FERC ORDER 2222 & DER POLICY AND IMPLEMENTATION REPORT

July 2025

CURRENT NEWS AND NEW DEVELOPMENTS

Summary of the latest developments in FERC Order 2222 and DER policy implementation

FERC and several states took action on distributed energy resource (DER) policy, the implementation of virtual power plants (VPPs), and FERC Order 2222 in the last several months. A summary of the actions is listed below.

RTO/ISO Order Implementation:

- On June 2, 2025, FERC approved by letter order MISO's third compliance filing to FERC with regards to the removal of a 10 MW minimum threshold in the review of physical withholding by market monitors, and the addition of a requirement that Electric Distribution Companies (EDCs) must inform DER aggregators when DER operation is overridden by the EDC [LINK]
- MISO submitted an additional compliance filing on May 16 in response to the remaining outstanding directives in FERC's order on MISO's second FERC Order 2222 compliance filing. This filing reflects FERC's acceptance of a June 1, 2029 implementation date and removes an earlier implementation date option proposed by MISO to use the DRR-Type I participation model. [LINK]

State FERC Order 2222 Implementation:

- On May 29, 2025, Indiana URC staff hosted a stakeholder meeting regarding rules that may be needed for a registration and study process of DER aggregations participating in wholesale markets via distribution systems in Indiana. [LINK]

- The DC Department of Energy and Environment (DOEE) has issued a Request for Information (RFI) regarding DER aggregations and FERC Order 2222 implementation in the District of Columbia. The purpose of the RFI is to gather insight into market interest and potential next steps that District agencies, utilities, and industry groups could consider taking to advance the deployment of virtual power plants and DER aggregations in D.C. Responses are due August 1, 2025. [LINK]

Other DER Policy Developments:

- On June 6, 2025, the Maryland PSC issued Order No. 91674, approving Commission Staff's modified proposed application for a License to Operate as a Distributed Energy Resource Aggregator (DERA). The effective date for the application is July 1, 2025. [LINK]
- On June 11, 2025, the Maryland PSC approved V2G regulations as part of its DRIVE Act implementation. The new rules are effective July 7, 2025. [LINK]
- In New York's Grid of the Future proceeding (Case 24-E-0165), the first iteration of the Grid of the Future Plan was filed on March 31 [LINK]. Stakeholder comments were initially due May 21, 2025, but on May 13th, the deadline was extended to July 15, 2025. [LINK]
- In the Commonwealth of Virginia, stakeholder comments were due June 9, 2025, on Proposed Rules relating to interconnection for small electrical generators and storage. By July 16, 2025, Commission Staff will file its response to any comments, proposals, or requests for hearing submitted to the Commission on the Proposed Rules. [LINK]

KEY ISSUES ANALYSIS

Consumer Protections

Protection of DER owners and electric consumers is paramount in the implementation of FERC Order 2222. While FERC Order 2222 is focused on the participation of DER aggregators in wholesale electric markets and explicitly does not intrude on regulation of retail electric sales, the primary venue for consumer protections will be retail regulators. Nevertheless, FERC Order 2222 does include several policies and provisions intended to protect customers: prohibitions on double compensation, requirements to use wholesale market participation agreements, and various coordination requirements.

- **Double Compensation:** The policies on double compensation and RTO/ISO compliance with these policies were the subject of last month's tracker report, and will not be re-reviewed here.
- **Market Participation Agreements:** FERC Order 2222 requires the execution and existence of Market Participation Agreements signed by DER aggregators. Market Participation Agreements are standard market participation agreements that define a DER aggregator's role and responsibilities and its relationship with the RTO/ISO. A key provision designed to protect consumers is the requirement that market participation agreements must include an attestation that the distributed energy resource aggregator's aggregation is compliant with the tariffs and operating procedures of

the distribution utilities and the rules and regulations of any relevant electric retail regulatory authority.[1]

- **Coordination Requirements:** While the FERC Order 2222 coordination requirements largely address the interaction between RTOs/ISOs, electric distribution companies, and DER aggregators, several of the required provisions are designed to ensure that DER owners and retail consumers are not subject to discrimination and abuse. For example, as discussed in the March tracking report, FERC Order 2222 requires that RTOs/ISOs and electric distribution companies must conduct comprehensive and non-discriminatory DER registration and DER review processes.[2] A future tracking report will review coordination requirements.

In their compliance filings with FERC Order 2222, each RTO/ISO complied with these provisions, albeit with variations across the RTOs and ISOs. As discussed in the May tracker report, each of the RTOs and ISOs developed double compensation and counting processes that have been approved by FERC. All of the RTOs and ISO complied with the Market Participation Agreement requirements by developing or adapting existing market participation agreements. Approval of these agreements by FERC was largely noncontroversial. The development of coordination requirements is a work in progress. FERC approved the structure of DER registration and electric distribution company review processes, but many of the details and systems (e.g., communications pathways) needed for coordination are still under development.

State Action Needed

In addition to RTO/ISO implementation of FERC Order 2222, state and local regulators will also need to implement policies that provide DER owners and consumers protection. Specific policies that state and local regulators should consider implementing include: DER aggregator licensing, information sharing rules, electric distribution company DER review processes, dual participation structures to allow DER participation in utility retail programs and RTO/ISO market products, and rules on customer selection and switching of aggregators.

- **DER Aggregator Licensing:** An important consumer protection policy that should be considered is the licensing of DER aggregators to operate in a state or local jurisdiction. Licensing rules can protect consumers by requiring DER aggregators to file various important information such as corporate structure and DER aggregation approach, along with key legal attestations that the DER aggregator will comply with codes of conduct, state rules and state tariffs. The specificity of these licensing rules will likely vary by state and will be dependent on state and local statutes and regulatory structures. While this is being managed at the RTO/ISO level in one fashion, each

[1] FERC Order 2222, P 352
[2] FERC Order 2222, P 292

regulatory authority will need to determine how aggregators are allowed to operate and interact with retail customers.

- **Information Sharing Rules:** The sharing of information about DER assets, DER owners, customer usage and tariff participation will be critical to the effective implementation of FERC Order 2222. Nevertheless, to preserve and protect the DER owner and customer privacy, cybersecurity, and critical infrastructure information, detailed rules on who can access and authorize access to this information will be needed. For example, access to customer usage information typically requires authorization from the end-use customer. State and local regulators will need to examine and consider the data needs and access of electric distribution companies, DER aggregators, RTOs/ISOs, retail electric providers, and VPPs carefully, while at the same protecting DER owners and customers with appropriate privacy policies.
- **Electric Distribution Company DER Review:** As discussed in the March Tracking Report, the review of DERs for possible participation in a DER aggregation is a core aspect of FERC Order 2222. This review is designed to ensure that DERs are capable of participating (i.e., are not precluded from participation due to participation in another aggregation or retail program) or do not create reliability concerns. In addition, review processes should be designed to not allow a DER site to be included in an aggregation without proper documentation from a customer to validate their participation. State and local regulators should consider setting rules or conduct oversight on how this DER review is conducted. Without clear rules and effective oversight to protect DER owners, DER aggregators, and customers, potential for discriminatory actions and self-dealing by electric distribution companies is possible.
- **Dual Participation Rules –** There are significant value streams that DERs can provide to a distribution utility. It is possible for new inverters to help correct power factor to reduce technical losses on the grid and extend the life of all connected equipment. Active management of the DERs on a feeder or substation could defer or eliminate capital upgrades of those systems. While FERC Order 2222 is focused on wholesale market participation, each regulatory authority should consider the value streams their distribution companies could capture with DERs and determine appropriate structures to allow both the distribution grid and the wholesale market to benefit from DERs.
- **Customer Selection and Switching Rules:** To protect customers from fraud and abuse, processes should be implemented that support customer selection of aggregators and allow customers to switch to a different aggregator at a future time. In addition, customers should be provided with sufficient information about their rights and choices prior to participating in an aggregation, including signing and agreeing to data privacy and security rules. Rules and programs should also be developed to inform customers who are enrolled in a program currently about their switching rights so they can make informed decisions and limit negative impacts from bad faith players.

In addition, state and local regulators will need to incorporate oversight and dispute resolution processes into their workflows and policies. Potential abuses by DER aggregators and electric distribution

companies need to monitored, and procedures to address complaints about payments and tariff violations will likely be needed.

The Use of a DER Registry to Assist

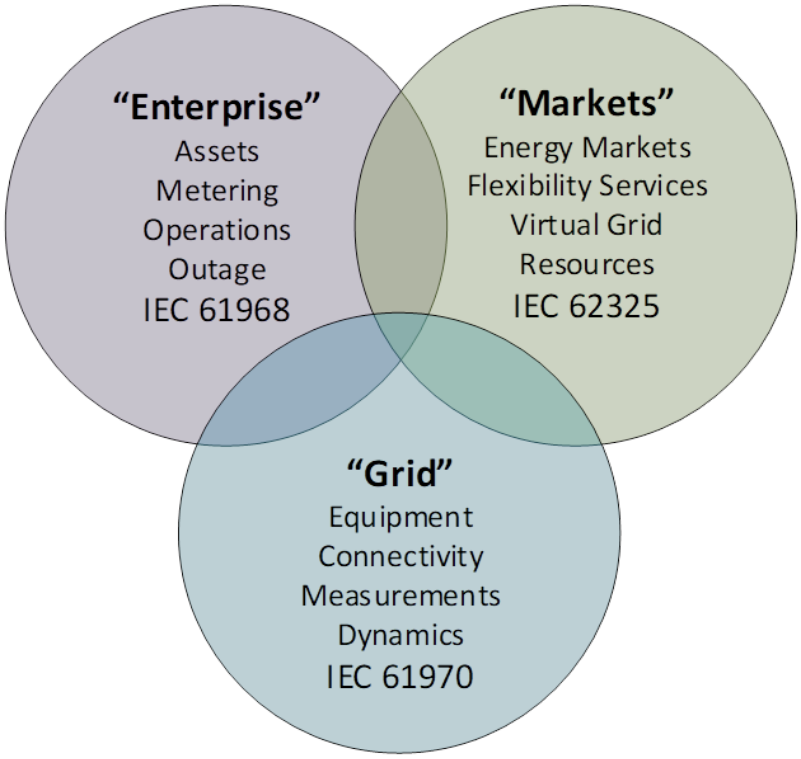
A DER Registry can provide a common database (single point of truth), which incorporates necessary data privacy and security protections that will protect DER owners and consumers. The implementation of FERC Order 2222 requires that consumers be provided with the opportunity to select their aggregator, change their aggregator and ensure no aggregator has access to their information without the customer's selection of them as their aggregator. A consumer should not be expected to understand the complexity of the aggregation and enrollment requirements. These structures are complex and are the reason that competitive aggregators exist. However, due to the competitive nature of these aggregators, a DER Registry should provide necessary protections and information to the DER owner to allow them to understand how their DER is currently enrolled so they can make their decisions effectively without risk of an uninformed, or bad faith, actor requesting them to switch. In the event the DER owner does want to make a change, the DER Registry should facilitate that transition on the date the DER becomes eligible to switch aggregators, according to the specific utility retail program or RTO/ISO market product rules. With a central DER Registry, this administrative process can allow DER aggregators to quickly screen possible DER candidates for eligibility and thereby avoid wasteful and inaccurate DER aggregations that a utility or RTO/ISO would reject in their review process.

CIM – The Best Technology You Never Knew About

Introduction to CIM

Over the past decade or two, millions of dollars have been spent by electric utilities to develop corporate business-level data glossaries and more technically focused data dictionaries. But very few of the projects charged with developing such tools investigated the completely free, open-source electric utility data model known as the Common Information Model, or CIM. The CIM was developed by electricity industry experts for use by the electricity industry, and covers data used from the largest investor-owned utility to the smallest rural cooperative, representing data related to generation, transmission, distribution, metering and meter data, customer data and, yes, even distribution-connected customer energy devices.

The CIM is expressed in Unified Modeling Language (UML) and can represent over 2,000 different utility data objects. Each object is represented by a UML class and has a well-defined definition along with typically multiple data attributes and several relationships to other objects. The model is hierarchical, with some objects being specializations of other objects. For example, a "switch" is one of the CIM classes which is further specialized into fuses, jumpers, reclosers, breakers, and so on. All switches have common attributes including rated current, a normal position, and a position at the present time. Specialized classes add other elements, for example the breaker has a breaking capacity and an in-transit time. All attributes have well-defined types with explicit units-of-measure to minimize the possibility of misinterpreting the data for each instance of the object.



The ability to create a representation of the power grid was the motivation behind the original CIM development work and the core of many interoperability successes around the world. Because each element of any power system can be represented by one of these objects and because each object has associated terminal objects, the entire power grid can be logically assembled into a networked set of data. With such data as a foundation, any power grid can be described and used as the basis for utility software solutions, such as planning analysis simulators and real-time grid management tools.

Building upon the grid representation library (which practitioners call the "Grid Package"), an entire library of objects has been established to track the day-to-day operations of an electric utility. The scope of this section of the CIM entitled the "Enterprise Package" covers many functions across the utility including customer information management, metering and payment, asset management, planned and unplanned outage management, switching operations, and work management. While representations in the Grid Package are often long-lived, for example a switch object might remain unchanged for years, the data in the Enterprise Package is much more dynamic. Tracking individual transactions among utility systems, all with unique identifiers, allows for data correlation and orchestration.

The third section of the CIM was developed to support wholesale electricity markets and was named the "Markets Package." Here market transactions like bids and offers, clearing results, dispatches, and settlement information are all modeled to support energy, capacity, and Essential Reliability Service[3] markets. This modelling also includes the concept of locational marginal pricing and, not surprisingly, ties directly to the "Grid Package" so that financial transactions can be aligned with the physics of the power system. This illustrates the point that, while there are different sections of the CIM, the model itself is unified, allowing the users to select elements across the packages without restriction. To avoid the risk of this article delving into the details of the CIM, it is helpful to point those interested in such details to the "Common Information Model Primer"[4], an excellent guide to understanding the CIM which is maintained and published at no cost by EPRI.

A Case Against CIM?

The business case for CIM has existed for decades. But for those who have been developing and proselytizing its use there are common excuses which are often raised as weaknesses. The IT manager might say "standards are too rigid and slow," the grid planner might say "my grid is unique and would never fit into the CIM", and the management consultant might note in a million-dollar study that, "adopting the CIM is too expensive". While all of these have some kernel of truth (standards can be rigid, grids do have unique features, and there is a cost to any change), none of them is defensible.

Standards Are Slow and Rigid. Yes, it takes months – sometimes years – to develop standards and gain international approval. And yes, the CIM has a set of international standards; but the underlying CIM model is open-source and can be used for a variety of uses without needing to wait for that process to play out. In fact, this is the recommended approach to using CIM. First, one starts with the problem which needs a common approach, for example describing asset characteristics to populate an asset management system. The implementer can use elements of the CIM to make her own implementation inside the utility. And as more and more utilities find the same need, then – and only then – does one create the standard and start to move the industry to implement the standard. Standards exist for common "use cases" of the CIM. IEC 61970[5] standards implement standard exchanges for the Grid Package, IEC 61968[6] for the Enterprise Package, and IEC 62525[7] for the Markets package. If one has a common need and/or has a vendor who has a multi-national product, chances are there is already a CIM "profile" ready and available from the IEC.

[3] https://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/ERS Abstract Report Final.pdf
[4] https://www.epri.com/research/products/000000003002029927
[5] https://webstore.iec.ch/en/publication/61167
[6] https://webstore.iec.ch/en/publication/32542
[7] https://webstore.iec.ch/en/publication/31487

Every Grid is Unique. Primarily based on the customer base (urban, suburban, rural, etc.), there are different ways to construct grids (networked, radial, looped, etc.). Plus, there are many different topologies that can be implemented inside substations, often balancing cost against reliability. Finally, more often than one might like to admit, utilities implement different terminologies and different processes for things that are quite similar across all utilities. All of these variations can be modelled since the CIM has the individual elements available in the library and it is up to the user at each utility to map them to their terminologies (or update their non-standard terminology). As for differences in the physical grids themselves, the modeler can connect the virtual data elements together as they are connected in the real world.

The CIM is Expensive. Change is costly. And radical change can be extremely costly. This is why those who have implemented CIM often recommend a gradual implementation. Using CIM in conjunction with specific interfaces during system upgrades is often the best approach. Have a new outage management system coming in? Ask the vendor to implement a CIM interface to publish the outages. These interfaces might already be in the chosen vendor's platform and then one only need to build an adapter or update the subscribing systems. Over time implementing CIM interface-by-interface, the entire enterprise can be standardized in perhaps a decade, with the error-prone, unreliable interfaces the target in the short term.

A New Case For CIM

The number of wholesale market operators in the United States is small. There are seven. These organizations could have adopted CIM when they were established under FERC jurisdiction or at any time after; but they have not. In fact, a cottage industry began to flourish in the 2000s where vendors would build standard interfaces to each market operator so that participants in multiple markets did not have to manage the frequent user interfaces and data format changes across multiple regions. But a few success stories exist in this domain, most notable at ERCOT, where a CIM-based model exchange process was established with its transmission-owning members.

The number of transmission utilities is larger and varies depending on how the count is performed, but it is safe to estimate this number in the several hundred range. Again, these companies could have adopted CIM for internal benefit, especially as the age of mergers and acquisitions has collapsed the numbers. But only a few have made the transition, such as AEP, which has embraced CIM leveraging Siemens solutions.[8] Other transmission utilities have begun to consider the CIM for their internal processing, especially since

[8] https://assets.new.siemens.com/siemens/assets/api/aep-casestudy-intl-version.pdf

the benefits have been clearly documented by EPRI outlining the need for a central Network Model Manager (NMM) tool to be deployed inside each transmission utility.[9]

The industry has been slow, at times hostile, towards moving away from proprietary, vendor-defined interfaces both among systems inside their utilities and between systems among utilities; but there is a an even more compelling case to implement the CIM at distribution.

The number of distribution utilities is large. While there are less than 200 investor-owned utilities serving the majority of electricity customers in the United States, EIA reports[10] nearly 800 customer-owned utilities (generally cooperatives) and over 2,000 government-owned utilities (generally municipal utilities). Focusing on the Grid package, there are many different stakeholders who currently would like some of the data from these utilities. It is hard to argue that this demand will only grow. Example of entities include:

- **Bulk Power System Operators** to improve system planning studies, optimize short-term and long-term outage planning, and improve the reliability of system operations including congestion management.
- **Electricity Market Operators** to enable the coordination of services at both transmission and distribution to support FERC Order 2222 and improve market forecast for distribution-connected resources.
- **External Stakeholders** to perform wide-areas studies across regions as well as explore the impacts of new technologies on the costs of energy and the levels of reliability and to streamline interconnection processing for proposed developments.

It is difficult to envision how any of these can be achieved without a standard representation of distribution grids, and the only real option for delivering standards representations is using the CIM.

Clearly, it would be difficult to have a standard representation of distribution grids without the use of the robust, consensus-based information model like the CIM. To illustrate how it could be used, it is helpful to look to the Common Grid Model Exchange Standard (CGMES). CGMES is a subset within the IEC 61970 series and has facilitated the publication of grid models in Europe starting in 2009. Each of the roughly 40 transmission operators across Europe publishes its models to the respective Regional Security Coordinator (RSC) each hour, not only with the grid topology, but also with current state information like energy flows and outages. Each RSC, in turn, assembles the individual grid models into a regional model to perform contingency analysis, calculate capacity values, coordinate outages, and assess resource adequacy.

[9] https://www.epri.com/research/products/3002003053
[10] https://www.eia.gov/todayinenergy/detail.php?id=40913

The CGMES example supports the publication of transmission models, but concepts are similar for distribution-models, especially with clear guidance on how to create an equivalent model available from the NERC[11] when those distribution models need to be connected to transmission models. Until recently, unbalanced models for the low-voltage networks were not fully supported by the CIM; however, recent focused efforts including from EPRI and the National Laboratories, means that support is available in the next edition of the CIM and is in the process of being vetted by vendors.[12]

Looking Ahead

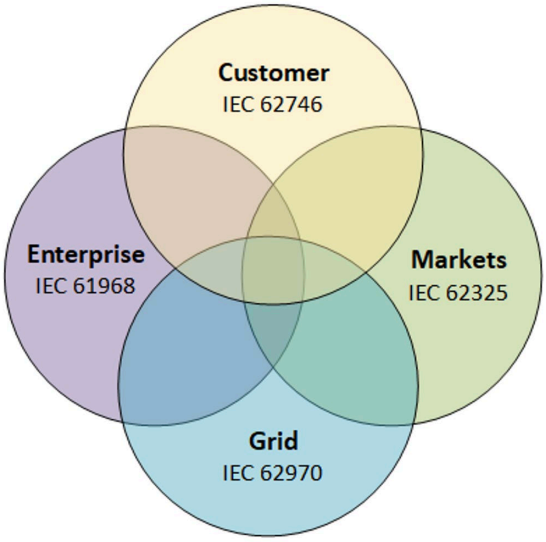
The future power system looks radically different from today with the majority of the bulk power coming from intermittent renewable resources connected to the grid and offset by large amounts of local power production from smaller installations. While this alone is a radical change, the ever-increasing need for grid support services to keep such a chaotic system in balance means that grid services, especially grid services supplied by distribution-connected customer-owned devices, is essential. Supplementing the support for low-voltage, unbalanced networks in the Grid Package, there are equally revolutionary improvements in the Enterprise and Market Packages.

The Enterprise package has a robust methodology for tracking what is known as "data sheet" information. This data encapsulates the manufacturer-supplied capabilities of any given device, such as the voltage at which the device can be operated and the maximum current the device can transmit. Historically used to support traditional assessment management functions for utility-owned equipment including transmission and distribution lines, transformers, and switches – the same approach is not available to be used to track commercial devices, like solar inverters, stationary batteries, and smart electric vehicle charging. This model becomes the hub of device registry that each distribution utility must keep understanding how the power system will react to different conditions, including the behavior of the customers operating those devices, which is a function of things like weather but also more difficult to model, like the driving patterns of an individual electric vehicle owner.

[11] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_A_Parameterization.pdf

[12] https://www.epri.com/research/products/000000003002027444

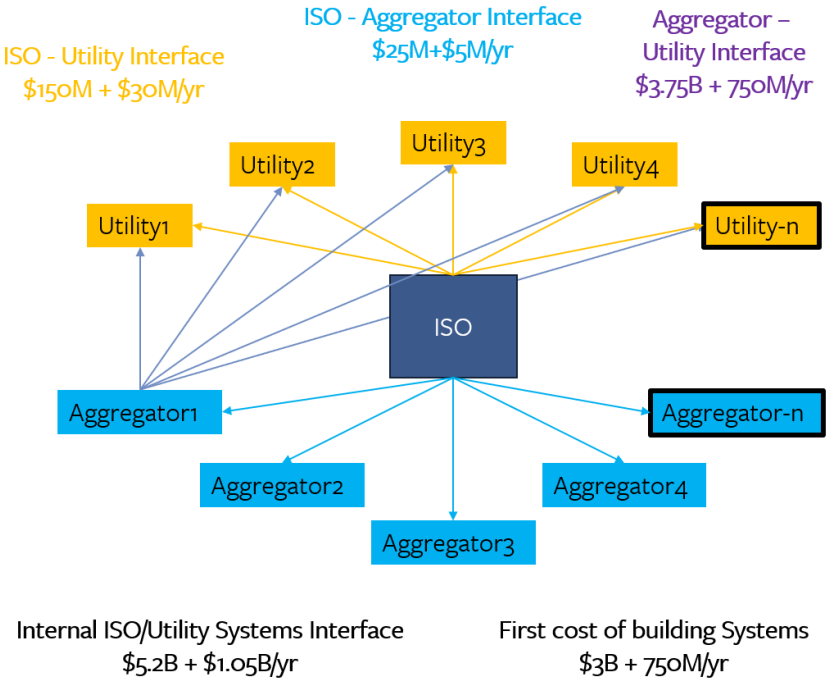
Finally, for the devices which can provide distribution grid services like local congestion management, the Market Package has been updated with all the features needed to extend the existing wholesale market concepts to those of the virtual power plant. Since the CIM already supports demand response resources for wholesale markets, which are often comprised of very small customer-owned devices not tracked by the utility, the support of local flexibility markets like those already a reality in Europe is available. Furthermore, the need to model the operational modes and response to abnormal system conditions for inverter-based resources, as defined by IEEE 1547[13], is also embedded in the CIM.



Thus, distribution-connected, customer-owned energy devices from batteries and solar inverters tracked by the utility to devices like thermostats and smart water heaters which can provide services when aggregated into a virtual power plant have all three legs: (1) the device models are available in the Enterprise Package; (2) they are mappable – when deemed important enough to be tracked by the utility – to physical representations in the Grid Package; and (3) when supplying services – either alone or as an aggregation – the Market Package provides the market perspective to track the economic transactions. Given the importance of this new era in power grid, a new series of CIM data exchange standards was launched to cover interfaces to the customer as the IEC 62746 series and in November of 2024, the first set of message profiles were published entitled "IEC 62746-4: Demand Side Resource Interface"[14].

As our industry transitioned from analogue mimic boards in our control rooms, to digital screens presenting information for our new digital Energy Management Systems (EMSs), we encountered significant issues with custom interfaces to the 12,000 or so generation facilities made by a handful of equipment vendors that were connected to the grid. This drove the industry, through EPRI, to develop the CIM to minimize this cost. Today, we face a very similar situation incorporation of DERs into our grid. But this time we have hundreds, or thousands, of equipment vendors and millions of DERs. The use of CIM in this instance to effectively enable DERs at a reasonable cost is paramount.

[13] https://standards.ieee.org/ieee/1547/5915/
[14] https://webstore.iec.ch/en/publication/78336



The Cost of Business as Usual:

$12BN + $2.6BN/yr

- Over 3,000 utilities, the RTOs/ISOs and Aggregators will have to independently create and maintain their own systems. Functionality limited to 'their scope'.
- DER Enablement to utility programs and market products inhibited by administrative processes of interface and information exchange
- Provides no direction for existing utility system software vendors to improve their systems for DER data use and exchange
- Costs are significant and escalating

This simple example above illustrates the cost of our industry approaching the implementation of DERs in ad hoc or customer application fashion. The CIM provides the foundation to eliminate these substantial costs for the industry while we strive to enable DERs to the grid and markets.

TRACKER TIPS AND HIGHLIGHTS

The Policy Tracker is available to the public at FERC2222.org. [LINK] If you would like to recommend content for the Tracker or provide feedback, please contact us.

The Policy Tracker allows users to filter and search for content within a database of content pertaining to DER Policy, with emphasis on the implementation of FERC Order 2222. The keyword search functionality includes review of the source documents within the database, while the filters allow users to narrow their searches based on issue topic, RTO/ISO, and state or federal regulators.

The following figure shows a search for the "VPP" issue tag.

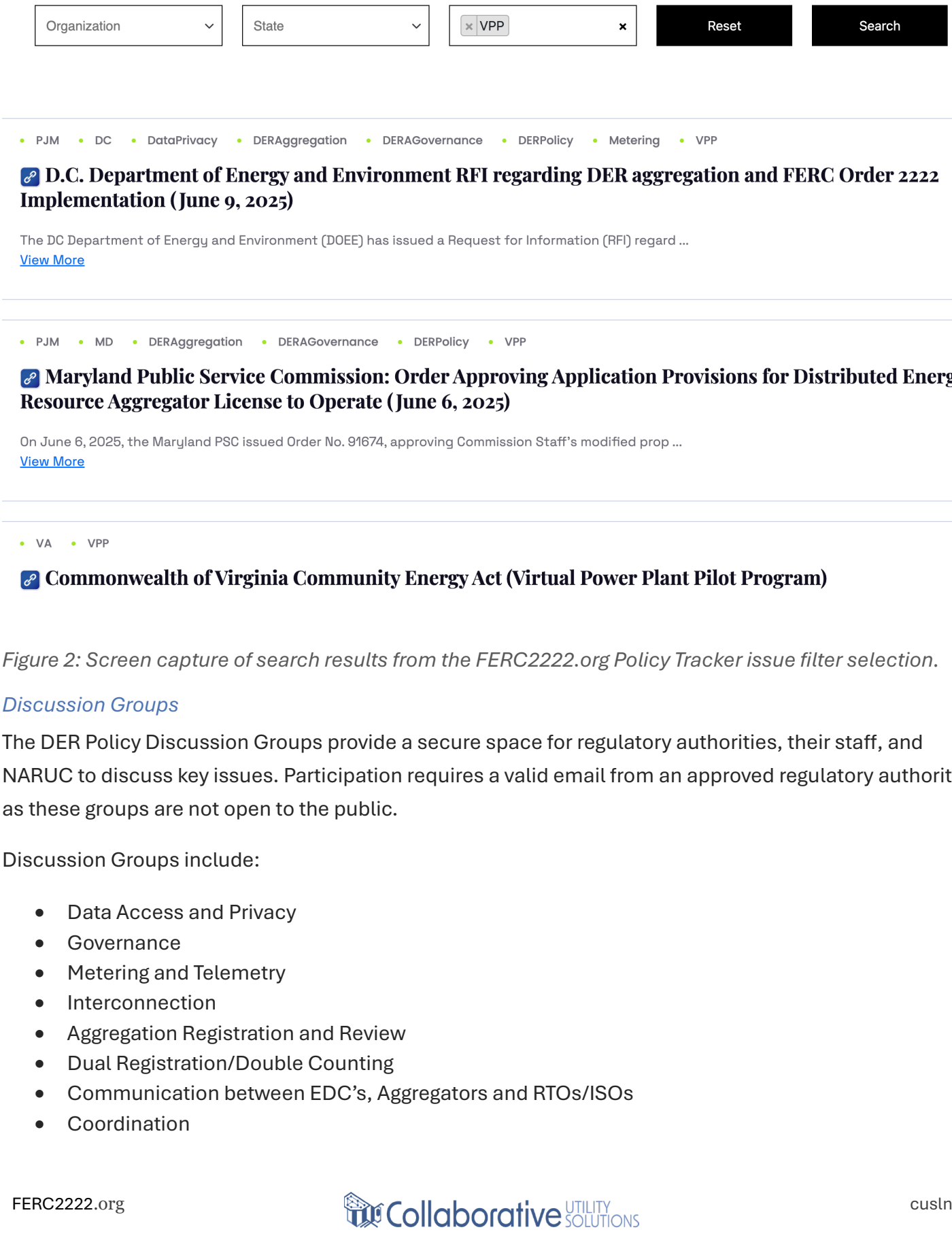


Figure 2: Screen capture of search results from the FERC2222.org Policy Tracker issue filter selection.

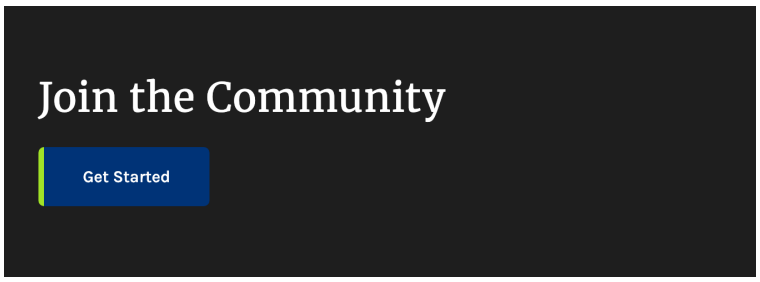
Discussion Groups

The DER Policy Discussion Groups provide a secure space for regulatory authorities, their staff, and NARUC to discuss key issues. Participation requires a valid email from an approved regulatory authority, as these groups are not open to the public.

Discussion Groups include:

- Data Access and Privacy
- Governance
- Metering and Telemetry
- Interconnection
- Aggregation Registration and Review
- Dual Registration/Double Counting
- Communication between EDC's, Aggregators and RTOs/ISOs
- Coordination

- Cost and Investment Recovery



To access the Discussion Groups feature, navigate to the Discussion Groups page on FERC2222.org [LINK] and click on the "Get Started" button (see Figure 3). You will then be prompted to enter your email address. If your email domain is already white-listed, you will be sent an email with a login code to complete the login process. If your email is not white-listed and you believe it should be, please contact us at 2222website@cusln.org.

DISCLAIMER