

Dr. Brad Borum
Indiana Utility Regulatory Commission
101 West Washington Street, Suite 1500 East
Indianapolis, Indiana 46204

April 2, 2026

CAC, ELPC, SUN, and Vote Solar Comments on CenterPoint’s 2025 IRP re: Distributed Energy Resources (“DERs”)

Dear Dr. Borum,

Citizens Action Coalition of Indiana, Inc. (“CAC”), Environmental Law & Policy Center (“ELPC”), Solar United Neighbors (“SUN”), and Vote Solar respectfully submit the following comments regarding the 2025 Integrated Resource Plan (“IRP”) of CenterPoint Energy Indiana (“CenterPoint”) as it relates to distribution planning and distributed energy resources (“DERs”).

While we acknowledge and appreciate CenterPoint’s willingness to engage with stakeholders on DER-focused strategies in their most recent IRP, we recommend that CenterPoint focus on additional opportunities to deploy near-term, “no-regrets” solutions, in particular DERs, to help hedge the risks created by dramatic changes in load forecasts. Many utilities are facing an avalanche of potential load growth, largely from proposed hyperscale data centers but also from growth trends in manufacturing and electrification. These trends are coming at a pace that is difficult to address through Indiana’s three-year resource planning cycle and create risks for Indiana consumers and the environment due to the generally large, expensive, and polluting nature of new power plants. If large load growth does not materialize on either the scale or timeline as the utility projects, Indiana ratepayers will be stuck paying for unnecessary infrastructure. Near-term, “no-regrets” clean energy solutions can help mitigate these risks.

There are many important aspects and values of resource and distribution system planning, including articulating and planning for the electric grid we want to have decades into the future. It also allows us to create strategic visions for safe, reliable, and affordable grids as customers deploy increasing amounts of distributed energy resources. As the value of this opportunity grows, so does the importance of aligning distribution system, transmission, and resource planning. Proactive distribution planning that anticipates the economic benefits of electrification should integrate high levels of distribution grid-connected resources and manage their deployment alongside bulk system generation in a way that minimizes costs and maintains reliability.

The conventional utility planning approach for DERs (to the extent they account for DERs at all) is to treat them as an exogenous variable in capacity expansion modeling. Like weather or the economy, DER growth is viewed as something that “happens to” the utility and needs to be planned around, rather than something that the utility can affect through its own actions. In fact, DERs can bring great value to the Company’s customers and can be utilized as a tool for providing safe and reliable utility service.

We previously asked CenterPoint to conduct distribution system planning as part of its IRP process. In particular, we asked CenterPoint to deploy non-wires alternative concepts to increase

system resilience and bring down customer costs. While we appreciate the headway that CenterPoint has made and the continued collaboration with stakeholders, we believe that CenterPoint largely incorporated DERs as bundled demand-side resources and scenario inputs, rather than as a competitive, capacity resource that can be tapped to meet system needs.

We reiterate the following recommendations and ask that CenterPoint update its IRP to begin this important work now.

Continue Working with Stakeholders to Explore Additional Options for Incentivizing Customers to Adopt DERs

We appreciate CenterPoint’s engagement with stakeholders to incorporate new methods for modeling and incentivizing customer adoption of DERs, including adding a DG solar resource portfolio with a \$500 per kW incentive and various demand response (“DR”) programs that could encourage DER adoption. However, as we outline below in the section on Virtual Power Plants (“VPP”), there are concrete steps the Company must take to enhance its DER modeling in subsequent IRPs. This does not mean that we are replacing this incentive modeling with VPP below; rather, we envision that traditional distributed generation and VPPs represent valuable capacity that each need to be included in CenterPoint’s IRP.

In Energy Futures Group’s (EFG) expert report on the Company’s IRP Proposal (transmitted separately and including many of the same parties signed on this letter), they provided feedback on CenterPoint’s DG solar portfolio. Under Section 2.2 Distributed Solar Sensitivity of EFG’s memo, they note that there is no clarity as to whether other grid benefits of DG were accounted for by the utility. We agree. The Lawrence Berkeley National Laboratory (LBNL) published a study in 2024 that further emphasizes the benefits of DERs and DER forecasting in IRPs.

The technology and market landscape for distributed energy resources has evolved considerably since the coalition first requested that CenterPoint model DG solar as a selectable resource. While we acknowledge and appreciate that CenterPoint took that step in this IRP cycle, the emergence of VPPs now represents best practice for integrating customer-sited resources into resource planning. VPPs aggregate diverse behind-the-meter assets—solar, battery storage, EV chargers, smart thermostats, and flexible loads—into dispatchable capacity resources that can be called upon during system peaks. As MISO’s shift to seasonal capacity accreditation under the Direct Loss of Load (“DLOL”) framework increasingly rewards dispatchable capacity, VPPs become significantly more valuable than standalone DG solar, which in the evolving MISO resource accreditation framework primarily provides energy benefits but limited capacity value. The VPP frameworks described below represent the next logical step in this evolution.

We look forward to continuing to work with the Company on innovative approaches to incorporate DERs into the IRP process so that CenterPoint and its ratepayers can enjoy their full benefits, including the benefits these resources can create for distribution and transmission systems (e.g., deferred or avoided investments, mitigated congestion, reduced line losses, etc.), in addition to the capacity benefits and reduced fuel costs more typically analyzed. Importantly, the costs of the DER resources offered to the model as a supply side resource should only reflect the cost to the utility of measures it takes to increase adoption above the status quo baseline; it should not reflect the

cost of the customer’s investment in their DER, which effectively means these resources are capital free for the Company and its ratepayers.

Critically, DERs are fuel-cost-free resources, which means they also eliminate fuel cost risk—one of the most significant long-term uncertainties in resource planning. Natural gas prices have been highly volatile over the past quarter century. Henry Hub spot prices have swung from under \$2.00/MMBtu to over \$9.00/MMBtu, driven by hurricanes, geopolitical crises, and shifting market fundamentals. Every megawatt of capacity met through DERs rather than gas-fired generation is a megawatt that is permanently insulated from this price volatility. As CenterPoint’s own modeling shows, fuel cost assumptions are one of the primary drivers of portfolio cost differences across scenarios. Resources that eliminate fuel cost exposure entirely deserve full consideration as capacity resources, not merely as load-modifying demand-side measures.

Set DER Deployment Targets Consistent with Current IRP High Adoption Scenarios

CenterPoint should be required or strongly encouraged to explain how its distribution plan will put the Company on track to meet or exceed the level of DER deployment in its IRP.

We recommend that CenterPoint work with technical experts and stakeholders to proactively plan investments in hosting and other necessary system capacity to support DG and EV additions consistent with DER deployment targets. The Company should use DER and electrification scenario analysis in load and potential studies to plan distribution system investments. Such investments may be necessary to increase hosting capacity on circuits where the Company expects distributed generation growth, or where adding DER would provide grid value.

Take Proactive Steps to Further Integrate Distribution-Level Planning into the IRP Process

We would like to see the Company conduct advanced forecasting to better project the levels of DER deployment at a feeder level. The Company should leverage advanced distribution planning tools to identify opportunities and needs at a granular level. CenterPoint should plan for aggregated DERs to provide system value, including energy/capacity during net peak hours in all seasons. Aggregated DERs can also contribute to avoiding or deferring traditional distribution upgrades in addition to providing energy and capacity benefits and, as such, we recommend that the Company explore customer DER programs in all its planning processes (resource, distribution, and transmission planning).

Model Grid Enhancing Technologies (GETs)

CenterPoint should expand its analysis in the next IRP to evaluate Grid Enhancing Technologies (“GETs”) as a distinct transmission and reliability tool, rather than leaving them outside the modeled resource set. The Company’s 2025 IRP recognizes that transmission planning is an important part of resource adequacy and system reliability, emphasizes increased collaboration with transmission and distribution planning, and notes that evolving system conditions require tools that can maintain reliability at lower cost. Yet the IRP does not appear to model GETs as a candidate strategy for increasing transfer capability, reducing congestion, improving utilization of existing transmission assets, or deferring more capital-intensive network upgrades. Where load growth, resource shifts, and accreditation changes are increasing pressure on both the bulk and

local system, the Company should not limit its options to conventional wires upgrades or new generation additions if lower-cost transmission optimization measures may also provide material value.

At a minimum, CenterPoint should assess whether dynamic line ratings, advanced power flow control devices, and topology optimization software could provide cost-effective benefits under a range of future conditions relevant to this IRP. Those benefits may include increasing usable transmission capacity, improving access to lower-cost resources, reducing curtailment and congestion, supporting reliability during high-stress system conditions, and deferring or reducing the scale of traditional transmission investments. The Company should evaluate GETs both as a stand-alone sensitivity and in combination with high-load, high-renewables, and high-DER scenarios, so that stakeholders and the Commission can understand whether relatively fast, modular transmission upgrades could reduce customer costs while preserving flexibility in an uncertain planning environment. Because the IRP already emphasizes optionality, affordability, and the need to respond to changing system conditions, GETs are a natural candidate for inclusion in the Company’s next round of planning analysis, consistent with SEA 422 (2025).

Update the 2025 IRP to Include a Comprehensive Analysis of Virtual Power Plants

The Case for VPPs as Capacity Resources

VPPs harness behind-the-meter, customer-provided PV, batteries, EVs, chargers, heating and cooling, and flexible loads to supply bulk-system capacity and flexibility. Unlike standalone distributed generation, VPPs can be dispatched during system peaks to deliver firm capacity—making them directly comparable to conventional generation resources in CenterPoint’s capacity expansion modeling.

A critical question for any utility pursuing a VPP program is how the program will capture capacity value under the MISO resource adequacy framework. As a MISO Load Serving Entity, CenterPoint’s VPP capacity value will be determined by MISO’s tariff provisions governing resource registration, accreditation, and peak demand forecasting. The answer has major implications for program cost-effectiveness, rate design, and the pace of distributed energy deployment. We recommend that CenterPoint evaluate two distinct pathways for monetizing VPP capacity value and design its programs accordingly.

Two Pathways for Monetizing VPP Capacity Value in MISO

Pathway 1: Supply-Side MISO Market Registration

Under this pathway, CenterPoint would register its aggregated distributed storage and VPP fleet with MISO as a planning resource. The fleet would earn Seasonal Accredited Capacity (“SAC”) and produce Zonal Resource Credits (“ZRCs”) that can be offered into the Planning Resource Auction (“PRA”), used in Fixed Resource Adequacy Plans (“FRAPs”), or sold bilaterally. This is the established approach: Xcel Energy proposes registering its Capacity*Connect battery fleet in Minnesota as a DRR Type I resource, and DTE Electric in Michigan registers its entire 657 MW demand response portfolio as Load Modifying Resources (“LMRs”) with MISO. CenterPoint’s own IRP materials appear to reflect a similar approach. The Company states that it has signed a contract with a commercial and industrial demand response aggregator for implementation by 2026. CEIS 2025 IRP – Vol. 2, pdf pp. 303-304 (MPS pp. 40-41). And its 2024 all-source RFP repeatedly solicited “LMR/DR” products, required those products to satisfy MISO LMR/DR

requirements, and assigned performance and replacement-capacity obligations consistent with conventional supply-side capacity treatment. CEIS 2025 IRP – Vol. 2, pdf pp. 65-68 (ASRFP pp. 6-25 – 6-28).

Our assessment of the current situation is that, under MISO’s current and forthcoming rules, CenterPoint could pursue a market participation pathway through three potential avenues:

- DRR Type I (available now): Demand Response Resource registered as a Load Modifying Resource, dispatched during MISO-declared emergencies, with capacity accreditation according to Schedule 53B. This requires GVTC testing, deployment within 6 hours of notification, and ability to sustain for 4 continuous hours.
- Electric Storage Resource (“ESR”) (available now, but requires wholesale market participation): Registered as a generation-equivalent resource, accredited according to Schedule 53. Enables participation in energy and ancillary services markets but requires telemetry and full market integration. May require each asset in the portfolio to be registered separately.
- Distributed Energy Aggregated Resource (“DEAR”) (capacity market participation targeted for approximately June 2030 under FERC Order 2222): MISO’s Order 2222 compliance framework will allow aggregations of DERs—down to a 100 kW minimum—to participate directly in wholesale capacity, energy, and ancillary services markets. However, implementation has been delayed: in January 2025, FERC rejected MISO’s proposed interim model (using DRR Type I as a bridge) because DRR Type I’s 1 MW minimum size requirement is ten times Order 2222’s mandated 100 kW minimum. On January 13, 2026, FERC approved MISO’s revised implementation plan. Midcontinent Independent System Operator, Inc., Docket Nos. ER22-1640-006 and ER22-1640-007, Letter Order (Jan. 13, 2026) (Accession No. 20260113-3053).

This means that VPP programs designed and approved in 2025–2028 must rely on the existing DRR Type I, ESR, or the demand-side approach described below for their first several years of operation. Program design may anticipate a potential transition to DEAR when it becomes available.

The supply-side pathway provides regulatory certainty—MISO’s tariff has well-defined rules for resource registration, accreditation, and performance—and creates a transparent, FERC-jurisdictional revenue stream through ZRC market value. However, it comes with growing program and transaction costs. Under MISO’s Module E-1, Section 69A.1.2.1(c), any resource registered as a planning resource must have its load reduction added back to the historical load data used for coincident peak demand forecasting. The VPP cannot simultaneously earn ZRCs and reduce the utility’s capacity obligation through a lower load forecast. Additionally, MISO’s pending LMR reform proposal (filed at FERC on April 4, 2025, docket ER25-1886) would impose a maximum six-hour notification time and shift to actual-availability-based accreditation beginning in PY 2028/29, tightening performance requirements for all demand-side planning resources.

Pathway 2: Demand-Side Capacity Obligation Avoidance

Under this pathway, CenterPoint would not register its distributed storage fleet with MISO. Instead, the utility would dispatch the fleet to shave its own system peak during the hours that determine its Coincident Peak demand as a Load Serving Entity. Because the fleet is not registered, MISO’s meters see a lower actual peak demand—and CenterPoint’s resulting Planning Reserve Margin Requirement (“PRMR”) is correspondingly reduced. A lower PRMR means the utility needs fewer ZRCs to meet its capacity obligation. The “capacity value” is realized not as revenue from selling ZRCs, but as an avoided cost of procuring them.

This approach is modeled on MISO’s established treatment of mature Energy Efficiency Resources (“EERs”). Under MISO’s framework, a fully implemented EE measure’s effect on load is simply embedded in the LSE’s historical load data and flows naturally into a lower coincident peak demand forecast. The EE does not earn ZRCs—but it permanently reduces the LSE’s capacity obligation through lower forecasted demand. MISO explicitly permits this under Section 69A.1.1(b)’s “may include” language for EE reductions.

The key tariff distinction is between “demand resources” (Section 69A.1.1(b): forecasts “shall... [be] augmented to include the normal Demand from forecasted demand resources, whether registered or not”) and “energy efficiency programs” (same section: “Such forecasts may include Demand reductions achieved by energy efficiency programs”). The argument is that an unregistered, utility-controlled distributed battery energy storage system (“BESS”) program that consistently shaves system peak should receive the same demand-side treatment as mature EE—particularly given that a metered storage fleet provides far superior measurement & verification compared to deemed EE savings.

This pathway is not yet approved for distributed storage and would require proactive engagement with MISO through the Resource Adequacy Subcommittee (“RASC”) and with the Commission to establish the precedent. However, it offers important advantages: the capacity value is not affected by MISO’s transition from the current 95% administrative capacity credit for 4-hour storage to the DLOL methodology in PY 2028-29, which is projected to reduce supply-side storage accreditation to approximately 50–65%—a potential loss of 30–45 percentage points of capacity credit. Programs designed under the demand-side pathway avoid this accreditation erosion entirely.

Account for MISO’s Evolving Accreditation Framework in Long-Term Cost-Benefit Analyses

Two concurrent MISO reforms will significantly affect the economics of supply-side VPP programs. First, MISO’s pending DR/ER reform proposal (filed at FERC April 4, 2025, docket ER25-1886) would impose a maximum six-hour notification time for LMR accreditation and shift to actual-availability-based accreditation beginning in PY 2028/29. DTE Electric in Michigan is already adapting to that change by closing its D1.8 Dynamic Peak Pricing tariff to new customers because the tariff’s notification requirements are incompatible with the proposed accreditation framework.

Second, MISO’s transition from the current 95% administrative capacity credit for 4-hour battery storage to the Direct Loss of Load (“DLOL”) methodology (also in PY 2028-29) is projected to reduce storage accreditation to approximately 50–65%. While MISO has not finalized the DLOL values, this represents a potential 30–45 percentage point reduction in capacity credit. Together,

these changes mean that VPP programs entering service in the mid-to-late 2020s could face substantially different supply-side economics than those modeled under current rules. For now, CenterPoint’s long-term cost-benefit analyses should use the post-reform accreditation rates—not the current 95%—as the base case.

Conversely, these tightening supply-side requirements strengthen the relative attractiveness of the demand-side pathway (Pathway 2), where capacity value is realized through load forecast reduction rather than MISO accreditation and is therefore unaffected by DLOL changes.

Leverage RERRA Authority Under FERC Order 2222

FERC Order 2222 preserves state Relevant Electric Retail Regulatory Authority (“RERRA”) oversight over some interconnection and grid use matters. While Order 2222 does not allow retail regulators to broadly prohibit DERs from participating in wholesale markets, it continues to reflect the prior “opt-out” of demand-response only aggregations under Order 719. Thus, while states may not “opt-out” heterogeneous mixes of DERs that include demand response, they may still opt-out homogeneous aggregations of only demand response. Whether the IURC may exercise the ability to opt-out depends on its statutory authority and constitutional limits. However, it retains significant authority through its regulation of utilities to promote VPPs—whether utility-led or third-party aggregated.

Given that MISO’s DEAR capacity market pathway is not expected until approximately June 2030, and FERC’s January 2025 rejection of MISO’s proposed DRR Type I interim model means there is no Order 2222-compliant pathway for DER aggregations in MISO before then, CenterPoint’s VPP programs must rely on existing registration categories or the demand-side capacity avoidance approach.

Additionally, when DEAR becomes available (~2030), it will open MISO’s capacity market to independent, non-utility DER aggregators for the first time. CenterPoint should design its VPP programs now to deliver ratepayer value that justifies continued utility operation even if competitive aggregators enter the market.

Specific Recommendations for CenterPoint’s VPP Analysis

We recommend that CenterPoint take the following concrete steps:

1. Retain VPP placeholder scenarios (e.g., 50 MW and 150 MW build cases) in the current IRP using default assumptions, to signal that a fuller VPP analysis will accompany the next IRP.
2. Model VPP capacity value under both pathways: (a) supply-side MISO registration using tentative post-DLOL accreditation rates (50–65% for 4-hour storage) as the base case, with CONE as the cost-effectiveness benchmark; and (b) demand-side capacity obligation avoidance using the Cost of New Entry as the avoided cost benchmark.
3. Begin developing BTM VPP programs in the interim outside of the resource planning process. Using the building blocks established in the most successful VPP programs in the country, the Solar United Neighbors (SUN) Model Tariff (available at SolarUnitedNeighbors.org/VPP) provides a great starting point for VPP program implementation and the ability to scale programs quickly and cost-effectively. Notably, the tariff provides pathways for VPPs to include a diversity of “bring your own device”

resources, including customer battery storage, EVs, and smart thermostats/home HVAC systems.

4. Ensure all VPP cost-benefit analyses clearly identify which capacity pathway is assumed, model post-reform MISO accreditation rates as the base case for long-term program economics, and include sensitivity testing of the alternative pathway.
5. Engage MISO through the Resource Adequacy Subcommittee (RASC) to seek clarification on whether unregistered, utility-controlled distributed storage that reduces metered peak demand should be treated like mature energy efficiency for CP forecasting purposes under Module E-1, Section 69A.1.1(b).
6. Track FERC Order 2222 implementation and plan for a potential transition to DEAR registration when it becomes available (~2030), which may offer a more naturally suited supply-side registration category for distributed storage aggregations with a lower 100 kW minimum participation threshold.

VPP programs directly address key challenges identified throughout these comments, including interconnection queue congestion, load growth pressures, and cost management. Modeled in 50-megawatt blocks whose capital charges are offset by transparent distribution- and transmission-deferral credits, a VPP lets CenterPoint secure firm, clean capacity while postponing millions in feeder and network upgrades—all without wrestling with retail-rate or adoption uncertainty. A robust VPP analysis ensures that the IRP also tests the broader customer-side opportunity that will become increasingly valuable as Indiana’s grid evolves.

Conclusion

We appreciate the Company’s engagement on incorporating DERs into its IRP process. We ask that the Company continue to engage with stakeholders on these issues to ensure that CenterPoint can fully realize the benefits of a clean, affordable, and equitable electric grid through accelerated deployment of DERs and GETs on an optimized distribution and transmission system.

We are ready to supply detailed inputs and technical support to help CenterPoint evaluate both capacity pathways, apply the Levelized Cost of Capacity (LCOC) framework, and build a flexible, least-cost DER roadmap for Indiana’s energy future. Utilities already leverage residential customer demand response programs such as smart thermostats throughout the country. The technology is proven, the regulatory pathway under MISO’s existing tariff framework is available, and peer utilities in MISO territory are already moving forward. This makes 2026 the ideal time to integrate distributed resources into CenterPoint’s strategic planning. We stand eager to assist as soon as practicable.

Respectfully submitted,

Citizens Action Coalition
Environmental Law & Policy Center
Solar United Neighbors
Vote Solar