Project Memorandum

Date: February 14, 2022

To: Travis McCullar, Chief Electrical Engineer, Frankfort Plant Board

From: Craig Brown, Project Manager, 1898 & Co.

Subject: 2022 Rate Design Services

The Frankfort Plant Board (FPB) engaged 1898 & Co., a division of Burns & McDonnell Engineering Company, to conduct various reviews and analyses related to electric rate design. This Project Memorandum (Memo) presents the results and recommendations resulting from these studies. This Memo presents recommendations for the following rate design topics:

- Review of current rate class structure
- Primary service rates
- Net metering policy and avoided cost rates
- Green tariff/REC purchase programs
- PURPA obligations
- Gratis (in house) rates
- LED lighting rates
- Rate design for EV Chargers

REVIEW OF CURRENT RATE CLASS STRUCTURES

FPB requested 1898 & Co. to review its existing rate classes with a focus on the defining criteria for each class. FPB has four principal rate classes: Residential, General Service (GS), Large Power (LP), and Large Power – High Load Factor (LP-HLF). The qualifications and rates for these classes are shown in Table 1 on the following page. The Residential and GS rates include a customer charge and an energy charge, whereas the LP and LP-HLF rates include customer, energy, and a demand charge.

The qualifications for the GS class are all non-residential customers with an average monthly demand of less than 50 kW. The LP class is for all commercial and industrial customers whose average demand is 50 kW or greater. If the customer's average demand is greater than 1,000 kW and has a load factor of greater than 55%, they move up to the LP-HLF rate.

Table 1: FPB Rate Classes

Description	Residential (RS)	General Service (GS)	Large Power (LP)	Large Power High Load Factor (LP-HLF)
Qualifications	All Residential	Non-residential up to 50 kW	Non-residential > 50 kW	Non-residential > 1,000 kW & LF > 55%
Customer Charge	$11.45	$18.50	$75.00	$225.00
Energy Charge (per kWh)	$0.09400	$0.09665	$0.05875	$0.05310
Demand Charge (per kW)		$0.00	$12.12	$11.83

Evaluation of GS and LP Rate Classes

FPB has received some negative feedback from customers regarding large bill increases when moving from the General Service (GS) to the Large Power (LP) rate. To evaluate the appropriateness of the current rate structures, 1898 & Co. started by evaluating bill calculations at the various break points between classes. We first ran scenarios comparing the GS and LP rates for a customer at 50 kW with various load factors (i.e., various kWh usage levels relative to the same peak demand).

The comparisons are shown in Table 2 on the following page. Each scenario is calculated with a demand of 50 kW and energy usage of 10,000, 15,000, or 20,000 kWh. For scenario 1, with a 27% load factor, the bill impact when moving from GS to LP is an increase of 29%, which is significant and understandable that customers may complain when moving to the higher rate. Under scenario 2, a 41% load factor results in a bill that is only 6% higher, and using a 55% load factor under scenario 3, the calculated bill using LP rates is 5% lower. We identified the breakeven energy usage for a 50kW customer where the monthly bill would be the same under both rates. The breakeven usage was 17,480 kWh, which is a 48% load factor. A 48% load factor is a high bar to achieve for a smaller commercial customer.

Table 2: General Service and Large Power Rate Comparison

Description	Scenario 1				Scenario 2				Scenario 3			
Monthly Demand	50 kW				50 kW				50 kW			
Monthly Energy	10,000 kWh				15,000 kWh				20,000 kWh			
Load Factor	27%				41%				55%			
	GS		LP		GS		LP		GS		LP	
Customer Charge	$	18.50	$	75.00	$	18.50	$	75.00	$	18.50	$	75.00
Energy Charge	$	966.50	$	587.50	$	1,449.75	$	881.25	$	1,933.00	$	1,175.00
Demand Charge	$	-	$	606.00	$	-	$	606.00	$	-	$	606.00
Total Bill	$	985.00	$	1,268.50	$	1,468.25	$	1,562.25	$	1,951.50	$	1,856.00
% Change				29%				6%				-5%

Breakeven Scenario				
Monthly Demand	50 kW			
Monthly Energy	17,480 kWh			
Load Factor	48%			
	GS		LP	
Customer Charge	$	18.50	$	75.00
Energy Charge	$	1,689.46	$	1,026.96
Demand Charge	$	-	$	606.00
Total Bill	$	1,707.96	$	1,707.96
% Change				0%

Evaluation of LP and LP-HLF Rate Classes

All customers with an average demand greater than 50 kW qualify for the Large Power rate. If a customer has an average demand of greater than 1,000 kW (1 MW) *and* an average load factor greater than 55%, they qualify for the LP-HLF rate. The LP-HLF rate has a higher customer charge and slightly lower energy and demand charges. As shown in Table 3, we conducted a similar comparison between the two classes at the breakpoint of 1,000 kW.

Each scenario is calculated with a demand of 1,000 kW and energy usage of 250,000, 350,000, or 450,000 kWh. For scenario 4, with a 34% load factor, the bill impact when moving from LP to LP-HLF is a decrease of 6%. Under scenarios 5 and 6, using a 48% and 62% load factor results in a bills that are 6% and 7% lower under the LP-HLF rate, respectively. There is no breakeven point between the LP and LP-HLF rates – the LP-HLF rate is always lower, regardless of energy usage.

Table 3: Large Power LP-HLF Rate Comparison

Description	Scenario 4		Scenario 5		Scenario 6	
Monthly Demand	1,000 kW		1,000 kW		1,000 kW	
Monthly Energy	250,000 kWh		350,000 kWh		450,000 kWh	
Load Factor	34%		48%		62%	
	LP-HLF	LP	LP-HLF	LP	LP-HLF	LP
Customer Charge	$ 225.00	$ 75.00	$ 225.00	$ 75.00	$ 225.00	$ 75.00
Energy Charge	$ 13,275.00	$ 14,687.50	$ 18,585.00	$ 20,562.50	$ 23,895.00	$ 26,437.50
Demand Charge	$ 11,830.00	$ 12,120.00	$ 11,830.00	$ 12,120.00	$ 11,830.00	$ 12,120.00
Total Bill	$ 25,330.00	$ 26,882.50	$ 30,640.00	$ 32,757.50	$ 35,950.00	$ 38,632.50
% Change	-6%		-6%		-7%	

Recommendations

1898 & Co. recommends two changes resulting from our evaluation. First, we recommend the creation of a new rate class between the GS and LP classes. This rate should include a demand charge and be generally structured like the LP rate, but with a lower demand charge and higher energy charge. We recommend the rate be for customers with an average demand greater than 50 kW and up to somewhere in the range of 500 kW to 1,000 kW. This will help alleviate the large bill impacts that currently occur between the GS and LP classes. We recommend the class be named General Service Demand (GSD). The actual execution of this recommendation will require further study to determine the specific customer who would be impacted by the change.

The second recommendation is to modify the energy and demand charges in the LP-HLF class to better differentiate the value of a high load factor customer. A properly designed HLF rate will have a higher demand charge and a lower energy charge than the comparable non-HLF rate (LP in this case). Having a higher demand charge will result in a breakeven load factor, so the rate isn't simply lower than the LP rate. A properly design HLF rate will be beneficial to the customer when they can consistently demonstrate a high load factor. We recommend a breakeven load factor of around 50%. By having a lower energy charge versus the comparable rate, the higher the customer's load factor increases, the lower their average rate will be. As with the GSD recommendation, the actual execution of this recommendation will require further study and analysis.

PRIMARY CUSTOMER RATE

FPB has received requests from customers expressing interest in taking service at primary voltage (13.8 kV). The FPB system and existing rate structure are designed around customers taking service at secondary voltage. When taking service at a primary voltage (or higher), typically the customer will own any facilities behind the meter to the actual load center(s). This can simply be a transformer that the customer owns along with the service lines to specific load centers or a more elaborate system where the customer operates a secondary distribution system behind the primary metering point that includes secondary lines, additional line transformers, service drops, and numerous metering points.

There are two general benefits for the customer taking service at a primary voltage:

- In the case where the customer operates a secondary distribution system behind the primary meter, all load is aggregated and totalized at the primary metering point instead of being measured at each of the secondary metering sites. This will generally result in lower demand charges because only the combined coincident demand of all the submeters is measured and not the sum of the individual meter's demands.
- Because electric rates are generally developed based on the assumption that customers take service at a secondary voltage, primary service rates are often discounted to account for line losses that occur in the secondary system between the primary metering point and final service location.

Currently, FPB does not have provisions in its Large Power rate to compensate for service at a primary voltage. It does, however, have a definition for Primary Service within its Electric Service manual. It states, "*Primary service is available for commercial and industrial customers having multiple service points or large single loads*." It further defines customer-owned facilities as "*All conductors, transformers, and poles as may exist are owned and maintained by the customer. Ownership by the Plant Board terminates at the metering point. The customer may tap his facilities and make his own extensions for his own use*."

1898 & Co. recommends two changes to FPB's rates and policies to enable Primary Service:

1. Add a primary service discount to the Large Power and Large Power High Load Factor rates.
2. Establish a valuation and compensation policy for existing secondary service customers that wish to be served at a primary voltage.

Primary Service Discount

A discount for primary service is typically accomplished through a discount to the demand and energy charges. Ideally, the cost differential between primary and secondary service would be identified through an unbundled cost of service study and a detailed line loss study, neither of which are currently available nor achievable in a costly manner for FPB. As an alternative, we recommend the application of a percentage discount to the actual billing determinants (kW and kWh) to reflect the lines losses between primary and secondary voltage service. A typical line loss percentage from primary to secondary voltage is in the range of 2% - 3%. Note that it is the actual billing determinants that are adjusted, not the rates. The billing units would be reduced by a set percent and applied to the existing LP or LP-HLF rate. Example tariff language is shown below.

> PRIMARY METERING ADJUSTMENT: The monthly Demand and Energy Charges are based on secondary metering. When a primary meter is installed, the customer's measured kWh and kW shall be decreased by 2.0%.

Compensation for Secondary System

The more complicated aspect of establishing a primary meter rate is the application to an existing customer. If an existing customer that currently operates on a secondary voltage system across numerous buildings and metering points all within a single geographic footprint wishes to transition to a single primary metering location, the existing secondary conductor, poles, line transformers, service drops, and meters would all be "behind the meter" now. Per the FPB policy, a customer taking service at a primary voltage should be owned and operated by the customer.

Generally speaking, it is unlikely that existing customers have an interest in operating and maintaining their existing secondary distribution system, let alone purchasing it outright. However, should a customer wish to explore the option, we recommend the application of industry standard valuation methods for the valuation of the secondary distribution system. The definition of fair market value according to the Uniform Standards of Professional Appraisal Practice (USPAP) is as follows:

> "Market value is the most probable price which a property should bring in a competitive and open market under all conditions requisite to a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus."

There are three common valuation methods for determining fair market value (FMV) for real property, including electric distribution systems: the income approach, the cost approach, and the market approach. Because the sale or transfer of these assets will not produce a cash flow for the purchaser, the income approach is not the preferred option. The market approach bases valuations on actual sales of similar assets. Since finding comparable sale information that matches the subject property is often difficult, the market approach is also not recommended. This leaves the cost approach, which is the most common approach for determining the fair market value of utility property.

The cost approach to valuation can be based on original cost, reproduction cost, or replacement cost, all adjusted for depreciation. The two most applicable to the valuation of an existing distribution system are original cost and reproduction cost. Original cost less depreciation (OCLD) represents the actual cost of the assets when placed into service, less accumulated depreciation to date. This is synonymous with net book value. OCLD is generally considered the floor for valuation purposes and sets the lower band for a range of values to be considered. A more appropriate method for determining FMV is reproduction cost less depreciation (RCLD). RCLD represents the cost to reproduce the exact system at today's construction costs, less adjustment for deprecation. There are additional aspects of valuation that may need to be considered on a case-by-case basis including stranded assets, inventory, and materials and supplies.

While the valuation of the secondary distribution system is an important aspect of this process, if the customer is unwilling to purchase the system outright, FPB may elect to offer the transaction through a monthly facilities charge. The valuation of the system would still be a primary component, but it could be structured as more of a lease of the facilities. Additional charges would need to be developed for the operation, maintenance, and routine capital replacements for the system. It is not possible to establish a system-wide policy on what these charges are but should be developed on a case-by-case basis with the specific customers.

AVOIDED COST RATES FOR LARGE SOLAR INSTALLATIONS

FPB has an existing net metering policy that applies to facilities with a maximum rated capacity of 30 kW or less. The policy is available to customers up to a 1% cap of annual system peak demand, both of which are consistent with Kentucky state precedent. While net metering is not considered an ideal method for compensating customers with behind the meter generation, the overall impact on FPB and subsidization of other customers is small at this point. However, FPB does not have a policy for compensating customers that have generation facilities that do not qualify under the net metering policy.

FPB has requested 1898 & Co. to develop a compensation policy for customers with behind the meter generation that exceeds the net metering threshold of 30 kW. For these customers, metering should be in place that separately measures the energy used from the FPB grid and the excess customer generation exported to the grid. All energy used from the grid should be billed to the customer at regular retail rates and the customer receives the full benefit of its generation to serve its native load. If there is excess generation, that is exported to the grid, we recommend use of a modified Value of Solar (VOS) rate to compensate the customer for this energy.

A VOS rate is an alternative to net metering. Unlike net metering, a VOS rate dissociates the customer payments for electricity consumed from the compensation they receive for solar electricity generated. Under a VOS rate, the utility purchases some (i.e., the net excess) or all of the generation from a solar installation at a rate that is independent of retail electricity rates. The transaction can take two forms:

1. Buy All – Sell All approach – customer pays for all energy at regular retail rates and all generated energy is sold back to the utility at the VOS rate.

2. Net Export approach. Customer generation is first used to fully serve native load. Any additional load required is purchased from the utility at regular retail rates. Only the excess generation exported back to the grid is compensated at the VOS rate.

Of these two options, we recommend using the Net Export approach. This allows the customer to fully benefit from their investment in solar facilities and links the purchases of excess generation to what is actually exported back to the grid.

Calculating the VOS rate (the amount paid by the utility to the customer for excess distributed solar generation) involves identifying the tangible benefits and real costs that solar provides to the electric system. The value of each is calculated and those values are summed to form a bundled purchasing rate for solar generation. The electric system benefits (e.g., cost savings) attributable to solar can include energy, capacity, transmission and distribution system deferral, and line loss reductions, as well as environmental and other benefits that may vary from system to system. The VOS rate can also be used as a means through which the utility receives compensation for the costs of integrating the solar generation into the electricity system or for providing transmission and distribution services in connection with the solar system. For FPB's system, we considered the following components:

- Avoided energy costs

- Avoided generation demand costs
- Avoided transmission demand costs
- Avoided distribution demand costs
- Distribution system deferred capital investment
- Cost of integrating additional solar into the distribution system
- Environmental benefits

These categories can be grouped into two categories: costs that are passed through via FPB's power supply agency, Kentucky Municipal Energy Agency (KyMEA), and costs that are budgeted for by FPB. The first three, generation and transmission energy and demand costs are paid by FPB to KyMEA. FPB is responsible for distribution system costs.

KyMEA rates include a single charge for energy ($/kWh) and four demand charges, one for generation (billed demand) and three for transmission services, as shown below.

Table 4: KyMEA Rates

Rate Component	Charge	Unit
Energy Charge	$0.024702	Per kWh
Demand Charges		
Billed Demand	$14.0400	Per kW
KU Transmission	$2.9829	Per kW
KU Ancillary	$0.3029	Per kW
MISO Transmission	$1.5350	Per kW

To evaluate the impact of a solar facility on FPB's electric system, we modeled a 100 kW PV solar system using NREL's System Advisory Model (SAM) and PVWatts. The SAM is able to produce an hourly profile for a PV system for a year based on a specific set of assumptions and at a specific geographic location. A location in Frankfort (FPB Admin Building) and a weather profile for Frankfort were selected. The PV array modeled was a 100 kWDC nameplate capacity with a DC to AC ratio of 1.15 and an inverter efficiency of 98%. We modeled a fixed tilt, open rack system with a 35 degree tilt, 180 degree azimuth, ground coverage ratio of 0.3, and losses of 14%. The output of the model is the simulated actual hourly output of the array for one year. By using 100 kW as the base nameplate capacity, all output can be viewed as the percentage of capacity actually produced.

The goal of modeling the hourly output was to gain an understanding of the potential output of the facility at the time of FPB's system peak. FPB's demand charges paid to KyMEA are based on the single maximum peak during the month. Therefore, it is only a solar array's contribution during that single hour that can contribute to reducing generation and transmission demand costs on the FPB system. Table 5 shows the date and time of the FPB system monthly peak for 2020 – 2021 and the model contribution at the time of the peak. The third column shows the actual modeled output at the specific time of the peak and the fourth column shows the average PV output at the hour the peak occurred.

Table 5: FPB System Peak 2020-2021

Date and Time of Peak	Peak kW	PV Output at Peak	Average Monthly PV Output at Peak Hour
1/22/2020 8:15:00 AM	114,509	3.35	8.42
2/14/2020 9:45:00 AM	112,392	11.16	36.36
3/6/2020 1:30:00 PM	90,216	11.96	50.78
4/15/2020 8:15:00 AM	78,624	38.89	24.09
5/26/2020 3:45:00 PM	104,126	38.32	27.69
6/10/2020 3:00:00 PM	121,565	39.27	34.96
7/21/2020 5:00:00 PM	129,629	10.58	31.12
8/26/2020 4:30:00 PM	128,419	15.35	16.76
9/10/2020 4:00:00 PM	119,246	19.11	26.04
10/23/2020 3:00:00 PM	86,688	1.27	4.74
11/30/2020 6:00:00 PM	92,534	27.80	21.54
12/2/2020 8:15:00 AM	103,622	6.86	8.35
1/29/2021 8:30:00 AM	112,392	15.30	8.42
2/17/2021 8:45:00 AM	121,262	45.76	27.60
3/3/2021 7:45:00 AM	94,853	19.39	17.86
4/28/2021 2:30:00 PM	88,704	14.60	47.02
5/24/2021 4:15:00 PM	114,408	34.75	27.69
6/29/2021 3:45:00 PM	128,117	32.32	34.96
7/26/2021 3:45:00 PM	126,806	35.25	31.12
8/12/2021 4:45:00 PM	132,552	21.05	16.76
9/14/2021 3:45:00 PM	117,331	30.12	26.04
10/14/2021 4:45:00 PM	102,514	8.48	4.74
11/23/2021 8:15:00 AM	98,784	25.36	21.54
12/20/2021 8:30:00 AM	100,901	0.11	8.35
Average PV Output		21.11	23.46

Typically, the FPB system peaks around 4:00 PM between May and October and around 8:00 AM from November through April, with the occasional anomaly in the shoulder months. This is significant when evaluating the cost avoidance of solar systems because the maximum output of a solar facility is centered around noon and is significantly less at the start and end of the day when FPB peaks. By averaging the system PV output at the hour of the monthly peak, we have estimated a solar array operating in the FPB system will contribute at 23.46% of nameplate capacity at the time of the system peak. To translate this back into the development of a VOS rate for FPB, we will apply a 23.46% credit for avoided generation and transmission demand costs to the average KyMEA demand charges applied on a $/kWh basis at the FPB system load factor of 67.8%[1]. The KyMEA energy charge will be credited at 100%. The VOS credits for generation and transmission are shown in

Table 6.

Table 6: VOS for Generation and Transmission

Rate Component	Rate	Rate in $/kWh	VOS Contribution	VOS Credit
Energy Charge	$0.0247 per kWh	$0.0247	100%	$0.02470
Demand Charges				
Billed Demand	$14.0440 per kW	$0.02838	23.46%	$0.00666
KU Transmission	$2.9829per kW	$0.00603	23.46%	$0.00141
KU Ancillary	$0.3029per kW	$0.00061	23.46%	$0.00014
MISO Transmission	$1.5350 per kW	$0.00310	23.46%	$0.00073
VOS Generation Energy Credit				$0.02470
VOS Generation Demand Credit				$0.00666
VOS Transmission Demand Credit				$0.00229

Distribution System and Other Credits

Distribution facilities are sized and designed to serve the maximum load of a customer regardless of the timing of the system peak (non-coincident peak or NCP). The distribution system will experience some diversification in NCP the farther away from the actual load centers (i.e., the NCP at a distribution substation will likely be less than the sum of the individual customer NCPs it serves). Because there is effectively no chance that a customer's solar array will always be exporting to the grid at the time of the customer's NCP, there are no savings related to distribution costs. The same distribution facilities must be installed to serve the customer's NCP regardless of solar output. As such, there is no VOS credit for distribution demand costs. Similarly, there is a comparable likelihood that in an area of multiple PV facilities, FPB could either defer future distribution investment or may have to upgrade distribution facilities to handle the increased

[1] Average monthly system load factor January 2020 – December 2021.

load exported to the grid. As such, there is neither a credit for deferred distribution costs nor an adder for increased distribution costs.

The final aspect of a VOS rate for FPB was considered in environmental benefits. This category is more subjective and there are no tangible costs that can be evaluated. In the future, if a carbon tax or similar environmental legislation is enacted, this should be considered in a VOS rate. However, until such time we do not recommend adding arbitrary costs to a VOS rate.

Table 7 shows our recommended VOS rate of $0.03365/kWh. This rate should be updated annually with changes to KyMEA rates.

Table 7: Recommended Value of Solar Avoided Cost Rate

Rate Component	Rate ($/kWh)
Avoided energy costs	$0.02470
Avoided generation demand costs	$0.00666
Avoided transmission demand costs	$0.00229
Avoided distribution demand costs	$0.00
Distribution system deferred capital investment	$0.00
Cost of integrating additional solar into distribution system	$0.00
Environmental benefits	$0.00
Total VOS Rate	**$0.03365**

An additional point of consideration for the Board is if the availability of this policy and if it should be limited in any way. The program could have two potential limits – one for the maximum size a customer can install behind the FPB meter and one for overall aggregate participation. From an individual size limitation, we consider the historic peak usage to be an appropriate starting point. The goal is to not incentivize a customer overbuilding their PV system with the intent of selling energy back to FPB. This could be modified above or below this amount by only allowing up to 80% of peak or allowing up to 120% of historic peak to allow room for growth. From an aggregate participation perspective, you can go beyond the 1% of system peak limit under the Net Metering Policy because the compensation is more appropriate. A cap of 10% of system peak would be reasonable.

REVIEW OF PURPA OBLIGATIONS UNDER KYMEA CONTRACT

FPB requested 1898 & Co. review its obligations under the Federal Energy Regulatory Commission (FERC) regulations under the Public Utility Regulatory Policies Act (PURPA) as it related to Qualified facilities (QF). QFs are independent generating resources that utilities are obligated to purchase power from under certain conditions. The power is generally compensated at the utility's avoided cost of power. QFs fall into two categories:

Cogeneration Facility
A cogeneration facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy. For example, in addition to the production of electricity, large cogeneration facilities might provide steam for industrial uses in facilities such as paper mills, refineries, or factories, or for HVAC applications in commercial or residential buildings. Smaller cogeneration facilities might provide hot water for domestic heating or other useful applications. To be considered a qualifying cogeneration facility, a facility must meet all the requirements of 18 C.F.R. §§ 292.203(b) and 292.205 for operation, efficiency, and use of energy output as well as be certified as a qualified facility (QF) pursuant to 18 C.F.R. § 292.207. There is no size limitation for qualifying cogeneration facilities.[2]

Small Power Production Facility
A small power production facility is a generating facility of 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources. Pursuant to 18 C.F.R. § 292.204(a), the power production capacity of any small power production facility, together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts. An affiliated small power production QF located one mile or less from the instant facility is irrebuttably presumed to be at the same site. As of December 31, 2020, an affiliated small power production QF located more than one mile and less than 10 miles from the instant facility is rebuttably presumed to be at a separate site. An affiliated small power production QF located 10 miles or more from the instant facility is irrebuttably presumed to be located at a separate site.[3]

FPB Obligations
1898 & Co. reviewed FPB's All Requirements Contract (Contract) with KyMEA and spoke with KyMEA staff directly to identify any obligation that FPB may have related to potential QFs located within the FPB service territory. As stated in Section 3b. of the Contract, *KyMEA will submit a request to the FERC for waiver of the Member's purchase obligations under the PURPA and for approval of the Agency's undertaking of such PURPA purchase obligations, all for the period of the Service Term. The Agency shall be responsible for filing the request and taking such actions as it deems reasonable to obtain FERC's approval thereof. The Agency's costs of preparing and making such filing and other activities i n connection with FERC proceedings to obtain or retain such approvals shall be included in the Revenue Requirements hereunder or otherwise equitably assessed to the All Requirements Members. Each PURPA purchase made by the Agency in an All Requirements Member's stead pursuant to the FERC waiver shall be an All Requirements Power Supply Resource.*

What this means for FPB is that KyMEA has assumed all potential QF obligations and any QFs located in FPB's service territory will be treated like an all requirements resource shared with all KyMEA members.

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[2] https://www.ferc.gov/qf
[3] Ibid.

GREEN TARIFF

FPB requested 1898 & Co. to evaluate the potential of adding a Green Rate option for electric customers that desire to contribute to renewable energy. Green Tariffs are common around the United States and the most common approach is through the purchase or assignment of Renewable Energy Credits (REC). RECs represent the energy generated by renewable energy sources, such as solar or wind power facilities. Buying RECs is not equivalent to buying electricity. Instead, RECs represent the clean energy attributes of renewable electricity. One REC is equal to 1,000 kWh of renewable energy.

Green Tariffs are generally designed where customers can purchase "blocks" of renewable energy attributes. Customers elect to contribute a fixed dollar amount or a certain number of blocks at a fixed price per block. That money is then used to purchase RECs from regional renewable energy sources. The RECs are then retired on the customer's behalf.

We recommend that FPB design a green tariff that is similar to LG&E's Green Power Program. Because FPB does not own any renewable energy sources, it must purchase RECs from the holder that owns the renewable generation. This is most effectively accomplished through Green-e (green-e.org), which is a certification program that ensures that the RECs purchased are legitimately from renewable energy resources. Through green-e, FPB can purchase RECs on behalf of its customers. Because the pricing of RECs can be somewhat volatile, we recommend that FPB get indicative pricing before the program is launched so initial pricing can be set for customers and they have an indication of how many RECs they are purchasing. The LG&E program has separate block definitions for residential/small commercial and large commercial/industrial.

Residential/Small Comm:	1 block = \$5 = ~1.26 RECs
Large Comm/Industrial:	1 block = \$13 = ~4.2 RECs

The specific number of RECs purchased on behalf of the customer will vary based on current REC pricing. 1898 & Co. can provide specific tariff language to get the program started.

KYMEA Green Power Program

As a longer-term option for FPB, we recommend that you transition the operation and administration of the Green Program to KyMEA, which is currently developing its own program that will be available to all KyMEA member utilities.

As part of its IRP2020 Action Plan, KyMEA is creating a green energy program called Power Green Kentucky™. "Power Green Kentucky gives members' retail customers the option to request up to 100% green energy. The green energy is sourced from the Ashwood Solar I Project and SEPA Hydro. When a member's customer participates in the program, KYMEA allocates that portion of its renewable portfolio to the customer who purchased the Green Power. KYMEA charges the member for the green power; and the member, in turn, charges the retail customer. KYMEA creates a non-fungible KYMEA Green Tag, which self-certifies that the energy was generated from an eligible carbon-free energy resource (renewable electricity) and was fed into the KYMEA shared system of power lines that transport energy."

Power Green Kentucky is also designed to mimic LG&E's Green Power Program, so it would be a natural transition for FPB customers. Further, because KyMEA can self-certify the RECs for its own renewable resources, this is a lower cost option for all members.

REVIEW OF IN HOUSE/GRATIS RATES

It is very common for publicly-owned utilities, whether an enterprise fund of a municipal government or an independent utility board such as FPB, to have discounted rates or provide free service to internal users or municipal offices. Currently, FPB has a Municipal Service rate class that is applied to both internal users (Water, Cable, Internet, etc.) and municipal offices for electric service. The municipal rate is structured like the General Service class rate with an $18.50 customer charge and an energy charge of $0.8950/kWh. The energy charge is about 7% lower than the GS energy charge. All municipal and FPB "customers" are charged with this rate regardless of load size (i.e., there are no demand charges for larger customers).

The rationale to provide discounted or free service is simple – if municipal offices paid full rates those costs would have to be passed on to residents through other charges or taxes. In the example of internal FPB users, it may be considered an offset for the Water Department to charge the Electric Department less for water service and the Electric Department to charge the Water Department less for electric service.

When evaluating the appropriateness of providing free or discounted service to internal users, it is important to consider the overall financial model that FPB operates under. That is, FPB is a not-for-profit enterprise and once the revenue requirement is determined as to what total revenue should be recovered in rates, any discounts provided to one group of customers must be recovered through higher charges to other customer classes, all else equal. The fact is there is not a cost-based justification to charge lower rates to municipal customers. That being said, it is not inherently wrong to do so as a policy decision. As long as the rate is priced above the marginal cost of service and a contribution is being made to fixed cost recovery, a rate is deemed non-discriminatory.

Recommendation

It is the recommendation of 1898 & Co. that all customers should pay rates based on the service they qualify for and small discounts for municipal service are unnecessary. For internal customers with loads of 50 kW and below, this is not likely to be very impactful. However, we strongly recommend that if municipal rates are to be continued, FPB should create a Municipal Demand rate. Having an energy-only rate design for large customers could be detrimental to equitable cost recovery if the large load peak is coincident with the overall system peak. A Municipal Demand rate could be easily designed by applying a similar discount to the LP rate design.

REVIEW OF RETAIL LED LIGHTING RATES

As with many utilities, FPB has begun to transition its streetlights and retail area and security lights from HPS to LED. LED lights have the advantage of lower energy use and longer expected life. The offset to these advantages is LED lights have a larger up front capital cost per light. FPB has approached the pricing of these LED lights in a similar manner to many other utilities; that is, they use the same price for the higher wattage HPS light they are replacing. This is often an appropriate estimate as the lower energy costs are offset by the higher capital cost.

1898 & Co. has developed LED lighting rates using a bottom-up cost-based approach for other utilities and was able to leverage existing models and apply them to FPB costs. When designing a rate for area lights, we considered the following components:

- Capital cost of the light/fixture/photocell
- Installation costs to place the light in service (labor, benefits adder, materials, equipment)
- Maintenance or relamp costs (replacing a burned out bulb)
- Power supply costs (KyMEA energy and demand charges)
- Distribution costs to deliver power to the light/pole

Capital and installation costs were provided by FPB and are summarized in

Table 8.

Table 8: LED Lighting Costs

LED Light	Replaced	Equipment Cost	Installation Cost	Installed Cost
53 W LED Security Light	100 W HPS	$98.77	$222.50	$321.27
129 W LED Security Light	250 W HPS	$256.59	$222.50	$479.09
141 W LED Area Light	400 W HPS	$414.00	$222.50	$636.50
371 W LED Area Light	1,000 W MH	$762.27	$222.50	$984.77

1898 & Co. utilized an in-house fixed charge rate model to determine the amount of the install cost to be recovered on an annual basis. The recovery was based on a fifteen-year life for the LED fixture and no relamp cycles or maintenance is expected.

Monthly energy usage was estimated based on the nameplate wattage and operation 12 hours a day, 365 days per year (4,380 annual hours). Power supply costs are based on the current KyMEA energy rate plus an estimate of the demand costs for months when the lights are on during peak hours. Generally, in winter months, the FPB system peaks around 8:00 AM when lights are likely to be on. To estimate the cost to deliver power thought the FPB distribution system to the light, we relied on the most recent cost of service (COS) study, conducted in 2013. We estimated the COS-based lighting rates on a $/kWh basis and escalated the costs at 1.5% per year to inflate the cost to 2022 dollars. The rate design by component is shown in Table 9.

Table 9: LED Light Rate Design

LED Light	Monthly kWh	Annual Capital Recovery	Monthly Capital Rate	Delivery Cost Rate	Monthly Retail Rate
53 W LED Security Light	19	$34.00	$2.83	$2.86	$5.69
129 W LED Security Light	47	$50.70	$4.22	$7.07	$11.29

141 W LED Area Light	51	$67.35	$5.61	$7.67	$13.28
371 W LED Area Light	135	$104.21	$8.68	$20.29	$28.97

Table 10 shows a comparison of current LED lighting rates with the recommended rates using a bottom-up COS approach.

Table 10: LED Light Rate Comparison

LED Light	Replaced	Current Rate	Recommended Rate	Variance
53 W LED Security Light	100 W HPS	$9.40	$5.69	($3.71)
129 W LED Security Light	250 W HPS	$13.06	$11.29	($1.77)
141 W LED Area Light	400 W HPS	$14.21	$13.28	($0.93)
371 W LED Area Light	1,000 W MH	$29.15	$28.97	($0.18)

RATES FOR ELECTRIC VEHICLES AND EV CHARGING

FPB requested 1898 & Co. make recommendations and provide guidance on designing of rates for electric vehicles (EV) and for EV Charging stations. The FPB has installed some level 2 chargers and has plans to install a level 3 Direct Current Fast Charger (DCFC). Currently FPB purchases and installs the chargers, and the city pays for the usage under the Municipal rate of $0.0895/kWh. The city does not charge users for the electricity to charge their vehicles.

The typical issue in designing rates for EV chargers is they generally have very low load factors, that is there is little energy usage relative to peak demand. Despite the best intentions, public charging stations are not used on a consistent basis, primarily because number of EVs on the road is still small relative to the overall population of cars. This results in the standard energy charges in most rate classes not recovering enough of the cost to serve the load when factoring in demand costs. FPB's power supply costs are very demand dependent, with a combined generation and transmission demand charge of over $18.00/kW and an energy rate of just $0.0247/kWh. Further, all but one of the KyMEA demand charges are based on the single highest hourly peak of the FPB system as a whole. This means if one of these chargers is in use at the time of the system peak, the demand cost is fully attributable to the charger itself, and with DCFC's having a peak output of 62.5 kW, the cost can be quite impactful. For reference, the power supply cost to FPB of a 60-minute charge on a DCFC charger during the FPB system peak is $1,180. That's $1,179 ($18.8648 x 62.5 kW) for demand costs and about $1.50 for the energy charge. Under the current Municipal Rate, FPB would recover $5.59 ($0.0895 x 62.5 kWh)

While this example is extreme and the average rate per kWh would decrease with every kWh from the charger the rest of the month, it does explain why public EV charger rates are often in the range of 25 to 35 cents per kWh. At this point we have only considered the power supply costs from KyMEA. FPB must also recover costs for the distribution system that delivers power to the charger, the recovery of the initial capital cost of the charger, and all administrative and general costs that are recovered from all ratepayers. The tables on the following page show an estimate of the cost basis for a DCFC and a level 2 charger with a monthly load factor of 10%. The capital cost for the DCFC ($45,000) and level 2 charger ($10,000) are both assumed have a 12 year life to spread the cost recovery over.

Chargepoint CPE 250. 62.5kW output DC		**Level 2 Charger**	
Demand	62.50	Demand	5.50
Load Factor	10%	Load Factor	10%
Monthly Energy @ 10% LF	4,562.50	Monthly Energy @ 10% LF	401.50
Coincidence w/ FPB Peak	100%	Coincidence w/ FPB Peak	80%
KyMEA Demand ($/kW)		**KyMEA Demand ($/kW)**	
Billing	$14.0440	Billing	$14.0440
Transmission	$2.9829	Transmission	$2.9829
	$0.3029		$0.3029
	$1.5350		$1.5350
	$18.8648		$18.8648
Demand Cost per kWh	**$0.2584**	**Demand Cost per kWh**	**$0.2067**
KyMEA Energy ($/kWh)	**$0.0247**	**KyMEA Energy ($/kWh)**	**$0.0247**
Monthly KyMEA Cost		**Monthly KyMEA Cost**	
Demand	$1,179.05	Demand	$83.01
Energy	$112.69	Energy	$9.92
KYMEA Bill	$1,291.74	KYMEA Bill	$92.92
Bundled FPB Rate per kWh		**Bundled FPB Rate per kWh**	
Average KyMEA $/kWh	$0.283	Average KyMEA $/kWh	$0.231
FPB Distribution	$0.030	FPB Distribution	$0.030
Capital Cost Recovery	$0.086	Capital Cost Recovery	$0.218
Total Rate	**$0.399**	**Total Rate**	**$0.479**

Cost Base Rates for EV Chargers

Using the assumptions shown above, we estimate that the EV chargers installed or planned to be installed cost the FPB in the range of $0.399 - $0.479 per kWh. While we don't recommend this rate be applied directly to the city for charger usage, it should be used as a guideline to recover an appropriate amount of cost from the city for providing EV chargers as a service. Creating a Municipal Demand Rate, as recommended previously in this report, would also be an acceptable option to charge the city for EV charging infrastructure.

Rates for Personal EV Charging

Frankfort is somewhat unique in that it provides EV charging free of charge at its public charging stations. Typically, for reasons of convenience and because public chargers are more expensive than home charging, residential customers will choose to charge at home. We do not recommend creating a new or separate rate for EV charging. In general, 1898 & Co. does not recommend specific "end use" rates. The proper way to incorporate EV charging into the system is to design a rate that sends the proper economic signal to the customer that results in charging at certain times. This is best accomplished through time-of-use (TOU) rates that both incent the customer to not charge during peak times and rewards them with lower rates during off peak times. A typical TOU rate design that supports EV growth would be as follows:

- On peak rate – the seasonal, weekday 4 hour window when peaks typically occur (2:00-6:00 PM in Summer, 6:00 AM – 10:00 AM in the winter – priced to capture demand costs
- Off peak rate – all non-On Peak weekday hours and weekends – priced below current non-TOU energy charge
- Super off peak rate – ultra-low rate from midnight – 6:00 AM – priced at variable cost of energy to incent overnight charging.

Sample rates may look like the following:

- On Peak: $0.25/kWh
- Off Peak: $0.08/kWh
- Super Off Peak: $0.03/kWh

The goal of this rate structure is to disincent customers from charging at times of potential system peaks. Customers are further rewarded by charging overnight with an even lower rate. Because FPB's power supply costs do not vary hour-to-hour but are solely driven by the single monthly coincident peak, the super off peak rate may not be necessary for FPB. We recommend FPB consider starting a pilot program to test TOU rates on the residential class.

SUMMARY OF CONCULSIONS AND RATE RECOMMENDATIONS

To summarize, 1898 & Co. makes the following recommendations:

1. Create a new General Service Demand rate class.
2. Adjust the rate design for the LP-HLF rate class to have a higher demand charge and lower energy charge.
3. Add a Primary Meter Discount to the LP and LP-HLF tariff language
4. Establish a policy to value distribution system assets that a customer will be required to take ownership of or otherwise compensate FPB for using a range of fair market valuation including OCLD and RCLD.

5. Establish a Value of Solar (VOS) rate as a basis for FPB's avoided cost rate for compensating excess generation of customers with generators that exceed the parameters of the Net Metering Policy. The initial rate should be set at $0.03365/kWh and updated annually.
6. KyMEA has assumed all obligations for FPB related to PURPA QFs.
7. FPB should establish a Green Rate Program structured like LG&E's Green Power program and purchase green-e certified RECs. Once KyMEA establishes its Green Power Kentucky program, FPB can transition the operation and administration of the program to KyMEA.
8. FPB should eliminate the Municipal Service rate and charge all customers based on their service characteristics.
9. If the Board chooses to maintain the Municipal Service rate, it should create a new Municipal Service Demand Rate
10. FPB should update the rates for LED area and security lights using the rates in Table 9.
11. Establish a pilot program on an opt-in basis for residential TOU rates.