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1:00 PM Eastern Time

Interconnection + Enabling DERs Through Industry Collaboration

FERC2222.org

Facilitating Collaboration Among Policy Makers on DER Integration

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Collaborative Utility Solutions

Empowering the Energy Transition

DOE Project Information

This is a project in collaboration with PNNL sponsored by the DOE Office of Electricity. The view and opinions expressed in this presentation are CUS' alone and do not necessarily reflect those of DOE or PNNL.

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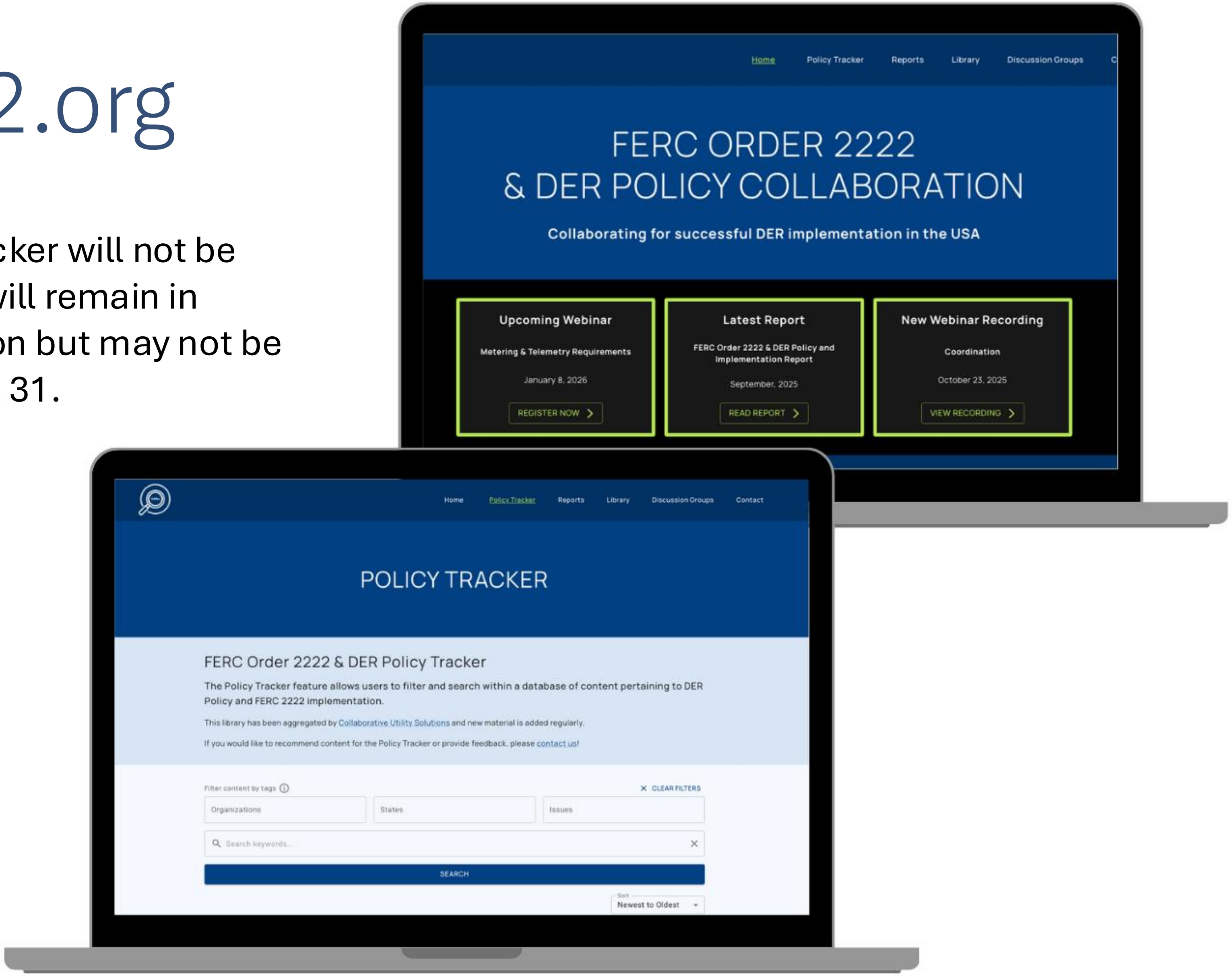
As of August 31, the tracker will not be kept current. Website will remain in place with all information but may not be updated beyond August 31.



Recent FERC Order 2222 Developments

- SPP filed a third compliance filing to address directives include in FERC's September 2025 compliance order. The third compliance filing addresses two, non-controversial changes required by FERC: clarifying that the host utility is the EDC that will be reviewing DER aggregations and clarifying nonperformance penalty terms.
- In Virginia, Governor Spanberger signed SB223 on April 22, 2026, establishing a Distributed Energy Resources Task Force as an advisory commission within the executive branch, with the purpose of developing a comprehensive strategy to advance the Commonwealth's transition toward integrated DER markets and to support the Commonwealth's compliance with FERC Order 2222.

Other DER Policy Developments

- On Mar. 16, 2026, Gov. Maura Healey issued Executive Order No. 654, stating that Massachusetts will bring 10 GW of new energy resources online, under contract, or under development by the end of 2035, including new solar, VPPs, managed EV charging, EE and DR.
- On April 21, 2026, the Hawaii PUC instituted a proceeding to design and implement a VPP grid-services program to improve upon existing scheduled-dispatch grid-services programs, incentivize new customer-sited DERs and comprehensively aggregate legacy and future DERs to support grid operation in the HECO territories.
- On Apr. 20, 2026, the New Jersey BPU issued another RFI in response to Governor Mikie Sherrill's Executive Order No. 2, which had directed the Board to accelerate deployment of both distributed and utility-scale storage and to develop a VPP program to aggregate behind the meter resources. In July, the NJBPU Staff published a Straw Proposal and scheduled a public meeting for July 30 to discuss the proposal. Stakeholders were invited to submit written comments on the straw proposal in Docket No. QO26030099 by August 17, 2026.
- NAESB – The working group at NAESB has been working to develop a standard for the minimum set of data requirements that should be included in any DER Registry. This has been a very long and detailed process over several years and is expected to be completed in September .

Other DER Policy Developments

- The Maryland PSC issued an Order on May 6, 2026, addressing comments and recommendations related to utility conceptual reports filed in Case No. 9778 and created a Data Exchange Work Group (DEWG), which over the next 6 months is directed to 1) develop regulations for third-party access to customer data; 2) file RFP criteria for a Green Button Connect My Data-compliant data exchange platform; 3) file a model third-party data access tariff; and 4) file a phased DER Registry roadmap.
- Maryland passed the Utility RELIEF Act (HB1532) (signed by Gov. Moore on May 12, 2026) which expedites local permitting for rooftop solar; expedites interconnection of data centers that use clean energy sources to meet their demand (including DR and VPPs); allows plug-in solar to bypass utility approval and interconnection if <1,200 W.
- Per the DRIVE Act, Maryland IOUs filed reports due July 1 relating to potential for deferral of distribution system projects. Comments are due Sept 15, 2026.

Other DER Policy Developments

- On May 13, 2026, the Minnesota Public Utilities Commission approved Phase 2 of Xcel's Capacity*Connect program as a "learning phase." Xcel is partnering with Sparkfund to deploy 50-200 MW of utility-owned, FTM, distribution-connected BESS by the end of 2028,which will be aggregated and dispatched to MISO wholesale markets as a VPP.
- The Michigan PSC is reviewing an expedited VPP pilot application filed in June 2026 by DTE Electric Company (DTE) in Case No. U-21653. The proposed pilot would enroll up to 100 residential batteries to evaluate customer enrollment rates, customer charging patterns, and event participation over a 2-year period.
- Staff of the New York PSC was granted an extension until October 30 to file their Grid of the Future Report. The report was previously due to be filed June 30. PSC Staff also held a technical conference on June 25 to discuss the project.
- The Department of Energy and Environment in DC recently issued a regulatory roadmap for implementing FERC Order 2222 in the District.

FERC Order 2222 – Interconnection

- FERC determined that it would "decline to exercise our jurisdiction over the interconnections of distributed energy resources to distribution facilities for the purpose of participating in RTO/ISO markets exclusively as part of a distributed energy resource aggregation."
- Found that the physical interconnection of DERs remains governed by state and local law for facilities interconnected to the distribution system.
- RTO/ISO compliance with FERC's interconnection determinations was relatively non-controversial.
  - All the RTOs and ISOs complied with the Commission's determinations on the lack of application of FERC Order 2003 and 2006 to individual DERs participating in DER aggregations, and the Commission has approved these revisions.

RERRA Activity – Interconnection

- Many states are modernizing their small-generator interconnection procedures to ensure that interconnected DERs can participate efficiently in wholesale DER aggregations and virtual power plants (VPPs)
- State and local regulators are updating interconnection rules to streamline review processes, reduce queue delays, improve hosting-capacity analysis, incorporate advanced inverter capabilities under IEEE 1547-2018, establish storage-specific procedures, enable flexible and limited-export interconnections, and improve utility transparency and data sharing.
- A growing number of states are also beginning to address the unique operational issues raised by Order 2222
  - For example, California, New York, Massachusetts, and Maryland
- Few states have adopted rules that explicitly govern DER aggregation interconnection under Order 2222.

FERC vs. NERC definitions

- FERC's DER definition includes demand response/load modification (market-focused); NERC's is narrower — only resources that inject power and affect safety/reliability.
- Demand response is not new — utilities have managed load variability since Edison's Pearl Street era, and it doesn't require an interconnection agreement.
- Injecting power into the grid raises distinct safety/reliability concerns, so it does require a utility interconnection agreement.
- Historical confusion: behind-the-meter generators were once lumped into demand response programs, with inconsistent utility practices; today, the standard is that any injecting resource needs an interconnection agreement.

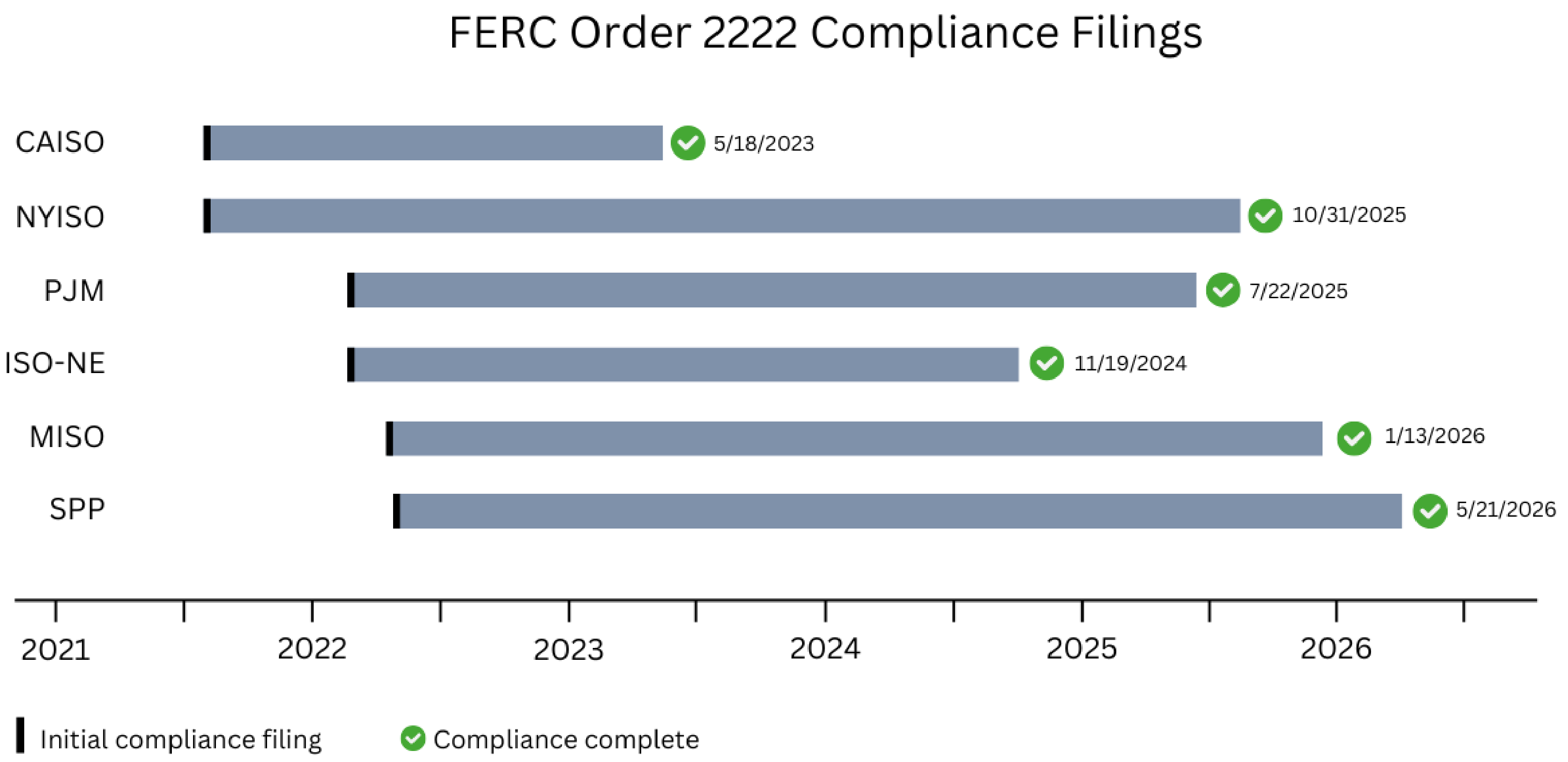
Individual DERs vs. Aggregated DERs

- Individual DERs are studied on their own parameters, plus system-wide factors (other DERs on the line, overall grid conditions), before interconnection is approved.
- Individually installed DERs serve the owner's own purposes and operate independently.
- Aggregations shift many independent resources into coordinated action for a program or market purpose — this changes grid impact significantly.
- Analogy: a group pulling a rope randomly vs. pulling together in unison — very different effects on the system!

FERC's Approach to Aggregations

- FERC does not require a separate interconnection agreement for aggregations, which is logical because aggregations can span many feeders, substations, or an entire utility system.
- Utilities and RTOs/ISOs still retain the right to study aggregations' coordinated impact on the grid.
- These aggregation impact studies are a key part of the approval process at both the distribution utility and RTO/ISO level.

Status of FERC Order 2222 Compliance



Status of FERC Order 2222 Implementation

RTO/ISO	Order 2222 Implementation Date	Status
California Independent System Operator	November 1, 2024	Complete
New York Independent System Operator	April 30, 2027	Partial implementation today; full Order 2222 implementation by April 2027.
ISO New England	**Energy & Ancillary Services:** November 1, 2026 **Capacity:** In place for Forward Capacity Auction 19	On schedule

Status of FERC Order 2222 Implementation

RTO/ISO	Order 2222 Implementation Date	Status
Midcontinent Independent System Operator	**Phase 1:** June 1, 2027 **Phase 2:** June 1, 2029	Phased implementation
PJM Interconnection	**Capacity:** February 1, 2027 (for 2028/29 Delivery Year) **Energy & Ancillary Services:** February 1, 2028	Phased implementation
Southwest Power Pool	**Second Quarter 2030**	Latest implementation schedule

Status of RERRA FERC Order 2222 Implementation

- Only a few states have taken action on implementing FERC Order 2222.
- Maryland, Pennsylvania and New Jersey have initiated proceedings to implement Order 2222.
  - Of these three states, Maryland and New Jersey are the furthest along.
  - The New Jersey Board of Public Utilities (NJBPU) recently issued a VPP Straw Proposal in July 2026.
- Virginia is considering FERC Order 2222 in its DER Task Force.
- Several other states that have considered aspects of FERC Order 2222.
  - Proceedings in Indiana, Iowa, Michigan, Minnesota, Missouri, and Wisconsin focus on whether the third-party demand response and DER aggregators enabled by FERC Order 2222 can operate within their states.

FERC2222.org Reports

- September 2024 – Introduction and Welcome
- November 2024 – History of FERC Order 2222
- January 2025 – Governance
- March 2025 – Aggregation Registration and Review
- May 2025 – Dual Registration/Double Counting
- July 2025 – Customer Protections
- September 2025 – Coordination
- November 2025 – Metering and Telemetry
- January 2026 – Communications Between DERAs and EDCs
- March 2026 – Communications and Control for DERs
- May 2026 – Enabling DERs through Industry Collaboration
- July 2026 - Interconnection

The Common Information Model (CIM) is...

- An information model for organizing shared data, sometimes called an "ontology" or "semantic Model"
- Expressed in Unified Modelling Language (UML)
- Specific to the electric utility industry
- Maintained as an open source Apache 2.0 by UCAIug
- The foundation of four families of IEC data exchange standards:
    - IEC 61970 Series (Grid)
    - IEC 61968 Series (Enterprise)
    - IEC 62325 Series (Markets)
    - IEC 62746 Series (Customer)

Success of the Modern Grid?

- Bulk Power System – Broadly adopted with EMS and Transmssion
  - Number of Wholesale Market Operators = 7
  - Transmission Owners/Operators ~500
  - Generation facilities ~10,000
- Distribution System – Meter & CIS adoption, low adoption in other areas of distribution
  - Distribution Utilities ~3,000
  - Electricity Customers ~160,000,000
  - Rooftop Solar ~5,000,000
  - Electric Vehicles ~5,000,000
  - Grid Device "Ceiling" **~500,000,000** (using 3x Customers)

Europe's Success in Grid Model Data

1. Each TSO builds its own Individual Grid Model (IGM) for its control area; each IGM describes the Equipment with Connectivity plus a Solved Powerflow
2. Each RCC (Regional Coordination Centre) merges the relevant IGMs into a Common Grid Model (CGM) with a CGM-wide Powerflow
3. Results used for regional capacity calculations, security analyses, and market operations
4. Process is completed over multiple timeframes:
    - Planning Cases: Y-1 (Year Ahead) + D-2 (Two Days Ahead)
    - Operational Schedule Cases: D-1 (Day-Ahead) + **Multiple Intraday/Hourly**!!!!!
    - Tens to Hundreds of Millions in savings

Europe’s Success in Market Harmonization

The European Union has harmonized wholesale markets across the continent with standard data exchanges built on the CIM, and published as IEC profiles.

- IEC 62325-451-1:2017 market acknowledgement
- IEC 62325-451-2:2014 scheduling
- IEC 62325-451-3:2014 transmission capacity allocation
- IEC 62325-451-4:2017 settlement and reconciliation
- IEC 62325-451-5:2015 problem statement and status request
- IEC 62325-451-6:2018 publication of information
- IEC 62325-451-7:2021 balancing
- IEC 62325-451-8:2022 HVDC Scheduling process

North America is Next!

DERs

NORTH AMERICAN
CIM PROFILE

1) Confirm first scope, governance structure, and stakeholder commitments
2) Formed task forces and beginning work, gaining NERC/vendor/utility support and interest
3) Meet periodically as a group, meet measurable checkpoints
4) Interoperability aligned to the 12 to 18-month goal

Two New White Papers

Distributed Energy Resources:
From the Margins to the Mainstream

How to Determine the Real Value of DERs

In the interest of time today, we will cover on a few slides covering these papers. The appendix contains a more complete overview. We encourage everyone to take the opportunity to read these papers as they summarize lessons learned over the past 5 years and provide real world context for a path forward.

Executive Summary

- **The industry has crossed a decisive cost threshold.** Realizing DER value now requires structural change across three fronts:
    - **An evolution in planning –** replace top-down Integrated Resource Planning (IRP) with bottom-up Integrated System Planning (ISP) that starts at the distribution edge.
    - **A regulatory correction –** a DER Power Purchase Agreement achieving the same grid outcome as a utility-owned peaker should receive equivalent financial treatment.
    - **A return to collaboration –** FERC Order 2222 is a mandate to rebuild shared infrastructure, data standards, and coordinated planning across the industry.
- **The scale of change is already underway.** Solar PV module costs have fallen 97% since 2006, Li-ion battery pack costs are down more than 90% since 2010, and the industry expects 262 GW of new DER and flexibility capacity between 2023 and 2027.
- **"There are no silver bullets — we need them all."** Large baseload resources remain essential; DERs are the fastest tool to add capacity, defer infrastructure, and build reliability and resilience.

The DER Cost Revolution

Technology maturation, manufacturing scale, and sustained federal R&D have driven DER costs down dramatically, and DERs have moved from tolerated load modifiers to dispatchable, market-eligible grid resources.

Technology	Then	Now
Solar PV Module Cost	~$7/W (2000)	<$0.25/W (early 2020s) — 96% reduction
Li-ion Battery Pack Cost	>$1,200/kWh (2010)	<$150/kWh (mid-2020s) — >90% reduction
LFP Battery Cost	$750/kWh (2010)	$72/kWh (2024) — 90% reduction
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- **FERC Order 2222 (2020) –** requires RTOs to allow DER aggregations into wholesale energy markets, elevating rooftop solar, batteries, and smart thermostats to the same standing as a gas peaker.
- **Virtual Power Plants –** have moved from pilot programs to operational reality; the Rocky Mountain Institute confirms VPPs can match or beat the cost of a gas peaker plant.
- **LBNL VPP Inventory (2025) & EVs/V2G –** LBNL now catalogs active VPP programs nationwide, while vehicle-to-grid pilots are turning millions of parked cars into a distributed storage fleet.

From IRP to ISP

Utilities have long planned top-down: forecast load, build large central generation, then size distribution last. ISP inverts that hierarchy, starting with granular, location-specific distribution needs.

Dimension	Integrated Resource Planning (IRP)	Integrated System Planning (ISP)
Conducted by	Individual utilities / LSEs	Grid operators with stakeholders
Primary question	What resources should we acquire?	How should the system evolve as a whole?
Geographic scope	Utility service territory	Aggregated to Bulk system level
Transmission treatment	Often assumed as fixed/given	Central variable in the analysis
Regulatory context	State PUC approval	Broad stakeholder engagement
Demand-side integration	Rarely considered	Required input
DER treatment	Load modifier / net load input	Utility-class dispatchable resource

- **Makes DERs visible as grid assets –** the difference determines whether a utility builds a $30M substation or deploys a $4M DER plant instead.
- **Enables Non-Wires Alternatives –** Con Edison's Brooklyn-Queens program used customer-sited resources to defer a $1.2 billion substation project.
- **Aligns investment with grid needs –** utilities can target DER incentives precisely where distribution capacity is scarce, improving resilience for vulnerable circuits.

The DER Value Stack

- Seven distinct value streams DERs deliver that central station resources structurally cannot:
   1. **Locational & avoided infrastructure –** a well-placed 5 MW battery can defer tens of millions in substation upgrades.
   2. **Resilience & reliability –** islanding capability lets hospitals and critical loads ride through outages.
   3. **Peak demand & capacity value –** equivalent peaking capacity at a fraction of capital cost, deployed in months.
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   5. **Avoided emissions & compliance –** no fuel cost, no carbon liability, no criteria pollutant emissions.
   6. **Customer engagement & flexibility –** load can be shifted, shed, or modulated in real time.
   7. **System utilization & load factor –** reshapes the load duration curve feeder by feeder, reversing a 30-year decline in system load factor.

Central station plants provide bulk energy across the system. DERs deliver precision value at the grid edge: deferred infrastructure, local reliability, peak shaving, power quality, environmental compliance, demand flexibility, and load factor improvement.

The goal is not to choose between them; it is to ensure that every resource competes on a genuinely level playing field and is deployed where it delivers the most value.

The Central Principle of DER Valuation

DERs are not another generation resource to be compared only on $/kW-yr. **They are a system transformation technology that provides value at every level of the power system simultaneously:** bulk generation, transmission, distribution, and customer.

Any valuation methodology that evaluates them at only one level will produce a result that is both mathematically incorrect and strategically dangerous.

The correct question is not ‘what does a DER cost per kW’; it is ‘what is the full system cost avoided and value when DERs are deployed instead of the alternative?’

Answer that question correctly, and the playing field will be level for DERs to become a valued part of the utility resource portfolio.

Wrap it Up!

From 2023 Presentation

FERC Order 2222

Four primary categories for successful implementation

1. Legislative/Regulatory to enable (On-going for next few years)
   - Includes things like permitting (SolarAPP+), standards adoption (1547-2018) and interconnection process/administration (PowerClerk) and many more (metering, telemetry, governance of aggregators, dual registration, etc.)
   - Phased/Tiered – MO LBNL report is a great framework to consider implementation
2. DER Administration, Data Sharing and Retail/Market enrollment for DER Aggregations – DER Registry (Needed now)
3. DER Operational Coordination – NREL PRECISE, ADMS, DERMS, etc. (Needed in a couple of years for most areas)
4. Settlement (Needed in a couple of years for most areas)

Reframing how we think about FERC 2222

<u>2222 is an incredible and unique opportunity for our industry – Not a burden</u>

By having all of industry attack this issue simultaneously, we have the unique opportunity to develop collaborative solutions at a much lower cost than 3000+ utilities doing it ad hoc.

Please consider these four opportunities in this 2222 implementation process

1. Non-Profit DER Registry is first example. Estimated savings to industry $20-$40 billion in next 10 years.
2. CIM-inspired data structures could lead to another $100B of savings by recognizing that DERs are the new player and if CIM APIs exist from registry to all other CIM structures (and thus utility systems). The onus shifts from the utility industry to the vendor industry to create CIM APIs to known data structures. This would lead to the elimination all software integration costs to enable DERs (as well as many other aspects of grid operation) to the grid and market as well drive a broader implementation of CIM with the same benefits to all other utility system interfaces. (UK example and DOE project) This fundamentally speeds up the innovation cycle across our entire industry.
3. Meter/Settlement if done 'Right' could lead to another $75B of savings and simplify 2222 implementation for meter data sharing and settlement
4. Common Communication Systems – Consumers are paying for multiple overlapping networks for Gas, Water and Electric communication systems for AMI and operations. Isn't it time for these utilities to work together on one shared cost infrastructure? Isn't it time for utilities across your state to work together on a combined solution for all?

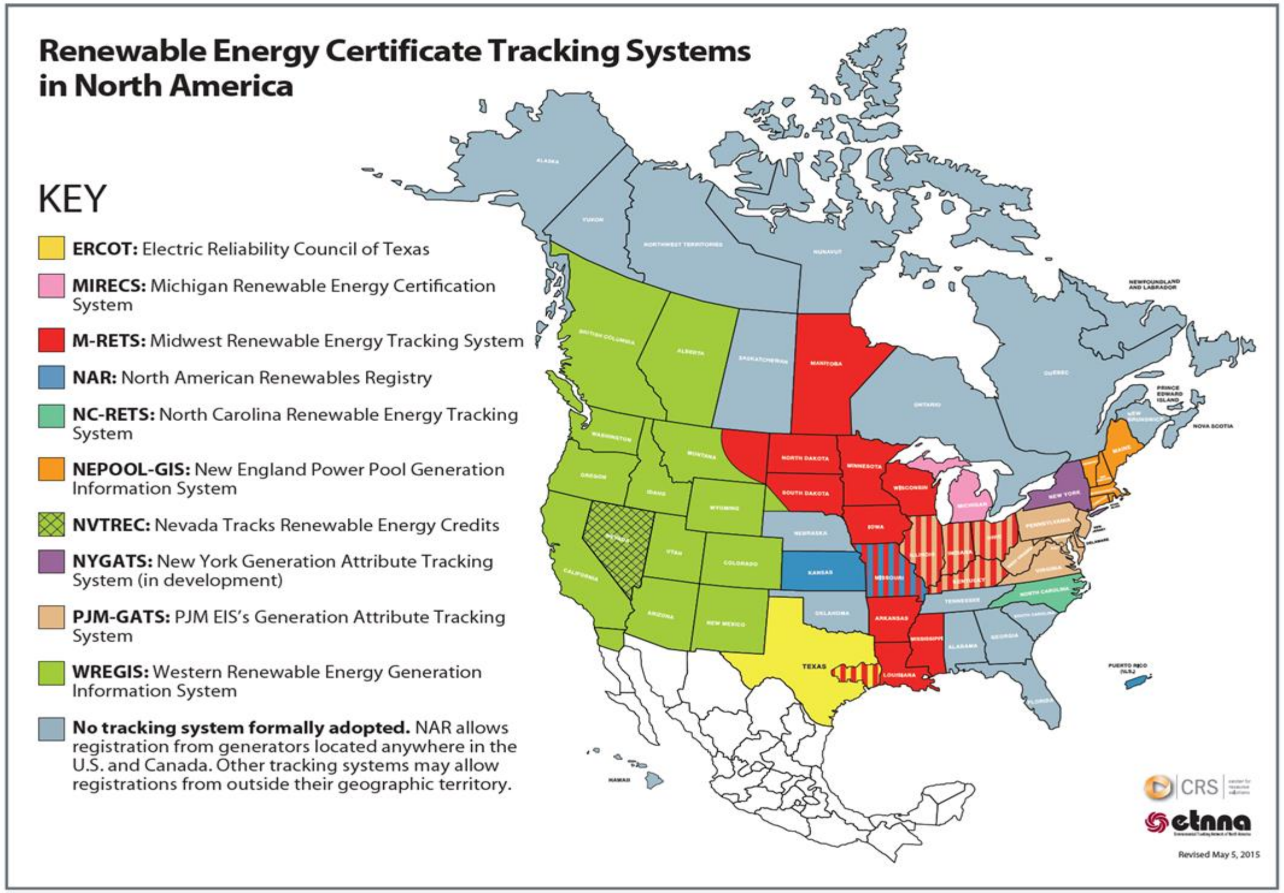
A step in the right direction – Partial Collaboration with REC Tracking Systems

Dozens of REC tracking programs initially. 11 made it to the mainstream

Many states forced to use multiple systems across different ISO's.

The Non-Profit DER Registry is an opportunity to fully collaborate. Allowing us to skip over years of ad hoc development, implementation and confusion.

In addition, AI will soon give us enormous power to marshal DER resources. But that can only happen efficiently if the data is accurate, and consistent/normalized across multiple systems. The resulting ecosystem would provide the requisite situational awareness that otherwise eludes multiple parties that need it.



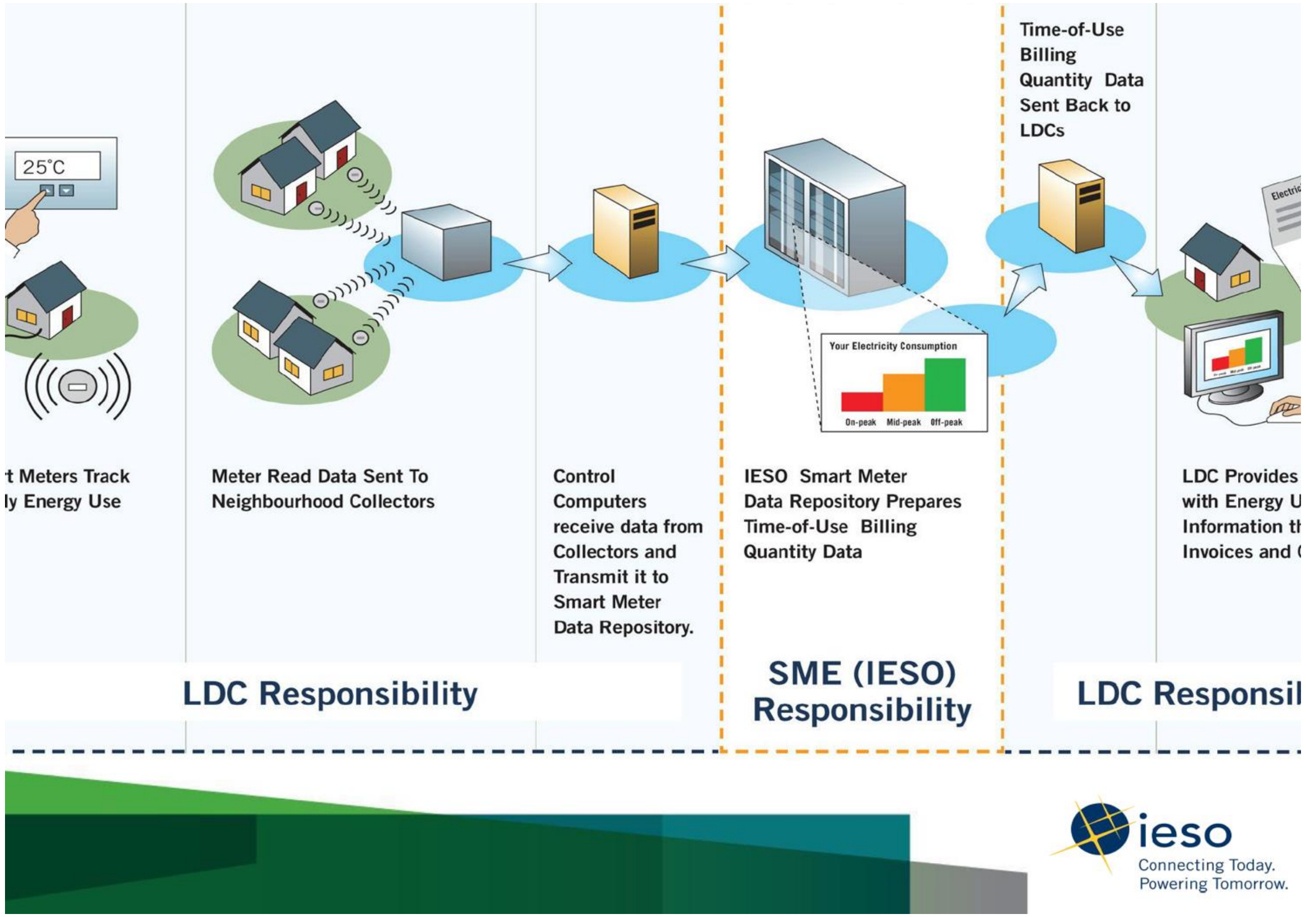
Meter/Settlement Savings Example

Smart Meter Texas did it wrong! They made a 'mirror' and doubled costs by having utilities continue storing data and also creating a second 'open data repository'.

Ontario did it RIGHT! Distribution utilities manage their meters and head end collection systems, but the ISO/Province runs the only data repository that everyone has access to.

Dramatic cost reduction in compute, storage and personnel/outsourcing costs in Ontario's structure. Provides fair access to data based on RERRA approval.

2222 sets the stage for states to do this "Right" versus the way it has always been done.



Critical Role of the RERRA Going Forward

- The Federal Process is fundamentally concluded (FERC and RTO/ISO filings). This has established an overall framework for implementation.
- The ‘rubber is going to meet the road’ in the state processes.
- State commissions can allow costs to spiral with ad hoc, one-off processes and systems, or they can proactively push collaboration across their state to lower costs and more effectively enable DERs.
- It’s not magic, there are clear examples that prove these cost savings across the US and the world. But it is hard to fight against industry momentum that drive independent decisions from every utility.

It is up to State Regulators to make a choice on how to move forward and the cost burden that is imparted to their constituents.

Thank you!

Tracking a wide range of key policy issues related to DER integration across the U.S. has been no small task. We thank those Commissioners and Staff at state commissions and RTOs/ISOs who assisted Collaborative Utility Solutions in crowdsourcing information to be included in the Policy Tracker. We would also like to recognize and thank DOE for sponsoring this initiative for the past two years.

After August 31, 2026, the Policy Tracker will no longer be updated on a regular basis but will remain online at ferc2222.org.

Appendix

Overview of White Papers

Distributed Energy Resources: From the Margins to the Mainstream

A Case for Integrated System Planning and a Level Playing Field

Prepared by Collaborative Utility Solutions

May 2026

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Closing the Regulatory Gap

- **The distortion –** under cost-of-service regulation, utilities earn a return only on capital they own. A DER PPA that meets the identical need as a utility-owned peaker earns the utility nothing — it is an operating expense, not rate base. The playing field is not level for a utility to consider DERs vs Central Station facilities.

- **The fix –** a DER PPA that demonstrably defers a gas peaker should earn equivalent financial treatment, provided it meets truly equivalent performance guarantees, penalties, and utility visibility and control.

- **Regulatory pathways for commissions:**
  - Pre-approve DER deployments via IRP/ISP or competitive solicitation
  - Define a regulatory structure that levels the playing field
  - Share risk: utilities own procurement risk, operators own performance risk
  - Track DER performance against load factor and grid parameters

FERC 2222: A Call for Collaboration

FERC Order 2222 requires RTOs/ISOs to allow DER aggregations into wholesale markets — and is an opportunity to rebuild shared infrastructure.

Collaborative Opportunity	Estimated Industry Value
Non-Profit DER Registry	$20–$40 billion over 10 years
Common Information Model (CIM) data standards	$100 billion+ in avoided integration costs
Collaborative meter data & settlement infrastructure	$75 billion over time
Shared communication infrastructure (gas, water, electric)	Reduces redundant AMI network costs

The question is not whether the industry can afford to collaborate. It is whether it can afford not to.

The Call to Action

- **What Must Change:** Re-Institute Collaboration, Re-Invent Planning to ISP vs IRP, Transform Regulation to level the playing field, and Reduce Barriers.

- **Who Can Effect these Changes:**
  - **Regulators –** encourage bottom-up ISP alongside IRP; establish DER compensation pathways; enforce IEEE 1547 interconnection standards; use Order 2222 to build shared infrastructure.
  - **Utilities –** insist on visibility and control of grid-connected DERs; integrate distribution capacity analysis into IRP/ISP; treat Order 2222 as collaboration, not compliance, insist technology platforms move to CIM to minimize cost of interface and information sharing.
  - **Technology providers –** build regulatory and operational literacy; understand interconnection and NERC CIP requirements; adopt open standards (CIM APIs) over proprietary lock-in.
  - **DOE & federal government –** expand R&D on data standards and grid-enhancing technology; use convening authority to accelerate shared infrastructure; support computational tools for bottom-up ISP.

How to Determine the Real Value of DERs

A Practitioner's Guide to Capturing the Full Value Stack of Distributed Energy Resources

Prepared by Creation Energy

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The Load Duration Curve Drives Everything

Traditional Utility Load Duration Curve

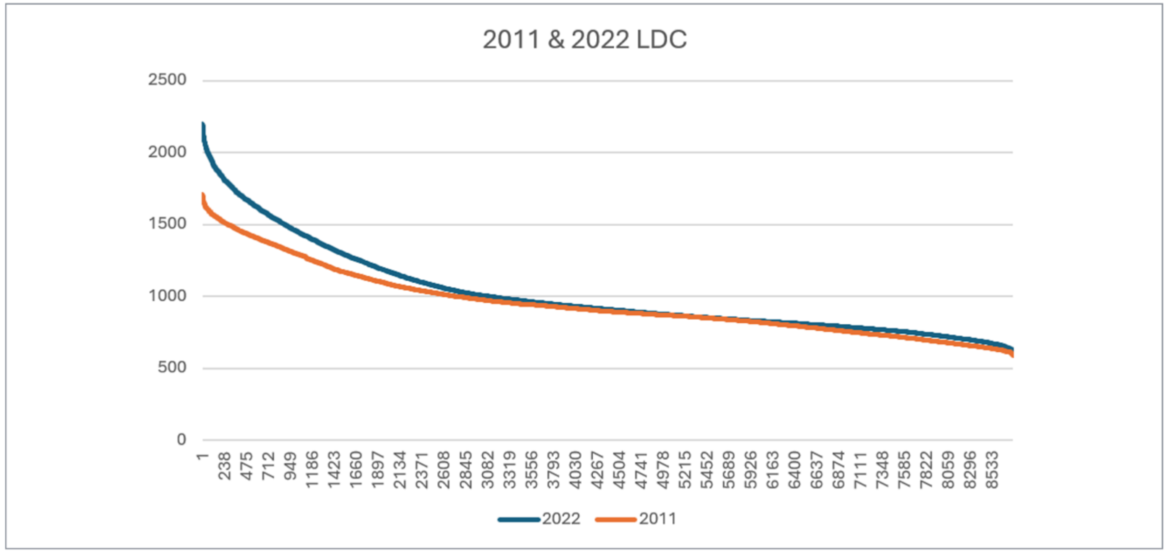
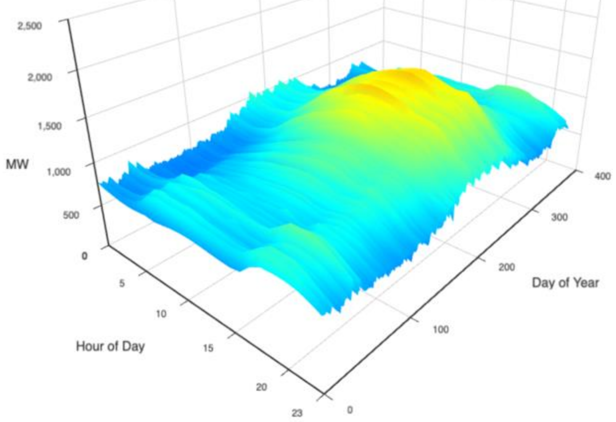


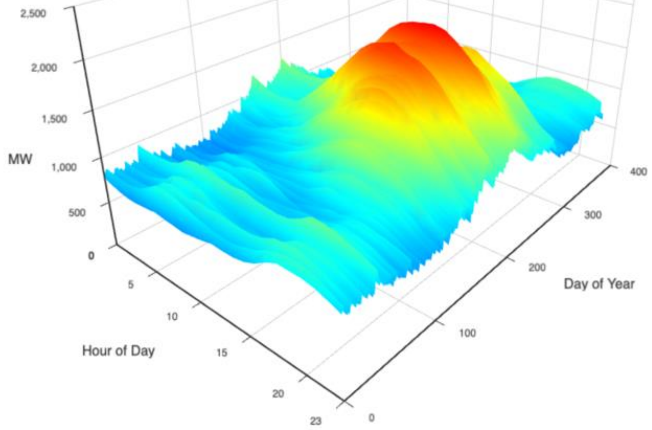
Figure 1: Traditional Utility Load Duration Curve

Or viewed in a 3D topography

2011



2022



Peak Load Reduction and Load Factor Improvement

- **Case study baseline:** a representative service territory adding 25,000 new homes and 250 Grid Optimization (GO) Stations.
- **Load factor recovery:** 0.46 (2022) holds flat under conventional growth, but climbs to 0.63 when DERs are deployed alongside the new load.
- **Peak swing:** conventional growth adds +113 MW of new peak; DER deployment instead avoids 679 MW of peak growth — a 792 MW swing.
- **Revenue unlock:** 4.8 million MWH/yr of latent grid capacity is freed, worth roughly $577M/yr at $0.12/kWh (conservatively $288M/yr by year 10, or $144M+/yr even at just 25% capture).
- **Peer benchmark:** the case utility had the fastest load-factor deterioration (–1.00%/yr) among 9 peers studied (range –0.14% to –0.88%/yr) — DER deployment is projected to reverse the trend of the utility falling from a 56% load factor to 43% load factor and increase it to 63.1% (+17 points) over the next 10 years.

Power Factor & Phase Balance Correction

DERs provide more than just capacity and energy

- **Power factor today:** typical feeders run 0.84–0.92 PF lagging; DER four-quadrant inverters can correct this to 1.0 in real time.
- **Phase imbalance is widespread:** a study of 3,000 feeders found 87% operating with imbalance greater than 10%, and 24% critically imbalanced above 25%.
- **Loss reduction:** correcting power factor cuts technical losses 40–60% and releases up to 14% of feeder capacity without any hardware changes.
- **Efficiency value:** 1–2 million kWh per feeder per year in White Tag-certifiable energy efficiency savings.
- **Correction impact:** an EnerNex study found correcting just 4% of phase imbalance cuts grid- and customer-side motor losses by roughly 40% — a real-time capability no prior grid technology could deliver.

Non-Wires Alternatives

Targeted DER deployment can substitute for traditional infrastructure upgrades at a fraction of the capital cost.

Traditional Upgrade	Typical Cost	DER Alternative	DER Cost
Substation transformer upgrade	$5.0M	5MW DER across 3–4 feeders	$2.0M
Feeder reconductoring (per mile)	$1.2M	1–2MW DER per feeder	$0.4M

- **EV-ready design avoids retrofit costs:** unmanaged EV charging retrofits run $2,000–$8,000 per home; DER deployments built with EV-ready capacity sidestep this cost entirely.

The Complete DER Value Stack

Quantified at case-study scale, DERs deliver value across every level of the power system simultaneously — not just capacity and energy.

Quantified Value Summary (Utility Scale Deployment)

Value Stream	Estimated Value	Basis
Peak Load Reduction (679 MW avoided)	**$476-815M**	Capital cost avoidance at $700-1,200/kW
Latent MWh Revenue Unlock (4.8M MWh)	**~$577M/yr**	At $0.12/kWh on existing infrastructure
T&D Loss Savings (63.5 vs 36.5 MW IRP effect)	**Significant**	Per 50 MW deployment; system-wide loss reduction
Non-Wires Alternative Deferrals	**$1-5M each**	Per substation/feeder upgrade avoided
Energy Efficiency via PF/PB Correction	**$2-4M/yr**	1-2M kWh per feeder × ~250 feeders × $0.08/kWh
Renewable Energy Certificates (RECs)	**$5-15/MWh**	Market rate per certified solar MWh produced
Spinning Reserve / Reserve Margin Reduction	**Significant**	+6 MW effective per 50 MW; reduces procurement cost
Speed of Deployment vs. Central Station	**3-5 yr savings**	Avoided cost of multi-year permitting, siting, financing
Critical Customer Resilience	**Program avoided**	Eliminates need for separate backup gen programs
EV Infrastructure Avoidance	**$2-8K/home**	Cost of retrofit service upgrades vs. built-in design
Phase Balance & Stability Improvement	**Qualitative**	Reduced cascading failure risk; equipment life extension
Social Equity / Affordable Housing DERs	**Qualitative**	Eliminates cost-shift from affluent rooftop solar programs

Figure 18: Quantified Value Summary (Utility Scale Deployment)

Caveat: Not All DERs Are the Same

DER value depends entirely on how a resource is designed, sized, and controlled — not simply on whether it exists.

Design Choice	Low-Value DER Deployment	High-Value DER Deployment
Sizing	Sized for customer bill savings	Sized for feeder peak / grid needs
Inverter capability	Single-quadrant, real power only	Four-quadrant (PF + phase balance capable)
Utility visibility	No utility control or telemetry	Real-time SCADA integration
Dispatch logic	Customer benefit only	Co-optimized for customer and grid
Installation context	Retrofit (30–50% cost premium)	New construction (lowest-cost integration)
Value captured	Single stream (net metering)	Full value stack (8+ revenue streams)
Who benefits	One customer	All utility customers

The Regulatory Solution

- **Regulatory commissions should establish clear pathways for utilities to:**
  - Seek pre-approval of DER PPAs through an integrated resource planning or competitive solicitation process, applying the same scrutiny applied to traditional capital projects.
  - Creating a level playing field for the utility earn an authorized return on the DERs instead of only central station or supply side resources.
  - Share the risk appropriately: utilities bear procurement and contract management risk; third-party operators bear performance and technology risk.
  - Track DER performance to improve grid parameters of efficiency, power factor, phase balance, and most importantly, system load factor.