Wabash Valley
POWER ALLIANCE

2023 Integrated Resource Plan

May 2024

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Wabash Valley
POWER ALLIANCE

2023 Integrated Resource Plan

Section 1

OVERVIEW

Membership

Wabash Valley Power Association, Inc. d/b/a Wabash Valley Power Alliance (WVPA) or the Company, is a generation and transmission (G&T) cooperative based in Indianapolis, Indiana. WVPA was incorporated December 12, 1963, pursuant to the Indiana Non-Profit Corporation Act. The Articles of Incorporation were amended in 1975 and approved by the Secretary of State on September 4, 1975. The Public Service Commission of Indiana, now the Indiana Utility Regulatory Commission (IURC), granted the Company a Certificate of Convenience and Necessity on January 13, 1978. This authorized WVPA to supply power to its member distribution cooperatives (Members). WVPA provides wholesale electricity to twenty-three Members: nineteen in central and northern Indiana, three in Illinois and one in Missouri. In turn, distribution Members supply electricity to more than 334,000 retail members. Nearly 76 percent of WVPA's retail customers reside in Indiana, with approximately 16 percent in Illinois, and 8 percent in Missouri. Table 1-1 provides a list of Wabash Valley's Members and their office locations.

Table 1-1 WVPA Members

Member	*Location*
Boone REMC	Lebanon, IN
Carroll White REMC	Monticello, IN
Citizens Electric Corporation	Perryville, MO
Corn Belt Energy Corporation	Bloomington, IL
EnerStar Electric Cooperative	Paris, IL
Fulton County REMC	Rochester, IN
Heartland REMC	Markle, IN
Hendricks Power Cooperative	Avon, IN
Jasper County REMC	Rensselaer, IN
Jay County REMC	Portland, IN
Kankakee Valley REMC	Wanatah, IN
Kosciusko REMC	Warsaw, IN
LaGrange County REMC	LaGrange, IN
M.J.M. Electric Cooperative	Carlinville, IL
Marshall County REMC	Plymouth, IN
Miami-Cass REMC	Peru, IN
Newton County REMC	Goodland, IN
NineStar Connect	Greenfield, IN
Noble REMC	Albion, IN
Parke County REMC	Rockville, IN
Steuben County REMC	Angola, IN

Tipmont REMC	Linden, IN
Warren County REMC	Williamsport, IN

Service Territory

Territorial assignments to electric cooperatives in Indiana were designated under the Rural Electric Membership Corporation Act of 1935 as amended. Much of the service territory is used for agricultural production both for crops and livestock. Correspondingly, many local co-op consumers work in agriculture, either directly or through related industries. Significant portions of consumers in WVPA member-territories commute to large and small cities that contain a number of commercial and industrial businesses. Indiana metropolitan areas within or near Member service areas include the cities of Anderson, Elkhart, Fort Wayne, Gary, Indianapolis, Kokomo, Lafayette, Muncie, and South Bend. Major Illinois cities near Member service areas include Chicago, Peoria, Springfield, and Bloomington. The major Missouri city near Member service territory is St. Louis. The major interstate highways serving the area are I-55, I-65, I-69, I-70 and I-74.

Figure1-2 illustrates WVPA's composite service territory. The areas identified on this map are not exclusively served by WVPA Members. Numerous municipal electric utilities, as well as investor-owned utilities, permeate this service area.

Figure 1-2 WVPA Service Territory

Except as outlined in the WVPA distributed generation policy, the Company supplies all of our Members' power requirements from owned generating resources, purchases from other electric utilities or energy marketing companies and wholesale market purchases. The WVPA Members service areas span six sub-balancing areas across the Midcontinent Independent Transmission System Operator (MISO) and PJM Interconnection (PJM) regional transmission organization (RTO) footprints. WVPA plans requirements holistically to avoid oversupply and manages specific resources to meet reliability needs. Table 1-3 illustrates the percentage of energy delivered into each of the six sub-balancing areas.

TABLE 1-3 Power Delivery by Balancing Area - As of 1/1/2024

Sub-Balancing Area	***% Energy Delivered** (kWh basis)*	***Balancing Area***
Duke Energy Indiana (DUKE)	33%	MISO
American Electric Power (AEP)	21%	PJM
Northern Indiana Public Service Company (NIPSCO)	19%	MISO
Ameren Missouri (AMMO)	17%	MISO
Ameren Illinois (AMIL)	9%	MISO
AES Indiana (IPL)	1%	MISO

WVPA also supplies power to one non-member Indiana customer under a separate wholesale firm requirements agreement that ends in 2028.

Cooperative Structure

WVPA is incorporated as a G&T cooperative and adheres to the seven cooperative principles:

- Voluntary and Open Membership
- Democratic Member Control
- Members' Economic Participation
- Autonomy and Independence
- Education, Training, and Information
- Cooperation Among Cooperatives
- Concern for Community

The principle of Democratic Member Control shapes the Company's routine operations. WVPA's business and affairs are governed by a Board of Directors consisting of one Director nominated by each Member (one Member, one vote). WVPA staff develops and presents, for Board action at regularly scheduled meetings, corporate goals and objectives, work plans, budgets, policies, and rate matters.

Across the electric utility industry, and specifically at WVPA, managing enterprise risk is a high priority. WVPA's Board identifies the Company's risk management objectives and provides oversight. The risk structure consists of the Board, CEO, a Risk Oversight Committee, an Internal Risk Management Committee, a Risk Officer and ACES, a nationwide energy management company. This structure utilizes a Risk Matrix to identify and prioritize risks associated with commodity prices, power and fuel delivery, financial issues, environmental impacts, regulatory policy, etc. Strategies are developed to mitigate the potent effects on WVPA. The risk structure monitors the resource plan on a quarterly basis by reviewing a dashboard with key indicators and stress cases. This ongoing review process allows WVPA to adjust its power portfolio to better match the inherent risks of providing power to its Members.

New in this IRP

This IRP incorporates the provisions for public electric utilities passed by the Indiana General Assembly in 2023. House Enrolled Act (HEA) 1007 accounts for the reduction in summer or winter unforced capacity (UCAP) threshold from 30% to 15% and identifies five attributes required for decisions concerning energy infrastructure. [1] These "pillars" are reliability, affordability, resiliency, stability, and environmental sustainability and are utilized in a scorecard to compare resource portfolios from the IRP process. The pillars are embedded in the WVPA mission and vision statements which guide Board decision making and are incorporated in a portfolio scorecard in Section 5.

Mission Statement

"WVPA exists to meet the collective needs of our member-owners and provide **reliable**, **stable**, and **responsible** energy solutions."

Vision Statement

"WVPA will be a trusted energy partner working collaboratively with member-owners to grow and the develop **vibrant communities** they serve."

Changing Energy Landscape

Since WVPA's 2020 IRP, the electricity markets and energy landscape have changed dramatically due to many factors including recently enacted changes to the MISO and PJM resource adequacy capacity constructs, renewed focus on reliability risks as resource portfolios transition to renewables, and increasing prevalence of distributed energy resources (DERs). In addition, the Bipartisan Infrastructure Law[2] and Inflation Reduction Act (IRA)[3], enacted in 2021 and 2022 respectively, support multiple federal funding opportunites for electricity infrastructure.

[1] https://iga.in.gov/pdf-documents/123/2023/house/bills/HB1007/HB1007.04.ENRS.pdf
[2] See https://www.congress.gov/bill/117th-congress/house-bill/3684/text
[3] See https://www.energy.gov/lpo/articles/transforming-clean-energy-financing-and-supply-chains-united-states-lpo-one-year-after

RTO Capacity Constructs

In June 2023, the MISO resource adequacy construct changed from a summer peak based approach to seasonal requirements. The "all hours matter" view includes seasonal requirements and resource accreditation enhancements which became effective in the 2023/2024 planning year. The framework with seasonal Planning Reserve Margin Requirements (PRMR) and resource capacity accredidations is reflected in this IRP. FERC recently approved PJM's proposed changes to the Reliability Pricing Model (RPM) which will accredit resources based on Expected Unserved Energy (EUE) year round versus Equivalent Forced Outage rate (EFORd) and summer peak requirements starting in PY 25/26. WVPA's current AEP contract includes capacity services through 2032, so the change will not impact the 3 year short-term action plan. WVPA will incorporate this change in subsequent IRPs.

Reliability and Resource Portfolio Transitions

While the majority of recent resource additions in MISO and PJM are solar, concerns about grid reliability have prompted reconsiderations of thermal unit retirements. In it's *Reliability Imperative* report, MISO cites a call to action for stakeholdes to work together and move faster to address urgent and complex risks of a "looming mismatch" between the pace of adding new resources and retirement of older resources. They further cite the need to refine resource plans to accelerate the additon of reliability attributes and maintain transition resources as reliability "insurance" until new technologies become viable at grid scale.[4]

North American Electric Reiability Corporation (NERC) issued its *2023 Long Term Reliabilty Assessment*[5] containing with specific analysis of RTO market areas and the risks associated with potential loss of load. The report recommended the following actions:

- Add new resources with reliability attributes and enhance existing resources
- Build out transmission to support resources
- Improve planning, operational, and resource procurement processes to encompass more complex power systems

[4] See report at page 7: https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216

[5] See https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf

- Strengthen relationships among stakeholders and policymakers

WVPA is keenly aware of these challenges and is focused on reliability. WVPA remains committed to targeting net-zero carbon emissions by 2050, however interim milestone dates may shift to maintain reliabilty.

For this IRP period, WVPA modeled the retirement of its coal-fired resources, Gibson Unit 5 and Prairie State Unit 1, as well as its Wabash River Highland combustion turbine. Additionally, the IRP includes the retirement of Rockport Units 1 and 2 coal-fired resources in 2028 that supply part of WVPA's power purchase agreement (PPA) with AEP.

Distributed Energy Resources (DERs)

WVPA has seen growth in Distributed Energy Resource (DER) penetration including distributed generation (DG), electric vehicles (EVs) as well as demand response participation over the past three years. This IRP includes future forecasts with these factors in mind. Recent solar DG growth indicates a jump from nearly 7 MW to 20 MW over a two-year period.

MISO and PJM are actively working with stakeholders to develop FERC Order 2222 compliance plans to enable DERs to participate in their respective wholesale markets. While WVPA Members are exempt from Order 2222 as small utilities, the Company participates in stakeholder meetings to monitor developments which may impact current and future demand response program participation.

Federal Funding Opportunities

This IRP accounts for IRA tax incentives for renewable and energy storage in the DER forecast for retail user-owned and potential new portfolio resources. In addition, potential projects, which stemmed from the IRA, are specifically considered in Section 2, Resource Assessment. They include solar and storage under the United States Department of Agriculture (USDA) New Empowering Rural America (ERA)[6] combined grant and loan forgiveness program, and USDA Powering Affordable Clean Energy

[6] See https://www.rd.usda.gov/programs-services/electric-programs/empowering-rural-america-new-era-program

(PACE)[7] loan forgiveness program, as well as the BIL enabled Department of Energy Grid Resilience and Innovation Partnerships (DOE GRIP)[8] grant program.

Integrated Resource Plan (IRP) Process

Every electric utility in the State of Indiana that is publicly, municipally or cooperatively owned must prepare an IRP every three years to comply with the IURC's "Rule 7", technically 170 IAC 4-7. As a cooperatively owned electric utility, WVPA is exempt from the public advisory process requirement in Section 8.170 IAC 4-7-2.6 of the IURC's Draft Proposed Rule amending 170 IAC 4-7 Guidelines for Integrated Resource Planning by an Electric Utility.

At WVPA, the Budgets and Forecasting Department is responsible for coordinating the development of the IRP with input from the Engineering & Operations, Communications, Marketing, & Advocacy, Power Supply, and Risk Management & Regulatory Affairs departments.

The Company has developed the IRP using the following six major steps:

1. Power Requirements Forecasting
2. Energy Efficiency Evaluation
3. Demand Response Evaluation
4. Distributed Energy Resource (DER) Forecast
4. Supply-Side Evaluation
5. Integration
6. Financial Review

The following describes the process for each step.

1. Power Requirements Forecasting

The Billing and Rates Department is responsible for developing the power requirements forecast for WVPA. The monthly peak demand and energy requirement of each Member and requirements customer is forecasted. These forecasts are aggregated into a composite forecast for WVPA. WVPA surveys residential customers to determine the saturation levels of electric appliances and asks each individual Member to review their respective forecast. Demographic

[7] See https://www.rd.usda.gov/programs-services/electric-programs/powering-affordable-clean-energy-pace-program

[8] See https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program

and economic data from various sources is considered in the projection of each Member's energy requirements. The forecasted energy requirements are normalized for weather. The forecast is re-estimated every three years or more often as changes and requirements dictate. Section 3 describes the forecasting model in more detail.

2. Demand-Side Management – Energy Efficiency Evaluation

WVPA Member distribution cooperatives serve retail customers. WVPA develops retail Energy Efficiency (EE) programs for the Members to offer. The EE programs are evaluated for the benefit to the Company, its Members and their customers by comparing program costs to the expected cost of a market-based resource or option purchase. Primary evaluation, measurement and verification (EM&V) activities are reviews of satisfaction, impact and cost-effectiveness. The Retail Programs and Services (RP&S) Working Group, comprised of WVPA staff and Member systems' personnel, completed a thorough review of the current and potential programs with the assistance of Skytop Consulting in 2023. The group recommended a portfolio of residential programs and commercial and industrial EE programs for the WVPA portfolio. Programs were selected based on each Member's mix of customers, electric energy end-uses, and power supply requirements. The Committee develops programs, and measurement and verification protocols to evaluate the technical and economic viability of EE programs. WVPA coordinates centralized marketing and outreach for each program.

3. Demand-Side Management – Demand Response Evaluation

The RP&S Working Group and Skytop also evaluated current and potential Demand Response (DR) programs with a new emphasis on seasonal peak demand reduction capabilities. Individual WVPA Member Co-ops offer the programs to retail end-users. DR programs are evaluated for the benefit to the Company, its Members and their retail customers by comparing program costs to the expected cost of a market-based resource or option purchase. In 2023, the standard California DSM tests were applied. See Section 2 and Appendix H or further details and results. The RP&S Working Group develops programs to evaluate the technical and economic viability of DR alternatives. Pilot program results are then used, along with forecasts of power supplies and wholesale market power prices, to determine whether full-scale program should be initiated. Analysis of DR programs is ongoing. If a program is considered beneficial, WVPA provides price signals and collaborates with Members to encourage adoption of the DR program.

4. Supply-Side Evaluation

The Budgets and Forecasting Department with input from the Power Supply department is responsible for estimating costs associated with power generation and purchases. The Company surveys the market on a regular basis and routinely makes inquiries to other utilities, power marketers and generating facility construction consultants. Responses to these inquiries have included offers for construction of new generation as well as for power supply contracts. WVPA determines which resources are most likely to be available at the time new capacity is needed and uses estimated costs for these expected units in its cost projection studies.

5. Integration

The integrated production cost is developed with the recommended EE and DR resource programs and the most economic supply-side resources for each scenario. The PLEXOS® model, developed by Energy Exemplar, is used to evaluate the production costs for the integrated plan. The Power Supply Department reevaluates the resource plan regularly.

6. Financial Review

The 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. These forecasts are reviewed to ensure that the conditions of the corporate financial policy are met and financing requirements are reasonable. The Budgets and Forecasting Department uses a financial forecasting model to input company capitalization, balance sheet, and similar financial information to develop a comprehensive forecast of cash flows, income statement, and rates. Financial forecasts are updated quarterly or as necessary.

Wabash Valley
POWER ALLIANCE

2023 Integrated Resource Plan

Section 2

RESOURCE ASSESSMENT

Planning Areas

WVPA plans for its power requirements in all balancing areas jointly, to provide power to Members at the lowest reasonable cost. These include the six transmission zones in MISO and PJM as shown in Table 1-3.

ACES' power dispatch center operates 24 hours a day and is responsible for scheduling power resources into the MISO and PJM systems on behalf of the Company. ACES' dispatchers manage the contracted WVPA resources as well as purchase and sell power in the short-term wholesale power market. In its energy management role, ACES' staff is responsible for dispatching the Company's demand response (DR) programs. WVPA DR representatives inform ACES' staff members of current program objectives, program parameters and information management functions. ACES utilizes the DR programs to manage costs, including high wholesale market prices, and respond to capacity shortages.

Planning Criteria

Planning criteria for WVPA is developed by MISO and PJM. These RTOs evaluate the reliability within their respective regions and establish rules to determine how the Company and other load serving entities provide capacity to meet the requirements. As described in Section 1, WVPA demonstrates its ability to own or contract for 85% of the capacity requirements to limit auction exposure to less than 15% for any given season to comply with HEA 1007.

For planning year 2023/2024, MISO changed to a seasonal (Summer, Fall, Winter, Spring) requirement to better match capacity needs with available resources. The MISO footprint Planning Reserve Margin Requirement (PRMR) by season are 9% for Summer, 14.2% for Fall, 27.4% for Winter, and 26.7% for Spring for planning year 2024/2025. This seasonal reserve requirement represents installed capacity at the MISO region peak that will limit the loss of load expectation to 0.1 day in a year. MISO adjusts the seasonal reserve requirement for load diversity and unit availability. WVPA's resources are seasonally accredited in the MISO market based on the resources ability to serve load during critical hours. The Company can also purchase capacity credits to meet its PRMR in the annual planning reserve auction. Starting in 2024, WVPA forecasts approximately 89% of its load in MISO.

PJM has a similar process to determine the reserve requirements. PJM's current capacity allocation is 14.7% installed (ICAP). Currently, the majority of the Company's PJM requirements are managed by AEP through 2033. WVPA plans to provide capacity in the long term to meet its capacity allocation to hedge the price of the PJM allocated costs.

For the IRP, these seasonal reserve requirements are used for planning WVPA 's future resource requirements.

WVPA currently owns approximately 83% of its capacity requirements. The rest of the Company's current resources are provided under various contractual arrangements. Many of the contractual resources are firm supplies that include capacity.

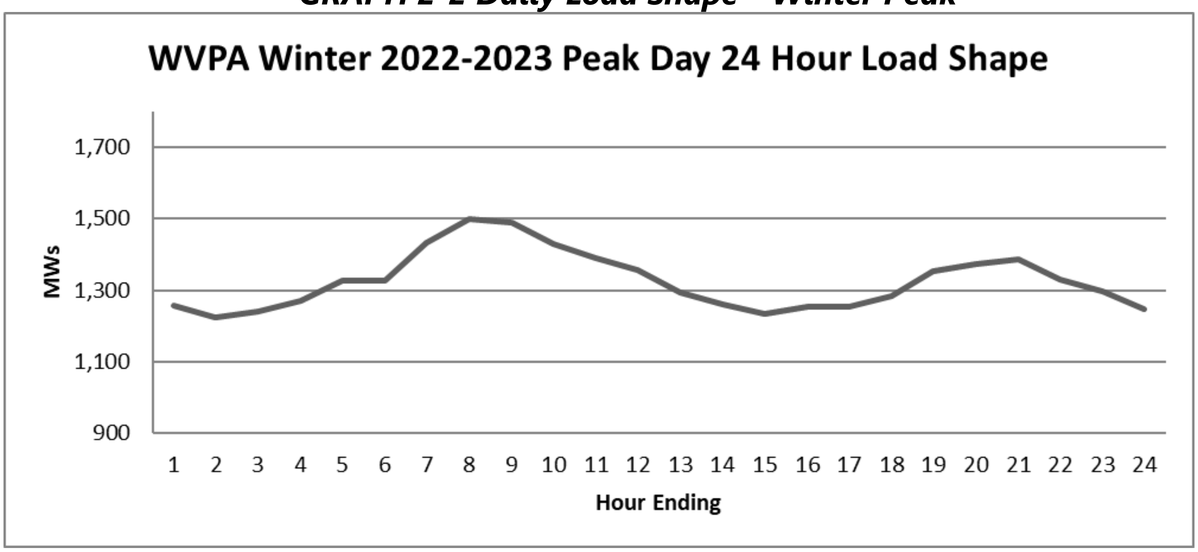
Loads and Load Characteristics

Each WVPA Member serves a variety of residential, commercial and industrial loads. Most of the load is residential. As the following tables illustrate, the Company's winter peak usually occurs at 8:00 p.m. and the summer peak generally occurs in the evening around 6:00 p.m. These peak times reflect the highly residential nature of the load. WVPA has two large customers whose summer demand may be interrupted. The peak demand reported in Table 2-1, Graph 2-2, Table 2-3 and Graph 2-4 excludes the interruptible portion of this load.

TABLE 2-1 Wabash Valley Coincident Peak Demands – Winter

Winter						
	Coincident Demand *	Peak			Day of Peak Temp. Range **	
Years	(MW)	Month	Day	Time EPT	Low F	High F
2012-2013	1,391.50	Jan	Mon	8 p.m.	6	19
2013-2014	1,593.30	Jan	Mon	7 p.m.	-14	20
2014-2015^	1,527.10	Jan	Wed	8 p.m.	-4	10
2015-2016^	1,312.10	Jan	Mon	8 p.m.	0	10
2016-2017	1,320.40	Dec	Mon	8 a.m.	-8	11
2017-2018	1,435.60	Jan	Tue	9 a.m.	-13	4
2018-2019	1,497.10	Jan	Wed	8 p.m.	-13	0
2019-2020	1,317.30	Feb	Fri	8 a.m.	3	16
2020-2021	1,523.90	Feb	Mon	7 p.m.	12	15
2021-2022	1,444.98	Jan	Wed	9 a.m.	-9	11
2022-2023	1,648.90	Dec	Fri	7 p.m.	-8	4

GRAPH 2-2 Daily Load Shape – Winter Peak



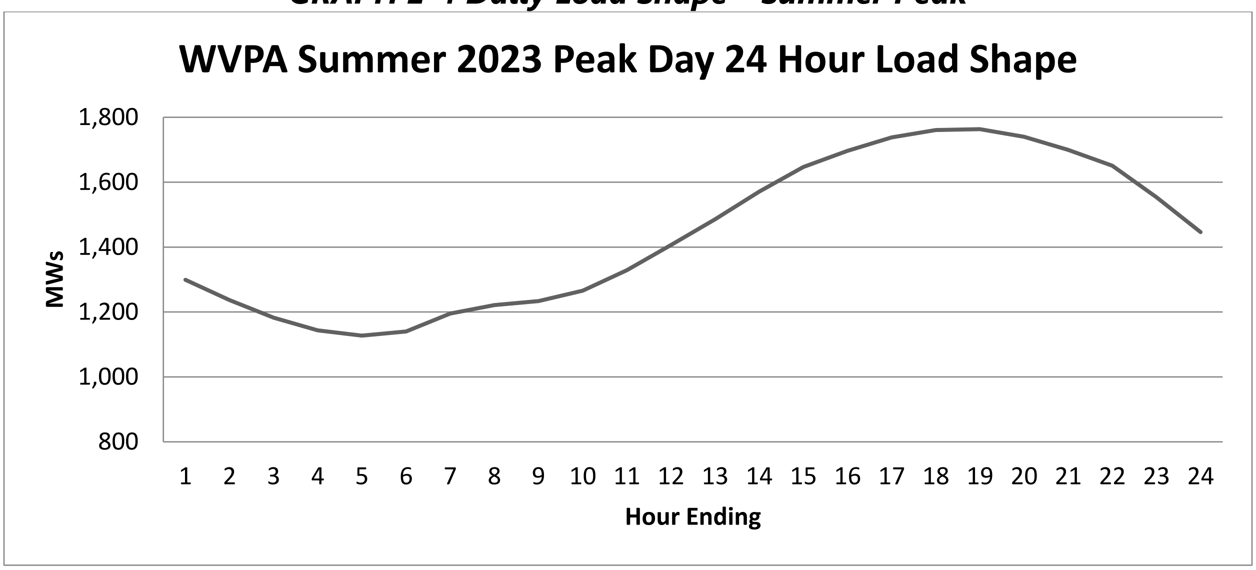
* Coincident demand includes pass-through load but excludes interruptible load
** Fort Wayne (AP) Weather Station
^ One Cooperative terminated Membership effective Jan. 2015 and one cooperative terminated Membership effective July 2015

TABLE 2-3 Wabash Valley Coincident Peak Demands – Summer

Summer							
	Coincident Demand*	Peak			Day of Peak Temp. Range **		Consec. Days Over
Year	**(MW)**	**Month**	**Day**	**Time EPT**	**Low F**	**High F**	**85**
2013	1,660.70	Jul	Thu	7 p.m.	73	91	5
2014	1,591.90	Aug	Mon	5 p.m.	68	87	1
2015^	1,479.30	Jul	Tue	7 p.m.	66	88	3
2016	1,592.30	Aug	Thu	7 p.m.	74	90	11
2017	1,510.30	Jul	Wed	7 p.m.	65	89	2
2018	1,584.50	Jun	Mon	6 p.m.	75	94	4
2019	1,631.00	Jul	Fri	6 p.m.	77	91	7
2020	1,623.40	Jul	Thu	6 p.m.	69	92	12
2021	1,684.10	Aug	Tue	6 p.m.	68	91	4
2022	1,703.50	Jul	Tue	7 p.m.	68	91	3
2023	1,763.40	Aug	Thu	7 p.m.	70	90	2

^ One Cooperative terminated Membership effective Jan. 2015 and one cooperative terminated Membership effective July 2015

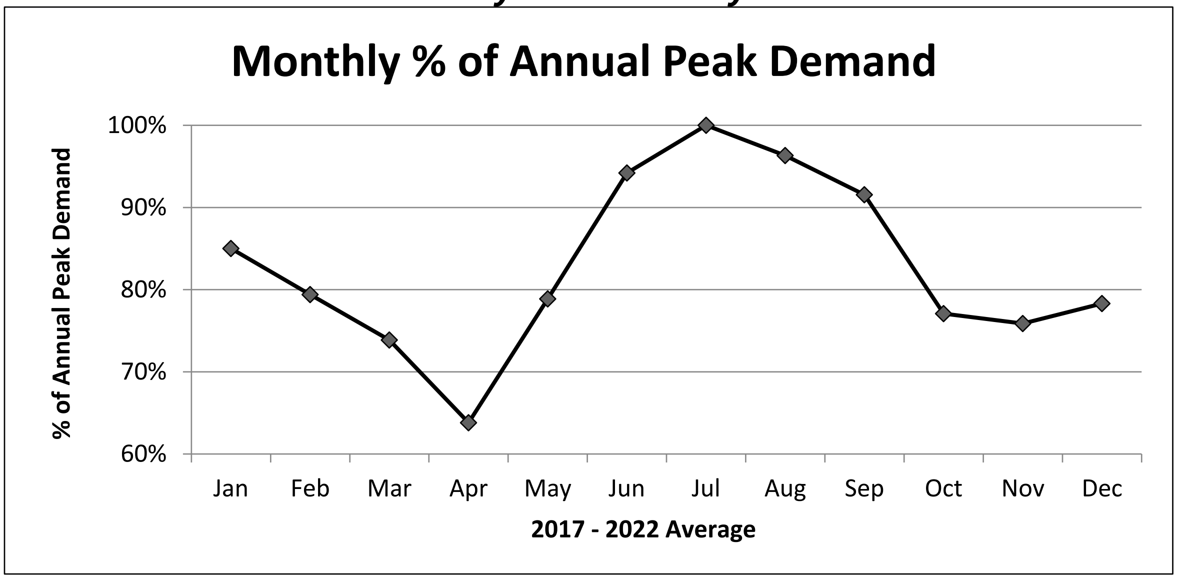
GRAPH 2-4 Daily Load Shape – Summer Peak



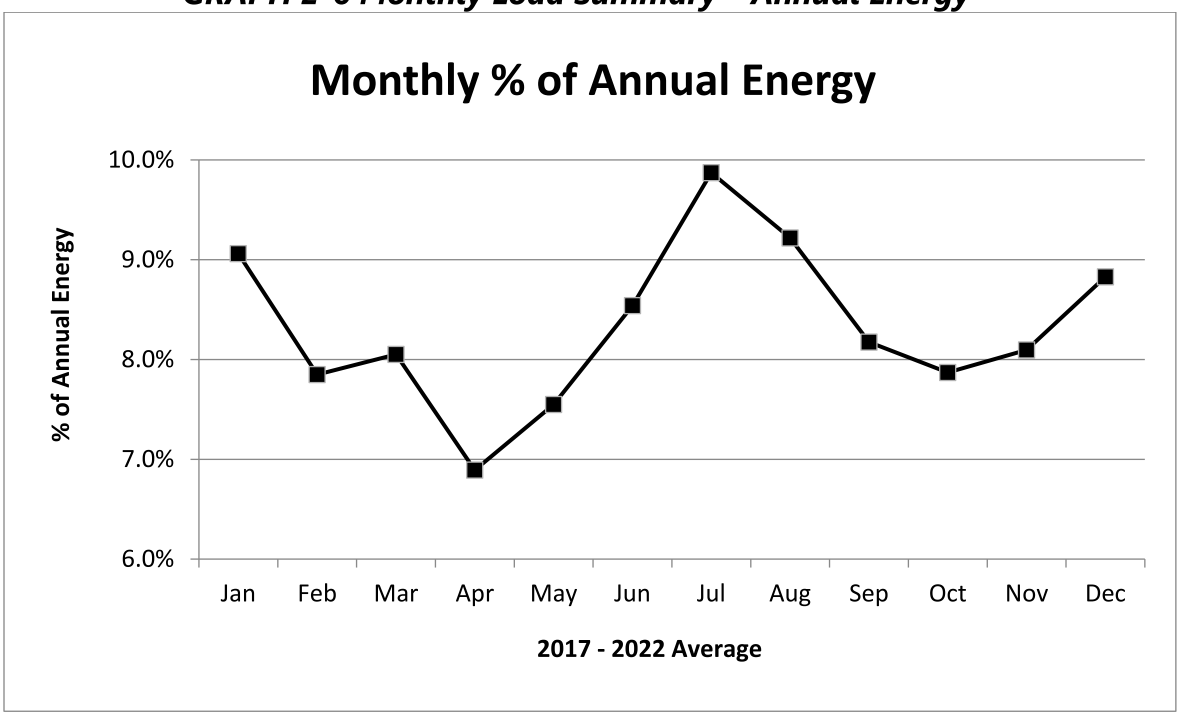
The following graphs illustrate the average monthly system load characteristics.

* Coincident demand includes pass-through load but excludes interruptible load
** Fort Wayne (AP) Weather Station
^ Two co-ops terminated memberships in 2015 (Jan and July)

GRAPH 2-5 Monthly Load Summary - Annual Peak



GRAPH 2-6 Monthly Load Summary – Annual Energy



Residential Survey

WVPA conducts a residential saturation survey on behalf of its members every three years. Approximately 71% of residential customers have central air conditioning and 11% of residential customers use a heat pump to cool their homes. Twenty-nine percent of residential customers heat their homes with an electric system.

The Company has conducted surveys since the early 1980s. The results are used in the load forecast as an estimate of energy conservation measures and to develop programs to better serve the residential customers. The last survey was conducted in late 2022 for 2023 publication.

In general, the results of the 2023 residential survey were comparable to the 2020 survey. In the 2023 survey, participants were asked additional energy-related questions, including one designed to gauge the level of awareness and interest in distributed generation. Nearly 4% of survey participants have installed some form of on-site generation and another 12% have seriously considered installing it. This is a 3-point increase from the 2020 survey. When asked their personal fuel source preference for electricity generation, 31% had no preference and just wanted the lowest-priced option, 26% prefer a mix of fossil fuels and renewables, 15% strongly prefer the use of renewable sources, 12% strongly prefer fossil fuels, 11% somewhat prefer renewables and 5% somewhat prefer fossil fuels. Respondents were asked about all-electric vehicles (AEV) and hybrid plug-in vehicles. Only 2% of survey participants currently own or lease an AEV and only 1% own or lease a hybrid plug-in. Among the 97% of survey participants who do not currently own or lease an AEV or hybrid plug-in, 9% have seriously considered (an increase of 5 points from 2020) and 18% (an increase of 6 points from 2020) have somewhat considered leasing or purchasing an AEV or hybrid plug-in.

New to the survey were views on battery storage. While less than 1% of survey participants already have battery storage, 30% have either seriously considered installing it or thought about installing it. Additionally, nearly 31% of participants have a generator that could power part or all of a home.

Non-Member Loads

As described in our system profile, WVPA supplies power to one non-member Indiana customer under a separate wholesale firm requirements agreement that ends in 2028.

This non-member Indiana load is forecasted at approximately 198 MW and 1,150 GWh annually and is situated in the AEP sub-balancing area of PJM. This customer's demand above 30 MW may be interrupted.

Existing Resources

WVPA 's existing resources include both supply-side and DR resources. Supply-side resources incorporate generation resources owned by the Company or purchased from other utilities. DR resources include several programs implemented by WVPA Members.

1. Supply-Side Resources

WVPA owns several electric generating units (listed below) within the MISO and PJM footprint.

TABLE 2-7 Generation Ownership

Resource (Wabash Valley Share)	MW (ICAP)	Fuel Type
Gibson Unit 5	156	Coal
Prairie State Units 1 and 2	83	Coal
Holland Energy	313.5	Natural Gas
Wabash River Highland	172	Natural Gas
Vermillion	240	Natural Gas
Lawrence	86	Natural Gas
Landfill Gas	52.8	Landfill or Natural Gas
Solar	6.8	Solar
Total Owned Generation	**1,110.2**	

a. Gibson Unit 5

WVPA has a 25% undivided ownership in Gibson Unit 5. It is jointly owned with Duke Energy Indiana (Duke Indiana) and Indiana Municipal Power Agency (IMPA). Gibson Unit 5, located in southwestern Indiana, is a 625 MW coal-fired generating facility operated by Duke Indiana. Operating under the Gibson Unit 5 Joint Ownership, Participation, Operation, and Maintenance Agreement (Gibson 5 Agreement), each party is responsible for paying its proportionate share of operating costs for the plant. In return, the Company is entitled to approximately 156 MW of capacity and related energy output of the plant. Gibson Unit 5 is equipped with "scrubbers" to stay in compliance with sulfur dioxide (SO_2) and particulate matter emissions regulations and programs. Duke Indiana also installed Selective Catalytic Reduction (SCR) equipment on Gibson Unit 5 for compliance with nitrogen oxide (NO_x) emission regulations.

Duke Indiana, the majority owner of Gibson Unit 5 and the other units at Gibson Station, has the responsibility for fuel procurement, fuel inventory, and operation. For 2022 and 2023, Gibson Unit 5 Station burned an average of .967 million tons of coal per year. The coal is purchased through various contracts and the spot market. WVPA reviews Duke Indiana's fuel procurement contracts and practices on a regular basis.

Gibson Unit 5 has a 625 MW net dependable capacity. For modeling purposes, WVPA forecasted that Gibson Unit 5 retires May 31, 2029; however, WVPA and joint owners are in the process of determining the plan, timing, and cost for retirement of the unit.

b. Prairie State

In May 2016, WVPA acquired a 5.06% interest in the Prairie State Energy Campus (PSEC) located in Marissa, Illinois, which consists of Prairie State Units 1 and 2 and an on-site captive coal mine. Unit 1 and Unit 2 were placed in commercial operation in June 2012 and November 2012, respectively. The total net capacity of the coal-fired generating facility operated by the Prairie State Generating Company (PSGC) is 1,650 MW. The Company's share totals 83 MW (split evenly between Units 1 and 2). Eight other public power utilities own the remaining 1,567 MW in various percentages of ownership. Operating under a Participation Agreement, each party is responsible for paying its proportionate share of operating costs for the plant.

PSEC was designed and constructed with modern environmental control technologies, including low NO_x burners, selective catalytic reduction units to further reduce NO_x, dry and wet electrostatic precipitators to limit particulate emissions, SO_2 scrubbers and hydrated lime injection for acid gas removal.

PSEC's on-site captive coal mine produces bituminous coal from the Illinois Basin. Maximum annual production is approximately 7 million tons. It has proven reserves that are expected to provide the power plant with 100% of required fuel through 2042. As a result, PSEC is not exposed to volatile coal prices or rising railroad transportation costs.

In September 2021, the Illinois governor signed the Climate and Equitable Jobs Act (CEJA), that makes Illinois the first state to require 100% carbon-free energy by 2045. To meet the requirements of this legislation, WVPA has assumed, for modeling purposes, that Unit 1 will retire on June 1, 2038, and Unit 2 will retire on December 31, 2045 (outside the time horizon of this IRP). WVPA and joint owners continue to investigate the economics and technical feasibility of carbon capture, operational changes, or other mitigating measures, to eliminate carbon emissions from these facilities.

c. Holland Energy

WVPA is a 50% owner of Holland Energy. Hoosier Energy is the other 50% owner. Holland Energy is an approximately 627 MW combined cycle generating facility comprised of two GE Frame 7FA combustion turbines, two Notre-Eriksen Heat Recovery Steam Generators (HRSG) and a single Toshiba steam turbine. Both combustion turbines are equipped with a dry low-NO_x combustion burner system and inlet-air evaporative cooling. The HRSGs are equipped with SCRs and with large natural gas-fired duct burners to supplement steam production. The HRSGs both supply a single 344 MW Toshiba steam turbine. The facility is equipped with Continuous Emission Monitoring Systems (CEMS) to monitor the NO_x emission from both HRSG stacks. Holland Energy is located on a combined 220-acre tract north of Effingham, Illinois.

The Company oversees natural gas procurement for Holland Energy. Holland Energy purchases natural gas from a single national supplier at market-based rates. The supplier utilizes both its firm transportation and storage agreement on the Natural Gas Pipeline Company of America (NGPL) pipeline to service Holland Energy.

The CEJA also impacts this facility. To meet the requirements of the legislation, WVPA assumed, for modeling purposes, that Holland Energy will retire on December 31, 2044 (outside the time horizon of this IRP). WVPA and Hoosier Energy continue to investigate the economics and technical feasibility of carbon capture, operational changes, or other mitigating measures to eliminate carbon emissions from this facility.

d. Wabash River Highland

In early April 2017, WVPA completed the installation of new dry low-NO_x combustion hardware on the Unit 8 combustion turbine, a GE Frame 7FA referred to as Wabash River Highland CT which operates as a simple cycle peaker using natural gas as its only fuel source. After additional upgrades to the compressor and installation of advanced gas path turbine parts, which occurred in the spring of 2022, Wabash River Highland CT now has a capacity ranging from 153 MW in the summer to 192 MW in the winter. The combustion turbine is in Vigo County, Indiana.

The Company procures the natural gas for Wabash River Highland by purchasing from a national supplier at market-based rates.

e. Vermillion

The Vermillion generating station consists of eight (80 MW) gas-fired GE Frame 7EA generators. Wabash Valley owns a 37.5% undivided ownership interest in Vermillion or 240 MW. The summer capacity rating for each of the Vermillion units is 72 MW.

Duke Indiana, the majority owner of Vermillion, has the responsibility for fuel procurement and operations.

f. Lawrence

WVPA owns one-third of the Lawrence generating station which consists of six GE LM6000 simple cycle generating units. Hoosier Energy owns the other two-thirds of the facility. Each of these gas-fired units has a summer capacity rating of 43 MW. The Lawrence facility was jointly constructed by Hoosier Energy and WVPA and went into commercial operation in May 2005.

Hoosier Energy, the majority owner of Lawrence, has the responsibility for fuel procurement and operations.

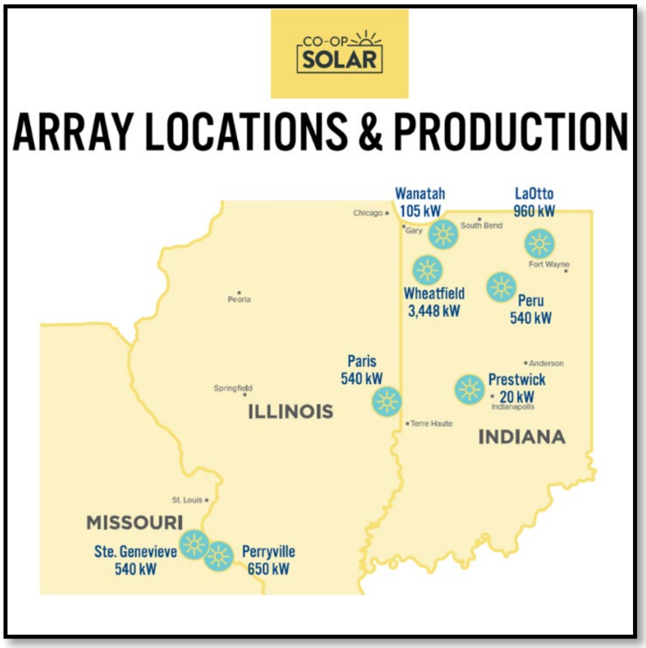
g. Landfill Gas

WVPA installed landfill gas-fired internal combustion (IC) generating units at existing solid waste landfill sites in central and northern Indiana and purchased a site at an existing solid waste landfill site in central Illinois. Currently, the Company operates fifty Caterpillar 3516 engine-generators and eight Caterpillar 3520 engine-generators at seven Waste Management (WM) landfill sites and one GFL Environmental (GFL) landfill site which in aggregate are capable of generating nearly 53 MW. The IC generators at each site are operated and maintained under contracts with Waste Management of Indiana, Inc. and MacAllister Machinery Company, Inc.

WVPA entered into 20-year agreements with a third party to sell medium BTU (MMBtu) landfill gas produced and collected at three WM sites. The third party purchases the MBtu landfill gas, converts it into pipeline quality Renewable Natural Gas (RNG) and sells it to an industrial customer(s) under a long-term contract and/or to the transportation market. By 2024, Wabash Valley plans to convert the engine-generators at all three sites to run on natural gas as peaking generation.

h. Solar

WVPA owns eight community solar facilities located in Indiana, Illinois and Missouri with a total nameplate capacity of 6.8 MW as shown in the map and table below. The sites were constructed to facilitate retail members voluntary renewable energy block subscriptions.



Resource	kW	In-Service Year
Wanatah, IN	105	2017
Peru, IN	540	2017
Ste. Genevieve, MO	540	2017
Paris, IL	540	2017
LaOtto, IN	960	2019
Perryville, MO	650	2019
Wheatfield, IN	3,448	2019
Hendricks, IN	20	2014
Total	**6,803**	

i. Power Purchases

Remaining capacity and energy requirements come from power purchases from various sources. WVPA has a mixture of base, intermediate, load-following and peaking power purchase contracts and may be characterized as both long and short-term contracts. The Company purchases blocks and seasonal amounts of power from numerous suppliers. The major long-term resources are purchased from AEP, Duke Indiana, NextEra, Mercuria and Morgan Stanley. Also, WVPA is currently purchasing 218.8 MW of output from wind turbines and 198 MW of output from solar generation. The following table describes the Company's existing purchased power resources.

TABLE 2-8 Wabash Valley's Energy and Capacity Purchases Summary

Supplier	Type	Expires	MW	Comments
AEP	Firm	2033	150	Load Following
Duke Indiana	Firm	2032	70	65% Min. Capacity Factor
Duke Indiana	Unit Peaking	2024	50	
Duke Indiana	Firm	2031	160-180	65% Min. Capacity Factor; 6/1/20-5/31/22 = 160MW 6/1/22-5/31/23 = 170MW 6/1/23-12/31/31 = 180MW
Duke Indiana	Firm	2025	55	50% Min. Capacity Factor
Hallador	Capacity	2029	150-250	Fixed Price; Capacity only
Morgan Stanley	Firm	2018-2025	100	Fixed Price
NextEra	Firm	2023-2030	25-75	Fixed Price; 2023 25 MW; 2024 40 MW; 2025-2030 75 MW
NextEra	Firm	2024-2032	50	Fixed Price
Morgan Stanley	Firm	2024-2035	50	Fixed Price
Morgan Stanley	Firm	2026-2032	100	Fixed Price
NextEra	Firm	2028-2037	50-100	Fixed Price; 2028-2032 50 MW; 2033-2037 100 MW
Agriwind	Wind Turbine	2038	8.4	
Pioneer Trail Wind Farm	Wind Turbine	2030	10	
Zimmerman Energy	Landfill Gas	2039	5.6	
Meadow Lake Wind V	Wind Turbine	2037	25	
Meadow Lake Wind VI	Wind Turbine	2038	75.4	
Harvest Ridge Wind Farm	Wind Turbine	2040	100	
Prairie State Solar	Solar	2048	99	
Dressor Plains Solar	Solar	2048	99	
Prairie Wolf Solar	Solar	2034	50	Fixed Price; Capacity only
Voltus	Capacity	2025	4	Fixed Price; Capacity only
Various Suppliers	Short-Term	Various	Various	Usually 1-2 years in duration

j. Market Resources

WVPA has numerous agreements which provide access to economical market energy and the ability to cover periods of extreme temperature or unplanned outages with emergency energy. These purchases are typically priced at the prevailing market price and do not include a significant demand charge. Additionally, the Company operates in the MISO and PJM energy markets which provide energy to WVPA loads at incremental hourly market prices.

k. Environmental Effects

Gibson Unit 5

WVPA owns a minority share of Gibson Unit 5. Duke Indiana, the majority owner of Gibson Unit 5 and Gibson Station, includes the significant environmental effects from this unit in its IRP. Duke Indiana is currently evaluating options for compliance with and monitoring potential changes to carbon-related rule(s) applicable to electric utility generating units, the rule related to the Disposal of coal combustion residuals (CCR) from Electric Generating Utilities and other significant environmental regulations.

Prairie State Generating Company (PSGC)

WVPA owns a 5.06% share of the coal-fired generating facility operated by the PSGC. PSGC is currently regulated by the Acid Rain Program and the Cross-State Air Pollution Rule (CSAPR). PSGC does not receive Acid Rain Program allowances. Because PSGC commenced commercial operation after January 1, 2010, PSGC receives new unit set-aside allowances for both the CSAPR Annual nitrogen oxides (NOx) and sulfur dioxide (SO2) program – these allowances are determined during each operating year by the United States Environmental Protection Agency (USEPA). Additionally, each year USEPA issues CSAPR NOx ozone season allowances to PSGC; thus, PSGC is not subject to the new unit set-aside allowance program for the NOx ozone season. If PSGC is short on allowances for any given program, WVPA will elect to transfer the needed allowances from the Company's accounts, purchase allowances and/or request PSGC to purchase allowances on WVPA's behalf. The facility is equipped with the following types of environmental control technologies:

Type	*Description*
1. Low- NO_x Burners	Impede the formation of NO_x by lowering the temperature of the boiler flame to control the way coal combusts
2. Selective Catalytic Reduction (SCR)	Injects product into the air stream as it passes over a catalyst, causing NO_x to be converted to nitrogen and water
3. Dry Electrostatic Precipitator (Dry ESP)	Uses electrodes to place an electric charge on large particulates then captured by an oppositely charged plate
4. SO_2 Scrubbers (Scrubbers)	Injects a limestone/water mixture into the air stream, where it reacts to capture the SO_2
5. Wet Electrostatic Precipitator (Wet ESP)	Uses multiple high-voltage fields to attract fine particulates to an electrode, which is washed with water to capture the constituents

The control equipment removes more than 85% of NO_x, 98% of SO_2, 99% of particulate matter and 90% of mercury. The facility requires water to run both the power plant and mine and has an on- site pond that stores enough water for ~30 days' use or ~778M gallons. Water is pumped 15 miles from the Kaskaskia River, which is a tributary of the Mississippi River. PSGC acquired back-up water rights from the State of Illinois; if the flow of the Kaskaskia River is insufficient, then the State will release water from the Carlyle and Shelbyville Lakes into the Kaskaskia River to ensure sufficient flow. Water intake is permitted and monitored by the U.S. Army Corps of Engineers and the Illinois Environmental Protection Agency (IEPA).

Holland Energy

Wabash Valley is a 50% owner of Holland Energy located in Illinois. The facility is a gas-fired combined cycle combustion turbine. It is currently regulated by the Acid Rain Program and CSAPR. It has a Title V air operating permit issued by the IEPA. The facility is equipped with SCR for NO_x removal. SO_2 emissions from a gas-fired facility are de minimis.

In terms of 2023 SO2, NOx, and NOx ozone season annual emissions, Holland Energy is estimated as follows:

SO2 (tons)	*NOx (tons)*	*NOx Ozone Season (tons)*
<6	~122	~56

As finalized, the USEPA's Mercury and Air Toxics Standards (MATS) rule does not apply to this facility as it is gas-fired.

Holland is not a significant generator of solid waste. Solids removed from the treatment of raw (incoming) water from the Kaskaskia River are shipped off-site to a non-hazardous landfill. No on-site landfills are present. Holland is not a large generator of hazardous waste. The CCR regulation, discussed for Gibson Unit 5 above, would not affect Holland as it combusts no coal.
Water used within the plant processes comes from the Kaskaskia River. The facility has an intake structure to bring in the raw water and pre-treats the water prior to using it within the facility processes. The Holland Energy facility is permitted to discharge process waters and plant drainage to the Kaskaskia River through an outfall. All storm water and other waters from the plant are permitted to be discharged through two outfalls to an unnamed tributary to Brush Creek. Potable water used at the facility originates from potable wells and sanitary wastewaters are now directed to a local treatment plant.

Holland is subject to the §316(b) of the Clean Water Act for Cooling Water Intake Structures at Existing Facilities

Wabash River Highland

The Wabash River Highland facility is owned by WVPA. The facility is a natural gas-fired simple cycle unit. It is currently regulated by the Acid Rain Program and CSAPR. It has a Tile V air operating permit issued by the Indiana Department of Environmental Management (IDEM). The facility is equipped with dry low-NO_x burners for NO_x removal. SO_2 emissions from a gas-fired facility are de minimis.

SO_2, NO_x, and NO_x ozone seasons air emissions on an annual basis are estimated as follows, but will vary from year to year:

SO2 (tons)	NOx (tons)	NOx Ozone Season (tons)
~1.4	~102	~46

Similar to Holland, USEPA's MATS rule no longer applies to this facility as it was converted from syngas to natural gas-fired.

Additionally, the plant is not a significant generator of solid waste as an operation. The CCR regulation, discussed for Gibson Unit 5 above, does not affect Wabash River Highland as it combusts no coal.

Because the plant does not utilize water for generation, Wabash River Highland neither consumes nor discharges process water. Therefore, the plant is permitted to discharge only storm water and metal cleaning waters.

Simple Cycle Gas Turbines

Significant environmental effects from owned generation assets are modeled and accounted for in the budgeting process for unit operations. Vermillion Generation Station and Lawrence Generating Station consist of natural gas, simple cycle peaking units. Since these units utilize natural gas as a fuel source and run relatively few hours on an annual basis, the emissions are negligible compared to other base load units. Other entities have responsibilities for compliance with the Title V air operating permits at these gas-fired peaker combustion turbine sites. These sites do not generate significant amounts of solid waste.

Landfill Gas

WVPA owns several, small landfill gas generator facilities that are located on landfills owned by WM in Indiana and GFL in Illinois. The WM-related generating facilities are subject to air permits issued by IDEM; but because the sites are owned by WM, the air permits are issued to them. The Illinois facility is subject to air permits issued by IEPA to the Company as owner. These generating facilities do not create significant amounts of solid wastes.

SO_2 & NO_x Allowances

The Acid Raid Program and CSAPR are in effect. WVPA maintains an electronic SO2 & NOx emissions inventory. The inventory accounts for allowances held in reserve including any USEPA allocations and allowances from market purchases. The allowance inventory is in accounts under the USEPA's Clean Air Markets Division (CAMD) which sets up a number of checks and balances for oversight of allowance transactions. For those facilities in which the Company is a minor owner (Gibson Unit 5, Lawrence Generating Station, PSGC and Vermillion Generating Station), the SO2 and NOx allowances are held in accounts by the majority owner. For Holland Energy in Illinois, Wabash Valley maintains the allowance account under CAMD.

The Company routinely checks on the SO2 & NOx status (including NOx ozone season) under CSAPR and the Acid Rain Program:

- Amount of SO2, NOx, and NOx ozone season allowances present in the account;
- Projected SO2, NOx, and NOx ozone season emissions estimates;
- Actual SO2, NOx, and NOx ozone season emissions on a quarterly or semi-annual basis;
- Current market price of SO2, NOx, and NOx ozone season allowances; and
- Tracking of volatility of SO2, NOx, and NOx ozone season allowance market.

Carbon Emission Pollution Standards

In May of 2023, the EPA published proposed new carbon pollution standards for fossil fuel fired power plants with ambitious reductions in carbon pollution. The proposed standards are based on technologies such as carbon capture and sequestration/storage (CCS), low greenhouse gas hydrogen firing, and natural gas co-firing. Due to the uncertainty of the regulations within the proposed rule, Wabash Valley continues to evaluate a compliance strategy with these changing standards for its facilities. In addition, Wabash Valley is reviewing and evaluating state-specific rules that affect the electric utility industry.

2. Demand-Side Management – Demand Response Resources

WVPA and its Members have successfully included DR resources as part of the power supply portfolio for more than 40 years, when the direct-load control (DLC) program for residential water heaters was established. The Company coordinates control of the DR resources to effectively manage overall power costs with a focus on capacity benefits. In MISO, DR program assets are registered as Load Modifying

Resources (LMRs) to participate in the seasonal Planning Resource Auction (PRA). Most of the programs were created to support the historic summer peak based planning criteria and are being enhanced to optimize other seasons, with a special focus on winter capabilities to align with higher reserve margin requirements.

Each year WVPA works with its members to evaluate the power supply environment and to determine how to incorporate DR programs into the overall power supply portfolio. In 2023, the Retail RP&S Working Group worked with a third-party vendor, Skytop Consulting, to complete a thorough review of the DR and EE portfolio. Publicly available data from Midwest utilities Market Potential Studies (MPS) was leveraged to minimize administrative costs. The group conducted robust discussions and suggested modifications based on deep knowledge of retail members as described in detail in Section 4 and Appendix H.

Since 2012, WVPA has offered the PowerShift® program, an updated DLC program. To date, 19 of the 23 Members have signed agreements to participate in the PowerShift® program. The PowerShift® program includes participants' water heaters (WH), air conditioners (AC), pool pumps (PP), field irrigators (FI), ditch pumps (DP) and grain dryers (GD).[3] In 2018, Wabash Valley introduced an updated commercial and industrial (C&I) load control program under the PowerShift® umbrella program. Five Co-op Members are currently participating in the C&I PowerShift® program. As of fall 2023, more than 20 retail members are participating to provide 24 MW of summer capacity and nearly 8 MW of winter capacity. The available resources fluctuate year over year based on retail participation.[4]

TABLE 2-9 Wabash Valley's PowerShift® Program Summary (kWs in 12/2023)

Participants per Co-op	ACW	CIW	DPW	FIW	PPW	WHW	Grand Total
Boone						881	881
Carroll White	603			7	4	3,582	4,196
Citizens	66					60	126
Corn Belt	1,673					469	2,142

[4] The majority of DR resources are located in the MISO footprint with about 3 MW of field irrigation resources in PJM.

Enerstar	111			1		66	178
Fulton	56			238		2,039	2,333
Hendricks	284					2,423	2,707
Jasper						55	55
Kankakee Valley	947		20	159		425	1,551
Lagrange	129			277			406
Marshall	200				4	95	299
Miami Cass	139					725	864
Ninestar	43					82	125
Noble				97			97
Parke	740	4		6		185	935
Steuben	737			68	22	822	1,649
Tipmont	666					1,039	1,705
Total	6,394	4	20	853	30	12,948	20,249

TABLE 2-10 Wabash Valley's PowerShift® Program C&I Summary

Co-op	***Summer Capacity (kW)***
Boone	87
Carroll White	205
Citizens Electric	128
Fulton	6,179
Heartland REMC	5,837
Hendricks Power	3,624
Miami Cass	6750
Newton	932
Parke	475
Total	**24,216**

DR programs continue to be an integral part of WVPA 's power supply portfolio with the primary purpose to keep power supply costs as low as possible. The Company now approaches DR programs as a resource, just like a peaking plant. The economics, operation, environmental compliance evaluation and planning are all treated similar to a peaking plant. WVPA is engaged with MISO and PJM on matters relating to demand response and the states in which we operate and will provide input on any federal or state plan that impacts Demand-Side Management program design, implementation and compliance with a finalized carbon-related rule affecting electric utility generating units.

a. Goals & Objectives

WVPA and its Members possess a goal of controlling costs and improving efficiency to supply reliable power at the lowest reasonable cost. In addition, the Company and its Members want to offer the end retail customer the greatest possible value in electric service and to assist them in improving their quality of life.

Marketing at WVPA is a collaborative effort with the Members and is closely tied to the Company's DR efforts. WVPA is promoting end-use technologies that are beneficial to the retail customer and allow the Company to control operating costs. WVPA currently has approximately 60 MW of summer load reduction capability enrolled in the PowerShift® program.

Now is both a challenging and exciting time for DR. Edge-of-grid resources have never been more abundant. Yet finding successful business cases and navigating the marketplace of software providers adds a degree of complexity and uncertainty due to device compatibility issues.

Quality meter data is as vital as ever for Measurement & Verification (M&V) purposes. To improve the availability of meter data, WVPA is working with our Member Cooperatives and the National Information Solutions Cooperative (NISC) to implement a new meter data management (MDM) system. NISC's G&T focused MDM will enable access to the Member Cooperative's validated, estimated, and edited meter data. Which is an improvement from the pre-validated, estimated, and edited meter data from the Member Cooperative's AMI. The new MDM will also simplify the M&V process with improved meter data aggregation and reporting functionality. 5

[5] MISO proposed requiring 8760 data in its Demand Side Resource Interface (DSRI) in a November 2023 Resource Adequacy Subcommittee (RASC) meeting. See https://cdn.misoenergy.org/20231107-08 RASC Item 11aii LMR Accreditation (RASC-2019-9)630751.pdf

b. Existing Programs

i. Water Heaters

Electric water heaters that have a two-way communicating advanced metering infrastructure (AMI) network switch installed can participate in the PowerShift® program. WVPA has deemed that each water heater provides 0.6 KW of load reduction. This value was determined using historical analysis, industry best practices and has diversity built in. Under the PowerShift® program, all water heaters are shut off for 100% of the event duration.

ii. Air Conditioners

Air conditioners that have a two-way communicating AMI network switch installed can participate in the PowerShift® program. WVPA has deemed that each air conditioner provides 1.0 KW of load reduction. This value was determined using historical analysis, industry best practices and has diversity built in. Under the PowerShift® program, all air conditioners are cycled off for 50% of the event duration, typically 15 minutes on and 15 minutes off.

iii. Wi-Fi Thermostats

Launched in mid-2021, this program was discontinued in 2023 due to low-cost effectiveness with only 1 MW of total capacity. The Company is reviewing the program for changes and potential reinstatement in the future.

iv. Pool Pumps

Pool pumps that have a two-way communicating AMI network switch installed can participate in the PowerShift® program. WVPA has deemed that each pool pump provides 1.0 KW of load reduction. This value was determined using historical analysis, industry best practices and has diversity built in. Under the PowerShift® program, all pool pumps are shut off for 100% of the event duration.

v. Field Irrigation

Field irrigators that have a two-way communicating AMI network switch installed can participate in the PowerShift® program. WVPA has deemed that each field irrigator provides 75% of nameplate (ranging from 3 to 123 KW) pump horsepower in KW reductions. Under the PowerShift® program, all field irrigators are shut off for 100% of the event duration. These participants provide 47% of the current PowerShift® load reductions.

vi. Entire Home

This program ended in 2022 because the 2G cellular radios used in the switches were abandoned by the cell providers, making our switches non-operable. Technology obsolescence caused a reduction of about 6.5 MW in summer DR resources. In 2024, we are actively developing an alternative "entire home" DR program using generators and/or batteries.

vii. Ditch Pumps

Ditch pumps that have a two-way communicating AMI network switch installed can participate in the PowerShift® program. WVPA has deemed that each ditch pump provides 75% of nameplate pump horsepower in KW reductions. Under the PowerShift® program, all ditch pumps are shut off for 100% of the event duration.

viii. Grain Dryers

Grain dryers that have a two-way communicating AMI network switch installed can participate in the PowerShift® program. WVPA uses the nameplate power rating for each dryer to obtain the KW reduction available. Under the PowerShift® program, all grain dryers are shut off for 100% of the event duration.

ix. C&I Program

The C&I program works with WVPA's Member's larger retail customers to provide a load reduction usually by performing a manual process. Wabash Valley notifies the participant of the PowerShift® event prompting the participant to take the appropriate actions to achieve their load reduction commitment. WVPA measures the event compliance using the participant's hourly meter data.

The PowerShift® program is a registered resource in MISO. This market determines when the program is called and the compensation the Company receives.

3. Demand-Side Management – Energy Efficiency Programs

The goal of WVPA's Energy Efficiency (EE) programs is two-fold: deliver cost-effective energy savings and a high level of member satisfaction.

WVPA started offering EE programs to Member cooperatives in 2008 with a residential new construction program focused on helping builders and homeowners construct a high performance, comfortable, durable and low energy cost home. Since 2008, the Company has worked jointly with our Member cooperatives, retail members and our Power Supply staff to develop attainable savings goals that lessen baseload power supply costs and increase retail member satisfaction throughout the service territory. The EE programs were reviewed by the RP&S Working Group and modified as described above. The POWER MOVES® initiative represents more than wholesale cost savings; it represents a way to help retail members (both residential and commercial/industrial) save on their monthly utility bills.

The POWER MOVES® programs offer many opportunities for participation by members located throughout WVPA territory although none is directly targeted to low-income residential ratepayers. WVPA encourages Member cooperative energy advisors to take weatherization training through the Indiana Community Action Association (INCAA) and to maintain contact with their local Community Action Program (CAP) agencies. WVPA staff maintains relationships at INCCA to educate trainers and managers about the benefits that electrification of certain equipment can provide their low-income clients. Although not a formal program, WVPA pays rebates to weatherization agencies for installing qualifying energy efficient equipment in client homes.

WVPA determines the costs, characteristics, and other parameters of the residential and C&I energy efficiency programs by conducting research into the technology offered. The Company takes into consideration each technology's purchase cost, operating cost, minimum efficiency, common application in the market, availability in our markets and ease of implementation among other factors. Research is conducted by WVPA staff, Member cooperative staff and sometimes third-party consultants and may include interviews with retail members or contractors.

A brief description of the programs included in the POWER MOVES® EE program portfolio follows. Further details of the program can be seen at PowerMoves.com.

a. Residential

i. Air Source Heat Pump Rebate

Residential customers are offered a rebate to install a new air source heat pump when they replace an existing electric resistance system, air source heat pump, propane or fuel oil heating system. In certain situations, a rebate is given for heat pumps in new construction homes. New heat pumps must meet minimum efficiency standards. The air source heat pump rebate has been modified to incorporate recent innovations in compressor technology allowing for cold climate heat pumps and ductless heat pumps.

ii. Geothermal Heat Pump Rebate

Residential customers are offered a rebate to install a geothermal heat pump when they build a new home. Additionally, retail customers with existing electric resistance or fossil fuel systems are also eligible for this rebate. New geothermal units must meet minimum efficiency standards.

iii. Dual Fuel Air Source Heat Pump Rebate

Residential customers are offered a rebate to install a new dual fuel air source heat pump when they replace an existing electric resistance system, air source heat pump, propane or fuel oil heating system. In certain situations, a rebate is given for heat pumps in new construction homes or to add a new heat pump to an existing fossil fuel furnace. New heat pumps must meet minimum efficiency standards.

iv. Energy Star Variable Speed Pool Pumps

This rebate ended on 12/31/23 due to improved efficiency standards and equipment in the marketplace. Participation was limited as well.

v. Heat Pump Water Heaters

Residential customers are offered a rebate to install a new heat pump water heater when replacing an existing electric resistance tank water heater. Rebates are also available to install heat pump water heaters in new construction homes.

vi. POWER MOVES® Home Program

WVPA pays the Home Energy Rating System (HERS) fee to encourage residential customers building new homes to follow our specific set of high-performance construction standards. Residential customers and home builders split additional rebates that can be earned based on the home's final HERS rating.
new construction homes.

vii. Wi-Fi Thermostats

Residential customers are offered a rebate to replace an existing non-smart thermostat with a new Wi-Fi enabled thermostat.

b. Commercial & Industrial (C&I)

i. Lighting Retrofit Incentives

WVPA offers a prescriptive rebate to encourage C&I accounts to replace existing inefficient lighting with new more efficient lighting. Incentive amounts vary based on the type of bulb or fixture being replaced and installed.

ii. Non-lighting Retrofit Incentives

WVPA offers a prescriptive rebate to encourage C&I accounts to replace existing inefficient heating and cooling systems with new more efficient heating and cooling systems. Additionally, the Company offers rebates for variable frequency drives, compressed air, refrigerated cases, and other miscellaneous measures. New equipment must meet minimum efficiency standards.

iii. C&I Custom Retrofit Program

C&I customers who wish to receive incentives for energy efficient equipment that does not fit into any other C&I category are asked to submit energy savings projects for review by an independent third party engineering firm. Incentives are based on the projected amount of energy savings and a set amount per KWh.

iv. Business New Construction Program

The intent of this program is to encourage the construction of energy-efficient commercial/industrial buildings. Incentives are provided to increase building and system efficiency over the base energy code for Indiana, Illinois and Missouri. WVPA has a set list of prescriptive measures, but we will also review projects and offer a custom rebate for items that are not included on the prescriptive list.

Owners/developers who are constructing a new commercial building or a new addition to an existing building or are conducting a major renovation to an existing building or multi-family dwellings of six or more units are eligible for this program.

c. Estimated Annual and Lifetime Energy Savings

Savings reflect the Company reported values in its 2023 EIA report as shown below.

Table 2-11 Energy Efficiency Programs Estimated Energy Savings

Energy Efficiency Program	2023 kWh Savings (Deemed)	Weighted Avg Life of Program (Years)	Life Cycle Savings (MWh)
Existing Homes Mechanical	1,466,976	23.5	34,462
Residential New Construction	52,835	25.0	1,321
C&I Prescriptive	12,842,450	13.6	175,050
C&I Custom	5,928,184	15.0	88,812
Business New Construction	16,594,076	12.7	210,676
Total	**36,884,521**		**510,320**

4. Transmission Resources

WVPA takes service under the PJM tariff for delivery to load in the AEP local balancing area and service under the MISO transmission tariff for Ameren Illinois, Ameren Missouri, AES Indiana, and Duke Indiana local balancing areas. The Company receives grandfathered transmission service under a long-standing interconnection agreement for the NIPSCO area which terminates in January 2025. All ancillary services are coordinated or purchased through these agreements.

In the Duke Indiana transmission pricing zone, along with Duke Indiana and IMPA, WVPA owns a proportionate share of the transmission system referred to as the Joint Transmission System (JTS). The Transmission and Local Facilities Agreement and the Operation and Maintenance Agreement (Transmission Agreement) divides the ownership of the JTS, as well as proportionately divides the operating costs and revenues among the three joint owners. The JTS is under MISO operational control. Duke Indiana, as the majority JTS owner, is directly responsible for planning and operation of the joint system with MISO. The Company coordinates planning with Duke Indiana via committees established within operating contracts between Duke Indiana, IMPA and WVPA. The goal of this arrangement is to plan for an optimal transmission system utilizing a single system design approach.

In the Ameren Missouri planning area, WVPA owns networked transmission assets and has entered into a joint pricing zone agreement with Ameren Missouri. In other local balancing areas, WVPA predominately owns transmission taps that are part of the network integrated transmission system that comprises the balancing area. The Company coordinates with PJM, MISO, and the appropriate transmission owners within both regional transmission organizations (RTOs) regarding both the operation and maintenance of existing transmission lines as well as the planning for new facilities. Furthermore, WVPA provides long-range load forecast information to support coordinated planning within the RTOs.

5. Transmission Impacts on Resource Planning

As described above, WVPA participates within both the MISO and PJM RTOs. The structure of both RTOs inherently incorporates the value of transmission by operating the markets with locational pricing. The locational marginal price (LMP) is influenced by the impact of transmission congestion within the markets. Currently, the Company's load is located primarily in regions with adequate transmission facilities. Congestion is not a major factor in WVPA 's power portfolio. However, the Company uses financial transmission rights (FTRs) to hedge the cost of the transmission congestion that does exist within the portfolio. Currently, the Company has adequate allocations of FTRs to provide cost hedging for WVPA sources to its load through the existing FTR allocation processes in PJM and MISO. Due to the nature of the FTR processes in the RTOs, this may change due to the future availability and configuration of transmission capability.

By utilizing the LMP, the Company does consider the value of transmission system upgrades. WVPA uses Indiana Hub forecasted market prices as an assumption in the IRP and allows the market to price the value of expected transmission use and limits in the future relative to the definition of the Indiana Hub. The Company's resources and loads are located generally in or near the Indiana Hub, so the price provides a reasonable estimate of value over the time horizon of the study.

Additionally, both RTOs administer locational capacity markets that incorporate import capability to determine the pricing in the local resource zones. Currently, WVPA 's load and most of its resources are in unconstrained zones. MISO and PJM have processes to evaluate and integrate new transmission to improve transmission system reliability and market efficiency.

WVPA provides data and information to MISO and PJM as a part of several processes to support each RTOs overall transmission planning process:

1) WVPA provides load forecasts and planning information to the local balancing/transmission areas and to the RTOs. Both RTOs have processes to plan for additional facilities in a coordinated manner to meet the reliability needs and improve the value of the transmission system. These planning processes include projects being built for reliability and to improve transmission congestion to reduce cost. As available, the Company uses information from the RTOs to estimate costs and evaluate changes in the system that could impact WVPA's plans.

2) WVPA provides planning information to MISO and PJM for Interconnection Studies as well as to the regional transmission owner/operator for new and/or upgraded facilities required to support load or generation. WVPA informs them of ongoing load growth and generation installations. The result of these interconnection processes is a study which incorporates the Company's proposed facilities. WVPA, in turn, examines the study to extract any information on upgrades or additional costs that should be included in the Company's evaluation of a specific project.

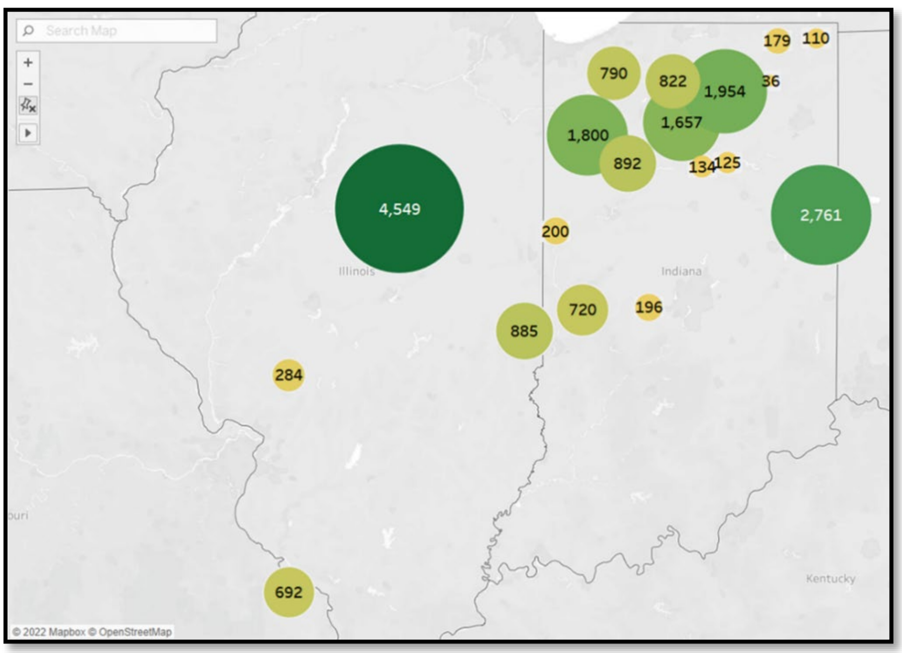
3) WVPA offers or self-schedules its generation to meet the requirements of MISO's and PJM's locational capacity markets. MISO and PJM clear the markets and limit importing capacity between capacity zones. As part of the forecasting process, the Company monitors the price of the capacity auctions and periodically surveys the market to determine locational capacity price.

Distributed Generation

Currently, WVPA has a policy that any customer-owned Distributed Generation (DG) unit greater than 25 kW sell excess energy directly to the Company under the avoided cost concept and not net metering. Any customer-owned generator 25 kW or less is managed locally by the Member. WVPA promotes providing avoided cost payments to prevent other Members from subsidizing the customer-owned generator which may result with net metering. DG is factored into the IRP either through the inclusion of such resource as a generator or utilizing the generator to offset load as a behind the meter resource while being cognizant of any environmental regulations that may impact these generators. If a facility is expected to operate at a high capacity factor, the Company would remove the annual energy output and the average kW output of the generator from the load forecast. WVPA developed a Distributed Energy Resource (DER) forecast to include DG and Electric Vehicle (EV) adoption as described in Section 3 of this IRP.

Among the highlights of current DG levels, approximately 40 MW of Member-owned and customer-owned DG exists across the WVPA footprint at more than 2,100 sites. Interest in DG has increased over the past few years with current concentrations in kW per Co-op as shown in the following map.

2023 Distributed Generation (DG) (kW)



1. Generation Planning

WVPA Members' retail customers have completed several distributed generation projects totaling less than 10 MW that are not emergency backup resources. These projects will supply part of the customer's energy requirements, while the local Member will supply the remainder.

2. Transmission Planning

WVPA coordinates the interconnection of distributed generation with the area transmission owners and the appropriate RTO. The Company provides information as required by their transmission system planning staffs so that appropriate studies can be carried out. This includes information to these operators about the location and operation of customer generation resources.

WVPA will provide assistance to its members on an as-required basis, particularly for those distributed generation facilities requiring interconnection with transmission facilities.

3. Distribution Planning

The Distributed Generation policy calls for the Company to coordinate, as necessary, with the Member serving the distributed generation customer. WVPA facilitates discussions as requested between distributed generation end-use customers and members to develop a formal Interconnection Agreement.

The Interconnection Agreement generally includes provisions that address:

- Certification, from a qualified electrical engineer, of the reliability and safety of the proposed distributed generation project or facility and interconnection equipment.
- Transmission of power from the distributed generation project or facility to any load utilizing a member distribution system.
- Reimbursement to WVPA and the member for the costs of interconnection facilities installed, constructed, or maintained for a distributed generation project or facility.
- Installation of necessary safety and system protection equipment and implementation of operating protocol to assure the safety of Wabash Valley, Member, and other personnel as may be affected by the operation or existence of a distributed generation facility.
- Indemnification of WVPA and a member by a Customer which owns the distributed generation project or facility against liability for any injuries or damages to person or property which might result from the operation or existence of the distributed generation facility and, upon request, proof of the Customer's ability to financially guarantee the indemnification.

- Responsibility and requirements for the control, operation, and maintenance of the distributed generation project or facility and any related equipment.
- Metering requirements and payment for any net energy exported to the grid from the distributed generation project or facility.
- WVPA and the member inspection rights of the project; and
- Proof of insurance held by the owner of the distributed generation, both prior to and during commercial operation of the distributed generation, in an amount equaling that which is identified within the Interconnection Agreement.

4. Load Forecasting

As further described in Section 3, the forecast uses regression modeling to project peak demand and energy requirements, but this projection is adjusted as required to reflect the impact of customer owned distributed generation. To date, customer distributed generation projects have had minimal impact on WVPA ’s load requirements. The Company continues to monitor technology developments in distributed products to determine if future load will be impacted by customer generation and storage.

2023 Integrated Resource Plan

Section 3

LOAD FORECAST & FORECASTING METHODOLOGY

Introduction

WVPA's load forecast process is based on constructing member-specific forecast models that account for long-term structural changes, as well as expected population and economic growth. WVPA uses an end-use modeling framework developed by Itron, Inc. (Itron) which utilizes Itron's MetrixND® regression modeling software and Forecast Manager™ database. The general approach is to estimate monthly linear regression models that relate system energy and peak demand to constructed end-use model variables for heating, cooling, and other use. The constructed model variables reflect increases in population and economic growth, end-use saturation and efficiency changes, and weather conditions.

WVPA presented load forecasts to each of our cooperative members and the Company's Board approved the final 2023 Power Requirements Study (PRS) for use in the 2024 Budget and 2023 IRP as our Base Case Load Forecast.

Overview

WVPA's membership is comprised of twenty-three member systems spread throughout three states, two RTOs and six sub-balancing areas. Given wide geographic spread and differences in underlying economies, we recognize the need to analyze and forecast loads at the member cooperative level. We estimate separate monthly energy (MWh) and coincident peak demand (MW) models for each member using linear regression; the models incorporate end-use intensity trends as well as county-level economic and weather data specific to the member service area. We derive member retail sales by applying distribution loss factors to member total energy requirement forecasts.

While the forecast is developed at the system delivered energy level, we disaggregate the forecast into residential, commercial and industrial (C&I), and other (primarily street lighting) for presentation to our members. This disaggregation allows us and our members to better understand the factors driving local load growth and provides a basis for member feedback as to the reasonableness of the forecast results.

Monthly residential billing data is used in constructing residential average use and customer regression models for each Member. The average use models incorporate residential end-use intensities for the East North Central Census (ENC) Division derived from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO). Other use sales models are estimated with simple linear trend specification.

We continue to derive C&I sales as the difference between total member sales and residential and other use sales forecasts. C&I sales data still proves to be a challenge for modeling as C&I sales are only available on an annual basis for many of our members.

One of the factors that significantly improved our forecast accuracy is capturing end-use efficiency improvements in both the residential and commercial sectors through member-weighted intensity indices. As we develop our forecast models at the individual member-level, forecasts capture the unique customer mix, economics, and weather conditions associated with the member service area.

Figure 3-1 depicts WVPA's load forecast development process.

Figure 3-1 Load Forecast Development Process

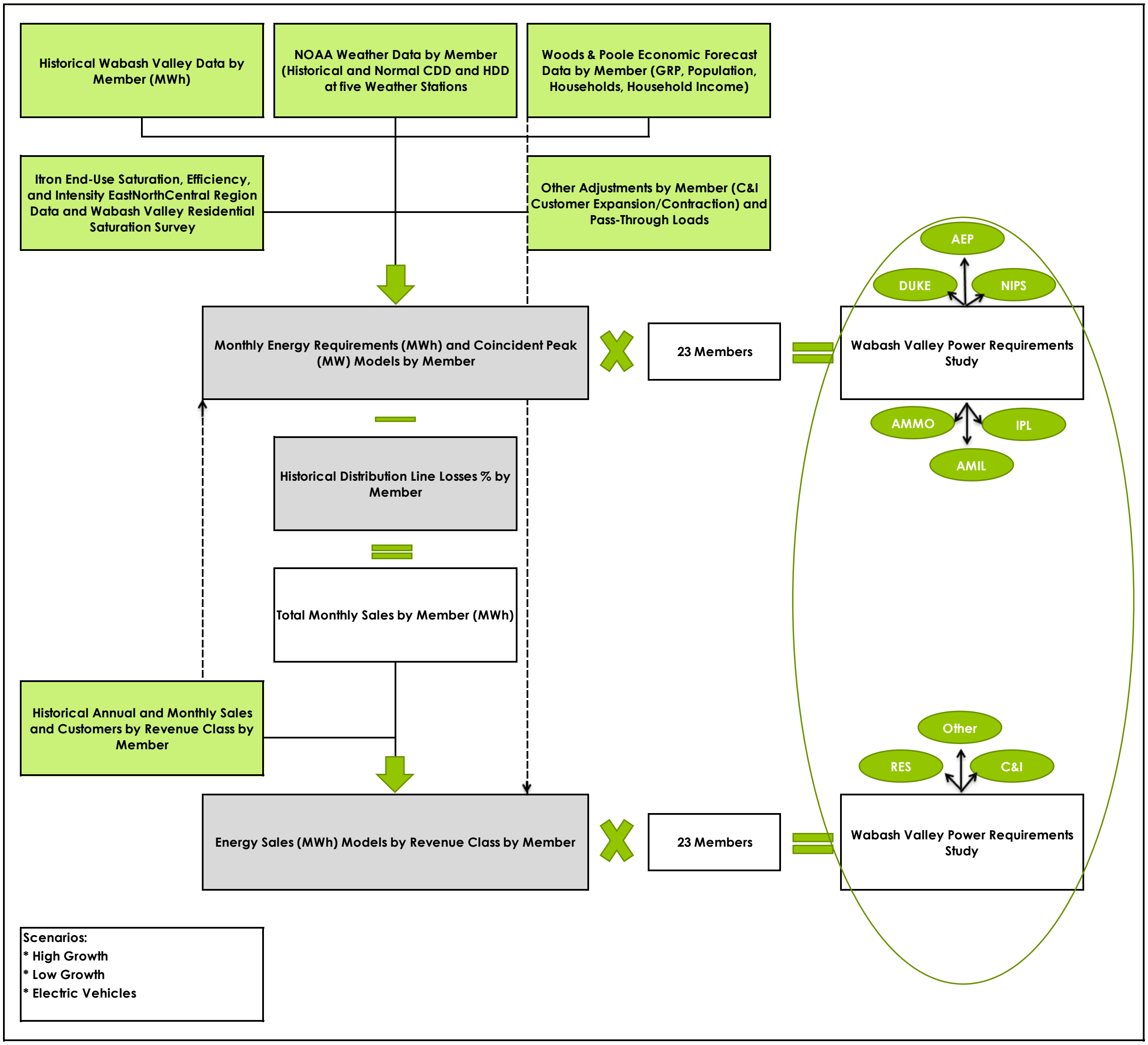
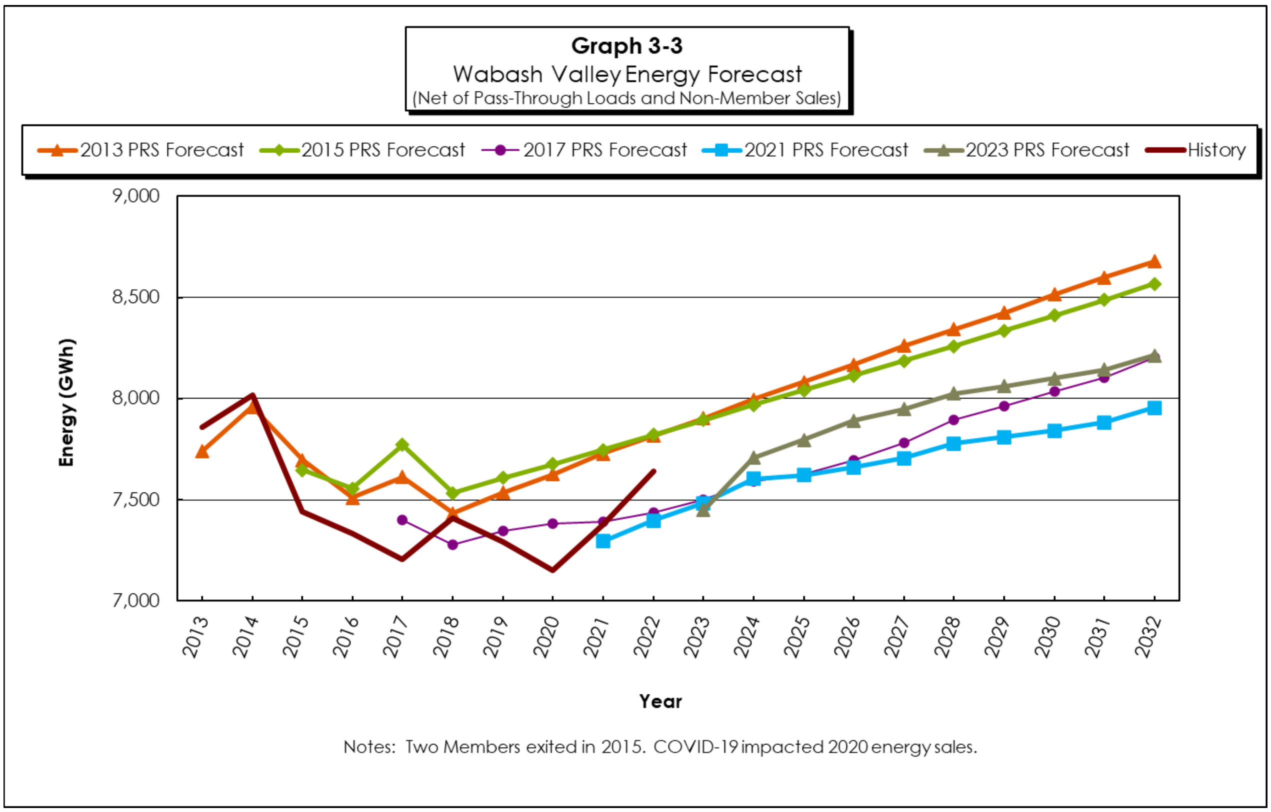


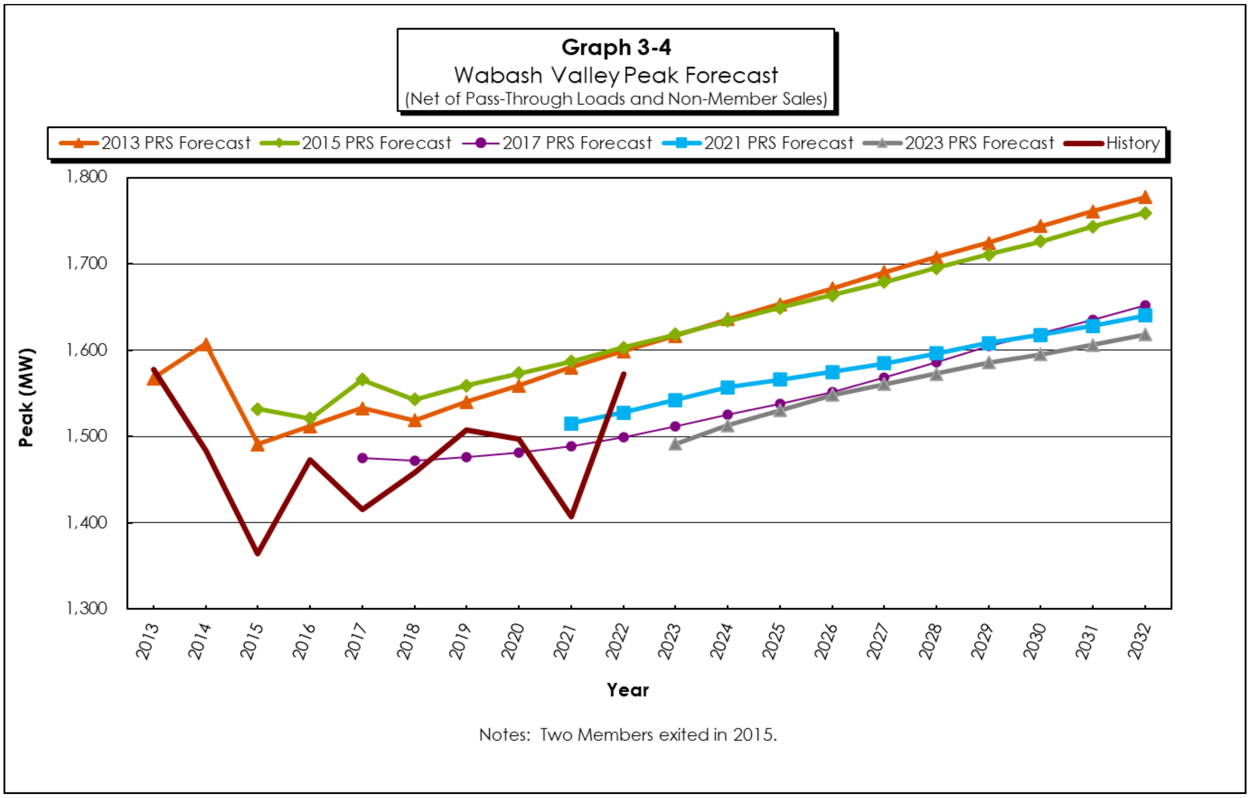
Table 3-2 summarizes annual energy sales and summer coincident peak net of Pass-Through Loads which is referred to as our “Motherload”. Pass-Through Loads customers are large power customers with non-conforming load that require separate forecasts. Over the planning horizon, Motherload energy requirements are expected to average 0.9% per year with annual growth in system coincident peak demand averaging 1.1%.

Table 3-2
Base Case Load Forecast Energy Sales and Summer Coincident Peak Forecast (Net of Pass-Through Loads)

Year	Energy Sales (GWh)	% Change		Summer Coincident Peak (MW)	% Change
2023					
2024	7,713	3.5%		1,514	1.5%
2025	7,806	1.2%		1,533	1.3%
2026	7,912	1.4%		1,553	1.3%
2027	7,983	0.9%		1,570	1.1%
2028	8,083	1.3%		1,588	1.1%
2029	8,130	0.6%		1,604	1.0%
2030	8,181	0.6%		1,617	0.8%
2031	8,235	0.7%		1,631	0.9%
2032	8,319	1.0%		1,646	0.9%
2033	8,363	0.5%		1,662	1.0%
2034	8,437	0.9%		1,680	1.1%
2035	8,517	0.9%		1,700	1.2%
2036	8,625	1.3%		1,720	1.2%
2037	8,688	0.7%		1,741	1.2%
2038	8,778	1.0%		1,762	1.2%
2039	8,868	1.0%		1,784	1.2%
2040	8,976	1.2%		1,805	1.2%
2041	9,037	0.7%		1,826	1.2%
2042	9,130	1.0%		1,849	1.3%
24-42		0.9%			1.1%

Graphs 3-3 and 3-4 compare the current and prior-year forecasts. The exit of three Members have had a significant impact on the load forecasts. The 2013 and 2015 PRS Forecasts were each more conservative but still displayed elevated growth. The 2017 PRS Forecast, developed with our new modeling framework, trends more closely to history excluding 2020 energy which carries the impact of COVID-19 driven by C&I business closures most strongly felt from March to May 2020. As we move forward, the Company will seek to gauge the performance of the 2023 PRS forecast against actual results and adjust our modeling framework and key inputs and assumptions accordingly.





Key Inputs and Assumptions

Regression analysis is a statistical process for estimating the relationships between a dependent variable and the factors that impact that variable over time. The load forecast is based on regression models that relate monthly energy, demand, customers, and average use (in the residential sector) to changes in weather conditions, household growth, economic activity, and end-use energy intensity. Forecast model drivers are described below:

1. Historical WVPA Data

Historical monthly energy and peak demand are derived from 2009-2022 wholesale hourly load data (MWh) by Member.

2. Weather Data

Historical and normal monthly heating degree days (HDD) and cooling degree days (CDD) are calculated from daily temperature data measured by the National Oceanic and Atmospheric Administration (NOAA) at five weather stations: Fort Wayne IN, Indianapolis IN, Peoria IL, South Bend IN and St. Louis MO.

For energy, Itron selected the base temperature by analyzing the sales/weather relationship and determining the temperature at which heating and cooling loads begin. A temperature base of 55 degrees is used in calculating HDD and a temperature base of 65 degrees is used in calculating CDD. Normal degree-days are calculated by averaging monthly degree-days over a 20-year period (2003 to 2022).

For peak demand, Itron selected the base temperature by analyzing the coincident peak/weather relationship and determining the temperature at which heating and cooling peak demand occurred. A temperature base of 50 degrees is used in calculating peak HDD and a temperature base of 70 degrees is used in calculating peak CDD. Normal peak-day degree-days are calculated over a 10-year period (2013 to 2022) using a *rank and average* approach. Rank and average entails *ranking* monthly peak-day HDD and CDD within each year from the highest to the lowest value and then *averaging* across the ten-year period. The resulting peak-day degree-days are then mapped to specific months based on the likelihood of where they will occur (e.g., the highest peak-day CDD is mapped to July and the highest peak-day HDD is mapped to January.)

3. Economic Data

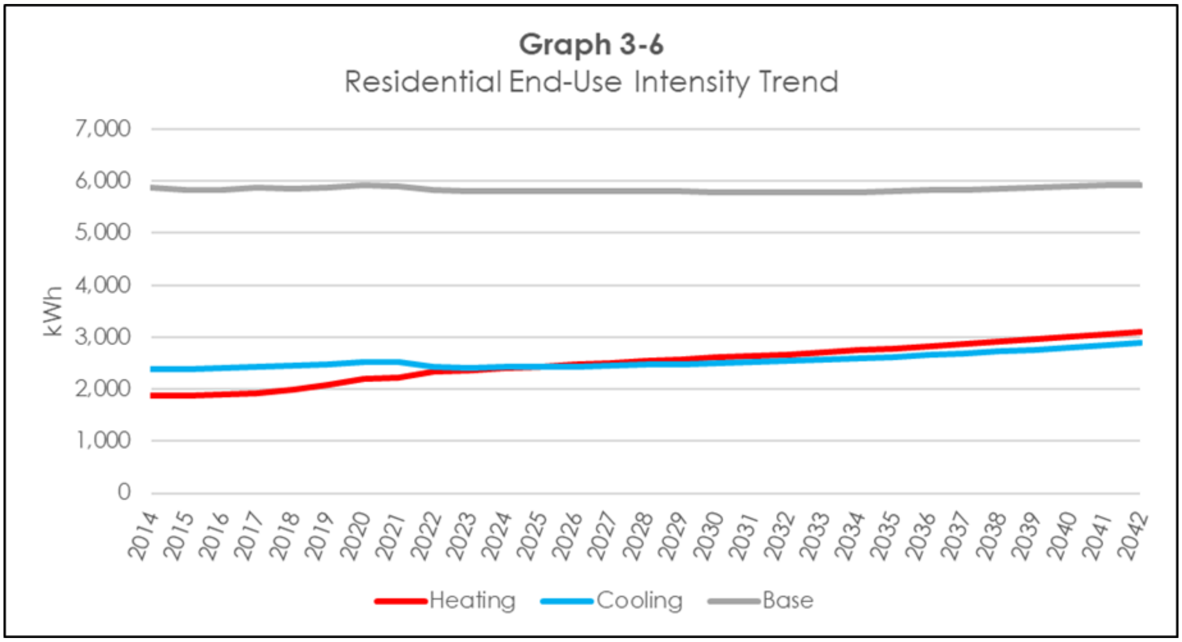
The base load forecast incorporates Woods & Poole 2022 county forecasts of Gross Regional Product (GRP), population, number of households and household income. We derive member-level, economic data by weighting economic data across counties based on the number of customers in each county. Woods & Poole project population growth on par with historical growth across the counties served by our members. Projected household growth slows from the historical growth as household formation slows. GRP and household income growth are strong tracking U.S. economic growth. Table 3-5 shows forecasted economic compounded annual growth rates (CAGR) for the Company as a whole.

Table 3-5 Key Composite Economic Variables – CAGR

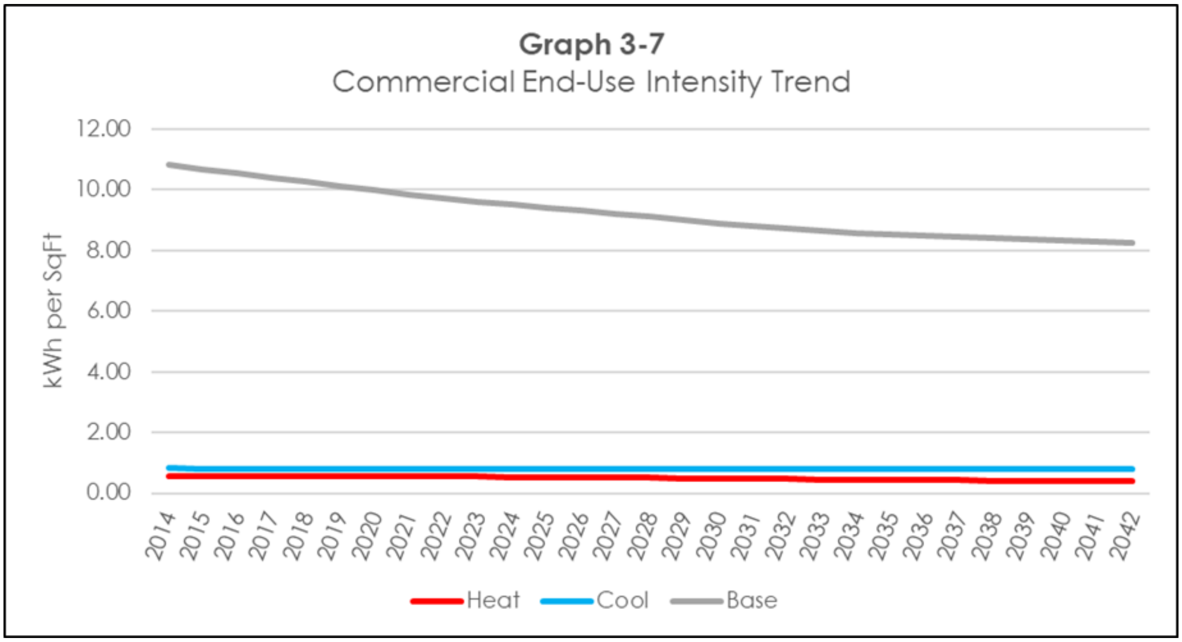
Variable	2024-2042 %	2016-2022 %
GRP	1.8%	1.7%
Population	0.5%	0.6%
Households	0.5%	0.7%
Household Income	2.1%	2.3%

4. End-Use Appliance Saturation and Efficiency Trends Data

End-use energy intensity projections start with EIA 2022 appliance saturation and efficiency projections for the ENC U.S. Census Division (this includes Illinois, Indiana, Ohio, Michigan and Wisconsin). End-use energy intensities are derived by combining end-use saturation and efficiency projections. Itron developed and maintains historical and projected end-use data for Itron's Energy Forecasting Group (EFG) members. Residential end-use saturation estimates are adjusted to reflect results from WVPA's 2022 residential saturation survey. Graph 3-6 shows residential heating, cooling and base-use intensity trends.



EIA's end-use efficiency projections reflect both new standards and regional energy efficiency program activity. In total, residential intensities are expected to increase 0.5% over the long-term. Base-use (non-weather sensitive end-uses) declines because of improving end-use efficiency (e.g., refrigerators, freezers, dryers, water heaters) but is countered by increasing miscellaneous loads (plug loads). Heating and cooling intensities increase largely driven by expected growth in heat pumps. Graph 3-7 shows commercial end-use intensity trends for the ENC Census Division. Commercial intensities are measured in kWh per square foot. Commercial intensities decline 0.6% per year with ventilation and lighting efficiency improvements having the largest impact. We assume end-use intensities in WVPA's service area track that of the ENC Census Division.



5. Large Customer Load Adjustments

Large changes in load due to customer activity will not necessarily be captured in regression models based on historical load data. Limited energy and demand adjustments (spot load adjustments) are made to account for specific customer business activity that may be the result of business expansion/contraction or the addition or loss of a major customer. Spot load adjustments are provided by Member cooperative staff or developed through internal insights and discussions. These adjustments are summarized in Table 3-8.

Table 3-8
Spot Load Adjustments

Year	Energy Sales (GWh)	Summer Coincident Peak (MW)
2024	102.6	11.1
2025	136.0	12.6
2026 - 2042	171.3	18.0

WVPA also forecasts pass-through Loads. Pass-through load customers are large power customers with non-conforming loads that can customize their power supply portfolio based on respective risk tolerances. A separate forecast is developed for each pass-through load customer utilizing regression models and information provided by each customer meshed with internal insights and discussions. Pass-through loads are not included in the total energy or peak load managed by WVPA. However, the large power customers are included in WVPA's total planning load because the Company has the ultimate responsibility to meet the large power customers' energy requirements and make purchases at market to meet the minimum reliability requirements. WVPA and our members have minimal risk related to these pass-through loads. WVPA works closely with each of the large power customers to purchase defined products for energy from bilateral counterparties and/or to purchase additional energy, capacity and transmission requirements from the applicable RTO energy, capacity and transmission markets. These costs are "passed-through" directly to each customer.

The pass-through loads' energy sales and summer coincident peak demand are reflected in a separate column in Table 3-15 Total Member System Requirements and Table 3-18 Member Summer Coincident Peak Demand, respectively.

6. Historical Member Sales Data

Historical retail sales (kWh), customers and revenue are provided by each member. Residential data is available monthly, and C&I and Other are available on an annual basis.

Many of WVPA's members have implemented advanced metering infrastructure (AMI) but we do not have access to this granular level detail. In WVPA's next load forecast survey, members will be asked about current and planned AMI activity and potential applications associated with load analysis.

7. Demand-Side Management

Potential Demand Response (DR) and future program-related energy efficiency (EE) savings are treated as a resource rather than a reduction to load. EE measures deployed by members is included in the current load as a starting point. See Section 4 for a detailed discussion of EE and DR evaluation.

8. Distributed Energy Resources

Prevalence of Distributed Energy Resources (DERs) is expected to grow in the coming years. To understand potential impacts, the Company worked with Itron to develop a long-term DER forecast which includes Electric Vehicles (EVs) and solar Distributed Generation (DG). The methodology and subsequent data are described at a high level below and in detail in Appendix J.

Electric Vehicles (EV)

WVPA's 2023 PRS includes organic impacts of EVs in our base case load forecast. Adoption of EVs in Indiana has increased over the past few years, however, penetration in rural areas lags urban areas. The 2023 State of Indiana Bureau of Motor Vehicle data was used in this IRP as a starting point for EV volumes across the WVPA footprint to include IL and MO areas. The resulting data indicates approximately 2,200 EVs are in use, which is under 1% of the area households. Itron provided a long-term forecast using both high and low EV adoption trends. The low adoption forecast was used in the base forecast and alternative forecasts were utilized in scenario modeling.

To support EV education, adoption, and understanding Member grid impacts, WVPA has installed four public EV charging sites which are in the process of being commissioned. These are located in Covington, Fair Oaks, Peru and Whitestown, IN, and are part of a statewide initiative funded in part by VW Mitigation Trust funds administered by IDEM.[1] WVPA also shared lessons learned with the Indiana Department of Transportation (INDOT) as part of their National Electric Vehicle Infrastructure (NEVI) fund planning processes.[2] WVPA opted not to apply directly for the NEVI funds, however, it's members are expected to serve a few proposed sites. Public charging energy usage data will be collected for inclusion in future analyses.

[1] See https://goevin.com/ for more information about the GoEV IN program.
[2] See https://www.in.gov/indot/current-programs/innovative-programs/electric-vehicle-charging-infrastructure-network/

Distributed Generation

Over the past few years, WVPA members have experienced Distributed Generation (DG) growth. Retail members as well as individual Co-ops have installed primarily solar DG. Over 2,100 sites account for nearly 47 MW of generation across the footprint. The output of these assets is embedded in the current loads. To understand potential future impacts of incremental solar DG additions on the WVPA load curves, Itron developed a forecast of future DG based on the EIA growth rates of solar capacity for the East North Central census region. Impacts of solar as well as the combined impacts of EVs and DG are included in Appendix J.

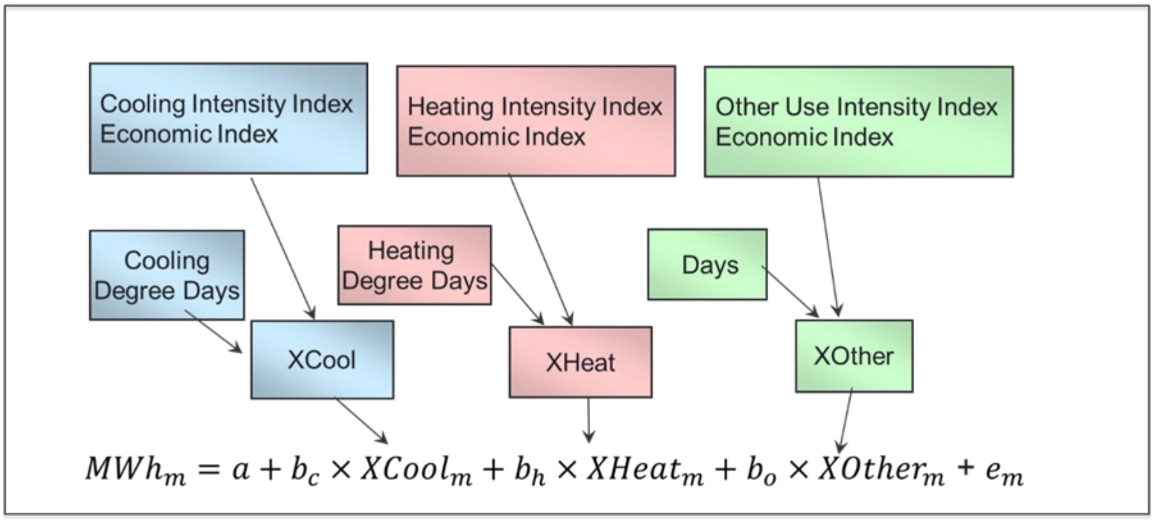
Methodology

1. Energy Requirements Model

Delivered energy (MWh) and coincident peak demand (MW) forecasts are derived for each Member using an end-use model structure initially implemented by Itron.

The model structure is to define delivered monthly energy (m) in terms of member heating (XHeat), cooling (XCool), and non-weather sensitive (XOther) energy requirements. Figure 3-9 shows the model structure.

Figure 3-9 Delivered Energy Model Structure



Model coefficients (bc, bh, and bo) are estimated using linear regression. XCool and XHeat interact with end-use intensity trends, economic drivers and weather conditions. XOther interacts with Other Use intensity trends, economic drivers and number of days. The estimated model coefficients essentially calibrate system level heating, cooling and base-use energy requirements to total delivered Member energy. A description of the model variables is summarized below:

Economic Index. The economic index weights service area number of households (*HH_IDX*) and gross regional product (*GDP_IDX*). The index is designed to capture long-term customer growth and economic activity as reflected in gross regional product. For example, the economic index for one member is calculated as:

- EconIdx = HH_IDX$^{\wedge 0.8}$ * GDP_IDX$^{\wedge 0.2}$

Households (HH_IDX) and Gross Regional Product (GDP_IDX) are indexed to a common year (2009) and combined such that the weights equal 1.0. For many Members, number of households has a much stronger weight. The weights are determined by evaluating out-of-sample model statistics for different sets of weights.

The economic data is provided by county. An economic data series is derived for each member based on their location. For members that span more than one county, the economic data series is weighted to reflect the number of customers served in each county.

End-Use Intensity Index. End-Use Intensity Indexes are developed for heating, cooling, and other use based on EIA's end-use saturation, efficiency, and intensity forecasts for the ENC Census Division. Residential intensities are adjusted to reflect the Company's residential appliance saturation survey. Residential and commercial intensities are weighted to reflect the mix of residential and commercial sales within the member service area. For example, the cooling intensity index for one member is calculated as:

- Cool_IDX = ResCool_IDX^0..60 * ComCool_Idx^0.40

Similar weighted indices are constructed for Heating and Other Use.

Model Variables. Cooling (XCool), Heating (XHeat), and Other Use (XOther) model variables are constructed by combining the economic and intensity indices with Member service area CDD, HDD, and number of calendar days. Model variables are calculated as:

- XCool = CDD65_Idx * Econ_Idx * Cool_Idx
- XHeat = HDD55_Idx * Econ_Idx * Heat_Idx
- XOther = Days_Idx * Econ_Idx * Other_Idx

The variables are interactive as the impact of one variable on energy requirements depends on the other. The impact of CDD for example can be expected to increase with customer growth and economic activity and decrease with improvements in cooling efficiency.

The cooling index (Cool_Idx) incorporates information about residential and commercial cooling equipment saturation, efficiency trends, residential thermal shell integrity and size of homes. The economic index variable (Econ_Idx) reflects customer growth and regional economic activity. The CDD Index (CDD65_Idx) captures monthly variation due to summer weather conditions.

The heating index (Heat_Idx) incorporates information about residential and commercial heating equipment saturations, efficiency trends, residential thermal shell integrity and size of homes. The economic index variable (Econ_Idx) reflects customer growth and regional economic activity. The HDD Index (HDD55_Idx) captures monthly variation due to winter weather conditions.

XOther incorporates information about residential and commercial base load appliance and equipment saturation and efficiency trends (Other_Idx). The economic index variable (Econ_Idx) reflects customer growth and regional economic activity. The Days Index (Days_Idx) captures monthly variation due to the number of days in the month.

Binary Variables. Monthly binary variables are used to account for large monthly energy variations that are not captured by the model variables – XHeat, XCool and XOther. Other than number of days and the weather variables, the model variables reflect long-term economic and end-use energy intensity trends that are constructed from annual data series. Binary variables allow us to isolate short-term monthly variations that are not weather-related or captured in the number of days. Binary variables are also used to capture seasonal variation and shifts in load resulting from loss or gain of major customers. Accounting for variations that are not directly related to model variables strengthens the model's ability to capture long-term usage trends.

Capturing Efficiency Improvements. The constructed end-use model variables and estimation process captures both end-use standards and regional efficiency program activity. EIA estimates end-use specific efficiency program savings within the Census Division. The information is used to help calibrate the end-use choice models such that a greater proportion of highly efficient technology options are selected. In turn average stock efficiency increases at a slightly higher rate.

The model estimation process also contributes to capturing efficiency activity by calibrating the end-use model variables to actual delivered energy.

2. Coincident Peak Model

The coincident peak demand models are based on a model specification similar to that of the energy models. The difference is that the model variables are constructed using monthly coincident peak-day CDD and HDD. Peak-day CDD and HDD are determined by finding the average daily temperature for each weather station that occurred on the day of the system peak. For modeling, each member is assigned to one of five regional weather stations based on that member's geographic location. Model variables are constructed as:

- PkXCool = PkCDD70_Idx * Econ_Idx * Cool_Idx
- PkXHeat = PkHDD50_Idx * Econ_Idx * Heat_Idx
- PkXOther = Econ_Idx * Other_Idx

Seasonal variation in base-use is captured with monthly binaries.

3. Sales to System Model

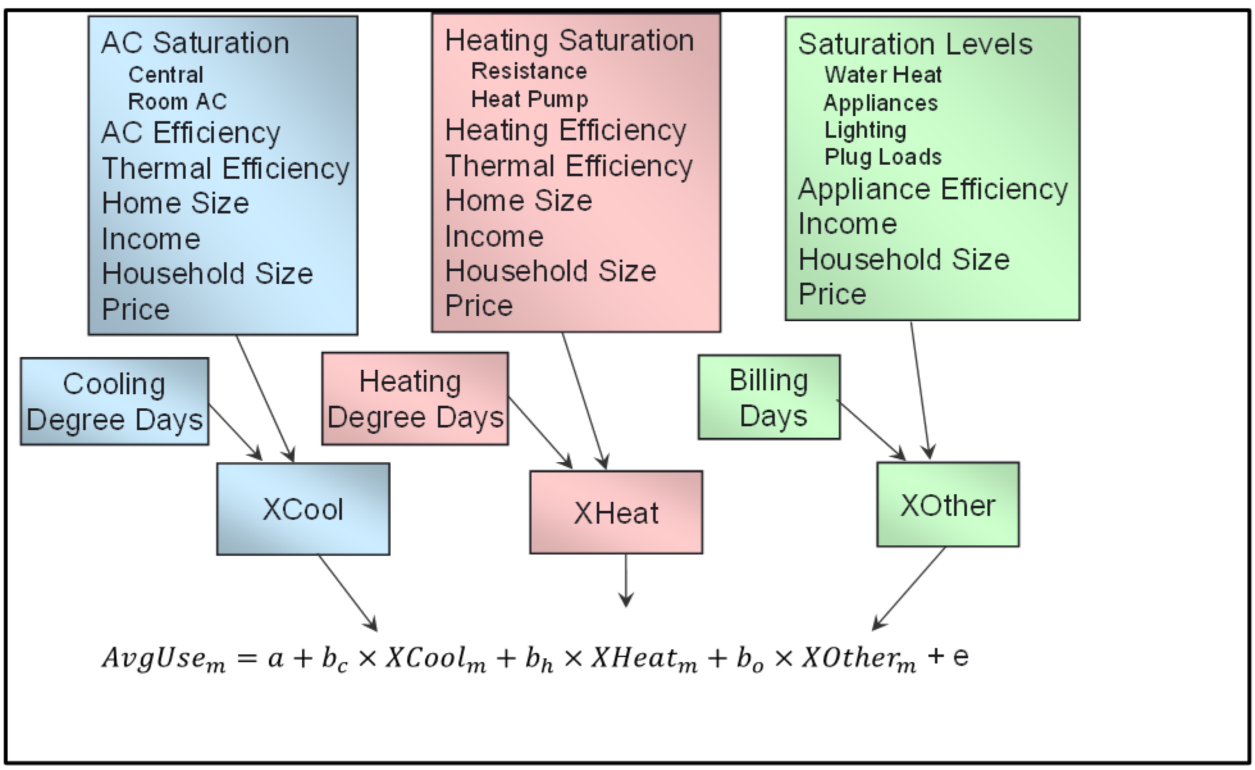
Member sales are based on the member system energy requirements forecast. Historical *sales to energy ratios* are calculated for each member. A simple regression model is used to project the ratio through the forecast period. Member sales forecasts are then derived by multiplying the member energy forecast by the *sales to energy ratio* forecast. On average, the *sales to energy ratio* is 0.958 implying a system average distribution loss factor of 4.2%.

Customer class sales (residential, commercial, and other use) are derived for each member. Monthly regression models are estimated for residential and other use sales are projected with exponential smoothing models. We calculate monthly commercial sales as total retail sales minus residential and other use; historical data does not support directly estimating monthly commercial sales models.

4. Residential Customers and Average Use Models

The residential sales forecast is derived as the product of customer and average use forecasts. Customer forecast models are simple regression models that relate monthly customers to number of households in the counties served by the Member. Residential average use forecast is derived from a monthly Statistically Adjusted End-Use (SAE) model. Similar to the system model, monthly average use is expressed in terms of heating requirements (XHeat), cooling requirements (XCool) and other use (XOther). The constructed model variables incorporate household income, household size, weather conditions, and end-use energy intensities. Models also include monthly binaries to account for monthly variation not captured by the model variables and binaries for large residuals that cannot be explained with available data. Figure 3-10 shows the residential average use model.

Figure 3-10 Residential Average Use Model Structure



5. Other Classifications Models

Simple linear regression with a trend variable or exponential smoothing models are used to forecast member sales classified as *Other*. Other sales include Seasonal, Irrigation, Public Street & Highway Lighting, Other Sales to Public Authority and Sales for Resale.

6. Non-coincident Peak to Coincident Peak Model

Member's non-coincident peak demand forecast is based on the historical relationship between the Member's own peak (non-coincident demand) and member's system coincident peak. We used historical member load data to construct a monthly demand ratio of own peak to coincident peak demand. A simple regression model is used to project the demand ratio over the forecast horizon. We then derived a non-coincident peak demand forecast by multiplying the coincident peak demand forecast with the demand ratio forecast.

7. Energy and MW Ratio Models

Fifteen of WVPA's twenty-three members serve load within a single sub-balancing area. The other eight members serve load within two or more sub-balancing areas. For these eight members, we allocated load to the sub-balancing areas based on historical sub-balancing area load ratios.

Forecast Model Assessment

We evaluated model in-sample statistics to assess the models' explanation of historical load variation. Key model statistics include the R-squared, Adjusted R-squared, Mean Absolute Percent Error (MAPE) and Durbin-Watson statistic. Overall, statistics indicated strong model fit. Member energy requirements models' Adjusted R-Squared ranges from 0.925 to 0.987 with an average Adjusted R-Squared of 0.953. Average Member energy model MAPE is 2.3%. Monthly coincident peak demand variation tends to be a bit higher than energy as coincident peak demand is determined partly by simultaneous demand of other members. Coincident peak models' Adjusted R-Squared ranges from 0.723 to 0.951; the average across all models is 0.871. The average coincident peak model MAPE is 4.84%. Table 3-11 summarizes the model statistics.

Table 3-11 Model Statistics

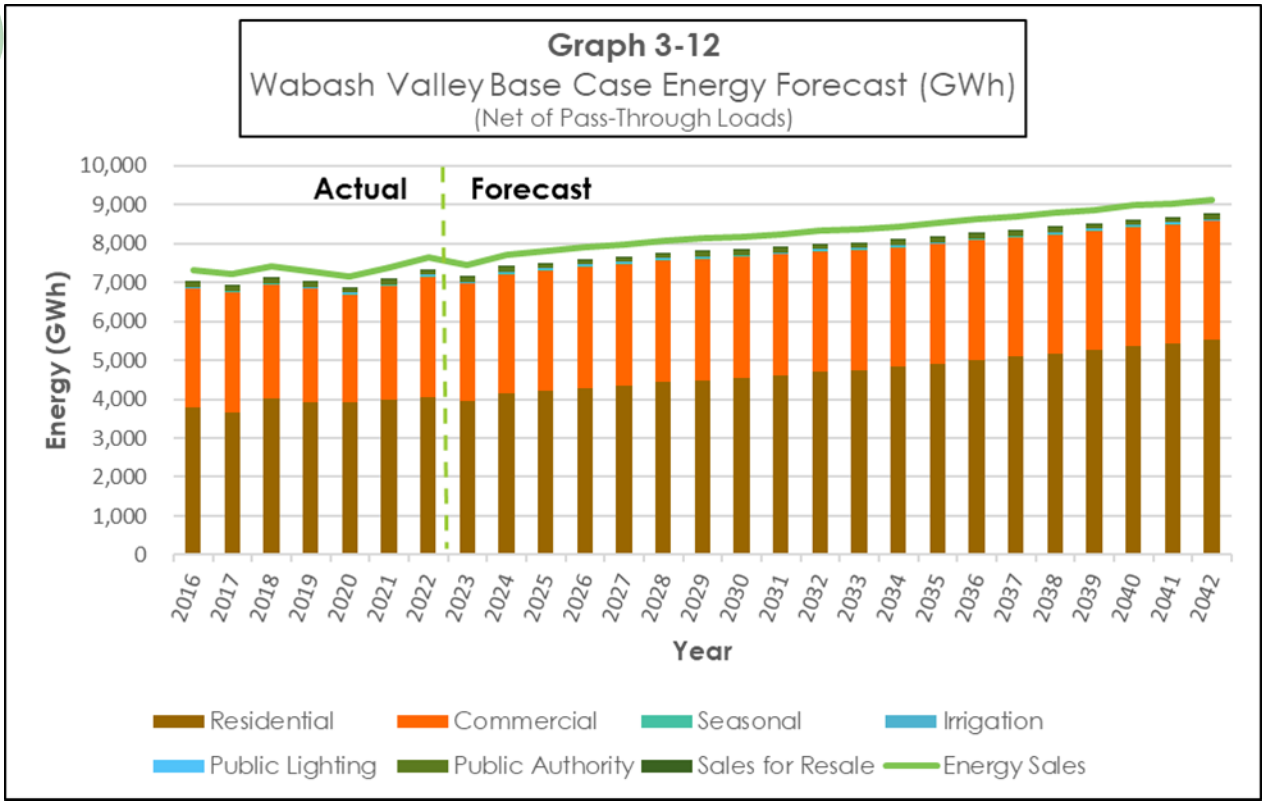
Model	Statistic	Range	Average	Median
Energy Requirements	**R-squared**	92.5% - 98.7%	95.3%	95.4%
	Adj R-squared	92.0% - 98.5%	94.8%	95.0%
	MAPE	1.5% - 3.4%	2.3%	2.2%
	Durbin-Watson	1.8 – 2.2	2.0	2.1
Coincident Peak	**R-squared**	75.7% - 95.6%	88.2%	90.1%
	Adj R-squared	72.3% - 95.1%	87.1%	89.2%
	MAPE	3.7% - 6.7%	4.8%	4.7%
	Durbin-Watson	1.2 – 2.4	1.8	1.8

We also examined model predicted values and residuals as part of the model assessment task. This includes looking for residual patterns (ideally, we would not find any pattern) and identifying and correcting for large outliers.

Furthermore, we assessed forecasted energy, peak, and sales growth rates for consistency against household, gross regional product, energy intensity trends and combination of these variables. Given strong historical and projected efficiency gains, long-term energy requirements track lower than regional economic growth projections. At the individual Member level, annual energy requirements for 2024 to 2042 average between 0. 1% to 2.1% growth; coincident peak demand growth averages between 0.2% and 2.0%. The range of these average growth rates reflects the diversity of our member systems.

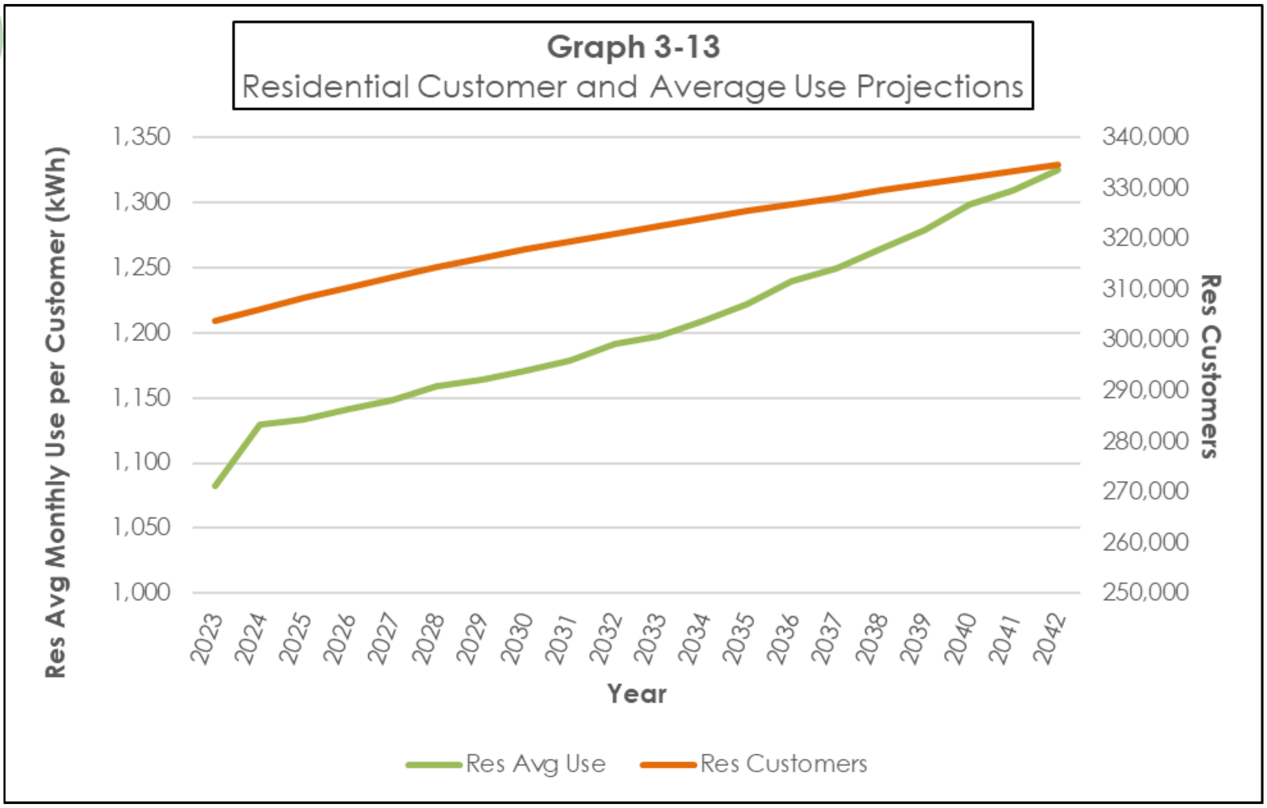
Base Case Forecast Result

We develop total system energy requirements, peak demand, and class sales by aggregating member-level forecasts. Graph 3-12 illustrates WVPA's base case wholesale energy sales and members' retail sales by revenue class.



Through 2042, system energy requirements are expected to average 0.9% annual growth. From 2024 to 2042, residential sales increase by 1.6% annually and commercial sales and the other revenue classes are essentially flat.

Forecasted residential sales are driven by a combination of slow customer growth and an increase in average use. On a system-wide basis, residential customers are expected to grow by an average 0.5%. Residential customer growth is mostly concentrated in the more suburban service territory directly surrounding Indianapolis. Average use growth is slight in the front half of the forecast but is projected to accelerate in the back half growing by 0.8% over the entire forecast horizon. Graph 3-13 depicts WVPA's residential customer and average use projections.

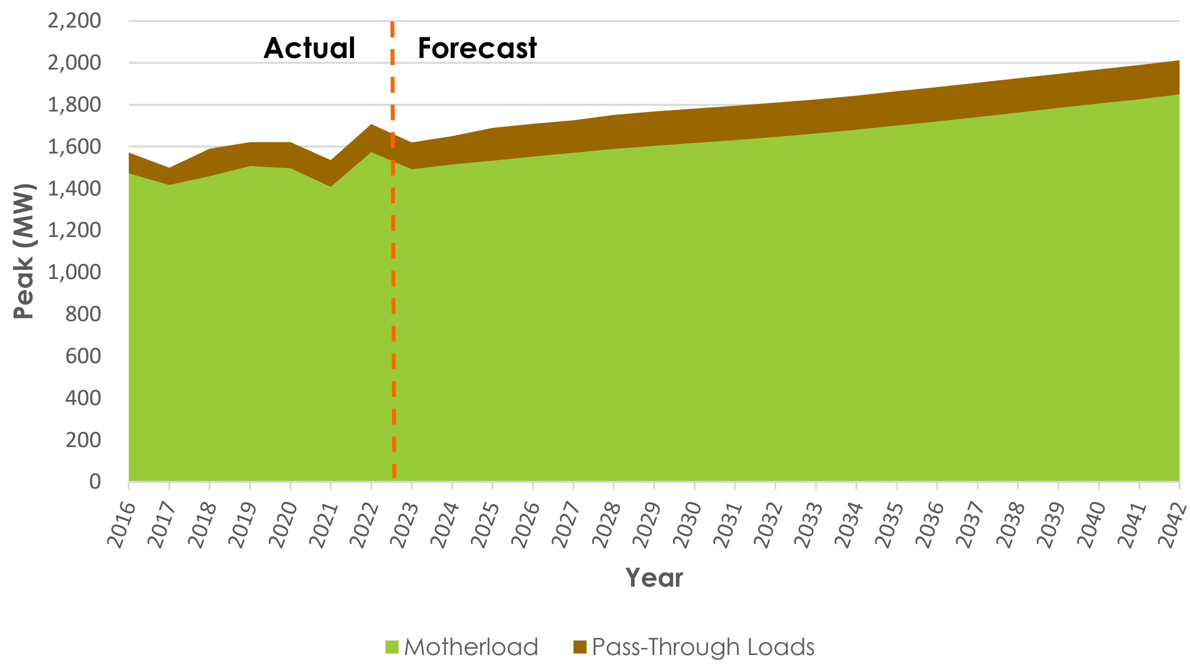


We derive the commercial sales forecast by subtracting residential and other customer classes from total retail sales. Although the small and large commercial revenue classes are not specifically modeled, member commercial sales forecasts are consistent with forecast assumptions. On an aggregate basis, commercial sales are projected to increase through 2026, flatten for the remainder of the decade and then gradually decline. By 2042, commercial sales projections are essentially flat to 2024. The commercial sales forecast is justifiably lower as commercial sector end-use intensity projections are expected to decline because of federal energy efficiency standards and technological improvements particularly in ventilation and lighting. Additionally, both GRP and household projections are lower than in the 2016 to 2022 period.

In the last few years, WVPA has more consistently started obtaining historical monthly C&I sales data from the majority of our members. We will continue to perform analysis to evaluate how well each member's forecast by class compares to actual results and consider implementing a bottom-up C&I model for those members whose individual load forecast may need improvement and for which monthly C&I data is available.

Summer coincident peak demand is projected to increase 1.1% per year, reaching 1,849 MW in 2042 for our Motherload and 2,013 MW including Pass-Through Loads. Graph 3-14 shows historical and forecasted summer peak demand for our Motherload and additional Pass-Through Loads. WVPA historical load peak demand by customer class is not readily available and the Company does not forecast peak demand by customer class.

Graph 3-14
Wabash Valley Base Case System Peak Demand Forecast (MW)



Tables 3-15 through 3-18 provide system forecast details.

Model inputs, results and statistics are included in Appendix G in electronic format.

Table 3-15

WABASH VALLEY POWER ASSOCIATION 2023 Base Case Load Forecast Total Member System Requirements							
Year	Notes	Sales Net Pass-Through (GWh)	% Growth	Pass-Through (GWh)	% Growth	Total System Sales (GWh)	% Growth
2016		7,332		618		7,950	
2017		7,207	-1.7%	706	14.2%	7,913	-0.5%
2018	[1]	7,411	2.8%	980	38.8%	8,391	6.0%
2019		7,291	-1.6%	969	-1.1%	8,260	-1.6%
2020		7,149	-1.9%	1,029	6.2%	8,178	-1.0%
2021	[2]	7,379	3.2%	992	-3.6%	8,371	2.4%
2022		7,639	3.5%	1,003	1.1%	8,642	3.2%
2023		7,449	-2.5%	934	-6.9%	8,383	-3.0%
2024		7,713	3.5%	1,017	8.9%	8,730	4.1%
2025	[3]	7,806	1.2%	1,133	11.4%	8,939	2.4%
2026		7,912	1.4%	1,189	4.9%	9,101	1.8%
2027		7,983	0.9%	1,189	0.0%	9,172	0.8%
2028		8,083	1.3%	1,217	2.4%	9,300	1.4%
2029		8,130	0.6%	1,245	2.3%	9,375	0.8%
2030		8,181	0.6%	1,245	0.0%	9,426	0.5%
2031		8,235	0.7%	1,245	0.0%	9,480	0.6%
2032		8,319	1.0%	1,245	0.0%	9,564	0.9%
2033		8,363	0.5%	1,245	0.0%	9,608	0.5%
2034		8,437	0.9%	1,245	0.0%	9,682	0.8%
2035		8,517	0.9%	1,245	0.0%	9,762	0.8%
2036		8,625	1.3%	1,245	0.0%	9,870	1.1%
2037		8,688	0.7%	1,245	0.0%	9,933	0.6%
2038		8,778	1.0%	1,245	0.0%	10,023	0.9%
2039		8,868	1.0%	1,245	0.0%	10,113	0.9%
2040		8,976	1.2%	1,245	0.0%	10,221	1.1%
2041		9,037	0.7%	1,245	0.0%	10,282	0.6%
2042		9,130	1.0%	1,245	0.0%	10,375	0.9%
AVERAGE GROWTH RATES							
22-27		69	0.9%	37	3.5%	106	1.2%
27-32		67	0.8%	11	0.9%	78	0.8%
32-37		74	0.9%	-	0.0%	74	0.8%
37-42		88	1.0%	-	0.0%	88	0.9%
22-42		75	0.9%	12	1.1%	87	0.9%
24-42		79	0.9%	13	1.1%	91	1.0%

[1] Two accounts moved onto the Pass-Through rate on 1/1/2018.
[2] One account forecasted to move onto the Pass-Through rate in 2021.
[3] One account forecasted to move onto the Pass-Through rate in 2025.

Table 3-16

WABASH VALLEY POWER ASSOCIATION 2023 Base Case Load Forecast Member System Requirements Net of Pass-Through Loads						
Year	Notes	Energy Net Distr. Losses (GWh)	% Growth	Distribution Line Losses	Energy Sales (GWh)	% Growth
2016		7,013			7,332	
2017		6,915	-1.4%	4.1%	7,207	-1.7%
2018	[1]	7,111	2.8%	4.0%	7,411	2.8%
2019		7,002	-1.5%	4.0%	7,291	-1.6%
2020		6,846	-2.2%	4.2%	7,149	-1.9%
2021	[2]	7,083	3.5%	4.0%	7,379	3.2%
2022		7,312	3.2%	4.3%	7,639	3.5%
2023		7,139	-2.4%	4.2%	7,449	-2.5%
2024		7,391	3.5%	4.2%	7,713	3.5%
2025	[3]	7,478	1.2%	4.2%	7,806	1.2%
2026		7,577	1.3%	4.2%	7,912	1.4%
2027		7,645	0.9%	4.2%	7,983	0.9%
2028		7,741	1.3%	4.2%	8,083	1.3%
2029		7,785	0.6%	4.2%	8,130	0.6%
2030		7,834	0.6%	4.2%	8,181	0.6%
2031		7,887	0.7%	4.2%	8,235	0.7%
2032		7,968	1.0%	4.2%	8,319	1.0%
2033		8,011	0.5%	4.2%	8,363	0.5%
2034		8,082	0.9%	4.2%	8,437	0.9%
2035		8,159	1.0%	4.2%	8,517	0.9%
2036		8,263	1.3%	4.2%	8,625	1.3%
2037		8,324	0.7%	4.2%	8,688	0.7%
2038		8,411	1.0%	4.2%	8,778	1.0%
2039		8,497	1.0%	4.2%	8,868	1.0%
2040		8,601	1.2%	4.2%	8,976	1.2%
2041		8,660	0.7%	4.2%	9,037	0.7%
2042		8,750	1.0%	4.2%	9,130	1.0%
AVERAGE GROWTH RATES						
22-27		67	0.9%		69	0.9%
27-32		65	0.8%		67	0.8%
32-37		71	0.9%		74	0.9%
37-42		85	1.0%		88	1.0%
22-42		72	0.9%		75	0.9%
24-42		76	0.9%		79	0.9%

[1] Two accounts moved onto the Pass-Through rate on 1/1/2018.
[2] One account forecasted to move onto the Pass-Through rate in 2021.
[3] One account forecasted to move onto the Pass-Through rate in 2025.

Table 3-17

WABASH VALLEY POWER ASSOCIATION 2023 Base Case Load Forecast Total Member Energy by Class, Net of Distribution Losses (GWh)										
Year	Notes	Residential	Commercial	Seasonal	Irrigation	Public Lighting	Public Authority	Sales for Resale	Total Energy	% Growth
2016		3,799	3,037	17	19	11	121	9	7,013	
2017		3,666	3,080	17	14	10	120	8	6,915	-1.4%
2018	[1]	4,026	2,911	19	16	9	123	7	7,111	2.8%
2019		3,928	2,898	18	20	9	121	8	7,002	-1.5%
2020		3,914	2,760	20	27	7	113	5	6,846	-2.2%
2021	[2]	3,988	2,921	21	18	7	123	5	7,083	3.5%
2022		4,059	3,077	21	23	7	119	6	7,312	3.2%
2023		3,946	3,018	21	22	7	119	6	7,139	-2.4%
2024		4,152	3,064	21	22	7	119	6	7,391	3.5%
2025	[3]	4,205	3,098	21	22	7	119	6	7,478	1.2%
2026		4,271	3,131	21	22	7	119	6	7,577	1.3%
2027		4,339	3,131	21	22	7	119	6	7,645	0.9%
2028		4,432	3,135	21	22	7	119	6	7,742	1.3%
2029		4,484	3,126	21	22	7	119	6	7,785	0.6%
2030		4,549	3,110	21	22	7	119	6	7,834	0.6%
2031		4,614	3,097	22	22	7	119	6	7,887	0.7%
2032		4,698	3,094	22	22	7	119	6	7,968	1.0%
2033		4,756	3,079	22	22	7	119	6	8,011	0.5%
2034		4,833	3,073	22	22	7	119	6	8,082	0.9%
2035		4,912	3,069	22	22	7	120	6	8,158	0.9%
2036		5,015	3,071	22	22	7	120	6	8,263	1.3%
2037		5,087	3,061	22	22	7	120	6	8,325	0.8%
2038		5,176	3,059	22	22	7	120	6	8,412	1.0%
2039		5,263	3,056	23	22	7	120	6	8,497	1.0%
2040		5,370	3,053	23	22	7	120	6	8,601	1.2%
2041		5,440	3,041	23	22	7	120	6	8,659	0.7%
2042		5,534	3,037	23	22	7	120	6	8,749	1.0%
AVERAGE GROWTH RATES										
22-27		1.3%	0.3%	0.0%	-0.9%	0.0%	0.0%	0.0%		0.9%
27-32		1.6%	-0.2%	0.9%	0.0%	0.0%	0.0%	0.0%		0.8%
32-37		1.6%	-0.2%	0.0%	0.0%	0.0%	0.2%	0.0%		0.9%
37-42		1.7%	-0.2%	0.9%	0.0%	0.0%	0.0%	0.0%		1.0%
22-42		1.6%	-0.1%	0.5%	-0.2%	0.0%	0.0%	0.0%		0.9%
24-42		1.6%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%		0.9%

[1] Two accounts moved onto the Pass-Through rate on 1/1/2018.
[2] One account forecasted to move onto the Pass-Through rate in 2021.
[3] One account forecasted to move onto the Pass-Through rate in 2025.

Table 3-18

WABASH VALLEY POWER ASSOCIATION 2023 Base Case Load Forecast Member Summer Coincident Peak Demand							
Year	Notes	Load Net of Pass-Through MW	% Growth	Pass-Through CP MW	% Growth	Total System CP MW	% Growth
2016		1,473		99		1,572	
2017		1,416	-3.9%	84	-15.2%	1,500	-4.6%
2018	[1]	1,459	3.0%	131	56.0%	1,590	6.0%
2019		1,507	3.3%	115	-12.2%	1,622	2.0%
2020		1,497	-0.7%	125	8.7%	1,622	0.0%
2021	[2]	1,407	-6.0%	129	3.2%	1,536	-5.3%
2022		1,573	11.8%	135	4.7%	1,708	11.2%
2023		1,492	-5.1%	128	-5.2%	1,620	-5.2%
2024		1,514	1.5%	136	6.3%	1,650	1.9%
2025	[3]	1,533	1.3%	156	14.7%	1,689	2.4%
2026		1,553	1.3%	156	0.0%	1,709	1.2%
2027		1,570	1.1%	156	0.0%	1,726	1.0%
2028		1,588	1.1%	164	5.1%	1,752	1.5%
2029		1,604	1.0%	164	0.0%	1,768	0.9%
2030		1,617	0.8%	164	0.0%	1,781	0.7%
2031		1,631	0.9%	164	0.0%	1,795	0.8%
2032		1,646	0.9%	164	0.0%	1,810	0.8%
2033		1,662	1.0%	164	0.0%	1,826	0.9%
2034		1,680	1.1%	164	0.0%	1,844	1.0%
2035		1,700	1.2%	164	0.0%	1,864	1.1%
2036		1,720	1.2%	164	0.0%	1,884	1.1%
2037		1,741	1.2%	164	0.0%	1,905	1.1%
2038		1,762	1.2%	164	0.0%	1,926	1.1%
2039		1,784	1.2%	164	0.0%	1,948	1.1%
2040		1,805	1.2%	164	0.0%	1,969	1.1%
2041		1,826	1.2%	164	0.0%	1,990	1.1%
2042		1,849	1.3%	164	0.0%	2,013	1.2%
AVERAGE GROWTH RATES							
22-27		(1)	0.0%	4	2.9%	4	0.2%
27-32		15	0.9%	2	1.0%	17	1.0%
32-37		19	1.1%	-	0.0%	19	1.0%
37-42		22	1.2%	-	0.0%	22	1.1%
22-42		14	0.8%	1	1.0%	15	0.8%
24-42		19	1.1%	2	1.0%	20	1.1%

[1] Two accounts moved onto the Pass-Through rate on 1/1/2018.
[2] One account forecasted to move onto the Pass-Through rate in 2021.
[3] One account forecasted to move onto the Pass-Through rate in 2025.

Alternative Forecasts

In addition to modeling the base case load forecast, WVPA also developed two alternative forecasts for high and low growth projections with the objective of capturing reasonable high and low long-term energy and demand outcomes.

Over the long-term, electric sales are driven by population growth, increase in productivity (reflected in GDP), and end-use efficiency improvements. Recognizing that some members are experiencing faster growth than others, high and low scenarios are based on member-specific population growth projections. For the high case, we assume that the population growth rate increases 50% faster than the base-case population growth. If the base case population growth rate is 0.3% per year, then the high case population growth rate is 0.45% (50% higher). We assume that the relationship between population and the economic drivers (number of households and GDP) remains the same - faster population growth results in stronger economic growth. The low case assumes that long-term population growth rate is 50% lower than the base case. If the base-case population growth is 0.3%, the low case population growth rate projection is 0.2% (50% lower). Lower population growth translates into lower household and GDP growth.

To further adjust the base case load forecast, WVPA has started to utilize electric vehicle and distributed generation adjustments in the alternative scenarios. The high growth scenario emphasizes more EV usage. The low growth scenario emphasizes more distributed generation. More information is included in Section 5.

After adjusting the key input economic data, EV usage, and distributed generation; WVPA created a high growth set and low growth set of models for each Member and then summed up the results for the Company. Comparisons of the high and low growth forecasts to the base case load forecast are provided below and in Table 3-19 through Graph 3-21.

1. High Growth

In the high growth case, energy requirements will grow by 1.6% per year, reaching 10,326 GWh by 2042. The high growth energy forecast is 13.1% higher than the base case forecast in 2042.

Under this scenario, summer coincident peak demand grows by 1.9% per year, reaching 2,129 MW in 2042. The high growth demand forecast is 15.2% higher than the base case forecast in 2042.

2. Low Growth

In the low growth case, energy requirements will grow by 0.3% per year, reaching 8,101 GWh by 2042. The low growth energy forecast is 11.3% lower than the base case forecast in 2042.

Under this scenario, summer coincident peak demand also grows by 0.3% per year, reaching 1,683 MW in 2042. The low growth demand forecast is 9.0% lower than the base case forecast in 2042.

Table 3-19

WABASH VALLEY POWER ASSOCIATION 2023Alternative Forecasts Member Energy Requirements Net of Pass-Through Loads (GWh)				
Year	Notes	Base Case	High Growth	Low Growth
2016		7,332		
2017		7,207		
2018	[1]	7,411		
2019		7,291		
2020	[2]	7,149		
2021	[2]	7,379		
2022		7,639		
2023		7,449	7,551	7,449
2024		7,713	7,758	7,652
2025	[3]	7,806	7,876	7,704
2026		7,912	8,007	7,760
2027		7,983	8,104	7,779
2028		8,083	8,234	7,820
2029		8,130	8,336	7,812
2030		8,181	8,466	7,807
2031		8,235	8,580	7,809
2032		8,319	8,729	7,840
2033		8,363	8,841	7,832
2034		8,437	8,988	7,847
2035		8,517	9,144	7,868
2036		8,625	9,329	7,919
2037		8,688	9,468	7,929
2038		8,778	9,633	7,966
2039		8,868	9,798	8,000
2040		8,976	9,988	8,050
2041		9,037	10,136	8,059
2042		9,130	10,326	8,101
AVERAGE GROWTH RATES				
22-27		0.9%	1.2%	0.4%
27-32		0.8%	1.5%	0.2%
32-37		0.9%	1.6%	0.2%
37-42		1.0%	1.7%	0.4%
22-42		0.9%	1.5%	0.3%
24-42		0.9%	1.6%	0.3%

[1] Two accounts moved onto the Pass-Through rate on 1/1/2018.

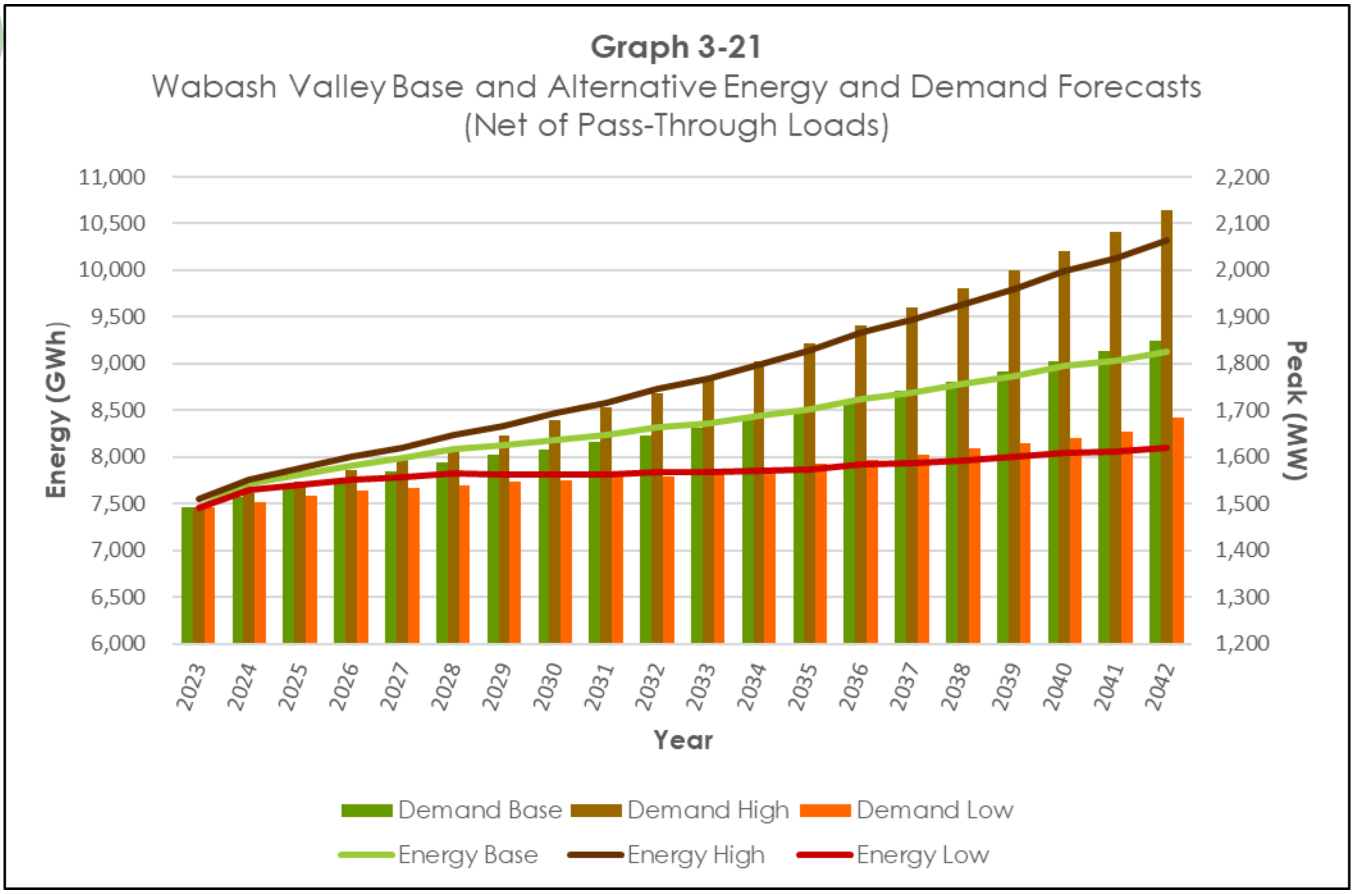
[2] One account forecasted to move onto the Pass-Through rate in 2021.

[3] One account forecasted to move onto the Pass-Through rate in 2025.

Table 3-20

WABASH VALLEY POWER ASSOCIATION 2023Alternative Forecasts Member Summer CP Demand Net of Pass-Through Loads (MW)				
Year	Notes	Base Case	High Growth	Low Growth
2016		1,473		
2017		1,416		
2018	[1]	1,459		
2019		1,507		
2020		1,497		
2021	[2]	1,407		
2022		1,573		
2023		1,492	1,492	1,492
2024		1,514	1,523	1,503
2025	[3]	1,533	1,547	1,516
2026		1,553	1,572	1,527
2027		1,570	1,594	1,533
2028		1,588	1,618	1,540
2029		1,604	1,646	1,546
2030		1,617	1,679	1,550
2031		1,631	1,707	1,560
2032		1,646	1,737	1,559
2033		1,662	1,770	1,566
2034		1,680	1,805	1,574
2035		1,700	1,843	1,584
2036		1,720	1,881	1,593
2037		1,741	1,921	1,605
2038		1,762	1,960	1,617
2039		1,784	2,000	1,628
2040		1,805	2,040	1,642
2041		1,826	2,083	1,654
2042		1,849	2,129	1,683
AVERAGE GROWTH RATES				
22-27		0.0%	0.3%	-0.5%
27-32		0.9%	1.7%	0.3%
32-37		1.1%	2.0%	0.6%
37-42		1.2%	2.1%	1.0%
22-42		0.8%	1.5%	0.3%
24-42		1.1%	1.9%	0.6%

[1] Two member cooperatives left Wabash Valley in 2015. This forecast ref
the departure of one member on 1/1/2015 and one member on 7/1/2
[2] Two accounts moved onto the Pass-Through rate on 1/1/2018.
[3] One account forecasted to move onto the Pass-Through rate in 2021.



Weather Normalization

The impact of weather was explicitly accounted for in the load forecast development. The energy requirements, coincident peak and residential average use models all incorporated heating and cooling degree days and applied projected normal weather to the forecasts. The historical actual versus weather normalized energy requirements are presented in Table 3-22.

Table 3-22

WABASH VALLEY POWER ASSOCIATION Actual versus Normalized Energy Requirements (GWh)		
Year	Actual	Weather Normalized
2016	7,332	7,283
2017	7,207	7,300
2018	7,411	7,212
2019	7,291	7,226
2020	7,149	7,189
2021	7,375	7,341
2022	7,642	7,575

2023 Integrated Resource Plan

Section 4

SELECTION OF RESOURCE OPTIONS

WVPA continuously reviews and analyzes potential future resource options to meet its projected peak and energy requirements. The Company's goal is to develop and maintain a diverse portfolio of power supply resources, both supply-side and demand-side, with contract terms, fuel types, counterparties and ownership options that promote reliable, low-cost service to its Members. WVPA plans requirements for the system in MISO and PJM markets holistically to avoid over supply and manages specific resources to meet reliability needs.

Supply-Side Resource Options

WVPA regularly determines the amount of capacity we will need to meet our load requirements (including reserves) over the next one to two years, as well as a twenty-year planning horizon. WVPA's resource portfolio shows that the Company needs additional capacity to meet projected demand requirements starting in 2025 primarily due to MISO's increased winter reserve margin requirements. Once the power supply requirements are determined, WVPA evaluates several types of power supply alternatives, including long-term and short-term power supply agreements, RTO capacity auctions, new generating capacity and wholesale energy market purchases. We evaluate each of these resources using the Company's production cost and financial analysis models to determine which supplies, or combinations of supplies, meet expected requirements at the least cost. Additionally, WVPA analyzes the resources with stochastic risk modeling to evaluate the impact of uncertainty with the proposed resource.
WVPA continues to examine potential new and existing thermal and renewable[1] generating resources (both independently and jointly owned) in anticipation of capacity and energy needs in 2025 and beyond. Estimated costs for new capacity are compared to expected long-range wholesale electric market prices. WVPA utilizes cost and performance parameters from the National Renewable Energy Lab's (NREL) Annual Technology Baseline (ATB)[2] for resource comparison. Thermal and storage resources are

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[i]WVPA supports renewable energy by owning landfill gas and solar generation and purchasing the output from wind, solar and biogas facilities. WVPA sells, separately, the environmental attributes associated with this generation to third parties, and therefore does not claim the generation as renewable within our own supply portfolio.

[2] NREL (National Renewable Energy Laboratory). 2023. "2023 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/electricity/2023/data

modeled as defined by NREL while renewable resources are adjusted to reflect recent market indicative quotes. NREL includes three ranges of costs: conservative, moderate and advanced. The advanced costs assume technology improvements that reduce build costs.

For this IRP, WVPA did not include coal-fired generation as a resource alternative to align with our carbon reduction goals as well as it is becoming increasingly uneconomic.

1. Peaking Power Expansion Alternatives

The installed capital cost, including Allowance for Funds Used During Construction (AFUDC), for a new build simple cycle F-class 233 MW natural gas combustion turbine (NGCT) is approximately $1,135/kW (stated in 2028 dollars). This technology option includes environmental emission controls for criteria pollutants. For modeling purposes, we also obtained fixed O&M (FOM) and variable O&M (VOM) costs from the NREL's ATB. FOM includes all labor (operations, maintenance, supervision, and administrative labor) as well as annual property taxes and insurance costs. VOM includes all non-fuel consumables, waste disposal costs (ash, spent catalyst materials, other liquid waste streams), and maintenance materials. The NGCT's projected capacity and operating costs are presented in Table 4-1 Expansion Plan Alternatives.

2. Combined Cycle Expansion Alternatives

The installed capital cost, including AFUDC, for a new build H-class combined cycle (NGCC) is approximately $1,287/kW (stated in 2028 dollars). The NGCC power plant is configured in a 2x1 configuration using two F-class combustion turbine/heat recovery steam generator (HRSG) trains. Steam generated in the HRSG is combined to feed a common steam turbine. The NGCC power plant without carbon capture can provide full-load power output of approximately 727 MW-net. This technology option includes the same environmental emission controls as described above. For modeling purposes, we also obtained FOM and VOM costs from the NREL's ATB. The NGCC's projected capacity and operating costs are presented in Table 4-1 Expansion Plan Alternatives.

TABLE 4-1 Expansion Plan Alternatives – Natural Gas Resources (Stated in 2028 dollars)

Unit	50-MW F-Class CT	50-MW F-Class CC	50-MW H-Class CC
Typical Capacity Factor	10%	80%	80%
Capacity Cost ($/kW-month)	$6.28	$6.96	$7.12
Fixed Cost ($/kW-month)	$2.30	$2.90	$2.87
Variable O&M Cost ($/MWh)	$7.66	$2.22	$2.22
Fuel Cost ($/MWh)	$43.60	$27.50	$26.94
Avg. Total Cost ($/MWh)	$168.78	$46.62	$46.27
	Avg. Cost at different Capacity Factors		
5% Capacity Factor	$286.31	$300.01	$302.91
10% Capacity Factor	$168.78	$164.87	$166.04
20% Capacity Factor	$110.02	$97.30	$97.60
30% Capacity Factor	$90.43	$74.77	$74.79
40% Capacity Factor	$80.64	$63.51	$63.38
50% Capacity Factor	$74.76	$56.75	$56.54
60% Capacity Factor	$70.84	$52.25	$51.97
70% Capacity Factor	$68.05	$49.03	$48.71
80% Capacity Factor	$65.95	$46.62	$46.27
90% Capacity Factor	$64.32	$44.74	$44.37

3. Renewable[i] Power Expansion Alternatives

This IRP includes several renewable[i] power expansion resources including land-based wind, utility-scale photovoltaic (PV) solar and utility-scale 4-hour battery storage based on adjusted cost estimates from the NREL's ATB. In addition, wind and solar

[i] WVPA supports renewable energy by owning landfill gas and solar generation and purchasing the output from wind, solar and biogas facilities. WVPA sells, separately, the environmental attributes associated with this generation to third parties, and therefore does not claim the generation as renewable within our own supply portfolio.

PPAs are included based on the levelized cost of energy (LCOE). These renewable[i] alternatives' projected capacity and operating costs are presented in Table 4-2 Renewable[i] Expansion Plan Alternatives.

TABLE 4-2 Renewable[i] Expansion Plan Alternatives – Wind, Solar and Battery (Stated in 2028 dollars)

Unit	50-MW Wind PPA	50-MW Solar PPA	1-MW Battery
Installed Capital Cost ($/kW)	$2,046	$1,863	$1,730
Typical Capacity Factor	35%	25%	17%
Capacity Cost ($/kW-month)	$8.52	$7.76	$7.21
Fixed Cost ($/kW-month)	$3.58	$2.03	$3.21
Variable O&M Cost ($/MWh)	$0.00	$0.00	$2.62
Fuel Cost ($/MWh)	$0.00	$0.00	$31.69
Avg. Total Cost ($/MWh)	N/A	N/A	$100.03
LCOE ($/MWh)	$61.10	$49.48	
LCOE ($/kW-month)			$11.39

As described in the overview section, federal funding opportunities have the potential to drive prices down for specific solar plus storage projects across the country. In particular, the following projects were considered over the past year.

New ERA projects

WVPA submitted a letter of intent to the USDA in the fall of 2023 to construct several large utility scale solar+battery generation facilities under the New Empowering Rural America (ERA) programs. The program includes a combination of grant and low intertest loans to provide affordable renewable energy for rural America. As of the publication of this IRP, WVPA has not been notified regarding the status of its request.

PACE projects

WVPA supported thirteen distribution Co-op member letter of interest submissions under the United States Department of Agriculture (USDA) Powering Affordable Clean Energy (PACE) program to construct microgrids at 37 sites in the fall of 2023. Most of the sites are solar + storage with a few storage-only options to complement existing solar and digester generation facilities. One member was invited to apply for funding for approximately 7 MW nameplate capacity at three sites. These assets align with DER forecasts, therefore, they are not explicitly modeled in the IRP. The Company continually monitors federal and state funding opportunities to benefit Co-op members.

4. Joint Project Participation

WVPA evaluates the potential cost benefits in participating as an equity partner in the construction or purchase of generating capacity versus sole ownership. This type of project involves joining with other electric utilities or developers in evaluating and developing generating facilities. The Company continues to monitor projects for possible participation as they develop.

In certain scenarios, where capacity estimates of the expansion plan alternatives exceed WVPA's needs, it is assumed the Company will partner with another entity in building or purchasing additional generation.

5. Environmental Effects

WVPA's evaluation of all supply-side resources includes assessment of each alternative's environmental impact. The Company currently owns generating units and purchases power through contracted supplies. For capacity expansion, WVPA evaluated resources that represent both construction of new facilities and power purchase agreements from existing resources. New thermal unit construction alternatives consisted entirely of natural gas units. These units are regulated for nitrogen oxides (NO_x), along with minor amounts of other air emissions. These units will eventually be regulated for emissions of carbon dioxide (CO_2). Solid and hazardous waste generated by these units is expected to be negligible. The Company's evaluation of these units includes potential NO_x control equipment, adjustments to combustion temperature, and permit limitations. Our final assessment concludes that these units could operate as peaking resources with limited operating hours and not exceed the limits set in the air emissions control operating permits.

Contract provisions in the Company's purchase power agreements stipulate that the resource will be operated in compliance with applicable environmental regulations and operating permit conditions.

Purchase power agreements are executed with other electric utilities or from wholesale power marketers. The power supply offered may be from an existing resource able to demonstrate compliance with applicable environmental regulations. The supply may also be offered from a proposed but as-yet nonexistent facility. As with new generating units, WVPA determines that the proposed resource has appropriate control technology and operating processes included in the cost of power supply. Again, the Company's purchase power contract provisions require that the supplying facility will be operated in compliance with applicable environmental regulations and operating permit conditions.

Due to the lack of clarity of any carbon pollution regulation at this time, WVPA did not attempt to estimate the cost of complying with carbon regulation for purposes of this IRP. However, the Company acknowledges that carbon pollution standards and other probable future regulations are factors when assessing new resources. In September 2021, WVPA announced a plan to target net-zero carbon dioxide emissions in our power generation portfolio by 2050. In comparison to 2005 emissions, the Company plans to attain a 50% reduction in carbon output by 2031 and 70% by 2040. WVPA and our Members value sustainability which guides our pursuit of sustainable, affordable, and reliable energy that increasingly features more renewable[i] energy resources. The expansion resource plan results indicate emissions in terms of tons per MWh as part of the scorecard evaluation metrics in Section 5.

6. Seasonal Power Supply Alternatives

WVPA works closely with ACES to identify and quantify market prices, trends and short-term market positions. ACES was established by WVPA and other REMC utilities to optimize short-term market transactions and provide risk assessment services.

The Company typically purchases short-term market power and options to meet transient peak demands caused by extreme weather or seasonal maintenance outages. Through the MISO and PJM markets, WVPA also optimizes its energy portfolio by purchasing energy from the market when that energy has a lower cost than dispatching additional power resources. WVPA uses ACES risk assessments of expected future market prices in making decisions regarding additional market energy or option purchases to hedge the cost of power.

7. Supply-Side Resource Selection Factors

WVPA employs several decision-making factors in selecting new power supply resources. While price is clearly important, WVPA also considers the technical viability of a proposed project. This includes an analysis of the long-term reliability of the resource, assessing any fuel supply, environmental compliance and transmission interconnection constraints. The Company also evaluates the creditworthiness of any proposal's counterparty, especially when considering the likelihood of proposed (but uninitiated) projects meeting targeted completion dates. Some of the additional factors that WVPA considers are operational flexibility, resource deliverability and location, impact on diversification of the Company's power portfolio, overall price risk exposure, equity requirements and contract term.

Demand-Side Resource Options

In this IRP, demand-side resource options are evaluated on a comparable basis to supply-side resources. WVPA's planning and evaluation of DR and EE programs is highly dependent upon a collaborative process with its Members. Input from the Members is invaluable for the process of evaluating existing programs, collecting information on program implementation, gaining information on the program's technical and economic potential and customer acceptance of new programs. The Company has both a Retail Programs and Services (RP&S) Working Group that are comprised of Members' personnel. Many of the RP&S working group members are energy advisors who interface directly with retail members who participate in programs, the deep knowledge of marketability was especially helpful. Staff from IL, MO, and IN shared varying experiences and all were committed to offering programs that support member satisfaction as well as an overall cost-effective portfolio.

DR Planning Process

The RP&S Working Group and WVPA staff worked closely with Skytop consulting throughout 2023 to review EE and DR options starting from current internal cost estimates and recent program experience.

The screening process consists of the following steps:

- Identifying EE and DR measures and technologies
- Determining if measures are consistent with overall goals
- Determining if there is adequate market potential
- Conducting economic evaluation
- Securing approval from WVPA and Member Co-op executive leaders
- Implementing programs

a. Identify Technologies

WVPA uses several sources of information to identify potential EE measures and DR technologies including participation in utility working groups. A major source of program possibilities is the Members' knowledge and experience with various technologies that allows the Company to compile options that have some degree of viability before conducting a formal analysis. WVPA also identifies potential programs through association with the National Rural Electric Cooperative Association's research, various trade journals, conferences and seminars.

The residential and commercial portfolio analysis included traditional and beneficial electrification programs described in Table 4-3 below under the branded names of PowerMoves for EE and PowerShift for DR.[4]

[4] For more information, see: https://www.powermoves.com/

Table 4-3 Potential Energy Efficiency Programs

	POWER MOVES	
	Program	**Description**
Res	HVAC - Existing Homes	Heating Ventilation and Air Conditioning (HVAC) replacement equipment incentives
	HVAC - New Construction	New home HVAC units
	Heat Pump Water Heater	New or existing home water heater incentives
	Pool Pump	New or existing pool pump incentives
	PowerMoves Home Program	New home construction incentives including shell measures, insulation, windows, doors, HVAC, etc.
	Yard Equipment - Beneficial Electrification	Electric lawn mowers, trimmers, chain saws, etc.
	Wi-Fi Thermostat	Incentives for smart programmable thermostats
C&I	C&I Prescriptive	Includes HVAC, chillers, compressors, lighting, variable frequency drives, refrigeration, etc.
	Business New Construction	New Construction measures
	C&I Custom	Any measures not included in prescriptive

The Demand Response portfolio analysis included the programs described in Table 4-4 for residential and C&I members.

Table 4-4 Potential Demand Response Programs

	PowerShift®	
	Program	**Description**
Res	Residential DLC - A/C, water heaters, pool pumps	Direct Load Control (DLC) via Advanced Metering Infrastructure (AMI) for Air conditioners, water heaters and pool pumps
	Residential Wi-Fi T-Stats	Centralized control of smart thermostats as Load Modifying Resources (LMRs)
	Residential Battery Storage	Centralized control of home energy storage systems as LMRs
	Residential Whole Home	Centralized control of whole home generators as LMRs
C&I	C&I DLC - grain dryer, field irrigation, ditch pumps	Direct Load Control (DLC) via Advanced Metering Infrastructure (AMI) for Air conditioners, water heaters and pool pumps
	C&I Contracts	Retail members agree to reduce load with 2 hour notification as LMRs. Legacy participants are summer only with year round expansion.

b. Determine if Measures are Consistent with Overall Goals

The primary objective of EE and DR at WVPA is to reduce wholesale power costs to the membership. EE reduces load requirements and DR provides capacity to meet MISO requirements. In addition, WVPA and Co-op Members want to offer the end retail customer the greatest possible value in electric service, improve members satisfaction, and to assist them in improving their quality of life.

c. Assess Market Potential

This step involves assessing the potential application of the technology in the Company's service territory. This step eliminates the measures that would not prove successful because of an economic or technical inability to utilize the technology. WVPA gauges customer interest and identifies potential pilot areas.

The parties agreed to assess the economic and achievable potential for EE and DR through a hybrid approach in lieu of a more costly Market Potential Study. Skytop combined publicly available EE and DR program information for the Midwest with their experience and knowledge to develop potential program information. Skytop created an Excel based cost benefit analysis tool for the parties to collaboratively agree upon 3-year EE and DR plans for residential and C&I member users.

d. Conduct an Economic Evaluation

Five standard Demand Side Management (DSM) tests were employed for EE analysis and two tests were used for DR analysis. Results of metrics over 1.0 indicate benefits outweigh costs based on the specific test categories of inputs.

Standard Metric	**EE**	**DR**
Utility Cost Test (UCT)	X	X
Total Resource Costs Test (TRC)	X	x
Societal Costs Test (SCT)	X	
Participant Cost Test (PCT)	X	
Ratepayer Impact Measure (RIM)	X	

Skytop included MISO and PJM benefits, seasonal demand reductions, select capacity auction/market results or avoided costs of a simple cycle combustion turbine (CT) in the analysis. Cost benefit results are shown in Table 4-5 and Table 4-6 below. The Beneficial Electrification programs were not recommended for implementation due to uneconomic results in all tests.

Table 4-5 Energy Efficiency Portfolio Results

EE Analysis OUTPUTS - Benefit Cost Ratios					
	Utility Cost Test (UCT)	**Total Resource Cost Test (TRC)**	**Societal Cost Test (SCT)**	**Participant Cost Test (PCT)**	**Ratepayer Cost Test (RIM)**
Residential Beneficial Electrification	*-1.64*	*0.46*	*0.51*	*0.25*	*0.85*
Residential Energy Efficiency	*1.82*	*0.94*	*1.83*	*2.34*	*0.56*
Total Residential Programs	**0.92**	**0.78**	**1.39**	**1.61**	**0.48**
C&I Beneficial Electrification	*NA*	*NA*	*NA*	*NA*	*NA*
C&I Energy Efficiency	*3.69*	*1.38*	*2.71*	*2.20*	*0.76*
Total C&I Programs	**3.69**	**1.38**	**2.71**	**2.20**	**0.76**
Other Portfolio Costs	*NA*	*NA*	*NA*	*NA*	*NA*
Portfolio Total	**3.03**	**1.24**	**2.41**	**2.06**	**0.73**

Table 4-6 Demand Response Portfolio Results

Demand Response Analysis Outputs							
	ISO	**Summer Peak Demand (MW)**	**Fall Peak Demand (MW)**	**Winter Peak Demand (MW)**	**Spring Peak Demand (MW)**	**Utility Cost Test (UCT)**	**Total Resource Cost Test (TRC)**
Residential	MISO	19.27	12.81	14.67	14.23	1.15	1.01
	PJM	0.11	0.03	0.00	0.03	2.91	1.37
	Total	**19.38**	**12.84**	**14.67**	**14.26**	**1.15**	**1.02**
C&I	MISO	55.26	11.61	0.94	21.86	1.79	1.79
	PJM	3.69	1.26	0.00	2.48	2.88	2.88
	Total	**58.95**	**12.87**	**0.94**	**24.34**	**1.85**	**1.85**
MISO Total	MISO	74.53	24.42	15.61	36.09	1.56	1.49
PJM Total	PJM	3.79	1.29	0.00	2.51	2.88	2.81
WVPA Total	**All WVPA**	**78.32**	**25.71**	**15.61**	**38.60**	**1.62**	**1.55**

e. Securing Approval and Implementation

The Total Resource Cost (TRC) results in Table 4.5 and 4.6 were used to recommend programs to the Co-op CEOs for total portfolio approval. The C&I portfolio produced very strong results at 1.38. While the residential programs were slightly less than 1.0, the team committed to offering programs for both residential and C&I members with a total portfolio greater than 1.0.

Beneficial electrification EE programs, including offering EV charging incentives were considered but not selected.

Approved EE and DR programs are rolled out to Members. WVPA supports the programs as long as they continue to meet the Company's goals. Staff review EE and DR results and budget allocations with the Board of Directors on an annual basis.

f. Forecasting Future EE and DR

WVPA engaged with Skytop Consulting to provide a set of 20-year energy efficiency and demand response savings scenario forecasts for use in this IRP. These forecasts are meant to provide a set of potential savings scenarios that could be achieved over the 20-year forecast timeline based on extrapolations of low, medium, and high growth scenarios as informed by secondary research of several potential studies completed near WVPA's service territory.

Skytop recently completed a three-year planning forecast update for WVPA's energy efficiency (EE) and demand response (DR) programs, which serves as the basis for the starting point of each scenario. WVPA leveraged the three-year planning work and benchmarking of other recently completed EE and DR potential studies in the region to inform potential WVPA EE/DR savings. This benchmarking work informed the trajectory of the remaining years of the 20-year forecast to determine a base, low, medium, and high growth scenario.

The benchmarking research detailed savings percentages of sales (by residential and C&I sectors) and cost estimates ($/MWh or $/MW saved by residential and C&I in real 2024 dollars) for energy efficiency and demand response as reported in other potential studies. Each scenario has a target percentage of sales, and associated costs, from the benchmarking that the current WVPA programs ramp up to over the timeline of the IRP. The resulting scenarios provide a range of potential EE and DR savings that could be achieved by WVPA depending on level of funding and retail participation.

WVPA selected the low EE and DR growth scenarios into the IRP as their base scenario. This scenario represents what WVPA believes could possibly be achieved from EE and DR with moderately more funding and expansion in the 20-year forecast. WVPA decided to use the low growth scenario to represent that there are potential growth opportunities for EE and DR to expand but is not excessively higher than current program levels. The results assume that a certain percentage of sales for EE and of peak demand for DR will be achieved and ramped up to over the forecast, then that percentage of sales remains the same for the future years. See Appendix I for a detailed discussion of the forecast methodology and results.

The portfolio costs were aggregated for inclusion in the modeling process as shown in Table 4-7 below.

TABLE 4-7 Demand-Side Expansion Plan Alternatives – DR and EE (Stated in 2028 dollars)

Unit	1-MW Commercial DR	1-MW Residential DR	1-MW Commercial EE	1-MW Residential EE
Installed Capital Cost ($/kW)	N/A	N/A	$633	$1681
Typical Capacity Factor	1%	1%	50%	45%
Capacity Cost ($/kW-month)	$4.37	$4.65	$3.51	$9.30
Fixed Cost ($/kW-month)	$4.37	$4.65	N/A	N/A
Avg. Total Cost ($/MWh)	$598.53	$636.43	$10.59	$25.28

Avoided Costs

The mix of transmission and power supply resource assets, along with transmission congestion in the region, impacts short-term avoided costs for WVPA. The long-term avoided cost for capacity approaches the incremental cost of a new peaking unit and the cost of network transmission to deliver the capacity to the distribution points of the Company's Members.

The avoided energy costs are based upon the economic dispatch order of all production resources. It should be noted that WVPA prepares our IRP with minimal use of the RTO markets to meet future power supply needs. WVPA selects resources that we believe can reasonably be relied upon to meet our long-term resource requirements. The Company believes that too much reliance on future incremental capacity market purchases produces substantial price volatility risk that goes against the essential purpose of the IRP. However, if we did allow the model to select a greater amount of incremental capacity market purchases, the modeling results would be considerably different due to the current, much lower, market prices. For example, prices from the most recent MISO planning resource auctions (PRA), as reflected in Table 4-8, are much lower than WVPA's forecasted avoided capacity cost of $6.381/kW-month which is based on a peaking simple cycle combustion turbine unit, and is described in Table 4-9 and Appendix D.

TABLE 4-8 MISO Historical Auction Clearing Price ($/kW-month)

Zone	Planning Year			
	2021-2022	2022-	2023-2024	2023-2024
Zone 6	$0.152	$7.198	$0.30	$0.30

Estimated annual avoided costs for 2023 through 2042, excluding transmission service fees, are shown in Table 4-9. Note that this table gives avoided costs for both capacity and energy components.

TABLE 4-9 WVPA Avoided Cost Forecast (Stated in nominal dollars)[(1)]

Year	Capacity ($/kW-month)	Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	Around the Clock Energy ($/MWh)
2023	6.381	$32.36	$30.88	$31.68
2024	6.540	$41.30	$38.62	$39.75
2025	6.704	$48.31	$44.51	$46.30
2026	6.872	$48.73	$45.17	$46.84
2027	7.043	$48.13	$44.78	$46.34
2028	7.219	$43.90	$40.99	$42.37
2029	7.400	$44.37	$41.34	$42.75
2030	7.585	$44.02	$41.28	$42.56
2031	7.775	$42.14	$39.63	$40.80
2032	7.969	$41.38	$39.40	$40.33
2033	8.168	$42.56	$40.62	$41.52
2034	8.372	$42.71	$40.98	$41.78
2035	8.582	$43.42	$41.69	$42.49
2036	8.796	$44.66	$42.41	$43.46
2037	9.016	$45.59	$43.48	$44.47
2038	9.242	$46.53	$44.64	$45.52
2039	9.473	$46.41	$44.73	$45.51
2040	9.709	$46.99	$45.44	$46.16

Year	Capacity ($/kW-month)	Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	Around the Clock Energy ($/MWh)
2041	9.952	$47.93	$46.35	$47.08
2042	10.201	$48.89	$47.28	$48.03

(1) Additional detail and data regarding the calculation of WVPA's avoided cost forecast are included in Appendix D of this report.

System Reliability

WVPA's system planning goal is to assure a highly reliable supply of electric power to its Members at the lowest reasonable cost. Resource ownership and purchase power agreements are WVPA's preferred strategy to manage risk and uncertainties due to market price volatility and counterparty credit exposure. WVPA participates in both MISO and PJM RTO markets with specific required reserves for loads and resource accreditation rules.

Until the beginning of 2034, the majority of WVPA's PJM load obligation is being met through an all-requirements contract with AEP. AEP is responsible for the capacity costs allocated to the load and providing appropriate capacity in the PJM market.

As described in Section 2, WVPA included the seasonal MISO requirements in the IRP modeling based on MISO's Loss of Load Expectation (LOLE) study.[5] The model also includes estimated seasonal resource accreditation values that are based on a resources ability to perform during historic emergency or tight margin hours over the past three years.

Resource Portfolio Modeling

1. Potential Futures

The landscape of the electric utility industry has been changing dramatically recently. For WVPA, this comes at a challenging but opportunistic time as approximately 600 MWs of firm capacity and generation will retire or expire over the next decade. This

[5] For details, see https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf

coincides with potential regulatory and demand challenges faced by the cooperative. WVPA took a different approach than usual in designing its IRP expansion and scenario modeling. The approach WVPA used was to identify four possible foreseeable futures (or paths) that have some likelihood of materializing.

The goal of this IRP is to identify a mix of new resources that, when considered with the existing portfolio, provides the best combination of expected costs and associated risks and uncertainties for WVPA and its Members. To achieve that goal, four potential futures were defined based on the current environment as well as a carbon reduction path and significant load changes as described in Table 4-10.

Table 4-10 Potential Futures Evaluated in IRP Analysis

Future	Description	Objective
Current Environment	Assumes load from the Power Requirements Study (PRS) plus low EV growth projections, current environmental regulations, and demand side resource trends continue. Allows all technologies: NGCC, NGCT, Solar, Wind, Battery, DR and EE to compete in optimization of future resource mix.	Find the least-cost resource plan to serve forecasted Member load requirements in terms of "business as usual."
Carbon Reduction	Assumes stricter restrictions on thermal units. All coal is retired, and gas units are limited to 50% capacity factor after 2034. Allows NG, Solar, Wind, Battery, DR and EE to compete in optimization of future resource mix.	Assess ability to serve forecasted Member load requirements while mitigating risks of stricter environmental regulations to minimize carbon output.
Load Reduction	Assumes a 150 MW load loss in 2030 which represents a 9% reduction in member load.	Understand portfolio impacts of abrupt changes in load requirements.
Bold Economic Growth	Assumes large load additions in two of the 20 years which may reflect data center or manufacturing expansions in the footprint.	Understand impacts of significant economic growth.

Current Environment

The Current Environment future optimizes the portfolio considering industry trends as inputs and all potential locally viable resources options. Although other technology options exist (e.g., nuclear, hydropower, geothermal, etc.), they are not considered viable due to being uneconomic or unavailability in the Midwest at this time. Load growth is reflective of our latest power requirements study after adjusting for a modest amount of electric vehicle growth determined by a study of possible EV growth levels within our territories. The 20-year compounded average growth rate (CAGR) is 1.024% for energy and 0.981% for annual peak demand.

Carbon Reduction

In the Carbon Reduction future, increased regulation of thermal unit output is the main assumption change. Coal units are retired and Investment in NG technology is restricted to a 50% capacity factor to minimize carbon output. Other more subtle assumption changes include renewable cost advancements and greater electric vehicle load and residential distributed generation. All future needs are met by a combination of NGCC, solar, wind, battery, and demand-side resources. Seasonal short-term needs are allowed to be met through the capacity auction up to 15% of member load. This portfolio serves as a bookend to inform risk mitigation discussions should strict regulations be implemented.

Load Reduction

The Load Reduction future anticipates the loss of load due to a severe economic downturn. The model accounts for the abrupt loss of 150 MW or about 9% of the WVPA footprint in 2030. By adjusting WVPA's expansion plan for this loss, exposure to forward and spot markets are minimized.

Bold Economic Growth

The Bold Economic Growth scenario anticipates large load additions of 500 MW each in 2028 and 2032 to reflect growth such as data center or manufacturing facilities in the WVPA footprint. Similar load changes are forecasted in the PJM footprint as described in

PJM's Load Forecast Supplement report.[6] The resulting portfolio includes additional resources to meet the load and reserve margins in all four seasons of the year.
Key elements of each future are summarized in Table 4-11.

Table 4-11 Key Elements of Each Potential Future

	Potential Futures			
Elements	**Current Environment**	**Carbon Reduction**	**Load Reduction**	**Bold Economic Growth**
Load Forecast	PRS	PRS	PRS less 150MW in 2030	PRS + 500MWs in 2028 & 2032
EV Forecast	Low	Mid	None	Mid
DG Forecast	None	Mid	None	None
EE/DR Forecast	Low	Mid	Low	Low
Energy Price Forecast	Reference	Zero Carbon	Mid	Mid
Fuel Price Forecast	Mid	Mid	Mid	Mid
New Build Costs	Moderate	Advanced	Moderate	Moderate
Capacity Price Forecast	Mid	Mid	Mid	Mid
Carbon Price Forecast	None	None	None	None

2. Existing Resource Forecasted Retirements/Expirations

The Company assumes that existing power purchase agreements expire at the end of the current contract term and existing owned generation retires per the timing outlined

[6] See https://www.pjm.com/-/media/planning/res-adeq/load-forecast/load-forecast-supplement.ashx, pages 19-25.

in Section 2. These assumptions are summarized in Table 4-12 and are the same for all four potential futures.

TABLE 4-12 Existing Resource PPA Forecasted Retirements/Expirations(1)

Year	MW (ICAP)
2023	
2024	Duke Indiana Unit Peaking PPA (50 MW)- Duke terminated early
2025	Duke Indiana PPA (55 MW)
2026	
2027	
2028	
2029	Hallador Firm Capacity Purchase (250 MW)
2030	Pioneer Trail Wind PPA (10 MW) Gibson 5 (156MW)
2031	Duke Indiana PPA (180 MW)
2032	Duke Indiana PPA (70 MW)
2033	AEP PPA (150 MW)
2034	Prairie Wolf Solar Capacity Purchase (50 MW)
2035	
2036	
2037	Meadow Lake Wind V PPA (25 MW)
2038	Prairie State 1 (41.5 MW) AgriWind PPA (8.4 MW) Meadow Lake Wind VI PPA (75.4 MW)
2039	Zimmerman Energy LFG PPA (7.6 MW)
2040	Harvest Ridge Wind PPA (100 MW)
2041	WR Highland (160) MW

WVPA utilizes the PLEXOS® model to evaluate supply-side and demand-side resource options on an equivalent basis. Plexos® selects resources in order to reduce the overall portfolio cost, regardless of whether the resource is on the supply or demand-side.

Specifically, both the Plexos® LP long-term optimization model, also known as "LT Plan®," and the Plexos® medium-term simulation model, also known as "MT Schedule®," are used to find the optimal portfolio of future capacity and energy resources that minimizes the Company's variable and fixed costs over the twenty-year plan horizon for each of the four futures and then for each future against each scenario to produce 24 expansion plan results. Detailed results are discussed in Section 5.

2023 Integrated Resource Plan

Section 5

RESULTS ANALYSIS

Financial Forecast

The primary objective of this IRP is to fulfill our mission by evaluating our Members' requirements to provide reliable, stable, and responsible energy solutions for the next 20 years. The financial forecast for the IRP modeling calculates the Company's expected revenue requirement based on production costs, capital recovery costs and financial performance targets such as TIER (Times Interest Earned Ratio), DSC (Debt Service Coverage Ratio), Fixed Charge Ratio and Equity Percentage.

While WVPA may consider sole or joint ownership of generating facilities, each project would first be measured against a comparable power purchase agreement. WVPA maintains its financial health through adherence to a prudent financial policy. The following is a summary of major objectives of the Company's financial policy:

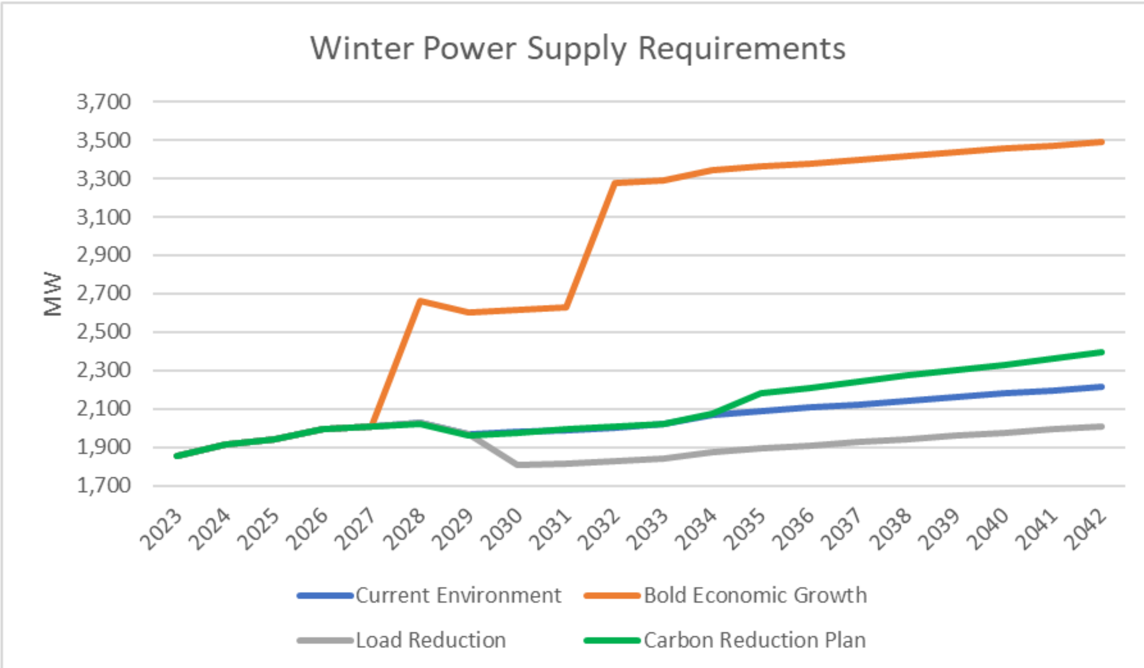
1. Minimize the long-run cost of providing service to the Members with recognition that the quality of such service will be maintained at levels consistent with prudent utility practice and acceptable risk levels.
2. Preserve WVPA as a going concern entity by maintaining and replacing its assets in accordance with industry standards and ensuring that adequate amounts of funds are available from internal and external sources to accommodate these needs.
3. Maintain the ability to access capital markets in order to finance facilities required to accommodate the Members' demand for electricity by maintaining the financial standards required of these markets for credit worthiness.

Expansion Modeling

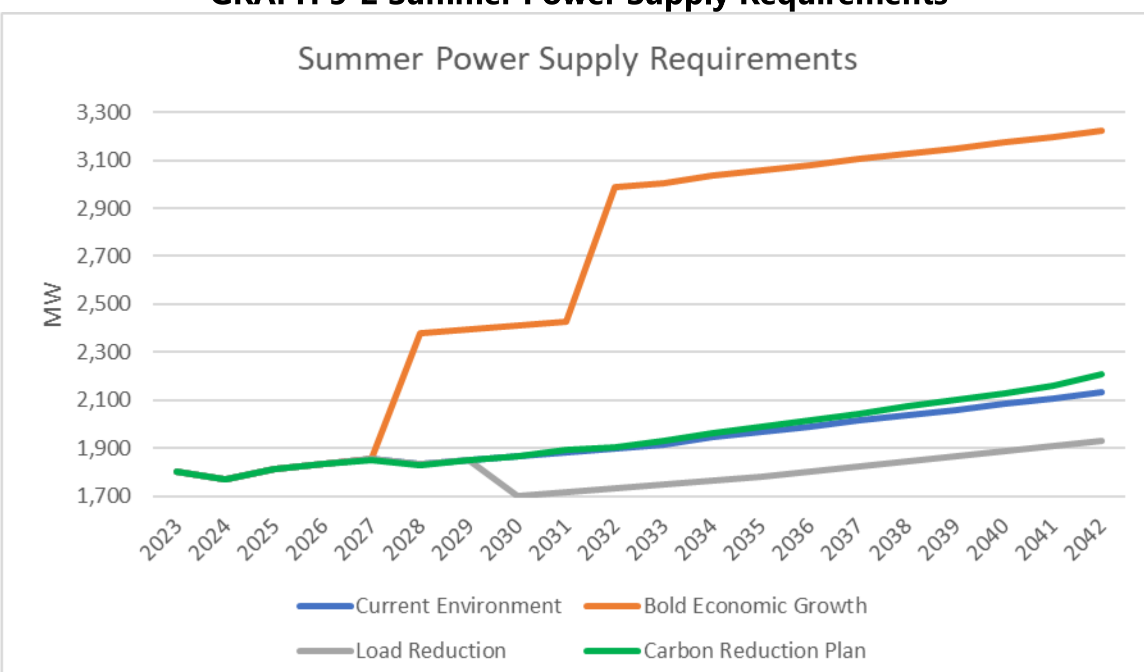
As discussed previously, WVPA designed expansion plans based on four potential futures. WVPA executed the Plexos® LT Plan® and the Plexos® MT Schedule® models deterministically under differing sets of assumptions to determine the expansion plans for the four potential futures described in Section 4.

Graphs 5-1 and 5-2 show how total power supply requirements differ in each potential future for summer and winter. These differences are driven by alternative load forecasts as explained in Section 4.

GRAPH 5-1 Winter Power Supply Requirements



GRAPH 5-2 Summer Power Supply Requirements



Even though WVPA is a summer peaking entity, winter power supply requirements are greater due to the MISO planning reserve margin requirement (PRMR) for winter being greater than the PRMR for summer. Table 5-3 shows the seasonal PRMR percentages assumed for IRP purposes.

TABLE 5-3 MISO Planning Reserve Margin Requirement Assumptions

Summer	Fall	Winter	Spring
9.00%	14.20%	27.40%	26.70%

Table 5-4 shows how much higher or lower each future's winter power supply requirements are compared to the Current Environment at various points in the time horizon.

TABLE 5-4 Requirements % Variance

Alternate Futures	2027	2032	2037	2042
Bold Economic Growth	0.0%	63.6%	60.0%	18.7%
Load Reduction	0.0%	-8.8%	-9.4%	-5.7%
Carbon Reduction	-0.2%	0.2%	5.5%	8.0%

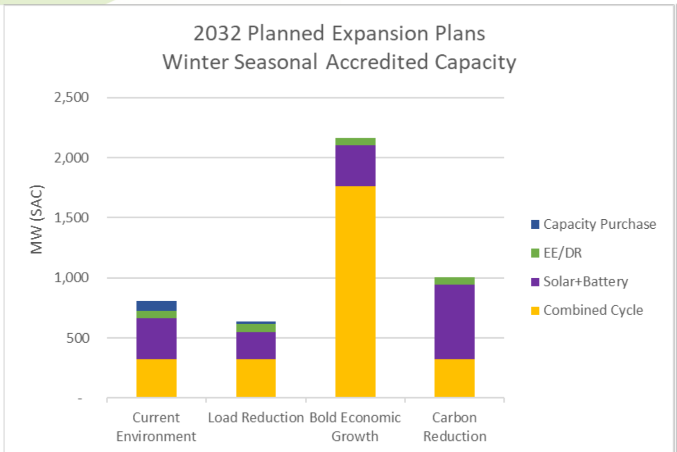
Model Results

Power supply requirements inputs include expected Member demand, losses, contractual firm sales, and estimated MISO PRMR for each season through 2042. Capacity needs are determined by subtracting the estimated accredited values for existing owned and contracted resources and planned additions from the power supply requirements. While MISO PRMR and resource accreditation values are expected to change slightly each year, consistent values are used for thermal resources throughout the 20-year modeling period as a simplifying assumption. Solar accreditations decline in the model over the forecast period to mimic MISO's expected reduction in Equivalent Load Carrying Capability (ELCC) as more solar resources are online. The model limits capacity purchases from the MISO Planning Resource Auction (PRA) to 15% to comply with Indiana HB1007.

The resource plan for each of the four potential futures includes demand side management and natural gas resource additions beginning in 2025, which is driven by the need for winter capacity. Subsequent additions of solar and storage resources are suggested in 2029 in preparation for the retirement of Gibson 5 and expiration of long-term contracts. The specific MW values and years vary based on the input assumptions.

Capacity expansion plans for potential futures stated in seasonal accredited capacity for winter and summer are presented below. Figures 5-5 and Figure 5-6 compares the planned expansion resources for all eight cases in 2032, the mid-point of the time horizon, and in 2042, the final year. This capacity represents the resources selected to fill the capacity gap resulting from the forecasted retirement of owned generation and the expiration of existing purchase power agreements summarized in Table 4-12.

FIGURE 5-5 Winter Expansion Plan Comparisons



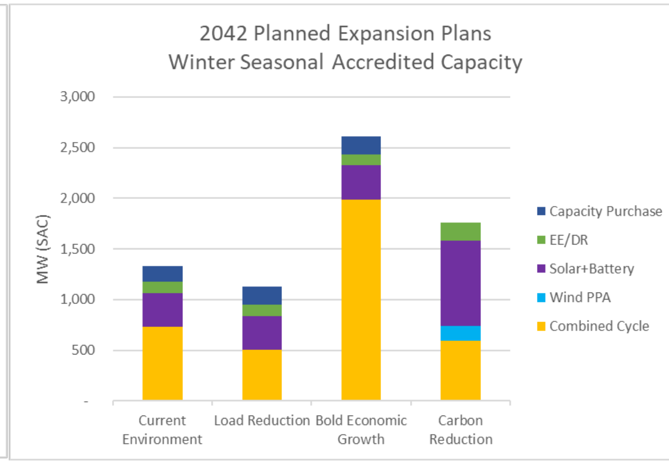
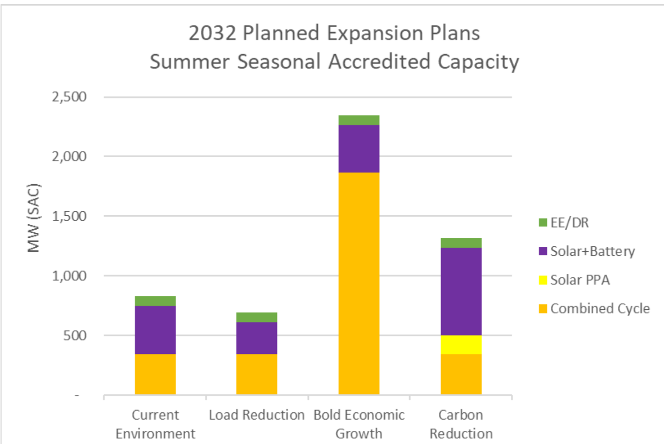
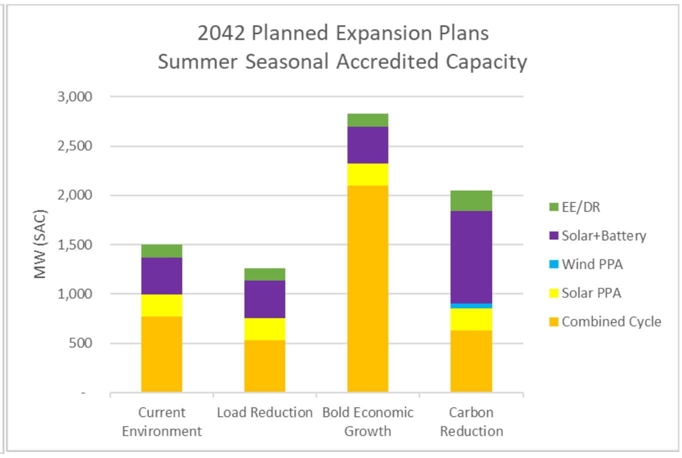


FIGURE 5-6 Summer Expansion Plan Comparisons





Key points of capacity additions by 2042 for all four expansion plans are summarized below by resource type:

Energy Efficiency (EE): Overall, EE resources have a low average total cost prompting their consistent selection across all four expansion plans. The main limit of EE is its achievable potential.

Demand Response (DR): Demand response is selected in each future, however as a longer-term capacity solution, it competes with the intermittent short-term capacity need resulting from the MISO seasonal capacity requirements and resources that also have energy value.

Capacity Purchase: The purpose of the IRP is to meet the needs of our members through capacity planning not the Planning Resource Auction (PRA). For this reason, capacity purchases are limited; however, under the new MISO seasonal capacity construct, intermittent capacity purchases may be necessary. For IRP modeling, capacity purchases were given a one-month lifespan and limited to no more than 15% of the power supply requirements. Capacity price assumptions can be found in Appendix C.

Combined Cycle (NGCC): Natural gas combined cycle plans were part of every futures expansion plans. This is partly due to modeling the purchase of an existing plant in 2025. Other than EE, DR, and capacity purchases, WVPA only modeled existing projects or projects with a reasonable likelihood of being completed prior to 2028. Generally, this limited expansion opportunities to one combined cycle plant and two solar+battery hybrid projects. The combined cycle plant was the overwhelmingly preferred selection. Furthermore, additional combined cycle units were built in every future in later years.

Combustion Turbine (NGCT): Combustion turbines were not a resource of choice in any of the futures. This is mostly due to the installed and operating costs of a combined cycle and a combustion turbine being very close. With the added energy value of the combined cycle, it was always the preferred choice. Another factor is the retirement of a coal plant and expiration of multiple purchase power agreements, which drive WVPA's need to replace 4,500 GWh of energy production annually.

Solar PPA: Despite the declining seasonal capacity accreditation value, solar PPAs were still heavily selected across all four expansion plans as compared to the 2020 IRP. However, in the 2023 IRP, the solar PPAs are utilized to replace energy (not capacity) often coinciding with the expiration of energy only PPAs.

Wind PPA: Other than in the carbon reduction future, wind was not selected. This is partially due to the generation shape and seasonal capacity accreditation values, but it is also reflective of an increase in the levelized cost assumptions.

Solar+Battery Hybrid Projects: This resource was selected as both an ownership and purchase power agreement opportunity. In every future except the carbon reduction future, 200 MWs was chosen in 2029 and 100 MWs was chosen between 2032 and 2034. As expected, the hybrid resources were utilized in the carbon reduction plan to serve both capacity and energy needs in those years, with an additional 550 MW added by 2042.

As mentioned previously, WVPA executed expansion plans for all potential futures. The following discussion will focus on the resulting expansion plans in terms of capacity additions in MWs and the driving forces that lead to those results.

Preferred Expansion Plan (Current Environment)

WVPA's preferred resource plan results from the Current Environment Future This plan is built on the expected, or most likely, assumptions. As discussed in Table 4-10, the goal of this future is to find the least-cost resource plan to serve forecasted member load requirements in terms of "business as usual." This future assumes load from the Power Requirements Study (PRS) plus low EV growth projections, current environmental regulations, and demand side resource trends continue. Table 5-7 summarizes WVPA's existing generating resources and anticipated capacity needs through 2042. Power Supply Requirements include expected Member demand, losses, contractual firm sales, and estimated reserves for the winter season. The winter position drives overall capacity needs since winter PRMR values are higher and resource accreditation values are lower than the spring, summer, and fall values. Winter Seasonal Accreditation (SAC) values are used to calculate capacity needs with the right most columns presenting the optimal incremental additions to the portfolio of supply-side and demand-side resources to meet WVPA's future capacity needs. Installed Capacity and Summer SAC Values can be found on the expansion plans in Appendix A.

Table 5-7 Preferred Resource Plan Winter (SAC MWs)

Year	Power Requirements	Existing	Capacity Needs	Capacity Market	NGCC	Solar, Wind, Battery Owned	Solar, Wind, Battery PPAs	EE & DR
2023	1,852	1,620	232	233	0	0	0	0
2024	1,914	1,637	277	273	0	0	0	5
2025	1,941	1,736	205	0	324	0	0	10
2026	1,994	1,678	316	0	324	0	0	14
2027	2,009	1,778	231	0	324	0	0	20
2028	2,025	1,778	247	0	324	0	0	20
2029	1,967	1,768	199	0	324	224	0	30
2030	1,979	1,431	548	0	324	224	0	39
2031	1,991	1,424	567	0	324	224	0	43
2032	2,004	1,195	809	83	324	224	112	66
2033	2,019	1,106	913	165	324	224	112	87
2034	2,071	972	1,099	167	504	224	112	92
2035	2,088	969	1,119	183	504	224	112	96
2036	2,106	969	1,137	196	504	224	112	101
2037	2,125	969	1,155	214	504	224	112	102
2038	2,142	964	1,178	0	729	224	112	114
2039	2,163	909	1,254	75	729	224	112	114
2040	2,180	904	1,277	100	729	224	112	111
2041	2,198	884	1,314	130	729	224	112	119
2042	2,218	884	1,334	159	729	224	112	110

The driving force behind this expansion plan is to solve both capacity and energy needs over the back half of the forecast. Even though WVPA has capacity and energy needs as early as 2025 due to the expiration of two purchase power agreements and the cancellation of a 200 MW solar project, these needs multiply in the early to mid-2030s. The long-term expansion planning model chooses to purchase a 360 MW combined cycle plant in the first quarter of 2025 and build a 200 MW solar+battery hybrid facility in 2029, other supply side projects being chosen in the 2034–2035-time frame due to the loss of approximately 650 MWs of baseload generation between 2030 and 2033. This is partially offset by the expiration of a large non-member sale in April 2028. From 2034-2037, 760 MW of generation is added to the WVPA portfolio; 360 MWs of NGCC and 400 MWs of solar including 200 MWs of battery. Energy needs still require dispatchable resources and the batteries help in this aspect. Still, intermittent resources such as solar definitely have a place in the WVPA portfolio. Capacity purchases are mostly limited to January. Due to the one-month life span, these intermittent purchases are the capacity option of choice even at capacity prices greater than WVPA avoided demand cost forecast.

Carbon Reduction Resource Plan

One alternative to WVPA's preferred resource plan is the Carbon Reduction Resource Plan. This plan was built on a theoretical long-term regulatory carbon emission restriction. The goal of this future is to assess WVPA's ability to serve forecasted Member load requirements while mitigating risks of stricter environmental regulations that target carbon output. This is achieved by increasing restrictions on thermal units. All coal is retired, and gas units are limited to 50% capacity factor after 2034. All technologies are still allowed to compete under the stricter set of emission standards, but advanced technology cost improvements are assumed for renewable resources (TABLE 5-8).

TABLE 5-8 Renewable Expansion Plan Alternatives - Advanced Cost Assumptions

(Stated in 2028 dollars)

Unit	50-MW Wind PPA	50-MW Solar PPA	1-MW Battery
Installed Capital Cost	$1,590	$1,497	$1,003
Typical Capacity Factor	35%	25%	17%
Capacity Cost ($/kW-	$6.63	$6.24	$4.18
Fixed Cost ($/kW-month)	$3.58	$2.03	$3.21
Variable O&M Cost	$0.00	$0.00	$2.62
Fuel Cost ($/MWh)	$0.00	$0.00	$31.69
Avg. Total Cost ($/MWh)	N/A	N/A	$100.03

LCOE ($/MWh)	$61.10	$49.48	n/a
LCOE ($/kW-mo)	n/a	n/a	$7.96

In this future, EE and DR programs are also expanded along with EV and DG adoption.

TABLE 5-9 summarizes WVPA's existing generating resources and anticipated capacity needs through 2042. Power Supply Requirements include expected Member demand, losses, contractual firm sales, and estimated reserves. The winter position drives overall capacity needs since winter PRMR values are higher and resource accreditation values are lower than the spring, summer, and fall values. Winter Seasonal Accreditation (SAC) values are used to calculate capacity needs with the right most columns presenting the optimal incremental additions to the portfolio of supply-side and demand-side resources to meet WVPA's future capacity needs. Installed Capacity and Summer Values can be found on the expansion plans in Appendix A.

TABLE 5-9 Carbon Reduction Resource Plan Winter (SAC MWs)

Year	Power Requirements	Existing	Capacity Needs	Capacity Market	NGCC	Solar, Wind, Battery Owned	Solar, Wind, Battery PPAs	EE & DR
2023	1,852	1,620	232	233	0	0	0	0
2024	1,914	1,637	277	273	0	0	0	5
2025	1,941	1,736	205	0	324	0	0	10
2026	1,993	1,678	315	0	324	0	0	14
2027	2,006	1,778	228	0	324	0	0	20
2028	2,025	1,778	246	0	324	0	0	20
2029	1,964	1,768	196	0	324	224	0	32
2030	1,977	1,431	546	0	324	224	0	32
2031	1,993	1,424	569	0	324	224	0	43
2032	2,007	1,195	812	0	324	224	392	65
2033	2,022	1,106	916	0	324	224	392	90
2034	2,072	972	1,099	66	324	224	392	93
2035	2,182	969	1,213	0	324	224	469	104
2036	2,211	969	1,242	0	504	224	469	121
2037	2,242	969	1,273	0	504	224	469	127
2038	2,272	964	1,308	0	504	224	536	153
2039	2,302	909	1,393	0	504	224	536	149
2040	2,331	904	1,427	0	504	224	761	175
2041	2,362	884	1,478	0	594	224	761	181
2042	2,395	884	1,511	0	594	224	761	179

The overall energy and capacity needs of the Carbon Reduction future are largely the same as the Current Environment future except for greater electric vehicle load and distributed generation. This leads to a cumulative average growth rate in peak demand of 1.168% vs 0.981% in the current environment future. That said, the real changes between the two plans exist in the controls placed on carbon emissions and improved costs of renewable energy solutions. Much like the preferred plan, the carbon reduction plan chooses to purchase a 360 MW combined cycle plant in the first quarter of 2025 and build a 200 MW solar+battery hybrid facility in 2029. Beyond that expansion changes quite a bit. NGCC still has a place in the long-term planning and only decreases by 150 MWs between the preferred plan and carbon reduction plan by 2042. However, due to coal retirement and the 50% capacity factor limitation, generation from fossil fuel resources dropped by more than 50%. By 2042, over 3,300 GWh of annual energy was replaced by a large buildout of solar and wind resources. By 2042, more than 2,200 MWs of solar and wind generation will be added to the portfolio compared to 1,000 MWs in the preferred case. Although fossil fuel capacity dropped by 192 MWs (including coal retirement), an additional 450 MWs of battery capacity was installed to meet energy needs. By 2042, this expansion plan is long on capacity while meeting all the energy needs of our members.

Load Reduction Plan

Another alternative to WVPA's Preferred resource plan is the Load Reduction Plan. This plan was developed to understand portfolio impacts of abrupt changes to member load. This future assumes a 150 MW or 9% load reduction in 2030. This loss is then compounded from 2031 through 2042. Energy loss is calculated based on the implied average monthly load factor of our member load. All technologies are allowed to compete under the same set of assumptions used in the Current Environment future. TABLE 5-10 summarizes WVPA's existing generating resources and anticipated capacity needs through 2042. Power supply requirements include expected Member demand, losses, contractual firm sales, and estimated reserves. The winter position drives overall need since winter PRMR values are higher and resource accreditation values are lower than the spring, summer, and fall values. Winter Seasonal Accreditation (SAC) values are used to calculate capacity needs with the right most columns presenting the optimal incremental additions to the portfolio of supply-side and demand-side resources to meet WVPA's WVPA future capacity needs. Installed Capacity and Summer SAC Values can be found on the expansion plans in Appendix A.

TABLE 5-10 Load Reduction Resource Plan Winter (SAC MWs)

Year	Power Requirements	Existing	Capacity Needs	Capacity Market	NGCC	Solar, Wind, Battery Owned	Solar, Wind, Battery PPAs	EE & DR
2023	1,852	1,620	232	233	0	0	0	0
2024	1,914	1,637	277	273	0	0	0	5
2025	1,941	1,736	205	0	324	0	0	10
2026	1,994	1,678	316	0	324	0	0	14
2027	2,009	1,778	231	0	324	0	0	20
2028	2,025	1,778	247	0	324	0	0	20
2029	1,967	1,768	199	0	324	224	0	29
2030	1,805	1,431	374	0	324	224	0	32
2031	1,816	1,424	392	0	324	224	0	41
2032	1,828	1,195	633	20	324	224	0	65
2033	1,841	1,106	735	102	324	224	0	86
2034	1,877	972	905	154	324	224	112	91
2035	1,892	969	923	168	324	224	112	95
2036	1,909	969	939	180	324	224	112	100
2037	1,926	969	956	106	414	224	112	101
2038	1,941	964	977	114	414	224	112	113
2039	1,960	909	1,051	97	504	224	112	114
2040	1,976	904	1,072	113	504	224	112	120
2041	1,993	884	1,108	148	504	224	112	120
2042	2,011	884	1,126	176	504	224	112	111

The overall energy and capacity strategy for the load reduction plan is the same as the Preferred plan. The driving force behind this expansion plan is to solve both capacity and energy needs over the back half of the forecast. However, because the reduction in load occurs prior to the mid-2030s build-out in the Preferred plan, the build-out is delayed and less than the Preferred plan but follows the same fuel mix with the reduction of baseload NGCC resources. Combined cycle expansion is 200 MWs less in 2034 and grows to 250 MWs less by 2042; everything else stays largely the same. This makes sense because 150 MWs after adjusting for winter PRMR of 27.4% equals 191 MWs in 2030. Plus, the dispatchable availability of the combined cycle makes it a good resource to serve load or to eliminate if load is eliminated.

Bold Economic Growth Plan

One final alternative to WVPA's Preferred resource plan is the Bold Economic Growth Resource Plan. This plan was developed to understand portfolio impacts of significant economic growth such as data centers locating inside our territory. This future assumes a 500 MW load addition with a 95% load factor in 2028 and again in 2032. All technologies are allowed to compete under the same set of assumptions used in the Current Environment future. TABLE 5-11 summarizes WVPA's existing generating resources and anticipated capacity needs through 2042. Power supply requirements include expected Member demand, losses, contractual firm sales, and estimated reserves. The winter position drives overall need since winter PRMR values are higher and resource accreditation values are lower than the spring, summer, and fall values. Winter Seasonal Accreditation (SAC) values are used to calculate capacity needs with the right most columns presenting the optimal incremental additions to the portfolio of supply-side and demand-side resources to meet WVPA's future capacity needs. Installed Capacity and Summer SAC Values can be found on the expansion plans in Appendix A.

TABLE 5-11 Bold Economic Growth Resource Plan Winter (SAC MWs)

Year	Power Requirements	Existing	Capacity Needs	Capacity Market	NGCC	Solar, Wind, Battery Owned	Solar, Wind, Battery PPAs	EE & DR
2023	1,852	1,620	232	233	0	0	0	0
2024	1,914	1,637	277	273	0	0	0	5
2025	1,941	1,736	205	0	324	0	0	10
2026	1,994	1,678	316	0	324	0	0	14
2027	2,009	1,778	231	0	864	0	0	20
2028	2,662	1,778	884	0	864	0	0	20
2029	2,604	1,768	836	0	864	224	0	30
2030	2,616	1,431	1,185	58	864	224	0	39
2031	2,628	1,424	1,204	72	864	224	0	43
2032	3,278	1,195	2,083	0	1764	224	112	66
2033	3,293	1,106	2,187	0	1764	224	112	87
2034	3,345	972	2,373	181	1764	224	112	92
2035	3,362	969	2,393	197	1764	224	112	96
2036	3,380	969	2,411	210	1764	224	112	101
2037	3,399	969	2,429	228	1764	224	112	102
2038	3,416	964	2,452	237	1764	224	112	114
2039	3,437	909	2,528	89	1989	224	112	114
2040	3,454	904	2,551	114	1989	224	112	111
2041	3,472	884	2,588	144	1989	224	112	119
2042	3,492	884	2,608	173	1989	224	112	110

The added loads represent a 32% and 64% increase in winter power requirements and a 44% and 87% increase in energy needs in 2028 and 2032 respectively. Due to the large capacity needs and the 95% capacity factor, expansion modeling chooses to meet these needs entirely with natural gas combined cycle units. This makes sense because intermittent resources cannot meet the energy needs of these loads and at 95% capacity factors batteries don't have the necessary time to cycle without massively overbuilding.

Five Pillars and Portfolio Scorecard

As mentioned in Section 1, WVPA developed a scorecard in this IRP to incorporate the five attributes or "pillars" for energy infrastructure decisions identified in HEA 1007 which include: reliability, affordability, resiliency, stability, and environmental sustainability. The Company Board of Directors actively considers these attributes when voting on resource investments including generation, supply side, and transmission projects. Key elements of each attribute and how the Company incorporates them into resource planning are defined below.

1. **Reliability** – Adequacy of electric service including meeting load requirements all hours of the year and operating the system to respond quickly to disturbances

The Company achieves load requirements with planning reserves for all IRP periods, considering the performance of resources. Model parameters limit dependence on market purchases for capacity and energy as stop gaps between investments to mitigate uncertainty risks.

2. **Affordability** – Electric service is affordable across residential, commercial, and industrial customer classes

The Company includes expected costs with the focus on least cost reasonable portfolio results for Members.

3. **Resiliency** – Ability to adapt to changing conditions and withstand and rapidly recover from disruptions

The Company includes multiple types of resources and fuel sources and limits dependency on any one resource as part its risk management strategy. In addition, energy storage is an added tool to improve grid resiliency.

4. **Stability** – Maintain state of equilibrium with frequency and voltage parameters within industry standards

The Company includes inertial resources with the ability to support system frequency. In addition, future inverter-based resources including solar and energy storage are expected to possess grid-forming capabilities to support system voltage. Since WVPA is not a NERC registered Transmission Operator or Local Balancing Authority, it relies on its Investor Owned Utility (IOU) transmission partners[1] to monitor and control system conditions. This attribute is consistent across all portfolios, so it is not listed as a comparative metric in the scorecard.

5. **Environmental Sustainability** – Impact of environmental regulations are included in costs and consumers interest in environmentally sustainable sources of electricity

The Company has included existing and potential future environmental regulations as described in Section 4 and distributed and utility scale renewable resources in modeling. The expected carbon emissions are reported for each portfolio.

Table 5-12 includes scorecard metrics to compare the ability of various portfolios to reflect the attributes. Snapshot years of 2032 and 2042 were utilized to indicate results across the forecast period.

TABLE 5-12 Scorecard Metrics

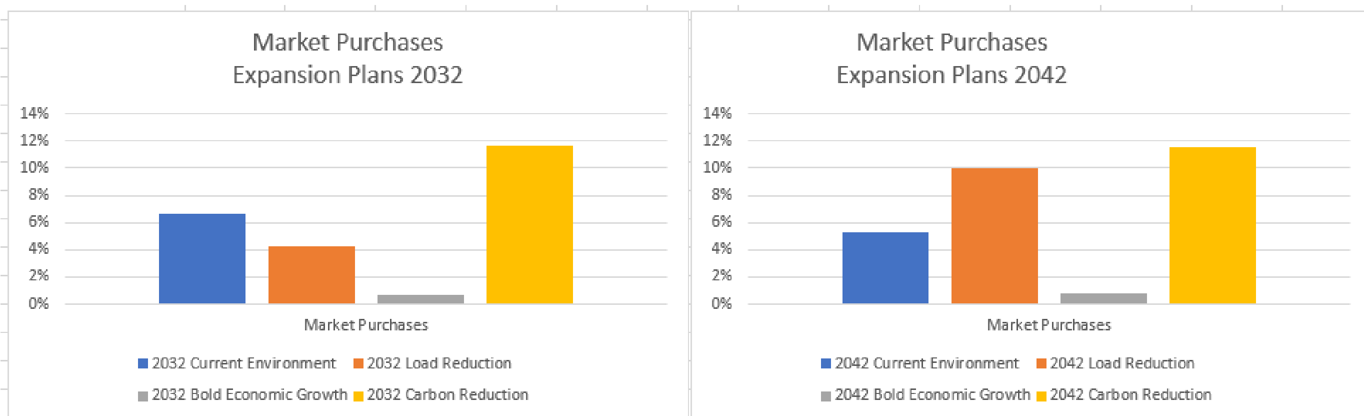
Attribute	Metric
Reliability& Stability	Market dependency for energy purchases based on a percentage of portfolio
Affordability	Comparison of average costs to the Preferred Plan
Resiliency	Diversity of Resources for energy by percentage of portfolio
Environmental Sustainability	Carbon Emissions in terms of metric tons per MWh

[1] IOU transmission partners include AES Indiana, AEP- I&M, Ameren IL, Ameren MO, Duke Energy Indiana, and NIPSCO.

Reliability & Stability

WVPA considers asset ownership and contract certainty ways to ensure reliable resources and grid stability. We measured these factors in terms of market dependency for energy based on a percentage of the portfolio compared to owned and contracted resources for each expansion plan as shown in TABLE 5-13.

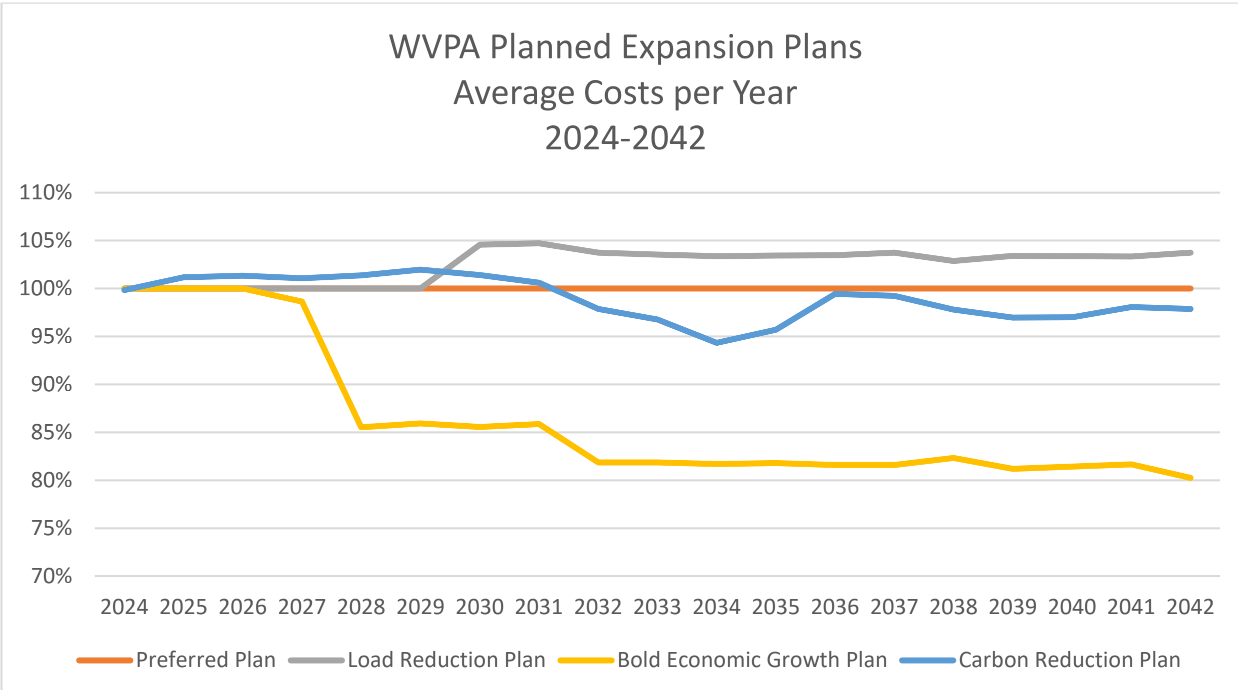
TABLE 5-13 Reliability & Stability through low Market Purchase %



Affordability

Affordability is measured in terms of the portfolio costs compared to the Preferred plan. This depicts annual variances based on average costs as shown in GRAPH 5-14 for each of the four future expansion plans. While the Bold Economic Plan costs are the lowest up to 2032, this future is optimistic. Therefore, affordability drives the Preferred Resource plan selection.

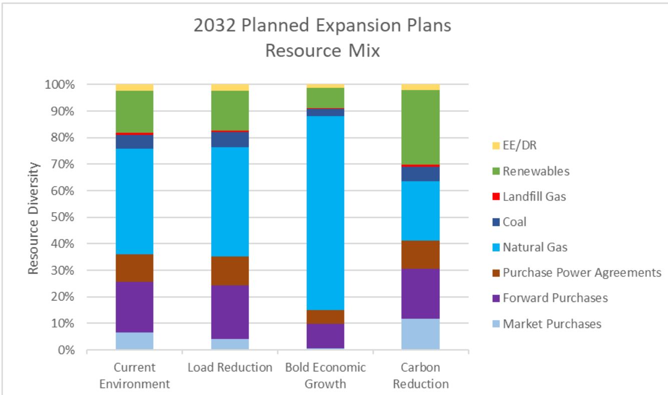
GRAPH 5-14 Affordability Comparisons

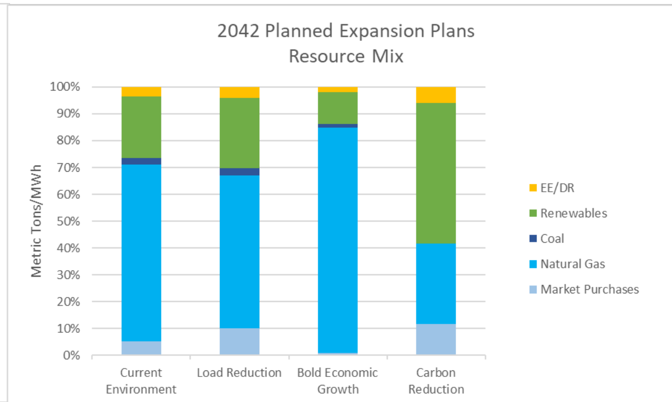


Resiliency

Resiliency is defined as the ability to adapt to changing conditions and withstand and rapidly recover from disruptions. WVPA considers maintaining a diverse resource mix as a way to support resiliency by not relying too heavily on one resource type. In this IRP, we measured resiliency through resource diversity for each expansion plan as shown in TABLE 5-15. The Bold Economic Resource Plan indicates the most dependency on natural gas while Preferred Resource Plan indicates the most balanced mix based on overall resource mix.

TABLE 5-15 Resiliency through Resource Diversity

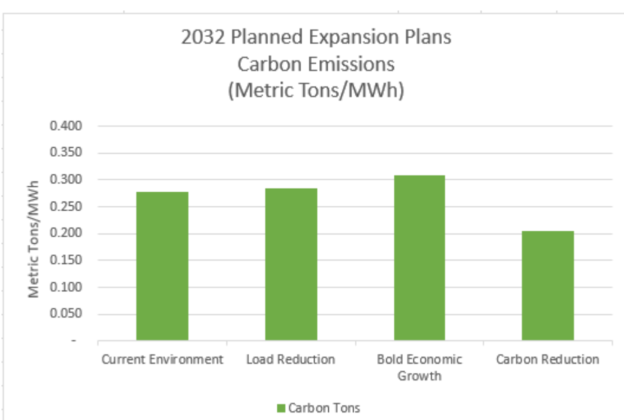


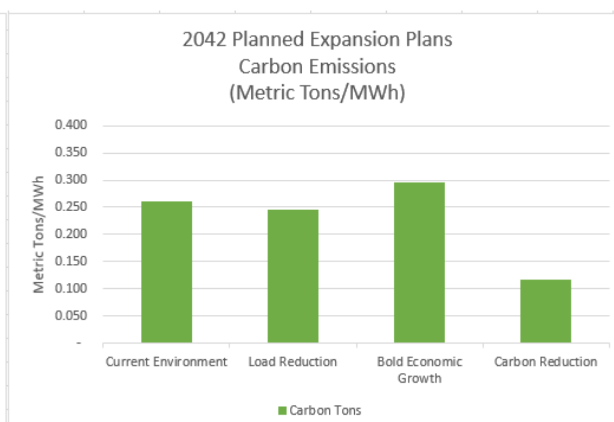


Environmental Sustainability

WVPA measured environmental sustainability in terms of CO_2 impacts to compare resource plans in this IRP. TABLE 5-16 depicts the CO_2 emissions in terms of metric tons per MWh for each of the four expansion plans.

TABLE 5-16 Sustainability through Emissions





The collective results of the five pillar metrics comprise the Scorecard in TABLE 5-17 below

TABLE 5-17 IRP Futures Scorecard

	Scorecard Results Across Potential Futures			
Attribute	Current Environment	Carbon Reduction	Load Reduction	Bold Economic Growth
Reliability & Stability	+	-	+	+++
Affordability	++	+	-	+++
Resiliency	++	+	++	-
Environmental Sustainability	+	+++	++	-

Scenario Modeling

The following discussion focuses on how the four defined expansion plans performed against various deterministic scenarios/sensitivities. The following are the six scenarios analyzed:

- Current Trends
- High Natural Gas Prices
- Low Natural Gas Prices
- High Load Growth
- Low Load Growth
- Carbon Regulation

Current Trends

The “Current Trends” scenario reflects WVPA’s view of the world based on the policies in place at the time of the IRP’s development with the following assumptions:

- Continued population and economic growth within our service territory consistent with trends as forecast by Woods and Poole;
- EV adoption that is still gaining momentum which has minimal impact on our overall load growth and shape;
- Future commodity pricing assumptions based on projections provided by Horizons Energy LLC (Horizons) that are intended to represent a probable outcome in energy, coal, gas and capacity markets; and
- No carbon price assumptions due to the lack of clarity at the time of the analysis.

High Natural Gas Prices

Our “High Natural Gas Prices” scenario uses Horizons High Natural Gas Scenario to adjust Energy and Natural Gas prices.

Low Natural Gas Prices

Our “Low Natural Gas Prices” scenario uses Horizons Low Natural Gas Scenario to adjust Energy and Natural Gas prices.

High Load Growth

Our “High Load Growth” Scenario assumes stronger development within our service territory driven by higher population and economic growth. In addition to strengthening our electric demands, we would expect a faster growing economy to support greater adoption of EVs.

Low Load Growth

Our “Low Load Growth” scenario assumes weaker development within our service territory driven by lower population and economic growth. Compared to the Bold Economic Growth future, we would expect weakening electric demands and no EV growth. We did include increased DG adoption to further reduce load.

Carbon Regulation

Our "Carbon Regulation" scenario mirrors our Carbon Reduction future. All coal is retired, and gas units are limited to 50% capacity factor after 2034. EE, DR. EV and DG adoption increases as well.

Graph 5-18 shows the assumption changes between the various scenarios/sensitivities.

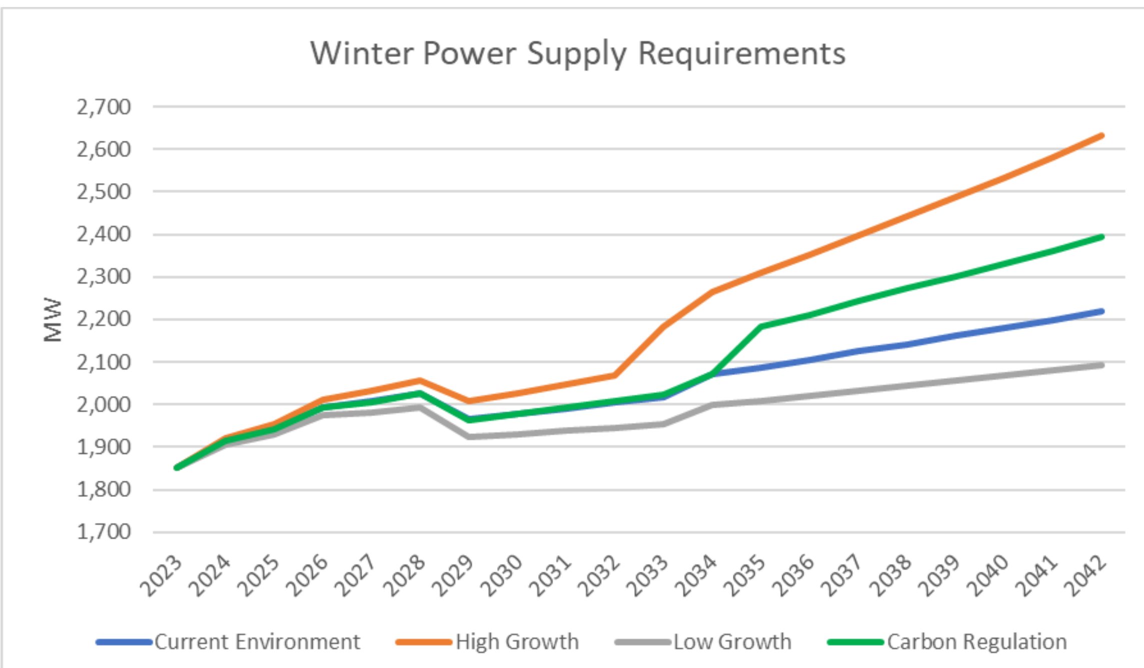
GRAPH 5-18 Winter Power Supply Requirements

Scenarios/Sensitivities						
Elements	**Current Trends**	**High Natural Gas Prices**	**Low Natural Gas Prices**	**High Load Growth**	**Low Load Growth**	**Carbon Regulation**
Load Forecast	PRS	PRS	PRS	High Growth	PRS	Mid Case
EV Adoption Load Forecast	Low Case	Low Case	Low Case	High Case	None	Mid Case
DG Adoption Forecast	None	None	None	None	Mid Case	Mid Case
Energy Price Forecast	Reference Case	High NG Prices Case	Low NG Prices Case	Reference Case	Reference Case	Zero Carbon Additions Case
EE/DR Forecast	Low Potential Savings	Low Potential Savings	Low Potential Savings	Low Potential Savings	Low Potential Savings	Mid Potential Savings
Gas Price Forecast	Reference Case	High NG Prices Case	Low NG Prices Case	Reference Case	Reference Case	Carbon Case

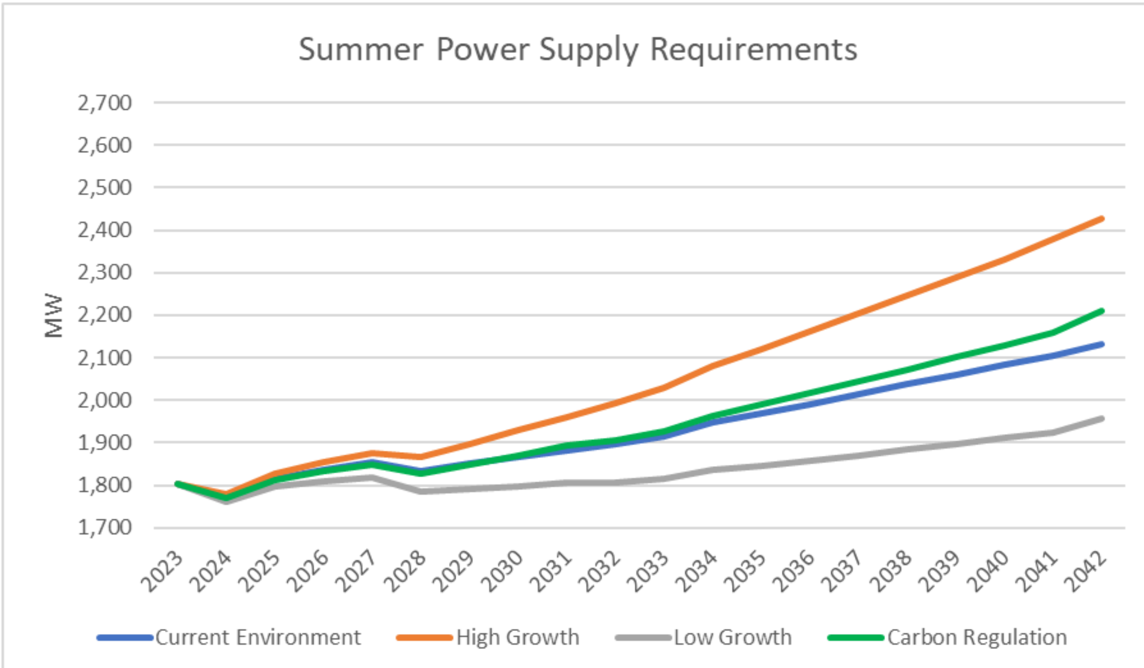
Coal Price Forecast	Reference Case	Reference Case	Reference Case	Reference Case	Reference Case	Reference Case
Capacity Price Forecast	Reference Case	Reference Case	Reference Case	Reference Case	Reference Case	Reference Case

Graph 5-19 and Graph 5-20 shows how total power supply requirements differ in each potential future for summer and winter. These differences are driven by alternative load forecasts as explained in Section 3 and in the scenario assumptions above.

GRAPH 5-19 Winter Power Supply Requirements



GRAPH 5-20 Summer Power Supply Requirements



Even though WVPA is a summer peaking entity, winter power supply requirements are greater due to the MISO planning reserve margin requirement (PRMR) for winter being greater than the PRMR for summer. Table 5-3 shows the seasonal PRMR percentages assumed for IRP purposes.

The decrease in 2028 is driven by the forecasted end of WVPA's wholesale firm requirements sale to one non-member Indiana customer. TABLE 5-21 shows how much higher or lower each scenario's winter power supply requirements are compared to the Current Trends at various points in the time horizon.

TABLE 5-21 Requirements % Variance

Alternate Scenarios	2027	2032	2037	2042
High Load	1.2%	3.2%	12.9%	18.7%
Low Load	-1.4%	-2.9%	-4.4%	-5.7%
Carbon Regulation	-0.2%	0.2%	5.5%	8.0%

Table 5-22 shows how commodity prices differ in each potential scenario. We depict how much higher or lower each scenario commodity prices are compared to the Current Trends at various points in the time horizon. Appendix C Market Price Assumptions displays these energy, natural gas, coal, and capacity market prices.

TABLE 5-22 Commodity Prices % Variance

Alternate Scenarios	Commodity	2027	2032	2037	2042
High Natural Gas	Energy 7x24	22.9%	22.1%	22.4%	23.8%
	Natural Gas	50.2%	47.1%	47.8%	48.6%
High Natural Gas	Energy 7x24	-29.0%	-29.7%	-34.1%	-43.2%
	Natural Gas	-50.2%	-47.1%	-47.8%	-48.6%
Carbon Regulation	Energy 7x24	-7.5%	-25.8%	-26.3%	-26.2%
	Natural Gas	1.2%	-1.4%	-3.0%	-5.7%

Scenario Results

This section will provide an analysis by scenario for the results depicted in the following table. TABLE 5-23 shows a levelized rate comparison in dollars per MWh by scenario across all four expansion plans. The best performing scenarios are highlighted in blue.

TABLE 5-23 Levelized Cost Comparison

	Potential Futures			
Scenarios	Current Environment	Carbon Reduction	Load Reduction	Bold Economic Growth
Current Trends	$86.4	$87.0	$86.4	$90.1
High Natural gas	$94.9	$93.8	$94.6	$100.6
Low Natural gas	$79.2	$81.8	$79.0	$83.5
High Load Growth	$85.3	$85.3	$85.5	$88.2
Low Load Growth	$88.3	$89.0	$88.0	$92.2
Carbon Regulation	$86.7	$85.8	$86.3	$93.5

Current Trends

The Current Environment and Load Reduction plans produce very similar results under the current trends scenario, but things look quite different when you take a closer look. The Current Environment plan has a considerably lower variable rate because it relies on its larger cheaper portfolio for energy while the Load Reduction plan relies on market purchases to make up for planning for load loss that never materialized. What the Load Reduction Plan saves in lower ownership and fixed costs it gives back in variable power costs. In this scenario, the economic difference is small, but the added risk of relying on an increasingly volatile power and capacity market is large. Just as the Load Reduction Plan counts on the spot market to purchase power, the Bold Economic Growth plan is counting on the market to sell generation it planned for large load increases that never came or left. Leaving the portfolio a thousand MWs long is mush risker than 150 MWs short. The Carbon Reduction plan is going to perform similarly to the Current Environment plan since gas generation only varied by 150 MWs, so it has the dispatchable generation to compete with Current Environment plan. The Carbon Reduction plan assumes lower costs for wind and solar due to technological improvements.

High Natural Gas Prices

The results of this sensitivity analysis were predictable. High natural gas prices drove up energy prices, but not to the extent that gas prices increased. Market implied heat rates decreased by on average 18% over reference case. The Current Environment and the Bold Economic Growth plans rely quite a bit on natural gas generation to supply their load. While market purchases did displace some natural gas generation, it did so at increased costs and left costly generating assets sitting idle. The Bold Economic Growth plan performed poorly again. This is a product of investing almost $3B in natural gas generation only to have operating costs greater than spot market energy to operate. The Carbon Reduction plan is the big winner here due to its greater reliance on renewable generation. The Load Reduction Plan also performed poorly due to its reliance on the spot market for a bigger portion of its energy needs. It did perform better than the Current Environment plan due to lower ownership and fixed costs.

Low Natural Gas Prices

Load Reduction plan as expected was the best performer because of its greater reliance on a soft energy market. Market implied heat rates increased by on average 30% over reference case. Because of this, all plans performed very well. The portfolios that rely on natural gas saw their generating costs go down as well as getting greater value from their owned assets and the Load Reduction plan benefited from lower market prices and lower fixed costs.

High Load Growth

Even though the Current Environment plan is the top performer in this sensitivity. There isn't much separation between Current Environment and Load Reduction. This is due to each plan being optimized for their particular load forecast. Above that load forecast, variable costs should be pretty similar. One small offset of larger load spreads fixed costs over more MWh. The Carbon Reduction plan is in a unique position of overbuilding generation to plan for restrictions on carbon emissions. This plan has plenty of natural gas generation to call on when loads increase if there are no new environmental constraints. Because of this, the Current Environment and Carbon Reduction plans perform evenly. As for the Bold Economic Plan, load growth was its purpose. It is still the worst performer due to its large, fixed costs, but you can see how changes in load or natural gas prices can have a profound effect on its performance.

Low Growth

All that was said about High Load Growth is just the opposite for Low Load Growth. Load Reduction Plan does outperform the Current Environment plan, but lower loads are what it was designed for. Its smaller portfolio allows it to meet the needs of its members without overly relying on the energy market and its lower fixed costs lead to lower levelized rates. The Bold Economic Plan was unable to take advantage of its large portfolio and was penalized by large fixed and ownership costs. The Carbon Reduction Plan was hurt by its large amount of non-dispatchable intermittent resources leading to large spot market sales at a loss when compared to the costs of the renewable purchase power agreements. The Current Environment plan proved to be flexible due to its design for base PRS load and large dependence on dispatchable natural gas resources.

Carbon Regulation

The Carbon Reduction Plan performed the best in the carbon regulation scenario. First off, one condition that has an impact on the results is the timing of the regulation only occurring in years 2035-2042. That said, the Current Environment and the Load Reduction plans performed well. The environment created by the carbon regulation made for a flood of no-variable-cost generation which drives down spot energy prices; something which is a benefit in the Load Reduction Plan. As for the Current Environment plan, it has an even mix of NGCC and renewable expansion capacity from an installed capacity perspective. This allows the gas units to dispatch up to 50% and count on the spot market, renewable generation and batteries to help make up for lost generation.

Scenario/Sensitivity Results Summary

In summary, all the plans have value under specific conditions. It is important to mention again that while the Load Reduction plan tends to be a competitive, that is due to its reliance on the spot energy market and this comes with a level of risk that WVPA wants to avoid. The Carbon Reduction plan was also a very good performer, but its risk comes from overbuilding its portfolio to serve its capacity need through NGCC and batteries and energy needs through solar and wind. This comes with a large amount of ownership cost and a large amount of intermittent energy. Overall, the Current Environment plan performed well under all sensitivities and is the Preferred plan in this IRP.

STOCHASTIC ANALYSIS

WVPA performed stochastic analyses to introduce a range of uncertainties to the deterministic results of each plan. The results provide a range of potential performance results to measure risks.

Stochastic Assumptions

Sensitivity analysis is an ongoing process at WVPA. Financial forecasts are generally updated quarterly to reflect changes in energy, coal, and natural gas market prices. We develop other sensitivities as needed to examine the potential impact of uncertainties due to Member load changes, plant outages, economic purchase and sales opportunities, resource availability and similar system planning functions.

Future Member energy requirements, energy, coal, natural gas and capacity market prices and environmental legislation are expected to have a significant impact on production costs. WVPA ran sensitivity analysis to examine the impact of several of these uncertainties.

1. Member Energy Requirements

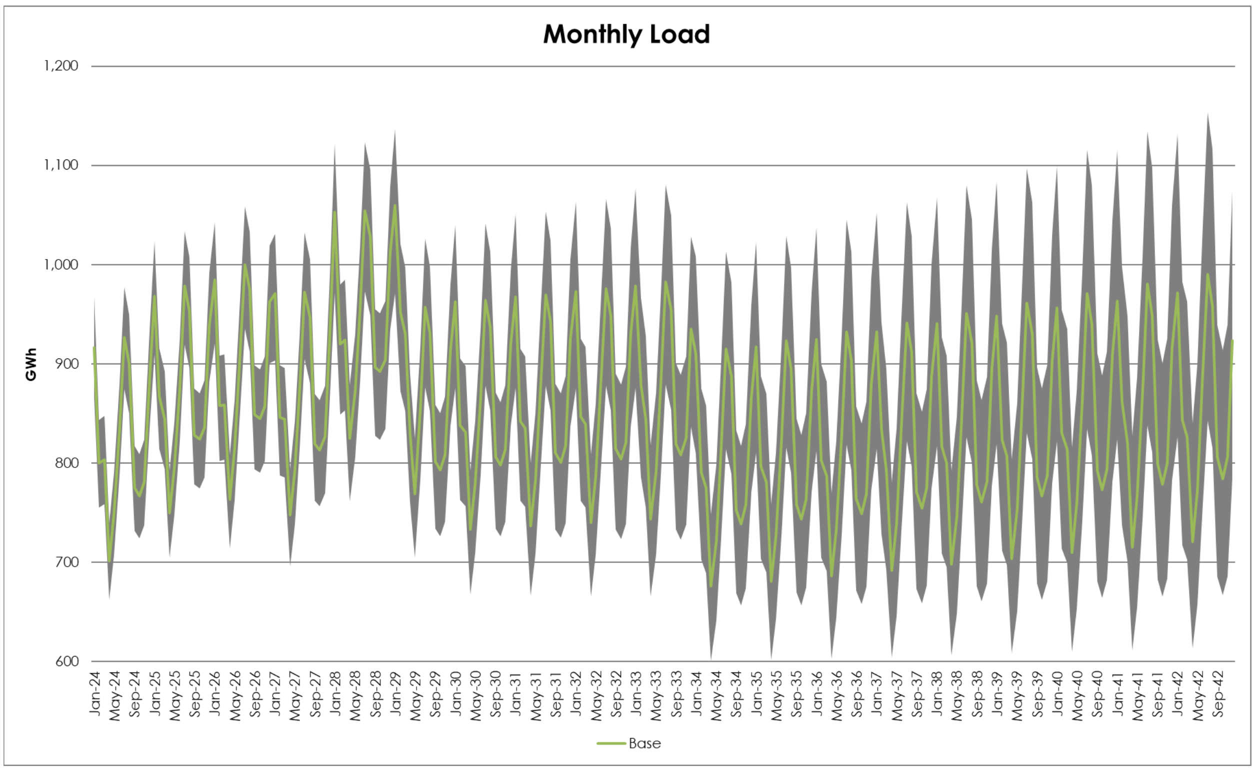
As discussed, Section 3 and earlier in this section, the 2023 Power Requirements Study produced a base case load forecast of Member consumption. WVPA also developed two alternative forecasts estimating load under high and low growth. We modeled and analyzed these alternative forecasts as part of the high and low growth futures. We also used them to set our boundaries for the stochastic load variables.

The base case load forecast only captures a modest amount of electric vehicle (EV) growth using the low forecast described in Appendix J (Long-Term DER Energy and Demand Forecast). The high growth forecast was developed by adjusting population, households, and GDP variables only. For stochastic modeling purposes, we felt it was important to capture a high level of EV growth; therefore, we used the high EV forecast described in Appendix J.

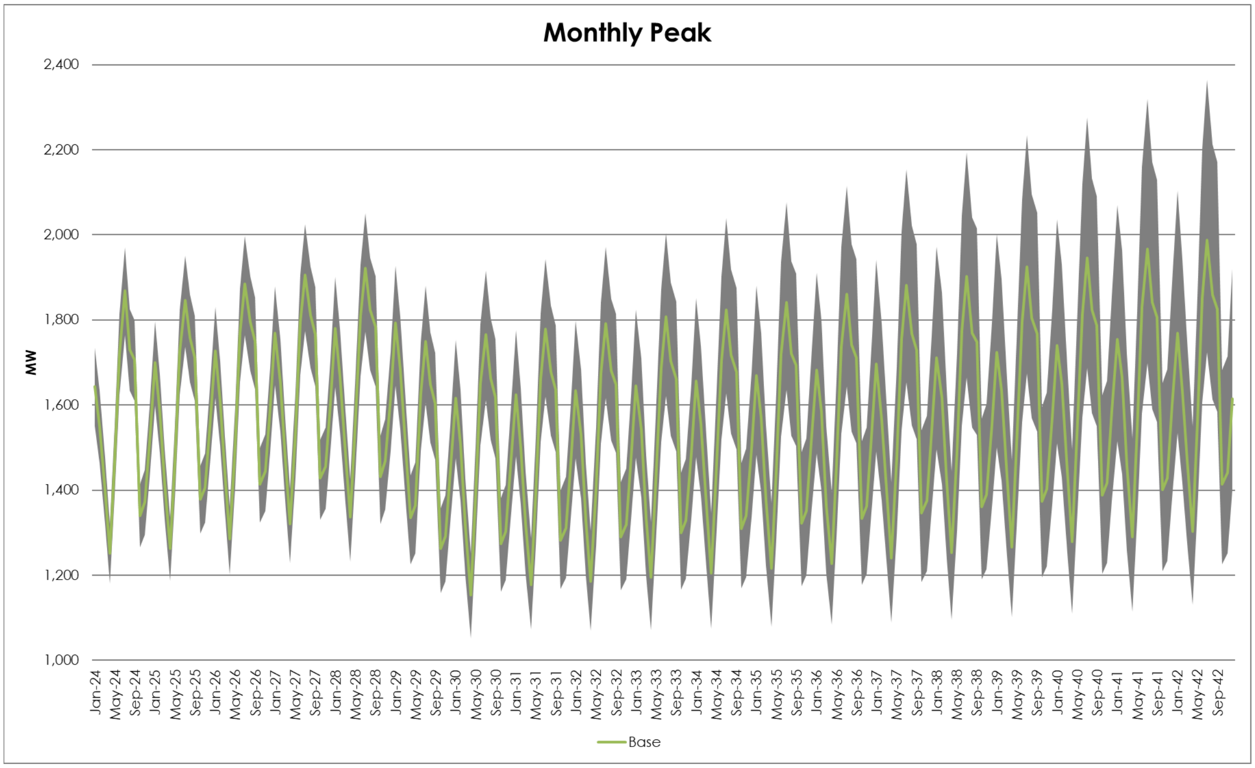
The high growth (including EV) energy and demand forecasts are 11.52% higher and 13.96% higher, respectively, than the base case forecast in 2042. The low growth energy and demand forecasts are 9.9% lower and 8.2% lower, respectively, than the base case forecast in 2042.

For stochastic modeling purposes, WVPA created a Member Load variable using the low growth forecast (including DG) as the floor and the high growth forecast (including EVs) as the ceiling. The resulting variable profile is reflected in terms of energy in GRAPH 5-24 and in terms of demand in GRAPH 5-25.

GRAPH 5-24 Monthly Load (GWh)



GRAPH 5-25 Monthly Peak (MW)



2. Market Prices

WVPA uses projections of energy, coal, natural gas, and bilateral capacity market prices in forecasting expected production costs. The PLEXOS® production cost model estimates the amount of energy purchased from the energy market based on unit dispatch limitations, the marginal cost of incremental supply from the Company's portfolio and the projected market price at the time of a proposed transaction. For this IRP, WVPA chose to limit market purchases to a maximum of 353 MWs from 2025-2028 then subsequently decreasing to 250 MWs due to the expiration of a non-member pass-through load sale. We added this limit in part because WVPA's Pass-Through customers have traditionally chosen to meet their energy requirements by entering into short-term forward contracts or purchasing on the spot market. Furthermore, we did not want to presume that higher volumes of spot energy would be available while planning to meet the long-term energy requirements of our Members.

WVPA projects natural gas prices, based on the forward price at the Henry Hub delivery node, for resources with fuel costs indexed to natural gas prices. All of our natural gas resources and the natural gas portion of our cost-based purchase power agreements are indexed to natural gas forward price projections.

WVPA also projects coal prices, based on the spot market in the Illinois Basin, for resources with fuel costs that are either coal-fired or fuel costs that have a relationship to the fluctuation in coal prices. The Company owns a share of three coal-fired units, Gibson Unit 5, and Prairie State Units 1 and 2. Prairie State includes an on-site captive coal mine and is not subject to the price volatility of Illinois Basin coal. However, the unhedged coal related to Gibson Unit 5 and the cost-based purchase power agreements are indexed to Illinois Basin forward cost projections through 2032.

Recent history can attest to the broadening volatility of energy, natural gas and coal market prices. Long-range market price forecasts provided by ACES and other forecasting sources suggest relatively flat energy market prices through 2042. WVPA is active in the energy market as both a seller and buyer. Therefore, the Company considers it prudent to assess scenarios where market prices not only decrease from the current forecasted levels but also increase.

WVPA reviewed the volatility of historical forward-looking price curves used in long-term forecasts over the previous thirteen years. We analyzed period-over-period growth in the individual forecasts. Therefore, year one volatility is significantly lower than year twenty volatility. We then applied this analysis to our base case market price assumptions. Due to the extreme volatility of the curves, we constrained our high price calculations to two standard deviations of the mean and our low-price calculations to one standard deviation of the mean.

For capacity price stochastic modeling, WVPA created a variable that used the 2023/2024 MISO Planning Reserve Action (PRA) zone 6 price averaged across all seasons of $9.25/MW-day escalating by 2.5% as the floor and the 2024 MISO CONE zone 6 value of $120,340/MW-year escalating by 2.5% as the ceiling.

WVPA's Market Price stochastic variables are defined as follows:

- Energy Prices: High Prices range from +17% in 2024 to +101% in 2042. Low Prices range from -8% in 2024 to -51% in 2042.
- Natural Gas: High Prices range from +22% in 2024 to +64% in 2042. Low Prices range from -11% in 2024 to -33% in 2042.
- Coal Prices: High Prices range from +26% in 2024 to +103% in 2044. Low Prices range from -13% in 2024 to -52% in 2042.
- Capacity Prices: High Prices range from +7% in 2024 to +13% in 2042. Low Prices range from -97% in 2024 to -97% in 2042.

The resulting variable profiles are reflected in Graph 5-26, Graph 5-27, Graph 5-28 and Graph 5-29.

GRAPH 5-26 7x24 Energy Price

[redacted]

GRAPH 5-27 Coal Price

[redacted]

GRAPH 5-28 Natural Gas Price

[redacted]

GRAPH 5-29 Capacity Price

[redacted]

Stochastic Results

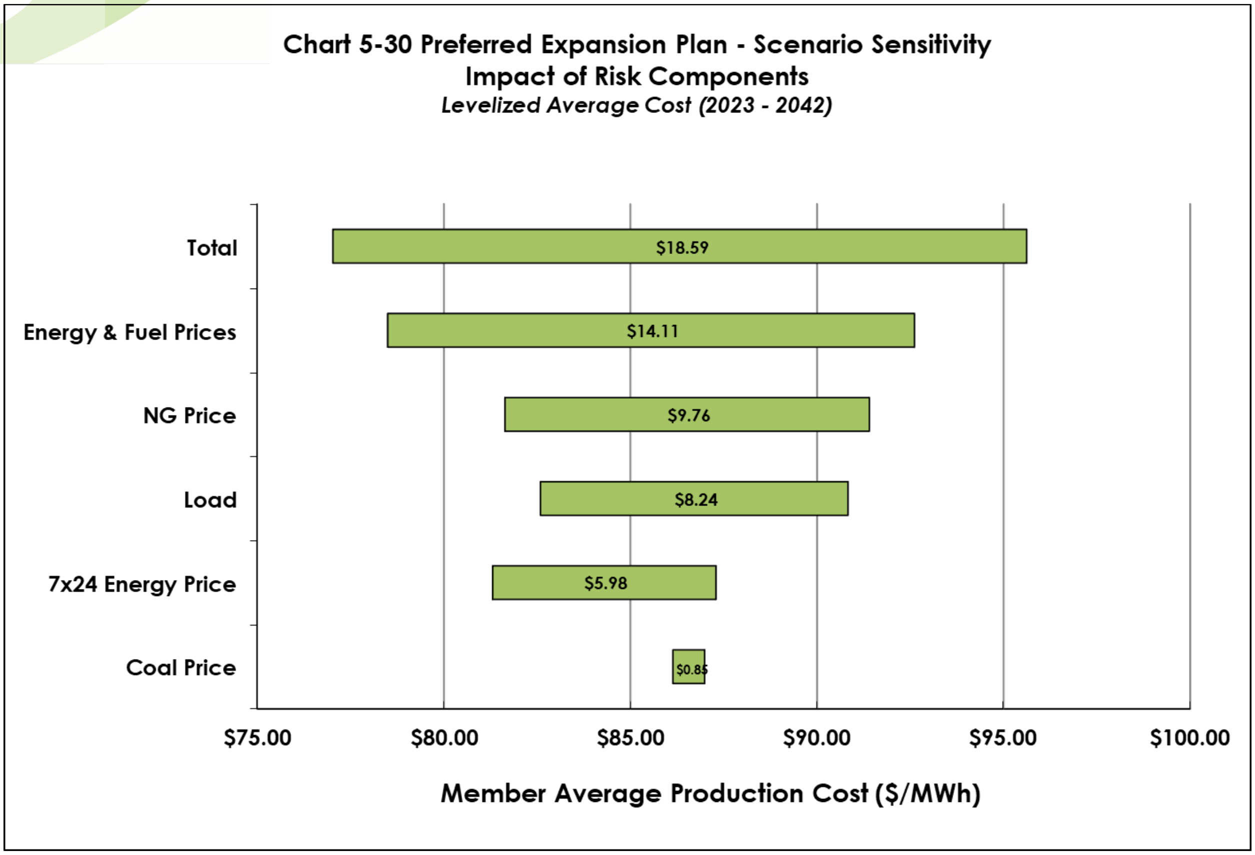
The following discussion provides a summary of the impact of the stochastic variables on the four expansion plans. Please note that all of the costs reflected in the charts are 20-year levelized costs.

Within the next decade WVPA's portfolio will change dramatically. With expected plant retirements and contract expirations, WVPA will lose over 600 MWs of baseload generation. WVPA views this as an opportunity instead of a challenge. The electric industry is facing challenges from regulatory and societal pressures and an aging resource fleet, WVPA has been planning for these issues through incremental changes in our portfolio.

1. Preferred Expansion Plan

We executed the preferred expansion plan against the stochastic variables defined earlier. Chart 5-30 shows the impact of the various risk components. The largest individual risk component is natural gas price volatility. There is little surprise here. Expansion modeling starts adding natural gas combined cycles by 2025 and NG accounts for 60% of total owned and contracted generation by 2034. Since natural gas is by far the greatest fuel source in this expansion plan and natural gas is 0% hedged beyond the first few years, it makes sense that this would drive volatility the most. Market energy price volatility also had a large impact on levelized cost. We based our stochastic samples on the historical forward-looking price curves used in long-term forecasts over the previous ten years. Over that time frame, the natural gas, coal, and spot energy markets have experienced dramatic price changes.

Comparing this IRP to past submissions is difficult due to evolving modeling practices as well as reexamination and broadening of stochastic variables. These changes help to enhance the accuracy and overall measurement of risk. While comparison is challenging, some changes in risk are intuitive due to portfolio changes.



An analysis of WVPA's six separate risk variables follows:

- **Capacity Price** – Capacity price has been a minor risk component in the past and in the 2023 IRP shows no substantial volatility in stochastic modeling. The driver of this is that WVPA prepares our IRP with the idea that we will build or procure almost all our capacity needs. Moreover, we do not allow the model to sell capacity (or energy) in the spot market to eliminate building based on speculation as opposed to minimizing risk. Another change to the 2023 model was the aspect of Seasonal Accredited Capacity (SAC). In past IRPs, capacity needs were purchased to meet UCAP needs for annual power requirements. This led to an annual capacity purchase. Because of seasonal power requirements and seasonal capacity values, WVPA allowed for intermittent capacity purchases for as little as a month. For the most part, this led to capacity being purchased for only a month or two in the winter. This is an oversimplification of the impact, but in the 2020 IRP's base plan showed a capacity volatility of $0.21. If you divide that by 12, you get $0.02. Therefore, we removed capacity from the tornado charts. Future IRPs might need to rethink the approach. By then we will have more history with the capacity market under SAC rules.

- **Coal Price** – Coal generation has historically supplied a large portion of WVPA's needs either through ownership or cost based PPAs. With the forecasted retirement of Gibson Unit 5 and expiration of our cost based PPAs, WVPA's exposure to coal will be limited to Prairie State after 2032. Prairie State's coal has very little price volatility due to the on-site captive coal mine. Furthermore, AEP plans to retire coal units and replace them with renewable energy as soon as 2028 which further limits our exposure to coal.

- **Energy Price** – As with capacity, WVPA prepares our IRP with the idea that we will build or procure almost all our energy needs and not sell excess energy into the spot market. Again, this is to eliminate building based on speculation as opposed to minimizing risk. As referenced earlier, we do allow a portion of our pass-through loads' energy needs to be purchased in the market. While model economics leads to substantially less market purchases than allowed, we currently project around 2,500 GWhs of annual pass-through loads energy needs (including one non-member) in 2026. Therefore, WVPA still displays some risk in the energy market. One change to stochastic modeling this year is that WVPA allowed the spot market to be fully utilized for both purchase and sales. This was not the case in expansion modeling, but we felt it was the best way to properly measure plans that overbuild energy resources like the bold economic growth plan and carbon reduction plan against the preferred plan and load loss plan.

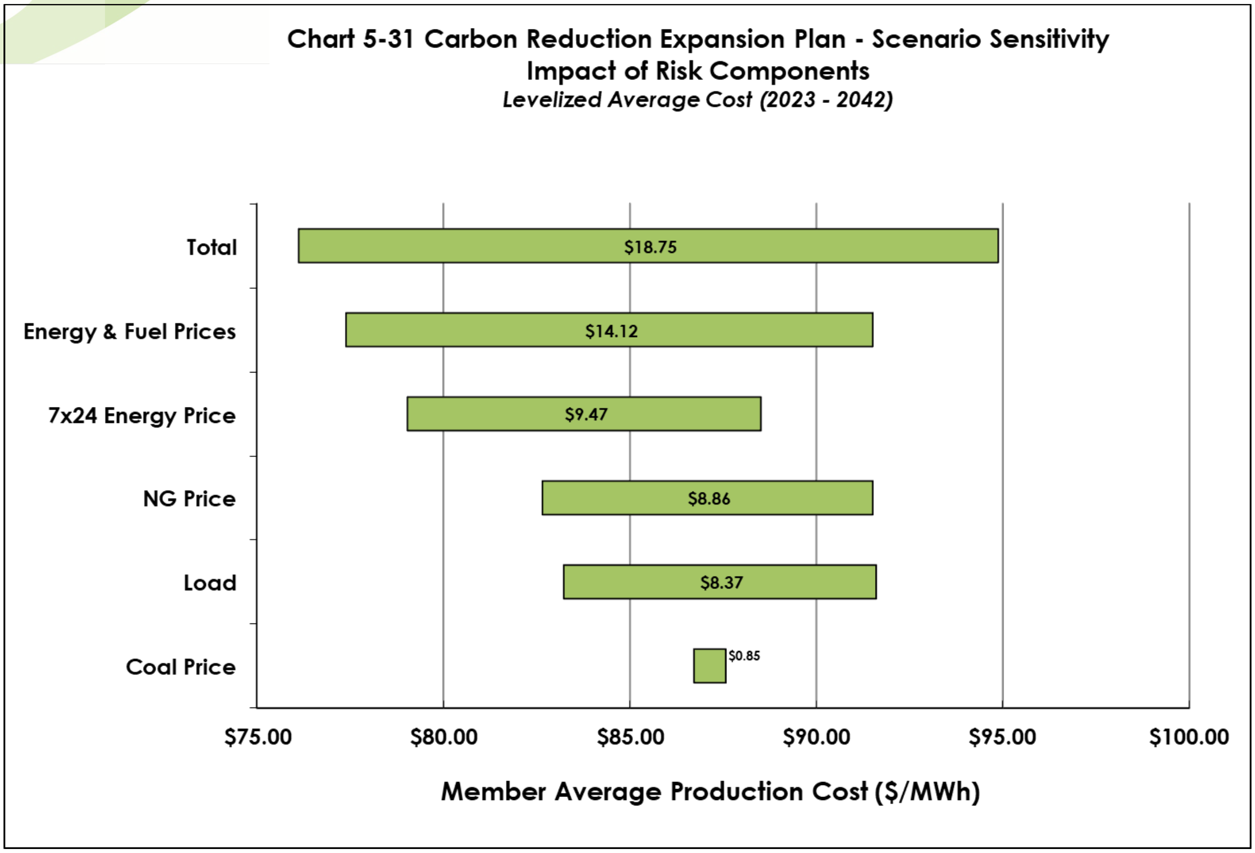
- **Member Load** – This risk has grown over past IRPs, but this is mostly due to changes in defining the stochastic variables. We not only broadened our alternative growth assumptions, but we chose to include the aggressive EV growth as part of the ceiling and aggressive DR as part of the floor. Still, load variance is a significant risk to WVPA as we will need to replace a large quantity of generation and capacity in the next decade due to plant retirements and contract expirations. Earlier, we referenced limiting market purchases in previous IRP and expansion modeling; but that limitation is turned off for stochastic modeling here because at higher loads WVPA's preferred expansion plan and load loss plan do not meet the capacity and energy needs of our Members.

- **Natural Gas Price** – As our exposure to coal declines, we might assume that our exposure to natural gas would increase. While WVPA continues to have significant exposure to natural gas, this IRP continues to add renewable generation and supply side resources as alternatives to fossil fuel generation to our preferred expansion plan. Even though natural gas resources contribute to our projected future, a very large part of our expiring generation is now replaced with renewable[i] energy and battery capacity.

- **Carbon Tax** – WVPA's believes that any carbon regulation in the future will center around emission or capacity factor limitations instead of a tax. A carbon stochastic was not performed in this IRP, but one will be included in future IRPs more than likely centering around forced retirements and fossil fuel limitations rather than carbon capture or fuel switching.

2. Carbon Reduction Expansion Plan

We executed the carbon reduction expansion plan against the stochastic variables defined earlier. Chart 5-31 shows the impact of the various risk components. The main difference between the carbon reduction expansion plan and the preferred expansion plan is the addition of 1,200 MWs more of renewable PPAs. The main assumption in developing this plan was coal retirement and the 50% capacity factor limitation after 2034. As mentioned earlier in this section, this plan solved its capacity needs similar to the preferred plan but solved its energy needs through renewables. Given that carbon variables were left out of the stochastic analysis, this plan performs well.



The overall direction of the results shown in Chart 5-31 are as expected, but the magnitude of the change is quite a bit less than expected. This was driven primarily by our practice of capping market purchases and sales prior to stochastic analysis. A summary of the changes between the base and alternate plans follows:

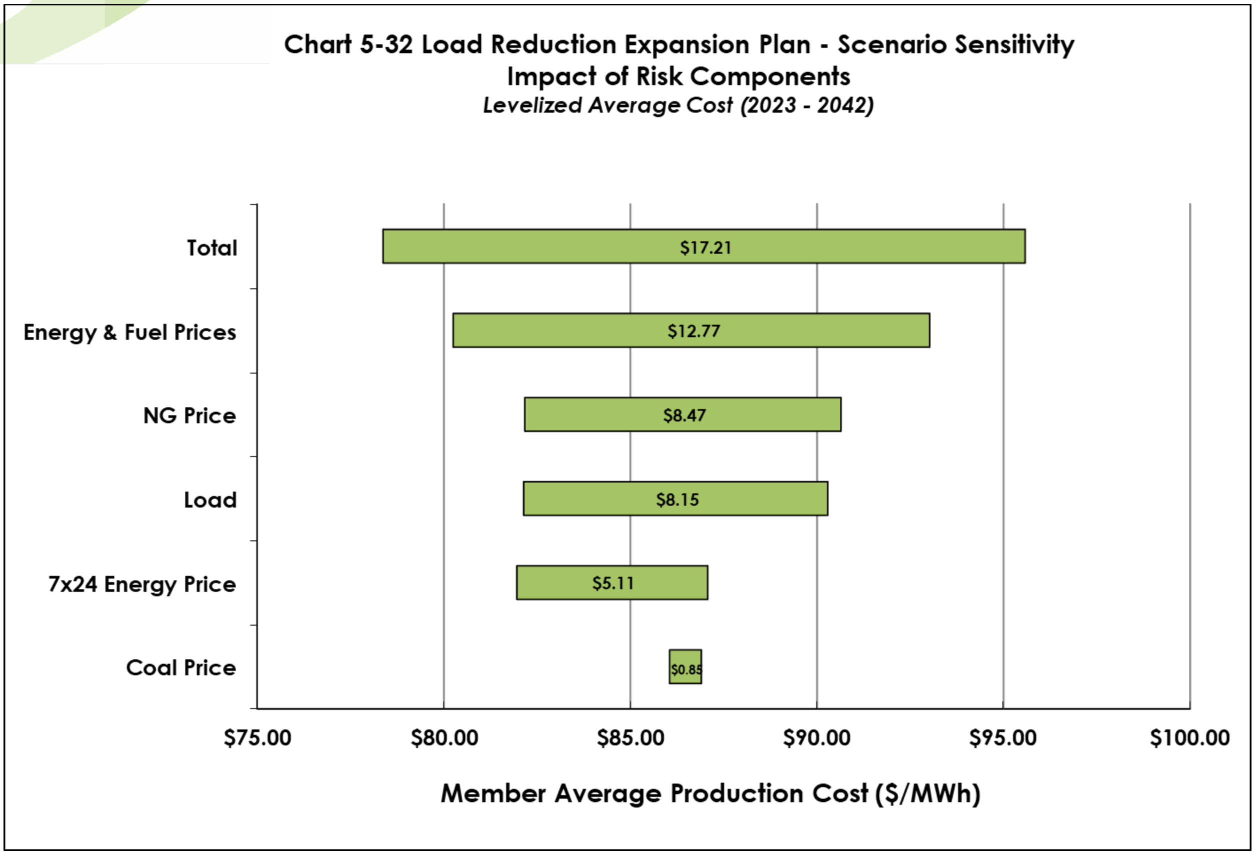
- Energy Prices – This risk proves to be the largest influencing factor. This is due to the portfolios large combined cycle fleet that was built primarily for capacity, but dispatched by energy and gas prices. This means a range of energy prices combined with a steady gas price leads to a wide range of generation and profit margins even with a high correlation between energy and gas prices.

- Fuel Prices – As mentioned in the energy price section, even though this plan was built around renewables, it has a lot of gas sitting on the sideline. Since the spot market is available for stochastics, natural gas prices are a fairly big risk. Coal is minimal due to a retiring fleet.

- Member Load – This risk proves to be the smallest. This is largely due to the large amount of non-dispatchable intermittent resources, and the plan was built on higher loads due to higher electric vehicle adaption. Because of the non-dispatchable resources, costs don't change much from the mean. Because the plan was built on higher load assumptions, there is already a step toward meeting loads on the high side.

3. Load Reduction Expansion Plan

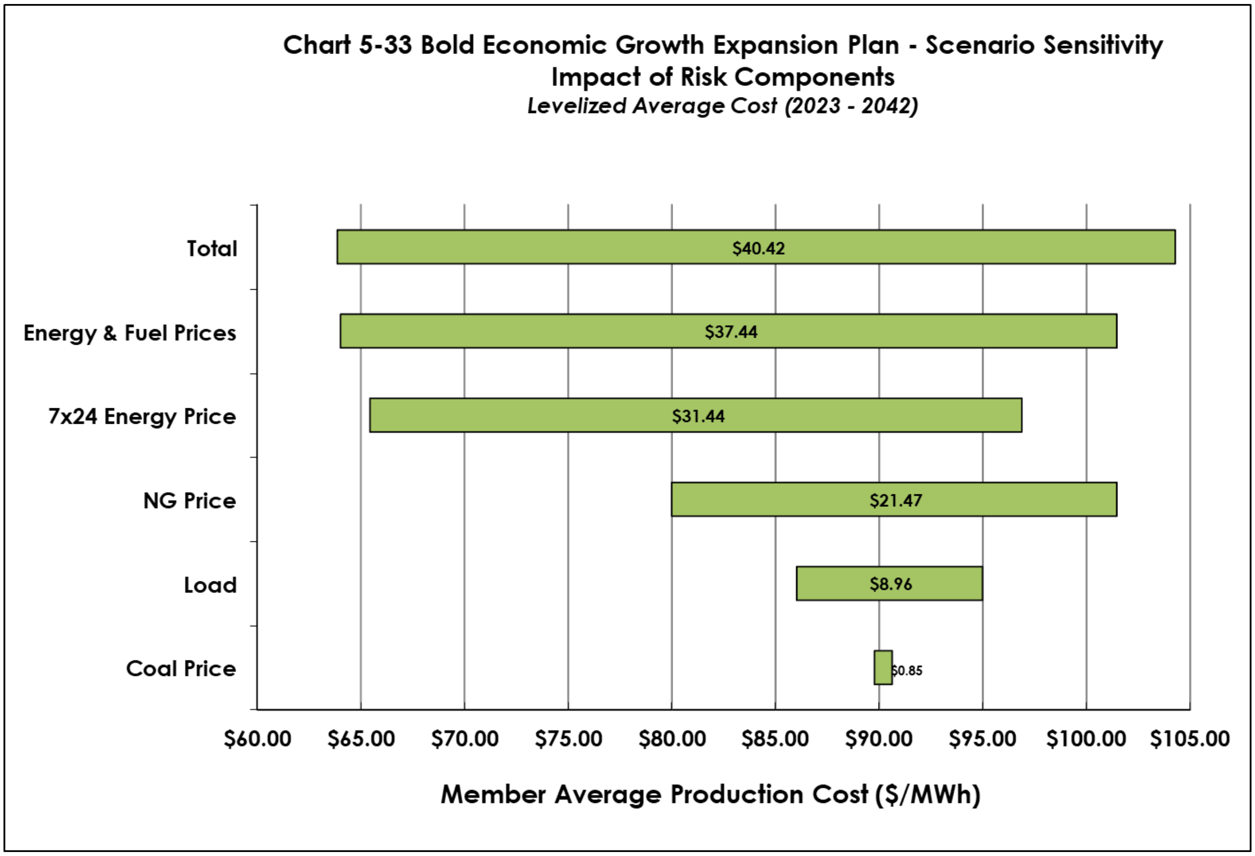
We executed the load loss expansion plan against the stochastic variables defined earlier. Chart 5-32 shows the impact of the various risk components. Over the 20-year forecast, the only difference between the load loss expansion plan and the preferred expansion plan is the subtraction of 250 MWs of NGCC. The main assumption in developing this plan was the loss of 150 MW load in 2030.



The overall direction of the results shown in Chart 5-33 are somewhat surprising. WVPA expected that less owned generation and more reliance on the market would increase risk. What this shows is decreased overall risk. The Load Reduction plan has similar renewable generation as the Preferred plan, and it basically replaced a combined cycle with market purchases. After looking into this rather deeply, WVPA concludes that the correlation between load and energy prices is greater than the correlation between load and natural gas prices. Since load swings are more than likely served through market purchases, the correlation between the two somewhat minimized the impact. . Lower ownership costs also help narrow the impact of load changes because less costs are spread among the varying member sales. In future IRPs, it might help to widen some of the bands or perhaps include correlation in the variables to fully access risk.

4. Bold Economic Growth Expansion Plan

We executed the bold economic growth expansion plan against the stochastic variables defined earlier. Chart 5-33 shows the impact of the various risk components. The only difference between the bold economic growth expansion plan and the preferred expansion plan is the addition of 1,400 MWs more of combined cycle generation. The main assumption in developing this plan was to plan for an additional 1,000 MWs and 8,300 GWh of annual energy requirements (half in 2028 and half in 2032). Our stochastic load variables are based mostly on adjusting economic growth variables, so the highest point is still well below the capacity of this portfolio. That is the point of this analysis. What is the impact if you plan for large industrial load additions that never materialize or come and go?



The overall direction of the results shown in Chart 5-33 are as expected. A summary of the changes between the base and alternate plans follows:

- Energy Prices – This risk proves to be the largest with good reason. Regardless of the sample of load, this portfolio is going to be very dependent on the market to recover stranded costs. In practice, this will be handled through firm sales which will eliminate some risk, but the graph indicates the level of risk.

- Fuel Prices – With 228% of the NGCC as the preferred expansion plan, you'd expect risk to be around $22.25/MWh. It comes in at $21.47/MWh, so the same reasons that apply to the preferred plan apply here as well. Coal is minimal due to a retiring fleet.

- Member Load – This risk proves to be the smallest. The risk of load is in line with the other plans, and a little higher due to fixed costs. However, it gets lost in the magnitude of the other variables.

Conclusions

The objective of WVPA's IRP is to develop a resource portfolio that minimizes the long-term cost of providing service to our Members while delivering that service at levels consistent with prudent utility practice and acceptable risk levels.

While the Company may consider sole ownership of a generation asset, it is more likely that we will participate in a joint ownership project or enter into a long-term power purchase agreement in order to diversify our portfolio while taking advantage of economies of scale. Because of this, the models in this IRP are designed to look at different fuel options and ownership/PPA options along with energy efficiency and demand response alternatives while limiting participation in RTO capacity markets.

Aside from incremental capacity market purchases, EE and DR, the model chose natural gas combined cycle, solar, and battery owned and PPA resources to meet energy and capacity needs. Wind PPAs were only chosen in the carbon reduction plan. Assuming the cost of renewable[i] energy continues to decline, wind and solar resources will serve as viable energy options while batteries will help meet capacity under the new seasonal accredited capacity rules, especially in a potential future with carbon regulation.

All plans have value under the right conditions. While the Load Reduction plan tends to be competitive, it is due to its reliance on the spot energy market. The Carbon Reduction plan performed well but includes the risk of overbuilding the portfolio to serve the needed capacity through NGCC and batteries to adhere to the MISO seasonal capacity construct and is reliant on the energy market for much of its value. This plan also includes a significant amount of ownership costs and large volumes of intermittent energy. Other risks (such as credit risk) exist that are not quantified in the stochastic analysis, Overall, the Current Environment plan performed well under all sensitivities and is the preferred plan by WVPA.

Short-term Action Plan

WVPA has made substantial progress towards the activities outlined in our 2020 IRP short-term action plan.

- The PPA contract for 199 MW of solar power from Speedway Solar, located in Shelby County, Indiana, was terminated due to force majeure conditions in 2022. The developer cited extreme cost increases that prohibited the expected construction and COD in 2024.
- WVPA worked with our joint owners to extend the retirement of Gibson Unit 5 from 2026 to 2029.
- WVPA coordinated residential and C&I EE and DR programs and worked to increase Member participation in these programs.
- WVPA completed DER and EV pilot programs, improved DG tracking and considered new technologies and business models for future programs.
- WVPA and its Members prepared letters of interest for federal funding to provide cost effective renewable[i] energy.
- WVPA incorporated changes due to the RTO's resource adequacy constructs including seasonal requirements and resource accreditation into it risk mitigation efforts and long-term planning.
- To continually improve reliability, investments were made in upgrades and additions to WVPA's transmission system. The Company maintained its investment position within the JTS.

- WVPA managed its resources to meet its capacity and reliability requirements of MISO, PJM and NERC.
- WVPA monitored developments surrounding the carbon emission pollution standards for new, modified, reconstructed and existing electric utility generating units and other environmental legislation. The Company incorporated knowledge at this time into the current IRP.
- WVPA continues to seek alliances, partnerships, and opportunities for joint operations with other electric utilities. These activities may include participation in new or existing power production facilities and combined system planning. The Company anticipates that these strategies have the potential to produce lower costs and mitigate risks.

Major activities in the next three years include:

- WVPA will continue to coordinate various residential and C&I EE and DR programs and work to increase Member participation in these programs.
- WVPA will monitor the changing energy landscape and adjust to incorporate changes to the RTO's resource adequacy constructs including system attribute enhancements.
- To continually improve reliability, expenditures will be made in upgrades or additions to WVPA's transmission system. The Company also plans to maintain its investment position within the JTS.
- WVPA will manage its resources to meet its capacity and reliability requirements of MISO, PJM, and NERC.
- WVPA will monitor developments surrounding the carbon emission pollution standards for new, modified, reconstructed and existing electric utility generating units and other environmental legislation. The Company expects to take the necessary steps to meet requirements and manage the cost impacts for the Members.

- WVPA may seek alliances, partnerships, and opportunities for joint operations with other electric utilities. These activities may include participation in new or existing power production facilities and combined system planning. The Company anticipates that these strategies have the potential to produce lower costs and mitigate risks.

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[i] WVPA supports renewable energy by owning landfill gas and solar generation and purchasing the output from wind, solar and biogas facilities. WVPA sells, separately, the environmental attributes associated with this generation to third parties, and therefore does not claim the generation as renewable within our own supply portfolio.