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Introduction to Planning

1. Introduction

We pose some questions:

a. What is energy system planning? What is power system planning? What is the difference?
b. Who does it? Where is it done?
c. Why is it done?
d. How frequently is it done?
e. How is it done?

You will begin to get answers to these questions in these notes. In particular, we will address the following in these introductory notes.

Section 2: Infrastructure systems, energy systems, & power systems;

Section 3: Definition and process

- Planning objectives: Define "planning" and identify fundamental planning objectives;
- Planning horizons: Identify why planning horizons for power systems are so long;

Section 4: Planning categories, e.g., temporal scales, geo-scales;

1. Describe RTO planning processes (queues, capacity procurement, transmission expansion planning, interregional planning);
2. Describe siting & permitting processes.

Section 5: Policy developments

Section 6: Reliability-based vs. economic/value-based T-planning

Section 7: RTO planning processes; regional/interregional planning

Section 8: Planning tools

Section 9: Planning at a national scale

Section 10: Onshore vs. offshore

2. Infrastructure systems, energy systems, & power systems

The term "infrastructure" in our context refers to the basic physical and organizational structures and facilities needed for the operation of a society or enterprise. The term “infrastructure systems” broadens this notion to clearly include communications, computing, coordination, scheduling, and decision needed to operate the structures and facilities. We use the term “civil infrastructure systems” to refer to those that are “hard[1],” i.e., those that comprise large, physical networks critical to societal function nationwide, including those which provide energy, water (including wastewater systems), transportation, and/or communications. Solid waste systems (landfills) are also sometimes included as hard infrastructure. Another term related to “hard” infrastructure systems” or “civil infrastructure systems,” but more expansive, is “critical infrastructure systems,” which is defined by the US Department of Homeland Security [1], and includes:

- Chemical sector
- Commercial facilities sector
- Communications sector
- Critical manufacturing sector
- Dams sector
- Defense industrial base sector
- Emergency services sector
- Energy sector
- Financial services sector
- Food and agriculture sector
- Government facilities sector
- Healthcare and public health sector
- Information technology sector
- Nuclear reactors, materials, and waste sector
- Transportation systems sector
- Water and wastewater system sector

In this list, those highlighted in yellow are directly included in the nation’s list of “hard” or “civil” infrastructure systems; those highlighted in grey are indirectly included.

[1] “Soft” infrastructures refer to institutional infrastructure required to maintain economic, health/cultural/social standards of a country, such as financial, health care, government, law enforcement, & emergency services systems.

We use the term “energy infrastructure system” or “energy system” to capture all infrastructures which contribute to the production, transportation, conversion, and use of energy in all of its forms. This is a very broad definition! It includes at least the following:

- Electric production/transmission/distribution systems
- Natural gas production/transmission/distribution systems
- Coal production and transportation systems
- Nuclear fuel production/transportation/enrichment/waste systems
- Hydro systems
- Petroleum production/refining/transportation systems
- Agricultural production systems for biomass and biofuel and associated transportation systems
- All energy consuming systems

One way to illustrate energy flows between these systems is through Sankey diagrams published annually by Lawrence Livermore National Laboratory [2]. The numbers on this diagram indicate annual US energy in quads (1×10^{15} BTUs). By coincidence, the total annual energy produced from all forms is about 100 quads, therefore, all numbers on this diagram can be interpreted as percentage of total annual energy produced from all forms. Some observations are (i) at almost 70%, petroleum + natural gas are definitely the largest two energy resources; (ii) we reject (lose) 67% of all produced energy (mainly heat); (iii) non-CO_2 producing resources (on left, above gas) are only about 16%. It can be useful in assessing proposed energy-related innovations to place them in the context of this diagram.

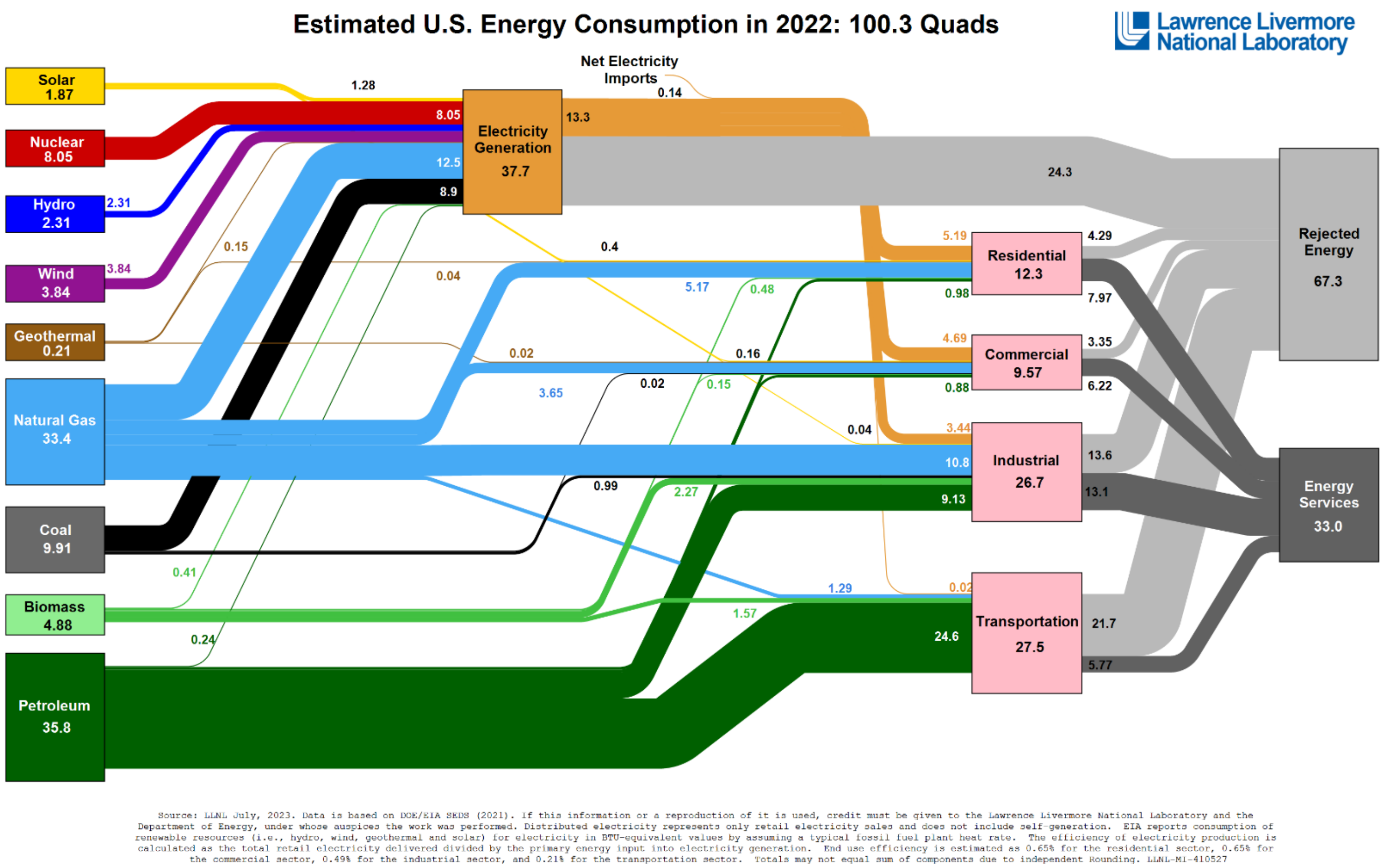

Figure 2-1: 2022 US Sankey "energy flow" diagram [2]

The coupling between energy systems and transportation systems gets a lot of attention, since transportation systems require so much energy. Figure 2-2 illustrates these two infrastructure systems and their coupling.

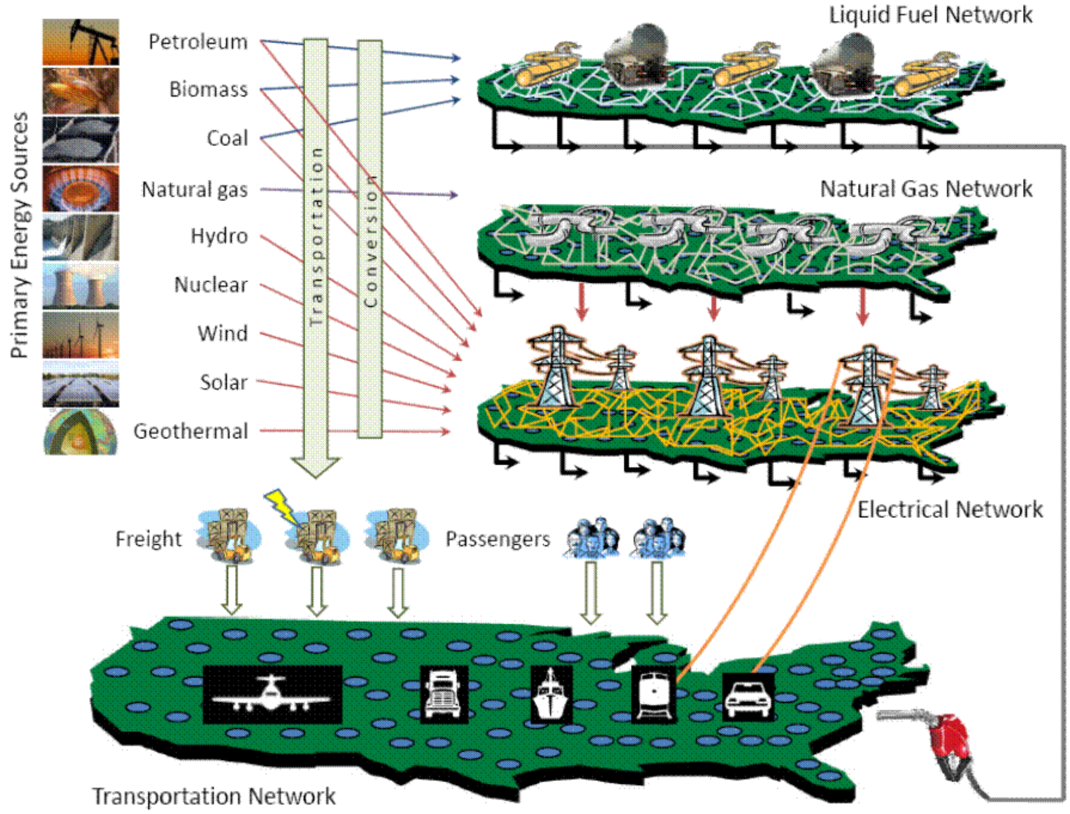

Figure 2-2: Energy and transportation infrastructure systems

It is clear from Figure 2-2 that the electric system is a subsystem within the overall energy system. However, it is a key subsystem as it interconnects with almost all of the other energy subsystems, and because it's interconnection with transportation is growing.

We refer to the electric system as the electric power system, or just power system. There may be times when the term "energy system" is used to denote "power system," because the power system is such a critical piece of the energy system, but, strictly speaking, use of the term "energy system" to mean "power system" is improper use of terminology. In this course, although "energy system planning" is within our domain of interest, we will mostly emphasize "power system planning," unless otherwise stated.

3. Definition and process

First, let's begin with looking at a few definitions of the word "planning." What is it?

From [3], we learn that planning is associated with

1. A scheme, program, or method worked out beforehand for the accomplishment of an objective: a plan of attack.
2. A proposed or tentative project or course of action: had no plans for the evening.
3. A systematic arrangement of elements or important parts; a configuration or outline: a seating plan; the plan of a story.

Reference [3] provides a business definition of planning as: "A Basic management function involving formulation of one or more detailed plans to achieve optimum balance of needs or demands with the available resources. The planning process (1) identifies the goals or objectives to be achieved, (2) formulates strategies to achieve them, (3) arranges or creates the means required, and (4) implements, directs, and monitors all steps in their proper sequence."

Another way we can think of planning is in terms of actions taken, and in terms of the thing produced by those actions, and it is in fact this way that a well-known reference [4, ch. 2] on electric systems planning defines it, as indicated below.

- "The *planning process* is the systematic assembly and analysis of information about electric energy supply, transport, and demand, and the presentation of this information to decision-makers who must choose an appropriate course of action."
- "The *plan* is a statement of the choices made by decision-makers at any one point in time in order to meet specific goals and objectives."

It is useful to also consider what planning is NOT [4]:

“There are several things that energy planning should not be. Energy planning should not be an end in itself. The interminable conduct of studies and preparation of planning documents that are not implemented is a futile exercise and a waste of valuable human resources. Energy planning should not be an excuse for inaction. Deferring action pending the preparation of a plan is acceptable only to a point. Continuing inaction may lead to consequences that are worse than taking action in the absence of a systematic analysis. Finally, planning should not be a substitute for decision-making. Difficult decisions and choices must be made in order to implement an energy programme. The energy planning process can only assist by making information available to decision-makers.”

Planning approaches may be distinguished in a number of ways, but all of them must consist of some of the following steps [4].

1. Define planning goals
2. Determine the planning category
3. Identify information required from the planning process
4. Choose the analysis process and associated tools
5. Conduct the analysis
6. Present results to decision-makers
7. Document the information, analysis results, decision, and decision rationale

> In this course, we will emphasize the steps highlighted in yellow.

We make a few brief comments about the first two of the above steps in Sections 3.1, 3.2 and 4. Step 6 is perhaps the most important, but it can only be done well after thoroughly understanding the other steps. Step 7 is more important than it might seem, for enabling people (the colleagues of the planner and possibly the planner his/herself) to answer future questions of what happened in the study. Steps 3-5, highlighted in yellow, will be emphasized in this course, with focus on the features of the various tools used and how to use them within a planning study.

3.1. Definition of planning goals

All planning exercises have as their ultimate aim to inform the capital investment decision-making associated with expanding the electric system. But these exercises may occur at a local, regional, or national level. For example,

- Local: A local utility must identify a plan to meet their load growth over the next 5 years and over the next 10-20 years.
- Regional: This is the level at which the Regional Transmission Organizations (RTOs) operate. For example, MISO maintains a guiding principle that [5] "Midwest ISO regional expansion plans should identify efficient investments in the transmission infrastructure system to (bold emphasis added):
    - Develop transmission plans that will ensure a **reliable and resilient** transmission system that can respond to the operational needs of the MISO region.
    - Make the benefits of **an economically efficient electricity market** available to customers by identifying solutions to transmission issues that are informed by near-term and long-range needs and provide reliable access to electricity at the lowest total electric system cost.
    - Support **federal, state, and local energy policy and member plans** and goals by planning for access to a changing resource mix.
    - Provide **an appropriate cost allocation mechanism** that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
    - Analyze **an appropriate range of system scenarios and make the results available** to federal, state, and local energy policy makers and other stakeholders to provide context and to inform choices.
    - **Coordinate planning processes with neighbors** and work to eliminate barriers to reliable and efficient operations.

- National: Goals at this level could be [4]:
  - To develop appropriate government policies influencing the development of the electric system, and
  - To provide signals to appropriate industries and institutions as to the directions that will be taken in the future.

It is also necessary to specify planning criteria which are used to evaluate the achievement of the goals. A set of criteria that reflects typical thought in the power system planning community might be:

- Cost:
  - Minimize investment costs
  - Minimize production costs
- Reliability:
  - Maximize reliability (e.g., minimize LOLE)
  - Avoid large-scale blackouts
- Resilience: Minimize cost impacts of extreme events.
- Sustainability:
  - Minimize "Criteria" air pollutants (Ozone, Particulate Matter, Carbon Monoxide, Nitrogen Oxides, Sulfur Dioxide, Lead)
  - Minimize CO_2 emissions

When formulating an optimization problem to facilitate planning, most of the above "criteria" can be considered as either objectives or constraints.

If two or more of the above criteria are considered objectives, then the problem is inherently multi-objective. In general, planning problems are inherently multi-objective. Multi-objective problems are more complex than single-objective problems; therefore, it is often the case that planning problems identify a single objective (e.g., minimize cost) and model all other goals as constraints.

For long-term planning at a regional and national level, I formulated the following "design objectives," characterized by the acronym EES-S/FRRA.

- EES-S:
    - **E**nvironmental sustainability: air quality, CO_2, radioactive waste, impact on wildlife, ecosystems, forests, water,…
    - **E**conomic sustainability: is the technology economically attractive?
    - **S**ocial sustainability: do people want the technologies, the plan?
- FRRA:
    - **F**lexibility: operational speed of response to balance load in response to changes caused by load and resource variability, contingencies, and net-load ramping.
    - **R**eliability: service availability
        - At transmission level, LOLE and NERC TPL-005-1 (performance-disturbance table)
        - At distribution level, SAIDI, SAIFI
    - **R**esilience: the ability to minimize and recover from cost-consequences of extreme events;
    - **A**daptability: A long-term version of resilience – the ability to economically adapt infrastructure to adverse and permanent changes in technology availability/fuel availability or cost. (Ex: Fukushima).

Of the above, we make the following comments:

- Flexibility has become very important as variable generation (wind and solar) penetrations have grown, since they have increased the variability seen by the dispatchable generation. One increases flexibility by increasing the operationally available capacity that is "fast" and controllable.
- SAIDI is the system average interruption duration index and expresses the average outage duration over a year for each customer served. SAIFI is the system average interruption frequency index and expresses the

average number of interruptions that a customer would experience over a year. A typical number for SAIDI is 1.5 hours per year; a typical number for SAIFI is 1.1 interruptions per year. These indices are most heavily influenced by the distribution infrastructure and events affecting it.

- Resilience:
  - Relation to speed of recovery: This term is often used to reflect the speed of recovery from an outage event. This feature, however, is already captured in SAIDI.
  - Example: To illustrate what is meant by the "resilience" definition above, consider the economic influence of Hurricanes Katrina and Rita in 2005, each of which shut-in over 80% of daily gas production in the gulf of Mexico immediately after their occurrence [6].
  - Figure 3-1 illustrates the impact of this event on natural gas prices around the nation in the first four months following. The effect on electricity prices was similar. In this plot, the colored area represents the increased price per unit of demand and is a measure of resilience[2].
  - Figure 3-2 generalizes this concept. The key difference between this notion of resilience and that associated with speed-of-response is that here, we focus on resilience of the service cost, in contrast to the resilience of energy availability.
  - In addition, resilience is usually associated with extreme events, e.g., climate-related such as hurricanes and other high-wind events (tornados, derechos), extreme snow/ice events, extreme temperature events, floods, droughts, wildfires; and non-climate related including earthquakes, tsunamis, volcanic eruptions, geomagnetic disturbances, cyber events, and cascading outages.
- We will discuss adaptability later in the course.

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[2] This is the increase in total price paid for energy if the demand was always one unit, e.g., if the ordinate is $/MWhr, then the colored area represents increase in price paid if the demand is 1 MW. Of course, the demand is not 1 MW; it varies. To obtain the actual increase in price paid, one needs to first multiply the ordinate ($/MWhr) by the demand at each particular time. The resulting "colored area" (difference between $/hr curve with and without the event) would give the total additional price paid.

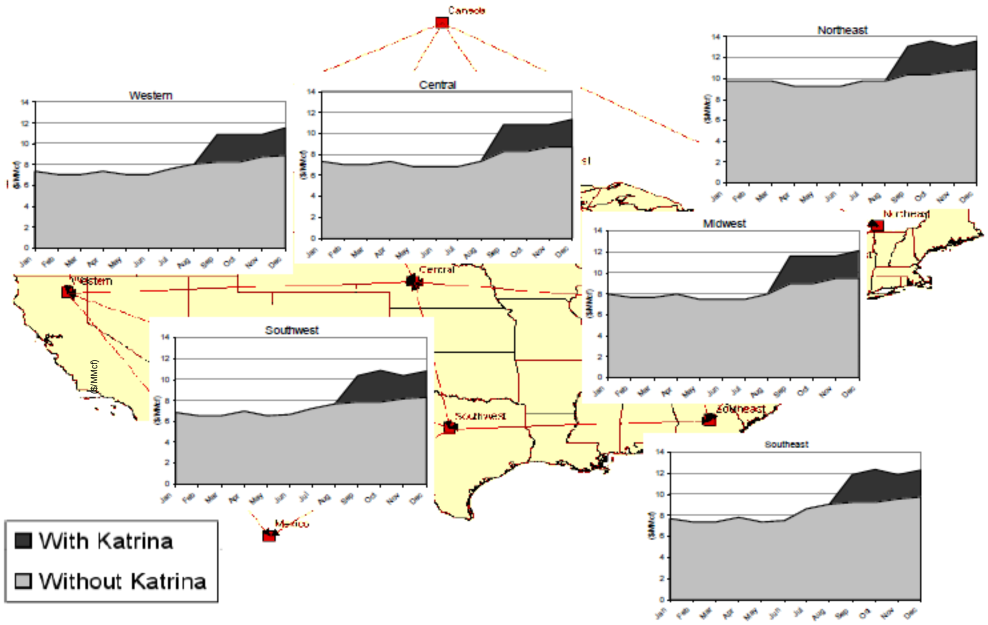
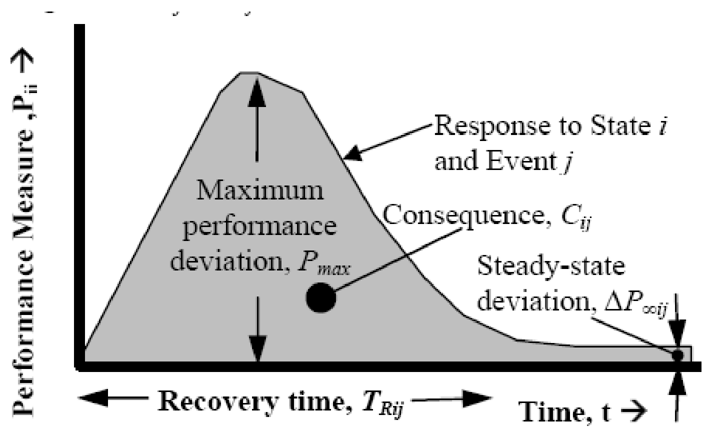


Figure 3-1: Effect of Katrina/Rita on Natural Gas Prices



Resilience metric for an event & state

Figure 3-2: Generalization of resilience

3.2. Planning Horizons

Electric power systems consist of power generation stations, transmission and distribution circuits, substations, and associated transformers, voltage control equipment, and protection equipment, together with equipment that facilitates monitoring, communication, and information processing to enable decision and control.

The process to plan and build such facilities takes many years. The amount of time between the first year that investment can take place in the planning analysis and the last year that investment can take place in the planning analysis is called the planning horizon (also "decision horizon"). A 20-yr planning horizon is illustrated in Figure 3-3.

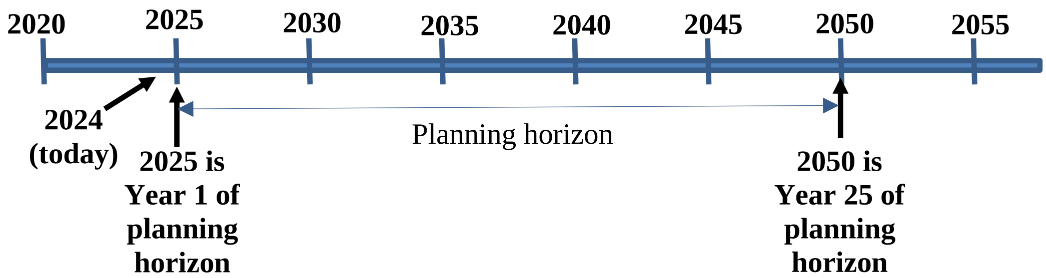


Figure 3-3: Illustration of a 25-year planning horizon

Many regulatory bodies require that electric utilities have a 10-20 year planning horizon for generation facilities. The North American Electric Reliability Corporation (NERC) requires in Planning Standard TPL-005-0 [7] (Regional & Interregional Self-Assessment Reliability Reports) that "each Regional Reliability Organization shall annually conduct reliability assessments of its respective existing and planned Regional Bulk Electric System (gen and transmission facilities) for:

- The current year (winter and summer),
- Near-term planning horizons (years one through five), &
- Longer-term planning horizons (years six through ten).

Some national studies have 20-30 or even 40-yr planning horizons.

The planning horizon is long because

- it takes long time to plan, cost allocate, permit, & site such facilities,
- such facilities live a long time, and so we need a significant time after they are built to evaluate their performance.

The complexity of the first issue, to plan, permit, and site such facilities, is illustrated in Figure 3-4 below for developing new transmission (adapted from [8] and taken from [9]). Some high-level comments and more detailed comments on Figure 3-4 follow:

- Observe - time from project initiation to "build line" can range from 7.5-13 years!
- RTO planning coordination and cost allocation activities are in blocks 1 and 2.
- "Project initiation" (top yellow box) can arise via a single stakeholder or via the RTO planning process.

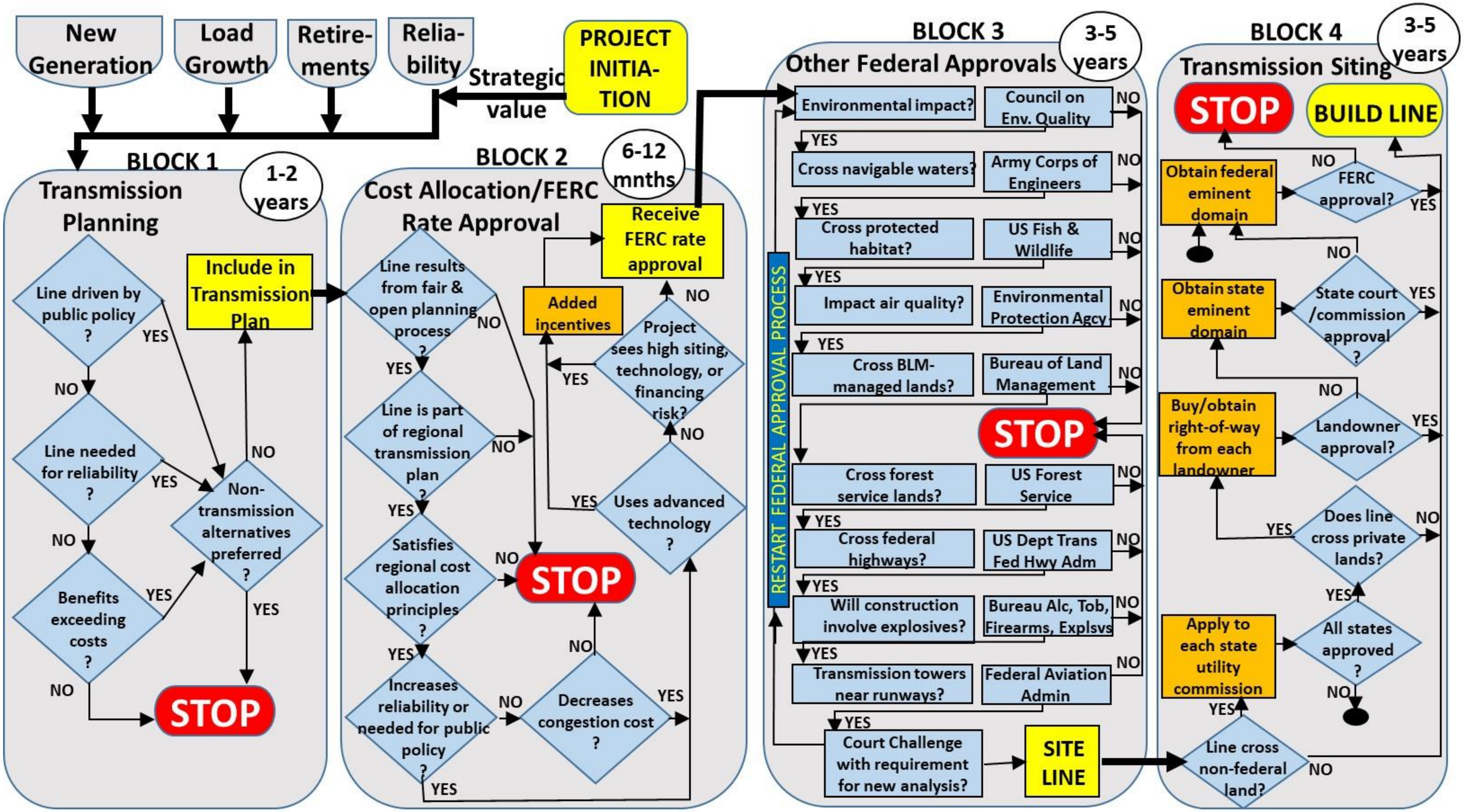


Figure 3-4: Transmission planning, cost allocation, approval, siting process

More detailed comments adapted from [9] on Figure 3-4 follow:

- Project initiation: To initiate development of a transmission project, there necessarily must be an entity or coalition that identifies that the transmission project may be of strategic value. This entity or coalition may or arise out of an RTO planning effort or it may arise otherwise and be brought to an RTO planning effort. This step is critical because nothing moves forward without it; this step is difficult because it requires experience and understanding on how to evaluate benefits of transmission together with the ability to bring together organizations interested in obtaining those benefits and able to provide funding towards pursuing them. The identified strategic value motivates a business plan to financially justify and guide the project.
- Transmission planning (Block 1): This process, typically requiring 1-2 years, needs attention from experienced planners to design the transmission project and its technical features, consider alternatives, assess risks, ensure that the plan meets reliability requirements, and quantify costs and benefits and return on investment. Although the project may arise out of an RTO planning effort, it may also be brought to an RTO planning effort.
- Cost allocation/FERC rate approval (Block 2): FERC requires that the project be part of a fair and open planning process, that it be assessed within the planning process of affected RTOs, and that it satisfy the RTOs' cost allocation principles. FERC also has authority to adjust cost recovery based on "added incentives" [10][3]. This step typically requires 6-12 months.
- Other Federal approvals (Block 3): There are a variety of Federal permits that may need to be obtained depending on the nature of the project. Any of the various Federal agencies granting these permits can effectively stop the project. This step may require 3-5 years. Effort has been made to address the required Block 3 time by granting the US Department of Energy "lead agency" status [11], thereby coordinating and streamlining the process.
- Transmission siting (Block 4): The most significant uncertainties occur during efforts to obtain transmission siting. Block 4 uncertainties occur largely because of division of power between state and federal agencies. Unlike natural gas transmission, states are primary decision-makers for siting interstate electric transmission; there are strong arguments being made today that, in order to obtain the very significant benefits of regional and interregional transmission, FERC will need more siting authority [12], while state authorization and review processes are simplified [13]. The Biden administration has made significant effort to reduce this time, as described in [14], with funding provided for state regulators to do so as indicated in the solicitation of [15].

More generally, the ***analysis time*** for planning is often long (can be a year or more) because it is a complex activity and because it is important as an essential societal function. Reasons for the importance of electric power planning follow:

1. Financing: The equipment is capital-intensive, i.e., expensive,

[3] In 2006, FERC built into its processes (based on a section 219 Congress added to the Federal Power Act) the ability to add incentives for transmission projects proposed by a member of an RTO that ensures reliability or reduces cost of delivered power by reducing congestion, particularly for projects that present special risks or challenges. As described in [10], such incentives focus on risk and include higher return on equity; recovery of incurred costs if a project is abandoned for reasons outside the applicant's control; inclusion in rate base of 100% costs for construction work in progress; use of hypothetical capital structures; accelerated depreciation for rate recovery; and recovery of pre-commercial operations costs as an expense or through a regulatory asset. FERC recently issued a Notice of Proposed Rulemaking to extend/refine their approach for evaluating incentive requests; see FERC Notice of Proposed Rulemaking, "Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act," Docket RM20-10-000, March 20, 2020. www.ferc.gov/sites/default/files/2020-05/20200320145741-RM20-10-000_0.pdf. .

requiring careful analysis and decision to minimize financial risk exposure on the part of the equipment owners.

2. Multiple organizations: The equipment will be interconnected within an overall system that is owned and operated by many different organizations, and so each affected organization must have access to information necessary to consider the impacts of the new equipment on their operations.
3. Land: The power generation stations, the transmission and distribution circuits, and the substations require significant land areas necessitating engagement in what can be extremely complex land acquisition processes.
4. Environmental impacts: Many facilities have environmental effects, for example:
   - Power plant impacts, including impact of fossil fired plants on water usage and emissions, ability to store wastes from nuclear plants, impact of hydroelectric facilities on fish-kill/recreational activities, wind turbine noise and wind turbine impact on wildlife, and solar land use displacing other uses (e.g., farming).
   - Effects of overhead transmission lines including visual aesthetics, corona-induced audible noise, communications interference (particular AM radio), and induced currents in underlying objects from high electric field levels.
5. Cost of energy: The cost of electric energy, which is heavily determined by planning decisions, directly affects all of us via our own residential use of it. In addition, we are all indirectly affected by the cost of electric energy in two ways:
   - Through our dependence on industrial and commercial organizations that pass on their cost of electric energy to us through the products and services that we purchase from them.
   - Through our ability to compete in international markets (including those within our own country) and the related impact

that has on job growth and gross domestic product (GDP).

6. Reliability: Decisions on which equipment to build and when, together with load growth and retirements of old equipment, directly impact the reliability levels of interconnected grids. These reliability levels, or conversely, the extent to which customers see interruptions and/or transmission unavailability causes generation owners to use higher- priced energy, also affect the cost of energy.

These reasons point to the fact that planning and building new infrastructure facilities is important, affecting our entire society.

Therefore we as a society have concluded that it is appropriate to impose regulatory oversight in this process. Regulatory oversight generally occurs at two levels:

- Federal level: The Federal Energy Regulatory Commission (FERC) [16] regulates the *interstate* transmission of electricity, natural gas, and oil. In regards to electric systems, FERC
  - regulates the transmission and wholesale sales of electricity in *interstate* commerce;
  - ensures the reliability of high voltage *interstate* transmission system,
  - licenses and inspects private, municipal, and state hydroelectric projects,
  - monitors and investigates energy markets,
  - uses civil penalties and other means against energy organizations and individuals who violate FERC rules in the energy markets,
  - oversees environmental matters related to natural gas and hydroelectricity projects and major electricity policy initiatives
  - administers accounting and financial reporting regulations and conduct of regulated companies.

FERC does *not*

- regulate retail electricity and natural gas sales to consumers, or approve the physical construction of electric generation, transmission, or distribution facilities (done by the state regulator),
- regulate activities of the municipal power systems, federal power marketing agencies (like Tennessee Valley Authority), and most rural electric cooperatives,
- regulate nuclear power plants (done by Nuc. Regulatory Comm.),
- approve development of electric transmission facilities (although it has some limited authority to do so, it generally does not use it).

- State level: A list of state regulatory bodies for utilities may be found at [17]. The authority for these bodies varies somewhat, but the following statements from the web page of the Iowa Utilities Board (IUB) [18] are typical:

> "The Board regulates the rates and services of electric, natural gas, communications, and water utilities and generally supervises all pipelines and the transmission, sale, and distribution of electrical current….Also included in the Board's jurisdiction is certification of electric power generators (476A), granting of franchises for electric transmission lines (478),…"

4. Planning categories

There are two different sets of attributes which can be used to identify the planning category. The first set (a) and (b) below is traditional and has always been of interest to electric system planners. The second set (c) and (d) have become of increasing interest as the industry has matured. These sets are:

a. Time-frame: short-term, mid-term, long-term
b. Subsystem: load, distribution, generation, transmission
c. Collaboration level: single-entity vs. collaborative
d. Geographic scale: local, regional, national

Figure 4-1 illustrates the possibilities with respect to the first two attribute sets (a) and (b). Although all combinations of time frame and subsystem can occur, the types of planning studies of most interest to us in this course are colored in yellow.

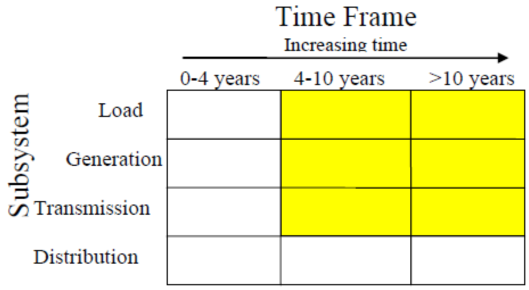


Figure 4-1: Subsystem and time frame

Figure 4-2 illustrates possibilities with respect to the 3rd and 4th attribute sets (c) and (d). Of these, only the combinations in yellow have occurred in practice. Single company studies and joint studies at a local level have always occurred. Regional studies including multiple companies began occurring after the 1965 blackout, most of which were coordinated by the regional reliability councils or regional power pools.

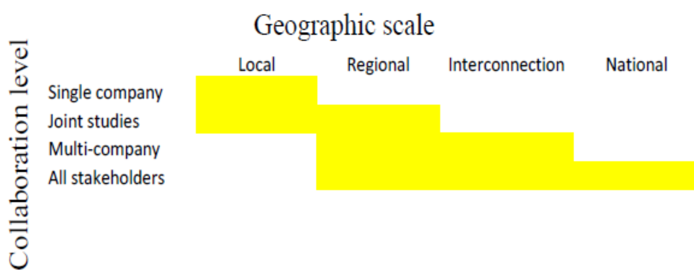


Figure 4-2: Collaboration level and geographic scale

Independent system operators (ISOs), in their capacity as regional transmission organizations (RTOs), now perform the function of coordinating regional planning studies which involved multiple companies at first and now involve all stakeholders. FERC via its Order 1000 requires RTOs to consider studies at the interregional level [19], an issue we describe in more detail in the next section. A few studies that are national in scope have been performed by the US national labs, but this is not yet industry practice.

5. Policy developments

5.1. 1978 PURPA (qualifying facilities, QFs)

Utilities had to interconnect/buy, at avoided cost, energy from QFs (small power producers using 75% renewables or cogen).

5.2. 1992 Energy Policy Act, Exempt wholesale gens (EWGs)

EWGs – any technology, utilities did not have to buy their energy, but they did have to provide them w/ transmission, but no price rules.

5.3. FERC Orders 888, 889, and 2000

Orders 888 and 889 were made in 1996; Order 2000 occurred at the end of 1999 [20]. Order 888 required utilities to separate generation and transmission functions and provide non-discriminatory "open access" to their transmission facilities. Order 889 required procedures for sharing transmission system information (resulted in OASIS sites). Order 2000 encouraged transmission owners to create RTOs.

5.4. FERC Order 890

On Feb 16, 2007, FERC issued Order 890. Two requirements of this rule were [21]: (1) Transmission providers must participate in a coordinated, open and transparent planning process on both a local and regional level, and (2) Each transmission provider's planning process must meet FERC's nine planning principles: *coordination*, *openness*, *transparency*, *information exchange*, *comparability*, *dispute resolution*, *regional coordination*, *economic planning studies*, *and cost allocation*.

For example, in regard to openness and transparency, MISO publicizes its "Business Practice Manuals (BPM)" on the internet. In regard to most of the rest of these principles, MISO heavily and regularly engages with a group of "stakeholders." In the BPM on Transmission Planning [22], MISO identifies "stakeholders" as transmission owners, generation owners, load serving entities, transmission customers, other regional transmission operators (RTOs), and state regulators. They make the following statement in their planning BPM.

SPM: sub-regional planning meetings.
CEII: Critical Energy Infrastructure Information
BPM: Business practice manual

4.1 Stakeholder Interactions during Regional Planning Cycle

At each major step of the planning process, the MISO planning staff will engage stakeholders through the following planning groups and through various working groups, task forces and workshops that may be organized by these planning groups.

4.1.1 Subregional Planning Meetings

Subregional Planning Meetings (SPMs) are established under Attachment FF to the Tariff for the purpose of providing an interface to stakeholders on a more localized basis than the centralized stakeholder meetings of the Planning Subcommittee and the Planning Advisory Committee. SPMs are open stakeholder meetings subject to the CEII provisions under the Tariff and as described in *Section 2.7* of this BPM. At a minimum, one SPM will be established for each of the four planning regions established under Attachment FF (North, Central, East and South). The SPMs will occur at the times and for the purposes listed in *Table 4.1.1-1* below associated primarily with the bottom-up planning process described in *Section 4.3* of this BPM.

Purpose	Date	Location (Subject to change)
1. Provide additional input to MISO planning staff on stakeholder issues and needs. 2. Discuss pre-planning information and develop MTEP cycle study scope. 3. Review and provide input to planning models. 4. Review and discuss known issues proposed projects and solution ideas.	January	North, Central, East and South (locations to be announced)
Purpose	Date	Location (Subject to change)
1. Review system performance issue identified in initial phase analysis. 2. Discuss possible alternative solutions to issues.	March/April	North, Central, East and South (locations to be announced)
1. Review results of alternative analyses. 2. Comment on proposed preferred solutions.	June/July	North, Central, East and South (locations to be announced)

Figure 5-1 [23] illustrates stakeholder input into the MISO planning process.

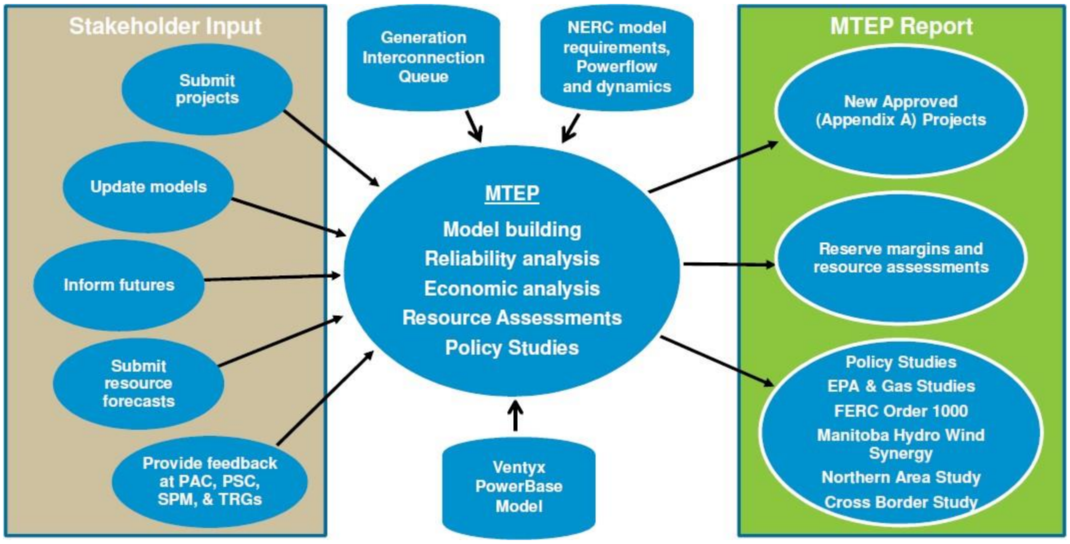


Figure 5-1: Stakeholder input in the MISO planning process

5.5. DOE-funded interconnection-wide planning

As part of the American Recovery & Reinvestment Act (responding to the 2008 recession), the US Department of Energy (DOE) funded interconnection-wide planning efforts, one in Eastern Interconnection, one in Western Electric Coordinating Council (WECC), and one in Electric Reliability Council of Texas (ERCOT). These three interconnections are shown in Figure 5-2.

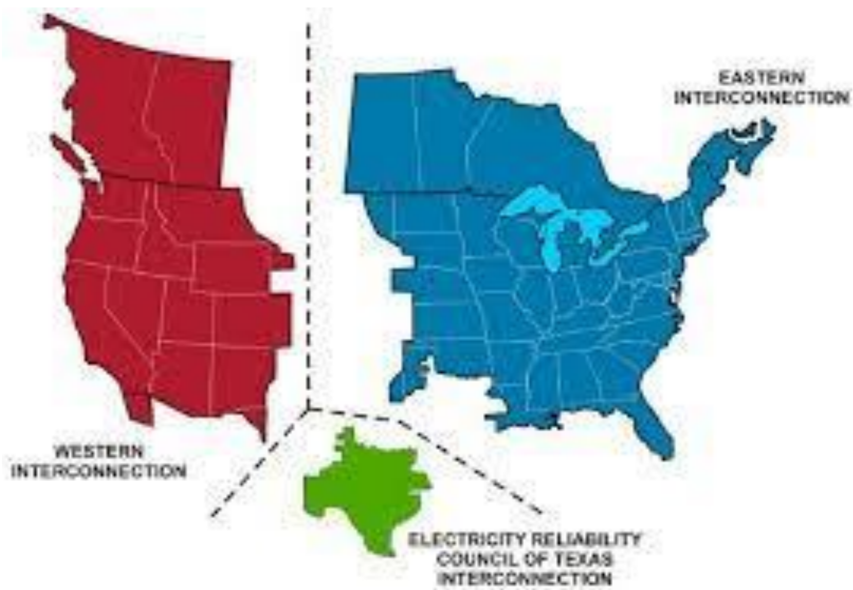


Figure 5-2: The three interconnections involving the contiguous US

WECC and ERCOT had previously performed interconnection-wide planning studies, but the Eastern Interconnection (EI) had not [24].

The EI effort under this initiative occurred under the guidance of sister organizations created for this purpose. A technical/engineering group was called the *Eastern Interconnection Planning Collaborative* (EIPC), while a policy group was called the *Eastern Interconnection States Planning Council* (EISPC). These two groups met separately but coordinated between themselves. They were active from 2010-2014 [25]. This effort was focused on interregional transmission planning. At one point in time, their website had the following:

First of its kind. EI planning authorities. Policy options.

Inter-connection wide. Policy options.

> "The EIPC represents a first-of-its-kind effort, to involve Planning Authorities in the Eastern Interconnection to model the impact on the grid of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders. This work will build upon, rather than replace, the current local and regional transmission planning processes developed by the Planning Authorities and associated regional stakeholder groups within the entire Eastern Interconnection. Those processes will be informed by the EIPC analysis efforts including the interconnection-wide review of the existing regional plans and development of transmission options associated with the various policy options."

The EIPC was a partnership between 27 transmission planning authorities in the Eastern U.S., as listed in Figure 5-3 along with several policy options studied [26]. NOTE: Ref [26] is very good reading!!!

Main EIPC-studied policy options:
1. Gas-dominated future
2. 30% (electric energy) national renewable
3. High nuclear
4. High carbon-price future
5. High demand-response future

- Alcoa Power Generating Inc.
- American Transmission Company
- Duke Energy Carolinas
- Duke Energy Florida
- Duke Energy Progress
- Electric Energy Inc.
- Entergy *
- LGE/KU (Louisville/Kentucky Utilities)
- Florida Power & Light
- Georgia Transmission Corporation
- IESO (Ontario, Canada) #
- International Transmission Company
- ISO-New England * #
- JEA (Jacksonville, Florida)
- MAPPCOR *
- Midcontinent ISO *
- Municipal Electric Authority of Georgia
- New York ISO * #
- PJM Interconnection * #
- PowerSouth Energy Cooperative
- South Carolina Electric & Gas
- Santee Cooper
- Southern Company *
- Southwest Power Pool
- Tennessee Valley Authority * #

*Principal Investigators for the DOE Project
#Participating Planning Authority for the DOE Gas-Electric System Interface Study

Figure 5-3: EIPC member transmission planning authorities

The EISPC represented all 39 states comprising the EI together with the District of Columbia, New Orleans and eight Canadian Provinces. One of the main motivators for the EIPC/EISPC effort was the need for performing technical and regulatory/policy analysis at the interconnection (rather than just regional) level. This was something addressed by FERC Order 1000, as described in the next section.

5.6. FERC Order 1000

One of the most far-reaching regulatory changes ever regarding electric transmission investment was issued July 21, 2011, by FERC in the form of Order-1000 [27] on planning and cost allocation for electric transmission facilities. It has four major components:

(i) *Interregional transmission planning requirements*: Each pair of neighboring transmission planning regions must share information and jointly evaluate attractive interregional transmission facilities (but no requirement to produce an actual plan for such facilities) [28].

(ii) *Transmission cost allocation:* It requires the cost of transmission solutions chosen to meet regional transmission needs to be allocated fairly to beneficiaries [28], stating that "the costs of transmission facilities must be allocated to those that benefit in a manner at least roughly commensurate with the estimated benefits received."

(iii) *Nonincumbent developer [elimination of the right of first refusal (ROFR)]*: It directed transmission providers to replace the ROFR tariffs with competitive processes by which non-incumbent transmission providers could be selected to develop an identified new regional transmission facility on a basis comparable to the incumbent [29].

(iv) *Regional transmission planning requirements*:

- From Order890, transmission providers must participate in a regional transmission planning process; from Order-1000, this process must consider transmission needs driven by public policy established by state or federal laws and evaluate solutions to those needs.
- Each region must produce a regional transmission plan reflecting solutions that meet the region's needs more efficiently or cost-effectively.
- Stakeholders must have opportunity to participate in identifying/evaluating solutions to regional needs.

6. Reliability-based vs. economic/value-based T-planning

Another attribute characterizing the planning category has come about as electricity markets have developed. This is the so-called planning paradigm. The traditional planning paradigm has been mainly reliability-focused, i.e., additional facilities would be planned and built to address violations of reliability criteria. These criteria are extensive, but they are succinctly captured by the so-called performance- disturbance table of NERC Standard TPL-004-1 provided in Table 1 [30]. Note the term in the last column "non-consequential load loss." This is defined as "non-Interruptible load loss other than consequential load loss and the response of voltage sensitive load including load that is disconnected from the system by end-user equipment" [31]. It might be easier to understand "consequential load loss," which is defined as "all load that is no longer served by the transmission system as a result of transmission facilities being removed from service by a protection system operation designed to isolate the fault." <u>More succinctly, consequential load loss is load that is isolated as a result of fault clearing. So a simpler definition of non-consequential load loss is any load loss not isolated as a result of fault clearing</u>.

Table 1: NERC Disturbance-Performance Table

Category	Initial Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/ A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following:				
		1. Generator				
		2. Transmission circuit				
		3. Transformer[5]	3ϕ	EHV, HV	No[9]	No[12]
		4. Shunt device[6]				
		5. Single pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus section fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal breaker fault[8] (non-bus-tie-breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal breaker fault (bus-tie breaker)	SLG	EHV, HV	Yes	Yes
P3 Multiple Contingency	Loss of generator unit followed by system adjustments[9]	Loss of one of the following:				
		1. Generator				
		2. Transmission circuit				
		3. Transformer[5]	3ϕ	EHV, HV	No[9]	No[12]
		4. Shunt device[6]				
		5. Single pole of a DC line	SLG			
P4 Multiple contingency (*Fault plus stuck breaker*[10])	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-bus-tie breaker) attempting to clear a fault on one of the following:		EHV	No[9]	No
				HV	Yes	Yes
		1. Generator				
		2. Transmission circuit	SLG			
		3. Transformer[5]				
		4. Shunt device[6]				
		5. Bus section				
		6. Loss of multiple elements caused by a stuck breaker[10] (bus-tie breaker) attempting to clear a fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple contingency (*Fault plus relay failure to operate*)	Normal System	Delayed fault clearing due to failure of non-redundant relay[13] protecting the faulted element to operate as designed, for one of the following:	SLG	EHV	No[9]	No
				HV	Yes	Yes
		1. Generator				
		2. Transmission circuit				
		3. Transformer[5]				
		4. Shunt device[6]				
		5. Bus section				
Category	Initial Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P6 Multiple contingency (*Two overlapping singles*)	Loss of one of the following followed by system adjustments.[9]	Loss one of the following:	3ϕ	EHV	No[9]	No
		1. Transmission circuit				
		2. Transformer[5]				
	1. Transmission circuit	3. Shunt device[6]				
	2. Tranformer[5]	4. Single pole of a DC line	SLG	HV	Yes	Yes
	3. Shunt device[6]					
	4. Single pole of a DC line					
P7 Multiple contingency (*Common structure*)	Normal System	Los of:	SLG	EHV, HV	Yes	Yes
		1. Any two adjacent (vertically or horizontally) circuits on common structure[11]				
		2. Loss of bipolar DC line				

Steady State and Stability Performance Extreme Events

Steady State and Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that protection systems and automatic controls are expected to disconnect for each contingency.

b. Simulate normal clearing unless otherwise specified.

Steady State

1. Loss of a single generator, transmission circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, transmission circuit, single pole of a different DC line, shunt device, or transformer forced out of service prior to system adjustments.
2. Local area events affecting the transmission system such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all transmission lines on a common right-of-way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large load or major load center.
3. Wide area events affecting the transmission system based on system topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber-attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to system adjustments.
2. Local or wide area events affecting the transmission system such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in delayed fault clearing.
   b. 3Ø fault on transmission circuit with stuck breaker[10] or a relay failure[13] resulting in delayed fault clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in delayed fault clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in delayed fault clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.

The most important planning tools for performing reliability-based planning are power flow simulators and time-domain (stability) simulators. On the other hand, the development of locational marginal price (LMP) electricity markets has created the need to identify investments that decrease production costs by an amount in excess of the investment cost. Important tools for making this assessment are the production simulator (or "production cost simulator") and investment planning models. This type of planning has been called economic planning, or value-based planning.

One may ask the following question:

➔To what extent is this objective different from that of a reliability-motivated plan?

To consider this question, consider some discussion from the 2007 MISO expansion plan report (MTEP-2007) [32] (bolding is added):

1.3 The Planning Context for MTEP 07

MTEP 07 is a transitional MTEP report. It isolates on those upgrades that are driven almost

Transition from reliability planning to economic (market-motivated) planning and to policy-related planning.

exclusively by peak load period transmission capacity needs to reliably serve load during those relatively few peak demand hours of the year. These are the traditional “must-do” projects needed to “keep the lights on”. While this infrastructure is essential for reliability, and will also provide for some level of improved efficiency of market operations, it is not designed using tools that comprehensively address maximizing total value of transm

Reliability planning is not sufficient.

investment, and energy costs. **As a consequence, the sum total of these expansions, while impressive in total investment terms, is likely not sufficient to provide for near optimal levels of investment.** However, the Midwest ISO approach to transmission planning is undergoing fundamental and significant changes. **These changes are a response to not only the Midwest ISO energy market, but to evolving energy policy related decisions at both the federal and state levels,** FERC initiatives to promote improved regionally coordinated planning, and developing structures for more equitable transmission pricing policies.

Despite functional disaggregation (unbundling), G&T planning must be coordinated!

• • •

Integration of Interconnection and Long-term Planning Processes

There is a natural and inseparable intertwining of planning for long-term load growth, and for interconnection of new generation. This is true despite the fact that as a consequence of the Open Access Order 888 in 1996, these two processes have been forced apart to accommodate the need to fairly interconnect independent suppliers. The separation of these processes was necessitated by the separate competitive supply positions, business objectives, and plans of the independent supplier and the integrated Transmission Provider at the outset of implementation of Order 888 and its follow-on Order 2000 addressing generator interconnections. **Melding together the independent decisions of a multitude of independent suppliers and load serving entities into a cohesive and efficient transmission infrastructure remains a puzzle that the industry continues trying to solve.**

We still don’t know how to coordinate G&T planning when they compete: competition & coordination don’t easily mix!

The Midwest ISO believes that the RTOs are uniquely positioned to reintroduce the cohesion in generation and transmission planning that has been stretched since the open access rule. We and our stakeholders have lived through the effects of this separation and experienced first hand the difficulty and frustration of trying to at once achieve fast, effective, and fair generator interconnections, while developing an efficient forward looking long-range transmission plan. These difficulties have been the result of some growing pains surely, but at the core we believe are the result of essentially adopting the pro-forma procedures enacted in Order 2000 to ensure fair and comparable interconnection service, and applying them to the high volume of interconnects the RTO must deal with. The advantage of the broader regional focus of the RTO is frustrated by the pro forma procedures, the sequential nature of which does not lend itself to any kind of efficiency of scope.

• • •

The $64,000 question!

The trick is to solve the open access sixty-four thousand dollar question: “where should I locate transmission and of what design, when I don’t know where, when or how much generation suppliers will bring on to the grid”. The answer comes by linking together the planning analyses that we have been pursuing, until recently, on somewhat separate tracks.

Long-term, high volume view is needed.

We have recognized that in order to develop efficient transmission expansions, a long term view is needed. There are efficiencies in developing facilities that can move higher volumes of electricity; with respect to right-of-way utilization and in facility costs per unit of power. These

Forecasting generation is difficult, but not doing it will raise costs due to (per-gen project) small incremental transmission fixes.

facilities take longer to permit and develop, and so require the longer view. A longer term view cannot be planned for without some assumptions about load and generation. Neither of these is particularly easy to predict, but of the two, load forecasting can be done with less error using traditional methods. **Forecasting where the generation may be, its size, operating characteristics and location is difficult and has a significant element of risk. However, this is a risk that must be accepted, unless we are willing to live with the costs that result from repeated increments of small upgrades to the transmission grid and the limitations that that process places on the ability to introduce new generation effectively.**

From [33] (written in 2005):

Economic transmission planning refers to transmission not needed for reliability but rather to enhance market efficiency (reach lower cost generation and reduce congestion).

Corresponding with Midwest ISO's efforts was **the increasing interest of FERC in transmission planning and expansion to not only protect reliability but also to enhance competition by building transmission to alleviate chronic transmission congestion and to access remote generating resources. Such economic transmission planning, called that because it refers to transmission not needed for reliability**, typically looks at scenarios such as the 10,000-MW Midwest ISO wind scenario and incorporates load flow and dispatch models to measure the reliability impacts and the costs and benefits of the proposed generation and transmission additions. In addition to Midwest ISO, the Southwest Power Pool, PJM, NYISO, and the RMATs process in the West are all carrying out various forms of economic transmission planning. Such economic transmission planning represents an opportunity to access remote wind resources, and for this reason, the wind industry is keenly interested in it. Yet economic transmission planning faces at least three challenges.
1) Economic transmission planning is viewed separately from transmission planning for reliability, yet the two may be intertwined, i.e., certain reliability fixes may be necessary in order for an economic transmission addition to move forward.
2) These economic transmission studies may not result in any action; market participants are asked, rather than required, as is the case with reliability studies, to contribute financially to support any identified transmission upgrades or expansion.
3) Related to the previous point, economic transmission planning studies are time, labor, and cost intensive, and efforts to keep them going may fail without some sign of success.

In the time frame 2008-2010, MISO began speaking of different transmission planning project categories; the first MTEP report referring to this project categorization was the 2010 MTEP report [34] which specified the different categories as follows:

- Generation interconnection project: This does what is necessary to interconnect a new generator to the grid;
- Baseline reliability project: This develops plans to correct a violation of NERC reliability criteria.
- Market efficiency project: This reduces market congestion and increases market efficiency.
- Multi-value project (MVP): Addresses energy policy needs and/or creates widespread benefits (for reliability and for market efficiency).

These categories, & 2 more (participant funded, transmission delivery service) are described in Table 2 below, taken from a 2013 report [35].

Table 2: MISO Transmission Planning Categories

Allocation Category	Driver(s)	Allocation to Beneficiaries
Participant Funded ("Other")	Transmission Owner identified project that does not qualify for other cost allocation mechanisms.	Paid by requestor (local zone)
Transmission Delivery Service Project	Transmission Service Request	Generally paid for by Transmission Customer; Transmission Owner can elect to roll-in into local zone rates
Generation Interconnection Project	Interconnection Request	Primarily paid for by requestor; 345 kV and above 10% postage stamp to load
Baseline Reliability Project	NERC Reliability Criteria	100% allocated to local Pricing Zone
Market Efficiency Project	Reduce market congestion when benefits are 1.25 times in excess of cost	Distributed to Local Resource Zones commensurate with expected benefit; 345 kV and above 20% postage stamp to load
Multi Value Project	Address energy policy laws and/or provide widespread benefits across footprint	100% postage stamp to load

This categorization also appears in the latest MISO BPM on planning [22] in the form of Table 3.

Table 3: Table of MISO project categories [22]

	Bottom-Up Projects	Top-Down Projects	Externally Driven Projects
Other Projects	X		
Baseline Reliability Projects	X		
Market Efficiency Projects		X	
Multi-Value Projects		X	
Generation Interconnection Projects			X
Transmission Delivery Service Projects			X
Market Participant Funded Projects			X

In the 2016 MTEP report [36], most transmission projects were either MVP or baseline reliability projects, per Figure 6-1. But in the 2020

MTEP report [37], there are no MVP projects; most are generator interconnection, baseline reliability, or "other," per Figure 6-2.

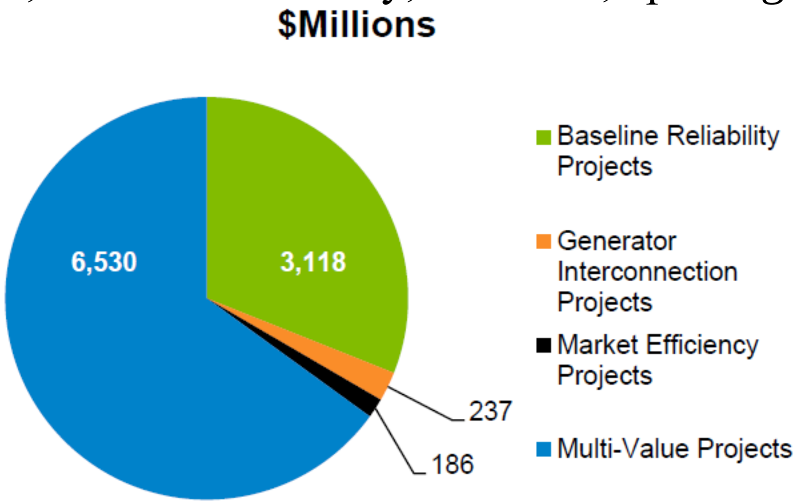


Figure 6-1: Cost allocation to MTEP2016 transmission project categories

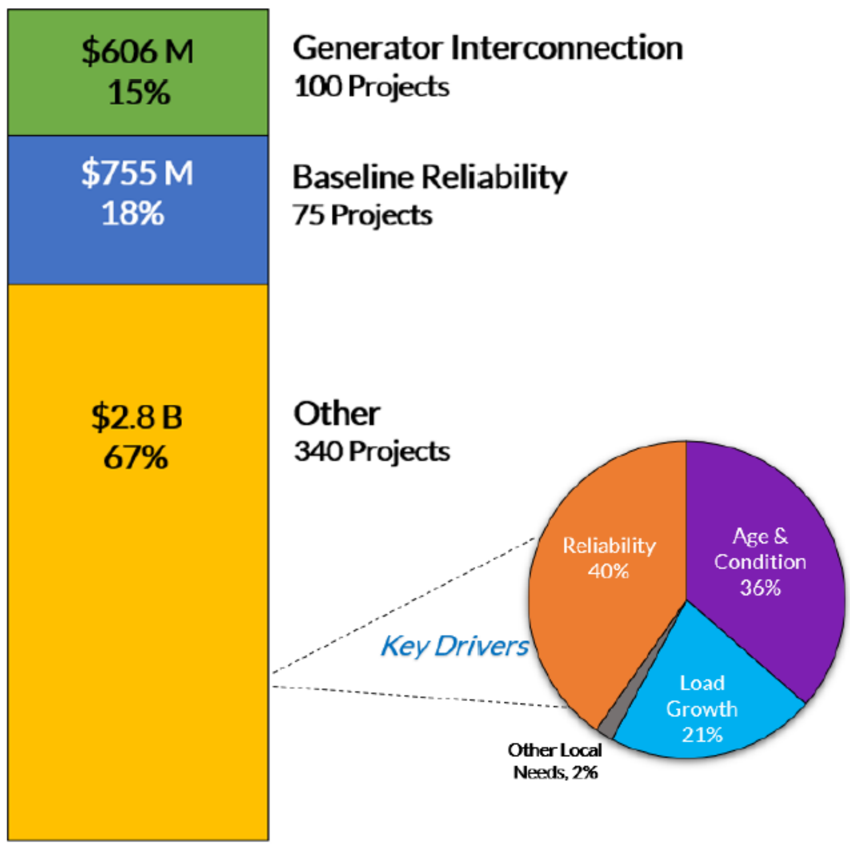


Figure 6-2: Cost allocation to MTEP2020 transmission project categories

The "other" category shown in Figure 6-2 is described in the MISO

MTEP report for 2020 [37] as follows:

> "Consistent with MTEP19, MTEP20 Other projects reflect significant asset replacement in the Central region that implement updated system designs in order to operate more efficiently and reliably. Updating systems from straight buses to ring buses and breaker and a half are a priority for safety and reliability."

The "Central region" mentioned above includes eastern Missouri, most of Illinois except the Chicago/metropolitan area, and Indiana. The question of why there were no market efficiency projects or MVPs can be answered by reviewing the MISO MTEP reports for 2017-2019.

7. RTO planning processes: regional/interregional planning

We have focused heavily on the transmission planning process implemented at MISO, which includes the following functions [37]:

- Model development
- Generator interconnection planning
- Transmission service planning
- Cyclical regional expansion planning activities
- Interregional coordination with neighboring transmission planning regions
- System Support Resource studies for unit suspension or retirement
- Transmission-to-Transmission interconnection
- Load interconnections
- Focus studies

The process in which MISO integrates these functions is summarized at a high level in Figure 7-1 [22].

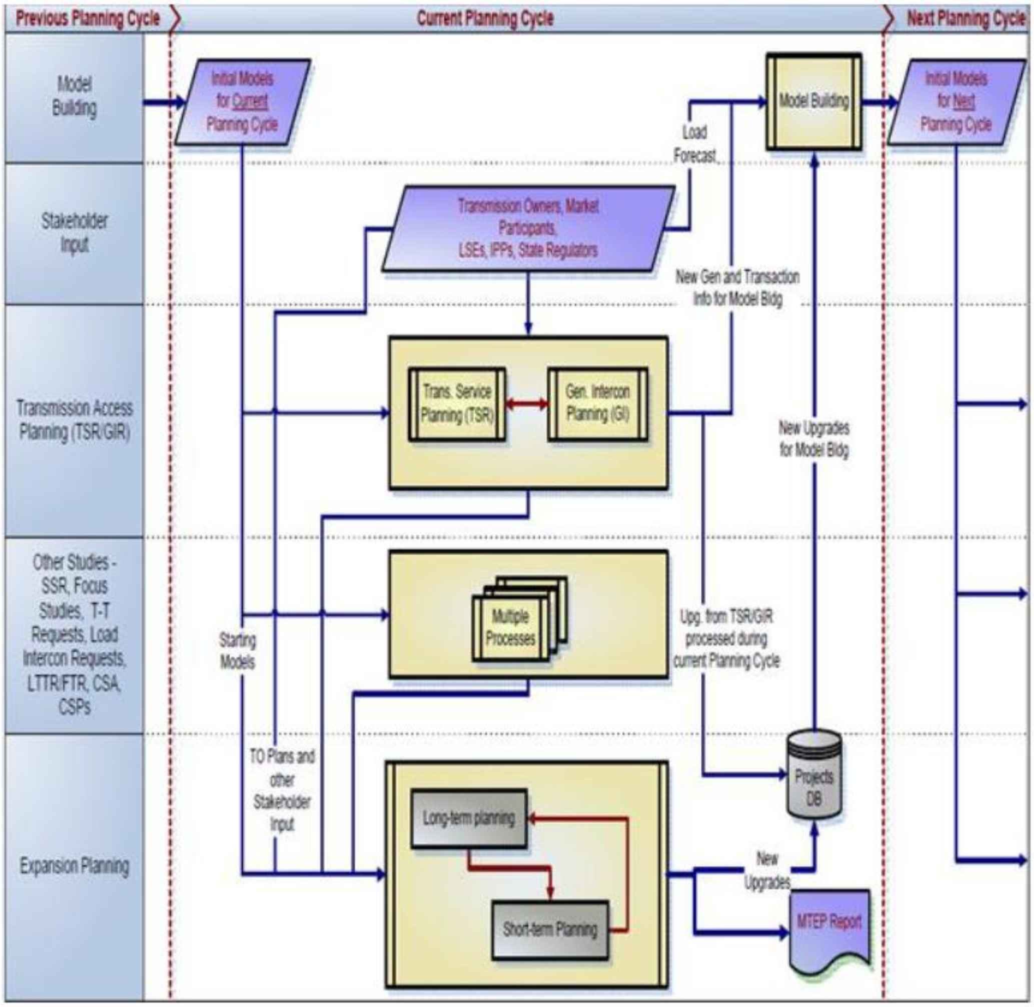


Figure 7-1: Summary of MISO's transmission planning process [22]

There are four comments to make related to Figure 7-1:

1. We consider the cycle shown as the one implemented in year *k*.
2. The model building for year *k*+1 begins in year *k*, and is subject to stakeholder input, as shown.
3. The long-term (10 year) planning occurs at the bottom, in the row called "expansion planning." It results in the year *k* MTEP report.
4. The middle row, called "Transmission access planning," focuses on point-to-point transmission access needs and generator interconnection studies. This row interfaces with the "Generator Interconnection Queue," where generator interconnection requests are stored and prioritized. All RTOs have a generator interconnection queue.

5. There are two planning functions not indicated in Figure 7-1:
    a. Capacity procurement function: This function ensures that there is enough capacity within the region to satisfy all hours of the year, driven by the annual peak demand. All RTOs have some kind of capacity procurement function, and some of them are implemented in the form of a capacity market. This function is typically driven by resource adequacy assessment.
    b. Long-range transmission planning (LRTP): This function has been under consideration at MISO for a while but was only formally added in 2020 [38] and is now in full-swing [39]. It provides a transmission road map of grid evolution that will be the foundation to drive future investment decisions. LRTP is needed to determine how transmission can help to ensure a reliable future system as the resource portfolio shifts. The need for LRTP is urgent, given the resource changes already happening, the speed of portfolio change desired by many of MISO's members, and the length of time it takes a transmission project to go from concept to reality. LRTP looks comprehensively at MISO's region and is very much a collaborative effort with stakeholders.
        - It addresses near-term needs as well as a longer 20-40 year horizon;
        - It is a regional approach for the overall footprint addressing both subregional and regional drivers;
        - It will consider interregional coordination to provide additional opportunities for system optimization.
        - It is divided into tranches. Tranche 1 was completed in July, 2022; it resulted in 18 different transmission projects totaling $10.3B, as indicated in Figure 7-2.

ID	DESCRIPTION	EXPECTED ISD	EST COST ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689
5	Tremval – Eau Claire – Jump River	6/1/2028	$505
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755
8	Beverly – Sub 92	12/31/2028	$231
9	Orient – Denny – Fairport	6/1/2030	$390
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769
11	Maywood – Meredosia	6/1/2028	$301
12	Madison – Ottumwa – Skunk River	6/1/2029	$673
13	Skunk River – Ipava	12/31/2029	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572
15	Sidney – Paxton East – Gilman South – Morrison Ditch	6/1/2029	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261
17	Hiple – Duck Lake	6/1/2030	$696
18	Oneida – Nelson Rd.	12/29/2029	$403
	TOTAL PROJECT PORTFOLIO COST		$10,324

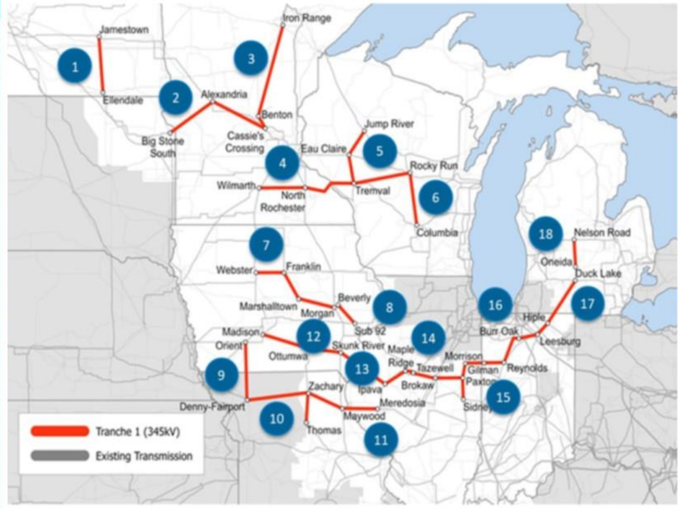


Figure 7-2: MISO LRTP Tranche 1 result

- MISO LRTP Tranche 2 is ongoing right now; tentative/early transmission concepts are identified in Figure 7-3.

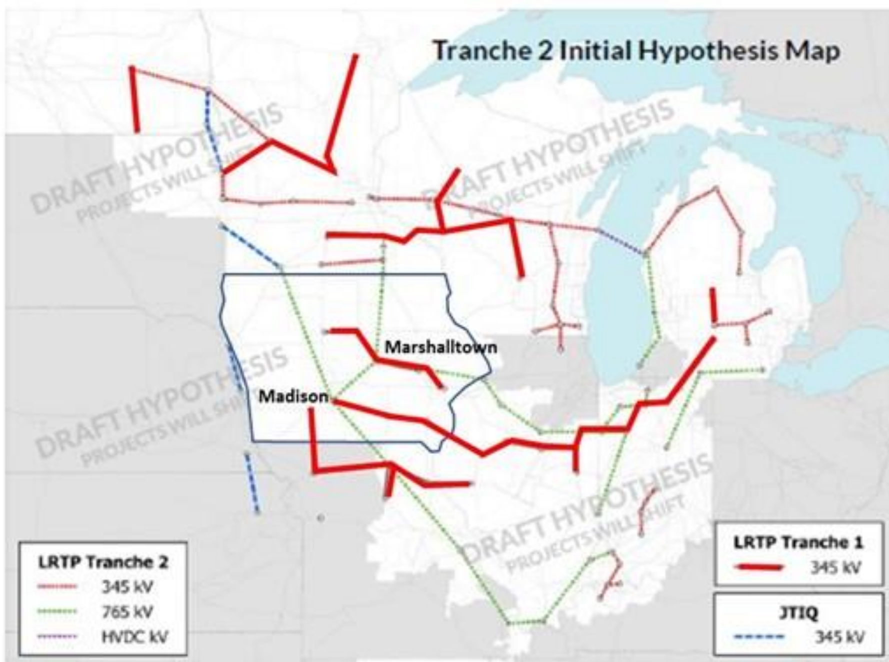


Figure 7-3: MISO LRTP Tranche 2 early results

- There is also a planned Tranche 3 and 4 [39] to focus on MISO's south region and the N-S interface, respectively.

There have been several previous large-scale regional and interregional transmission development efforts in the US, the most notable of which are as follows:

- The Pacific AC Intertie (PACI) and DC Intertie (PDCI), completed in 1970 [40], see Figure 7-4
- The AEP 765 kV transmission developments completed in 1972 [41], see Figure 7-5;
- The Texas Competitive Renewable Energy Zone (CREZ) initiative completed in 2013 [42], see Figure 7-6, about $6.9B;
- The MISO multi-value projects (MVP), completed in 2021 [43], see Figure 7-7, about $5.2B.

Figure 7-4: PACI and PDCI

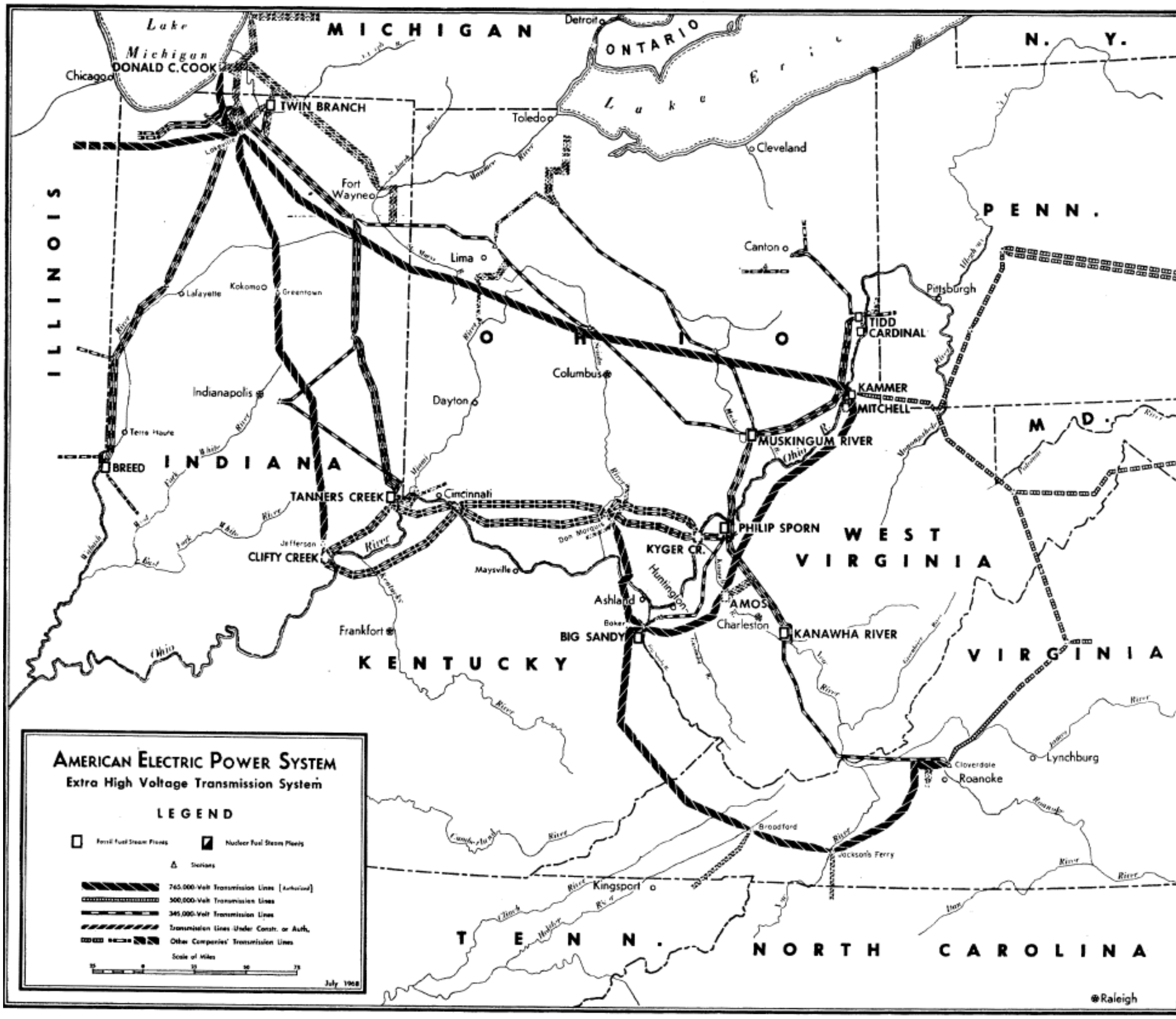


Figure 7-5: AEP 765 kV network, built in 1969-1972

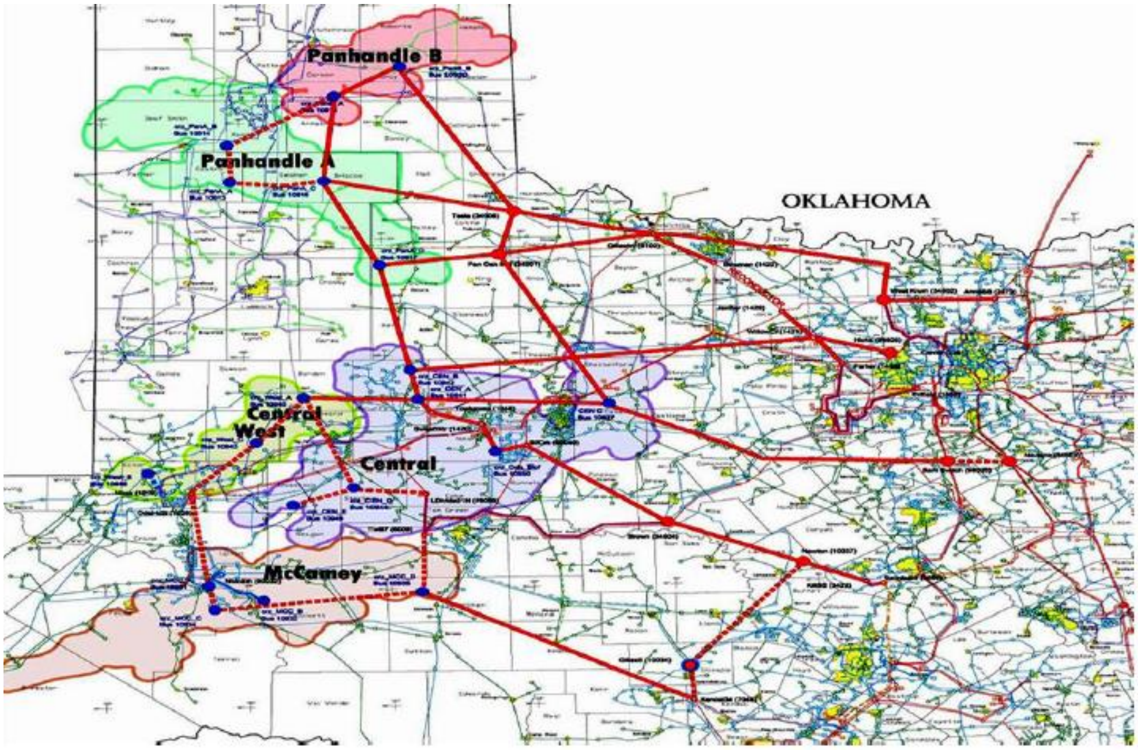


Figure 7-6: The 345 kV CREZ system

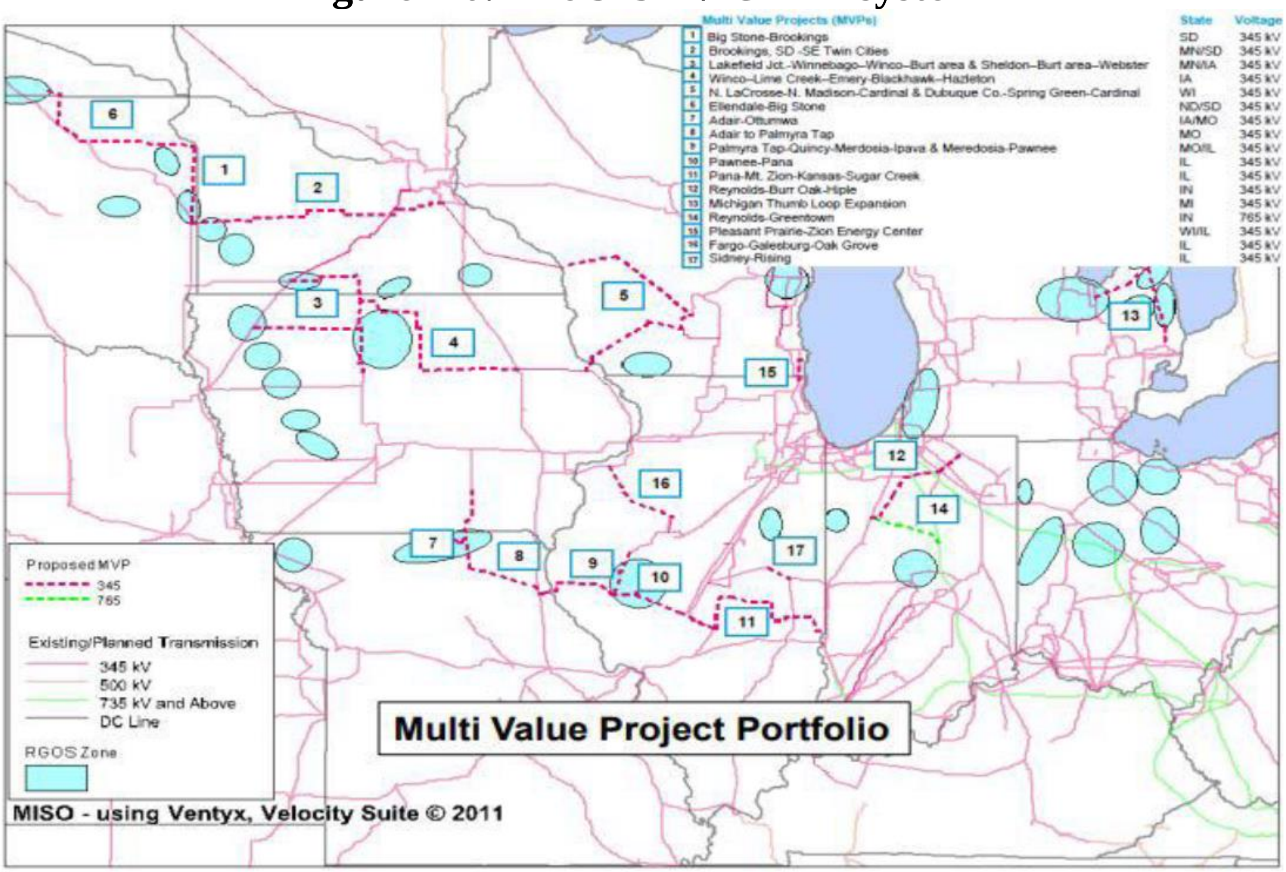


Figure 7-7: MISO MVP projects

8. Planning tools

We will not do justice in these notes to planning tools, but we do want to at least mention three that have become very increasingly important over the past few years:

- Production simulation
- Expansion planning
- Reliability evaluation (resource adequacy analysis)

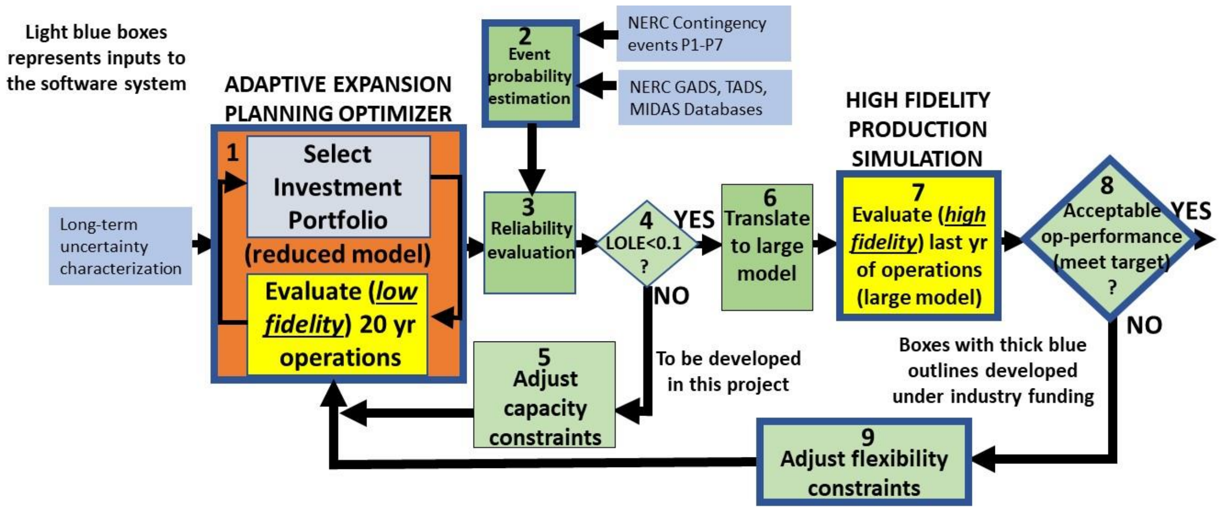


Figure 8-1: Planning flow using expansion planning, production simulation, and reliability (resource adequacy)

9. Planning at a national scale

Planning at a national scale has become of high interest over the past ten years, evolving to the concept of a *macrogrid*, which is a high-capacity interregional coast-to-coast transmission overlay with ability to move very large amounts of electric energy from any part of the nation to any other part of the nation. Figure 9-1 illustrates. The macrogrid concept, analogous to the interstate highway system developed with the congressional legislation of the 1956 Federal High Act, has received significant attention over the last ten years, starting with a DOE-sponsored project in 2012 [44]; a 2016-2017 project led by the National Renewable Energy Laboratory [45, 46]; a 2018 symposium at ISU [47] involving 140 participants from throughout the nation; two posted blogs sponsored by the Energy System Integration Group (ESIG) [48, 49]; a four-day workshop in December 2020 spanning two weeks convened by ESIG and involving over 70 experts; and an 80 page summary report [50] sponsored by the Americans for a Clean Energy Grid (ACEG) and the American Council on Renewable Energy (ACORE) under their Macrogrid Initiative [51]. Indeed, the Biden administration has had significant interest in the macrogrid, as it strongly speaks to infrastructure development, economic stimulus, and climate change, all of which are high on the Biden agenda [52, 53, 54, 55], and has continued to fund studies related to it [56]. An initiative comprised of a variety of stakeholders has been organized to pursue Macrogrid development [57].

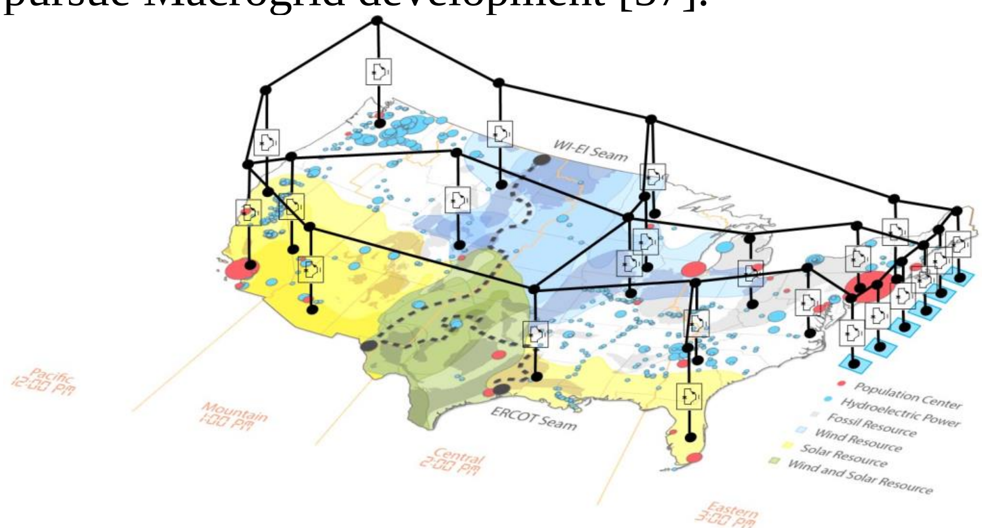


Figure 9-1: The macogrid design

10. Onshore vs offshore

A final comment here extends from observing in Figure 9-1 the presence of a transmission leg to facilitate access to offshore wind. Some comments pertaining to this follow:

- The cost of energy from offshore wind is significantly higher than the cost of energy from onshore wind.
- There is a very large offshore wind resource on the North American Atlantic seaboard, with waters that are generally not too deep.
- From a $/kw-hr basis, it may well be less expensive to supply eastern (and western) load centers with midwestern wind. However, building electric generation resources provides economic development (jobs!) that provide significant local benefits that also influence decision-making on this.
- The above macrogrid design facilitates both onshore wind in the Midwest and offshore wind in the Atlantic.

Several studies have been completed recently, including one led by NREL [58, 59], where several different offshore designs were developed, one of which, called the "backbone" design, is shown in Figure 10-1, which supports 85 GW of offshore wind capacity.

In another study performed by three universities [60], an offshore backbone transmission system was designed to support 100 GW of offshore wind capacity, as shown in Figure 10-2 and Figure 10-3. These latter two figures illustrate that the transmission design problem for offshore wind must not only develop an offshore transmission system but also must identify points of interconnection with the onshore transmission system, and in addition, must expand the onshore transmission system.

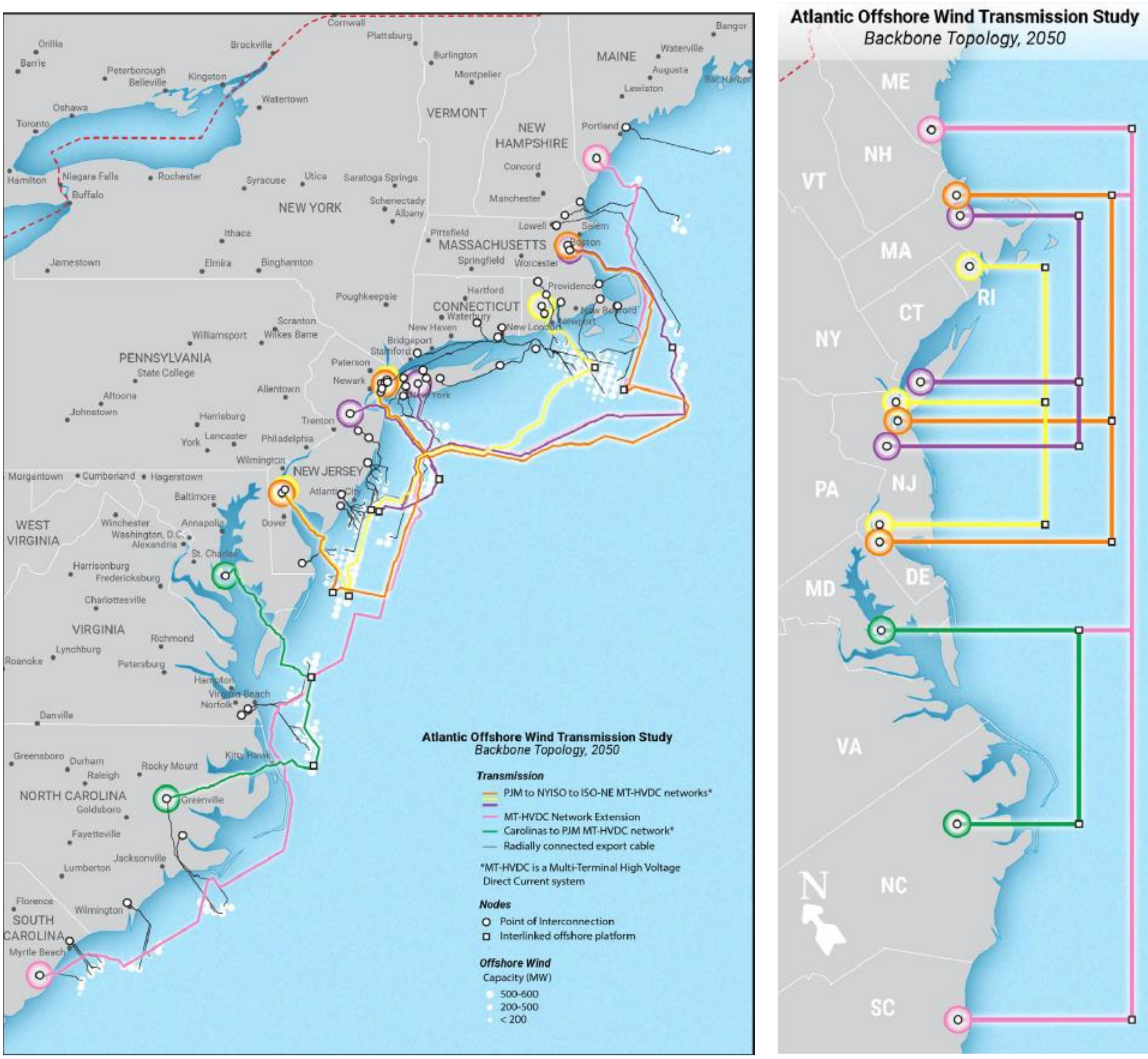


Figure 10-1: 85 GW backbone design: actual (left), topological (right)

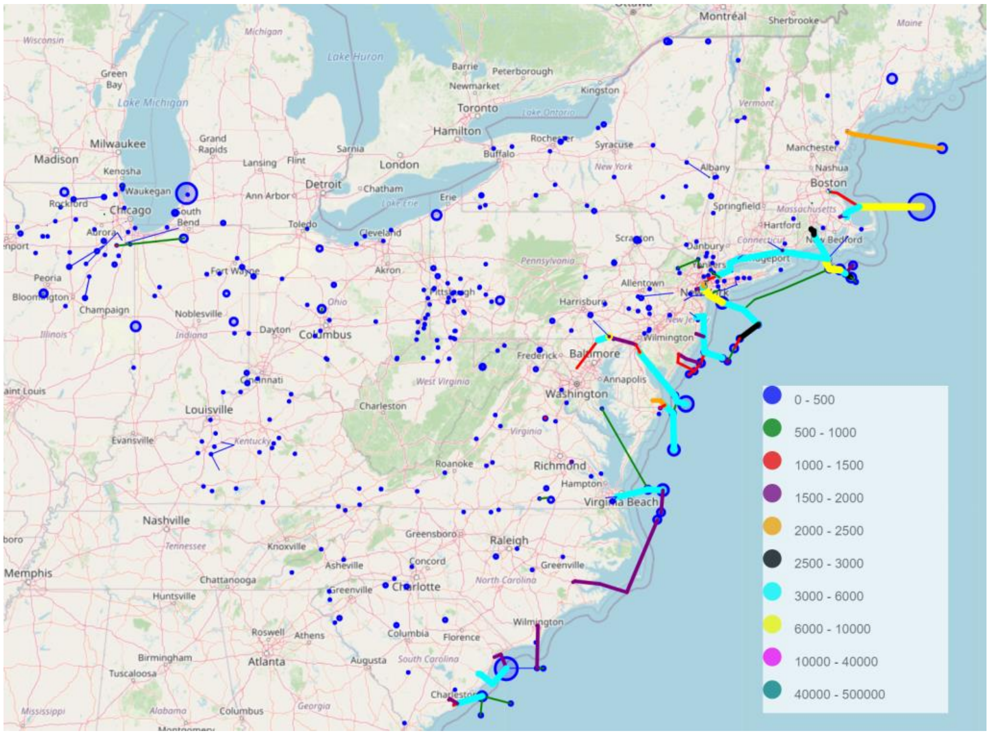


Figure 10-2: Onshore and offshore transmission investments for 100 GW offshore wind capacity

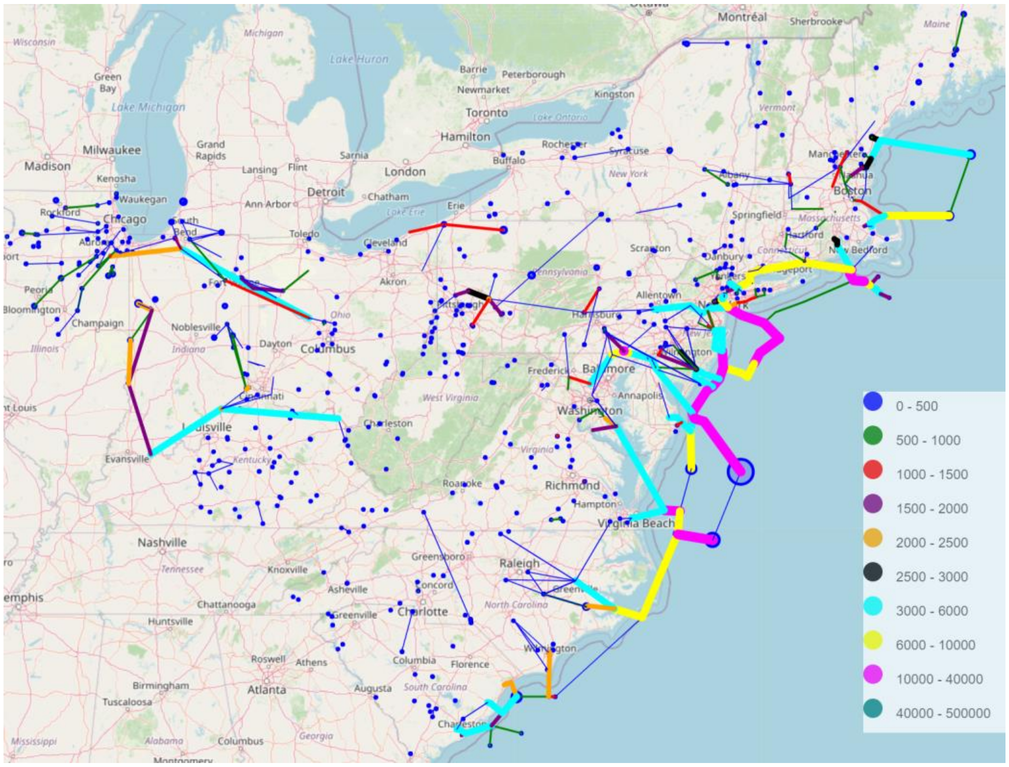


Figure 10-3: Onshore and offshore transmission investments for 200 GW offshore wind capacity

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