FERC ORDER 2222 & DER POLICY AND IMPLEMENTATION REPORT

May 2026

CURRENT NEWS AND NEW DEVELOPMENTS

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

FERC and several states have acted 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 provided below.

RTO/ISO Order 2222 Implementation:

- 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. [LINK]

Other DER Policy Developments:

- On Mar. 16, 2026, Governor Maura Healey issued Executive Order No. 654, stating that the Commonwealth of Massachusetts will bring ten gigawatts ("GW") of new energy resources online, under contract, or under development by the end of 2035, including four new GW of solar, two-and-a-half GW of new energy supply into the New England power grid connecting to Massachusetts customers, and three-and-a-half new GW from demand management, such as virtual power plants. To give energy consumers more opportunities to control their energy usage, maintain connectivity and reduce energy bills, three-and-a-half GW of the ten GW goal should be achieved from new load management strategies, such as virtual power plants, electric vehicle charging management, energy efficiency and demand response programs. To support these strategies, the Department of Energy Resources ("DOER") shall publish a review of existing demand and customer supply programs offered in the Commonwealth by September 1, 2026. Further, to facilitate the integration of additional electricity supply, alleviate grid constraints, and reduce peak energy demand, there shall be an additional goal of five GW of energy storage online or under development within Massachusetts by the end of 2035. [LINK]

- On Apr. 20, 2026, the New Jersey Board of Public Utilities issued another RFI in response to Governor Mikie Sherrill's Executive Order No. 2 (issued Jan. 20, 2026), which 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. The executive order also states that within 90 days of the Order, Phase 2 of the Garden State Energy Storage Program (GSESP) shall be launched, accelerating the deployment of distribution-scale battery storage incentives while the Phase 1 transmission-scale program continues. Because Phase 2 resources— distributed battery storage systems—are part of the foundational assets for future VPPs, this RFI is intended to solicit information on both programs to ensure that the programs are coordinated. [LINK]
- The Maryland legislature passed the Utility RELIEF Act (HB1532) in its 2026 legislative session and was signed by Governor Moore on May 12, 2026. This legislation expedites local permitting for rooftop solar; creates expedited interconnection of data centers that use clean energy sources to meet their demand, and explicitly includes the use of demand response and virtual power plants as clean energy sources; allows plug-in solar to bypass utility approval and interconnection if they are below 1,200 W; and increases the procurement of utility scale battery storage to 1.6 GW. [LINK]
- 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 directing further action. Some key issues addressed in the order include creation of 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. Utilities are ordered to provide quarterly confidential DER registration reports beginning no later than 90 days from the date of the Order. Exelon Utilities are directed to provide DERMS development reporting. Interconnection Working Group is ordered to develop proposed regulations for device-level metering and communications protocols. Office of Cybersecurity shall continue to develop cybersecurity regulations in coordination with utilities. Additional provisions apply to Southern Maryland Electric Cooperative (SMECO). [LINK]
- 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 megawatts (MW) of utility-owned, front-of-meter, distribution-connected battery energy

storage systems (BESS) by the end of 2028, which will be aggregated and dispatched to the Midcontinent Independent System Operator (MISO) wholesale market as a VPP. Xcel also plans to implement a limited grid Distributed Energy Resources Management System (DERMS) to support Capacity*Connect. [LINK]
- The Staff of the New York PSC has announced a technical conference on June 25, 2026, to preview its Grid of the Future Report, which is due to be filed June 30. [LINK]

KEY ISSUES ANALYSIS

Enabling DERs Through Industry Collaboration

With this month's report, we invite readers to dive in deeper on two new white papers released this month addressing DER topics.

Below is a brief description of each of the two white papers, with the full papers attached to the end of this report (see Appendix).

DERs from the Margins to the Mainstream: A Case for Integrated System Planning and a Level Playing Field

Large baseload and dispatchable resources such as nuclear, hydro, and natural gas with carbon capture, remain essential to bulk energy delivery and grid stability. But DERs can be deployed dramatically faster, at lower cost, and with greater locational precision than large central station projects. The utilities that move first, embrace bottom-up planning, level the financial playing field for DERs, and lead broader collaboration initiatives, will find themselves with lower costs, more resilient systems, and a stronger relationship with their customers.

How to Determine the Real Value of DERs

Distributed Energy Resources have been transformational to the utility industry across the world as their cost has declined. Unfortunately, they have been deployed without utility visibility or control. This has created as many, or more, problems for the grid technically and economically. Coordinated planning and evaluation of DERs represent the single greatest opportunity to help affordably serve customers in decades, but we must value these resources appropriately.

TRACKER TIPS AND HIGHLIGHTS

The Policy Tracker is available to the public at FERC2222.org [LINK]. New content is added regularly! 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, organization, and state.

For tips on how to use the Policy Tracker search and filter function, see the Tips and Tricks section of the November Report [LINK] .

Recordings and slide decks from all previous bi-monthly webinars can be viewed on the Library page [LINK]. If you are unable to view a webinar recording due to network restrictions please contact us and we will provide access to the recordings directly. The Library is also a great resource for important information regarding DER Policy, standards, and background information relevant to FERC Order 2222.

Upcoming Webinar

Join our next webinar will be on Thursday, June 25th [LINK]. We'll dive into the two white papers attached to the end of this report, focusing on **Enabling DERs Through Collaboration**. Have questions or insights on this topic or on broader developments related to FERC Order 2222? We'd love for you to join the discussion and share your perspective!

DISCLAIMER

This material was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor the United States Department of Energy, nor the Contractor, nor any or their employees, nor any jurisdiction or organization that has cooperated in the development of these materials, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness or any information, apparatus, product, software, or process disclosed, or represents that its use would not infringe privately owned rights.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or Battelle Memorial Institute. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

APPENDIX

May 2026

Prepared by Creation Energy Ltd.
Author Chris Hickman
chris.hickman@creation.energy

How to Determine the Real Value of DERs

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

Distributed Energy Resources have been transformational to the utility industry across the world as their costs have declined. Unfortunately, most have been deployed without utility visibility and control. This has created many, or more, problems for the grid technically and economically than they have been able to solve. Coordinated planning and evaluation of DERs represent the single greatest opportunity to help affordably serve customers in decades but we must value these resources appropriately and create equivalent regulatory recovery mechanisms to level the playing field.

Table of Contents

© 2026 | Creation Energy Ltd.

Executive Summary

Distributed Energy Resources are the most misvalued assets in utility planning today. When a utility's Integrated Resource Planning model compares a DER portfolio against a gas peaker on capacity and energy alone, DERs appear more expensive. That comparison is wrong: the math is not bad, but it accounts for less than half the value DERs actually deliver.

This paper provides utilities and regulators with a practical framework for evaluating DERs in their systems. It provides a structured, evidence-based breakdown of the major value stream that a properly designed and deployed DER portfolio produces: from the reduction of peak load and the improvement of system load factor, to the elimination of grid losses through the correction of power factor and phase imbalance and transport losses, the deferral of distribution infrastructure, and a dozen additional streams that rarely appear in any IRP model.

A direct comparison illustrates the point: a 50 MW DER portfolio deployed in the load pocket produces a net system effect of 63.5 MW. A 50 MW central station peaker produces a net system effect of only 36.5 MW. Directly comparing the actual effect on utility system can be viewed this simply. However, within the utility and regulatory framework, DERs must be modeled in an Integrated Resource Plan (IRP) to provide both the utility and their regulator the comfort that this new resource (DERs) is a cost-effective and valuable part of utility resource portfolio. This paper will move through some of these simple comparisons to set the stage and help explain how DERs deliver value and then provide a deep dive with a specific utility to demonstrate these values.

In the specific utility example, deploying DERs across 25,000 homes and 250 grid optimization stations reduces system peak by 679 MW, improves load factor from 0.46 to 0.63, and unlocks over $577 million in annual latent revenue capacity within the existing infrastructure footprint, before a single dollar of non-wires alternative savings, power factor correction value, or REC revenue is counted.

The playing field is not level today. Planning frameworks do not recognize these DER values in the analysis and regulatory frameworks do not allow equivalent earning potential for the utility. Even if a DER can provide equivalent, or higher value, a utility is clearly advantaged by choosing a central station facility they can own versus a DER they cannot. To effectively move forward and provide an affordable, reliable, and clean energy future, DERs must be appropriately analyzed and allowed equivalent recovery.

> *DERs are not simply another resource choice. They are the first technology in over 100 years capable of simultaneously fixing the three root-cause problems of the electric grid: the Load Duration Curve Peak (System Load Factor), Power Factor, and Phase Imbalance. Any valuation framework that ignores a complete value framework is not a fair DER analysis; it is a partial, systematically biased accounting that will produce an answer that undervalues DERs and does not recognize the significantly positive impact they can deliver for a utility and their customers.*

© 2026 | Creation Energy Ltd.

1. The Foundation: Understanding What the Grid Actually Costs

1.1 The Load Duration Curve Drives Everything

Before any DER value can be quantified, the utility's Load Duration Curve (LDC) must be understood at a granular level. The LDC ranks all 8,760 hours of the year from highest demand to lowest, revealing exactly how much capacity the utility must maintain at every level of system load. It is not merely a planning tool; it is the single most important driver of every generation investment, every wires upgrade, and every rate increase the utility pursues. Figure 1 shows the traditional line chart for a utility LDC.

Traditional Utility Load Duration Curve

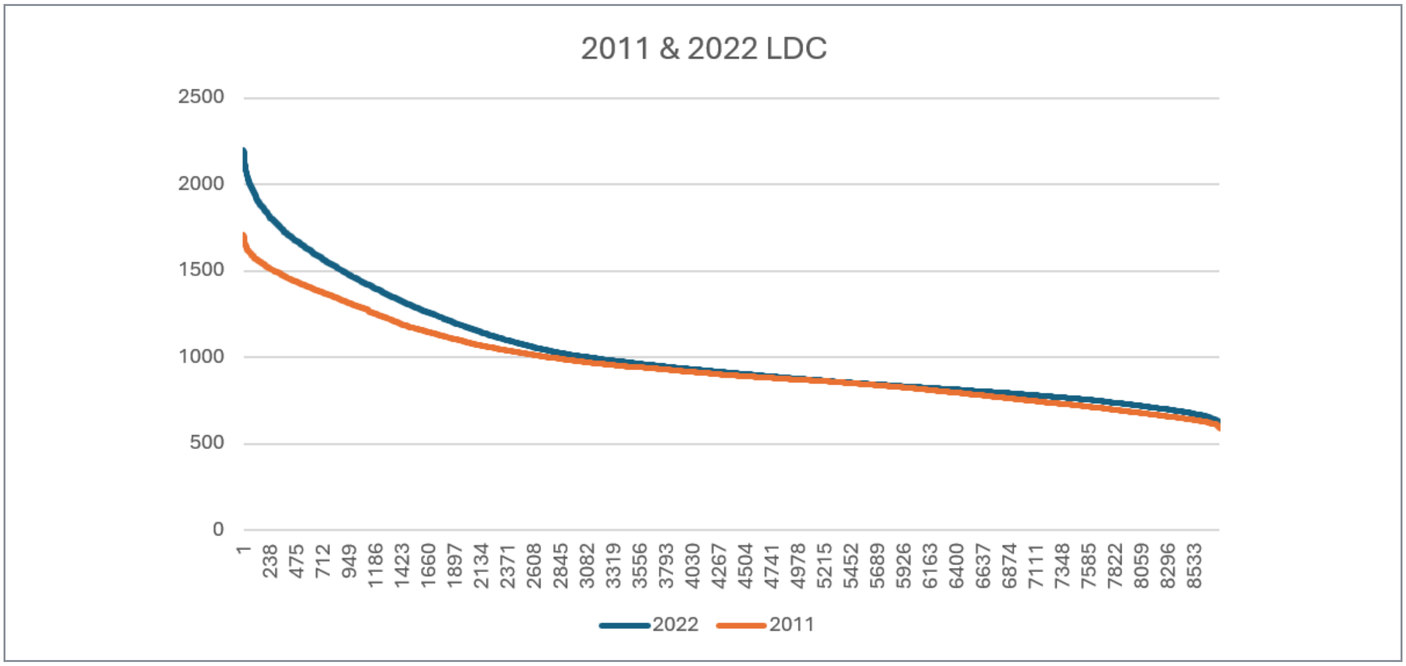

Figure 1: Traditional Utility Load Duration Curve

The fundamental problem the LDC reveals is one of radical imbalance between investment and utilization. Utilities are legally obligated to serve peak demand reliably. But peak demand, the top of the curve, occurs for only a tiny fraction of the year. Every megawatt of capacity built to serve that peak must be financed, maintained, and staffed whether it is utilized for one hour or 8,760 hours.

Examining the 2022 LDC reveals precisely what kind of solution is required to reshape and flatten the curve. The utility managed approximately 750 MW of peak load that existed for only 800 of the year's 8,760 hours. The chart below shows the precise hourly exposure at each MW threshold. This analysis must guide the required solution to improve the LDC:

Utility Hourly Exposure by MW Threshold (2022 Data)

MW Threshold	Total Hours / Yr	Max Cont. Hours	Annual Exposure ▶
2200 MW	1	1 hrs	1 hrs
2100 MW	14	4 hrs	14 hrs
2000 MW	54	6 hrs	54 hrs
1900 MW	128	8 hrs	128 hrs
1800 MW	251	10 hrs	251 hrs
1700 MW	417	11 hrs	417 hrs
1600 MW	632	12 hrs	632 hrs
1500 MW	887	13 hrs	887 hrs
1400 MW	1,174	15 hrs	1174 hrs
1300 MW	1,505	17 hrs	1505 hrs
1200 MW	1,883	22 hrs	1883 hrs

Figure 2: Utility Hourly Exposure by MW Threshold (2022 Data)

> *Critical design insight: A 4-hour product has very limited effect on the LDC. An 8-hour product that can permanently shift load, or directly serve peak demand, for at least 251 hours per year can remove 400-500 MW from the top of the curve. Duration matters as much as nameplate capacity.*

1.2 Peak Load Grows Faster Than Base Load

Everything in the electric system, including generation equipment, conductors, transformers, and customer loads, becomes less efficient as temperature rises. Air conditioning, which drives the residential and commercial peak, is simultaneously the largest single contributor to peak demand and the load that grows fastest as temperatures increase. The result is a structural, physics-driven tendency for peak load to outgrow base load over time.

While the traditional LDC line graph captures the same underlying data, viewing the full 8,760-hour profile in three dimensions reveals a much clearer understanding of this challenge for the utility.

© 2026 | Creation Energy Ltd.

Three Dimensional 8760 Shapes (2011 & 2022)

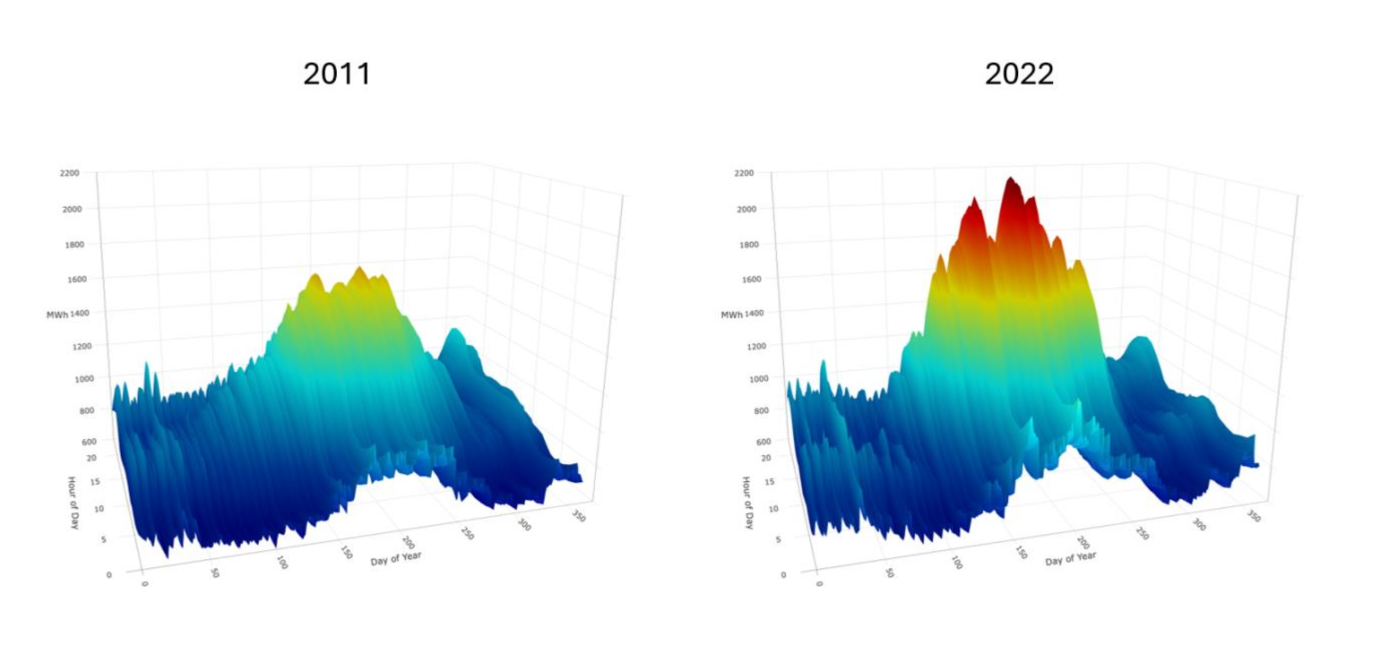

Figure 3: Three Dimensional 8760 Shapes (2011 & 2022)

This demonstrates clearly that the LDC does not remain static, nor does it grow uniformly across all hours of the year. Its peak grows faster than its valley, year after year. Each degree of warming, each new air conditioner installed, each new data center brought online widens the gap between the peak the utility must build for and the average load that actually recovers their investment. This widening gap is captured precisely by a single metric: the load factor.

1.3 The Load Factor: The Single Most Important System Efficiency Metric

Load factor is the ratio of average load to peak load. It measures how efficiently the utility's generation, transmission, and distribution assets are utilized. A load factor of 0.60 means assets are used, on average, at 60% of their rated capacity. A load factor of 0.46 means 54 cents of every dollar of infrastructure investment is idle on average.

The utility's load factor data from 2011 through 2022 tells a consistent and troubling story:

Figure 3: Utility Annual Load Factor 2011-2022 (Higher = Better)

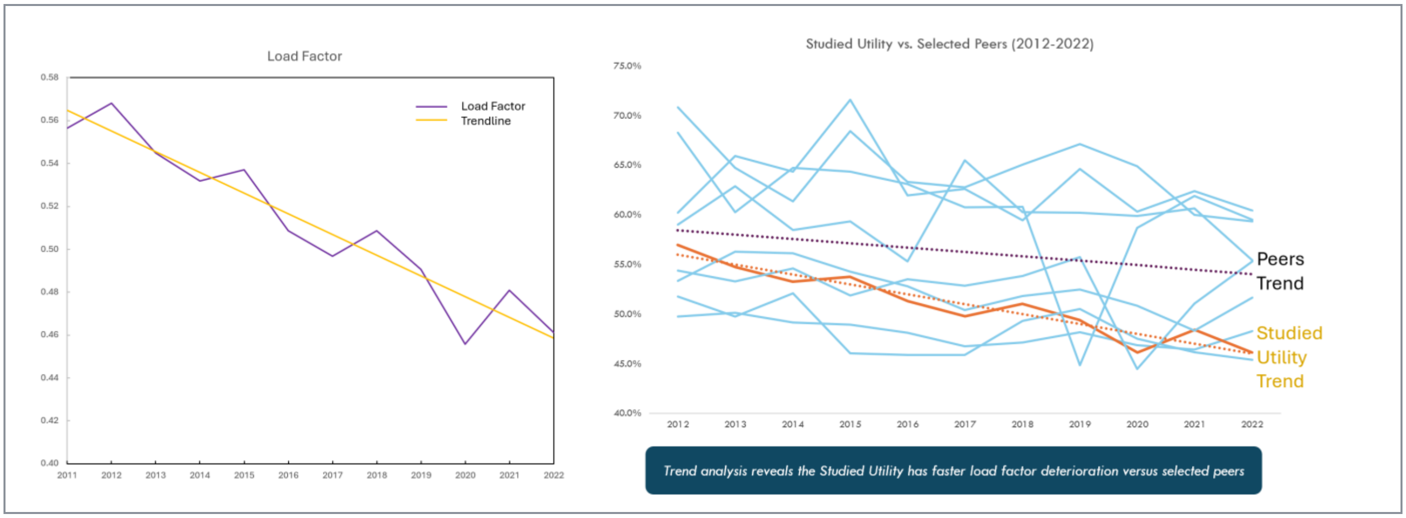

Figure 4: Utility Annual Load Factor 2011-2022 (Higher = Better)

The downward trend, from 0.56 in 2011 to 0.46 in 2022, is not coincidental. It reflects the compounding effect of peak-driving loads (largely cooling) growing faster than base load, while the utility continued to build central station capacity to match peak rather than investing to reshape the LDC. Every year the load factor declines, the utility serves less energy with more infrastructure, raising costs for all customers.

Benchmarked against peer utilities, the data tells a striking story.

Load Factor Peer Benchmarking: UTILITY vs. Selected Balancing Authorities (CY2022)

Utility	CY2022 Load Factor	Annual Linear Trend
Utility A	60.4%	(0.38%)
Utility B	59.5%	(0.88%)
Utility C	59.3%	(0.60%)
Utility D	55.4%	(0.14%)
Utility E	55.3%	(0.24%)
Utility F	51.7%	(0.55%)
Utility G	48.3%	(0.29%)
STUDIED UTILITY	**46.2%**	**(1.00%)**
Utility I	45.4%	(0.44%)
WITH DERs (Projected)	**63.1%**	**+17.0%**

Figure 5: Load Factor Peer Benchmarking - Utility vs. Selected Balancing Authorities (CY2022)

> *At 1.00% per year, the utility's load factor deterioration is the fastest of all nine utilities in the benchmark group. Peer utilities range from 0.14% to 0.88% annual deterioration. At current trajectory, the utility will reach the 0.40 threshold within a decade. DERs are the only proactive tool available to reverse this trend.*

This is not new information for the utility industry. The economic reality is that no cost-effective technology solution to reshape the LDC has existed until now. Technology solutions were simply not available to address the root cause of the LDC. For the past 30 years, the industry has relied on non-technology workarounds. Time-of-Use (TOU) rates and Demand Response (DR) programs are the primary tools deployed. These policy-driven tools have been piloted and implemented across every utility shown in Figure 5. It should be very clear that they are not addressing the problem. This paper does not evaluate TOU or DR program efficacy in depth, but it is important to note that these efforts, regardless of their reported value, have had little measurable impact on peak load management or the declining load factor trend evident across the industry. DERs, a technology-enabled and dispatchable resource, offer the first viable solution to this problem in the industry's history.

2. Value Stream 1: Peak Load Reduction and Load Factor Improvement

2.1 The Transformational DER Effect at Scale

The most powerful and most consistently undervalued contribution DERs make to the utility system is the reshaping of the load duration curve itself. Unlike any central station resource, a DER portfolio deployed in the load pocket can simultaneously reduce peak demand and raise the base load floor, improving load factor from both directions simultaneously.

The following analysis compares two development scenarios against the utility's 2022 baseline LDC: (1) the addition of 25,000 homes through conventional non-DER development; and (2) the addition of 25,000 DER-enabled homes combined with 250 Grid Optimization (GO) Stations. The full magnitude of the DER effect is captured in Figure 6 and illustrated in Figure 7.

Load Duration Curve Scenario Comparison

Metric	2022 Baseline	Non-DER Development (+25,000 homes)	DER Development (+25,000 homes + 250 GO Stations)
Load Factor	0.46	0.46	0.63
Peak Load (MW)	2,201	2,314	1,635
Min Load (MW)	617	633	617
Avg Load (MW)	1,015	1,068	1,026
Peak Delta vs Non-DER	—	+113MW	−679 MW

Figure 6: Load Duration Curve Scenario Comparison

These numbers tell a multi-layered story. Conventional development without DERs makes an already-deteriorating situation worse: 25,000 new homes push peak demand from 2,201 MW to 2,314 MW, further straining infrastructure and suppressing load factor. DER-enabled development reverses the trajectory entirely: the same 25,000 homes, paired with grid optimization stations, reduces peak to 1,635 MW, a 679 MW swing from worst to best case, all without a single new wire or substation.

Load Duration Curve Scenario Comparison: Utility System

© 2026 | Creation Energy Ltd.

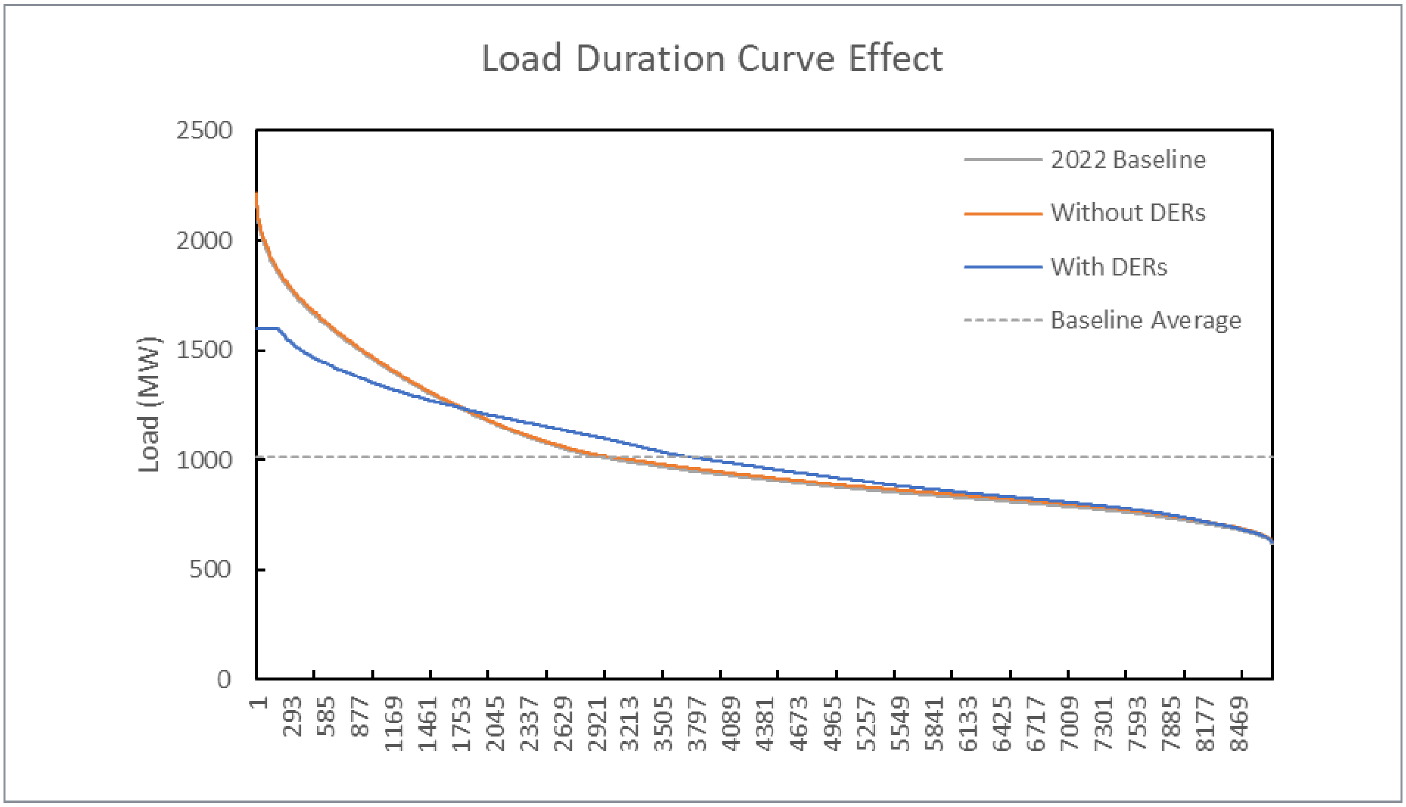

Figure 7: Load Duration Curve Scenario Comparison - Utility System

2.2 Quantifying the Value of Load Factor Improvement

When DERs flatten the top of the load duration curve, they accomplish something no central station resource can: they unlock latent capacity already embedded throughout the generation fleet and wires system. Infrastructure built and financed to serve peak demand suddenly has headroom to serve additional load without new capital investment.

To translate this into dollar terms, the analysis shifts the DER-improved load duration curve back up to the previous peak level and calculates how much additional energy could be served using the existing asset base. At this utility's scale, the result is:

MWH's and Revenue Unlocked with DERs

Incremental MWh Unlocked	Revenue at $0.12/kWh	Conservative 10-yr View (50%)
4,813,463 MWh / year	$577,615,554 / year	~$288M / year by Year 10

Figure 8: MWH's and Revenue Unlocked with DERs

This value, serving more customers on infrastructure already built and financed, is the equivalent of filling empty seats on an aircraft already in the air. Incremental cost is minimal; incremental revenue is nearly pure margin.

> *The load factor improvement value alone, conservatively estimated at 25% capture in the short term, represents over $144 million in annual revenue potential for the utility without any additional capital investment in generation, transmission, or distribution.*

3. Value Stream 2: The In-Load-Pocket IRP Advantage

3.1 Why Location Changes Everything

The most fundamental error in comparing DERs to central station resources is treating them as though they occupy the same position in the power system; they do not. A central station peaker, whether gas, utility-scale solar, or large battery, is sited outside the load pocket. Its output must travel through transmission conductors, through substation transformers, and along distribution feeders to reach the customer. Every step of that journey incurs losses, requires spinning reserves to cover contingencies, and demands infrastructure investment.

DERs, by definition, are located at or near the point of consumption. They eliminate transportation losses rather than incur them. They reduce the amount of spinning reserve the system requires rather than add to it. And because they correct power factor and phase balance at the point of load, they generate energy efficiency benefits that propagate back through the entire feeder, substation and transmission system upstream.

IRP System Effect: 50 MW Central Station vs. 50 MW DER In-Load Pocket

Traditional 50 MW Central Station Peaker	50 MW DER In-Load Pocket Portfolio
Starting Nameplate: 50 MW	**Starting Nameplate: 50 MW**
T&D Losses (10%): LOSE 5 MW	**NO T&D Losses:** GAIN 5 MW
Spinning Reserve (12%): LOSE 6 MW	**Reduces Spinning Reserve:** GAIN 6 MW
PF/PB Efficiency: LOSE 2.5 MW	**PF/PB Correction:** GAIN 2.5 MW
NET IRP EFFECT: 36.5 MW	**NET IRP EFFECT: 63.5 MW+**

Figure 9: IRP System Effect - 50MW Central Station vs 50MW DER In-Load Pocket

The net result: a 50 MW DER portfolio delivers a system IRP effect of 63.5 MW while a 50 MW central station peaker delivers only 36.5 MW. That is a 74% greater effective contribution per nameplate megawatt, a differential that should appear explicitly in every utility resource comparison but almost never does. This is a simple comparison to illustrate the comparative nature of central station and DERs. It helps to understand the results of an IRP tool like Plexos achieves positive results when running much more complex dispatch and economic strategies of these two options.

> *This is not double-counting. An IRP model compares how each solution affects the total system. The T&D loss savings, spinning reserve reduction, and power factor efficiency gains are real, measurable changes to system-wide load. The IRP process is structured to compare the outcomes of different case studies and then compare those outcomes. They belong in the analysis.*

3.2 Deployment Timeline: An Undervalued Dimension

Central station resources require four to six years, and sometimes decades, to plan, permit, site, and construct. DERs can be deployed in months. In an era of rapidly rising peak demand driven by data centers, industrial electrification, and EV adoption, this speed advantage has direct financial value: avoided carrying costs on deferred capacity, avoided risk of supply shortfalls during the construction window, and avoided exposure to construction cost overruns that plague large infrastructure projects.

Construction Time Frames

Build Timeline Comparison		Years
Gas Peaker (Traditional)		6+ years
Utility-Scale Solar Farm		4 years
Utility Battery Storage		3 years
DER Portfolio (50 MW)		1.5 years

Figure 10: Construction Time Frames

4. Value Stream 3: Power Factor Correction

4.1 The Problem That Has Never Been Solved

Power factor is the ratio of 'true power' (the kilowatts actually doing work) to 'apparent power,' the total current drawn from the system. A power factor of 1.0 means every ampere flowing through the grid is doing useful work. A power factor of 0.85 means 15% of the current flowing through every wire, transformer, and conductor in the system is non-productive reactive current, generating heat, consuming capacity, and degrading efficiency at every point from the generator to the customer meter. A simple explanation of power factor is shown in Figure 5.

Power Factor Explained via the Power Wagon

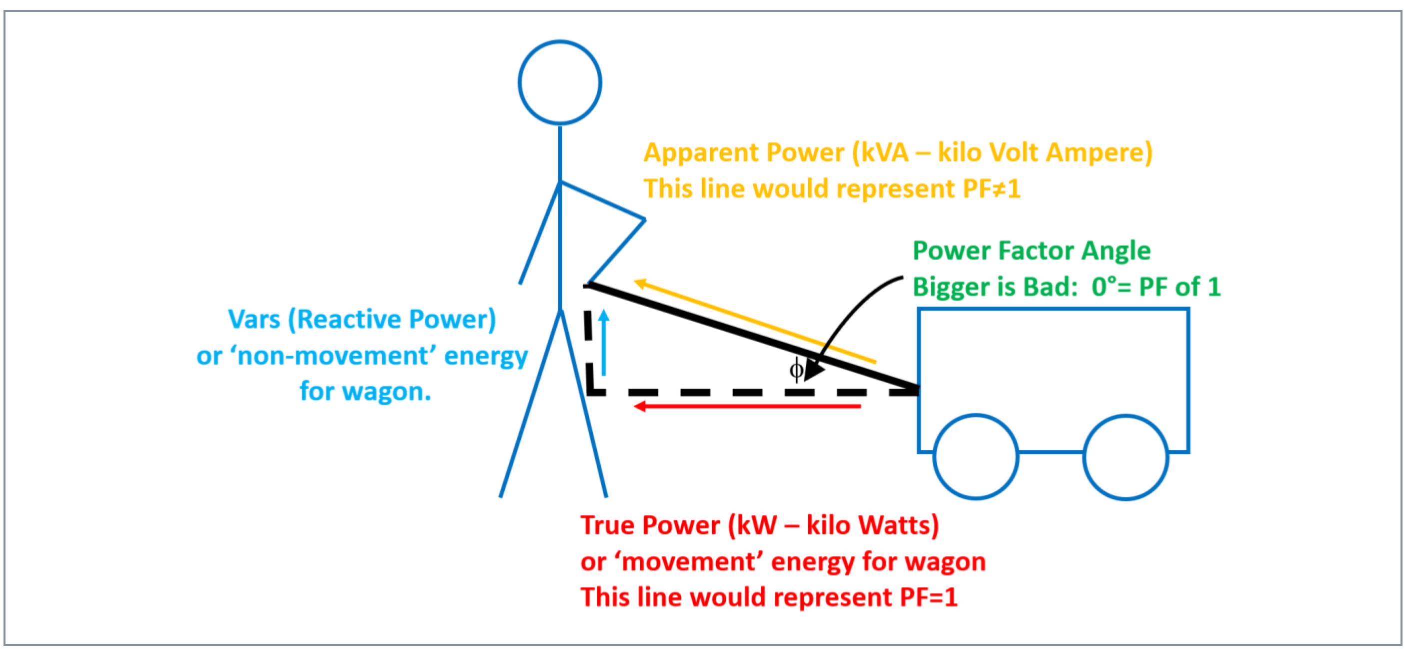

Figure 11: Power Factor Explained via the Power Wagon

Distribution feeders in the United States today typically operate between 0.84 and 0.92 power factor lagging. This is not a design choice but a structural consequence of the inductive nature of residential and commercial loads (motors, ballasts, HVAC compressors). For over 100 years, utilities have had no practical way to correct it at scale. They have simply absorbed the losses, built extra capacity to compensate, and passed the cost to ratepayers.

Power Factor: Before and After DER Correction

PF = 0.84 - 0.92 (Typical Today)	PF = 1.00 (With DER Correction)	Improvement
15-16% of current is reactive (wasted)	0% reactive current	**Eliminates reactive losses entirely**
Central generation must produce VARs	VARs generated at the load point	**No long-distance VAR transport**
i^2R losses elevated throughout network	i^2R losses minimized at all levels	**40-60% reduction in losses**
Grid stability reduced by VAR flow	VAR flow eliminated from bulk system	**Improved stability margins**
Equipment operates above rated current	All equipment at rated efficiency	**Life extension for all grid assets and customer equipment**
Required: larger conductors & transformers	Existing infrastructure used optimally	**Deferred infrastructure upgrade or replacement**

Figure 12: Power Factor - Before and After DER Correction

4.2 How DERs Fix It

Modern four-quadrant inverters, the type paired with solar and battery DER deployments, can dynamically adjust power factor anywhere between 0.8 and 1.2 leading or lagging. Receiving real-time signals from substation SCADA systems, a fleet of residential inverters can collectively correct power factor for an entire distribution feeder, 24 hours a day, 365 days a year.

The key insight is that power factor correction via inverter requires only that the inverter has a source on its DC bus, which solar and battery provide, and incurs virtually no additional energy losses at the customer site. It is, in effect, a free system efficiency improvement that comes embedded in every DER installation that is IEEE 1547 compliant. Testing at Pecan Street has confirmed that four-quadrant inverters can achieve unity power factor at the feeder level through real-time SCADA integration[1].

4.3 Quantifying the Value

Correcting power factor and phase balance on the distribution system could eliminate 40 to 60 percent of the technical losses. Applied across the U.S. grid, which consumed approximately 4,000 terawatt-hours in 2022[2] and incurred roughly 400 GWh in technical losses, even a 5-percentage-point improvement in loss reduction through DER deployment represents 200 GWh in annual savings nationally. At the individual feeder level, the value is 1 to 2 million kWh of energy efficiency per feeder per year, classified and certifiable as White Tag energy efficiency savings.

Power Factor Correction: Value Components

1. Energy efficiency savings: 1-2M kWh per feeder per year (White Tag certifiable) 2. Capacity release: Correcting PF from 0.86 to 1.0 effectively increases feeder capacity by 14% without hardware changes 3. Life extension: Reduced reactive current lowers thermal stress on all conductors, transformers, and customer motors 4. Grid stability: Eliminating VAR flow from traditional central station generation to the distribution system reduces reactive power demand on the bulk electric system, improving voltage stability margins across the network

5. Value Stream 4: Phase Balance Correction

5.1 A Structural Problem Built Into Every Feeder

American distribution networks serve homes on a single-phase basis. When a subdivision of 52, 119, or 18 homes is connected to a three-phase feeder, perfect balance is impractical to achieve, and even if it were achieved at the moment of construction, it would not survive the first change in customer behavior.

Phase Balance for One Day

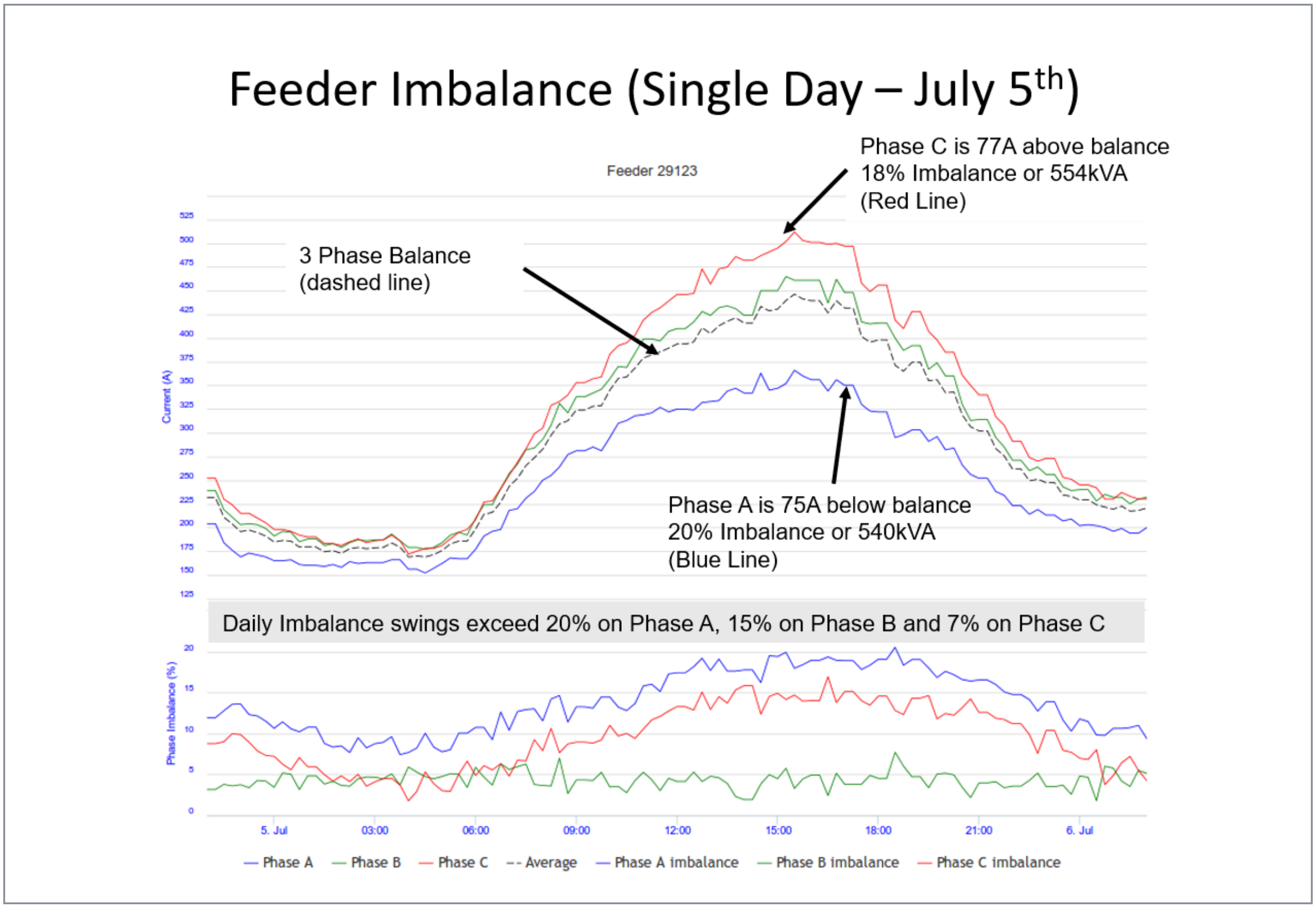

Figure 13: Phase Balance for One Day - Feeder Imbalance

Phase imbalance is dynamic: it shifts throughout the day as customers wake up, turn on appliances, run air conditioning, and charge vehicles. It shifts seasonally as heating and cooling loads redistribute across phases.

© 2026 | Creation Energy Ltd.

Phase Balance in Winter and Summer

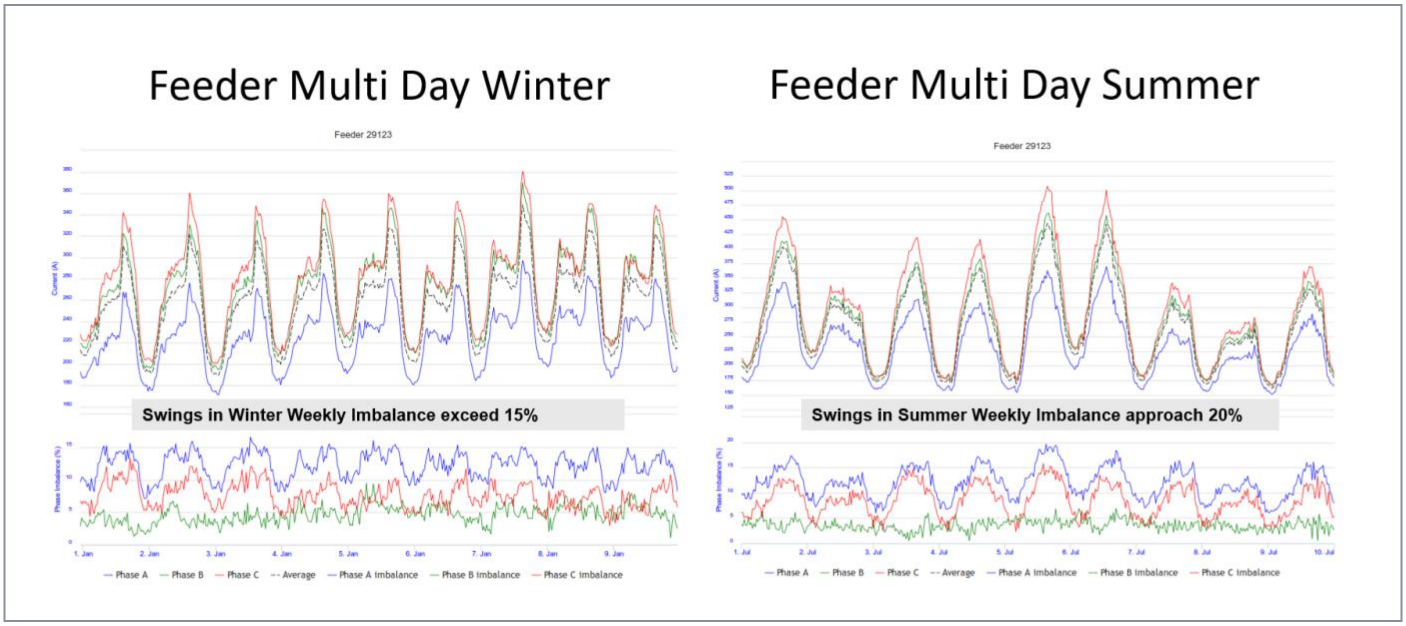

Figure 14: Phase Balance in Winter and Summer

Traditional correction methods, such as manually repositioning transformer taps, cannot track this dynamic imbalance. A correction made for summer peak conditions can worsen winter imbalance on the same feeder. A study of 3,000 distribution feeders[3] found that 87% operated with imbalance greater than 10% and 24% were critically imbalanced above 25%. These feeders were not being managed; they were being tolerated.

5.2 The Cost of Tolerating Imbalance

The cost of tolerating phase imbalance has been studied extensively. An Enernex modeling study[4] is unambiguous: correcting just 4% of phase imbalance on a typical feeder reduces both grid-side and customer-side motor losses by approximately 40%. This is not a marginal improvement; it is a fundamental reduction in the waste that has been baked into every distribution circuit for the past century.

Value of Correcting Phase Balance

Phase Imbalance: Loss Reduction Opportunity		% Loss
Feeder losses at 0% imbalance (ideal)		5 % loss
Feeder losses at 2% imbalance		6.5 % loss
Feeder losses at 4% imbalance (typical)		9 % loss
Motor losses at 0% imbalance		4 % loss
Motor losses at 2% imbalance		5.5 % loss
Motor losses at 4% imbalance (typical)		7.5 % loss

Figure 15: Value of Correcting Phase Balance

5.3 DERs Solve What No Previous Technology Could

Phase imbalance is dynamic, so its correction must be dynamic. Four-quadrant inverters connected to solar and battery DER systems can inject or absorb current on a per-phase basis in real time, tracking the imbalance as it shifts throughout the day and across seasons. A fleet of DER-enabled homes on a feeder, coordinated by a simple signal from utility SCADA, can maintain near-zero imbalance continuously, something no previous technology has been capable of achieving.

> *Phase balance correction via DERs produces 40-60% reduction in distribution technical losses and extends the life of every transformer, conductor, and customer motor on the served feeder. This is a perpetual, ongoing efficiency gain with no fuel cost and no incremental operating expense beyond the DER deployment itself.*

6. Value Stream 5: Non-Wires Alternatives

6.1 The Distribution Planning Window Opportunity

Every utility with a significant distribution system has feeders and substations approaching their thermal capacity limits. Historically, the only solution has been reconductoring (replacing undersized wire with larger-gauge wire), substation transformer upgrades, or new substation construction. These are capital-intensive projects that take years to plan and permit, cost millions of dollars each, and produce additional capacity that immediately begins to deteriorate toward the next upgrade threshold.

DERs offer a fundamentally different approach. By reducing peak demand at the feeder level through local solar generation, battery dispatch, and permanent load shift, a 1 to 2 MW DER deployment on a single feeder can defer or eliminate the reconductoring project that would otherwise be required within the planning horizon. At the substation level, deploying 5 to 10 MW of DERs across several feeders fed by a common substation can defer or eliminate a transformer upgrade.

Solution Cost Comparison

Non-Wires Alternative: Cost Comparison		$K
Substation transformer upgrade		5000 $K
Feeder reconductoring (per mile)		1200 $K
5 MW DER on 3-4 feeders (vs substation)		2000 $K
1-2 MW DER per feeder (vs reconductor)		400 $K

Figure 16: Solution Cost Comparison

The economic comparison is compelling. A 1 to 2 MW DER deployment on a feeder that would otherwise require reconductoring costs a fraction of the traditional infrastructure alternative, is deployed in months rather than years, and delivers a full value stack of peak reduction, power factor correction, phase balance, energy efficiency, and renewable generation, rather than simply adding wire capacity. A 5 to 10 MW DER deployment across a substation area defers a $3 to 5 million transformer upgrade while delivering all the same additional value streams. It is critical to understand that these options can only be pursued if the utility has both visibility and control of the DERs. Random actions of customer installed DERs cannot provide this unique value to the grid if the utility cannot depend on their performance and dynamically control their dispatch.

6.2 EV Infrastructure: Build It Right the First Time

Unmanaged EV adoption is already forcing utilities to retrofit electrical services, upgrade transformers, and reconductor feeders to serve charging loads that were never anticipated in the original distribution design. These retrofits are expensive: $2,000 to $8,000 per home for service upgrades, and substantially more for feeder-level infrastructure. Worse, uncontrolled EV charging often occurs during the evening peak, adding to the very peak demand problem that is already driving load factor deterioration.

DER deployments designed from the outset to include EV-ready infrastructure, including service entrances sized for up to three EVs per home and community fast-charging stations that can serve managed charging, to eliminate the retrofit problem before it occurs. The avoided cost of future service upgrades, measured across a portfolio of thousands of homes, represents a significant and entirely avoidable capital expenditure for a utility.

7. Value Streams 6 Through 8: Ancillary Services, Environmental, and Resilience

7.1 Ancillary Services: Reserve Margin and System Support

Every megawatt of peak demand that DERs reliably reduce is a megawatt for which the system no longer needs spinning reserve. Reserve margin requirements, typically 12 to 15 percent of peak capacity, are expensive to maintain. They require generating units to be kept synchronized to the grid, burning fuel and incurring wear, even when their output is not needed. A reliable DER portfolio that consistently reduces peak by 400 to 600 MW reduces the reserve margin requirement by 48 to 90 MW, with direct, quantifiable savings in fuel costs and generating unit wear.

Beyond reserve margin, DER inverters can provide frequency regulation, voltage support, and reactive power locally, all of which are ancillary services that the system must otherwise procure from central station generators. In markets where these services are priced and compensated, DER aggregations can participate directly, generating revenue streams that further improve their economics.

7.2 Renewable Energy Certificates and Carbon Value

Every megawatt-hour of solar energy produced by a DER deployment is certifiable as renewable generation, producing Solar Renewable Energy Certificates (SRECs) or standard RECs depending on the jurisdiction. In states with Renewable Portfolio Standards, these RECs have direct compliance value for the utility. Beyond RECs, zero-carbon peaking, achieved by using DER solar and storage to displace gas peaker starts, produces measurable, verifiable carbon reductions that translate directly into emissions compliance value and support for corporate and regulatory sustainability commitments.

Grid energy efficiency improvements through DER deployment are recognized as White Tags and can far exceed the impact of all existing utility site/building energy efficiency programs. We have focused holistically on energy efficiency as a behind the meter solution. Attacking power factor, phase balance and deploying DERs in the load pocket provide a new, and very significant opportunity to address grid efficiency.

7.3 Resilience: Critical Customers and Community Value

DER deployments can be designed with islanding capability for designated critical customers: police stations, fire departments, emergency medical services, and critical care facilities. This provides resilient backup power without a separate, expensive backup generation program. The value of this resilience, measured in avoided outage costs, regulatory compliance with critical facility reliability standards, and community trust, is real and material, even if it does not appear in a traditional cost-benefit model.

DERs deployed in affordable housing communities address an equity dimension that traditional DER programs, such as rooftop solar incentives, demand response enrollment, and EV charger rebates, consistently fail to reach. Studies have repeatedly shown that incentive-based DER programs disproportionately benefit affluent customers who can afford upfront equipment costs, shifting program costs to all ratepayers while concentrating benefits on a few. A DER deployment integrated into new affordable housing construction eliminates this inequity by delivering clean energy resources and bill savings to customers who would not otherwise have access to them.

> *Social equity is not merely a soft value. Cross-subsidy from conventional DER incentive programs creates regulatory exposure and public legitimacy risk for utilities. DER deployments in affordable housing eliminate the subsidy problem at its root while expanding the customer base that benefits from the grid's transition.*

8. The Complete DER Value Stack

8.1 All Value Streams, Consolidated

The table below consolidates all value streams identified in this analysis, organized by category and quantifiability. A DER evaluation that accounts only for capacity and energy is capturing, at best, 20 to 30 percent of the value these resources actually deliver.

Complete DER Value Stream Reference Table

Category	Value Stream	Quantifiable?	Description / Proxy Value
Capacity & Energy			
Capacity & Energy	**Peak Load Reduction**	High	Direct avoided cost of peaking generation; ~$700-1200/kW-yr
Capacity & Energy	**Load Factor Improvement**	High	Latent revenue from serving additional MWh on existing infrastructure; ~$577M/yr at scale
Capacity & Energy	**Permanent Load Shift (8-hr)**	High	Displaces highest-cost energy hours; valued at hourly LMP during on-peak periods
Transmission & Distribution			
Transmission & Distribution	**T&D Loss Elimination**	High	+5 MW effective gain per 50 MW DER portfolio vs. central station
Transmission & Distribution	**Non-Wires Alternatives**	High	Deferral/elimination of feeder reconductors & substation upgrades; ~$1-5M per project
Transmission & Distribution	**Reserve Margin Reduction**	High	+6 MW effective gain per 50 MW DER portfolio; reduces spinning reserve procurement
Power Quality			
Power Quality	**Power Factor Correction**	High	Eliminates reactive power flow; reduces i²R losses 40-60% on served feeders
Power Quality	**Phase Balance Correction**	High	Reduces technical losses 40% with only 4% imbalance correction; 1-2M kWh EE/feeder/yr
Power Quality	**Energy Efficiency (White Tags)**	High	~2.5 MW continuous EE per 50 MW DER deployment; ~20,000 MWh/yr per portfolio
Ancillary Services			
Ancillary Services	**Spinning / Operating Reserves**	Medium	Reduced reserve procurement requirement for the system
Ancillary Services	**Frequency Regulation**	Medium	Rapid inverter response for frequency support; market value varies by RTO
Ancillary Services	**Voltage Support (VARs)**	Medium	Local VAR injection eliminates need for central station reactive dispatch
Environmental			

Environmental	**Renewable Energy Certificates (RECs)**	**Medium**	Certified SREC/REC delivery for each MWh of solar production
Environmental	**Carbon Offset / Emissions Avoidance**	**Medium**	Zero-carbon peaking displaces gas combustion; value tracks carbon market
Strategic / Unquantified			
Strategic / Unquantified	**Speed of Deployment**	**Qualitative**	6-24 months vs. 2-6+ years for central station; critical in high-growth periods
Strategic / Unquantified	**Critical Customer Resilience**	**Qualitative**	Islanding capability for emergency services without separate backup program
Strategic / Unquantified	**EV Infrastructure Avoidance**	**Qualitative**	Built-in EV-ready design eliminates future costly service upgrades
Strategic / Unquantified	**Social Equity**	**Qualitative**	DERs in affordable housing; eliminates affluent-customer cross-subsidy in traditional programs
Strategic / Unquantified	**Community Investment**	**Qualitative**	Capital deployed in service territory vs. remote central station site
Strategic / Unquantified	**System Stability Improvement**	**Qualitative**	Reduced VAR flow improves bulk system stability margins across the network

Figure 17: Complete DER Value Stream Reference Table

8.2 The Quantified Value Summary

For the utility case study, the quantifiable value streams, those for which defensible proxy values can be established, are summarized in Figure 18 below. Values are presented per the scale of the 25,000-home plus 250 Grid Optimization Station deployment modeled throughout this analysis:

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)

> *The combined quantifiable value streams comfortably exceed the full cost of the DER program that generates them. When non-wires alternative deferrals, ancillary service value, and REC revenue are added to the load factor improvement and T&D savings, the economics of a well-designed DER portfolio are not marginal, they are decisive.*

9. Critical Caveat: Not All DERs Are the Same

The value stack described in this paper is not automatically delivered by every DER. It requires DERs designed, sited, integrated, and dispatched with the explicit goal of delivering grid services, not solely customer bill reduction. The distinction is critical.

Low-Value DER Deployment	High-Value DER Deployment
Sized only for customer bill optimization	Sized for feeder peak demand and grid needs
Single-quadrant inverter (energy only)	Four-quadrant inverter (PF/PB correction capable)
No utility communication or control	Real-time SCADA integration with utility dispatch control and visibility
Dispatched only for customer benefit	Co-optimized for customer + grid benefit
Retrofit installation (30-50% cost premium)	New construction (lowest possible cost)
Single value stream: net metering	Full value stack: 8+ simultaneous streams

© 2026 | Creation Energy Ltd.

Benefits one customer	Benefits all utility customers

Figure 19: Low vs High Value DER Deployments

DERs focused on a single value proposition, such as energy arbitrage, demand charge reduction, or net metering, lose the ability to provide multiple simultaneous services to the grid. The evaluation framework a utility uses to value DERs must reflect the deployment type it is actually procuring or incentivizing, not an idealized version. In addition, the contracts for these DERs must also be equivalent. They must have the same performance guarantees and penalties a utility would include in a utility scale contract.

10. Leveling the Playing Field for Distributed Energy Resources

10.1 The Fundamental Regulatory Distortion

Under traditional cost-of-service regulation, a utility earns its authorized return on equity only on capital it directly owns and places into rate base. A gas peaking plant, a utility-scale solar farm, and a new substation all flow through the capital expenditure process, receive regulatory approval, and generate a return for shareholders year after year over a multi-decade depreciation schedule. This dynamic applies equally to municipal utilities and rural electric cooperatives, for whom it is far more effective to finance and own a resource than to expense a PPA service in their annual operating budget. The utility has every financial incentive to build and own these assets, regardless of whether an equivalent, cheaper, or better-performing alternative exists[8].

A DER deployment that meets the identical system need as a comparable central station facility earns the utility precisely nothing if procured through a service or Power Purchase Agreement structure. It is treated as an operating expense, not a capital investment. It does not grow the rate base. It does not generate a return. From a pure shareholder value perspective, it is a drag. This is not a hypothetical problem. It is a predictable, rational response by utility management to the incentive structure the traditional regulatory structure has created[7,8]. It is worth acknowledging that this regulatory compact enabled the delivery of reliable, affordable, and safe electricity for a century, a necessary structural evolution from the earliest days of electrification when competing utilities built incompatible systems down the same street. It is a model with proven results, but one that must be thoughtfully modified to level the playing field.

10.2 Why Utilities Should Not Own (All) DERs Directly

One might ask: why not simply allow utilities to own and operate DERs themselves? The answer is absolutely yes: if the resources is of adequate scale, it will make sense for the utility to own and operate that asset. For example, A large-scale community system operating at utility voltage. This is the type of DER utilities that can readily design, own, and operate within existing regulatory structures and with existing utility personnel. However, when distributed resources live on customer premises, the acceptance of liability on private property and the deployment of utility line crews to customer rooftops does not fit well in any utility operating model. The reality is that most utilities are not structured or staffed for this type of model at scale, nor should we force them to be.

A robust ecosystem of third-party DER developers and operators has emerged precisely because they have built the competency, the technology platforms, and the risk appetite to do this work efficiently. This is a sensible division of labor: the utility procures the capacity, the third party delivers and operates the assets, and ratepayers get a cost-effective grid resource[5,6].

10.3 The Regulatory Fix: Equivalent Regulatory Structures for DERs

The policy logic is straightforward: if the grid benefit is equivalent, the financial treatment should be equivalent as well. A utility that signs a 30-year PPA with a DER developer to deliver 50 MW of dispatchable DERs, capacity that demonstrably defers a gas peaker and potentially other utility system upgrades that would otherwise have been built, should be able to seek regulatory approval to finance and earn on that PPA in an equivalent fashion to a central station, utility owned resource. However, it is important that the DER resource be held to a truly equivalent standard: comparable performance guarantees and penalties, and equivalent visibility and control for the utility. The approved contract, with its defined performance standards and cost exposure, is economically indistinguishable from building the peaker, except that it is likely to provide higher overall value, be faster to deploy, deliver reliability and resiliency the peaker cannot, create more effective partnerships between utilities and customers, and provide a clean energy resource without future fuel price risk[8].

Regulatory commissions should establish clear pathways for utilities to:

1. Seek pre-approval of DER PPAs through an integrated resource planning or competitive solicitation process, applying the same scrutiny applied to traditional capital projects.
2. Capitalize the PPA obligation on a present-value basis, subject to ongoing performance true-ups, and earn an authorized return on the approved balance.
3. Share the risk appropriately: utilities bear procurement and contract management risk; third-party operators bear performance and technology risk.
4. Track DER performance to improve grid parameters of efficiency, power factor, phase balance, and most importantly, system load factor.

This structure is not a gift to utilities. It is a correction, restoring the neutrality that should have always existed between build-own-operate and procure-and-contract strategies. The gas peaker or central station renewable facility does not deserve a privileged position simply because it fits neatly into a nineteenth-century regulatory model.

10.4 The Cost to Ratepayers of Getting This Wrong

Every year this regulatory gap persists, utilities face a quiet but compounding incentive to prefer capital-intensive, central station solutions over cost-effective and high-value distributed ones. The result is billions of dollars of potentially avoidable infrastructure: gas peakers that run only a handful of hours per year, transmission upgrades that could have been deferred, central station projects with decade-long lead times and a continually declining system load factor, while the DER alternative sits on the shelf, a new and valuable tool for utilities but financially invisible to the utility's income statement[7,8].

11. Conclusion: Valuing DERs Correctly

The electric utility industry has undervalued distributed energy resources for decades because it has evaluated them through a framework designed for a different era. Capacity and energy metrics, applied in isolation, will always make DERs appear more expensive than a gas peaker. They are not, when their full value is properly accounted for.

A properly designed 50 MW DER portfolio delivers 63.5 MW of effective system benefit to the IRP. A 50 MW gas peaker delivers 36.5 MW. DERs correct power factor and phase balance, eliminating 40 to 60 percent of distribution technical losses. They defer substation and feeder upgrades that would otherwise consume millions in capital. They improve load factor, unlocking latent revenue capacity in existing infrastructure. They generate RECs and displace carbon emissions. They can be deployed in months, not years. They deliver resilience to critical customers and equity to communities that traditional programs have consistently failed to reach.

None of this value appears automatically in a conventional resource planning model. It must be explicitly identified, quantified where possible, and listed where it cannot yet be quantified, with a commitment to improve those estimates as DER deployments are monitored over time.

The Central Principle of DER Valuation

> *DERs are not another generation resource to be compared just on $/kW-yr basis. 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 crucial part of the utility resource portfolio.*

Appendix: Bibliography

References cited in this paper are listed below in citation order. Government and laboratory publications are available through their respective agency websites unless otherwise noted.

[1] Pecan Street Inc.. "Grid Services via Residential DER Integration: Four-Quadrant Inverter Performance Studies." ***Pecan Street Research Institute, Austin, TX, 2020–2023.*** *Field research confirming four-quadrant inverter capability to achieve unity power factor at the feeder level through real-time SCADA integration in residential deployments. Available: pecanstreet.org/research*

[2] U.S. Energy Information Administration (EIA). "Electric Power Annual 2022." ***U.S. Department of Energy, 2023.*** *Primary data source for U.S. grid consumption figures (approximately 4,000 TWh in 2022) and distribution system loss estimates. Available: eia.gov/electricity/annual*

[3] Electric Power Research Institute (EPRI). "Distribution Feeder Phase Imbalance: Prevalence, Impact, and Mitigation Strategies." ***EPRI, 2019.*** *Analysis of phase balance conditions across a sample of 3,000+ distribution feeders; finding that 87% operated with imbalance greater than 10% and 24% were critically imbalanced above 25%. Available: epri.com*

[4] Enernex Corporation. "Phase Imbalance Modeling Study: Loss Reduction and System Impact of Dynamic Phase Balance Correction on Distribution Feeders." ***Enernex / EPRI, 2018.*** *Quantitative modeling study demonstrating that correcting 4% phase imbalance on a typical feeder reduces grid-side and customer motor losses by approximately 40%.*

[5] U.S. Department of Energy. "Pathways to Commercial Liftoff: Virtual Power Plants." ***U.S. DOE Office of Clean Energy Demonstrations, 2023, updated 2025.*** *Estimates VPPs could reduce U.S. peak demand by 80–160 GW by 2030; provides the definitive federal policy framework for DER aggregation at scale. Available: energy.gov*

[6] Brehm, K., McEvoy, A., Usry, C., and Dyson, M.. "Virtual Power Plants, Real Benefits." ***Rocky Mountain Institute (RMI), 2023.*** *Quantitative case for VPPs as a least-cost grid resource; one of the most-referenced DER policy papers of the past three years. Available: rmi.org*

[7] Lawrence Berkeley National Laboratory. "DER Aggregations and Wholesale Markets (Five-Report Series)." ***LBNL, 2022–2024.*** *Comprehensive series on Order 2222 compliance challenges and state regulatory opportunities to advance DER aggregations in wholesale markets. Available: emp.lbl.gov*

[8] National Association of Regulatory Utility Commissioners (NARUC). "Regulators' Financial Toolbox: Virtual Power Plants." ***NARUC, 2023.*** *Translates DER and VPP technical concepts into the language of state public utility commissions; frames VPPs at an inflection point with accelerating consumer adoption. Available: naruc.org*

For further information:

Chris Hickman • Creation Energy LLC • chris.hickman@creation.energy

Prepared by Collaborative Utility Solutions

May 2026

Distributed Energy Resources

From the Margins to the Mainstream

A Case for Integrated System Planning and a Level Playing Field

Drawing on decades of experience across generation, transmission, distribution, grid operations, regulatory interaction, policy development and a passion for enabling the success of the utility industry.

Table of Contents

© 2026 | Collaborative Utility Solutions

1. Executive Summary

The electric power industry stands at a genuine inflection point. Distributed Energy Resources (DERs), once treated as curiosities at the margins of the grid, have crossed a decisive threshold. Solar photovoltaic module costs have fallen more than 97 percent since 2006.[12] Lithium-ion battery storage pack costs have dropped over 90 percent since 2010.[11] The U.S. Department of Energy (DOE), through the SunShot Initiative, the Grid Modernization Initiative, and a sustained pipeline of R&D investment at the National Renewable Energy Laboratory (NREL) now National Laboratory of the Rockies (NRL), Pacific Northwest National Labs (PNNL), Oak Ridge National Laboratory (ORNL) and Lawrence Berkeley National Laboratory (LBNL), deserves substantial credit for catalyzing this cost revolution.[17]

Yet economic competitiveness alone does not guarantee that DERs will be deployed where they provide the most grid value, at the scale the grid needs, and in ways that strengthen rather than complicate reliable system operation. That outcome requires deliberate, structural change in how the electric utility industry plans its grid, values investments, and engages with the technology ecosystem growing up around it.

This paper presents three interconnected changes that are necessary to unlock the full potential of DERs:

- **An evolution in planning:** The industry must supplement and, in many contexts, replace the century-old top-down utility planning model, currently referred to most often as the Integrated Resource Planning (IRP) model with bottom-up Integrated System Planning (ISP) that begins at the distribution edge, identifies locational grid needs with granular precision, and recognizes the value that DERs present to solve these needs while, in aggregate, meeting overall resource portfolio requirements.
- **A regulatory correction:** The structural financial disadvantage DERs face under traditional cost-of-service regulation must be corrected. A DER Power Purchase Agreement that achieves the same grid outcome as a utility-owned peaking plant should receive equivalent financial treatment. This is not a subsidy; it is the removal of a distortion.[10]
- **A return to collaboration:** FERC Order 2222, which requires RTOs to allow DER aggregations to participate in wholesale energy markets, is more than a market rule change.[15] It is a call for the industry to collaborate effectively once again, building shared infrastructure, common data standards, and coordinated planning frameworks that no single utility, regulator, or technology provider can build alone.

Wood Mackenzie projects that 262 GW of new DER and demand flexibility capacity will be installed in the United States from 2023 to 2027, approaching the 272 GW of utility-scale central station resource installations expected in the same period.[3] The DOE estimates that Virtual Power Plants alone could reduce U.S. peak demand by 80-160 GW by 2030.[1] Used thoughtfully and planned deliberately, DERs are the fastest tool the industry has to address capacity shortfalls, defer infrastructure investment, and deliver cleaner electricity to customers who are already installing them with or without utility coordination.

There are no silver bullets, we need them all. Large baseload and dispatchable resources, including nuclear, hydro, and natural gas with carbon capture, remain essential to bulk energy delivery and grid stability. But DERs can be deployed dramatically faster, at lower cost, and with greater locational precision than large central station projects. The utilities that move first, embracing bottom-up planning, leveling the financial playing field for DERs, and leading broader collaboration initiatives, will find themselves with lower costs, more resilient systems, and a stronger relationship with their customers.

A second paper detailing the results of a blended ISP/IRP process to develop the actual value of DERs will be coming out soon!

2. Background and History of Distributed Energy Resources

Origins and Early Development (1970s-1990s)

The concept of Distributed Energy Resources, defined as small-scale power generation and storage technologies sited close to the point of consumption, traces its roots to the energy crises of the 1970s. The Public Utility Regulatory Policies Act of 1978 (PURPA) was a landmark early response, requiring utilities to purchase power from small qualifying facilities and cogenerators, laying the regulatory groundwork for distributed generation.[14]

During the 1980s and 1990s, DERs were largely synonymous with diesel backup generators, small-scale hydro, and early wind turbines, technologies that were costly, inconsistent, and viewed by most utilities as a nuisance rather than a resource. Solar photovoltaic (PV) modules in 1990 cost roughly $10-$12 per watt, placing them far beyond reach for mainstream deployment.[12] Battery storage technology remained an engineering curiosity confined to niche military, telecommunications, aerospace, and critical system applications.[11]

The DOE's Catalytic and Enduring Role

No single institution has done more to advance DER technology, economics, and policy than the U.S. Department of Energy. With early efforts taking shape in the Carter Administration, and expanding significantly in the 1990s, DOE's Office of Electricity and NREL invested heavily in R&D programs targeting solar, wind, advanced inverters, and energy storage.[17]

The DOE's SunShot Initiative, launched in 2011, set an audacious goal of driving utility-scale solar costs to $0.06/kWh by 2020. The industry achieved that target three years early, in 2017, a milestone that validated both the ambition of federal R&D investment and the power of market forces once properly catalyzed.[17,12] DOE's Grid Modernization Initiative simultaneously addressed the critical question of how to integrate high penetrations of DERs without compromising reliability.

The DOE's Vehicle Technologies Office and Loan Programs Office have been instrumental in catalyzing the battery storage industry, helping drive lithium-ion battery pack costs from over $1,200/kWh in 2010 to below $150/kWh by the mid-2020s.[11] The DER Interconnection Roadmap released in January 2025, a product of DOE's i2X initiative incorporating input from over 45 organizations, sets a national agenda for interconnection reform.[5]

The Cost Revolution (2000s-Present)

The story of DER adoption is, at its core, a story of relentless cost decline driven by technology maturation, manufacturing scale, and policy support:

Technology	Then	Now
Solar PV Module Cost	~$7/W (2000)	<$0.25/W (early 2020s): 96% reduction
Utility-Scale Solar LCOE	N/A (not viable)	$0.025/kWh (2024), new floor
Onshore Wind LCOE	~$0.08/kWh (2010)	<$0.03/kWh (best regions)
Li-ion Battery Pack Cost	>$1,200/kWh (2010)	<$150/kWh (mid-2020s): >90% reduction
Li-Iron Phosphate (LFP) Battery Cost	$750/kWh (2010)	$72/kWh (2024): 90% reduction

Sources: *BloombergNEF Battery Price Survey*[11]*; NREL Annual Technology Baseline*[12]*; IRENA Renewable Power Generation Costs*[13]*; DOE SunShot Progress Reports*[17]*; Wood Mackenzie 2023 DER Outlook*[3]

These economics have transformed DERs from boutique, subsidy-dependent projects into a cost-effective resource option in many U.S. markets. While the industry has still not effectively determined a consistent value framework for DERs that recognizes all the value streams they can provide in a resource portfolio, a framework is now taking shape. According to Wood Mackenzie's 2023 U.S. Distributed Energy Resource Outlook, 262 GW of new DER and demand flexibility capacity was projected for installation from 2023 to 2027, approaching the 272 GW of utility-scale resource installations expected in the same period.[3]

Growing Industry Acceptance (2010s-Present)

For much of their history, utilities and grid operators treated DERs as unpredictable, uncontrollable variables, specifically load modifiers to be tolerated rather than dispatched. That posture has fundamentally changed:

- **FERC Order 2222 (2020)** was a watershed regulatory moment, requiring RTOs to allow DER aggregations to participate in wholesale energy markets, effectively elevating rooftop solar, batteries, and smart thermostats to the same market standing as a natural gas peaker plant.[15]
- **Virtual Power Plants (VPPs)** have moved from pilot programs to operational reality. Rocky Mountain Institute's analysis confirms VPPs can provide dispatchable capacity at an equivalent or lower cost of constructing and operating a gas peaker plant. [2,4]
- **LBNL's VPP inventory report (2025)** catalogs active VPP programs across the U.S. with detailed operational profiles, providing the most comprehensive empirical database of real-world VPP performance data currently available.[8]
- **Electric Vehicles (EVs)** have emerged as the next frontier, with Vehicle-to-Grid (V2G) pilots proliferating across the country, turning millions of parked cars into a vast, distributed storage fleet.

With over 5 million rooftop solar installations in the U.S. and grid-scale battery storage additions doubling year over year, the challenge has shifted from *whether* DERs can play a meaningful role,

© 2026 | Collaborative Utility Solutions

to *how fast* utilities, regulators, and technology providers can evolve to harness their full potential.[3]

3. How Utilities Have Planned Historically: Top-Down Planning

The Century-Old Planning Paradigm

The electric utility industry was built on a top-down planning philosophy that made complete sense for its era. Beginning in the early twentieth century, utilities designed their systems from the bulk power level downward: forecast load growth, build or contract for large central generating stations, design high-voltage transmission to move power from plant to population center, and finally size distribution infrastructure to deliver that power to customers. The customer sat passively at the very bottom of this planning hierarchy, a load to be served rather than a resource to be engaged.

This model was rational when generation technology rewarded scale, when customers had no ability to generate, store, or manage their own electricity, and when information about system conditions was sparse and slow. While called many different names over time, the last two name changes for utility planning processes are significant. First, Least Cost Planning. The utility planning process became very focused on the mandated obligation of a utility to provide resources at the lowest cost, so the process was referred to as least cost planning. Second, Integrated Resource Planning (IRP). This evolution shifted focus to include social agendas. Mandated 'non-generation' programs such as energy efficiency and demand response and mandated renewable portfolio programs were now required, the barrier to these higher cost solutions removed by mandate, and stakeholders for the utility could engage in a public process to provide their input into the resource mix selected in the process. IRP is the formal framework most state-regulated utilities use today. Utilities project 20-year load forecasts, identify supply-side resource needs, and propose portfolios of generation to meet them, while incorporating regulatory mandates and stakeholder input. The distribution system is largely an afterthought, sized to carry load and not designed to host resources.

For nearly a century, this overall process has worked effectively. The system was reliable, rates were predictable, and the engineering logic was sound. Large economies of scale in central generation drove down the cost of electricity for generations of Americans, enabling financing of the electrification of rural America and powering the industrial expansion of the twentieth century.

The Structural Assumptions of IRP

Integrated Resource Planning rests on foundational assumptions listed here that, while valid for most of the twentieth century, have quietly eroded in the twenty-first:

- Customers are passive. Load grows predictably, shaped primarily by economic activity and weather, not by customer technology choices.

- Generation economies of scale dominate. Larger plants produce cheaper electricity. The optimal investment is almost always a bigger plant, not smaller plants or distributed infrastructure.
- The transmission grid is largely a given. IRP selects resources; transmission and distribution planning handles interconnection as a downstream consequence, not a co-equal variable.
- Demand-side resources are generally considered as load modifiers, not as resources.
- Long planning horizons are reliable. A 20-year IRP built on reasonable assumptions will remain directionally valid for its full term.

Why the Old Model Is Showing Its Cracks

The realities of dramatic new load growth are straining a model that has been predicated on central station resources and low sustained incremental load growth due to these drivers:

- **Load forecasting has become structurally unreliable.** The flat or slowly growing load curves utilities planned against since the 1970s have been disrupted by distributed solar, energy efficiency, and the explosive growth of EV charging and data center load. Forecasts that were once accurate within a few percent over a 10-year horizon are now routinely wrong within 3-5 years.[7]
- **The distribution system has become the most complex part of the grid.** Millions of rooftop solar systems, batteries, EVs, and smart devices are being interconnected with little coordinated planning. Distribution systems designed as passive delivery infrastructure are now asked to manage bidirectional power flows, voltage fluctuations, and hosting capacity constraints never contemplated in their original design.[7]
- **Supply-side solutions are no longer always the right answer.** When a distribution circuit approaches its capacity limit, the traditional top-down response is automatic: upgrade the conductor, add a substation transformer, or build a new line, costing tens to hundreds of millions of dollars. The question top-down planning rarely asks: could customer-sited resources solve this problem faster and at a higher value instead?[7,10]

4. Flipping the Model: Bottom-Up Integrated System Planning

The ISP Imperative

Bottom-up Integrated System Planning (ISP) inverts the traditional hierarchy. Rather than beginning with bulk generation needs and working downward, it begins with a granular, location-specific understanding of distribution system needs, circuit by circuit and substation by substation, and asks what combination of customer-sited resources, grid investments, and supply-side additions most efficiently meets those needs.[7]

While IRP is conducted by individual utilities asking "What resources should we acquire?", ISP is a grid-level planning process asking "How should the system evolve as a whole"? ISP explicitly models the interdependencies between transmission and distribution infrastructure and resource siting decisions, recognizing that where one builds a solar array, a battery, or implements DERs matters as much as if one builds it.

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	Single utility service territory with larger regional interactions	Targeted and then 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

Why ISP Is a Game Changer

- **It makes DERs visible as grid assets.** Top-down planning typically treats customer-sited solar, storage, and demand response as load modifiers, variables to be netted out of the forecast. Bottom-up ISP treats them as utility-controlled, dispatchable grid resources that can be sited, contracted, and dispatched to solve specific, localized grid needs that can scale to become an important part of the overall resource mix. The difference is not semantic; it determines whether a utility builds a $30 million substation or deploys a $4 million DER Plant instead.[2,7]

- **It enables Non-Wires Alternatives (NWAs).** Con Edison's Brooklyn-Queens Demand Management Program used customer-sited resources to defer a $1.2 billion substation project, the landmark demonstration that this approach works at scale in a complex urban environment.[18]
- **It aligns customer investment with grid needs.** When utilities know where distribution capacity is scarce, they can target DER investment precisely where it delivers the most grid value. Without bottom-up visibility and utility coordination, DER incentives and programs are geography-blind and routinely benefit areas with ample capacity while leaving constrained areas underserved.[9]
- **It improves resilience planning.** Top-down planning optimizes resources, not the system. Bottom-up planning identifies specific communities and circuits with elevated vulnerability and designs targeted resilience investments where they matter most, an increasingly important consideration as climate-driven weather events concentrate outage risk.[6]

Recognizing the Need for Bottom-Up Planning

States including California, New York, Hawaii, and Minnesota have made bottom-up distribution planning a regulatory requirement, recognizing that the grid of the future cannot be planned from the top-down alone.[7] The two processes are increasingly understood as complementary: a well-functioning ISP can inform individual utility IRPs by clarifying what transmission capacity will be available and where, while utility IRPs feed regional ISPs with load forecasts and resource plans.

> The utilities that master bottom-up Integrated System Planning will find themselves with a powerful competitive and regulatory advantage: lower infrastructure costs, faster response to changing load patterns, more resilient systems, and a genuinely collaborative relationship with the customers whose decisions now shape the grid as much as any central station plant ever did.

5. The Value Proposition for Distributed Energy Resources

DERs vs. Central Station and Utility Supply-Side Resources

For most of the twentieth century, the electric grid operated on a simple, elegant premise: build large, centralized power plants, transmit electricity over high-voltage lines, and deliver it to passive customers at the end of the wire. That model optimized for economies of scale at the generation level. While the resource mix was optimized, the grid system to deliver it was not part of this optimization analysis, leaving enormous value stranded everywhere else in the system. Distributed Energy Resources unlock that stranded value.

The value DERs provide is not simply supplying electrons, it is a fundamentally different type of value. DERs can deliver targeted response from many locations on the grid, helping the grid balance less predictable sources, like wind generation, and more erratic loads, like EV charging stations. Support includes not only energy balancing, but also the potential for voltage stabilization, phase balancing, power quality management, and enhanced system stability. Understanding this value stack is essential to making the economic case for DERs on a level playing field.

The DER Value Stack

1. Locational and Avoided Infrastructure Value

Central station plants generate power hundreds of miles from load centers, requiring massive investment in transmission and distribution (T&D) infrastructure and incurring significant losses to transport that energy to load. DERs, sited at or near the point of consumption, can defer or eliminate costly T&D upgrades by reducing peak demand on congested circuits and substations, and reduce losses. A well-placed 5 MW battery can defer tens of millions of dollars in substation and distribution upgrades, value that a remote gas peaker can never provide, regardless of its size or efficiency.[7]

2. Resilience and Reliability

Large central station plants and the long transmission lines connecting them represent single points of failure at enormous scale. DERs such as solar with storage, small generators, fuel cells, and even small-scale rooftop wind provide islanding capability, allowing critical loads including hospitals, emergency services, and water treatment plants to ride through grid outages entirely. Resilience value is increasingly recognized by regulators and insurance markets as a core grid attribute.[6,4]

3. Peak Demand Reduction and Capacity Value

Peaking power plants, typically gas combustion turbines, are among the most expensive assets in any utility portfolio, running as few as 50-200 hours per year yet requiring full capital build-out. DER portfolios with direct utility visibility and dispatch control, can provide equivalent or superior peaking capacity at a fraction of the capital cost, with zero fuel price exposure, and with lead times measured in months rather than the 5-7+ years required to permit and construct a new gas plant.[2,1]

4. Voltage Support and Power Quality

Transmission-connected resources operate far upstream of the distribution system and have limited ability to address local voltage fluctuations, harmonics, phase balance, and reactive power imbalances at the feeder level. Advanced inverter-based DERs such as solar, storage, and EVs equipped with grid-following and grid-forming inverter technology can provide real-time voltage regulation, volt/VAR optimization, and power factor correction precisely where the problem exists. This is a service that central station generation physically cannot perform from behind a high-impedance transmission network.

5. Avoided Emissions and Environmental Compliance Value

Central station fossil fuel plants carry long-term variable fuel price, potentially a greenhouse gas price, and environmental compliance risk. DERs, predominantly solar, wind, and storage, carry no fuel cost, no carbon liability, and no criteria pollutant emissions, insulating utilities and ratepayers from regulatory and commodity risk that grows more uncertain with each passing year.[13]

6. Customer Engagement and Load Flexibility

Central station resources can only supply power; they cannot shape demand. DERs embedded in customer premises can create new energy production resources while enabling load to be shifted, shed, or modulated in real time, effectively creating a new, reliable, and dispatchable resource for utilities that reduces system stress during peak periods.[1,10]

7. System Utilization and Load Factor Improvement

Perhaps the most underappreciated DER value is the ability to improve utility system load factor. Effective dispatch of DERs enables utilities to reshape the load duration curve and limit peak demand: feeder by feeder and at scale across the entire system. The electric industry has experienced a persistent decline in load factor for over thirty years. As with gas peaking units, infrastructure must be fully deployed yet is severely underutilized, driving fewer kilowatt-hours sold for every dollar of infrastructure invested, a fundamental contributor to rising rate pressure. For the first time in the industry's history, we have a cost-effective tool to arrest this decline and reverse the trend.[1,7]

Where Central Station Resources Still Lead

It is important to be intellectually honest: central station resources retain meaningful advantages that DERs cannot yet replicate. Bulk energy delivery, sustained output duration over many days or months, fuel diversity (hydro, fossil, nuclear), and inertia provision for grid frequency stability all continue to highlight the reality that a reliable grid must include a variety of resources. There are no silver bullets. DERs are a critical and increasingly cost-competitive part of the resource portfolio that will deliver significant value, but they are *part* of the solution, not the whole solution.

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.

6. Leveling the Playing Field for Distributed Energy Resources

The Fundamental Regulatory Distortion

Under traditional cost-of-service regulation, a utility earns its authorized return on equity only on capital it directly owns and places into its rate base. Every capital investment, be it a gas peaking plant, a utility-scale solar farm, or a new substation, all flow through the capital expenditure process, receive regulatory approval, and generate a return for shareholders year after year over a multi-decade depreciation schedule. This dynamic applies equally to municipal utilities and rural electric cooperatives, for whom it is far more effective to finance and own a resource than to expense a service in their annual operating budget. This is largely driven by the very low cost of capital that utilities can obtain for these long-term, guaranteed recovery investments that private developers cannot match. The utility has every financial incentive to build and own these assets, regardless of whether an equivalent, cheaper, or better-performing alternative exists.[10]

A DER deployment that meets the identical need of a comparable central station facility earns the utility precisely nothing if procured through a third-party Power Purchase Agreement. It is treated as an operating expense, not a capital investment. It does not grow the rate base. It does not generate a return for the investors. From a pure shareholder value perspective, it is a drag. This is not a hypothetical problem. It is a predictable, rational response by utility management to the incentive structure the traditional regulatory structure has created.[10,9] It is worth acknowledging that this regulatory compact has allowed for the delivery of reliable, affordable, and safe electricity for a century, a necessary structural evolution from the earliest days of electrification when competing utilities built incompatible systems down the same street. It is a model with proven results, but one that must be thoughtfully modified to level the playing field.

Why Utilities Should Not Own (All) DERs Directly

One might ask: why not simply allow utilities to own and operate DERs themselves? For larger-scale community systems that have public access and operate at utility voltage, utilities can readily design, own, and operate these resources effectively. However, when distributed resources live on customer premises, the acceptance of liability on private property and the deployment of utility line crews to customer rooftops does not fit well in any utility operating model. The reality is that most utilities are not structured or staffed for this model at scale, nor should we force them to be.

A robust ecosystem of third-party DER developers and operators has emerged precisely because they have built the competency, the technology platforms, and the risk appetite to do this work efficiently. This is a sensible division of labor: the utility procures the capacity, the third party delivers and operates the assets, and ratepayers get a cost-effective grid resource.[1,2]

The Regulatory Fix: PPA Rate-Base Treatment

The policy logic is straightforward: if the utility benefit is equivalent, the financial treatment should be equivalent. A utility that signs a 30-year PPA with a DER developer to deliver 50 MW of dispatchable DERs, capacity that demonstrably defers a gas peaker and potentially other utility system upgrades that would otherwise have been built, should be able to seek regulatory approval to finance and earn on that PPA in an equivalent fashion to a central station resource. There are several different regulatory mechanisms that may be considered, such as a capital PPA, designated regulatory asset, etc. While there is no single answer to the structure, and each regulatory authority should determine their preferred method, the simple point is that the playing field needs to be leveled appropriately to allow utilities the ability to effectively consider DERs as part of their resource mix. However, it is important that the DER resource be held to a truly equivalent standard: comparable performance guarantees and penalties, and equivalent visibility and control for the utility. The approved contract, with its defined performance standards and cost exposure, should be economically indistinguishable from building the peaker, except that it is likely to provide higher overall value, be faster to deploy, deliver reliability and resiliency the peaker cannot, create more effective partnerships between utilities and customers, and provide a clean energy resource without future fuel price risk.[10]

Regulatory commissions should establish clear pathways for utilities to:

1. Seek pre-approval of DER deployments through an integrated resource/system planning process or competitive solicitation process, applying the same scrutiny applied to traditional capital projects.
2. Define the regulatory structure to level the playing field for DERs.
3. Share the risk appropriately: utilities bear procurement and contract management risk; third-party operators bear performance and technology risk.
4. Track DER performance to improve grid parameters of efficiency, power factor, phase balance, and most importantly, system load factor.

This structure is not a gift to utilities. It is a correction, restoring the neutrality that should have always existed between “build-own-operate" and “procure-and-contract" strategies. The gas peaker or central station renewable facility does not deserve a privileged position simply because it fits neatly into a nineteenth-century regulatory model.

The Cost to Ratepayers of Getting This Wrong

Every year this regulatory gap persists, utilities face a quiet but powerful incentive to prefer capital-intensive, central station solutions over cost-effective and high-value distributed ones. The result is billions of dollars of potentially avoidable infrastructure: gas peakers that run only a handful of hours per year, transmission upgrades that could have been deferred, central station projects with decade-long lead times and a continually declining system load factor, while the DER alternative sits on the shelf, a new and valuable tool for utilities but financially invisible to the utility's income statement.[10,9]

7. The Opportunity FERC Order 2222 Provides for Collaboration

Thirty Years of Fragmentation

As we examine the regulatory landscape, we would be remiss not to recognize the significant step that FERC took with Order 2222. As with most regulatory mandates, the initial view from industry stakeholders was one of significant new compliance burdens. In reality, FERC Order 2222 is an incredible opportunity for the industry, one that deserves to be embraced with the same collaborative spirit that built the modern grid in the first place.

To understand why FERC Order 2222 is such a significant opportunity, one must first understand how profoundly the electric utility industry's capacity for collective problem-solving has eroded over the past three decades. From the 1930s through the 1980s, the electric utility industry operated as a network of regulated monopolies that collaborated extensively on planning, standards development, reliability, and shared infrastructure. The North American Electric Reliability Corporation (NERC) was founded in 1968 precisely as a collaborative response to the 1965 Northeast Blackout, an acknowledgment that the interconnected grid demanded interconnected governance.[16]

The deregulation wave of the 1990s fundamentally disrupted this collaborative culture. Beginning with FERC Orders 888 and 889, which opened transmission to competitive access, and accelerating through the creation of independent system operators, regional transmission organizations, and retail choice initiatives, the industry was deliberately restructured to promote competition among utilities. That competition has driven real efficiency gains in the bulk electric system, but it has come at a cost that is rarely acknowledged: the progressive fragmentation of the industry's capacity to solve problems together.

Over thirty years of deregulation, utilities, generators, transmission owners, distribution companies, retail suppliers, and technology providers have been increasingly incentivized to pursue their own interests rather than optimize system-wide outcomes. Data standards have proliferated without coordination. Interconnection processes have become balkanized across dozens of jurisdictions. The result is a grid whose physical infrastructure remains deeply interconnected, but whose governance, planning, and commercial frameworks have become deeply fragmented.

This fragmentation has been particularly costly for DER integration. DERs are inherently cross-system assets: a rooftop solar installation affects the distribution feeder, the substation transformer, the distribution utility's load forecast, the RTO's capacity market, and potentially the wholesale energy market, all simultaneously. The 3,000-plus electric utilities, cooperatives, and municipal systems in the United States, each pursuing its own path, have produced thousands of approaches to DER interconnection, metering, compensation, and data management, most of them incompatible and nearly all of them more expensive than they need to be.[5]

Order 2222: A Call to Collaborate Again

FERC Order 2222, issued in September 2020, is the most consequential federal DER policy action since PURPA. By requiring RTOs and ISOs to revise their tariffs to allow DER aggregations to participate in all wholesale electricity markets on a level playing field with traditional resources, Order 2222 creates a single, consistent national framework for DERs to be valued as grid resources.[15] LBNL's five-report series on DER aggregations and wholesale markets provides the most thorough regulatory analysis of Order 2222 compliance challenges currently available.[9]

But Order 2222 is more than a market rule change. Read carefully, it is an implicit acknowledgment that the fragmented approach of the past thirty years is no longer adequate for the grid challenges ahead, and an invitation, perhaps even a mandate, for the industry to rebuild its collaborative capacity. The basic design of Order 2222 requires all parties to coordinate and share information, which will necessitate, in many cases, the development of new tools to track and communicate. The question is whether the industry will seize that invitation or treat Order 2222 as yet another compliance exercise to be managed independently by each participant. While there are many potential collaborative efforts the industry could pursue, Order 2222 has highlighted four primary initiatives whose dramatic cost savings are only achievable through genuine industry collaboration.

Opportunity 1: A Non-Profit DER Registry

Today, DERs are registered and tracked through a patchwork of utility-specific systems that do not communicate with one another and require expensive, custom integration work for every market participant. A central DER registry, built once, governed by industry, maintained collaboratively, accessible to all participants, and operated efficiently as a not-for-profit service, could eliminate tens of billions of dollars in redundant systems development. Estimated savings to the industry over ten years: $20-$40 billion. This is not a technology challenge; rather it is a coordination challenge that thirty years of fragmentation have created a system which is harder to manage than it should be.[5]

Opportunity 2: Common Information Model (CIM) Data Structures

The Common Information Model (CIM) has long provided a standard data architecture for generation and transmission systems. Extending CIM data exchanges to the DER domain, creating known, standardized data structures that all utility systems can speak, would shift the integration burden from utilities to the vendor ecosystem, where it belongs. Rather than every utility paying for custom integrations, vendors would build to a common standard once for their product. Estimated value: $100 billion or more in avoided integration costs industry-wide, with a secondary benefit of dramatically accelerating the innovation cycle across the entire utility software ecosystem.[5] Recently, EPRI has helped advance the CIM with additional support for distribution grid as well as hosting events to help vendors interoperate their software solutions. Progress is being demonstrated effectively by the US research and national lab groups, but adoption by industry is significantly lagging.

Opportunity 3: Collaborative Meter Data and Settlement Infrastructure

Meter data management for DERs, the foundation of settlement, compensation, and market participation, is currently being built separately by thousands of utilities using proprietary systems that cannot easily share data across service territories or with the market. The Ontario model, with shared infrastructure, common standards, and distributed management, is a template the U.S. industry should adopt. Estimated savings from doing this right: $75 billion over time, with a compound benefit of making every future market initiative cheaper and faster to implement.[5] Europe is progressing even faster, implementing a technology called “data spaces” to dramatically expand access to data across multiple industry segments, including the electricity and broader energy ecosystem.

Opportunity 4: Shared Communication Infrastructure

Today's utility customers are served by multiple overlapping communication networks, including separate systems for electric AMI, natural gas AMI, water AMI, and many additional redundant networks, often owned and operated by different entities in the same geographic area. Consumers pay for all of these networks through their utility bills. A collaborative approach to shared communication infrastructure, built jointly by gas, water, and electric utilities within a service territory or state, would dramatically reduce cost while improving data quality and coverage.

> Order 2222 is not a burden to be managed. It is a once-in-a-generation opportunity. By having all of industry attack the DER integration challenge simultaneously and collaboratively, we have the unique opportunity to develop solutions at a fraction of the cost of 3,000+ utilities doing it ad hoc.
>
> The question is not whether the industry can afford to collaborate.
>
> It is whether it can afford not to.

8. Why Change Is So Hard in the Electric Utility Industry

A Perspective from the Field

After decades working across generation, transmission, distribution, and grid operations, we have watched the electric utility industry navigate wave after wave of technological transformation, from the electrification of rural America to the integration of digital controls, from the deregulation era to the rise of distributed energy resources. In every cycle, the same frustration surfaces from the outside world: why does the utility industry move so slowly? The answer is not stubbornness. It is a responsibility to maintain reliability.

Lives Hang in the Balance: Utilities Know It

Every decision made in a utility control room, every relay setting, every protection scheme, every software update pushed to a substation carries consequences that most industries never have to contemplate. When a hospital loses power during surgery, when a water treatment plant goes dark in a heat emergency, when a natural gas pipeline loses its electric-driven compressors in the dead of winter, people die. Electric utilities carry this weight every single day, and they do not take it lightly. The mandate is clear and unwavering: deliver reliable, safe, and affordable electricity. Not most of the time. All of the time.

This is why utilities invest so heavily in redundancy, why protection systems are engineered with multiple layers of fail safes, and why new technology and operational changes go through rigorous internal review before anything touches the live grid. It is not bureaucracy for its own sake; it is engineering discipline applied to a system where failure is measured in human lives and economic collapse, not customer churn or quarterly earnings.

The Frameworks Are Immense and Exist for Good Reason

The electric utility industry operates within one of the most complex regulatory and technical ecosystems on the planet. NERC reliability standards, FERC tariff obligations, state public utility commission rate cases, EPA environmental compliance, OSHA workforce safety mandates, and cybersecurity frameworks like NERC CIP all govern how utilities plan, build, and operate the grid. These are not arbitrary hurdles; they are the hard-won product of real failures, real disasters, and real lessons learned over more than a century of operation. Understanding them takes years of immersion. Dismissing them takes only a press release.

Interconnected systems mean that a decision made in one control area can cascade across thousands of miles in milliseconds. The 2003 Northeast Blackout left 55 million people without power from a sequence of events that began with a software alarm failure in Ohio.[16] The grid does not forgive small mistakes. A technology that performs flawlessly in a laboratory or well-controlled pilot program may behave in entirely unexpected ways when connected to an interconnected grid with thousands of simultaneous variables and millions of customers depending on an uninterrupted power supply.

The Problem With Disruption Over Collaboration

The technology community increasingly arrives at the utility industry's doorstep not as a partner, but as a disruptor, armed with compelling demonstrations, venture-backed urgency, and a narrative that frames utility caution as institutional inertia. What is missing from that narrative is intellectual honesty about the stakes. Proving a technology works in a lab with limited practical exposure is a long way from proving it is ready to be woven into the fabric of a grid that serves millions of people with little tolerance for unexpected failure modes.

Utilities are not opposed to innovation. They are opposed to unmitigated risk to the critical infrastructure. The difference matters enormously. When technology providers choose to work with utilities, understanding the interconnection studies, the protection coordination requirements, the cybersecurity protocols, the NERC compliance obligations, and the regulatory process, remarkable things happen. Smart grid deployments scale. Advanced metering infrastructure transforms demand response. Battery storage reshapes capacity planning. The innovation moves forward, and it moves forward safely.

The Path Forward Is Partnership, Not Pressure

The electric grid is the backbone of modern civilization. Every economic transaction, every hospital, every school, every home depends on it functioning reliably. The men and women who operate, maintain, and engineer that grid understand their obligation better than anyone. They are not the enemy of progress. They are its most important quality control, and they have earned that role through decades of delivering on a promise that most people only notice when it is broken.

The sooner the broader energy technology ecosystem embraces that truth and trades disruption for genuine collaboration, the faster and more safely the industry will transform. The utilities will get there. They always have. But they will do it on a timeline that reflects the weight of their responsibility, and without gambling with the lives of the people they serve.

© 2026 | Collaborative Utility Solutions

9. Summary and Call to Action

Where We Are: A True Inflection Point

The electric power industry has arrived at a genuine inflection point in the story of Distributed Energy Resources. The foundation has been built. The question now is whether the industry can adapt its planning frameworks, regulatory structures, and collaborative culture to use it.

What Must Change: A Clear-Eyed Assessment

- **Re-Invent Planning.** Planning frameworks must evolve from purely top-down IRPs to bottom-up ISPs that begin at the distribution edge and appropriately values DERs as utility-class resources.[7]
- **Transform Regulation.** Regulatory structures that create systematic financial disadvantage for DERs must change, allowing utilities to earn authorized returns on DERs that achieve equivalent, and even enhanced, outcomes when compared to traditional resource investments.[10]
- **Re-Institute Collaboration.** Collaborative capacity must be rebuilt. FERC Order 2222 provides the clearest mandate in a generation for the industry to collaborate again, on shared registries, common data standards, joint meter and settlement infrastructure, and shared communication networks.[15,5]
- **Reduce Barries.** The relationship between utilities and technology providers must mature from adversarial disruption to genuine partnership. Neither side can build the grid of the future alone.

Throughout all of this, intellectual honesty demands acknowledgment: there are no silver bullets. DERs are a critical and increasingly cost-competitive and valuable part of the resource portfolio, but they are not the whole solution. The goal is not to replace one model with another; it is to ensure that every resource, distributed and centralized alike, competes on a genuinely level playing field and is deployed when and where it delivers the most value to the utility and their customers.

The Call to Action

For Regulators

- Encourage bottom-up ISP as a complement to IRP in every state, requiring utilities to track a new set of grid health metrics including load factor, power factor, phase balance, and distribution efficiency at a circuit level.[7]
- Establish clear pathways for utilities to receive appropriate compensation for DER investments that achieve equivalent, or enhanced, outcomes comparted to traditional resource investments, with appropriate risk-sharing, performance guarantees, and penalty mechanisms.[10]
- Engage with utilities to ensure technology being implemented meets the IEEE 1547 current standard, and that interconnection rules are structured to allow DER interconnection while

requiring all resources capable of injecting into the grid to follow safety protocols required to keep utility line personnel safe.

- Use the Order 2222 implementation process as a vehicle for developing shared industry infrastructure, including registries, data standards, and settlement systems, rather than allowing it to become thousands of separate compliance exercises.[15,9]

For Utilities

- Be willing to engage in the DER conversation with clarity and confidence. Be clear that utility visibility and control of resources connected to the grid you are required to manage is a non-negotiable requirement, not an obstacle. Integrate distribution capacity analysis and locational net benefit assessments into annual planning cycles to inform your IRP and ISP processes.[7]
- Engage proactively in Order 2222 implementation as a collaborative opportunity, not a compliance burden. Invest in the shared infrastructure that makes DER integration cheaper for everyone.
- Work with your regulatory authority to develop procurement frameworks that create a level playing field for DER investment without requiring utilities to assume non-traditional utility risk.[18]

For Technology Providers

- Invest in the regulatory, operational, and technical literacy that earns utility trust. Understand interconnection studies, protection coordination, NERC CIP compliance, and state commission processes before asking utilities to trust your technology with their grid. It is not the utility's responsibility to make your business model work; it is your responsibility to provide a solution that is competitive with, or more valuable than, existing options.
- Build to open, common standards, including CIM APIs, standard interconnection interfaces, and interoperable communication protocols, rather than proprietary architectures that lock utilities into single-vendor dependencies. While proprietary architectures may seem more profitable in the short term, vendors who invest in CIM compatibility will find dramatically greater market opportunity as the industry moves in this direction. The current construct of thousands of incompatible software interfaces is unsustainable, and those who help solve it will earn durable market share.

For the DOE and Federal Government

- Continue and expand investment in R&D programs targeting data standards and system architecture to support lower technology costs, advanced inverter and grid-enhancing technology capabilities, and the computational tools needed for bottom-up ISP.[17]
- Use the convening authority of DOE and FERC to accelerate the development of shared industry infrastructure, including the DER Registry, CIM data standards, and collaborative meter and settlement frameworks.[5]

The transformation of the electric grid is already underway. The distributed revolution is not coming; it is here.

The only question that remains is whether the utilities, regulators, and technology providers who share responsibility for the grid will adapt their planning frameworks, their regulatory structures, and their collaborative culture quickly enough to harness what is already being built.

The grid has survived every previous wave of transformation by combining engineering discipline with the courage to change. It will survive this one too, if the industry chooses collaboration over fragmentation, technology providers choose partnership over disruption, and regulators can support honest assessment over comfortable inertia.

Appendix A: Bibliography

All references are listed in citation order as they appear in the paper. Government and laboratory publications are available through their respective agency websites unless otherwise noted.

[1] U.S. Department of Energy. *"Pathways to Commercial Liftoff: Virtual Power Plants."* **U.S. DOE Office of Clean Energy Demonstrations, 2023, updated 2025.** Estimates VPPs could reduce U.S. peak demand by 80-160 GW by 2030. Available: energy.gov

[2] Brehm, K., McEvoy, A., Usry, C., and Dyson, M.. *"Virtual Power Plants, Real Benefits."* **Rocky Mountain Institute (RMI), 2023.** Quantitative case for VPPs as a least-cost grid resource. Available: rmi.org

[3] Wood Mackenzie. *"2023 U.S. Distributed Energy Resource Outlook."* **Wood Mackenzie Power & Renewables, 2023.** Projects 262 GW of new DER and demand flexibility capacity from 2023 to 2027.

[4] Rocky Mountain Institute. *"Power Shift: How Virtual Power Plants Unlock Cleaner, More Affordable Energy."* **Rocky Mountain Institute (RMI), 2024.** Capacity expansion modeling demonstrating VPPs can displace gas peakers cost-effectively across multiple grid scenarios. Available: rmi.org

[5] U.S. Department of Energy / Interconnection Innovation e-Xchange (i2X). *"DER Interconnection Roadmap."* **U.S. DOE, January 2025.** Incorporates input from over 45 organizations. Sets national agenda for interconnection reform. Available: energy.gov/i2x

[6] National Renewable Energy Laboratory. *"Virtual Power Plants and Energy Justice."* **NREL, 2024.** Analyzes VPP use cases through an energy justice lens with focus on underserved communities. Available: nrel.gov

[7] National Renewable Energy Laboratory. *"Distribution Capacity Expansion Planning: Current Practice, Opportunities, and Decision Support."* **NREL, 2022.** Foundational analysis of bottom-up distribution planning methodologies. Available: nrel.gov

[8] Lawrence Berkeley National Laboratory. *"Virtual Power Plants: Insights, Profiles, and Inventory."* **LBNL, 2025.** Most comprehensive empirical database of real-world VPP performance data available. Available: emp.lbl.gov

[9] Lawrence Berkeley National Laboratory. *"DER Aggregations and Wholesale Markets (Five-Report Series)."* **LBNL, 2022-2024.** Includes analysis of state regulatory opportunities to advance DER aggregations and FERC Order 2222 compliance. Available: emp.lbl.gov

[10] National Association of Regulatory Utility Commissioners (NARUC). *"Regulators' Financial Toolbox: Virtual Power Plants."* **NARUC, 2023.** Translates DER and VPP technical concepts into the language of state public utility commissions. Available: naruc.org

[11] BloombergNEF. *"BloombergNEF Battery Price Survey: Annual Edition."* **Bloomberg Finance L.P., 2024.** Primary data source for lithium-ion and LFP battery pack cost trends 2010-2024.

[12] National Renewable Energy Laboratory. *"Annual Technology Baseline (ATB)."* **NREL, 2024.** Annual publication tracking cost and performance of electricity generation and storage technologies. Available: atb.nrel.gov

[13] International Renewable Energy Agency (IRENA). *"Renewable Power Generation Costs."* **IRENA, 2024.** Annual global survey of renewable energy levelized costs of electricity. Available: irena.org

[14] U.S. Congress. *"Public Utility Regulatory Policies Act of 1978 (PURPA)."* **U.S. Government, 1978.** Pub. L. 95-617. Required utilities to purchase power from qualifying small generators; foundational legislation for distributed generation.

[15] Federal Energy Regulatory Commission. *"Order 2222: Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators."* **FERC, September 2020.** Docket No. RM18-9-000. Available: ferc.gov

[16] U.S.-Canada Power System Outage Task Force. *"Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations."* **U.S. DOE and Natural Resources Canada, April 2004.** Definitive post-event analysis of the Northeast Blackout of 2003. Available: energy.gov

[17] U.S. Department of Energy. *"SunShot Initiative: On the Path to SunShot, Utility-Scale Solar."* **U.S. DOE Office of Energy Efficiency and Renewable Energy, 2016-2017.** Documents SunShot cost targets and progress, including the early achievement of the $0.06/kWh goal in 2017. Available: energy.gov/eere/solar/sunshot-initiative

[18] Con Edison / New York State Department of Public Service. *"Brooklyn-Queens Demand Management Program: Final Report."* **Consolidated Edison Company of New York, 2018.** Documents the non-wires alternative program that deferred a $1.2 billion substation project using customer-sited DERs. Available: dps.ny.gov