Electric Plant Board of the City of Paducah

Paducah Power System “PPS”

2021 Electric Rate Study

Draft Report

Presented to PPS Board June 14, 2021

Letter of Transmittal

Electric Plant Board of the City of Paducah
1500 Broadway
Paducah, KY 42001

Honorable Board Members:

Presented herein is a study of the electric rates of Paducah Power System (PPS) for your consideration. Table 1 on the following page includes a summary of the existing rates and the recommended adjustments thereto. The proposed rates on Table 1 are based on the analyses summarized in the attached report, which should be read in its entirety.

The analysis of electric rates can be a complex and data-intensive undertaking. This report results from a culmination of efforts from the Board and several PPS team members. As you know, the Board participated in a series of workshops throughout the fiscal year to gain a better understanding of the issues and the nature of the analysis. The goal of this report and the associated workshops has been to help you fully understand the reasoning for the staff recommendations for rate adjustments herein and to make informed decisions regarding those recommendations.

The discussion in this report has been separated into subject matter sections. All supporting tables are numbered by section and included at the end of the report.

[FINAL REPORT TO INCLUDE: A draft of this report was presented to the Board at their meeting on June 14, 2021. At that meeting the Board voted to {ACTION TAKEN}. This final report reflects any changes to the draft report required by the Board {and the adopted rates, if applicable}.]

Respectfully submitted,

Doug Handley
Director of Finance, Power Supply and Rates

Electric Plant Board of the City of Paducah, Kentucky
Existing and Proposed Rates [1]

Table 1

	Existing Rates	Proposed Rates
Residential		
Customer Charge	$ 14.75	$ 16.50
Energy Charge	0.11153	0.14478
PCA - June/July 2021	0.02305	(0.00689)
Total		
General Service Nondemand (GS-1)		
Customer Charge	22.00	33.00
Energy Charge	0.12217	0.14947
PCA - June/July 2021	0.02305	(0.00689)
Total		
Drain Pumps		
Customer Charge	65.00	77.00
Energy Charge	0.09391	0.12197
PCA - June/July 2021	0.02305	(0.00689)
Total		
General Service Small Demand (GS-2)		
Customer Charge	115.00	160.00
Energy Charge - first 15 MWh	0.11938	0.14100
Energy Charge - over 15 MWh	0.07495	0.11218
Demand Charge - over 50 kW	16.49	17.25
PCA - June/July 2021	0.02305	(0.00689)
Total		
Seasonal		
Customer Charge	115.00	160.00
Energy Charge - first 15 MWh	0.13529	0.16600
Energy Charge - over 15 MWh	0.09086	0.13718
Demand Charge - over 50 kW	20.49	21.25
PCA - June/July 2021	0.02305	(0.00689)
Total		
General Service - Large Demand [GS-3]		
Customer Charge	275.00	275.00
Energy Charge	0.06736	0.09972
Demand Charge - first MW	15.25	16.50
Demand Charge - over 1 MW	17.62	16.50
PCA - June/July 2021	0.02305	(0.00689)
Total		
Industrial Service (IS-1)		
Customer Charge	275.00	295.00
Energy Charge	0.05257	0.08672
Demand Charge	18.38	17.25
PCA - June/July 2021	0.02305	(0.00689)
Total		

[1] Existing rates include Power Cost Adjustment (PCA) in effect for June 2021. Proposed rates include PCA effective July 2021. Customer Charges per customer are billed monthly. Energy Charges and PCA are billed based on monthly metered consumption in kWh. Demand Charges, if applicable, are billed based on monthly metered demand in kW. One MWh = 1,000 kWh; one MW = 1,000 kWh.

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I. INTRODUCTION

Introduction

The Electric Plant Board of the City of Paducah, Kentucky, doing business as Paducah Power System (or "PPS"), is a municipal utility organized and existing pursuant to the "Little TVA Act" that is codified under Kentucky Revised Statutes ("KRS") 96.550 – 96.901. PPS is a distinct corporate entity governed by a five-person Board, appointed by the Mayor subject to the approval by the City Commission of the City of Paducah. Among the specified powers and duties of the Board is the authority to set the rates charged by PPS for electric service provided to its customers.

The Board is also authorized to issue revenue bonds, which are obligations of PPS payable solely from the revenues from operation of the utility. These outstanding revenue bonds have been issued pursuant to a master indenture and certain other supplemental indentures (collectively, the "Bond Indenture"), which requires PPS to adjust rates as needed to maintain a required debt service coverage ("DSC") ratio. The DSC ratio and other financial metrics impact the ratings assigned to PPS and its bonds by the bond rating services (e.g. Moody's, S&P, Fitch), which impacts the marketability of the bonds and the interest cost.

Generally, the last adjustment of the PPS electric rates based on a comprehensive study occurred in 2014. While the power cost adjustment ("PCA") billing mechanism ensures recovery of a majority of the utility's revenue requirements (i.e., wholesale power costs), the PCA cannot be used to pay non-power costs. Therefore, base rates need to be adjusted periodically, in line with local operating costs, to ensure financial stability and reliable operation of the local distribution utility.

Purpose

The purpose of this electric rate study is to propose adjustments to PPS electric rates that are intended to accomplish two goals:

- Provide for an adequate level of electric revenues to finance normal operating expenses, capital expenditures, debt service payments and other reserves to ensure financial strength and stability for the utility while imposing the least burden possible on our customers.
- Adjust rate levels and structures by rate class to reflect consideration of the allocated cost to serve each respective rate class while also recognizing the impacts of any change from the existing rates.

Scope

This electric rate study has been structured and executed consistent with the typical industry-accepted approach for municipal electric utilities. Specifically, municipal utilities are typically focused on a "cash basis" approach to revenue requirements in order to meet scheduled debt service payments and fund capital expenditures. (Alternatively, investor-owned utilities are more concerned with the regulated rate of return on the accrual basis net book value of plant investments.) Likewise, this cash basis approach is also employed in the utility's budget, allowing for a levelized budget to form the basis for the "test year" revenue requirements.

The test year revenue requirements represent the total system "cost of service" for purposes of determining the overall level of rates. This total system cost of service is allocated to the various rate classes, resulting in the "allocated cost of service" (or "ACOS"). The allocated cost of service provides the revenue requirements for each individual rate class, which are compared to the revenues produced by the existing rates to determine the level of adjustment needed for each individual rate. These individual rate level adjustments may vary from the overall system average rate adjustment.

For purposes of this electric rate study, the allocated cost of service has been developed for the following basic rate classes:

- Residential
- General service non-demand
- General service small demand
- Large Commercial and Industrial

This excludes revenues from lighting rate classes, miscellaneous service fees and charges and other sources, all of which are treated as offsets against operating costs to determine "net" revenue requirements for cost allocation purposes. In each case, these other rates, fees or charges can be developed independent of the ACOS study and adjustments may be implemented on an as-needed basis.

II. REVENUE REQUIREMENTS

Net Revenue Requirements

Generally, revenue requirements for municipal utilities refers to the cash basis expenditures for operating expenses plus debt service, capital expenditures and transfers to reserves. Depreciation and amortization, as non-cash expenses, are not included. Net revenue requirements reflect an offset to these expenditures for income and revenues other than rate revenues.

To evaluate the adequacy of the current level of rates, a 10-year forecast model was developed to project the revenues from existing rates as compared to the net revenue requirements. This forecast model ensures that rates are not based on an unusual or infrequent occurrence that could have been mitigated through other measures. This also allows for the scheduling of annual capital expenditures and transfers to reserves, for example, to smooth out fluctuations in the projected revenue requirements that could create temporary cash flow issues.

Table II-1 presents a summary of estimates for the current fiscal year ending June 30, 2021 ("FY 21") and the 10-year ("FY 22" through "FY 31") projections of revenues from existing rates, revenue requirements, the annual deficit of revenues and the adjusted surplus or deficit resulting from estimated revenues from an assumed rate increase. Some highlights of the projected amounts on Table II-1 are as follows:

- Revenues from existing rates is based on a detailed forecast of monthly billing units – customers, energy sales, and demand, if applicable – for the 10-year period times the existing rates and a forecast of the monthly power cost adjustment ("PCA") factor.
- Revenues from existing rates have been separated into power cost revenues, which includes revenues from the base component mentioned above and the PCA, and non-power cost base rate revenues. Purchased power costs represent approximately two-thirds of the total revenue requirements for PPS.
- The forecast of monthly PCA factors is based on projections (monthly through FY 24 and annually thereafter) of wholesale power costs, primarily billings from Kentucky Municipal Power Agency ("KMPA"), compared to the revenues from power cost component in base rates, which is currently $0.07732 per kWh. The projected PCA factors have been scheduled to ensure all power costs are recovered and certain minimum reserve balances are maintained.
- The annual power cost revenues, plus or minus the regulatory debit or credit, equal total purchased power costs. In addition to billings from KMPA, purchased power costs include net revenue from a power sales agreement related to the PPS peaking plant.
- Non-power expenses, net of other revenues, are summary amounts for detailed forecasts by budgeted line items. In total, these net expenses are projected to increase by 2.2% or less annually.
- The debt service revenue requirement represents the annual accruals for the currently outstanding bond issues for PPS. While a future refunding bond issue may lower debt service in some years of the forecast period, no such bond issue has been assumed.
- The capital expenditures revenue requirement is based on projections of future needs for vehicles, equipment and improvements to the electric system facilities. Two large substation upgrade projects are projected for FY 23 and FY 25, which are assumed to be financed from bank loans. Otherwise, capital expenditures are projected to increase by 2.5% or less annually.
- Revenue requirements include transfers to the emergency reserve fund that total $15,000,000 over the forecast period. Transfers to the emergency reserve fund have been scheduled annually to produce total annual revenue requirements approximately equal to the total of revenues from existing rates and revenues from an assumed rate increase. In other words, the declining amounts of annual transfers to reserve offset the increasing amounts of other revenue requirements so that the assumed one-time rate adjustment covers all projected revenue requirements for the entire forecast period.
- Projected revenues from an assumed rate increase are based on a calculated increase in the average cost per kWh for all customers times the annual energy sales for the forecast period. The rate increase is calculated to produce annual revenues approximately equal to the annual revenue requirements highlighted above.
- Based on the estimates, assumptions and projections reflected in Table II-1, the debt service coverage ratio for PPS would range from 1.56 to 1.74 over the forecast period.

In sum, the 10-year forecast model provides projections that aid in budgeting and financial planning. The model also helps verify that the annual amounts of revenue requirements are reasonable over the forecast period. However, further cost analysis and rate design will be based on only the FY 22, or “test year”, revenue requirements. As described further below, the test year revenue requirements are functionalized and classified into categories that facilitate cost allocation and subsequent rate design.

Functionalization of Revenue Requirements

In order to facilitate cost allocation, the revenue requirements are summarized into functional categories. The PPS chart of accounts, as prescribed by the Federal Energy Regulatory Commission (“FERC”), facilitates recording of plant balances and operating expenses into functional categories. These categories represent the basic electric utility functions of power supply, transmission, distribution and customer-related costs and also includes a general category for revenue-related items.

The revenue-related category includes costs and revenues that are allocated to all other categories on a pro rata basis. This includes costs that are directly related to revenues, such as sales expenses, and other expenses and revenues that are not directly related to any other functional category. As shown near the bottom of Table II-2, the sum of the revenue-related revenue requirement has been allocated based on the revenues associated with all other functional categories, using the rationale that the revenue requirements for each category will be a reasonable proxy for the associated revenues.

Table II-2 also reflects the allocation of certain revenue requirements across multiple functional categories as follows:

- The allocation of property taxes has been based on the relative assessed values of property in each functional category.
- The allocation of debt service has been based on the original use of the Series 2009 Bonds, which was issued to finance construction of the PPS peaking plant and other improvements. (Subsequent PPS bond issues only refunded portions of these bonds.)
- The allocation of capital expenditures has been based on the nature of the purchases and projects in the estimated capital budget for FY 22, which is fairly representative of most of the forecast period.

Finally, the projected revenues from lighting have been deducted from the revenue requirements at the bottom of Table II-2. Thus, the adjusted revenue requirement represents the revenue target for all other rate classes, excluding the lighting rate classes. The allocation of lighting revenues has been based on the pro rata functionalization of all other revenue requirements, using the rationale that the functionalization of the lighting rate classes would not be materially different from all other rate classes.

As discussed above, the functionalization of detailed line items of revenues and expenses creates a summary of revenue requirements into categories of costs that reflect the general purposes for which those costs were incurred. As discussed below, these functionalized revenue requirements are further characterized according to certain cost-causation classifications that facilitate allocation to rate classes.

Classification of Revenue Requirements

The goal of classification is to group the revenue requirements according to categories that correspond to the factors used to allocate costs to rate classes, such as customer, energy and capacity. Specifically, the cost classifications and the corresponding allocation factors are as follows:

- Energy (power supply) – energy sales
- Capacity (power supply) – coincident peak ("CP") demands
- Transmission capacity – CP demands
- Distribution capacity – combination of non-coincident ("NCP") demands and weighted customer counts
- Customer – weighted and unweighted customer counts

While the classification of functionalized costs may be fairly straightforward for some categories, the classification of power supply costs into energy-related and capacity-related costs has been based on a special technique demonstrated on Table II-3.

The classification of power supply costs shown on Table II-3 reflects the general nature of different types of generating capacity. Specifically, peaking capacity is a resource generally used for capacity only because:

a) it reacts quickly to respond to peak demand load requirements or market prices and
b) other resources usually provide lower-cost energy.

Therefore, it is assumed that other resources, e.g. the Prairie State coal plant, are utilized to satisfy both energy and capacity needs. More specifically, to the extent that the capacity cost of such resources is greater than the capacity cost of the peaking plant (on a cost-per-MW basis), such excess capacity cost is assumed to be incurred to obtain the associated energy.

As shown on Table II-3, the various functionalized costs associated with power supply displayed on Table II-2 have been rearranged for purposes of this calculation. Specifically, the power supply costs associated with the PPS peaking plant are summarized first in order to derive a capacity cost per MW for peaking capacity. This peaking capacity cost per MW is then multiplied by the capacity (in MW) of Prairie State (PSGC) and Hydro capacity to derive the capacity-related portion of the fixed costs associated with those respective resources. The balance of the fixed costs, along with the variable costs, are considered energy-related costs.

The classification of all test year revenue requirements is summarized on Table II-4, including the energy and capacity related costs of power supply as classified on Table II-3. As shown on Table II-4, transmission and customer functional costs are classified into transmission capacity-related and customer-related cost classes, respectively. Also, distribution costs are considered a combination of distribution capacity-related and customer-related. The ratio of distribution costs allocated to the customer-related category is based on a review of the nature of the detailed distribution operation and maintenance expenses.

As shown on Table II-4 and set forth in the footnotes thereto, the various classes of capacity-related costs are kept separate because they are allocated using different methodologies, as discussed further in the next section. Specifically, the following table indicates the type of allocation factor used for each class of costs:

CLASS OF COSTS	ALLOCATION FACTOR
Power Supply Energy	Energy
Power Supply Capacity	1CP Demand
Transmission Capacity	4CP Demand
Distribution Capacity	NCP Demand
Customer	Weighted Customer

III. ALLOCATED COST OF SERVICE

Introduction

Generally, all of the net costs[1] incurred by PPS must be recovered from PPS customers because all of those costs were incurred to serve those customers. Put another way, those customers' requirements for service drive the utility's costs in various ways, which are referred to as cost-causation factors, such as:

- The number, size and type of customers needing service.
- The total energy consumed by customers.
- The peak demand for power by customers, individually and collectively.

Therefore, to ensure fairness to all customers, rates should be designed to recover the costs allocated to each rate class and those costs should be allocated based on cost-causation factors. The following is a discussion of the various cost allocation factors used in this study, which are set forth on Table III-1.

Customer Allocation Factors

There are two types of customer allocation factors demonstrated on Table III-1 – unweighted and weighted, designated with the codes "CU" and "CW", respectively. The unweighted customer allocation factor is based on the test year (projected FY 22) customer billing units, i.e. customer-months, for each rate class. A somewhat-outdated example of a cost directly related to the relative customer counts would be postage for mailing bills – the cost is the same for each customer, regardless of type or size of customer.

The weighted customer allocation factor recognizes that larger customers, in general, drive certain customer-related costs to a larger degree than smaller customers. Therefore, weighting factors have been applied to the unweighted customer numbers to develop the weighted allocation factors. The

[1] Net costs, in this case, represents costs net of any offset by income or revenues other than rate revenues.

weighting factors represent typical relationships between the costs to establish service to the various classes of customers. The weighted customer allocation factors are considered more relevant than the unweighted customer allocation factors for purposes of this study and are used to allocate the customer costs and the customer related portion of distribution costs, as demonstrated on Table III-2.

Energy Allocation Factors

The energy allocation factor (coded as "KWH") is simply the relative percentage of the projected test year energy sales by customer class. This ensures energy-related power supply costs are allocated based on the relative energy sales to customer classes, as demonstrated on Table III-2.

Demand Allocation Factors

As shown on Table III-1, there are three demand allocation methodologies used in this study, as follows:

- 1CP – annual coincident peak (CP)
- 4CP – average of four summer (June – September) monthly coincident peaks
- NCP – average of the monthly non-coincident peaks for each rate class

In order to estimate the respective demand values required for each of these demand allocation methodologies, historical interval[2] data were analyzed to find the relevant demands and those demands were used to calculate "load factors" for the respective time periods. A load factor is a ratio of the actual energy used to the hypothetical energy used if the peak demand amount was used every hour of the calculation period. To illustrate, consider the following example calculation:

A.	Total system annual energy usage	534,316	MWh
B.	Total system annual peak demand	120	MW
C.	Total hours in year (24 x 365)	8,760	hours
D.	Energy used at 100% load factor (B x C)	1,051,200	MWh
E.	Annual system 1CP load factor (A / D)	51	%

Once a particular load factor has been calculated from actual historical data, that load factor can be applied to the relevant energy usage for a projected period to estimate the demand that would be used in that projected period. Therefore, actual historical load factors are used to calculate test year demands based on projected test year energy usage.

The projected demands are used in the demand allocation factors set forth above and in Table III-1 to allocate the following fixed or capacity related costs, as demonstrated on Table III-2:

- 1CP – power supply capacity costs
- 4CP – transmission capacity costs
- NCP – distribution capacity costs

[2] The data collected from the automated metering infrastructure (AMI) is energy usage for each 15-minute interval in the billing period for each customer. The contribution to various peak demands can be determined by summarizing the energy usage by defined customer groups during specific intervals.

The power supply capacity costs are allocated based on the 1CP demand, which occurred in August 2020 of the historical analysis period, because this represents the maximum system demand and all generating capacity and power supply resources are sized to meet this demand.

Transmission capacity is used to transport power to and between the major substations in the PPS system. The relative loads at these locations may vary based on the time of year and the customer mix served from those substations. Therefore, the average of the CP demands for the four summer months of June through September of the historical data analysis period were used to develop the 4CP demand allocation factors to account for variations that may occur among the customer classes during the year. Other non-summer months are not considered relevant because total demands are much lower and therefore ample transmission capacity is already available.

The distribution network capacity is structured to carry energy from the substations all the way to the individual customer. Lines, poles and transformers, for example, are sized and positioned based on the collective demands of the customers served in the various areas of the network. The individual customer class peak demands (NCP) provide a proxy for the relevant share of the drivers for these distribution system costs.

Summary of Allocated Cost of Service

The test year allocated cost of service is summarized on Table III-2. As shown on this table, the various classified costs have been allocated to rate classes based on the appropriate energy, capacity and customer-related allocation factors discussed above. This table also presents an adjustment to the preliminary cost of service results and the resulting deficit compared to the revenues from existing rates.

From a rate management perspective, an allocated cost of service study is a useful tool. If the data and analysis is reliable, the study results provide a good indicator for where rate levels should be or at least the direction of rate adjustments by class. Management should also consider the level of current rates and the magnitude of rate adjustments indicated by the study.

In this case, the analysis is considered reliable, but the underlying historical data may not be representative of long-term usage patterns. The only interval data available to be used in this study was for the period of May 2020 through February 2021. During this period, many customers of PPS were impacted by the COVID-19 pandemic to varying degrees. For example, residential consumption was greater than average at times due to increases in working and schooling from home. Meanwhile, many retail businesses, especially dining and entertainment, saw much lower volume than usual.

While it is not possible to measure exactly how these events impacted the analysis, the preliminary allocated cost of service has some unexpected results. Specifically, the preliminary allocated cost of service would indicate adjustments from the existing rate levels for two rate classes – residential and general service small demand – significantly different from the system average adjustment. Moreover, these differences are somewhat offsetting. Therefore, an adjustment to the preliminary allocated cost of service results for the effects of non-typical historical loads has been incorporated on Table III-2 as an increase in the revenue requirements for the general service small demand rate class and an offsetting decrease in the revenue requirements for the residential rate class. Overall total system revenue requirements are unchanged by this adjustment and the rank of rate adjustments are maintained – residential as the highest and general service small demand as the lowest.

Finally, Table III-2 compares the adjusted allocated cost of service to the revenues from existing rates to determine amount and percentage of increased revenues required for each rate class. These represent targeted revenue adjustments for purposes of designing proposed rates, as discussed in the following section.

IV. RATE DESIGN

Introduction

In the rate design phase, specific adjustments are proposed for individual components of each rate structure based on the goals of the rate study and other rate design considerations. For purposes of this study, the primary goal is to recover the allocated cost of service, as adjusted. As discussed above, the ACOS should be one of several considerations in rate design but not necessarily the only or overriding consideration. However, in light of the reasonableness of the results, after the adjustment discussed above, the adjusted ACOS will be considered a requirement for the projected revenues from each of the proposed rate structures designed herein.

Other rate design considerations for purposes of this study include the following:

- Power cost adjustment – Purchased power costs have been allocated to rate classes and therefore reflected in the adjusted ACOS. But as actual power costs will vary from the amount built into the rates, the PCA will provide a billing mechanism to match revenues with costs. As discussed below, the PCA will be reset based on an adjustment to the power cost component of base rates. This adjustment will affect all electric rate schedules.
- Customer charges – The proposed customer charges should reflect two considerations – the allocation of customer-related costs and the general relationship of fixed and variable total system costs. The allocation of customer-related costs would justify customer charges lower than the existing charges in each rate class, but not significantly lower. This means that the existing customer charges are also contributing to some recovery of capacity-related costs. Given the high proportion of fixed costs for PPS, this is a favorable condition. Therefore, no decreases in customer charges have been proposed.
- Demand charges – For those rate classes that incorporate demand charges, the capacity-related costs allocated to those rate classes provides an indicator of cost-based adjustments to the demand charge component. The allocation of capacity-related costs in this study would indicate significant increases in the demand charges for those affected rate classes. Therefore, subject to other considerations, increases in the demand charge components are proposed.
- Existing rate levels – Any changes in rates must consider the effects on individual customer's bills. Only an across-the-board percentage adjustment would create the same impact on all customers within the class. Different magnitudes of adjustments for individual rate components will cause differences in the percentage change in customer bill amounts at different usage levels. Such adjustments should be tempered to reduce significant bill amount fluctuations.

It should also be noted that the revenue requirement for each rate class per the adjusted ACOS applies, in some cases, to more than one rate schedule within the rate class. For example, the general service nondemand rate class includes small commercial and drain pump rate schedules. Therefore, rates must be designed for each rate schedule such that the sum of the projected revenues from all included rate schedules equals the revenue requirement for the rate class. The following is a discussion of the proposed adjustments to the individual rate components of each rate schedule.

Power Cost Adjustment

The purpose of the power cost adjustment (PCA) billing mechanism is to provide a pass-through of purchased power costs on a near-current basis because those costs:

a) represent a significant proportion of the total system budget (approximately two-thirds of the test year net revenue requirements),
b) can vary significantly based on changes in weather, market prices and other factors, and
c) are not subject to management control (at least, not in the short term).

Therefore, PPS management has been authorized to adjust the PCA factor on a quarterly basis within the following parameters:

- Strict accounting for revenues collected for power costs vs. power costs paid to ensure that PPS neither under-collects nor over-collects purchased power costs from its customers.
- The PCA factor should be set quarterly but with a longer view for reducing fluctuations in the PCA factor and maintaining a PCA fund reserve to absorb monthly fluctuations in over or under collections.

Generally, the PCA factor (a rate per kWh of sales) is calculated as the purchased power cost per kWh minus the amount of power costs included in base rates. In calculating the quarterly PCA factor, a monthly forecast of purchased power costs is compared to a forecast of revenues from a combination of the PCA factor and the amount of power costs included in base rates. Maintaining a reserve of PCA funds to absorb the fluctuations forecast for monthly cumulative balances of over or under collections is also a consideration.

As part of this rate study, the proposed rates herein incorporate a new amount of power costs included in base rates. This reset of the power costs in base rates has no effect on the total amount charged to customers for power costs, which is based on actual costs incurred. Since actual costs are compared to the sum of the PCA and the amount of power costs in base rates, increasing or decreasing the amount of power costs in base rates simply decreases or increases the level of the PCA factor, respectively.

All of the proposed rates herein have been designed based on a reset of the amount of power cost in base rates from the current level of $0.07732 per kWh to the proposed level of $0.10000 per kWh. Table IV-1 summarizes the test year purchased power costs and illustrates the effects of the reset of the power cost in base rates on the projected average PCA factor for FY 22. As shown on this table, the projected average cost of purchased power for FY 22 is $0.09311 per kWh. Based on this cost and the current amount of power cost in base rates, the indicated average PCA for FY 22 would be $0.01579 per kWh, which represents a decrease from the current PCA of $0.02305 per kWh with no change in the amount of power cost in base rates.

The proposed rates herein have been designed based on an increase in the amount of power cost in base rates, which increases the affected base rates and further decreases the indicated average PCA for FY 22. Since the proposed amount of power cost in base rates is greater than the projected actual costs of purchased power for FY 22, the projected PCA factor and billing amount would be a credit, or negative amount, on customers' bills. In the comparison of current rates and proposed rates that follow, the typical bill amounts are calculated using the current PCA charge of $0.02305 and the proposed PCA credit of $0.00689 per kWh, respectively.

Residential Rates

The existing residential rate consists of a customer charge, an energy charge and the PCA. The proposed residential rate retains this structure with some adjustments to each component, as shown at the top of Table IV-2. The proposed customer charge has been increased to improve the fixed costs recovery. As discussed above, the amount of power cost in base rates has been increased, resulting in a lower PCA on average. The proposed energy charge has been increased to recover the remaining revenue requirement. As shown on this table, the projected total revenue from the proposed rates ties to the allocated cost of service, as adjusted, for the residential rate class shown on Table III-2.

Also shown on Table IV-2 are calculations of monthly bill amounts under the current and proposed rates over a range of energy (kWh) usage levels typical for residential customers. The average usage for residential customers is approximately 1,000 kWh. At that level, the bill amount under the proposed rates would be $5.06, or 3.4%, higher than under the current rates. At lower usage levels, the percentage increase is greater due to the increased customer charge, but the bill amounts are all within $5.00 of each other. At higher usage levels, the percentage increase declines.

General Service Nondemand Rates

The existing general service nondemand rate schedule (GS-1) consists of a customer charge, an energy charge and the PCA. The proposed rate retains this structure with some adjustments to each component, as shown at the top of Table IV-3. The proposed customer charge has been increased to improve the fixed costs recovery. As discussed above, the amount of power cost in base rates has been increased, resulting in a lower PCA on average. The proposed energy charge has been increased to recover the remaining revenue requirement.

Also shown on Table IV-3 are calculations of monthly bill amounts under the current and proposed rates over a range of energy (kWh) usage levels typical for small commercial customers. The average usage for these customers is approximately 2,000 kWh. At that level, the bill amount under the proposed rates would be $5.72, or 1.8%, higher than under the current rates. At lower usage levels, the percentage increase is greater due to the increased customer charge, but the bill amounts are all within about $10.00 of each other. At higher usage levels, the percentage increase declines.

Also included in the general service nondemand rate class is a rate schedule for drain pump service, which has only one customer. The rates for drain pumps were adjusted to maintain the existing relationships between this rate schedule and GS-1. The projected combined revenue from the proposed GS-1 rates and the proposed drain pumps rates ties to the allocated cost of service, as adjusted, for the general service nondemand rate class shown on Table III-2.

General Service Small Demand Rates

The existing general service small demand rate schedule (GS-2) consists of a customer charge, an energy charge, a demand charge and the PCA. The proposed rate retains this structure with some adjustments to each component, as shown at the top of Table IV-4. The proposed customer charge and demand charge have each been increased to improve the fixed costs recovery. As discussed above, the amount of power cost in base rates has been increased, resulting in a lower PCA on average. The proposed energy charge has been increased to recover the remaining revenue requirement.

This rate schedule (GS-2) is intended for commercial customers with demand over 50 kW or energy usage over 15,000 kWh per month. Smaller commercial customers qualify for service under the GS-1 rate schedule. The proposed rates for these rate schedules have been designed to produce approximately equal monthly bill amounts at the 15,000 kWh usage level. Below this level, GS-1 produces lower bill amounts with GS-2 producing lower bills at higher usage levels. This provides an economic incentive for commercial customers to request the appropriate rate schedule.

Also shown on Table IV-4 are calculations of monthly bill amounts under the current and proposed rates over a range of billing demand (kW) and energy (kWh) usage levels typical for small commercial customers. The average demand for these customers is approximately 90 kW and the average energy usage is approximately 32,500 kWh. At that level, the bill amount under the proposed rates would be $78.17, or 1.7%, higher than under the current rates. The changes in monthly bill amounts generally vary based on demand levels and “load factor”[3]. Generally, higher demand levels have larger increases. Within each demand level, the bill impacts are less favorable at higher energy usage levels. This is because the proposed demand charge has been increased less, on a percentage basis, than the other rate components to maintain some comparability with the proposed demand charges for the large demand rate schedules.

Also included in the general service small demand rate class is a rate schedule for seasonal service, which has only one customer. The seasonal rates were adjusted to maintain the existing relationships between this rate schedule and GS-2. The projected combined revenue from the proposed GS-2 rate and the proposed seasonal rate ties to the allocated cost of service, as adjusted, for the general service small demand rate class shown on Table III-2.

Large Commercial and Industrial Rates

There are two rate schedules in the large commercial and industrial rate class – general service large demand (GS-3) and industrial service (IS-1). Both rate schedules apply to customers with monthly billing demand of 1,000 kW or more. To qualify for IS-1, the customer must be a manufacturer. Otherwise, the GS-3 schedule applies.

The existing general service large demand rate schedule (GS-3) consists of a customer charge, an energy charge, a demand charge and the PCA. The proposed rate retains this structure with some adjustments to each component, as shown at the top of Table IV-5. The most significant proposed adjustment to this

[3] Load factor is the relationship between energy usage relative to demand; with more energy usage for a given demand level resulting in a higher load factor.

rate schedule is the proposed single-step or “flat” demand charge. The cost of service and industry practice does not support the inverted demand charge structure in the existing rate. The proposed demand charge represents approximately the weighted average of the two existing demand charge levels. As discussed above, the amount of power cost in base rates has been increased, resulting in a lower PCA on average. The proposed energy charge has been increased to recover the remaining revenue requirement.

Also shown on Table IV-5 are calculations of monthly bill amounts under the current and proposed rates over a range of billing demand (kW) and energy (kWh) usage levels typical for large commercial customers. As shown on this table, the monthly bill amounts at the minimum demand of 1,000 kW are expected to increase by 4.0 – 5.3% due to the increase in the demand charge for the first 1,000 kW. At larger billing demand levels, the bill amounts are expected to increase by less than 2.8%.

The existing industrial service rate schedule (IS-1) consists of a customer charge, an energy charge, a demand charge and the PCA. The proposed rate retains this structure with some adjustments to each component, as shown at the top of Table IV-6. Primarily, the adjustments to the demand and energy charges are intended to maintain certain relationships to the GS-3 rates; specifically, a higher demand charge and a lower energy charge. Since the proposed GS-3 demand charge applicable over 1,000 kW decreased, the proposed IS-1 demand charge decreased. As discussed above, the amount of power cost in base rates has been increased, resulting in a lower PCA on average. The proposed energy charge has been increased to recover the remaining revenue requirement.

Also shown on Table IV-6 are calculations of monthly bill amounts under the current and proposed rates over a range of billing demand (kW) and energy (kWh) usage levels typical for industrial customers. As shown on this table, the monthly bill amounts are not expected to vary outside a range of plus or minus 2.0%.

V. SUMMARY OF PROPOSED RATES

Table V-1 presents each of the existing and proposed rates, along with the test year billing units and pro form annual revenues. This table calculates the increase in annual revenues and the percentage increase for each rate schedule.

VI. REPORT TABLES

The following tables, which have been referenced in previous sections, are included in this section:

Paducah Power System

Forecast of Revenues and Revenue Requirements

Description	FY21 Estimated	Projected FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
REVENUES FROM EXISTING RATES											
Power Cost Revenues	50,109,913	50,963,039	52,292,337	52,508,373	55,461,441	56,552,666	59,341,747	59,026,414	61,693,813	61,563,808	62,450,015
Regulatory Debit/(Credit)	(105,672)	(1,213,427)	40,980	507,287	(5,485)	(4,993)	(15,358)	642	(2,098)	6,475	(14,402)
Non-Power Base Rate Revenues	23,315,523	22,428,188	23,728,413	24,208,382	23,709,713	23,724,995	23,728,141	23,757,100	23,767,097	23,788,017	23,778,839
TOTAL REVENUES FROM EXISTING RATES	73,425,435	73,391,228	76,020,751	76,716,755	79,171,155	80,277,662	83,069,888	82,783,514	85,460,909	85,351,826	86,228,854
PURCHASED POWER											
KMPA Costs	54,153,600	53,898,973	56,367,658	55,822,699	58,333,388	59,497,256	62,349,928	62,126,399	64,868,757	64,826,969	65,773,932
Net Peaking Cost/(Revenue)	(4,149,360)	(4,149,360)	(4,034,341)	(2,807,040)	(2,877,432)	(2,949,583)	(3,023,539)	(3,099,343)	(3,177,043)	(3,256,685)	(3,338,318)
TOTAL PURCHASED POWER	50,004,240	49,749,613	52,333,317	53,015,660	55,455,956	56,547,673	59,326,389	59,027,056	61,691,714	61,570,284	62,435,614
OTHER NET EXPENSES											
Generation Expense	1,304,580	1,330,672	1,357,285	1,384,431	1,412,120	1,440,362	1,469,169	1,498,553	1,528,524	1,559,094	1,590,276
Transmission Operating Expense	19,587	19,979	20,378	20,786	21,202	21,626	22,058	22,499	22,949	23,408	23,876
Distribution Operating Expense	2,503,843	2,553,920	2,604,999	2,657,099	2,710,241	2,764,445	2,819,734	2,876,129	2,933,652	2,992,325	3,052,171
Customer Accounting Expense	1,796,733	1,864,735	1,899,286	1,934,528	1,970,475	2,007,140	2,044,539	2,082,686	2,121,596	2,161,284	2,201,766
Sales Operating Expense	1,247,477	1,272,427	1,297,875	1,323,833	1,350,310	1,377,316	1,404,862	1,432,959	1,461,619	1,490,851	1,520,668
Administrative & General Operating Expense	2,657,262	2,710,407	2,764,615	2,819,908	2,876,306	2,933,832	2,992,509	3,052,359	3,113,406	3,175,674	3,239,187
Transmission Maint. Expense	11,779	12,015	12,255	12,500	12,750	13,005	13,265	13,531	13,801	14,077	14,359
Distribution Maint. Expense	1,886,671	1,924,404	1,962,892	2,002,150	2,042,193	2,083,037	2,124,697	2,167,191	2,210,535	2,254,746	2,299,841
Administrative & General Maint. Expense	168,028	171,388	174,816	178,313	181,879	185,516	189,227	193,011	196,871	200,809	204,825
Total Tax & Tax Equivalent	1,987,407	2,027,155	2,067,699	2,109,052	2,151,234	2,194,258	2,238,143	2,282,906	2,328,564	2,375,136	2,422,638
Total Expense, excluding Purchased Power	13,583,368	13,887,103	14,162,101	14,442,599	14,728,707	15,020,538	15,318,204	15,621,825	15,931,517	16,247,404	16,569,608
Total Non-Operating Income	(1,966,357)	(2,004,343)	(2,043,088)	(2,082,608)	(2,122,919)	(2,164,036)	(2,205,976)	(2,248,754)	(2,292,387)	(2,336,894)	(2,382,290)
Total Misc. Revenue	(1,531,017)	(1,575,247)	(1,632,546)	(1,669,652)	(1,705,774)	(1,730,362)	(1,765,717)	(1,781,959)	(1,816,880)	(1,834,760)	(1,859,137)
NON-PURCHASED POWER NET EXPENSES	10,085,995	10,307,513	10,486,467	10,690,339	10,900,014	11,126,139	11,346,512	11,591,112	11,822,250	12,075,750	12,328,181
Debt Service	11,010,150	11,010,025	11,006,900	11,005,150	11,272,150	11,266,900	11,270,025	11,270,525	11,267,650	11,270,400	11,267,775
Capital Expenditures	4,550,056	4,594,602	4,706,905	5,275,292	5,405,594	5,897,497	6,035,735	6,178,120	6,324,777	6,475,833	6,631,421
Transfer to Reserve Funds	-	3,530,000	3,380,000	2,650,000	2,080,000	1,410,000	1,090,000	740,000	405,000	40,000	(325,000)
TOTAL REVENUE REQUIREMENTS	75,650,441	79,191,753	81,913,589	82,636,440	85,113,715	86,248,210	89,068,661	88,806,813	91,511,391	91,432,266	92,337,990
Surplus/(Deficit)	(2,225,005)	(5,800,525)	(5,892,838)	(5,919,685)	(5,942,560)	(5,970,548)	(5,998,773)	(6,023,299)	(6,050,482)	(6,080,440)	(6,109,136)
REVENUES FROM RATE INCREASE		5,801,656	5,895,949	5,920,740	5,946,169	5,972,257	5,999,024	6,026,493	6,054,686	6,083,625	6,113,336
Adjusted Surplus/Deficit		1,131	3,111	1,055	3,609	1,709	251	3,194	4,204	3,185	4,201
Debt service coverage ratio	1.21	1.74	1.73	1.72	1.66	1.65	1.63	1.61	1.60	1.58	1.56

Paducah Power System

Table II-2

Functionalization of Test Year Revenue Requirements

Description	FY22	Power Supply	Transmission	Distribution	Customer	Revenue
KMPA/Prairie State costs						
Fixed Cost	42,219,879	42,219,879				
Variable Cost	2,425,188	2,425,188				
Other purchased power						
Net MISO/KU	2,771,953		2,771,953			
Hydro	6,481,952	6,481,952				
PURCHASED POWER COST	53,898,973	51,127,019	2,771,953	-	-	-
Peaking capacity revenue	(4,158,000)	(4,158,000)				
Generation-Fuel	8,640	8,640				
TOTAL POWER SUPPLY COST	49,749,613	46,977,659	2,771,953	-	-	-
Operating Expenses						
Generation Expense	1,330,672	1,330,672				
Transmission	19,979		19,979			
Distribution	2,553,920			2,553,920		
Customer Accounting	1,864,735				1,864,735	
Sales	1,272,427					1,272,427
Admin & General	2,710,407					2,710,407
Maintenance Expenses						
Transmission	12,015		12,015			
Distribution	1,924,404			1,924,404		
Admin & General	171,388					171,388
Taxes - Property	2,027,155	886,903	76,227	778,739	139,331	145,956
TOTAL O&M EXPENSES	13,887,103	2,217,575	108,221	5,257,063	2,004,066	4,300,179
Other Non-rate Revenues						
Non-operating income	(2,004,343)					(2,004,343)
Fiber Rental Income	(337,929)					(337,929)
Interest Income	(209,253)					(209,253)
Service Charges/Fees	(416,608)				(416,608)	
Pole Attachment Fees	(472,257)			(472,257)		
KMPA Admin Charge	(139,200)					(139,200)
NET OTHER REVENUE REQ	10,307,513	2,217,575	108,221	4,784,805	1,587,458	1,609,454
Other Revenue Requirements						
Debt Service	11,010,025	8,620,160	2,154,942	-	234,922	-
Capital Expenditures	4,594,602	95,000	374,418	3,509,142	260,000	356,042
Transfer to Reserve Funds	3,530,000					3,530,000
TOTAL REVENUE REQUIREMENT	79,191,753	57,910,394	5,409,534	8,293,947	2,082,380	5,495,496
Alloc. of Revenue-related	-	4,318,352	403,387	618,476	155,282	(5,495,496)
Offset for Lighting Revenues	(1,664,546)	(1,307,998)	(122,183)	(187,332)	(47,034)	
ADJUSTED REVENUE REQUIREMENT	77,527,206	60,920,748	5,690,738	8,725,091	2,190,629	-

Paducah Power System

Table II-3

Classification of Power Supply Costs

Description	Power Supply		Energy	Peaking Capacity	PSGC Capacity	Hydro Capacity
POWER SUPPLY CAPACITY - MW				104	120	18
Peaking Plant Costs						
Generation-Fuel	8,640		8,640			
Generation Expense	1,330,672			1,330,672		
Taxes - Property	886,903			886,903		
Debt Service	8,620,160			8,620,160		
Capital Expenditures	95,000			95,000		
TOTAL PEAKING PLANT COSTS	10,941,375		8,640	10,932,735	-	-
Capacity Cost per MW		[1]		105,122		
KMPA/Prairie State costs						
Fixed Cost	42,219,879	[1]	29,605,185		12,614,694	
Variable Cost	2,425,188		2,425,188			
Other purchased power						
Hydro	6,481,952	[1]	4,629,064			1,852,888
Peaking capacity revenue	(4,158,000)			(4,158,000)		
TOTAL REVENUE REQUIREMENT	57,910,394		36,668,076	6,774,735	12,614,694	1,852,888
Alloc. of Revenue-related	4,318,352		2,734,322	505,189	940,672	138,169
Offset for Lighting Revenues	(1,307,998)		(828,206)	(153,018)	(284,923)	(41,850)
ADJUSTED REVENUE REQUIREMENT	60,920,748		38,574,192	7,126,906	13,270,444	1,949,207

[1] The fixed costs of Prairie State and Hydro capacity are allocated to capacity based on the cost per MW of peaking capacity.

Paducah Power System

Table II-4

Summary Classification of Test Year Revenue Requirements

Description	FY22		Power Supply Energy	Power Supply Capacity	Transmission Capacity	Distribution Capacity	Customer
COST CLASSIFICATION:							
Power Supply Costs	60,920,748	[1]	38,574,192	22,346,557			
Operating Expenses							
Transmission	5,690,738	[2]			5,690,738		
Distribution	8,725,091	[3]				7,416,328	1,308,764
Customer	2,190,629	[4]					2,190,629
TOTAL REVENUE REQUIREMENT	77,527,206		38,574,192	22,346,557	5,690,738	7,416,328	3,499,392

[1] Power supply capacity costs are considered coincident (1CP) peak demand related.

[2] Transmission capacity costs are considered coincident (4CP) peak demand related.

[3] Distribution capacity costs are considered a combination of non-coincident peak (NCP) demand related and customer related. The customer portion is related to the weighted customer counts and represents 15% of the total.

[4] The directly-classified customer costs are related to the weighted customer counts.

Paducah Power System

Table III-1

Test Year Allocation Factors

Rate Class	Alloc Factor	Residential	General Service - Nondemand	General Service - Small Demand	Large Commercial & Industrial	TOTALS
Rate Codes		20,22	40,94	50,57	54,55,58	
CUSTOMER ALLOCATION FACTORS:						
Test Year monthly bills		227,445	34,255	5,654	70	267,425
Customer allocation factor - unweighted	CU	85.05%	12.81%	2.11%	0.03%	100.00%
Weighting factors		1.00	2.00	10.00	25.00	
Weighted monthly bills		227,445	68,511	56,544	1,750	354,250
Customer allocation factor - weighted	CW	64.20%	19.34%	15.96%	0.49%	100.00%
ENERGY ALLOCATION FACTOR:						
Test Year energy sales - MWh		216,197	56,765	183,977	67,898	524,837
Energy allocation factor	KWH	41.19%	10.82%	35.05%	12.94%	100.00%
DEMAND ALLOCATION FACTORS:						
August 2022 energy sales - MWh		24,795	6,171	18,893	6,900	56,759
1 CP Load Factors - August		49%	48%	62%	79%	56%
1 CP Demand - MW		68	17	41	12	138
1 CP demand allocation factor	1CP	49.24%	12.46%	29.76%	8.54%	100.00%
4 CP Load Factors - Jun-Sep		13%	12%	16%	20%	14%
4 CP Demand - MW		193	53	134	38	418
4 CP demand allocation factor	4CP	46.26%	12.61%	31.95%	9.18%	100.00%
NCP Load Factors - average		51%	52%	62%	73%	
NCP demands - MW		48	13	34	11	106
NCP demand allocation factor	NCP	45.78%	11.86%	32.26%	10.11%	100.00%

Paducah Power System

Table III-2

Test Year Allocated Cost of Service

	Alloc Factor	Residential	General Service - Nondemand	General Service - Small Demand	Large Commercial & Industrial	TOTALS
		20,22	40,94	50,57	54,55,58	
Power Supply						
Energy	KWH	15,889,918	4,172,115	13,521,861	4,990,298	38,574,192
Capacity	1CP	11,003,533	2,784,053	6,651,300	1,907,671	22,346,557
Transmission Capacity	4CP	2,632,422	717,551	1,818,169	522,596	5,690,738
Distribution						
Capacity	NCP	3,395,109	879,257	2,392,325	749,637	7,416,328
Customer	CW	840,287	253,111	208,901	6,465	1,308,764
Customer	CW	1,406,485	423,661	349,661	10,822	2,190,629
PRELIMINARY ACOS		35,167,754	9,229,747	24,942,217	8,187,489	77,527,206
Adjust for Non-typical Loads		(1,603,411)	-	1,603,411	-	-
ADJUSTED ACOS		33,564,343	9,229,747	26,545,628	8,187,489	77,527,206
Revenues from Existing Rates		32,450,590	9,014,679	26,067,860	8,025,916	75,559,046
Net Increase in Revenues		1,113,753	215,067	477,768	161,572	1,968,161
Net Increase in Revenues - %		3.43%	2.39%	1.83%	2.01%	2.60%

Paducah Power System

Table IV-1

Power Costs Included in Base Rates

Description	FY22	
KMPA/Prairie State costs [1]		
Fixed Cost	$ 42,219,879	
Variable Cost	2,425,188	
Other purchased power		
Net MISO/KU [2]	2,771,953	
Hydro	6,481,952	
PURCHASED POWER COST	53,898,973	
Peaking capacity revenue [3]	(4,158,000)	
Generation-Fuel	8,640	
TOTAL POWER SUPPLY COST	$ 49,749,613	
TOTAL FY22 SALES - kWh	534,315,783	kWh
Purchased Power Cost per kWh	$ 0.09311	per kWh
Power Cost in Base Rates - Current Rates	$ 0.07732	per kWh
Indicated Average FY22 PCA	$ 0.01579	per kWh
TOTAL	$ 0.09311	per kWh
Power Cost in Base Rates - Proposed	$ 0.10000	per kWh
Indicated Average FY22 PCA	$ (0.00689)	per kWh
TOTAL	$ 0.09311	per kWh

[1] Includes costs associated with Prairie State, which is jointly owned by PPS through membership in KMPA. Primarily consists of operating costs billed by PSGC to KMPA and financing costs incurred by KMPA.

[2] Transmission expenses consist primarily of amounts billed to KMPA from MISO and KU/LGEE net of certain MISO costs reimbursed by KU/LGEE.

[3] Represents revenue associated with capacity sale by PPS to KYMEA.

Paducah Power System

Table IV-2

Residential Rate Design

	Billing Units	Current Rates	Proposed Rates	Existing Rates Revenue	Proposed Rates Revenue
Residential Rates					
Customer Charge	227,445	14.75	16.50	3,354,811	3,752,840
Energy Charge	216,197	0.11153	0.14478	24,112,440	31,301,314
PCA - June/July 2021	216,197	0.02305	(0.00689)	4,983,338	(1,489,811)
Total Revenues				32,450,590	33,564,343

	Billing Units	Current Rates	Proposed Rates	Monthly Increase	Percent Increase
Comparison of Monthly Bill Amounts at Typical kWh Usage Levels					
	100	28.21	30.29	2.08	7.4%
	200	41.67	44.08	2.41	5.8%
	300	55.12	57.87	2.74	5.0%
	400	68.58	71.66	3.07	4.5%
	500	82.04	85.45	3.41	4.2%
	600	95.50	99.23	3.74	3.9%
	700	108.96	113.02	4.07	3.7%
	800	122.41	126.81	4.40	3.6%
	900	135.87	140.60	4.73	3.5%
	1000	149.33	154.39	5.06	3.4%
	1100	162.79	168.18	5.39	3.3%
	1200	176.25	181.97	5.72	3.2%
	1300	189.70	195.76	6.05	3.2%
	1400	203.16	209.55	6.38	3.1%
	1500	216.62	223.34	6.72	3.1%
	1600	230.08	237.12	7.05	3.1%
	1700	243.54	250.91	7.38	3.0%
	1800	256.99	264.70	7.71	3.0%
	1900	270.45	278.49	8.04	3.0%
	2000	283.91	292.28	8.37	2.9%

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Table IV-3

General Service - Nondemand Rate Design

	Billing Units	Current Rates	Proposed Rates	Monthly Increase	Percent Increase
General Service-Nondemand Rates					
Customer Charge		22.00	33.00		
Energy Charge		0.12217	0.14947		
PCA - June/July 2021		0.02305	(0.00689)		
Typical Bill Amounts for kWh Usage Levels					
	200	51.04	61.52	10.47	20.5%
	400	80.09	90.03	9.94	12.4%
	600	109.13	118.55	9.42	8.6%
	800	138.18	147.06	8.89	6.4%
	1000	167.22	175.58	8.36	5.0%
	1200	196.26	204.10	7.83	4.0%
	1400	225.31	232.61	7.30	3.2%
	1600	254.35	261.13	6.78	2.7%
	1800	283.40	289.64	6.25	2.2%
	2000	312.44	318.16	5.72	1.8%
	2200	341.48	346.68	5.19	1.5%
	2400	370.53	375.19	4.67	1.3%
	2600	399.57	403.71	4.14	1.0%
	2800	428.62	432.23	3.61	0.8%
	3000	457.66	460.74	3.08	0.7%
	3200	486.70	489.26	2.55	0.5%
	3400	515.75	517.77	2.03	0.4%
	3600	544.79	546.29	1.50	0.3%
	3800	573.84	574.81	0.97	0.2%
	4000	602.88	603.32	0.44	0.1%

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Table IV-4

General Service - Small Demand Rate Design

	Current Rates	Proposed Rates
General Service-Demand Rates		
Customer Charge	115.00	160.00
Energy Charge - first 15 MWh	0.11938	0.14100
Energy Charge - over 15 MWh	0.07495	0.11218
Demand Charge - over 50 kW	16.49	17.25
PCA - June/July 2021	0.02305	(0.00689)

Typical Bill Amounts for kW and kWh Usage Levels

Billing kW	Billing kWh	Current Rates	Proposed Rates	Monthly Increase	Percent Increase
	4,563	765	772	7	0.9%
25	9,125	1,415	1,384	(31)	-2.2%
	13,688	2,065	1,996	(69)	-3.3%
	9,125	1,415	1,384	(31)	-2.2%
50	18,250	2,570	2,514	(56)	-2.2%
	27,375	3,464	3,475	10	0.3%
	13,688	2,477	2,427	(50)	-2.0%
75	27,375	3,876	3,906	29	0.8%
	41,063	5,218	5,347	129	2.5%
	18,250	3,394	3,376	(18)	-0.5%
100	36,500	5,183	5,298	115	2.2%
	54,750	6,971	7,219	248	3.6%
	27,375	5,113	5,200	86	1.7%
150	54,750	7,796	8,082	286	3.7%
	82,125	10,479	10,964	485	4.6%
	36,500	6,832	7,023	191	2.8%
200	73,000	10,409	10,866	457	4.4%
	109,500	13,986	14,709	723	5.2%
	91,250	17,144	17,962	818	4.8%
500	182,500	26,087	27,570	1,483	5.7%
	273,750	35,029	37,178	2,148	6.1%

Paducah Power System

Table IV-5

General Service - Large Demand Rate Design

	Current Rates	Proposed Rates
General Service-Large Demand Rates		
Customer Charge	275.00	275.00
Energy Charge	0.06736	0.09972
Demand Charge - first MW	15.25	16.50
Demand Charge - over 1 MW	17.62	16.50
PCA - June/July 2021	0.02305	(0.00689)

Typical Bill Amounts for kW and kWh Usage Levels

Billing kW	Billing kWh	Current Rates	Proposed Rates	Monthly Increase	Percent Increase
	182,500	32,025	33,716	1,691	5.3%
1000	365,000	48,525	50,656	2,131	4.4%
	547,500	65,024	67,597	2,572	4.0%
	273,750	49,085	50,436	1,351	2.8%
1500	547,500	73,834	75,847	2,012	2.7%
	821,250	98,584	101,257	2,673	2.7%
	365,000	66,145	67,156	1,011	1.5%
2000	730,000	99,144	101,037	1,893	1.9%
	1,095,000	132,144	134,918	2,774	2.1%
	456,250	83,205	83,876	672	0.8%
2500	912,500	124,454	126,228	1,774	1.4%
	1,368,750	165,704	168,579	2,875	1.7%
	547,500	100,264	100,597	332	0.3%
3000	1,095,000	149,764	151,418	1,654	1.1%
	1,642,500	199,263	202,240	2,976	1.5%
	638,750	117,324	117,317	(7)	0.0%
3500	1,277,500	175,074	176,609	1,535	0.9%
	1,916,250	232,823	235,901	3,078	1.3%
	730,000	134,384	134,037	(347)	-0.3%
4000	1,460,000	200,384	201,799	1,416	0.7%
	2,190,000	266,383	269,562	3,179	1.2%

Paducah Power System

Table IV-6

Industrial Service Rate Design

	Current Rates	Proposed Rates
Industrial Service		
Customer Charge	275.00	295.00
Energy Charge	0.05257	0.08672
Demand Charge	18.38	17.25
PCA - June/July 2021	0.02305	(0.00689)

Typical Bill Amounts for kW and kWh Usage Levels

Billing kW	Billing kWh	Current Rates	Proposed Rates	Monthly Increase	Percent Increase
	182,500	32,456	32,113	(343)	-1.1%
1000	365,000	46,256	46,681	425	0.9%
	547,500	60,057	61,249	1,192	2.0%
	228,125	40,501	40,068	(433)	-1.1%
1250	456,250	57,752	58,278	526	0.9%
	684,375	75,002	76,488	1,485	2.0%
	273,750	48,546	48,022	(524)	-1.1%
1500	547,500	69,247	69,874	627	0.9%
	821,250	89,948	91,726	1,778	2.0%
	319,375	56,591	55,977	(615)	-1.1%
1750	638,750	80,742	81,471	728	0.9%
	958,125	104,893	106,965	2,071	2.0%
	365,000	64,636	63,931	(705)	-1.1%
2000	730,000	92,238	93,067	830	0.9%
	1,095,000	119,839	122,203	2,364	2.0%
	410,625	72,681	71,886	(796)	-1.1%
2250	821,250	103,733	104,664	931	0.9%
	1,231,875	134,784	137,442	2,657	2.0%
	456,250	80,727	79,840	(887)	-1.1%
2500	912,500	115,228	116,260	1,032	0.9%
	1,368,750	149,730	152,680	2,950	2.0%

Electric Plant Board of the City of Paducah, Kentucky
Revenue from Existing and Proposed Rates [1]

				Pro Forma Annual Revenues			
	Billing Units [2]	Existing Rates	Proposed Rates	Existing Rates	Proposed Rates	Increase/ (Decrease)	Percent Increase
Residential							
Customer Charge	227,445	14.75	16.50	3,354,811	3,752,840		
Energy Charge	216,197	0.11153	0.14478	24,112,440	31,301,314		
PCA - June/July 2021	216,197	0.02305	(0.00689)	4,983,338	(1,489,811)		
Total				32,450,590	33,564,343	1,113,753	3.4%
General Service Nondemand (GS-1)							
Customer Charge	34,032	22.00	33.00	748,713	1,123,070		
Energy Charge	56,615	0.12217	0.14947	6,916,599	8,462,257		
PCA - June/July 2021	56,615	0.02305	(0.00689)	1,304,965	(390,130)		
Total				8,970,277	9,195,196	224,919	2.5%
Drain Pumps							
Customer Charge	223	65.00	77.00	14,495	17,171		
Energy Charge	151	0.09391	0.12197	14,171	18,405		
PCA - June/July 2021	151	0.02305	(0.00689)	3,478	(1,040)		
Total				32,144	34,537	2,392	7.4%
General Service Small Demand (GS-2)							
Customer Charge	5,642	115.00	160.00	648,879	902,789		
Energy Charge - first 15 MWh	80,956	0.11938	0.14100	9,664,548	11,414,936		
Energy Charge - over 15 MWh	102,554	0.07495	0.11218	7,686,387	11,504,462		
Demand Charge - over 50 kW	226,788	16.49	17.25	3,739,735	3,912,094		
PCA - June/July 2021	183,510	0.02305	(0.00689)	4,229,899	(1,264,564)		
Total				25,969,449	26,469,717	500,269	1.9%
Seasonal							
Customer Charge	12	115.00	160.00	1,380	1,920		
Energy Charge - first 15 MWh	468	0.13529	0.16600	63,262	77,622		
Energy Charge - over 15 MWh	-	0.09086	0.13718	-	-		
Demand Charge - over 50 kW	-	20.49	21.25	-	-		
PCA - June/July 2021	468	0.02305	(0.00689)	10,778	(3,222)		
Total				75,420	76,320	900	1.2%
General Service - Large Demand [GS-3]							
Customer Charge	48	275.00	275.00	13,200	13,200		
Energy Charge	50,520	0.06736	0.09972	3,403,049	5,037,679		
Demand Charge - first MW	41,456	15.25	16.50	632,204	684,024		
Demand Charge - over 1 MW	51,169	17.62	16.50	901,603	844,293		
PCA - June/July 2021	50,520	0.02305	(0.00689)	1,164,493	(348,135)		
Total				6,114,549	6,231,061	116,512	1.9%
Industrial Service (IS-1)							
Customer Charge	22	275.00	295.00	6,050	6,490		
Energy Charge	17,377	0.05257	0.08672	913,519	1,506,879		
Demand Charge	32,625	18.38	17.25	599,648	562,781		
PCA - June/July 2021	17,377	0.02305	(0.00689)	400,544	(119,746)		
Total				1,919,761	1,956,404	36,643	1.9%

[1] Existing rates include Power Cost Adjustment (PCA) in effect for June 2021. Proposed rates include PCA effective July 2021. Customer Charges per customer are billed monthly. Energy Charges and PCA are billed based on monthly metered consumption in kWh. Demand Charges, if applicable, are billed based on monthly metered demand in kW.

[2] Annual billing units for Customer Charges is customer-months; for Demand Charges is kW-months; and for Energy Charges and PCA is MWh (1,000 kWh).