A New Framework for DER Value in the Speed-to-Power Era

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Introduction

The idea that distributed energy resources (DERs) can defer or even eliminate the need to build new electric generation, transmission, and distribution resources is intuitive, if not entirely simple. When customers self-supply a portion of their electricity needs through onsite resources, utilities need to supply less power, slowing the pace at which they need to build new resources. This concept, which this paper will refer to as the "**Deferral Paradigm,**" serves as the basis for almost all DER compensation mechanisms that exist in the US today.

These mechanisms typically attempt to estimate the cost of the future grid buildout avoided due to DER operation and then set DER compensation at or below the avoided cost. When these avoided cost estimates are accurate,[1] DER deployment reduces total system cost through provision of grid services at lower cost than the traditional alternatives.

The Deferral Paradigm has appropriately been dominant in most locations in the US for the past few decades because load growth was low or even stagnant. From 2000 to 2024, US electricity demand grew by less than 1% per year.[2] Low load growth meant that the typical planning procedure was to forecast growth, plan for grid buildout to be ready at the future date when new loads seek to connect and execute on planned buildout at a manageable pace. DERs influenced this process by applying a downward effect on load forecasts, resulting in deferral of need dates for new grid buildout. The Deferral Paradigm captures this dynamic quite well.

But what if the system hosting the DERs has a queue of loads, such as data centers, that are waiting for service because grid buildout is lagging behind demand? And what if the DERs could create the ability for some of the queued loads to obtain service more quickly? In these locations, DERs no longer slow down grid buildout, and the predominant source of their value is in providing the capacity needed for new load connections. This constitutes a shift from the Deferral Paradigm to a new "**Speed-to-Power (STP) Paradigm**."

Over the past two years, the explosion of data center development has increased US load growth forecasts to 5.7% per year through 2030.[3] Presumably, this phenomenon is shifting

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1 In practice, the cost-reflectivity of DER compensation (i.e., the accuracy of avoided costs) varies widely, and in many cases, DERs are over- or under-paid for the grid services they provide. These issues are the subject of ongoing regulatory proceedings in several US jurisdictions, and we do not discuss them in this paper.

2 John D. Wilson, Sophie Meyer, Zach Zimmerman, and Rob Gramlich. *Power Demand Forecasts Revised Up for the Third Year Running, Led by Data Centers*. Grid Strategies, November 2025. https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf.

3 Ibid.

many locations in the US toward the STP Paradigm, where grid buildout is lagging demand and there is potentially large value for accelerating new load connections.

We believe this paradigm shift calls for new methods to compensate DERs. Specifically, it raises three foundational questions:

- Should the value of DERs be measured differently under the STP Paradigm than under the Deferral Paradigm?
- Should the costs of DER compensation be allocated differently among ratepayers?
- Should DER compensation transition between paradigms as system conditions change?

This paper argues that the answer to all three of these questions is yes and explains why existing valuation approaches are insufficient under the STP Paradigm. We also present a revised framework for compensating DERs that better reflects their value to the electric system.

Section I describes DER value in the STP Paradigm and contrasts it with the Deferral Paradigm via simplified illustrations of the benefits of DER deployment in the two cases. We show that the primary benefit in the Deferral Paradigm is system cost reduction, and the primary benefit in the STP Paradigm is accelerated load connection and increased grid throughput.

Section II provides conceptual discussion and example calculations describing a benefits framework for the STP Paradigm. Under this framework, DER value comes from three sources: (i) the value to the queued customers of being able to connect earlier; (ii) the rate reduction for existing customers from spreading fixed system costs over more grid throughput; and (iii) the downward impact on market prices for all ratepayers due to the introduction of new supply. We focus on rate reduction benefits to ratepayers due to increased throughput from the existing system and discuss considerations for other benefits at a high level. We then discuss practical aspects of assessing the costs and benefits of DER deployment for STP.

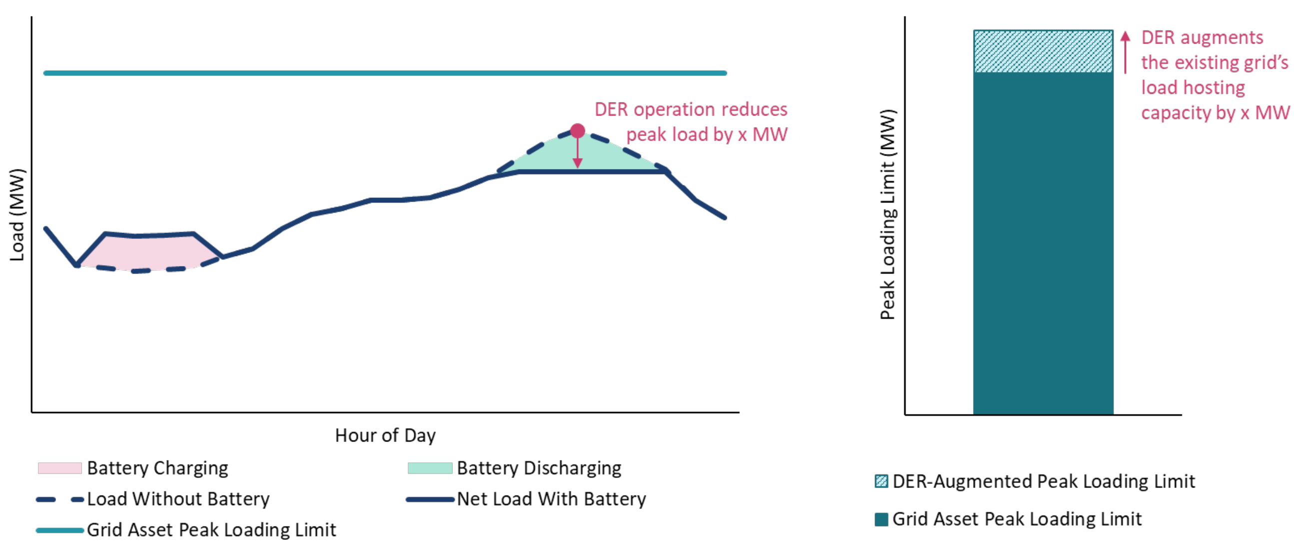
Section III explores the implications for those who should bear the cost of DER compensation under the STP Paradigm. We show that most of the value accrues to new loads that can connect sooner. This supports introducing new cost allocation mechanisms under which those loads help fund the DERs that enable their interconnection. At the same time, because some benefits continue to flow to all ratepayers, it remains appropriate to allocate a portion of DER compensation across the broader ratepayer base.

Section IV discusses the challenges of measuring the value of STP, and Section V details some of the expected implementation and regulatory considerations for the use of DERs under the STP Paradigm. Section VI concludes with a recap and presents several prerequisite steps for realizing the value of DERs for accelerating large load connections.

I. Illustrations of the Deferral and Speed-to-Power Paradigms

In both the Deferral and STP paradigms, DERs serve a similar function. By reducing load, shifting load, or injecting power at the right place and time, DERs can reduce the net peak load experienced by grid assets serving the location, as illustrated in Figure 1(A). An alternative framing of this type of operation is that DERs increase the capability of the grid to serve load in the location ("load hosting capacity"), as shown in Figure 1(B).

FIGURE 1. (A) PEAK LOAD REDUCTION USING A LOAD-SHIFTING DER; (B) EXISTING GRID'S LOAD HOSTING CAPACITY



Regardless of paradigm, it is important to note that several conditions must be met for planners to account for DERs in this manner:

- Sufficient DER capacity must be available by the time grid needs arise
- The DER capacity must be in the right locations to mitigate location-specific grid constraints

- The DER capacity must have appropriate availability and operating attributes to reliably provide the required grid services
- Appropriate market structures, rates, programs, or direct control mechanisms must be in place to ensure that the DER can be operated as planned
- Appropriate grid capabilities must be in place to ensure grid operators have sufficient real-time visibility of grid and DER asset states

When all these conditions are met, DER operation can essentially free up system generation, transmission, and distribution capacity outside of the capacity expansion steps that are part of the utility's plan.

While the DER's function is similar in that it creates capacity headroom, the benefits of augmenting the grid's load hosting capacity are very different in the Deferral and STP paradigms. As shown in Figure 2, increasing load hosting capacity in the **Deferral Paradigm** allows the existing grid in this location to serve planned load growth for an additional five years, through Year 13. If the grid's capacity were not augmented with DERs, the upgrade would have been needed in Year 8. Value in this paradigm is derived primarily from the deferral of capital expenditures and the time value of money associated with that deferral.

FIGURE 2. IMPACT OF DERS IN THE DEFERRAL PARADIGM

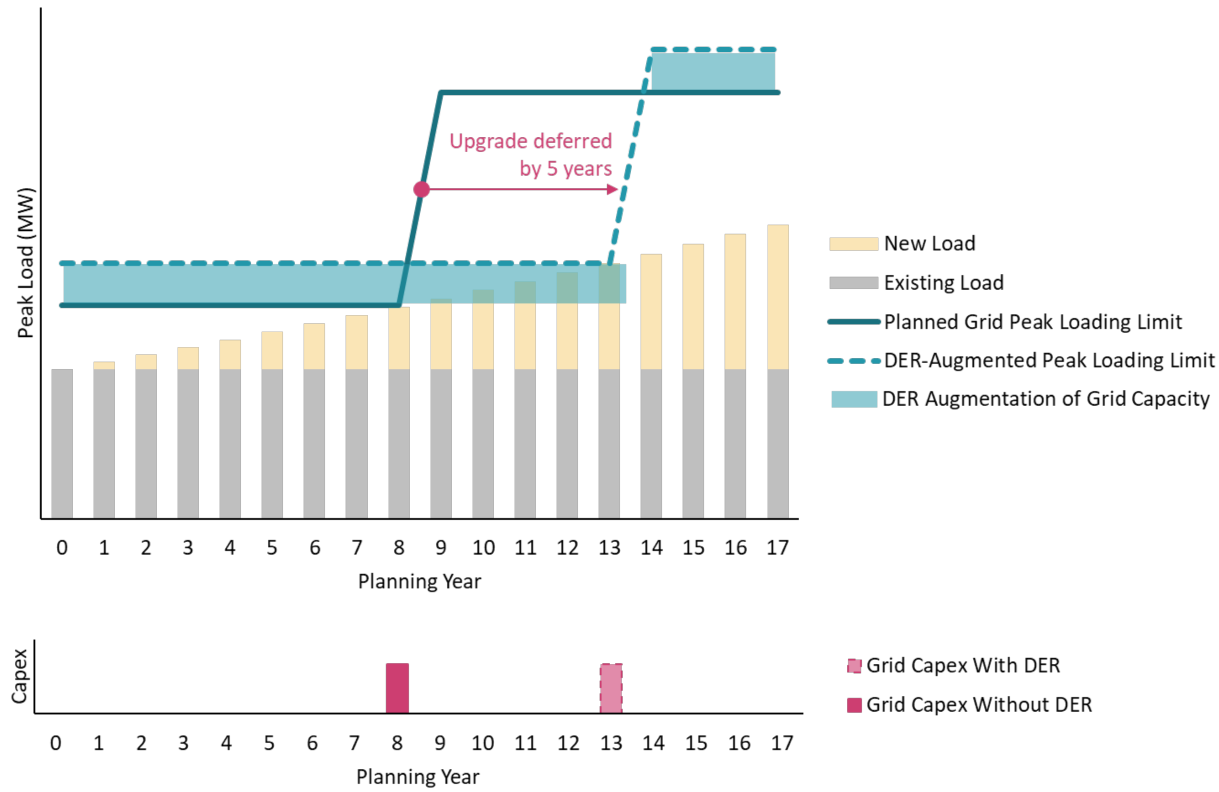
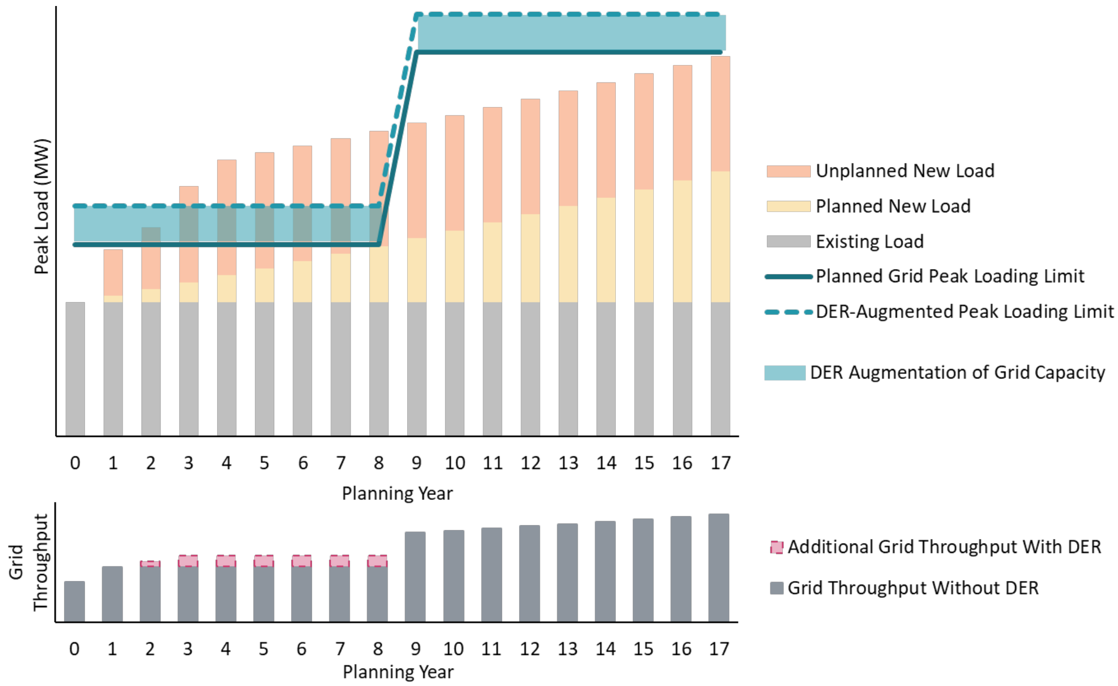


Figure 3 illustrates the STP Paradigm, using a scenario in which the same location experiences an *unplanned* spike in requests for new load connections. The hypothetical shows a case where the planned grid upgrade cannot be accelerated, and, beginning in Year 2, some of the unplanned new customers begin to form a queue and face delayed connection. The queue grows through Year 8, when the planned grid upgrade is completed, and all the queued customers receive service, with delays of up to six years.

The figure also shows the impact of the additional load hosting capacity created by DERs in this location. From Years 2 to 8, the additional hosting capacity allows more of the unplanned new customers to be connected on time, thereby reducing connection delays relative to the planned status quo without DERs. In contrast to the Deferral Paradigm, the impact of DERs in the STP Paradigm is not to reduce grid expenditures. Rather, their impact is to reduce the connection delays faced by new loads and to increase the throughput of the existing grid.

FIGURE 3. IMPACT OF DERS IN THE SPEED-TO-POWER PARADIGM



It is important to note that the Deferral and STP paradigms are not necessarily mutually exclusive. In fact, the second half of Figure 3 (Year 9 onwards) shows that after the grid upgrade is completed, the location returns to the Deferral Paradigm. Load continues to grow, and, by Year 17, new load would again necessitate a grid upgrade if not for the additional load hosting capacity provided by the DERs. This implies that most DERs will exist in some mix of the two paradigms at any given time or transition between paradigms at different points during their useful lifetime.

This is likely for two reasons. First, the different types of grid assets serving a location (generation, transmission, primary distribution, and secondary distribution) can have different load growth rates, constraints, and utilization at any point in time. For example, a system with plenty of spare transmission capacity may still have a queue of delayed new loads if there is insufficient generation capacity to serve them. Second, the grid itself is constantly evolving, with assets being modernized, replaced, upgraded, and added. As grid conditions change, a constraint limiting load growth may be resolved, or a long-deferred upgrade may be necessary, and these developments can change the need for DER-provided grid services.

Therefore, the purpose of this paper is not to advocate for replacing existing deferral-based valuation frameworks but to highlight that without an STP framework, an important source of DER value may be overlooked.

II. The Economics of DERs Accelerating Speed-to-Power

The differences in DER impacts in the two paradigms lead to important differences in the value of DERs from various perspectives, as summarized in Table 1.

TABLE 1. DER BENEFITS AND COSTS FROM VARIOUS PERSPECTIVES IN STP AND DEFERRAL PARADIGMS

	Perspective	STP Paradigm	Deferral Paradigm
Benefits	**Utility Cost Perspective**	DERs have limited impact on total system cost as there is no change to timing or magnitude of planned capital expenditures.	DERs reduce total system cost by allowing some capital expenditures to be deferred.
Benefits	**Existing Ratepayer Perspective**	• Increasing the throughput of the existing grid allows costs to be spread over more kWh, thereby reducing rates and providing bill reductions. • In organized capacity markets, reducing queued load can materially reduce market clearing prices, reducing rates for all ratepayers.	All else equal, the reduction in total system cost translates to lower rates for all ratepayers. If the DERs significantly reduce utility sales, there may be scenarios where they reduce total system cost but increase rates.
Benefits	**New Customer Perspective**	New customers avoid delays to connection, thereby avoiding: • The cost of alternative energy supply (e.g., onsite generation); or, if alternatives are not available, • The cost of lost business activity or other economic value.	
Costs	**Utility Cost Perspective**	The cost of deploying and operating DERs adds to system costs.	
Costs	**Existing Ratepayer Perspective**	Impacts depend on the allocation of DER costs among existing and new customers.	DER costs are typically collected through rates that apply to all customers.
Costs	**New Customer Perspective**	If DERs are deployed under "Bring Your Own Capacity (BYOC)" mechanisms, new customers may bear the entire cost of DER deployment.	

The methodology for estimation of value in the Deferral Paradigm is well-established and typically uses the utility cost perspective. DERs reduce system costs by deferring grid infrastructure upgrades. There are costs associated with deploying the DERs, including upfront incentives, ongoing payments, and program administration costs, some of which are transfers between customer groups. If the grid cost reduction is greater than the DER deployment cost, there is a net total cost reduction, and the DERs are considered to be net beneficial from the utility cost perspective.

In the STP Paradigm on the other hand, the usefulness of the utility cost perspective is limited because the primary benefit of DERs is not reducing *overall* utility costs but reducing *per kWh costs* by accelerating the connection of queued new customers and increasing the throughput from the existing grid. Therefore, we outline an approach to assess the benefits and costs of DERs in this paradigm primarily from the perspective of existing ratepayers.

The impacts for existing ratepayers of accelerating STP are based on changes to revenue requirements, throughput, and rates. Other than paying to incentivize and operate the DERs, the utility's capital plans and associated revenue requirements have not changed. There is likely a net increase in energy sales because the large, connected load probably has a higher load factor than the customers who shifted their peak use to make room for the large load. The utility's cost of serving this added energy must be factored in.

In simple terms, the changes in revenue requirement associated with STP are:

This is an increase in revenue requirements, since there is a larger amount of energy being served, almost surely adding some additional energy supply costs to revenue requirements, and an additional cost for the DER capacity acquired. However, there is also an increase in *revenue collections* due to the higher level of energy sales. Because most utility tariffs are based on embedded costs that collect much more than incremental energy costs, the added sales are likely to create much more utility revenue than the utility's energy costs have grown.

The rate impact of STP for existing ratepayers is therefore the delta between the increased revenue requirements and increased revenues due to higher volume of sales:

Change in revenue collected from existing ratepayers = **Cost to connect and serve new load** – **Revenue collected from new load**

Depends on applicable rate design and cost allocation mechanisms

If the revenue collected from the new load exceeds the cost to serve the new load, this reduces the cost to be collected from the rest of the customers on this system, and therefore, rates will decline relative to the status quo.

It is reasonable to think that the effect of DER-driven STP would be to lower rates in many systems under plausible conditions. Controllable DER capacity (demand response in particular) can be purchased for $50-$100/kW-year in many places, far below current natural gas turbine costs of $200/kW-year or more.[4] DER costs may be less than the fixed costs embedded in many utility tariffs today, which is what they collect in revenues for each added kWh sold. Hence, from the standpoint of the average utility customer, using additional DERs for STP is likely to lead to lower rates than would occur under the status quo.

A recent Brattle report presented an analysis of a hypothetical utility using DER technologies in an application similar (but not identical) to our STP example. For a 3,000 MW exemplar utility with 33% load growth over five years, the authors found that the addition of DERs in the $50–$100/kW-year price range reduced rate increases substantially, reducing an increase that would otherwise be 10–15% by at least three and a half percentage points.

Of course, this finding depends entirely on the utility's ability to incentivize and control a sufficient amount of optimally located and cost-effective DER capacity. This takes us to the practical aspects of implementing and measuring the STP use case.

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[4] Several Brattle studies contain surveys and literature reviews that find substantial supply potential in this price range. See, for example, *Hyperscaler Support for Community Energy Programs: Options and Impacts for Household Energy Investments* (The Brattle Group, June 2026) and *The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability* (The Brattle Group, March 2026).

III. Challenges in Measuring Value in the Speed-to-Power Use Case

Unlike the deferral value calculations, estimating the reduction in rates enabled in the very simple STP use case illustrated above does not require projecting capital costs that will not occur. While the STP Paradigm thus frees us from the need to model highly uncertain alternative capital expansions, it is not without challenges.

In the STP Paradigm, planners must model out the operational implications of adding DERs to the current base expansion plan in some detail. They must examine operating scenarios with the right amount, location, and operability of DERs with and without a new large load customer and make certain that all system reliability and operational constraints are satisfied. The operating requirements the DER aggregation must meet must be acceptable and feasible for both system planners and DER aggregators. Planners must also verify that the DER aggregations have the operating characteristics needed to maintain reliability. These challenges notwithstanding, it is inherently feasible for engineers to measure the effect of changed load shapes on a system that they have planned and modeled extensively and operate on an ongoing basis.

A final challenge that should be acknowledged is cost allocation. Every public utility ratemaking exercise requires the application of cost allocation principles to a real-world situation. In the STP Paradigm, regulators will have to allocate additional costs for DERs and any other additional costs between the large loads who gain service more quickly and the general customer base, who gain from sales-driven rate reductions.

While the beneficiary pays principle might argue for a methodology that allocates these costs in proportion to the benefits received, it is not always applied mechanically, because utilities and regulators may also consider public policy goals, equity, reliability, administrative simplicity, and broader system benefits. Large loads may agree to bear all of the DER costs that enable their faster connection to the system to have the "social license" to proceed, which is emerging as an important consideration in large-load siting and interconnection discussions.[5]

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[5] For example, a new data center may be welcomed if it pays for required interconnection upgrades, signs a long-term contract, brings local economic benefits, uses clean energy, and does not raise rates for other customers. It may lack social license if it is perceived as consuming scarce grid capacity, increasing costs for households, or receiving preferential treatment without clear public benefits.

IV. Implementation and Regulatory Aspects of Using DERs for Speed-to-Power

It is not unusual for new customers to wait for connection to electric service, and every utility has well-worn processes for accepting and processing new service requests. In the past, most delays in providing services were largely related to the time required to do any necessary design, permitting, engineering, procurement, and construction of the physical facilities needed to connect the customer. In other words, the delays were rarely due to the absence of generation and transmission capacity sufficient to deliver power to the load with reliability. When service discrimination or service delay complaints were filed with regulators, these too typically hinged on the allocation of the utility's distribution engineering resources to one customer over another, not questions involving scarce generation capacity.

The rapid growth of data centers has changed all this. According to a recent report by Wood Mackenzie, US utilities have requested about 241 GW of data center loads as of January 1, 2026.[6] The requests are concentrated in about 20 utilities; among them, seven have requests exceeding 8 GW. The scale of these requests underlines the magnitude of the challenge, as it takes even the most ambitious utilities many years to add multiple gigawatts of generation and transmission capacity.

Utilities with these large request backlogs have established increasingly formal procedures for accepting, processing, and prioritizing these large requests for service. For example, Virginia's Dominion Energy has recently filed formal large load queuing procedures with the Virginia state utility regulator. Under the proposed process, summarized in Figure 4, a large load must first go through a seven-to-ten-month initial feasibility screening process before entering the official queue. Applications are limited to 300 MW each, although customers can request a series of 300 MW blocks that are staged three years apart. Once in the queue, each applicant is given a number indicating its place in it. The current expectation is that the overall timeline from initiation to execution is likely to take five to ten years.

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[6] Wood Mackenzie, "Newly added US data center capacity slows down considerably in Q4 2025, as market struggles to keep up with explosive demand." News release, March 16, 2026. https://www.woodmac.com/press-releases/newly-added-us-data-center-capacity-slows-down-considerably-in-q4-2025-as-market-struggles-to-keep-up-with-explosive-demand/.

FIGURE 4 – DOMINION ELECTRIC PROPOSED QUEUING PROCESS FOR LARGE LOADS

Source: Reproduced based on the Direct Testimony of J.R. Vitiello, Virginia Electric and Power Co., Case PUR-2026-00011.

It is typical to study the impact of these loads in batches for feasibility assessment purposes. For instance, Dominion studies the generation and transmission additions needed to serve the queued applicants in batches of ten applications, or about a 3,000 MW addition. The generation and transmission additions needed to serve one batch of applications are determined by studies of generation sufficiency, load flows under both normal and N-1 conditions, stability studies, and other factors. Many of the results of these studies – and therefore the upgrades needed – will depend on the specific locations of the large load applicants in each batch.

If a utility decides to expend funds to pay for added DERs to create headroom and move the queue forward, this is in accord with a basic public service mission, provided that the benefits to ratepayers from accelerating the queue outweigh the cost of the DER payments. The queue continues to operate as designed; the utility is simply finding a way to service the whole queue more quickly by making more efficient use of its system.

Consider a large load willing and able to pay for enough headroom-creating DER capacity to offset its full load (say, 300 MW). First, its actions to create the headroom would have to be reflected in an altered base case used to study the immediate batch of LL applications. There is nothing to prevent this in principle, and this lies at the heart of the entire idea of using DERs to create headroom. As noted, the utility operating the queue would have to be convinced that the DER headroom was assured, and that the new level of post-DER adequacy could be recognized as complying with regional transmission organization (RTO) and North American Electric Reliability Corporation (NERC) rules, as well as any relevant state requirements.

Beyond this hurdle, there are at least two additional challenges to the use of large load funded headroom to speed that large load project forward. First, under the batch study approach, it is not clear how the benefits of this headroom creation would accrue collectively to a batch, much less to a single project within the batch.

For example, assume the batch study found that one transmission project was needed to accommodate the first five projects, and a second upgrade was needed to connect the remainder of the projects in the batch. Suppose further that the utility's studies show that, irrespective of the large load's investment in DERs, the first set of upgrades are needed. They further show that, as a result of the large load's investment, the size of the second upgrade can be smaller – headroom has indeed been created, but it does not take effect until the second upgrade is implemented.

Now assume that the smaller size of the second upgrade saves money, but there is no significant difference in the time needed to build the second upgrade. In this hypothetical case, the whole point of the large load's own investment in rapidly deployed DER resources has dissipated. Whereas the investment, in concept, should create headroom more rapidly than many transmission additions, when it is combined with an ongoing forward program of successive building stages it may not change timelines as directly as the timing of the resources it creates. In other words, the timing of genuine headroom creation may simply not translate into faster connection for any one member of the queue.

It is possible to imagine a more limited situation in which a utility has only one large load applicant they cannot serve without a very long upgrade cycle unless the large load rapidly procures the right sort of DERs. In this case, there could be a much more direct relationship between the DER resources, the headroom they create, changes in the utility planner's base case, and a subsequent ability to connect that DCD earlier. However, this scenario is rare, as large load queues seem much larger than one project.

Finally, this discussion would seem to have implications for how DER STP capacity could be funded in ways that would seem more consistent with public utility principles. To see this, consider a program in which the large load directly pays customers who host DERs, giving them a payment in exchange for them signing up with the utility to allow the utility to partially control their load. There is nothing wrong with this arrangement in theory, and if the contract with the utility had the proper provisions in it applying to the right sort of DERs, the utility could have confidence that headroom was created as intended.

But the final part of the arrangement could be problematic. In exchange for being the beneficiary of the contracts with the DERs, the utility agrees to move the large load from whatever queue position it occupies to a much earlier position that connects sooner. It seems that this would raise questions about whether these quid pro quos should be allowed.

In contrast, if the large load is funding DER headroom by providing earmarked funds directly to the utility, the quid pro quo concerns would seem to be less. Here the utility is the entity procuring higher amounts of DERs, albeit with a customer-contributed funding source, but nonetheless doing so under conditions examined and approved by regulators. If this program created headroom, and the utility and its regulator agreed that awarding that headroom to the contributing customer in the form of a better queue position, the transparency afforded by regulation would seem to make the approach more consistent with the principles of regulation.

V. Conclusion

The accelerating demand for electric service from data centers and other large loads requires a broader framework for valuing distributed energy resources than the traditional Deferral Paradigm alone can provide. Under the Deferral Paradigm, DER value is measured primarily by the avoided or delayed cost of generation, transmission, or distribution infrastructure. That framework remains important, particularly for non-wires alternatives and other location-specific applications where DERs can reliably defer a known upgrade.

However, in systems where service requests exceed the pace of grid expansion, the relevant question is no longer only whether DERs can help the utility build later; it is whether DERs can help the utility serve earlier. In this Speed-to-Power Paradigm, DER value arises from creating usable system headroom that allows queued load to connect sooner while preserving reliability and avoiding undue cost shifts.

This distinction matters because the two paradigms have different beneficiaries and valuation challenges. Deferral of grid buildout is primarily a system benefit: DERs reduce the net present value of revenue requirements by delaying capital additions and, in some cases, reducing energy costs. Speed-to-power benefits, by contrast, are often concentrated initially in the large load customer whose project can be energized sooner, while potentially also creating broader ratepayer benefits by spreading fixed system costs over additional sales.

Recent load growth forecasts and resource plans show that this is not a marginal issue. Data center demand has become a major driver of near-term utility planning, and, in some regions, the scale and timing of requested load now exceed the assumptions embedded in conventional planning and tariff design. The appropriate policy response is to recognize both grid buildout deferral and speed-to-power as distinct DER services that may coexist, overlap, or dominate under different system conditions.

A revamped DER compensation framework should therefore be dynamic, locational, and tied to the specific grid service being provided. Where DERs defer a planned investment, compensation should continue to reflect the avoided-cost logic of the deferral paradigm, with stronger attention to location, operational certainty, duration, and deliverability. Where DERs create headroom for earlier load interconnection, compensation should reflect the incremental value of accelerated service, including the willingness of the connecting customer to fund the DER capability, any rate-mitigation benefits for other customers, and any reliability or market-price effects associated with the additional resource.

The resulting framework should also be transparent and fair. Customers that fund or enable headroom should have their queue position accelerated based on regulator-approved procurement mechanisms that allow customer-funded DER development when it demonstrably creates reliable headroom.

Implementation should begin with tariff and interconnection reforms that make speed-to-power a defined, testable service rather than a potential auxiliary benefit of DERs. Utilities and regulators should establish:

1. **A formal study process** for evaluating whether specified DER portfolios create dependable headroom under normal, contingency, and peak risk conditions

2. **Tariff provisions** that assign DER procurement costs to the large load customer to the extent the accelerated interconnection benefit is customer-specific, while allocating any proven systemwide benefits more broadly

3. **Operational requirements** for telemetry, dispatchability, performance measurement, and non-performance penalties for the DER portfolios creating the capacity headroom

4. **Queue rules** clarifying when DER-enabled headroom can change energization timing, whether it benefits an individual customer or a study batch, and how similarly situated customers will be treated.

These steps would translate the conceptual value of DER-enabled speed-to-power into a transparent, regulated service provided by the electric system – a service that can accelerate economically valuable load interconnections while preserving reliability, protecting existing customers, and maintaining the non-discriminatory principles at the core of utility regulation.

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