: APRIL 2017

Submitted by: Michelle K. Carpenter (Signature)
MICHELLE K. CARPENTER, CPA

Title: CONTROLLER

Date Submitted: MARCH 20, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

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FEB 17 2017

PUBLIC SERVICE
COMMISSION

Company		EAST KENTUCKY POWER COOPERATIVE			
		FUEL ADJUSTMENT CLAUSE SCHEDULE			
Month Ended		JANUARY 2017			
					FAC Factor*
Fuel Fm (Fuel Cost Schedule) / Sales Sm (Sales Schedule)	=	31,311,745 / 1,196,786,531	=	(+)	$0.02616
Fuel (Fb) / Sales (Sb)	=	$33,087,730 / 1,097,928,848	=	(-)	$0.03014
					($0.00398)

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FEB 20 2017

FINANCIAL ANA

Effective Date for Billing	MARCH 2017
Submitted by (Signature)	Michelle K. Carpenter MICHELLE K. CARPENTER, CPA
Title	CONTROLLER
Date Submitted	FEBRUARY 17, 2017

* (Five decimal places in dollars or three decimal places in cents - normal rounding)

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Contract Capacity Price is really a Financial Hedge Example of How the Hedge Works

Planning Year	Our Contract Price	RTO Price (BRA Resource Clearing Price)	Settlement
2019/2020	$125/MW-day	$140	Morgan Pays SKRECC difference ($15*68*31)
2020/2021	$125/MW-day	$60	SKRECC Pays Morgan difference ($65*68*31)

- Not a perfect hedge because RTO Price is not the final price
- Not a perfect hedge because volume could be plus or minus 68 MW

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2020/2021 RPM Base Residual Auction Results

2020/2021 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins resulting from the 2020/2021 RPM BRA in comparison to those from 2007/2008 through 2019/2020 RPM BRAs.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

	RTO													
Auction Results	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012[1]	2012/2013	2013/2014[2]	2014/2015[3]	2015/2016[4]	2016/2017[5]	2017/2018	2018/2019	2019/2020	2020/2021[6]
Resource Clearing Price ($/MW-day)	$40.80	$111.92	$102.04	$174.29	$110.00	$16.46	$27.73	$125.99	$136.00	$59.37	$120.00	$164.77	$100.00	$76.53
Cleared UCAP (MW)	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7	164,561.2	169,159.7	167,003.7	166,836.9	167,305.9	165,109.2
Reserve Margin	19.1%	17.4%	17.6%	16.4%	17.9%	20.5%	19.7%	18.8%	19.3%	20.3%	19.7%	19.8%	22.4%	23.3%

1) 2011/2012 BRA w as conducted w ithout Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) 2020/2021 BRA Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers

The Reserve Margin presented in Table 1 represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the Fixed Resource Requirement alternative). The 2020/2021 RPM BRA cleared 165,109.2 MW of unforced capacity in the RTO representing a 23.9% reserve margin. The reserve margin for the entire RTO is 23.3%, or 6.7% higher than the target reserve margin of 16.6%, when the Fixed Resource Requirement (FRR) load and resources are considered.

New Generation Resource Participation

The total quantity of new Generation Capacity Resources offered into the auction was 3,143.5 MW (UCAP) comprised of 2,536.6 MW of new generation units and 606.9 MW of uprates to existing generation units. The quantity of new Generation Capacity Resources cleared was 2,823.8 MW (UCAP) comprised of 2,389.3 MW (UCAP) from new generation units, predominantly natural gas combined cycle, and 434.5 MW from uprates to existing generation units.

Table 2A shows the breakdown, by major LDA, of capacity in UCAP terms of new units and uprates at existing units offered in the auction and capacity actually clearing in the auction. Ninety percent of the new generation capacity that offered into the 2020/2021BRA cleared the auction.

CAPACITY HEDGE

2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	TOTALS
$27.73	$125.99	$136.00	$59.37	$120.00	$164.77	$100.00	$76.53	
$125.00	$125.00	$125.00	$125.00	$125.00	$125.00	$125.00	$125.00	
$97.27	($0.99)	($11.00)	$65.63	$5.00	($39.77)	$25.00	$48.47	
	$0.99 x 68 MW x 365 = **$24,571**	$11.00 x 68 MW x 365 = **$273,020**			$39.77 x 68 MW x 365 = **$987,091**			**$ 2,508,059**
$97.27 x 68 MW x 365 = **$2,414,241**			$65.63 X 68 MW x 365 = **$1,628,936**	$5.00 x 68 MW x 365 = **$124,100**		$25.00 x 68 MW x 365 = **$620,500**	$48.47 x 68 MW x 365 = **$1,203,025**	**$ 12,041,420**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	CASE NO. 2008-00409
GENERAL ADJUSTMENT OF ITS	)	
WHOLESALE ELECTRIC RATES	)	

TESTIMONY OF
WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: October 31, 2008

NUCOR EXHIBIT 7

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and depreciation studies.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of East Kentucky Power Cooperative, Inc. ("EKPC").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to present the financial summary and supporting exhibits detailing how EKPC derived the amount of the requested revenue increase, (ii) describe EKPC's proposed pro-forma revenue, expense, and rate base adjustments, (iii) describe the calculation of EKPC's adjusted net margin and revenue deficiency for the fully forecasted test period ended May 31, 2010, (iv) describe the calculation of the 13-month average of EKPC's rate base and capitalization for the fully forecasted test period; (v) to sponsor the fully allocated class cost of service studies based on EKPC's cost of providing service for the 12 months ended May 31, 2010; and (vi) to support EKPC's proposed wholesale rates to its members.

TABLE 2 Electric Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return Phase I Rates**
Rate E	3.20%	6.12%
Rate B	2.53%	6.63%
Rate C	2.33%	6.02%
Rate G	0.50%	4.43%
Large Special Contract	2.86%	5.72%
Special Contract – Pumping Stations	29.52%	29.52%
Steam Service	4.74%	10.66%
Total System	3.17%	6.19%

Determination of the actual adjusted and proposed rates of return are detailed in Seelye Exhibit 7, pages 21-22 and pages 23-24, respectively.

V. RATE DESIGN

Q. Please describe how EKPC proposes to transition to a cost-based rate structure.

A. The unit charge components of EKPC's current rates do not accurately reflect the cost of providing service. From a cost of service perspective, too large of a portion of EKPC's fixed costs are recovered through the energy charge component of its rates. This is particularly true of EKPC's Rate E. The cost of service study indicates that a large portion of its fixed costs that are currently recovered through the energy charge should instead be recovered through the demand charge component of EKPC's rates. Rather than moving to a fully cost-based rate design in a single step, EKPC is proposing to move to a cost-based rate design in two phases. Under its rate design proposal in this

EKPC is proposing to increase each rate component of each rate schedule by the same percentage.

Q. Have you prepared an exhibit detailing the revenue impact of the Phase I rates?

A. Yes. The revenue impact of EKPC's Phase I rates is detailed in Seelye Exhibit 9. This schedule shows the impact of the Phase I rates on the components of each rate schedule. The proposed revenue increase for each rate schedule, stated as a dollar amount and as a percentage, is shown on page 1 of this exhibit.

Q. How were the Phase II rate developed?

A. The Phase II rates were developed based on the results of the cost of service study. Specifically, the individual charges within each rate schedule were based on the unit costs determined from the cost of service study. Consequently, the demand charges, substation charges, and meter-point charges included in the Phase II rates are higher than those included in the Phase I rates. However, the energy charges in the Phase II rates are lower than those included in the Phase I rates.

Q. What is the proposed metering point charge for the Phase II rates?

A. For the Phase II rates, EKPC is proposing to increase the metering point charge from the current level of $125 per month to $230 per month. The $230 charge is supported by the cost of service study.

Q. Please describe the changes to the substation charges in the Phase II rates?

A. EKPC currently has substation categories: (i) 1,000 to 2,999 kVa, (ii) 3,000 to 7,499 kVa, (iii) 7,500 to 14,999 kVa, and (iv) greater than 15,000 kVa. For the Phase II rates, EKPC proposes to incorporate the following six substation categories: (i) 1,000 to 4,999

Seelye Exhibit 10

Forecasted Period Phase II
Summary
Rate Impact Test Year Ended May 31, 2010

	Current	Proposed	$ Incr	% Incr
Rate E	698,429,400	753,775,327	55,345,926	7.92%
Rate B	57,697,996	62,333,404	4,635,408	8.03%
Rate C	23,333,746	25,502,456	2,168,710	9.29%
Rate G	19,703,308	21,561,891	1,858,583	9.43%
Large Special Contract	49,563,171	52,580,542	3,017,371	6.09%
Steam Service	13,439,988	14,113,041	673,053	5.01%
Pumping Stations	11,330,994	11,330,994	-	0.00%
Total	873,498,604	941,197,656	67,699,051	7.75%

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Billing Units (Current)		Current Rate	Current $
RATE E				
Metering Point Charge				
All Customers	3,734	$	125.00	466,750
Substation charges				
Substation 1,000 - 2,999 kVa	36	$	944	33,984
Substation 3,000 - 7,499 kVa	504		2,373	1,195,992
Substation 7,500 - 14,999 kVa	2,544		2,855	7,263,120
Substation > 15,000 kVa	578		4,605	2,661,690
	3,662			11,154,786
Demand Charge				
Option 1 (Owen)	2,343,000	$	6.92	16,213,560
Option 2	21,481,000	$	5.22	112,130,820
	23,824,000			128,344,380
Energy Charge	kWh			
On-Peak (Option 1)	564,787,000	$	0.035406	19,996,849
Off-Peak (Option 1)	526,652,000	$	0.034904	18,382,261
On-Peak (Option 2)	4,782,184,968	$	0.042470	203,099,396
Off-Peak (Option 2)	4,450,671,032	$	0.034904	155,346,222
	10,324,295,000			396,824,727
Sub-Total -- Base Rates				536,790,643
FAC	10,324,295,000		0.00749	77,306,791
Environmental Surcharge	$ 614,097,434		13.73%	84,331,966
Total Billings				698,429,400
Annual Increase Rate E				

Description	Billing Units (Proposed)	Proposed Rate	Proposed $
Metering Point Charge			
All Customers	3,734	230.00	858,820
Substation charges			
Substation 1,000-4,999 kVa	48	1,168.00	56,064
Substation 5,000-9,999 kVa	396	3,087.00	1,222,452
Substation 10,000-14,999 kVa	2,513	4,265.00	10,717,945
Substation 15,000-29,999 kVa	645	9,220.00	5,946,900
Substation 30,000-50,999 kVa	48	14,488.00	695,424
Substation > 51,000 kVa	12	16,155.00	193,860
	3,662		18,832,645
Demand Charge Rate E			
All kW	23,824,000	10.10	240,622,400
			-
			240,622,400
Energy Charge			
On-Peak kWh	5,346,971,968	0.032382	173,145,646
Off-Peak kWh	4,977,323,032	0.031880	158,677,058
			-
			-
			331,822,705
Sub-Total -- Base Rates			592,136,570
FAC			77,306,791
Environmental Surcharge			84,331,966
Total Billings			753,775,327

TARIFF I.G.S.
(Industrial General Service)

AVAILABILITY OF SERVICE.

Available for commercial and industrial customers with contract demands of at least 1,000 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet normal maximum requirements.

RATE.

Service Voltage

	Secondary	Primary	Subtransmission	Transmission	
Tariff Code	356	358/370	359/371	360/372	
Service Charge per month	$ 276.00	$ 276.00	$ 794.00	$ 1353.00	
Demand Charge per KW					
Of monthly on-peak billing demand	$ 24.13	$ 20.57	$ 13.69	$ 13.26	
Of monthly off-peak billing demand	$ 1.60	$ 1.55	$ 1.51	$ 1.49	IIII
Energy Charge per KWH	2.921¢	2.806¢	2.768¢	2.730¢	IIII
Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand .... $0.69/ KVAR					RRRR

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

MINIMUM DEMAND CHARGE.

The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	Primary	Subtransmission	Transmission	
$ 25.83/KW	$ 22.21/KW	$ 15.30/KW	$ 14.86/KW	IIII

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

(Cont'd. on Sheet No. 10-2)

DATE OF ISSUE: February 7, 2018

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: /s/ Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated January 18, 2018

KENTUCKY
PUBLIC SERVICE COMMISSION
Gwen R. Pinson
Executive Director
Gwen R. Pinson
EFFECTIVE
1/19/2018
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

TARIFF I.G.S.
(Industrial General Service)

ADJUSTMENT CLAUSES.

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following: T

Fuel Adjustment Clause	Sheet No. 5
System Sales Clause	Sheet No. 19
Franchise Tariff	Sheet No. 20
Demand-Side Management Adjustment Clause	Sheet No. 22
Kentucky Economic Development Surcharge	Sheet No. 24
Capacity Charge	Sheet No. 28
Environmental Surcharge	Sheet No. 29
School Tax	Sheet No. 33
Purchase Power Adjustment	Sheet No. 35
Decommissioning Rider	Sheet No. 38

T

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1) Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator.

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

(Cont'd on Sheet No. 10-3)

DATE OF ISSUE: February 7, 2018

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: /s/ Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated January 18, 2018

KENTUCKY
PUBLIC SERVICE COMMISSION
Gwen R. Pinson
Executive Director
Gwen R. Pinson
EFFECTIVE
1/19/2018
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

TARIFF I.G.S.
(Industrial General Service)

CONTRACT CAPACITY

The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW in multiplies of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial Customers who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

DATE OF ISSUE: February 7, 2018

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: /s/ Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated January 18, 2018

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES OF) EAST KENTUCKY POWER COOPERATIVE, INC.)	CASE NO. 2008-00409

ORDER

East Kentucky Power Cooperative, Inc. ("EKPC") a generation and transmission cooperative headquartered in Winchester, Kentucky, generates, transmits, and sells electricity to more than 500,000 customers in all or parts of 89 Kentucky counties through its 16 member-owner distribution cooperatives. EKPC owns and operates approximately 2,600 megawatts of generating capacity located at four different sites. Its generation, transmission and other assets combined have a total value in excess of $2.5 billion.

BACKGROUND

On September 30, 2008, EKPC filed a notice of intent to file an application for approval of an increase in its electric rates based on a forecasted test period. On October 31, 2008, EKPC submitted its application seeking an increase in revenues of $67.9 million, which it identified as its Phase I increase, with a proposed effective date of December 1, 2008. The application included a second schedule of rates, which was identified as EKPC's Phase II increase, which it proposed to become effective one year after its Phase I rate increase was implemented. EKPC also submitted a motion requesting approval to establish a regulatory asset based on the revenues its proposed rates would generate for the months of April and May of 2009. The motion reflected the planned April 1, 2009 in-service date of EKPC's Spurlock Unit 4 and its assumption that its proposed rates would be suspended for the full six months permitted by statute.

By Order dated November 26, 2008, the Commission found that an investigation would be necessary to determine the reasonableness of EKPC's proposed rates and suspended the rates for six months, from December 1, 2008, up to and including May 31, 2009, pursuant to KRS 278.190(2). That Order included a procedural schedule for processing this case, which provided for discovery on EKPC's application, intervenor testimony, discovery on intervenor testimony, rebuttal testimony by EKPC, a public hearing, and an opportunity for the parties to file post-hearing briefs. It also included a separate procedural schedule to investigate and address EKPC's request to establish a regulatory asset.

The Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG") and the Kentucky Industrial Utility Customers, Inc. ("KIUC") requested and were granted full intervention in this proceeding. Both parties conducted discovery on EKPC's application and filed testimony stating their positions on the requested increase in rates.

On February 23, 2009, EKPC filed a request asking that an informal conference be scheduled on March 5 and March 6, 2009 for the purpose of discussing possible settlement of the case. The request was granted and an informal conference, which lasted only one day, was held at the Commission's offices on March 5, 2009.

On March 13, 2009, on behalf of itself and the intervenors, EKPC filed a unanimous Settlement Agreement ("Settlement"). The Settlement consists of a 10-page document with two exhibits: Exhibit 1, EKPC's Billing Analysis (proof of revenues) and Exhibit 2, EKPC's Revised Tariffs.

At the March 27, 2009 public hearing, EKPC presented testimony in support of the Settlement. It responded to cross-examination by Commission Staff and questions from the Commission. Under the Settlement, the parties waived cross-examination of each others' witnesses. None of the parties proposed filing post-hearing briefs.

SETTLEMENT

The Settlement, attached as Appendix A to this Order, reflects a unanimous resolution of all issues raised in this case. The major provisions of the Settlement include the following:

- EKPC's rates for electric service will be increased to recover $59.5 million more in annual revenues, with the new rates effective for service rendered on and after April 1, 2009.
- The increase in EKPC's rates will be accomplished via an allocation and rate design that is generally consistent with what EKPC proposed for its Phase I increase in rates.
- A Times Interest Earned Ratio ("TIER") of 1.35 will be included in EKPC's environmental cost recovery ("ECR") filings. This is the same TIER used for ECR purposes since EKPC's previous rate case.

- The regulatory asset authorized for EKPC in Case No. 2008-00436[1] will be amortized over three years beginning in April of 2009.
- EKPC will receive a cash return on Construction Work in Progress ("CWIP") and will cease to accrue any Allowance for Funds Used During Construction ("AFUDC"), effective with the date of the Order approving the Settlement.
- EKPC's tariffs for interruptible electric service will be modified to include increases in the monthly credits to participating customers and reductions in the annual and daily interruptions.
- EKPC's request for authority to establish a regulatory asset related to unrecovered revenues for the months of April and May, 2009 is no longer applicable based on the effective date of the Settlement.
- EKPC will not implement its Phase II rate proposal.

ANALYSIS OF THE AGREEMENT

EKPC proposed an annual revenue increase of $67.9 million.[2] The AG proposed an annual increase of $40.1 million, while KIUC proposed an annual increase of $32.1 million. The Settlement contains the parties' unanimous recommendation that EKPC's electric revenues should be increased by $59.5 million.

---

[1] The Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages (Ky. PSC Dec. 23, 2008).

[2] Based on changes occurring after it filed its application, including recognition of the regulatory asset authorized in Case No. 2008-0436, EKPC revised its calculated revenue deficiency to an amount in excess of $74 million.

The other significant provisions of the Settlement are discussed in the following paragraphs.

TIER – Environmental Cost Recovery

Typically, an electric utility with an environmental surcharge approved pursuant to KRS 278.183 uses the equity return, in the case of an investor-owned utility, or the TIER, in the case of a cooperative, from its most recent rate case as the return component of the environmental costs included in its surcharge. Since the Settlement in this instance does not include a specific TIER in support of the agreed-upon revenue increase, the parties agreed that a 1.35 TIER, the TIER authorized in EKPC's previous rate case, should continue to be included in its surcharge calculations.

Regulatory Asset Amortization

The Settlement authorizes EKPC to amortize over three years the $12.3 million regulatory asset resulting from the Commission's approval of EKPC's request for such treatment of its purchased power replacement costs associated with forced outages experienced in calendar year 2008. This treatment allowed EKPC to avoid a condition of technical default under the debt service coverage requirement contained in its private credit facility.

Cash Return on CWIP / Cease AFUDC Accounting

Historically, EKPC accrued AFUDC on major construction projects, capitalizing the interest expense incurred during the construction period. Such capitalized interest expense becomes part of the cost of the asset financed by the debt which gives rise to the interest expense. AFUDC is reflected on the income statement as an offset against interest expense and, effectively, is a non-cash income item.

Ceasing to accrue AFUDC eliminates this non-cash item from EKPC's income statement. Therefore, its reported income will reflect only cash earnings, which are the earnings given consideration by debt rating agencies. Not accruing AFUDC also results in the installed cost of an asset being less than under AFUDC accounting, which will result in lower depreciation expense over the life of the asset.

Phase II Rates

EKPC's proposed Phase II rates were intended as a means of implementing a revenue neutral rate adjustment that would better align its rates with its cost-of-service. The Phase II rates would have shifted more fixed cost recovery from the energy charge component to the demand charge component of EKPC's rate schedules. While there will be no Phase II rate adjustment under the terms of the Settlement, the Commission is very much interested in cost-of-service-based rates and demand-side management programs that incentivize both the utility and customers to practice energy efficiency in a cost-effective manner. Given the expectation that it will file a new rate application within the next few years, the Commission anticipates that EKPC will address these issues at that time.

SUMMARY

The Settlement provides that the rates, terms and conditions contained therein will become effective upon the Commission's approval thereof. The parties recommend that the new rates become effective for service rendered on and after April 1, 2009, and agree that, if the Settlement receives Commission approval, no requests for rehearing or appeals will be filed.

Based on a review of the Settlement, the exhibits attached thereto, and the case record, including intervenor testimony; the Commission finds that the provisions of the Settlement are reasonable and in the public interest. The Settlement was the product of arms-length negotiations among knowledgeable, capable parties and should be approved. Such approval is based solely on the reasonableness of the Settlement in total and does not constitute a precedent on any individual issue.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by EKPC are denied.

2. The Settlement, attached hereto as Appendix A, is approved in its entirety.

3. The rates and charges for wholesale electric service set forth in Exhibit 2 to the Settlement are fair, just and reasonable for EKPC to charge for service rendered on and after April 1, 2009.

4. EKPC shall file, within 20 days of the date of this Order, its revised tariffs as set forth in Exhibit 2 to the Settlement, reflecting that they were approved pursuant to this Order.

5. EKPC shall amortize over three years, beginning in April 2009, the regulatory asset authorized by the Commission in Case No. 2008-00436.

By the Commission

ENTERED
MAR 3 1 2009
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

Attachment DC 2-39
Public 15/139

Madison, Michael

From: Greg Shepler
Sent: Tuesday, April 03, 2018 5:16 PM
To: Lynne Travis
Subject: Fw: Quick Question
Attachments: September 2017 Billing & Monthly Reports

From: Dennis Holt <dholt@skrecc.com>
Sent: Thursday, October 26, 2017 1:07 PM
To: Greg Shepler
Cc: Carter Babbit
Subject: RE: Quick Question

We utilize the E-2 Tariff; however, the Schedule B and Schedule C are in place for a few of our larger industrial accounts. I have attached a copy of the most recent EKPC Billing including their analysis sheets.

Dennis Holt
V.P. of Engineering and Operations
South Kentucky RECC
Somerset, Kentucky 42503
Phone 606-678-4121
Cell 606-872-3555

From: Greg Shepler [mailto:Greg.Shepler@enervision-inc.com]
Sent: Thursday, October 26, 2017 10:56 AM
To: Dennis Holt <dholt@skrecc.com>
Cc: Carter Babbit <Carter.Babbit@enervision-inc.com>
Subject: RE: Quick Question

Also — another request. Can we get a copy of EKPC's most recent long range financial forecast?
Thanks,

Greg Shepler

From: Greg Shepler
Sent: Thursday, October 26, 2017 10:15 AM
To: 'Dennis Holt' <dholt@skrecc.com>
Cc: Carter Babbit <Carter.Babbit@enervision-inc.com>
Subject: Quick Question

Dennis,

EKPC EXHIBIT 1

DC 2-39 PUBLIC
16/139

As we're looking at the numbers, does SKRECC elect Option 1 or Option 2 (lower Demand charge) on the E-Tariff?

Thanks,

Greg Shepler Managing Principal
T (678) 510-2921 I C (678) 525-2017 I (888) 999-8840
greg.sheoler@enervision-inc.com I vvww.enervision-inc.com

ENERVISION 4170 Ashford Dunwoody Road Suite 550 I Atlanta, GA 30319

Delivering results to help you succeed!

DC 2-39 PUBLIC
17/139

Madison, Michael

From: Yewande Otekeiwebia <Yewande.Otekeiwebia@ekpc.coop>
Sent: Thursday, October 05, 2017 1:07 PM
To: Alan Coffey; Allen Anderson; Ashley Kerr; Dennis Holt; Jeff C. Greer; Kendra Baker; Kevin Newton; Marylou Henderlight; Michelle Herrman; Ruby Patterson; Sharon Keith
Cc: Laura Wilson
Subject: September 2017 Billing & Monthly Reports
Attachments: South Ky 320.pdf; South Ky 330.pdf; South Ky 335.pdf; South Ky 370.pdf; South Ky 400.pdf; South Ky Cagles Facility Charge.pdf; South Ky DLC.pdf; South Ky EDR Load Factor Report_201709.pdf; South Ky Green Power.pdf; South Ky Invoice Supplement_EDR Discount 093017.pdf; South Ky Invoice.pdf; South Ky Stats.pdf; EKPC Factor 0917.pdf; FA0817 1 pg.pdf

Good Afternoon,

Attached is the September billing along with the monthly reports. Please note that our energy rates have been revised to reflect the change in our base fuel rate, in accordance with PSC Case No. 2017-00002 Order.

Let us know if you have any questions.

Thanks,
Yewande

Yewande Otekeiwebia, CPA
East Kentucky Power Cooperative
Senior Revenue Accountant
(859) 745-9263
Yewande.Otekeiwebia@ekpc.coop

EAST KENTUCKY POWER COOPERATIVE
A Touchstone Energy Cooperative

KW-Sch. B Contract	7.17
Excess B Contract	9.98
KW-Sch. C	7.17
KW-Sch. DB	3.59
Excess DB	4.99
KW-Sch. E	7.99
KW-Sch. E2	6.02
KW-Sch.GM	6.98
KVA 1000- 2999	1088.00
KVA 3000- 7499	2737.00
KVA 7500- 14999	3292.00
KVA 15000- 99999	5310.00

EAST KENTUCKY POWER COOPERATIVE INC.
P.O. Box 707 Winchester, Kentucky 40391
Statistics For Month of September 2017

SOUTH KENTUCKY RECC

KWH-Sch. B/C	.040502
KWH-Sch. E On-Peak	.042752
KWH-Sch. E Off-Peak	.042174
KWH-Sch. E2 On-Peak	.050899
KWH-Sch. E2 Off-Peak	.042174
Fuel Rate	-.007040
Surcharge Rate	.158900

					KW				KWH		
Substation	KVA Rating	Constant KW/KWH	Rate Sch	NON-CP P.F.	Billing Demand	CP TOD Demand	NON-CP Demand	Contract Demand	Billing KWH	Actual KWH	Minimum KWH
Albany	11200	4800	E2	.94	5,668	5,668	7,018	0	2,891,769	2,891,769	0
Asahi											
--Toyotetsu		7200	C		7,237	7,232	6,627	3,000	3,528,915	3,528,915	1,200,000
--Substation Share		3600	E2		2,665	2,665	3,751	0	1,758,276	1,758,276	0
Total Substation				.97	9,902	9,897	10,378	3,000	5,287,191	5,287,191	1,200,000
Bronston	25200	7200	E2	.99	6,903	6,903	8,245	0	3,174,695	3,174,695	0
Cabin Hollow											
--Armstrong World Industries		1200	B		2,978	2,978	3,226	2,700	1,602,647	1,602,647	1,080,000
--Substation Share	12400	3600	E2		3,770	3,770	4,032	0	1,611,330	1,611,330	0
Total Substation				.96	6,748	6,748	7,258	2,700	3,213,977	3,213,977	1,080,000
Cemetery Road	5600	3600	E2	.95	2,186	2,186	2,229	0	839,880	839,880	0
East Pine Knot											
--McCreary Federal Prison		7200	C		2,300	1,610	1,840	2,300	1,048,330	1,048,330	920,000
--Substation Share	14000	4800	E2		1,593	1,593	1,754	0	690,419	690,419	0
Total Substation				.95	3,893	3,203	3,594	2,300	1,738,749	1,738,749	920,000
East Somerset	11200	4800	E2	.96	5,608	5,608	6,136	0	2,374,044	2,374,044	0
Floyd	14000	7200	E2	.97	3,828	3,828	4,337	0	1,647,207	1,647,207	0
Gap of the Ridge	14000	4800	E2	.96	5,278	5,278	6,148	0	2,337,031	2,337,031	0
Gregory Road	7000	3600	E2	1.00	1,184	1,184	1,377	0	500,234	500,234	0
Homestead											
--Belden Electronics #1		600	B		900	444	466	900	360,000	290,622	360,000
--Belden Electronics #2		1200	B		1,425	831	840	1,425	570,000	466,375	570,000
--Substation Share	42000	12000	E2		9,964	9,964	12,387	0	4,998,726	4,998,726	0
Total Substation				.96	12,289	11,239	13,693	2,325	5,928,726	5,755,723	930,000
Jabez	12000	4800	E2	.98	1,855	1,855	2,283	0	850,820	850,820	0
Jamestown	12000	3600	E2	.95	3,440	3,440	4,333	0	1,773,024	1,773,024	0
Monticello											
--Wal-Mart Stores East		500	B		800	549	574	800	320,000	301,507	320,000

South Kentucky Rural Electric Cooperative Corporation

Case No. 2018-00050

East Kentucky Power Cooperative Supplemental Data Requests

25. Please refer to South Kentucky's response to EKPC's First, Item 26 and EKPC Attachment 26 (Confidential version). Please provide the basis for each of the following escalation factors included in the net present value ("NPV") analysis. Include all supporting workpapers, spreadsheets, assumptions, and other relevant documentation.

a. 20 Year Compare tab, Column E, Rows 10, 18, 19, 20, and 21.

b. PJM Summary tab, Column S, Rows 4 through 13.

c. Adders tab, Columns J through M, Row 5.

Response:

Without waiving the confidentiality of the referenced attachment, South Kentucky provides the following information.

a. 20 Year Compare, Column E escalators:

i. Total Cost @ EKPC Rate ($M) = 2% based on EKPC's 2015 Twenty-Year Financial Forecast, 2015-2034 (Attachment EKPC#2-1). The stated escalation rates were adjusted to 2% as a conservative measure in the analysis.

ii. EKPC Supply ($M) – See (i) above

iii. Alt Supply @ EKPC Rate ($M) - See (i) above

iv. Alt Supply NITS ($M) – The historical PJM Transmission Revenue Requirement and Rates for the EKPC Transmission Zone can be found on the PJM website: www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx under the header: Network Integration Transmission Service Revenue Requirements & Rates. The EKPC Transmission Zone rate of $21,334 $/MW-Year, effective July 1, 2016 was assumed for 2017 and escalated by 3%. The 3% escalation rate represents an average of 5 years of historical data as noted in EKPC Attachment 1-26 (Confidential version), sheet labeled "Adders".

v. Alt Supply Ancillaries, PJM ($M) – PJM costs fluctuate over time. The 2% escalation is in line with other escalators utilized in the analysis.

b. PJM Summary, Column S, rows 4-13 = See (v) above

c. See (iv) above.

pjm

Billing, Settlements & Credit

PJM manages all aspects of the electric grid and the wholesale market, including the purchase and sale of energy, transmission services and ancillary services. PJM provides weekly and monthly invoices for each market participant. The market settlements and billing FAQs provide an introduction to how charges are billed in the market.

Guides

Guides	Date
Emergency Energy Settlement Process for April 2015 Load Management Events PDF	5.4.2015
Guide to Billing: PDF | WEB Contains billing line items, charges/credits and references	
Requirements for Agency Agreements PDF Guidelines for using an agent to conduct business with PJM	
Credit Overview & Supplement PDF An overview of the credit policy and requirements, and supplement to the Open Access Transmission Tariff, Attachment Q	
Market Settlements Reporting System Reports Documentation	
Drivers of Uplift	
5-Minute Settlements	

Reconciliation Billing Determinants

2018

Monthly Billing Determinants CSV Daily & Hourly Billing Determinants CSV	March
Monthly Billing Determinants CSV Daily & Hourly Billing Determinants CSV	February
Monthly Billing Determinants CSV Daily & Hourly Billing Determinants CSV	January

Past Years

2017

2016

2015

2014

2013

Billing Determinant Definitions

Contact PJM

Member ? Community

(866) 400-8980
(610) 666-8980

Other Contacts

Email:
Credit Group
Market Settlements Group
Cash Management Group

Credit

PJM Settlement, Inc. - Credit

New to Billing, Settlements & Credits?

Market Settlements/Billing FAQs

Guide to Billing: PDF | WEB

Monthly Billing Statement Example

Quick Reference Guide to Market Settlements by Type of Business PDF

Subscribe to the Bill Notice Email List

Training

How billing, settlements and credit work at PJM

Market Settlements 101

Market Settlements Advanced

Market Settlements Subcommittee (MSS)

Upcoming Meetings | Past Meeting Materials

Issue Tracking

Subscribe to the MSS email list

Weekly Billing Calendars

Reconciliation billing determinants are used by PJM to reconcile past months' billings between EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for certain allocations that are based on real-time load ratio shares. The reconciliation kWh data supplied to PJM by the EDCs, which represents the difference between the scheduled Retail Load Responsibility eSchedules and the "actual" customer usage based on metered data, are multiplied by the applicable billing determinants to determine the reconciliation billing amounts for each of the following:

Scheduling, System Control & Dispatch Service Charges

Regulation Charges

Transmission Loss Credits

Synchronized Reserve Charges

Network Integration Transmission Service Revenue Requirements & Rates

	Date
January 2018 PDF	1.16.2018
December 2017 PDF	11.30.2017
July 2017 PDF	8.18.2017
June 2017 PDF	8.8.2017
March 2017 PDF	3.20.2017
January 2017 PDF	1.12.2017

Past Years

2016 | 2015 PDF

THEO, PLC & NSPL Methodology Inventory
An inventory of the procedures for calculation of THEO, PLC, and NSPL for each of the electric distribution companies.
Formula Rates

Network Service Peak Loads

	Date
2018 PDF	12.13.2017
2017 PDF	6.6.2017

Past Years

2009-2016 PDF

Transmission Enhancement Worksheets

Weekly Billing Calendars

Learn how to add the Market Settlements Billing schedule to your personal calendar

June 2018 - May 2019 PDF
June 2017 - May 2018 PDF

All dates - Web version

PJM Business Holiday Calendar: 2018 | 2017 PDF

Holiday Deadline Extensions: 2018 | 2017 PDF

Manuals

M-27: Open Access Transmission Tariff Accounting
Current PDF | Redline PDF

M-28: Operating Agreement Accounting
Current PDF | Redline PDF

M-29: Billing
Current PDF | Redline PDF

Agreements

Operating Agreement PDF

Open Access Transmission Tariff PDF

Seams Elimination Charge/Cost Adjustment/Assignment (SECA) Refund Report Filing Attachments - 9.18.2017

Final SECA Refund Report PDF

SECA Refund Reporter: 9.15.2017 | 10.2.2017 | 10.31.2017 XLS

Attachment A - SECA Refund Report - User Guide PDF

Attachment B - SECA Settlements Chart PDF

Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$136,237,027	$50,960
AEP (AEP)	$1,280,920,675	$56,991.36
AP (APS)	$128,000,000	$17,895
ATSI (ATSI)	$574,583,780	$45,057.62
BC (BGE)	$216,851,881	$32,851
ComEd, Rochelle (CE)	$728,237,019	$34,392.02
Dayton (DAY)	$40,100,000	$13,295.76
Duke (DEOK)	$106,450,109	$20,055
Duquesne (DLCO)	$133,905,125	$47,891.68
Dominion (DOM)	$925,628,000	$47,375.56
DPL, ODEC (DPL)	$135,927,090	$32,938
East Kentucky Power Cooperative (EKPC)	$75,851,112	$26,424
MAIT (METED, PENELEC)	$132,435,983	$22,612.39
JCPL	$138,342,213	$23,232.10
PE (PECO)	$151,703,000	$20,942
PPL, AECoop, UGI (PPL)	$433,895,406	$61,792
PEPCO (PEPCO)	$166,094,793	$25,229
PS (PSEG)	$1,185,164,918	$120,931.26
Rockland (RECO)	$19,661,232	$49,695
TrAILCo	$272,626,368.81	n/a

Effective July 1, 2017

www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx
NITS Revenue Requirements & Rates July 2017

Focused Management and Operations Audit of East Kentucky Power Cooperative, Inc.

FINAL REPORT

Presented to:
The Kentucky Public Service Commission

By:

THE LIBERTY CONSULTING GROUP

The Liberty Consulting Group
65 Main Street, P.O. Box 1237
Quentin, Pennsylvania 17083-1237
admin@LibertyConsultingGroup.com

April 20, 2010

EKPC EXHIBIT 2

approved the Spurlock #1 scrubber in August. The Commission also granted in August 2006 the requested CPCN for Smith #1 and CT's #8 - #12, in anticipation of load growth in the member systems served by EKPC.

EKPC thus found itself, as 2006 progressed, facing large capital needs, not only for new sources of power, but also for environmental compliance at existing stations. These already large capital needs came with other major, potential consumers of EKPC's financial resources: the forced outage expenses and potential penalties from EPA.

Recognizing the severe strain of these events on EKPC's finances, the Commission initiated on October 27, 2006 a Financial Condition Investigation (Case No. 2006-00455), stating:

> *East Kentucky Power files monthly and annual financial reports with the Commission. A review of these reports indicates that East Kentucky Power's operations are producing negative net income since the last quarter of 2004. Based on the Commission's statutory authority under KRS 278.250 to "investigate and examine the condition of any utility subject to its jurisdiction," the Commission finds that an investigation should be initiated to review the financial condition of East Kentucky Power.*

In November 2006, EKPC gave notice of its intention to file a rate case seeking $50-60 million in rate relief and announced the impending retirement of its CEO. EKPC named a new, interim CEO in December 2006. That same month, Warren Rural Electric Cooperative cancelled plans to become a member owner of EKPC. The Commission responded with an investigation of the adequacy of EKPC's generating capacity (Case No. 2006-00564).

EKPC did make its planned rate filing in January 2007 (Case No. 2006-00472), seeking $43.3 million in additional revenues. The filing also demonstrated the seriousness of EKPC's financial situation by seeking emergency rate relief and by noting the deferral of already past-due maintenance on Spurlock #2 and Dale #3. Further demonstrating EKPC's financial situation was the testimony of a CFC executive that EKPC would not qualify for an investment grade credit rating. The Commission granted EKPC $19 million in interim rate relief on April 1, 2007, stating:

> *As a general matter, prudently managed utilities will not willingly place themselves in a position where interim rate relief during the suspension period is necessary to avoid a material impairment of the utility's credit or operations. This is especially true of rural electric cooperative corporations. KRS 278.095 provides that a cooperative "shall be operated on a nonprofit basis for the mutual benefit of its members and patrons." While low rates are desirable, this must be balanced against the necessity that a cooperative remain financially and operationally viable. With the shadow of Big Rivers Electric Corporation's bankruptcy only recently receding in the memory of Kentucky utility jurisprudence, all directors and officers of jurisdictional utilities should take note that the extraordinary relief authorized under KRS 278.190(2) is just that – extraordinary.*

Many of the conclusions in this report relate to the fundamental role of the board and expectations for the performance of individual directors and the board as a whole. A key element of reforming governance at EKPC must therefore be a reexamination of the board's role in the business of EKPC.

4. Elevate the priority of strategic planning as a board function and become heavily involved in providing strategic direction to management. *(Conclusion 3)*

The MCR effort brought a sound beginning to the kind of strategic thinking that the board should embrace on a continuing basis. But it is clear that the initial work was not sustained at the board level, and most board members remain unaware of its conclusions and subsequent results. The board needs to do far more in both formulation of strategies as well as implementation and continuous testing and monitoring of strategies.

Reports against a strategic baseline should be provided regularly, and to some extent they already are. But they are clearly ineffective at the board level. Formulation of plans needs to be a periodic board task and status of implementation needs to be a monthly topic. Further, these tasks need to be discussed at length, and not just dismissed with the issuance of a management report.

5. Elevate the priority of EKPC's financial health and the board's sensitivity to it. *(Conclusion 4)*

The financial health of EKPC is not given sufficient attention by the board. Targets for TIER and equity should be established and managed, with the board exhibiting a long-term commitment and understanding of what constitutes adequate financial health. Again, the first part (targets) are to a large extent already in place. But the thinking behind those targets at the board level and an understanding of the adequacy of long-term targets is lacking.

6. Reconcile the conflict of interest immediately in favor of EKPC. *(Conclusions 5 and 6)*

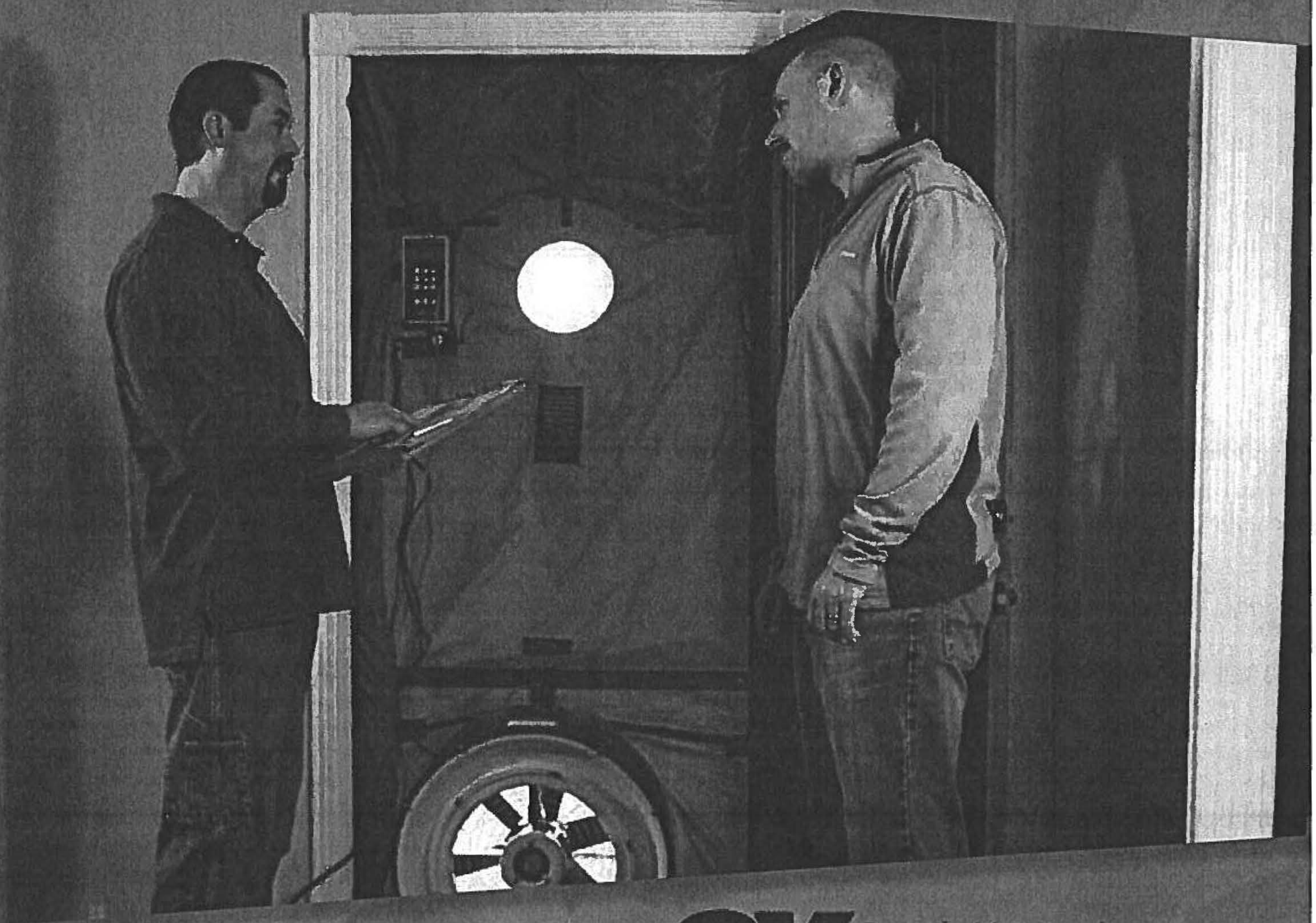
Liberty has concluded that a de facto conflict does indeed exist and it is real, continuing and dangerous. The conflict forces a philosophy of low rates at the expense of all else and hence influences all of the board's actions in key areas, including financial health, rate strategies, and strategic planning. It manifests itself most directly in the balancing of financial health, as expressed in targets for TIER and equity, against the goal of lower rates.

Since this recommendation calls for a change in underlying philosophy, there is a tendency to see the required fixes as intangible, but that is not true. A fundamental change in thinking is necessary, but that must be accomplished along with numerous tangible actions.

The board must articulate a new, EKPC-centric way of thinking and acknowledge that, while the consumer's voice must be heard, a role of consumer advocate is not acceptable for directors. Further the board needs to commit to enforcing this notion on a continuing basis, with specific measures for the removal of directors who sacrifice EKPC's interests for others, including the interests of the distribution cooperatives.

GUIDING PRINCIPLES

Owned by you, working for you



SK South Kentucky RECC

SOUTH KENTUCKY RURAL ELECTRIC COOPERATIVE CORPORATION

2015 ANNUAL REPORT

OWEN ELECTRIC-SHELBY ENERGY
EXHIBIT 1

Cover: **South Kentucky RECC's Charlie Ball, left, energy advisor, conducts a blower-door test at member Craig Whitaker's home.** South Kentucky offers energy audits to members to help them save money on electric bills. Photo: Tim Webb

Right: (in front sitting) South Kentucky RECC CEO Allen Anderson and employees, left to right, Derek Maurath, Line Technician, Nancy Duncan, cashier; Doug Conley, Materials Manager, Bruce Parkey, Special Projects Engineer, Auburn Cook, Service Center Representative, Joe Langdon, IT Manager, and Christy Stevens, General Ledger Accountant, adhere to the 7 Cooperative Principles making for a better electric cooperative for South Kentucky RECC members. Photo: Tim Webb

THE GUIDING PRINCIPLES

South Kentucky RECC is proud to be unique.

We are unique in that we are a cooperative business, owned by you, working for you, and guided by The Seven Cooperative Principles, which 171 years after they were first written, are still relevant today.

This annual report highlights the achievements South Kentucky RECC has made by adhering to these principles.

For instance, we rely on the principle of **Cooperation Among Cooperatives** as we work with our partner co-ops to deal with new EPA regulations.

Kentucky enjoys affordable and reliable electricity thanks to its coal-fired power plants, which supply about 90 percent of our electricity. As the EPA's Clean Power Plan places steep limits on carbon emissions from those plants, SKRECC is working with our national association and a network of 900 co-ops across the country to craft innovative solutions and a united response.

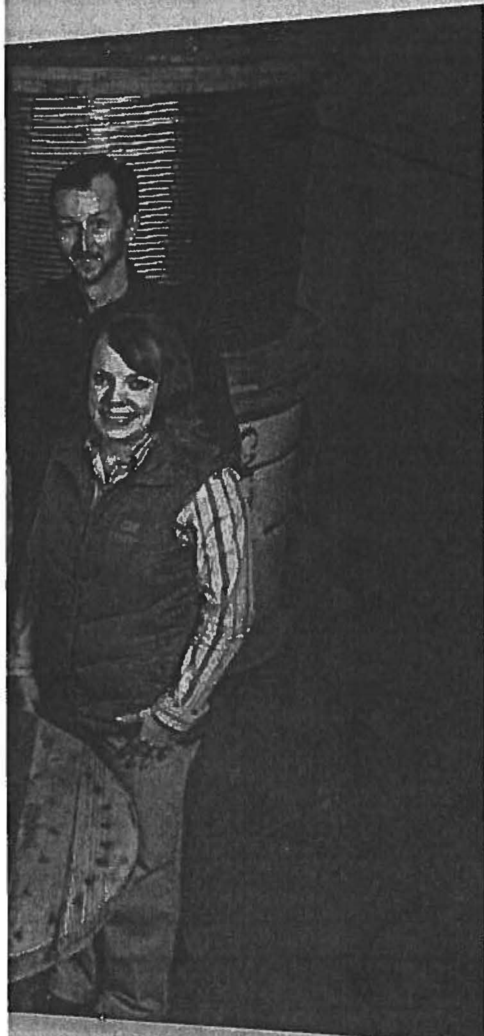
While the regulations may ultimately impact how we generate your energy, our mission of safe, reliable, and affordable electric service does not change.

KEEPING ENERGY AFFORDABLE

The principles of **Open and Voluntary Membership** and **Democratic Member Control** ensure you have a say in how South Kentucky RECC does business.

Elected by you, our board of directors sets policy and hires a co-op president/CEO, who in turn hires professionals to carry out our mission.

SKRECC exerts its **Autonomy and Independence** in crafting strategy and hiring decisions.



TIMWEBBPHOTOGRAPHY

We employ experts in the fields of engineering and operations, information technology, communications, member services, and community and economic development. Some of the best, brightest, most creative, and dedicated people have chosen careers that serve their communities working at South Kentucky RECC.

HOW REGULATIONS IMPACT YOUR ELECTRIC RATES

Current and yet-to-be implemented regulations affect the cost to generate electricity. To comply, our co-op power supplier, East Kentucky Power Cooperative, has invested hundreds of millions of dollars in environmental control equipment.

Because the new EPA regulations will force us to use less coal to generate electricity, we expect to see upward pressure on energy prices for Kentuckians over the next several years.

We take our **Members' Economic Participation** very seriously as we watch out for your interests. Unlike investor-owned utilities, SKRECC does not create profits for investors and shareholders. Any excess dollars or margins are assigned to our members in the form of a capital credit and returned to members when the board of directors sees the co-op has the financial strength to do so.

We provide energy audits, rebates, and energy-efficiency tools all of which helps you to actually use less electricity, which keeps costs lower for all members.

STAYING SAFE AND STAYING INFORMED

Since delivery of electricity is a complex process, South Kentucky RECC places a high value on providing **Education, Training, and Information.** Working with South Kentucky RECC's Safety and Loss Control team, as well as the Kentucky Association of Electric Cooperatives' Safety & Loss Prevention team, we are proud of how safely our employees work.

We have also expanded our informational services to members over the past year. Members can now use a smart phone app to check usage, pay bills, and text outages. They can use the online member portal at www.skrecc.com to conduct much of their

Perhaps the most important cooperative principle we follow at South Kentucky RECC is Concern for Community. We give back to our community through our People Fund program, which allows members to round up their electric bill to the nearest dollar, then awards grants from that funding to community organizations, like schools, food banks, senior citizens centers, and many others, whose financial needs are not being met by other resources. South Kentucky RECC also encourages employees to participate in community events, like American Cancer Society Relay For Life or March of Dimes WalkAmerica. Last year's WalkAmerica team raised more than $4,000 for the event (photo below). Photo: South Kentucky RECC

business with the co-op, as well as follow hourly electric usage, view bill history, and pay bills.

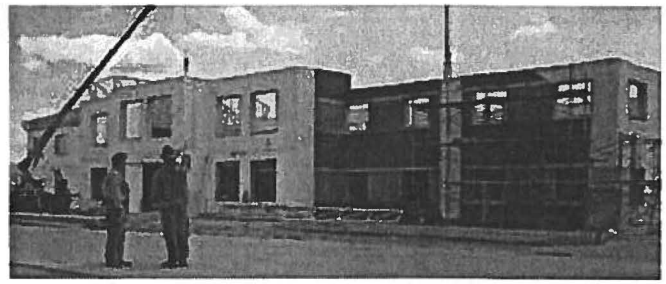
Timely and important information about your electric cooperative and member benefits can be found on skrecc.com, in *Kentucky Living* magazine, and look for us on Facebook and Twitter.

YOUR COMMUNITY IS OUR COMMUNITY

Your cooperative employees are your neighbors. Because of our Concern for Community, we support and participate in many area causes and events. South Kentucky RECC is part of your community, and we will continue to participate in events and activities that help us all. You'll see co-op employees volunteering for local community groups, conducting school safety programs, and sponsoring local events.

In addition, South Kentucky RECC has made a long-term commitment to community through the construction of a new headquarters in Somerset. The Kentucky Public Service Commission in March 2015 granted approval to purchase the former Sumerset Houseboats facility for construction of the new headquarters. Bids were let in August, and D.W. Wilburn Inc., based in Somerset, was the low bidder and began construction immediately. From all indications, construction is on track and estimates for completion is October. The current headquarters on North Main Street, Somerset, is for sale with conditions that it cannot be occupied until the co-op's move is complete later this year.

Each day, SKRECC remembers who owns our co-op—you do. Thank you for your trust as we remain guided by The Seven Cooperative Principles in each of our decisions to protect and improve the quality of life for our community.



South Kentucky RECC CEO Allen Anderson meets with Somerset SKRECC headquarters project manager Steve Wilson, with construction firm D. W. Wilburn, to discuss progress on the building.

7 COOPERATIVE PRINCIPLES

Cooperatives operate according to the same core principles and values. Cooperatives trace the roots of these principles to the first modern cooperative founded in Rochdale, England, in 1844.

VOLUNTARY AND OPEN MEMBERSHIP

Cooperatives are voluntary organizations, open to all people able to use its services and willing to accept the responsibilities of membership, without gender, social, racial, political, or religious discrimination.

DEMOCRATIC MEMBER CONTROL

Cooperatives are democratic organizations controlled by members—those who buy the goods or use the services of the cooperative—who actively participate in setting policies and making decisions.

MEMBERS' ECONOMIC PARTICIPATION

Members contribute equally to, and democratically control, the capital of the cooperative benefiting members in proportion to the business they conduct with the cooperative rather than on the capital invested.

AUTONOMY AND INDEPENDENCE

Cooperatives are autonomous, self-help organizations controlled by members. If the co-op enters into agreements with other organizations or raises capital from external sources, it is done so based on terms that ensure democratic control by members and maintain the cooperative's autonomy.

EDUCATION, TRAINING, AND INFORMATION

Cooperatives provide education and training for members, elected representatives, managers, and employees so they can contribute effectively to the development of their co-op.

COOPERATION AMONG COOPERATIVES

Cooperatives serve their members most effectively and strengthen the cooperative movement by working together through local, national, regional, and international structures.

CONCERN FOR COMMUNITY

While focusing on member needs, cooperatives work for the sustainable development of communities through policies and programs accepted by the members.

Rick Holloran, Chairman, KAEC Representative District #3

Cathy Crew Epperson Vice Chairman District #1

Lee Coffee Secretary/Treasurer EKP Representative District #7

Greg Redmon District #2

Billy G. Hurd District #4

Greg Beard District #5

OFFICIAL BUSINESS MEETING AGENDA
ANNUAL MEETING OF MEMBERS

SOUTH KENTUCKY RECC

Where: South Kentucky RECC Farm (¾ mile west of Fishing Creek Bridge on HWY 80 in Pulaski County)

When: Thursday, June 9, 2016

Registration Time: 4:00 PM

Business Meeting Time: 7:00 PM

TThe annual membership meeting of South Kentucky RECC organizes to take action on the following matters:

1. Call of Meeting to Order
2. Determine Quorum Present
3. Reading of the Notice of the Meeting and Proof of Mailing
4. Consideration and Approval of the Minutes of the 2015 Annual Meeting
5. Presentation and Consideration of Reports of Officers, Directors, and Committees
6. Report on the Election of Board Members— District 4 and District 7
7. Unfinished Business
8. New Business as proposed in Section 3.08 of the Bylaws
9. President & CEO's Report
10. Adjournment

South Kentucky RECC
A Touchstone Energy Cooperative

Boris Haynes District #6

Mark David Goss Attorney

Allen Anderson CEO

MEMBERS BY COUNTY

(as of December 31, 2015)

Adair County	706
Casey County	1,931
Clinton County	7,344
Cumberland County	23
Laurel County	12
Lincoln County	1,365
McCreary County	6,838
Pulaski County	30,501
Rockcastle County	80
Russell County	11,003
Wayne County	13,774
Pickett County (TN)	181
Scott County (TN)	23

Average Kilowatt-hour Use

(Residential per month)

2005	1,119
2015	1,081

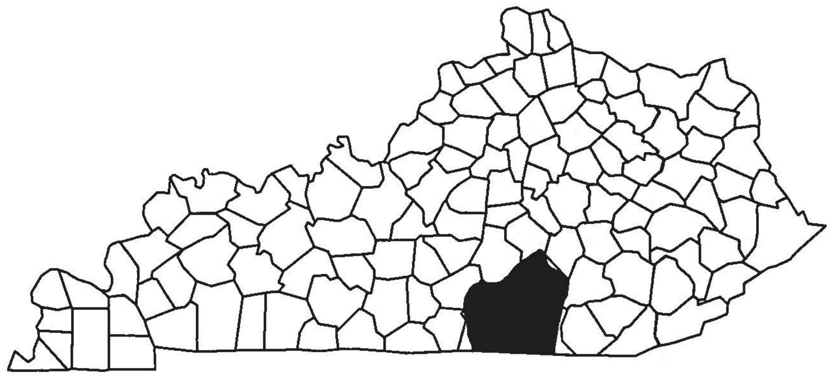
Miles of Line

2005	6,475
2015	6,813

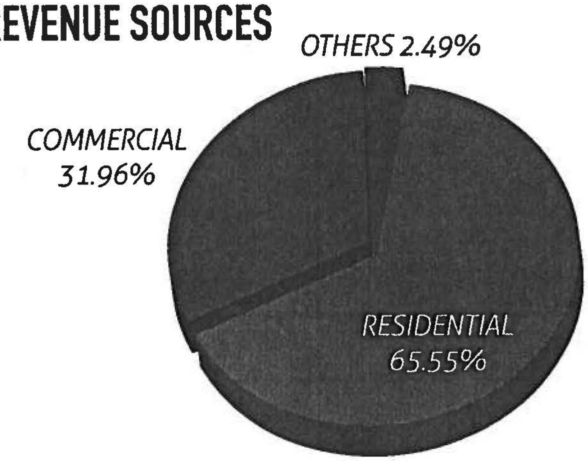
Consumers Per Mile

2005	9.53
2015	9.82

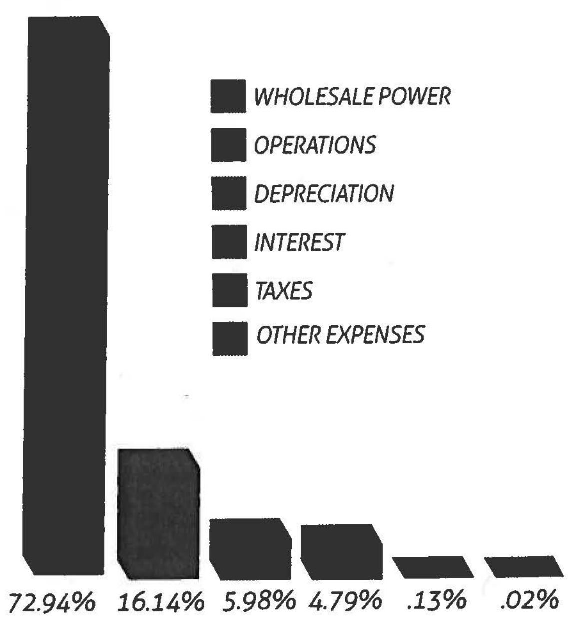
SERVICE AREA



REVENUE SOURCES



MAJOR COSTS



STATEMENT OF OPERATIONS

For the Year Ending December 31, 2015

Operating Revenue	$128,691,016
Cost of Electric Service	
Cost of Electricity Purchased from East Kentucky Power	$93,010,261
Cost of Operating the Distribution System	$20,576,427
Depreciation Expense	$7,624,270
Interest Expense on Loans	$6,114,162
Public Service Commission Assessment	$165,657
Other Expenses	$32,123
Total Cost of Electric Service	$127,522,900
Gross Margins from Electric Service	$1,168,116
Non Operating Income	$8,779,230
Net Margins (Deficit)	$9,947,346

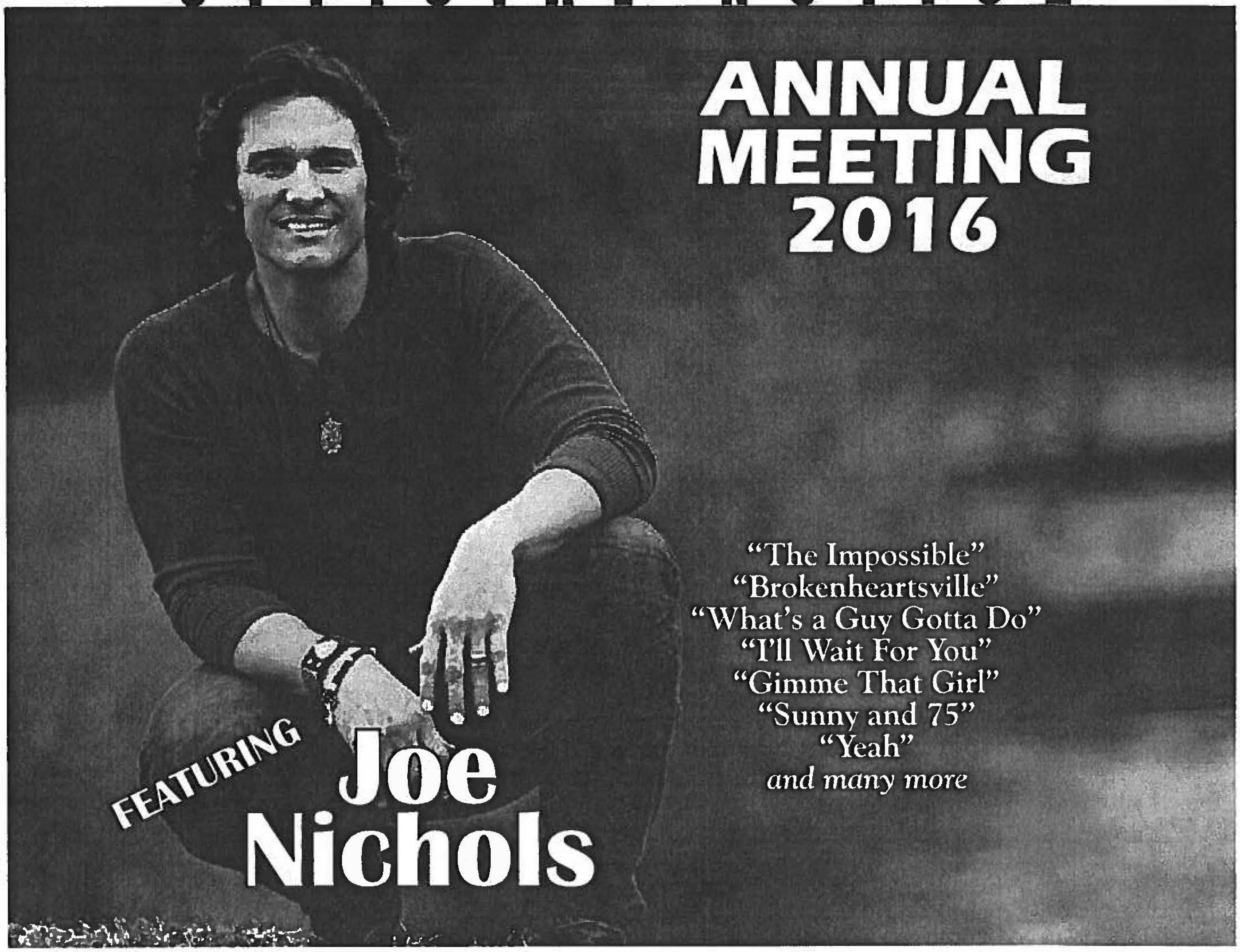
BALANCE SHEET

For the Year Ending December 31, 2015

ASSETS	
Total Poles, Wires, and Other Equipment	$238,973,368
Less Accumulated Depreciation	$63,070,154
Net Value of Poles, Wires, and Other Equipment	$175,903,214
Investments in Associated Organizations	$64,755,284
Cash and Equivalents	$15,542,262
Accounts and Notes Receivable	$6,811,190
Material in Inventory	$1,385,640
Prepaid Expenses	$639,354
Other Assets	$5,701,212
Total Assets	$270,738,156
LIABILITIES AND MEMBERS' EQUITY	
Consumer Deposits	$1,561,236
Members and Other Equities	$104,217,720
Long-Term Notes Payable	$137,561,460
Notes and Accounts Payable Owed to Vendors	$14,982,079
Other Liabilities	$12,415,661
Total Liabilities and Members' Equity	$270,738,156

South Kentucky RECC
A Touchstone Energy Cooperative

OFFICIAL NOTICE



Registration - 4 p.m. EDT
Business Meeting - 7 p.m.

Thursday, June 9

SKRECC FARM

3/4 mile west of Fishing Creek Bridge on KY 80 near Nancy, KY, in Pulaski County

- Free bucket and light bulbs for all registering members
- Prizes for all ages
- Information about South Ky. RECC and our many services
- Rides and fun for the kids

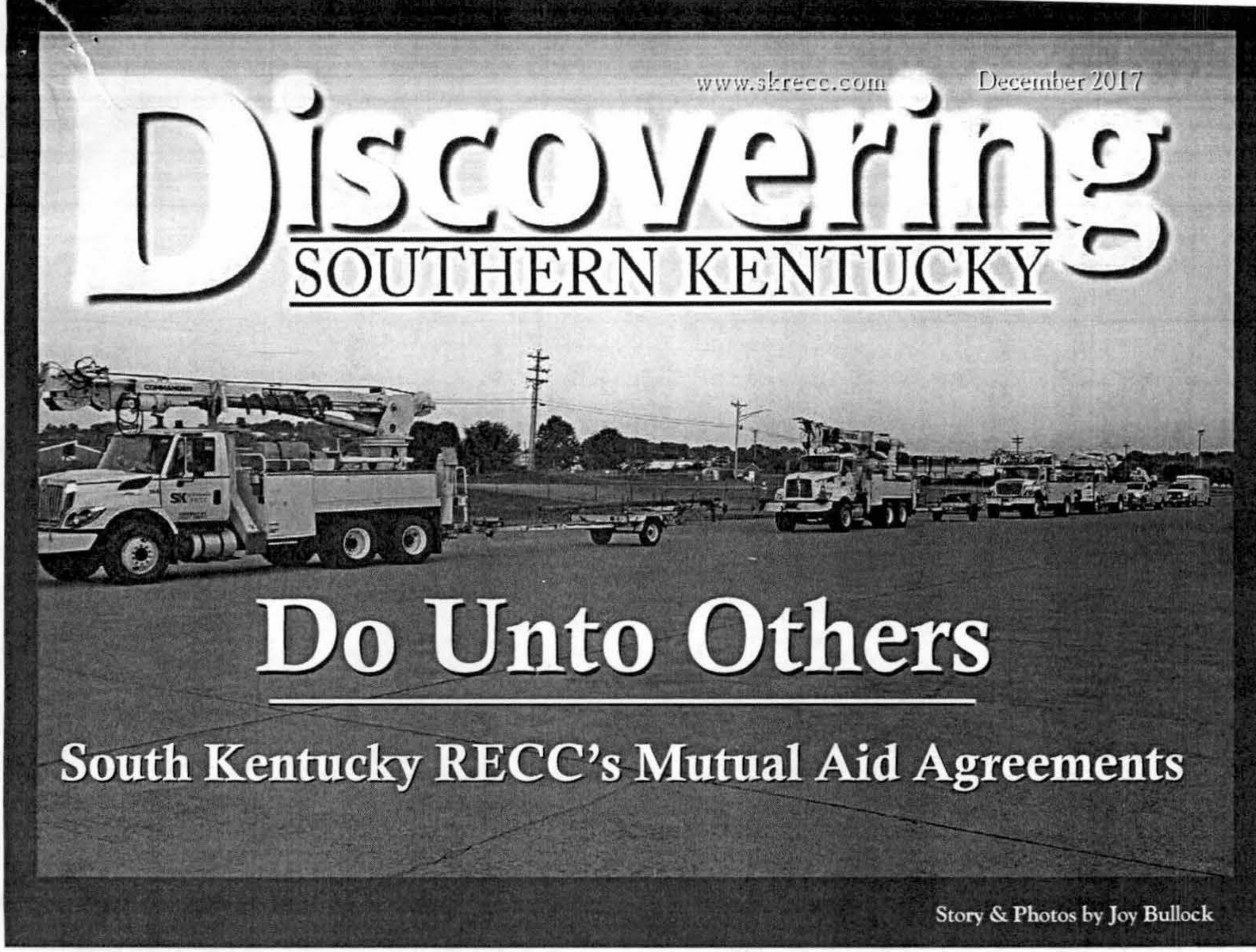
Call (606) 451-4137 for more information.

South Kentucky RECC
A Touchstone Energy Cooperative

All offices of SKRECC will be CLOSED Annual Meeting day!

www.skrecc.com December 2017

Discovering SOUTHERN KENTUCKY



Do Unto Others

South Kentucky RECC's Mutual Aid Agreements

Story & Photos by Joy Bullock

> *"Be the beacon of light in someone's darkness"*
>
> —Randi G Fine, inspirational author, speaker, counselor, and radio show host

Above, South Kentucky RECC crews and equipment lined up to go to Coastal Electric Cooperative in September after that co-op suffered major damage from Hurricane Irma.

While that quote from Randi G. Fine pertains to the human condition, South Kentucky RECC strives to be the literal "beacon of light in someone's darkness" through its mutual aid contracts with other Kentucky electric cooperatives and through Touchstone Energy.

A mutual aid contract is an agreement that SKRECC has with other co-ops that says we will provide emergency assistance in the form of personnel, equipment, materials, etc. when they experience major outages. In turn, these co-ops will do the same if South Kentucky RECC experiences a major outage situation.

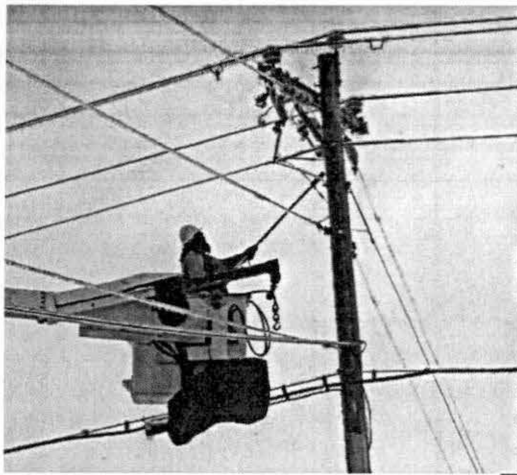
The most recent event for which South Kentucky RECC provided aid was in September when the co-op sent three, four-man crews to Coastal Electric Cooperative, in Midway, Georgia, to aid with restoration following Hurricane Irma.

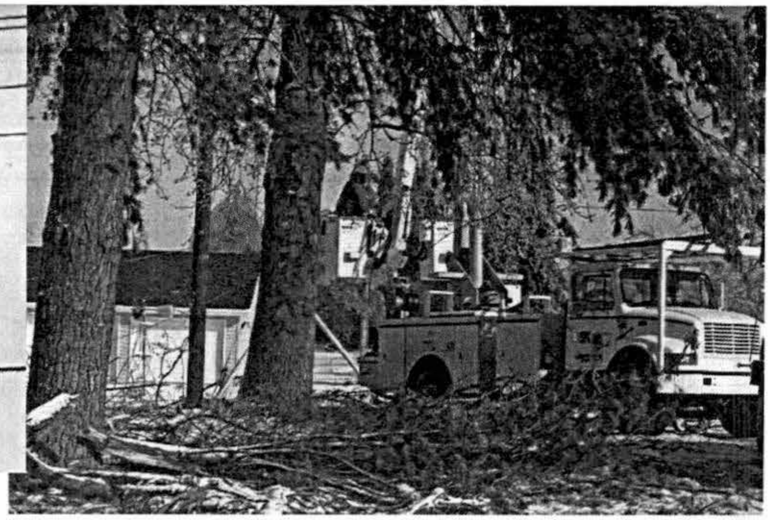
Coastal Electric CEO Whit Hollowell says the assistance from mutual aid contracts is very welcome.

"Cooperation among cooperatives is alive and well. People all across Coastal Georgia benefitted from hard work and dedication as they partnered with us to restore our system."

The most notable example for mutual aid contracts and their benefits was the extreme ice storm that Kentucky endured in 2009. At that time, with the majority of the state without electric, more than 1,100 electric co-op employees from Alabama, Florida, Georgia, Illinois, Indiana, Michigan, Minnesota, Mississippi, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, and Virginia assisted with restoration efforts. An equal number of contract

OWEN ELECTRIC-SHELBY ENERGY
EXHIBIT 2





In 2009, when a major ice storm crippled most of Kentucky without affecting SKRECC, crews went to Inter-County Energy, Danville, to assist. In both photos, crews are working in the Perryville area to restore power.

labor was also employed and in force assisting. In addition, South Kentucky RECC, one of only a couple of co-ops not greatly affected by the storm, sent crews to assist neighboring co-ops, which had most of their systems without power.

South Kentucky RECC Interim CEO Dennis Holt says the co-op was fortunate that it wasn't affected greatly, but he adds that we never know when it might strike our system.

"One of the greatest benefits of being a Touchstone Energy Cooperative is the aid that we can get from our sister cooperatives when the need arises. We have been very fortunate for a number of years that we haven't had a devastating, weather-related outage on our system. That could change this winter.

"While a number of the co-ops that we have provided assistance for over the past couple of years have had outages due to hurricanes, our biggest threat in Kentucky is ice. Kentucky is located in the portion of the United States that is usually on the fringe of winter storms, which means it is more susceptible to ice, as shown in the storm of 2009. When you get a great deal of ice laying heavily on power lines or tree limbs, that can spell disaster to a co-op."

Holt adds that South Kentucky RECC, as a cooperative, adheres to the seven cooperative principles; one of which is 'Cooperation Among Cooperatives.'

"I don't know of any better way to show our cooperation than by assisting a co-op that is trying to restore power following a major outage," says Holt. "Another cooperative principle is 'Concern for Community.' When it comes right down to it, we are all community, and we need to help our neighbors."

South Kentucky RECC members can now receive discounts with three area air ambulance services: Air Evac, Air Methods, and PHI.

Applications for all three air ambulance services are available at all South Kentucky RECC offices.

For more information and pricing, contact:

Air Evac Lifeteam (part of the AirMedCare Network):
Dorothy Smith, Membership Sales Manager
(606) 306-7705 or by email:
dorothy.smith@airmedcarenetwork.com
Visit their website at: www.AMCNREP.com

Air Methods Advantage:
(855) 877-2518 or by email:
airmethodsadvantage@airmethods.com
Visit their website at: www.airmethodsadvantage.com

PHI Air Medical:
Chandra Younger, National Membership Representative
(859) 608-0029 or by email: cyounger@phihelico.com
Visit their website at: www.phiairmedical.com

• *South Kentucky RECC cannot guarantee that the air ambulance you have membership with will be the one used in the event of an emergency.*

Weathering Winter Storms Safely

Winter storms can bring bitterly cold temperatures, high winds, and even ice and snow. Such weather can cause hazardous road conditions, downed power lines, and extended power outages. South Kentucky RECC shares tips on preparing for and safely weathering winter storms.

Before a storm ever begins, tune into your local weather service for the weather forecast. It is important to know the differences among various watches and warnings.

- Winter Storm Watches signify that stormy conditions, including heavy snow, freezing rain or sleet, are a possibility within the next few days.
- Winter Storm Warnings call for stormy conditions to begin within the next 24 hours.
- Blizzard Warnings advise those in the affected areas to seek refuge immediately due to high levels of snow, strong winds and resulting near-zero visibility to those traveling on the road.

"Heavy snow and accumulating ice can easily bring tree limbs down onto power lines, cutting off power to homes and businesses," says Dennis Holt, South Kentucky RECC Interim CEO.

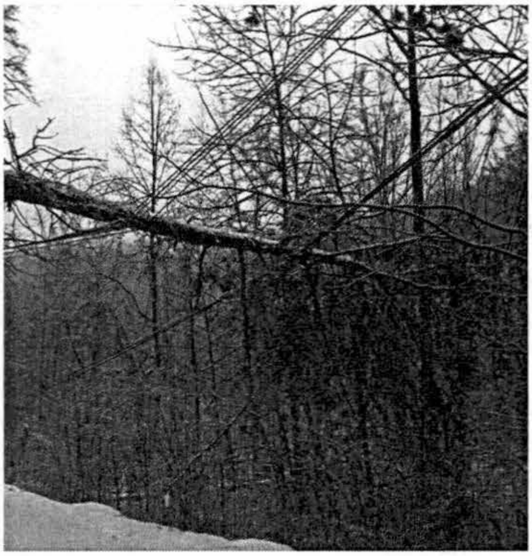
If power lines go down because of a winter storm and the electricity goes out, first notify the co-op of the outage.

Have an emergency kit prepared for your home before a storm strikes to help you and your family weather the storm and the outage safely and comfortably. Some of the items this kit should include are bottled water, nonperishable food, flashlights, a weather radio and extra batteries.

If you are using an alternative heating source during a power outage, be sure to know how to use it safely and that you have all supplies for it gathered. To help you and your family stay warm during an outage, dress warmly, cover windows at night, close off unneeded rooms, and place draft blocks at the bottom of doors.

When the power is restored, there will be a power surge. To protect your circuits and appliances, switch off lights and unplug appliances. Leave one light switched on as a quick reminder that the power is restored.

Due to the potential for a winter storm to bring down power lines, individuals should only venture outside if absolutely necessary. Downed power lines could be submerged in snow and



ice, making them difficult to see. Therefore, stay indoors if possible. If you must go outside, use caution and treat all downed and hanging lines as if they are energized. Stay away, warn others to stay away, and immediately contact South Kentucky RECC or 911.

"A power line does not need to be sparking or arcing to be energized," Holt says. "It's best to assume all low and downed lines are energized and dangerous. Lines that appear to be dead can become energized as crews work to restore power, or sometimes from improper use of emergency generators."

If travel is necessary, be especially cautious driving, and keep an emergency kit in your vehicle. Kit supplies should include a windshield scraper, a first aid kit, a cell phone charging adaptor, booster cables, a blanket and a flashlight with extra batteries.

Never drive over a downed line because that could pull down the pole and other equipment, causing additional hazards. If you see a downed line, do not get out of your car. The safest place is inside the vehicle. Contact SKRECC immediately.

Many SKRECC members are in households that have someone who needs some type of life support system, such as oxygen. Should you be part of such a household, it is important that you have an emergency plan in place in the event of a major outage. While South Kentucky RECC does all it can, including utilizing contract labor and support labor from sister cooperatives, there may be instances that power cannot be restored for several hours, or even days. Members requiring life support need to be prepared to go somewhere that has electricity to sustain equipment.

Outages are an unwanted part of winter weather; however, be assured that South Kentucky RECC does all it can to provide the best possible service to its members and is prepared for all types of weather and the situations that come with it.

Keep your local South Kentucky RECC office number or (800) 264-5112 in your phone contacts or nearby to report an outage.

For more information on outages, energy-efficiency programs, and to keep up with the changes and happenings of the co-op, follow South Kentucky RECC on

facebook

twitter

Visit www.skrecc.com to pay your bill online, to visit our outage center, or for more information about the Co-op Connections Program or our energy-efficiency programs.

The address for the new Somerset headquarters is:
200 Electric Avenue
Somerset, KY 42501

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Address all correspondence to: DISCOVERING SOUTHERN KENTUCKY, P.O. Box 910, Somerset, Kentucky 42502.

South Kentucky RECC
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People Fund Drive Winner

Through the month of September, South Kentucky RECC placed special emphasis on the co-op's People Fund.

The People Fund was started in 2004. It allows SKRECC members to "round up" their monthly bills to the nearest dollar, with that change being used to create a system of grants available to organizations in our local communities whose financial needs are not being met by other agencies or resources. To date, more than $225,000 has been distributed in nearly 400 grants to organizations/groups, including local schools, food banks, and many other organizations. The most that rounding up can cost any member in a year is $11.88, or $.99 each month.

As part of the emphasis, any South Kentucky RECC member that registered their account for People Fund was included in a drawing for $250, which was anonymously donated and did not come from the co-op or People Fund, and two University of Kentucky versus University of Tennessee football tickets for October 28.

For more information on the People Fund, contact your local office or visit www.skrecc.com.

South Kentucky RECC member Gordon Hicks, center, Wayne County, accepts his prize from left, SKRECC System Inspector and Chairman of the People Fund Don Bethel and, right, Interim SKRECC CEO Dennis Holt.

The offices of South Kentucky RECC will be CLOSED on Monday, December 25, and Tuesday, December 26, for Christmas. Offices will also be CLOSED on Monday, January 1, for New Year's.

If you have an emergency, please call your local office number or (800) 264-5112 for 24-hour dispatch. You can pay your bill by phone, online at www.skrecc.com, or download our mobile app SKRECC.

From our family to yours

Merry Christmas &

Happy New Year!

*Big Sandy R.E.C.C.
Big Sandy R.E.C.C.
504 11th Street
Paintsville, KY 41240

*David T Royse
Attorney At Law
Ransdell Roach & Royse PLLC
176 Pasadena Drive, Building I
Lexington, KENTUCKY 40503

*Honorable James M Miller
Attorney at Law
Sullivan, Mountjoy, Stainback & Miller, PSC
100 St. Ann Street
P.O. Box 727
Owensboro, KENTUCKY 42302-0727

*William H May, III
Hurt, Deckard & May
The Equus Building
127 West Main Street
Lexington, KENTUCKY 40507

*Dan H McCrary
Balch & Bingham, LLP
1710 Sixth Ave. North
Birmingham, ALABAMA 35203

*Jake A Thompson
Crawford & Baxter, P.S.C. Attorneys at Law
523 Highland Avenue
P. O. Box 353
Carrollton, KENTUCKY 41008

*Bradley Cherry
Grayson R.E.C.C.
109 Bagby Park
Grayson, KY 41143

*Farmers R.E.C.C.
Farmers R.E.C.C.
504 South Broadway
P. O. Box 1298
Glasgow, KY 42141-1298

*Jesse S Unkenholz
Balch & Bingham, LLP
1710 Sixth Ave. North
Birmingham, ALABAMA 35203

*Brandon Music
W. Jeffrey Scott, PSC
PO Box 608
Grayson, KENTUCKY 41143

*Honorable James M Crawford
Crawford & Baxter, P.S.C. Attorneys at Law
523 Highland Avenue
P. O. Box 353
Carrollton, KENTUCKY 41008

*Kent Chandler
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Carol Hall Fraley
President & CEO
Grayson R.E.C.C.
109 Bagby Park
Grayson, KY 41143

*John Douglas Hubbard
Fulton, Hubbard & Hubbard
117 E. Stephen Foster Avenue
P.O. Box 88
Bardstown, KENTUCKY 40004

*Nolin R.E.C.C.
Nolin R.E.C.C.
411 Ring Road
Elizabethtown, KY 42701-6767

*Clayton O Oswald
Taylor, Keller & Oswald, PLLC
1306 West Fifth Street, Suite 100
Post Office Box 3440
London, KENTUCKY 40743-3440

*Jason Floyd
Fulton, Hubbard & Hubbard
117 E. Stephen Foster Avenue
P.O. Box 88
Bardstown, KENTUCKY 40004

*South Kentucky R.E.C.C.
925-929 N Main Street
P. O. Box 910
Somerset, KY 42502-0910

*Honorable David A Smart
Attorney at Law
East Kentucky Power Cooperative, Inc.
P. O. Box 707
Winchester, KY 40392-0707

*Fleming-Mason Energy Cooperative, In
Fleming-Mason Energy Cooperative, Inc.
1449 Elizaville Road
P. O. Box 328
Flemingsburg, KY 41041

*Honorable Michael L Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Steven M Madison
Balch & Bingham, LLP
1710 Sixth Ave. North
Birmingham, ALABAMA 35203

*Inter-County Energy Cooperative Corp
Inter-County Energy Cooperative Corporation
1009 Hustonville Road
P. O. Box 87
Danville, KY 40423-0087

*Scott B Grover
Balch & Bingham, LLP
1710 Sixth Ave. North
Birmingham, ALABAMA 35203

*Honorable Matthew R Malone
Attorney at Law
Hurt, Deckard & May
The Equus Building
127 West Main Street
Lexington, KENTUCKY 40507

*Jackson Energy Cooperative Corporati
Jackson Energy Cooperative Corporation
115 Jackson Energy Lane
McKee, KY 40447

*Ted Hampton
General Manager
Cumberland Valley Electric, Inc.
Highway 25E
P. O. Box 440
Gray, KY 40734

*R. Michael Sullivan
Sullivan, Mountjoy, Stainback & Miller, PSC
100 St. Ann Street
P.O. Box 727
Owensboro, KENTUCKY 42302-0727

*Licking Valley R.E.C.C.
Licking Valley R.E.C.C.
P. O. Box 605
271 Main Street
West Liberty, KY 41472

*Honorable W. Jeffrey Scott
Attorney At Law
P.O. Box 608
311 West Main Street
Grayson, KENTUCKY 41143

*Honorable W. Patrick Hauser
Attorney At Law
P. O. Box 1900
Barbourville, KENTUCKY 40906

*Honorable Ruth H Baxter
Attorney at Law
Crawford & Baxter, P.S.C. Attorneys at Law
523 Highland Avenue
P. O. Box 353
Carrollton, KENTUCKY 41008

*Blue Grass Energy Cooperative Corp.
Blue Grass Energy Cooperative Corp.
1201 Lexington Road
P. O. Box 990
Nicholasville, KY 40340-0990

*Rebecca W Goodman
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Clark Energy Cooperative, Inc.
Clark Energy Cooperative, Inc.
2640 Ironworks Road
P. O. Box 748
Winchester, KY 40392-0748

*Roger R Cowden
Senior Corporate Counsel
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, KY 40392-0707

*East Kentucky Power Cooperative, Inc
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, KY 40392-0707

*Robert Spragens, Jr.
Spragens & Higdon, P.S.C.
15 Court Square
P.O. Box 681
Lebanon, KENTUCKY 40033