Comments of Citizens Action Coalition of Indiana, Solar United Neighbors, Environmental Law & Policy Center, and Vote Solar on IURC Implementation of FERC Order 2222 following May 29, 2025 Stakeholder Meeting

July 21, 2025

Citizens Action Coalition of Indiana, Solar United Neighbors, Environmental Law & Policy Center, and Vote Solar (collectively, the "Public Interest Organizations") appreciate the opportunity provided by the Indiana Utility Regulatory Commission (IURC or Commission) to participate in the May 29, 2025 stakeholder meeting related to the implementation of Federal Energy Regulatory Commission (FERC) Order 2222 pursuant to Ind. Code Section 8-1-40.1-4. Per the Commission's request, we respectfully submit the following additional comments in response to the discussion during the meeting, as well as suggestions for next steps.

Distributed energy resources could play a significant role in solving MISO and PJM's resource adequacy problems. Load growth projections indicate that more generation is needed in the near future, but utility-scale generation faces bottlenecks at the transmission level, such as load congestion that requires building additional transmission lines, lengthy interconnection queues, and onerous local siting restrictions. Meanwhile, the ongoing shortage in gas turbines is delaying the construction of gas-fired plants by up to seven years.[1] Distributed energy resources can be constructed faster than traditional resources and are sited close to the load, avoiding the lengthy construction times and cost associated with transmission lines. The Commission should encourage the continued development of distributed energy resources to address the state's resource adequacy needs.

DER Interconnection versus DERA Registration

As a preliminary matter, we are concerned that the stakeholder discussion conflated two different processes, namely, how to interconnect an individual distributed energy resource (DER) and how to register a distributed energy resources aggregation (DERA). In Order 2222, FERC reminded participants that DER interconnection and DERA registration are separate and distinct.[2] FERC deliberately chose to exercise jurisdiction over the latter, but not the former: state and local authorities remain in charge of the DER interconnection, while the RTOs oversee DERA registration.[3] That said, FERC cautioned that interconnection review should not be used to create "unnecessary barriers" to DERA participation, and that "abuses" could move FERC to assert jurisdiction over interconnection.[4]

[1] Jared Anderson, *US Gas-Fired Turbine Wait Times As Much As Seven Years; Costs Up Sharply*, S&P Global (May 20, 2025), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.
[2] FERC No. RM18-0009, Order No. 2222, 172 FERC ¶ 61,247 at P 102 (filed Sept. 17, 2020).
[3] Order No. 2222, 172 FERC ¶ 61,247 at P 96.
[4] Order No. 2222, 172 FERC ¶ 61,247 at P 101.

Because of this distinction, we are concerned by the stakeholder proposal to add a 15-day state-level review of the DERA registration before the DERA is submitted to MISO/PJM, which then starts a 60-day clock. Order 2222 is clear that DERA registration should not be an overly cumbersome process. DER interconnection requests, not DERA registration, should be the main vehicle for studying and resolving grid reliability issues.[5] To the extent that utilities wish to perform a study during DERA registration, those studies must not delay the utility's review of the registration past the 60-day limit.[6] The stakeholder proposal, however, would add another layer of review between DER interconnection and the RTO's review of the DERA registration. We are concerned that this extra review could become an undue barrier, especially if, in practice, it causes delays exceeding the 15-day review period.

Moreover, we are concerned that extensive reliability studies at the DERA registration stage could likewise become an undue barrier to DERAs. At the same time, we recognize that maintaining reliability is paramount. For that reason, we would genuinely appreciate more details from stakeholders about why additional reliability studies for DERA registrations may be necessary, what additional reliability studies would be performed, and for which DER aggregations (i.e., would additional study be required for all DER aggregations, or only certain ones). It is our understanding that most DERs (leaving aside exceptions like vehicle battery storage) already passed reliability studies when they initially interconnected to the grid, and we have not seen any evidence that an aggregation of DERs could harm grid reliability in a manner distinct from the impact that each individual DER could have. It is also unclear why utilities conducting DER interconnection review could not contemplate aggregated impacts of DERs at the interconnection stage, given that DERs could act in parallel even if they are not part of a DERA.[7] We therefore ask that the utilities provide representative examples and technical details of the aggregation-specific reliability impacts that the utilities believe are most pressing. The utilities should also identify the studies that would be conducted to address these concerns, and the representative costs that would be assigned to each DERA for completing such studies. Such information will aid stakeholders and the Commission in evaluating the potential policy and market implications of the utilities'

[5] Order No. 2222, 172 FERC ¶ 61,247 at P 294.

[6] Order No. 2222, 172 FERC ¶ 61,247 at P 295.

[7] We are aware that when a utility studies an individual DER interconnection, they assume that there is a degree of randomness to when scattered DER resources will be injecting power—in other words, if a group of DER resources is not part of a DERA, it is assumed that they will not be acting in synchrony. Thus, some utilities have claimed that the interconnection review purportedly fails to capture the synchronous effects that will occur when the DERs become aggregated and start responding to wholesale market signals. *See e.g.* Indiana Michigan Power, *Engineering Impacts from Distributed Energy Resources*, https://www.in.gov/iurc/files/I-and-M-DER-Aggregation-Engineering-Impacts.pdf. However, this explanation also raises more questions. How likely is it that DER resources would be correlated even in the absence of wholesale market effects? For instance, weather conditions and time-of-day usage patterns would have similar impacts on net injections for nearby DERs. Are interconnection reviews designed to model "worst-case" strain upon the grid, and if so, is the assumption of randomness consistent with worst-case modeling? What degree of randomness do these studies assume for non-DERA DERs? And do these studies assume that DERA DERs act in perfect synchrony, or do they recognize that DERAs will also have some variability?

proposed additional reliability studies on DERAs; for instance, aggregators could take those impacts into consideration when they choose which DERs to comprise an aggregation.

We agree with the Commission that some aggregations may be easier to study than others, and the rules could expedite and potentially apply different studies for easier aggregations in a manner analogous to the Level 1, Level 2, and Level 3 interconnection review procedures.[8] That said, the Commission does not need to promulgate rules to spell out every detail for how DERA registrations will be evaluated, as MISO and PJM are implementing those procedures pursuant to Order 2222. The Commission's proactive engagement with Order 2222 is laudable and will benefit the implementation process, as long as the Commission's rules remove barriers to DER participation.

Data Sharing and DERA Registration Discrepancies

Stakeholders also raised concerns about discrepancies between the data submitted by the aggregator and the utility's data on file for the customer. Stakeholders believed that these discrepancies caused delays, and made it difficult to comply with the 60-day deadline for DERA registration review. We would appreciate additional details from stakeholders about these discrepancies, what data mismatches are most common, and what processes utilities, customers, and aggregators follow to resolve those discrepancies. The Commission should ask for a step-by-step breakdown of the data reconciliation process, and a rough estimate of how many days each step takes. This will help stakeholders identify which steps are causing the most delays, and plan for how to meet the 60-day deadline.

At the same time, the Commission should require the investor-owned utilities under its jurisdiction to assess whether they are devoting sufficient resources to reviewing DER interconnection requests and DERA registrations in order to meet state and federal response deadlines, as applicable. The utilities and applicants can resolve data discrepancies more quickly if the utility provides sufficient staff to promptly communicate the discrepancies to the applicant.

Indiana consumers deserve fast response times. For comparison, Pacific Gas & Electric commented at a 2018 FERC technical conference that they have "roughly a three business day turnaround" for approving rooftop solar applications.[9] PG&E explained that it had streamlined its review process and was capable of connecting 4,000 rooftop solar DERs per month.[10] The Commission should order the investor-owned utilities to publicly report what steps they are taking to comply with response deadlines.

Additionally, stakeholders discussed the possibility of using a centralized website to coordinate data sharing between customers, aggregators, and utilities. We offer support for a statewide

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[8] *See* 170 IAC §§ 4-4.3-6 through 4-4.3-8.
[9] FERC No. RM18-0009, *Transcript of April 11, 2018 DER Conference* at 351, (filed May 2, 2018), https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20180502-4008&sid=13081455-4580-4f03-994e-7efd7748a301.
[10] *Id.*

standard interface where a customer goes to a centralized user-friendly website, picks an aggregator from a list of registered aggregators, agrees to various customer data privacy waivers to give the selected aggregator access, and accomplishes other necessary items and tasks on this one-stop-shop site.

Dual Participation

We reiterate our comments from the stakeholder meeting that the Commission should not categorically exclude net metering customers from participating in DER aggregations, as there may be exceptions where the customer is providing different services on the retail and wholesale levels.[11] For instance, a net metering customer could provide energy from rooftop solar panels to the utility at the retail rate, but also have a battery storage system that provides capacity services to the wholesale market. A battery system on its own cannot qualify for net metering, which means that the customer may not receive compensation for capacity under the net metering tariff.[12] The capacity services should be eligible for wholesale compensation without causing the customer to forfeit their net metering status.

Excess Distributed Generation (EDG) customers should not be excluded from participating in DER aggregations either. The EDG credit is determined each year by taking the average marginal wholesale price of electricity paid by the electricity supplier during the most recent calendar year multiplied by 1.25.[13] Since this compensation level is only for the electricity value of the excess generation and does not include other services the DER system can provide to the market such as for capacity, it's unreasonable to restrict EDG customers from also participating in DER aggregations. Further, because the EDG credit is constant throughout the year, it does not compensate customers with storage capacity who provide grid services such as shifting electric discharge to peak demand times. RTO markets can better incentivize storage customers to provide electric capacity at the system peak, when it is needed most.

Electric Storage

Indiana must continue developing energy storage resources—both utility-scale and distributed storage—because batteries play a valuable role in regulating grid stability. For instance, batteries can respond nearly instantaneously to deviations in grid frequency.[14] Batteries can also provide other ancillary services, such as operating reserves and voltage support.[15] Utility representatives

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[11] FERC recognized that "there may be instances in which an individual distributed energy resource could technically, reliably, and economically provide multiple, distinct services at wholesale and retail levels." Order No. 2222, 172 FERC ¶ 61,247 at P 163.
[12] *See* 170 IAC § 4-4.2-1(d) (defining "Eligible net metering energy resource") and Ind. Code § 8-1-37-4(a).
[13] *See* Ind. Code § 8-1-40-17.
[14] U.S. Energy Information Administration, *Battery Storage Applications Have Shifted as More Batteries Are Added to the U.S. Grid* (Nov. 1, 2021), https://www.eia.gov/todayinenergy/detail.php?id=50176.
[15] North American Electric Reliability Corporation, *Energy Storage: Impacts of Electrochemical Utility-Scale Battery Energy Storage Systems on the Bulk Power System* at 1 (February 2021), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf;

have raised concerns about the impact of renewable DERs on grid stability, but energy storage resources, including distributed storage, will actually aid the stability of the grid and support the integration of distributed generation. In fact, a recent analysis from the North American Electric Reliability Corporation (NERC), found that areas with high penetration of storage, such as Texas, have improved frequency response, reducing the likelihood of blackouts.[16]

Considering the need for more storage, Indiana has room to improve. The state had 337 MW of utility-scale storage as of April 2025, including the 200 MW Pike County Energy Storage project that AES brought online in March 2025.[17] 337 MW is a good start, but is barely 1% of Indiana's total net summer generating capacity, which exceeds 28,000 MW.[18] By contrast, the Electric Reliability Council of Texas (ERCOT) reported that storage provided nearly 6% of total capacity in 2024, with that figure expected to grow to 15% in the next five years.[19] The Commission should consider how it can facilitate the development of distributed storage, including by streamlining interconnection rules. The recent proposed updates to Indiana's interconnection rules are a great example of the Commission's leadership in removing unnecessary barriers. The proposed rule would expressly include energy storage systems in the interconnection procedures and increase the eligible system size for Level 1 review from 10 kW to 25 kW, which will facilitate dispatchable resources that provide valuable reliability and stability grid services.[20]

Demand Response

The Commission should consider lifting the state's ban on third-party demand response aggregation. The stakeholder meeting confirmed that Indiana currently prohibits third-party (non-utility) aggregators from directly bidding demand response into RTO markets.[21] Utilities are allowed to run their own demand response aggregation programs, and may engage third-party aggregators to liaison with customers on the utility's behalf. The utility-run programs have historically had low participation rates, though some utilities anticipate expanding their programs later this year, by partnering with third-party aggregators. While the Commission should encourage these utility-run demand response programs, the Commission should go a step further

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Rocky Mountain Institute, *The Economics of Battery Energy Storage* at 14-15 (Oct. 2015), https://rmi.org/wp-content/uploads/2017/03/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf.

[16] North American Electric Reliability Corporation, *2025 State of Reliability* at 10-11 (June 2025), https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2025_Overview.pdf

[17] U.S Energy Information Administration, *Preliminary Monthly Electric Generator Inventory* (May 22, 2025), https://www.eia.gov/electricity/data/eia860m/

[18] U.S. Energy Information Administration, *Indiana State Energy Profile* (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=IN.

[19] Electric Reliability Council of Texas, *Advancing Reliability 2024* at 6 (March 2025), https://www.ercot.com/files/docs/2025/03/14/ERCOT-2024-State-of-the-Grid.pdf.

[20] RM #24-01 Regarding 170 IAC 4-4.3, https://www.in.gov/iurc/rulemakings/rulemakings-pending-and-effective/rm-24-01-regarding-170-iac-4-4.3/.

[21] Order at p. 51, *In the Matter of the Commission's Investigation Into Any and All Matters Related to Commission Approval of Participation by Indiana End-use Customers in Demand Response Programs Offered by the Midwest ISO and PJM Interconnection*, Cause No. 43566 (filed July 28, 2010).

by allowing third-party aggregators to directly bid into RTO markets. Permitting both would incentivize utilities and aggregators to innovate and optimize their programs for maximal participation.

Third-party aggregators offer certain advantages for Indiana consumers. For instance, utility programs may have high minimum curtailable load thresholds, which could limit the customers who are able to participate.[22] Aggregators have the flexibility to design programs that serve a broader purpose and may reach a wider subset of customers, allowing for a greater participation rate and capturing a cost-effective resource that is not being utilized today. Ultimately, demand response benefits all consumers—not just program participants—because it reduces the need to invest in costly generating capacity and transmission infrastructure, whose costs would have been passed down to end-use customers.

Demand response resources are particularly important at this moment in time as MISO and PJM face uncertain and tightening capacity conditions. Demand response resources may be added faster and without the cost and long-term investment required for new interconnection, siting and right-of-way, construction, developer financing, permitting, and transmission/distribution upgrades for new generation. As the Commission recognized at the stakeholder meeting, demand response is not an injection of energy. For that reason, demand response is less complex than other types of DERs, and should not require a study on grid impacts. If the Commission does lift the ban, market conditions will incentivize customers to enroll in demand response programs: MISO's Planning Resource Auction cleared summer 2025 capacity at $666.50/MW, up from a mere $30/MW from the previous summer.[23] The auction was a clear signal that with tightening capacity, demand response will be a crucial piece of the capacity toolkit in the years to come.

<u>Hosting Capacity</u>

The Commission should consider additional ways for streamlining the interconnection of DERs: one potential solution would be ordering investor-owned utilities to perform an analysis of hosting

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[22] For instance, NIPSCO's RTO demand response tariffs require customers to be capable of reducing their load by a minimum 1 MW. *See* NIPSCO Rider 581, Demand Response Resource Type 1 (DRR 1) – Energy Only (Aug. 2, 2023), https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/electric-rates/2023-to-current/rider-581.pdf; NIPSCO Rider 582, Emergency Demand Response Resource (EDR) – Energy Only (Aug. 2, 2023), https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/electric-rates/2023-to-current/rider-582.pdf. NIPSCO's 1 MW minimum is consistent with MISO's DRR-Type 1's minimum, but MISO allows EDR resources if they meet a 100 kW threshold. MISO, *Demand Response 101 Workshop* at 35 (May 10, 2024), https://cdn.misoenergy.org/20240510%20Demand%20Response%20101%20Workshop%20Presentation632828.pdf.

[23] MISO, Planning Resource Auction Results for Planning Year 2025-26 at 27 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. Notably, all 9,004.4 MW of demand response offered for summer 2025 cleared the auction, the first time this had happened in three years. In other words, the auction would have cleared more demand response (and potentially brought down the overall clearing price) if more demand response was available. *Id.* at 22.

capacity and make maps of the data publicly available. The stakeholder meeting made clear that consumers, utilities, and aggregators would all prefer to minimize futile interconnection requests. Utilities can help by publicly showing where the grid has spare capacity for power injections, also known as "hosting capacity."

Utilities are no stranger to creating maps of hosting capacity: the Department of Energy has published an Atlas showing the many other states and utilities that have compiled such maps.[24] In fact, I&M's website has a hosting capacity map for its *Michigan* service territory, but not for Indiana.[25] By publishing hosting capacity data in a publicly available and easily understandable map, utilities can help potential interconnection customers self-assess whether a DER interconnection would be viable. The Commission should direct the state's investor-owned utilities to develop hosting capacity maps.

Thank you again for the opportunity to provide comments at this time. We look forward to continued participation in the Commission's implementation planning process going forward.

Sincerely,

Citizens Action Coalition of Indiana

Solar United Neighbors

Environmental Law & Policy Center

Vote Solar

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[24] U.S. Department of Energy, U.S. Atlas of Electric Distribution System Hosting Capacity Maps, https://www.energy.gov/eere/us-atlas-electric-distribution-system-hosting-capacity-maps.
[25] Indiana Michigan Power, Hosting Capacity Map, https://www.indianamichiganpower.com/company/about/hosting-capacity.