Cost-Effectiveness of Local Distribution Tied Solar within KyMEA

Tom Harris,[1] Walt Baldwin,[2] and Sarah Turner[1]

1 National Renewable Energy Laboratory
2 Lydian Technologies

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-7A40-87697
December 2023

Cost-Effectiveness of Local Distribution Tied Solar within KyMEA

Tom Harris,[1] Walt Baldwin,[2] and Sarah Turner[1]

1 National Renewable Energy Laboratory
2 Lydian Technologies

Suggested Citation
Harris, Tom, Walt Baldwin, and Sarah Turner. 2023. *Cost-Effectiveness of Local Distribution Tied Solar within KyMEA*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-87697. https://www.nrel.gov/docs/fy24osti/87697.pdf

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-7A40-87697
December 2023

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

NOTICE

This work was authored [in part] by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Solar Energy Technologies Office. The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government.

Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

Acknowledgments

We wish to thank the National Community Solar Partnership (NCSP) under the U.S. Department of Energy for funding this research. The National Renewable Energy Laboratory (NREL) is a national laboratory of the U.S. Department of Energy Solar Energy Technologies Office operated by the Alliance for Sustainable Energy, LLC. We are grateful to Joyce McLaren, Michael Ingram, and Karlynn Cory for their valuable feedback during the peer review process.

List of Acronyms

AC	alternating current
AR	all requirements
BAU	business as usual
BREC	Big Rivers Electric Corporation
CP	coincident peak
DA	day ahead
DER	distributed energy resource
FERC	Federal Energy Regulatory Commission
FPB	Frankfort Plant Board
GW	gigawatt
IPMC	Illinois Power Marketing Company
KyMEA	Kentucky Municipal Energy Agency
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
MISO	Midcontinent Independent System Operator
MW	megawatt
NCP	noncoincident peak
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NITS	network integration transmission service
NSRD	National Solar Radiation Database
P2P	point-to-point transmission
PPA	power purchase agreement
PV	photovoltaic
PPS	Paducah Power System
SEPA	Southeastern Power Administration
SERC	Southern Electric Reliability Council
G&T	generation and transmission
TVA	Tennessee Valley Authority

Executive Summary

The Kentucky Municipal Energy Agency (KyMEA) is a joint action agency that provides electric transmission and energy services to 11 municipal utilities. One of KyMEA's member cities, Frankfort, has a goal to reach 100% renewable generation for the city's electricity load by 2023. By 2030, it seeks to achieve 100% carbon-free city operations and 100% renewable electricity communitywide. The aim of this research was to determine whether the Frankfort city government can reduce its power costs by implementing distribution-tied solar photovoltaics (PV) without cross subsidization from other KyMEA member utilities or other Frankfort Plant Board customers.

We simulated the KyMEA generation portfolio and transmission system from KyMEA's cost perspective, using the NREL Engage™ capacity expansion model. Running Engage as a simple merit order dispatch model, we compared KyMEA's operation costs under baseline conditions to its operation costs with Frankfort meeting a portion of the city's load with 11.54 megawatts of distribution-tied PV. The cost perspectives of the City of Frankfort and its municipal utility, Frankfort Plant Board, meanwhile, were calculated outside of the Engage model.

The simulations indicate that it could be cost-beneficial to KyMEA, and that it is likely to be cost-neutral or beneficial to Frankfort Plant Board for Frankfort city government to implement distribution-tied utility-scale PV. Not only did the addition of the solar PV system, as modeled, result in no additional costs to KyMEA members, the new load attributes resulting from the distribution-tied PV lowered KyMEA's cost to serve load by improving the system load factor, reducing system transmission and energy costs, and increasing revenues from market energy sales.

Table of Contents

List of Figures

List of Tables

1 Background

The purpose of this study was to investigate how plans to develop a distribution-tied photovoltaic (PV) power system in Frankfort, Kentucky, could financially impact the Kentucky Municipal Energy Agency (KyMEA). KyMEA is a joint public agency formed among Kentucky municipal utilities that coordinates local generation to meet its customer electric power needs.[1] Specifically, KyMEA provides wholesale electric power generation and transmission (G&T) services to municipal utilities on behalf of the agency's member communities. These municipal utilities and their communities are listed in Table 1.

Table 1. KyMEA Members

KyMEA Community	Population	Municipal Utility	In MISO/ LG&E* Footprint	2021 Annual Consumption (GWh)	2021 Peak Load (MW)	2021 Average Load (MW)
Barbourville	3,165	Barbourville Utilities	Yes	87	19	10
Bardwell	723	Bardwell City Utilities	Yes	9	2	1
Benham	500	Benham Power Board	Yes	Not in an all-requirements sales contract		
Berea	15,844	City of Berea Municipal Utilities	No	Not in an all-requirements sales contract		
Corbin	7,304	City Utilities Commission of Corbin	Yes	81	19	9
Falmouth	2,139	City of Falmouth Utilities	No	18	5	2
Frankfort	25,527	Frankfort Plant Board	Yes	652	133	74
Madisonville	19,591	City of Madisonville, Electric Department	Yes	267	58	31
Owensboro	59,643	Owensboro Municipal Utilities	No	Not in an all-requirements sales contract		
Paris	8,553	City of Paris Combined Utilities	Yes	63	17	7
Providence	2,981	City of Providence Utility Office	Yes	29	7	3

* LG&E refers to the Louisville Gas and Electric Company / Kentucky Utilities Company transmission network while MISO refers to the Midcontinental Independent System Operator network.

Sources: Table 1 contains information from KYMEA's website (https://www.kymea.org) and a KyMEA open records request. Additional information on the individual communities can be found in the following references: Barbourville Utilities n.d., Benham Power Board n.d., City of Berea n.d., Corbin Utilities Commission n.d., City of Falmouth n.d., Frankfort Plant Board n.d., City of Madisonville n.d., Owensboro Municipal Utilities n.d., City of Paris n.d., and Webster County n.d.

Frankfort, Kentucky is served by the Frankfort Plant Board (FPB) municipal utility, which is one of KyMEA's 11 members, eight of which, including the FPB, entered into an all-requirements (AR) sales contract, agreeing to purchase all of their energy needs through KyMEA ("Kentucky

[1] To learn more about KyMEA and the communities the agency serves, visit https://www.kymea.org.

Municipal Energy Agency: All Requirements Power Sales Contract" 2016). In 2021, the City of Frankfort passed a resolution to support clean energy and reach 100% renewable electricity for city government operations by 2023, 100% clean energy for city government operations by 2030, and 100% clean renewable electricity community wide by 2030 (City of Frankfort n.d.).

To achieve these clean energy goals, the Frankfort city government has been working with the National Renewable Energy Laboratory (NREL) to develop two distribution-tied single-axis tracking solar PV projects with a total nameplate capacity of 11.54 MWac.[2] The power generated would be owned by the City of Frankfort to meet the government's operational electricity load, consistent with the city's 2023 goals. Though at the time of writing these solar PV projects are still in the proposal stages of development, when in operation, they could affect the AR sales contract[3] FPB made with KyMEA in 2016.

The city government's PV projects would reduce the power it would procure from FPB, reducing its revenues, and in turn reducing the power FPB would procure from KyMEA. This would reduce the agency's load and decrease the revenues of KyMEA as well. The implications of the load and revenue reductions to KyMEA are the primary focus of this study. The study was designed to understand the financial impact of Frankfort's PV projects on each stakeholder. By modeling KyMEA's G&T system, we set out to answer how solar PV projects in Frankfort would affect KyMEA's costs and revenues.

1.1 KyMEA's G&T System

To perform a cost analysis of Frankfort's PV projects, we first collected data on KyMEA's G&T system to develop a business-as-usual scenario. While KyMEA's generation portfolio will continue to evolve over time, we focused on KyMEA's known generation assets, as planned for the 2023/2024 period, as a point of reference.[4]

In 2016, KyMEA assembled an initial portfolio of resources for the AR sales contract, consisting of purchase power agreements (PPAs) with Big Rivers Electric Corporation (BREC), Dynergy, and Paducah Power System (PPS). From December 2017 to April 2018, KyMEA's AR project power supply portfolio expanded to include an 11 MW diesel power plant from the City of Paris and a 32 MW allotment of hydroelectric power from the Southeastern Power Administration (SEPA).[5] In August of 2018, KyMEA executed a twenty-year agreement with MAP Energy and Open Road Renewables to procure 62.5% of the output from an 86 MW Ashwood Solar I power plant; however, KyMEA's share increased and they will procure 100% of the Project's generation. The facility was scheduled to go into service in 2022, but construction delays have

[2] These solar projects will be described later in this study, but additional information on project development can be found at (National Renewable Energy Laboratory 2022). NREL is currently involved in helping Frankfort conduct feasibility studies for the two solar PV projects.

[3] A definition of an all requirements sales contract can be found in the glossary.

[4] Most of these observed changes have been related to the Ashwood Solar I project. More information can be found at ("KYMEA and RWE Break Ground on Largest Solar Project in Kentucky").

[5] SEPA's generation comes from nine hydroelectric plants constructed under the U.S. Army Corps of Engineers' Cumberland System of Projects. KyMEA's AR members entered into agreements for KyMEA to integrate their entitlements to SEPA's hydroelectric power. For more information on these power plants and KyMEA's power supply in general, visit https://www.kymea.org/power-supply/.

pushed the project into 2024 (KYMEA "Ashwood Solar I", "KYMEA and RWE Break Ground on Largest Solar Project in Kentucky"). In 2022, KyMEA commenced its most recent five-year contract with Duke Energy Indiana, acquiring 60 MW of capacity from the utility's energy system. Table 2 provides a summary of these generation sources along with KyMEA's contract terms. In total, KyMEA will have access to 349 MW of power capacity once the Ashwood Solar PV power plant is generating power.

Table 2. KyMEA 2023/2024 Generation Portfolio

Source	Resource Type	Nameplate Capacity (MW)	Contract Expiration Date
Big Rivers Electric Corporation (BREC)/D.B. Wilson Power Plant	Coal	100	May 31, 2029
City of Paris/Paris Power Plant	Diesel	11	May 31, 2029
Paducah Power System (PPS)/Paducah Power System Plant No. 1	Natural Gas	60	May 31, 2029[6]
Southeastern Power Administration (SEPA)/AR Members' Allotments	Hydroelectric	32	May 31, 2029[7]
RWE Renewables America LLC/Ashwood Solar I Project	Solar Photovoltaic	86	November 30, 2042[8]
Duke Energy Indiana/Subsidiary of Duke Energy	Duke Energy Indiana System Power[9]	60	May 31, 2027
KyMEA's Total Available Nameplate Capacity		**349[10]**	

KyMEA also negotiates contracts with transmission service providers to deliver electricity. Currently, all KyMEA's PPA resources are located in territories serviced by either the Louisville Gas and Electric Company (LG&E) / Kentucky Utilities Company (KU), Tennessee Valley Authority (TVA), or the Midcontinent Independent System Operator (MISO).[11] MISO, functioning as an independent grid operator, operates competitive deregulated wholesale electric power markets where individual generators can bid to supply power. In contrast, TVA and LG&E are vertically-integrated utilities that manage the generation, transmission, and distribution of electricity to retail ratepayers in accordance with local regulations.

[6] Initially 90 MW, KyMEA reduced its contracted capacity from PPS to 60 MW starting in 2023.
[7] A complete resource obligation table of KyMEA's contracts in 2021 can be found at (KYMEA 2021). This includes each city's entitlements to SEPA's hydropower generation.
[8] The contract expiration date for the Ashwood Solar I Project is dependent on the commercial operation date, which is currently projected to start in 2024 but may be subject to change.
[9] Duke Energy Indiana's resource types include coal, gas, solar, wind, and fuel oil. Details on Duke's energy capacity can be found at (Barbknecht 2023).
[10] We did include the Ashwood I Solar capacity, but only under the assumption that the project will be completed and available for dispatch by 2024.
[11] KyMEA's transmission contracts can be found at (KYMEA 2021).

177 MW of firm transmission in MISO is available to KyMEA through the MISO point-to-point (P2P) transmission service.[12] Meanwhile, transmission lines through LG&E/KU territories are facilitated through the network integration transmission service (NITS). How these transmission services interact with KyMEA's generation sources are explored further in the next section.

[12] 160 MW of KyMEA's total firm transmission capacity can be attributed to the agency's contracts with Duke and BREC. The additional 17 MW of transmission capacity under BREC is from an agreement that BREC will help KyMEA meet its reserve margin as needed.

2 Study Approach

For this study, we employed NREL's Engage capacity expansion and simplified production cost model to explore the economic cost or benefit to KyMEA if the City of Frankfort successfully built a distribution-tied PV system. Engage is a free and publicly available capacity expansion modeling tool that simulates and optimizes G&T costs within broad technical and sociopolitical parameters set by the modeler, from geospatial constraints to policies and regulations.[13]

2.1 Model Formulation

2.1.1 Demand

The communities of Benham, Berea, and Owensboro were not included since they do not have an all-requirements power sales contract with KyMEA and consequently are not responsible for covering KyMEA's operating contracts. Since the proposed PV systems would be connected through the MISO/LG&E transmission network, we chose to focus only on AR members that would potentially be affected by Frankfort's solar PV systems. As such, even though Falmouth has an AR sales contract with KyMEA, we did not include the city's load in the analysis since Falmouth relies on a different G&T system than Frankfort. KyMEA's seven AR members had a coincident peak load of 248 MW in 2021, which was projected by KyMEA to increase through end of decade as shown in Figure 1.[14] The aggregate of the hourly loads of the seven communities of interest was used as KyMEA base system load the modeled scenarios.[15]

---

[13] To learn more about Engage, visit https://www.nrel.gov/state-local-tribal/engage-energy-modeling-tool.html.

[14] Open records request to KyMEA for hourly demand data on AR members located within the MISO/LG&E footprint.

[15] Note that in Figure 1, there is a second, smaller peak demand for electricity in winter as well. This is likely partially due to more than half of Kentucky residential households relying on electricity for heating in the winter, which can partially explain why there is a peak in the winter (U.S. Energy Information Administration n.d.). This potential shift in seasonal system peak vies for the importance of system planning on a regional level looking forward, considering that other communities may consider distribution-connected PV as well.

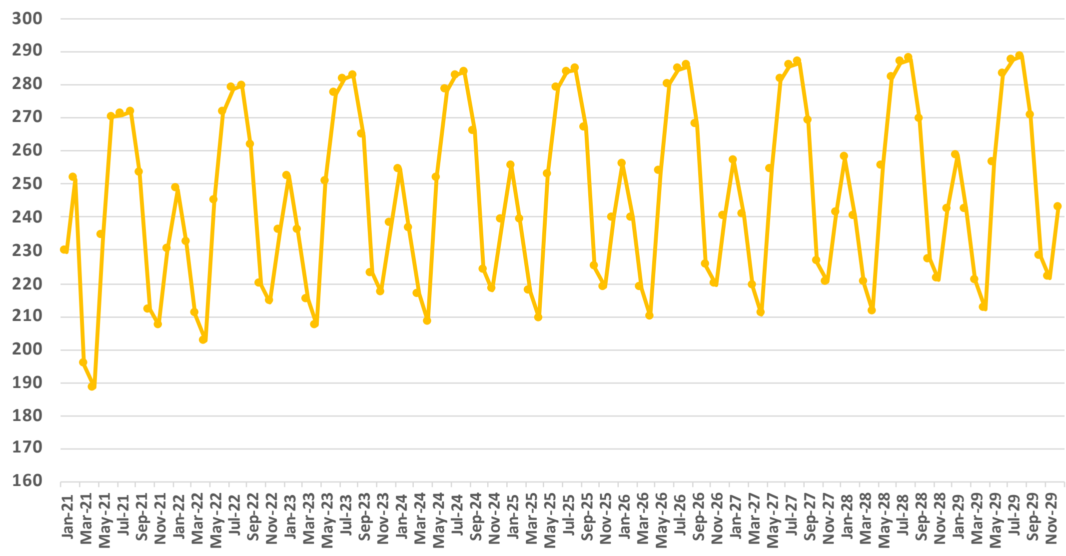

Figure 1. KyMEA's projected electricity demand, 2021–2029

Source: KyMEA open records request. The y-axis represents power in MW.

2.1.2 Interconnecting Generation and Transmission

KyMEA's G&T system was a complex framework to model since grid conditions for KyMEA's generation sources vary considerably based on their location, as represented in Figure 2.

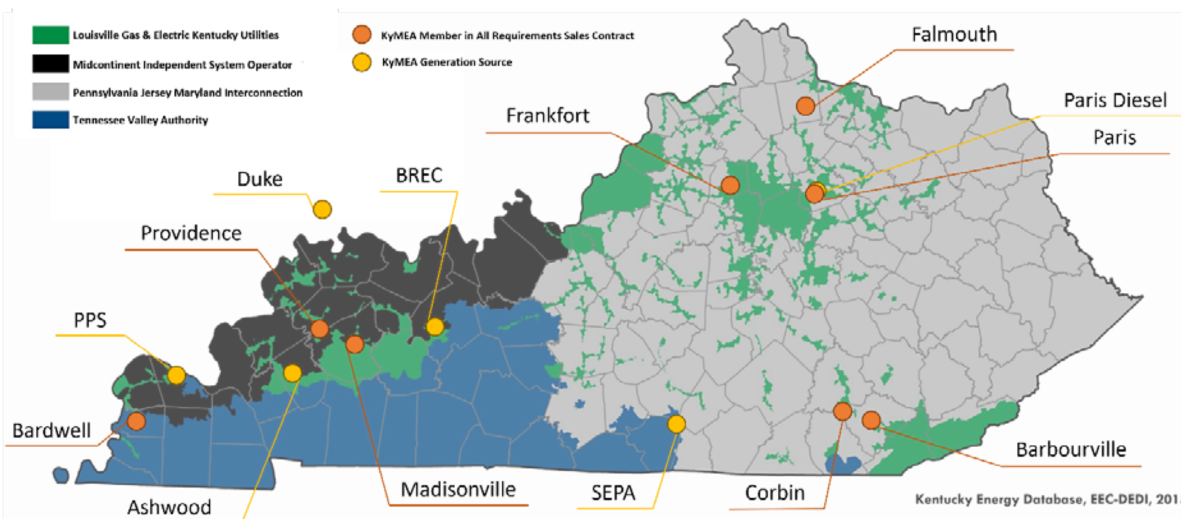

Figure 2. Map of KyMEA's G&T system according to Kentucky Balancing Authority areas

Source: Bone 2019[16]

[16] An original map of Kentucky Balancing Authority areas can be found at (Bone 2019). Even though SEPA generation represents the share from a system of nine hydroelectric plants, the map's location for SEPA is based on Wolf Creek Dam.

Note: BREC: Big Rivers Electric Corporation, PPS: Paducah Power System, and SEPA: Southeastern Power Administration

While SEPA's hydroelectric generation is typically sold into the MISO transmission system, the hydropower plants maintain the option to deliver their production using transmission lines owned by LG&E and TVA. Prices for electricity in MISO fluctuate throughout the day, according to demand and generation availability. KyMEA generally bids into the MISO market when the price paid for SEPA's service is high enough to cover its marginal costs; otherwise, KyMEA is likely to utilize the LG&E TVA interconnection point. This latter option is a rare occurrence due to hydropower's comparatively low variable cost.

Duke and BREC's coal power plant, meanwhile, are KyMEA's only generation resources located within the MISO footprint. As such, KyMEA has the option to:

1. Dispatch its generation resources into MISO's wholesale market,
2. Dispatch its generation resources into the LG&E network, utilizing the MISO P2P, or
3. Purchase electricity imports from MISO's wholesale market, utilizing the MISO P2P.

The decision which or which combination of these dispatch and purchase options to elect is informed by the 177 MW constraint on the MISO P2P transmission service, which is the maximum power KyMEA can contractually move from MISO into LG&E, including from MISO's wholesale market, as represented in Figure 3. Consequently, KyMEA's decision to deploy which generation resources into which network and when depends on what is most economical. Thermal generators, for example, often operate at higher variable costs since they rely on fuel, requiring MISO prices to be higher to sell into the wholesale market. Consequently, even though the coal-fired BREC generation resource can physically dispatch electricity into either MISO or LG&E; in practice, it would always be more economic for KyMEA to export BREC generation into MISO when wholesale prices are high and to purchase imports from MISO when prices are low.

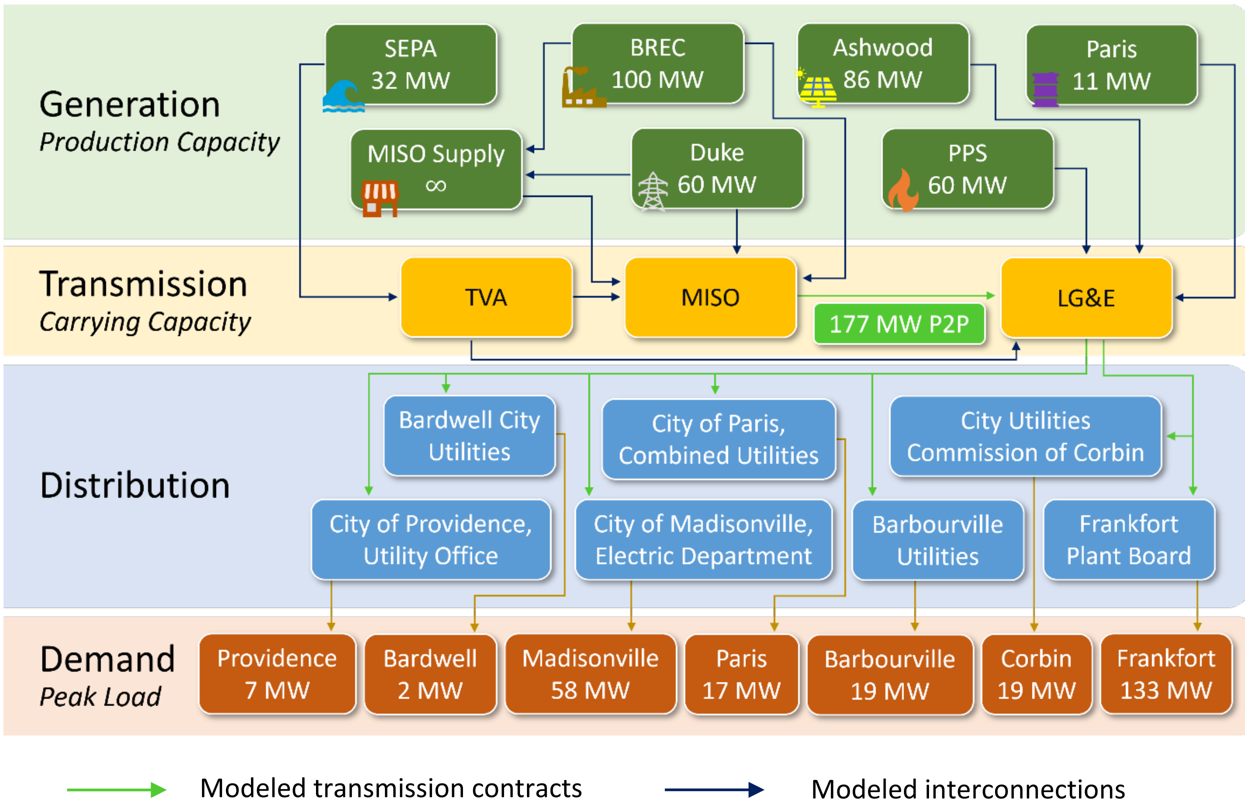

Figure 3. Diagram of KyMEA's physical and modeled interconnection points

Paris Diesel, PPS Natural Gas, and Ashwood Solar are the only resources under KyMEA's generation portfolio that do not have the option to choose between transmission service providers; they are always dispatched into the LG&E network.

2.1.3 Engage Economic Dispatch Model

Engage, as an economic dispatch model, is designed to dispatch the variable operating cost generation assets to meet demand during every interval in a simulation, respecting all constraints. For this case study, we utilized hourly time intervals. Modeled constraints refer to the modeled restrictions on power plant operations, such as maximum power that can be dispatched by each plant or in association with each power contract, the amount of hydroelectric power available during a particular time period, and interconnections between generation and loads as relevant to the economics being modeled—in this case the LG&E NITS tariff—and the costs, variable and fixed, that are incurred by KyMEA for dispatching generation and utilizing the transmission network. Represented in the model were size, location, dispatchability, and weather-related characteristics of generation output; the cost of and necessity of utilizing the LG&E transmission network to serve the municipal system loads with the contracted generation; and the municipal system loads.

For this study, our focus was not on optimizing generation capacity of the solar PV systems to achieve the lowest cost. Instead, we aimed to calculate the annual cost from KyMEA's perspective, given cost-optimal dispatch. The model accounted for annual fixed and variable costs of the generation contracts and for utilization of the LG&E network on the basis of the

NITS tariff.[17] To achieve this, we set fixed capacities for each generation source and the MISO P2P transmission line, according to their contract terms. In this way, must-pay and allocation generation resources (such as solar PV and SEPA) were dispatched first, then all other power plants were allocated based on their individual economics. All the generation resources were modeled to pass through the LG&E network since each AR member has an interconnection point to LG&E. That way, irrespective of their grid location, all generation sources incur LG&E NITS fees when deployed to meet demand. The model also permitted selling generation from BREC, Duke and SEPA, which have access to MISO, into MISO. More details on this process can be found under Appendix B.3.

Electricity delivered from BREC, Duke, or MISO's wholesale market, was modeled to utilize MISO's P2P transmission service, for which there is a fixed cost and no variable (utilization) cost.[18] Future transmission costs are subject to change, pending certain dispute resolution with the Federal Energy Regulatory Commission (U.S. Federal Energy Regulatory Commission 2023).

2.2 Engage Scenarios

Two scenarios were modeled:

1. **Business as usual (BAU)**, which modeled KyMEA's existing G&T contracts to determine the agency's current costs and deployment profiles.
2. **Frankfort's distributed energy resource (DER)**, which analyzed how KyMEA's G&T costs could change if a portion of Frankfort's load was met through 11.54 MW of distributed PV generation.

As shown in Table 3, many components in the Frankfort DER scenario were unchanged from the BAU. The only difference between the scenarios was the adjustment of Frankfort's load profile to show reduction in load (with corresponding change in timing and size of Frankfort's peak demand) resulting from production from two distribution system connected single-axis tracking solar PV projects that would together have a total nameplate capacity of 11.54 MWac.

[17] Although the NITS tariff bills KyMEA on the basis of a member's demand at the time of the LG&E system coincident peak, due to model limitations, simulated NITS monthly peak demand charges were based on the KyMEA AR members' collective peak load.
[18] Costs for both MISO P2P and LG&E transmission services were derived from KyMEA billing, obtained from an open records request.

Table 3. Engage Components by Scenario

Each component was used to calculate KyMEA's total costs for one year in Engage, based on generation resources currently planned for 2023/2034.

Demand		
Scenario(s)	**Component**	**Description**
Both BAU & DER	KyMEA Load	2021 hourly aggregate load for KyMEA AR members Paris, Providence, Bardwell, Madisonville, Barbourville, and Corbin.
BAU only	Frankfort Load	2021 hourly aggregate load for Frankfort.
DER	Adjust Frankfort Load using a DER	Frankfort-adjusted, coincident load after subtracting out the kWh production of the city's 11.54 MW solar PV project.[19]

Generation					
Scenario(s)	**Component**	**Type**	**Production Capacity Cost ($/kW-year)**	**Electricity Production Cost ($/kWh)**	**Production Sold into MISO**
Both BAU & DER	BREC	Dispatchable PPA	$171.00	$0.023	Yes
	Duke	Dispatchable PPA	$67.20	$0.030	Yes
	Paris	Dispatchable PPA	$51.30	$0.034	No
	PPS	Dispatchable PPA	$48.00	$0.060	No
	Ashwood	Dispatchable PPA	-	$0.040	No
	SEPA	Allocation	$101.21	-	Yes
	MISO	Day Ahead Market	-	2021 Prices	-

Transmission			
Scenario(s)	**Component**	**Carrying Capacity Cost**	**Description**
Both BAU & DER	LG&E NITS	$3.29/kW-month[20]	All generation was modeled to go through this transmission network, with a 3.06% carrying loss on the lines.
	MISO P2P	$20.93/kW-year	Transmission service was modeled to deliver electricity from resources located in the MISO network, represented as a fixed cost.

The City of Frankfort aims to construct both solar PV projects on the same site to take advantage of the economies of scale from coincidental construction (National Renewable Energy Laboratory 2022). One is expected to be a 6.54 MW AC (or 8.2 MW DC) solar PV project that would offset the city government's annual electricity consumption in accord with Frankfort's resolution to have 100% renewable generation for the city's electricity load by 2023. The second is expected to be a 5 MW solar PV project designed to be eligible for additional project funding

[19] Note that one cannot simply subtract the solar PV capacity of 11.54 from the coincident peak demand for Frankfort of 133 MW; rather, the actual generating capacity during the hour is considered and thus the revised Frankfort peak demand.
[20] We calculated the LG&E transmission cost in Engage on a monthly normalized cumulative power (NCP) basis as opposed to a cumulative power basis, as done by LG&E/KU.

under the Inflation Reduction Act (IRA) (U.S. Congress 2021–2022). Frankfort is in an advantageous position to apply for all three tax credits under the IRA—the 30% investment tax credit, the energy communities bonus,[21] and the low-income communities bonus.[22] The 5 MW solar PV project in turn would provide economic benefits to disadvantaged census tracts of the population while contributing to the 2030 citywide goal of 100% renewable energy. The production profiles for Frankfort's PV system and KyMEA's generation resources for Ashwood Solar and SEPA hydropower can be found in Appendix B.1.

In addition to the generation resources, we also incorporated prices from MISO's day ahead market into the Engage model to determine for both scenarios:

1. When it could be economic, for KyMEA to dispatch electricity exports into MISO,
2. What additional revenue KyMEA could gain from selling its generation into MISO, and
3. When it could be economic to purchase electricity imports from MISO to meet AR member demand.

We utilized prices from MISO's day ahead market to represent economic opportunities in day-to-day operations. Appendix B.2 contains more information on the historical prices used to model MISO's DA market at the Indiana Hub as well as the production costs for each generator.

[21] Eligibility for the **energy community bonus tax credit** can be determined using the IRA mapping tool at https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d.
[22] Eligibility for the **low-income tax credit bonus tax credit** can be determined using the IRA mapping tool at: https://experience.arcgis.com/experience/12227d891a4d471497ac13f60fffd822. However, the allocations for these bonus tax credits are limited by caps, and most of the allocations have been reserved, as shown in the EJ tracking website: https://experience.arcgis.com/experience/12227d891a4d471497ac13f60fffd822

3 Model Results

The Engage modeling results suggest that both KyMEA and Frankfort may benefit if the City meets a portion of its load through a local DER. Specifically, the Frankfort DER scenario indicates that Frankfort could construct the City's proposed solar PV projects at a maximum cost ranging from $53.33/MWh to $88.31/MWh while lowering KyMEA's levelized cost of energy. In other words, as long as solar PV projects in Frankfort cost less than these values, according to the modeled scenarios, they could be economically competitive for the City, as described below.

3.1 Financial Impact on the Generation and Transmission System

Engage modeling results indicate that the DER scenario could reduce expenses and improve generation system dispatch economic efficiency relative to the BAU scenario, and could collectively reduce the agency's expenses by $1.17 million. These cost reductions are shown in Table 4, which itemizes the annual fixed and variable operating costs according to each scenario. As a convention, KyMEA costs are represented as negative numbers and revenues are represented as positive numbers. The positive numbers in the Difference column can result from increased revenues from selling into MISO and/or decreased operating costs KyMEA experienced under the DER scenario.

Table 4. KyMEA's G&T System Annual Costs as Modeled in Engage

Engage Components	Cost Type	BAU Total Costs ($ Millions)	DER Total Costs ($ Millions)	Difference ($ Millions)
BREC Coal Power Plant	Fixed	-17.10	-17.10	-
	Variable	14.21	14.22	0.01
Paris Diesel Power Plant[23]	Fixed	-0.56	-0.56	-
	Variable	-	-	-
PPS Natural Gas Plant	Fixed	-2.88	-2.88	-
	Variable	-4.01	-3.99	0.02
SEPA Hydropower	Fixed	-3.24	-3.24	-
	Variable	2.10	2.12	0.02
Duke Energy Indiana	Fixed	-4.03	-4.03	-
	Variable	6.26	6.29	0.03
Ashwood Solar Farm	Fixed	-	-	-
	Variable	-6.86	-6.86	-
MISO Supply Day Ahead Market	Fixed	-	-	-
	Variable	-35.32	-34.43	0.89
MISO P2P Transmission	Fixed	-3.70	-3.70	-
	Variable	-	-	-
LG&E NITS Transmission	Fixed	-	-	-
	Variable	-8.18	-7.98	0.20
	Total Cost	**-63.33**	**-62.16**	**1.17**

We found that Frankfort's DER reduced and shifted the aggregate peak demand for Frankfort, which in turn altered the peak demand for KyMEA's AR members, as seen in Figure 4. This lowered KyMEA's operating costs in two ways:

1. Frankfort's DER **reduced the frequency** in which KyMEA would need to dispatch generation to meet AR member load, particularly **expensive generation during peak demand**. This change is seen through the $20,000 of cost reductions from PPS and the $890,000 of reductions from MISO's DA market where less generation is purchased to meet demand. It is also seen in the reduced utilization of KyMEA's LG&E transmission network, lowering LG&E NITS fees by $200,000.

2. Frankfort's DER slightly shifted the aggregate peak demand during some parts of the year for KyMEA's AR members, **impacting when KyMEA could cost optimally bid its**

[23] The Paris diesel power plant is the only generation resource not dispatched by Engage under both scenarios. This is to mirror real-world operations since KyMEA relies on the plant more often to provide grid resilience.

generation into MISO's DA market. When MISO's market price is higher than the generation asset's variable cost, KyMEA earns revenue when it sells generation from BREC, Duke, and SEPA into MISO. These net revenues, while small, are reflected in Engage as negative costs since they offset the agency's expenses. Table 4 shows how even though SEPA's annual production did not change under the DER scenario, the hydropower resource reduced its operating costs by $20,000 through selling its generation into MISO when it would be more competitive.

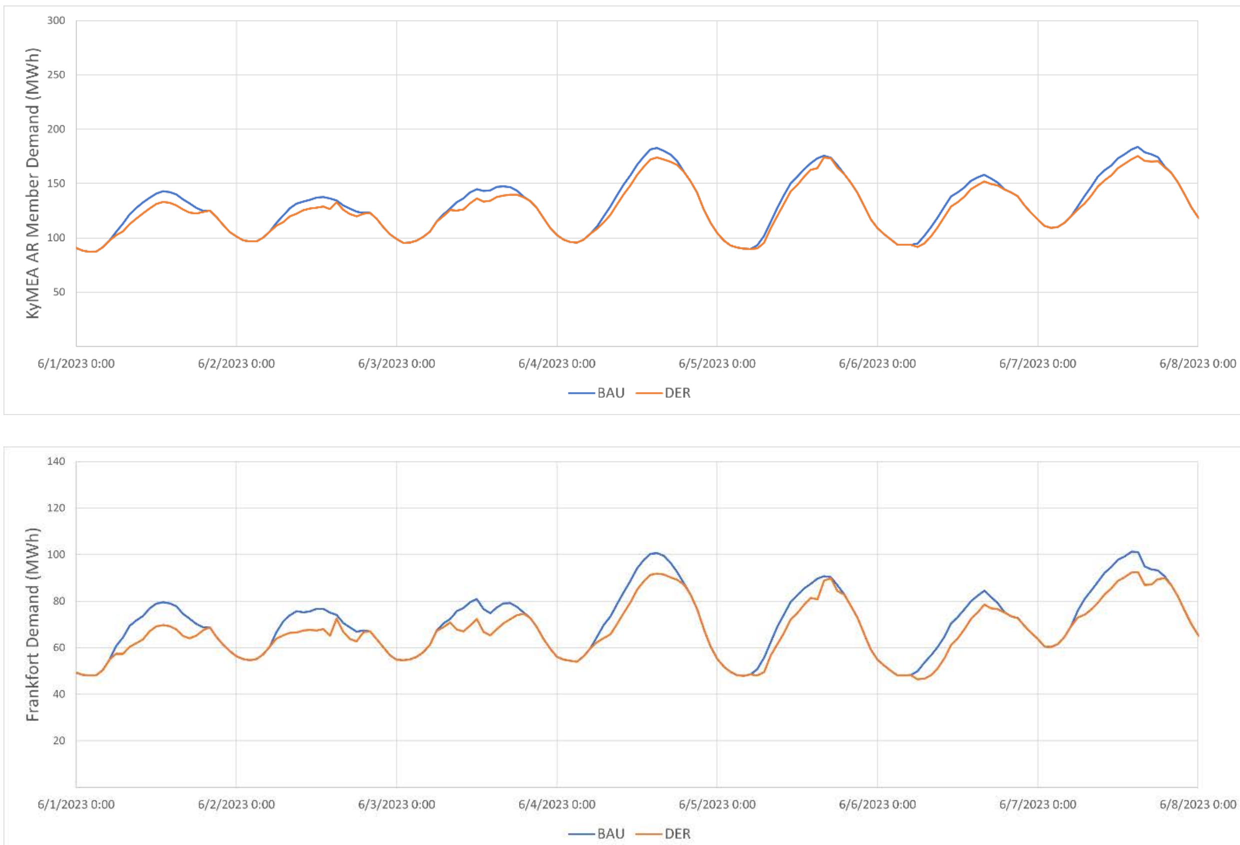

Figure 4. Load change under one week in June for Frankfort (bottom) and KyMEA (top)

3.2 Financial Impact on Stakeholders

3.2.1 KyMEA

The modeling results demonstrate that improvements in system economic efficiency and cost reductions from the DER could financially offset most of KyMEA's decreased revenues. Table 5 details the changes to KyMEA's power sales by AR member, where revenue represents demand and energy payments at 2021 KyMEA rates.[24] All member revenues KyMEA receives remain unchanged except for Frankfort's, which decreased by $1.37 million, representing a 1.8% reduction from KyMEA's total revenues as a direct result of the DER generation. This reduction

[24] These revenues do not include agency fees nor member-owned resource credits. KyMEA member-owned resource credits are included in KyMEA's generation costs.

in revenue is mostly offset by the $1.17 million reduction in G&T expenses as seen in Table 4, leaving the agency with a net operating difference of $200,000, which could be represented as the cost of Frankfort's solar PV projects to KyMEA. As discussed further in the section, this change in KyMEA revenue could be compensated by the City of Frankfort to ensure the financial impact to KyMEA is offset. Increases in revenue are shown as positive numbers while decreases in revenue are shown as negative numbers. The G&T Expenses Difference at the bottom of the table represents the combined cost reduction and increased revenues from MISO in Table 4.

Table 5. KyMEA Revenues by Member

KyMEA Member	BAU Revenue ($ Millions)	DER Revenue ($ Millions)	Difference ($ Millions)
Barbourville	5.74	5.74	-
Bardwell	0.55	0.55	-
Corbin	5.36	5.36	-
Frankfort	41.18	39.81	-1.37
Madisonville	16.33	16.33	-
Paris	4.37	4.37	-
Providence	1.88	1.88	-
Total Revenue Decrease	**75.41**	**74.04**	**-1.37**
G&T Expenses Difference	**-**	**-**	**1.17**
Operating Revenue	**-**	**-**	**-0.20**

3.2.2 Frankfort Plant Board

The model indicates that Frankfort's solar PV projectswould similarly reduce FPB's retail revenue by approximately $2.06 million. This reduction was calculated by multiplying Frankfort's projected total solar production, presented in Table 6, by FPB's municipal rate of $0.094 per kWh since that generation would otherwise result in revenue FPB would receive from Frankfort. However, FPB also could be expected to reduce its costs by $1.37 million, as shown in Table 5, since it would no longer need to procure as much power from KyMEA to meet Frankfort's demand, resulting in a projected net reduction of $690,000 to FPB's retail revenue. Similar to KyMEA, this is a net revenue change that FPB could be compensated for.

Table 6. Frankfort Plant Board's Revenues

FPB Sales	BAU	DER	Difference
Total MWh	652,123.52	630,180.14	-21,943.38
Total Revenue ($ Millions)	**61.30**	**59.24**	**-2.06**
KyMEA Cost Difference ($ Millions)	**-**	**-**	**1.37**
Operating Revenue ($ Millions)	**-**	**-**	**-0.69**

3.2.3 City of Frankfort

From Frankfort's perspective, $2.06 million represents the projected annual avoided cost of electricity the city would no longer have to pay FPB if it received its electricity from a local DER. If the City of Frankfort separately paid approximately $690,000 to FPB and $200,000 to KyMEA as cost offset payments, so that its adjusted lost revenues were covered, Frankfort could still have an estimated $1.17 million in funding, in avoided costs, available to construct and operate its two solar PV projects.[25] These funds, distributed across the annual production of the solar PV facilities, could cover solar PV costs up to $53.33 per MWh. These estimates are not intended to capture what the cost of a solar PV project might be in Frankfort; they are intended to identify the amount that Frankfort could have on-hand to support development of solar PV based on potential cost reduction payments to FPB.

This study demonstrates that Frankfort's PV projects could financially offset any changes in revenue if the City used its $2.06 million available revenue to compensate FPB and KyMEA for their reductions in sales revenue. A visual aid representing the flow of operational cost reductions and payments is shown as Figure 5.

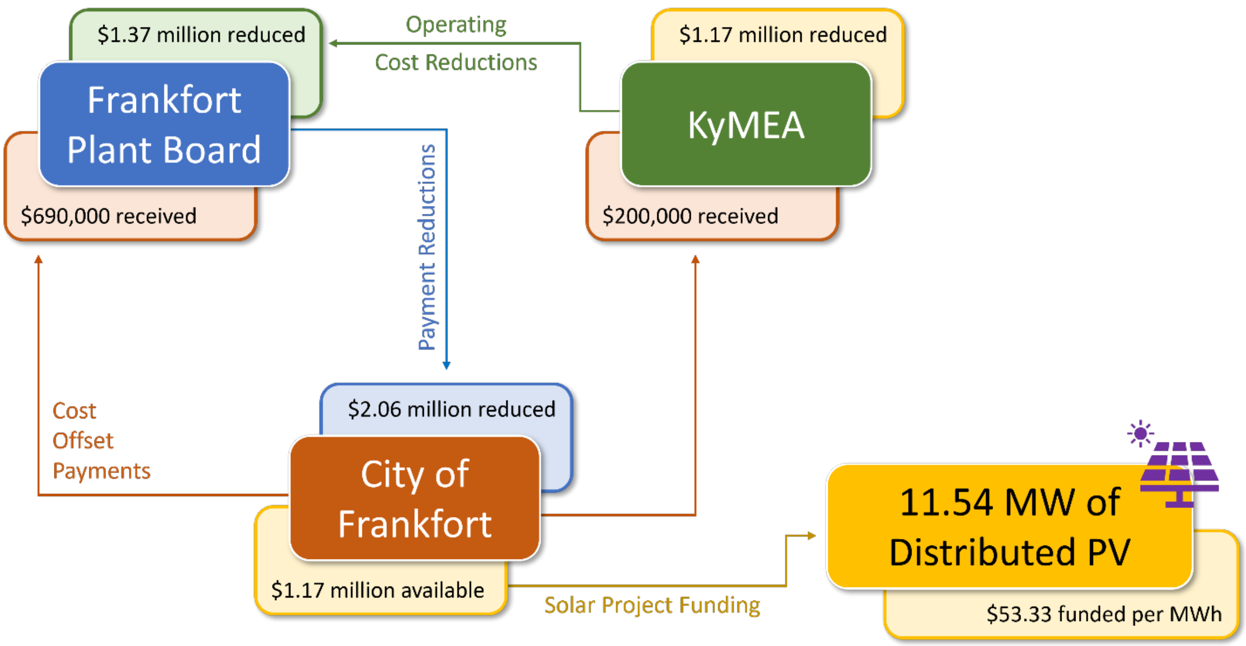

Figure 5. Diagram of a cost offset payment structure

[25] It is important to note that the City of Frankfort is only meant to be representative of the Frankfort municipality for this case study. The City of Frankfort as an entity would not actually be the one responsible for reimbursing KyMEA and FPB for the $890,000 difference in revenue streams; only their share of the 11.54 MW solar PV project. The off-takers of the remaining 5 MW that is planned to serve Frankfort's census tracts would be responsible for the rest of the payment. Since the 5 MW project, however, is still in development, the City of Frankfort was used by us to represent Frankfort as a whole.

3.3 Valuing the Capacity Contribution of Photovoltaics

While, according to the above analysis, solar in Frankfort shows promise for development without negative impacts on KyMEA's AR sales contract, the approach may undervalue Frankfort's potential solar PV projects. As the following initial numbers indicate, this is an opportunity worthy of further research.

The model indicates that the Frankfort solar PV could reduce the total capacity needed to serve KyMEA's load. The $53.33/MWh solar project funding value does not capture the dollar value of the solar's capacity contribution. As a starting point for future analysis this value can be assigned approximate values through utilizing the existing KyMEA Member Resource Credit (MRC) combined with a de-rated nameplate or the modeled annual capacity reduction and the average of KyMEA's existing contracted capacity.

KyMEA existing MRC is intended to compensate members for the capacity contribution of their generation resources. This credit is $3.85 kW-month. Utilizing the KyMEA MRC and the nameplate capacity of the Frankfort Solar de-rated by the Southern Electric Reliability Council's (SERC) recommended solar planning capacity value of 58% would set this solar capacity value at approximately $300,000.[26]

An alternate method to approximate the value of the solar capacity contribution can be determined utilizing the DER scenario modeled annual peak reduction. Table 7 shows how the annual peak demand in August was reduced by 7.26 MW. If the average capacity value of KyMEA's existing capacity contracts is $105,760.22 MW-Year, the solar's annual capacity value is approximately $770,000.

[26] SERC Central's solar capacity value came from the North American Electric Reliability Corporation (NERC) 2023 Summer Reliability Assessment, which can be read in detail at (North American Electric Reliability Corporation 2023).

Table 7. KyMEA System Monthly Peak Demand

Month	BAU Peak (MW)	DER Peak (MW)	Difference (MW)
January	198.69	198.66	(0.02)
February	211.83	207.57	(4.26)
March	166.10	165.78	(0.32)
April	158.12	150.95	(7.17)
May	207.40	200.19	(7.21)
June	241.99	231.86	(10.13)
July	235.24	227.01	(8.23)
August	248.24	240.98	(7.26)
September	215.70	210.76	(4.93)
October	182.23	173.65	(8.58)
November	173.16	172.64	(0.53)
December	174.17	174.17	0.00

Inclusion of the KyMEA MRC value or the modeled annual peak reduction value with the $53.33/MWh solar project funding value would result in, respectively, $66.99/MWh or $88.31/MWh, of available funding for the construction and operation of Frankfort's solar resource. These calculations are broken down further in Appendix C.2.

4 Conclusion

This study investigated the financial implications of Frankfort's plans to develop two distribution-tied PV power systems that would operate independently of KyMEA's G&T system. Specifically, we wanted to determine how Frankfort's reduced demand could impact KyMEA's all-requirements sales contract if sales for KyMEA and FPB decreased as a result of the city's solar production. By simulating KyMEA's G&T system in Engage, we found that Frankfort could pursue DER development. To minimize impacts, Frankfort could use the cost reductions from the solar PV facility to compensate KyMEA and FPB for the estimated revenue decreases experienced from the solar PV while still maintaining enough funding to cover the cost of constructing the city's solar PV facilities.

We established that this dynamic was feasible since Frankfort's compensation to KyMEA and FPB constitutes a small portion of the total operational cost reduction KyMEA would experience under a DER scenario. In other words, even though Engage's model shows that Frankfort's solar production would reduce KyMEA's sales revenues by $1.37 million, $1.17 million of this reduction could be offset through improvements in KyMEA's economic efficiency and operational cost reductions. These improvements in turn could translate over to FPB's revenues by reducing the amount of G&T the municipal utility would otherwise procure from KyMEA. Frankfort's DER enhances G&T economic efficiency by lowering KyMEA's system peak load and adjusting AR member demand during times when selling power to MISO is more cost-effective. The increased revenues from MISO, combined with reduced reliance on KyMEA's more expensive generation resources, represent operational cost reduction that did not occur under the model's business-as-usual scenario.

Overall, the results from this analysis are promising since they demonstrate how Frankfort can pursue its renewable energy targets while preserving the financial integrity of KyMEA and FPB. This study showed not only how Frankfort's solar PV facilities could remain cost-neutral to FPB, but also how they could lead to improved economic system efficiency and reduced capacity requirements. While not specifically studied in this report, lower emissions and enhanced resilience could also be notable benefits to consider when evaluating the value of Frankfort's DER.[27]

Despite these encouraging results, future research is needed to refine the inputs and thus results of the model. We significantly relied on publicly available data to estimate KyMEA's G&T system costs as well as the dispatch profiles of its generation resources. While these data sources are a valuable starting point, NREL welcomes the opportunity to work more closely with KyMEA on developing future cost projections, which will improve the precision of the models developed in Engage.

[27] Solar systems can be a key contributor to grid resilience but system design, integration and operation with the grid, and resilience valuation are all essential to ensuring the intended outcome. (Solar Energy Technologies Office)

Glossary

Term	Definition
All requirements	A contract that legally binds a supplier to sell a specified good or service to a purchaser, who in turn is legally required to buy said products. In the context of this paper, KyMEA as a seller is legally required to procure electricity generation while its members are required to purchase it.
Network Integration Transmission Service (NITS)	A demand-based charge for transmission service, typically billed based on the product of the customer's network service peak load value (MW), the transmission rate ($/MW-day), and the number of days in the term divided by the forecast term volume.

References

Barbknecht, McKenzie. 2023. "Duke Energy Indiana commits to purchase up to 199 megawatts of solar power from Shelby County-based facility." *Duke Energy.* June 22, 2023. https://news.duke-energy.com/releases/duke-energy-indiana-commits-to-purchase-up-to-199-megawatts-of-solar-power-from-shelby-county-based-facility#:~:text=Duke%20Energy%20Indiana%2C%20a%20subsidiary,it%20Indiana's%20largest%20electric%20supplier.

Barbourville Utilities. "Home." Accessed October 2, 2023. https://barbourville.com/.

Benham Power Board. "Home." Accessed October 2, 2023. https://benhampowerboard.wordpress.com/.

Bone, Greg. 2019. *Kentucky Energy Profile*, *7th Edition*. Frankfort, KY: Kentucky Energy and Environment Cabinet Office of Energy Policy. https://eec.ky.gov/Energy/KY%20Energy%20Profile/Kentucky%20Energy%20Profile%202019.pdf.

City of Berea. "About Us." Accessed October 2, 2023. https://bereaky.gov/.

City of Falmouth. "Home." Accessed October 2, 2023. https://cityoffalmouth.com/Default.aspx.

City of Frankfort. "Frankfort 100." Accessed October 2, 2023. https://www.frankfort.ky.gov/1937/Frankfort100.

City of Madisonville. "Home." Accessed October 2, 2023. https://www.madisonvilleliving.com/.

City of Paris. "Home." Accessed October 2, 2023. https://paris.ky.gov/.

Corbin Utilities Commission. "Home." Accessed October 2, 2023. https://corbinutilities.com/.

Federal Energy Regulatory Commission. "Electric Quarterly Reports (EQR)." Accessed October 2, 2023. https://www.ferc.gov/power-sales-and-markets/electric-quarterly-reports-eqr.

Frankfort Plant Board. "Home." Accessed October 2, 2023. https://fpb.cc/.

"Kentucky Municipal Energy Agency: All Requirements Power Sales Contract." *Frankfort Electric and Water Plant Board.* Entered August 16, 2016. https://static1.squarespace.com/static/509ac5d5e4b011ec8327ecea/t/58a611596a49639715be29f5/1487278479668/Frankfort+KyMEA+All+Requirements+Contract+8.16.16.pdf.

KYMEA. "About." Accessed October 2, 2023. https://www.kymea.org/about/.

KYMEA. "Ashwood Solar I." Accessed October 2, 2023. https://www.kymea.org/power-resources/ashwood-solar-i/.

KYMEA. "Power Supply." Accessed October 2, 2023. https://www.kymea.org/power-supply/.

KYMEA. 2021. *August 26, 2021 Combined Meeting of the AR Project Committee and the KYMEA Board of Directors*. Louisville, KY: KYMEA. https://kymea.s3.us-east-2.amazonaws.com/2021/10/August-26-2021-Combined-Meeting-of-the-AR-Project-Committee-and-the-KYMEA-Board.pdf.

"KYMEA and RWE Break Ground on Largest Solar Project in Kentucky." *KYMEA*. Accessed October 2, 2023. https://www.kymea.org/kymea-and-rwe-break-ground-on-largest-solar-project-in-kentucky/.

MISO. "Market Reports: Day-Ahead Pricing." Accessed October 2, 2023. https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ADay-Ahead%2FMarketReportName%3ADay-Ahead%20Pricing%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc.

National Renewable Energy Laboratory. "National Solar Radiation Database." Accessed October 2, 2023. https://nsrdb.nrel.gov/.

National Renewable Energy Laboratory. 2022. *Pathways to Frankfort 100: NREL Report for City of Frankfort, Kentucky*. Golden, CO: National Renewable Energy Laboratory. https://frankfort.ky.gov/DocumentCenter/View/3904/NREL-Phase-1-Final-Report.

North American Electric Reliability Corporation. 2023. *2023 Summer Reliability Assessment*. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

Owensboro Municipal Utilities. "Home." Accessed October 2, 2023. https://omu.org/.

Tennessee Valley Authority. "Wolf Creek: Latest Operating Information." Accessed October 2, 2023. https://www.tva.com/environment/lake-levels/wolf-creek.

U.S. Congress. House. Budget Committee. *H.R.5376 - Inflation Reduction Act of 2022: Energy Security.* 117th Cong, 2021–2022. https://www.congress.gov/bill/117th-congress/house-bill/5376/text/pl.

U.S. Department of Energy. "Energy Community Tax Credit Bonus." Accessed November 11, 2023. https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d.

U.S. Department of Energy, Solar Energy Technologies Office. "Resilient Distribution Systems Powered by Solar Energy." Accessed December 14, 2023. https://www.energy.gov/eere/solar/resilient-distribution-systems-powered-solar-energy.

U.S. Energy Information Administration. "State Profile and Energy Estimates: Kentucky." Accessed November 11, 2023. https://www.eia.gov/state/?sid=KY.

U.S. Federal Energy Regulatory Commission. *183 F.E.R.C. ¶ 61,122*. Louisville Gas and Electric Company & Kentucky Utilities Company, Docket Nos. EC98-2-005, ER18-2162-004. Issued May 18, 2023. https://elibrary.ferc.gov/eLibrary/filedownload?fileid=ce753209-4afd-cff0-961b-883022e00000.

Webster County. "Home." Accessed October 2, 2023. https://www.webstercoky.com/providence.php.

Appendix A. Background

A.1 Modeling KyMEA's Generation and Transmission System

The modeling pathways we developed in Engage relied on publicly available information on KyMEA's contracts with different generation resources and transmission providers. Figures 2 and 3 were based on Figure A-1, which was obtained from a KyMEA presentation.

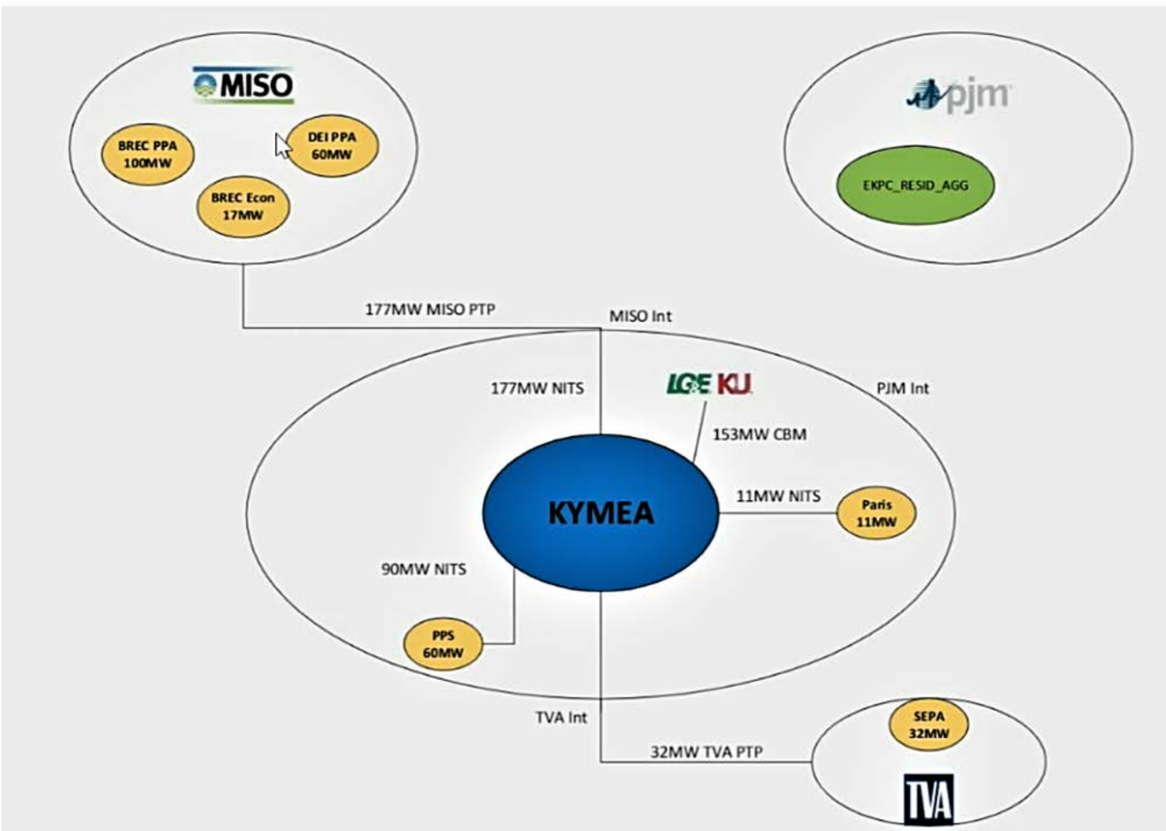

Figure A-1. KyMEA's G&T system from a KyMEA presentation

Appendix B. Engage Modeling Inputs

B.1 Production Profiles for Generation Resources

We determined the annual production of Frankfort's 11.54 MW solar PV system by consulting meteorological year data from NREL's National Solar Radiation Database (NSRD).[28] Figure B-1 represents the hourly projected capacity factors of a PV system in Frankfort, which was incorporated into the Engage model. This profile was used to reduce Frankfort's load so that the only generation KyMEA would need to dispatch would be the portion of Frankfort's demand not met through solar. We used the same capacity factor profile to determine the annual production of KyMEA's 86 MW Ashwood Solar resource.

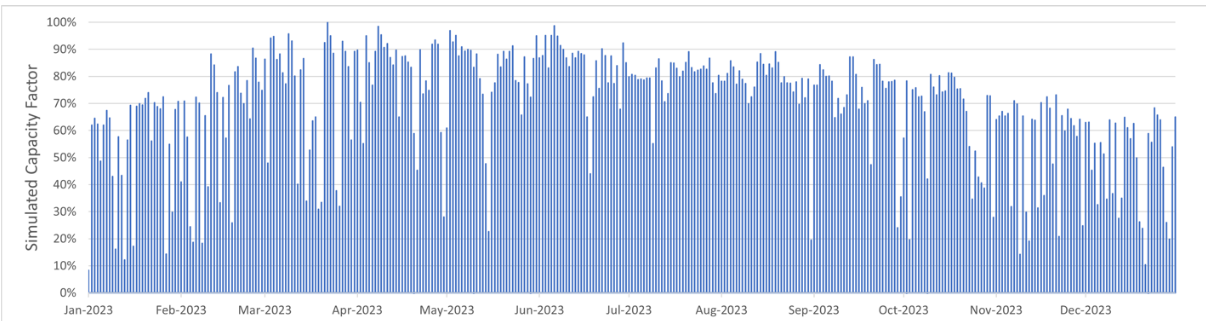

Figure B-1. Projected capacity factor of a PV system in Frankfort

Source: NREL's National Solar Radiation Database. Simulated from a 1 kW system to determine capacity factors.

We modeled SEPA's production, meanwhile, by pulling the monthly historical output for Wolf Creek Dam and spreading it evenly over each month to create an 8,760-generation profile, as shown in Figure B-2.[29] This was a significant limitation to the model as hourly production has the potential to vary significantly. This is an opportunity where we would especially welcome input from KyMEA to refine these numbers and obtain hourly resolution on SEPA hydropower production.

[28] Regional data sets for solar irradiance can be found at https://nsrdb.nrel.gov/.

[29] Through our open records request, we obtained monthly bills from KyMEA, which included the monthly production output from SEPA. This data was the basis for our SEPA production profile, but historical output for the Wolf Creek Dam can also be found under TVA at https://www.tva.com/environment/lake-levels/wolf-creek.

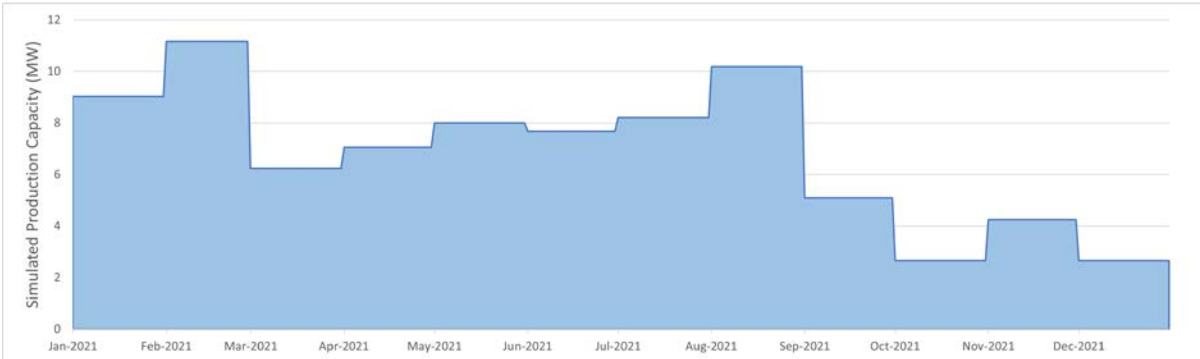

Figure B-2. Simulated SEPA historical dispatch profile

Source: KyMEA open records request.

B.2 Cost Inputs for Resources

We derived generation costs from KyMEA billing data, obtained through an open records request with KyMEA. We determined a generator's production capacity costs ($/kW) using the fixed annual costs of the resource and estimated its electricity production cost ($/kWh) using the generator's variable expenses, such as fuel. Since Ashwood Solar does not have a fuel cost, its total capital as well as operation and maintenance costs were summed and divided by the resource's projected output to calculate its hourly electricity production cost.

We also consulted the 2021 historical day ahead market prices at the Indiana Hub for MISO to determine KyMEA's import and export costs, where export costs are negative to represent additional revenue KyMEA can collect from selling its generation.

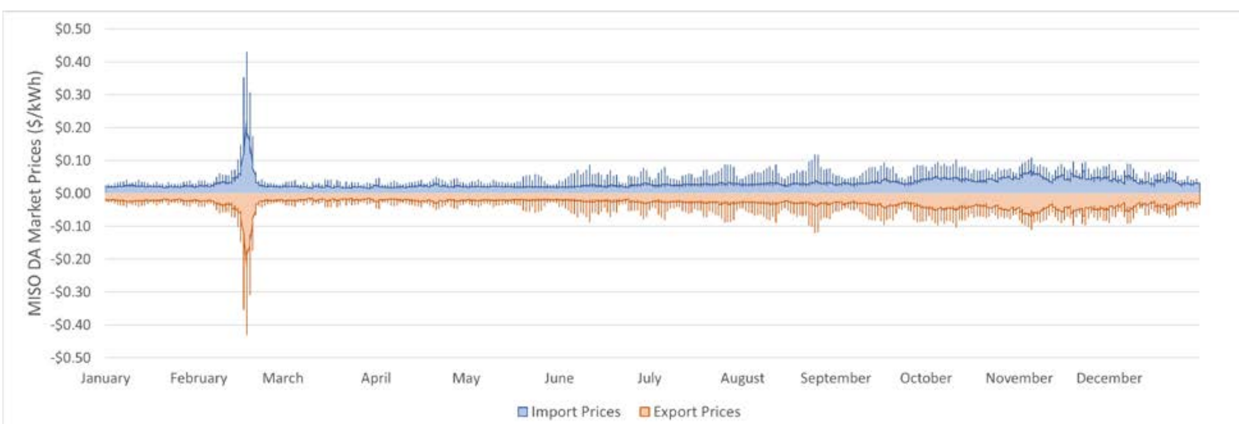

Figure B-3. MISO's DA market prices: imports (top) and exports (bottom)

Source: MISO n.d.

B.3 Specifics of the Engage Model Formulation

NITS "Demand" Charges

Although Engage has explicit (by design) capabilities to model most of the economic phenomena accounted for in this study, it does not currently have the designed capability to account for billing for demand peaks, so a capacity expansion capability of Engage was utilized to effect this accounting and its effect on optimal dispatch in the model.

We configured the KyMEA Engage model to use a transmission line asset as a proxy for the impact on the KyMEA's expenses of the LG&E NITS coincident demand charge. While a new transmission line is not actually envisioned as part of the project, the proxy allows for an understanding of a net change of costs and thus the value of the new DER as well as operational changes to how generation is purchased and sold. This allowed the model to derive an approximated cost of transmission system utilization according to the KyMEA LG&E NITS tariff that applies. Because the KYMEA is billed monthly on the LG&E tariff, in Engage, a capacity expansion transmission line was constructed for each month of the year and the LG&E transmission utilization was simulated by requiring the relevant generation to flow through those lines to meet the members' loads. The model applied a capacity cost to capacity expansion of each line and each month's line was capacity expanded to a capacity sufficient to carry that month's peak generation. By means of this monthly transmission line capacity expansion, the KyMEA perspective effectively saw (in addition to the commodity portion of the NITS tariff charges) monthly NITS "demand" charges as well.

Distribution-connected PV Production

Although Engage has the model components appropriate for representation of variable renewable resource technologies such as PV, distribution-connected PV was not explicitly represented in the model. Instead we opted to represent the resulting aggregate loads of the municipalities adjusted for production of the distribution-connected PV in the model in order to reduce the number of components in the model. This modeling approach should be no different to the outcome of the model from explicitly representing the relevant portion of the distribution system and the distribution-connected PV systems explicitly in the model.

Appendix C. Modeling Results

C.1 Load Attributes from BAU and DER Scenarios

Table C-1. KyMEA Maximum and Minimum Demand Load by AR Member

Member	BAU Max Load (MW)	DER Max Load (MW)	Difference in Max Load (MW)	BAU Min Load (MW)	DER Min Load (MW)
Barbourville	19.14	19.14	-	5.49	5.49
Bardwell	2.07	2.07	-	0.34	0.34
Corbin	18.85	18.85	-	4.66	4.66
Frankfort	132.25	127.44	(4.81)	38.44	38.44
Madisonville	56.84	56.84	-	1857	18.57
Paris	16.27	16.27	-	2.03	2.03
Providence	6.86	6.86	-	0.00	0.00

Table C-2. KyMEA Annual Energy Consumption by AR Member

Member	BAU (MWh)	DER (MWh)	Difference (MWh)
Barbourville	87,090.77	87,090.77	-
Bardwell	8,526.58	8,526.58	-
Corbin	81,006.45	81,006.45	-
Frankfort	652,123.52	630,180.14	(21,943.38)
Madisonville	267,017.33	267,017.33	-
Paris	63,414.62	63,414.62	-
Providence	29,293.31	29,293.31	-
Total	**1,188,472.58**	**1,166,529.20**	**(21,943.38)**

Table C-3. KyMEA Monthly Annual Energy Consumption

Month	BAU Peak (MWh)	DER Peak (MWh)	Difference (MWh)
January	108,976.47	107,963.01	(1,013.46)
February	105,921.65	104,716.46	(1,205.19)
March	89,833.11	87,978.27	(1,854.83)
April	83,234.94	81,150.71	(2,084.23)
May	88,128.42	85,689.27	(2,439.16)
June	107,495.93	104,952.44	(2,543.49)
July	116,499.67	113,882.58	(2,617.09)
August	120,767.17	118,288.92	(2,478.25)
September	95,435.81	93,393.26	(2,042.55)
October	87,922.73	86,311.15	(1,611.58)
November	91,295.58	90,153.90	(1,141.68)
December	92,961.09	92,049.21	(911.88)

C.2 Alternative DER Valuation Method Calculations

Table C-4. DER Valuation Methods

Approach	Method	Annual Value	Value per MWh Produced	Additive to $53.33 per MWh Funded
1)	Multiplied the DER's capacity against KyMEA's member resource credit, with a 58% SERC planning capacity value applied for solar.	$0.31 million	$14.13	$67.00
Calculation:	Calculation: *(Member_Capacity_Credit*12)*(Array_Nameplate*SERC_Capacity_Value)* where Member Capacity Credit = $3.85 ; SERC Capacity Value = 0.58 ; Array = 11,200 kW			
2)	Calculated the average portfolio capacity cost and determined the cost reduction value from a lower coincidental peak.	$0.77 million	$35.09	$88.31
Calculation:	*KyMEA_Average_Annual_Capacity_Cost * KyMEA_2021_Peak_Reduction* where Average Annual Capacity Cost = $105,760.2163 ; 2021 Peak Reduction = 7.26 MW & *Average Annual Capacity Cost = Total Generation Capacity Costs / Total Generation Capacity*			