Transforming Regional Transmission Planning: FERC Order 1920 Explained

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Photo by Dennis Schroeder, NREL 46840

Overview

- **Building for the Future Through Electric Regional Transmission Planning and Cost Allocation** issued May 13, 2024 and updated November 21, 2024 with 1920-A.
- The order requires transmission providers to:

Engage in regional long-term transmission planning to **identify transmission needs.**

Develop **processes and criteria** for selecting transmission facilities **to resolve those needs.**

Evaluate transmission facilities that will address interconnection-related transmission needs.

Consider advanced conductors, power flow control devices, dynamic line ratings, and transmission switching.

Consider local planning and "right sizing" replacement transmission facilities.

Develop a "backstop" cost allocation method and a process for voluntary funding and state agreement.

Icons from VectorStock

Key Topics

- Overall need for reform
- Long-term regional transmission planning
- Consideration of generator interconnection
- Consideration of transmission alternatives
- Regional transmission cost allocation
- Incentives and rights of first refusal
- Local transmission planning
- Interregional transmission coordination
- Compliance procedures
- Commissioner perspectives.

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Overall Need for Reform

Motivation: Order 1000 is not working.

- Current expansion is happening outside of the regional planning process through **local projects.**
- Non-Regional Transmission Organization (RTO) regions have **“black box”** planning.
- Some regions don’t have a platform for **state participation**
- ***There exists 3Us: unjust, unreasonable, and unduly discriminatory or preferential rates*** (¶85-89).

Current requirements fail to require transmission providers to:

- Perform a sufficiently **long-term** assessment of transmission needs.
- Account adequately on a forward-looking basis for **known determinants** of long-term transmission needs.
- Consider a broader **range of transmission benefits.**
- Require **state input** in planning and cost allocation.

“Sufficiently long-term, forward-looking, comprehensive regional transmission planning and cost allocation to meet long-term transmission needs is not occurring on a consistent and sufficient basis.” (¶112)

Key Topics

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Long-Term Regional Transmission Planning

Development of Long-Term Scenarios (LTSs)

LTS Requirements

Evaluating Benefits of Long-Term Regional Transmission Facilities (LTRTFs)

Evaluation and Selection of LTRTF

Implementation of Long-Term Regional Transmission Planning (LTRTP)

Photo by Dennis Schroeder, NREL 50673

Development of LTS

What: “Plausible” and “diverse” scenarios about the future electric power system over a sufficiently long-term horizon (¶412, 414).

Why: LTSs are used to identify future transmission needs which could include evolving reliability concerns, changes in the resource mix, and changes in demand (¶299).

Who: Transmission providers must develop and use LTSs to identify and evaluate LTRTFs needed to meet long-term transmission needs (¶298).

How: Use “best available data” for inputs about the future electric power (¶2).

- Transmission providers must develop at least **three distinct LTSs** with a planning horizon of not less than **20 years**. (¶344).
  - *Each LTS must include a sensitivity to account for "uncertain operational outcomes" during events such as sustained outages due to extreme weather.*

- LTSs must be reviewed and updated at least once **every 5 years** (¶378).
  - *Can be entirely new LTSs or updates to existing LTSs.*
  - *Transmission providers must determine whether to select LTRTFs no later than 3 years from the date when the long-term regional transmission planning cycle began.*
  - *Can propose more frequent planning intervals.*

LTS Requirements: Overview

Transmission providers must incorporate the following **seven factors** when creating LTSs:

1 Federal, Tribal, state, and local laws and regulations affecting the resource mix and demand.	2 Federal, Tribal, state, and local laws on decarbonization and electrification.	3 State-approved integrated resource plans.

4 Trends in fuel costs, performance, and availability of generation.	5 Resource retirements.	6 Generator interconnection requests and withdrawals.	7 Utility commitments and federal, Tribal, state, and local policy goals

- Each LTS must incorporate the first three factors, but the order gives latitude on how to weight or account for the remaining four (¶507, 516).

LTS Requirements: Specific Factors

Transmission providers must:

- Use an **open and transparent process** for developing LTSs, including factors to be included (¶528).
- **Consult with states** when incorporating state laws, policies and regulations into the development of LTS (¶308, 1920-A).
- Stakeholders must have **meaningful opportunity to provide timely input** on how and what information to incorporate in LTSs, including how to account for a specific factor (¶529).
- **Use discretion** on how to account for and include certain factors but must **post on OASIS[1] or a website**: (¶528–537)
    - A list of factors used
    - How factors will be treated
    - How any factors will be discounted (no justification is required)
    - Any factors not included.

[1]Open Access Same-Time Information System (OASIS), https://www.ferc.gov/OASIS

LTS Requirements: Stakeholder Process

- Transmission providers must develop at least **one sensitivity**, applied to each LTS to account for **"uncertain operational outcomes"** (¶597).
  - Focus on high-impact, low frequency extreme weather events
  - Events result in multiple concurrent and sustained generation and/or transmission outages
  - Does not specify cybersecurity events
  - Does not preclude consideration of more than one extreme event sensitivity.

- Sensitivity can be tested either **before or after** identifying potential regional transmission solutions to long-term transmission needs (¶594).

- Transmission providers can use sensitivities to determine the need for and benefit of **interregional transfer capability** (¶599).

LTS Requirements: Extreme Events

LTS Requirements: Data Inputs

- Transmission providers must use "**best available data inputs**" when developing LTSs (¶633).
  - Timely, developed using best practices and diverse and expert perspectives.
  - Data inputs must be updated whenever LTSs are revised/updated.
  - Data must correspond to the list of factors used to determine long-term transmission needs.
  - An open and transparent stakeholder process must be used to determine data inputs. Order 980 dispute resolution can be used to dispute data inputs.

- **Transmission providers have significant flexibility** in which data inputs they use in LTSs (¶638).

Upon request by states, transmission providers must conduct a **"reasonable number" of additional scenarios** to help **inform cost allocation methods** (¶414-416, 1920-A).

- Not intended to inform Long-Term Transmission Needs and facility selection.
- Additional scenarios do not have to meet requirements for LTS.
- May include a process for making requests in compliance filings.

LTS Requirements: Additional Scenarios

Engage in regional long-term transmission planning to **identify transmission needs.**

Order 1920: Key Requirements

Transmission providers must use a set of **seven required benefits** for evaluation of LTRTFs under each long-term scenario (¶740-819):

1. Avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement.
2. (a) Reduced loss of load probability or (b) reduced planning reserve margin.
3. Production cost savings.
4. Reduced transmission energy losses.
5. Reduced congestion due to transmission outages.
6. Mitigation of extreme weather events and unexpected system conditions.
7. Capacity cost benefits from reduced peak energy losses.

Evaluation of Benefits of LTRTF

Requirements for Transmission Providers To Evaluate Benefits

DO

- Calculate benefits over at least **20 years** from estimated in-service date.
- Use benefits to reflect **regional preferences** (¶734).
- Measure benefits by **individual category** (¶736).
- **Use discretion on methods** to measure each benefit (¶839).
- **Describe how** they will measure each benefit (¶837).
- [Optional] Use **additional benefits**, if desired, in a manner consistent with Order 890 and Order 1000 planning principles (¶729, 737).
- [Optional] Evaluate benefits of a **portfolio of transmission facilities** rather than facility by facility (¶889).

Evaluation of Benefits of LTRTF

DON'T

- **Combine benefit categories** when measuring (¶736).
- Use a **screening approach** to initially screen benefit categories for significance (¶739).
- [Optional] Describe methods for each benefit category **beyond what is needed** for stakeholders to understand how benefits will be measured (¶840).
- [Optional] Use measured benefits to inform identification of **long-term transmission needs** (¶449, 1920-A).

Transmission providers must:

File an evaluation process, including selection criteria, to identify and evaluate LTRTFs for selection.

Consult with and seek support from relevant state entities (RSEs).

Provide voluntary funding opportunities.

Perform reevaluation in certain circumstances.

Evaluation and Selection of LTRTF

Evaluation and Selection of LTRTF

Transmission providers must:

File an evaluation process, including selection criteria, to identify and evaluate LTRTFs for selection.

Transmission providers must file an evaluation process, including selection criteria that they will use to identify and evaluate LTRTFs for potential selection to address long-term transmission needs (¶911).

- Identify LTRTFs that address long-term transmission needs (¶916).
- Measure the benefits of the identified LTRTFs.
- Designate a point in the evaluation process to select or not select identified LTRTF, not later than 3 years following the beginning of the LTRTP cycle (¶955).
- Provide explanation for stakeholders to understand why a particular LTRTF (or portfolio) was or was not selected, including breakdown of costs and benefits by zone (¶954; ¶773, 1920-A).
- Can include qualitative factors but not required to account for siting or environmental justice considerations (¶959–962).

Transmission providers must:

Consult with and seek support from relevant state entities (RSEs).

RSE: Any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state (¶44).

- Evaluation process and selection criteria to be developed with RSE input (¶916, 994).
- Input does not equal support or approval (¶996).
- Transmission providers are not required to include selection criteria proposed by RSEs and have final authority to propose evaluation processes and selection criteria (¶924, 963).
- Transmission providers, not RSEs, determine whether to select LTRTFs to meet long-term transmission needs (¶1002).

Evaluation and Selection of LTRTF

Transmission providers must:

Provide voluntary funding opportunities.

RSEs and interconnection customers must have the opportunity to voluntarily fund all or part of the LTRTF cost that would otherwise not meet selection criteria (¶1012).

Process must outline:

(1) How to make voluntary funding opportunities available in a timely manner.
(2) Period during which RSEs and interconnection customers may exercise the option to provide voluntary funding.
(3) Method to determine the amount of voluntary funding required to ensure the project meets selection criteria.
(4) Mechanism to memorialize any voluntary funding agreement (¶1013).

Any portion of costs not voluntarily funded are cost allocated (¶1013).

Evaluation and Selection of LTRTF

Evaluation and Selection of LTRTF

Transmission providers must:

Perform reevaluation in certain circumstances.

Transmission providers must include provisions that require them—in certain circumstances—to reevaluate LTRTFs that were previously selected (¶1048).

Reevaluation to occur in the following situations:

- Delays in the development of a previously selected LTRTF would jeopardize reliability.
- The actual or projected costs of a previously selected LTRTF significantly exceed the cost estimate used when the project was selected.
- Significant changes in federal, Tribal, state, or local laws or regulations cause reasonable concern that a previously selected LTRTF may not longer meet selection criteria (¶1049).

Transmission providers must specify criteria to determine when one of these situations occur (¶1013).

No Selection Requirement

- Transmission providers are not required to select any particular LTRTF—even when a facility meets the selection criteria (¶1026).
- Final rule does not prohibit proposing such a requirement (¶1028).

*For projects that are selected, **selection does not entitle the developer to site and construct the LTRTF** and does not override other federal, state, and local jurisdiction for siting and construction (¶917).*

Evaluation and Selection of LTRTF

Order 1920: Key Requirements

Engage in regional long-term transmission planning to **identify transmission needs.**

Develop **processes and criteria** for selecting transmission facilities **to resolve those needs.**

Initial Timing

- Transmission providers must explain in their compliance filing how the initial timing sequence for LTRTP **interacts with existing regional transmission planning processes** (¶1071).
- Transmission providers **can integrate the new process with the existing process** to mitigate potential disruption (¶1072).
- Date for the **start of the new process must be within 1 year** from the date compliance filings are due, June 12, 2025 (¶1072).

Periodic Forums:

- **The Federal Energy Regulatory Commission (FERC) will organize periodic forums** for stakeholders to share best practices in implementing LTRTP.

Implementation of LTRTP

Key Topics

- ✓ Overall need for reform
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- ❑ Commissioner perspectives.

Motivation: Address **barriers to integrating new resources** that may otherwise not be built because of interconnection constraints.

Requirement: Transmission providers must evaluate regional transmission facilities that address certain **interconnection-related transmission needs.**

- Evaluation to be done in existing processes, rather than through LTRTP (¶1107).
- Does not require changes to existing cost allocation methods (¶1117).

Scope: Focus on **upgrades with demonstrated need** that are likely not being developed because of project costs.

- Current needs to be addressed in the near-term.
- Future interconnection-related needs will be addressed through LTRTP through the use of factor categories (1, 2, 6, and 7) (¶1127).

Coordination of Planning and Interconnection

Qualifying Criteria for Evaluation (¶1145):

1. Upgrade identified in at least two cycles or two interconnection studies in a first-come, first-served serial interconnection process in a 5-year window.
2. Project has a voltage of at least 200 kV and an estimated cost of at least $30 million.
3. Projects have not been developed and are not currently planned to be developed because the underlying interconnection request(s) has been withdrawn.
4. Project is not part of an executed generator interconnection agreement.
5. Interconnection withdrawals are within 7 years of when planning process starts.

Transmission provider does not need to select a solution.

Coordination of Planning and Interconnection

Engage in regional long-term transmission planning to **identify transmission needs.**

Develop **processes and criteria** for selecting transmission facilities **to resolve those needs.**

Evaluate transmission facilities that will address interconnection-related transmission needs.

Order 1920: Key Requirements

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For each identified transmission need and upgrade, transmission planning regions must consider (¶1198):

Dynamic line ratings	**Advanced power flow control devices**	**Transmission switching**	**Advanced conductors**

- Selection, evaluation, and use of alternative technology should be treated as an upgrade (¶1201).
- If upgrades to Energy Management Systems are required, this cost should be included in the evaluation.
- Both incumbent and non-incumbent transmission providers may use the applicable regional cost allocation method for alternative technologies (¶1203).
- FERC declined to add storage under this rule (¶1244).

Consideration of Transmission Alternatives

	GETs (DLR)	GETs (TTO)	GETs (APFC)	Reconductoring
Description	Dynamic Line Rating (DLR) enables increased thermal rating based on real-time temp/wind conditions	Transmission Topology optimization (TTO) are software based operational interventions that adjust power-flow to avoid congestion (re-route power-flow)[1]	Typically, power electronics based (FACTs) that are located at substations to control power flow (+address reliability), similar role to PSTs/PARs	Increases thermal rating by replacing conductors with advanced conductors (higher ampacity ratings)
Technical impact	High; 10-40% increased thermal rating	Medium; Effective congestion management (reducing binding operating periods)	Medium; Improved distribution of power flow in radial/meshed networks (potential transfer capability improvement 10-25%)	Highest; 50-100% increased thermal rating (effective on short-distance lines)
Cost / value	Low / Med	Low / Med	Med / Med	Med / High
Timeline (total)	3-12 months	<6 months	6-18 months	12-36 months
Regulatory/permitting	Low	Low	Low	Mid
Design	Mid	Low	High	Mid
Construction	Low	N/A	Mid	High

Relative timeline (qualitative)

Low Mid High N/A

[1] Assuming the switching hardware is already in place (almost always the case);
APFC – Advanced Power Flow Controller; FACTs – Flexible AC Transmission Technologies; PAR – Phase Angle Regulator; PST – Phase-Shifting Transformer

Wright, J., and Pandian, R. 2024. Options for Meeting Data Center Demand in Virginia: Focus on GETs and Reconductoring. Golden, CO: National Renewable Energy Laboratory. NREL/PR-6A40-90734. https://www.nrel.gov/docs/fy24osti/90734.pdf.

Comments on Consideration of Transmission Alternatives

Dynamic Line Ratings

- Uncertainty around temperature and wind speeds on 20-year planning horizon.
- Estimated benefits would be speculative and conservative.

Advanced Power Control Devices

- Less uncertainty than dynamic line ratings.
- Impact is localized and may not be measured in planning study.

Transmission Switching

- More appropriate than transmission optimization as it is scheduled in advance.
- Estimated benefits will depend on simulated system conditions.

Advanced Conductors

- More appropriate than operational interventions.

Difficult to make an apples-to-apples comparison with transmission lines.
Inappropriate to pick specific technologies.
Deployment timelines don't align with 20-year planning horizon at 5-year increments.
Time consuming with minimal benefit.

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Must have

Transmission providers are required to file one or more **ex ante cost allocation methods** that apply to selected facilities (¶1291).

Can have

Transmission providers can also include a **State Agreement Process**, but this cannot be the sole method for cost allocation (¶1292).

Reforms apply to **new facilities only** (¶1300).

Regional Transmission Cost Allocation

Ex Ante Cost Allocation Method

Must have

Must comply with five of the six Order 1000 regional **cost allocation principles** (¶1471):

1) The costs must be allocated to those that benefit in a manner at least roughly commensurate with estimated benefits.
2) Those that receive no benefit, either at present or in a likely future scenario, must not be involuntarily allocated costs.
3) A benefit-to-cost ratio, if adopted, cannot exceed 1.25 to 1.
4) Costs can only be allocated within the transmission planning region unless outside entities volunteer to assume a portion of costs.
5) The method to determine benefits and beneficiaries must be transparent.
6) Different cost allocation methods can be used for different types of transmission facilities.

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Not required to comply if RSEs indicate they agree as part of the engagement period or the State Agreement Process applies (¶1470).

Can have

State Agreement Process

State Agreement Approach: A process by which one or more RSEs may voluntarily agree to a cost allocation method for LTRTFs.

- Can apply to a single facility or portfolio of facilities.
- Can exercise the option either before or no later than 6 months after the facilities are selected (¶1402).

There is a **6-month engagement period** during which transmission providers must (¶1354):

- Provide notice of start and end dates for the 6-month period.
- Post contact information that RSEs may use to communicate with transmission providers about any cost allocation agreement or methods and a deadline for communication.
- Provide a forum for negotiations of cost allocation methods or the State Agreement Process that enables “meaningful participation” by RSEs.

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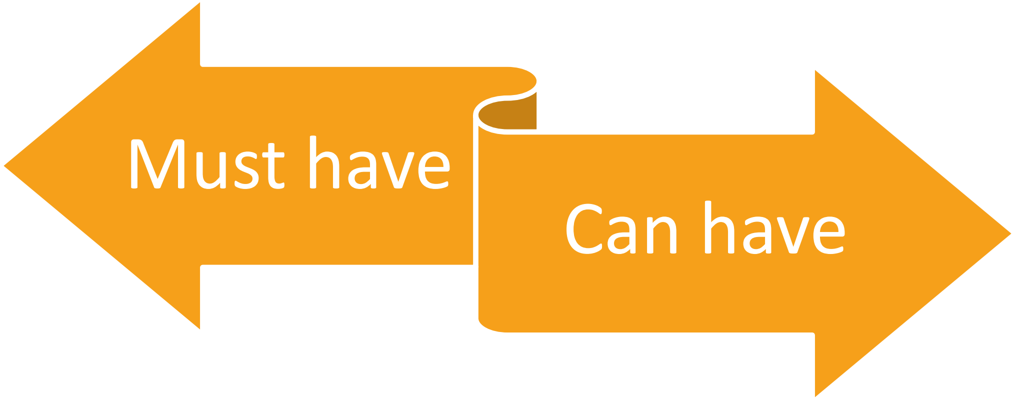
States define agreement

Up to 6-month extension of engagement period

Must consult with RSEs on updates to cost allocation methods



Ex Ante Cost Allocation Method

State Agreement Process

- Transmission providers may file their selected method but must submit any cost allocation or state agreement approach agreed to by RSEs (¶691, 1920-A).
- Alternative methods from RSEs will be evaluated on “equal footing” as the method preferred by transmission providers (¶692, 1920-A).

Regional Transmission Cost Allocation

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Consider advanced conductors, power flow control devices, dynamic line ratings, and transmission switching.

Develop a “backstop” cost allocation method and a process for voluntary funding and state agreement.

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Construction Work in Progress (CWIP) Incentive

The CWIP Incentive allows transmission developers to include 100% of CWIP costs in the rate base (Order 679).

- FERC declined to limit the availability of the CWIP Incentive for LTRTF at this time.
- More appropriate in a separate proceeding evaluating all transmission incentives comprehensively (¶1354).

Federal Right of First Refusal (ROFR)

Federal ROFR gives incumbent utilities the option to have exclusive control over building, maintaining, and owning transmission lines in their service territory before a project is opened to competitive bidding.

> **Order 1000** eliminated all federal ROFR and opened transmission projects to nonincumbent owners and operators through competitive bidding.

FERC proposed to **permit federal ROFR** for selected transmission facilities conditioned on incumbent utilities establishing **joint ownership** of transmission facilities (¶1548).

- Given investment trends, Order 1000 may have inadvertently discouraged investment.
- Unconditional ROFR remains unjust and unreasonable, but maybe eliminating all ROFR was *too* broad (¶1549).

In favor

- ✓ Reduces perverse incentives for incumbents not to build projects that may benefit users beyond their footprint.
- ✓ Reduces risk that incumbents will lose regional projects they have identified and planned during the solicitation process.
- ✓ Provides incentive for incumbents to plan regional projects with broad benefits as well as local projects.

Opposed

- x Benefits ratepayers with lower costs achieved through competitive transmission development.
- x Increases risk of anti-competitive behavior through conditional ROFR that could lead to excessive costs to consumers.
- x Increases risk of litigation over whether meaningful opportunities exist for third parties to participate in joint ownership that will slow project development.

FERC declined to adopt the proposal and stated the Commission would continue to consider it in other proceedings (¶1563).

Comments on Federal ROFR Reform

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Local Planning Inputs

Need for reform (¶1577)

Enhance the transparency of local transmission planning processes.

Information in local planning serves as the foundation for regional planning.

Require transmission providers to evaluate whether transmission facilities that need replacing can be **"right-sized"** to more efficiently or cost-effectively address long-term needs.

The majority of transmission facilities in many regions are more than 40 years old.

Transmission providers are required to publicly post the following:

(1) The **criteria, models, and assumptions** that they use in their local transmission planning process.

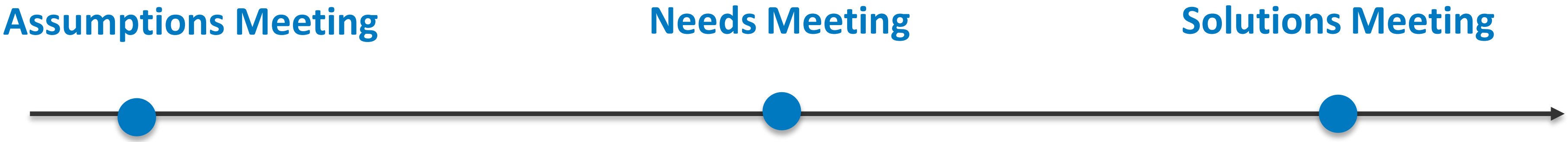
(2) The **local transmission needs** that they identify through the local transmission planning process.

(3) The **potential local or regional transmission facilities** that they will evaluate to address those needs (¶1625).

Local Planning Inputs

Enhanced transparency of local transmission planning inputs

Transmission providers are required to hold three public stakeholder meetings (¶1625).



The meeting schedule is triggered by the **submission of local transmission planning information** for inclusion in the regional plan and is not tied to a particular planning cycle.

Local Planning Inputs

Enhanced transparency of local transmission planning inputs

Transmission providers are required to hold three public stakeholder meetings (¶1625).

Assumptions Meeting

Review the criteria, assumptions, and models related to each transmission provider's local planning.

± 5 days

Post meeting materials.

≥ *25 days*

Needs Meeting

Review identified reliability criteria violations and other factors that drive the need for local transmission.

Post meeting materials.

± 5 days

≥ *25 days*

Solutions Meeting

Review potential solutions to those reliability criteria violations and other transmission needs.

± 5 days

Post meeting materials.

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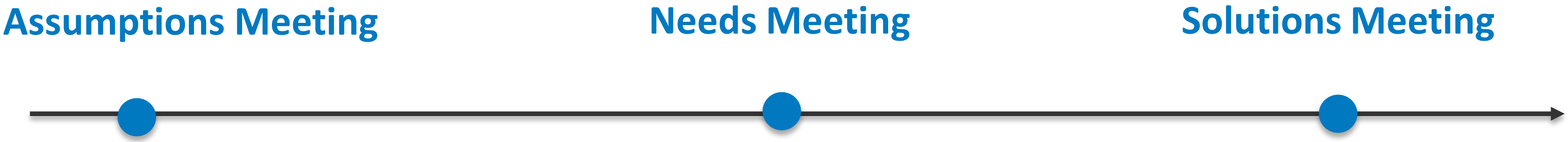
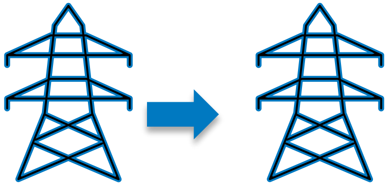


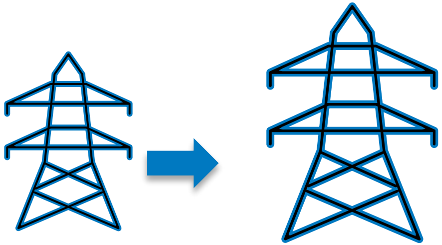
Transmission providers are not required to respond to every question or comment received through the stakeholder process but must respond in a manner that allows stakeholders to "**meaningfully participate**" in meetings (¶1656).

Local Planning Inputs

Enhanced transparency of local transmission planning inputs

Terms to Know





An in-kind replacement transmission facility is a new facility that:

- Replaces an existing facility.
- Would result in no more than an incidental increase in capacity over the existing facility.
- Is located in the same general route and/or uses the same rights-of-way as the existing facility (¶1678).

Right-sizing is modifying an in-kind replacement of an existing transmission facility to increase that facility's transfer capability (¶1678).

Transmission providers are required to:

(1) Submit a minimum voltage threshold for consideration of right-sizing (no higher than 200 kV).

(2) Propose a point "sufficiently early" in the planning cycle when transmission owners will submit their in-kind replacement estimates.

(3) Evaluate and post a list of projects to be replaced in the next 10 years that can be "right-sized" to more efficiently or cost-effectively address long-term needs (¶1677).

Right-sized replacements are eligible for federal ROFR.

Local Planning Inputs

Right-sizing

Transmission providers **can** propose a cost allocation method for selected right-sized replacements.

Must demonstrate/explain in compliance filings:

- That the cost allocation method is **just and reasonable** (¶1716).
- The **method used to determine the incremental portion of the costs** of a right-sized replacement (¶1719).
- The **method by which they will track the incremental portion of costs** over time that are allocated in accordance with the long-term transmission cost allocation method.

FERC **declined to require** this due to complexities and challenges associated with tracking the portions of costs of two projects and allocating costs with two methods.

Local Planning Inputs

Right-sizing

Order 1920: Key Requirements

Engage in regional long-term transmission planning to **identify transmission needs.**

Develop **processes and criteria** for selecting transmission facilities **to resolve those needs.**

Evaluate transmission facilities that will address interconnection-related transmission needs.

Consider advanced conductors, power flow control devices, dynamic line ratings, and transmission switching.

Consider local planning and "right sizing" replacement transmission facilities.

Develop a "backstop" cost allocation method and a process for voluntary funding and state agreement.

Key Topics

- ✓ Overall need for reform
- ✓ Long-term regional transmission planning
- ✓ Consideration of generator interconnection
- ✓ Consideration of transmission alternatives
- ✓ Regional transmission cost allocation
- ✓ Incentives and rights of first refusal
- ✓ Local transmission planning
- ❑ Interregional transmission coordination
- ❑ Compliance procedures
- ❑ Commissioner perspectives.

Transmission providers must revise interregional coordination procedures to reflect required long-term regional planning reforms (¶1751).

Coordination between **transmission planners.**

Revisions must account for:

(1) **Sharing of information** on long-term transmission needs and facilities to meet those needs.

(2) **Identification and joint evaluation** of interregional facilities that may be more efficient or cost effective to address needs (¶1751).

(3) **Allowing neighboring transmission planners to propose** an interregional transmission facility to address needs (¶1752).

Interregional Coordination

Coordination with the **public.**

Transmission planners must publish through their website or email lists:

(1) The long-term transmission needs discussed in interregional transmission coordination meetings.

(2) Any **interregional transmission facilities** proposed or identified in response to long-term transmission needs.

(3) The **voltage level, estimated cost, and estimated in-service date** of the interregional facilities proposed or identified.

(4) The **results of any cost-benefit evaluation** of interregional facilities, including overall benefits and benefits to each planning region.

(5) The interregional transmission facilities, if any, **selected** (¶1753).

Interregional Coordination

Key Topics

- ✓ Overall need for reform
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- ❑ Compliance procedures
- ❑ Commissioner perspectives.

Effective Date
Aug. 12, 2024

Compliance Timeline (§1768–1773, §507 1920-A)

Revise the Open Access Transmission Tariff (OATT) and other relevant documents necessary to demonstrate that it meets all the rule's requirements.

Effective Date
Aug. 12, 2024

10 months

Compliance Filings Due (minus interregional)
June 12, 2025

Compliance Timeline (¶1768–1773; ¶925, 1920-A)

Compliance Timeline (¶1768–1773; ¶925, 1920-A)

Effective Date
Aug. 12, 2024

Compliance Filings Due (minus interregional)
June 12, 2025

2 months

Compliance Filings for Interregional Transmission Coordination Due
Aug. 12, 2025

Revise OATT and other relevant documents necessary to demonstrate that it meets all the rule's requirements for interregional transmission coordination.

Compliance Timeline (¶1768–1773, ¶925, 1920-A)

Effective Date
Aug. 12, 2024

Compliance Filings Due (minus Interregional)
June 12, 2025

Compliance Filings for Interregional Transmission Coordination Due
Aug. 12, 2025

≤ 22 months

Deadline to Start First LTRTP Cycle
Effective Date for OATT Revisions
June 12, 2027

Key Topics

- ✓ Overall need for reform
- ✓ Long-term regional transmission planning
- ✓ Consideration of generator interconnection
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- ✓ Local transmission planning
- ✓ Interregional transmission coordination
- ✓ Compliance procedures
- ❑ Commissioner perspectives

Order 1920

- ✓ Commissioners Phillips and Clements emphasized the final rule is a **reliability** and **affordability** imperative.
- ✓ Failure to act would **hamper reliability and resilience** of the electric grid.
- ✓ Failure to act would leave customers responsible for **more costly upgrades** in the future.

- x Commissioner Christie strongly dissented, arguing that the ruling will result in **excess spending on transmission.**
- x Commission does **not have statutory authority** to issue an "absurdly complex bureaucratic blizzard of mandates and micromanagement."
- x Ruling **serves political, corporate and other special interests** rather than consumers.

Order 1920-A

- ✓ Commissioners Christie noted the changes "go a long way towards **restoring the state role to what the NOPR promised.**"

Key Topics

- ✓ Overall need for reform
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Thank you

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