Assessment of Wholesale Power Options for Memphis Light, Gas and Water

Preliminary Draft

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Submitted By:
ICF Resources, LLC

Contact Information

ICF

9300 Lee Highway
Fairfax, Virginia 22031

Judah Rose
Executive Director
703-934-3342
Judah.Rose@icf.com

David Gerhardt
Principal
703-218-2581
David.Gerhardt@icf.com

Lalit Batra
Manager
Lalit.Batra@icf.com

Vinay Gupta
Manager
vinay.gupta@icf.com

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1. Introduction

ICF Resources LLC ("ICF"), a subsidiary of ICF, was engaged by FLH Company (the "Client" or "FLH") to assess wholesale electric supply options for Memphis Light, Gas and Water (MLGW) including the proposed Bellefonte Power Purchase Agreement offered by FLH. MLGW is a municipal utility serving Memphis. MLGW currently purchases all of its wholesale power and transmission services exclusively from the Tennessee Valley Authority (TVA).

FLH Company, through its subsidiary Nuclear Development, LLC, is developing the Bellefonte 1 project located in northwest Alabama. Bellefonte 1 is a proposed 1,350 MW nuclear powerplant that was sold partially complete by TVA to FLH Company in early 2018. FLH projects completion of the nuclear unit within five to six years. MLGW's serve enough electrical load to consume of nearly all of the power produced by Bellefonte 1, with the small remainder available for sale to third parties. MLGW also needs incremental power during peak demand periods.

ICF assumes that the Bellefonte 1 project is completed by 1/1/2024 and sells its full output to MLGW at a rate schedule starting around $39/MWh, according to information provided to ICF by FLH. ICF's scope does not include a review of the Bellefonte 1 project's cost, performance and feasibility. However, ICF assessed the ability of FLH to deliver power to MLGW on the wholesale transmission grid, and made an economic comparison of supply options built around the Bellefonte 1 PPA.

ICF is a nationally recognized, independent consulting firm with approximately 5,000 employees, revenues of $1.2 billion and headquartered in the Washington, DC area. We find the main questions to be the following:

1. What rate would MLGW pay for TVA power over the next 20+ years?
2. Is the Bellefonte 1 power purchase agreement competitive against this rate?
3. What is the cost of procuring the remaining power needed by MLGW after Bellefonte 1?
4. How can MLGW best go about procuring this remaining power?
5. Can Bellefonte 1 power be transmitted to MLGW?
6. How can MLGW access backup generation reserves to ensure reliable service?
7. Overall, given the above, is it economically attractive for MLGW to purchase power from Bellefonte 1 plus additional sources, as compared to the normal full TVA rate?
8. If so, how can MLGW go about implementing this change? What challenges might be faced in implementation and how can MLGW address them?
9. What are the risks in not going forward?

A thorough assessment of the above questions necessarily touches on a range of legal and regulatory issues. ICF treats these issues in accordance with our experience in power systems and their regulation. Importantly, however, we are ***not*** lawyers, and we are ***not*** offering legal opinions or legal guidance on the issues involved. Where appropriate, we highlight our non-lawyer understanding of the relevant rules and statutes and in some cases, the range of potential outcomes.

ICF's findings are presented in this report.

2. Executive Summary

2.1 Current MLGW-TVA Contract

TVA currently supplies MLGW with all wholesale power requirements. MLGW has approximately 431,000 retail customer accounts and sells 14.3 TWh to end-users as of 2017. It is our understanding that MLGW purchases wholesale power (i.e., generation and transmission related services) from TVA under a long-term firm supply contract. It is also our understanding that MLGW can terminate service by providing a 5-year notice, while TVA can terminate service with a 10-year notice.[1] TVA rates under the contract reflect the average cost of service of TVA. In 2017, that rate was $74/MWh. The contract is referred to as an "All-Requirements" or "Full-Service Requirements" contract because TVA provides all of the wholesale power and high-voltage transmission used by MLGW. MLGW distributes the power at lower voltages to its customers on its own system.

MLGW is the largest single buyer of power from TVA, and consumes approximately 11% of TVA power sold to Local Power Companies (LPCs). MLGW is also the closest major LPC to the large deregulated competitive wholesale market known as Midcontinent Independent System Operator (MISO). This market is on the other side of the Mississippi River from MLGW.

2.2 Economic Analysis

ICF analyzed the costs of wholesale power over 20 years for the 2024 to 2043 period. ICF analyzed two principal scenarios:

- **Business As Usual** - First, ICF forecasted the cost of TVA power assuming the current contract with MLGW continues (i.e., a Business As Usual (BAU) case) based on public information from TVA and ICF's modeling of the future costs of fuel, power, etc.
- **Bellefonte 1 Plus Market Based Incremental Power** - Second, ICF forecasted the cost of power assuming the Bellefonte 1 PPA is in place and MLGW or its agent purchases incremental power requirements including energy and capacity at wholesale market prices. ICF also assessed the deliverability of both Bellefonte power and the incremental power required by MGLW. As noted, ICF relied on FLH for the Bellefonte 1 PPA parameters.

2.2.1 Results of Economic Analysis – Bellefonte PPA Vs BAU

ICF PROJECTS LARGE SAVINGS - $7.9 BILLION NET OVER 20 YEARS - PRIMARILY BECAUSE THE BELLEFONTE PPA COSTS ARE SIGNIFICANTLY LESS THAN PROJECTED TVA COSTS.

→Kwh Sold

TVA currently provides MLGW wholesale power supply at $74/MWh, and hence, an annual cost of approximately $1.0 billion per year.[2] In 2024, the first year of our study, we estimate MLGW's cost under the TVA contract

[1] ICF has not reviewed the TVA/MLGW contract and is not offering legal opinions. Also, ICF has not reviewed all of the other contracts of TVA, but rather presents its understanding of TVA's general contracting situation.

[2] The $1.0 billion cost represents the MLGW purchase of power in 2017.

would be approximately $1.075 billion. In contrast, however, switching MLGW to a combination of the Bellefonte 1 PPA and market based incremental power saves MLGW in net $0.335 billion – i.e., total costs decrease to approximately $0.739 billion. This equals wholesale power cost savings of approximately 40%. Over the 20-year period, there is aggregate net savings of approximately $7.9 billion[3].

The gross savings are even higher ($11.8 billion). We define gross savings as BAU less Bellefonte PPA and the costs of incremental electrical energy. Net savings are calculated taking into account further costs for capacity reserves, transmission, and management costs. For example, in 2024, the gross savings is $487 million. Gross savings can be useful because capacity procurement (to cover peak and reserve requirements) is the main cost difference between gross and net. Capacity has been essentially free in the MISO spot capacity market. We do not recommend reliance on spot capacity purchases, but we recognize the amount and cost of hedging is a strategic decision of MLGW. Notwithstanding, our primary economic conclusion is based on net savings.

MLGW has 431,000 retail customer accounts and on average, in the first year (i.e., 2024) savings per customer would be approximately $778. On a net present value basis, the **total net savings per customer** would range from $12,850 to $9,440 using a discount rate of 3.5% to 7% respectively. These savings are also very significant when compared to other parameters, including the Memphis municipal budget of approximately $0.7 billion per year not including MLGW.[4]

The savings primarily reflect Bellefonte PPA's cost being low compared to projected TVA full-service rates, and the plant supplies over approximately 70% of MLGW electrical energy needs. In the BAU case, TVA sells MLGW approximately 14 million MWhs at an approximate cost of $75/MWh starting in 2024. In contrast, in the first year (i.e., 2024), the Bellefonte PPA would provide approximately 70% of MLGW's power in the first year at a cost of $39/MWh. This is about half of the TVA rate (52%). For comparison, the PPA rate is comparable to the variable costs of TVA power (fuel, O&M, and purchase power), and thus, the PPA allows MLGW to effectively avoid the large capital recovery component built into TVA rates including depreciation, income, etc. This in turn reflects Bellefonte's low short-run variable costs (mostly fuel) and lower implied capital recovery requirements relative to TVA's on a going forward basis. Secondarily, even incremental power (the remaining 30% after Bellefonte) is less costly than the average TVA rate.

2.2.2 Economic Analysis – Incremental Power

Incremental power costs from neighboring systems are low compared to TVA's costs for incremental power. This is in part due to excess capacity in the market. Also, attractive physical and financial hedges are available. MLGW is across the river from and has easy access to the nation's largest organized wholesale power marketplace.

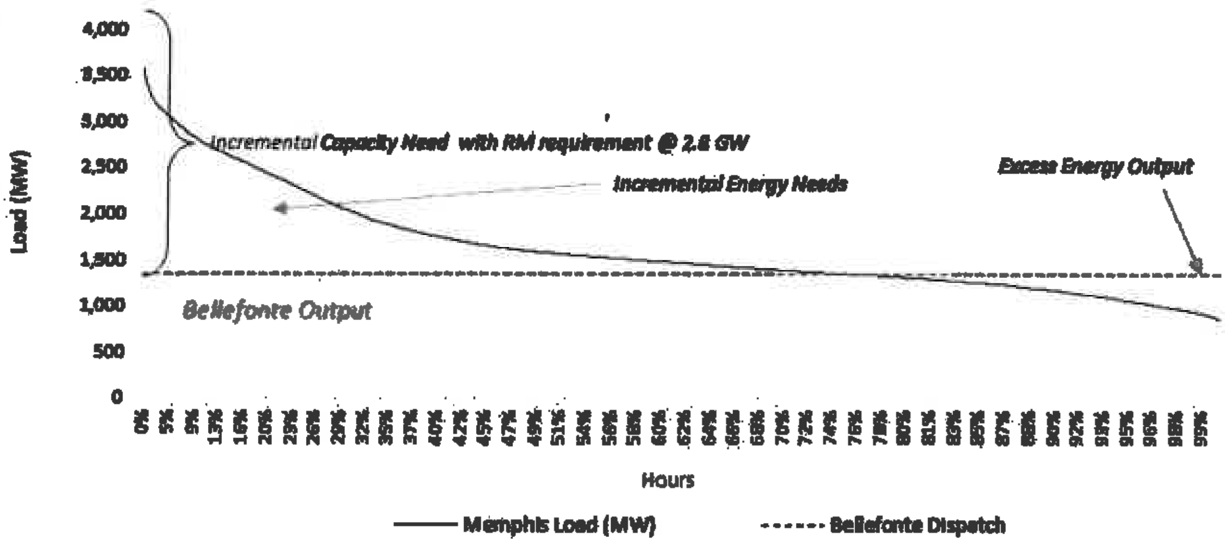
Bellefonte would meet over 70% of MLGW's needs on an energy basis (i.e. MWhs). We refer as the remaining MLGW needs as incremental power. Specifically, MLGW requires approximately 3.4 million MWh of incremental

[3] This is the cumulative undiscounted savings over the 20-year period of 2024 to 2043.

[4] The City of Memphis budget for 2019 is projected at approximately $685M

power (see Exhibit 1). In addition, MLGW also requires an additional 2,800 MW of capacity for reliability – i.e., to meet peak annual demand (approximately 2,200 MW – see graph) plus the reserve margin requirements[5].

Exhibit 1: Memphis Load Relative to Bellefonte 1 Output



Source: FERC 714, ICF and FLH Company

Several options exist to obtain this incremental power:

- MLGW can source incremental power from the TVA grid. This would be under what is known as a partial-requirements service contract. This is similar to the existing All Requirements contract except TVA would provide less power. This option requires agreement by TVA, which is not expectedly to be easily obtained.
- MLGW can source incremental power from nearby utilities.[6] Indeed, wholesale sales between large utilities and public power entities are common. The current TVA contract is an example of such a contract.
- MLGW can buy energy and capacity in the spot markets; we do not recommend this as an exclusive option due to the volatility of these markets. MLGW is adjacent to the nation's largest organized wholesale power market, which has had for years prices approximately half those of TVA.

[5] Utilities must maintain reserves to ensure reliable operation at the summer peak and during outages. This amount equals peak plus approximately 15%. The excess capacity above expected peak necessary to compensate for unit outages and the possibility of peak demand higher than expected. The 15% also assumes reserve sharing is in place to handle plant outages; the industry has sophisticated reserve sharing mechansims, requirements and regulaitons to ensure reliability. MLGW miht be required to have modestly higher reserves due to the size of Bellefonte 1 – e.. approximately 150 to 300 MW. See later discussion.

[6] https://www.gpo.gov/fdsys/pkg/GAOREPORTS-GAO-01-327/pdf/GAOREPORTS-GAO-01-327.pdf

- MLGW can transact spot and short-term energy combined with physical and financial hedges implemented by itself or an agent (e.g., another utility or third-party supplier). Specifically, the most attractive option for incremental power is purchasing power from the wholesale power market combined with physical hedges, especially the purchase or long-term contracting of existing combined cycles owned by Independent Power Producers (IPPs) in the Southeastern US[7]. The spot market purchases will likely be from MISO, the large centralized wholesale power exchange market located across the river from Memphis, although other options including bilateral sales exist. We recommend this hybrid, hedged approach (spot market purchases and long-term contracts/powerplant purchases) not only to decrease price volatility but also to take advantage of currently depressed prices for powerplants.

  Throughout the document, whenever we refer to market options – e.g., buying powerplants as a physical hedge, we emphasize that this can be done by a third party under contract or by MLGW. For example, a third-party provider of a partial requirements contract built around the Bellefonte 1 PPA and market options built up with a mix of existing CC and CT assets. This emphasizes the likely economics from such a contract (i.e., what the price will be), the flexibility MLGW will have in directing the hedging program, and making trade-offs between savings and potential volatility. We also emphasize whatever the volatility that exists, it is highly moderated by the Bellefonte 1 PPA, and must be compared to the volatility of rates under the TVA contract. There has been historical volatility of TVA rates, increasing reliance of TVA on non-baseload options (i.e., natural gas) which can increase volatility, and there is the risk that if MLGW does not contract for Bellefonte, someone else may, and this could put upward pressure on TVA rates as the fixed costs may be increased per MWh as the remaining LPC load decreases.

- Bellefonte 1 plus market options is facilitated by the ability to purchase power from open markets. MLGW is geographically adjacent to the nation's largest competitive deregulated wholesale power market, MISO.[8] MISO is an independent, not-for-profit entity regulated by the US Federal Energy Regulatory Commission ("FERC"). MISO has both energy and capacity markets[9]. In 2017, spot prices in this market were less than half of TVA rates.[10] MLGW can more easily access this very large and liquid marketplace than any other LPC/entity currently supplied by TVA because it is the only major (i.e., large load) LPC/entity adjacent to MISO.

The costs of incremental wholesale power, energy, and capacity available in MISO are moderately lower than current TVA rates. One would expect the costs to be higher because MLGW's incremental needs are largely on-peak power and capacity reserves, and these products should cost more than average costs or baseload power[11].

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[7] Other capacity purchase options are also possible – e.g., peakers. This is discussed later as a mix is recommended.

[8] We often refer to Entergy or MISO South when referring to the adjacent MISO marketplace. Size is measured in georgraphic area. It is the seond largest in terms of load.

[9] Capacity refers to first call on generation capacity. The MISO capacity market has very low prices, but also low liquidity. The energy market is large and liquid.

[10] In MISO, the all-hours average firm price was $31.4/MWh while the TVA rate to LPC was $74/MWh in 2017

[11] Because power cannot be easily stored, and demand and supply must be equal, as demand increases during on peak hours – e.g. afternoon, increasingly expensive units are used, and these units become the incremental or marginal-price setting source of power.

However, this is not the case because the market has excess low-cost, gas-fired capacity available for MLGW to contract or purchase.[12]

The purchases of IPP combined cycles and other plants occur frequently; a significant transaction was just announced on August 22, 2018 involving a plant that can deliver to either TVA or neighboring Entergy. Other recent transactions in this region also indicate that gas fired plants can be purchased at less than half of new plant replacement costs due to excess capacity.[13] This "locks in" attractive market conditions. The report identifies potential sources of incremental capacity.

2.2.3 Incremental Power Volatility and Hedging

As attractive as current market conditions are, we emphasize a balanced view of market and contract is important. For reasons discussed later, the costs of gas-fired power and spot market power purchases can be volatile. Furthermore, the reported spot market price can increase in the event of a large increase in demand – e.g., all of MLGW's incremental load coming onto market, especially its demand for capacity to meet annual peak demand plus reserves. While TVA would also have supply it would need to place, it could sell in a way that does not prevent an increase in capacity prices.

Two very important conditions unique to MLGW's situation mitigate concerns about market volatility. First, the volatility of MLGW rates would be low primarily because 70% of the power is under the Bellefonte PPA, which has prices pre-set by a pricing formula that is fixed to a very large extent.[14] Low-cost baseload power (i.e., coal or nuclear) from an Independent Power Producer (IPP) like FLH Company is not typically available. Indeed, TVA itself has increasingly moved away from baseload power to gas. Since slice-of-system deals at average costs are the norm, and these transactions do not allow for direct access to baseload supply but rather a mix. Second, these costs can be partially hedged via a strategy of ownership of capacity (physical) and other mechanisms such as short- to medium-term gas or power hedges (financial).

2.3 Feasibility

We assessed several aspects of the feasibility of a new contractual arrangement for MLGW's wholesale power including:

- **Availability of Firm Transmission** – Can Bellefonte power be delivered to MLGW? Who can deliver it? How much will it cost? Can incremental power be delivered to MLGW?

[12] For example, on August 22, 2018, Entergy, the utility adjacent to MLGW, announced purchase of modern advanced combined cycle for less than $400/kW – see MW Daily August 23, 2018, Page 3. The article estimates the price equals 41% of the cost of a new combined cycle.

[13] In 2017 Capital Power bought Decatur Energy Center from LS Power for $489/KW. In Feb 2015, TVA bought 760 MW of Quantam Ackerman Choctaw CCGT for $450/kW and in December 2014, Entergy bought ~2 GW of Union Power Station CCGT for ~$470/kW. See Exhibit 37 for list of recent transactions.

[14] The only non-fixed price component of the Bellefonte PPA price is an inflation factor associated with the underlying O&M component of price. This information was obtained from Nuclear Development, LLC. While ICF does not have the components of the PPA, we estimate this impact to be approximately 30% of the total all-in costs on a going forward basis.

- **Availability of Reserve Sharing Arrangements** – What happens if there is an outage of Bellefonte 1 during peak demand periods? Are reserves available from other utilities to keep the lights on? How does reserve sharing work in the power sector?
- **Availability of Alternative Procurement and Contracting Arrangements** – What is involved in replacing TVA beyond power supply? Can this be self-supplied? Can it be purchased from others e.g., can MLGW expect availability of alternative providers of Partial Requirements contracts organized around the Bellefonte PPA.[15]

2.3.1 Transmission

ICF power flow analysis concludes that power from Bellefonte 1 is deliverable to MLGW on the existing transmission grid without major upgrades.

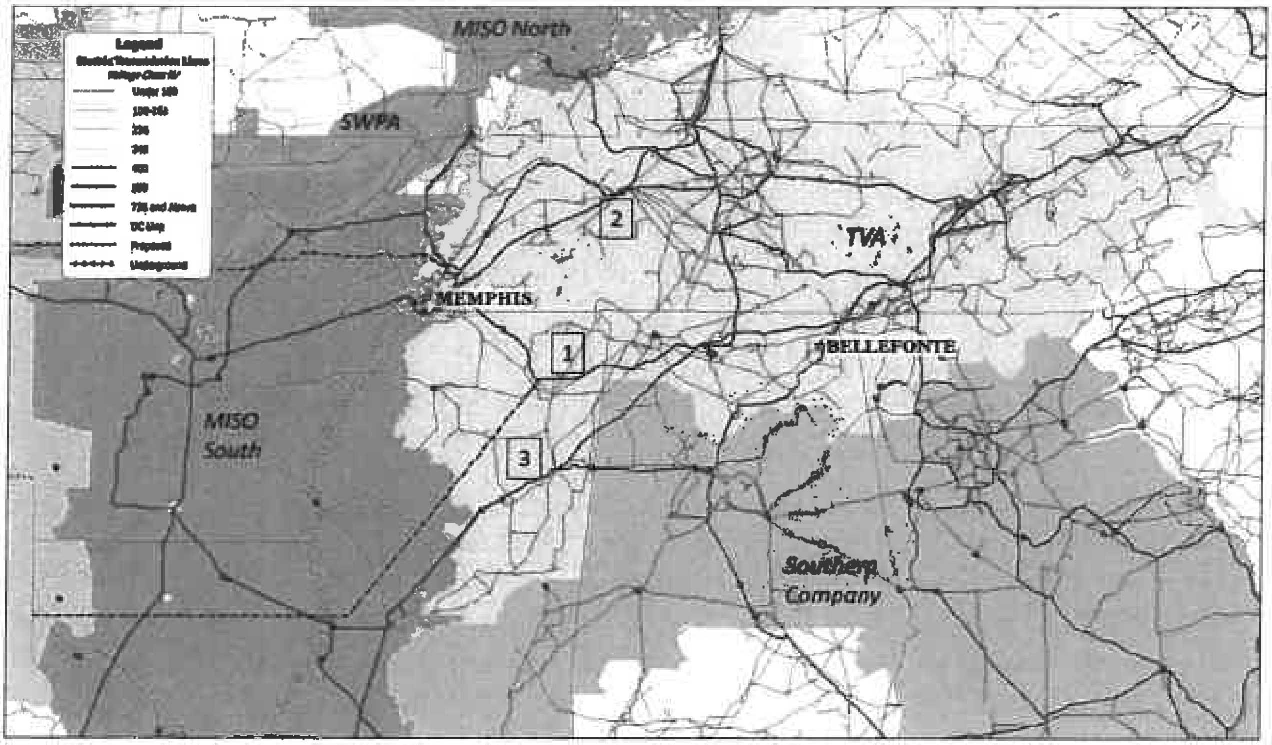
MLGW is surrounded on three sides by high capacity, 500-kV transmission lines owned by TVA. These 500-kV lines are part of the backbone or highway portion of TVA's power transmission system. Power is drawn from these lines by MLGW's 161-kV lines. On the fourth side, MLGW is bounded by the Mississippi River and the MISO competitive power market (see Exhibit 2).

MLGW can likely obtain open access service from TVA to transmit the power from Bellefonte to MLGW[16]. ICF conducted a detailed transmission grid modeling exercise and found that transmitting Bellefonte power to MLGW does not require major new transmission investment on TVA's or any other system (though interconnection service and immediate upgrades in the Bellefonte area are required). MLGW also has alternatives to bring in Bellefonte power via alternative open access transmission systems.

For example, MLGW can obtain incremental power via the MISO system. In our analysis of MLGW economics, we find it advantageous in some cases for MLGW to construct its own lines to MISO. When this is the case, we also conclude that power from Bellefonte 1 can also be delivered over these lines as an alternative to service on TVA's system.

[15] Wholesale supply arrangements that are built around a receiving utility's own generation is common, and referred to as partial requirements contracts. Wholesale power contracts are subject to FERC regulation if one of the parties is FERC jurisdictional, the contract involves transmission, (see discussion in later section), or reliability.

Exhibit 2: Transmission Lines and Balancing Authorities around Memphis



Source: Ventyx and ICF

2.3.2 Open Access Transmission and TVA

In accessing transmission service on the TVA system, MLGW would purchase firm transmission service in accordance with the US Federal Energy Regulatory Commission's (FERC's) Open Access transmission rules. FERC requires Transmission Providers (TPs) like TVA to comply with requests for transmission service in accordance with their published open-access transmission tariff. For example, in the case of Bellefonte, we anticipate that MLGW would purchase long-term, firm, point-to-point service with rights to extend transmission service over time.

Under FERC rules, if the transmission service requires transmission system upgrades, the TP can recover the costs from the buyer of the service, and can delay service provision as long as it is making appropriate efforts to implement the identified grid upgrades. Therefore, a key issue is how costly and involved will the upgrades be, if any are required. ICF analysis, using detailed grid "power flow" modeling and Critical Energy Infrastructure Information (CEII), finds no major upgrades on TVA's system are required.

There are some specific TVA aspects of transmission service; TVA is expected to resist providing service, based on past TVA actions and recent statements by TVA in their tariff, reports, etc. TVA claims it is not subject to open access as it pertains to its LPCs. TVA relies in large part on its reading of a section of the Federal Power Act: section 212(j). We are not lawyers and are <u>not</u> opining on the legal issues involved, but believe that these TVA specific conditions notwithstanding, open-access transmission is available from TVA. This belief has two supporting rationales. First, our conclusion derives from our general understanding of transmission rules and regulation. Second, our conclusion derives from very relevant FERC decisions. In light of the lower costs that TVA service provides, we discuss this issue at some length here and elsewhere in the report. However, it is not a sin qua non, transmission alternatives exist for MLGW that even TVA stipulates to.

We base our expectation that TVA will provide open access transmission in part on a non-lawyer reading of a parallel case involving TVA and another TVA wholesale customer. In this case, specifically in the US FERC Order Denying Rehearing, issued on June 20, 2006 in Docket No. TX05-1-006, FERC addresses the ability to obtain transmission service on the TVA system (paragraph 22). FERC states that, "our authority to implement portions of the open access policy established in the OATT (Open Access Transmission Tariff) derives from the requirement under sections 205 and 206 of the FPA (Federal Power Act) to remedy undue discrimination, not sections 210 or 211." (Parentheticals added)[17] Our non-lawyer understanding is therefore that even if Section 212(j)[18] prohibits FERC from ordering TVA to provide transmission services under Section 211 (which it appears to do), FERC can effectively order open access transmission under sections 205 or 206 via what is referred to as "reciprocity" – i.e., FERC prevents jurisdictional utilities from providing open access transmission to TVA, unless TVA provides open access to other jurisdictional utility systems.

Put another way, access to transmission is based on "belts and suspenders". Even if one is vitiated, the other remains.

TVA states it voluntarily has an open access tariff – i.e., voluntarily agrees to reciprocity and can change its view were it to involve service to one of its LPCs. While true, this exaggerates TVA's flexibility. Were TVA to decline to provide open access transmission via reciprocity to other systems e.g., MLGW, to our knowledge, TVA would be the only major entity in the US to do so. Furthermore, in such a unique circumstance, there may be adverse implications for many of TVA's current transmission activities. This is because TVA would lose open access transmission on other systems. Transmission is required for reserve sharing, transmission for economic reasons with neighbors, power purchase agreements, interconnection, handling inadvertent flows on other systems, etc. These are core utility activities. Accordingly, while theoretically possible, it is not practical to refuse reciprocity – i.e., to refuse open access.[19]

TVA opposition may manifest itself in other areas including stranded costs and fees for returning to TVA service later. However, we believe the threat of stranded costs is a red herring because MLGW would honor its contract which allows it to give termination notice without a charge. Put another way, stranded costs can only be estimated for a period where TVA expected to serve MLGW that but for open access was being shortened; this expectation is clear in the contract.[20] This is discussed further later.

2.3.3 Generation Reserve Sharing

Reserve sharing is a form of insurance and regulated by the FERC. The idea is that plant outages are highly independent, and it is not likely that everyone will need generation back-up at the same time. If during peak, one utility has an outage (e.g., MLGW loses Bellefonte 1), it can purchase back-up power from its neighbors.

[17] TVA appealed the FERC rejection of its appeal in federal court, but the case was settled and hence not decided by the court.

[18] Referred to as the TVA anti-cherry picking provision.

[19] Even if TVA could reject reciprocity, and withdraw from FERC's competitive construct, Congres could still change the law in this regard. We have no opinion on the prospects for legislation, but note porposals were made in the late 1990s to open TVA to further deregulation.

[20] All ICF statements on theTVA contract are caveated as our understanding in the absence of review and our inability as non lawyers to opine on legal issues.

Historically, transmission was originally built between utilities in significant measure to allow for this sharing of reserves.

Utilities, or groups of utilities, also referred to Balancing Authorities (BAs), are the sharing entities. Reserve sharing agreements cover the entire grid. In exchange for maintaining approximately 15% reserve capacity on a planning basis, maintaining their share of operating reserves (a category of quick response reserves such as spinning reserves), and meeting other requirements, in the event of an unexpected power plant outage, BAs can obtain power from their neighbors.

All utilities are subject to mandatory FERC reliability regulation rules and regulations on reserve sharing and reliability. The US Electric Reliability Organization (ERO) establishes and enforces these requirements; the US ERO is the North American Electric Reliability Corporation (NERC). BA agreements must conform to NERC compliance rules and standards.

MLGW qualifies for reserve sharing like any other US utility. The exact form reserve sharing takes depends on the contractual arrangements of MLGW. For example:

- In the case where MLGW has partial requirements service with TVA, TVA would still be providing the reserve sharing service.
- In the case where MLGW joins MISO, MISO would be providing the reserve sharing service.
- In the case in which another utility provides partial requirements service, they would provide the reserve sharing services.
- Finally, in the case where MLGW becomes its own Balancing Authority, it would form an agreement with a neighboring BA (e.g. MISO, other Southeastern Electric Reliability Coordination (SERC)[21] utilities, etc.) to provide reciprocal reserve sharing.

We are not aware of a circumstance in which a BA with transmission access to neighbors was denied access to a reserve sharing agreement that meets NERC requirements. This allows the BA to hold a reasonable level of reserves as opposed to going it alone, holding huge amounts of reserves, and acting as if the utility is on an island when it is in fact not. If large neighbors were to unfairly deny a neighbor access to reserve sharing agreements, it might be considered an anti-competitive exercise in market power.[22]

2.3.4 MLGW Can Procure Wholesale Requirements Supply from Other Suppliers

MLGW already has decades of experience contracting for wholesale power. However, the form of the contract is an "all- requirements" contract in which TVA handles the full set of wholesale requirements of MLGW ranging for baseload and peaking power, scheduling, reserves, balancing services, compliance with regulatory

[21] SERC covers the southeastern US except Florida.

[22] Requiring a new entity to cover any incremental costs of their joining a reserve sharing agreement would not be unduly discriminatory or anti competitive behavior. In general, the larger the sharing group, the lower the costs and the lower the reserve requirements. However, very large units can increase the costs and the incremental costs could be allocated to the entity with that unit. However, these costs are likely to be small because most groups already have at least one very large unit. In the absence of an agreement, the BA would have to obtain NERC approval for its reserve plan. It may also rely on best efforts fromneighbors with payment at rates regulated by FERC but not as attractive potentially compared ot if there was an agreement.

requirements, transmission procurement, planning, security coordination, etc. TVA also is large and has a diverse fleet of plants.

Most likely, some other entity will become the new requirements provider building the power supply and services around the Bellefonte PPA and incremental power. This is feasible and common in the industry. We describe in later sections the activities involved, the resources required, and while MLGW can self-provide these services, a more likely arrangement is some outsourcing with MLGW involved in setting strategic direction on hedging incremental power.

2.4 Results

In this section, we present more detailed results of our economic analysis.

ICF analyzed the economics of several contracting strategies and are shown below in Exhibit 3. We report both gross and net savings relative to a "Business as Usual" (BAU):

- **Gross Savings** - We define gross savings as the BAU case less the combined cost of the Bellefonte PPA plus incremental energy costs.
- **Net Savings** - We define net savings as gross savings less additional costs incurred to implement a particular scenario. These costs incurred could include but not limited to the building of new transmission lines, the securing of firm transmission, and securing of physical reserves need to maintain the reliability of the Memphis distribution system.

As discussed, we present both estimates because the main difference between gross and net is the cost of capacity, and this may involve trade-offs between hedging and costs.

2.4.1 Business as Usual (BAU)

Under the business as usual case, MLGW continues to purchase under TVA's full-service requirements contracts and the wholesale power costs reflect the average costs of service from TVA including average fuel, non-fuel O&M, purchased power, capital recovery, profits, etc. In 2024, costs are projected to equal approximately $1.1 billion. Over the 20-year period of 2024 to 2043 the average cost is $1.3 billion. This escalates over time in part as a function of general inflation, but also based on other factors (see Section 4.3 for a full review of our TVA rate projections). The TVA rate for LPCs has been in the range over the past 10 years (2008-2017) from a low of $62/MWh in 2008 to as high of $74/MWh in 2017, with about two-thirds of the rate reflecting recovery of fixed costs.[23] TVA rates have grown at an average of 2.2% per year over the past 10 years, and the rate is projected to grow at an average of 1.6% from 2024 to 2043. All the other cases that follow are discussed relative to this BAU case.

[23] Fixed cost includes fixed O&M, interest expenses, depreciation and tax equivalents.

Exhibit 3: Summary of Memphis Gross and Net Savings Relative a "Business as Usual" Case

Scenarios	Levelized Costs (2024-2043)	Cumulative Costs (2024-2043)	2024	2025	2030	2035	2040	2043
TVA Rate Cost - Business As Usual Case	1,260	27,424	1,075	1,097	1,245	1,356	1,490	1,587

Gross Savings: BAU Less Alternative Supply ($MM)	Levelized Savings (2024-2043)	Cumulative Savings (2024-2043)	2024	2025	2030	2035	2040	2043
Option #1 [TVA is BA / Partial Service Requirements from TVA]	374	7,883	307	315	377	410	452	485
Option #2A [MISO is BA / Inc. Power Hedged]	569	11,822	487	503	579	613	664	675
Option #2B [MISO is BA / Inc. Power Spot Market]	569	11,822	487	503	579	613	664	675
Option #3A [MLGW is BA / Inc. Power Hedged]	418	8,612	365	377	435	448	475	470
Option #3B [MLGW is BA / Inc. Power Spot Market]	418	8,612	365	377	435	448	475	470

Net Savings: Gross Savings Less Regulatory/Transmission Costs ($MM)	Levelized Savings (2024-2043)	Cumulative Savings (2024-2043)	2024	2025	2030	2035	2040	2043
Option #1 [TVA is BA / Partial Service Requirements from TVA]	374	7,879	307	315	377	410	452	485
Option #2A [MISO is BA / Inc. Power Hedged]	384	7,910	335	347	403	412	435	427
Option #2B [MISO is BA / Inc. Power Spot Market]	235	4,931	188	196	251	265	286	282
Option #3A [MLGW is BA / Inc. Power Hedged]	254	5,134	231	240	279	269	270	248
Option #3B [MLGW is BA / Inc. Power Spot Market]	104	2,155	84	89	127	122	121	103

Source: ICF

2.4.2 Bellefonte PPA Plus Physical Hedges to Cover Incremental Needs [24]

Most Economic Strategy: MLGW becomes part of MISO, purchases Bellefonte 1 power plus incremental MISO power, and buys contracts / existing powerplants as part of a physical sedging Strategy to further control the volatility of incremental power costs.

2.4.2.1 Results

We consider this the main alternative procurement strategy for MLGW compared to the BAU case. This is because it does not depend on the approval of TVA, does not have heavy reliance on unhedged spot market purchases for incremental power, and has the most savings relative to BAU. The annual gross savings is estimated at almost $487 million in the first year. The annual average net savings is estimated at $384 million per year, and $335 million starting in 2024, the first year of this study.[25] This is referred to Option #2A in the exhibit above. This is over a 30% savings in 2024 relative to the $1.1 billion in cost from the BAU case. This savings primarily reflects the lower costs of Bellefonte PPA; the PPA costs equal the variable costs of TVA and

[24] Also referred to as $25/kW-yr case. This is because the upfront purchase of the plants costs $25/kW-yr (i.e. fixed costs less energy margins) rather than forecasted higher levels due to eventual tightening in the market for capacity.

[25] Net savings is defined as gross savings less the costs incurred to implement a particular scenario. These cost incurred could include but not limited to the building of new transmission lines, the securing of firm transmission, and securing of physical reserves need to maintain the reliability of the MLGW distribution system.

allows MLGW to effectively avoid paying TVA's fixed costs. Savings per MLGW customer equal approximately $890 per year. As another perspective on the significance of the savings, in comparison, the 2019 annual projected budget of the Memphis excluding MLGW is approximately $685 million.[26] Over 20 years, cumulative savings gross is projected at $12 billion, and net savings cumulative is projected at $8 billion.

In addition to purchasing Bellefonte power and the associated firm transmission for delivery, MLGW purchases the needed transmission service to become part of MISO, or builds the transmission to directly interconnect, whatever costs the least. Large transmission lines link MLGW to TVA and then across the river to contiguous MISO. Where new lines are needed, the distance to key MISO substations would likely be small (~75-100 miles). Our estimate includes the cost of new line construction.

2.4.2.2 Hedging and Capacity Costs

MLGW would also purchase contracts / existing powerplants located in MISO to partly hedge against price volatility of incremental power – i.e., to hedge the approximately 30% of energy and 3,000 MW of capacity not covered by the Bellefonte PPA (this capacity covers peak plus required reserves[27]). This would supplement MLGW's main hedge in the Bellefonte PPA that has costs that are largely fixed. This "buy-capacity-now" hedge strategy is attractive because there is excess capacity in the wholesale power market that can be locked in via purchases of capacity. Recent comparable transactions (i.e., powerplant sales) strongly support the view that existing combined cycles can be purchased at approximately 40-50% of replacement costs.[28] These plants provide hedges against the potential for higher MISO energy and capacity prices later on. We assume these plants, a mix of combined cycles and peakers, can be purchased at $230/kW.[29]

These plants can also hedge their fuel costs, but the hedge most likely will have to be renewed periodically at prices then prevalent – i.e., it not a perfect hedge on its own[30]. Other hedging strategies may also exist. In addition, other capacity purchases may be economic including some peakers and other plants – e.g., existing renewables, otherwise-retiring coal plants, etc. These strategies would be investigated as part of the partial requirements contracting MLGW would undertake.

2.4.2.2 Recent Spot Prices versus ICF Forecasts

ICF forecasts the economics of this arrangement including future power prices using industry standard computer modeling as described in the appendix. This forecast shows rising spot prices. However, it should be noted that MISO spot prices have been very low, and if power were to be available in the future at these low prices, even greater savings would occur. Over the last 5 years, MISO prices, energy and capacity have averaged

[26] https://www.memphistn.gov/UserFiles/Servers/Server_11150732/File/Gov/Financial%20Division/FY_2019_Adopted_Budget/Budget%20Overview.pdf

[27] We focus here on energy and capacity because these are the largest wholesale services. Also required is transmission, ancillary services (usually thesmallest portion afterenergy, capacity and transmission), and system operations. We account for all of these items and is discussed in later sections.

[28] Choctaw at less than $400/kW in August 2018. Choctaw interconnects with TVA and Entergy.

[29] We estimate an 1/3 combined cycle and 2/3 simple cycle combustion turbine mix based on the incremental load requirements of MLGW after Bellefonte 1 capacity is considered.

[30] Long term financial hedging can require mark to market collateral requirements, and hence, long term financial hegding is not typical practice. Hedging is unlikely to be perfect, due to basis differences, but likely to be efficacious overall.

$31.55/MWh. In comparison, TVA costs averaged $69/MWh. In 2017, spot energy and capacity combined costs were $31.4/MWh versus approximately $74/MWh for TVA full requirements service. That is, market prices for incremental power have been very low; TVA in 2017 had rates approximately 139% higher[31]. We do not recommend exclusive reliance on spot sales alone without hedges for incremental power in part because we expect higher capacity prices in particular over time, but the exact extent of hedging as opposed to spot or short-term transactions would be determined over time.

The hedging costs assume that the capacity purchased is located in MISO and has no basis difference[32] with MLGW. If the capacity is purchased outside of MISO, additional transmission charges may be needed in order to sell the power output of the capacity in MISO. However, even if plants are purchased outside MISO, they may still generate revenue from power than can be sold outside MISO[33]. If half the capacity is bought outside MISO and one wheel of firm transmission to MISO is required, then costs increase tens of millions of dollars per year.

Finally, there are additional costs incurred in becoming part of MISO, namely the socialization of on-going and future transmission infrastructure and MISO admission fees.

A variation on this "buy-capacity-now/soon" strategy was analyzed with MLGW being is own Balancing Authority (BA). We referred to this as Option #3A in the Exhibit above. Savings are less than in Option #2A as the cost of securing firm transmission to access contracts in the MISO market outweighs avoiding the costs of joining MISO.

2.4.3 Bellefonte PPA Plus Spot Market to Cover Incremental Needs [34]

In this case, MLGW becomes part of MISO, purchases Bellefonte power plus incremental MISO spot power, and does ***NOT*** hedge – e.g., does not buy contracts /existing powerplants as part of a hedging strategy for incremental power volatility risk.

This is the same as the previous case except MLGW does not purchase generation capacity to hedge incremental power risks but rather relies on spot purchases. This is referred to Option #2B in the exhibit above. This is not only a more volatile strategy, but on an expected basis has higher costs and less savings relative to BAU. This is because we expect the low costs of existing units will not be available over time. Rather, there currently exists a temporary buying opportunity. Thus, we do not recommend a highly spot-market oriented approach, and is shown to emphasize the double benefit of attention to incremental power early – i.e., lower expected costs and less volatility.

[31] The cost of incremental capacity and energy in the MISO market would have been in 2017 $32/MWh, with capacity available at near zero price. While we do not recommend reliance exclusively on spot purchasing due to volatility and in the case of capacity illiquidity. However, savings would have been $440 million were spot purchases made at spot prices. In 2024, we forecast savings for incremental power at $440 million versus TVA.

[32] Basis difference refers to differences in prices by location. For example, if market prices rise, the value of having the power plants would increase, offsetting the impact. However, if the percent increase of power delivered to MLGW increases faster than prices at the busbar of the powerplant, the hedge could have basis risk.

[33] One can think of all incremental energy being purchased from MISO, all incremental capacity purchased, and the energy porfits from operating the purchased capacity being used to offset the costs of the MISO purchase power.

[34] Also referred to as $50/kw year case. This is because without up front purchase of the plants, they eventually cost more $50/Kw Year (i.e. fixed costs less energy margins) rather than $25/kw year because of the forecast of the eventually tightening market for capacity.

Annual net savings equal $235 million per year, and $188 million starting in 2024, the first year of this study. This is over 20% savings in 2024 relative to the $1.1 billion in cost from the BAU case.

A variation on this "spot purchases" option strategy was analyzed with MGLW being is own Balancing Authority (BA). We referred to this as Option #3B in the exhibit above. Savings are less than in Option #3A as the cost of securing firm transmission to access the MISO spot market outweighs avoiding the costs of joining MISO.

2.4.4 Bellefonte PPA Plus TVA Partial Requirements Service to Cover Incremental Needs

In this scenario, MLGW buys power under the Bellefonte PPA, and incremental power is purchased from TVA under a Partial Requirements contract. This is referred to Option #1 in the Exhibit above.

We do not consider this case as attractive to MLGW because its costs are likely higher than what the current market alternative suggests. This may also not be feasible to the extent it requires agreement by TVA. Because TVA provides primarily incremental on-peak power rather than both on-peak and off-peak, and because on-peak is usually more costly than off-peak, the costs are higher than TVA's average for Full Requirements, and higher than the market alternative discussed above. Note, the premium for on-peak power is based on TVA's tariff, but a negotiated outcome might differ.[35]

2.5 Implementation Challenges

Historical experience has shown that TVA resisted the departure of its full-service customers. Based on this historical record, and TVA statements in their public materials, TVA may challenge the use of its transmission lines to serve MLGW load, and may attempt to claim its right to physically disconnect MLGW from the grid. TVA may also attempt to impose stranded costs on MLGW, and if MLGW would reverse its decision back sometime in the future, TVA may impose some type of "re-integration" fee.[36] TVA is also likely to tout its experience, its diverse portfolio, and its average cost approach to rates.

However, we believe that MLGW's can save significantly on power costs and can successfully overcome implementation challenges because:

Past FERC Transmission Decisions - While we are not lawyers, and cannot offer legal opinions, TVA's claims it does not have to provide open access transmission to MLGW is implausible. This is because:

- It violates the principles of open access that are at the core of the industry deregulation and structure. It is also strongly in opposition to the principles underlying 20 years of deregulation and reliance on open access including the reciprocity principle, a cornerstone of FERC policy since Order 888 in 1996.
- Furthermore, and most importantly, FERC has repeatedly addressed this specific TVA claim in another case of a utility desiring to terminate its contract. FERC has already ruled on this matter and concludes that TVA's claims to have the ability to deny transmission services, etc are incorrect. We discuss this further in the section on transmission access. This view is expressed in a FERC decision and sustained

[35] http://www.florenceutilities.com/Electricity_Department/Rate_Chart/Wholesale%20Power%20Rate%20-%20Schedule%20WS.pdf

[36] See previous examples of Warren County and City of Bristol.

on an appeal of the Commission decision. Effectively FERC has a belts and suspenders approach to requiring open access, and at most, TVA's argument eliminates the suspenders but leaves the belt.

- We are not aware of any major power system in the US to not implement reciprocity – i.e., provide open access in order to have open access. Operations might be so hampered that FERC has directly addressed the opposite concern; FERC has assured TVA it will be able to obtain open access on other systems because it is so necessary to offer competitive service[37].
- Furthermore, with the caveat that we are not offering legal opinions, TVA actions to withhold open access transmission could be seen as an exercise in market power and manipulation. Open access is a predicate for competitive markets.

Past Instances – Customers have successfully departed TVA requirements contracts without adverse circumstances, namely the City of Bristol in 1997.

Bellefonte 1 Risks – It was not part of our scope to assess the degree of completion or the costs of finishing Bellefonte. Rather, ICF assumed the costs and performance of the Bellefonte PPA would perform as contracted. However, ICF has assessed the availability of transmission, the costs of incremental power, and the costs of TVA service. ICF has also assessed important feasibility issues such as access to transmission service and reserve sharing.

Recontracting Risks - Of course, were the contract to be terminated, a new TVA/MLGW contract, if desired by both parties, would have to be negotiated. However, as we have shown, MLGW has many options.

2.6 Conclusions

ICF analysis indicates very large expected savings from the Bellefonte PPA relative to a continuation of TVA full requirements service. MLGW has a rare opportunity to have baseload power at low cost. It would also be able to take advantage of low costs for incremental power existing in the market today. Other advantages exist and can be summarized as:

Contractual Flexibility – While we have not reviewed the contract between TVA and MLGW, it is our understanding that TVA must give 10-year notice to terminate requirements service while MLGW must only give five-year notice. This asymmetry favors MLGW, and provides protection. These five years versus 10 years is important because the lead-time to complete Bellefonte is approximately 5 years, not 10 years. Further, it is our understanding that the contract does not require giving notice as soon as alternative options are being implemented or considered. Thus, there is some flexibility to see how things develop.

Location – MISO – The specific circumstances give considerable optionality and back-up to MLGW. MLGW is located at the western extremity of the areas served currently by TVA via sale of wholesale services, and the western area of the contiguous US not served by an organized market – i.e., the southeastern US is the last remaining major area not to have an organized electrical energy market. It is adjacent to MISO, the nation's largest organized competitive market place. For example, MLGW can access incremental power via TVA – i.e., MISO to TVA to MLGW, but also directly by the construction of new transmission over a very short distance to tie in into the massive and liquid MISO system.

Open Access Transmission – Available – "First Come First Serve" - TVA – As discussed, the TVA system can accommodate the transfer of power from Bellefonte to MLGW without upgrades. Under open access rules, there is a "first-come first-serve" allocation of transmission capability. Later customers cannot access the system's current available transmission capacity, but rather can only access what would be left over after accounting for the usage by the Bellefonte to MLGW move. There is a first mover advantage to MLGW that could be lost by dilatory action regarding transmission service[38].

Location – Southern Company – While not likely required, the Bellefonte plant is also located on the edge between the Southern Company and the TVA systems. It can readily interconnect to Southern Company system and wheel the power through Southern to MISO and then to MLGW. This is not as economic as directly through TVA, but is an option in the unlikely case TVA blocks the transmission transfer of Bellefonte.

Baseload Option – Even if there is a resource option available at a low cost to a utility provider like TVA, the buyer (i.e., MLGW) currently accesses only average costs, not the cost of the new, low-cost option. This is especially the case when discussing nuclear power, which is built by utilities with costs, recovered not for the nuclear powerplant alone but in the context of an average cost accounting and ratemaking. MLGW has a chance to access a nuclear unit with low costs, and not have to pay average TVA costs. The plant is also close in size to the MLGW's baseload demand and thus MLGW can leverage a single contract to hedge over 70% of its energy requirements. This option is not likely to be a common option for entities of MLGW's size.

Buyer's Market – Existing, modern on-line gas fired powerplants are available at low cost compared to new units to handle incremental power and reserve requirements as an alternative to relying on spot markets. Rarely is a comparable transaction as apropos as the one announced August 22, 2018 in Mississippi where neighboring Entergy bought a plant at reportedly 41% of replacement cost (i.e., the cost of a new gas-fired combined cycle).

Bellefonte is a Hedge - Underlying this recommendation of physical hedging of incremental power is our experience that rate stability is often a goal of municipal utilities like MLGW. However, we emphasize that attitudes to risk and volatility are decisions that will likely have to be made by MLGW in counsel with their experts and/or contractors. Further, since 70% is at very stable pricing according to our understanding of the Bellefonte PPA, some risks for lower costs can be attractive. Also, a claim that the strategy of relying on the Bellefonte PPA and incremental power from MISO plus purchases of long term contract / powerplants and other shorter-term hedges is a risky and volatile strategy would be hyperbolic especially when the TVA LPC price over the last ten years itself has varied $12/MWh between $62/MWh and $74/MWh.

Lastly, we find that Bellefonte's low rate may, in part, be due to circumstances unique to the project, and there may be an advantage to being the primary/first off-taker of power in a market like TVA where system costs are spread across a wide customer base. If others were to exit the system based on the Bellefonte 1 opportunity, TVA's fixed costs would have to be borne, in whole or in part, by the remaining customers.

In summary, we find the following and detail our analysis in the remainder of this report:

[38] We have not estimated the amount of remaiing transmission service. However, in general, each firm transaction decreases it, all else equal.

- Bellefonte 1 can serve a majority of MLGW's energy needs at a rate significantly lower than TVA (see chapters 3-5)
- MLGW has multiple options for sourcing its remaining "incremental" needs including hedging options (ch 6);
- Accessing the MISO market offers a wider range of purchase power options at affordable prices (ch 7-8)
- Though MLGW has legal rights to pursue alternate power, TVA may push back but lacks the ability to deny transmission or otherwise impede the transaction (ch 9)
- We detail incremental capabilities required by MLGW should it choose to source power outside of TVA which we expect to be available (ch 10)

3. Overview of Memphis Light, Gas, and Water

Memphis Light, Gas and Water is the nation's largest three-service municipal utility, serving nearly 421,000 customers. Founded in 1939, MLGW meets the utility needs of Memphis and Shelby County by delivering reliable and affordable electricity, natural gas and water services. MLGW is led by a President and Board of Commissioners who are appointed by the Mayor of Memphis and approved by the Memphis City Council. The remainder of this section of the report focuses solely on the provision of electricity. Summary statistics for MLGW electric sales are shown in Exhibit 4.

Exhibit 4: Breakdown of MLGW Electric Customers and Sales

2017 Summary	Customer (Count)	Sales (TWh)
Residential	370,693	5.04
Commercial - General Service	43,469	6.14
Industrial	118	1.87
Outdoor Lighting and Traffic Signals	17,186	0.17
Interdepartmental	36	0.09
Total	**431,502**	**13.31**

MLGW does not own or directly contract with any significant generation resources. As such, the reliability and affordability of the power it provides to its customers depends in large part on the reliability and affordability of the wholesale power and grid services it purchases from third parties. Historically, all of these services have been provided by TVA, the largest federal power agency in the US. Further, MLGW is TVA's largest single customer, representing 11% of TVA's total load.

Wholesale power needs can be summarized into the following major buckets:

- **Energy and load shape:** total electric energy (TWh) provided at the right levels instantaneously throughout the year
- **Peak demand plus reserves:** total maximum electric capacity (GW) needed during the peak hour in a year, plus a reserve margin to insure against contingency
- **Transmission:** connection from generation to interface points between the distribution and transmission grids, resilient against transmission outages
- **Ancillary services:** operating reserves (i.e., spinning and non-spinning), voltage regulation, and others that ensure grid stability
- **System operation:** technical needs for managing, scheduling, and regulating a wholesale grid interface with its existing distribution system.

Finally, MLGW needs the technical capabilities to interface and contract with the required services above.

MLGW's average expected energy and peak demand for the period 2018 to 2027 are 14,219 GWh and 3,561 MW, as reported in FERC's latest Form 714, released in 2017. There is expected annual energy growth from 2018 to 2027 averaging 0.43%, and total peak demand reaches 3,631 MW by 2027. Exhibit 5 below shows ICF's projection of energy and peak for MLGW.

Exhibit 5: MLGW Projected Peak and Energy Demand

Year	Memphis, Light, Gas and Water Summer Peak Demand (MW)	Peak Demand Growth (%)	Net Energy for Load (GWh)	Net Energy Growth (%)
2018	3,496		13,959	
2019	3,508	0.34%	14,006	0.34%
2020	3,522	0.40%	14,064	0.42%
2021	3,537	0.43%	14,124	0.43%
2022	3,552	0.42%	14,184	0.42%
2023	3,567	0.42%	14,245	0.43%
2024	3,583	0.45%	14,307	0.44%
2025	3,599	0.45%	14,370	0.44%
2026	3,615	0.44%	14,434	0.45%
2027	3,631	0.44%	14,500	0.46%
2028	3,647	0.44%	14,564	0.44%
2029	3,663	0.44%	14,629	0.44%
2030	3,679	0.44%	14,693	0.44%
2031	3,695	0.44%	14,758	0.44%
2032	3,712	0.44%	14,824	0.44%
2033	3,728	0.44%	14,889	0.44%
2034	3,745	0.44%	14,955	0.44%
2035	3,761	0.44%	15,021	0.44%
2036	3,778	0.44%	15,087	0.44%
2037	3,794	0.44%	15,154	0.44%
2038	3,811	0.44%	15,221	0.44%
2039	3,828	0.44%	15,288	0.44%
2040	3,845	0.44%	15,356	0.44%
2041	3,862	0.44%	15,424	0.44%
2042	3,879	0.44%	15,492	0.44%
2043	3,896	0.44%	15,561	0.44%
Average (2018-2043)	**3,690**	**0.43%**	**14,735**	**0.44%**

Source: FERC Form 714 and ICF

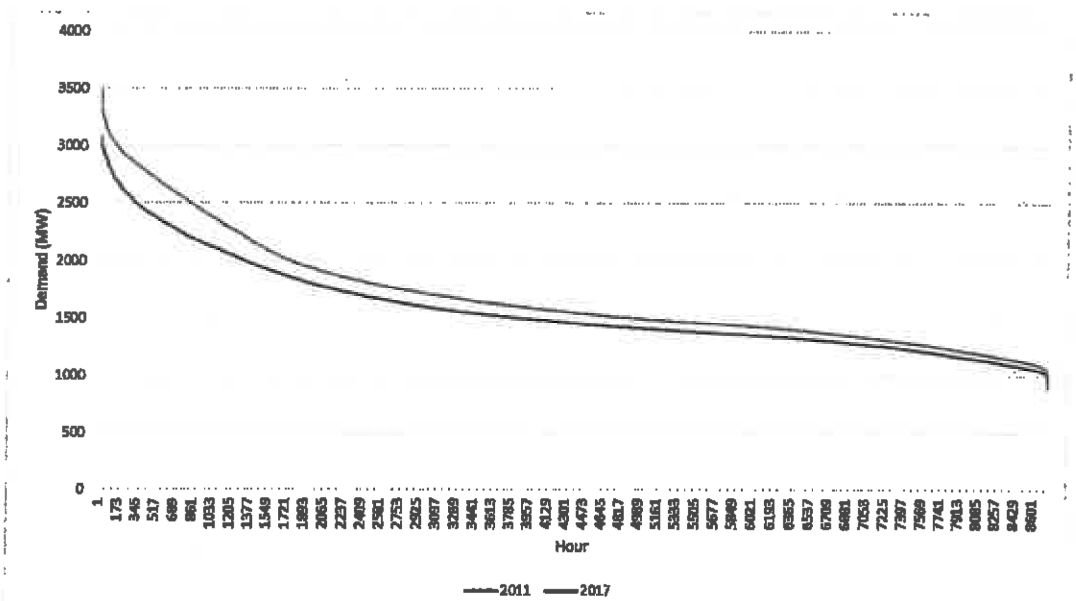
In service territories connected to broad regional networks with reserve sharing (such as the Eastern Interconnect), standard reserve margin requirements are often around 13-15%. Therefore, MLGW's capacity need including reserves (15% reserves) in 2018 is estimated at approximately 4 GW. In 2040, this will grow to 4.4 GW.

Separately, MLGW will require sufficient operating reserves to handle contingencies such as the loss of the largest unit. Elaborate procedures and contracts exist and are standard in the industry, and are discussed separately. Because the Bellefonte unit 1 is very large at 1,350 MW, some additional modest costs associated with operating reserve increments may exist. By complying with planning and operating reserve requirements, MLGW can access long standing, highly regulated "insurance" in the form of reserves to handle operations. These options existed, exist today, and will continue to exist, though these arrangements are currently contracted out to TVA.

MLGW's load shape for 2017 is presented below in Exhibit 6 in the form of a load duration curve – demand levels and their frequency are shown. The maximum single-hour demand was 3,500 MW in 2017, and all-hours service is required above approximately 900MW of load. Critically, and as discussed later, in most hours there is enough demand to absorb the entire output of the plant – i.e., 1,350 MW or more.

MLGW's load variation over the course of a year reflects its primarily residential and commercial customers. One measure of the shape is the load factor, which was 51% in 2017. The average load was 1,576 MW in 2017 and it is projected to be 1,633 MW in 2024.

Exhibit 6: MLGW Hourly Energy Demand



Source: *FERC Form 714*

Ancillary service needs are estimated based on energy requirements, shape (e.g., ramping needs) and uncertainty in the generation supply and peak load of the system. In general, a utility with adequacy capacity reserves and flexible, dispatchable generation will be able to meet the ancillary service needs of the grid. On average, ancillary service costs generally range from $0.4-2.0/MWh of load served.[39]

Finally, MLGW is not only a wholesale power customer of TVA but also relies on TVA for transmission service and system operation. TVA manages and constructs new transmission lines to maintain NERC reliability standards and apportions the costs to its customers.

[39] Over the last 5 years (2013-2017), MISO system-wide ancillary services cost averaged $0.11/MWh while PJM was $0.93/MWh.

4. TVA Supply and Ratemaking

This chapter provides an overview of the TVA system and discusses typical LPC contracts with TVA. We provide a summary of TVA's average system cost approach to ratemaking. We also provide a historical time series of TVA system average costs and sales rates to LPCs. Finally, we provide a detailed discussion on ICF's approach (based on average system costs) to forecasting TVA rates over the 2024 to 2043 time period. These projected LPC rates are used in our "Business-As-Usual" case to project Memphis annual purchase power costs.

TVA has a unique and complex legal and institutional situation. This has important implications for MLGW. This also requires special attention to TVA statements. At the same time, however, MLGW also has unique circumstances of its own increasing its options and making them more advantageous compared to other LPCs.

4.1 TVA System

Tennessee Valley Authority ("TVA") is a corporate agency instrumentality of the United States ("U.S.") that was created in 1933 by legislation enacted by the U.S. Congress. TVA supplies power to a population of over nine million people in most of Tennessee, northern Alabama, northeastern Mississippi, and southwestern Kentucky and in portions of northern Georgia, western North Carolina, and southwestern Virginia.

TVA operates as a traditional regulated utility to the extent that it maintains the functions of transmission and generation system operation together. Power supply in TVA is largely procured from TVA-owned generating units and secondarily from units owned by independent third-party entities. Another feature common to traditional utilities is its rates. Rates in TVA are based on average embedded costs.[40]

However, unlike other traditional utilities, its sales are mostly wholesale under long-term contract rather than to native load customers. TVA sells wholesale power to local power companies (LPC), which are mostly municipalities and cooperatives, and which in turn resell the power to their end use customers at retail rates. LPCs accounted for 87% of TVA power sales in 2017. TVA sells 13% of its power directly to certain end-use customers, primarily large commercial and industrial loads and federal agencies with loads larger than 5,000 kilowatts.

TVA also differs from traditional regulated utilities in that it is not subject to rate regulation by an independent state public utilities commission. Rather, the TVA board sets rates and policies including policies affecting the mix of powerplants, the disposition of assets, costs, cost volatility, etc. TVA's board is appointed by the President and confirmed by Congress with members having five-year terms.

TVA's financial structure also differs from traditional utilities. Most very large traditional utilities with large generation fleets have a mix of debt and equity financing. If approved by the state Commission, it can raise capital as needed – e.g. to finish a nuclear plant. However, TVA is debt financed and subject directly to the US Congress in this regard. Initially, all TVA operations were funded by federal appropriations. Direct appropriations for the TVA power program ended in 1959, and appropriations for TVA's stewardship, economic development, and multipurpose activities ended in 1999. Since 1999, TVA has funded its operations from sale of electricity and power system financings consisting primarily of sale of debt securities. TVA is not authorized to issue equity securities. TVA also has a debt ceiling set by Congress, and hence, there can be limitations on TVA activities due

[40] TVA uses a ratemaking approach formally called the debt-service coverage (DSC) approach. Under the DSC approach, rates are set so that operating costs and obligations on principal and interest on on debt are covered.

to financial limitations – e.g., as the total debt approaches the ceiling, and in the absence of congressional action, it may not be able to implement certain activities, even economic activities, due to financial limitations.[41]

Debt is supported by the US government. This can be thought of as the reason why under the TVA Act, TVA is limited by the "fence" provision limiting power sales activity (e.g., firm, long-term sales to distribution entities for use by end users) to within a defined service area.

TVA also differs from traditional utilities in the legal provisions regarding its sales of electricity, with direct immediate implications for MLGW. A traditional US utility has a franchised territory provided by the state in which they have the monopoly on the sale of power to "native" load customers with the expectation that this franchise will continue indefinitely. As noted, TVA makes the vast majority of its sales under contract, and municipal utilities and other public power entities make end use sales. TVA does not rely on a franchised utility territory with native load customers. Expectations about service duration are clearly set out in contracts. We return to this issue in the context of TVA potentially wishing to collect "stranded" costs.

The Federal Power Act (FPA) includes a provision that is frequently mentioned, especially by TVA itself, as facilitating TVA's ability to sell power within its service area. This provision, often called by TVA the "anti-cherrypicking"[42] provision. It is the view of FERC, however, this FPA provision prevents the FERC from ordering TVA under section 211 to provide open access to its transmission lines to others to deliver power to LPC customers after a certain date. However, as discussed, FERC has ordered that this provision not be construed as preventing FERC from ordering "reciprocity" in all jurisdictional tariffs, and hence, can effectively require TVA provide open access transmission. Reciprocity requires any entity, such as TVA, to only be able to access the open access transmission of others if TVA reciprocates; the entire US portion of the power grid operates under open access. See further discussion in Chapter 9.

Another characteristic distinguishing the TVA market, and other southeastern US areas, is the absence of a competitive electrical energy power market operated by a FERC-regulated entity, such as an independent RTO or ISO. The southeastern US is the only major region in the contiguous US not to have an organized exchange style electrical energy market run by a not-for-profit entity regulated by FERC. Since 1999, one region after another, with this one exception, have adopted these markets[43]. Therefore, there is less price transparency, and greater reliance on cost-based pricing. However, bilateral transactions facilitated by open access transmission are common in this region. Furthermore, there are many IPP powerplants in the region. Lastly, this wholesale bilateral market is still subject to FERC regulation.

Notwithstanding, MLGW is adjacent to MISO, a large organized market. Prices of wholesale power on the other side of the Mississippi River from MLGW can be accessed by the public in real time via the internet. In addition, TVA is contiguous to the PJM organized market located to the north and east of TVA.

[41] TVA can issue bonds in an amount not to exceed $30.0 billion outstanding at any time and TVA has a total debt of $25 billion on its balance sheet as of September 30, 2017.

[42] Federal Power Act s.212(j) is "anti-cherrypicking" provision. The term anti-cherry pciking is not mentioned in the statute.

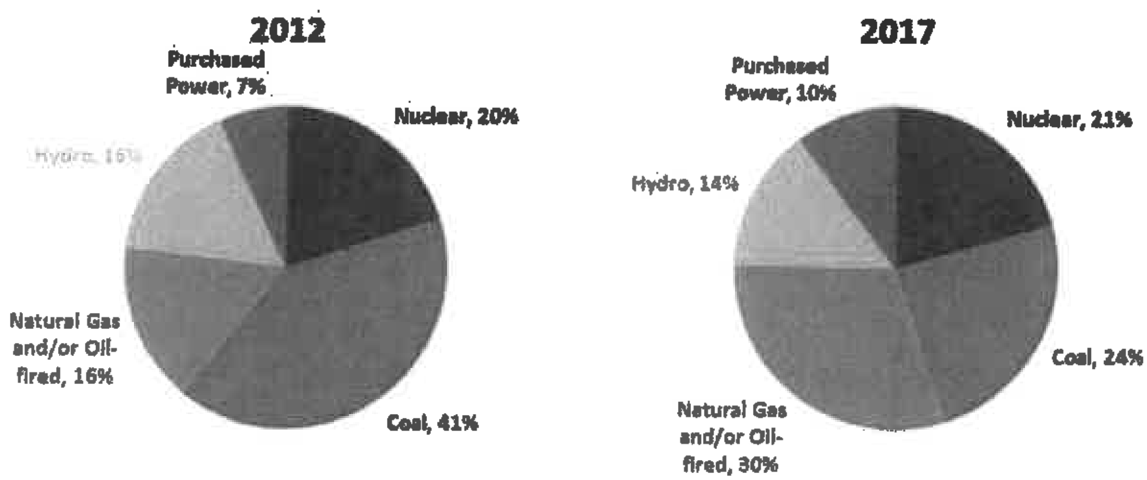
[43] The interior western states with the excption of Colorado have FERC regulated electrical energy markets for balancing.

4.1.1 Capacity and Generation Mix

TVA is similar to the broader Southeastern US in that it has relied significantly on coal generation in the past. However, TVA differs from other regions in the southeast in that it also has a high reliance on hydro-electricity. Furthermore, TVA is also distinguished from some other US regions by significant reliance on nuclear power.

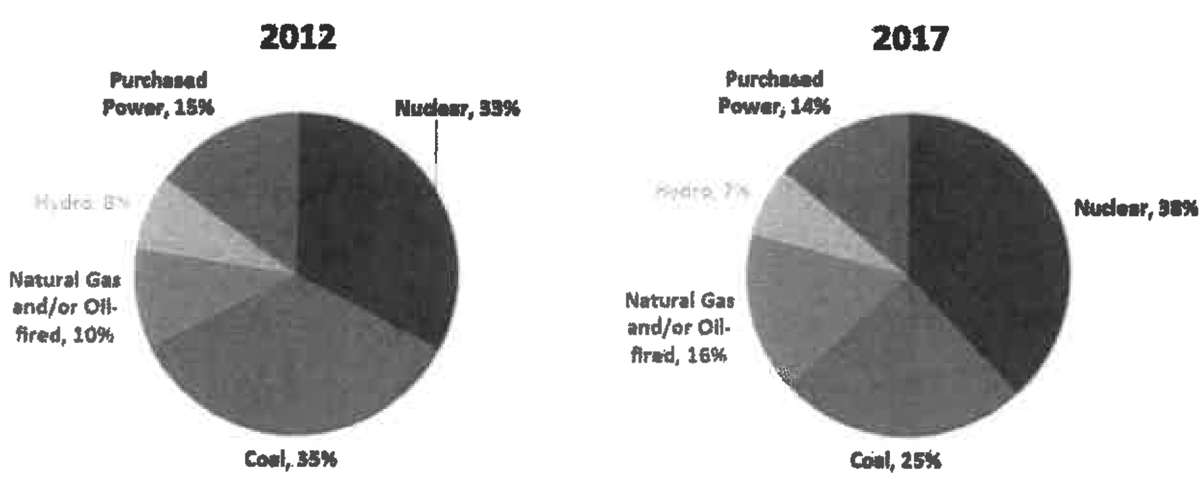
However, consistent with the trend being observed across much of the country, natural gas-fired generation is now increasingly replacing coal in the region. In 2017, coal accounted for 24% of TVA's capacity mix as opposed to 41% in 2012 (see Exhibit 7). Among the coal powerplants that TVA retired was the Allen coal-fired powerplant located near Memphis. This increased reliance on gas increases the volatility of average costs.

Exhibit 7: TVA Existing Capacity and Contracts by Fuel Type



Source: *TVA 10K Reports*
Note: Purchased power includes coal, natural gas and/or oil-fired, wind, solar, hydro and landfill gas resources

Exhibit 8: TVA Generation by Primary Fuel-Type



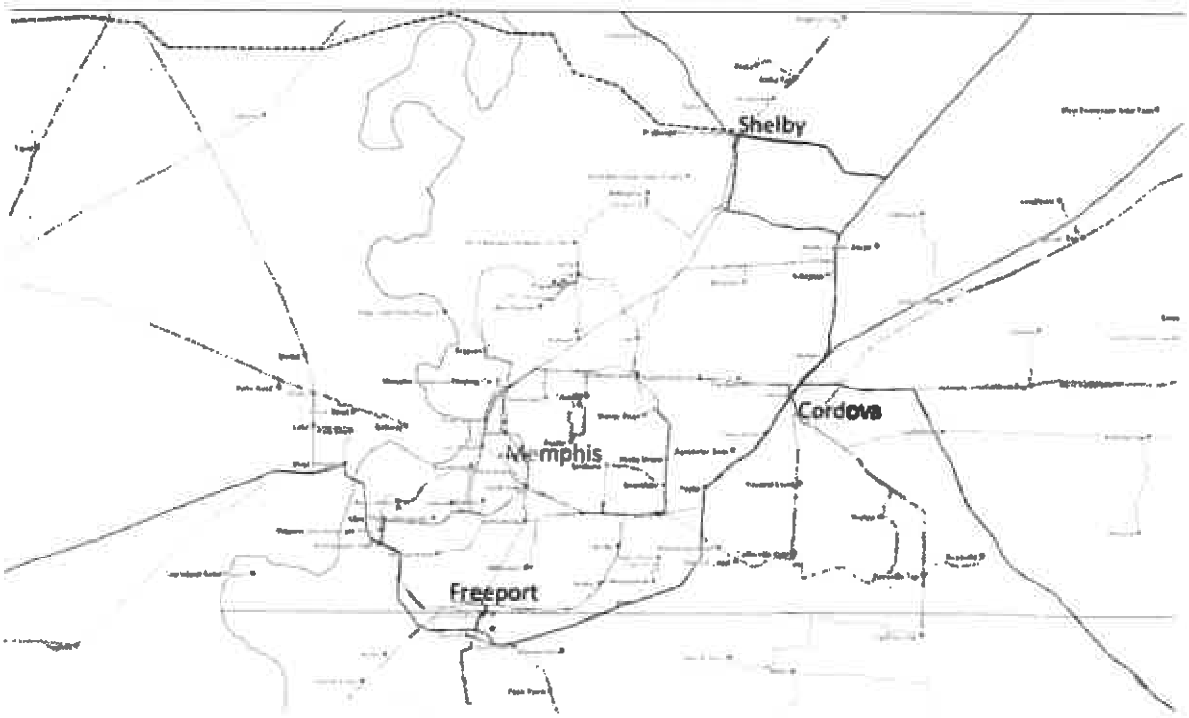
Source: *TVA 10K Reports*
Note: Purchased power includes coal, natural gas and/or oil-fired, wind, solar, hydro and landfill gas resources

In TVA's most recent IRP issued in October 2015[44], TVA emphasized compliance with The Clean Power Plan (CPP). At the time, the CPP established state-specific emission goals to lower CO2 emissions from power plants, targeting a 32 percent[45] nationwide reduction in CO2 emissions from 2005 levels by 2030. TVA has reduced GHG emissions from both its generation stations and its operations. Since the election of 2016, the CPP has been changed, and policy direction is less clear. TVA board members are appointed by the President and confirmed by Congress for five-year terms.

4.2 MLGW Contract with TVA

TVA supplies into Memphis: three major delivery points at Cordova, Freeport, and Shelby.

Exhibit 9: Transmission Grid around Memphis (with major 500kV substations noted)



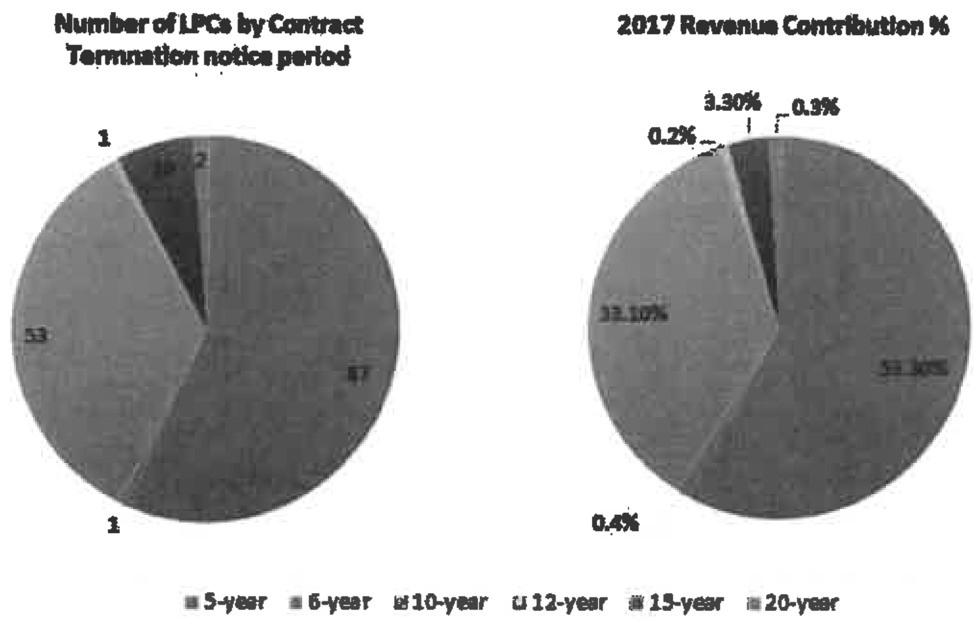
Source: Ventyx and ICF

[44] "From a portfolio planning perspective, we think the TVA's carbon emission rate is a better customer-focused planning metric for use in the IRP. While the IRP models the amount of carbon contained in the delivered energy to our customers it does not model a potential compliance strategy for TVA with the Proposed Clean Power Plan. However, as a crude comparison, TVA has made a 30 percent reduction in CO_2 emissions from a 2005 baseline, the stated objective of the regulation. One might assume that TVA would then have a low compliance hurdle with the CPP"

[45] TVA 2017 10-K

TVA has wholesale power contracts with 154 LPCs, as of September 30, 2017. These LPCs purchase power under contracts that require five, ten, or fifteen years notice to terminate. Typically, LPCs and TVA have the same termination notice period. However, it is our understanding that five of the LPCs with five-year termination notices, TVA has a 10-year termination notice, which becomes a five-year termination notice if TVA loses its discretionary wholesale rate-setting authority. Furthermore, it is our understanding that MLGW's contract carries a five-year termination notice.

Exhibit 10: Number of LPCs and their revenue contribution by contract termination notice period



Source: TVA 2017 10-K

LPCs with 5-year and 10-year termination notices accounted for 53% and 33% of operating revenues in 2017 respectively. TVA's largest LPC, MLGW, has contract with a five-year termination notice period, and accounts for approximately 10 percent of TVA's revenues. Long-term firm contracts enable wholesale customers to be treated the same as a utility's native load in terms of access to average costs.

4.3 TVA Full Services Rate Forecast

As noted, according to TVA Act, the TVA board has the authority for establishing the rates TVA charges for power. These rates are not set by any independent state or federal regulatory body. The rates are revised over the time to reflect change in costs, including the changes in fuel, non-fuel operation and maintenance (O&M), power purchase costs, etc.

Average costs are determined by the revenue requirements of TVA including interest, and depreciation and other costs divided by sales, with revenue requirements distinguished by rate class e.g. industrial versus municipal. More specifically, average costs are calculated as the sum of depreciation and interest on legacy and new power plants, fuel costs, purchase power costs, operation and maintenance costs, emission allowance costs, payments to states and counties in lieu of taxes ("tax equivalents") divided by sales volumes. The majority of TVA generation costs are fixed costs such as O&M, depreciation, and interest, and the capital structure reflects debt at interest rates close to that of federal government debt. TVA maintains the high-voltage transmission system, and transmission cost is embedded into the average system costs for requirements service. Therefore, the price for requirements service would also include transmission, provided either at average transmission costs, or at a network tariff rate.

TVA rates to LPC customers also include additional margin as the TVA Board may consider desirable for investment in power system assets, retirement of outstanding bonds, notes, or other forms of indebtedness in advance of maturity.

TVA uses a wholesale rate structure that is comprised of a base rate and a fuel rate. In setting the base rates, TVA derives annual revenue requirements such that all its operating costs and obligations to pay principal and interest on debt are recoverable. Power rates are adjusted by the TVA Board to a level deemed to be sufficient to produce revenues approximately equal to projected costs (exclusive of the costs collected through the fuel rate). In 2015, TVA restructured its base rates to improve cost alignment with capacity-related on-peak demand charges and seasonal time-of-use ("TOU") energy rates that differ by on-peak and off-peak periods to better reflect how TVA incurs generation costs.

Fuel costs include costs for natural gas, fuel oil, coal, purchased power, emission allowances, nuclear fuel, and other fuel-related commodities.

4.3.1 Historical Rate Trends

As shown in Exhibit 11 below, in 2017 the average system cost for TVA was $66/MWh and the average selling price to LPCs was $74/MWh, with the additional $8/MWh used to cover for retirement of outstanding bonds, notes, or other bonds in advance of maturity, investment in power system assets. Average cost of power increased on an annual average basis of 2%, from $54/MWh in 2008 to $66/MWh in 2017. The selling price to LPCs increased on an annual average basis of 1.8%, from $62/MWh in 2008 to $74/MWh in 2017.

The additional margin above average cost of power for LPC customers is 11% or $8/MWh in 2017.

Exhibit 11: Historical Average System Cost for TVA (2008-2017)

Cost Parameters	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Fuel Cost	4,176	3,114	2,092	2,926	2,680	2,820	2,730	2,444	2,126	2,169
O&M	2,307	2,395	3,232	3,617	3,510	3,428	3,341	2,838	2,842	3,362
Emission Cost	0	0	0	0	0	0	0	0	0	0
Purchased Power	NA	1,631	1,127	1,427	1,189	1,027	1,094	950	964	991
Interest Expenses	1,376	1,272	1,294	1,305	1,273	1,226	1,169	1,133	1,136	1,346
Depreciation	1,224	1,598	1,724	1,772	1,919	1,680	1,843	2,031	1,836	1,717
Tax Equivalent	491	544	457	662	622	548	540	525	522	525
Total Cost of Power ($MM)	9,574	10,554	9,926	11,709	11,193	10,729	10,717	9,921	9,426	10,110
Total Sales (GWh)	176,304	163,804	173,662	167,730	165,255	161,925	158,057	158,163	155,855	152,362
Average Cost of Power ($/MWh)	**54**	**64**	**57**	**70**	**68**	**66**	**68**	**63**	**60**	**66**
Selling Price to LPC ($/MWh)	**62**	**72**	**66**	**74**	**72**	**72**	**73**	**72**	**71**	**74**

Source: TVA 10-K

Over the last 10 years, TVA sales declined by 1.6% on average. All else being equal, this tends to increase average costs because fixed costs are spread over fewer sales.

The capacity mix of TVA transitioned from a coal- to gas-dominant portfolio with major coal retirements occurring in the past decade. With the reduction in gas prices from 2008 to 2017, the fuel cost declined from $24/MWh in 2008 to $14/MWh in 2017. O&M cost increased by an annual average of 5%/yr, from $13/MWh in 2008 to $22/MWh in 2017.

Hydro accounts for 8% of TVA generation, which is dependent upon amount of precipitation and runoff, initial water levels, generating unit availability. When these factors are unfavorable, TVA increases its reliance on purchased power. A portion of TVA's capability provided by power purchase agreements is provided under contracts that expire between 2023 and 2038, and the most significant of these contracts include the Red Hills coal (440 MW) plant, Decatur and Morgan Energy Center gas plants (1,335 MW total), and wind plants totalling 1,540 MW. During 2017, TVA acquired approximately 12 percent of the power that it purchased on the spot market, approximately two percent through short-term power purchase agreements, and approximately 86 percent through the long-term power purchase agreements.

TVA has a total debt of $25 billion on its balance sheet as of September 30, 2017. The average maturity of long-term power bonds was 16.6 years, and the average interest rate was 4.67 percent. TVA plans to reduce total debt to approximately $20 billion by 2023. TVA also uses short-term debt to fund short-term cash needs, as well as to pay scheduled maturities and other redemptions of long-term debt. TVA's average interest expense over last 10 years remained close to $1.3 billion, equivalent to $8/MWh.

Depreciation and amortization expenses increased from $1.2 billion in 2008 to $1.7 billion in 2017, and the contribution of depreciation and amortization to the total TVA costs increased from 13% in 2008 to 17% in 2017. This was primarily driven by gas and nuclear capacity additions.

The TVA Act requires TVA to make tax equivalent payments to states and counties in which TVA conducts its power operations. The total amount of these payments is 5% of gross revenues from sales of power during the preceding year, excluding sales or deliveries to other federal agencies and off-system sales with other utilities, with a provision for minimum payments. Tax equivalents averaged $0.5 billion over last 10 years.

4.3.2 Forecast Rate Trends

In projecting future rates for TVA, ICF used the previously described average system cost approach. ICF forecasts the annual LPC price to increase from $75/MWh in 2024 to $102/MWh in 2043, averaging $88/MWh in this period. The LPC price increases at rate of 1.6% over the forecast. This LPC rate is used in our "Business-As-Usual" case to project MLGW annual purchase power costs.

The LPC price reflects the following total cost components divided by sales volume:

- **Fuel costs** – are based on ICF modeling projections for TVA. Fuel costs increase 2.7% per year from $14/MWh in 2024 to $23/MWh in 2043, primarily due to increases in gas prices. In real 2017-dollar terms, fuel costs increase 0.6% on an annual average basis. With more reliance on gas in long term, fuel costs increase. ICF expects 1 GW of economic coal retirement in 2025 and another 1 GW in 2030, both of which are replaced by combined cycle builds.

- **O&M costs** – are based on ICF projections for the TVA fleet. O&M costs increase from $21/MWh in 2024 to $31/MWh in 2043, growing at our assumed inflation rate of 2.1%. In real 2017-dollar terms, O&M cost is $18/MWh in 2024 and remains flat to 2043.

- **CO2 allowance costs** - are based on ICF modeling projections. ICF assumes region-specific charges on CO2 from the power sector beginning as early as 2026, consistent with an expected delay in U.S. CO2 regulation. CO2 prices increase from $1/ton in 2026 to $29/ton in 2043.

- **Purchase power costs** – are based on reported contracts. Power purchase agreements for Decatur and Morgan Energy Center gas plants expire in 2023 and 2026 respectively. We assumed no contract extension for TVA contracted thermal assets. Based on TVA's interconnection queue, TVA is expected to negotiate new solar and wind power purchase agreements. With the expiry of gas, coal, and wind contracts between 2023 and 2038, ICF expects new solar in TVA and wind contracts in MISO will be negotiated at the levelized cost of approximately $56/MWh and $73/MWh respectively.[46] These are approximately 40% lower than previous solar and wind contracts which were reported to have a price of $80-$90/MWh in 2016. In years where TVA self-generation and energy purchased from contracts are not able to meet energy demand, the residual energy is purchased at spot firm all-hours price from

[46] The levelized cost of $56/MWh and $73/MWh for solar in TVA and wind in MISO respectively are based on ICF views. $80-90/MWh are from a recent TVA presentation found at" *https://www.tva.gov/file_source/TVA/Site%20Content/About%20TVA/Our%20Leadership/Board%20of%20Directors/Meetings/2016/August%2025/Aug%202016%20Board%20Deck.pdf.*

neighboring regions (i.e., MISO, PJM, and Southern). SEPA hydro purchases are assumed to continue through 2043.

- **Interest expenses** - Is assumed to be based on short- and long-term debt. Details were obtained from TVA's 2017 10K and TVA's website.[47] Incremental capital needs for capital expansion, environmental compliance, transmission, and major maintenance are assumed to be financed through net income margin and new debt raised for 10- to 20-year durations at a debt rate of approximately 5%.[48] Also, short-term financing needs including working capital are met by short-term bond issuances. With increasing long-term debt maturities, total long-term debt declines over forecast leading to reduction in interest expenses through 2043.

- **Depreciation of costs** – are based on legacy plant depreciation[49] levels reported in the 2017 TVA 10-k and on ICF's assumption on new power plants (new plants include firm builds and model-forecasted capacity additions in the absence of Bellefonte 1). Depreciation expense increased at an annual rate of 1.5% from $13/MWh in 2024 to $17/MWh in 2043. TVA's 2017 annual report provides 2018 to 2020 annual capital expenditures estimates associated with capacity expansion, environmental, transmission and reliable operation of generating assets. Based on the TVA annual report, ICF assumed environmental, transmission and reliability capital expenditures from the year 2020 to remain flat throughout the entire forecast.

- **Tax equivalent costs** - reflect 5% of gross revenues from sales of power during the preceding year.

- **Sales** - are based on TVA and other projections such as found on FERC Forms.[50] ICF projects energy demand to remain essentially flat, consistent with the growth rates projected in 2019 IRP Working Group presentation.[51] Sales forecast is driven by energy demand, including 4% losses estimate based on TVA's historical time series.

- **Premium for LPC Costs** – are estimated based on the premium relative to average system costs over the last six years, which is approximately 11%.

Appendix A has further details on modelling assumptions used for TVA (including fuel prices, capital costs, CO2 prices, etc.)

[47] *https://www.snl.com/IRW/CustomPage/4063363/GenPage.aspx?IID=4063363&GKP=1073746881*

[48] Illustratively, we assume the debt rate is the weighted average cost of long term debt sourced from TVA's 2017 10K.

[49] For depreciation calculations, property, plant, and equipment depreciation rates are performed by asset classes. For example, coal, gas and nuclear, hydro and transmission assets are assumed from 2017 10K. Other capital expenditure associated with capacity expansion, environmental, transmission and reliability are assumed to depreciate using fixed depreciation method over a 30-year booklife. Amortization expenses are calculated as the delta between reported 'Depreciation' and 'Depreciation and Amortization' in the 2017 10K. The average of 2014 to 2017 amortization expenses are assumed in above calculations.

[50] Sales volume and sales revenue for residential, commercial and LPC customers are sourced from TVA's 10-K. Net energy demand forecasts for the years 2018 to 2027 are sourced from FERC Form 714. Post 2027, ICF assumes net energy demand will grow at last five-year average (2023-2027) annual growth rate.

[51] *https://www.tva.com/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/2019%20Documents/2019%20IRP%20Working%20Group%20Meeting%20%202.pdf*

Exhibit 12 summarizes ICF estimates of the average system cost of power for TVA and the sales price to the LPC class of customers in the TVA service territory over select forecast years. The 20-year average system cost is $79/MWh and the 20-year average sales price to LPCs is approximately $88/MWh. The LPC sales price increased on average 1.6% on average, from $75/MWh in 2024 to $102/MWh in 2043 in nominal terms.

Exhibit 12: Average System Cost Approach Projections for TVA

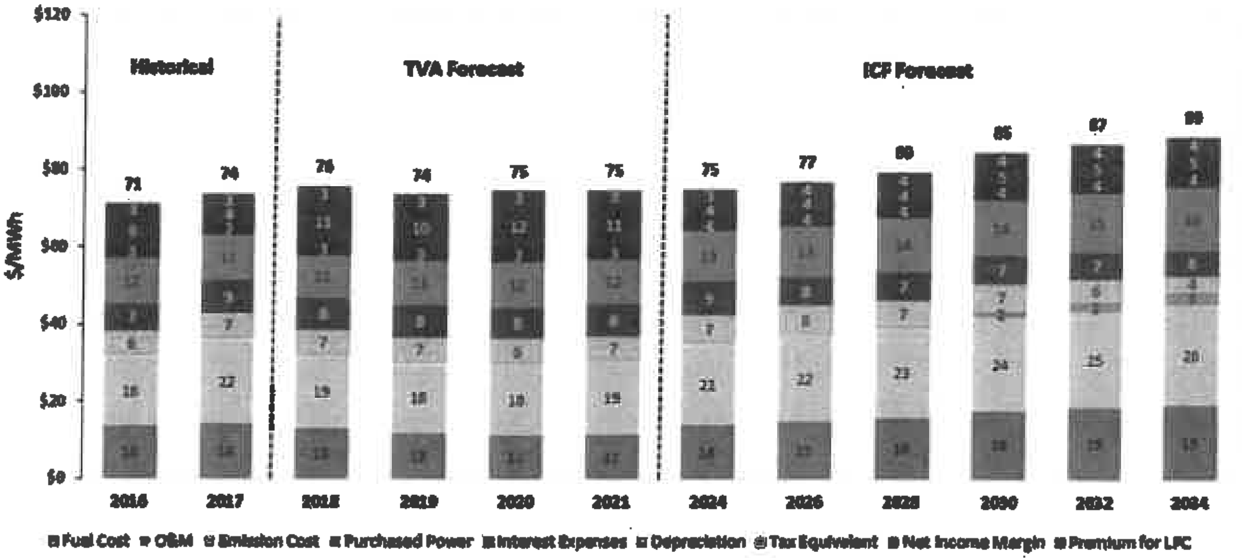
Cost Parameters	Average (2024-2043)	2024	2026	2028	2030	2032	2034	2036	2038	2040	2043
Fuel Cost	2,868	2,110	2,272	2,417	2,714	2,812	2,931	3,067	3,216	3,414	3,508
O&M	3,960	3,234	3,405	3,549	3,651	3,802	3,963	4,127	4,303	4,485	4,768
Emission Cost	461	5	53	138	250	355	479	598	711	844	1,039
Purchased Power	850	1,135	1,142	1,079	1,082	906	650	632	638	680	720
Interest Expenses	964	1,309	1,142	1,118	1,127	1,097	987	955	886	663	550
Depreciation	2,317	1,963	2,003	2,111	2,172	2,298	2,489	2,352	2,493	2,473	2,617
Tax Equivalent	629	541	554	566	597	615	635	654	666	697	724
Total Cost of Power ($MM)	12,048	10,295	10,569	10,978	11,593	11,886	12,133	12,385	12,914	13,256	13,925
Total Sales (GWh)	151,899	152,250	152,065	152,057	152,000	151,943	151,887	151,830	151,773	151,717	151,631
Average Cost of Power ($/MWh)	79	68	70	72	76	78	80	82	85	87	92
Selling Price to LPC ($/MWh)	88	75	77	80	85	87	89	91	95	97	102

***Source:** ICF projections*

Exhibit 13 below shows ICF's projected LPC sales prices build up price for TVA relative to the historical build-up of LPC sales prices as well as recent TVA forecasts. Historical LPC sale price range between $71/MWh to $74/MWh between 2016 to 2017. In a recent August 2018 board presentation, TVA provided projections from 2018 to 2021 which when combined with other data ranged from $74/MWh to $76/MWh.[52]

[52] https://www.snl.com/Cache/1500112522.PDF?O=PDF&T=&Y=&D=&FID=1500112522&iid=4063363. TVA provided income statement estimates for FY2018 to FY21. Fuel and purchased power estimates are reported as aggregate expenses. ICF assumes purchase power expenses for 2018 to 2021 reported in TVA forecast in Exhibit 13 to remain flat and equivalent to 2017 actuals. To calculate a $/MWh value for 2018-2021, this combined estimate was divided by energy sales assumed to be similar to ICF's forecast over this same time period.

Exhibit 13: Comparison of Historical and Forecast Projections of LPC Sales Price for TVA ($/MWh)



Source: Historical data is from TVA's 10K. TVA forecast is from TVA Board Presentation (August 22, 2018). ICF projections are ICF.

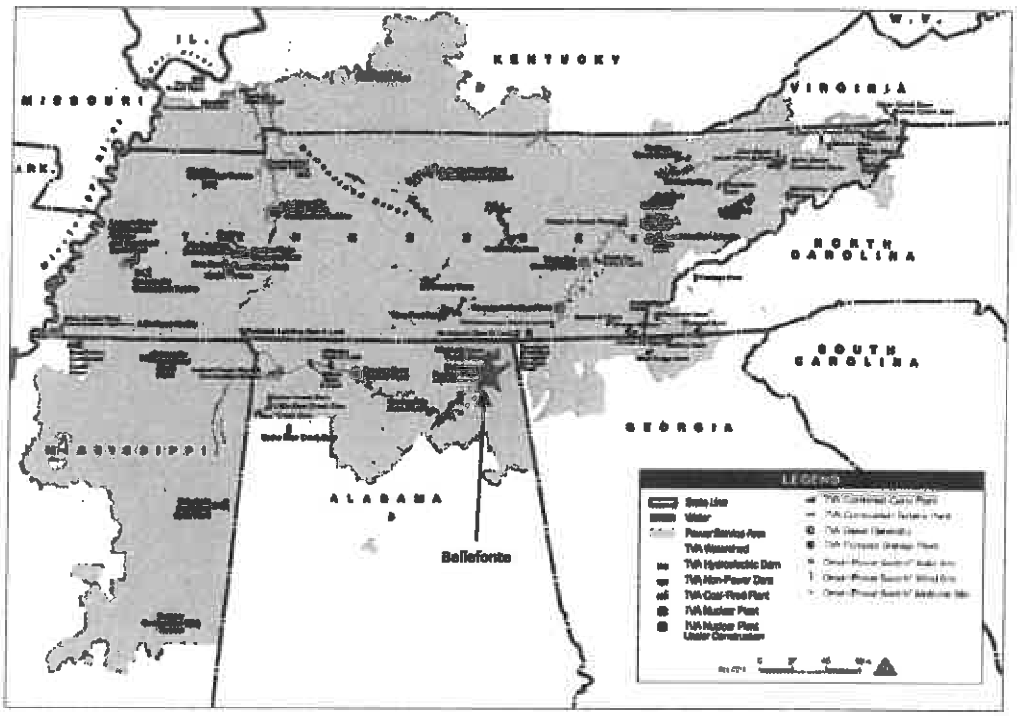
5. Bellefonte 1 Nuclear Plant

The chapter provides a review of the Bellefonte nuclear station, describes our understanding of the proposed Bellefonte 1 PPA[53] and provides a detailed analysis regarding the deliverability of Bellefonte 1 power to the City of Memphis.

5.1 Overview of Plant

Bellefonte is a proposed nuclear generating plant located in the TVA service territory in northeastern Alabama as shown in Exhibit 14 below. Development first started at the Bellefonte site by TVA in 1975, and at various points up to four separate nuclear units had been proposed. However, TVA only made meaningful progress on units 1 and 2, though development proceeded in fits and spurts through TVA's ownership of the site.

Exhibit 14: Bellefonte Nuclear Plant Location



Source: TVA

In 2015, TVA determined that it would be unlikely to need a large plant like Bellefonte for the next 20 years, and in May 2016 elected to declare the plant surplus, and sell the 1600-acre site at an auction. The auction took place on November 14, 2016 and FLH Company purchased the Bellefonte nuclear plant at the auction. In 2018, FLH Company purchased an option on the site.

[53] We have not reviewd the PPA.

The Bellefonte nuclear generating station is geographically located within the TVA region, but is also in close proximity to the Southern Company power system. The station's option to connect directly to these two very large utility systems at similar grid upgrade costs is a critical advantage of the project.

Given below is a table summarizing the key characteristics parameters of Bellefonte 1 power plant.

Exhibit 15: Bellefonte 1 Nuclear Plant Parameters

Plant Parameters	*Value*
Plant Capacity	1,350 MW
Online Year	2024
Forced Outage Rate	1.0%
Planned Outage Rate	4.4%
Net Availability	94.6%
Net Energy per Year (avg)	11.19 TWh

Source: FLH Company

5.2 Bellefonte Power Purchase Agreement

ICF's understanding is that the offer is for the full 1,350 MW of capacity available from Bellefonte 1. We estimate that based on availability of the plant at 94.6% the available energy would be 11.19 TWh. We further understand that the first-year offer price is for $39/MWh. This rate is essentially held flat for the term of the PPA with the exception of an inflation factor applied to the O&M component of the $39/MWh. Based on ICF experience, the three main components to nuclear costs are recovery on and of capital, O&M, and fuel expense. Of those, O&M is approximately 30% of the total cost recovery. If a 2.1% annual inflator is applied to 30% of the $39/MWh, this translates into an annual growth of approximately 0.7% for the total PPA rate. ICF has not reviewed the tenure of the PPA, but for the purposes of this study, we have assumed twenty years starting in 2024. As a result, the PPA starts at $39/MWh in 2024 and only reaches $44.5/MWh by 2043. This is one of drivers to savings for MLGW: initially there is large savings compared to the TVA rate ($75/MWh vs $39/MWh), and as time goes, the TVA rate increases at 1.6% per year in our projections whereas Bellefonte's PPA rate is escalating at only 0.7% per year, increasing savings over time.

5.3 Deliverability of Bellefonte Capacity to Memphis

Under FERC Open Access transmission rules, transmission providers (TPs) are required to meet requests for transmission service in accordance with their published open access transmission tariff. For example, we anticipate that transmission would involve long-term, firm, point-to-point service with rights to extend transmission service over time. However, if the transmission service requires transmission system upgrades, the TP can recover the costs from the entity requesting the service, and can delay service provision as long as it is making appropriate efforts to implement the identified grid upgrades. Therefore, a key issue in this context is to assess the cost and nature of upgrades required, if any, to facilitate the dispatch of power from Bellefonte 1.

The assessment of transmission availability and system upgrades typically involve the use of commercially available alternating current (AC) transmission power flow models to simulate grid operation and assess the impact of the proposed injections or supply under normal and contingencies conditions. The power flow data files used in the simulations are protected under the Critical Energy Infrastructure Information (CEII) protocol. FERC regulates access to the power flow data files provided by the North American Electric Reliability Corporation (NERC), the transmission providers and the Southeastern Electric Reliability Council (SERC) (i.e. through FERC 715 filings). In recent years, ICF has applied and secured CEII clearance to access the FERC 715 (power flow) data files filed by transmission providers in NERC. ICF used the 2017 FERC 715 filings by transmission providers in its current power flow assessment. Accordingly, ICF used the PowerWorld™ transmission model together with FERC-provided CEII data to evaluate power system impacts and system upgrade requirements associated with the proposed dispatch. ICF supplemented the CEII data with information from ABB Velocity Suite and publicly available data.

5.3.1 Methodology

In assessing the impacts, it is necessary to model the flows on the grid assuming power injection at Bellefonte 1. Bellefonte 1 was assumed to inject at the Widow's Creek 500kV substation as proxy[54]. This in turn requires that other power plants' power injection be commensurately decreased (dispatched down) in order to comply with the grid requirement that supply and demand be balanced instantaneously[55]. The most common practice among transmission providers assessing transmission service or interconnection requests is to dispatch down *pro rata* the output/injection of generators in the region.[56]

ICF ran the *pro rata* case assuming reductions from TVA (excluding reductions from nuclear units in TVA) and two alternative dispatch-down cases in response to the injection of Bellefonte power into the TVA system. ICF also ran a case dispatching down TVA units but interconnecting Bellefonte 1 within Southern territory. ICF used the PowerWorld load flow model for the simulation. In each case, ICF assessed grid conditions (i.e., line-by-line, transformer-by-transformer, etc.) to determine the resulting flows and whether there were any element overloads or voltage violations. In the event of overloads or violations, ICF undertook to increase grid capacity via the addition of another transmission circuit – i.e., double circuiting. Adding another circuit or element is usually more expensive compared to other grid modifications (e.g., re-dispatch, re-conductoring, terminal equipment upgrades), and hence, ICF cost estimates may be considered upper-end estimates. The analysis incorporates assessment of numerous contingency conditions in accordance with standard industry practice[57]. The analysis involving multiple configurations of contingencies is part of the complexity involved in power flow analysis. The contingency analysis helps ensure that the delivery can be treated as firm.

ICF Base Case for this deliverability modeling review was SERC's latest power flow case for the summer peak of year 2021, the closest released year to the proposed online date of Bellefonte #1[58]. ICF tabulated existing overloads and violations in the Base Case, and then assessed incremental overloads and violations due to the

[54] The Bellefonte node currently exists at 161 kV.

[55] Incremental losses need to be supplied if any, and hence, the amount dispatched down may not precisely equal the injection, and vice versa.

[56] See later discussion of protocols in SPP and MISO. We did not find documentation of the TVA protocol. Thus we investigated multiple cases based on protocols elsewhere.

[57] ICF monitored violations at lines, transformers, and buses at 115 kV and above within TVA, Southern Company and MISO South.

[58] This is the latest FERC provided CEII data set, vintage 2016. ICF also reviewed other materials to determine whether major changes have occurred since the case was developed.

addition of Bellefonte 1 and a concomitant reduction (i.e., re-dispatch) in generation from other units. Only incremental line overloads have been identified across the three cases. ICF estimated the costs of double-circuit upgrades using NREL's JEDI Transmission Line Model.[59] As noted, lower costs might be possible (e.g., via terminal upgrades rather than double circuiting), especially if the overloads are small. Overloads in Affected (as opposed to Host) system are treated in accordance with standard practice[60].

5.3.2 Deliverability Results

Transmitting power from Bellefonte to MLGW did not result in any overloads on the TVA system, and hence, no TVA upgrade costs were allocated to Bellefonte (See Exhibit 16). The pro rata case (Case A) yielded a few incremental overloads, but all were in another Affected system, at 230kV and 115kV lines within the Southern Company Georgia Power service territory. These Affected system costs would not be allocated to Bellefonte. Not even these Affected system overloads were found in alternate cases where changes in re-dispatch were more localized in the area of Memphis (e.g., Case B: Allen and Southaven) or otherwise away from the boundary of TVA and Georgia Power (Case C). Case D is similar to Case A but with Bellefonte interconnected to Southern. This case also yielded a few incremental overloads, but all were in other Affected systems.

[59] The Jobs and Economic Development Impacts (JEDI) Transmission Line Model is developed by National Renewable Energy Lab (NREL). The JEDI models are tools that estimate the economic impacts of constructing and operating power assets and the JEDI Transmission Line Model specifically provides cost estimations including construction capital costs and operation and maintence expenses associated with transmission line projects. Inputs to the JEDI model include transmission line type (voltage and AC/DC), line length, and etc. We assume that all of the proposed MLGW transmission projects are 500 kV AC lines and line lengths are based on ABB's Ventyx database.

[60] Here we emphasize shift factor based cut offs – i.e. cost allocation excludes injections where the shift factor is lower than the cutoff point – e.g. 4-5 percent. Shift factors represent the percentage of power injected that flows on a particular element; for each injection there are as many shift factors as grid elements. While there is some variation across TPs regarding the exact cut-off percentage, it is small and not enough for any cutoff in use to be triggered.

Exhibit 16. Re-Dispatch Cases Analyzed and Resulting Incremental Line Overloads

	Case A	Case B	Case C	Case D
Interconnection	TVA	TVA	TVA	Southern
Re-Dispatch Adjustments for Case	Proportional generation reduction across TVA, except nuclear	Allen and Southaven CCs reduced to 50%; remaining energy proportional across TVA except nuclear	Proportional generation reduction across TVA combined cycles west of Bellefonte	Proportional generation reduction across TVA, except nuclear
Additional Lines Overloaded (#)	3	0	0	3
Total Length of Addtl. Overload Lines (miles)	26	0	0	18
Location of Affected Lines	Southern Company – GA	-	-	TVA-Memphis and MISO-Arkansas
Double-Circuit Upgrade Costs	There are $66 million of estimated costs in an Affected System; see discussion.	-	-	There are $63 million of estimated costs in the Affected Systems; see discussion.

Source: ICF using data from PowerWorld and Ventyx

We therefore conclude that physical deliverability of power from Bellefonte 1 to MLGW is feasible at no upgrade cost or time hurdle for the project. This is not surprising because TVA actively pursued the Bellefonte project through 2013; presumably, internal studies to TVA verified general deliverability of power from the local area.

An alternative means of assessing transmission availability is to review of the transmission provider's Open Access Same-Time Information System (OASIS) sites where near-term firm transfer capability is sometimes reported. This is not the preferred method even when available. This is because it is uncommon to provide availability in the period when Bellefonte 1 will come on-line – i.e., 4-5 years in the future. In this case, OASIS review of contractual availability of firm transmission was an even more challenging approach as no information was reported for firm internal (i.e., within TVA) transmission.

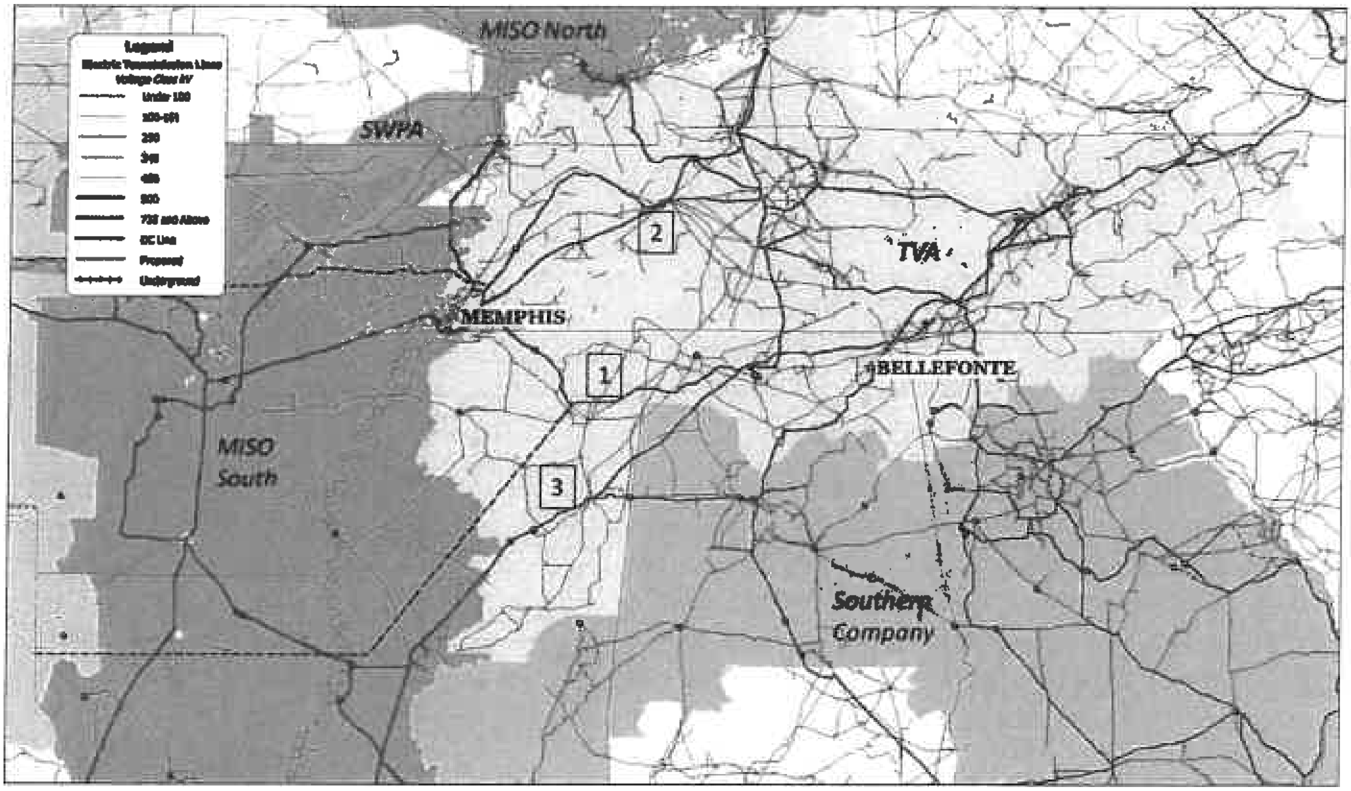
5.3.3 Potential Pathways Examined and Re-Dispatch Method Employed

Exhibit 17 below shows the transmission grid in the vicinity of Bellefonte and MLGW. MLGW, covering the city of Memphis plus a small surrounding area, is currently a TVA full requirements customer and therefore interconnects with TVA. While not directly interconnected to MISO at a local level, MLGW is across the river from and very near to MISO-Arkansas due west (also referred to as MISO South)[61]. Major 500 kV lines run from the TVA system to MISO South near the service area of MLGW. The 500 kV lines are shown in red and are the highest voltage lines in the region; transfer capability is proportional to the square of the voltage, all else equal.

[61] MLGW is south of the MISO South/North boundary; there is a major transfer constraint across this boundary and greater excess capacity exists in the south. All else equal, this is a benefit for MLGW.

While reviewing the 500 kV backbone pathways provides a heuristic view of the power flow, actual flows occur in a manner to minimize impedance, and hence, some flow is on lower voltage lines as well[62].

Exhibit 17. Transmission Lines and Balancing Authorities around MLGW



Source: Ventyx and ICF

As shown, if interconnected to the 500kV system near the plant, there are several 500kV transmission paths that run directly to the Memphis area (labeled 1-3 in Exhibit 17 above). Paths 1 and 2 use exclusively TVA lines; path 3 crosses through Southern Company and MISO but there are parallel path flows on the TVA system, and therefore TVA is an Affected system. We do not consider this significant[63].

Since MLGW is currently served exclusively by TVA, we constructed our re-dispatch cases on the assumption that TVA would back down a subset of existing units. As noted, given that supply and demand must be balanced and is held constant in these cases, some other generators must decrease their output. The cases analyzed are:

[62] Lower voltage lines shown in blue in the graphic are at 161 kV. Power flow is a non-linear phenomenon and minimizes impedance which, while lower for high voltage lines, all else equal, increases as the lines load up so that some power automatically redistributes to lower voltage lines.

[63] TVA does not claim parallel path flows are not permitted. TVA in their most recent 10-k, on page 23 states "However, other utilities may use their own transmission lines to serve customers within TVA's service area, and third parties are able to avoid the restrictions on serving end-use customers by selling or leasing a customer generating assets rather than electricity."

- **Case A** - The simplest solution is to reduce output at all dispatchable non-nuclear units across TVA territory – this constituted Case A. This is also consistent with the way transmission providers conduct generation interconnection and deliverability studies[64].

- **Case B** - The TVA generating units closest to Memphis are the combined cycles Allen (replacing an existing coal plant at the same site) and Southaven. With MLGW served primarily by Bellefonte 1, the output of these units for local load would be reduced, and it is possible that TVA would dispatch down the units.

- **Case C** - We constructed Case C assuming that TVA primarily adjusts dispatch against its combined cycles (including contracted IPPs) between Bellefonte 1 and Memphis.

- **Case D** - Finally, we constructed Case D using the same reduction methodology as outlined in Case A but with Bellefonte interconnected with Southern. We performed an additional step due to the interconnection with Southern, whereby dispatch reductions come from Southern units to estimate interconnection upgrades needed in Southern, then analyzed deliverability to MLGW. Costs shown in Exhibit 19 are additive of both of these steps.

As noted, *pro rata* dispatch down is common practice. Further, to validate these redispatch cases, we used ABB's PROMOD model and ran ICF's latest Base Case with and without Bellefonte #1 included in 2021. The results from this simulation indicate that Case A is the closest representation of economic dispatch across TVA (using $3.05/MMBtu gas prices at Henry Hub): across TVA, coal and combined cycles as a fleet each reduced dispatch by approximately the same amount, while Allen and Southaven continued to dispatch the same with or without Bellefonte #1. However, to ensure a robust result, we considered three additional cases (B, C and D). Other cases are possible depending on TVA operations, actual fuel prices/demand, etc.

In Cases A, B and C, we assumed Bellefonte would interconnect at 500kV at the existing Widow's Creek bus, near the existing plant location[65]. Localized capital expenditures for infrastructure necessary to step up the plant output to 500kV and interconnect at the existing bus were not included in the study[66]. As part of the study, ICF tested 1,855 contingencies. These include all N-1 contingencies within TVA at 161kV and above, plus key N-1-1 contingencies identified by TVA's transmission reliability margin (TRM) reports[67]. We also tested N-1 contingencies at 500kV in Southern Company and MISO South transmission areas. As discussed above, Case D assumed Bellefonte would interconnect with Southern. For case D, we did 3,358 N-1 contingencies within TVA, SOCO, and MISO South at 161 kV and above.

[64] MISO sinks queued generation to the entire classic MISO region according to MISO DPP 2016 West February West Area Phase 1 Study, Table 5. SPP Guidelines for Generator Interconnection Requests states that for interconnection studies, "the existing on-line generation is backed down across the SPP footprint on a load ratio basis in accordance with dispatch orders presented by individual transmission owners". Case A is consistent with SPP's method as TVA is the only owner of the analyzed transmission system.

[65] Except when the alternative path (path #3) with interconnection into Southern in Alabama.

[66] According to information given to ICF by FLH, these 500kV interconnection expenditures are captured in the total construction cost estimates for Bellefonte unit 1

[67] TVA's flowgates TRM values released in January 2018 (http://www.oatioasis.com/TVA/TVAdocs/TVA_FlowGates_TRMValues_01312018.pdf) indicate three key N-2 contingencies, namely loss of Bwn-Seq and Norcross-Oconee 500 kV lines, loss of SSHD TVA – SSHD EKPC line and SSHD 161/69 kV transformer, and loss of Shawnee 500/161 kV transformer and Shawnee FP1/FP2

Exhibit 18 and Exhibit 19 below show the overloaded lines in Case A and Case D (all are in Affected Systems), and our estimate of the cost to fully double-circuit each line:

Exhibit 18. Case A Overloaded Lines and Double-Circuit Cost Estimate – Affected System Impacts

Lines	Voltage	Ending Bus Area	Loading %	Bellefonte to MLGW Shift Factor	Length (miles)	Est. Cost per Mile	Total Cost
6SRS2! To 6VOGTLE	230kV	SCEG and SoCo-GA	101.0%	0.68%	21	$1.57 M/mi	$32.9M
3GAINES FRY to 3GWINCO WFP	115kV	SoCo-GA	106.5%	0.09%	5	$6.59 M/mi	$33.0M
3SHOAL CREEK to 3GWINCO WFP	115kV	SoCo-GA	109.5%	0.09%	Section of above line	$6.59 M/mi	-
Total							$65.9M

Source: ICF using data from PowerWorld and Ventyx

Exhibit 19. Case D Overloaded Lines and Double-Circuit Cost Estimate – Affected System Impacts

Lines	Voltage	Ending Bus Area	Loading %	Bellefonte to MLGW Shift Factor	Length (miles)	Est. Cost per Mile	Total Cost
5FREEPORT #1 to 5SHELBY DR74	161kV	TVA	100.3%	3.23%	7	$3.98 M/mi	$29.8M
3PINNACLEI to 3NATURAL STP	115kV	MISO-AR	100.4%	0.04%	10	$3.17 M/mi	$33.0M
3NATURAL STP to 3MAYFLOWER%	115kV	MISO-AR	102.2%	0.04%	Section of above line	$3.17 M/mi	-
Total							$62.8M

Source: ICF using data from PowerWorld and Ventyx

We do not include these costs in our analysis because:

- The Bellefonte shift factor on each of these lines is very small. Affected system impacts are ignored in cases in which the shift factor is below approximately 5%, which is the case for each of the above.
- Furthermore, the results of the other cases show that overloads can be avoided on these lines with slightly different re-dispatch patterns. This further mitigates the potential for cost allocation to the transmission service.
- To the extent that the identified system elements are almost at maximum usage in the non-Bellefonte case (i.e., the Base Case or Reference Case), it is more appropriate for load or other system users to pay all or part of the cost.
- Additionally, the low overload percentages suggest that full double-circuits across the lines may not be needed to relieve the constraints. As noted earlier, terminal upgrades such as phase shifting transformers, reactance devices, may suffice.

In summary, pathways 1 and 2 shown in Exhibit 17 reflect the simplest contract path for firm transmission from Bellefonte 1 to MLGW: namely TVA interconnection and firm transmission service[68]. Both paths are fully contained within TVA territory. In our study, there are no attributable overloads indicated on any of the 500kV lines between Bellefonte and Memphis, nor any overloads on lower voltage lines, nor any local overloads in the Memphis area under any of the cases studies. Our study suggests that there is adequate transmission capacity in place to deliver the full output of Bellefonte 1 to MLGW.

[68] In this case, the Interconnection and Transmission service grid studies are the same from the perspective of analyzing grid upgrades.

6. MLGW Incremental Wholesale Needs and Options

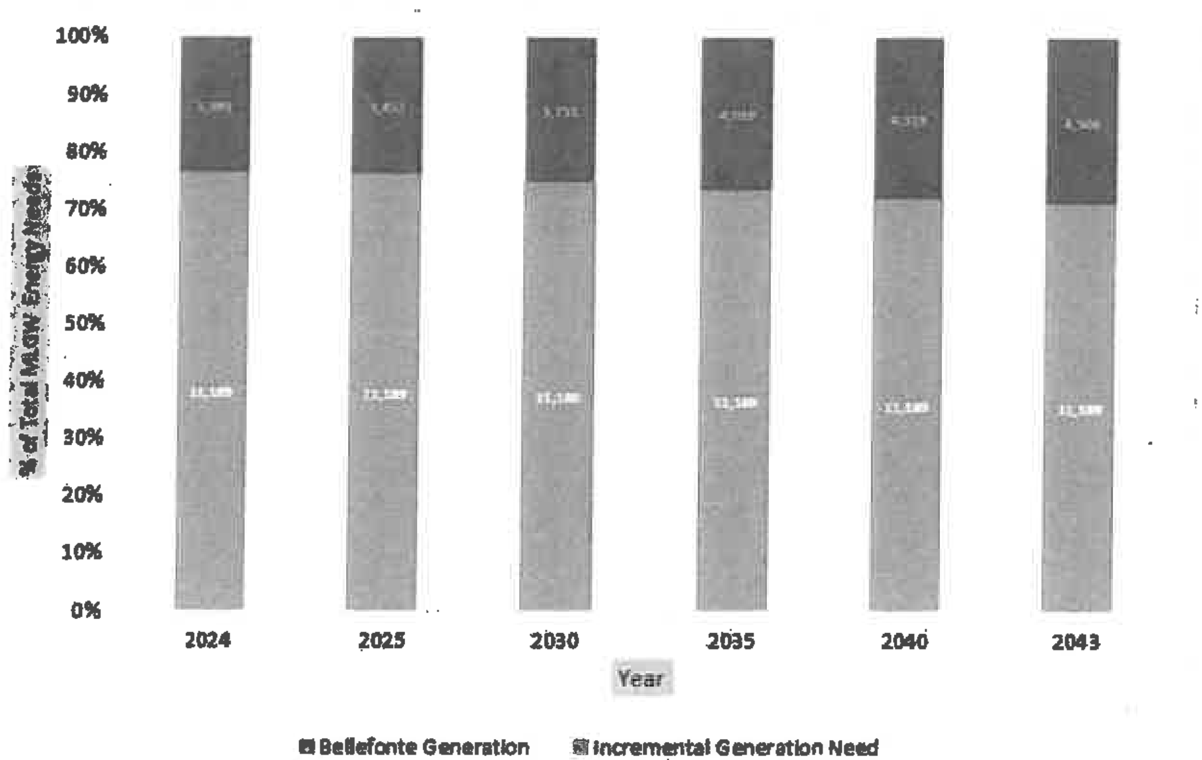
In this chapter we discuss both the incremental need of MLGW outside of the Bellefonte PPA and the supply options for MLGW, e.g., to become its own balancing authority. We assume that this could likely be in the context of a partial requirements contract with a third party – e.g., a power company including traditional regulated companies or deregulated companies. The key is that it can be "do it yourself" or contracted out.

6.1 Incremental Demand

The full output of Bellefonte 1 would serve most of MLGW's total energy needs by providing nearly around-the-clock baseload power. However, some remaining intermediate and peak energy, planning capacity reserves, and ancillary services would have to come from other sources.

MLGW is expected to have nearly 3.6 GW of peak (4.1 GW including reserve) and 14.3 TWh of energy requirement in 2024 and increasing to 3.9 GW (4.5 GW including reserve) and 15.6 TWh by 2043. We assume a 15% reserve capacity requirement for MLGW. As shown in Exhibit 20 and 21, Bellefonte could provide an average of 74% for energy and an average of 36% for peak (or 32% including reserve) requirement for MLGW over 2024-2043 period. Hence, the incremental need for energy and peak are on average 3.9 TWh and 2.4 GW (or 2.9 GW including reserve), respectively which MLGW would need to procure from alternative sources along with ancillary services.

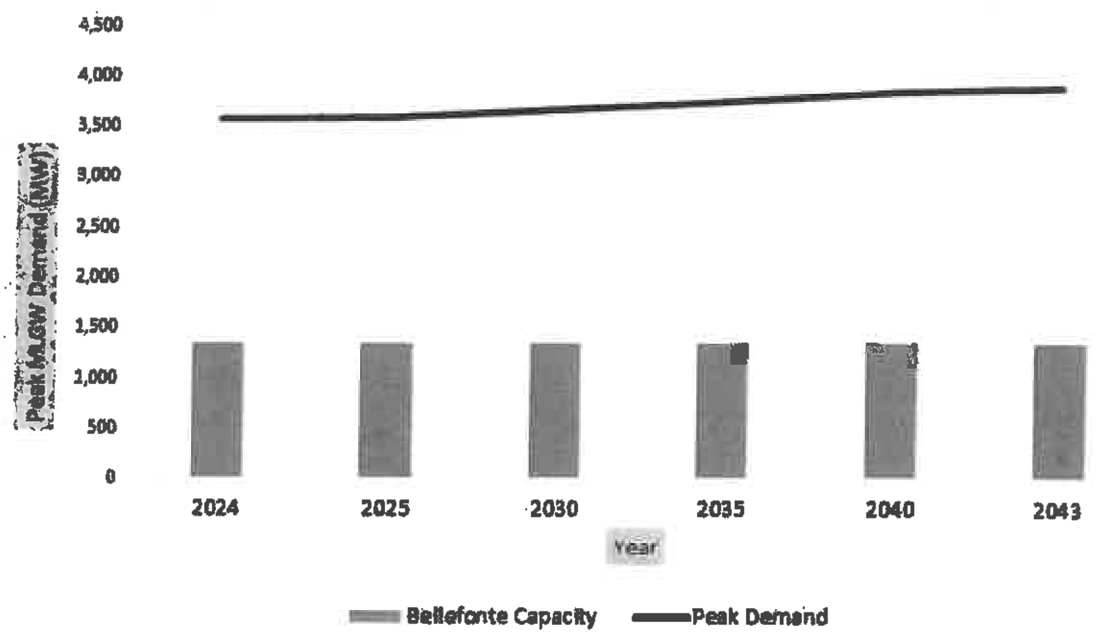
Exhibit 20. MLGW Incremental Energy Needs with Bellefonte 1 (MWh)



Source: ICF

Going forward there would be potential spare capacity primarily driven by uncontracted merchant capacity (IPP) and capacity rolling off PPA contracts that would help MLGW meets its peak requirements optimally going forward.

Exhibit 21. MLGW Incremental Peak Demand Needs with Bellefonte 1



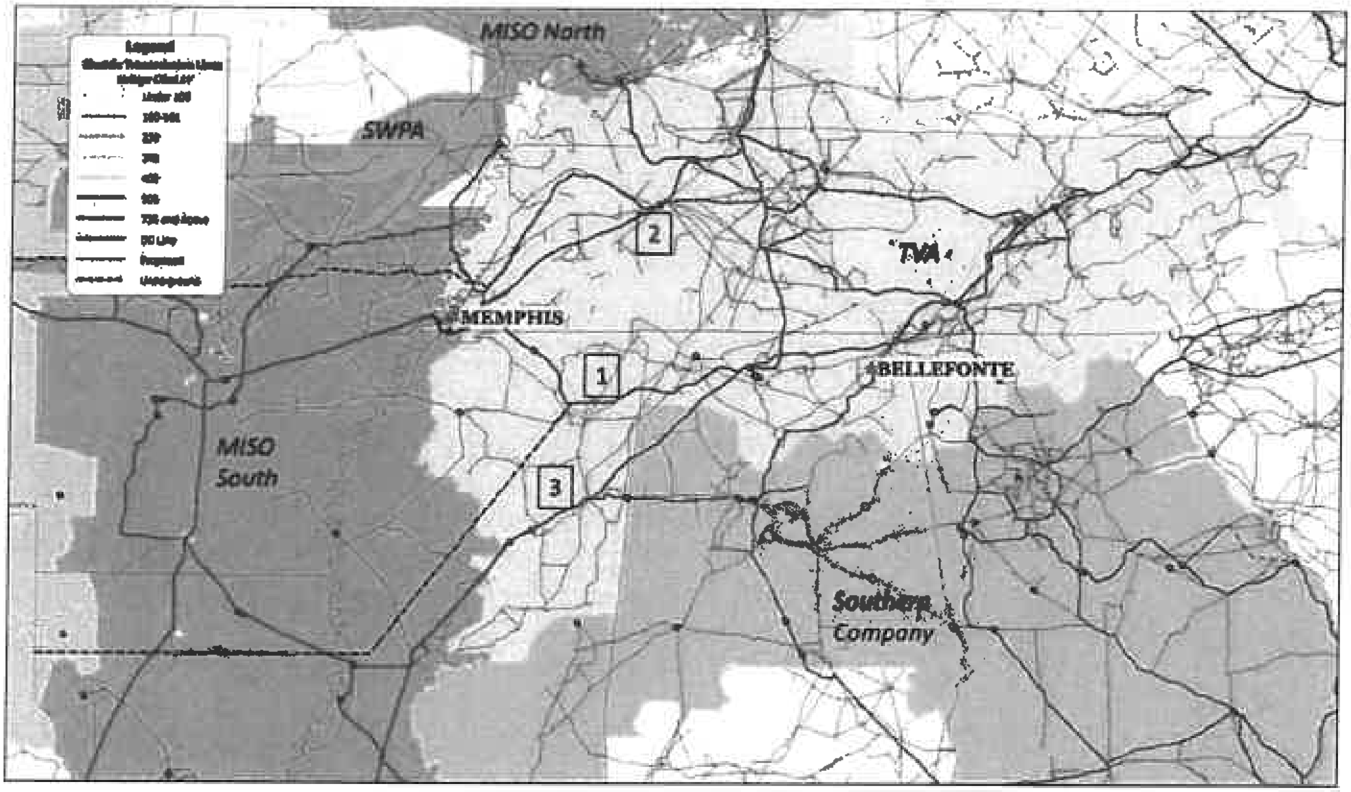
Source: ICF

Were MLGW to contract for Bellefonte's output, it would have to restructure its current wholesale power contract with TVA, or source its remaining needs from other entities.

6.2 Energy Landscape and MLGW Options

The energy geography surrounding MLGW is shown below in Exhibit 22:

Exhibit 22. Memphis Sits at the Juncture of Three Major Power Markets



MLGW sits near the intersection of three major regions that operate and are regulated very differently. Currently MLGW is a part of TVA, a federally-owned, nonprofit, vertically integrated utility. It borders the southern portion of the Midcontinent Independent Service Operator (MISO), a partially deregulated area with functional Day-2 energy markets, capacity and ancillary service markets, but largely comprised in the south of the Entergy operating companies. Nearby to the south is Southern Company, an investor-owned, regulated and vertically integrated utility. Additional, further to the north and west are other ISO territories in the Southwest Power Pool (SPP) and PJM Interconnection (PJM).

Our focus in this report is on TVA, MISO, and to a limited extent Southern Company. If MLGW opts out of TVA, it is certainly possible for them to source power from SPP, PJM or other regions. Power coming from these regions will have to be transmitted across the intervening MISO or TVA territory at the cost of firm transmission. The same is true for power coming from Southern Company, however, we include this region in our analysis since it is part of the Southeastern Reliability Coordinating area (SERC), a region that includes TVA (and by extension MLGW), and is also a key alternate transmission pathway for Bellefonte as will be described in Chapters 5 and 8.

Exhibit 23 below summarizes the key characteristics of the markets in this study:

Exhibit 23. Characteristics of Surrounding Power Markets

Market	Real-Time Energy Market		Day-Ahead Energy Market		Capacity Market	Ancillary Services Market	Financial Transmission Rights (FTR)
	RTO/ISO	Bilateral	RTO/ISO	Bilateral	RTO/ISO	RTO/ISO	RTO/ISO
MISO	Yes-liquid	Yes	Yes-liquid	Yes	Yes – prompt auctions	Yes	Yes
TVA	No	Yes-illiquid	No	Yes-illiquid	No	No	No
SOCO	No	Yes – slightly more liquid	No	Yes-illiquid	No	No	No

Source: ICF

The different operations in each market affects the wholesale power procurement options available to MLGW. For example, in TVA or Southern Company, the lack of liquid centralized exchange style markets limits MLGW to purchasing power from TVA, or at most, bilaterally contracting with the independent power producers (IPPs) interconnected in TVA. In MISO, by contrast, MLGW could still bilaterally contract with individual plants or utilities, but it could also participate in liquid markets and conceivably meet its entire needs via spot purchases of energy, capacity, and ancillary services.

6.3 MLGW Contracting Options

Broadly, we see three main alternatives for MLGW that will be explored in depth in this section of the report:

Option 1: Continue with TVA as Partial Services Requirements

The most straightforward option if available is to simply contract for Bellefonte 1's power and source all remaining requirements from TVA. This would require minimal change on the part of MLGW operations and comparably less upfront investment. In effect, the TVA contract would be similar in character to the current one, except that TVA would be serving a smaller quantity of MLGW load. This option relies, of course, on TVA's willingness to offer such a contract and what the terms would be.

Option 2: Join MISO

Our "intermediate" option in terms of complexity for MLGW is to exit from TVA service and interconnect itself with MISO. This would allow it to access the MISO energy, capacity and ancillary markets and make it cheaper to contract existing plants in MISO. MISO would serve as the balancing authority and would coordinate inter-regional transmission, among other services. This could be achieved via TVA lines or new lines from MLGW across the river.

Option 3: Become an Independent Balancing Authority

Our final option is for MLGW to separate from TVA and serve as its own Balancing Authority. In this case, MLGW could still interface with MISO energy markets via interchange schedules or a pseudo-tie, but would require MLGW to balance its own grid, contract with external plants for services, etc.

Options 2 and 3 involve fairly broad changes in MLGW's operations. Our assessment shows that they would likely need to construct and own new high-voltage transmission lines, plan and contract much more actively for their future wholesale needs, and involve greater exposure to market pricing. However, they each offer the advantages of access to a broader set of energy resources (i.e., they are not tied to TVA's set rate) including the ability to source from Bellefonte 1. Option 1 involves considerably less change, but is subject to availability. MLGW's exit from full-services contracting with TVA *could* negatively affect TVA, and historical experience shows that TVA has vigorously resisted attrition of its full-service customers (we detail some of these challenges in Chapter 7 and 9). Exhibit 24 summarizes the three options:

Exhibit 24. Options for MLGW

Case	Option 1: TVA Partial Services Req.	Option 2: Join MISO	Option 3: Independent Utility
Balancing Authority	TVA	MISO	MLGW
Remaining Power Needs	TVA	MISO	MISO/SERC
Reserve Sharing Group	TVA	MISO	SERC

Source: ICF

Importantly, while we will refer to these three options throughout this report, they do not represent the only options for MLGW. Alternate combinations of balancing authority and power sources may be possible. Additionally, there are various ways to interface with MISO especially that can carry differing costs and qualitative benefits for MLGW. Our report details some of these options in Chapter 7. The remainder of the report builds out our estimate of costs, benefits, and qualitative considerations for these cases.

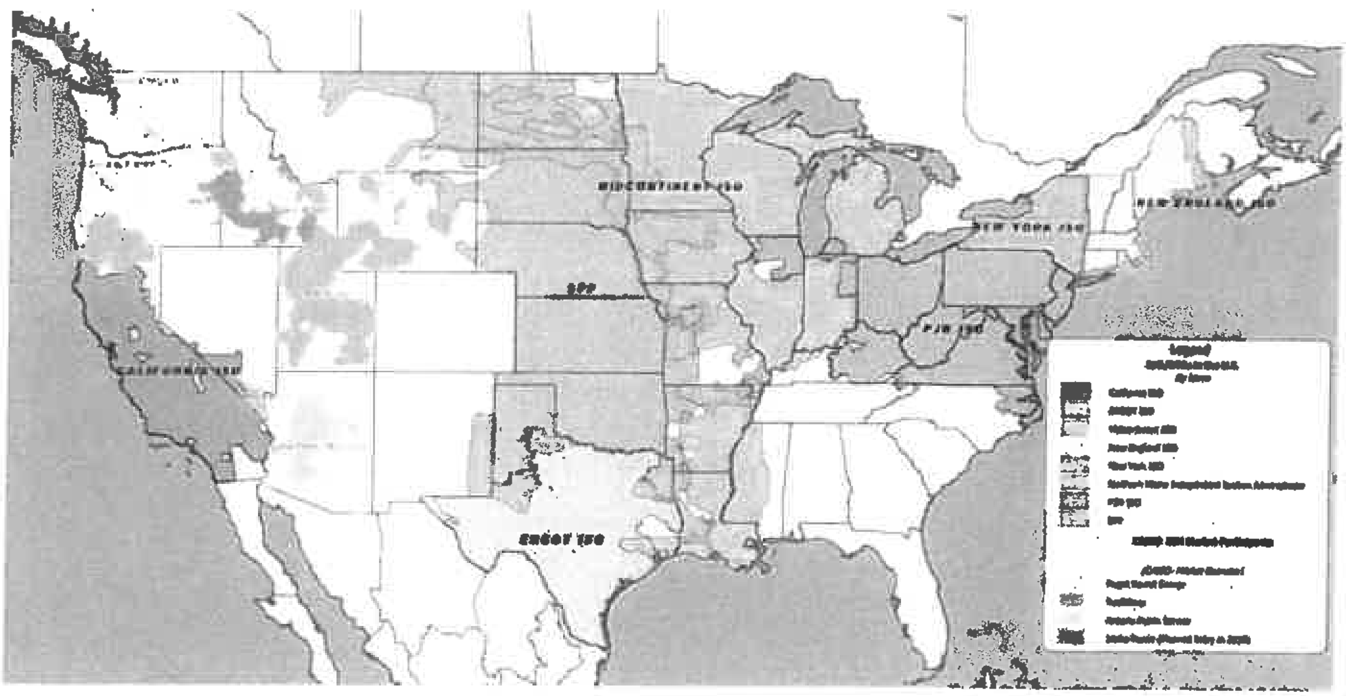
7. MISO Wholesale Power Market

7.1 Market Background

MISO is an organized RTO power market. Wholesale spot prices have been very low compared to TVA rates in recent years.

MLGW has not had much direct interaction with MISO. However, this is a result of an anomalous situation: MLGW is part of one of the only regions not in an organized exchange style RTO market. In the Exhibit 25 below, shaded areas have or will have an organized electrical energy market using nodal pricing for at least real-time markets; most also have day-ahead markets. Therefore, among major regions in the contiguous US, only the southeastern US completely lacks an organized market. This includes TVA. However, this region borders organized markets to the north and east, largely MISO, and fortuitously for MLGW, it sits on the seam between MISO and the Southeastern US.

Exhibit 25. MISO and Other ISO/RTOs in the US



In terms of load served, MISO is the second-largest ISO/RTO in the country after PJM. However, MISO serves a much larger geographic area. Exhibit 26 shows the MISO market statistics for year 2017.

Exhibit 26. MISO 2017 Statistics

Market Statistic	MISO
2017 Total Generation Capacity	173 GW
2017 ICAP Capacity [net of In-operable capacity + de-rates]	150 GW
2017 Peak Demand	121 GW
2017 Forecasted Peak	125 GW
ICAP Reserve Margin (%)	24.0%
2017 Energy Served	665,012 GWh
States Covered	15
Population Served	~42 MM
2017 Installed Wind Capacity	16.4 GW
2017 Installed Solar Capacity	0.2 GW

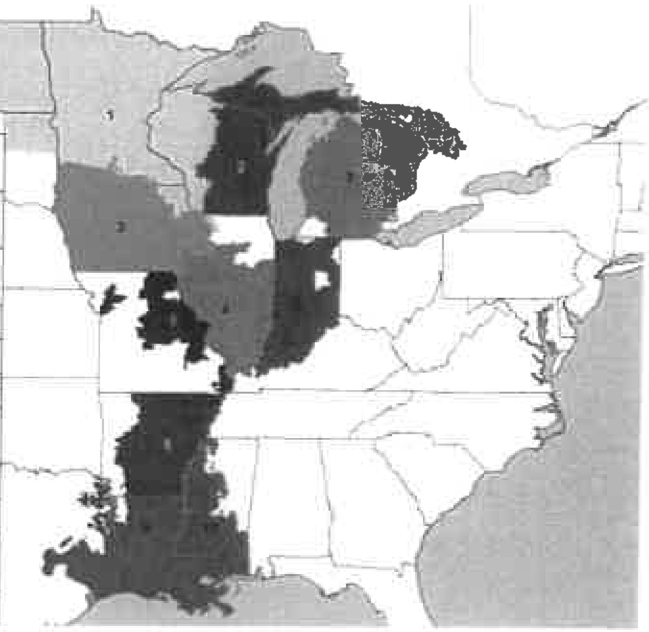
Source: MISO

MISO's role varies regionally, especially vis-a-vis Canada. While the market area covers 15 states in the US and is limited to US coverage, the reliability coordination coverage extends into Canada, covering the central Canadian province of Manitoba. In the United States, MISO covers parts of Wisconsin, Minnesota, and Michigan, large parts of Indiana, Illinois, Iowa, Arkansas, Mississippi, Louisiana, Missouri, Kentucky, North Dakota, Montana, South Dakota, and Texas.

Most of the areas in MISO are served by vertically integrated utilities which own or have long term PPAs for significant amount of existing capacity. In MISO territory, only two areas (lower Michigan and Illinois) are open for limited retail competition.

MISO is organized into ten Local Resource Zones (LRZ). Entergy's accession to MISO resulted in the integration of MISO South (Zone 8 and 9), which occurred in 2013 in response to strong regulatory pressure from FERC to join a RTO. Entergy has five operating companies. These include numerous public power entities including cooperatives, and municipalities, and a few other utilities. In 2015, MISO created a separate capacity LRZ 10 which includes Entergy – Mississippi and South Mississippi Electric Power Association. Collectively, LRZ 8-10 are referred to as MISO South (see Exhibit 27). MLGW borders MISO South (LRZ 8 – Arkansas, and LRZ 10 – Mississippi). In some respects, MISO treats MISO south separately from the rest of MISO due to transmission limitations north south effectively between Zones 5 and 8.

Exhibit 27. MISO Local Resource Zones

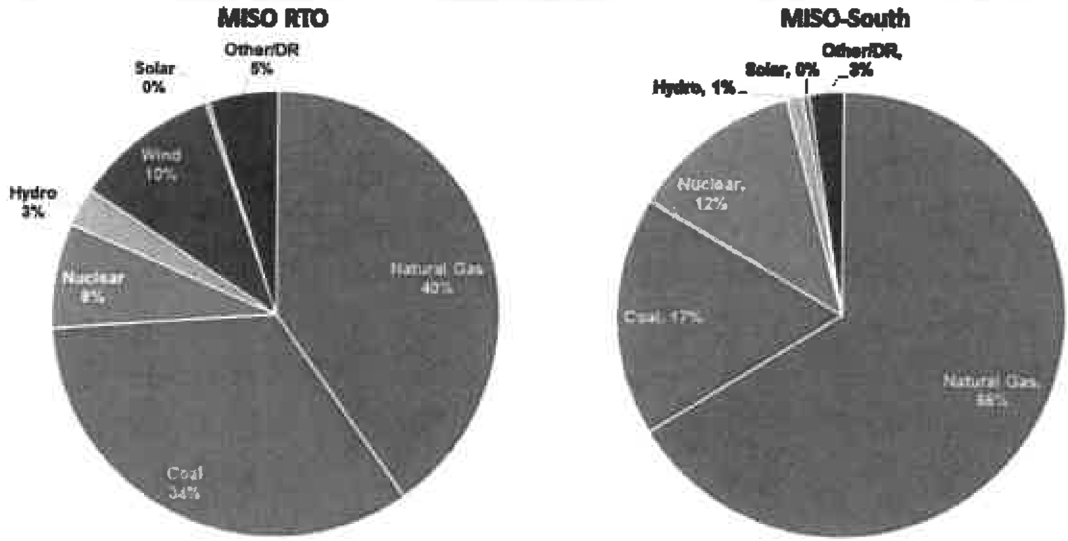


Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$1.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$10.00
3	ALTW, MEC, MPW	$10.00
4	AMIL, CWLP, SIPC	$10.00
5	AMMO, CWLD	$10.00
6	BREC, CIN, HE, IPL, NIPS, SIGE	$10.00
7	CONS, DECO	$10.00
8	EAI	$10.00
9	CLEC, EES, LAFA, LAGN, LEPA	$10.00
10	EMBA, SME	$10.00

Source: MISO

MISO has installed capacity (ICAP, de-rated) of approximately 150 GW. The historically dominant fuel types are natural gas and coal, although each of these have declined in absolute terms and as shares of capacity in recent years. Between 2010 and 2018, coal and natural gas/oil capacity fell by approximately 11 GW and 9 GW, respectively. In the same period, wind capacity expanded by around 11.5 GW, largely in the plains states (especially Iowa) with comparably little in MISO-South. The capacity mix in MISO South remains gas dominated (nearly 68%) followed by coal (18%) and nuclear (13%). Exhibit 26 shows the makeup of total nameplate capacity in MISO as a whole and MISO South. This means that MLGW, were it to access MISO south, would be frequently accessing gas fired generation in terms of the marginal price setting unit. However, Arkansas has more coal on average than MISO South generally, and hence, coal can be a price setting source as well.

Exhibit 28. MISO Installed Capacity Mix 2018[69]



Source: Ventyx, 2017 MISO State of the Market Report

7.1.1 Energy and Ancillary Service Markets

MISO's energy market structure is based on locational marginal pricing (LMP), also referred to as nodal pricing. Under an LMP-based market, market prices can vary significantly by location as transmission constraints and losses develop and potentially create thousands of different prices across the grid.

The largest contributor to price separation across LMPs is when energy is constrained by transmission limitations. In an unconstrained system, power could flow from the cheapest generators to the load centers and incur only small physical loss charges along the way. However, transmission constraints mean that more expensive units, favorably located on the transmission grid, must be run instead, creating a higher price behind the binding constraint. Generally speaking, areas with more load than generation experience higher prices than areas with more generation than load.

In practice, the variation in pricing is usually more limited. MISO is required to plan the system to eliminate persistent and significant congestion.

MISO operates two main energy markets: a day-ahead (DA) and real-time (RT)[70]. Prices in both are established according to cost minimization across the system subject to cost-based offers for generation, projections of load and ancillary service requirements, operational constraints on generators, and transmission constraints across the system. Ancillary services are cleared with energy, though ancillary services are priced zonally and not individually at every LMP node. MLGW, were it part of MISO could buy all of its energy requirements from MISO. As discussed elsewhere, hedging is likely to be an important activity supplementing spot purchases in any case.

[69] This is based on Nameplate Capacity - renewables are not de-rated

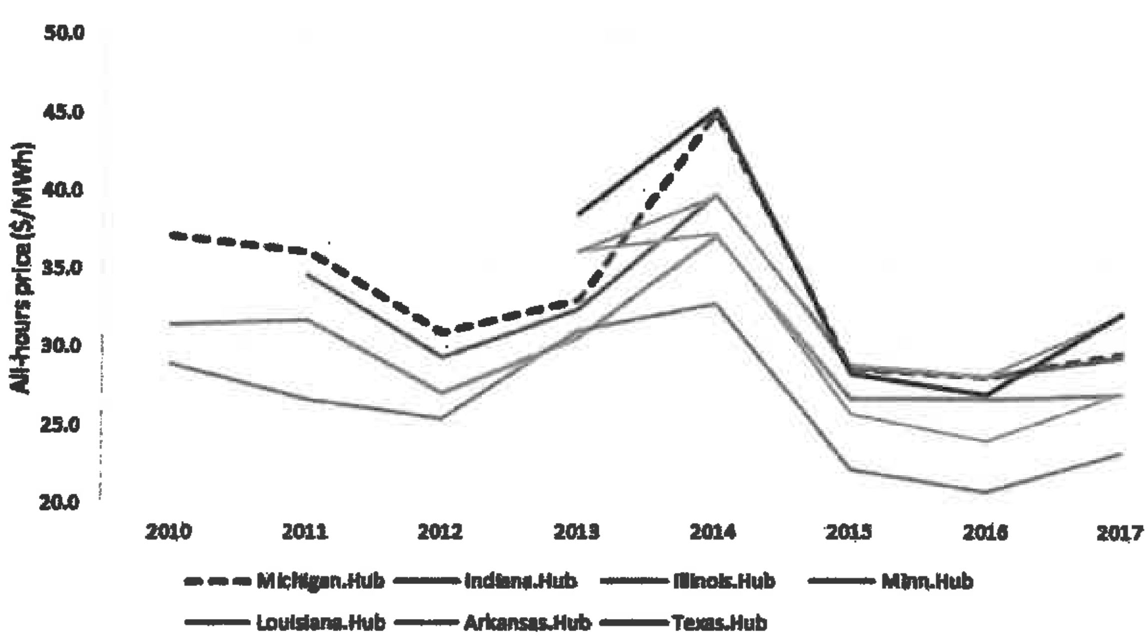
[70] The only LMP markets without both day ahead and real time are in the western US.

The day-ahead market results in commitments to dispatch the following day, and the real-time market results in actual instruction from MISO to plants for generation of electricity. In MISO, when the market is unable to meet demand, the LMP price is administratively set based on the level of shortage and can reach up to $3,500/MWh, under the most extreme scarcity conditions.

At trading hubs, specific nodal prices are aggregated to create a reference price. The ISOs/RTOs calculate and post the prices at the trading hubs to create a price index, which can be then used to establish a reference for forward markets. Trading hub-based contracts can be used to purchase forward power. Bilateral and forward-market transactions for power are also allowed. These contracts may settle financially (covering the cost for a specified quantity of energy at a given time) or schedule physical delivery across the grid.

Historical DA prices at major MISO trading hubs are shown below in Exhibit 29. As can be seen, the Arkansas price for all hours energy over the past three years has averaged approximately $26/MWh. Not shown, capacity prices have been close to zero. Even with adjustments to make apples to apples, these prices are well below TVA prices.

Exhibit 29. Historical DA Prices at Major MISO Trading Hubs



Source: Ventyx

Energy pricing in MISO follows the prices of natural gas, coal, and weather, as well as other factors. In the past three years, all hours prices across MISO have been low (~$25-26/MWh) in large part due to low natural gas prices. Prices were much higher in 2014 due to the "polar vortex" extreme cold event that resulted in natural gas price spikes, plant outages and unexpectedly high winter demand. Prices at Arkansas Hub, the closest to MLGW, are in general slightly lower than the rest of the market but otherwise follow the same trends.

7.1.2 Capacity Market

The goal of capacity markets is to maintain system reliability at peak demand (i.e. having more than enough resources to meet peak including contingencies such as unit outages, higher-than-expected demand, etc.) by compensating units for providing needed going-forward reserve capacity. Some peaking reserve units are needed even though they may rarely or never be called on to produce energy and therefore would otherwise earn no revenues[71].

The capacity market is enacted through requirements placed on load-serving entities (LSEs) such as utilities. LSEs in MISO must meet two reserve requirements: the Planning Reserve Margin Requirement (PRMR) and the Local Clearing Requirement (LCR). The local clearing requirement is the amount of capacity a zone must procure internally to meet its own peak demand requirements. The Planning Reserve Margin Requirement is the amount of capacity a zone must procure, which can include imports, to fulfill its share of MISO's peak demand reliability requirements. An LSE can meet its obligations by owning or contracting for capacity from existing generators, or by purchasing capacity in the spot Planning Resource Auction (PRA).

The PRA results in capacity commitments for one-year periods. The commitment period is June to May; with the auction clearing two months prior to the start of the commitment period. The bids are cleared through a single, sealed-bid clearing price auction against a vertical demand curve, unlike ISO-NE, PJM, and ISO-NE, where bids are cleared against sloping demand curves. Exhibit 30 below summarizes the key aspects of MISO's capacity market construct.

Exhibit 30. Key Capacity Market Attributes in MISO

Parameter	MISO
Commitment Term	12 months
Timing	Prompt
Demand Curve	Vertical
Locational Sub-Markets	10
Performance Incentives	No

Exhibit 31 below shows the 10 capacity zones with the most recent clearing prices:

[71] Bid prices are also restricted by market manipulation rules. Thus, revenues can still be too low to cover costs; this is referred to as the missing money problem.

Exhibit 31. MISO Capacity Market Zones and PRA Results ($/MW-day)

Zone	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019
Zone 1	1.05	3.29	3.48	19.72	1.50	1.00
Zone 2	1.05	16.75	3.48	72.00	1.50	10.00
Zone 3	1.05	16.75	3.48	72.00	1.50	10.00
Zone 4	1.05	16.75	150.00	72.00	1.50	10.00
Zone 5	1.05	16.75	3.48	72.00	1.50	10.00
Zone 6	1.05	16.75	3.48	72.00	1.50	10.00
Zone 7	N/A	16.75	3.48	72.00	1.50	10.00
Zone 8	N/A	16.44	3.29	2.99	1.50	10.00
Zone 9	N/A	16.44	3.29	2.99	1.50	10.00
Zone 10	N/A	N/A	N/A	2.99	1.50	10.00

Source: MISO

MISO capacity market offers are not subject to a Minimum Offer Price Rule (MOPR) requirement. With the dominance of the utilities (which can include owned generation in their rate base and therefore not require additional revenues from the PRA), and a general lack of buy-side market power mitigation measures, MISO capacity auctions often see most generators bid at or near $0, and therefore clear at very low prices. For perspective, if MLGW were able to procure 3000 MW of capacity at the most recent MISO capacity prices of $10/MW day, the annual costs would be approximately $11 million, or $3-4/MWh if allocated to the 3 million MWhs of incremental energy required. For additional perspective, total costs for MLGW of the TVA contract were approximately $1 billion. However, as stated in this report in several locations, the volumes in the capacity market are thin.

7.2 Forecasted Market Prices

ICF makes use of two primary models to simulate market evolution and prices in the US. First, we utilize our proprietary IPM zonal production cost model to simulate plant economics and project economic new builds, retirements, and capacity prices over time. We then use the results of this model in conjunction with ABB's PROMOD nodal security-constrained economic dispatch (SCED) model, which adds further detail of hourly energy pricing at the nodal level. Further details of these models can be found in Appendix.

7.2.1 Energy and Ancillary Service Prices

Exhibit 32. MISO Arkansas Hub Historical and Projected Energy Prices, Fuel Prices, and Implied Heat Rates

MISO Arkansas Hub	Year	All-Hour Energy Price ($/MWh)	On-peak Energy Price ($/MWh)	Off-peak Energy Price ($/MWh)	Delivered Gas Price ($/MMBtu)	CO2 Price ($/ton)	All-Hour Energy IHR (Btu/kWh)	On-peak Energy IHR (Btu/kWh)	Off-peak Energy IHR (Btu/kWh)
Historical	2013	36.1	37.5	34.9	3.8	0.0	9,421	9,785	9,107
	2014	37.3	41.3	33.6	4.4	0.0	8,389	9,287	7,570
	2015	25.7	28.4	23.2	2.7	0.0	9,598	10,622	8,666
	2016	24.0	27.2	21.1	2.5	0.0	9,498	10,753	8,361
	2017	27.1	30.6	23.9	3.0	0.0	9,017	10,195	7,952
Projected	2018	28.8	33.0	24.9	2.9	0.0	9,962	11,422	8,632
	2019	28.8	32.9	25.1	2.7	0.0	10,566	12,057	9,207
	2020	28.4	32.4	24.7	2.6	0.0	10,945	12,502	9,522
	2023	34.9	40.3	29.9	4.0	0.0	8,796	10,173	7,550
	2025	36.2	41.6	31.2	4.2	0.0	8,706	10,019	7,510
	2030	46.6	53.4	40.4	5.1	5.4	9,072	10,404	7,859
	2035	56.3	64.1	49.3	5.9	13.2	9,586	10,896	8,392
	2040	65.5	74.7	57.1	6.5	21.7	10,116	11,546	8,820

Notes: Energy prices reflective of MISO-Arkansas hub and delivered gas for Texas Gas Zone 1+$0.05/MMBtu (in 2012$) LDC and 2.75% tax;

Both coal and natural gas are major energy sources in MISO South and as such, the market dynamics depend on the interplay of natural gas and coal pricing trends. As gas prices have dropped, coal plants have increasingly been on the margin, and so energy prices have decreased more slowly than gas (see Exhibit 30).

All-hour energy prices for MISO Zone 8 are projected to increase over the 2018 to 2040 period. This escalation is driven primarily by increase in gas prices, inflation, and the projected national regulation of carbon emissions starting in 2026 and beyond. These factors are partially offset by new capacity entry in MISO, consisting mainly of solar and natural gas in the near term and natural gas in the mid- to long-term. Decreasing gas prices in the near term lead to nearly flat or dipping power prices.

Forward prices indicate a weak outlook for gas prices in 2018 and 2019, as growth in shale gas production continues to outpace demand growth. Coal remains marginal in many hours in 2018 to 2020, leading to high system heat rates. In subsequent years, ICF projects modest upward pressure on gas prices, as demand growth accelerates (from new LNG export capability, growing exports to Mexico, and increases in industrial and power sector demand). Despite the projected long-term increase over recent levels, gas prices are expected to remain below pre-recession levels.

In the long run, as gas prices track higher, gas becomes the marginal fuel in most hours again and energy prices track more closely with natural gas prices. Implied heat rates begin increasing after 2025 due to the influence of assumed carbon regulation; the carbon-adjusted system heat rates after 2030 are essentially flat or falling.

ICF assumes carbon pricing in MISO to take effect with an allowance price of $1/ton in 2026, $5.4/ton in 2030, $13.2/ton in 2035, and $21.7/ton in 2040 for existing sources.

7.2.2 Capacity Prices

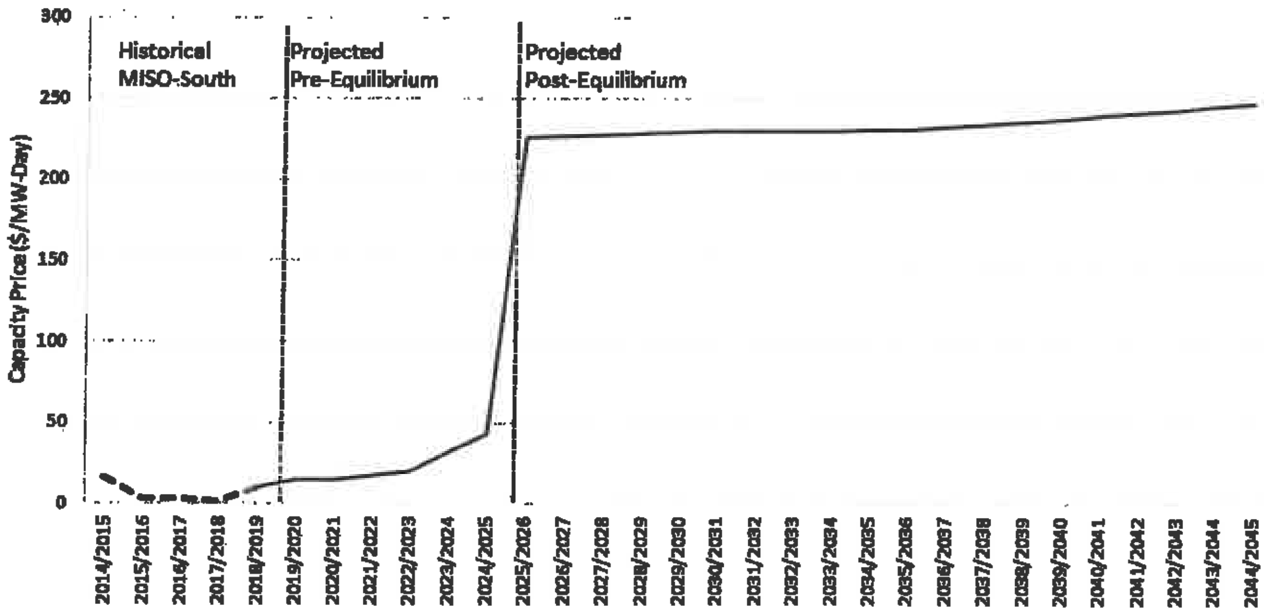
Exhibit 33 summarizes the Base Case merchant capacity price forecast for MISO. ICF projects low capacity prices in the near term owing to a surplus of supply in MISO and the lack of value placed on this surplus capacity in the MISO capacity market.

In the equilibrium period, ICF assumes that the existing units will not realize a net CONE [72]capacity price as the utilities in MISO would prefer to contract with new technologies and build their own capacity rather than re-contracting with an old facility at net CONE prices. ICF's view of capacity prices for an existing capacity during equilibrium period reflects going forward fixed cost of a combine cycle facility ($25/kW-yr in 2018$), increasing with inflation. Over time, capacity oversupply is projected to decline leading to tightening reserve margins, and thereby, increasing capacity prices in the mid-2020s. Prices for new units are projected to increase to $225/MW-day ($82/kW-yr) by 2025 as the system comes into equilibrium.

The current capacity surplus market reflects a "buyers' market" and so MLGW can lock in or buy the capacity at most competitive and discounted rates, whereas once the market is in equilibrium – the market would turn to a "sellers' market" and the entering in to a contract or purchasing plant would be relatively costly which is implied by the net CONE type pricing.

[72] CONE stands for "cost of new entrant", i.e., the capital cost required to build a power power plant. The term Gross CONE typically includes the going forward fixed costs along with capital recovery. Net CONE = Gross CONE (capital + fixed costs) – Energy Margin (Energy Revenue –fuel – consumables – major maintenance).

Exhibit 33. MISO Capacity Price Projection

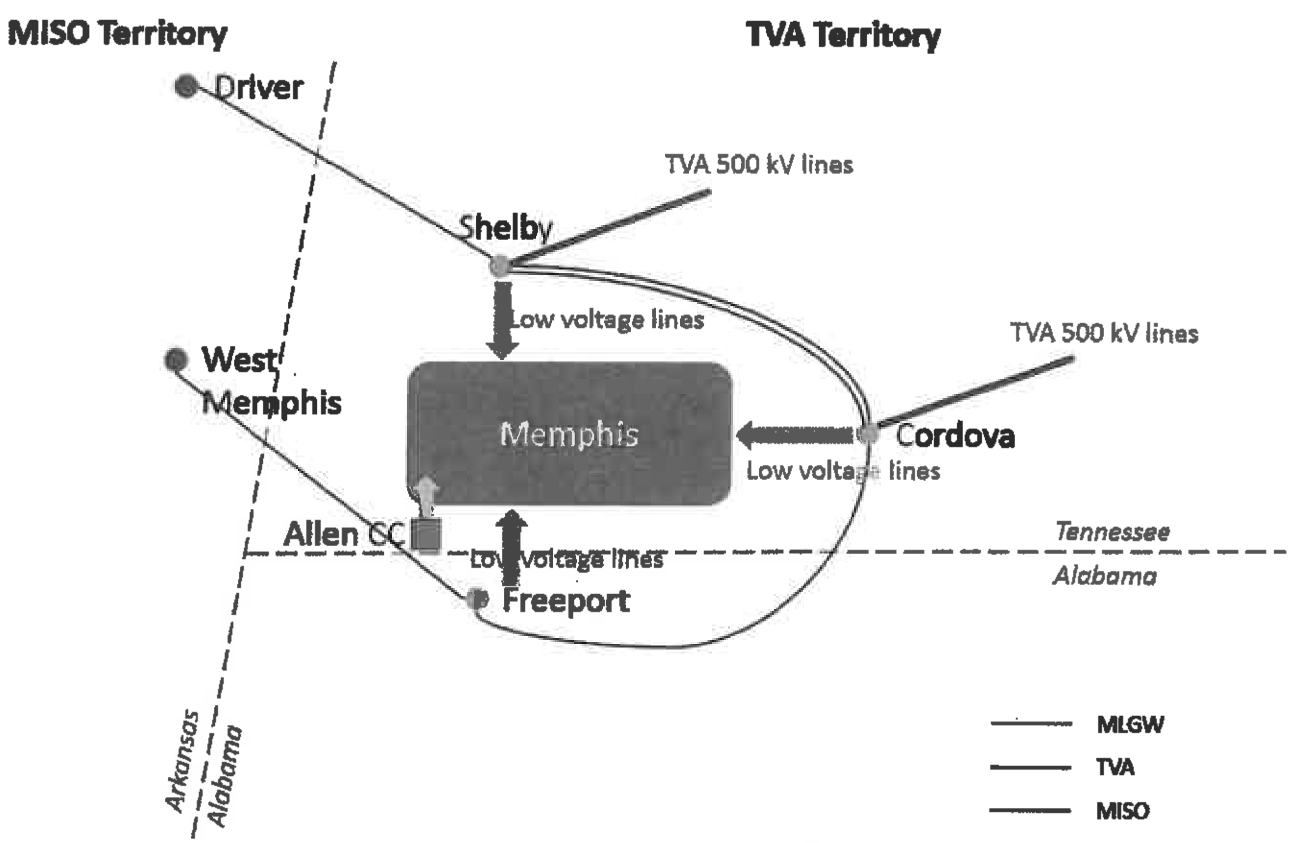


Source: Historical data was obtained from MISO PRA and projections are ICF

7.3 Transmission between MLGW and MISO

TVA, MISO and the MLGW service area are all interconnected with one another through at least one 500kV line and many lower voltage connections. TVA interconnects with Southern through four 500kV lines including one branch within Alabama, two at the Alabama-Mississippi border, and one in Georgia. There is only one 500 kV connection between Southern and MISO which starts from Jackson, Mississippi and ends in East Feliciana Parish, Louisiana. TVA and MISO South are interconnected through four 500 kV branches, with two bridging the transmission area border in Choctaw, Mississippi and another two linking Arkansas and Memphis.

Exhibit 34. Representation of Existing 500kV Network around Memphis



Source: ICF

As shown in Exhibit 34 above, the two Arkansas-Memphis linkages start from the West Memphis substation and Driver substation in Arkansas, and feed into Freeport substation and Shelby substation in Memphis, respectively. The Shelby and Freeport substation in Memphis, together with the Cordova substation, then form a horseshoe shape 500 kV transmission loop that surrounds Memphis. A set of 161 kV and lower voltage lines come out of the three substations to deliver power into the MLGW load service territory in Memphis. These low voltage lines are owned by MLGW.[73]

MLGW does not own any significant generation assets and the only large-scale power plant located in Memphis is the TVA-owned 1,200 MW Allen CC plant[74]. More specifically, in 2017 around 24% of MLGW energy demand was served by the Allen plant, while the remainder 76% was dependent on the stability and reliability of the surrounding transmission loop.[75] Exhibit 35 below details the key characters of the 500 kV lines forming the loop.

[73] Ventyx

[74] There are a few small solar projects in Memphis but the sizes are minimal. The retired Alen coal plant is still on site and might be a source of power under revised regulations.

[75] Calculated by ICF based on EIA Form 923 and FERC Form 714.

Exhibit 35. Characteristics of 500 kV forming the loop

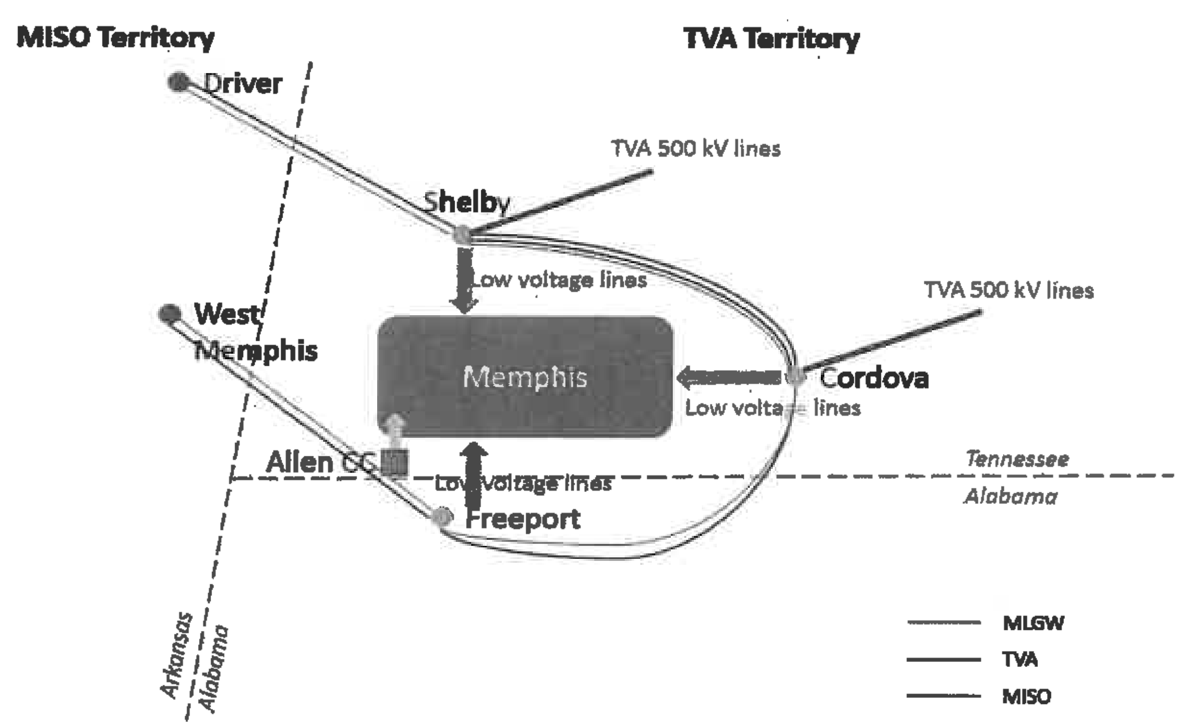
Line Name	# of circuits	Mileage	Ownership
Driver - Shelby 500 kV	1	18	TVA
Shelby - Cordova 500 kV	2	20.5	TVA
Cordova - Freeport 500 kV	1	25.3	TVA
Freeport - West Memphis 500 kV	1	15	TVA

Source: ABB Ventyx database, compiled by ICF

As has been established in section 5.3, MLGW can get all its power needs with the existing physical transmission connections and the corresponding system upgrades depending on the interconnection assumption for Bellefonte. MLGW joining MISO through a contractual movement would not affect such physical deliverability.

Nevertheless, MLGW may still want to build its own physical connections with MISO for various reasons. For example, as will be discussed further in Chapter 10, it is more economic than paying the transmission charges that TVA and MISO can impose on MLGW for using their transmission lines. Moreover, the capacity of the existing TVA-MISO may be less sufficient for meeting MLGW's load growth from a long-run perspective. In this case, MLGW can consider building a single-circuit loop in parallel to the existing one as shown in Exhibit 36 below

Exhibit 36. Representation of 500kV Network with Additional Single Circuit



Source: ICF

ICF estimated the cost to build and operate such single-circuit loop using NREL's JEDI Transmission Line Model as listed in Exhibit 37.

Exhibit 37. New Lines to be constructed for Single-Circuit Direct MLGW Connectivity with MISO

From Bus	To Bus	Voltage (kV)	length (mile)	# of circuits	Capital Cost (million 2018$)	Annual O&M Costs (million 2018$)
Memphis-MISO single-circuit loop case						
Freeport	West Memphis	500	15	1	94.6	0.28
Shelby	Driver	500	18	1	96.6	0.30
Shelby	Cordova	500	20.5	1	99.6	0.32
Freeport	Cordova	500	25.3	1	109.2	0.38
Total			**78.8**		**400.0**	**1.28**

Source: ICF using data from PowerWorld and Ventyx

8. Procuring Incremental Power

MLGW has several methods available at its disposal for actually procuring its incremental power needs. The choice of contracting and procurement strategy could have a large impact on the ultimate cost of this capacity. We discuss the provision of both energy and firm capacity, however, in many cases the considerations are similar.

8.1 Spot Market Contracting

As discussed in Chapter 6, the only organized, transparent and highly liquid spot market for energy in the region is run by MISO. There is also a MISO capacity market with close to zero prices and liquidity limitations. While Southern Company operates power exchanges across its transmission grid, actual trading volume is limited, and MLGW would additionally have to secure transmission from Southern Company through either TVA, MISO or both to its service territory, adding cost. Therefore, we do not recommend exclusive or very high reliance on bilateral non-RTO markets, and in general, recommend careful use of spot and hedging opportunities.

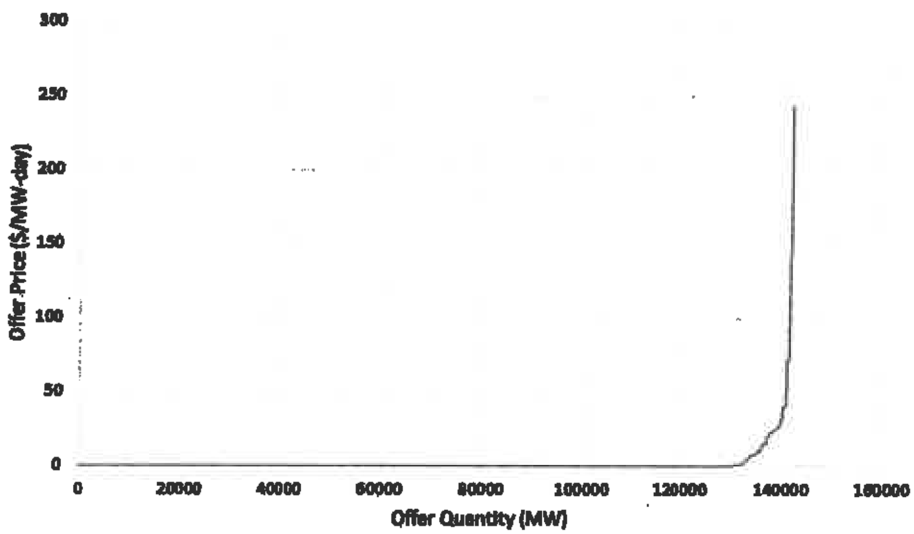
Spot markets can be volatile, especially capacity markets

Spot market prices have been extremely attractive recently compared to TVA rates. Over the last 5 years, MISO South spot prices for energy and capacity have averaged $31.55/MWh (all hours firm supply). In comparison, TVA costs averaged $69/MWh. In 2017, spot energy and capacity combined costs were $31.4/MWh versus approximately $74/MWh for TVA full requirements service. That is, market prices for power have been very low; TVA in 2017 had rates approximately 139% higher[76].

However, MISO's energy markets are day-ahead and real-time, and its capacity market extends out only to the upcoming year. As such, MLGW cannot hedge forward its needs very far by participating in MISO's formal spot markets exclusively. Spot energy prices depend heavily on natural gas prices, especially in southern parts of MISO, which historically has been one of the most volatile commodities traded, and heavily weather dependent. Spot capacity prices can also spike up unexpectedly, especially due to the use of a vertical demand curve in the MISO capacity market, the PRA. As shown in Exhibit 38, the tail end of MISO's capacity offer curve becomes extremely non-linear, so tightening in the market can result in a concomitant non-linear increase in capacity prices.

[76] This is not exactly apples to apples. There is a premium for on peak power not included in the MISO data. This is around 3-6$/mwh on the energy side; spot capacity is essentially free in MISO South, at least for reported prices in the planning resource auction.

Exhibit 38. MISO 2018/2019 Capacity Price Offer-Curve



Source: ICF using data from MISO

MLGW is a large enough consumer to influence the MISO-South merchant market, especially the spot capacity market

MISO South is dominated by Entergy, which largely meets its own needs through self-owned generation or long-term contracts. The merchant markets, while liquid in comparison to all other regions in the Southeastern US, might not be able to fully absorb MLGW without experiencing price increases, especially capacity price increases. This exists even if MLGW tries to buy longer-term energy in forward markets, since the physical power would still have to be procured from the same resource base. Put another way, historically low spot prices would not be a good benchmark if a load the size of MLGW joins the market. It should be noted that MLGW has limited energy requirement averaging 4 TWh, which is ~2% of MISO-South load, whereas the peak requirement (including reserves) is 3 GW which is ~9% of MISO-South load.

The MISO spot market is forecasted to tighten because of retirements exceeding builds over the next 3-5 years; if this does not happen, savings could be higher than estimated

Much of the IPP capacity was the result of builds 10 to 15 years ago. Over time, there have been significant retirements and few merchant IPP additions in this region. For example, TVA has retired 8.18 GW over the last ten years. This tightening increases the chances of price increases in both energy and especially capacity. MLGW's integration into MISO would hasten the tightening. While one might argue TVA adds as much capacity on the supply side as MLGW demands incrementally, TVA might have market power – i.e. is not a pure price taker unaware of the extent to which their decisions might affect prices.

Overall, we believe that the presence of spot markets in MISO does provide a benefit to MLGW in offering a competitive, liquid source of energy and for small amounts of capacity, and especially for opportunistic purchases when the prices are very low. Further, given that around 70% of MLGW's energy needs are met by the Bellefonte PPA at very stable pricing, some exposure to markets that may have even low but volatile costs can be manageable or even attractive. However, we do not recommend heavy reliance on these markets for going-forward needs.

8.2 Contracting with Existing Power Plants

A second option for MLGW involves purchasing or long-term contracting existing power plants. For reasons that will be discussed in greater depth in Chapter 10, if MLGW does join MISO, it becomes less costly to source power plants within the MISO footprint, especially for firm capacity that is the bulk of MLGW's remaining needs after Bellefonte. There are several ways MLGW can financially own a plant without owning the physical infrastructure.

- **Tolling contracts and other physical power purchase agreements:** these allow MLGW to purchase long-term physical power from a specific plant or portfolio, usually at a rate indexed to fuel prices plus a fixed payment. MLGW therefore owns either a portion of or the entirety of the physical output of a plant without owning the physical plant itself. This serves as a natural hedge: if the plant under contract becomes uneconomic over the long run, it means that market prices are necessarily less than the cost of the contract, so MLGW can source from the spot markets instead and its downside risk is capped by the contract. There is risk of high fuel prices, however, this is common across all cases, and downside risk is capped by the spot price.

- **Financial PPAs / contract for differences / heat rate call options, etc:** these function similarly to the physical contracts above, only they operate on a purely financial basis and do not track the power from plant to load. MLGW purchases physical power from the market and gets paid according to the revenues of the plant. Financial contracts for gas or power usually require mark to market collateral, or the potential need to post collateral. The amount of collateral required increases when there is a problem with the utility's financing, exacerbating the liquidity risks facing the utility. Also, the greater the volume and the longer the term, the greater the potential collateral requirements. Thus, there is usually a continual resetting of short term contracts to manage that risk. As a result, the gas or power prices generally then reflect the then current market conditions. Therefore, hedging against market risk is helpful but not perfect. This often leads to the purchase of powerplants which do not have this collateral risk.

- **Physical purchase of plants:** actual ownership of the equipment and the physical production of the plant.

Each of the above modes is common within MISO, and results in essentially the same stream of costs to MLGW (usually a fixed price plus a variable rate according to the capability of the plant). However, as we discuss, there is a discrepancy between our forecasts and market prices in that we expect the market to eventually tighten and have higher prices than recent spot prices, but the costs of buying existing gas fired powerplants is low. Alternatively, the market seems to have a very high, unrealistic discount rate or lack of buyers, and hence prices for existing plants are low.

The crucial difference between buying a plant and buying from the spot market is that MLGW can lock in its costs over the long term, and existing prices are very low.

The recent combined cycle (CCGT) transactions in SERC, TVA and MISO suggest a value of less than $400/kW. For example, Entergy recently purchased the Choctaw combined cycle for a value around 1/3 to 40% of replacement costs. Other recent transactions for gas plants in SERC have traded for similar values, often between 1/3 and 1/2 of replacement value, as shown in Exhibit 39. Savings can further be obtained in terms of initial price by buying peaking units versus CCGTs. Our analysis assumes a 1/3, 2/3 split in purchases between combined cycle and peaking gas fired power plants.

Exhibit 39. Recent Combined Cycle and Combustion Turbine Transactions in SERC

Year of Announcement	*PLANT NAME*	*OWNER*	*TECHNOLOGY TYPE*	*CURRENT OPERATING CAPACITY (MW)*	*BUYER NAME*	*SELLER NAME*	*Value ($/kW)*
2018	Choctaw Energy Facility	Entergy Mississippi	Combined Cycle	810	Jacksonville	GenOn Energy	387
2017	Decatur Energy Center	Capital Power Corporation	Combined Cycle	805	Capital Power Corporation	LS Power Development, LLC	489
2015	Ackerman Combined Cycle Plant (Quantum)	Tennessee Valley Authority	Combined Cycle	765	Tennessee Valley Authority	Investor group	447
2014	Union Power Facility	Entergy Louisiana, LLC	Combined Cycle	1980	Entergy Corporation/ Union power station	Entegra TC LLC	470
2014	Columbia Energy Center (SC)	LS Power Development, LLC	Combined Cycle	633.2	LS Power Equity Advisors, LLC	Calpine Corporation	402
2014	Decatur Energy Center	LS Power Development, LLC	Combined Cycle	805	LS Power Equity Advisors, LLC	Calpine Corporation	402
2014	Hog Bayou Energy Center	LS Power Development, LLC	Combined Cycle	245	LS Power Equity Advisors, LLC	Calpine Corporation	402
2014	Carville Energy Center	LS Power Development, LLC	Combined Cycle	545	LS Power Equity Advisors, LLC/ Power plant portfolio	Calpine Corporation	402
2014	Santa Rosa Energy Center	LS Power Development, LLC	Combined Cycle	247.9	LS Power Equity Advisors, LLC	Calpine Corporation	402
2013	Bayou Cove	Alexandria City of LA	Combustion Turbine	320	Alexandria City of LA	NRG Energy, Inc.	257
2012	Broad River Energy Center	Energy Capital Partners LLC	Combustion Turbine	984.8	Energy Capital Partners LLC	Calpine Corporation	434
2011	Calhoun Energy Center	LS Power Group	Combustion Turbine	752	LS Power Group	NextEra Energy, Inc.	441
2011	Cherokee County Cogeneration	LS Power Group	Combined Cycle	101	LS Power Group	NextEra Energy, Inc.	441
2011	Magnolia Combined Cycle Gas Plant	Tennessee Valley Authority	Combined Cycle	999	Tennessee Valley Authority	Kelson Energy Inc.	436
2010	Thomas A. Smith Energy Facility (Murray Energy)	Oglethorpe Power Corporation	Combined Cycle	1340	Oglethorpe Power Corporation	KGen Power Corporation	396
2009	Acadia Energy Center	Entergy Louisiana, LLC	Combined Cycle	1205.5	Entergy Corporation/ Acadia Power Partners unit 2		436
2008	Southaven Energy Center	Tennessee Valley Authority	Combined Cycle	891	Tennessee Valley Authority/ Southaven power plant	Goldman Sachs Group, Inc.	518

Source: ICF and SNL

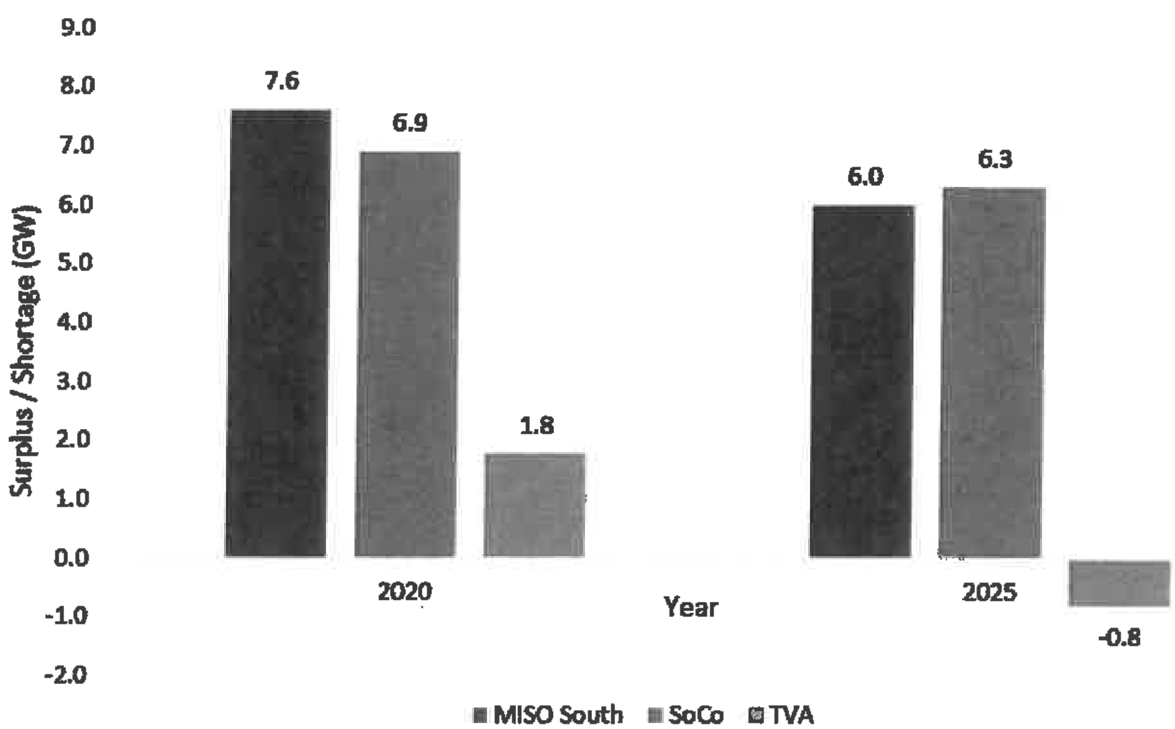
8.3 Supply/Demand Outlook and Available Plants

MLGW's ability to source energy, capacity and ancillary service from neighboring markets at reasonable rates depends in large part on the availability of excess capacity in those markets. In markets where supply is tight, buyers will either find a lack of available counterparties to contract or will have to pay very high prices since the bargaining power of suppliers increases non-linearly. Therefore, in order to establish whether MISO, Southern Company and TVA are viable options, we need to investigate the supply/demand dynamics of the markets. Second, a general understanding of the supply makeup in each market is important for understanding price formation and market dynamics over time.

At the same time, actual prices are also valuable indicators of current conditions. As noted, existing gas plants trade at discounts to replacement costs and MISO prices are way below TVA prices. This reinforces the conclusions regarding current excess capacity.

Over the last ten years, most of regions across US are experiencing low to flat demand growth driven largely by increasing penetration of energy efficiency. The three regions of interest MISO, Southern and TVA are expected to have peak and energy demand growth of 0.5%, 0.2% and 0.1%, respectively over 2019-2045 period. Exhibit 38 shows projected capacity surplus/shortage in 2018 and 2024 over the peak demand including target reserve margin requirement. Exhibit 37 shows capacity position considering expected firm new builds and retirements absent any unplanned builds/retirements, where Exhibit 39 shows capacity position considering both firm and unplanned builds/retirements. Of the three regions, MISO-South and Southern are expected to be long in 2025 with 6 and 6 GW of surplus capacity, respectively, whereas TVA is relatively short. A market with surplus will reflect a "buyer's market" and will allow MLGW to be able to better bargain the purchase or contract price relative to a market which is short in capacity ("seller's market") where buyer has limited choice.

Exhibit 40. Projected Capacity Surplus/Shortage in 2020 and 2025 by region adjusted for Economic Retirements (GW)



Source: ICF

The Exhibit 41 shows potential IPP contracting opportunities for the MLGW's incremental energy and peak requirement. As discussed in 6.1 section, MLGW would need around 3 GW of incremental capacity to meet its peak and reserve requirement. We have summarized the IPP capacity in MISO South, Southern and TVA, which MLGW can look at for buying or contracting. We have categorized the capacity as merchant un-contracted and merchant contracted and further by its cogen status. The contracted capacity is further broken down by its PPA expiration vintage (pre- and post-2023).

- Of 14 GW of contracted merchant capacity, there is over 4 GW of capacity where the PPA is expiring by end of 2023 (consistent with MLGW's contract expiration with TVA). Similarly, there is around 11 GW of merchant capacity, of which around 5 GW is cogen and remaining in non-cogen. While some of the cogen capacity may not be available due to its captive use requirements, but there would still be enough capacity that can help MLGW to meet its needs.
- TVA: TVA currently has limited excess capacity and any economic retirement will bring the system in supply/demand. However, migration of MLGW could delay the need for new capacity. By 2023, contract for two CCGT (Decatur and Morgan) will expire and these plants would be available in the market for re-contracting.
- Southern: Southern is currently long in capacity and there is around 6 GW of capacity which is either fully merchant or where the contract is expiring before 2024. Southern is projected to

have flat demand growth of 0.2%, so it is expected the long position will continue without further retirements.

- MISO South: MISO South is currently long in capacity and there is around 6 GW of capacity which is either merchant or where the contract is expiring before 2024. There is over 4 GW of cogen capacity and some of this capacity may not be available due its other captive and steam obligations.

Exhibit 41: IPP Capacity Available for Contracting

Utility Region	Tech Type	Cogen Capacity (MW)	Merchant Capacity (MW)	*Contracted Capacity(MW)*		*Total Capacity Regin wise (MW)*
				PPA Expiring before 2023	PPA Expiring after 2023	
TVA	CC		766	725	749	2240
	Coal				440	440
SERC-SE	CC	552	1434	2328	3647	7961
	Peaker		2024	632	2210	4866
MISO-South	CC	3316	1180			4496
	Coal	202		473	1349	2024
	OGS	100			575	675
	Peaker	974	300		210	1484
Total		*5143*	*5704*	*4158*	*9180*	

Source: ICF

8.4 TVA Partial Services Contract

TVA's wholesale rate structure includes two components: a demand charge and an energy charge. The demand charge is based on the customer's peak monthly usage and increases as the peak increases. The energy charge is based on the kilowatt hours ("kWh") used by the customer. The rate structure also includes a separate fuel rate that includes the costs of natural gas, fuel oil, purchased power, coal, emission allowances, nuclear fuel, and other fuel-related commodities; realized gains and losses on derivatives purchased to hedge the costs of such commodities; and tax equivalents associated with the fuel cost adjustments.

A comprehensive rate restructuring was approved by the TVA Board on August 21, 2015, and implemented on October 1, 2015 which is summarized as (see exhibit 42):

Exhibit 42. TVA Rate Tariff

Standard Service		
On Peak Demand Charge	Summer Period	$7.13 per kW of Onpeak Billing Demand per month
	Winter Period	$6.27 per kW of Onpeak Billing Demand per month
	Transition Period	$6.27 per kW of Onpeak Billing Demand per month
Maximum Demand Charge	Summer Period	$2.61 per kW of Maximum Billing Demand per month
	Winter Period	$2.61 per kW of Maximum Billing Demand per month
	Transition Period	$2.61 per kW of Maximum Billing Demand per month
Non-Fuel Energy Charge	Summer Period	3.670 cents per kWh per month (as adjusted by TOU Amount below)
	Winter Period	3.366 cents per kWh per month (as adjusted by TOU Amount below)
	Transition Period	3.243 cents per kWh per month
TOU Amounts to be added to Non-Fuel Energy Charge	Summer Period	
	During onpeak hours	1.5 cents per kWh per month
	During offpeak hours	-0.7 cents per kWh per month
	Winter Period	
	During onpeak hours	0.8 cents per kWh per month
	During offpeak hours	-0.2 cents per kWh per month

Source: TVA

ICF built up the wholesale rate for MLGW for full service using the above rate schedule and adding fuel charges to the rate. The rate comes out to be $71/MWh (see Exhibit 43).

Exhibit 43. TVA Full Service and Partial Service Build Up

	Non Fuel Energy Charge (million$)	On Peak Demand Charge (million$)	Maximum Demand Charge (million$)	Total Charge (million $)	Total Load (TWh)	Rate Excluding Fuel Cost ($/MWh)	Fuel Cost ($/MWh)	TVA Rate ($/MWh)
Full Service	479	189	72	740	14	52	19	71
Partial Service	96	78	30	204	3	75	19	94

Source: ICF

For partial service, ICF assumed that the baseload will be served by the Bellefonte 1 and the Memphis will be dependent on TVA only for the remaining energy requirement, i.e. Memphis will need only partial service from TVA. In this case, the partial service rate for Memphis when the baseload is served by Bellefonte 1 is calculated to be $94/MWh.

The 2015 energy demand of MLGW was used to develop the full-service requirement and partial service requirement rate for MLGW. On-peak demand charges and maximum demand charges were calculated for every month using the on-peak demand and maximum demand, whereas non-fuel energy charges were calculated for every hour according to the rates provided by TVA in 2015 rate schedule. A constant fuel cost of $19/MWh, mentioned in the TVA 10-K report is assumed in both full service and partial service rate.

8.5 Other Requirements Service Providers

Requirements service and the associated contracts are common and usually involves a large generating utility selling to the nation's very large number of public power buyers, mostly municipal and cooperative entities. MLGW's contract with TVA is an example. Traditionally, utilities sell via requirements contracts, as opposed to native sales, 10-25 percent of their total sales. Big potential providers near MLGW are TVA, Southern Company, and Entergy. Historically, much of FERC regulation was orientated around ensuring that requirements customers, as long as they were long-term firm customers, were not discriminated against by larger utilities, often IOUs in terms of rates to native load customers being lower. In the pre-open access transmission period, rates were primarily cost based and similar across similar customers in order to provide protection. Over time, FERC has migrated to greater emphasis on competition, especially in areas with RTOs.

Other companies can provide requirements service – e.g. a company with little or no generation. They can purchase the generation or contract for it and provide the same services that traditional requirements contractors provide.

8.6 Self-Build Options

As discussed earlier the cost of existing capacity is well below that of new capacity and thus with availability of existing from various markets, this option was not explored further.

9. Previous Experience Exiting TVA and TVA Response

MLGW is a Local Power Company (LPC) of TVA. It has wholesale power contract signed with TVA, which requires MLGW to purchase all of its electric power consumed from TVA[77] for the duration of the contract. Under the contract, MLGW buys power from TVA, and resells the power to their retail customers. Per the contract term with TVA, MLGW could choose to terminate the contract upon a five-year notice and find other power supply sources. However, there are certain risks or issues that should be considered for this move.

MLGW is TVA's largest LPC, and TVA's preference is to continue to sell power to LPCs. While LPCs have a legal right to terminate their service contracts with TVA, historical experience shows that TVA has resisted such departures. It also has made claims that its unique legal situation under the TVA Act and Federal Power Act is relevant to contract termination and LPCs obtaining alternative service.

9.1 Possible TVA Actions

9.1.1 TVA claims ability to set reintegration fees for returning load

In the event that a customer terminates its contract, and then wants to become a LPC, TVA may attempt to charge a reintegration fee. In historical cases, when several distribution customers, including WRECC, filed notice to TVA indicating their intention of terminating the contracts, TVA granted a period of only several months for them to rescind their notices without incurring reintegration fees.

9,1.2 TVA claims it does not need to provide transmission service because of the "anti-cherrypicking" provision: Federal Power Act 212(j)

Our understanding of TVA's claim is subject to the caveat that we are not offering legal opinions.

As discussed elsewhere in this report, TVA has made the claim, rejected twice in FERC decisions (once in its decision and once on appeal) that TVA may reject transmission service requests to parties similar to MLGW after it leaves TVA system.

TVA agrees that, all else equal, FERC, under FPA Section 211, has the jurisdiction to order a transmitting utility, to provide transmission services to other electric utilities per their applications. However, TVA also claims FPA Section 212(j) grants TVA exemption from this rule as it pertains to territory-restricted utilities like TVA. The provision states that no order issued under section 211 may require an electric utility, who is prohibited by federal law from selling power outside a defined area, to provide transmission services to another entity, if the power to be transmitted will be consumed within the area set forth for this utility[78].

TVA's service territory is restricted by law, and hence in TVA's view, it is the basis at least in terms of fairness, but also in law, that it receive special protection against competition under the Federal Power Act (FPA). The service territory of TVA is defined and restricted by the TVA Act. Specifically, per the requirement from the TVA Act, unless specifically authorized by the Congress or under certain minor exceptions, TVA cannot enter into contracts which would make TVA or its distributors "a source of power supply outside the area for which TVA or

[77] 10 K report, https://www.sec.gov/Archives/edgar/data/1376986/000137698615000047/tve-09302015x10k.htm

[78] FPA Section 212(j)

its distributors were the primary source of power supply on July 1, 1957"[79]. This provision restricts TVA's service territory to a historically defined area, and again in TVA's view lays out the foundation on which the FPA section 212(j) may be applied to TVA. The provision of the FPA 212(j), referred by TVA as the "anti-cherrypicking" provision, precludes FERC from ordering TVA under FPA section 211 ("under this chapter") to provide transmission access or services to others to serve the customers within TVA service area.

As noted here, FERC strongly asserts that open access transmission has a separate legal foundation (not within the chapter) namely in FPA Section 205 and 206. In the U.S FERC Order Denying Rehearing, June 20, 2006, Docket No. TX05-1-006, related to the ability to obtain transmission service on the TVA system (paragraph 22), FERC states that:

> *"our authority to implement portions of the open access policy established in the OATT (Open Access Transmission Tariff) derives from the requirement under sections 205 and 206 of the FPA (Federal Power Act) to remedy undue discrimination, not sections 210 or 211" (parentheticals added).*

There is a further statement that Sections 824 I, j, I, m shall not be construed to modify, impart or supersede the anti-trust laws and protections against unfair methods of competition.

It effectively, in our view, means there is a belt and suspenders basis for open access. The second part of the basis for open access, was the requirement that open access tariffs require reciprocity. Any entity that wanted to use open access transmission of a jurisdictional utility, had to reciprocate, and any agreement of the non-jurisdictional utility to accept reciprocity makes in incumbent on the jurisdictional utility to reciprocally provide open access. Also, there is nothing in section 211 that makes it the exclusive basis for requiring open access, and Section 212 j is also very specific that it only applies to 211.

As discussed, we are not aware of any utility not abiding by the reciprocity requirement because it would put it at a significant disadvantage in its operations. Indeed, much of the original discussion during the development of Order 888 was how to prevent jurisdictional utilities denying utilities like TVA open access. Further, it would have to renegotiate transmission arrangements in order to address reserve sharing, economic short- and long-term transactions, inadvertent power flows, and short-and long-term transmission across its system, anti-competitive issues, etc. However, problems notwithstanding, TVA still can decline reciprocal treatment; apparently, Congress left that open to TVA[80]. If TVA takes this step, which we do not think it will, MLGW has alternatives which even TVA would stipulate exist. These alternatives are discussed below in addition to seeking legal remedies.

TVA itself concedes transmission service is available under some circumstances. TVA in their most recent 10-k, on page 23 states:

> *"However, other utilities may use their own transmission lines to serve customers within TVA's service area, and third parties are able to avoid the restrictions on serving end-use customers by selling or leasing a customer generating assets rather than electricity".*

[79] TVA Act

[80] This is an interpretation of Congressional intent and is not based on any specific information appertaining to intent except section 212 j and 211, and the overall context.

Even though it appears to us that FERC will force TVA to provide transmission to MLGW, or require TVA not to be able to reciprocally have transmission under open access rules, TVA historically has cited the so-called "anti-cherrypicking" provision to reject transmission service request from its competitors and to appeal against associated FERC orders. When Warren Rural Electric Cooperative Corporation (WRECC) intended to leave TVA and signed an agreement with East Kentucky Power Cooperative (EKPC) for alternative wholesale power supply, EKPC asked TVA to provide transmission access to deliver its power to WRECC. TVA denied the request saying that it was not required to do so under the "anti-cherrypicking" provision. When FERC issued a final order directing TVA to provide interconnection services to EKPC, TVA, considering that such interconnection would generate un-compensated transmission service from TVA system, filed appeal in the U.S. Court arguing that this order was against the "anti-cherrypicking" provision; our understanding is that the case was not decided because there was a settlement. These examples show TVA's strong position and attitude in taking the "anti-cherrypicking" rule to protect itself from losing customers. Note, anti-cherry picking is terminology not mentioned in the act itself.

Elaborating on its view, TVA, asserts that not being not a public utility under the FPA, it is exempt from the requirement to provide open access non-discriminatory transmission services under the FERC Order No. 888. While that is strictly true, in our view, this minimizes the impact of the reciprocity rule. Continuing, TVA argues it has elected to voluntarily comply with this order and has launched its Open Access Same-time Information System (OASIS) to assist potential customers to obtain transmission services from TVA. It emphasizes in its Standards of Conduct that the compliance of these regulations are only "to the extent they are consistent with TVA's responsibilities under the TVA Act and other applicable law"[81]. TVA in its transmission service guidelines states that customers are not eligible for transmission services that FERC cannot order under section 212 (j) of the FPA[82].

If TVA successfully blocks a transmission service request for service to MLGW on the basis of the "anti-cherrypicking" provision or any other basis, MLGW would have to serve its load and meet NERC requirements using exclusively MISO or its own lines. This would include delivery of Bellefonte 1 power to MLGW; additionally, Bellefonte 1 would likely have to construct its own line to Southern Company territory to interconnect. As noted, TVA does not dispute this – i.e. they do not claim a territorial service territory.

9.1.3 TVA may attempt physical disconnection of MLGW from TVA grid

In previous cases where LPC customers tried to leave TVA, TVA has indicated that it would physically disconnect the customer's system from TVA system to avoid power flows from TVA to the load that has left without appropriate compensation. TVA claimed that this is standard operating procedure when customers leave and did this to the City of Bristol when they left in 1995 and threatened to do to Warren Rural Electric Cooperative when they attempted to leave in 2006. There is a possibility that TVA might attempt to disconnect MLGW system from the TVA grid when the contract is terminated, bringing difficulty for MLGW to source alternative power supply or reserve sharing arrangements from TVA. The practical result would be equivalent to denial of service under the anti-cherrypicking rule, but could introduce further complications around the physical substations and interfaces between MLGW's distribution and TVA's transmission grids.

[81] http://www.oatioasis.com/TVA/TVAdocs/Implementing.pdf

[82] http://www.oatioasis.com/TVA/TVAdocs/TVA_TSG_FY2018.pdf

We find this unlikely for the same reasons we find it unlikely that TVA will deny transmission service. Such an act may also be considered to be anti-competitive, and violating reliability provisions of the Federal Power Act.

MLGW's proximity to MISO also creates potential backup options should TVA win the right to disconnect, as described further elsewhere in this report.

9.1.4 TVA might attempt to impose stranded costs upon termination of the contract

Traditionally, stranded cost is associated with native load customers being relieved of the obligation to pay for costs in rates due to deregulation, and those costs not being recoverable in a competitive market. In such a case, the utility had the expectation it would serve the customer in perpetuity, and but for the deregulation, the costs would have been recovered.

In 1996, FERC adopted a definition of stranded costs caused by Order 888. This applied to requirements customers exiting contractual arrangements, resulting in assets whose costs cannot be recovered in a market situation.

Historically, TVA has attempted to impose these stranded costs on departing customers. TVA estimated the stranded costs using the FERC "revenue loss" methodology, which calculates the potential wholesale revenue loss due to the departure of a customer over a length of period that TVA expected the customer to stay in its system. When the 4-County Electric Power Association intended to leave, TVA estimated a stranded cost for it ranging from $57 to $133 million[83]. When the City of Bristol, Virginia considered leaving, TVA estimated its stranded cost allocation as around $54 million[84]. These costs are significant: 4-County Electric Power Association and the City of Bristol have annual electric consumption of around 1.1 TWh and 0.9 TWh respectively, compared to MLGW's 14 TWh. These so-called stranded costs mainly arose from TVA's uneconomic nuclear assets and high debt rate. TVA might attempt to impose stranded costs if MLGW intends to leave. Based on a rough calculation from FERC methodology, we estimate that the stranded cost might be around $350 to $500 million.

Prior experience also shows that TVA is willing to negotiate these charges. In the example of the City of Bristol (VA), the City ultimately reached an agreement with TVA where Bristol would not be charged for stranded costs, but would purchase transmission and ancillary services from TVA. If MLGW could negotiate to get similar arrangements, it might be exempt from the stranded cost charge.

Whether or not it negotiates, TVA's ability to impose stranded costs is questionable. First, it has been ten years since Order 888, and if TVA wanted to change the contract to have a stranded cost component, it could have. Second, if it was concerned, if could have lengthened the contract termination from 5 years.

[83] https://books.google.be/books?id=9G6zqNvscVQC&pg=PA36&lpg=PA36&dq=bristol+leaving+TVA+stranded+cost+calculation&source=bl&ots=ujohqUgcgH&sig=aRkMLgSicT56-vj5B1twOHRtglM&hl=en&sa=X&ved=2ahUKEwiB9raYlczcAhUCl6wKHbZLAn0Q6AEwAHoECAAQAQ#v=onepage&q&f=false

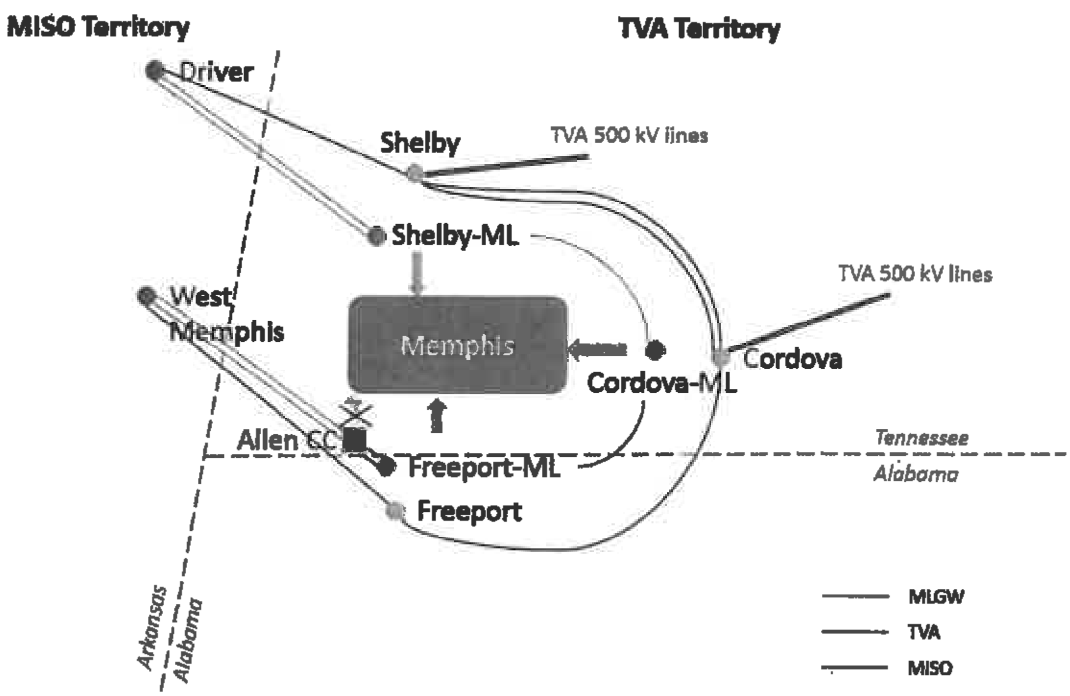
[84] https://books.google.be/books?id=9G6zqNvscVQC&pg=PA36&lpg=PA36&dq=bristol+leaving+TVA+stranded+cost+calculation&source=bl&ots=ujohqUgcgH&sig=aRkMLgSicT56-vj5B1twOHRtglM&hl=en&sa=X&ved=2ahUKEwiB9raYlczcAhUCl6wKHbZLAn0Q6AEwAHoECAAQAQ#v=onepage&q&f=false

9.2 Direct interconnection to MISO

Nevertheless, if TVA is able to disconnect and or deny service, MLGW can invest in transmission to maintain its ability to source power and keep reliability according to NERC standards. As the existing Driver-Shelby and West Memphis – Freeport connections are owned by TVA, MLGW will need to build its own connections with MISO for power intake and transmit the power into Memphis city. One option is to replicate the existing transmission configuration surrounding Memphis to avoid a cross board disturbance and thus needs for reconfiguration within MLGW. Therefore, the proposed transmission projects include three new substations at the same location as Shelby, Cordova, and Freeport, and the same parallel horseshoe 500 kV connection looping Driver – Shelby – Cordova – Freeport – West Memphis.

The three new substations will take over the corresponding load serving lines owned by MLGW as shown in Exhibit 44 Furthermore, the MISO-MLGW connections need to be double-circuited to ensure reliability under N-1 contingency conditions. This is mainly due to two reasons. First, at the moment the 1,200 MW Allen CC serves MLGW directly and can provide close to a third of its peak demand; with Allen removed from the Memphis transmission area the total MLGW demand would rely on power injection from the new Shelby, Cordova, and Freeport substations. Second, within the existing system, power can flow into Shelby, Cordova, and Freeport through multiple 500kV lines including the two from MISO and another three from inner TVA to Shelby and Cordova; in the disconnection case Memphis loses power injection from TVA and would solely depend on MISO import.

Exhibit 44. Memphis-TVA physical disconnection case



Source: ICF

ICF estimated the costs to build the proposed incremental transmission facilities using the Jobs and Economic Development Impacts (JEDI) Transmission Line Model developed by National Renewable Energy Lab (NREL). We assume that all of the proposed MLGW transmission projects are 500 kV AC lines and line lengths are based on ABB's Ventyx database. Exhibit 45 below lists the costs to build and maintain the new lines.

Exhibit 45. Cost to Build and maintain new lines

From Bus	To Bus	Voltage (kV)	length (mile)	# of circuits	Capital Cost (million 2018$)	Annual O&M Costs (million 2018$)
Freeport -ML	West Memphis	500	15	2	129.2	0.32
Shelby-ML	Driver	500	18	2	132.8	0.33
Shelby-ML	Cordova-ML	500	20.5	1	99.6	0.32
Freeport -ML	Cordova-ML	500	25.3	1	109.2	0.38
Total			**111.8**		**470.8**	**1.35**

Source: ICF using data from PowerWorld and Ventyx

Additionally, ICF also tested this configuration through load flow modeling using PowerWorld and identified system upgrades required for the configuration change. This physical disconnection case was constructed based on the same SERC power flow case as described in section 5.3. We first implemented the configuration change. After that, as MLGW demand will all be sourced from MISO import, we assume that the Bellefonte plant is interconnected within Southern and the remainder demand met by Southern and MISO generation. That is, we dispatch down TVA generation on a pro rata basis by the size of MLGW demand, inject Bellefonte within Southern, and scale up MISO South and Southern generation proportionally by the delta between MLGW demand and Bellefonte output. ICF tested 3390 N-1 contingencies for the physical disconnection case to identify thermal and voltage violations under contingency conditions. Exhibit 46 below shows the overloaded lines in the physical disconnection case. One of the lines is in TVA, an Affected System in this case, while all other violations are in MISO South. We estimate the system upgrade costs using NREL's JEDI Transmission Line model as developed earlier, assuming that the overloaded lines would be double-circuited.

Exhibit 46. Overloaded Lines in Physical Disconnection

Lines	Voltage	Ending Bus Area	Affected System	Loading %	Bellefonte to MLGW Shift Factor	Length (mi)	Est. Cost per Mile	Total Cost
3PINNACLE! to 3NATURAL STP	115	MISO.S-AR	N	100.5%	0.04%	5	$2.87 M/mi	$16.5M
3NATURAL STP to 3MAYFLOWER%	115	MISO.S-AR	N	102.3%	0.04%	5	$2.87 M/mi	$16.5M
5BATESVILLE to 5TALLHACH IP	161	TVA	Y	109.2%	1.87%	4	$3.03 M/mi	$12.6M
5OXFORD MS to 5BRTTNY WDS	161	TVA	Y	112.5%	3.18%	0.5	$16.94 M/mi	$8.4M
3PLUM POINT to 3GREENBROOK	115	MISO.S-MS	N	106.9%	0.28%	6	$2.3 M/mi	$14.7M
3GREENBROOK to 3HORN LAKE!	115	MISO.S-MS	N	123.9%	0.28%	3	$3.82 M/mi	$11.3M
3HORN LAKE! to 3DESOTO MS	115	MISO.S-MS	N	155.8%	0.67%	3	$3.78 M/mi	$11.4M
Total								$91.4M

Source: ICF using data from PowerWorld and Ventyx

Again, as the Bellefonte to MLGW shift factor for all overloaded lines are below 5% such costs would not be allocated to Bellefonte or MLGW.[85] TVA might argue that despite of the physical disconnection of MLGW, as the existing TVA-MISO lines remain intact, the physical power still flows through TVA's system in Tennessee and Mississippi, wheels through MISO, and comes back to MLGW, rather than completely looping through Southern and MISO. That would be the most extreme case and further studies would be needed to tackle the actual physical flow impact on the TVA system.

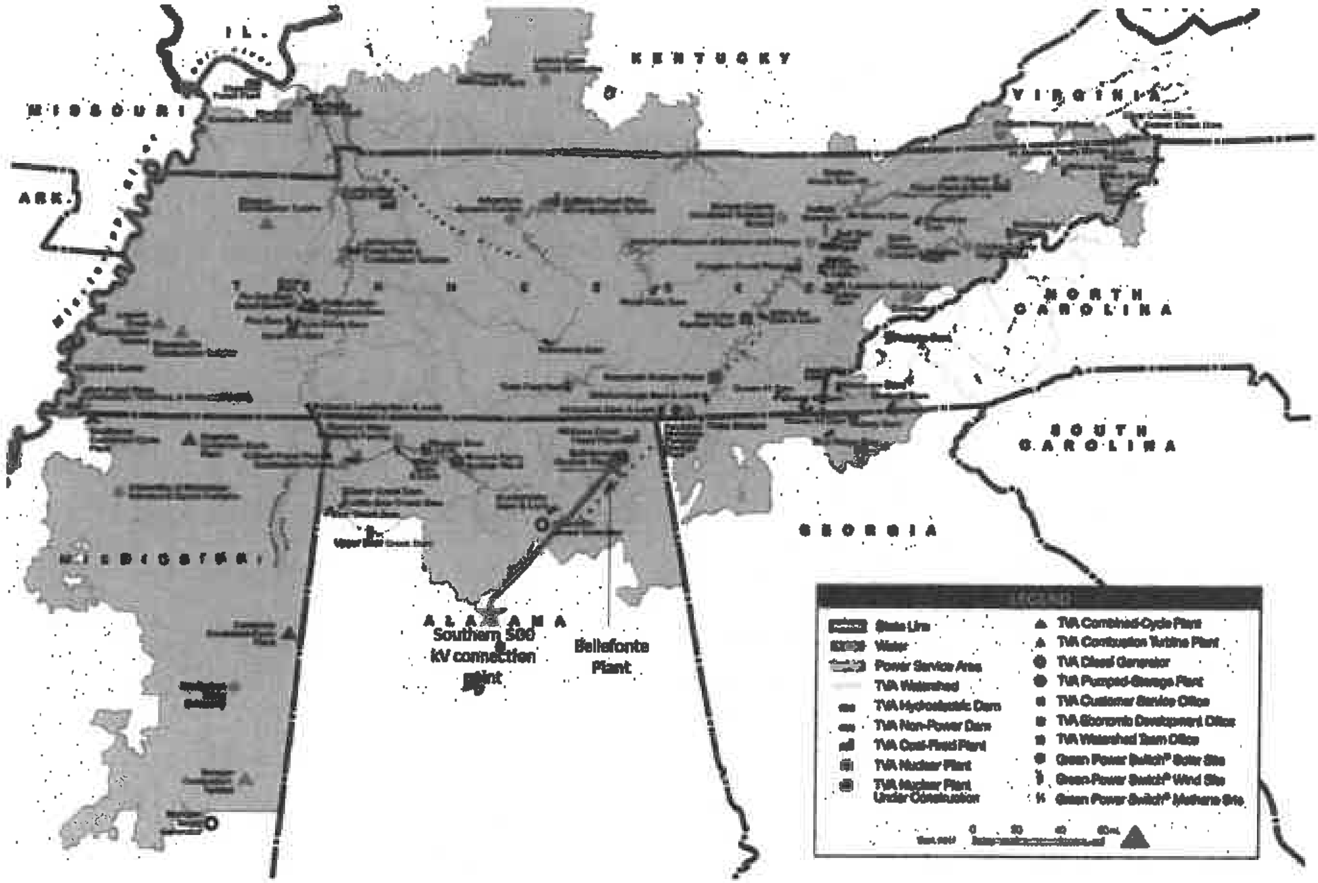
Denial of transmission: Bellefonte can interconnect with Southern

A related issue to denial of transmission service to TVA would be denial of firm transmission from Bellefonte. In effect, Bellefonte could be prevented from using TVA lines, since its power would be flowing to MLGW. In this case, Bellefonte, which sits in TVA territory, would have to construct its own line out of TVA territory and interconnect in a neighboring grid. The most logical choice is Southern Company.

As discussed in Chapter 5.3, ICF estimated the deliverability of Bellefonte to MLGW using a case in which Bellefonte interconnects in nearby Southern Company territory. Our modeling indicates that little to no grid upgrades would be needed, except the dedicated new line to get power from the Bellefonte site directly to the Southern Company grid. Exhibit 47 below shows the location of this line.

[85] For TVA lines, impacts on affected systems are not required to be ameliorated if the shift factor is very small – i.e. the percentage of the injected power flowing on the affected system element is < ~5% or some similar lower percentage. For the MISO lines, MISO's generator interconnection manual notes that if a study generator does not contribute more than 5% of the DFAX (shift factor) on any flowgate with a loading violation, it is considered fully deliverable.

Exhibit 47. Bellefonte Interconnection with Southern



We estimate the cost of this line to be approximately $273 million of capital investment plus an operation and maintenance cost of $1.5 million per year, or an equivalent of $3/MWh when annualized and compared to Bellefonte's output.

10. MLGW System Operations

10.1 Alternate Contractual Arrangements

MLGW may need to establish an alternative operating structures and arrangements in order to procure power from Bellefonte. The most important decision to make is how it will balance its system power supply and demand. Based on the different choice of Balancing Authority (BA), different regulatory and operational requirements shall be considered, and different arrangements will be made in terms of power supply, compliance of reserve requirements, transmission services, etc. We describe in this section three alternative structures that MLGW could pursue. For each option, we discuss the potential arrangement of the following aspects:

- Power supply source
- Compliance of contingency and regulation reserve requirements
- Transmission services
- Infrastructure development
- Personnel costs
- Administrative costs

10.1.1 TVA as Balancing Authority

In this option, MLGW will become only a partial customer of TVA. Instead of buying wholesale power only from TVA, it will be allowed to shop for more competitive power supply. TVA will continue providing wholesale dispatch and balancing services for MLGW. Similar arrangements have been made for smaller LPCs in TVA. The specific arrangement of this option are discussed below:

- **Power supply source**
  MLGW will look for more competitive power supply source within TVA territory. It may choose to contract with Independent Power Producers (IPPs) with lower rates than TVA. MLGW can take TVA power as backstop resource.

- **Compliance of contingency and regulation reserve requirements**
  TVA, as the balancing authority, will take direct responsibility for complying with NERC reliability standards, including meeting the contingency and regulation reserve requirements. Since MLGW will become a partial customer, it is a possibility that TVA will seek to recover some of the compliance costs from MLGW. For example, TVA might set certain reserve requirements for MLGW. For example, having a large contingency (loss of Bellefonte 1) might increase total operating reserve requirements, and the costs presumably would be allocated to MLGW. In this case, MLGW will be responsible for owning or contracting enough capacity to meet these requirements.

- **Transmission services**
  MLGW would not need to purchase firm transmission services from as the TVA rate charged to MLGW would already include charges for firm transmission

- **Infrastructure development**
  No major infrastructure development will be needed in this option. MLGW will be able to continue using existing TVA grid and associated meters. The existing billing infrastructure can handle the billing. Memphis becomes a sink in TSIN to allow the power to be scheduled to Memphis by the supplier. Confirmation of the schedules should be able to be handled by the existing personnel or it could be set up as an auto confirmed schedule.

- **Personnel costs**
  There is minimal to no incremental personnel cost for this arrangement. The existing billing area of the utility should be able to handle the supplier bills and TVA bills. While the utility could add an energy contract manager position to facilitate the creation of RFPs for additional supply and serve as the contact point for TVA and suppliers, they could also contract for the service

- **Administrative Costs**
  Balancing authorities incur costs for providing reliability coordination and system operation services, and for paying FERC administrative fees. For this case it is assumed that TVA administrative costs would be continued to be recovered through their rates.

10.1.2 MISO as Balancing Authority

In this option, MLGW will join the MISO market as an RTO member. MISO will provide all market services for Energy, Operating Reserve, and Transmission Service. Specific arrangements of this option are discussed below:

- **Power supply source**

  MLGW will source alternative power supply from the MISO market, either by spot purchase from the energy market or by contracting with IPPs within MISO territory.

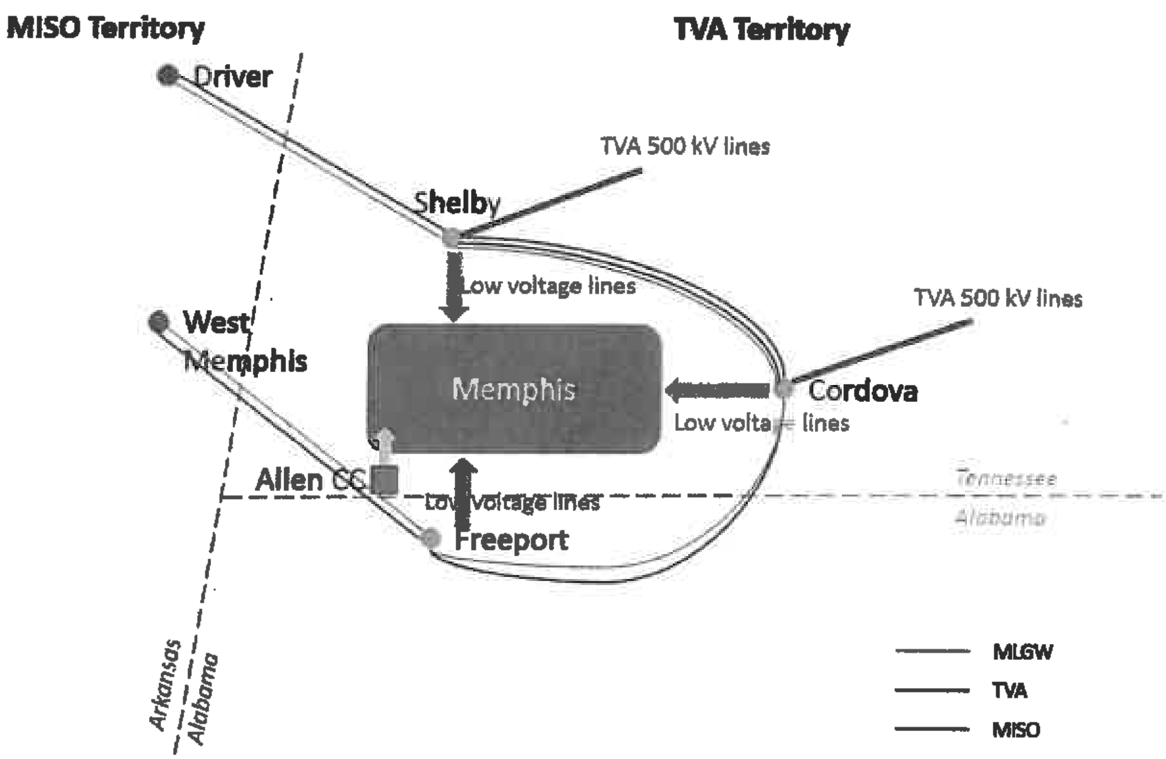
- **Compliance of contingency and regulation reserve requirements**
  In this option, MISO as the balancing authority will take direct responsibility for complying with NERC reliability standards, including meeting the contingency and regulation reserve requirements. MISO assigns Resource Adequacy (RA) requirement to individual load serving entities (LSEs). LSEs can choose to comply by either bilateral contracting or participating in the MISO capacity auction. As such, it is possible certain costs might have to be borne by MLGW to meet its RA requirement other than what ICF have assumed for this case.

- **Transmission services**
  As a member of the MISO RTO, MISO allocates the cost of transmission projects to its members. As a result, ICF assumes that these costs will be allocated to MLGW as well when they join the RTO. No other transmission related cost has been assumed for this case. [86]

[86] ICF's preliminary analysis does not show any significant cost due to violations on the Entergy Arkansas system and hence no additional cost is being assigned.

- **Infrastructure development**
  It is assumed that the existing billing infrastructure can handle the billing with the supplier and MISO. Additionally, it is also anticipated the existing Transmission and Distribution (T&D) Control Center can handle all communications with MISO as they do now with TVA. Lastly, in order to receive its incremental needs, MLGW will have to build its own transmission lines to receive power from MISO South. ICF assumes that MLGW will construct a line that connects Driver – Shelby – Cordova – Freeport – West Memphis to receive power from MISO. Exhibit 48 shows the loop described before.[87]

Exhibit 48. Loop Connecting Driver – Shelby – Cordova – Freeport – West Memphis



- **Personnel costs**
  It is expected that a small number of new full-time equivalents will be necessary to support this option. In addition to a contract manager, a full time MISO regulatory support person, and an additional settlements person would be required.

- **Administrative costs**

  MLGW would have to pay MISO administration fee as MISO handles operating the market and for providing other services to their footprint. An additional annual FERC charge would also be levied on MLGW.

10.1.3 MLGW as Balancing Authority (BA) - Pseudo tie load with MISO

Under this case, MLGW will establish themselves as a BA and will exit TVA. For its incremental needs beyond Bellefonte, MLGW will source power from MISO. While MLGW can rely solely on imports from MISO there are reliability concerns associated with this option. Therefore, ICF proposes that MLGW pseudo ties its load with MISO. Pseudo tie refers to the situation in which there is firm transmission, and dispatch is directed by another entity. In this case, MLGW would act more like a local balancing authority in MISO.

Specific arrangements of this option are discussed below:

- **Power supply source**

  Loads pseudo-tied into MISO are included in the Local Balancing area load calculation and assigned a Load Zone defined in the MISO LBA. The load will be subject to the MISO Energy and Operating Reserves Market and accounted for in centralized dispatch. MLGW will be responsible for short-term supply adequacy and long-term supply adequacy. Improper supply options will lead to compliance and potential reliability issues, as well as greater cost than anticipated.

- **Compliance of contingency and regulation reserve requirements**

  Similar to the previous case (10.1.2), MISO will take direct responsibility for complying with NERC reliability standards, including meeting the contingency and regulation reserve requirements. However, the responsibility of securing a contract for such services might fall on MLGW.

- **Transmission services**

  MLGW will need to purchase firm transmission services from MISO to deliver power from its contracted resources to their load centers. MISO requires that a non-interconnected network load which is pseudo-tied into MISO be part of a pricing zone in MISO, so that they are subject to that rate for network service.

- **Infrastructure development**

  The infrastructure required in this case would be similar to what was discussed in section 10.1.2

- **Personnel costs**

  Similar to the previous case, it is expected that a small number of new full-time equivalents will be necessary to support this option. In addition to a contract manager, a full time MISO regulatory support person, and an additional settlements person would be required.

- **Administrative costs**

  Since the load would be dispatched by MISO, ICF assumes MLGW will still be charged MISO's administration fee. Similar to the MISO as Balancing Authority case, MLGW will pay FERC fees as well.

10.1.4 MLGW as Balancing Authority- Stand Alone Utility on Wholesale Level

Under this case, MLGW will establish themselves as a utility and will exit TVA. For its incremental needs beyond Bellefonte MLGW will contract with either TVA or MISO to fulfill those needs. MLGW will also be responsible for securing reserve on its own.

The specific arrangements of this option are discussed below:

- **Power supply source**
  MLGW will operate independently. Apart from firm supply from Bellefonte, MLGW will need to contract or build and operate assets to provides all their incremental energy and capacity needs.

- **Compliance of contingency and regulation reserve requirements**
  MLGW will need to contract or build and operate assets to provides all their ancillary service needs. MLGW can join existing reserve sharing groups but these agreements have to be negotiated with the entities and may have a lengthy application process.

- **Transmission services**
  MLGW will need to purchase firm transmission services from MISO/TVA to deliver power from these markets to their load centers. While procuring capacity and energy from TVA is certainly possible, the uncertainty revolving around TVA's use of the anti-cherrypicking provision makes it challenging to assess such a case.

- **Infrastructure development**

  It is assumed that the existing Memphis T&D Control Center can be utilized for Dispatch but a Dispatch System that allows the Dispatchers to match supply to the load and to meet NERC compliance requirements will be required. There will also need to be other systems to support scheduling and trade capture. Lastly, if MLGW would contract or import power from MISO, similar to 10.1.2 then in order to receive its incremental needs, MLGW will have to build its own transmission lines to receive power from MISO South. ICF assumes that MLGW will construct a line that connects Driver – Shelby – Cordova – Freeport – West Memphis to receive power from MISO.

- **Personnel costs**
  MLGW will have to add a significant number of full time equivalents in order to operate independently outside of TVA or MISO. The discussion below does not address compliment required if they decide to build and operate their own assets, but assumes the assets are contracted but dispatchable by MLGW –

  - **Generation Dispatch** – it is assumed that MLGW while contracting for a large portion of firm supply with Haney will need either contracted dispatchable or owned flexible supply (generation or demand response) to meet their spinning reserve, standby reserves, and regulation obligation. While this function can be contracted, if staffed, they will need 5 Dispatchers.
  - **NERC Compliance and Training** – MLGW will now have responsibility at a minimum for Generator Operator and BA Operator NERC Compliance requirements. They also will need to provide training for their Generation Dispatch team and create protocols to show compliance with NERC compliance standards. At a minimum, they will need 2 Compliance/Training coordinators.
  - **Trading** – MLGW will need the ability to hedge to reduce risk as well as buy physical power, both long and short term, to balance their load obligations. It is assumed they will need 2 traders. Initially, it is assumed that they will not require a full-time real time trading desk and will balance their load with the dispatch desk using owned and contracted assets.

- **Scheduling** – MLGW will need a scheduler that can reserve transmission for the traders and confirm schedules. They will need to be knowledgeable on the transmission paths around the area and the system used to reserve and confirm scheduled transactions.
- **Back Office** – MLGW will have to add additional capability to receive, reconcile, and pay invoices. While it is assumed that existing infrastructure can manage a large portion of this, at a minimum a single person should be added.
- **Contract Management/Legal/Regulatory** – Similar to previous cases a contract manager is needed. In addition, it is assumed a full-time attorney knowledgably in FERC and state requirements as well as a par-legal that can perform regulatory support would be required.
- **IT Support** – Additional infrastructure will be added to support the trading, scheduling and dispatch functions. There also will be support from IT required to support NERC compliance requirements, especially in the area of Cyber Security standards. It is assumed two additional IT personnel will be required in this case.
- **Other Support** – This case assumes that there are two full time equivalents required to provide support for tasks such as load forecasting, long range adequacy planning, etc.

- **Administrative costs**
  MLGW will pay FERC fees similar to previously discussed cases.

According to the analysis above, we summarize the various constructs and their associated costs for each option in Exhibit 49.

Exhibit 49. Summary of Regulatory Construct

Alternative Structure	TVA as BA	MISO as BA	MLGW as BA		
			Pseudo tie load into MISO	**Contract with TVA resources**	**Contract with MISO resources**
Power supply	TVA resources	MISO resources	MISO resources	TVA resources	MISO resources
Compliance of reserve requirements	TVA	MISO RA requirement	MISO RA requirement	TVA	MISO RA requirement
Transmission service costs	YES - TVA	NO	YES - MISO	YES - TVA	YES - MISO
Allocated system transmission costs	NO	YES	NO	NO	NO
Infrastructure development costs	NO	YES	YES	NO	YES
Personnel costs	YES - Low	YES - Medium	YES - Medium	YES - High	YES - High
BA Administrative costs	YES - TVA	YES - MISO	YES - MISO	YES - MLGW	YES - MLGW
FERC Administrative costs	YES	YES	YES	YES	YES

10.2 Assessment of Cost

Having discussed the basic structure of each alternative regulatory arrangements, we provide a quantitative assessment of regulatory cost for each option in this section.

10.2.1 Regulatory Costs – TVA as Balancing Authority

Additional regulatory costs associated with this case are minimal. As highlighted before TVA administrative costs are recovered through TVA rates. The only other additional cost considered for this case is if Memphis chooses to engage a contract manager. Therefore, the estimated costs are presumed to be the current cost (already covered by the TVA rate) plus additional personnel cost. ICF expects the first-year cost of this case to be approximately $175MM. This case is considered as the status quo state.

10.2.2 Regulatory Costs – MISO as Balancing Authority

A breakdown of the methodology for estimating the regulatory cost for this case is discussed below -

- **MISO Administration Fee:** MISO 's administrative costs were estimated using $/MWh cost projections presented in the MISO 2017 Budget presentation published on their website and applied to MLGW's Energy for load projections. ICF grows the admin fees using 2018-2022 real cumulative growth rate along with inflation throughout the forecast horizon.

- **FERC Fees:** For this analysis, the current FERC assessment charges in $/MWh were estimated based on historical data available in FERC Form 528 and were and applied to MLGW's Energy for load projections. ICF grows the FERC fees using 2015-2018 real cumulative growth rate along with inflation throughout the forecast horizon.

- **Transmission Allocation Cost:** MISO does not socialize the cost of all of the projects among their member and rather follows specific methodology based on project type and their beneficiaries to allocate the cost of new projects Exhibit 50 shows a breakdown of the allocation category and the allocation methodology.

Exhibit 50. Summary of MISO Cost Allocation Mechanisms

Allocation Category	Drivers	Allocation to Beneficiaries
Market Efficiency Project	Reduce market congestion when benefits exceed cost by 1.25 times	Distributed to Cost Allocation Zones commensurate with expected benefit, 345 kB and above 20 percent postage stamp to load.
Transmission Delivery Service Project	Transmission Service Request	Generally paid for by transmission customer, Transmission Owner can elect to roll in into local zone rates
Generation Interconnection Project	Interconnection Request	Primarily paid by the requestor, 345 kV and above 10 percent postage stamp to load.
Multi-Value Project	Address energy policy laws and/or provide widespread benefits across footprint	Postage Stamp to Load
Market Participant Funded	Transmission Owner-identified project that does not qualify for other cost allocation mechanisms; can be driven by reliability, economics, public policy or some combination of the three	Paid for by Market Participant
Baseline Reliability Project	NERC Reliability Criteria	Local Pricing Zone

Source: *MTEP 2017*

There are a number of complications associated with analyzing transmission allocation cost. For example, the cost of Generation Interconnection Projects (GIP) are primarily paid by requestors. Baseline Reliability Projects are only allocated to respective planning zones etc. Given the complexity around the cost allocation mechanism, ICF conservatively assumes that MLGW will be assigned cost from all projects that are expected to be shared regardless of the project type. Currently, MTEP 2017 lists approximately $6.6 billion of the transmission investments are on a cost sharing basis. ICF assumes that the cost of all these projects will be shared equally across all planning zones and MLGW will be allocated cost based on a MISO wide peak load shape basis. The allocated cost is grown throughout the forecast horizon using inflation. While this might over estimate allocated cost to MLGW however MISO might under take projects in the future cost of which could be shared with MLGW.

- **MLGW Operational Cost:** ICF assumes that the cost of hiring a full time MISO regulatory support person, and an additional settlements person would be required would be 300k to 350k per year, plus benefits at 40%, and will increase with inflation.

  Ownership of Transmission Lines: ICF assumes the cost of building a loop that connects Driver – Shelby – Cordova – Freeport – West Memphis to receive power from MISO will be on average $57.4 MM between 2024 and 2043.

ICF expects the first-year cost of this case to be approximately $73.2MM

10.2.3 Regulatory Costs – MLGW as Balancing Authority, Pseudo Tie Load into MISO

A breakdown of the methodology of estimating the regulatory cost for this case is discussed below -

- **MISO Administration Fee:** Similar to MISO as Balancing Authority case, ICF assumes the same methodology for calculating MISO administration fee.

- **FERC Fees:** Similar to the previous case an annual FERC charge would be assessed to MLGW. The cost was assumed using the same methodology as in MISO as a Balancing Authority case.

- **MLGW Operational Cost:** Similar to the MISO as Balancing Authority Case, ICF assumes that the cost of hiring a full time MISO regulatory support person, and an additional settlements person would be required would be 300k to 350k per year, plus benefits at 40%, and will increase with inflation throught the forecast horizon.

- **Network Integration Service Fees:** ICF assumes that MLGW will be charged Entergy Arkansas zonal rate. ICF uses the 2018 Zonal Rate reported attachment O of schedule and increases with inflation throughout the forecast horizon.

- **Ownership of Transmission Lines:** Similar to the MISO as Balancing Authority, in order to receive its incremental needs from MISO, MLGW will have to build its own transmission lines to receive power from MISO South. ICF assumes that MLGW will construct a line that connects Driver – Shelby – Cordova – Freeport – West Memphis to receive power from MISO. ICF assumes that the cost to build this loop will be on average $57.4 MM between 2024 and 2043.

- **Local Balancing Authority Charges:** Pseudo-ties are charged Schedule 24 (Local Balancing Authority Cost Recovery) cost. ICF grows the Local Balancing Authority Charges using 2015-2018 real cumulative growth rate along with inflation throughout the forecast horizon.

Overall, ICF expects the first-year cost of this case to be approximately $177MM.

10.2.4 Regulatory Costs – MLGW as Balancing Authority, Contract with TVA/MISO Resources

A breakdown of the methodology of estimating the regulatory cost for this case is discussed below -

- **FERC Fees:** Similar to the previous case an annual FERC charge would be assessed to MLGW. The cost was assumed using the same methodology as in MISO as a Balancing Authority case.

- **MLGW Operational Cost:** A cost breakdown by Personnel is shown in Exhibit 51.

Exhibit 51. Personnel Cost

Personnel	Cost
Generation Dispatch	700,000
NERC Compliance and Training	238,000
Trading	420,000
Scheduling	119,000
Back Office	105,000
Contract Management/Legal/Regulatory	350,000
IT Support	126,000
Other Support	224,000
Total	2,282,000

Additionally, ICF assumes that the cost of a CIP Secure Dispatch Platform is $5 to $7 million. There will also be a need for other systems to support scheduling and trade capture. ICF assumes the cost of such support systems would be $2 million. These one-time cost amount to approximately $9MM in the first year. A maintenance charge is assumed every year to maintain these systems. As a result, the cost drop significantly year two onwards as the one-time system installation cost to manage and scheduling dispatch etc. drop off. Throughout the forecast horizon, these costs are increased with inflation

- **Network Integration Service Fees:** ICF assumes that MLGW will be charged Entergy Arkansas zonal rate if it chooses to meet its incremental requirement for power from MISO. Similar to the Pseudo tie case, ICF uses the 2018 Zonal Rate reported attachment O of schedule and increases with inflation throughout the forecast horizon to account for Network Integration Service Fee.

  If MLGW chooses to meet the incremental requirement for power from TVA, since it is not a member of TVA anymore it will have to pay TVA's zonal rate. TVA's zonal rate was taken from OATI Oasis website and increased with inflation throughout the forecast horizon.

- **Ownership of Transmission Lines:** Similar to previous cases, in order to receive its incremental needs from MISO, MLGW will have to build its own transmission lines to receive power from MISO South. ICF assumes that the cost to build the loop from Driver to West Memphis will be on average $57.4 MM between 2024 and 2043. MLGW may not have to build these lines in case the incremental requirements are met from TVA, however, as highlighted before this is significant regulatory risk associated with that option.

Overall, ICF expects the first-year cost of this case to be approximately $95.6MM to $182MM depending on whether it contracts with resources in TVA or MISO.

A comparison of first year regulatory structures cost across each case is shown below in Exhibit 52.

Exhibit 52. Comparison of First Year Regulatory Structure Cost by Case

BA	TVA	MISO	MLGW		
Power supply	TVA resources	MISO resources	MISO resources	TVA resources	MISO resources
Regulatory Costs (2024) w/o MLGW Transmission Build	**175,000**	**26,390,649**	**130,922,358**	**95,641,127**	**135,301,062**
Regulatory Costs (2024) w MLGW Transmission Build	**175,000**	**73,161,440**	**177,693,149**	**95,641,127**	**182,071,852**
Allocated system transmission costs		18,124,276	0	0	0
MISO Administrative Fee		6,157,353	6,157,353	0	0
Local Balancing Authority cost		0	255,944	0	0
MLGW Operating Cost	175,000	490,000	490,000	11,282,000	11,282,000
Contingency reserve sharing group admin costs		0	0	0	0
FERC Administrative Fee		1,619,021	1,619,021	1,619,021	1,619,021
Transmission service costs (NITS)		0	122,400,041	82,740,106	122,400,041
Memphis Ownership of Transmission Lines		46,770,790	46,770,790		46,770,790

11. Cost-Benefit Analysis and Conclusions

11.1 Results

ICF analyzed the economics of several contracting strategies and are shown below in Exhibit 53. We report both gross and net savings relative to a "Business as Usual" (BAU). We define gross savings as the BAU case less the combined cost of the Bellefonte PPA plus incremental energy costs. We define net savings as gross savings less the costs incurred to implement a particular scenario. These cost incurred could include but not limited to the building of new transmission lines, the securing of firm transmission, and securing of physical reserves need to maintain the reliability of the Memphis distribution system.

11.1.1 Business As Usual (BAU)

Under the business as usual case, MLGW continues to purchase under TVA's full-service requirements contracts and the wholesale power costs reflect the average costs of service from TVA including average fuel, non-fuel O&M, purchased power, capital recovery, profits, etc. In 2024, costs are projected to equal approximately $1.1 billion. Over the 20-year period of 2024 to 2043 the average cost is $1.3 billion. This escalates over time in part as a function of general inflation, but also based on other factors (see Section 4.3 for a full review of our TVA rate projections). The TVA rate for LPCs has been in the range over the past 10 years (2008-2017) from a low of $62/MWh in 2008 to as high of $74/MWh in 2017, with about two-thirds of the rate reflecting recovery of fixed costs.[88] TVA rates have grown at an average of 2.2% per year over the past 10 years, and the rate is projected to grow at an average of 1.6% from 2024 to 2043. All the other cases that follow are discussed relative to this BAU case.

[88] Fixed cost includes fixed O&M, interest expenses, depreciation and tax equivalents.

Exhibit 3: Summary of Memphis Gross and Net Savings Relative a "Business as Usual" Case

Scenarios	Levelized Costs (2024-2043)	Cumulative Costs (2024-2043)	2024	2025	2030	2035	2040	2043
TVA Rate Cost - Business As Usual Case	1,260	27,424	1,075	1,097	1,245	1,356	1,490	1,587

Gross Savings: BAU Less Alternative Supply ($MM)	Levelized Savings (2024-2043)	Cumulative Savings (2024-2043)	2024	2025	2030	2035	2040	2043
Option #1 [TVA is BA / Partial Service Requirements from TVA]	374	7,883	307	315	377	410	452	485
Option #2A [MISO is BA / Inc. Power Hedged]	569	11,822	487	503	579	613	664	675
Option #2B [MISO is BA / Inc. Power Spot Market]	569	11,822	487	503	579	613	664	675
Option #3A [MLGW is BA / Inc. Power Hedged]	418	8,612	365	377	435	448	475	470
Option #3B [MLGW is BA / Inc. Power Spot Market]	418	8,612	365	377	435	448	475	470

Net Savings: Gross Savings Less Regulatory/Transmission Costs ($MM)	Levelized Savings (2024-2043)	Cumulative Savings (2024-2043)	2024	2025	2030	2035	2040	2043
Option #1 [TVA is BA / Partial Service Requirements from TVA]	374	7,879	307	315	377	410	452	485
Option #2A [MISO is BA / Inc. Power Hedged]	384	7,910	335	347	403	412	435	427
Option #2B [MISO is BA / Inc. Power Spot Market]	235	4,931	188	196	251	265	286	282
Option #3A [MLGW is BA / Inc. Power Hedged]	254	5,134	231	240	279	269	270	248
Option #3B [MLGW is BA / Inc. Power Spot Market]	104	2,155	84	89	127	122	121	103

Source: ICF

2.4.2 Bellefonte PPA Plus Physical Hedges to Cover Incremental Needs [89]

Most Economic Strategy: MLGW becomes part of MISO, purchases Bellefonte 1 power plus incremental MISO power, and buys contracts / existing powerplants as part of a physical sedging Strategy to further control the volatility of incremental power costs.

2.4.2.1 Results

We consider this the main alternative procurement strategy for MLGW compared to the BAU case. This is because it does not depend on the approval of TVA, does not have heavy reliance on unhedged spot market purchases for incremental power, and has the most savings relative to BAU. The annual gross savings is estimated at almost $487 million in the first year. The annual average net savings is estimated at $384 million per year, and $335 million starting in 2024, the first year of this study.[90] This is referred to Option #2A in the exhibit above. This is over a 30% savings in 2024 relative to the $1.1 billion in cost from the BAU case. This savings primarily reflects the lower costs of Bellefonte PPA; the PPA costs equal the variable costs of TVA and

[89] Also referred to as $25/kW-yr case. This is because the upfront purchase of the plants costs $25/kW-yr (i.e. fixed costs less energy margins) rather than forecasted higher levels due to eventual tightening in the market for capacity.

[90] Net savings is defined as gross savings less the costs incurred to implement a particular scenario. These cost incurred could include but not limited to the building of new transmission lines, the securing of firm transmission, and securing of physical reserves need to maintain the reliability of the MLGW distribution system.

allows MLGW to effectively avoid paying TVA's fixed costs. Savings per MLGW customer equal approximately $890 per year. As another perspective on the significance of the savings, in comparison, the 2019 annual projected budget of the Memphis excluding MLGW is approximately $685 million.[91] Over 20 years, cumulative savings gross is projected at $12 billion, and net savings cumulative is projected at $8 billion.

In addition to purchasing Bellefonte power and the associated firm transmission for delivery, MLGW purchases the needed transmission service to become part of MISO, or builds the transmission to directly interconnect, whatever costs the least. Large transmission lines link MLGW to TVA and then across the river to contiguous MISO. Where new lines are needed, the distance to key MISO substations would likely be small (~75-100 miles). Our estimate includes the cost of new line construction.

2.4.2.2 Hedging and Capacity Costs

MLGW would also purchase contracts / existing powerplants located in MISO to partly hedge against price volatility of incremental power – i.e., to hedge the approximately 30% of energy and 3,000 MW of capacity not covered by the Bellefonte PPA (this capacity covers peak plus required reserves[92]). This would supplement MLGW's main hedge in the Bellefonte PPA that has costs that are largely fixed. This "buy-capacity-now" hedge strategy is attractive because there is excess capacity in the wholesale power market that can be locked in via purchases of capacity. Recent comparable transactions (i.e., powerplant sales) strongly support the view that existing combined cycles can be purchased at approximately 40-50% of replacement costs.[93] These plants provide hedges against the potential for higher MISO energy and capacity prices later on. We assume these plants, a mix of combined cycles and peakers, can be purchased at $230/kW.[94]

These plants can also hedge their fuel costs, but the hedge most likely will have to be renewed periodically at prices then prevalent – i.e., it not a perfect hedge on its own[95]. Other hedging strategies may also exist. In addition, other capacity purchases may be economic including some peakers and other plants – e.g., existing renewables, otherwise-retiring coal plants, etc. These strategies would be investigated as part of the partial requirements contracting MLGW would undertake.

2.4.2.2 Recent Spot Prices versus ICF Forecasts

ICF forecasts the economics of this arrangement including future power prices using industry standard computer modeling as described in the appendix. This forecast shows rising spot prices. However, it should be noted that MISO spot prices have been very low, and if power were to be available in the future at these low prices, even greater savings would occur. Over the last 5 years, MISO prices, energy and capacity have averaged

[91] https://www.memphistn.gov/UserFiles/Servers/Server_11150732/File/Gov/Financial%20Division/FY_2019_Adopted_Budget/Budget%20Overview.pdf

[92] We focus here on energy and capacity because these are the largest wholesale services. Also required is transmission, ancillary services (usually thesmallest portion afterenergy, capacity and transmission), and system operations. We account for all of these items and is discussed in later sections.

[93] Choctaw at less than $400/kW in August 2018. Choctaw interconnects with TVA and Entergy.

[94] We estimate an 1/3 combined cycle and 2/3 simple cycle combustion turbine mix based on the incremental load requirements of MLGW after Bellefonte 1 capacity is considered.

[95] Long term financial hedging can require mark to market collateral requirements, and hence, long term financial hegding is not typical practice. Hedging is unlikely to be perfect, due to basis differences, but likely to be efficacious overall.

$31.55/MWh. In comparison, TVA costs averaged $69/MWh. In 2017, spot energy and capacity combined costs were $31.4/MWh versus approximately $74/MWh for TVA full requirements service. That is, market prices for incremental power have been very low; TVA in 2017 had rates approximately 139% higher[96]. We do not recommend exclusive reliance on spot sales alone without hedges for incremental power in part because we expect higher capacity prices in particular over time, but the exact extent of hedging as opposed to spot or short-term transactions would be determined over time.

The hedging costs assume that the capacity purchased is located in MISO and has no basis difference[97] with MLGW. If the capacity is purchased outside of MISO, additional transmission charges may be needed in order to sell the power output of the capacity in MISO. However, even if plants are purchased outside MISO, they may still generate revenue from power than can be sold outside MISO[98]. If half the capacity is bought outside MISO and one wheel of firm transmission to MISO is required, then costs increase tens of millions of dollars per year.

Finally, there are additional costs incurred in becoming part of MISO, namely the socialization of on-going and future transmission infrastructure and MISO admission fees.

A variation on this "buy-capacity-now/soon" strategy was analyzed with MLGW being is own Balancing Authority (BA). We referred to this as Option #3A in the Exhibit above. Savings are less than in Option #2A as the cost of securing firm transmission to access contracts in the MISO market outweighs avoiding the costs of joining MISO.

2.4.3 Bellefonte PPA Plus Spot Market to Cover Incremental Needs [99]

In this case, MLGW becomes part of MISO, purchases Bellefonte power plus incremental MISO spot power, and does *NOT* hedge – e.g., does not buy contracts /existing powerplants as part of a hedging strategy for incremental power volatility risk.

This is the same as the previous case except MLGW does not purchase generation capacity to hedge incremental power risks but rather relies on spot purchases. This is referred to Option #2B in the exhibit above. This is not only a more volatile strategy, but on an expected basis has higher costs and less savings relative to BAU. This is because we expect the low costs of existing units will not be available over time. Rather, there currently exists a temporary buying opportunity. Thus, we do not recommend a highly spot-market oriented approach, and is shown to emphasize the double benefit of attention to incremental power early – i.e., lower expected costs and less volatility.

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[96] The cost of incremental capacity and energy in the MISO market would have been in 2017 $32/MWh, with capacity available at near zero price. While we do not recommend reliance exclusively on spot purchasing due to volatility and in the case of capacity illiquidity. However, savings would have been $440 million were spot purchases made at spot prices. In 2024, we forecast savings for incremental power at $440 million versus TVA.

[97] Basis difference refers to differences in prices by location. For example, if market prices rise, the value of having the power plants would increase, offsetting the impact. However, if the percent increase of power delivered to MLGW increases faster than prices at the busbar of the powerplant, the hedge could have basis risk.

[98] One can think of all incremental energy being purchased from MISO, all incremental capacity purchased, and the energy porfits from operating the purchased capacity being used to offset the costs of the MISO purchase power.

[99] Also referred to as $50/kw year case. This is because without up front purchase of the plants, they eventually cost more $50/Kw Year (i.e. fixed costs less energy margins) rather than $25/kw year because of the forecast of the eventually tightening market for capacity.

Annual net savings equal $235 million per year, and $188 million starting in 2024, the first year of this study. This is over 20% savings in 2024 relative to the $1.1 billion in cost from the BAU case.

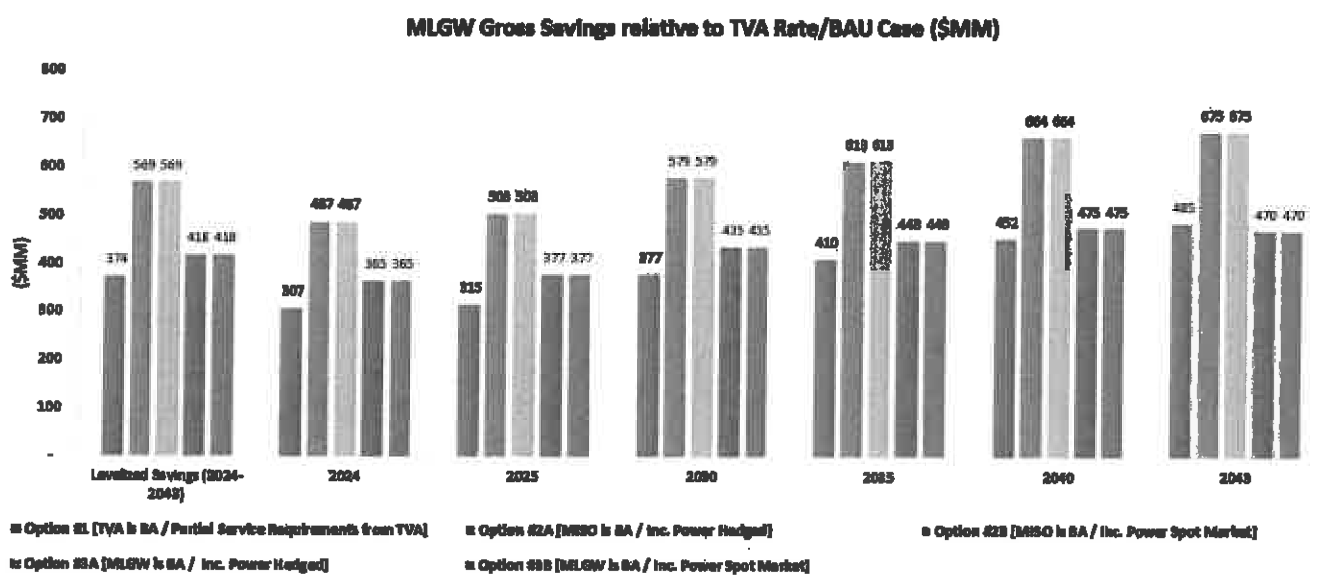
A variation on this "spot purchases" option strategy was analyzed with MGLW being is own Balancing Authority (BA). We referred to this as Option #3B in the exhibit above. Savings are less than in Option #3A as the cost of securing firm transmission to access the MISO spot market outweighs avoiding the costs of joining MISO.

2.4.4 Bellefonte PPA Plus TVA Partial Requirements Service to Cover Incremental Needs

In this scenario, MLGW buys power under the Bellefonte PPA, and incremental power is purchased from TVA under a Partial Requirements contract. This is referred to Option #1 in the Exhibit above.

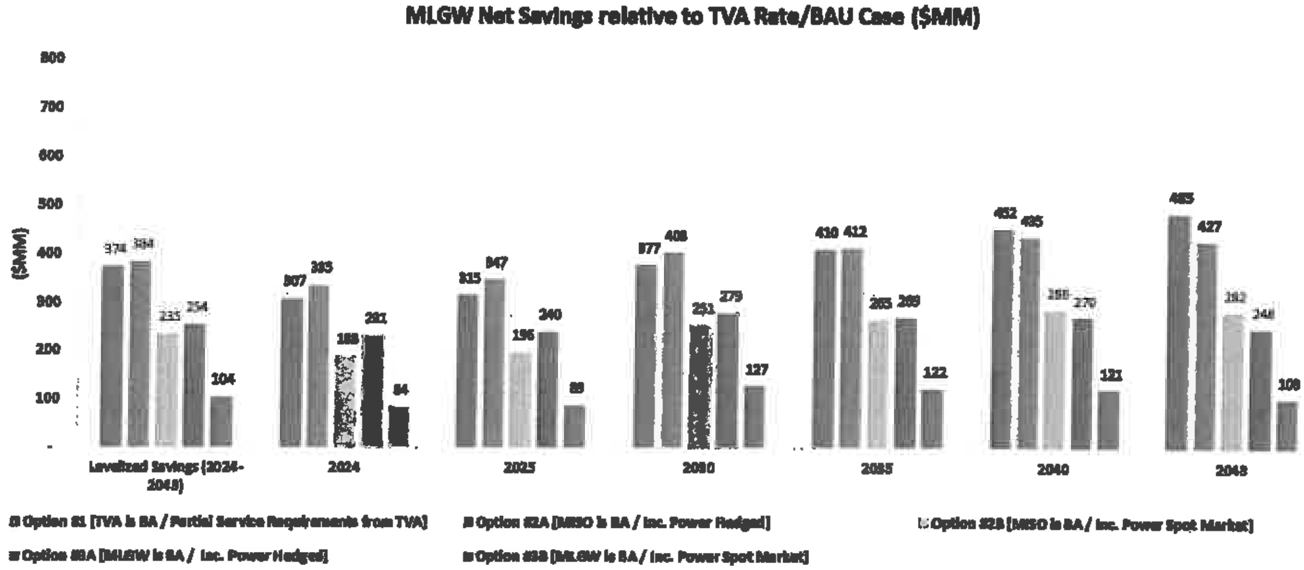
We do not consider this case as attractive to MLGW because its costs are likely higher than what the current market alternative suggests. This may also not be feasible to the extent it requires agreement by TVA. Because TVA provides primarily incremental on-peak power rather than both on-peak and off-peak, and because on-peak is usually more costly than off-peak, the costs are higher than TVA's average for Full Requirements, and higher than the market alternative discussed above. Note, the premium for on-peak power is based on TVA's tariff, but a negotiated outcome might differ.[100]

Exhibit 54. MLGW Gross Savings Relative to TVA Rate/BAU case ($MM)



[100] http://www.florenceutilities.com/Electricity_Department/Rate_Chart/Wholesale%20Power%20Rate%20-%20Schedule%20WS.pdf

Exhibit 55. MLGW Net Savings Relative to TVA Rate/BAU case ($MM)



12. Appendix A: Market Modeling Assumptions

12.1 Modeling Approach

ICF makes use of two primary models to simulate market evolution and prices in the US. First, we utilize our proprietary IPM zonal production cost model to simulate plant economics and project economic new builds, retirements, and capacity prices over time. We then use the results of this model in conjunction with ABB's PROMOD nodal security-constrained economic dispatch (SCED) model, which adds further detail of hourly energy pricing at the nodal level.

ICF's forecasts of future power operations, including the wholesale power market price forecasts in this report, were generated using ICF's proprietary Integrated Planning Model (IPM®) and associated data system. IPM® is a simulation model projecting wholesale market power prices based on an analysis of the engineering economic fundamentals. The model does not extrapolate from historical conditions but rather for given future conditions (new demands, new firm plants, new fuel market conditions, new environmental regulations), IPM® determines how the industry will function.

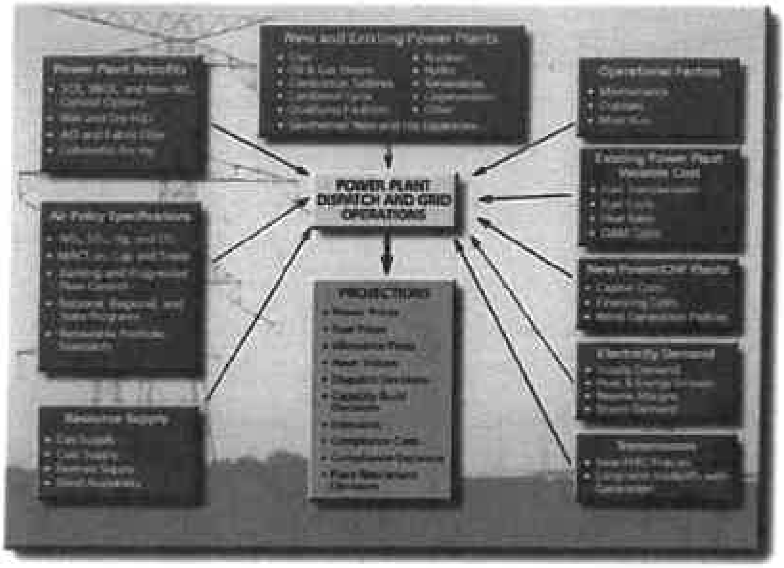
Specifically, the model projects plant generation levels (i.e., dispatch), merchant power plant revenues and costs, new power plant construction, mothballing, retirements, retrofitting, upgrades, fuel consumption, and inter-regional transmission flows. The model makes these projections by calculating production, and therefore production costs and prices, using a linear programming optimization routine with dynamic effects (i.e., it looks ahead at future years and simultaneously evaluates decisions over specified years).

Dispatch of plants is determined endogenously by the model through simulation of hourly market economics. The resultant capacity factors are a function of the competitive position of each plant, taking operational constraints into consideration. Effectively, plants with variable costs below hourly market-clearing prices are dispatched and more expensive plants are not, subject to additional constraints. The realized energy prices reflect average prices for spot supply during the hours in which the plant is dispatched.

ICF's IPM® power model is widely accepted by rating agencies and investment banking institutions. The model has been used in hundreds of industry and plant valuation assignments for power industry participants. The model has also been used extensively in litigation and administrative regulatory settings. Lastly, the model has been used extensively internationally and by industry-wide entities such as Electric Power Research Institute (EPRI), Edison Electric Institute (EEI), and CRIEPI (Japan's EPRI).

ICF also used an additional transmission model (GEMAPS) to set transfer limits in IPM®. Transmission constraints are identified by key bottlenecks in the region. The power flows take into consideration firm and non-firm transmission constraints. Hence, effective plant operations are limited by major interface constraints to define the correct level of disaggregation of sub-markets in IPM, and to validate our near-term analysis. These models employ either AC load flow or nodal DC load flow analysis. These models are very helpful for detailed transmission analysis, but cannot be readily used for valuation. This is because they cannot conduct integrated assessments of investment decision-making.

EXHIBIT A-1: IPM® MODELING STRUCTURE



ICF is also a licensed user of ABB's PROMOD. PROMOD performs a chronological nodal security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) of generation resources to serve load and reserve requirements, similar to the current implementation in the nodal markets in the U.S. PROMOD is a highly detailed model that chronologically calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. It uses a detailed electrical model of the entire transmission network, along with generation shift factors that determine how power from generating plants will flow over the AC network. This enables PROMOD to capture the economic penalties of re-dispatching generation to satisfy transmission line flow limits and security constraints. PROMOD captures the hour-by-hour, node-by-node flows of power, given the topology of the grid, the location of power plants, and dozens of other data inputs.

The output of PROMOD IV includes hourly locational marginal prices (LMP) for all generator and load buses, hourly forecast of congestion across transmission lines and interfaces along with associated congestion costs, system-wide congestion costs, and hourly dispatch of generating units. The model also captures the effect of marginal losses on power prices. This approach is similar to the market design of most Independent System Operators (ISOs).

PROMOD IV is also able to perform probabilistic simulations of market operations using a Monte Carlo approach. This feature enables the assessment of the impact of uncertainty on key market parameters such as power prices and congestion patterns. The probabilistic simulation is especially useful for evaluating the effect of renewable generation variability and fuel price volatility.

12.2 Key Input Assumptions

The key modeling assumptions in this study include projections of natural gas prices, peak and energy demand, demand-side management, new build costs, financing costs, supply changes, environmental regulation and transmission changes. Exhibit below summarizes the key assumptions ICF has used to model the TVA and MISO marketplaces.

TVA				
Peak and Energy Demand Growth (Annual Avg. %)	**Peak (MW, annual avg. growth)**		**Energy (GWh, annual avg. growth)**	
TVA	(2018: 28,662), 0.2% growth		(2018: 157,874), 0.0% growth	
Fuel and Emissions Prices	**Henry Hub ($/MMBtu)**	**TVA Delivered Gas ($/MMBtu)**	**Carbon ($/ton)**	**ILB Coal Commodity ($/MMBtu)**
2018	2.88	2.98	0.0	1.64
2019	2.76	2.77	0.0	1.61
2020	2.67	2.60	0.0	1.59
2022	3.44	3.58	0.0	1.68
2025	4.03	4.29	0.0	1.81
2030	4.99	5.27	5.4	2.07
2035	5.72	6.02	13.2	2.33
2040	6.41	6.76	21.7	2.45
2043	6.82	7.20	29.3	2.56
Firm Builds and Retirements	**2018**	**2019**	***2020***	**2021-2026**
Wind	0	0	*0*	0
Solar	1	68	*0*	0
Thermal Builds[101]	1,517	0	0	1,350
Thermal Retirements	1,169	0	*0*	0
Capital Costs and Financing	**2020 Cost ($/kW)**	**2025 Cost ($/kW)**	***Note***	**Real Capital Charge Rate**
CC	991	1,100	*All-in, summer kW*	4.7%
CT	645	715	*All-in, summer kW*	5.2%
Wind	1,604	1,719	*AC-basis before ITC*	4.4%
Solar	1,286	1,357	*AC-basis before ITC*	4.4%

[101] Include TVA's Allen Plant CC which came online in 2018

MISO				
Peak and Energy Demand Growth (Annual Avg. %)	**Peak (MW, annual avg. growth)**		**Energy (GWh, annual avg. growth)**	
MISO RTO	(2018: 119,507), 0.4% growth		(2018: 698,112), 0.4% growth	
MISO Zone 8	(2018: 7,110), 0.8% growth		(2018: 40,614), 0.8% growth	
Fuel and Emissions Prices	**Henry Hub ($/MMBtu)**	**Zone 8 Delivered Gas ($/MMBtu)**	**Carbon ($/ton)**	**PRB Coal Commodity ($/MMBtu)**
2018	2.88	2.89	0.0	0.70
2019	2.76	2.73	0.0	0.70
2020	2.67	2.59	0.0	0.70
2022	3.44	3.49	0.0	0.74
2025	4.03	4.15	0.0	0.80
2030	4.99	5.14	5.4	0.91
2035	5.72	5.88	13.2	1.04
2040	6.41	6.60	21.7	1.19
2043	6.82	7.03	29.3	1.28
Firm Builds and Retirements	**2018**	**2019**	***2020***	**2021-2026**
Wind	1,972	2,400	2,695	824
Solar	522	1,863	2,220	2,245
Thermal Builds	1,077	1,706	720	510
Thermal Retirements	2,943	450	151	520
Capital Costs and Financing	**2020 Cost ($/kW)**	**2025 Cost ($/kW)**	***Note***	**Real Capital Charge Rate**
CC	996	1,105	*All-in, summer kW*	4.1%
CT	645	715	*All-in, summer kW*	4.7%
Wind	1,602	1,717	*AC-basis before ITC*	3.8%
Solar	1,280	1,351	*AC-basis before ITC*	3.8%

- **Natural gas:** ICF utilized forward traded over month of March 2018 for 2018-2020 and its own fundamentals forecast (as of May 2018) from 2022 onwards, with 2021 reflecting transition from forwards to fundamentals.

- **Demand and energy:** Values through 2023 are sourced from the 2018 Loss of Load Expectation (LOLE) report. Thereafter, peak is assumed to grow at the average rate over 2021-2023. Energy demand is calculated based on load factor from Purdue's Independent Load Forecast from November 2017.

- **Firm builds and retirements:** Firm builds are sourced from Ventyx and the MISO Generator Interconnection Public Queue. Retirements are sourced from MTEP 2018 and Ventyx. ICF considers thermal capacity as firm if the unit is under construction or unit meets two of the following criteria; a) it is fully permitted, b) it has a PPA for an amount 50% or more of the total output, and c) it has secured financing for at least 50% of the project costs.

Wind and solar builds are assumed to be 15% (for 2020 and 2021) to 35% (2018 and 2019) of interconnection queue projects that are in the Definitive Planning Phase (DPP), System Impact Study. However, the model is allowed to build further capacity based on the economics throughout the forecast.

- **Coal prices:** ICF utilized coal forwards for 2018-2019 and its fundamental coal forecast from 2021 onwards, with 2020 reflecting transition from forwards to fundamentals. ICF generates coal production price curves and solves dynamically in the model based on usage.

- **Capital costs:** ICF generates bottom-up component cost assumptions for thermal and renewable projects.

- **Financing:** ICF assumptions including the tax changes enacted in late 2017. Notably, we use a lower-than-merchant equity return rate of 10% to reflect utility cost of capital and lack of full returns on merchant projects.

- **National Carbon:** ICF uses a probability-weighted approach of three cases: delayed-CPP, full legislative action, and no regulation over time.