IURC Implementation re: FERC Order 2222
October 12, 2023 Roundtable Discussion at IGCS, Conference Room B

Discussion topics: cost recovery, cost allocation, and distribution wheeling charges

SUMMARY NOTES:

Attendees (alphabetical by organization and names):

AES Indiana
- Matt Fields
- Shelby Leisz

Bartholomew County REMC
- Courtney Metzger

Citizens Action Coalition of Indiana (CAC)
- Ben Inskeep
- Kerwin Olson

Duke Energy Indiana, LLC
- Roger Flick
- Jim Hummel
- Andrew Wells

Hoosier Energy
- Michelle Lynch

Hoosier Environmental Council
- Delaney Barber

Indiana Michigan Power Company (I&M, AEP)
- Caleb Loveman
- Dona Seger-Lawson

Indiana Office of Utility Consumer Counselor
- Scott Jones

Indiana Utility Regulatory Commission staff:
- Brad Borum
- Rich Brunt
- Steve Davies
- Beth Heline
- Ren Norman
- Dale Thomas

Northern Indiana Public Service Company, LLC (NIPSCO/Nisource)
- Jett Kelley
- Tiffany Murray
- Robbie Sears

Solar United Neighbors
- Zach Schalk

Southern Indiana Gas and Electric Company (dba CenterPoint Energy Indiana South)
- Jeff Earl

State Utility Forecast Group
- Doug Gotham, Purdue University

Tipmont REMC
- Ron Holcomb

Wabash Valley Power Alliance (WVPA)
- Rebecca Moore Davrich
- Dan Phillips

Acronyms used:

- 2222 – FERC Order 2222
- DER – distributed energy resource
- DR – demand response
- EDC – electric distribution company; term used by ISOs/RTOs
- EDG – excess distributed generation (see Indian Code chapter 8-1-40)
- EE – energy efficiency
- EPRI – Electric Power Research Institute
- EV – electric vehicle
- FERC – Federal Energy Regulatory Commission
- IAC – Indiana Administrative Code
- ISO – independent system operator (aka RTO)
- IURC – Indiana Utility Regulatory Commission
- MISO – Mid-continent Independent System Operator
- NERC – National Electric Reliability Corporation; sets standards to be approved and enforced by FERC
- OUCC – Indiana Office of Utility Consumer Counselor
- PJM – PJM Interconnection LLC
- RDER – DER that is connected and mixed in with load, such as at a house
- REMC – rural electric membership corporation – Indiana's electric cooperatives
- RERRA – relevant electric retail regulatory authority; in Indiana, this is the IURC and can also be the boards of municipal utilities and of REMCs.
- RTO – regional transmission organization – Indiana has electric utilities in two RTOs – MISO and PJM
- UDER – DER that is connected to a dedicated utility facility.

Introductions:

Sign in sheet; request to be added to email distribution list.

NOTE: Voltus provided comments prior to the meeting, which are posted on the IURC website at: https://www.in.gov/iurc/home/implementation-re-ferc-order-2222/.

Discussion:

Quotes from comments submitted

Co-gen – wheeling definition

No other states have imposed wheeling charges, but may be under discussion in other states.

How is DERs trying to get to a market different than a qualifying facility trying to get to a market?

Different equipment may be needed for aggregation and incremental costs analyzing and studying the interconnection should be participant-funded (i.e., by the DERs and/or aggregators).

Does anyone disagree that access to the wholesale market should be participant funded?

Where's the federal market being created? At transmission node.

DER/aggregator gets to market through distribution utility.

Difference between wholesale pricing and where the electricity is being used.

Distribution utility is not an intermediary.

Displacing electrons – still pushing electricity through the distribution system.

Renewable natural gas putting onto the system vs. being transported - federal permit

If an entity causes a utility to incur costs that the utility wouldn't otherwise incur, then the cost causer pays those costs. Also look at whether there are benefits to other customers. We don't have enough information to understand what will need to be done to bring DERs and aggregators on-line.

What's the difference between a customer that uses generation for its own load versus one that puts the generation on the utility system? Net load is the same. Is there something else driving costs?

Possible metering and line upgrades – not enough experience to make an informed decision; other than standard policy of the entity causing the costs paying those costs. How to predict the costs?

Will the costs defeat the value? Additional costs could defeat DERs. No one has shown the economics of DERs participating in the wholesale market.

No one knows how much it is going to cost. Start to track the costs; maybe defer those costs. If smaller amount, not a big deal; but if it is millions, then it is.

Ancillary services – being observed at point of interconnection. Everything happens at point of connection, but value is reduced the further it gets away from that point of the interconnection. In the Blackout of 2003, lack of reactive power was the issue. Connection flows throughout and reduces as it gets farther from that point of connection.

Frequency response can help throughout the system. So, a battery on the distribution system would cross over to the grid.

We don't know enough to set rates yet.

IC 8-1-2.4 – contracts to purchase or wheel electricity at rates Commission finds reasonable and nondiscriminatory

Today costs are unknown;

One time costs (meter, upgrade) vs. longer term costs – is there a way to separate that?

The interconnection rule deals with the one-time cost of the interconnection. Participation rule may look at the other costs of getting to market.

If build a bigger distribution "road", the first one down it shouldn't be responsible for all of the cost.

Under the Commission's main extension rules (particularly for water and wastewater mains), the initial person pays and gets reimbursed through subsequent connectors.

Utility uses revenue to reduce connection costs, but utility may not be getting revenue from DER/aggregator.

Distribution system is agnostic. If additional distribution is required, cost causer should pay. Fixed cost in rate design. Where to get revenue utility needs to cover the costs?

New entrants into the market, using distribution system to get their product to the market; shouldn't they have to pay something to use that system? They should pay something that then could be a credit for the other customers. If going to use the system to provide product, then aggregator should cover that cost of doing business.

The rate for wheeling energy – based on utility's actual expenses plus no more than 2.0 mills per kilowatt-hour of electricity wheeled. See 170 IAC 4-4.1-6(c)((3). Every customer (including DERs) is paying for the distribution system. Those who use the grid for more than their receipt of energy, then may have a charge/cost for that usage.

If retail customer is participating in retail programs, that takes place on the retail distribution system. What additional cost would there be for an existing EDG customer to participate in the wholesale market? There is a cost to play in the wholesale market. If customer chooses to change from retail to wholesale, there are additional costs, such as operating, managing, regulatory, administrative cost being put on retail utility to provide access to the wholesale market. If no additional interconnection costs, then perhaps no additional costs, but that's the point of studying it. Retail utility has lost control of its retail system for customers participating at wholesale.

To really understand the costs, you need someone who understands the engineering and operations of the distribution system to do detailed analysis of different types of transactions and the actions the utility has to take and see whether there are differences in the costs for wholesale participation, whether there are system benefits, whether the costs is put upon the retail utility, etc.

At start of creating an RTO, the only way to resolve the philosophical debate was to examine each transaction type and analyze all of the implications of the transaction – engineering, accounting, economics – who is occurring costs, causing costs, and who benefits? How to account for who has responsibility? We need this type of analysis to truly understand the implications.

If look at an individual coming onto wholesale market, cost could be small. But as more participate at wholesale, there could be a bigger challenge and larger impact.

Those things we need to deal with up front vs. those things we need to deal with later as they come up.

What needs to be in place day one? What are those things we need to be monitoring in case they need to be dealt with in the future? What needs to be in place in a reasonable amount of time now? What can be addressed further down the line?

As long as have fundamental structures to capture the information needed in the future?

Also, how to track the benefits? As it changes over time?

Retail utility is also participating in the wholesale market. It already exists.

Fear and concern of unknown costs could delay or prevent participation. Don't put things in place based on unqualified fears.

Look at other states and what they are doing, such as California and New York

There are also examples in Indiana – net metering rule (transaction costs were prohibitive to make them wholesale providers; when got to a certain level of saturation, then changed; may be too early to define those costs, but can still have a process for costs and when rates may need to be adjusted. Costs to other ratepayers, participants non-discriminatory; policy directive.

Here are the costs we do know initially; other costs and benefits that are not yet identified will be determined at a later day. Tracking, ability for utility to seek it, aggregator disputes.
These are the participation costs; these are the costs that should be tracked as participation grows. Could be differences between types of DERs (DR, etc.) Can be set up to reopen process and look at later. Initially, minimize the transaction costs.

The value of solar is to offset your own load. Will a retail customer want to participate in wholesale market?

DER can't be paid twice for the same product. But there are products that are not part of the retail program that could be compensated at the wholesale market.

Cost incurred by somebody to monitor and make sure the customer isn't getting compensated for the same product twice.

There may be some models that make it impossible for the DER to participate at retail and wholesale, so it doesn't have to be monitored. There may be other solutions.

During an emergency, utility could be counting on that DER for the utility's reliability. If DER goes to wholesale instead, then there could be costs to the distribution utility.

It's a state decision regarding whether to allow compensation in both the retail and wholesale levels for the same product.

Contracts are in place for EDG and for wholesale; customer can't change immediately and has to stay in one or the other for a set period of time. So there could be a standard agreement for DERs and DER aggregators.

How do we know if they are selling into the wholesale market while still participating at retail? Aggregator must inform the distribution utility. Some sort of verification system regarding participation in both.

There could be an interconnection cost model upfront, and then participation model that adds certain costs/fee.

It would be good to model it, but who will pay for the modeling?

[Break]

Cost of aggregation should be on aggregator, but it will likely be part of the contract between the aggregator and the DERs.

Under the interconnection rule, it's the customer.

Interconnection costs are distinct from aggregation costs. Aggregation costs can be in different buckets – administration, etc.

There could be penalties. If aggregator makes a commitment for generation and the generation doesn't show up, then utility must make up the difference. If there's an emergency and the aggregator is supposed to do the cut off and doesn't do it, then the utility has costs.

Market participants have penalties. FERC puts the obligation/penalty on the aggregator if the distribution utility is in outage; that happens at the RTO level.

Is there a duty by the utility if it causes penalties to be incurred by aggregator?

What would be the dispute resolution process at the IURC?

What are the obligations to perform at the retail level?

Storm outage is a risk the aggregator has to take.

The utility has a service obligation to the customer. Utility must be reasonable.

Such obligations may be part of the contract between the utility and the aggregator.

Aggregator will still be seeing the weather and can decide to not bid in resources.

Utility should not be held responsible for aggregator's failure.

We need to have transparency and clarity to determine the reasonableness of the utility's actions.

FERC issued a decision not agreeing to MISO's timeline or the lack of multi-nodal.

October 20th MISO DER Task Force will be regarding state's processes re: DERs

Nov 6th – Steve will be presenting at the Midwest Chapter of the Energy Bar Association in a panel on 2222.

It would be helpful if stakeholders and staff started outlining the possible components of the possible new rules.

Thanks to everyone for your interest and participation!

Next Steps:

Next roundtable discussion will be on possible next steps:
November 9, 2023; 9:30 a.m. to 12:00 p.m.; Conference B

- Comments may be submitted at any time to URCComments@urc.in.gov