REGULATORY ASSISTANCE PROJECT

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Transitioning to Distribution System Operators in Brazil

Functions, benefits and strategic pathways

Luiz G. S. de Oliveira, Raj Addepalli, Bibiana Sáenz, Felipe Villegas Gómez and Alejandro Hernández

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We want to emphasize that all views, opinions and insights presented in this report, as well as any errors or omissions, are solely the responsibility of the authors. No statements have been directly attributed to any individuals acknowledged in this section.

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List of Acronyms

- ACL – Ambinete De Contratação Livre (Free Contracting Environment)
- ACR – Ambiente de Contratação Regulado (Regulated Contracting Environment)
- ADMS – Advanced distribution management systems
- AEMO – Australian Energy Market Operator
- AMI – Advanced Metering Infrastructure
- ANEEL – Agência Nacional de Energia Elétrica (Brazilian Electricity Regulatory Agency)
- BCA – Benefit-cost Analysis
- CCEE – Câmara de Comercialização de Energia Elétrica (Chamber of Electric Energy Commercialization)
- CNPE – Conselho Nacional de Política Energética (National Council for Energy Policy)
- CSIRO – Commonwealth Scientific and Industrial Research Organization
- DER – Distributed Energy Resources
- DERMS – DER management systems
- DNO – Distribution Network Operator
- DNSP – Distribution Network Service Providers
- DSO – Distribution System Operator
- ENA – Energy Networks Australia
- ENTR – Electricity Network Transformation Roadmap
- EPRI – Electric Power Research Institute
- ESO – Electric System Operator in United Kingdom
- MME – Ministério de Minas e Energia (Ministry of Mines and Energy)
- NREL – National Renewable Energy Laboratory
- NWA – Non-wires alternatives
- OFGEM – Office of the Gas and Electricity Markets
- ONS – Operado Nacional do Sistema (National System Operator)
- OpEN – Open Energy Networks Initiative
- RDM – Revenue Decoupling Mechanism
- RIIO – Revenue = Incentives + Innovation + Outputs
- SCADA – Supervisory Control and Data Acquisition
- SIN – Sistsema Interligado Nacional (National Interconnected System)
- TSO – Transmission System Operator
- VPP – Virtual Power Plants

Executive Summary

Current Context and Needs

Brazil's electricity sector is undergoing a pivotal transformation driven by rapid growth in distributed energy resources (DERs), climate commitments and evolving consumer demands. The anticipated expiration of 20 distribution concession contracts between 2025 and 2031 presents a strategic opportunity to advance regulatory agendas and modernize grid infrastructure and operational frameworks. Traditional distribution utilities must transition into dynamic distribution system operators (DSOs) to manage bidirectional power flows, integrate DERs and enhance grid resilience. This shift is critical to balancing Brazil's decarbonization goals with rising energy demand, which is projected to grow at 3.4% annually through 2034. Challenges such as high nontechnical losses, DER integration complexities, aging infrastructure and affordability underscore the urgency for reforms that align with emerging market dynamics.

DSO Model Benefits and Functions

In this context, Brazil may consider reforming the framework of distribution utilities. Transitioning from a passive model, characterized by distribution network operators (DNOs), to a more proactive approach as distribution system operators could facilitate the active harnessing of the substantial untapped resources available at the distribution level. This shift has the potential to enhance the overall efficiency and effectiveness of the energy distribution system. The DSO model integrates three core roles: **system operation** for real-time grid management, **system planning** for long-term DER integration strategies, and **market operation** to competitively procure DER services. Enhanced DER integration enables utilities to optimize grid performance through dynamic operating envelopes and real-time monitoring, thereby reducing solar curtailment and improving reliability. By leveraging non-wires alternatives (NWAs), such as DER flexibility and storage, utilities can defer costly infrastructure upgrades, thus lowering consumer costs. The DSO framework also expands market participation, allowing DER aggregators to provide energy, capacity and ancillary services at distribution and wholesale levels, fostering competition and innovation. Improved service offerings reduce reliance on fossil fuel peaking plants, aligning with Brazil's climate targets while ensuring affordability.

Defining a Brazilian DSO Pathway

Brazil's transition requires a phased approach combining immediate actions with systemic reforms. **Immediate priorities (2025–2027)** focus on foundational policies: Dynamic tariffs (e.g., time-of-use pricing) and automated demand-response pilots will target industrial and commercial sectors to unlock flexibility. Regulatory sandboxes will test DER aggregation, virtual power plants (VPPs) and NWAs in high-penetration regions like São Paulo and Minas Gerais. Prohibiting utilities from owning DER assets ensures market neutrality, while substation-level monitoring and

DER payment mechanisms based on system value (e.g., avoided congestion costs) will optimize grid planning.

Long-term reforms prioritize strategic recommendations embedding DSO functions into renewed concession contracts, using a **maturity assessment framework** to evaluate technical infrastructure, operational capabilities and market readiness. Revenue decoupling mechanisms (RDMs) will align utility incentives with DER adoption by delinking revenues from energy sales, ensuring financial stability amid potentially declining net demand. Concurrently, grid modernization efforts must accelerate smart meter deployment and advanced distribution management systems (ADMS) for real-time DER visibility. DER-centric planning, including locational constraint mapping and flexibility procurement strategies, will guide cost-effective investments, taking lessons from the UK's RIIO-ED2 framework. Retail market evolution will incentivize retailers to bid aggregated flexibility into wholesale markets, creating consumer revenue streams while reducing peak loads. Coordinated protocols between DSOs and the national system operator (ONS) will balance centralized and localized grid management, drawing from hybrid international models like Australia's Open Energy Networks. **Implementing these recommendations must be discussed among Brazilian stakeholders in a phased approach that** ensures progressive adaptation and identifies the best priorities according to the context of the different utilities and systems:

- **Assessment (2025–2026):** Conduct DER-potential mapping, regulatory sandbox design and stakeholder engagement.
- **Pilots (2026–2027):** Test market rules, NWAs and DER aggregation in collaboration with the Brazilian Electricity Regulatory Agency(ANEEL) and the Brazilian Electricity Commercialization Chamber (CCEE).
- **Market Evolution (2028–2030):** Scale dynamic pricing, VPP integration and ADMS deployment.
- **Full Integration (2031+):** Establish mature DER management systems, bulk power coordination and consumer participation programs.

Critical Success Factors

Several factors are required for success, including: performance-based incentives, standardized DSO-TSO coordination protocols, consumer engagement campaigns and well-designed performance metrics.

Brazil can leverage its robust infrastructure and ANEEL's regulatory innovations (e.g., tariff sandboxes) to create a resilient, consumer-centric energy system. International lessons from Australia and the UK underscore the importance of phased flexibility markets and hybrid governance. This transition may position Brazil to lead the reform of the electricity distribution sector in Latin America.

Introduction

The power system is changing rapidly worldwide with the evolution of new technologies, customer expectations and government climate policies. On the supply side, the decline in renewable resource costs and the presence of public policy goals to reduce greenhouse gas emissions are accelerating adoption of renewable resources (e.g., utility-scale land-based wind and solar).[1] On the transmission side, newer technologies (e.g., dynamic line ratings, advanced conductors) are increasing the transmission capacity of existing infrastructure and reducing congestion on the lines and the need for new infrastructure.[2] On the distribution side, behind-the-meter distributed energy resources (DERs) (e.g., energy efficiency, distributed generation, storage, electric vehicles, etc.)[3] are rapidly proliferating.[4] Meanwhile, advancements in other important infrastructures (e.g., telecommunication, internet and digital technologies) are facilitating this transition at blistering pace.

These developments have opened a new set of possibilities that can accelerate the power system's transition from being a one-way power flow, from central generation to the customer, to a two-way flow with customers integrating their DER into the distribution system.

They also bring the possibility of flexible demand, one that can adapt to variable renewable generation. In this new context, the DER resources can provide energy, capacity and ancillary services to individual customers, distribution utilities or even the wholesale electric system operator in an aggregated mode, offering valuable operational flexibility.

The falling costs of DER and advanced metering,[5] combined with growing customer acceptance and environmental awareness of these resources and internet-enabled communication modes, are further driving this shift. Customers demand easy-to-use tools to modify their electric usage and help control their bills. Investors are ready to invest in this space, especially because the actions assist climate change goals. All of the above form a good recipe for an accelerated transition to a cleaner energy economy.

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[1] Rocky Mountain Institute. (n.d.). *Renewable energy deployment surge puts global power system on track for the IEA's ambitious net-zero pathway* [Press release]. https://rmi.org/press-release/renewable-energy-deployment-puts-global-power-system-on-track-for-ambitious-net-zero-pathway/#:~:text=Globally%2C%20wind%20and%20solar%20need%20to%20grow%20from,wind%20generation%20at%20sufficient%20rates%20for%20five%20years.

[2] U.S. Department of Energy. (December 2020). *Advanced transmission technologies.* https://www.energy.gov/sites/prod/files/2021/03/f83/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC_0.pdf

[3] While many DERs are behind the meter, some are in front of the meter (e.g., community aggregation solar units, EV charging stations) but are still connected to the distribution system at the lower voltage levels.

[4] International Energy Agency (IEA). (n.d.). *Unlocking the potential of distributed energy resources.* https://iea.blob.core.windows.net/assets/3520710c-c828-4001-911c-ae78b645ce67/UnlockingthePotentialofDERs_Powersystemopportunitiesandbestpractices.pdf

[5] For example, the cost of residential PV units dropped from $7.53/watt in 2010 to $2.71 in 2020. National Renewable Energy Laboratory. (2021, February 10). *Documenting a decade of cost declines for PV systems.* https://www.nrel.gov/news/program/2021/documenting-a-decade-of-cost-declines-for-pv-systems.html

Need for Intervention by Regulators

Efficient deployment of DERs will ultimately reduce overall system costs to consumers, provide more choices to consumers and lead to lower overall emissions in the sector. It does not happen, however, without active intervention by regulators. Distribution utilities need to be assured they would be no worse off by implementing the programs, especially when the programs reduce sales and, potentially, their profits. Utility regulators can implement rate-making mechanisms, such as revenue decoupling, to make the utilities whole for lost revenues associated with loss of sales. Further incentives through the use of performance-based regulatory ratemaking mechanisms may also be needed to motivate utilities to promote DERs that benefit the system and all customers.

Technological developments have created space for a new market player to enter the industry as a provider of DER aggregation. Third-party DER providers and aggregators are private entities that bring private capital to the industry and new business models and new technologies to customers and utilities, enabling them to participate in DER programs at the wholesale level or the distribution level. These market players require market rules for how they should interact with customers, utilities and system operators. They require regulatory clarity about how they can operate and regulatory stability so they can invest over the long term.

As DERs for the most part require customer acceptance and participation, they also require buy-in from customers. Customers need to be convinced that the benefits of participating in DER programs exceed any costs they may incur. To the extent that customers use less power at different hours in a day or export power to the system at certain times, there need to be utility tariffs that price the transactions granularly. Customers also need to be educated on DER opportunities and the benefits and costs associated with them.

Each of these segments requires different regulatory strategies to motivate them. Finally, a Distribution system operator (DSO) can be considered for implementation to further integrate the DERs into the utility system in a cost-effective manner that benefits the system and customers. This paper discusses the concept of a DSO, the building blocks necessary to support a DSO, the benefits and challenges in creating a DSO, some international experiences with a DSO and a potential road map for getting there from the status quo.

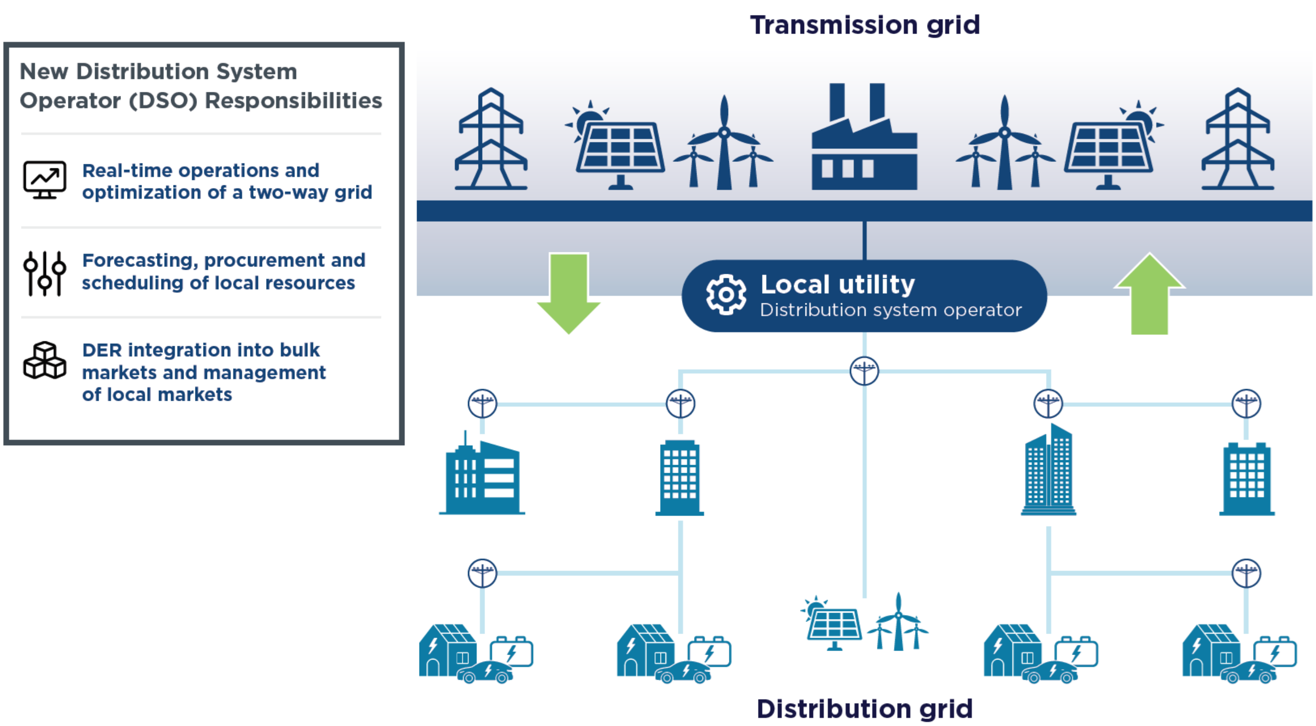
What is a DSO Model and Why is it Necessary?

There is no standard DSO structure in the world today that is considered best practice. Countries are evolving in how they integrate DERs into their system, depending on the penetration of DERs, system characteristics, system needs and regulatory goals.

There are different models for DSO structure depending on who plans, owns and maintains the distribution assets, who does system operations, who owns and provides DER products and services, and how DER markets are structured.[6] In this paper, our focus is more on the additional functionalities built into a DSO concept and how to advance them in the near to medium term rather than on long-term DSO structures.

The DSO must focus on operating the distribution system subject to constraints to maintain a reliable system and minimize costs. However, the transition to this model can have several stages and, at least in the initial stages of transition, the current distribution utility can perform all of these functions — planning, investing in and owning/maintaining the distribution system. Figure 1 illustrates key DSO responsibilities.[7]

Figure 1. Key DSO responsibilities



Source: Brisley, S. (2024, November 13). *What is a distribution system operator?*

As the distribution utility transitions to a DSO, the additional functionalities can be considered in at least three dimensions: planning, operations and markets. These are further discussed below.

[6] Jadhav, A., et al. (December 2024). *Considerations for introducing distribution system operators in India*. National Power Systems Conference. https://www.researchgate.net/publication/387157163_Considerations_for_Introducing_Distribution_System_Operators_in_India

[7] Brisley, S. (2024, November 13). *What is a distribution system operator?* Camus. https://www.camus.energy/blog/what-is-a-distribution-system-operator

Evolution of Planning Function

Historically, system planning focused on ensuring adequate generation and delivery infrastructure for reliable electric service. Power flow was one way, from the generator to the customer via transmission and distribution systems. However, the proliferation of variable resources and DERs adds more complexity to the planning function. Variable and nondispatchable resources, such as solar and wind, are increasingly being added at bulk power and distribution levels. Additionally, some renewable resources, like onshore and offshore wind, are located far from load centers, creating challenges related to transmission availability.

With significant increases in the penetration of DERs, power is injected from the DERs into the distribution system, making the system a two-way power flow system. Concentrated DERs in one location can overwhelm the local distribution system and affect reliability. For example, exporting rooftop solar power to the distribution system in low load periods can cause operational issues such as voltage fluctuations and frequent operation of protective devices.[8] The introduction of additional large loads from data centers and crypto businesses is also affecting distribution system planning. A DSO that can optimize the DER resources can address the new loads more cost-effectively.

DERs offer energy, capacity, ancillary services and flexibility to the system but necessitate changes in distribution planning. Distribution utilities must improve their forecasting capabilities, including estimating potential DER penetration (and demand flexibility) in coming years.[9] This forecasting exercise would help identify necessary system upgrades and costs, thus determining optimal DER locations, selecting DER types that provide the most value to the system and developing updated interconnection protocols. DERs can also supply products and services that are useful to bulk power operators. Given these dynamics, there is a critical need for enhanced coordination between DSOs and bulk power system operators in planning and operations.

To increase the facilitation and promotion of DERs, the utility planning process must become more transparent to allow DER providers to assess opportunities about where to invest in the system to maximize their value and meet current and future system requirements. As utilities modernize their distribution systems, they must consider how they integrate DERs to maximize the value to customers.

Evolution of Operations

The primary role of bulk power system operators and distribution operators is maintaining system reliability. Historically, this was achieved by utilizing dispatchable resources to mitigate

[8] Sharma, V., Aziz, S., Haque, M. & Kauschke, T. (2020, October). Effects of high solar photovoltaic penetration on distribution feeders and the economic impact. *Renewable and Sustainable Energy Reviews 131*. https://www.sciencedirect.com/science/article/abs/pii/S1364032120303129

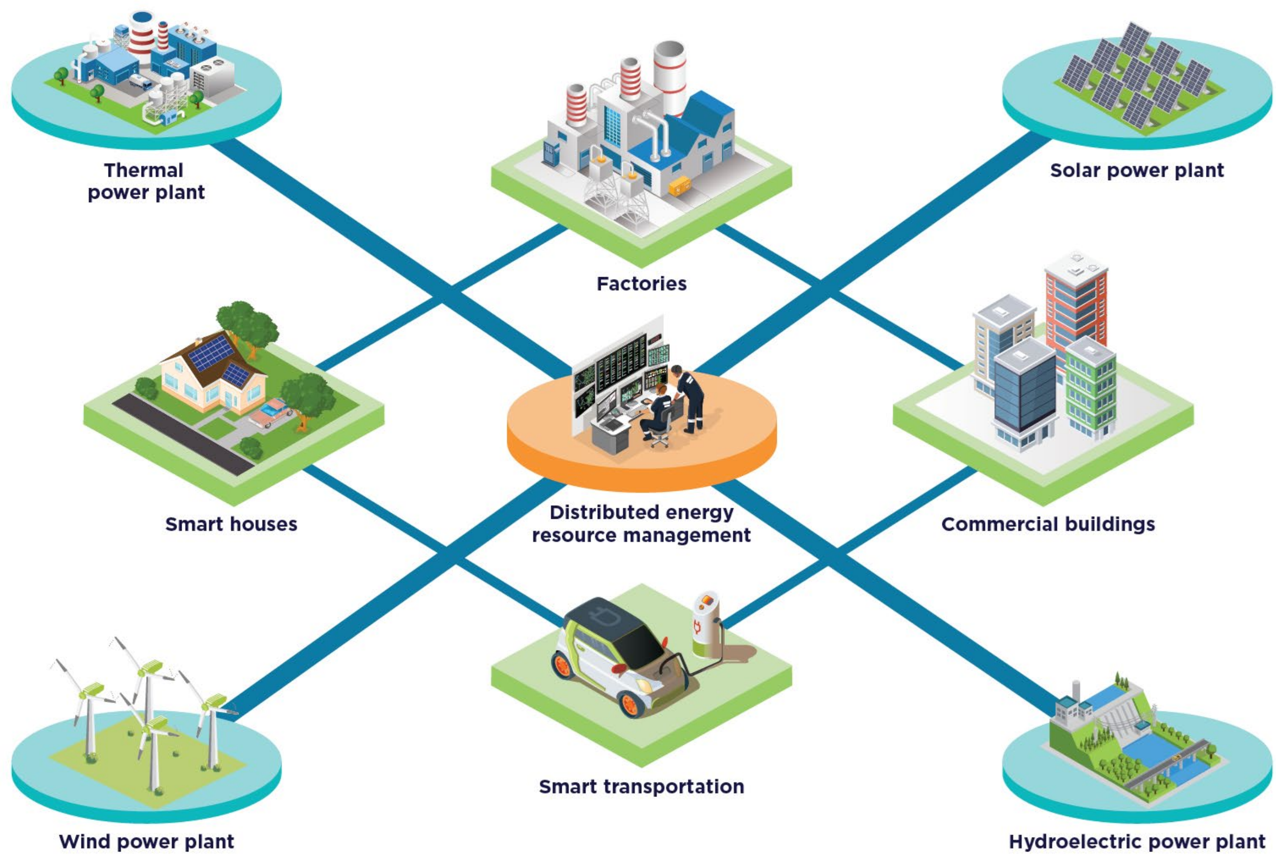
[9] Murphy, S., Schwartz, L., Pereira, G. & Davis, Cl. (2025, January). *Bridging the gap on data and analysis for distribution system planning: Information that utilities can provide regulators, state energy offices and other stakeholders*. Berkeley Lab. https://emp.lbl.gov/publications/bridging-gap-data-and-analysis

Hledik, R., Ramakrishnan, A., Peters, K., Edelman, S. & Brooks, A. (2025, January). *New York's grid flexibility potential.* Brattle. https://www.brattle.com/insights-events/publications/brattle-experts-conduct-a-study-to-determine-new-yorks-grid-flexibility-potential-in-2030-and-2040/

system imbalances. However, the increasing presence of variable, nondispatchable resources and DERs has made system operation more complex. Furthermore, bulk power system operators lack visibility into DERs unless they exceed a certain threshold (e.g., 500 kW or more). This lack of visibility underscores the increasing importance of coordination between DSOs and bulk power operators.

With DER operational visibility, DSOs are uniquely positioned to use various DER products and services optimally to ensure reliability and minimize customer cost. System operations will benefit from good forecasting of DER resource availability on a real-time basis and a looking-forward basis. DER management systems (DERMS) can help the distribution operators manage a diverse set of DERs individually and in aggregate. Figure 2 from the National Renewable Energy Laboratory (NREL) illustrates the architecture of DERMs that distribution system operators can use.[10]

Figure 2. DERMS architecture



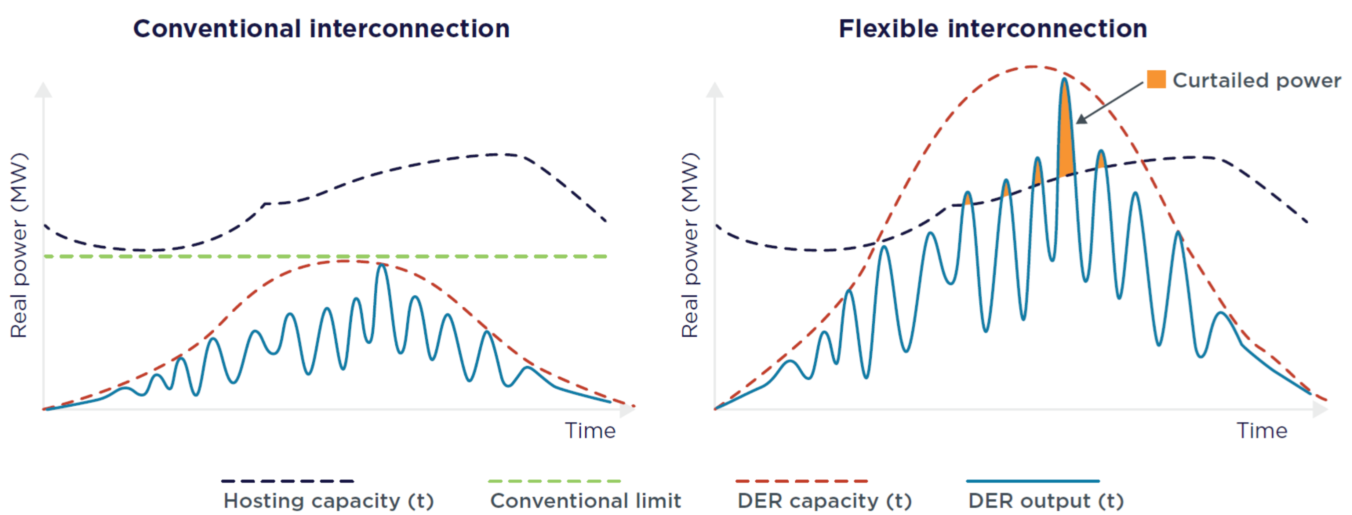
Source: National Renewable Energy Laboratory. (n.d.). *Distributed energy resources management system (DERMS).*

[10] See the blog on DERMS from the National Renewable Energy Laboratories (NREL): National Renewable Energy Laboratory. (n.d.). *Distributed energy resources management system (DERMS)*. https://www.nrel.gov/grid/distributed-energy-resource-management-systems.html

Some DSO operations would include real-time load monitoring, network monitoring, enhanced fault detection/location, automated feeder and line switching, and automated voltage and reactive power control. The DSO must consider how to commit and dispatch DER and integrate net load impact information with utility grid operations. The monitoring and dispatch of DERs will complement the increased use of intelligent grid-facing equipment such as sensors, reclosers, switched capacitors and voltage monitors.[11]

Further, implementing a DSO allows the optimization of the use of available DER to reduce system costs while maintaining reliability. For example, a DSO can implement flexible interconnections, which can play a key role in achieving these by minimizing the need for costly distribution-system upgrades. Flexible interconnections allow for "more DER generation per unit of delivery capacity available, maximizing use of existing grid assets."[12] Figure 3 from an Electric Power Research Institute (EPRI) publication illustrates this concept of how DER utilization is increased using flexible interconnection compared to a conventional interconnection.[13]

Figure 3. Conventional vs. flexible interconnection



Source: Electric Power Research Institute (EPRI). (2021, June). Characterizing the value of flexible interconnection capacity solutions (FICS).

[11] State of New York Public Service Commission, Case 14-M-0101, Order on February 26, 2025, adopting regulatory policy framework and implementation plan. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={0B599D87-445B-4197-9815-24C27623A6A0}

[12] Electric Power Research Institute (EPRI). (2021, June). *Characterizing the value of flexible interconnection capacity solutions (FICS)*. https://www.epri.com/research/products/000000003002022432

[13] Electric Power Research Institute (EPRI). 2021.

Evolution of Competitive Markets

The products and services bought and sold in competitive wholesale electric markets are well understood wherever competitive markets exist. The products include energy (day-ahead, real-time, etc.), capacity (spot, forward markets) and various ancillary services (operating reserves, balancing, etc.). While product definitions and characteristics vary, most are procured competitively (with room for bilateral trading in many markets), and prices are determined based on supply and demand. There are exceptions where certain products may still be cost based (e.g., black start service), and there may be limits on pricing when there are market-power concerns.

The DSO competitive market must evolve similarly. DER products and services must be procured on a competitive basis. In the near term, the procurement of DER products and services — such as grid services including peak load modifications, nonbulk ancillary services and load management to help defer distribution investments — will likely be through RFPs and the application of dynamic utility tariffs. Eventually, the products and services bought and sold can proliferate and more sophisticated auction approaches can be used for procurement. They will evolve based on DSO capabilities, needs, DER provider penetration and sophistication, and customer needs.

As some DER resources may participate in both the DSO market and the wholesale market, mechanisms must ensure no double counting or double payment for the same service; coordination between the DSO and the wholesale market operator is required.

Benefits of a DSO

There are numerous benefits to implementing a DSO model. One of the most significant advantages is the ability to harness DERs, which in most cases are cleaner, reduce carbon and other emissions, enhance reliability and resilience and contribute to making power more affordable.

Enhanced DER Integration

A DSO can facilitate the growth of DERs by integrating them into the distribution system and providing a level playing field where all DERs can compete and participate in the marketplace and receive compensation aligned with the value they provide to the system. By procuring products and services from DERs on a competitive basis and remaining independent of DER asset ownership, the DSO fosters neutrality and builds confidence among market participants. The DSO can also streamline interconnection protocols to minimize delays and costs for the DER integration, which lowers investment costs and accelerates their adoption. The DSO can effectively plan for DER growth by identifying the locational and time-based system needs of the system, as well as the specific reliability attributes required. This information must be shared among the marketplace participants to maximize DER investments in optimal locations with the right attributes, thus reducing costs, improving their availability and increasing their value to the system.

Improved Basket of Services

The DSO can also enhance the range of services available by using DERs to meet the energy, capacity and ancillary service needs of the system. This enhanced basket of services reduces reliance on central generators, thus lowering power purchase costs and emissions by decreasing the need for expensive peaking fossil fuel plants.

Optimization of Distribution Assets and Costs

The DSO can use DERs judiciously to optimize distribution assets and reduce the need for new delivery infrastructure and associated costs. For example, instead of investing in additional distribution infrastructure (e.g., substations, poles, cables), a portfolio of DERs can sometimes be used to meet the same system reliability needs. Utilizing NWA tends to avoid the building of new distribution or transmission assets, which saves money for customers. Additionally, flexible interconnections[14] and use of DERMS[15] can enable a greater DER output without requiring additional new distribution investment, thus reducing overall costs.

Current Brazilian Market Setup

Current Industry Structure and Future Vision

Institutional Framework: The evolution of Brazil's electricity sector reflects its transition from a state-controlled, vertically integrated model to a more sophisticated market structure. Privatization in the 1990s marked the first significant reform, attracting private investment and improving operational efficiency. A second reform in 2004 introduced Law 10848/2004,[16] which established a hybrid market model with regulated and free contracting environments. A comprehensive institutional framework governs the sector. The Ministry of Mines and Energy (MME) sets policies and oversees concession processes. ANEEL acts as an independent regulator, implementing policies, setting tariffs and monitoring activities. The ONS manages power system operations, coordinating generation and transmission to optimize resources. CCEE oversees market operations in regulated and free environments while conducting energy auctions under ANEEL's supervision. The National Council for Energy Policy (CNPE), linked to the presidency, provides strategic energy policy guidelines.

Market Structures: The Brazilian market is a hybrid model with two market environments: the Regulated Contracting Environment (ACR), where distribution companies purchase generation supplies through government auctions, under ANEEL's regulation with regulated tariffs; and the

[14] Flexible interconnection is a DER control strategy used to defer system upgrades and/or increase distribution system utilization. Electric Power Research Institute,2021.

[15] With DER management systems (DERMS), utilities can apply the capabilities of flexible demand-side energy resources and manage diverse and dispersed DERs, both individually and in aggregate. See further discussion in the NREL publication on this topic at https://www.nrel.gov/grid/distributed-energy-resource-management-systems.html

[16] Lei No. 10.848, de 15 de MARÇO de 2004, Presidência da República (Braz.). https://www.planalto.gov.br/ccivil_03/_Ato2004-2006/2004/Lei/L10.848.htm

Free Contracting Environment (ACL), where generators, traders and free consumers negotiate freely, covering about 40% of power demand.[17] Consumers in this environment pay separate bills for distribution services and energy consumption. Both markets are supervised by CCEE, which ensures compliance with ANEEL's regulations. This dual structure balances market competition with consumer protection while maintaining reliability through regulatory oversight. Distribution companies must navigate both environments and meet requirements for service quality, financial sustainability and universal access. The framework promotes efficiency and investment and ensures affordable tariffs and secure supply.

Distribution Market: The Brazilian electricity distribution sector operates as a natural monopoly. Distribution is treated as a public service, with private companies operating under 30-year concessions granted by the federal government. These concessions impose obligations, such as separating legal entities from generation and transmission activities, contracting to meet 100% of expected demand and adhering to ANEEL's service-quality metrics. The sector's privatization in the 1990s promoted significant changes. Between 2025 and 2031, 20 concession contracts — representing 62% of the power distribution market and serving 55.6 million consumer units — are set to expire.[18] The MME has outlined renewal guidelines, requiring proof of no "economic surplus," compliance with quality and economic sustainability indicators, and potential social compensation requirements.[19]

Tariff Setting: Tariff regulation is central to Brazil's electricity distribution framework under ANEEL's oversight. Revenues are governed by a price-cap methodology involving periodic tariff reviews every three, four or five years (depending on concession contracts) and annual adjustments for inflation and uncontrollable costs. This approach balances affordable tariffs with adequate returns on investment. ANEEL employs sophisticated methodologies considering operational costs, investment needs and efficiency targets. Benchmarking techniques establish efficient cost levels and productivity factors. Certain costs — such as energy purchases — are passed through to consumers, while others are subject to efficiency targets. Mechanisms addressing technical and nontechnical losses are tailored to each concession area's characteristics.

Outlook: Brazil's electricity sector is poised for growth, with demand projected to rise by 3.4% annually until 2034, to reach 870 TWh.[20] In 2024 alone, around 18 GW of generation capacity

[17] Information on consumption in the SIN may be viewed on CCEE's website; Consumo de energia no SIN https://www.ccee.org.br/web/guest/dados-e-analises/consumo

[18] Nota técnica No. 14/2024/SAER/SE, Processo No. 48300.000990/2022-41, Ministério de Minas e energia (Braz.). https://www.gov.br/mme/pt-br/assuntos/noticias/copy_of_Notatcnican142023SAERSE1.pdf

[19] Decreto No. 12.068, de 20 de Junho de 2024, Presidência da República (Braz.).https://www.planalto.gov.br/CCIVIL_03/_Ato2023-2026/2024/Decreto/D12068.htm

[20] Empresa de Pesquisa Energética. (n.d.). *Plano Decenal de Expansão de Energia 2034 (Ten-year energy expansion plan 2034)*. https://www.epe.gov.br/pt/publicacoes-dados-abertos/publicacoes/plano-decenal-de-expansao-de-energia-2034

was added, emphasizing the role of renewable energy sources.[21] Over the next decade, investment needs are substantial — around 600 billion Brazilian reais.[22] Development is guided by the Ten-Year Energy Expansion Plan, which outlines necessary investments to meet future demand. Recent regulatory updates focus on modernizing the distribution sector while ensuring economic sustainability.[23] These updates include new rules for distributed generation compensation, smart meter deployment guidelines, energy storage integration frameworks and gradual expansion of the free market with rules for low-voltage consumer migration.

Challenges for the Implementation of a DSO Model in Brazil

In transitioning to a DSO model, Brazil faces important challenges driven by the need to modernize its electricity sector and adapt to evolving market and technological conditions. While past reforms laid the groundwork for this transition, further adjustments are required to address critical issues such as regulatory gaps, infrastructure limitations and economic sustainability.

Revenue Decoupling: One of the key challenges lies in the existing regulatory framework, which has not decoupled revenues from energy sales and system operations. This bundled tariff structure limits incentives for utilities to optimize operations independently of energy sales, creating conflicts with energy efficiency goals and the integration of innovative technologies. Recent regulatory developments aim to address some issues through reforms such as distributed generation compensation and smart meter deployment guidelines. However, a consolidated public policy to facilitate the DSO transition is still lacking, particularly in areas like advanced orchestration and dispatching systems for distributed resources.

DER Growth: The rapid growth of DERs, especially solar PV, presents another challenge. In 2022 alone, Brazil's solar market experienced a 73% growth, demanding over 17 GW of PV modules and enabling investments exceeding 64 billion BRL. This expansion has disrupted traditional unidirectional power flows, requiring distribution companies to adopt new operational strategies and invest in advanced monitoring and control systems to manage bidirectional flows and grid stability. In addition, it has also led to several other issues, such as impacts on transmission operation by ONS, energy surplus resulting in curtailments and economic inefficiencies, and a heavy burden for regulated consumers due to the cross-subsidies basis of its expansion.

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[21] Cardozo, D. (2025, January). *Geração distribuída cresce 33,1% em 2024, com adição de 8,8 GW (Distributed generations grows 33.1% in 2024, with the addition of 8.8GW).* EIXOS. https://eixos.com.br/energia-eletrica/geracao-distribuida-cresce-331-em-2024-com-adicao-de-88-gw/ and Agência Nacional de Energia Elétrica. (2024, October). Expansão de 9,1 GW impulsiona matriz elétrica centralizada brasileira em 2024. Ministério de Minas e energia https://www.gov.br/mme/pt-br/assuntos/noticias/expansao-de-9-1-gw-impulsiona-matriz-eletrica-centralizada-brasileira-em-2024

[22] Cardozo, 2025.

[23] Agência Nacional de Energia Elétrica. (n.d.) *Agenda Regulatória da ANEEL para 2025-2026. Ministério de Minas e energia.* https://www.gov.br/aneel/pt-br/assuntos/governanca-regulatoria/agenda-regulatoria

Grid Resilience Issues: Extreme weather events in recent years have exposed vulnerabilities in Brazil's distribution infrastructure, leading to prolonged power outages and significant economic losses. Modernizing the grid to withstand such events requires substantial investment in redundancy measures, smart grid technologies and enhanced emergency-response capabilities.

Nontechnical Losses: In 2023, Brazil recorded significant losses equivalent to billions of dollars, driven by illegal connections and meter tampering. These losses increase tariffs for paying consumers and create financial strain on utilities. Addressing this issue requires stronger enforcement mechanisms, community engagement programs and advanced metering technologies.

Quality of Service: Service quality varies significantly across concessions, with some utilities struggling to meet regulatory standards. The sector requires substantial network modernization investments to improve reliability and reduce interruption frequency. Enhanced maintenance programs and better monitoring systems are essential for proactive problem identification and resolution. Distribution companies must also improve their response times to interruptions through better resource allocation and operational efficiency.

Subsidy Burden: The current tariff structure includes multiple subsidies that create significant market distortions and operational challenges. These subsidies result in higher costs for regulated consumers and complicated investment-recovery mechanisms for distribution companies. The complexity of tariff-setting mechanisms and various cross-subsidies creates an intricate system that often lacks transparency and efficiency and may counteract a modernized tariff structure.

Economic Sustainability: Distribution companies face mounting economic challenges in Brazil's complex operating environment, which is influenced by the abovementioned challenges. The need for substantial infrastructure investments places further pressure on financial sustainability. Regulatory limits on loss compensation through tariffs restrict companies' ability to recover costs effectively, creating a challenging environment for maintaining financial health while meeting service obligations.

Conduciveness to Moving to a DSO in Brazil

The rapid expansion of distributed generation, particularly solar PV, has added complexity to managing distributed resources. The current distribution model has struggled to provide the sophisticated control and coordination capabilities required to address this growth effectively. Modernizing distribution networks is essential to accommodate bidirectional power flows, integrate smart technologies and enable more active consumer participation in the energy system — key features that a DSO model is designed to support.

Addressing these challenges will require coordinated action among stakeholders, significant investments in infrastructure modernization and comprehensive regulatory reforms that align incentives with operational efficiency and technological innovation. The transition to a DSO model offers an opportunity to tackle these issues holistically while preparing Brazil's electricity sector for future demands. For this, Brazil can use the good conditions already in place to support this transition.

Current Infrastructure and Capabilities: Brazil's power sector infrastructure, backed by decades of technical expertise developed by Brazilian companies in managing complex power systems, demonstrates a strong foundation for transitioning to a DSO model. The National Interconnected System (SIN) serves approximately 99.9% of the Brazilian electricity market through an extensive network that has grown significantly in recent years. The transmission network now spans approximately 200,000 kilometers of lines operating at various voltage levels, with a compound annual growth rate of 4.8% between 2018 and 2023.[24] This robust expansion highlights Brazil's exceptional capacity for energy infrastructure planning, particularly in overcoming challenging geographical conditions. Brazilian utilities and system operators have developed advanced grid planning and operations methodologies, including globally recognized computational models for system expansion and management. This combination of extensive infrastructure and deep technical knowledge provides a solid foundation for implementing advanced distribution system operations.

Regulatory Support: The regulatory environment supports the transition through ANEEL's comprehensive 2025–2026 Regulatory Agenda. A key innovation in this framework is the implementation of regulatory sandboxes, with ANEEL already conducting two public calls for Tariff Sandboxes[25] that resulted in eight temporary experimental regulatory environments testing billing methods and new tariff modalities, such as best time tariff and quarterly dynamic tariff. The agenda also prioritizes integrating renewable sources and innovation in energy efficiency, including regulations for energy storage systems. This experimental approach to regulation, combined with the traditional framework, creates an environment conducive to implementing advanced distribution technologies while allowing for careful evaluation of new market models before broader implementation.

International Experience with DSO Models

This section describes the experiences of Australia and the United Kingdom in moving to a DSO model.

Australia

Australia is an interesting case study to the extent that it has had a significant evolution in the installation of rooftop solar by end users (and other DER resources) and therefore has high potential to develop a scheme that allows for maximizing the benefits of distributed energy resources (DER) at the level of the distribution network and also at the level of the transmission system and the wholesale market. Although Australia, like other markets around the world, is still

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[24] Operador Nacional de Sistem Eléctrico. (2025, April). *Sobre o SIN: O Sistema em Números (About the SIN: The System in Numbers)*. https://www.ons.org.br/paginas/sobre-o-sin/o-sistema-em-numeros

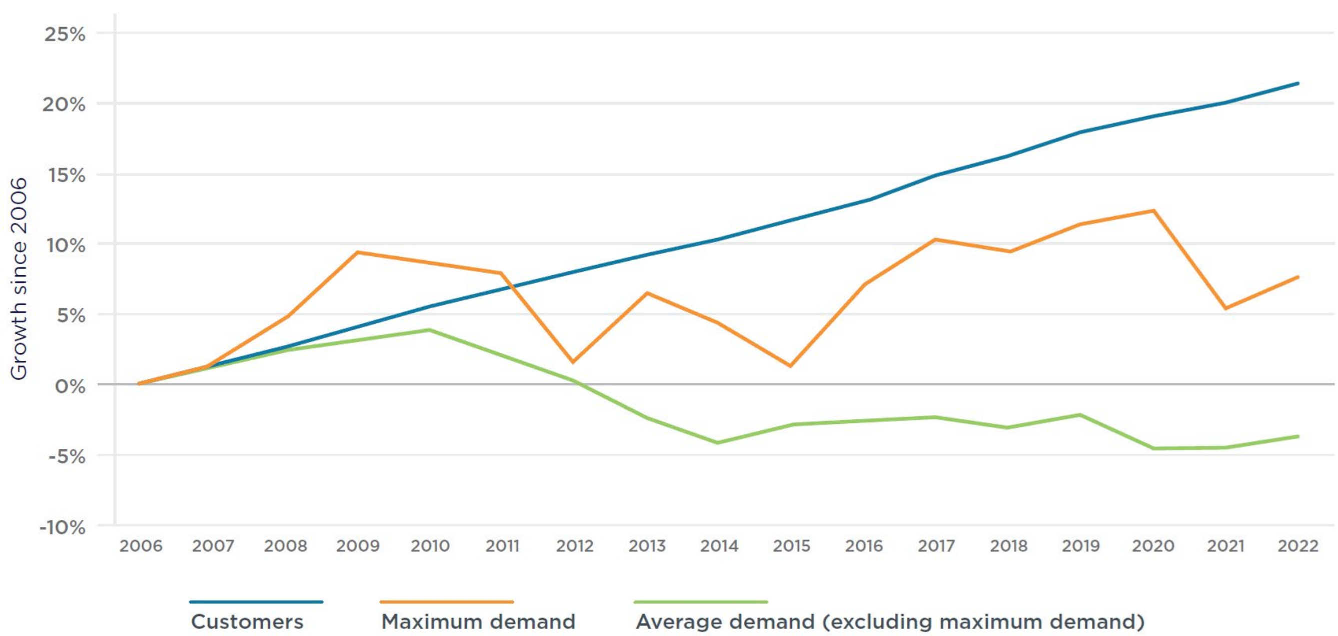
[25] Agência Nacional de Energia Elétrica. (n.d.) *Sandboxes Tarifários (Sandboxes Tariffs)*. Ministério de Minas e energia. https://www.gov.br/aneel/pt-br/empreendedores/sandboxes-tarifarios

in the early stages of its transition toward what a DSO could be, some elements identified are relevant and useful for illustrating the path that can be followed to achieve the full development of a DSO.

Drivers for Transition in Australia

Growth of DERs: Australia has the highest rooftop-solar penetration rate per capita globally, with well over 30% of households equipped with rooftop solar systems.[26] This growth has led to negative prices during the middle of the day, lowered wholesale prices and undermined demand for fossil-fueled power plants. In 2023, DERs (small-scale solar PV) contributed to nearly 11%[27] of the electricity supply, highlighting the need for smarter management systems. Per-user maximum demand has also decreased since 2010, leading to a scenario of excess capacity in distribution networks, in the context of an incentive toward capital investments by traditional service providers (Figure 4[28]).

Figure 4. Growth in customers and demand in electricity distribution networks



Source: Australian Energy Regulator.(2023, October 5). *State of the energy market 2023*.
Note: Maximum demand is the network sum of non-coincident, summated raw system maximum demand (megawatts). Non-maximum demand is the total energy delivered (gigawatt hours) for the year, excluding the energy delivered at the time of maximum demand divided by hours in the year minus one. The data show outcomes for the reporting period ending in that year (for example, the 2017-18 reporting year is shown as 2018).

[26] Australian PV Institute. (n.d.). *Mapping Australian photovoltaic installations*. https://pv-map.apvi.org.au/historical

[27] Australian government. (2024, April). *Australian Energy Statistics, Table O Electricity generation by fuel type 2022-23 and 2023*. Department of Climate Change, Energy, the Environment and Water. https://www.energy.gov.au/publications/australian-energy-statistics-table-o-electricity-generation-fuel-type-2022-23-and-2023

[28] Australian Energy Regulator.(2023, October 5). *State of the energy market 2023*. https://www.aer.gov.au/publications/reports/performance/state-energy-market-2023

Renewable Energy Goals: Australia is committed to significantly increasing the share of renewable resources in its electricity mix, with an official goal of achieving 82% renewable energy generation by 2030. This would require a significant increase in the penetration of renewable energy. While this goal may not be achieved, existing policies are likely to result in a substantial increase in wind and solar energy in the system. The current and anticipated penetration of DERs requires extensive integration of these resources.

Consumer Demand for Engagement: According to the Customer Forum[29] held by Energy Networks Australia, consumers increasingly demand control over their energy consumption, generation and bills. By empowering consumers through technologies like virtual power plants (VPPs) and demand-response programs, the system could transform customers into active participants in the energy market through aggregators, as they can earn an additional return on their investment. However, the regulatory developments required to unlock these benefits and encourage an aggregator's role have not been as timely and must overcome the traditional outlook of agents and institutions.

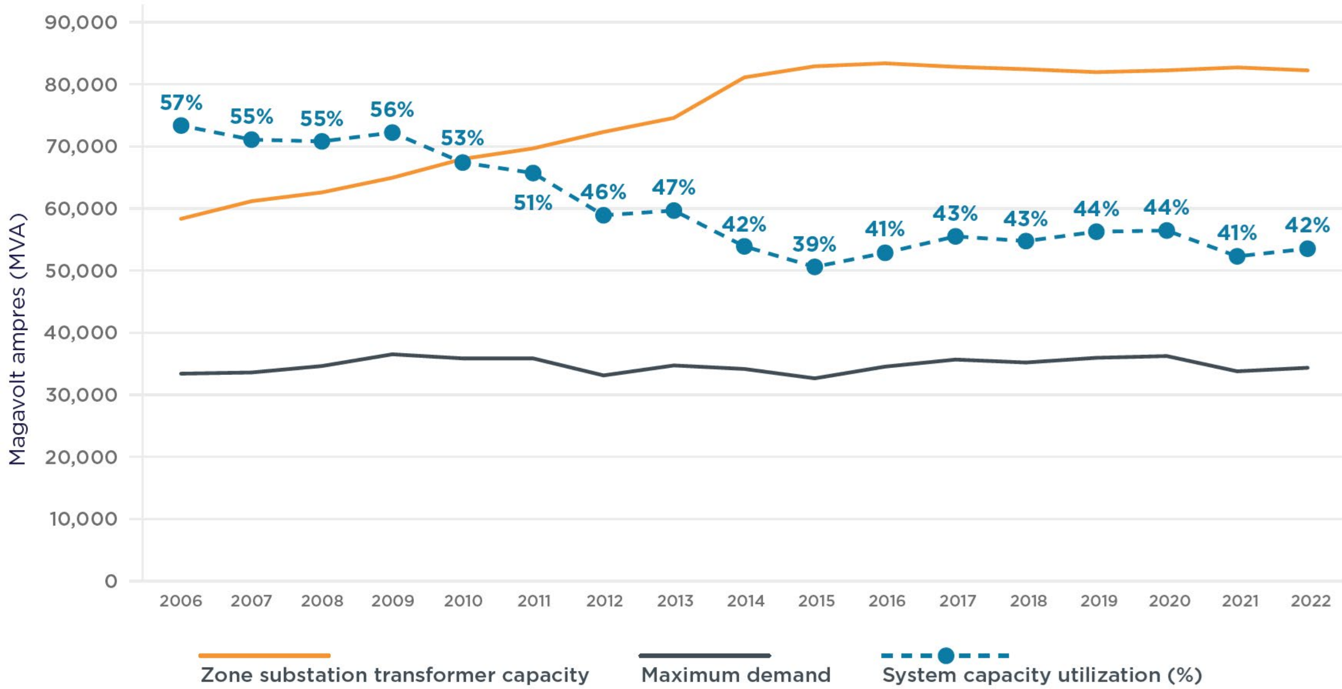
Overinvestment Risk: Grid economic regulation in Australia carries the risk of overinvestment, and some studies[30] suggest that there is a large opportunity to cut network costs by reforming the economic regulation of distribution networks, especially to enable DERs like solar batteries and smart appliances to provide network services. Network services that DER can provide commonly include congestion management, voltage control, reliability enhancement and network deferral. If DER can substitute for costly augmentation or replacement infrastructure — poles and wires and substation capex investment — this should reduce electricity service costs (Figure 5[31]).

[29] The Customer Forum is a group that attended workshops in October and December 2019 to help establish a more technical consumer understanding of OpEN and to understand consumer needs more directly. Energy Networks Australia. (2020, May 13). *Open Energy Networks Project: Energy Networks Australia Position Paper*. https://www.energynetworks.com.au/projects/open-energy-networks/).

[30] Kuiper, G. (2024). *Reforming the economic regulation of Australian electricity distribution networks. Institute for Energy Economics and Financial Analysis*. https://ieefa.org/resources/reforming-economic-regulation-australian-electricity-distribution-networks

[31] Australian Energy Regulator. (2023, July). *Electricity network performance report 2023.* https://www.aer.gov.au/publications/reports/performance/electricity-network-performance-report-2023

Figure 5. Total distribution network utilization



Source: Australian Energy Regulator. (2023, July). *Electricity network performance report 2023*

Initiatives for the Transition Process

The Electricity Network Transformation Roadmap (ENTR) developed by the Commonwealth Scientific and Industrial Research Organization (CSIRO) and Energy Networks Australia in 2017 set out a strategic plan for achieving a transition to a DSO model by 2027. A key element of the road map was the deployment of ADMS to enable real-time network management, DER integration and advanced grid services. However, this didn't materialize in any regulatory change in the expected direction.

Australia is still transforming its distribution activity, and some distributors have continued to move toward more cost-reflective tariff structures. For example, Ausgrid has an initiative (known as Project Edith[32]) that seeks to test dynamic network tariffs based on short-term marginal costs, adjusted for location and time. It aims to demonstrate how dynamic pricing can help integrate DER into the distribution network and improve economic efficiency. This project includes three key components:

1. Price calculation engine: Calculates dynamic rates considering internal data (load measurements, meter data, network connectivity) and external factors (weather, aggregator operation).

[32] Kuiper, G. (2023). *Growing the sharing energy economy. Institute for Energy Economics and Financial Analysis*. https://ieefa.org/resources/growing-sharing-energy-economy

2. API interface: Publishes network price data and dynamic trading limits every 5 minutes to enable real-time planning and response.
3. Basic billing engine: Determines the difference between the base network rate and the dynamic rate, allowing customers and aggregators to optimize their energy consumption and exports.

Project Edith is a key experiment in the evolution toward a DSO model in Australia. Its success could demonstrate the value of dynamic pricing in demand management and DER integration, directly impacting distribution market regulation and design in the Net Energy Metering.

Other distributors are proposing a tariff structure that responds to the trend of increased consumer energy resources and the role network tariffs can play in assisting their integration into the grid by signaling how and when the use of those resources drives costs and benefits to the network.[33]

Open Energy Networks (OpEN) Initiative[34]**:** The OpEN Initiative in Australia is a collaborative effort launched in 2018 by the Australian Energy Market Operator (AEMO) and Energy Networks Australia (ENA), an industry association, in response to the rapid growth of DERs, such as rooftop solar, battery storage and electric vehicles. It was developed to explore new frameworks for transforming traditional DNOs into more dynamic DSOs. The primary objective of OpEN is to create a flexible, decentralized grid capable of integrating DERs while maintaining grid stability, reliability and affordability. Through stakeholder engagement and pilot programs, OpEN evaluated three potential DSO models — centralized, decentralized and hybrid — and ultimately recommended a hybrid approach to balance centralized market operations with local grid management. This initiative highlights the need for regulatory innovation and investment in smart grid technologies, and the creation of dynamic market mechanisms, offering valuable insights for countries like Brazil in designing future-ready distribution frameworks. OpEN proposed three potential DSO models evaluated through cost-benefit analysis and stakeholder consultation:

- Centralized model: AEMO directly manages DER dispatch and grid services.
- Decentralized model: Distribution networks independently manage DERs within their regions.
- Hybrid model: AEMO and local DSOs share responsibilities between them, balancing centralized coordination with localized control.

The hybrid model was selected as the most viable approach for ensuring flexibility, efficiency and scalability in DER management. Initial pilots showed a 20% improvement in grid capacity

[33] SA Power Networks, Ergon Energy and Energex have continued to move toward more cost-reflective tariff structures. Australian Energy Regulator. (2024, September).*Draft decision - SA Power Networks Electricity Distribution Determination 2025-2030.* https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20-%20Overview%20-%20SA%20Power%20Networks%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[34] This initiative did not conclude in something concrete but shows available framework for distribution business transformation.

utilization and reduced curtailment of rooftop solar by 15%. By 2022, over 2 GW of DER capacity actively participated in demand response programs, contributing to peak load reduction.[35]

DER Integration: The potential net benefits from DER integration were estimated at 500 million AUD based on the cost-benefit assessment conducted for the 2019–2030[36] period. These estimations are expressed mainly as avoided distribution/transmission investments, reduced curtailment costs and reduced wholesale energy costs. Some studies for Australia have found the DSO cost-benefit assessment to be positive under a very high DER-uptake scenario[37]. In theory, it is possible to integrate DER without a DSO, but it becomes increasingly complex and inefficient as DER penetration rises. Without a DSO, distribution network service providers (DNSPs) can only take a passive approach to DER integration, which involves setting fixed limits on DER exports to prevent network issues like overvoltage and congestion [38]. However, this approach has several downsides:

- Static Export Limits: Fixed export limits reduce the amount of DER that can be utilized, leading to underutilization of renewable energy and financial losses for DER owners. The DSO gives DER owners, 24 hours in advance, location-specific limits on how much energy they can export or consume based on current network conditions. Dynamic operating envelopes help prevent overvoltage or congestion while maximizing DER utilization.

- Increased Costs: Without active management, DNSPs may need to invest heavily in network upgrades to accommodate higher DER penetration. These costs could be passed on to consumers through higher electricity prices.

- Inefficient Grid Operation: Passive DER integration does not take advantage of real-time data or market signals, resulting in inefficient grid operation and missed opportunities for grid support services that DER could provide. ADMS platforms integrate data from smart meters, supervisory control and data acquisition (SCADA) systems and IoT sensors to provide a real-time network view. This allows DSOs to detect and respond to issues like outages or network imbalances quickly.

- Limited Market Opportunities: Without a DSO, DNSPs cannot facilitate local energy markets or enable new business models (e.g., virtual power plants), thus limiting the economic value that DER can provide to both owners and the broader energy system. DSOs enable third-party aggregators to bundle DER (such as residential solar and battery systems) and offer services to the wholesale market or provide ancillary services like frequency control and demand response.

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[35] Economic Regulation Authority. (2024, December 4). *Western Power Demand Management Innovation Allowance 2022/23 to 2023/24 report.* https://www.erawa.com.au/cproot/24468/2/Notice-Publication-of-Western-Powers-202223-202324-demand-management-innovation-allowance-report.pdf

[36] Results from the cost-benefit assessment (CBA) conducted by Baringa Partners. The 500 million Australian dollars correspond to the net benefit from the "Central Scenario" in the 2019–2030 analysis.

[37] See footnote 33

[38] Based on Energy Networks Australia. (2020, May 13). *Open Energy Networks Project: Energy Networks Australia Position Paper*. https://www.energynetworks.com.au/projects/open-energy-networks/

Current Deployment Status

The evolution toward a DSO model in Australia is progressing at different rates across states, driven by the need to integrate high levels of DER while maintaining grid stability and cost efficiency. [39] For instance, in New South Wales, Ausgrid has advanced its transition by implementing an ADMS in phases, focusing on modernizing outdated control systems and enhancing DER visibility. Similarly, South Australia, through SA Power Networks (SAPN), is proposing ADMS technology to improve network management and aims to introduce tariff reforms, including two-way pricing, to manage solar export congestion. Queensland's Energex and Ergon Energy are progressing with ADMS implementation and tariff reform proposals to reflect real-time network conditions and demand. In Victoria, distributors have implemented smart network solutions and are undergoing consultations for cost-reflective tariffs to encourage efficient energy usage. Meanwhile, Tasmania, led by TasNetworks, is preparing to roll out new tariff structures while ensuring stakeholder engagement and gradual consumer transition.[40]

United Kingdom

Drivers for Transition in the UK

The UK is undergoing a major energy transformation to phase out fossil fuels and adopt clean energy sources such as wind, solar and hydrogen. With a commitment to reduce emissions by 78% by 2035 (compared to 1990) and achieve net zero by 2050, this transition requires electrifying key sectors like transportation and heating while integrating smart and flexible technologies to manage growing electricity demand efficiently. Electricity distribution systems are critical to this effort, enabling the efficient integration of renewable energy and balancing supply and demand through energy storage, smart grids and interconnections. Without flexibility, there is a risk of increased reliance on gas generation and higher system costs.

The UK government and Ofgem, the energy regulator, have proposed consecutive Smart Systems and Flexibility Plans (2017 and 2021) to present their vision and work programs for delivering a smart and flexible electricity system to avoid or defer network investments, avoid generation build, avoid curtailment of low carbon generation and better operate the system.[41] The

[39] Kuiper, 2024.

Kuiper, G. (2025, January). *The revolution will be in distribution: Faster, cheaper decarbonisation through integrating distributed energy resources (DER)*. Engineers Australia. https://www.engineersaustralia.org.au/sites/default/files/2025-05/IntegratingDER_GKuiper.pdf

[40] Australian Energy Regulator. (2024, September).*Draft decision - SA Power Networks Electricity Distribution Determination 2025-2030*. https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20-%20Overview%20-%20SA%20Power%20Networks%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[41] Ofgem. (2017, July). *Upgrading our energy system: Smart systems and flexibility plan.* https://assets.publishing.service.gov.uk/media/5a823917e5274a2e87dc1cab/upgrading-our-energy-system-july-2017.pdf

2021 plan emphasizes the importance of digitalization, innovation and public investment to accelerate this transition, projecting savings of up to 10 billion pounds annually by 2050.[42]

The DSO Model and Regulatory Approach

In line with decarbonization policy, DNOs are encouraged to advance DSO functions. The DSO should play three main roles (Table 1[43]):

- Planning and network development
- Network operation
- Market development

In compliance with the DSO rules, Ofgem introduced new distribution license obligations. As these functions develop, Ofgem will assess the need for further differentiation between DSO roles and traditional DNO activities or broader institutional reforms at the distribution level. This evaluation will examine how effectively DNOs handle potential conflicts of interest and facilitate markets impartially. Ofgem also established baseline activities to be developed by distributors — and remunerated by consumers — during the five-year period from April 2023 to March 2028[44] (a more detailed description of the distribution remuneration methodology is presented in the Annex).

[42] Department for Business, Energy and Industrial Strategy & Ofgem. (2021, July). *Transitioning to a net zero energy system: Smart systems and flexibility plan 2021*. https://assets.publishing.service.gov.uk/media/60f575cd8fa8f50c7f08aecd/smart-systems-and-flexibility-plan-2021.pdf

[43] Ofgem. (2020, August 28). *Next steps on our reforms to the long term development statement (LTDS) and the key enablers for DSO programme of work.* https://www.ofgem.gov.uk/sites/default/files/docs/2020/08/next_steps_on_our_reforms_to_the_long_term_development_statement_and_the_key_enablers_for_dso_programme_of_work_0.pdf

[44] Ofgem. (2021, September 30). *RIIO-ED2 Business Plan Guidance*. https://www.ofgem.gov.uk/publications/riio-ed2-business-plan-guidance

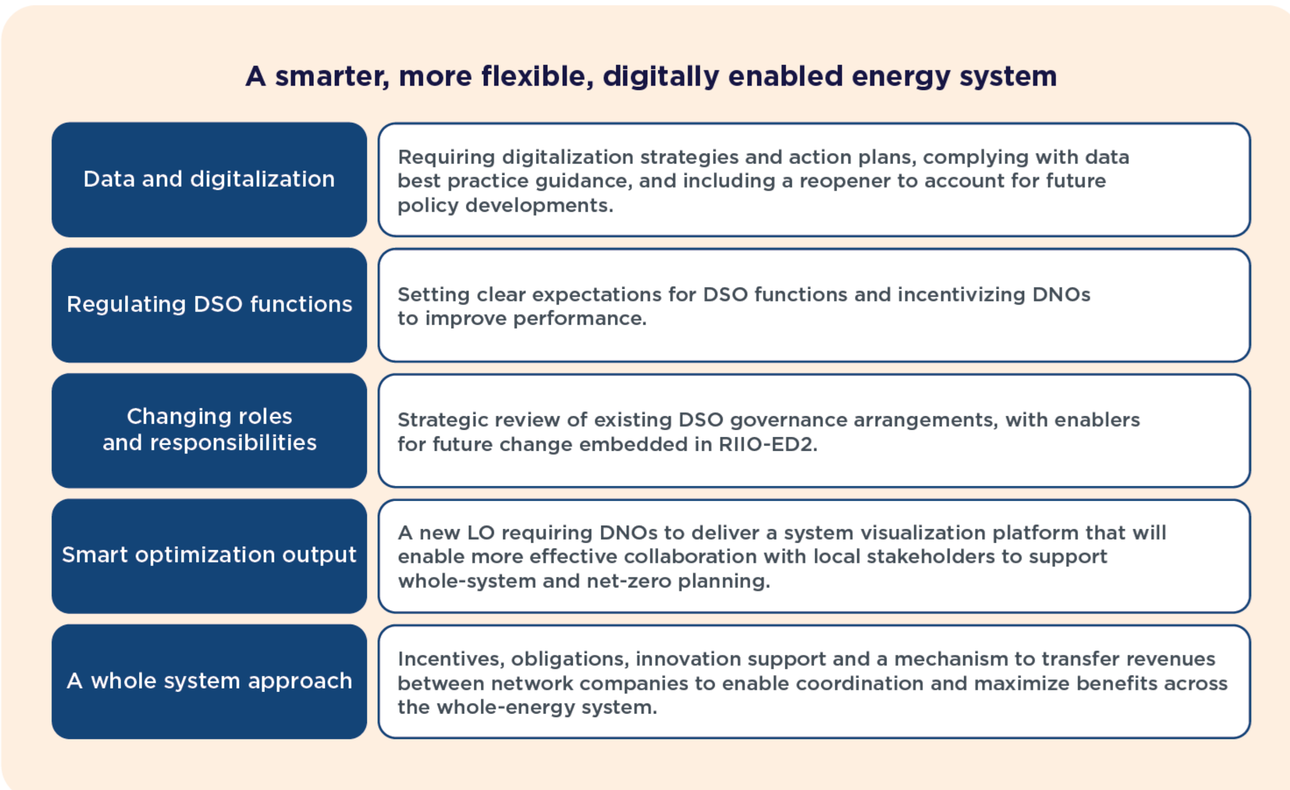
Table 1. Total distribution network utilization

Roles	Activities	Baseline expectations
Planning and network develop-ment	Plan efficiently in the context of uncertainty, taking account of whole system outcomes and promoting planning data availability.	DNOs must develop enhanced forecasting, simulation and modeling capabilities, supported by ongoing improvement processes. DNOs must submit a network visibility strategy describing how diverse data sources inform planning decisions, including flexibility. They should establish standard procedures for sharing planning information with other licensees, the electricity system operator (ESO), network users and interested parties. Finally, DNOs need transparent and robust methods to identify and evaluate solutions for network needs, employing competition where it is efficient.
Network operation	Promote operational network visibility and data availability	DNOs must submit a visibility strategy covering data sources — such as direct measurement, smart meters, data analysis and modeling — and explain how this monitoring will support operational decisions, including flexibility services. They should also provide the ESO with timely information on planned DER dispatch, enabling the ESO to identify available resources and facilitate DER value stacking across markets. Additionally, DNOs must gather sufficient DER characteristics to prevent potential disconnection events and make operational data (e.g., network configuration, substation losses, outages, feeder utilization) available in agreed common formats to help network users and stakeholders make better decisions.
	Facilitate efficient dispatch of distribution flexibility services	DNOs must create and regularly review a transparent framework for real-time DER dispatch, coordinating services (including curtailment and ESO flexibility) and avoiding market fragmentation. They must facilitate secondary trading by providing operational data and clear parameters and introduce participatory processes for decision making. Finally, DNOs should develop scalable, nonproprietary dispatch infrastructure, defining dispatch instruction types and usage rules — and should ensure these capabilities can be transferred to another party if needed.
Market develop-ment	Provide accurate, user-friendly and comprehensive market information	DNOs are expected to collect and publish all relevant planning and operational data to help market participants identify and value opportunities for providing network services. DNOs must collaborate with stakeholders to develop more consistent data publication strategies, actively engaging with market participants to determine the most helpful content and delivery methods.
	Embed simple, fair and transparent rules and processes for procuring distribution flexibility services.	DNOs must develop transparent, collaborative processes — engaging the ESO, other DNOs, service providers and third-party platforms — to standardize and update distribution flexibility services. They should define market time frames and contract lengths neutrally, justify any deviations and share the necessary data for secondary trading. DNOs must allow third-party market support services where efficient and address conflicts between their DSO function and network ownership or other business interests. Measures include executive-level accountability, board visibility of key decisions, and independent oversight, with consideration of alternative separation approaches if needed.

Source: Ofgem. (2020). *Next Steps on Our Reforms to the Long Term Development Statement (LTDS) and the Key Enablers for DSO Programme of Work.*

Concrete incentives for transitioning from the DNO model to the DSO are implemented with RIIO-ED2. The RIIO model is a performance-based remuneration, where revenue results from incentives, innovation and outputs (Revenue = Incentives + Innovation + Outputs). RIIO-ED2 covers the five-year period from 1 April 2023 to 31 March 2028 and introduces decisions on five fields (Figure 6[45]):

Figure 6. Regulatory decisions to support a smarter, more flexible, digitally enabled energy system



Source: Ofgem. (2022) RIIO-ED2 Final Determinations Core Methodology Document.

Data and Digitalization Package: The decisions include:

- The license obligation for DNOs to consult stakeholders and publish the digitalization strategy, in order to enhance transparency with stakeholders, and stakeholders' ability to influence DNO plans.
- A digitalization reopener that enables DNOs to apply for additional funding if their roles and responsibilities change, requiring new or improved digital services.
- The IT, operational technology, and data and digitalization cost taxonomy that DNOs must adopt when describing their spend in these areas, in order to increase transparency in IT spend and facilitate comparability between DNOs and cross-sector organizations.

[45] Ofgem. (2022, November 30). *RIIO-ED2 final determinations core methodology document.* https://www.ofgem.gov.uk/sites/default/files/2022-11/RIIO-ED2%20Final%20Determinations%20Core%20Methodology.pdf

Regulation of Distribution System Operation functions: The objective is to avoid or defer network reinforcement, resulting in lower customer bills. This regulation recognizes that certain standardization of DSO functions is required to provide coordinated DSO activities, operational inefficiencies and similar levels of ambition. However, DNOs´ strategy for DSOs could differ among DNOs based on the DSO transition issues prevalent in their regions.

This regulation includes a DSO incentive to drive DNOs to develop and use their network more efficiently, considering flexible alternatives to network reinforcement. It should result in lower bills for consumers. This incentive works as an ex-post review of DNOs' delivery of their DSO activities, which increases or reduces the return on regulatory equity, based on stakeholder surveys, performance panel assessments and outturn performance metrics. RIIO-ED2 regulation also recognizes that during the five-year period it is necessary to introduce changes in distribution tariffs in response to the roles, responsibilities and governance arrangements for DSO functions. These adjustments could include increasing or reducing cost allowances and recalibrating specified outputs and incentives. To achieve net zero at least cost, Ofgem considers a highly integrated energy system requiring more market participants communicating digitally to determine the optimal dispatch of assets on the system. It means that a DNO should share data about its current and future network. To do that, RIIO-ED2 includes the publication of the Smart Optimization Output.

The **Smart Optimization Output** encourages DNOs to maximize the use of existing infrastructure, optimize asset management and adopt innovative approaches like flexibility services to reduce the need for traditional network reinforcements. To achieve its purpose, the Smart Optimization Output is a new license obligation that requires DNOs to develop and publish a strategy with a collaboration plan, that considers the stakeholder engagement strategy for transparent data sharing in order to support local and regional net-zero strategies, and digital tools on the DNO's open data portal that provides accessible asset data, constraints and future network upgrades.

Finally, the RIIO-ED2 recognizes a whole-system approach. DNO investments and activities both affect, and are affected by, decisions and activities in other energy and social systems. There is significant potential for greater efficiencies within the energy network via increased collaboration on joint planning and investment. The regulation introduces whole-system elements to the price control process and settlement.

DSO Development: The Role of Regulators to Enable a DSO

Regulators are crucial in creating an enabling framework for a reliable and affordable electric system. Reforming the distribution sector to maximize efficiency and leverage the growing presence of DERs, advanced communication technologies and smart grid infrastructure is a key step in this process. Transitioning to a DSO model is a path that regulators should consider. However, for a DSO to function effectively, regulators must ensure all necessary building blocks are in place. Among other things, regulators must:

1. Identify and address utility concerns and take regulatory actions accordingly.
2. Develop and implement rules for DERs to participate in the market.
3. Identify and develop tools to allow customers to invest in and provide DER services to the wholesale system operator and the DSO.
4. Identify and provide guidance on the use of benefit-cost analysis (BCA). Numerous metrics exist for evaluating costs and benefits from a customer perspective, distribution utility/wholesale system operator perspective and overall societal perspective.

Address Distribution Utility Concerns

Lost Revenues: Implementing DERs can lead to lost revenues and reduced revenues for distribution utilities due to decreased sales or shifts in load patterns. The situation is aggravated if the DER-participating customers previously subsidized other customers, potentially discouraging utilities from supporting DER adoption to protect profitability.

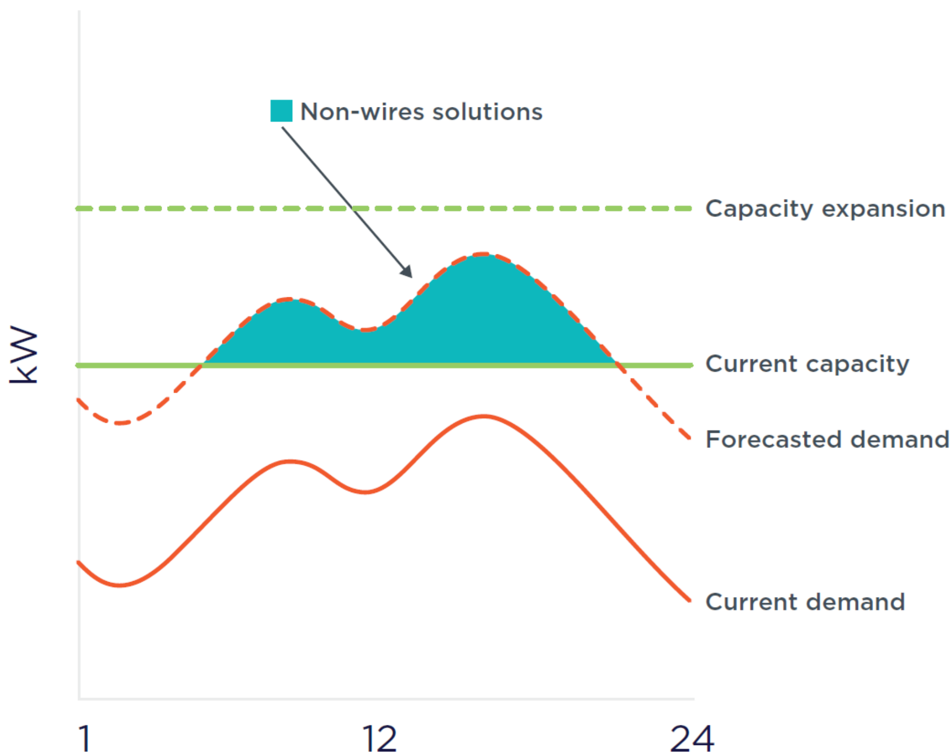
One way to address lost revenues and profits is via a rate-making tool such as a revenue decoupling mechanism (RDM), which enables utilities to recover a predetermined level of revenue in a given period, regardless of actual sales volumes. This approach has existed for over three decades in many countries. It was initially implemented to make utilities indifferent to energy efficiency measures but has been shown to deal effectively with other sales volatility risks, such as weather and changes in the economy. Decoupling ensures utilities can recover prudent costs even with lower sales, requiring them to return excess revenues to customers if sales go up. By decoupling profitability from sales, RDM incentivizes utilities to focus on cost reductions, thereby encouraging operational efficiency.

While RDMs remove disincentives to pursue energy efficiency and customer-sited DERs, they may not fully motivate utilities to embrace and promote DER adoption. Regulators should consider creating additional profit incentives tied to DERs' performance. For instance, they can create metrics that measure successful integration of DERs and reward utilities for meeting prescribed metrics. Successful performance-based rate-making models have been adopted in the U.S.

However, while RDMs make utilities indifferent to customer-sited resources, they may lead to the loss of contributions from DER-using customers, potentially increasing tariffs for other customers. Ideally, DER deployment should reduce certain wholesale supply costs and avoid other transmission and distribution costs. These avoided costs must be identified and accounted for in rate structures. Regulators should also address the distinction between short-term and long-term avoided costs based on the specific circumstances of each utility and the rate of DER penetration.

Non-Wires Alternatives: Traditionally, utilities plan for load growth using conventional engineering approaches to meet the needs of the supply side, such as building power plants and substations and extending network cables and transformers. However, an alternative approach is to leverage the demand side to meet system reliability needs in a more cost-effective and environmentally friendly way. This strategy, known as non-wires alternatives (NWA), involves using DERs to address system needs instead of traditional supply-side infrastructure. Regulators should require utilities to evaluate the feasibility of NWAs where practical, using competitive procurement processes to encourage third parties. This approach allows for innovative DER solutions that utilize advanced technologies and are cost-effective. Regulators should also address utilities' concerns about implementing NWAs. One key issue is that NWAs reduce the opportunity for utilities to invest in traditional distribution assets, which typically generate returns on investment. To counter this disincentive, regulators can develop mechanisms that align utilities' incentives with customer benefits when deploying NWAs. A simple illustration of the use of NWAs is shown in Figure 7.[46]

Figure 7. Use of non-wires alternatives



Source: Con Edison. (2019, April 17). *Non-wires solutions: Spring 2019 program update* [webinar].

[46] Con Edison. (2019, April 17). *Non-wires solutions: Spring 2019 program update* [webinar]. https://cdnc-dcxprod2-sitecore.azureedge.net/-/media/files/coned/documents/business-partners/business-opportunities/non-wires/archive/webinar.pdf?rev=a05616a2712742a08673608e7b248446

Employee Concerns: Job losses are often a concern raised when significant changes in the system are contemplated. It is unclear why there would be overall job reductions with increased DER penetration. The distribution utilities will still need their employees to do their typical tasks and more. The increased utility workload comes from interconnection work for distributed generation resources and work with DER developers and DER programs. Further, there is room for significant new employment opportunities in developing and deploying clean energy technologies and working with individual customers.

Develop Pilot and Demonstration Projects: Many distribution utilities may not be fully aware of the potential benefits that DERs can bring to the system. A gradual approach to get experience and work through the mechanics of DER programs would be the institution of pilot and demonstration projects. They should be well defined to test one or more hypotheses and produce results in a meaningful time frame to evaluate whether they can be rolled out on a larger scale.

Develop Business Rules for DER Providers

Licensing Requirements For DER Providers: Licensing requirements[47] should describe the qualification criteria for distributed energy providers that will deliver DER services and the details for any potential license revocations. Qualification criteria could include the provider's technical capabilities, financial wherewithal, past business experience and credit qualifications. They should not be onerous but sufficient to protect consumers from unqualified providers. The revocation of a license would be based on the provider failing to meet rules and regulations and violating established norms.

Market Business Rules for DER Providers: Business rules must specify the obligations and rights of the DER providers. They should cover areas such as:

- Marketing or advertising standards to which a DER provider must adhere.
- Consumer protections it must provide.
- Methods of enrolling customers and the contracts used to sign up customers.
- Procedures for dispute resolution with customers.

DER Customer Aggregation: To enable small customers to participate effectively in demand flexibility programs and wholesale markets, rules for customer aggregation must be developed. Aggregators play a critical role in pooling loads from multiple customers, facilitating their participation in distribution utility and wholesale market programs. By providing technical assistance and innovative business models, aggregators help customers identify demand flexibility opportunities and reduce barriers to participation. These efforts bring private capital into the sector while expanding access to advanced energy solutions.

[47] N.Y. Pub. Serv., Case 15-M-0180, Sr. No. 463, of October 19, 2017, Order establishing oversight framework and uniform business practices for distributed energy resource suppliers. https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-M-0180&CaseSearch=Search

Access to Customer Data: Access to customer data is essential for reducing the soft costs of DER providers and enabling effective customer enrollment.

Utilities hold valuable data on customers' historical data, including load profile, bill payment patterns and more. Allowing DER providers access to this data helps them target appropriate customers for marketing and program participation. However, robust protocols must be in place to protect customer privacy and ensure consent before sharing data. Clear guidelines should govern how data flows between customers, distribution utilities, wholesale system operators and DER providers to maintain trust and compliance with privacy laws.

Enable Customers to Participate:

Consumer Education: Without the participation of customers, DERs cannot be implemented. Customers need to understand the value that DERs provide them individually and the system collectively. They need to be convinced that the benefits of participating in DER programs outweigh any associated costs. Benefits include savings on electric bills, more comfort in the home or business, improved system efficiency, lower overall system costs, increased reliability and resilience and reduced harmful emissions. The costs include any infrastructure installations at customer sites to allow them to participate, usage curtailment when called upon , along with any other opportunity costs. Regulators, distribution utilities and wholesale system operators should provide customers with objective information on the benefits and costs of DER programs. DER providers will work with individual customers and explain the benefits and costs. Further, broad and focused customer education initiatives should be designed and delivered. This would also reduce soft costs to DER providers in the area of customer acquisition. Regulators, distribution utilities and wholesale system operators can also inform customers about qualified DER providers to contact.

Dynamic Pricing Signals: DERs provide value-added services to the grid at retail and wholesale levels. Their value is enhanced if they face real price signals that reflect the distribution utilities' true costs from a locational and time-dimension perspective. If they do not currently exist, new tariffs should be designed to provide granular unbundled price signals that will help to tease out cost-effective DERs. This could include hourly supply price signals and location-based supply pricing reflecting cost differentials. For example, serving customers at certain times of the day and/or season may cost more than at other times. Also, due to transmission constraints, serving customers in a particular area may cost more than in other places. The tariff pricing signals or, in the distribution case (which typically does not reflect locational cost differences), DER compensation signals should reflect these differentials so that DERs can be targeted first to higher-cost locations.

Incentives to Customers: Customers typically require incentives or financial support to invest in DERs or participate in demand flexibility programs. The incentives should be targeted to maximize interest in investing and participating in these programs. The incentives can come from the government in terms of tax policy or from utilities or DER providers.

Benefit-Cost Analysis Framework[48]

To evaluate DERs, regulators should develop a framework for benefit-cost analysis (BCA) that all stakeholders should understand and use. Traditional BCA metrics use the societal cost test, utility cost test, rate impact test, participant test and others to evaluate benefits and costs. They provide a BCA from different perspectives, including societal, utility, impacts on customer rates, and individual DER participant.

Benefits typically include avoided generation energy and capacity costs, avoided line losses, avoided transmission and distribution capacity and O&M costs, and avoided environmental costs. Costs typically include a customer's own costs for implementing DERs, utility DER program administration costs, utility customer incentives for DERs and costs for integrating DERs into the system. Some benefits and costs are quantifiable, and some are qualitative. The discount rate for future benefits and costs is a significant variable affecting the BCA.

The BCA can be done on a measure-level basis (individually for energy efficiency or demand response or distributed generation or storage) or on a combined basis (for multiple DERs at the same time, including their cross-interactions) to optimize from among competing DERs. For an illustration, see the Con Edison handbook on BCA for DERs.[49]

Implementation Strategy for the DSO Transition in Brazil

Phased Implementation Strategy

The transition to a DSO model in Brazil requires a carefully structured implementation strategy that considers the country's distinct characteristics while leveraging insights from international best practices. To ensure a successful transition, it is imperative to develop an implementation strategy that reflects the varying conditions of distribution utilities across Brazil.

Several key elements must be integrated into this implementation strategy. First, a comprehensive assessment of DER potential is essential to evaluate the integration possibilities across different regions. Additionally, the staged introduction of new functions and services should be considered, recognizing that utilities are at varying levels of sophistication and readiness for adopting new roles and responsibilities. Consumer engagement and participation are also critical; fostering active involvement by consumers in the DSO model will enhance acceptance and effectiveness.

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[48] Michals, J. (2021, February 25). *National standard practice manual for benefit-cost analysis of distributed energy resources (NSPM for DERs): Exploring optimization through benefit-cost analysis*. E4TheFuture. https://pubs.naruc.org/pub/685F9A10-155D-0A36-31D1-C5B6E6012E03

[49] Con Edison. (2020). *Electric benefit cost analysis handbook*. https://www.coned.com/en/our-energy-future/our-energy-vision/distribution-system-platform

Moreover, identifying and implementing necessary regulatory changes will facilitate the emergence of new roles within the DSO framework. Transition provisions must be established to guide the shift to the DSO model over a 30-year contract period, ensuring a gradual and manageable transition. It is also important to develop mechanisms that allow for the adaptation of roles and responsibilities in response to increasing DER penetration. Regulatory flexibility is crucial to accommodate the evolving functions of the DSO, and timelines should be aligned with projected DER growth scenarios to ensure timely adaptation. Clear transition rules must be defined for moving from the current operational model to the DSO model, and demonstration projects should be initiated to illustrate the value of DERs and explore effective integration strategies.

A phased implementation approach is essential given the complexity of advancing in all these dimensions simultaneously. This allows stakeholders to learn and adapt progressively to the new operational context. The proposed phases for the DSO transition in Brazil include an initial assessment, stakeholder engagement and regulatory development, followed by pilot projects and development of market rules, a gradual rollout of new functions and consumer programs for market evolution and ultimately, full implementation and continuous improvement.

In conclusion, the transition to a DSO model in Brazil is a multifaceted process that requires careful planning and execution. By adopting a phased approach, stakeholders can effectively navigate the complexities of this transition, ensuring that the unique characteristics of Brazil's distribution utilities are respected and leveraged for a successful outcome. Figure 8 below illustrates this proposition.

Figure 8. Phased implementation approach for DSO in Brazil

Assessment and Initial Planning (2025–2026)

The initial phase of the transition to a DSO model in Brazil, focusing on assessment and planning, may span from 2025 to 2026. A critical component of this phase is the ***technical assessment***, which involves a comprehensive ***evaluation of DER potential*** across various regions of Brazil. This evaluation must ***take into account the differing levels of grid infrastructure development and existing DER penetration***. By identifying areas with high DER growth potential and assessing the current technical capabilities of distribution utilities, stakeholders can better understand the landscape and opportunities for integration.

In parallel, developing a ***regulatory framework is essential to support the transition to DSO functions while ensuring the economic sustainability of distribution companies***. Drawing insights from Australia's OpEN Initiative, Brazil should explore three potential operational models: centralized, decentralized and hybrid. Evaluating these models will help determine the most suitable approach for Brazil's unique market structure, allowing for a regulatory environment that fosters innovation and supports the effective integration of DERs into the grid.

Pilot and Initial Market Implementation (2026–2027)

To facilitate the transition to a DSO model, Brazil should consider ***implementing regulatory sandboxes***, as inspired by Australia's successful approach. These controlled environments ***will provide a platform for testing new operational models and market mechanisms, allowing stakeholders to evaluate various DSO functions while minimizing associated risks***. Regulatory sandboxes can foster innovation and adaptability in the evolving energy landscape by creating a space for experimentation.

In conjunction with establishing regulatory sandboxes, the ***initial development of market rules*** should start. This development should ***focus on creating clear product definitions and market mechanisms, starting with pilot projects in mature distribution companies***. For instance, ONS plans to start testing the DSO model with large-scale DER, such as small hydro and biomass power plants, due to the less onerous regulatory barriers. The initial market development phase will encompass several key components, as outlined in Table 2:

Table 2. Conditions for initial market development

Component	Implementation focus
Technical systems	Deployment and testing of DERMS
Market rules	Establishment of basic product definitions and settlement mechanisms
Coordination	Development of protocols between the DSO and ONS

Market Evolution (2028–2030)

In the next phase of the transition to a DSO model, the focus will shift to ***advanced market operations,*** building on the insights gained from pilot experiences. This phase will aim to ***expand market operations to encompass several key initiatives***. First, the implementation of dynamic operating envelopes will be essential for real-time management of DERs, allowing for more responsive and efficient grid operations. Additionally, developing sophisticated market settlement systems will facilitate accurate and timely transactions within the market, enhancing overall operational efficiency. Furthermore, integrating VPPs and aggregation services will enable a more flexible and resilient energy system, allowing for the effective coordination of multiple DERs.

Concurrently, ***infrastructure modernization*** will be a critical focus area. The ***deployment of ADMS*** should be prioritized to enable real-time network management and seamless integration of DERs. This effort must be coordinated with ***ongoing smart meter rollout programs*** to ensure that the necessary data and communication capabilities are in place to effectively manage the evolving distribution network.

Full Implementation (2031 onwards)

The final phase of the transition to DSO should focus on achieving complete market integration across distribution utilities. This phase will encompass several critical components essential for the successful operation of the DSO framework. First, implementing comprehensive DER management systems will be vital for effectively overseeing and optimizing the performance of DERs within the grid. Additionally, sophisticated market operations will be necessary to facilitate seamless transactions and interactions among various market participants, ensuring a fluid and efficient marketplace.

Advanced coordination with the bulk power system will also play a crucial role in this phase, enabling better alignment between distribution and transmission operations and enhancing overall system reliability. Furthermore, developing mature consumer participation programs will empower consumers to engage actively in the energy market, fostering a more inclusive and responsive energy ecosystem.

Enabling Conditions for a DSO Transition

The successful implementation of a phased DSO transition relies on establishing key foundational conditions. These prerequisites create the framework and environment necessary for the transition to evolve effectively, ensuring a smooth transformation of distribution systems and markets.

Consumer Engagement and Protection

Drawing from Australia's experience, it is crucial to prioritize education and participation initiatives. Comprehensive consumer education programs that focus on several key areas will be essential. First, these programs should highlight the benefits and opportunities associated with participation in DER, thus helping consumers understand how they can contribute to and benefit from the evolving energy landscape. Additionally, educating consumers about new tariff structures will be crucial for fostering informed decision making and engagement in the market. Finally, it is important to clarify consumers' rights and responsibilities within the new market structure to ensure they are well equipped to navigate the changes.

In parallel, establishing a robust consumer protection framework will be critical to maintaining trust and confidence in the new system. This framework should include clear rules for DER providers to ensure accountability and reliability in service delivery. Transparent pricing mechanisms must be implemented to provide consumers with a clear understanding of costs associated with DER participation. Furthermore, effective dispute resolution procedures should be established to address any conflicts, ensuring that consumers have access to fair and timely resolutions. Lastly, data privacy and security measures must be prioritized to protect consumer information and maintain the integrity of the energy system. By focusing on education, participation and consumer protection, Brazil can create a supportive environment for successfully integrating the DSO model.

Transition Management

The implementation timeline for the DSO model must be closely aligned with the market opening process and regulatory agendas, especially those resulting from the new concession contracts set to occur between 2025 and 2031. This alignment may lead to new requirements and performance metrics that should be seamlessly incorporated for distribution utilities. By integrating DSO objectives into these regulatory agendas, Brazil can facilitate a smoother transition and ensure that utilities are held accountable for meeting the evolving demands of the energy market.

In addition, it is essential to establish a robust performance monitoring system to regularly evaluate the progress of the DSO implementation. This evaluation should encompass a range of key performance indicators, including technical performance metrics that assess the efficiency and effectiveness of the grid operations. Market efficiency indicators will provide insights into the functioning of the energy market, ensuring that it operates smoothly and competitively. Consumer satisfaction measures will gauge consumers' experiences and perceptions of the new system, while system reliability metrics will evaluate the overall stability and dependability of the energy supply. By systematically monitoring these aspects, Brazil can ensure that the transition to the DSO model is on track and that necessary adjustments can be made to enhance performance and outcomes.

New Planning Logic

The transition to a DSO model requires significant evolution in planning methodologies to address the complexities introduced by variable resources and DERs. The increasing penetration of DERs has transformed the grid into a two-way power flow system, introducing challenges such as localized system overloads, voltage fluctuations and operational issues during low load periods. Additionally, the growing presence of large loads, such as those from data centers, further complicates distribution planning. For this, planning must adopt approaches that account for all 8,760 hours of the year rather than focusing solely on peak load conditions. This includes preparing for extended periods of resource unavailability and addressing climate change-related extreme weather events, such as floods and heat waves, that exacerbate reliability concerns. Effective DER integration requires identifying necessary system upgrades, determining optimal DER locations, selecting resource types that maximize system value and updating interconnection protocols. Furthermore, enhanced coordination between DSOs and bulk power operators is essential to ensure that DERs function effectively as both resources and load modifiers while contributing energy, capacity, ancillary services and flexibility to the overall system.

DSO Maturity Assessment Framework for Brazilian Distribution Utilities

Having an analytical tool for assessing utilities' readiness for the DSO model may support decision making. Here, a structure framework offers an approach to evaluating distribution utilities' readiness for the transition to a DSO model. It considers Brazil's diverse market characteristics and regulatory environment to enable a systematic evaluation. This allows policymakers and regulators to coordinate the DSO transition better by considering the unique local conditions across the country.

Core Assessment Dimensions and Evaluation Criteria

The assessment framework is structured around three core dimensions: technical infrastructure, operational capabilities and market development. Each dimension is critical for evaluating the maturity of a specific distribution utility in relation to the DSO implementation, ensuring a successful transition.

The technical infrastructure dimension encompasses infrastructure requirements, data management and the integration of DERs. Operational capabilities focuses on grid management, maintenance and customer interface. Market development includes pricing mechanisms, DER integration and service offerings. For each of these dimensions, organizations can be classified into one of three maturity levels: basic, intermediate or advanced. Specific criteria can be applied to evaluate the maturity level.

Technical Infrastructure

Basic: use of SCADA systems, manual operations and legacy metering. Data management is limited to basic historical data storage, and the DER connection process is manual.

Intermediate: partially deploying advanced metering infrastructure (AMI) and automated switching capabilities. Data management includes real-time monitoring and basic analytics, while DER management is semi-automated.

Advanced: full AMI deployment, DERMS and advanced sensors. Data management utilizes AI and machine learning analytics with predictive capabilities, and DER orchestration is fully automated.

The evaluation criteria for the technical infrastructure level include network monitoring capabilities score, DER hosting capacity analysis tools, data management sophistication, automation level of grid operations and communication infrastructure coverage.

Operational Capabilities

Basic: one-way power flow management, manual dispatch, reactive maintenance and traditional call center customer interfaces.

Intermediate: Limited two-way management and essential forecasting characterize this level, along with condition-based maintenance and digital channels and basic applications for customer interaction.

Advanced: dynamic power flow management with real-time optimization, AI-driven predictive maintenance and an omnichannel platform for real-time customer engagement.

The evaluation criteria for operational capabilities include power flow management capabilities, maintenance sophistication, workforce technical expertise, emergency response systems and customer engagement platforms.

Market Development

Basic: fixed tariffs, net metering as the only DER integration option and standard service offerings.

Intermediate: time-of-use pricing options are available, along with basic flexibility services and enhanced digital services.

Advanced: dynamic pricing with locational signals, full market participation for DERs and innovative products, including VPP integration.

The evaluation criteria for market development include tariff structure sophistication, DER market-participation mechanisms, customer service capabilities, settlement systems maturity and data-sharing capabilities.

Table 3 summarizes this framework, providing a clear overview of the dimensions, maturity levels and evaluation criteria for assessing the transition to the DSO model.

Table 3. DSO maturity assessment framework

Technical infrastructure			
Maturity level	**Infrastructure requirements**	**Data management**	**DER integration**
Basic	SCADA, manual operations, legacy metering	Basic historical data storage	Manual DER connection process
Intermediate	Partial AMI deployment, automated switching	Real-time monitoring, basic analytics	Semi-automated DER management
Advanced	Full AMI, DERMS, advanced sensors	AI/ML analytics, predictive capabilities	Automated DER orchestration
Evaluation criteria	- Network monitoring capabilities score; DER hosting capacity analysis tools; data management sophistication; automation level of grid operations; communication infrastructure coverage		
Operational capabilities			
Level	**Grid management**	**Maintenance**	**Customer interface**
Basic	One-way power flow, manual dispatch	Reactive maintenance	Traditional call center
Intermediate	Limited two-way management, basic forecasting	Condition-based maintenance	Digital channels, basic apps
Advanced	Dynamic power flow, real-time optimization	Predictive maintenance, AI-driven	Omnichannel platform, real-time engagement
Evaluation criteria	- Power flow management capabilities; maintenance sophistication; workforce technical expertise; emergency response systems; customer engagement platforms		
Market development			
Level	**Pricing mechanisms**	**DER integration**	**Service offerings**
Basic	Fixed tariffs	Net metering only	Standard services
Intermediate	Time-of-use options	Basic flexibility services	Enhanced digital services
Advanced	Dynamic pricing, locational signals	Full market participation	Innovative products, VPP integration
Evaluation criteria	- Tariff structure sophistication; DER market-participation mechanisms; customer service capabilities; settlement systems maturity; data-sharing capabilities		

Implementation Categories

The DSO maturity assessment framework establishes three distinct implementation categories: foundation-building, transition-ready and DSO-capable. It creates a comprehensive classification system that acknowledges the diverse landscape of Brazilian distribution utilities. This structured approach enables the evaluation of utility capabilities and maturity levels, facilitating the development of tailored implementation strategies that align with each organization's specific needs and advancement potential. By categorizing utilities based on their current capabilities and readiness levels, the framework provides a clear pathway for progression while ensuring that implementation strategies remain realistic and achievable within Brazil's varied utility context.

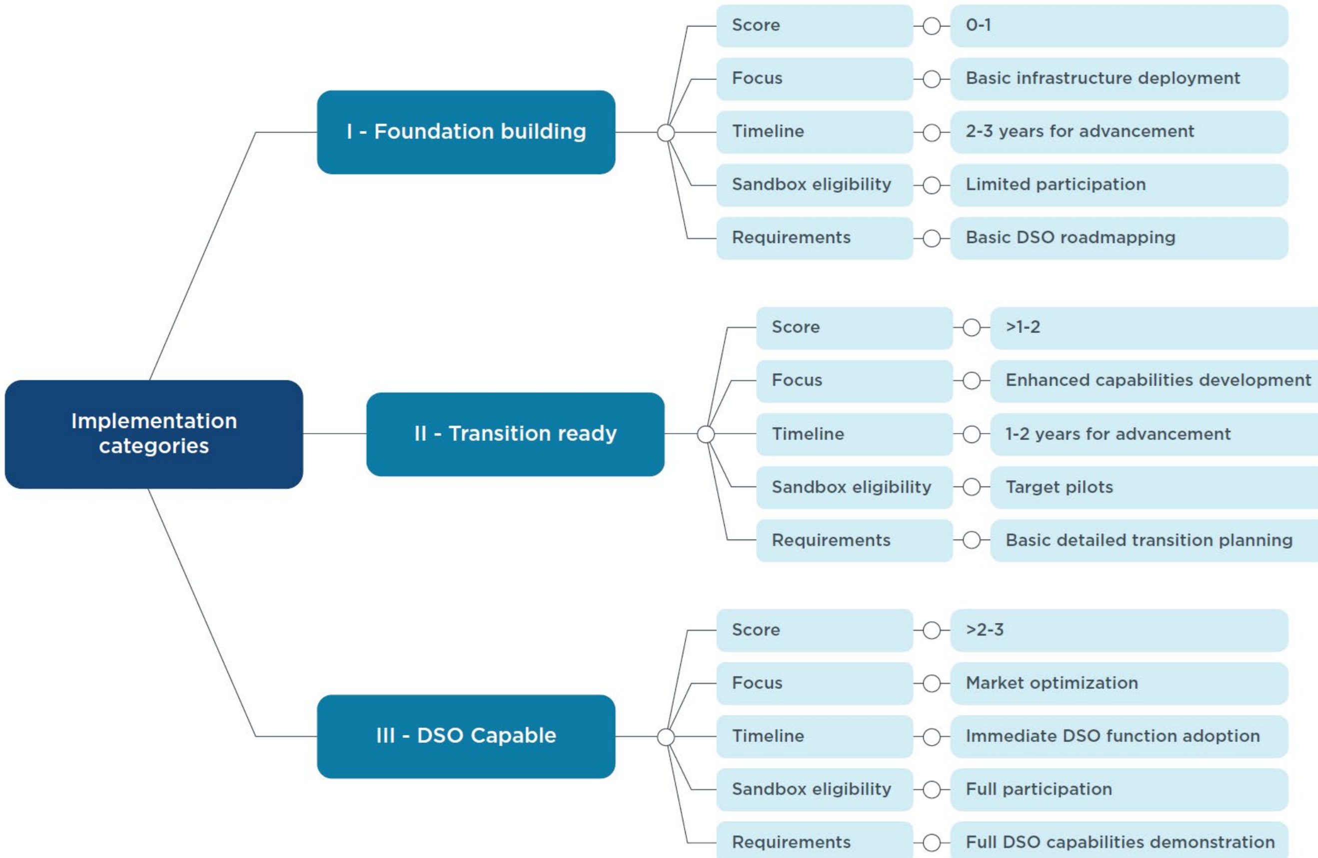
In the initial stage, "foundation-building" utilities demonstrate basic maturity, with scores between 0 and 1. These organizations focus primarily on deploying fundamental infrastructure, and are expected to require 2–3 years for advancement. While they will have limited sandbox-participation eligibility, their main task is developing a basic DSO road map to establish core competencies.

The "transition-ready" category encompasses utilities scoring between 1 and 2, representing an intermediate level of maturity. These utilities focus on developing enhanced capabilities and are expected to require 1–2 years to advance to the next level. They are eligible for targeted pilot programs and must engage in detailed transition planning to progress further.

At the highest level, "DSO-capable" utilities score between 2 and 3 and are positioned for market optimization. These advanced organizations are prepared for immediate DSO function adoption and enjoy full sandbox-participation eligibility. They must demonstrate comprehensive DSO capabilities, reflecting their readiness to implement sophisticated market operations and system management functions.

Figure 9 below illustrates these categories.

Figure 9. Output categories of the DSO maturity assessment framework



High-Level Recommendations

Brazil's transition to a DSO model must holistically address three core functions — system operation, system planning and market operation — while aligning with national priorities such as the market opening process, new concession contracts, grid resilience and DER integration. This transition requires a balance between centralized coordination and localized innovation, leveraging Brazil's technical expertise, regulatory modernization efforts (e.g., smart metering, tariff reform and sandboxes) and ongoing infrastructure upgrades to modernize distribution systems while maintaining reliability and affordability. The following recommendations, structured into immediate no-regret policies and strategic actions, aim to provide an initial road map for ensuring Brazil capitalizes on its unique opportunities during this critical regulatory window.

Immediate No-Regret Actions

Prioritize Demand-Side Flexibility Programs

Launch dynamic tariffs (e.g., time-of-use, locational pricing) to incentivize load shifting during peak solar-generation hours, thereby reducing curtailment of resources. Consider adopting Australia's dynamic operating envelopes model to adjust DER export limits in real time based on grid conditions. A possible immediate action is developing pilots on automated demand response programs targeting industrial/commercial sectors, with financial incentives for participation.

Expand Regulatory Sandboxes for DER Innovation

Test VPPs, aggregated demand response and NWAs in controlled environments. Focus on regions with high DER penetration to validate scalability. A possible action is partnering with retailers and aggregators to design market rules for DER participation to ensure fair competition and consumer protection. Sandboxes are an excellent tool to promote regulatory flexibility and deal with the uncertainty of new market designs.

Adopt Granular Network Utilization Metrics

Consider substation and feeder-level monitoring (as in Australia's OpEN Initiative) to optimize DER hosting capacity and reduce infrastructure costs. An action here can be publishing open-access grid constraint (heat) maps to guide DER developers and aggregators.

Prohibit Distribution Utilities from Owning DER/Demand Response Assets

Ensure market neutrality by restricting utilities from owning DERs or demand response resources. Fostering competition among third-party providers is crucial to more efficient market development. However, this recommendation may be balanced in the Brazilian context for specific assets (such as storage assets) or reviewed according to market evolution.

Develop a "Value-to-the-System" Payment Approach for DER Resources

Rather than adopting blunt instruments like net metering, adopt DER payment mechanisms that pay concomitant with the value they provide to the system (in terms of reliability, resilience, clean energy, avoidance of other costs, etc.). The payments can include avoided generation energy, capacity, ancillary service benefits, avoided transmission and distribution capacity, O&M benefits, avoided environmental pollution benefits and congestion relief benefits.

Strategic Recommendations

Align DSO Transition with Regulatory Agendas of New Concession Contracts and Market Opening Process

Integrate DSO functions (DER orchestration, flexibility markets) into the regulatory agenda consequent to the new concession contracts and leverage the market opening process. A potential action would be to use a DSO maturity assessment framework to set technical infrastructure, operational capabilities and market development milestones to comprehend the main development points for different contexts within the country.

Implement Revenue Decoupling Mechanisms

Decouple utility revenues from energy sales to eliminate disincentives for DER adoption while ensuring financial stability for distributors. Pair RDMs with performance metrics (e.g., DER integration success) to align utility incentives with system-wide benefits. One possible action is integrating RDMs into ANEEL's Regulatory Agenda, thus leveraging Brazil's existing tariff sandbox framework for rapid testing.

Modernize System Planning with DER-Potential Mapping

Mandate DER-potential mapping in grid planning to identify cost-effective NWAs (e.g., solar-plus-storage clusters for congestion relief). Adopt the UK's RIIO-ED2 approach, requiring utilities to publish 5-year flexibility procurement plans. A key action would be to develop transparent, participatory planning processes involving DER providers, aggregators and local authorities.

Accelerate Enabling Infrastructure Deployment

Fast-track smart meter rollout to enable real-time pricing and demand response. Deploy ADMS for real-time DER visibility and grid control. A necessary action here is coordinating with ONS to establish protocols for DSO-TSO coordination.

Foster Retail Competition and Consumer Engagement

Incentivize retailers to procure demand flexibility as a "first resource" for peak loads. Allow retailers to bid aggregated flexibility into wholesale markets and create revenue streams for consumers. An action would be simplifying billing/data-sharing processes and launching consumer education campaigns on DER benefits (e.g., bill savings and grid resilience).

Develop a Clear Road Map for Tariff Modernization

Developing new tariff structures is crucial for successfully transitioning to a DSO model. Providing the right economic signals to stakeholders is essential to ensure the efficient integration and management of DERs. Prioritizing the identification and implementation of steps toward more granular and dynamic tariffs will pave the way for a more responsive and resilient electricity grid.

Develop a Brazilian Pathway for DSO

Brazil should decide which model of DSO to adopt, considering its specific contexts. It is essential to discuss core DSO functions and implementation milestones that balance centralized coordination with localized DER management by distribution utilities. For instance, deciding who is responsible for market operation functions (e.g., utilities or CCEE) and protocols for DSO and ONS interaction. Interesting approaches to consider are the Australian "co-optimized" hybrid model and the UK's RIIO-ED2 framework. A key action here would be to define an agenda and organize stakeholders around it.

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Annex

UK Incentives for Transitioning from DNO to DSO

The UK has been transforming its DNO functions since 2015 through the RIIO methodology, which remunerates electricity distribution according to the roles of distribution license holders. The first stage, RIIO-ED1, laid the groundwork for the transition in 2015, but the full shift toward DSO functions must be further developed under RIIO-ED2, which covers the 5-year period from 1 April 2023 to 31 March 2028.

The RIIO model is a performance-based remuneration, where revenue results from incentives, innovation and outputs (Revenue = Incentives + Innovation + Outputs). Under the RIIO model, the distributors are responsible for developing and justifying a long-term strategy for delivering the network services that their customers value.[50] The RIIO-ED1 price control considered the need for DNOs to establish strategies for accommodating variable levels of low-carbon technologies on their networks while maintaining efficiency and cost-effectiveness. To meet these objectives, the regulator set six outputs that the electricity DNOs need to deliver for their consumers and the associated revenues they were allowed to collect for 8 years (April 2015 to March 2023):

- Incentives to reduce outages and improve the average duration of electricity supply.
- Reduction of network losses and carbon emissions, and promotion of operational sustainability.
- Monitoring customer satisfaction.
- Improvements in connection times for customers and distributed generation.
- Compliance with standards to protect workers and communities.
- Support for vulnerable customers and enhancements to priority service registers.

The DNOs must include the costs of delivering outputs for RIIO-ED1 and beyond in their business plans. To ensure consumers do not pay unnecessarily high prices, the DNOs had to justify their planned expenditures in the context of a long-term strategy. To ensure financial sustainability, RIIO-ED1 employed[51]:

- Totex (Total Expenditure): integrated assessment of operational and capital costs to encourage efficient investments. Totex analysis captures the key trade-offs between different areas of costs in establishing the overall levels of efficiency of network operators.
- Extended asset lifespan: extending asset lifespans to 45 years to stabilize tariffs.[52]
- Debt indexation: mechanisms to reflect market interest rate fluctuations.

[50] Ofgem. (2013). *Strategy decision for RIIO-ED1 — Overview*. https://www.ofgem.gov.uk/decision/strategy-decision-riio-ed1-overview

[51] Ofgem. (2013). *Strategy decision for the RIIO-ED1 electricity distribution price control — Financial issues*. https://www.ofgem.gov.uk/sites/default/files/docs/2013/02/riioed1decfinancialissues_0.pdf

[52] The 45-year asset life only applies to new investments from the commencement of RIIO-ED1 on 1 April 2015. Existing assets continue to use the existing 20-year asset life.

To recognize the uncertainties in technological adoption and demand changes, RIIO-ED1 implemented mid-period reviews, which allowed adjustments to regulatory goals and strategies, reopeners to reassess allowed revenues in response to unforeseen events (e.g., policy changes, extreme demand) and price indexation to automatically adjust tariffs to reflect external cost changes like inflation. The RIIO model had elements designed to drive innovation, including the longer price control period, the outputs focus and efficiency incentives. Companies could also highlight in their business plans where they proposed to roll out innovative technology, techniques or commercial strategies, which pose higher costs in the price control period than the business-as-usual approach. In addition, the Network Innovation Competition was created. It is an annual competition for funding larger-scale innovative projects that potentially deliver environmental benefits.

Finally, RIIO-ED1 required distribution companies to engage consumers and stakeholders in their strategic planning through public consultations and independent evaluations. The first three years of RIIO-ED1 allowed the reduction of the number of customer interruptions by 11% since the start of the price control and the average duration of interruptions by 9%. There have also been improvements in the level of customer service provided by DNOs, as well as the way in which they actively engage with all stakeholders and work to address the needs of their vulnerable customers. After 8 years under RIIO-ED1, it was updated with RIIO-ED2, to reflect Great Britain’s reinforced commitment, driven by the rise in gas prices during 2021–2022, to achieving net zero.

Regulatory Assistance Project (RAP)®
Belgium · China · Germany · India · United States

50 State Street, Suite 3
Montpelier, Vermont 05602
USA

+1 802 223 8199
info@raponline.org
raponline.org