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COMMENTS ON WABASH VALLEY POWER ASSOCIATION 2020 IRP

I. Introduction and Executive Summary

Tipmont Rural Electric Membership Cooperative ("Tipmont") is one of 23 members of Wabash Valley Power Association ("WVPA"). Tipmont is pursuing withdrawing its membership from WVPA and potential exit from full requirements electric service because it believes that doing so will allow it to better serve its own 28,000 cooperative members and customers. In recent years, Tipmont has determined that WVPA's motivations and interests diverge from those of Tipmont such that membership in WVPA may not be in the best interests of Tipmont and its members. In particular, Tipmont believes that it can better manage electric power costs for its customers and provide those customers with a greater mix of energy supply from new technologies, including from cost-effective distributed generation resources. By Tipmont's calculations, its members are paying approximately 30% more for power under WVPA's rates than if Tipmont were free to negotiate alternative power supply contracts.

For these reasons, Tipmont is pursuing terminating its membership in Wabash dependent upon the determination of a reasonable exit fee that compensates WVPA for "stranded costs"—investments made by WVPA to serve Tipmont's load that it would have expected to recover by virtue of Tipmont's membership—based on the date of exit. Tipmont is litigating with WVPA before the Federal Energy Regulatory Commission ("FERC") with respect to determination of the appropriate amount of an exit fee. Tipmont's final determination of whether to exit depends upon the outcome of the FERC proceeding because Tipmont cannot determine whether it is economically feasible to exit until it knows the rates and terms of exiting. At this time, WVPA contends that Tipmont's exit fee should be $236 million based on its calculation of stranded costs. Tipmont disagrees with WVPA's calculation[1] but notes that, if it were to be believed, it implies that, should all members of WVPA seek to exit at once, WVPA would apparently contend that it

[1] Tipmont contends that Wabash's proposed exit fee goes beyond making Wabash whole for its commitments to serve Tipmont under the wholesale contracts and improperly seeks to charge Tipmont inappropriate additional amounts for (1) costs arising from commitments made by Wabash that do not relate to serving Tipmont under the terms of its membership contracts and (2) investments that Wabash projects that it will make to serve Wabash's *other* members after Tipmont has exited. The parties also dispute whether Wabash's projections of market prices for capacity and energy in the FERC proceeding are realistic.

was owed $3 billion in stranded costs,[2] which, from Tipmont's perspective, casts serious doubt as to the economic viability and operations of WVPA, given that it publicly reports assets of $1,285,065,000.[3]

Until the amount and terms of the exit fee are determined in the FERC proceeding, Tipmont's status with WVPA is up-in-the-air. Tipmont is currently a member, but it may or may not be a member of WVPA in the future. Regardless, Tipmont has a direct interest in the matters reflected in WVPA's 2020 Integrated Resource Plan ("IRP")—either with respect to the wholesale rates it will pay for the purchase of electricity from WVPA as a member or with respect to the effect of WVPA's resource management decisions and its consequences on calculation of an exit fee.

Because of its continued interest in the planning and assessments made by WVPA, Tipmont has engaged in a close review of the IRP. Tipmont received notice of the submission on November 1, 2021, pursuant to 170 IAC 4-7, and a copy of the executive summary from WVPA's counsel. Prior to the submission, Tipmont was not extended an opportunity for input or comment.

With that background and explanation of Tipmont's unique perspective, Tipmont offers the following comments on WVPA's 2020 IRP, submitted on November 1, 2021,[4] to the Indiana Utility Regulatory Commission ("IURC").

Tipmont has the following five primary concerns with WVPA's 2020 IRP:

1. WVPA's 2020 IRP overlooks important developments within its own membership, including the potential withdrawal of Tipmont;
2. WVPA's 2020 IRP presents inconsistent assumptions on avoided costs and future market prices;
3. The 2020 IRP presents information that conflicts with WVPA's position before FERC in the matter of setting Tipmont's exit fee;
4. WVPA's 2020 IRP is inaccurate given known Midcontinent Independent System Operator ("MISO") wholesale market developments in recent years; and
5. The 2020 IRP is incomplete in its assessment of risk of generation ownership and long-term contracts.

In addressing these issues, Tipmont has identified certain questions as to which it believes the Director should seek a response from WVPA to better enable review of the IRP. Tipmont submits

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[2] *See* Tipmont's Wabash Valley Co-ops: Projected Stranded Cost Calculations, attached as Exhibit A.

[3] Wabash Valley Power Association, Who We Are, Fast Facts, https://www.wvpa.com/who-we-are/fast-facts/ (last visited Jan. 29, 2022).

[4] WVPA 2020 Integrated Resource Plan, Nov. 2021, *available at* https://www.in.gov/iurc/files/WVPA-2020-Integrated-Resource-Plan-Redacted.PDF (referred to herein as "2020 IRP"). WVPA's prior 2017 IRP, which is also referenced herein, was submitted on January 24, 2018. *See* WVPA 2017 Integrated Resource Plan, Jan. 2018, *available at* https://www.in.gov/iurc/files/WVPA-2017-Integrated-Resource-Plan.pdf.

that a robust examination of WVPA's 2020 IRP is important to protect the interests of the 245,000 Hoosier customers who receive their power through WVPA.

II. Analysis of WVPA's IRP

1 WVPA's IRP overlooks important developments within its own membership.

In October 2018, Tipmont provided WVPA with a conditional notice of withdrawal, subject to the negotiation of fair and equitable exit terms. As noted, the determination of fair and equitable exit terms for Tipmont is now pending before the FERC.[5] Under the contemplated exit solutions, Tipmont could cease to be a member of WVPA, and therefore no longer require supply and other wholesale service from WVPA, upon payment of an immediate buyout amount or after 10 years given payment of a buyout rate over that 10-year period.[6] However, none of WVPA's 2020 IRP load forecast scenarios (including the Base Case or sensitivities) take into account the possibility of Tipmont's departure and the resulting impact on its supply portfolio needs, as evidenced in WVPA's discussion on membership (page 2 of the 2020 IRP) and continuously growing load forecast (Table 3-2, page 40 of the 2020 IRP).

Tipmont recognizes that it has not yet made a final determination of whether it will exit and cannot reasonably do so until the amount and terms of its exit are fully determined. However, Tipmont submits that it would be prudent for WVPA, as part of its scenario analysis, to evaluate in some scenarios the impacts of Tipmont's potential departure on the supply portfolio in an effort to minimize supply surpluses following Tipmont's potential departure.[7]

WVPA's 2020 IRP is premised upon a Base Case load forecast of energy sales and summer coincident peak load growing at an average rate of 0.8% per year over the next twenty years.[8] Within WVPA's membership, Tipmont's load represents approximately 7.6% of total members' load (excluding passthrough load). For comparison purposes, as shown in the figure below, Tipmont's forecasted energy load in 2025 would be equivalent to the annual generation from a Natural Gas Combined Cycle ("NGCC") with a 94 MW nameplate rating, operating at a typical 70% capacity factor (per Table 4-1 of the 2020 IRP). As demand grows, the equivalent size of a NGCC to meet Tipmont' s energy consumption would grow to be 97 MW in 2030, 101 MW in 2035, and 105 MW by 2040, as shown in the figure below. Notably, at summer peak, Tipmont's peak load (currently at approxiamtely120 MW) would require an even larger NGCC for purposes

[5] FERC Docket ER20-1041.

[6] Prepared Direct Testimony of Jeff A. Conrad on behalf of Wabash Valley Power Association, Inc. Exhibit WV-0002. Docket ER20-1041-003. November 9, 2020.

[7] While WVPA did consider a Low Growth forecast which is 4.8% lower than the Base Case load by 2040, it did not consider a scenario where Tipmont's load, representing about 7.6% of WVPA's load, would depart the system.

[8] 2020 IRP, Table 3-2, at 40.

of MISO resource adequacy requirements. For example, after accounting for load growth, Tipmont's peak load would be equivalent to nearly 140 MW of unforced capacity ("UCAP") in 2025 and approaching 150 MW of UCAP by 2033.

Year	WVPA load (GWh)	Tipmont load* (GWh)	Equiv. NGCC** (MW)
2025	7,621	579	94
2030	7,842	596	97
2035	8,111	616	101
2040	8,488	645	105

* Assuming Tipmont's load represents 7.6% of WVPA's load

** Assuming a 70% capacity factor for energy generation

In their Base Existing Policy Power Supply Expansion Plan, WVPA expects a need for a new 150 MW NGCC resource (in UCAP terms) by 2026.[9] This expected need for WVPA to construct a new NGCC would be materially reduced and deferred if Tipmont were to leave, given the magnitude of Tipmont's energy and peak load, as shown above. WVPA's Base Existing Policy Power Supply Expansion Plan does not require any additional NGCC capacity until 2033.[10] A deferral in the construction of NGCC from 2026 to 2033 would mean significant capital and fixed operating cost savings for WVPA members. Based on Wabash's projected capacity cost and fixed cost for a new NGCC resource of approximately $8/kW-month,[11] Tipmont estimates a cumulative savings of over $80 million in present value terms over just this seven-year period (refer to Figure 2 below).[12] These savings represent avoidable fixed costs for power supply and would directly benefit all members of WVPA that would remain after Tipmont's departure.

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[9] 2020 IRP, Table 4-10, at 77.

[10] *Id.*

[11] 2020 IRP, Table 4-1, at 65. Specifically, see the capacity cost of $5.02/kW-month and fixed cost of $1.83/kW-month (2021 dollar terms). In order to escalate to 2026 dollars, a 2.5% annual inflation rate assumption was applied.

[12] In the calculation, a discount rate of 4.75% is applied, which is based on the WVPA's declared borrowing costs, as specified in WVPA Attachment O filing for 2021. See Cell G256 from the schedule filed with MISO: https://misodocs.blob.core.windows.net/transmissionownerratedata/WVPA/2021_WVPA_YE123120%20AttO_AU.xlsx (last visited Jan. 31, 2021).

Figure 2. Illustration of cumulative savings from deferring NGCC investment

	0.025	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
(a)	NGCC (MW UCAP)	0	0	0	0	0	150	150	150	150	150	150	150
(b)	Capacity Cost ($/kW-month)	$5.70	$5.84	$5.99	$6.14	$6.29	$6.45	$6.61	$6.78	$6.94	$7.12	$7.30	$7.48
(c)	Fixed Cost ($/kW-month)	$2.39	$2.45	$2.51	$2.57	$2.64	$2.70	$2.77	$2.84	$2.91	$2.98	$3.06	$3.14
(d) = (b) + (c)	Total Avoidable Fixed Costs ($/kW-month)	$8.09	$8.29	$8.50	$8.71	$8.93	$9.15	$9.38	$9.62	$9.86	$10.10	$10.36	$10.61
(e) = (d)*12	Total Avoidable Fixed Costs ($/kW-year)	$97.08	$99.51	$101.99	$104.54	$107.16	$109.84	$112.58	$115.40	$118.28	$121.24	$124.27	$127.38
(f) = [(a)*(e)]/1000	**Total Avoidable Fixed Costs ($ million)**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$16.5**	**$16.9**	**$17.3**	**$17.7**	**$18.2**	**$18.6**	**$19.1**
	Cumulative Savings, discount rate of 4.75%	**$81.9**	**million**										

In light of these circumstances, Tipmont submits that WVPA should be called upon to address

- **How would WVPA's portfolio expansion scenario change, if at all, assuming the departure of Tipmont in the short-term?**

2 ***WVPA's 2020 IRP presents inconsistent assumptions on avoided costs and future market prices.***

The objective of WVPA's IRP, as stated on page 71, is to select a portfolio of supply resources to meet future needs and provide reliable service while balancing the costs against risks. WVPA professes itself a founding member of MISO,[13] and has access to and participates in MISO's energy, capacity and ancillary services markets.

Without providing any sound economic justification, WVPA largely ignores the cost-effective opportunity of purchasing a portion of its wholesale energy and capacity needs from the market. Furthermore, WVPA's forecasts of avoided costs for energy and capacity are inexplicably different from their own forecasts of energy market prices and capacity market prices. These results are completely inconsistent with reality, as WVPA operates and dispatches its existing generation resources and schedules its load through the MISO organized markets. Furthermore, WVPA has access to bilateral capacity markets and has relied in the past on purchases of capacity from the bilateral markets to meet its resource adequacy (capacity) obligations.

WVPA is therefore artificially constraining its selection of resources in the future to protect the G&T entity from open-market competition rather than accounting for and realizing benefits of the wholesale market for its members and their customers.

2.1 Energy assumptions

WVPA states on page 71 that they prepare their IRP with "minimal use" of the RTO markets to meet future power supply needs. By marginalizing the use of MISO competitive markets for energy and capacity, WVPA's portfolio analyses using the Plexos model are performed through a "closed ecosystem" economic dispatch modeling exercise. Their analyses focus on calculating the production cost associated with dispatch of their own supply portfolio against their own load, with

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[13] *See* https://www.wvpa.com/industry-expertise/data-center/; (last visited Jan. 29, 2022); *see also* https://cdn.misoenergy.org/Transmission%20Owner%20Executed%20Signature%20Pages%20to%20the%20Transmission%20Owners%20Agreement95903.pdf (last visited Jan. 29, 2022).

wholesale market purchases modeled as a limited resource.[14] WVPA calculates an avoided cost of energy based on these "closed ecosystem" simulations. In addition, these same "closed ecosystem" simulations determine the optimal portfolio of supply resources for the future. As such, both the avoided cost of energy and the selected Base Resource portfolio ignore the potential benefits to WVPA's members from embracing the supply opportunities in the MISO wholesale markets for resource planning purposes.

As a further consequence of their methodological choices, WVPA ends up presenting two separate indicators of future energy prices: the estimated avoided cost of energy (documented in Table 4-5 on page 71 of the 2020 IRP) and the forecast of energy market prices (documented in Appendix C to the IRP), which is created from a blend of broker prices from ACES and a fundamental-based forecast from Horizons Energy LLC. These two forecasts for energy prices [redacted]

Figure 3. WVPA avoided cost of energy versus market price forecast

[redacted]

Sources: 2020 IRP, Table 4-5, page 71; Appendix C to the IRP.

In reality, WVPA's generation assets are offered into and dispatched according to MISO's energy market—irrespective of WVPA's load level at the time. Similarly, WVPA's load is served from the markets—irrespective of WVPA's generation level at the time. As such, WVPA's avoided costs (marginal costs of serving load) should in principle be entirely consistent with the market price for energy, [redacted]

To properly compare all available supply resource options (including market purchases) and demand-side options, WVPA's portfolio simulations should calculate costs of serving its members while considering operations of the entire MISO market (and other interconnected market areas that can be used to supply WVPA's load obligations) as opposed to their "closed ecosystem"

[14] 2020 IRP Appendix D.

simulation approach. This would also allow WVPA to evaluate which supply strategy and portfolio of assets results in the least cost option for its members, taking into account the uncertainty of future market prices. Indeed, WVPA has relied on exactly that approach in market studies that it has commissioned over the course of 2020 and 2021, and filed before the FERC.

Tipmont submits the Director should ask WVPA to respond to the following questions:

- **How do the energy market forecasts that WVPA has submitted to FERC compare to the avoided costs and market outlook that WVPA is presenting in this IRP?**
- **Given the observed disconnect between the avoided cost of energy produced by the model and assumed market prices, and the disconnect between actual market operations and the "closed ecosystem" methodology artificially imposed in the IRP, is WVPA's IRP meeting its own stated objectives?**

Ultimately, Tipmont submits that the Director should ask WVPA to consider more fully the opportunities of market purchases and sales into the competitive MISO markets.

2.2 Capacity assumptions

With respect to capacity prices, WVPA's forecast for avoided costs of capacity is based on the costs to construct a combustion turbine peaking resource.[15] This methodology is completely delinked from the realities of the MISO market, in which it is recognized that multiple resources can provide capacity, including other generation technologies and demand-side resources. Although the costs of a combustion turbine peaking resource sets the defector maximum price in MISO's residual capacity auction, the market value of capacity can fall below (or above) that price as seen in the wide range of prices in bilateral capacity sales filed with FERC in the *Electronic Quarterly Reports*. More importantly, similar to the argument about the avoided cost of energy, the avoided cost of capacity should be an output of WVPA's supply portfolio expansion modeling, reflecting the actual cost of the next best resource providing capacity (whichever it is) at each point in the future. In its present form, WVPA's avoided cost of capacity is meaningless as it only reflects the cost of an arbitrarily selected source of capacity, as opposed to WVPA's actual marginal cost of capacity based on market dynamics and MISO's rules and requirements around capacity purchases and sales.

Furthermore, in addition to the avoided cost of capacity, WVPA provides a forecast of what they label as "bilateral capacity prices" (sourced from ACES). These assumed bilateral capacity prices are [redacted] WVPA's projected avoided costs of capacity, as summarized in the figure below.[16] This disconnect is not explained in the IRP.

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[15] *Id.*, Appendix D.

[16] *Id.*, Appendix C and Appendix D.

Figure 4. WVPA avoided cost of capacity versus bilateral price forecast

[redacted]

Sources: 2020 IRP, Table 4-5, page 71; Appendix C to the IRP.

Reflecting the assumptions as to the avoided cost of capacity and artificial limit imposed in the methodology on wholesale market purchases, WVPA selects a base resource plan that includes 400 MW of new gas-fired resources (200 MW of NGCC sand 200 MW of natural gas fired combustion turbines ("NGCTs") by 2040 in the base power supply plan. Indeed, WVPA states on page 71 of the IRP that they prefer "minimal use" of the RTO markets to meet future power supply needs, and that if the model was allowed to select a greater amount of capacity market purchases, the optimal resource portfolio would be considerably different. However, while presenting a forecast for bilateral capacity prices, WVPA fails to explain why bilateral capacity market purchases or MISO Planning Resource Auctions ("PRAs") could not be relied upon to meet long-term capacity requirements. WVPA notes the price volatility of the MISO PRAs; however, that does not explain why bilateral purchases are excluded. Bilateral transactions can be structured over multiple years and can include many variants on indexed or fixed pricing. WVPA also fails to offer any explanation as to how this disconnect in avoided costs of capacity and assumed bilateral market prices can persist over 20 years,[17] and offers no explanation for reconciliation of the difference.

Indeed, the fact that WVPA continues to invest in more expensive new build suggest that they do not believe their own assumed bilateral market prices for capacity.

Tipmont submits the Director should ask WVPA to respond to the following questions:

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[17] 2020 IRP, at 79 ("Furthermore, forecasted bilateral capacity prices for the entire time horizon as provided in Appendix C are also lower than Wabash Valley's forecasted avoided capacity cost.").

- **How do the capacity market forecasts that WVPA has submitted to FERC compare to the avoided cost of capacity that WVPA is relying on and presenting in this IRP?**

- **Why would there be a permanent disconnect between the avoided cost of capacity and the market price of capacity?**

- **Based on the portfolio of existing resources and new resources selected in the base resource plan of the IRP, what is the imputed market value of capacity for WVPA to adequately serve its members and ensure resource adequacy pursuant to MISO rules?**

2.3 Example of disconnect between WVPA results and market prices.

Tipmont would like to point out to the Commission an example of the glaring disconnect between WVPA's modeling results and market prices for energy and bilateral capacity. According to the IRP, WVPA expects the average total costs of a NGCC (assuming a typical 70% capacity factor) to be $42.96/MWh in 2021 dollars,[18] which if escalated by inflation would be equal to $48.61/MWh in 2026.[19]

Conversely, its own market price forecasts[20] establishes the average market revenues that can be earned by such a resource, based on the assumed energy and capacity market prices, would be [redacted] in 2026.

[18] *Id.*, Table 4-1, at 65.

[19] WVPA's general inflation rate assumption is 2.5% (2020 IRP, at 78), which Tipmont used to inflate the 2021 cost of the NGCC.

[20] These market revenues are based on mid-point 7x24 Indiana Hub energy forecast, and mid-point bilateral capacity forecast from Appendix C to the 2020 IRP.

Figure 5. Economics of the proposed NGCC investment in WVPA's base resource plan

WVPA IRP Economics	2026
NGCC (MW UCAP)	150
NGCC (GWh) at 70% Capacity Factor	919.8
NGCC Average Total Cost at 70% CF (nominal $/MWh)	$ 48.6
NGCC Total Cost ($ million)	$ 44.7
Energy market prices (nominal $/MWh)	$ [redacted]
Capacity bilateral prices (nominal $/kW-month)	$ [redacted]
Total Revenues ($ million)	$ [redacted]
Total Revenues per MWh of generation (nominal $/MWh)	$ [redacted]
Above market cost ($ million)	$ [redacted]
WVPA load (GWh)	7,661
Above market cost per unit of WVPA load ($/MWh)	$ [redacted]

Source: NGCC parameters and costs come from 2020 IRP, Table 4-10, page 77; and Wabash assumptions on market prices come from Appendix C.

Given the annual generation volume of WVPA's planned NGCC addition in 2026 (919.8 GWh), this difference between NGCC costs and market revenues represents [redacted] in above-market costs that WVPA members would need to bear in 2026, or an increase of [redacted] in WVPA's wholesale supply rates in that year alone. Extrapolated over the IRP horizon (2026 – 2040) using WVPA's assumptions on cost and market prices, and discounted using WVPA's borrowing cost of approximately 4.75%,[21] the total *above-market costs* associated with the 150 MW NGCC borne by WVPA customers could represent close to [redacted] in unnecessary costs (in 2026 dollars).

Given the above example, Tipmont submits that the Director should ask WVPA to address:

- **How is ignoring the cost-effective opportunity offered by competitive markets in the best interest of consumers?**

3 *The 2020 IRP presents information that conflicts with WVPA's position before FERC in the matter of setting Tipmont's exit fee.*

As part of the litigation process at related to calculation of Tipmont's exit fee, WVPA has prepared and filed with FERC multiple documents pertaining to its future generation portfolio plans, as well as planned capital expenditures related to transmission and distribution infrastructure. However,

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[21] *See* Cell G256, WVPA Attachment O filing for 2021, *available at* https://misodocs.blob.core.windows.net/transmissionownerratedata/WVPA/2021_WVPA_YE123120%20AttO_AU.xlsx (last visited Jan. 31, 2022).

WVPA's 2020 IRP conflicts with those previous analyses both in terms of input assumptions but also in the methodology used to evaluate and address future supply needs.

For instance, in the IRP, WVPA presents assumptions around planned retirements of some of its assets, including Gibson 5 (156 MW in 2026), WR Highland (160 MW in 2037), and Prairie State 1 (41.5 MW in 2038).[22] WVPA also mentions that coal-fired resources Rockport Units 1 and 2, which supply part of WVPA's power purchase agreement with AEP, could shut down before the end of 2028 as part of a settlement agreement filed with the IURC. However, these forecasted retirements conflict with information that has been submitted to FERC regarding WVPA's retirement plans, notably with respect to Prairie State which WVPA previously considered retiring only in 2043, and WR Highland which WVPA had not considered retiring.[23] In the IRP, WVPA does not discuss the assumptions that were used to set the retirement date of these resources, nor do they discuss modeling changes that could explain the variations from analyses previously submitted to FERC. As a matter of fact, the IRP does not offer any analysis of existing asset economics.

Furthermore, as mentioned earlier, WVPA generally makes the argument in the IRP that they prefer to rely on acquisition and/or construction of new assets and strive to make minimal use of RTO market purchases.[24] However, this position is not consistent with the 30-year operating plans embedded in a public report prepared by WVPA consultant Black & Veatch ("B&V") and filed with the FERC ("B&V Report").[25] WVPA's views before the FERC presented in the B&V Report do not include any future long-term contracts or new generation assets; rather the assumptions were that future needs would be met through purchases from the competitive wholesale markets of MISO and PJM. It is unclear to Tipmont how WVPA can present one set of long-term plans to FERC and a completely different strategy in its IRP to the IURC.

Accordingly, WVPA should be asked to address the following issues:

- **Did WVPA study existing assets to determine whether they are profitable or uneconomic? What are the benefits from early retirement of assets?**

- **What is driving the difference in retirement assumptions provided in the IRP versus those provided to FERC? Which is correct?**

- **Given the different assumptions as to future long-term contracts and new generation assets versus market purchases between the IRP and the testimony that WVPA sponsored at FERC (e.g., the B&V Report), which is correct?**

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[22] 2020 IRP, Table 4-9, at 76.

[23] Black & Veatch. Forward-Looking Stranded Cost Exposure Study. Exhibit No. WV-0014. Docket No. ER20-1041-003. January 27, 2020, attached as Exhibit B ("B&V Report").

[24] 2020 IRP, at 71.

[25] B&V Report.

4 ***WVPA's 2020 IRP is inaccurate given known wholesale market developments.***

As noted, WVPA operates its generation and transmission assets within competitive wholesale markets run by the MISO and the PJM Interconnection LLC ("PJM"). The majority, almost 80%, of WVPA's members are located within the MISO footprint;[26] this includes WVPA's Indiana load (including Tipmont's). As such, Tipmont's comments will focus on WVPA's operations within MISO.

The MISO wholesale power markets have undergone significant developments in recent years. Indeed, the significant influx of investment in new renewable generation resources, and the resulting evolving generation mix, has led MISO to rethink both its transmission planning process and market design. Since 2019, as part of MISO's Reliability Imperative and practically for use in MISO's Transmission Expansion Planning ("MTEP") process and Long Range Transmission Plan ("LRTP")[27] initiative, MISO and its stakeholders, including WVPA, have been defining the fundamental supply-demand conditions or "Futures" for the MISO grid, markets, and encompassing the load of all MISO members over a twenty-year period. These Futures center around ranges of economic, policy, and technological possibilities including load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas price, and generation capital cost.[28] In these Futures, MISO is recognizing the growing importance, and impact, of distributed energy resources ("DERs") and changing consumer attitudes to electricity.

On the basis of what these Futures are projecting, and in parallel to the MTEP and LRTP planning process, MISO is also looking at reforming its Resource Adequacy ("RA") construct, which centers around procuring sufficient capacity to ensure system reliability.

Unfortunately, WVPA's 2020 IRP does not sufficiently examine how these market developments and accompanying market reforms could impact WVPA's existing and planned future supply portfolio, and ultimately its ability to provide its members with reliable supply and transmission service through investment decisions providing the right balance between low cost and mitigation of supply cost risk.

Notably, the 2020 IRP is mostly silent on details of how MISO regional transmission plans will impact WVPA and its members. The 2020 IRP also lacks discussion of WVPA's proposed local transmission plans and associated investments. Regional and local transmission investment should be integrated with the planning of supply portfolio investments. Generation investments may require additional transmission infrastructure—or, conversely, transmission investments could obviate or defer the need for some of the planned supply resource additions and vice versa.

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[26] 2020 IRP, Table 1-3, at 4.

[27] MISO, Long Range Transmission Planning – Technical Study Status, *available at* https://cdn.misoenergy.org/20210625%20LRTP%20Workshop%20Item%2004%20Technical%20Study%20Status563950.pdf (last visited Jan. 31, 2022).

[28] MISO, Futures Development, *available at* https://www.misoenergy.org/planning/transmission-planning/futures-development/ (last visited Jan. 31, 2022).

In addition, WVPA is not considering distributed energy resources ("DERs") in its analysis of generation resource expansion by not allowing for a proper co-optimization between traditional (utility-scale) power generation resources, market purchases, demand-side resources, and distributed resources.

Finally, WVPA has ignored the impact of changing capacity resource accreditation rule changes in MISO's RA construct, which may leave it short on UCAP in the future given its reliance on intermittent resources as part of its existing and future supply portfolio.

These shortcomings may result in unanticipated rate increases (when transmission and generation investment is not coordinated), and yield suboptimal collection of resources, burdening WVPA members with higher costs.

Tipmont requests that the Director ask WVPA:

- **Whether it has conducted any analysis that integrates regional and local transmission investment plans with WVPA's resource plans in the IRP to provide a clear assessment of the costs and benefits of the overall investment plan for WVPA's members and Indiana consumers.**

- **Whether it has studied explicitly the benefit of DERs in the resource plan and considered the extent to which DERs may be in the public interest because they defer more costly investments.**

- **Whether it has conducted any sensitivity analysis that demonstrates the implication of market reforms on capacity accreditation and other pertinent market changes in MISO.**

4.1 Transmission investments

The 2020 IRP is mostly silent on WVPA's own (local) transmission capital plans, and how transmission investment fits in with WVPA's proposed base resource plan for the future. The IRP also does not take into account MISO's regional plans and how that might affect rates in conjunction with WVPA's local plans.[29]

However, as part of IURC Cause No. 45656, WVPA requested authority to execute notes as evidence of indebtedness up to $330 million.[30] In its filing, WVPA identified over $423 million in planned capital investments over the 2022 – 2024 timeframe – over $381 million, or *90%,* of which were for transmission and distribution projects. For comparison, WVPA's total

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[29] Various issues could be considered. For example, WVPA could consider how geo-targeted EE/DSM could be deployed by a distribution utility to reduce monthly peaks and therefore transmission cost allocation. In addition, customer-connected DERs could be promoted by the distribution utility to reduce transmission costs and capacity market costs.

[30] WVPA Verified Petition, Cause No. 45656, filed Dec. 17, 2021.

accumulated transmission-related investments to-date (gross plant in service) only represents $320 million.[31]

So, the failure to comment on the transmission plans is glaring. But WVPA should not be making such transmission investments at all. WVPA's operative power supply contracts with all its members expressly provides the following:

> It is understood by and between the parties that the express intent of WVPA is not to own, operate or maintain any transmission Facilities and/or substations except as such ownership, operation and maintenance may inure to WVPA by reason of Transmission Participation Agreements and Transmission Operating and Maintenance Agreements with other suppliers, which suppliers own and operate bulk transmission systems.

Thus, these massive local transmission investments should not be undertaken by WVPA. It owes its members and this Commission an explanation.

Moreover, when performing system planning, transmission infrastructure and generation resources can sometimes be complements or substitutes. In some cases, generation investment will require transmission investment in order to be accessible to load – this is an example of complementary investments. In other instances, a generation project can defer a transmission investment or vice versa, indicating that generation and transmission are substitutes. A proper IRP should consider the full range of resources and benefit-cost tradeoffs. In its 2020 IRP, WVPA is not offering any insights into its transmission planning activities, or the transmission implications of WVPA's planned supply portfolio expansion. For instance, WVPA does not disclose whether generation resource investments contemplated as part of the base power supply plan will require additional transmission investments. Similarly, WVPA does not discuss whether transmission investments could obviate or defer the need for additional supply resources.

In addition, generation and transmission investments will both require capital, which will need to be recovered through rates. To the extent that the 2020 IRP examines future rate impacts of the supply resource plan but fails to consider the rate impacts of planned transmission investments over the next 20 years, it is incomplete in its presentation of the effects of investment on Indiana cooperatives and their end-users. For instance, assuming an annual carrying charge representing 13% of the investment value,[32] WVPA's planned [redacted] capital investment in transmission

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[31] *See* Cell I86, WVPA Attachment O filing for 2021, *available at* https://misodocs.blob.core.windows.net/transmissionownerratedata/WVPA/2021_WVPA_YE123120%20AttO_AU.xlsx (last visited Jan. 31, 2022).

[32] Tipmont estimated the carrying charge ratio by examining WVPA's Attachment O filing for 2021. Based on FERC Form 1 data for 2020, WVPA calculated that its annual transmission-related revenue requirement was $41 million (cell I202) versus a gross plant in service value of $320 million (Cell I86), representing a 13% ratio. *See* https://misodocs.blob.core.windows.net/transmissionownerratedata/WVPA/2021_WVPA_YE123120%20AttO_AU.xlsx (last visited Jan. 31, 2022).

and distribution would result in an additional [redacted] in annual costs (revenue requirement). If one were to spread this additional cost across WVPA's load in 2024 (7,602 GWh),[33] this [redacted] million annual revenue requirement from transmission investments represents an increase in rates of [redacted] to WVPA members.

4.2 Distributed energy resources consideration

As part of WVPA's resource selection process, it examines a range of supply-side options (such as natural gas-fired, wind, solar, or battery resources) or demand-side options (such as demand response or energy efficiency).[34] On page 26 of the 2020 IRP, WVPA mentions that they monitor technology developments in distributed energy products (i.e., distributed energy supply and distributed energy storage resources) to determine potential impacts on future load. However, they did not consider such DERs as part of their resource selection process.

With respect to DERs, WVPA claims on page 34 of the 2020 IRP that it recently "began allowing Members to self-supply up to 5% of the Member's non-coincident peak load." This claim is false. WVPA is apparently referring to one of the provisions of a new wholesale power supply contract that WVPA proposed to FERC and which would have applied to 21 of WVPA's 23 members. However, that new contract was never permitted to go into effect; FERC rejected it as being unjust and unreasonable.[35] Thus, members do not have the right to self-supply even this 5% of load through distributed generation. Moreover, even the proposed 5% artificial limit on members' ability to integrate DERs, together with WVPA's failure to consider DERs as an alternative to traditional wholesale generators in their portfolio expansion analyses, could lead WVPA to select a base resource expansion plan that is higher cost, or higher risk, than the alternative that would materialize if WVPA dynamically considered DERs on equal footing to other resources, without arbitrary limits, as part of its supply portfolio analyses. Indeed, given the current trend of penetration of solar PV DERs, it would appear that WVPA is distorting the results of the IRP in favor of conventional, utility-scale generation resources so that it can expand its own ratebase.

This oversight is somewhat analogous to a critique by the IURC Director of Research, Policy, and Planning (the "Director") on WVPA's 2017 IRP about its demand-side management ("DSM") practices.[36] With respect to DSM, the Director noted WVPA's lack of quality data from members, as well as the fact that DSM levels were "hardwired" into WVPA's model (as opposed to co-

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[33] 2020 IRP, Table 3-2, at 40.

[34] *Id.*, Section 4, at 63 *et seq*.

[35] FERC initially rejected WVPA's proposed new contract in 2019. *Wabash Valley Power Association, Inc.,* 168 FERC 61,189 (2019). WVPA then proposed to FERC a revised version of the new contract in February 2020. FERC rejected the revised contract in April 2020. *Wabash Valley Power Association, Inc.*, 171 FERC 61,073 (2020). WVPA has appealed FERC's decisions rejecting the new contract to the United States Court of Appeals for the District of Columbia Circuit, which appeal is pending.

[36] Final Director's Report for the 2017 Integrated Resource Plans. December 27, 2018.

optimized), and opined that these issues affected the perception of credibility of WVPA's long-term resource planning. Both of these critiques can be applied to WVPA's treatment of DERs in their 2020 IRP. It is also worth noting that, as part of its review of IMPA's 2017 IRP, the Director commented that while customer-owned resources were not currently a major factor now, future increased penetration of DERs was likely due to national trends.[37] If anything, this statement is even truer today than it was in 2018, as the capital costs of solar PV DERs has dropped approximately 10% since 2018 according to industry studies.[38]

In a similar vein, WVPA stated on page 45 of their IRP that they did not project the impact of EVs in their Base Case load forecast based on a modest adoption rate to date (although they did project the impact of EVs as an alternative scenario). Given the current technological trends, Federal and regional public policy objectives, and considering that WVPA's IRP covers a 20-year horizon, it would seem logical to include consideration of some level of EV adoption in the Base Case load forecast.

4.3 <u>MISO capacity resource accreditation rules are changing.</u>

In the 2020 IRP on page 101, WVPA mentions that they will monitor changes to MISO's RA construct. However, they fail to mention that MISO has already filed to request seeking approval by the FERC of changes to its current rules. MISO has achieved a high level of stakeholder support for these changes. More specifically, MISO is looking to implement major changes to its RA construct for the 2023-24 Planning Year.[39] WVPA, as a member of MISO, was well aware of this FERC filing and proposed reforms to the RA construct. The changes were extensively discussed in MISO's Resource Adequacy subcommittee prior to WVPA finalizing its IRP.[40] Notwithstanding its knowledge of upcoming changes to the RA construct, WVPA has not addressed the implications in this 20-year IRP. At the very minimum, WVPA should have commented on the directional implications of the proposed changes, which would have been clear given the extent to which these changes were discussed in the RA subcommittee throughout this past year.

In its filing to the FERC, MISO detailed its planned changes to the RA construct, as well as changes to resource accreditation rules. First, MISO is proposing to move from an annual to a seasonal RA

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[37] *Id.*

[38] NREL, U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020, at 8 (Jan. 2021), https://www.nrel.gov/docs/fy21osti/77324.pdf *available at* (last visited Jan. 31, 2022).

[39] MISO, Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct, at 1164 (Nov. 30, 2021), *available at* https://cdn.misoenergy.org/2021-11-30_RAN%20Seasonal%20Construct%20and%20Availability%20based%20accreditation608310.pdf (last visited Jan. 31, 2022).

[40] *See* https://www.misoenergy.org/stakeholder-engagement/committees/resource-adequacy-subcommittee/ (last visited Jan. 31, 2022).

construct. Second, MISO will also change resource capacity accreditation rules and base them on availability during times of need (each season), aligning the contribution of capacity to the seasonal RA construct and improving the management of reliability risks associated with increased penetration of intermittent resources. Current rules rely on an annual construct, with resource accreditation and system need defined around the peak summer period, which has overstated the capacity contribution of some resources to load conditions in other seasons.

For solar PV resources specifically, which feature prominently in WVPA's current supply portfolio as well as its base resource expansion plan, MISO plans to move away from an annual evaluation of solar generation contribution during system need, to a seasonal capacity credit allocation mechanism based on actual observed generation during times when resources are most needed.[41] While solar resource accreditation for spring, summer, and fall months would be similar to current rules, MISO anticipates that winter accreditation of solar resources would be dramatically different - close to 0 MW.[42,43]

This change to the solar capacity accreditation rules would affect WVPA's current and future resources (whether owned or contracted). Indeed, whether WVPA owns an intermittent resource or contracts for the full output of the resource, they can only benefit from an amount of capacity for that resource as high as MISO's rules allow. If the capacity accreditation of these resources declines in the winter season due to the new rules, WVPA's capacity supply portfolio will decline accordingly, resulting in incremental capacity needs to ensure resource adequacy. WVPA anticipates that by 2040, they will own or contract for approximately 700 MW of solar resources on an Unforced Capacity ("UCAP") basis.[44] As such, the new rules could create a shortfall of 700 MW of UCAP in the winter.

If WVPA had considered the upcoming MISO accreditation rules in theirs analyses, notably with respect to the risk the new rules pose to WVPA's preferred portfolio expansion strategy, the optimal base supply expansion plan may have been different (for instance, by including fewer solar

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[41] MISO, Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct, at 1109 (Nov. 30, 2021), *available at* https://cdn.misoenergy.org/2021-11-30_RAN%20Seasonal%20Construct%20and%20Availability%20based%20accreditation608310.pdf (last visited Jan. 31, 2022).

[42] Specifically, solar capacity credits will be based on historic output during hours ending 15, 16 and 17 EST for the relevant Spring, Summer, and Fall months (same as current rules). Winter accreditation will be based on hours 8, 9, 19 and 20 EST for the Winter months. The selected hours represent the typical seasonal peak demand hours for the specified Seasons.

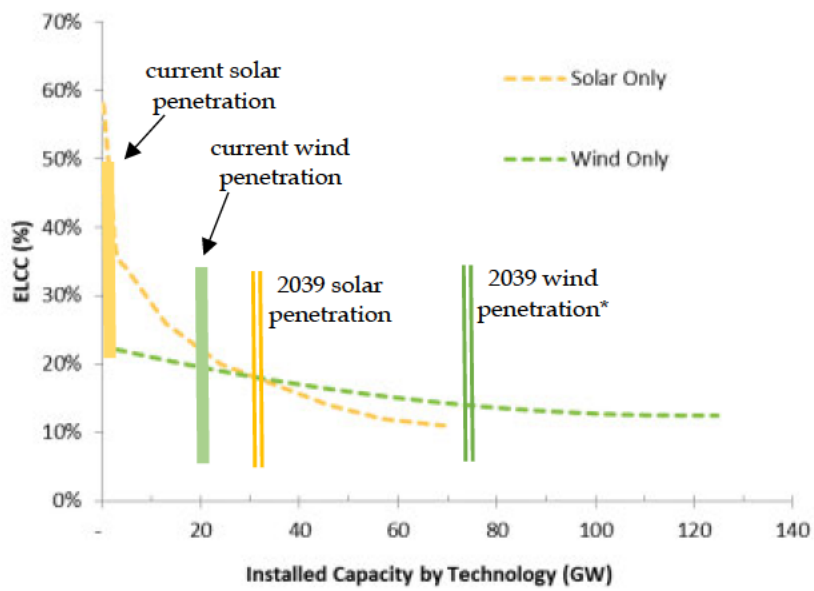
[43] MISO, Wind / Solar Generation Dispatch Assumptions In The Reliability Planning Models. Planning Subcommittee (PSC), at 20 (Oct. 15, 2019), *available at* https://cdn.misoenergy.org/20191015%20PSC%20Item%2004d%20Historical%20and%20Projected%20Wind%20Solar%20Gen%20Dispatch390437.pdf (last visited Jan. 31, 2022).

[44] Comprised of 202.2 MW of existing plus 500 MW of planned additions, as shown in Appendix A to the IRP.

resources in favor of additional capacity from other technologies such as gas-fired capacity, or alternatively solar modified with energy storage capability).

Another important consideration is that wind capacity credits are currently accredited through an annual Effective Load Carrying Capability ("ELCC") methodology.[45] The ELCC of a resource measures the additional load that the system can supply with the particular generator of interest, with no net change in reliability. In the future, both solar and wind capacity accreditation rules will essentially be based on the concept of ELCC. And, as wind and solar PV penetration increases across the MISO footprint, MISO is forecasting that the ELCC rate of wind and solar PV resources will decline, as shown in the figure below.

Figure 6. Change in ELCC as a function of installed capacity



* 2039 penetration levels are based on MISO Future 2 assumptions

Sources: MISO Futures Report. Page 5. December 2021.
https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

MISO. Renewable Integration Impact Assessment Summary report. Figure RA-3, page 29. February 2021. https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

However, in the 2020 IRP analysis, WVPA has not reflected this future development. For example, WVPA is keeping the UCAP value of their wind portfolio constant throughout the forecast

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[45] MISO. Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct. Page 1109. November 30, 2021, *available at* https://cdn.misoenergy.org/2021-11-30_RAN%20Seasonal%20Construct%20and%20Availability%20based%20accreditation608310.pdf (last visited Jan. 29, 2022).

horizon. Not only is this assumption inconsistent with MISO's expectations, it puts WVPA's resource plan at risk for under-delivering the required amount of capacity to ensure resource adequacy and meet MISO rules – exposing WVPA's members to additional costs in the future (and higher rates).

As mentioned previously, MISO's proposed changes have been discussed extensively in stakeholder committees, with initial discussion on potential changes to the RA construct given the increased trend in intermittent resource penetration dating as far back as 2018.[46] At a minimum, WVPA should therefore have initiated internal evaluations and scenario analyses to determine the potential impact of such rule changes on their capacity portfolio. Unfortunately, if these analyses were performed, they are not discussed in this IRP. Overall, WVPA's lack of consideration for changes in capacity accreditation could not only skew the result of the portfolio expansion analyses, but also leave WVPA with a shortfall in capacity resources especially during the winter season.

WVPA should be asked to address:

- **Whether it has conducted any internal evaluations and scenario analyses to determine the potential impact of MISO rule changes on WVPA's capacity portfolio, and, if so, what are the findings?**

- **What is the risk of additional costs and rate impacts on members?**

5 ***<u>The 2020 IRP is incomplete in its assessment of risks of generation ownership and long-term contracts.</u>***

In this IRP, as discussed previously, WVPA is purposefully creating and expanding its supply portfolio through analyses that minimize wholesale energy or capacity market transactions. MISO's wholesale markets are extremely competitive and have been responsible for delivering approximately $3.5 billion of annual market-related benefits to customers as explained in MISO's Value Proposition.[47] In addition, according to Tipmont's analysis, the cost of energy and capacity procured through the wholesale markets is 30% less expensive than the costs of supply that WVPA is currently charging its members. This reality raises important questions about WVPA's strategic goal to construct new resources when it can purchase from the market more cheaply. Not only is WVPA's strategy to minimize the use of market purchases more expensive, it also carries more long-term risk.

Even if WVPA were to enter into long-term contract or power purchase agreement (in lieu of outright ownership and operational control), there are important tradeoffs that need to be made

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[46] *See* https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/#nt=%2Friiatype%3AMeeting%20Recordings&t=10&p=0&s=Updated&sd=desc (last visited Jan. 31, 2022).

[47] *See* https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/ (last visited Jan. 31, 2022).

vis-à-vis shorter term market purchases. As shown in Table 2-8 (page 20) of WVPA's 2020 IRP, WVPA has over time executed many long-term contracts to supplement generation from its own resources. However, many of WVPA's previous long-term contract decisions have turned out to be costly to members. Indeed, a review of Duke Energy Indiana's *Electronic Quarterly Report* filings with the FERC indicate that Duke is charging WVPA currently in excess of $20/kW-month for hundreds of MWs of capacity (which is very much "out of the money" when compared against WVPA's avoided cost of capacity and [redacted] than WVPA's assumed bilateral capacity price of [redacted]). In a similar vein, the 150 MW firm contract with AEP, expiring in 2033, similarly carries a demand rate in excess of $20/kW-month. Indeed, WVPA specifically identified these contracts as a major supply procurement cost in discussions with its members and a primary source of WVPA rate increases for 2021.

WVPA claims that they want to avoid market purchases due to the volatility of market prices.[48] Although wholesale market prices can vary over time, long-term contracts at fixed price and generation ownership come with their own set of risks. For example, owned assets carry operational risks. Alternatively, due to technology improvements or a shift in market fundamentals, a generation investment can become uneconomic well before it is fully depreciated. Finally, there is also regulatory risk with long-term contracts and owned assets as regulators may impose new requirements that result in additional operating costs or capital expenditure, or even force the early retirement of a generation asset.

In addition, asset ownership carries additional financing burdens that market purchases do not – such as, for instance, equity requirements, borrowing costs, or additional margin requirements. In the IRP, WVPA did not share the impact on rates charged to its members from the various supply portfolios that it considered, and whether such impacts are reasonable. This lack of transparency is unfortunate, especially since WVPA's Budgets and Forecasting Department incorporates the production costing results with other corporate costs to develop budget, short-term (3-6 years), and long-term (20 years) financial forecasts.[49] In summary, WVPA has ignored many risks of ownership and long-term contracts in its integrated resource plan.

Spot market purchases can allow suppliers to balance and limit economic risks associated with long-term contracts or owned assets. In the longer term, spot markets will also reflect technological gains (in terms of efficiency improvements and lower costs) and innovation (in terms of adoption of new technologies that are lower cost than existing technologies). A long-term contract with a fixed price or a cost of service arrangement for a fixed technology robs consumers from harvesting the benefits of competitive wholesale markets.

Tipmont submits WVPA should be called upon to address the following questions:

- **Has WVPA considered whether relying on long-term ownership or contracting for resources may become uneconomic because of innovation or regulatory developments, especially given its current uneconomic investments.**

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[48] 2020 IRP, at 71.

[49] *Id.* at 8.

- **To achieve a prudent balance of low prices, reasonable volatility, reliable supply, and risk management, shouldn't WVPA analyze various levels of market purchases as part of the supply portfolio?**

- **Wouldn't such a portfolio appropriately offer some level of hedging of market prices, while also providing members with benefits from efficiencies inherent to markets as well as reducing risks associated with long-term commitments?**

Given the magnitude of stranded costs that WVPA claims in relation to Tipmont's potential exit, Tipmont has serious concerns that WVPA has undervalued the risks inherent in long-term commitments in a dynamic wholesale market environment with a functioning market. In other words, Tipmont is concerned that WVPA is preparing to further entrench itself in inefficient investments that create a "poison pill" for members who may seek to leave WVPA. That is <u>not consistent</u> with prudent resource planning or ultimately in the economic interests of members and end users.

III. <u>Conclusion</u>

Tipmont offers these comments in the interests of serving its members and ensuring that they have access to most efficient and reliable service possible. Tipmont believes the issues it has identified and questions it has raised should be addressed by WVPA prior to the Director's final report.

January 31, 2022

US.136593688.01

Wabash Valley Co-ops:
Projected Stranded Cost Calculations

Co-op Member	MWh Used WVPA 2020 Budget Projection	MWh Percentage WVPA 2020 Budget Projection	Projected Stranded Cost Per WVPA FERC filing
Boone REMC	402,976.6	5.51%	$169,745,769
Carroll White REMC	396,920.9	5.43%	$167,194,928
Citizens Electric Corporation (Missouri)	725,831.4	9.92%	$305,741,845
Corn Belt Energy (Illinois)	697,404.7	9.53%	$293,767,671
EnerStar Electric Cooperative (Illinois)	87,691.2	1.20%	$36,938,150
Fulton County REMC	103,998.6	1.42%	$43,807,314
Heartland REMC	692,659.9	9.47%	$291,769,020
Hendricks Power Cooperative	836,347.0	11.43%	$352,294,314
Jasper County REMC	240,569.7	3.29%	$101,335,137
Jay County REMC	183,304.3	2.51%	$77,213,241
Kankakee Valley REMC	302,728.3	4.14%	$127,518,194
Kosciusko REMC	498,273.6	6.81%	$209,887,709
LaGrange County REMC	103,886.1	1.42%	$43,759,925
Marshall County REMC	105,580.2	1.44%	$44,473,531
Miami-Cass REMC	138,934.8	1.90%	$58,523,484
M.J.M. Electric Cooperative (Illinois)	141,405.5	1.93%	$59,564,216
Newton County REMC	52,585.3	0.71%	$22,150,499
Ninestar Connect	299,138.1	4.09%	$126,005,894
Noble REMC	230,854.5	3.16%	$97,242,804
Parke County REMC	201,898.8	2.76%	$85,045,799
Steuben County REMC	200,393.6	2.74%	$84,411,764
Tipmont REMC	560,264.2	7.66%	$236,000,000
Warren County REMC	112,144.6	1.53%	$47,238,652
TOTALS	7,315,791.9		$3,081,629,860

Calculations were based on Wabash Valley's stranded cost figure of $236 million for Tipmont REMC reported to the Federal Energy Regulatory Commission and compared against Tipmont's 7.66% ownership of Wabash Valley. All co-ops are located in Indiana unless otherwise noted.

EXHIBIT A

PUBLIC VERSION - CONFIDENTIAL DATA REDACTED

FORWARD-LOOKING STRANDED COST EXPOSURE STUDY

Tipmont Rural Electric Membership Corporation– Early Departure From Wabash Valley Power Association, Inc.

BLACK & VEATCH PROJECT NO. 403479

FERC DOCKET NO. ER20-____-000

PREPARED FOR

Wabash Valley Power Association

27 JANUARY 2020

BLACK & VEATCH

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1. Executive Summary

1.1. INTRODUCTION

Wabash Valley Power Association, Inc. ("WVPA") is a generation and transmission ("G&T") cooperative that serves the wholesale power supply needs of twenty-three (23) Distribution Members ("Members") located in Indiana, Illinois and Missouri. On October 1, 2018, Tipmont Rural Electric Membership Corporation ("Tipmont") filed a complaint in Docket No. EL19-2-000 with the Federal Energy Regulatory Commission ("FERC" or the "Commission") asking the Commission to find that Tipmont be allowed early termination of its two wholesale power contracts ("Tipmont Contracts") with WVPA subject to Tipmont paying demonstrated stranded costs ("Tipmont Complaint").

On September 19, 2019, the Commission issued an order holding the Tipmont Complaint in abeyance for 90 days noting the parties stated in their pleadings that the issues related to the rates, terms and conditions for the early termination of the Tipmont Contracts could be addressed in a proceeding initiated by WVPA filing an unexecuted termination agreement proposing rates, terms and conditions to govern the early termination of the Tipmont Contracts and ordering WVPA to submit a status report within 90 days indicating whether – and if so, when – WVPA intends to make such a filing.

On December 12, 2019, WVPA filed a status report with the Commission reporting that on December 4, 2019, the WVPA Board of Directors authorized the filing of an unexecuted agreement containing the rates, terms and conditions for early termination of the Tipmont Contracts and that it anticipated filing the early termination agreement on or before February 21, 2020.

The early termination agreement approved by the WVPA Board provides (i) for a ten-year Buyout Period consistent with the terms and conditions of the Tipmont Contracts during which Tipmont is to remain a member of WVPA and purchase all of its electric power and energy requirements from WVPA, (ii) requires Tipmont to deposit into an escrow account each month buyout amounts at the board approved 10-year buyout rate of $14.91/MWh for all energy purchased by Tipmont during the Buyout Period, and (iii) upon completion of the Buyout Period pay over to WVPA's Trustee the amounts deposited by Tipmont, plus accrued interest, whereupon the Tipmont Contracts would be terminated at the end of the Buyout Period.

WVPA requested Black & Veatch Management Consulting, LLC. ("Black & Veatch") to prepare a study that quantifies WVPA's stranded cost exposure for both the contractual ten-year Buyout Period (stranded costs from 2031 to 2050) and an immediate termination of Tipmont's Contracts (stranded costs from 2021 to 2050), as requested in the Tipmont Complaint. This report presents and documents the study methodology and results for each of these scenarios.

1.2. OVERVIEW OF WABASH VALLEY POWER ASSOCIATION

WVPA is a not-for-profit generation and transmission cooperative formed in 1963 under Indiana law to enable its member cooperatives to obtain reliable long-term, all-requirements power. WVPA's twenty-five (25) Members are both owners and customers of WVPA. Twenty-three of the Members including Tipmont are not-for-profit distribution electric cooperatives that provide electric energy to their members at retail across the States of Indiana, Illinois, and Missouri. These WVPA Members serve nearly 300,000 residential customers and about 19,000 commercial and industrial customers. The other two Members are Wabash Valley Energy Marketing, Inc., a subsidiary of WVPA, and J. Aron & Company, Inc., neither of which has retail load serving obligations.

WVPA provides full requirements wholesale power and transmission services at cost-based rates to its Members pursuant to long-term wholesale power supply contracts. Each Member is required to pay WVPA for power furnished under the agreement in force in accordance with a Commission filed and approved Formulary Rate Tariff, FERC Electric Tariff Volume 1. The Members' aggregate peak demand requirement is about 1,565 MW in 2020. WVPA meets its Members' capacity and energy needs through a portfolio of owned and contracted power supply resources. WVPA currently owns approximately 1,100 MW of generating capacity in Indiana and Illinois and meets the remainder of its Members' needs through multiple power purchase agreements ("PPAs"). These PPAs have varying terms, and some extend through 2050.

WVPA is a transmission owner and transmission customer of the Midcontinent Independent System Operator ("MISO"), a transmission customer of PJM Interconnection, LLC ("PJM"), and a market participant in both MISO and PJM.

1.3. PURPOSE OF STUDY

Tipmont has executed two Wholesale Power Supply Contracts (WPCs) with WVPA. The 1977 Contract governs service until April 14, 2028. The 2006 Contract extends Tipmont's all-requirements power purchase obligation to December 31, 2050 and allows for early termination of both contracts. Early termination of the Tipmont Contracts is governed by the terms of the 2006 Contract and WVPA Board Policy D-2, which established a ten-year notice and buyout period.

WVPA retained Black & Veatch to evaluate WVPA's stranded cost exposure for the two scenarios described in Section 1.1 above.

1.4. STUDY METHODOLOGY

Black & Veatch used a three-step methodology that compares the costs derived under a Base Case (which assumes that Tipmont will remain a Member through December 31, 2050) to the costs derived under a Change Case (which assumes Tipmont leaves WVPA on either January 1, 2031 or January 1, 2021 and, thereafter, purchases its power requirements from a supplier other than WVPA). The stranded costs are calculated as the amount that would have to be paid by Tipmont to keep WVPA's other Members' costs unchanged over the Study's forecasted period.

1.5. STUDY RESULTS

The results for the ten-year Buyout Scenario over the forecasted period January 1, 2031 to December 31, 2050, show stranded costs (comprised of stranded power supply and fixed costs) of approximately $132 million, on a nominal basis. This amount is the total costs WVPA's remaining Members would have to absorb if Tipmont ceased its power purchases on January 1, 2031 without paying any stranded costs.

The results for the 30-year Buyout Scenario over the forecasted period January 1, 2021 to December 31, 2050, show stranded costs (comprised of stranded power supply and fixed costs) of approximately $319 million, on a nominal basis. This amount is the total costs WVPA's remaining Members would have to absorb if Tipmont ceased its power purchases on January 1, 2021 without paying any stranded costs.

2. Study Methodology

Black & Veatch used a three-step methodology to calculate WVPA's power supply-related stranded costs, as described below.

Step 1: Black & Veatch grouped WVPA's costs into two broad categories: Power Supply Costs and Fixed Costs. The following sections of this Report discuss in detail the costs included in each of these two categories. Black & Veatch then prepared a Base Case forecast of the Power Supply Costs using PROMOD(T), a computer-based chronological production costing model. Black & Veatch also reviewed WVPA's Fixed Costs forecasts. The Base Case assumes that Tipmont will remain a Member throughout the term of the Tipmont Contracts (i.e., through December 31, 2050).

Step 2: Black & Veatch prepared a Change Case forecast. The Change Case assumes that the Tipmont Contracts are terminated on either January 1, 2031 or January 1, 2021 and, thereafter, Tipmont purchases its power requirements from a supplier other than WVPA. Like the Base Case, power supply costs were forecasted using the PROMOD(T) model. The Fixed Costs forecast used in the Change Case was developed in consultation with WVPA.

Step 3: For each Case, Black & Veatch calculated an annual $/MWh rate that includes both Power Supply Costs and Fixed Costs. If Tipmont pays for all stranded costs related to the early termination of the Tipmont Contracts, the $/MWh rate for WVPA's remaining Members would remain unchanged. Using this analytical construct, Black & Veatch calculated the cost recovery from WVPA's remaining Members at a constant $/MWh cost level. The difference between the cost recovery from WVPA's remaining Members and the total Change Case cost is the stranded cost amount.

3. WVPA's Power Supply Costs

This section of the Report describes Black & Veatch's study of power supply-related stranded costs.

3.1 MEMBER LOADS

As described earlier, WVPA manages a portfolio of power supply resources designed to provide all-requirements services to its 23 Distribution Members. WVPA's Members are in six balancing areas. Within the MISO Region, WVPA serves members in the Duke Energy Indiana, Northern Indiana Public Service, Indianapolis Power and Light, Ameren Missouri and Ameren Illinois balancing areas. Tipmont is part of the Duke Energy Indiana balancing area. Additionally, WVPA serves members through a load-following contract in the PJM Region in the American Electric Power balancing area. The costs for WVPA's remaining two members were not included in the analysis because WVPA does not procure firm resources for these entities.

Figures 1 and 2 below provide an overview of the Energy and Peak Demand served by WVPA for each of the six balancing areas. For easy reference, Tipmont's load has been presented separately. The total load grows at a modest Annual Average Growth Rate ("AAGR") of 1% for both Energy and Peak Demand. As discussed in the following sections, Tipmont represents approximately 8% of the total Energy and Peak Demand served by WVPA.

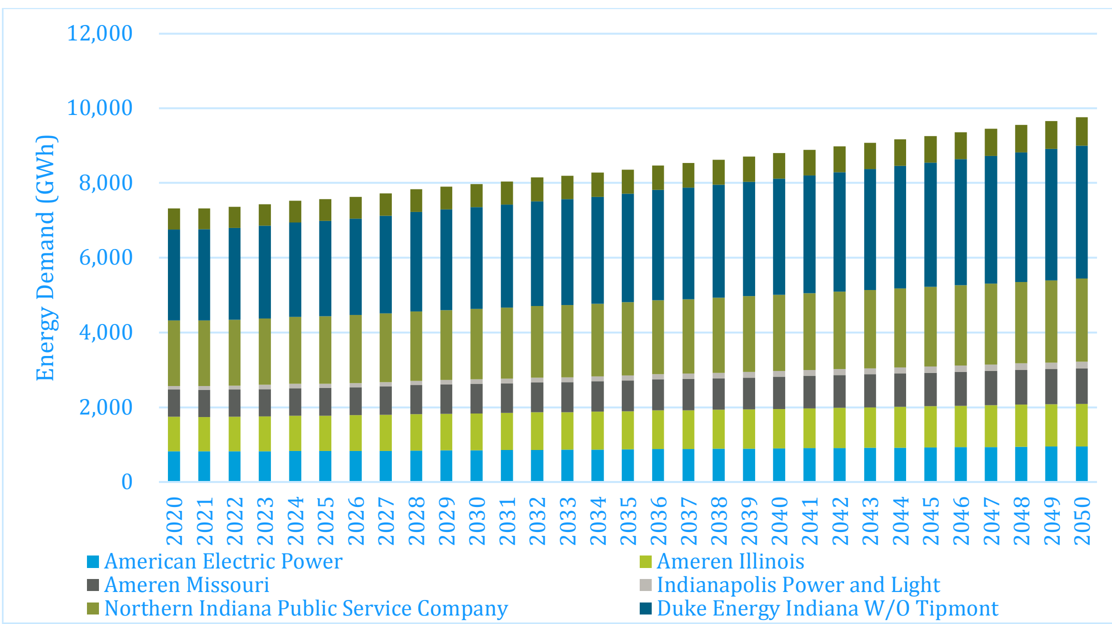

Figure 1 Energy by Balancing Area

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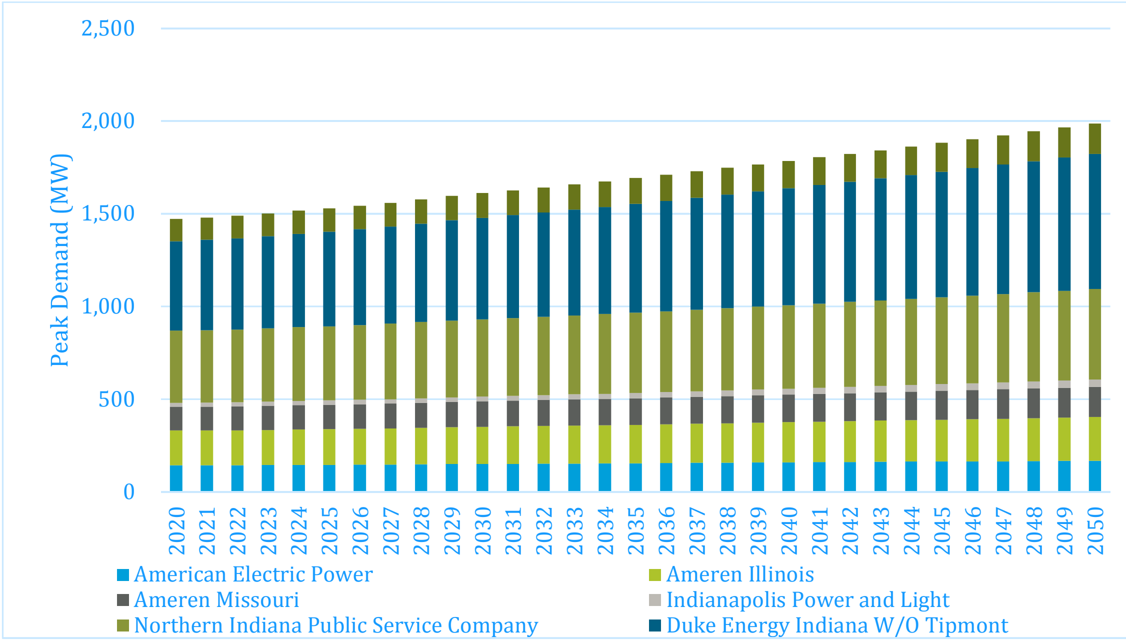

Figure 2 Peak Demand by Balancing Area

3.2 POWER SUPPLY OVERVIEW

WVPA owns over 1,000 MW of generation resources. These include coal-fired generation, natural gas-fired combined cycle and combustion turbines, landfill gas and a small portfolio of solar assets. Table 1 below provides an overview of the WVPA-owned generation resources that were modeled in the Study.

Table 1 Modeled Generation Units

UNIT	BALANCING AREA OR STATE	FUEL TYPE	ICAP (MW)	PROJECTED RETIREMENT DATE
Gibson Unit #5	Duke Indiana	Coal	156.25	12/31/2026
Prairie State	Ameren Illinois	Coal	83	10/31/2043
Holland CC	Ameren Illinois	Natural Gas	315.00	-
WR Highland CT	Duke Indiana	Natural Gas	166	-
Vermillion CTs	Duke Indiana	Natural Gas	267	-
Lawrence CTs	Duke Indiana	Natural Gas	98	-

Deer Croft	NIPSCO	Natural Gas	3.20	-
Clinton	Ameren Illinois	Land Fill Gas	3.20	1/31/2034
Deer Croft 2	NIPSCO	Land Fill Gas	3.20	12/31/2028
Earthmovers	AEP	Land Fill Gas	4.80	10/26/2030
Jay County	AEP	Land Fill Gas	3.20	12/31/2028
Liberty 1	NIPSCO	Land Fill Gas	3.20	12/31/2028
Liberty 2	NIPSCO	Land Fill Gas	3.20	1/22/2030
Liberty 3	NIPSCO	Land Fill Gas	6.40	1/4/2037
Oak Ridge	Duke Indiana	Land Fill Gas	3.20	12/31/2028
Prairie View 1	NIPSCO	Land Fill Gas	3.20	12/31/2028
Prairie View 2	NIPSCO	Land Fill Gas	3.20	12/31/2028
Twin Bridges 1	Duke Indiana	Land Fill Gas	3.20	12/31/2028
Twin Bridges 2	Duke Indiana	Land Fill Gas	3.20	12/31/2028
Twin Bridges 3	Duke Indiana	Land Fill Gas	3.20	01/16/2029
Twin Bridges 4	Duke Indiana	Land Fill Gas	3.20	06/06/2032
Kankakee Solar	NIPSCO	Solar	0.11	-
Citizen's Electric Solar	Ameren Missouri	Solar	1.14	-
Enerstar Electric Solar	Ameren Illinois	Solar	0.54	-
Miami Cass Solar	Duke Indiana	Solar	0.54	-
Jasper Solar	NIPSCO	Solar	3.00	-
Noble Solar	AEP	Solar	1.00	-

WVPA also has committed to approximately 1,600 MW of PPAs, over varying time periods, to meet its Members' load. Table 2 below provides an overview of these purchased power contracts that were modeled in the Study.

Table 2 Modeled Purchased Power Contracts

CONTRACT	BALANCING AREA OR STATE	CONTRACT TYPE	ICAP (MW)	START DATE FOR FUTURE CONTRACTS	EXPIRATION DATE
Ameren Sale	Illinois	Sale	3.20	-	2/24/2022
Duke 150/180	Duke Indiana	Purchase	150.00 160.00 170.00 180.00	-	5/31/2020 5/31/2022 5/31/2023 12/31/2031
Duke 55	Duke Indiana	Purchase	55.00	-	12/31/2025
Duke 70	Duke Indiana	Purchase	70.00	-	12/31/2032
AEP Load Following	AEP	Purchase	143.70	-	12/31/2033
Henry County CTs	Duke Indiana	Purchase	50.00	-	5/31/2025
County Line	Indiana	Purchase	4.37	-	12/4/2039
AgriWind PPA	Illinois	Purchase	8.40	-	12/31/2038
Harvest Ridge Wind	Illinois	Purchase	100.00	7/1/2020	6/30/2040
Meadow Lake V&VI Wind	Indiana	Purchase	25.00 75.00	-	1/2/2038 12/11/2038
Pioneer Trail Wind	Illinois	Purchase	10.00	-	2/8/2030
Dresser Plains Solar	Illinois	Purchase	99.00	1/1/2021	12/31/2047
Prairie State Solar	Illinois	Purchase	99.00	6/1/2020	5/31/2047
Hendricks Solar	Indiana	Purchase	0.03	-	7/6/2034
Speedway Solar	Indiana	Purchase	199.00	7/1/2023	6/30/2050

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MERCURIA ENERGY - JPMorgan 100MW	Indiana Hub	Purchase	100.00	-	12/31/2023
Morgan Stanley 18-25 100 MW	Indiana Hub	Purchase	100.00	-	12/31/2025
Morgan Stanley 19-22 100 MW	Indiana Hub	Purchase	100.00	-	12/31/2022
Morgan Stanley 24-35 50MW	Indiana Hub	Purchase	50.00	1/1/2024	12/31/2035
Morgan Stanley 26-32 100MW	Indiana Hub	Purchase	100.00	1/1/2026	12/31/2032
NextEra 21-30 50MW	Indiana Hub	Purchase	50.00	1/1/2021	12/31/2030
NextEra 24-32 50MW	Indiana Hub	Purchase	50.00	1/1/2024	12/31/2032

Appendix A to this report presents a detailed listing of Wabash Valley's Power Supply Cost Assumptions and Appendix B presents a detailed listing of Wabash Valley's Transmission Costs.

3.3 POWER SUPPLY COSTS

To begin our power supply cost analysis, Black & Veatch created the Base Case in its production costing model. To evaluate the costs of generation, Black & Veatch utilized PROMOD(T), licensed through ABB Ventyx. PROMOD(T) is a computer-based chronological production costing model developed for use in power supply system planning. PROMOD(T) simulates the hour-by-hour operation of a power supply system over a specified planning period. Required inputs include the operating and performance characteristics of generating units, fuel costs, and the system hourly load profile for each year. PROMOD(T) is a widely-used production modeling platform in the electric utility industry and has proven to be an effective production and simulation modeling program for the analysis of production dispatch and costing scenarios.

PROMOD(T) summarizes each generating unit's operating characteristics for every year of the planning or forecasting horizon. These characteristics include, among others, each unit's annual generation, fuel consumption, fuel cost, average net operating heat rate, the number of hours the unit was online, the capacity factor, variable operation and maintenance ("O&M") costs, and the number of starts and associated costs. Because Fixed O&M costs for existing units are generally considered sunk costs, PROMOD(T) does not consider these sunk costs in developing the dispatch costs of the generating units but does report these costs as part of the total operating costs.

For purposes of this Study, Black & Veatch input the following items into the power costing model based on historical information or forecasts either provided by WVPA or developed by Black & Veatch.

- Peak Demand and Energy forecast provided by WVPA.
- Unit or Contract Capacity provided by WVPA or obtained by Black & Veatch through contract review.
- Generating Profile for owned and contracted renewables provided by WVPA (data obtained either from developer or based on historical information).
- Energy Price and Fuel Price forecasts developed by Black & Veatch.
- Unit or Contract Operating Characteristics such as Variable O&M, Heat Rates (and incremental operating information, where applicable), Forced and Scheduled Outages, Run Times and Start-up Characteristics and Costs provided by WVPA.

Black & Veatch reviewed the historical data, PPAs and other documentation supporting the inputs into its production costing model. Black & Veatch also assumed that upon retirement or contract expiration of a generating unit, the energy required to meet customer loads would be procured through wholesale energy market purchases. The production costing model utilized a 1.8% escalation rate based on the recent Consumer Price Index ("CPI") for All Urban Consumers.

The production costing model simulated an hourly dispatch of units, contracts and market sales and purchases against load for each balancing area. The resulting outputs include the following:

- Unit and contract generation
- Variable O&M Costs
- Fuel Costs
- Net Market Purchases and Market Sales

In addition to the costing analysis conducted using the production costing model, Black & Veatch calculated the Fixed O&M cost for WVPA's generating units based on historical data. Demand charges for its PPAs were based on forecast data from the supplier. Black and Veatch also calculated forecasted transmission costs based on tariff and contract information provided by WVPA. Black & Veatch worked closely with WVPA to incorporate all transmission costs and any offsetting transmission revenue for each balancing area. These costs are either fixed or based on the level of load supplied. Black & Veatch utilized contractual escalation rates when specified, or a nominal 1.8% escalation rate, in most cases, if not specified.

3.4 PRIMARY PRICE INPUTS

This section describes the primary price inputs Black & Veatch utilized to model WVPA's stranded cost exposure.

Energy Prices

Black & Veatch used internally developed energy price forecasts as inputs into its production cost modeling to determine the dispatch of WVPA-owned units and the price for market sales and purchases, as needed, to meet WVPA's load on an hourly basis. In the event of a shortfall in meeting load in a single hour, market purchases were made at the forecasted market price.

Black & Veatch develops fundamental market price forecasts for the U.S. Energy Markets on a regular basis. Black & Veatch employs an integrated market assessment approach as the basis for the current industry structure as well as a starting point for long-term energy price analysis. In order to arrive at this market view, Black & Veatch draws on several commercial data sources and supplements them with its own assumptions for certain key market drivers (e.g., power

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plant capital costs, environmental and regulatory policy, natural gas exploration and development costs, and gas pipeline expansions). Black & Veatch uses all this information to develop a basis for modeling the U.S. power market.

Black & Veatch's fundamental price forecasting process employs an integrated view of the key drivers impacting North American power markets. Critical elements of the fundamental price forecasting process include the following:

- A thoughtful, transparent and internally consistent approach to analyses of the energy markets, industry trends, and the government policies that influence them;
- Incorporation of Black & Veatch's engineering and technical expertise across all key assumptions;
- A perspective on generation fuel sources; and
- An overall perspective of the electric power markets.

Black & Veatch's fundamental price forecasting process is designed to capture both the broad policy level assumptions and detailed structural market representations to arrive at a consistent market view. From a "top down" perspective, Black & Veatch assesses the current state of energy and environmental policies at both a U.S. and global level to determine their impacts on North American and regional energy markets and prices.

Concurrently, Black & Veatch addresses North American commodity markets using a detailed "bottom up" approach, using sophisticated structural market models to simulate market participant behavior in terms of new resource development, utilizing model inputs as diverse as power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and projected gas pipeline expansions.

Listed below are some of the key inputs that drive Black & Veatch's fundamental price forecasting process:

- Regional energy and peak demand forecast based on publicly available data.
- Black & Veatch's assumptions for coal plant retirements to meet proposed environmental regulations.
- Natural gas price forecasts for different gas trading hubs developed by Black & Veatch.
- Delivered coal price forecasts for all U.S. coal plants as well as mine mouth coal prices for different coal basins.
- Capital cost, operating costs and operational parameters for different generating alternatives spread across different technologies (i.e., for both conventional and renewable resources) developed by Black & Veatch.
- Renewable portfolio standards ("RPS") requirements by state and forecasts of renewable resources build out developed by Black & Veatch to meet state RPS requirements.
- Inter-zonal electric transmission constraints.
- Announced unit commissions and retirements.

Regional expansion plans developed by Black & Veatch to meet regional reliability criteria. These expansion plans consider the mix of units with different technologies.

Natural Gas Prices

Black & Veatch utilized the NYMEX Henry Hub natural gas futures prices for October 2, 2019 as a starting point. The Study utilized theses prices from 2020 through 2031. Beyond 2031, Black & Veatch calculated the 5-year CAGR of the NYMEX Henry Hub futures price curve for the 2027-2031 period and used that growth rate to extend the Henry Hub price curve out to 2050. The resulting price trajectory beyond 2031 closely tracks the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") 2018 High Oil & Gas scenario. The regional locational basis used in the Study is based on Black & Veatch's Energy Market Perspective ("EMP") and its long-term market fundamental model.

Black & Veatch used the NYMEX Henry Hub futures price curve based on our analysis of WVPA's fixed price PPAs over the past 4 years. Based on Black & Veatch's judgment, there existed a reasonable relationship between the NYMEX Henry Hub price levels and the future electric prices in WVPA's PPAs, after taking into consideration the implied market heat rate for the region.

Capacity Prices

The capacity costs and revenues were derived by calculating the capacity price based on the weighted average of WVPA's actual contracted costs for three recently executed PPAs at three different solar facilities. The equivalent capacity price was calculated considering the "all in" energy prices, associated prices for applicable renewable energy credits ("RECs"), the impact of the investment tax credit and the effective load carrying capacity ("ELCC") of solar resources (50 percent) as per the recent MISO guidelines. The energy prices for these contracts were all constant in nominal dollars until the end of the PPA term (2047 for two of these contracts and 2050 for the third contract). The capacity price as calculated under the above method was $119.34/MW-day. Since the contract prices were constant in nominal dollars without any escalation, Black & Veatch assumed the capacity price to be $119.34/MW-day in nominal dollars from 2026 until 2050. For the years 2020 through 2025, Black & Veatch increased the capacity prices from the recent capacity price level of $22.34/MW-day observed in the MISO market.

Appendix C to this report presents the energy, natural gas and capacity price forecasts that Black & Veatch used in this Study.

3.5 BASE CASE

The Base Cases reflect each of the assumptions described above related to Member loads, WVPA-owned generation units, PPAs and primary price inputs to derive WVPA's power supply costs on an annual basis for both scenario forecasted periods.

3.6 CHANGE CASE

To model the Change Case scenarios, Black & Veatch excluded Tipmont's Energy and Peak Demand from the analysis for the applicable periods. Under these scenarios, the dispatch of WVPA-owned generating units remained unchanged and, therefore, there was no change to the Variable O&M, Fixed O&M and Fuel Cost components. The reduced load, however, resulted in increased market sales in the early years and decreased market purchases in the later years. Because WVPA is long on generation and energy contracts in the early years, the net supply was greater than the load. This excess energy was sold in the market at Black & Veatch's forecasted energy market price for the corresponding hour, thereby increasing net market sales and revenues.

The Transmission Cost also decreased because certain rate calculations are based on load. Finally, the cost of capacity decreased due to the reduced load. Capacity and energy market revenues are treated as an offset to the power supply costs. There were no other changes to the costs.

4. WVPA's Fixed Costs

Black & Veatch reviewed WVPA's income statement to identify costs not included in the power supply cost analysis described in the previous section. WVPA provided Black & Veatch with current and forecasted fixed costs. While WVPA's Fixed Costs are not modeled as a component of its Power Supply Costs, they must also be recovered from its Members in addition to Power Supply Costs. Table 3 below presents WVPA's Fixed Cost Components for the Base Cases for 2021, the first year of the 30-year forecasted period. Appendices E and F to this report contain an annual summary of the Base Case Fixed Costs for both scenario forecast periods.

Table 3 WVPA's Fixed Cost Components – Base Case

FIXED COST COMPONENTS	2021 BASE CASE FORECAST ($ IN 000'S)
Pass Through Customer Administrative Adder	$(2,388)
Demand Response ("DR") Credits	$3,330
Amortization of Previous Member Buyout	$(783)
Property Tax	$5,773
Property Insurance	$1,682
Portfolio Management/Schedule Fees	$2,367
Gas Hedges	$515
Emissions Cost	$-
Energy Efficiency ("EE") Program Costs	$5,500
Demand Response Pilots	$-
Departmental A&G and O&M	$35,859
Depreciation	$53,390
Amortization	$7,586
Other Taxes	$1,021
Interest Expense on Long-Term Debt	$39,531
Interest Income	$(1,530)
Renewable Energy Credits (REC) Revenue	$(2,072)
Patronage Capital Income	$(2,914)
Margin	$26,000
Total	**$172,868**

4.1 BASE CASE

Black & Veatch has reviewed WVPA's 2021 forecast of fixed costs and considers it to be reasonable. The underlying methodology and assumptions used by WVPA to forecast its fixed costs are discussed in greater detail in Appendix D to this report.

4.2 CHANGE CASE

By their very nature, a utility's fixed costs do not change significantly based on its customers' energy needs. However, WVPA was able to identify the following changes to its Base Case forecast of Fixed Costs for the reasons explained below:

- Demand Response ("DR") Credits: WVPA gives Members an annual credit for each kW of direct control capability. Tipmont's share of DR capacity is forecasted to be 1.5 MW as of January 1, 2021.
- Energy Efficiency ("EE") Program Costs: WVPA offers residential and commercial & industrial EE programs to its Members under the POWER MOVES initiative. Tipmont's share of EE costs is estimated based on its load ratio share from 2031 to 2050.
- Departmental A&G and O&M: WVPA has removed certain A&G and O&M costs. Appendix D provides a detailed discussion.
- Depreciation, Property Tax and Property Insurance: WVPA has removed costs associated with the original cost of dedicated-use transmission facilities which Tipmont will be obligated to purchase upon its departure from WVPA and Tipmont's load ratio share of future planned transmission and distribution capital expenditures from 2031 to 2050.
- Interest Expense: Removed costs associated with Tipmont's load ratio share of transmission and distribution capital expenditures from 2031 to 2050.
- Interest Income: Changes associated with the cash-flow impacts caused by the above-described changes in WVPA's Fixed Costs.
- Portfolio Management/Scheduling Fees: WVPA has removed Tipmont's load ratio share of costs from 2031 to 2050.
- Margin: WVPA has removed Tipmont's load ratio share of margins from 2031 to 2050.

Appendices E1 and F1 to this report provide an annual summary of the Change Case Fixed Costs for both scenario forecast periods.

5. Study Results

Figure 3 below shows WVPA's system demand requirement for the Base and Change Cases. The only difference between the two Cases is Tipmont's demand requirement. As a point of reference, the decrease in WVPA's peak demand under the Change Case in 2021 is 130 MW, which is approximately 8.3% lower than under the Base Case.

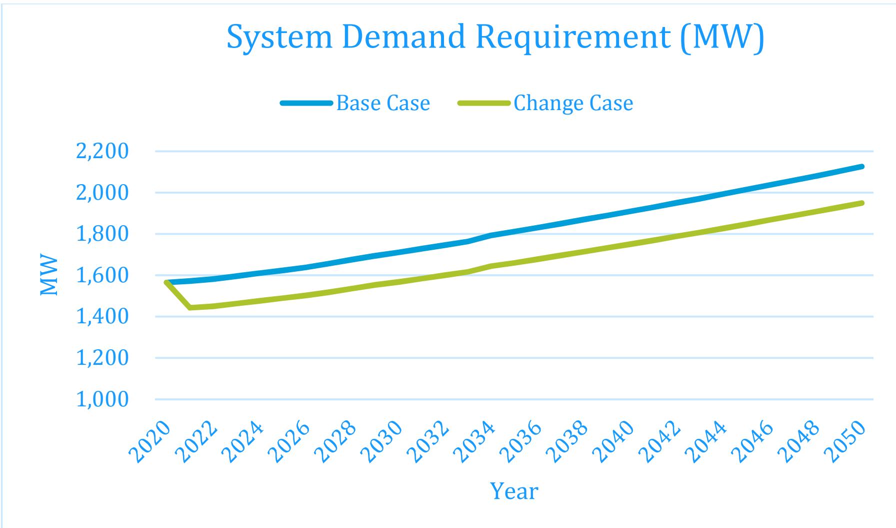

Figure 3 WVPA's System Peak Demand Per the Base and Change Cases

Figure 4 below shows WVPA's energy requirements for the Base and Change Cases. The only difference between the two Cases is Tipmont's annual energy requirement. Once again, as a point of reference, the decrease in WVPA's annual energy requirements is 562 GWh in 2021, which is approximately 7.6% lower than under the Base Case.

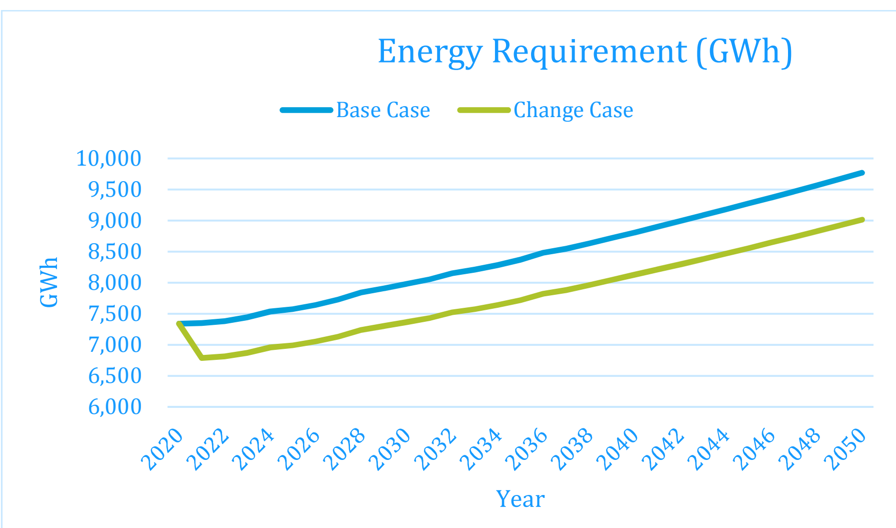

Figure 4 WVPA's Energy Requirement Per the Base and Change Cases

Figure 5 below shows WVPA's Power Supply Costs for the Base and Change Cases. As discussed in a previous section of this Report, the dispatch of WVPA-owned generation units remains unchanged from the Base Case to the Change Case. Therefore, there was no change to the Variable O&M, Fixed O&M and Fuel Cost. The reduced load, however, resulted in increased market sales in the early years of the forecasted period (2021-2030) and decreased market purchases in the later years of the forecasted period (2031-2050).

WVPA's Transmission Costs also decreased because some transmission tariffs have a volumetric-based rate component. Finally, WVPA's cost of capacity decreased due to WVPA's reduced load. In 2021, WVPA's Power Supply Costs in the Change Case decreased by 5.5% from the Base Case compared to a 7.6% decrease in its energy requirements.

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Figure 5 Comparison of Annual Power Supply Costs

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Figure 6 below shows WVPA's Fixed Costs for the Base and Change Cases. The Fixed Costs section of this Report provides the specific costs that decreased as a result of Tipmont's early departure. In 2021, WVPA's Fixed Costs in the Change Case decreased by about 0.2% from the Base Case compared to a 7.6% decrease in its energy requirements. However, by 2050, WVPA's Fixed Costs in the Change Case decreased by 3.7% from the Base Case.

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Figure 6 Comparison of Fixed Costs

END CUI/PRIV

Figure 7 below shows WVPA's Unit Costs (stated on a $/MWh basis and computed on a system wide basis) for the Base and Change Cases. Over the Study's forecasted period, WVPA's Unit Costs increased by about 4.1% per unit of its energy requirement.

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Figure 7 Comparison of Unit Costs

END CUI/PRIV

Table 4 below shows the total costs for the ten-year Buyout Base and Change Cases for Tipmont and WVPA's remaining Members in nominal dollars ($ millions). The total costs changed from approximately $14.3 billion to $13.4 billion over the period from 2031 through 2050 because of Tipmont's early termination of its WPCs with WVPA. If the remaining Members are to be made whole (i.e., if the unit costs of the remaining Members are to remain unchanged), the resulting stranded costs to be paid by Tipmont are equal to approximately $132 million.

Table 4 Summary Results (Nominal $ millions, 2031-2050)

Description	Base Case (with Tipmont)	Change Case (without Tipmont)	Unit Rate Increase to Remaining 22 Members	MWh of Remaining 22 Members	Cost Increase to Remaining 22 Members ($ million)
Power Supply Costs ($ in Millions)	$9,954	$9,116			
Fixed Costs ($ in Millions)	4,374	4,236			
Total Costs ($ in Millions)	$14,328	$13,352			
Total Sales (MWh)	177,517,000	163,788,000			
Average Member Rate ($/MWh)	$80.71	$81.52	$0.81	163,788,000	$132

Table 5 below shows the total costs for the 30-year Buyout Base and Change Cases for Tipmont and WVPA's remaining Members in nominal dollars ($ millions). The total costs changed from approximately $20.4 billion to $19.1 billion over the period from 2021 through 2050 because of Tipmont's early termination of its WPCs with WVPA. If the remaining Members are to be made whole (i.e., if the unit costs of the remaining Members are to remain unchanged), the resulting stranded costs to be paid by Tipmont are equal to approximately $319 million.

Table 5 Summary Results (Nominal $ millions, 2021-2050)

Description	Base Case (with Tipmont)	Change Case (without Tipmont)	Unit Rate Increase to Remaining 22 Members	MWh of Remaining 22 Members	Cost Increase to Remaining 22 Members ($ million)
Power Supply Costs ($ in Millions)	$14,204	$13,095			
Fixed Costs ($ in Millions)	6,156	6,012			
Total Costs ($ in Millions)	$20,360	$19,107			
Total Sales (MWh)	253,914,000	234,309,000			
Average Member Rate ($/MWh)	$80.19	$81.55	$1.36	234,309,000	$319

Appendices E, E1 and E2 to this report present the forecasted Power Supply Costs and Fixed Costs by year, and in total for the ten-year Buyout Scenario (costs from 2031-2050), for the Base and Change Cases. It also presents the calculation of stranded costs by year, and in total, over the same period. Appendices F, F1 and F2 present the same type of cost results over a 30-year Buyout Scenario (costs from 2021-2050).

Appendix A: Power Supply Cost Assumptions

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UNIT	2020 VOM, $/MWH	2020 FOM, $/KW-YEAR	FUEL COST $/MMBTU/$/MWH	HEAT RATE MIN, SUMMER, MMBTU/MWH	HEAT RATE MAX, SUMMER MMBTU/MWH	HEAT RATE AT DUCT FIRING (SUMMER) MMBTU/MWH	HEAT RATE MIN, WINTER MMBTU/MWH	MAX, WINTER MMBTU/MWH	TYPICAL SCHEDULE OUTAGE DURATION, DAYS PER YEAR	TYPICAL FORCED OUTAGE DURATION, DAYS PER YEAR
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[redacted]		[redacted]								

CONTRACT NAME	ENERGY CHARGE, $/MWH	DEMAND CHARGE, $/KW-YEAR	CONTRACT TYPE	MIN OUTPUT
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]		[redacted]	[redacted]

EXHIBIT B

[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]			[redacted]

END CUI/PRIV

EXHIBIT B

Appendix B: Transmission Costs

COUNTERPARTY	RTO	TYPE	2020 RATE	RATE TYPE	ESCALATION AND NOTES
PJM	PJM	Other Supporting Facilities and Scheduling Charges	$34,100	Per Month	1.8% escalation rate 2021 to 2050
AEP	PJM	Network (NITS)	$6,043	Per MW-Mo	1.8% escalation rate 2021 to 2050
AEP	PJM	Transmission Enhancement (RTEP)	$97,270	Per Month	1.8% escalation rate 2021 to 2050
Ameren IL	MISO	Transmission Service	$3,787	Per MW-Mo	1.8% escalation rate 2021 to 2050
Ameren IL	MISO	Wholesale Distribution Service (WDS)	$244,414	Per Month	Contractual escalations through 2022; 1.8% escalation rate 2023 to 2050
Ameren IL	MISO	Metering/O&M Charge	$5,467	Per Month	Flat throughout forecasted period
Ameren MO	MISO	Transmission Service	$1,605	Per MW-Mo	1.8% escalation rate 2021 to 2050
Ameren MO	MISO	Wholesale Distribution Service (WDS) + Administrative Charge	$10,803	Per Month	1.8% escalation rate 2021 to 2050
NIPSCO	MISO	Grandfathered Transmission Service	$2,180.00	Per MW-Mo	WVPA will pay MISO Schedule 9 OATT rate starting in 2025
NIPSCO	MISO	Grandfathered Distribution Service	$3,330.00	Per MW-Mo	Flat throughout forecasted period
NIPSCO	MISO	Grandfathered Regulation & Frequency Response Charge	$325.00	Per MW-Mo	WVPA will pay MISO Schedule 1&2 OATT rate starting in 2025
MISO	MISO	OATT	$450,000	Per Month	1.8% escalation rate 2021 to 2050

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MISO	MISO	Schedule 26 Network Upgrade Charge	Various	Per MW-Mo	Used indicative rates provided by MISO through 2024; 1.8% escalation rate 2025 to 2050
MISO	MISO	Schedule 26-A Multi-Value Project charge	$1.70	Per MWH	Used indicative rates provided by MISO through 2024; 1.8% escalation rate 2025 to 2050
Various	MISO	Facility/Wheeling Charges	$23,600	Per Month	1.8% escalation rate 2021 to 2050
DUKE JOINT TRANSMISSION SERVICE AGREEMENT					
DUKE	MISO	Load ratio share of owned transmission costs	$5,572,000	Annual	1.8% escalation rate 2021 to 2050
DUKE	MISO	Load ratio share of owned transmission revenue	$(3,070,000)	Annual	1.8% escalation rate 2021 to 2050
OTHER REVENUE					
MISO	MISO	Reactive Revenue (mostly MISO)	$(143,125)	Per Month	1.8% escalation rate 2021 to 2050
MISO	AMMO	Attachment O Revenue	$(6,207,000)	Annual	Near term forecast based on additional investment planned in AMMO; specific assumptions for 2020-2024;1.8 percent escalation thereafter

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Appendix C: Price Forecast

	ENERGY PRICE FORECAST, NOMINAL $/MWH												GAS PRICE, NOMINAL $/MMBTU		CAPACITY PRICE FORECAST, NOMINAL $/MW-DAY
	Indiana			Illinois			AEP-DAYTON			Missouri					
Year	On Peak	Off Peak	All Hours	On Peak	Off Peak	All Hours	On Peak	Off Peak	All Hours	On Peak	Off Peak	All Hours	Henry Hub	Chicago City Gate Basis	
2020	$33	$23	$28	$27	$20	$23	$30	$22	$26	$26	$21	$23	$2.4	-$0.01	$22.342
2021	$33	$24	$29	$28	$20	$24	$30	$23	$26	$27	$21	$24	$2.5	-$0.03	$43.836
2022	$34	$24	$29	$29	$21	$25	$31	$23	$27	$29	$22	$25	$2.5	-$0.05	$61.781
2023	$33	$24	$29	$29	$21	$25	$31	$23	$27	$28	$21	$25	$2.6	-$0.07	$77.014
2024	$34	$24	$29	$29	$21	$25	$31	$24	$27	$29	$21	$25	$2.6	-$0.08	$88.630
2025	$34	$23	$29	$30	$22	$25	$32	$24	$28	$29	$22	$25	$2.7	-$0.09	$101.945
2026	$35	$24	$30	$31	$22	$26	$32	$25	$28	$30	$23	$26	$2.8	-$0.09	$119.342

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2027	$36	$25	$31	$31	$23	$27	$33	$25	$29	$30	$23	$27	$2.9	-$0.08	$119.342
2028	$37	$26	$31	$32	$24	$28	$34	$26	$30	$31	$24	$27	$3.0	-$0.08	$119.342
2029	$38	$26	$32	$34	$25	$29	$35	$27	$31	$32	$25	$28	$3.1	-$0.07	$119.342
2030	$39	$27	$33	$35	$26	$30	$36	$27	$31	$33	$26	$29	$3.2	-$0.07	$119.342
2031	$40	$28	$34	$36	$26	$31	$37	$28	$32	$34	$27	$30	$3.3	-$0.08	$119.342
2032	$40	$28	$35	$37	$27	$32	$38	$28	$33	$35	$28	$31	$3.4	-$0.09	$119.342
2033	$41	$30	$36	$38	$28	$33	$39	$29	$34	$36	$29	$32	$3.5	-$0.09	$119.342
2034	$42	$31	$37	$39	$29	$34	$41	$29	$34	$37	$30	$33	$3.6	-$0.10	$119.342
2035	$43	$32	$38	$40	$30	$35	$41	$29	$35	$38	$31	$34	$3.7	-$0.11	$119.342
2036	$44	$32	$38	$41	$31	$36	$42	$30	$36	$40	$32	$36	$3.8	-$0.12	$119.342
2037	$45	$33	$39	$43	$32	$37	$43	$30	$36	$41	$33	$37	$3.9	-$0.13	$119.342
2038	$46	$34	$40	$44	$33	$38	$44	$30	$37	$43	$33	$38	$4.0	-$0.14	$119.342

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2039	$47	$34	$41	$45	$34	$39	$45	$31	$37	$45	$34	$39	$4.2	-$0.16	$119.342
2040	$48	$35	$42	$46	$35	$40	$46	$33	$39	$46	$35	$40	$4.3	-$0.16	$119.342
2041	$49	$35	$42	$48	$35	$41	$47	$33	$40	$48	$36	$42	$4.4	-$0.19	$119.342
2042	$50	$36	$43	$49	$36	$42	$48	$33	$40	$49	$37	$43	$4.5	-$0.19	$119.342
2043	$51	$37	$44	$50	$37	$43	$49	$35	$41	$50	$38	$44	$4.7	-$0.20	$119.342
2044	$52	$36	$44	$51	$38	$44	$50	$36	$43	$52	$39	$45	$4.8	-$0.20	$119.342
2045	$53	$37	$45	$52	$39	$45	$51	$37	$43	$53	$39	$46	$5.0	-$0.20	$119.342
2046	$54	$37	$46	$53	$39	$46	$52	$38	$44	$54	$40	$47	$5.1	-$0.21	$119.342
2047	$55	$38	$47	$54	$40	$47	$52	$38	$45	$55	$41	$47	$5.3	-$0.21	$119.342
2048	$56	$39	$47	$55	$41	$48	$53	$39	$46	$56	$42	$48	$5.4	-$0.22	$119.342
2049	$57	$39	$48	$56	$41	$48	$54	$40	$47	$57	$42	$49	$5.6	-$0.22	$119.342
2050	$58	$40	$49	$57	$42	$49	$55	$40	$47	$58	$43	$50	$5.7	-$0.23	$119.342

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Appendix D: Fixed Cost Forecast Inputs and Assumptions

General Assumptions

- A general escalation rate of 1.8% is based on the 2018 to 2019 growth rate of the Consumer Price Index.
- The Labor escalation rate of 3.0% is applied to Salaries and benefits. Historically, WVPA has budgeted and realized 3.0% annual wage increases and believes this pattern will continue in the future.
- The long-term debt rate is based on the Congressional Budget Office's August 2019 report, "An Update to the Budget and Economic Outlook: 2019 to 2029". The basis is CBO's projection of the interest rate on ten-year treasury notes. A credit spread of 1.05% over the CBO projection was used. The credit spread is based on the actual credit spread of WVPA's debt issued in 2018.
- The short-term investment interest rate is based on the actual interest rate WVPA earned on its cash balance in August 2019. The forecasted short-term investment rate maintains the spread of 1.55% between the long-term debt rate and the short-term investment rate.

Pass-Through Customer Administrative Adder

BEGIN CUI/PRIV

End CUI/PRIV

Demand Response ("DR") Credits

Members receive a projected credit adjusted annually based on the Producer Price index for each kW of direct load control capability. The 2020 budgeted rate of $53.96/kW is escalated at 1.8%. The capacity plan forecasts DR capacity of 60.6 MW for 2020 with no forecasted additions to capacity after 2020. Tipmont's share of DR capacity is forecasted to be 1.512 MW as of January 1, 2021.

Amortization of Member Buyout

Midwest Energy Cooperative ("MEC"), Paulding Putnam EC ("PP") and Northeastern REMC ("NE") early terminated their respective memberships with WVPA in 2012, 2015 and 2015, respectively. Each Member made a buyout payment to WVPA that was recorded as a liability and is being amortized as a credit to revenue through April 2028, the end date of the original wholesale power supply contracts.

Property Tax

Forecasted property tax is based on WVPA's 2020 budgeted property tax escalated at 1.8%. Indiana's property tax is calculated on the net value of plant and property in service with a floor of 30% of original cost. For Indiana generating assets, an estimate of when the floor would be reached was determined and the property taxes were kept flat from that point forward.

Property Insurance

Forecasted property insurance is based on WVPA's 2020 budgeted property insurance escalated at 1.8%.

Portfolio Management/Scheduling Fees

WVPA pays a nationwide energy management company an annual fee to schedule WVPA's generation resources into the MISO and PJM RTOs. The provider also manages contracted resources and buys and sells power in the short-term wholesale power markets. Forecasted fees are based on the 2020 budgeted fees escalated at 1.8%. For the Change Case, Tipmont's load ratio share of fees from 2031 to 2050 was removed.

Gas Hedges

The value of the gas hedges was derived by marking the financial hedges in place on August 14, 2019 against Black & Veatch's forecasted annual gas prices.

Emissions Cost

For purposes of this analysis, no emissions costs were assumed given lack of clarity regarding future environmental regulation.

Energy Efficiency ("EE") Program Costs

WVPA offers residential and commercial & industrial EE programs to its Members under the POWER MOVES initiative. Forecasted EE costs are based on 2020 budgeted costs and kept flat for the entire forecast period. For the Change Case, Tipmont's load ratio share of EE costs from 2031 to 2050 was removed.

Demand Response Pilots

WVPA began offering commercial & industrial DR pilot programs to its Members starting in 2019. Forecasted DR Pilots' costs are $50,000 in 2020 and $0 for the remaining forecast periods.

Departmental A&G and O&M

These costs reflect departmental expenses, such as salaries, benefits, legal expenses, etc. These costs are not included in Black & Veatch's dispatch model and analysis. In general, forecasted departmental expenses are based on 2020 budgeted costs escalated at 1.8%, except for salaries and benefits which are escalated at 3.0%.

In December 2018, WVPA acquired certain transmission assets from one of its members, Citizens Electric Corporation. Citizens' employees will continue to perform the O&M on these assets and WVPA will reimburse them for these services. Citizens' O&M is based on 2020 budgeted costs escalated at 1.8%.

With increased transmission capital expenditures, WVPA expects to incur incremental transmission O&M. A transmission O&M rate was calculated as follows: 2018 WVPA FERC Form 1 Transmission O&M (excluding account 565, property taxes, and insurance)/Average Transmission Plant. That constant rate was then applied to cumulative transmission capital expenditures (excluding Joint Transmission System capital expenditures, net of retirements) to estimate incremental transmission O&M.

Certain departmental expenses will decrease if Tipmont exits early. The following reduction in costs were identified from 2031 to 2050:

- Economic Development – costs such as aerial photography, website development, economic studies, regional contributions and other expenses.
- National Rural Electric Cooperative Association (NRECA) Dues – dues are assessed to WVPA based on MWh sales; the reduction in NRECA dues was estimated by multiplying MWh sales to Tipmont by the per MWh rate indicated on the 10/15/2019 dues invoice.
- Touchstone Energy National Fee – fees are assessed to WVPA for each of its Members based on average number of retail customers; Each Member's fee is outlined on the 12/12/2018 invoice.
- North American Reliability Corporation (NERC) and Reliability First (RF) Region Assessment - fees are assessed to WVPA based on MWh sales within the DUKE region. 2020 fees are based on 2018 MWh sales. Tipmont's share of NERC and RF fees, 19%, was estimated by multiplying MWh sales to Tipmont in 2018 by all MWh sales within the DUKE region for 2018.
- Board of Director Fees, Expenses & Education – removed the 2020 budgeted cost for one director
- Incremental Transmission Investment O&M – WVPA removed Tipmont's load ratio share of transmission and distribution capital expenditures from 2031 to 2050. This reduction in capital expenditures resulted in lower incremental transmission investment O&M from 2031 to 2050.
- National Renewable Cooperative Organization (NRCO) – removed Tipmont's load ratio share of fees
- North American Transmission Forum (NATF) – removed Tipmont's load ratio share of fees.

Depreciation

WVPA utilized annual depreciation rates from the 2020 Budget Study. These rates are based on 2019 forecasted annual depreciation from the asset management system divided by December 2018 depreciable base.

The ending balance of electric plant in service was calculated as follows:

$$\text{Plant in Service Ending Balance}_y = \text{Ending Balance}_{y-1} + \text{CWIP Balance}_{y-1} + \text{Capex}_y + \text{Retirements}_y$$

Where subscript y and y-1 denote years.

Base depreciation expense was calculated by applying the annual depreciation rates to the average ending balance of electric plant in service. However, if and when the calculated annual base depreciation expense exceeded the previous year's net plant ending balance, depreciation expense was limited to the previous year's net plant ending balance. This limitation mostly affected generating stations and rapidly depreciated assets (such as Demand Response, SCADA/Load Management and Technical Services).

Gibson is forecasted to retire 12/31/2026 and Prairie State is forecasted to retire 10/31/2043.

Amortization of acquisition adjustments for Vermillion, Holland, Prairie State, Clinton Land Fill and WVEM solar occur straight-line over varying time periods.

Gibson asset retirement obligation (ARO) forecasted depreciation and accretion is based on the 2019 Gibson ARO data received from Duke Energy. In addition, the Gibson December 31, 2016 gain/loss ending balance is being amortized straight-line over 15 years as ordered by FERC. Also, ARO depreciation and accretion for Gibson decommissioning from 2027-2044 is based on estimates provided by Duke Energy in 2019.

Prairie State asset retirement obligation (ARO) forecasted depreciation and accretion is based on the amount budgeted for 2020 and has been held constant through 2043 based on an estimated 27-year useful life of the mine which was acquired in 2016. In addition, the Prairie State mine coal reserves are being depleted at a rate of $8,900/month based on average historical usage.

For the Change Case, depreciation associated with the original cost of dedicated sole-use transmission facilities (which Tipmont will be obligated to purchase upon termination of its membership with WVPA) and Tipmont's load ratio share of transmission and distribution capital expenditures from 2031 to 2050 have been removed.

Amortization

WVPA has recorded regulatory assets and/or miscellaneous deferred debits that are being amortized as an expense over specific time periods. FERC has approved amortization of the Duke Termination and SG/WRU1 Retirement regulatory assets.

Other Taxes

Other Taxes represent payroll taxes and property taxes on General/Other plant. Forecasted other taxes are based on 2020 budgeted taxes escalated at 1.8%.

Interest Expense on Long-Term Debt

Forecasted interest expense is comprised of several pieces. First, forecasts for principal payments, interest expense and ending outstanding principal balance on existing debt as of October 2019 are determined. For existing variable debt, it is assumed that the rates in place as of October 2019 would hold for the life of the debt and that no debt would be retired early.

Second, existing debt issuance fees that have been deferred on the balance sheet and forecasted issuance fees for the 2020 credit facility amendment were amortized to interest expense over the life of the applicable debt issuance.

Third, the interest expense component of capital lease payments for WVEM's solar assets were forecasted.

Lastly, a forecast was developed for future debt issuances and the associated interest expense. The initial assumption is that a varying percent of annual capital expenditures will be financed with debt to maintain an approximate level of 45 days of cash on hand. A 30-year debt life with level principal payments was assumed and each debt issuance occurred mid-year which allowed for six months of interest expense in the first year and one principal payment in the first year. The long-term debt interest rate was applied, for the year of issuance, and was held constant until the debt matured.

For the Change Case, Tipmont's load ratio share of transmission and distribution capital expenditures from 2031 to 2050 was removed which resulted in lower new debt issuances and consequently less interest expense.

Interest Income

Interest income is calculated by applying the short-term investment rate to the average cash balance.

Renewable Energy Credits (REC) Revenue

REC revenue is based on WVPA's 2020 budget and is forecasted after 2020 by applying a historical average REC price for 2016 to October 2019 to generation from renewable resources from Black & Veatch's power supply cost model. The historical average REC price is escalated at 1.8%. Two historical average prices were calculated: (1) for Wind RECS (2) for other RECS because the price for Wind RECS is significantly lower.

Patronage Capital Income

WVPA earns patronage capital income on certain debt issuances with CoBank and CFC (National Rural Utilities Cooperative Finance Corporation). The amounts have been forecasted to decline based on the forecasted outstanding principal balance (CoBank) or forecasted interest payments (CFC). It is assumed that future debt issuances will not earn patronage capital income.

Margin

Margins must either be used to improve or maintain operations or be distributed to WVPA's Members. The maximum margin WVPA can collect from its Members is determined by a FERC approved formula which allows for a Debt Service Coverage (DSC) ratio of 1.3 and includes a 2.5% of revenue cap. For this analysis, margins from WVPA's 2020 Budget Study were used and adjusted, if necessary, to not exceed the cap. Starting in 2032, margins were kept flat at $24 million. For the Change Case, Tipmont's load ratio share of margins from 2031 to 2050 was removed.

Appendix E: Stranded Cost Calculation (2031-2050)

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Appendix E

Wabash Valley Power Association

Base Case - 20 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy Requirement (GWh)	[redacted]														
System Demand Requirement (MW)															
POWER SUPPLY COSTS															
Variable Cost															
Fixed O&M Cost															
Fuel Cost															
Market Purchase Cost / (Sales Revenue)															
Transmission Cost															
Net Capacity Cost / (Revenue)															
Contract Sales Revenue															
Total Power Supply Costs															
FIXED COSTS															
Pass Through Administrative Adder															
Demand Response Credits															
Amortization of Deferred Credit															
Property Tax															
Property Insurance															
Portfolio Management/Scheduling Fees															
Gas Hedges															
Emissions Cost															
Energy Efficiency															
Departmental A&G and O&M															
Depreciation															
Amortization															
Other Taxes															
Interest Expense - Long-term Debt															
Interest Income															
REC Revenue															
Patronage Capital Income															
Margin															
Total Fixed Costs															
Total Costs (Power Supply & Fixed)															
Average Member Rate ($/MWh)															
END CUI/PRIV															

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Appendix E

Wabash Valley Power Association

Base Case - 20 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Energy Requirement (GWh)	[redacted]										
System Demand Requirement (MW)											
POWER SUPPLY COSTS											
Variable Cost											
Fixed O&M Cost											
Fuel Cost											
Market Purchase Cost / (Sales Revenue)											
Transmission Cost											
Net Capacity Cost / (Revenue)											
Contract Sales Revenue											
Total Power Supply Costs											
FIXED COSTS											
Pass Through Administrative Adder											
Demand Response Credits											
Amortization of Deferred Credit											
Property Tax											
Property Insurance											
Portfolio Management/Scheduling Fees											
Gas Hedges											
Emissions Cost											
Energy Efficiency											
Departmental A&G and O&M											
Depreciation											
Amortization											
Other Taxes											
Interest Expense - Long-term Debt											
Interest Income											
REC Revenue											
Patronage Capital Income											
Margin											
Total Fixed Costs											
Total Costs (Power Supply & Fixed)											
Average Member Rate ($/MWh)											
END CUI/PRIV											

EXHIBIT B

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Appendix E

Wabash Valley Power Association

Base Case - 20 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	2047	2048	2049	2050	Total
Energy Requirement (GWh)	[redacted]				
System Demand Requirement (MW)					
POWER SUPPLY COSTS					
Variable Cost					
Fixed O&M Cost					
Fuel Cost					
Market Purchase Cost / (Sales Revenue)					
Transmission Cost					
Net Capacity Cost / (Revenue)					
Contract Sales Revenue					
Total Power Supply Costs					
FIXED COSTS					
Pass Through Administrative Adder					
Demand Response Credits					
Amortization of Deferred Credit					
Property Tax					
Property Insurance					
Portfolio Management/Scheduling Fees					
Gas Hedges					
Emissions Cost					
Energy Efficiency					
Departmental A&G and O&M					
Depreciation					
Amortization					
Other Taxes					
Interest Expense - Long-term Debt					
Interest Income					
REC Revenue					
Patronage Capital Income					
Margin					
Total Fixed Costs					
Total Costs (Power Supply & Fixed)					
Average Member Rate ($/MWh)					
END CUI/PRIV					

EXHIBIT B

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Appendix E1

Wabash Valley Power Association

Change Case - 20 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Energy Requirement (GWh)	[redacted]														
System Demand Requirement (MW)															
POWER SUPPLY COSTS															
Variable Cost															
Fixed O&M Cost															
Fuel Cost															
Market Purchase Cost / (Sales Revenue)															
Transmission Cost															
Net Capacity Cost / (Revenue)															
Contract Sales Revenue															
Total Power Supply Costs															
FIXED COSTS															
Pass Through Administrative Adder															
Demand Response Credits															
Amortization of Deferred Credit															
Property Tax															
Property Insurance															
Portfolio Management/Scheduling Fees															
Gas Hedges															
Emissions Cost															
Energy Efficiency															
Departmental A&G and O&M															
Depreciation															
Amortization															
Other Taxes															
Interest Expense - Long-term Debt															
Interest Income															
REC Revenue															
Patronage Capital Income															
Margin															
Total Fixed Costs															
Total Costs (Power Supply & Fixed)															
Average Member Rate ($/MWh)															
END CUI/PRIV															

Appendix E1

Wabash Valley Power Association

Change Case - 20 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Energy Requirement (GWh)	[redacted]										
System Demand Requirement (MW)											
POWER SUPPLY COSTS											
Variable Cost											
Fixed O&M Cost											
Fuel Cost											
Market Purchase Cost / (Sales Revenue)											
Transmission Cost											
Net Capacity Cost / (Revenue)											
Contract Sales Revenue											
Total Power Supply Costs											
FIXED COSTS											
Pass Through Administrative Adder											
Demand Response Credits											
Amortization of Deferred Credit											
Property Tax											
Property Insurance											
Portfolio Management/Scheduling Fees											
Gas Hedges											
Emissions Cost											
Energy Efficiency											
Departmental A&G and O&M											
Depreciation											
Amortization											
Other Taxes											
Interest Expense - Long-term Debt											
Interest Income											
REC Revenue											
Patronage Capital Income											
Margin											
Total Fixed Costs											
Total Costs (Power Supply & Fixed)											
Average Member Rate ($/MWh)											
END CUI/PRIV											

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Appendix E1

Wabash Valley Power Association

Change Case - 20 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	2047	2048	2049	2050	Total
Energy Requirement (GWh)	[redacted]				
System Demand Requirement (MW)					
POWER SUPPLY COSTS					
Variable Cost					
Fixed O&M Cost					
Fuel Cost					
Market Purchase Cost / (Sales Revenue)					
Transmission Cost					
Net Capacity Cost / (Revenue)					
Contract Sales Revenue					
Total Power Supply Costs					
FIXED COSTS					
Pass Through Administrative Adder					
Demand Response Credits					
Amortization of Deferred Credit					
Property Tax					
Property Insurance					
Portfolio Management/Scheduling Fees					
Gas Hedges					
Emissions Cost					
Energy Efficiency					
Departmental A&G and O&M					
Depreciation					
Amortization					
Other Taxes					
Interest Expense - Long-term Debt					
Interest Income					
REC Revenue					
Patronage Capital Income					
Margin					
Total Fixed Costs					
Total Costs (Power Supply & Fixed)					
Average Member Rate ($/MWh)					
END CUI/PRIV					

Appendix E2

Wabash Valley Power Association

Calculation of Stranded Costs - 20 Year Analysis

($ in thousands)

BEGIN CUI/PRIV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Change Case - Average Member Rate ($/MWh)	[redacted]												
Base Case - Average Member Rate ($/MWh)													
Difference (Increase to Remaining 22 Members)													
Change Case Energy Requirement (Remaining 22 Members) (MWh)													
Stranded Costs Related to Tipmont's Departure													

END CUI/PRIV

Appendix E2

Wabash Valley Power Association
Calculation of Stranded Costs - 20 Year Analysis
($ in thousands)

BEGIN CUI/PRIV	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Change Case - Average Member Rate ($/MWh)	[redacted]									
Base Case - Average Member Rate ($/MWh)										
Difference (Increase to Remaining 22 Members)										
Change Case Energy Requirement (Remaining 22 Members) (MWh)										
Stranded Costs Related to Tipmont's Departure										

END CUI/PRIV

Appendix E2

Wabash Valley Power Association

Calculation of Stranded Costs - 20 Year Analysis

($ in thousands)

BEGIN CUI/PRIV	2044	2045	2046	2047	2048	2049	2050	Total
Change Case - Average Member Rate ($/MWh)	[redacted]							
Base Case - Average Member Rate ($/MWh)								
Difference (Increase to Remaining 22 Members)								
Change Case Energy Requirement (Remaining 22 Members) (MWh)								
Stranded Costs Related to Tipmont's Departure								

END CUI/PRIV

Appendix F: Stranded Cost Calculation (2021-2050)

Appendix F

Wabash Valley Power Association

Base Case - 30 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Energy Requirement (GWh)	[redacted]										
System Demand Requirement (MW)											
POWER SUPPLY COSTS											
Variable Cost											
Fixed O&M Cost											
Fuel Cost											
Market Purchase Cost / (Sales Revenue)											
Transmission Cost											
Net Capacity Cost / (Revenue)											
Contract Sales Revenue											
Total Power Supply Costs											
FIXED COSTS											
Pass Through Administrative Adder											
Demand Response Credits											
Amortization of Deferred Credit											
Property Tax											
Property Insurance											
Portfolio Management/Scheduling Fees											
Gas Hedges											
Emissions Cost											
Energy Efficiency											
Departmental A&G and O&M											
Depreciation											
Amortization											
Other Taxes											
Interest Expense - Long-term Debt											
Interest Income											
REC Revenue											
Patronage Capital Income											
Margin											
Total Fixed Costs											
Total Costs (Power Supply & Fixed)											
Average Member Rate ($/MWh)											

END CUI/PRIV

Appendix F

Wabash Valley Power Association

Base Case - 30 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Energy Requirement (GWh)	[redacted]										
System Demand Requirement (MW)											
POWER SUPPLY COSTS											
Variable Cost											
Fixed O&M Cost											
Fuel Cost											
Market Purchase Cost / (Sales Revenue)											
Transmission Cost											
Net Capacity Cost / (Revenue)											
Contract Sales Revenue											
Total Power Supply Costs											
FIXED COSTS											
Pass Through Administrative Adder											
Demand Response Credits											
Amortization of Deferred Credit											
Property Tax											
Property Insurance											
Portfolio Management/Scheduling Fees											
Gas Hedges											
Emissions Cost											
Energy Efficiency											
Departmental A&G and O&M											
Depreciation											
Amortization											
Other Taxes											
Interest Expense - Long-term Debt											
Interest Income											
REC Revenue											
Patronage Capital Income											
Margin											
Total Fixed Costs											
Total Costs (Power Supply & Fixed)											
Average Member Rate ($/MWh)											

END CUI/PRIV

EXHIBIT B

Appendix F

Wabash Valley Power Association

Base Case - 30 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	2043	2044	2045	2046	2047	2048	2049	2050	Total
Energy Requirement (GWh)	[redacted]								
System Demand Requirement (MW)									
POWER SUPPLY COSTS									
Variable Cost									
Fixed O&M Cost									
Fuel Cost									
Market Purchase Cost / (Sales Revenue)									
Transmission Cost									
Net Capacity Cost / (Revenue)									
Contract Sales Revenue									
Total Power Supply Costs									
FIXED COSTS									
Pass Through Administrative Adder									
Demand Response Credits									
Amortization of Deferred Credit									
Property Tax									
Property Insurance									
Portfolio Management/Scheduling Fees									
Gas Hedges									
Emissions Cost									
Energy Efficiency									
Departmental A&G and O&M									
Depreciation									
Amortization									
Other Taxes									
Interest Expense - Long-term Debt									
Interest Income									
REC Revenue									
Patronage Capital Income									
Margin									
Total Fixed Costs									
Total Costs (Power Supply & Fixed)									
Average Member Rate ($/MWh)									

END CUI/PRIV

Appendix F1

Wabash Valley Power Association
Change Case - 30 Year Stranded Cost Analysis
($ in thousands)

BEGIN CUI/PRIV	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Energy Requirement (GWh)	[redacted]										
System Demand Requirement (MW)											
POWER SUPPLY COSTS											
Variable Cost											
Fixed O&M Cost											
Fuel Cost											
Market Purchase Cost / (Sales Revenue)											
Transmission Cost											
Net Capacity Cost / (Revenue)											
Contract Sales Revenue											
Total Power Supply Costs											
FIXED COSTS											
Pass Through Administrative Adder											
Demand Response Credits											
Amortization of Deferred Credit											
Property Tax											
Property Insurance											
Portfolio Management/Scheduling Fees											
Gas Hedges											
Emissions Cost											
Energy Efficiency											
Departmental A&G and O&M											
Depreciation											
Amortization											
Other Taxes											
Interest Expense - Long-term Debt											
Interest Income											
REC Revenue											
Patronage Capital Income											
Margin											
Total Fixed Costs											
Total Costs (Power Supply & Fixed)											
Average Member Rate ($/MWh)											
END CUI/PRIV											

Appendix F1

Wabash Valley Power Association

Change Case - 30 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Energy Requirement (GWh)	[redacted]										
System Demand Requirement (MW)											
POWER SUPPLY COSTS											
Variable Cost											
Fixed O&M Cost											
Fuel Cost											
Market Purchase Cost / (Sales Revenue)											
Transmission Cost											
Net Capacity Cost / (Revenue)											
Contract Sales Revenue											
Total Power Supply Costs											
FIXED COSTS											
Pass Through Administrative Adder											
Demand Response Credits											
Amortization of Deferred Credit											
Property Tax											
Property Insurance											
Portfolio Management/Scheduling Fees											
Gas Hedges											
Emissions Cost											
Energy Efficiency											
Departmental A&G and O&M											
Depreciation											
Amortization											
Other Taxes											
Interest Expense - Long-term Debt											
Interest Income											
REC Revenue											
Patronage Capital Income											
Margin											
Total Fixed Costs											
Total Costs (Power Supply & Fixed)											
Average Member Rate ($/MWh)											

END CUI/PRIV

Appendix F1

Wabash Valley Power Association

Change Case - 30 Year Stranded Cost Analysis

($ in thousands)

BEGIN CUI/PRIV	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**Total**
Energy Requirement (GWh)	[redacted]								
System Demand Requirement (MW)									
POWER SUPPLY COSTS									
Variable Cost									
Fixed O&M Cost									
Fuel Cost									
Market Purchase Cost / (Sales Revenue)									
Transmission Cost									
Net Capacity Cost / (Revenue)									
Contract Sales Revenue									
Total Power Supply Costs									
FIXED COSTS									
Pass Through Administrative Adder									
Demand Response Credits									
Amortization of Deferred Credit									
Property Tax									
Property Insurance									
Portfolio Management/Scheduling Fees									
Gas Hedges									
Emissions Cost									
Energy Efficiency									
Departmental A&G and O&M									
Depreciation									
Amortization									
Other Taxes									
Interest Expense - Long-term Debt									
Interest Income									
REC Revenue									
Patronage Capital Income									
Margin									
Total Fixed Costs									
Total Costs (Power Supply & Fixed)									
Average Member Rate ($/MWh)									

END CUI/PRIV

EXHIBIT B

Appendix F2

Wabash Valley Power Association
Calculation of Stranded Costs - 30 Year Analysis
($ in thousands)

BEGIN CUI/PRIV

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Change Case - Average Member Rate ($/MWh)	[redacted]									
Base Case - Average Member Rate ($/MWh)										
Difference (Increase to Remaining 22 Members)										
Change Case Energy Requirement (Remaining 22 Members) (MWh)										
Stranded Costs Related to Tipmont's Departure										

END CUI/PRIV

Appendix F2

Wabash Valley Power Association
Calculation of Stranded Costs - 30 Year Analysis
($ in thousands)

BEGIN CUI/PRIV

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Change Case - Average Member Rate ($/MWh)	[redacted]									
Base Case - Average Member Rate ($/MWh)										
Difference (Increase to Remaining 22 Members)										
Change Case Energy Requirement (Remaining 22 Members) (MWh)										
Stranded Costs Related to Tipmont's Departure										

END CUI/PRIV

Appendix F2

Wabash Valley Power Association

Calculation of Stranded Costs - 30 Year Analysis

($ in thousands)

BEGIN CUI/PRIV	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Change Case - Average Member Rate ($/MWh)	[redacted]									
Base Case - Average Member Rate ($/MWh)										
Difference (Increase to Remaining 22 Members)										
Change Case Energy Requirement (Remaining 22 Members) (MWh)										
Stranded Costs Related to Tipmont's Departure										

END CUI/PRIV

EXHIBIT B

Appendix F2

Wabash Valley Power Association

Calculation of Stranded Costs - 30 Year Analysis

($ in thousands)

BEGIN CUI/PRIV	Total
Change Case - Average Member Rate ($/MWh)	[redacted]
Base Case - Average Member Rate ($/MWh)	
Difference (Increase to Remaining 22 Members)	
Change Case Energy Requirement (Remaining 22 Members) (MWh)	
Stranded Costs Related to Tipmont's Departure	
END CUI/PRIV	