BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR APPROVAL OF A GENERAL CHANGE IN	)	DOCKET NO. 16-052-U
RATES, CHARGES AND TARIFFS	)	

Direct Testimony

of

Gwin Cash

on behalf of

Oklahoma Gas and Electric Company

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

A. My name is Gwin Cash. My business address is 321 North Harvey, Oklahoma City, Oklahoma 73102.

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

A. I am employed by Oklahoma Gas and Electric ("OG&E" or "Company") as the Rate Administration Manager.

Q. **Please summarize your educational background and professional qualifications.**

A. I received a Bachelor of Science in Applied Mathematics with a Specialization in Computing from the University of California, Los Angeles in 1999. I have worked in OG&E's regulatory department since January 2015 as the Rate Administration Manager. My responsibilities include maintaining OG&E's tariffs on file with the regulatory commissions and ensuring consistent application of these tariffs in the manner in which they are intended. Additional duties include, but are not limited to, computing rider factors and monthly retail revenue reporting. Prior to joining OG&E's regulatory department, I worked as a Senior Business Analyst for one year in OG&E's Sales and Customer Support department and as a Workforce Analyst for seven years in OG&E's Customer Service department.

Q. **Have you previously testified in front of the Arkansas Public Service Commission ("APSC" or the "Commission")?**

A. No, I have not. I have, however, testified in front of the Oklahoma Corporation Commission in OG&E's general rate case filing Cause No. PUD 201500273. In that Cause I testified to the Company's revenue *pro formas* and to changes to Terms and Conditions.

Q. **What is the purpose of your direct testimony?**

A. I sponsor the *pro forma* revenue and sales adjustments to Schedule C 2 (1 through 11) and Schedule E 11.1 and 11.2. In addition, I will explain revisions to OG&E's Terms and Conditions ("T&C"), request that the Company be released from certain reporting obligations, request approval of two new plan offerings, detail changes to the Company's current rider tariffs, and discuss the mechanics of two new rider tariffs.

PRO FORMA **REVENUE ADJUSTMENTS**

Q. **Please list the pro forma adjustments to revenue and sales in Section C that you are sponsoring.**

A. There are ten pro forma adjustments affecting the Arkansas jurisdiction that I am sponsoring and they are summarized below in Table 1 – Adjustment Summary.

Table 1 – Adjustment Summary

	Adjustment	**Amount**
1	Over/Under Recovery Amounts	$9,948,025
2	Energy Cost Recovery Rider (ECR) Removal	($76,656,281)
3	Non-ECR Rider Removal	($16,308,467)
4	Day Ahead Pricing	($1,113,123)
5	Large Customer	$724,137
6	Test Year End Customer Growth	$240,774
7	Weather Normalization	($473,006)
8	Renewable Energy Certificates	($442,416)
9	Pro Forma Year End Customer Growth	$60,153
10	Rider Revenue now Rolling into Base Rates	$6,682,042
	TOTAL	**($77,338,162)**

Q. **Why is the Company proposing these adjustments?**

A. These adjustments are necessary to accurately reflect normalized and annualized base rate revenues and kilowatt hour sales for OG&E's Arkansas customer groups. First, removing non base rate revenue from the test-year financial data provides the basis for rate design by removing revenues that are not at issue in this Cause and that occurred during the test year, but are not related to revenues from the billed energy (kWh) used for establishing cost-based rates. Such non-base rate revenues include ECR rider and non-ECR rider revenues. Second, revenues are adjusted again by adding rider revenues that the Company is proposing to now include in base rates. An example of this revenue adjustment is expenses associated with the SmartGrid rider. Third, the process of normalizing test-year revenues involves making adjustments for events that create abnormal revenues. An example of this is adjusting revenues to reflect normal weather. Fourth, the annualization process also adds certain revenues that are related to billed energy (kWh), but should be annualized for an entire year. Examples of this are the year-end customer adjustments. By making these adjustments to test-year revenues, the Company is able to develop normalized revenues and kWh sales in order to design fair and reasonable rates to recover the allocated cost of service.

Adjustment #1

Q. **Please describe Adjustment #1 related to Over/Under Recovery Amounts.**

A. This adjustment removes an over-recovery accounting adjustment of fuel and rider revenue collections, which has the effect of increasing revenue by $9,948,025.

Q. **Please explain why it is necessary to remove the over/under recovery of fuel expense revenue and rider collections.**

A. The over/under fuel and rider revenue recovery book balance includes accounting entries that track historical billed fuel cost adjustment revenues based on projections versus actual fuel expense. In addition, the rider collections over/under recoveries reflect accounting entries that track historical rider revenue balances versus actual annual revenue requirements. Since rider adjustments to the test year should be made based on billed revenues, these entries must also be removed. In the test year, there was a net over recovery of fuel and rider revenue. The accounting entry credit for this over recovery is adjusted back up to make the normalized revenues seem like this over-recovery did not occur.

Adjustment #2 and #3

Q. **Please explain Adjustment #2 – ECR Rider Removal, and Adjustment #3 – Non-ECR Rider Removal.**

A. These two adjustments modify book revenues and credits for riders that do not have expenses or plant that will be included in base rates, that will have plant included in base rates but at different revenue levels than in the test year, and that are associated with programs that modify customer usage. Adjustment #2 removes all ECR rider revenue reducing test year revenues by $76,656,281. Adjustment #3 removes all non-ECR rider revenues reducing test year revenues by $16,308,467 and reducing sales by 2,783,193 kWh. The total effect of these two adjustments is a reduction to test year revenues by $92,964,748 and a reduction to sales by 2,783,193 kWh.

Q. **Please explain why it is necessary to remove the revenue for riders that do not have expenses or plant included in base rates.**

A. Since the associated investment and expenses have not been included in the COSS, the rider revenues must be removed. The riders to which this portion of the adjustments pertain are the Energy Cost Recovery Rider (non-Crossroads revenue requirement), Energy Efficiency Cost Recovery Rider (program costs, incentives, and carrying costs), and the Transmission Cost Recovery Rider.

Q. **Please explain why it is necessary to adjust revenues for riders that have expenses or plant included in base rates.**

A. *Pro forma* base rate revenues should align with investment and expenses included in the COSS and proposed revenues in Schedule M to ensure there is a match between costs and revenues. The riders for which this adjustment is necessary are the Energy Cost Recovery (Crossroads ECR revenues), Energy Efficiency Cost Recovery (Lost Contribution to Fixed Costs ("LCFC")), and the SmartGrid rider.

Q. **Please explain why it is necessary to adjust revenues and sales for riders associated with programs that modify customer usage.**

A. This adjustment decreases energy, demand, and revenue to account for lost sales resulting from energy efficiency measures implemented through the EECR Rider through

December 2015 and projected through June 2017. Since energy saved by customers implementing energy efficiency measures is cumulative and changes every month when new measures are implemented, it is necessary to adjust each month of the test year to June 2017 levels. Decreasing test year sales to the savings recognized at June 2017 allows revenue, energy, and demand to be representative of the expected levels of sales going forward.

Adjustment #4

Q. **What is the adjustment made to the Day-Ahead Pricing?**

A. Adjustment #4 removes all incremental and decremental revenue and kWh associated with the Day-Ahead Pricing ("DAP") tariff participants from the test year. The remaining revenue is revenue that is only associated with the Customer Base Line ("CBL") portion of their bill. This adjustment produces a revenue decrease of $1,113,123 and a sales decrease of 29,094,416 kWh to the Arkansas jurisdiction.

Q. **Why is this adjustment appropriate?**

A. The costs associated with incremental and decremental kWh are based upon current system marginal costs and are therefore unrelated to embedded costs. In contrast, the CBL portion of the DAP billings is based upon standard rates and should be included in the cost of service study ("COSS") and base rate design.

Adjustment #5

Q. **Please explain Adjustment #5 Large Customer.**

A. Adjustment #5 adjusts revenues and energy sales to reflect customer migration within the test year. To accommodate this customer migration, energy sales and the associated revenues are removed from the rate class from which customers leave and those same energy sales and associated revenues, at the new rates, are added to the rate class to which customers are joining. This adjustment for migration primarily deals with migration between the Power and Light and General Service rate classes. Adjustment #5 also adds and removes revenues associated with large customers known to be joining or leaving the OG&E system. The purpose of this adjustment is to have the full test year sales and revenues reflect the expected rate revenue for all customers at the end of the test year. This adjustment resulted in a net increase to revenues of $724,137 and an increase to sales of 20,017,894 kWh.

Adjustment #6

Q. **What is the purpose of Adjustment #6 – Year End Customers?**

A. This adjustment modifies revenue, kWh, kW, and customer counts to account for customers that have either left the system or were new to the system. The adjustment results in a net revenue increase of $240,774 and a net sales increase of 7,392,700 kWh to the Arkansas jurisdiction.

Q. **Please explain why this adjustment is necessary.**

A. Customer counts and consumption volumes vary month-to-month during the test year. Adjusting test year books to reflect customer counts and consumption volumes at test year-end captures any growth or decline in customer counts and consumption volumes for each rate class.

Q. **What method was used for this adjustment?**

A. For all customer classes at service level five, which are the large volume rate classes, OG&E employed an average customer adjustment technique. For each month of the test year, the customer counts were adjusted to the June 2016 test year-end level. The sales adjustments were obtained using the average billing units per customer from the test year monthly data, their associated prices, and the incremental monthly customer counts

Adjustment #7

Q. **What is a weather normalization adjustment?**

A. A weather normalization adjustment changes revenue, energy, and demand to reflect normal weather in the test year. In this case this adjustment results in a revenue decrease of $473,006 and a decrease of 8,364,561 kWh to the Arkansas jurisdiction.

Q. Why are such adjustments necessary?

A. The effects of temperature on heating and cooling loads in relation to electricity usage can cause significant annual revenue swings and also cause test year revenue to differ from the expected revenue outcome for a normal year.

<u>Adjustment #8</u>

Q. Please explain the adjustment to remove Renewable Energy Certificate ("REC") revenue.

A. This adjustment removes revenues booked as a result of REC sales from various wind resources to the wholesale market during the test year. The proceeds from these sales are booked into miscellaneous revenue each month and are then credited though rider mechanisms or retained by shareholders in accordance with the order in each respective wind resource case. For the test year, this results in a revenue decrease of $442,416.

<u>Adjustment #9</u>

Q. What is the purpose of Adjustment #9 – Pro Forma Year End Customer Growth?

A. Like Adjustment #6 this adjustment modifies revenue, kWh, kW, and customer counts to account for customers joining and leaving the system. The difference is that this adjustment reaches out to June of 2017, the end of twelve month *pro forma* period. The adjustment results in a net revenue increase of $60,153 and a net sales increase of 2,783,193 kWh to the Arkansas jurisdiction.

<u>Adjustment #10</u>

Q. What is the purpose of Adjustment #10 – Riders Rolling into Base Rates?

A. Adjustment #10 adds to the test year revenues the revenue requirements associated with riders that have expenses rolling into base rates. This adjustment ensures that *pro forma* base rate revenues will align with investment and expenses included in the COSS and proposed revenues in Schedule M and that there is a match between costs and revenues. This adjustment adds $6,682,042 to the Arkansas jurisdiction.

CHANGES TO TERMS AND CONDITIONS OF SERVICE

Q. **What changes is the Company proposing to the Terms and Conditions section of the tariff?**

A. There are nine modifications to the Terms and Conditions of Service ("T&C") that I am sponsoring. They are:

- Remove Meter Testing Plan suspension language,
- Delete Section 105 Tariff Revision Symbols
- Delete Section 304 Voltage Verification
- Update Section 311 Standardizing Laboratory
- Update Section 402 Right of Way
- Update Returned Check Fee
- Update Meter Test Fee,
- Eliminate the Collection Fee, and
- Update Reconnection Fee.

Q. **Why is the Company proposing to remove Meter Testing Plan suspension language?**

A. As a result of an order issued by the Commission in Docket No. 10-109-U, the Company added language to Sections 104 and 309 of the T&C suspending the Company's meter testing requirement through the end of the Company's SmartGrid deployment in December 2012. With the deployment complete, this language is no longer necessary.

Q. **Why is the Company proposing to delete Section 105 Tariff Revision Symbols?**

A. Section 105 of the T&C provides tariff revision symbols that APSC used to require for tariff revisions. The APSC no longer requires the use of these symbols and because of this OG&E is proposing to delete this section.

Q. **Why is the Company proposing to delete Section 304 Voltage Verification?**

A. Section 304 of the T&C explains that it is the Company's policy to have continual voltage recording equipment on all of its distribution substations for the purpose of evaluating customer service. OG&E no longer uses this equipment. The functionality that this equipment provided is now being provided by the SmartGrid. OG&E is proposing to delete this section to reflect this new state.

Q. **What is the update to Section 311 Standardizing Laboratory?**

A. OG&E's Standardizing Laboratory has moved to a new location at 3220 S. High in Oklahoma City, OK and the Company needs to update Section 311 to reflect this move.

Q. **What is the update to Section 402 Right of Way?**

A. The language in this section is being refined to clarify whose responsibility it is to secure a right of way for the Company's service. It is the customer's responsibility to secure the necessary right of ways. The language in paragraph 4 of this section is updated to clarify this point.

Q. **What is the Company's update to the Returned Check Fee?**

A. The Company is proposing to change the amount it collects for returned checks from $15 to maximum amount allowed by Arkansas statute, Ark. Code Ann. § 4-60-103. Currently this section of the Arkansas code allows for a collection fee of $30 for a returned check. This update to the returned check collection fee of shall be reflected in section 509 of the Rate Schedule No. CRCA of the Company's T&C. This section will no longer state the amount of the returned check collection fee but will instead cite the Arkansas statute

Q. **What is the Company's update to the Meter Test Fee?**

A. The Company is proposing to increase the Meter Test Fee to $100.00 from $50.00. The Company is proposing to collect the full cost of a truck roll for a meter test. The full cost of a truck roll is $100.48 which aims to reduce a subsidy which is currently being paid by all other customers. This update is reflected in Section 510 of the T&C.

Q. **Why is the Company eliminating the Collection Fee?**

A. OG&E is seeking to terminate the customer premise visits requirement established in Order 8 of Docket No. 10-109-U. Order 8 adopted a Settlement Agreement between OG&E and the intervening parties. A stipulation of this Settlement Agreement was to revise the involuntary disconnection process to take into account the Company's new ability to perform remote disconnects. This revised policy requires OG&E to send an employee to the premise, if the customer has not been reached by telephone, to notify the customer of impending disconnection and to leave a notice if the customer is not home. With the full deployment of the SmartGrid and with the ability to remotely disconnect and reconnect service, OGE believes it unnecessary to have to send an employee to the premise to attempt to make an in-person contact with the customer. OG&E believes that the mailed shutoff notice and the attempts to reach the customer both by automated telephone call and by a human collections representative to be sufficient. The mailed shutoff notice itself, should be adequate because the mail is a free service for which no customer is required to pay. The shutoff notice is mailed 10 days prior to disconnection and that is adequate warning time of pending disconnection.

Q. **What data does OG&E provide, if any, to support its claim that the revised policy from Docket No. 10-109-U needs to be further revised?**

A. In the three years prior to the SmartGrid rollout (2009-2011) OG&E would leave about 3,300 notices to pay per year on average, the disconnect rate was 6.9%, and the average number of disconnects was 4,111. In the three years since the SmartGrid rollout (2013-2015), OG&E has visited the customer's premise about 15,000 times per year, the disconnect rate dipped to 6.3%, and the average number of disconnects has been 3,932. The revised policy from Docket No. 10-109-U has increased the number of in-person notices left for customers by more than a factor of 4. The small decrease in the disconnect rate is not significant enough to justify the increase in in-person notifications. During the test year, OG&E made 17,016 trips to premises to notify customers in person of a pending involuntary disconnection and received $255,240 in collection fee revenue for these trips. The expense associated with these trips was $120,776. OG&E believes customers are better off not being assessed these fees and avoiding these expenses and instead seeks to end the practice of leaving in-person notices and to no longer require a Collection Fee.

Q. **What is the Company's update to the Reconnect Fee?**

A. The Company is proposing two changes. The first is to assess a Reconnection fee to all service reconnections following involuntary disconnection instead of just reconnections that required a field visit. The second is to decrease the Reconnect Fee to $30.00 from $35.00.

Q. **Why is the Company requesting to collect a Reconnect Fee for all reconnections?**

A. The Company has evaluated all cost associated with the involuntary disconnection and reconnection process and found that the bulk of the cost is associated with expenses that have nothing to do with a field visit. These costs include expenses associated with the automated disconnect and reconnect systems (security certificate software, interface management software used for sending and receiving commands to and from the Smart meters, and the SmartGrid wide area network), the outbound dialer, outbound collection clerical labor, back office collection clerical labor, customer service labor, and postage for shutoff notices. For the test year, this expense totaled $149,758 or 89% of all reconnection cost. The remaining expense is associated with reconnects and disconnects that require a field visit. Because the bulk of all reconnect and disconnect expense is associated with non-field visit expense, the Company believes it fair to require all customers requesting a reconnection after an involuntary disconnect to pay the Reconnect fee.

Q. **Please explain the decrease of the Reconnection Fee from $35.00 to $30.00.**

A. During the test year, the total expense for all Reconnect orders totaled $168,092 and there were 5,660 reconnect orders worked. This results in an average cost of $29.70 per reconnect order. The Company is proposing to round this amount to $30. This update is reflected in Section 512 of the T&C.

Q. **Why should the Commission accept the Company's Reconnect fee proposal?**

A. In determining the expenses associated with reconnects and involuntary disconnects the Company has identified expenses that have previously been recovered through base rates that are incurred by only the small percentage of customers being involuntarily disconnected. These are the expenses associated with the outbound shutoff reminders, clerical and call center labor, and postage. Moving this cost to be recovered via the reconnection fee removes a subsidy provided by all other rate payers. Customers that currently are required to pay a Reconnect fee, because they required a field visit, are benefitting by having the fee reduced by 14%. Customers that currently do not pay a Reconnect fee, because they did not require a field visit, should pay a Reconnect fee because they are incurring costs associated with the reconnect and disconnect processes.

REPORTING RELEASE REQUESTS

Q. **Is the Company requesting that certain reports no longer be required?**

A. Yes. OG&E is requesting to be released from two reporting obligations: Centennial wind fuel savings reporting and SmartHours reporting requirements.

Q. **Please describe the Centennial wind fuel savings report.**

A. The Centennial wind fuel savings report presents the annual fuel savings provided by the Company owned Centennial wind farm that was placed in service in 2007. The report tracks the cost of the monthly generation of the wind facility, the resources displaced, and the resulting fuel savings. The report requirement was established by Order No. 9 of Docket No. 06-070-U. In this Docket, OG&E sought approval for recovery of the Centennial wind farm through base rates. In Order No. 9, the Commission approved a Settlement Agreement between the Company and intervening parties. This report was a provision of that settlement.

Q. **Please summarize the findings of the Centennial Wind fuel savings reports.**

A. OG&E has reported fuel savings for the calendar years of 2007 through 2015 and over these nine (9) years the Wind farm has provided a total savings of $10.5 million. The annual average savings has $1.16 million. (See Direct Exhibit GC-1)

Q. **Does OG&E own any other wind farms and are there any fuel savings reporting requirements for those wind farms?**

A. OG&E owns the OU Spirit wind farm that was approved for recovery in Docket No. 10-109-U and the Crossroads wind farm that was approved for recovery in Docket No. 12-067-U. There are no fuel savings reporting requirements for either wind farm.

Q. **Does OG&E have any wind energy purchase agreements ("WEPA") with any wind farms and are there any fuel savings reporting requirements for those wind WEPAs?**

A. Yes. The Keenan and Taloga wind farms that were approved for cost recovery in Docket No. 10-073-U. There are no fuel savings reporting requirements for either the Keenan or the Taloga WEPAs.

Q. **Please summarize the Company's request to be released from the Centennial report.**

A. The Company has demonstrated fuel savings year over year for the Centennial wind farm. In light of this fact and the fact that no other OG&E wind resource has this requirement, the Company requests to be released from this reporting requirement. The Company will be happy to make this data available upon request.

Q. **Please describe the SmartHours reporting requirement.**

A. The SmartHours reporting requirement was established by Order No. 8 of Docket No. 10-109-U in which OG&E sought approval for recovery of the Company's SmartGrid deployment through a SmartGrid rider. Order No. 8 approved a Settlement Agreement between the Company and intervening parties allowing for the SmartGrid recovery through the proposed rider. The SmartHours reporting requirement was a provision of this settlement.

Q. **Why is the Company requesting to be released from the SmartGrid reporting requirement?**

A. In this rate proceeding, OG&E is requesting that the expenses associated with the SmartGrid be included in base rates and is requesting to close the SmartGrid rider. With the closing of the SmartGrid rider OG&E believes the reporting requirement is no longer necessary and wishes to be relieved of this duty. The data included in the SmartGrid reporting requirement will still be available upon request.

NEW PLAN OFFERINGS

Q. **What are the new OG&E plan offerings about which you are testifying?**

A. I am requesting approval of a new light emitting diode ("LED") lighting tariff and a pre-payment billing option the Company calls PayGo.

Q. **What is LED Lighting?**

A. LED Lighting is a high efficiency, low maintenance, next generation of lighting technology. LED lighting is a white light which provides directional illumination more closely emulating a natural daylight environment. LED lighting is not only visually pleasing, but also provides a more efficient illumination over existing high pressure sodium ("HPS") lighting. Just as mercury vapor outdoor lighting replaced incandescent and HPS replaced mercury vapor, LED lighting is the technology that is supplanting HPS.

Q. **What are the benefits of LED lighting?**

A. LED lighting differs from incandescent and compact fluorescent lighting in several ways. LED lighting is more efficient, durable and longer lasting. Unlike Mercury Vapor, Metal Halide and High Pressure Sodium bulbs which require extended time for their gases to heat up so they can perform at their optimal level, LED lights light up immediately. In addition, LED lights stay cool to the touch even after extended use. Finally, they last up to 80,000 hours before reaching their L70 performance level (L70 equates to the LED light output dropping by 30%, or performance at 70% of nominal production standards). Prices for LEDs have fallen significantly in the last 10 years. A 60 watt LED light originally cost about $100, and was not readily available in the market. That same light may now be readily purchased in any hardware store for about $8.

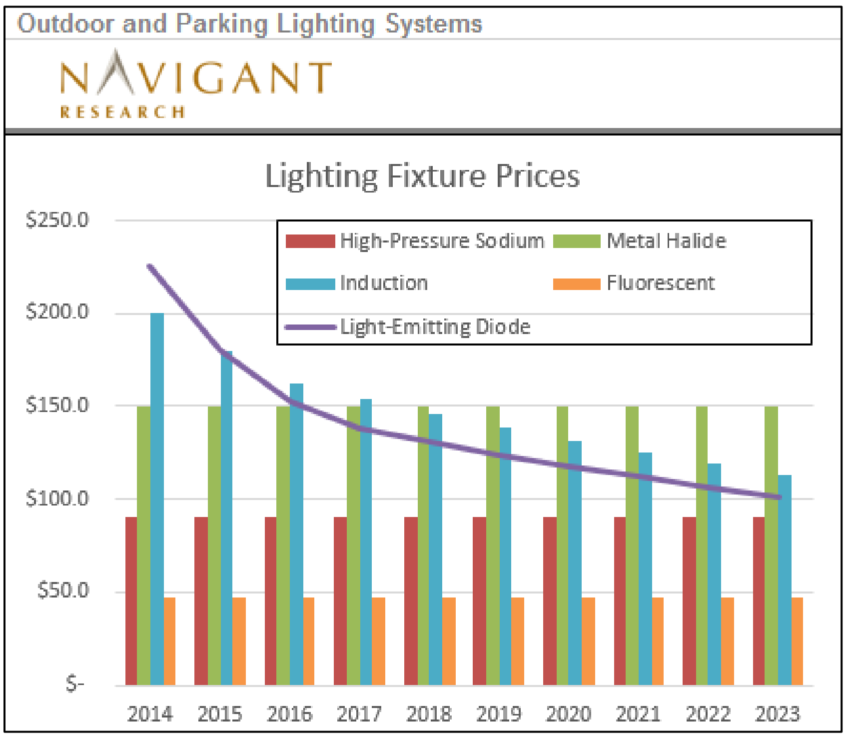
Q. **Why is OG&E requesting a new LED Lighting tariff?**

A. There are two primary drivers to OG&E's request: cost and availability. OG&E has observed decreases in fixture cost making LED lighting price competitive compared to existing fixture options. The second driver is availability. LED lighting is becoming more readily available from manufacturers (i.e. limited product lines), and OG&E lighting fixture suppliers have announced discontinuation of their HPS product lines.

Q. Why is the change to LED lighting being made at this time?

A. LED lighting prices have dropped over the last several years. This trend is expected to continue in the future. OG&E contracted with Navigant Research ("Navigant") to estimate forward looking expected fixture prices and availability through the year 2023. As seen in Chart 1, Navigant's research indicates LED fixture prices are expected to fall an average of 8.5% annually while HPS, metal halide ("MH") and fluorescent fixtures will remain constant.

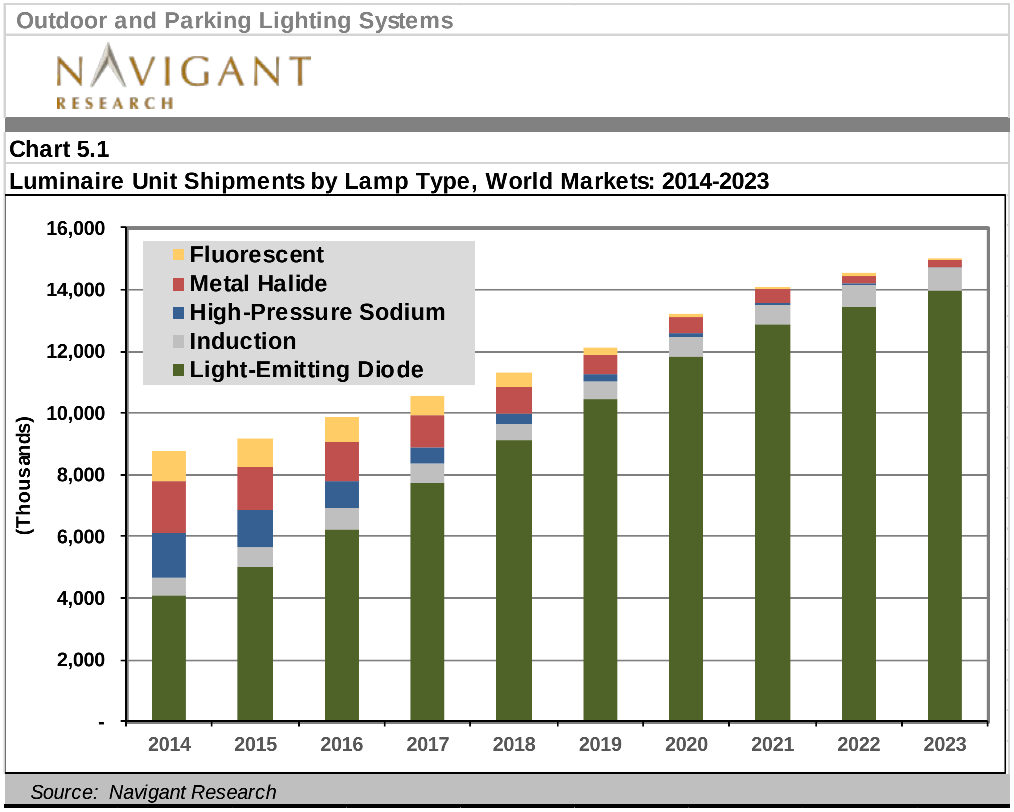
Chart 1: Expected Fixture Pricing 2014-2023



Q. What is driving these price trends?

A. Navigant's forecast indicates both HPS and fluorescent fixtures will become virtually unavailable by the year 2020. Additionally, as shown in Chart 2, MH fixture production is expected to fall by more than 85% by the year 2023.

Chart 2: Lighting Fixture Production 2014-2023



Q. **Are other utilities currently offering in LED lighting?**

A. Yes. OG&E is aware of other utilities offering LED lighting, including, Florida Power and Light, Pacific Gas and Electric, and Los Angeles Department of Water & Power.

Q. **Has OG&E received notice from its vendors notifying the Company that they are converting older product lines to LED?**

A. Yes, on August the 21st, 2015 GE Lighting informed OG&E via letter and company website that:

> *Due to failing demand for traditional lighting products and the accelerated adoption of solid state lighting, we would like to inform you that effective January 1, 2016 the following luminaire product families will be discontinued. GE will support open and confirmed orders until December 31, 2015. We wanted to make you aware of this change and during the September edition of the Highlights training session, we will go over this program in full detail along with an upgrade reference guide to provide you and your customers with energy saving/longer life LED product options.*

> *GE Lighting continues to focus on LED and intelligent lighting technologies, investing in the future of advanced lighting controls and energy efficient LED luminaries.*

In addition, on May 17, 2016, the Company also received notice from Beacon Products, informing OG&E that:

> *Based on our partnership with Pelco and OG&E, we have been supporting your orders for HID* [High Intensity Discharge] *products. However, in effort to help make the transition to LED, we will accept no more orders for HID products. The deadline for this order is Friday, May 20, 2016. After May 20, 2016, we will only accept orders for LED products.*

The full text of these notices is provided in Direct Exhibit GC-2 and 3.

Q. **How is OG&E planning to deploy LED lighting**?

A. OG&E will initiate the following deployment plan upon final order from the Commission approving the new LED Lighting tariff. OG&E plans to begin converting failed in-service fixtures to LED fixtures and to offer LEDs to new customers. For example, if the issue is a simple bulb replacement and OG&E still has access to that type of non-LED bulb (i.e. bulb production has not been cancelled), OG&E will replace the bulb. However, if OG&E does not have the bulbs, or if the issue is with the fixture, OG&E will convert the installation to an equivalent LED lighting fixture.

Q. **To whom is the new LED Lighting tariff available?**

A. The LED Lighting tariff, filed as part of Schedule H-10 Tariffs, Sheet Nos. 33.0-33.12, is available to OG&E customers in all areas, including municipalities, served by retail electric distribution lines and where the LED lighting fixtures are owned by the Company.

Q. **What are the new LED Lighting tariff prices?**

A. Table 1, below, details the LED fixture type and proposed pricing.

Table 1: LED Fixture Types and Proposed Pricing

LED Rate Code	Price of Fixture[1]	kWh	Watts
LED01	$6.45	16	47
LED02	$7.30	41	117
LED03	$8.82	49	139
LED04	$18.67	280	800
LED01D	$9.87	16	47
LED03D	$20.89	48	136

Included in the LED Lighting tariff is a standard LED replacement guide to assist customers in determining which LED fixture is to be installed during the transition period.

Q. **Please describe how these prices are calculated.**

A. OG&E develops prices for lighting fixtures using annual unit costs for capital and expenses. Capital costs are recovered using a fixed charge rate[2] (“FCR”) based on: 20 year depreciation, current utility capitalization, current return on equity and current tax rates. Expenses are recovered on a dollar for dollar basis. Table 2 summarizes the annual unit cost calculation that is contained in the workpapers submitted in conjunction with this filing.

Table 2: LED Lighting Price Calculation

Fixture (Unit Costs)	LED01
Capital Costs	$ 407.47
Fixed Charge Rate	15.56%
Annual Cost of Capital	$ 63.41
Annual O&M	$ 23.68
Annual Total Price	$ 87.09
Monthly Total Price	$ 7.26

[1] On existing wood distribution poles.
[2] The precise FCR calculation is include in the workpapers submitted in this Cause [see workpaper Pricing Calculation Worksheet.xlsx].

Q. **Does the new LED Lighting tariff have provisions for pole and other charges?**

A. Yes, the tariff format and other charges are the same as the two existing lighting tariffs. This is done to allow for consistency across the three tariffs. Also, the proposed tariff includes several new decorative pole options (tariff pole codes P13 through P21).

Q. **Please explain the early Conversion Fee calculation.**

A. OG&E anticipates some customers may desire to accelerate their fixture's conversion instead of waiting until it fails in-service. To accommodate these customers, OG&E calculated the average undepreciated value per fixture ($235.47) based on property accounting records as of July 31, 2016. The Company further calculates an additional $0.87 per month per fixture of depreciation. Assuming approval of the LED Lighting tariff in July 2017, the requested conversion fee is $225.00. See Direct Exhibit GC-4 for the complete calculation.

Q. **Please explain the purpose of the Early Termination Fee.**

A. OG&E requires a three year agreement to install a light. An Early Termination Fee will apply for customers who choose to discontinue lighting service from a fixture prior to the end of the three year term. The fee is to offset the costs associated with removing the fixture and returning it to inventory. The fee is $113.71 for the first fixture removed per service removal request for an individual service location. The amount is reduced to $50 for each additional fixture removed at that individual service location for that service trip (truck roll).

Q. **Please summarize your request for the new LED lighting tariff.**

A. For OG&E, the question surrounding the transition to LED lighting is not whether the Company should convert to LED lighting, but when. Furthermore, OG&E is already experiencing vendors, like GE Lighting and Beacon Products, cancelling non LED product lines as they transition toward energy efficient and aesthetically pleasing LED fixtures. The vehicle enabling OG&E to accomplish these activities is the proposed LED Lighting tariff, a high efficiency, low maintenance, next generation of lighting technology.

Q. **Please describe the PayGo billing option.**

A. The PayGo plan offers customers the choice of not providing a security deposit when initiating service, but instead, using the deposit to pre-pay for service. When their prepaid amount is consumed, subscribers must deposit additional funds for their service or their service will be disconnected. If service is disconnected, customers can have service reconnected by adding funds to their account. Under this plan customers are not charged Reconnection fees. Service can easily be re-established by simply depositing more funds into their account. OG&E previously offered this bill payment option as a proof of concept pilot concluding in 2012 in its Oklahoma service territory. The PayGo pilot was well received by subscribers. The plan description is shown in Section 220 of Rate Schedule No. GI of OG&E's Terms and Conditions of Service.

Q. **Are PayGo participants required to subscribe to any particular pricing plan?**

A. No, they are not. PayGo is a bill payment option, not a pricing plan. Participants may generally choose from any pricing plan available. Some alternatives, such as net metering tariffs, are not immediately available due to the added billing support complexity. OG&E is simply offering this bill payment option as a voluntary alternative.

TARIFF CHANGES

Q. **Is OG&E proposing changes to any of its riders?**

A. Yes. Three types of modifications are being made to the rider tariffs. First, as the Company is moving expenses associated with some of its riders into base rates these changes need to be reflected in the Company's rider tariffs. The Company is proposing to discontinue the SmartGrid Rider and to eliminate Lost Contribution to Fixed Cost that is collected via the Energy Efficiency Cost Recovery Rider. Second, the ECR is being modified to reflect the elimination of the requirement for a minimum level of off-system sales and to reflect Southwest Power Pool Integrated Market ("SPP IM") sales revenue. Lastly, OG&E is altering the Storm Damage Recovery Rider ("SDR") to function as a mechanism to recover incremental storm cost.

Q. **Please describe the SmartGrid rider.**

A. The SmartGrid rider, approved in Docket No. 10-029-U, recovers the annual revenue requirement associated with the Positive Energy® SmartGrid Program net of guaranteed O&M reductions resulting from deployment of SmartGrid technology.

Q. **Why is OG&E proposing to terminate the SmartGrid Rider?**

A. OG&E is proposing to include the expenses associated with the SmartGrid rider in base rates. This alternate collection method for these expenses leaves the SmartGrid rider with no expenses to collect and thus negates its necessity.

Q. **Please describe the EECR rider.**

A. The EECR rider, approved in Docket No. 07-075-TF, recovers the Company's energy efficiency program costs, including, but not limited to, incremental energy efficiency costs, lost contributions to fixed costs, utility incentive, and true- up costs.

Q. **Why is OG&E proposing to discontinue recovering LCFC?**

A. LCFC is reset to zero with each general rate case. The lost sales for which the LCFC is calculated are reflected in the billing units in the Company's proof of revenue statements. The COSS revenue requirement is collected over these billing units and the resulting new prices negate the need to continue to collect prospectively for LCFC for lost sales prior to the implementation of these new rates. With the Company's proposal to have a Formula Rate Plan Rider ("FRP"), as discussed by Company witness Don Rowlett, the price adjustments that normally occur with a general rate case will occur annually with the Company's Formula Rate Plan Reviews thereby negating the need to recover LCFC for the term of the FRP. This change is reflected in section 72.1 of sheet 72.0 and 72.6 of sheet 72.2 of the EECR.

Q. **Please describe the update to the ECR and why it is necessary.**

A. Prior to the SPP IM, OG&E operated its generation facilities on a self-serve basis and entered into off-system sales agreements with other utilities, selling energy into the SPP Energy Imbalance Service ("EIS") market. The revenue from those sales was credited to our customers through the ECR. The SPP IM, which replaced the EIS market when it went live in March 2014, multiple Balancing Authorities such as OG&E's have been consolidated into one SPP Balancing Authority. With the implementation of the SPP IM, off-system sales have been eliminated, negating the need for the minimum level of sales included in the ECR. Through a centralized economic clearing and commitment process, SPP is now responsible for having enough online generating resources to meet the SPP load and service obligations. To meet this obligation, all generating resources are required to be offered into the SPP IM, including OG&E's coal and natural gas fired generation, wind generation and all of its purchase power contracts.

Q. **Please describe the ECR rider tariff change associated with this change from the EIS to SPP IM.**

A. Participation in the SPP IM market changes the Company's level of control over off-system energy sales. Due to the inception of the SPP IM, the Company is recommending the deletion of Note (7) which refers to a minimum level of off-system and SPP IM sales revenue.

Q. **Please describe the Storm Damage Recovery rider.**

A. The SDR rider, approved in Docket No. 08-103-U, was established to recover the $533,280 in incremental storm restoration costs incurred by the Company during calendar year 2008. The SDR was designed to recover these costs over a two year period. These costs were fully recovered by October of 2011.

Q. **How does OG&E propose to update the SDR?**

A. The Company seeks to transform the SDR from a mechanism that was designed to collect the incremental storm costs of a single year to a mechanism to collect any incremental storm cost, pending Commission approval. The incremental storm costs shall be allocated using the final Customer Class Cost of Service allocation factors from this rate case and the SDR rates shall be designed to be collected over a two-year period. These changes are reflected on both sheets (74.0 and 74.1) of the SDR tariff.

Q. **Have you prepared tariff sheets that reflect the proposed changes?**

A. Yes. Please see the revised tariff sheets filed as part of Schedule H-10 Tariffs reflecting the updates to these two riders.

NEW RIDER TARIFFS

LARGE CAPITAL ADDITIONS ("LCA") RIDER

Q. **Please describe the mechanics of the LCA Rider.**

A. The LCA will take the product of the Arkansas jurisdictional revenue requirement of a Commission approved LCA project and the appropriate Class allocation factor. This product will be divided by the Class energy sales to determine the billing factor for each class. Recovery via these LCA factors will not begin until after both the Commission has approved recovery and the LCA project has achieved commercial operation.

Q. **Will the LCA Rider include a true-up mechanism or an annual redetermination?**

A. No, OG&E is not requesting a true-up or annual redetermination of the LCA factors. The LCA factors will remain constant until the time when either another LCA project has been approved by the Commission and has achieved commercial operation or the expenses associate with the LCA project has been included for recovery in a general rate proceeding.

Q. **Is the LCA Rider a blank check?**

A. No. The Company, under the LCA Rider will not be allowed to initiate recovery of a capital addition until after such time that the Commission has issued a final order approving the capital project and the cost associated with the project.

FORMULA RATE PLAN ("FRP") RIDER

Q. **What are the major provisions of the proposed FRP Rider?**

A. The major provisions include:

1. The use of a fully projected test year;
2. The utilization of the same return on equity authorized in Docket No. 16-052-U;

3. Any rate adjustment will be apportioned to the applicable rate classes in the same percentages as the base rate revenue requirements approved in Docket No. 16-052-U;
4. The FRP Rider rate adjustment shall not exceed four percent (4%) of each rate class' revenue for the twelve (12) calendar months preceding the FRP Rider projected test year;
5. The FRP Rider rate adjustment shall be based on a comparison of the projected earned rate for common equity for the projected test year to the target return rate for common equity. The target return rate shall be the return on common equity authorized in Docket No. 16-052-U;
6. The FRP Rider rate adjustment shall be zero if the earned rate for common equity is within a dead-band of the target return rate plus five-tenths percent (0.5%) and the target return rate minus five-tenths percent (0.5%);
7. Only one FRP Rider rate adjustment shall occur in any one three hundred and sixty-five (365) day period;
8. After the initial FRP Rider rate adjustment filing, the Company shall make annual FRP Rider rate adjustment filings;
9. The FRP Rider requires an adjustment to net any difference between the prior FRP Rider projected test year base revenue adjustment and the actual change in base revenue for that same time period. However, this historical netting adjustment shall not begin until the Company has accumulated a full twelve (12) months of a historical year to include in the FRP Rider Evaluation Report;
10. The initial term of the FRP Rider shall not exceed five (5) years from the date of the Commission's final order in Docket No. 16-052-U. However, the Commission may extend the term of the FRP Rider by no more than five (5) years upon a determination that it is in the public interest;
11. The FRP Rider provides for a review period of the FRP Rider Evaluation Report by the APSC Staff and all interveners as specified by Act 725 of 2015; and,
12. The FRP Rider provides for normal ratemaking adjustments and would exclude costs disallowed in Docket No. 16-052-U.

Q. **Please describe the filing procedures for an FRP review.**

A. On or around July 1 of each year beginning in 2018, the Company will file for a review of its rates under the terms of the FRP. Contained is this review will be a report of the Company's 12 months of historic revenue and a report of the Company's projected year revenues. Please note that the Company's first two FRP reviews will not include an historic year review because there will not be a comparative Projected Year revenues associated with the Historic Year.

Q. **Does the timeline outlined in the FRP Rider provide for a review period for the APSC Staff or other intervenors?**

A. Yes. All parties have until October 1 to file statements of errors or objections and supporting testimony. The Company will then have 15 days to review and to work with the parties to resolve errors and objections and file corrected Attachments.

Q. **What is the procedure should the Company and the parties not be able to resolve a dispute?**

A. A hearing before the Commission no later than November 10 will be set to settle such disputes and a final decision will be due no later than December 10. To accommodate any agreed upon or Commission ordered changes, the Company will submit a revised A-1 and implement new rates the first billing cycle of the month following the Commission's ruling.

Q. **Please provide a broad overview of the mechanics of the FRP Rider.**

A. The FRP Rider relies on a more streamlined analysis than what would be normally expected in a general rate case review. An annual review of the Company's Historical Year and Projected Year earnings, and any change in rates will be determined by the agreed upon formulas as set out in the FRP tariff and its accompanying attachments. The Company's Return on Equity ("ROE") is established in the Company's current general rate case and used in each FRP filing. Eliminating the need to litigate the ROE should contribute to the ability to process an FRP filing in a much shorter timeframe than that of a general rate case. The Company will calculate an ROE Bandwidth Rate Adjustment and a Netting Adjustment. If the sum total of the ROE Bandwidth Rate Adjustment and the Netting Adjustment falls within the four (4) percent bandwidth, as determined by statute, of total Company Annualized Filing Year revenues then base rate revenues will be adjusted accordingly. If the calculated total is outside the bandwidth then the adjustment is capped at four (4) percent.

Q. **Please describe in more detail the mechanics of the ROE Bandwidth Rate Adjustment.**

A. For the Projected Year, the Company will calculate the earned rate of return ("ERR") on equity and compare this amount to the target rate of return ("TRR"). The Projected Year is the 12 month calendar year immediately following an FRP filing. If the ERR falls within the rate of return bandwidth, then there is no revenue adjustment associated with rate of return. If the ERR falls outside of the rate of return bandwidth, then a revenue adjustment is made to the TRR.

Q. **Please describe in more detail the Netting Adjustment.**

A. For the Historical Year, the Company will calculate the actual ERR and compare this amount to the TRR. The Historical Year is the 12 months ended December 31 of the calendar year immediately preceding the filing of the FRP. If the ERR falls within the rate of return bandwidth, then there is no revenue adjustment associated with rate of return. If the ERR falls outside of the rate of return bandwidth, then a revenue adjustment is made to the TRR.

Q. **Is it necessary to discuss in greater detail any item in the FRP tariff?**

A. Yes. There is one item from OG&E's FRP tariff that warrant further explanation, those items are: the recommendation that the Cost of Service Study ("COSS") from Docket No. 16-052-U is used to determine the revenue and rate base allocators utilized in Attachments B-1 and D-1.

Q. **Please explain why OG&E is proposing to utilize the COSS to determine the revenue and rate base allocators used in Attachments B-1 and D-1.**

A. Arkansas jurisdictional revenues and rate base fluctuate from year to year. This proposal recognizes those fluctuations and allows the Company to correctly allocate these yearly changes to jurisdictional revenues and rate base. For example, if Arkansas jurisdictional rate base is less than what was determined in Docket No. 16-052-U, then the Company would be required to adjust base rates upward by a larger percentage than is necessary according to actual levels of rate base. With each FRP Filing the Company will submit an updated Schedule G-1, this filing is noted in Attachment E, Item 15.

Q. **Are there any tariffs whose rates will not be subject to the rate redetermination process of the FRP?**

A. Yes. There are six (6) riders whose rates will not be affected by the FRP. They are the Energy Cost Recovery Rider, the Energy Efficiency Cost Recovery Rider, the Storm Damage Recovery Rider, the Transmission Cost Recovery Rider, the Environmental Compliance Plan Rider, and the proposed Large Capital Additions Rider. Additionally, the rates associated with incremental and decremental usage of the Day-Ahead Pricing and the proposed Flex Pricing tariffs will be excluded from FRP review. Franchise fee rates of the Rider for Municipal Tax Adjustment will be excluded. The rates associated with the Renewable Energy Program Rider and the Load Reduction Rider will also be excluded from FRP review.

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

A. Yes.

Centennial Wind Value of Displaced Fuel & Purchased Power Studies					Direct Exhibit GC-1		
Centennial Savings							
Cumulative Annual Summary							
2007					Arkansas		
OGE MWH Replacement Only					Allocation		
Date	Base Case	Without Cent	Savings		Factor *	Savings	
January-07	$ 61,462,631	$ 62,400,822	$ 938,191		0.114681	107593	
February-07	$ 54,871,524	$ 56,449,091	$ 1,577,567		0.118292	186614	
March-07	$ 50,392,712	$ 52,119,066	$ 1,726,354		0.113692	196273	
April-07	$ 59,400,391	$ 61,127,356	$ 1,726,965		0.119883	207034	
May-07	$ 58,315,792	$ 59,859,437	$ 1,543,645		0.12774	197185	
June-07	$ 68,233,627	$ 69,268,059	$ 1,034,432		0.121612	125799	
July-07	$ 79,627,855	$ 80,528,747	$ 900,892		0.116275	104751	
August-07	$ 98,102,208	$ 99,655,179	$ 1,552,971		0.115894	179980	
September-07	$ 62,382,163	$ 63,681,236	$ 1,299,073		0.114087	148207	
October-07	$ 67,902,196	$ 69,906,417	$ 2,004,221		0.121111	242733	
November-07	$ 59,264,912	$ 60,753,905	$ 1,488,993		0.126459	188297	
December-07	$ 68,616,110	$ 69,695,157	$ 1,079,047		0.123199	132938	
		2007 Year End Total:	$ 16,872,351			2017404	0.119568636
2008					Arkansas		
OGE MWH Replacement Only					Allocation		
Date	Base Case	Without Cent	Savings		Factor *	Savings	
January-08	$ 71,375,993	$ 73,530,278	$ 2,154,285		0.11173	240698	
February-08	$ 61,141,422	$ 62,742,082	$ 1,600,660		0.115706	185206	
March-08	$ 67,372,076	$ 69,732,750	$ 2,360,674		0.114843	271107	
April-08	$ 66,895,949	$ 69,682,401	$ 2,786,452		0.115126	320793	
May-08	$ 73,257,526	$ 76,137,351	$ 2,879,825		0.116795	336349	
June-08	$ 113,616,762	$ 116,308,212	$ 2,691,450		0.10886	292991	
July-08	$ 130,699,294	$ 133,253,859	$ 2,554,565		0.111949	285981	
August-08	$ 103,891,020	$ 105,197,897	$ 1,306,877		0.111348	145518	
September-08	$ 59,752,327	$ 61,209,091	$ 1,456,764		0.112961	164558	
October-08	$ 44,609,830	$ 46,139,580	$ 1,529,750		0.114906	175777	
November-08	$ 35,248,707	$ 36,638,878	$ 1,390,171		0.113333	157552	
December-08	$ 41,345,803	$ 43,119,446	$ 1,773,643		0.11108	197016	
		2008 YTD Total:	$ 24,485,116			2773546	0.113274774

2009				Arkansas Allocation Factor *	Savings	
OGE MWH Replacement Only						
Date	Base Case	Without Cent	Savings			
January-09	$ 43,547,042	$ 44,671,057	$ 1,124,015	0.107873	121251	
February-09	$ 34,728,790	$ 35,590,219	$ 861,429	0.107871	92923	
March-09	$ 38,046,678	$ 38,740,061	$ 693,383	0.103451	71731	
April-09	$ 37,483,211	$ 38,437,497	$ 954,286	0.10697	102080	
May-09	$ 42,062,968	$ 42,684,133	$ 621,165	0.108322	67286	
June-09	$ 58,399,654	$ 59,100,515	$ 700,861	0.106859	74893	
July-09	$ 67,167,646	$ 67,808,330	$ 640,684	0.099029	63446	
August-09	$ 65,278,515	$ 66,024,749	$ 746,234	0.107038	79875	
September-09	$ 44,765,279	$ 45,220,215	$ 454,936	0.108685	49445	
October-09	$ 40,235,442	$ 41,117,385	$ 881,943	0.118062	104124	
November-09	$ 39,400,317	$ 40,356,935	$ 956,618	0.115235	110236	
December-09	$ 56,609,996	$ 57,562,929	$ 952,933	0.110588	105383	
		2009 YTD Total:	$ 9,588,487		1042673	0.108742177

2010				Arkansas Allocation Factor *	Savings	
OGE MWH Replacement Only						
Date	Base Case	Without Cent	Savings			
January-10	$ 71,840,889	$ 72,902,932	$ 1,062,043	0.109608	116408	
February-10	$ 59,112,997	$ 59,758,311	$ 645,314	0.114323	73774	
March-10	$ 49,984,588	$ 51,159,128	$ 1,174,540	0.11239	132007	
April-10	$ 41,860,294	$ 42,573,633	$ 713,339	0.113055	80647	
May-10	$ 50,912,812	$ 51,790,525	$ 877,713	0.124871	109601	
June-10	$ 77,977,627	$ 79,256,495	$ 1,278,868	0.114856	146886	
July-10	$ 83,666,639	$ 84,752,957	$ 1,086,318	0.106324	115502	
August-10	$ 83,854,594	$ 84,792,071	$ 937,477	0.107619	100890	
September-10	$ 57,259,379	$ 58,182,922	$ 923,543	0.107299	99095	
October-10	$ 41,058,327	$ 41,893,627	$ 835,300	0.110047	91922	
November-10	$ 37,592,928	$ 38,566,010	$ 973,082	0.115447	112339	
December-10	$ 49,827,893	$ 50,650,448	$ 822,555	0.108874	89555	
		2010 YTD Total:	$ 11,330,092		1268626	0.111969612

2011				Arkansas Allocation Factor *	Savings	
OGE MWH Replacement Only						
Date	Base Case	Without Cent	Savings			
January-11	$ 56,727,285	$ 57,326,890	$ 599,605	0.112526	67471	
February-11	$ 49,594,068	$ 50,438,564	$ 844,496	0.101845	86008	
March-11	$ 49,082,663	$ 49,878,724	$ 796,061	0.113918	90686	
April-11	$ 47,971,474	$ 48,899,325	$ 927,851	0.106591	98901	
May-11	$ 55,807,880	$ 56,687,288	$ 879,408	0.113102	99463	
June-11	$ 87,755,080	$ 88,669,251	$ 914,171	0.11201	102396	
July-11	$ 101,088,404	$ 101,835,365	$ 746,961	0.099346	74208	
August-11	$ 92,690,292	$ 93,279,706	$ 589,414	0.101797	60001	
September-11	$ 53,444,944	$ 53,956,097	$ 511,153	0.097636	49907	
October-11	$ 39,230,639	$ 39,734,240	$ 503,601	0.108629	54706	
November-11	$ 38,608,504	$ 39,072,419	$ 463,915	0.108932	50535	
December-11	$ 44,002,312	$ 44,354,199	$ 351,887	0.101145	35592	
		2011 YTD Total:	$ 8,128,523		869874	0.107015014

2012				Arkansas Allocation Factor *	Savings	
OGE MWH Replacement Only						
Month	Base Case	Without Cent	Savings			
January	$ 48,426,545	$ 48,967,752	$ 541,207	0.108932	58955	
February	$ 44,652,430	$ 45,184,319	$ 531,889	0.101145	53798	
March	$ 31,435,590	$ 32,035,547	$ 599,957	0.102689	61609	
April	$ 30,865,655	$ 31,393,026	$ 527,371	0.104462	55090	
May	$ 44,185,519	$ 44,805,010	$ 619,491	0.104639	64823	
June	$ 57,249,043	$ 57,953,724	$ 704,681	0.106891	75324	
July	$ 80,049,918	$ 80,644,864	$ 594,946	0.108986	64841	
August	$ 71,939,068	$ 72,404,616	$ 465,548	0.107271	49940	
September	$ 48,917,405	$ 49,374,607	$ 457,202	0.102004	46636	
October	$ 46,722,538	$ 47,342,465	$ 619,927	0.099259	61533	
November	$ 41,294,852	$ 41,987,655	$ 692,803	0.099818	69154	
December	$ 44,937,678	$ 45,563,760	$ 626,082	0.109913	68815	
		2012 YTD Total:	$ 6,981,104		730518	0.104642188

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2013					Arkansas		
OGE MWH Replacement Only					Allocation		
Month	Base Case	Without Cent	Savings		Factor *	Savings	
January	$ 44,983,533	$ 45,591,904	$ 608,371		0.098833	60127	
February	$ 37,541,933	$ 38,063,554	$ 521,621		0.105608	55087	
March	$ 43,898,171	$ 44,663,255	$ 765,084		0.104132	79670	
April	$ 44,063,235	$ 44,994,546	$ 931,311		0.102739	95682	
May	$ 47,749,957	$ 48,728,561	$ 978,604		0.106517	104238	
June	$ 57,614,591	$ 58,463,362	$ 848,771		0.102572	87060	
July	$ 66,056,991	$ 66,762,337	$ 705,346		0.10312	72735	
August	$ 64,945,895	$ 65,535,006	$ 589,111		0.100852	59413	
September	$ 59,234,287	$ 59,943,121	$ 708,834		0.100248	71059	
October	$ 44,865,350	$ 45,711,812	$ 846,462		0.107689	91155	
November	$ 46,113,021	$ 46,731,158	$ 618,137		0.110349	68211	
December	$ 58,280,676	$ 59,011,302	$ 730,626		0.104101	76059	
		2013 YTD Total:	$ 8,852,278			920496	0.103984082

2014					Arkansas		
OGE MWH Replacement Only					Allocation		
Month			Savings		Factor *	Savings	
January			$ 1,047,583		0.10235	107220	
February			$ 701,875		0.10106	70931	
March			$ 1,279,292		0.099032	126691	
April			$ 965,723		0.106739	103080	
May			$ 269,292		0.105045	28288	
June			$ (98,585)		0.10467	-10319	
July			$ 133,007		0.101438	13492	
August			$ 636,951		0.100013	63703	
September			$ 51,144		0.099347	5081	
October			$ 367,277		0.103803	38124	
November			$ 397,219		0.106498	42303	
December			$ 781,219		0.100832	78772	
		2014 YTD Total:	$ 6,531,996			667366	0.102168764

2015					Arkansas		
OGE MWH Replacement Only					Allocation		
Month			Savings		Factor *	Savings	
January			$ 594,513		0.099305	59038	
February			$ 590,608		0.101164	59748	
March			$ 509,852		0.099474	50717	
April			$ (88,556)		0.09938	-8801	
May			$ 47,413		0.100091	4746	
June			$ (24,270)		0.105613	-2563	
July			$ 75,431		0.098236	7410	
August			$ 100,330		0.104036	10438	
September			$ (100,465)		0.100698	-10117	
October			$ (58,616)		0.102998	-6037	
November			$ (289,191)		0.101586	-29378	
December			$ 303,967		0.096121	29218	
		2015 YTD Total:	$ 1,661,016			164419	0.098987006
		Cumulative Total	$ 94,430,964			10454922	0.1133888

* Oklahoma Allocation Factors - see monthly Oklahoma FCA report, Model Matrix-Juris tab.- Joint Variable Generation Costs Energy, cell D19

* Arkansas Allocation Factors - see monthly Arkansas TUA (ECR) report, EAF tab. -Total (PES), cell E32.

GE Lighting

Friday, August 21st

HID, Incandescent, Fluorescent & Induction Luminaire Discontinuation Notice – Effective January 1, 2016

Due to failing demand for traditional lighting products and the accelerated adoption of solid state lighting, we would like to inform you that effective January 1, 2016 the following luminaire product families will be discontinued. GE will support open and confirmed orders until December 31, 2015. We wanted to make you aware of this change and during the September edition of the Highlights training session, we will go over this program in full detail along with an upgrade reference guide to provide you and your customers with energy saving/longer life LED product options.

Product Category: Wall & Area
Catalog Reference: W4L, WM7M, WMTS, W1LR, W1SR, W1LG, W1SG, W25C, SPMM, SYMM, DCF, DCD, DSA, DSME, DSMT, DSMR, TSP, DMA, DMS, DMY, DKA, GPB, GH5
Product Family: Wallighter, Wallmount, Decashield, Decasphere, Decashield, ThinScape, Dimension, Garage Guardian

Product Category: Sports & Flood
Catalog Reference: PSFA, PSGC, PSFD, ULC, ULGC, ULT, PSGN, PSGV, SBF, SBN, HLU, VLU,V3SL, V3ST, PF1K
Product Family: Powr-Spot, Ultra-Sport, Powr-Spot, Powerflood, Versaflood

Product Category: Industrial
Catalog Reference: JVD, JVB, JVP, JVS, OG6, OBC, GP5, GHB, UG5, UG6, L4MD, L4MU, LM5, MMI, MML, L1M
Product Family: Versabeam, Jr. Versabeam, Omniglow, Prismatic, Uniglow, Lowmount, Minimite

Product Category: Post Tops
Catalog Reference: PTR, T2H, EDV, LGC, GAX, L,L6, LENX, LENF, V, MADX, MADF, P, T, A, ACA, TR1, TRC
Product Family: Patriarch, Torch, Edison, Legacy, Salem Streetdreams: Gallimore, Lantern, Lenoir, Vandermore, Madison, Traditional, Avery

Product Category: Roadway & Infrastructure
Catalog Reference: RPFS, RPFT, TGSM, TGTM, M4AC, M4AR, M4RC,

M4RR, and the MSRL, MSRA, MSCA, MSCL, M2RC, M2AR (non HPS)
Induction Options
Product Family: Turnpike, Tiger and select M-400 and M-250 luminaires, Including Induction

Product Category: Hazardous
Catalog Reference: H8, PMGA, FP2, H4
Product Family: Perma-Gard, Food-Pro and Incandescent and Fluorescent Luminaires

Product Category: Replacement Parts
Catalog Reference: 35-210907-46, -51,-58,-87, -90, -91, -92, -97 and ENC
Product Family: HPS Ballast Series Type, and Epoxy Encapsulated Ballasts

GE Lighting will no longer be creating new, custom non-LED luminaire configurations. These undocumented catalog numbers will no longer be allowed on quotes or orders.

GE Lighting continues to focus on LED and intelligent lighting technologies, investing in the future of advanced lighting controls and energy efficient LED luminaries.

We value our relationship and thank you for your continued support of GE.

Best Regards,

Teresa Bair
Product General Manager – Outdoor & Industrial Fixtures

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Monte Stutterheim
OG&E
321 North Harvey Avenue
Oklahoma City OK 73102

May 17, 2016

Mr. Stutterheim:

Based on the rapid growth of the Solid State Lighting business, Beacon Products made a decision to only produce LED lighting products. This decision was made more than a year ago to better focus our resources on servicing and supporting the growth of our LED products.

Based on our partnership with Pelco and OG&E, we have been supporting your orders for HID products. However, in effort to help make the transition to LED, we will accept one more order for HID products. The deadline for this order is Friday, May 20, 2016. After May 20, 2016, we will only accept orders for LED products.

We look forward to a continued relationship with you and hope you understand that this is a business decision that we have made in order to provide the best overall service experience.
Please feel free to contact Pelco if you have any questions.
Respectfully,

Donna M. Webb
Inside Sales Manager, Beacon Products

www.beaconproducts.com

Conversion Fee Calculation

Undepreciated Value	5,454,206.23		
Annual Depreciation	241,956.52		
Monthly	20,163.04		
Number of Fixtures	23,163		
Monthly Decrease per Unit	$ 0.87		
	YEAR	Month	Conversion Fee
	2016	July	$ 235.47
		August	$ 234.60
		September	$ 233.73
		October	$ 232.86
		November	$ 231.99
		December	$ 231.12
		January	$ 230.25
		February	$ 229.38
		March	$ 228.51
		April	$ 227.64
		May	$ 226.77
		June	$ 225.90
		July	$ 225.03