February 2026 Board Highlights

Pre-Board meeting: The Board met on Tuesday to hear more about building generation, toured the Domino and Lilly sites in the LEAP district and had dinner at Dull's Tree Farm, where they discussed a Rate Stability Fund.

CEO Opening Comments: Jeff Conrad acknowledged the collective relief of having Winter Storm Fern behind the organization and noted that the upcoming presentation from Kyle and Cordell—including Cordell's first time addressing the Board—would provide a candid, emotional play-by-play of how the event unfolded. He emphasized the team's dedication throughout the storm while minimizing risk and maximizing value for members. Jeff updated the Board on several ongoing strategic initiatives, beginning with the new transmission joint venture. He noted that agreement drafting is nearing completion, with a target of finalizing documents by next Wednesday, and emphasized that early courtesy notifications to Duke and AES were well-received and revealed no concerns about upcoming regulatory filings. He also addressed a topic raised in the previous meeting's Q&A regarding the Joint Transmission System (JTS), explaining that while IMPA appears hesitant, Duke signaled openness to exploring options should Wabash wish to exit the JTS in the future. Jeff stressed that any evaluation would begin internally—first through the transmission committee—because leaving the JTS would require careful consideration of both transmission and downstream distribution implications. He added that CEOs in Duke-served territories would be welcome participants in these discussions.

Co-op Connection: Noble REMC was featured this month. A video about Director Doug Burnworth was presented and CEO Brad McCrea shared more about the cooperative.

Winter Storm Fern: Vicki Duncan Gardner, Kara Baker, Cordell Miller and Kyle Tierney provided a look back at Winter Storm Fern (January 24th), emphasizing how both operational performance and communications challenges converged during the event. Vicki opened by framing the storm as not only a power-supply challenge but a true communications crisis, describing how unexpected MISO actions, inconsistent messaging, and rapidly shifting conditions strained established crisis-management principles of empathy, consistency, timeliness, and accuracy. Kara then walked through the communications timeline, explaining how early-morning Max Gen alerts, conflicting guidance from MISO, and multiple reversals on public-appeal needs created confusion for co-ops and communicators despite following the emergency manual as designed. Kyle and Cordell provided a deep operational breakdown of how the team prepared for extreme cold—including financial hedging, additional winter capacity, weather derivatives, and detailed plant-level winterization—and how a series of delayed MISO awards, unexpected RAC (reliability assessment commitment) instructions, and gas-day/power-day misalignment drove costly, time-compressed decisions. They detailed the Holland plant's experience, including strict NGPL pipeline Operation Flow Orders (OFO) rules that forced the purchase of two days of gas at high intraday prices, MISO's late cancellation of the commitment, and subsequent efforts to recover value through sales, additional RAC commitments, and make-whole payments. The team explained that despite sitting on $18M of gas at one point, coordinated actions across Wabash, Hoosier, Tenaska, and plant operators resulted in near break-even financial outcomes. Highland's experience, though impacted by OFOs, was more manageable due to more flexible pipeline conditions. They also highlighted strong performance from St. Joe and the coal fleet, which provided stability throughout the event. Key takeaways include: planning worked, but the storm exposed structural market flaws—particularly around RAC processes, MISO communications, and misaligned gas- and power-day timelines—that must be addressed at the procedural and regulatory level. Wabash and Hoosier are jointly pursuing follow-up conversations with MISO and gathering broader industry support to advocate for changes. Overall, the team emphasized a renewed commitment to strengthening crisis communications, refining operational strategy, and pushing for long-overdue market reforms.

DSR Committee: Lauren Schuettler presented an overview of the current demand response (DR) portfolio and the committee's recommended redesign of the DR program to strengthen performance, align incentives with actual grid value, and modernize the tariff. She began by outlining existing residential and C&I participation levels and historical activation patterns in MISO and PJM, noting that event lead times and operational expectations have varied significantly—highlighting the need for a more responsive, performance-based framework.

The recommended new Grid Emergency Program replaces the previous nameplate-based credit structure with performance-based incentives, shifting from a flat $6.67/kW-month payment to a seasonal credit—$7/kW-month in summer and winter and $2.50/kW-month in spring and fall—designed around updated cost and benefit modeling. A major policy shift eliminates the longstanding load add-back, meaning co-ops will now retain the avoided-cost benefit when members curtail during events. Program triggers will expand beyond market-declared emergencies to include price-based emergency thresholds, enabling more timely and economically aligned dispatch.

Testing requirements are standardized across residential and C&I resources, with one test per season, a two-week testing-window notice, day-ahead notification, and a two-hour advance alert. Resources must demonstrate 80% performance against a usable rating, initially set at 60% of nameplate for year one until real test data refines those values. Lauren provided examples illustrating how seasonal incentives and event-based energy payments (at $1,000/MWh) will combine to determine total compensation for various resource types.

She concluded with two forward-looking items:

1. The full tariff update is in development, with a Board resolution planned for next month to adopt the new credit structure beginning June 1.
2. A request from Hendricks Power will require Board approval for an exception to its DER carve-out limit to serve a new 3.4 MW solar-paired data-center equipment manufacturer in its territory.

Financial Report: Jackie Perius reported that the month of December ended $1.3 million under collected resulting in a $5.4 million unfavorable variance to budget. In December, energy sales were 5.3% above budget while demand was 0.4% above budget. 2025 ended at $8 million over collected (unaudited).

SDI Assets Sale: Chris Daniels briefed the Board on the future of Wabash Valley's long-standing relationship with SDI (Steel Dynamics Inc.), a 200-MW industrial load in Columbia City that Wabash has continued to serve even after Northeastern REMC exited membership. The current power-supply agreement with SDI ends in April 2028, and based on recent discussions with SDI and Northeastern, Wabash does not expect the contract to be renewed. Because Wabash still owns several transmission assets supporting SDI—including the Meridian 345-kV substation, a 10-mile 345-kV radial line, and protection equipment at SDI's plant—Chris explained that Wabash's strong preference is to divest these facilities rather than continue operating and maintaining them outside of member territory. Northeastern has expressed interest in acquiring the assets.

Wabash proposes selling the assets to Northeastern at book value (~$5 million). Although SDI's original contract gives them rights to any sale proceeds—because they funded the facilities through a 20-year facility charge—SDI has indicated they are willing to waive that right, allowing Wabash to retain the proceeds and avoid writing off the remaining asset value. Chris noted that selling the facilities will not reduce Wabash's transmission revenue, because the assets already generate no margin under FERC rules due to SDI's prior payment structure.

Next steps include securing SDI's formal waiver, finalizing agreements with Northeastern, and assigning or terminating related AEP TOP and emergency-maintenance agreements. Chris anticipates the transaction could be ready for Board authorization within one to two months.

Economic Development: Rachel Huser shared information on the rapid growth and shifting landscape of data center development, emphasizing how dramatically the volume and nature of large-load inquiries changed in 2025. WVPA received nearly 200 total leads, including 55 large-load requests—48 of which were data-center related—with only four coming from enterprise end-users and the remainder from developers. She explained that while WVPA's current large-load process works well for enterprise projects (where the end-user executes the ESA and credit review is straightforward), it is not structured to support sophisticated data-center developers, who often handle site design, permitting, and infrastructure development before an end user (e.g., Meta, Google, AWS) steps in.

Because developers typically cannot meet WVPA's A-minus credit threshold—and often will not be the party signing the ESA—they struggle to advance under the current process. At the same time, they request more detailed engineering and transmission information than the process allows prior to credit approval, creating a growing "expectation vs. deliverability gap" and heavy workloads for WVPA staff and member co-ops.

Rachel outlined two potential paths forward: Decline to engage with non-enterprise developers or continue working with qualified developers by creating a separate, fee-based development track.

Rachel recommended the second option including establishing clearer requirements and a cost-recovery structure to ensure WVPA's time and resources are protected while still pursuing high-value opportunities. Under this option, developers who will not execute the ESA would pay the existing $50,000 application fee, and—if advancing—an additional $200,000 development fee based on Indiana-market study benchmarks. WVPA would only proceed if the developer: Controls the site, has local EDC and co-op support, provides zoning confirmation, submits site plans and one-line diagrams, demonstrates relevant data-center development experience, specifies realistic, fixed load and timing requirements. She emphasized that no transmission or power-supply capacity would be reserved until an actual end user is identified and passes a full credit review.

Next steps include: coordinating with the six active developer-led projects, engaging co-ops directly, and working with communications staff to ensure clear, proactive messaging as WVPA adapts its process to support the evolving, high-stakes data-center market.

Nominating Committee: The following Directors are running for Officers unopposed: Bart Nesius (Chair), Doug Burnworth (Vice Chair), Tina Davis (2nd Vice Chair), Rick Risley (Secretary/Treasurer), Dennis Burton & Shane Rasler (Executive Committee). Kevin Cox and John Hand are the nominees for the Audit Committee (3-year term) and Ken Denton and Dennis Burton (alternative) are the ACES Board Representative nominations.

CEO Report: Jeff Conrad closed the meeting by thanking the Board for their engagement—particularly around the evolving large-load/data-center development process—and noted that continued feedback will be essential as WVPA refines its approach in the months ahead. Reflecting on the Winter Storm Fern discussion, he emphasized the storm's volatility as a reminder of why tools like a Rate Stabilization Fund may help smooth unpredictable market swings, even though reactions to the idea have been mixed. He reiterated that despite doing everything right during the storm, some factors remain outside WVPA's control, underscoring the importance of planning and financial resiliency.

Jeff also provided a brief update on WVPA's RUS loan application, sharing that RUS has requested a few additional items—one of which turned out to be obsolete—and the team is actively responding.

The meeting ended in Executive Session.