

NERC Reliability Functional Model Technical Document

Version 3

- Entity Responsibilities and Interrelationships
- Technical Discussions

This document is a companion to Version 3 of the Functional Model. It provides context, explanations, opinions, and discussions on various aspects of the Functional Model.

**Prepared by the
Functional Model Working Group**

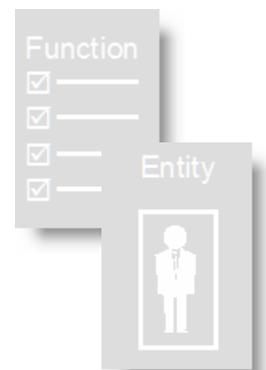


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Introduction

This document is intended as a companion to Version 3 of the Functional Model that will help the reader better understand the Model's Functions, Responsible Entities and their relationships. It is also intended to explain the changes made to Version 2 of the Model. This document therefore provides context, explanation and opinions. It is a companion to, rather than a formal part of, Version 3 of the Model.

Section 1 provides details about each of the Responsible Entities. Some entities, such as the Transmission Owner or Purchasing-Selling Entity, are adequately described in the Functional Model document, and there is little detail to add here. Others, such as the Interchange Authority and Balancing Authority, are more complex both unto themselves and in their relationship with other entities, and this document provides additional explanations.

Section 2 includes technical discussions on related topics and tasks such as managing bilateral transactions, task assignment and delegation, the planning functions, and boundary conditions. Many of these topics are mentioned in the Functional Model, but the details may not be obvious.

The discussion of Market Structures addresses the various types of markets and pools, and concludes that the Model is not dependent on any particular market structure or pool "depth."

There is also discussion of the concepts of a scheduling agent, as well as discussion of the relationship of the Market Operator and Balancing Authority, under both bid-based and cost-based dispatch of resources. In addition, certain concepts and conclusions from the report of the Functional Model Reliability Standards Coordination Task Force (FMRSCTF) are also discussed. This includes the implementation of the Reliability Coordinator and Interchange Coordinator entities in standards; Regional Reliability Plans, and Responsible Entity Areas and boundaries.

Section 1 – Entity Responsibilities and Interrelationships



1. Reliability Coordinator

The Reliability Coordinator's purview must be broad enough to enable it to calculate Interconnection Reliability Operating Limits, which will involve system and facility operating parameters beyond its own Area as well as within it. This is in contrast to the Transmission Operator, which also maintains reliability, but is directly concerned with system parameters within its own Area.

The Reliability Coordinator is the highest operating authority; the underlying premise is that reliability of a wide-area takes precedence over reliability of any single local area. Only the Reliability Coordinator is required to have the perspective/vision necessary to act in the interest of wide-area reliability.

The Reliability Coordinator also assists the Transmission Operator in relieving equipment or facility overloads through transmission loading relief measures if market-based dispatch procedures are not effective.

Role in Transactions. The Reliability Coordinator may deny Transactions with respect to transmission reliability and provides its denial to the Interchange Authority.

Day-ahead analysis. The Reliability Coordinator will receive the dispatch plans from the Balancing Authority on a day-ahead basis. The Reliability Coordinator will then analyze the dispatch from a transmission reliability perspective. If the Reliability Coordinator determines that the Balancing Authority's dispatch plans will jeopardize transmission reliability, the Reliability Coordinator will work with the Balancing Authority to determine where the dispatch plans need to be adjusted. The Reliability Coordinator obtains generation and transmission maintenance schedules from Generator Operators and Transmission Operators. The Reliability Coordinator can deny a transmission outage request if a transmission system reliability constraint would be violated.

The Transmission Operator is responsible for the reliability of its "local" transmission system in accordance with maintaining System Operating Limits (SOLs). However, in some circumstances, as noted above for reliability analysis associated with generation dispatch instructions, the Reliability Coordinator may become aware of a potential SOL violation and issue a dispatch adjustment. In this context the Reliability Coordinator therefore also has a limited role regarding the Transmission Operator's management of SOLs.

Emergency actions. The Reliability Coordinator is responsible for real-time system reliability, which includes calling for the following emergency actions:

- Curtailing Transactions
- Directing redispatch to alleviate congestion
- Mitigating energy and transmission emergencies
- Ensuring energy balance and Interconnection frequency, and
- Directing load shed.

The Reliability Coordinator, in collaboration with the Balancing Authority and Transmission Operator, can invoke public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.

System restoration actions. The Reliability Coordinator directs and coordinates system restoration with Transmission Operators and Balancing Authorities.

Authority to perform its reliability functions. The Reliability Coordinator's authority is documented in the Regional Reliability Plan issued by the Regional Reliability Organization for the Region in which the Reliability Coordinator Area resides. In cases where a Reliability Coordinator Area spreads over multiple Regions, its authority must be documented in and accepted by all the concerned Regions through their respective Regional Reliability Plans.

In addition, since the Reliability Coordinator may also have a role regarding the Transmission Operator's management of SOLs, delineation of its authority and that of the Transmission Operator needs to be clearly defined in the Regional Reliability Plan.

2. Planning Coordinator

The Planning Coordinator ensures a long-term (generally 1 year and beyond) plan is available for adequate resources and transmission within its Planning Coordinator Area.. That area encompasses a defined area and the customer demands therein. It may be smaller than, equal to, or larger than that of a Reliability Coordinator or a Regional Reliability Council.

In providing analyses and reports on the long-term resource and transmission plan(s) for the Planning Coordinator Area, the Planning Coordinator may also:

- Assess and publish system development trends (demands, transmission, and resources) within the Planning Coordinator Area in the time frame of generally one year and beyond, and
- Provide reports and data, as requested or required, to the Standards Developer, Compliance Monitor, Regional Councils, NERC, regulatory authorities, and governmental agencies.

Even when the transmission and resource plans developed by the Transmission Planners and Resource Planners comply with Reliability Standards, the Planning Coordinator will monitor the implementation of the transmission and resource plans, including the tracking of generating capacity, demand program, and transmission in-service dates. It will also evaluate the impact of revised transmission and generator in-service dates on transmission and resource adequacy.

In its evaluation of resource plans, the Planning Coordinator will likely review the conversion of various resource adequacy requirements and methodologies into equivalent resource capacity (or reserve) margins (or requirements) for use within the Planning Coordinator Area.

In some areas, there may exist more than one Planning Coordinator, each performing a different role demarcated primarily by the scale (area-wise) of assessment. In these cases, delineation of the role of the various Planning Coordinators needs to be clearly defined in the Regional Reliability Plan.

3. Balancing Authority

The Balancing Authority operates within the metered boundaries that establish the **Balancing Authority Area**. Every generator, transmission facility, and end-use customer must be in a Balancing Authority Area. The Balancing Authority’s mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and providing its frequency bias obligation. The load-resource balance is measured by the Balancing Authority’s Area Control Error (ACE) defined as:

See “Electrical and Physical Boundaries”

$$ACE = (I_A - I_S) - 10B(f_A - f_S)$$

Perfect balance occurs when $ACE = 0$; however, perfect balance requires perfect resource control, which is impossible. Therefore, NERC’s reliability standards require that the Balancing Authority maintain its ACE within acceptable limits.

Maintaining resource-demand balance within the Balancing Authority Area requires four types of resources management, all of which are the Balancing Authority’s responsibility:

- Frequency control through tie-line bias
- Regulation service deployment
- Load-following through generator dispatch
- Interchange implementation

Frequency control through tie-line bias. To maintain frequency within acceptable limits, the Balancing Authority controls resources within its Balancing Authority Area to provide its frequency bias obligation to the interconnection.

Regulation service deployment. To maintain its ACE within these acceptable limits, the Balancing Authority controls a set of generators within its Balancing Authority Area that is capable of providing regulation service.

See “Task Responsibilities and Delegation”

Load-following through generator dispatch. The organization that serves as the Balancing Authority will in general also perform the generator commitment and economic dispatch. Included in the commitment and dispatch tasks is the designation of those resources that are available for regulation service.

Interchange implementation. The Balancing Authority receives Interchange Schedules from one or more Interchange Authorities, and enters those Transactions into its energy management system.

Generation commitment and schedules from Load-Serving Entities. The Balancing Authority receives generation dispatch plans from the Market Operator and/or generator commitment and dispatch schedules from the Load-Serving Entities that have bilateral arrangements for generation within the market or the Balancing Authority Area. The Balancing Authority provides this commitment and dispatch schedule to the Reliability Coordinator.

Role in approving Transactions. The Balancing Authority approves bilateral Transactions with respect to the ramping requirements of the generation that must increase or decrease to implement those Transactions. The Balancing Authority provides its approval or denial to the Interchange Authority.

Energy Emergencies. In the event of an Energy Emergency, the Balancing Authority can implement public appeals, demand-side management programs, and, ultimately load shedding. Obviously, it must do this in concert with the Reliability Coordinator.

Failure to balance. The Balancing Authority must take action, either under its own initiative or direction by the Reliability Coordinator, if the Balancing Authority cannot comply with NERC's Reliability Standards regarding frequency control and Area Control Error.

See "Managing
Bilateral
Transactions"

4. Resource Planner

The Resource Planner develops a long-term (generally 1 year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Coordinator Area.

This Resource Planning function may be performed by one or more Resource Planners within the Planning Coordinator Area. The resource plans may include generation capacity from resources outside of the Planning Coordinator Area.

In some markets it may be required that the same entity be the Resource Planner as well as the Planning Coordinator. For example, the Resource Planner may also be the Planning Coordinator in those markets where there are no entities responsible or obligated to serve load. In these cases, the Planning Coordinator identifies the need for additional resources to be provided by the market.

In developing resource plans, the Resource Planner will also collect and develop related resource information for planning purposes from other entities, including:

- Demand and energy end-use customer forecasts from the Load-Serving Entities,
- Demand management data and programs,
- Generator unit performance characteristics and capabilities from Generator Owners and others, and
- Information on existing and proposed new capacity purchases and sales.

In developing and reporting its resource plans to the Planning Coordinator for assessment and compliance with reliability standards, the Resource Planner will be expected to:

- Identify those resources that may be considered firm resources (e.g., under contract, under construction, or environmental permits in place),
- Verify that resource plans meet adequacy resource requirements or identify resource deficiencies, and
- Work with the Planning Coordinator to identify potential alternative solutions to meet resource requirements should the resource plans be deficient.

In reporting on resource plan implementation to the Planning Coordinator, the Resource Planner should provide:

- The tracking of capacity and demand program in-service dates, and
- An evaluation of revised transmission and generation in-service dates on resource adequacy.

5. Transmission Operator

The Transmission Operator operates or directs the operation of transmission facilities, and is responsible for maintaining local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility. The Transmission Operator achieves this by operating the transmission system within its purview in a manner that maintains proper voltage profiles and System Operating Limits, and honors transmission equipment limits established by the Transmission Owner. The Transmission Operator is under the Reliability Coordinator's direction respecting wide-area reliability considerations, that is, considerations beyond those of the system and area for which the Transmission Operator has responsibility, that include the systems and areas of neighboring Reliability Coordinators. The Transmission Operator, in coordination with the Reliability Coordinator, can take action, such as implementing voltage reductions, to help mitigate an Energy Emergency, and can take action in system restoration.

Maintenance. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Operator must then develop the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provide those schedules to the Reliability Coordinator and others as needed.

The Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, who is ultimately responsible for maintaining its transmission facilities.

Bundled with the Reliability Coordinator or Transmission Owner

An organization may be a Transmission Operator without being a Reliability Coordinator or Transmission Owner. However, in many cases the Transmission Operator is bundled with one of these Responsible Entities.

Bundled with Reliability Coordinator. For example, consider an RTO with several members (Figure 1). The RTO registers with NERC as a Reliability Coordinator and Transmission Operator and is NERC-certified for both. The RTO then delegates some of the Transmission Operator Tasks as appropriate to its members. Regardless of this delegation, the RTO remains the entity responsible for complying with all Reliability Standards associated with the Reliability Coordinator and Transmission Operator, and would be NERC-certified for both.

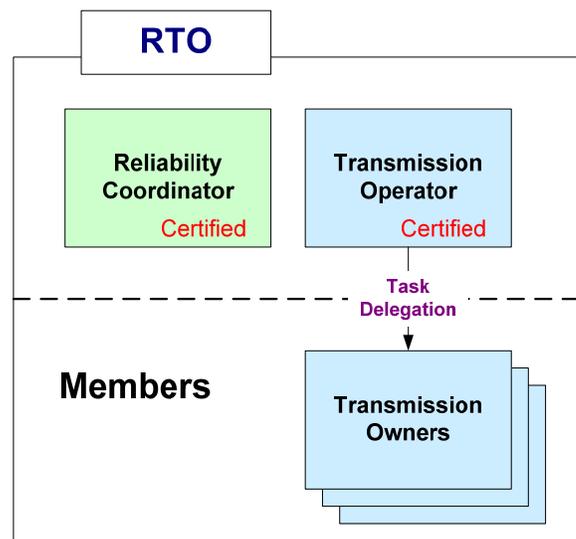


Figure 1 - Transmission Operator bundled with Reliability Coordinator.

Bundled with the Transmission Owner. In other situations, the RTO registers with NERC as the Reliability Coordinator, and its members register as Transmission Owners and Transmission Operators, as shown in Figure 2. In this case, the RTO is responsible for complying with all Reliability Standards associated

with the Reliability Coordinator and would be NERC-certified as such. The RTO members would be responsible for complying with all Reliability Standards associated with the Transmission Operator, and would be NERC-certified as such.

Large SCADA Centers (also known as Local Control Centers). The FMRSCF, in its report, noted the following concern:

“In several regions, RTOs have been initially designated as being responsible for a number of functions. A concern arises when operators of RTO member systems as large as 10,000 MW or more are not included on the list of responsible entities. The concern is that the chain of accountability for complying with reliability standards may be weakened in these instances. In contrast, entities in other regions operating systems of a few hundred MW are fully accountable for compliance with the standards.

“It may be the case that accountability is achieved through RTO agreements and protocols that members must follow to operate and plan reliable systems. However, this approach leaves some concern that accountability may be too remote for entities operating large transmission systems and that the benefits of reliability through “defense in depth” are undermined.

“As a mitigating measure, NERC and regional compliance programs should not be restricted from monitoring the larger SCADA centers as needed to verify compliance and including them in the readiness audits to help them strive for excellence in their reliability responsibilities. In the long term, there may be a need to develop criteria to ensure that the chain of accountability is strong and direct for all entities operating bulk electric system facilities.”

The FMWG shares the above concern, and also supports the suggested mitigating measure, which is compatible with the Functional Model. That is, NERC and Regional compliance programs would not be restricted from directly monitoring the larger Local Control Centers, as needed to verify compliance. Such audits have, in fact, already taken place. However, there would still be a single organization certified as Transmission Operator for given bulk electric assets, and this organization would be solely responsible to NERC for meeting the requirements specified in Reliability Standards.

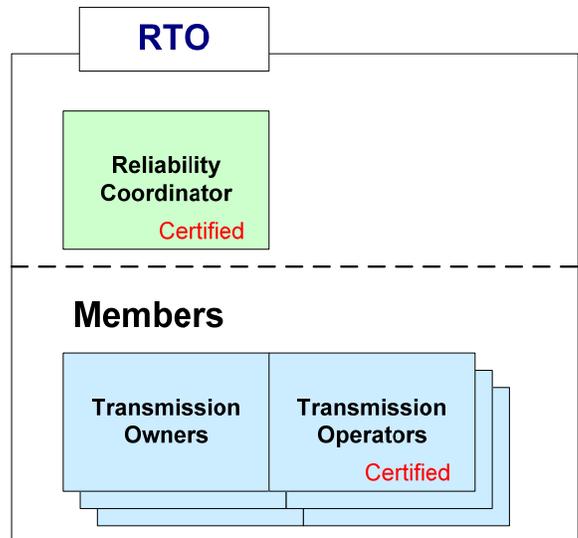


Figure 2 - Transmission Operator bundled with the Transmission Owner.

6. Interchange Authority

The Interchange Authority provides a service very similar to the Tag Authority that previously had been assigned to the Sink Balancing Authority. That is, it collects approvals or denials from Balancing Authorities, and Transmission Service Providers and verifies the validity of the source and sink.

The Interchange Authority provides the Balancing Authority with the individual bilateral Interchange Transactions. The Balancing Authority must track the individual Transactions in case one or more of them are curtailed by the Reliability Coordinator or by the Balancing Authority in those cases where a generator or load is interrupted. The Balancing Authorities then create a “net” interchange total for use in their energy management system as well as a “net” interchange for each neighboring Balancing Authority. The net Interchange Schedule for each neighboring Balancing Authority is used by the Receiving Balancing Authority for checkout with the neighboring Balancing Authorities.

All bilateral Transactions *that cross a Balancing Authority Area boundary* must be authorized by the Interchange Authority.

The Interchange Authority function is not needed to manage Bilateral Transactions that are internal to a Balancing Authority Area.

Assessing ramping capability and connectivity. The Balancing Authority (or Scheduling Agent, for those cases where the Transaction is between resource dispatch areas with multiple Balancing Authority Areas), approves/denies the capability to ramp the Transactions in or out and notifies the Interchange Authority. The connectivity of adjacent Balancing Authorities is also verified by the Balancing Authorities (or Scheduling Agent) before responding to the Interchange Authority.

Confirming transmission arrangements. The Transmission Service Provider is responsible for approving the Transaction by confirming to the Interchange Authority that there is a valid transmission service arrangement. During the authorization process, the Interchange Authority sends the “tag” to each Transmission Service Provider on the scheduling path. Thus, even if the Interchange Authority determines that the source and sink are “valid” generator and load busses, if the Transmission Service Provider, upon reviewing the “tag”, does not believe the source and sink information is equivalent to the source-sink information that was provided when the transmission service was arranged, can then inform the Interchange Authority that it (the TSP) does not approve the Transaction. The Transmission Service Provider must also ensure that there is a contiguous transmission path and that adjacent TSPs are on the scheduling path.

Ensuring balanced, valid Interchange Transactions. The Interchange Authority also ensures that the resulting Interchange Transactions are balanced and valid prior to physical delivery. This means:

- The source MW must be equal to the sink MW (plus losses if they are “self-provided”), and
- All reliability entities involved in the arranged Interchange are currently in the NERC registry.

Only when it receives approvals from the Transmission Service Providers, and Balancing Authorities does the Interchange Authority direct the Balancing Authorities to implement the Transaction. If either of these two – TSPs, or BAs – does not approve the Transaction, then the Interchange Authority cannot authorize the Transaction.

Curtailments. The Interchange Authority coordinates curtailments ordered by the Reliability Coordinator by notifying the Balancing Authorities, Transmission Service Providers, and Purchasing-Selling Entities. The Interchange Authority also communicates and coordinates the resulting modified Interchange Schedules that resulted from the curtailments.

7. Transmission Planner

In developing plans for transmission service and interconnection requests beyond one year, the Transmission Planner is expected to coordinate and jointly plan with other Transmission Planners, as appropriate, to ensure new facilities do not adversely affect the reliability of neighboring transmission systems.

In reporting its transmission expansion plan to the Planning Coordinator, the Transmission Planner is also expected to verify that its plans for new or reinforced facilities meet reliability standards or identify the transmission deficiencies. The Transmission Planner is to work with the Planning Coordinator to identify potential alternative solutions, including solutions proposed by stakeholders, to meet interconnected bulk electric system requirements.

The Transmission Planner, in connection with monitoring and reporting its transmission plan implementation to the Planning Coordinator, addresses:

- Transmission facility in-service dates
- Coordination with Transmission Operators on projects requiring transmission outages that can impact reliability and firm transactions, and
- The impact of revised transmission in-service dates on transmission and resource adequacy.

8. Transmission Service Provider

The Transmission Service Provider authorizes the use of the transmission system under its authority. In most cases, the organization serving as Transmission Service Provider is also the tariff or market rules administrator.

Role in approving Transactions. The Transmission Service Provider approves Interchange Transactions by comparing the transmission service previously arranged by the transmission customer (Purchasing-Selling Entity, Generator Owner, Load-Serving Entity) with the transmission information supplied by the Interchange Authority. The Transmission Service Provider then provides its approval or denial to the Interchange Authority.

See “Interchange Authority,” Section “Confirming transmission arrangements”

Providing Transmission Service. As its name implies, the Transmission Service Provider is responsible for providing transmission service to transmission customers, such as Generator Owners, Load-Serving Entities, and Purchasing-Selling Entities. The Transmission Service Provider determines Available Transfer Capability and coordinates ATC with other Transmission Service Providers. The Transmission Service Provider manages the requests for transmission service according to the Transmission Owner’s tariff, and within the operating reliability limits determined by the Reliability Coordinator. The Transmission Service Provider does not itself have a role in maintaining system reliability in real time — that is the Reliability Coordinator’s and Transmission Operator’s responsibility.

The Transmission Service Provider arranges for transmission loss compensation with the Balancing Authority.

9. Transmission Owner

The Transmission Owner owns and maintains its transmission facilities. It also specifies equipment operating limits, and supplies this information to the Transmission Operator, Reliability Coordinator, Transmission Planner, and Planning Coordinator.

In many cases, the Transmission Owner would have contracts or interconnection agreements with generators or other transmission customers that would detail the terms of the interconnection between the owner and customer.

Relationship with the Transmission Operator. The organization serving as Transmission Owner may also operate its transmission facilities and register with NERC as a Transmission Operator. In that case, it would also need to apply for organization certification as a Transmission Operator.

See "Transmission Operator," Section "Bundling with the Reliability Coordinator or Transmission Owner"

On the other hand, the Transmission Owner may arrange for another organization to operate its transmission facilities.

10. Distribution Provider

The Distribution Provider provides the physical connection between the end-use customers and the electric system. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.

The Distribution Provider is responsible for “local” safety and reliability. The Distribution Provider knows which customers are “critical” loads that should be shed only as a last resort, and provides the switches and reclosers for this emergency action. The Distribution Provider may need to demonstrate load-shedding capability to the Balancing Authority and Transmission Operator.

We may find the same organization serving as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well. Unlike the Load-Serving Entity, the Distribution Provider does not take title to any energy. However, in many cases an organization, such as a vertically integrated utility, may bundle these functions together.

11. Generator Operator

The Generator Owner may also operate its generating facilities or designate a separate organization to perform this Generator Operator service.

12. Generator Owner

The Generator Owner owns and maintains its generation facilities. It also specifies equipment operating limits, and supplies this information to the Generator Operator, Reliability Coordinator, Transmission Planner, and Planning Coordinator.

In many cases, the Generator Owner would have contracts or interconnection agreements with Transmission Owners that would detail the terms of the interconnection between these parties.

Relationship with the Generator Operator. The Generator Owner may also operate its generation facilities or arrange for another organization to operate those facilities.

13. Purchasing-Selling Entity

The Purchasing-Selling Entity (PSE) arranges for and takes title to energy that it secures from a resource for delivery to a Load-Serving Entity (LSE). The PSE also arranges for transmission service with the Transmission Service Provider(s) that connect the resource to the LSE.

The Purchasing-Selling Entity implements a bilateral Transaction between Balancing Authority Areas by submitting the Transaction information to the Interchange Authority.

14. Load-Serving Entity

The Load-Serving Entity (LSE) provides energy to its end-use customers, but does not include distribution services (“wires”).

The Load-Serving Entity will either own generation, contract with Generator Owners for capacity and energy to serve the LSE’s customers, or purchase capacity and energy from non-affiliated Generator Owners through a Purchasing-Selling Entity (or Market Operator), or a combination of these three options. The Load-Serving Entity is responsible for dispatching its affiliated generation resources to meet its load and has the “initial say” in that dispatch or redispatch.

The Load-Serving Entity will report its generation (affiliated and non-affiliated) arrangements to serve load to the Balancing Authority, which forwards this information to the Reliability Coordinator, sometime before the generation is actually dispatched, perhaps noon the day before for day-ahead analysis.

The LSE will also contract for reliability-related services (through the Market Operator if it is part of a market or pool) or directly from Generator Owners. The LSE may also provide certain reliability-related services itself.

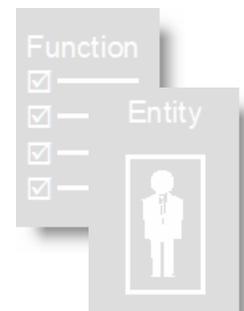
15. Compliance Monitor

NERC has overall responsibility for monitoring compliance with Reliability Standards, with Regions having the major role in the actual performance of the monitoring, under delegated authority from NERC.

16. Standards Developer

The Reliability Standards Developer is written to be NERC. The Reliability Standards referenced in the Model consist of standards developed by either NERC or a Region, that are approved by NERC. This would therefore not include Regional Criteria that are not submitted to NERC for approval.

Section 2 – Technical Discussions



1. Purpose and Guiding Principles of the Functional Model

The Functional Model breaks down the activities that must be done to maintain electric reliability by creating a set of Functions.

Each function consists of a set of Tasks so closely related to one another that separating those Tasks, by assigning them to different organizations, would threaten to impair the integrity of the Function.

The Model also defines the Responsible Entity for each Function and the specific relationships between that Responsible Entity and others.

An organization that is assigned responsibility for performing a Function must be responsible for each Task within that Function. For example, the Balancing Function includes generation commitment, dispatch, regulation, frequency response, and the integration of scheduled interchange. The entity responsible for maintaining the resource-demand balance within its metered boundaries, i.e., the Balancing Authority, is responsible for ensuring that all of these Tasks are performed.

An organization may delegate one or more of these Tasks to others, but it cannot delegate its responsibility. Allowing an entity to assign its responsibilities to others could result in uncertainty as to who is actually responsible for resource-demand balance, which, in turn, would make compliance enforcement difficult, if not impossible.

As noted a Function is assigned intact to an organization, because to do otherwise would threaten the integrity of the Function. This must be reconciled to the “real world” in which the tasks an organization performs may not completely align with the Tasks of a reliability Function under the Model. Moreover, the Model is clear that it does not impose structure on any organization to force alignment with the Model. The reconciliation is achieved in part through agreements between the organizations that together perform a Function’s tasks, describing the details of the sharing arrangement. Moreover, as discussed under Transmission Operator, NERC and Regional compliance programs and NERC organizational certification programs are not precluded from dealing directly with an organization such as a Local Control Center that may perform some of the Tasks but is not the Responsible Entity, where judged necessary to ensure effective compliance monitoring and certification.

The Model provides the framework on which the NERC Reliability Standards are based and enforced. That is:

- The Model defines each Function as the set of Tasks that are the responsibility of a Responsible Entity
- An organization registers to be the Responsible Entity for the performance of the Function and meeting applicable Reliability Standards
- NERC certification ensures that such an organization has the capability to perform the Function/Tasks and meet the standards requirements.
- A Reliability Standard details the specific reliability responsibilities and associates a Responsible Entity for each such requirement. The registered organization must meet all such requirements.

- NERC’s monitoring and compliance processes enforce these responsibilities in the standard by monitoring the registered organization.

Functions. The Functional Model differentiates between Functions and associated Responsible Entities. The diagram of the Model includes two names within each Function box as shown in Figure 4. The Function is shown in a larger typeface with the associated Responsible Entity underneath.

Responsible Entities.

Organizations, such as Regional Transmission Organizations, Regional Councils, and Transmission Operators, will register with NERC as Responsible Entities by identifying which Functions they perform.

For example, an RTO (organization) may register with NERC to be a Reliability Coordinator, Transmission Service Provider, Transmission Operator, and Transmission Planner. Thus we say that the RTO is the **Responsible Entity** for the Operating Reliability, Balancing, and Transmission Service Functions. We also use the expression that the RTO has “rolled up” these three Functions and is responsible for ensuring that the Tasks within each of those Functions are performed and all applicable standards requirements met (Figure 3).

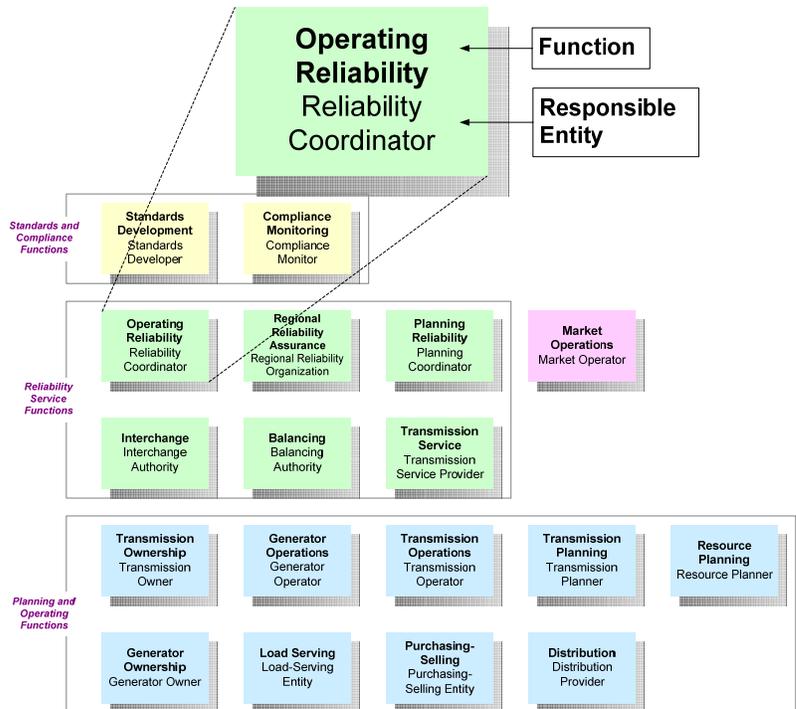


Figure 4 - The Functional Model depicts Functions and Responsible Entities

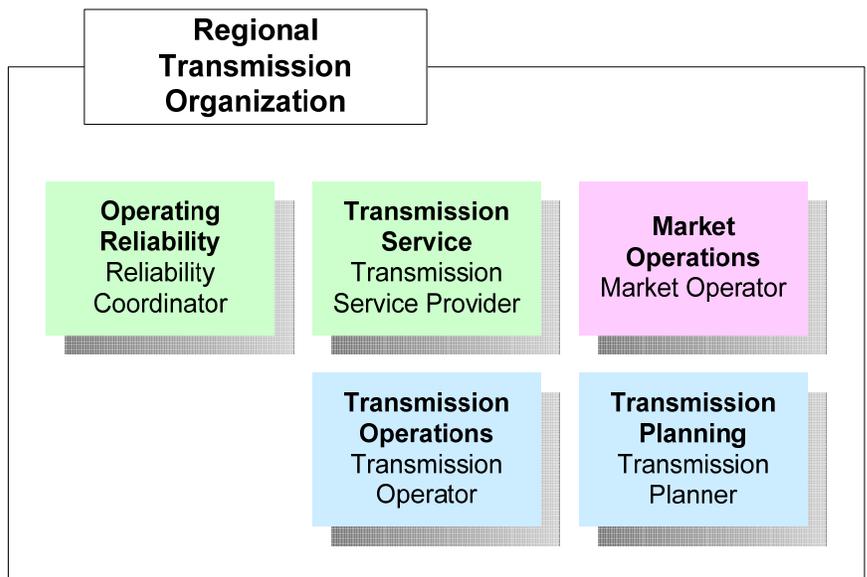


Figure 3 - Organizations are the entities responsible for performing the Functions they "roll up."

2. Reliability Standards

The Functional Model describes the Standard Development function and the Standards Developer responsible entity and how these are related to “reliability standards”.

A reliability standard defines certain obligations or requirements of entities that operate, plan, and use the bulk electric systems of North America.

Since reliability standards can be developed at the North American level as well as at the regional level (in some cases the regional level may be the same as an interconnection), there can be two levels of Standards Developer that can work separately or in conjunction with one another to develop a comprehensive reliability standard. Therefore the level of the Standards Developer and associated entity performing this work is a function of the make-up of the reliability standard

Reliability standards can be placed into one of three categories:

NERC Reliability Standards

NERC develops and maintains reliability standards using the NERC Reliability Standards Development Procedure. They are applicable across North America unless specifically stated within the standard and enable NERC and regional entities to measure the reliability performance.

NERC can use the Standards Development Procedure to approve a variance from a NERC Reliability Standard which is made part of the Standard. The three categories of variances are:

- Entity Variance that applies to an area less than a Region
- Regional Variance that applies to a Region but less than an Interconnection, and
- Regional Variance that applies to a Region on an Interconnection-wide basis.

Regional Reliability Standards Not Requiring Variances From NERC Reliability Standards

Regional entities may propose regional reliability standards that do not require variances from NERC reliability standards. In other words, the regional entity may:

- Set more stringent reliability requirements than the NERC reliability standard, or
- Cover matters not covered by an existing NERC reliability standard.

Regional entities must use a NERC-approved Regional Reliability Standards Development Procedure to develop these regional reliability standards. Such regional reliability standards must in all cases be approved by NERC and made part of the NERC reliability standards. As appropriate, NERC will process the regional reliability standard for approval as an:

- Interconnection-wide regional standard, or
- Non-Interconnection-wide regional standard.

Regional Reliability Standards that are directed by a NERC Reliability Standard

NERC may direct regional entities to develop regional reliability standards necessary to implement a NERC reliability standard. Such regional reliability standards that are developed pursuant to a direction by NERC shall be made part of the NERC reliability standards.

Regional entities must use a NERC-approved Regional Reliability Standards Development Procedure to develop these regional reliability standards.

As appropriate, NERC will process the regional reliability standard for approval as an:

- Interconnection-wide regional standard, or
- Non-Interconnection-wide regional standard.

Such standards require approval as a NERC reliability standard.

Note: Regions may develop other regional criteria, guides, procedures, agreements, etc.

Regional Criteria. Regions may develop regional criteria that are necessary to implement, to augment, or to comply with reliability standards, but which are not reliability standards. Regional criteria may also address issues not within the scope of reliability standards. These documents typically provide benefits by promoting more consistent implementation of the NERC reliability standards within the region. These documents are not NERC reliability standards, regional reliability standards, or regional variances.

3. Market Operations

The Market Operations Function is included in the Functional Model to provide an interface point between reliability and commercial functions. Market functions differ in design and responsibilities, depending on tasks delegated to the market.

The role of the Market Operator also varies in design and responsibilities, but all perform a resource integration task of one form or another under a set of market rules that are recognized by a state, federal, or provincial regulator.

The Market Operator in a Full-Service Market.

A full-service market is one which offers both the commercial services such as integrating resources ahead of real-time and settlement after completion of transactions and dispatch cycles, and implement the resource plan in real-time, making adjustment as necessary to meet other reliability requirements not envisaged during the resource integration process (for example, reliability constraints). In a full service market, the Market Operator tasks involve integrating resources in accordance with established market rules. Following its market rules and using available market mechanisms, the Market Operator integrates market resources by establishing a generation dispatch plan to meet the load forecast for the upcoming dispatch cycle (typically five minutes or longer). This generation dispatch plan is usually a function of:

- The generators' incremental bids ("merit order"). The established generation dispatch plan is submitted to the Balancing Authority for implementation.
- When the plan is tested for implementation, and limitations caused by transmission congestion are identified, the Balancing Authority will adjust the dispatch schedules accordingly. This constitutes a "security-constrained" dispatch.

Relationship between the Market Operator and Balancing Authority. In a full-service market, there is a close relationship between the Market Operator and the Authority Balancing. A full-service Market Operator performs resource integration tasks and is assigned the tasks of:

- Determining the generation dispatch plan (unit commitment) ahead of time,
- Integrating scheduled interchange into that generation plan,
- Designating which generators are available for regulation service, and
- Providing the generation dispatch plan to the Balancing Authority ahead of real time.

The Balancing Authority receives the plan, and implements it in real time.

In other markets, such as a traditional, vertically-integrated utility, the Balancing Authority is assigned all of the above tasks.

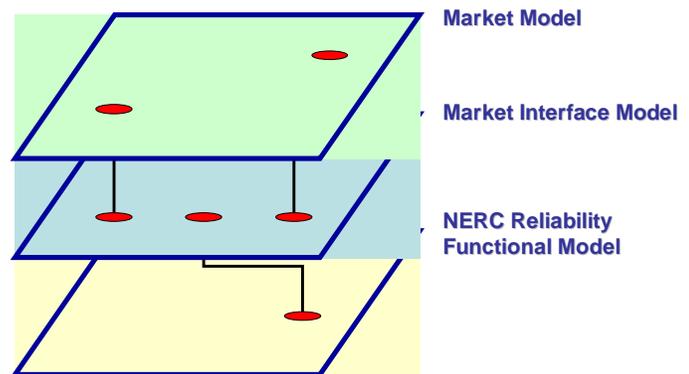


Figure 5 - Interface between market and reliability models

4. The Functional Model and Market Structures

This section explains how the Functional Model accommodates various market structures by examining these structures from the perspective of resource integration protocol.

Resource Integration Protocol. The resource integration protocol is defined herein as the method used to determine the merit order of the generation to be dispatched. Generally, resource integration protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority. The basis and the results for the resource integration algorithms for cost-based and bid-based dispatch are generally the same, which is why the Functional Model can accommodate either method.

Bid-based Resource Integration. In some areas of the U.S. and Canada, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will submit bids via the Generator Operators to the Market Operator. The market protocols are established by the regulatory authority, such as the Federal Energy Regulatory Commission. The Market Operator, in turn, provides the Balancing Authority with the generator dispatch plan so that the generators within the market footprint would be instructed to operate at the same incremental bid. Transmission constraints may cause the actual dispatch to deviate from the dispatch plan. Redispatch methods used to relieve the congestion may use direct resource assignments, may use area / zonal dispatch signals, or may use bus-signals. This zonal and bus methodologies are often referred to as “Locational-based Marginal Price,” or LMP.

Cost-based dispatch. Traditional, vertically-integrated utilities typically dispatch their resources based on actual fuel cost plus operations and maintenance costs and losses. The regulatory authority, such as the state public utility commission, might specify the accounting rules for calculating these costs. In this case, the “market” is cost-based, and the utility determines the resource plan according to the same incremental cost (“lambda”). Transmission constraints can cause the incremental costs to be different on either side of the constraint. Thus, the lambda can vary by location.

If the Market Area includes more than one Balancing Authority Area, then the Market Operator or resource integrator will also provide each Balancing Authority with the net “interchange” schedule that results from the resource plan (“Resource Dispatch Interchange Schedule”). Each Balancing Authority’s Resource Dispatch Interchange Schedule will be an import or export to the Balancing Area, and the sum of all Resource Dispatch Interchanges within the Market Area must add to zero at each dispatch cycle.

The table below describes how the current operating tasks are performed by both the vertically-integrated utility and the unbundled, full-service market operator.

Task	No Market – Vertically Integrated	Market – Unbundled
Unit Commitment	Utility (performing as the Generator Owner) decides which units to run.	Generator Owners decides which units to make available.
Economic Dispatch	<p>Utility (as resource integrator) performs economic dispatch calculation based on incremental costs or other requirements.</p> <p>Utility must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.</p>	<p>Market Operator collects bids from Generator Owners and develops integrated resource plans based on market rules (e.g., bids).</p> <p>Market Operator must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.</p>
Congestion Management	Results in different incremental costs (“lambdas”).	<p>Depending on the market structure, results in</p> <p>Different locational marginal prices (LMP), or</p> <p>Different marginal costs</p>
Regulation Service	<p>Utility (serving as the Balancing Authority, Load-Serving Entity, and Generator Owner) in concert with the Reliability Coordinator, determines the amount of regulation service required and designates those units that can be regulated to maintain ACE.</p> <p>Utility uses this information in its economic dispatch.</p>	<p>Balancing Authority, along with Reliability Coordinator, determines the amount of regulation service required.</p> <p>Generator Owners decide which units to bid in for regulation service.</p> <p>Market Operator runs bid pool for regulation service.</p> <p>Load-Serving Entity arranges for regulation services.</p>
Generator Control	<p>Utility (as Balancing Authority) pulses units that are designated by the resource integrator for regulation service.</p> <p>As regulating ability declines, the Balancing Authority asks the resource integrator for new dispatch plan.</p>	<p>Balancing Authority pulses units that are designated by the Market Operator for meeting energy and regulation service requirements.</p> <p>As regulating ability declines, the Balancing Authority asks the Market Operator for a new dispatch plan.</p>

5. Providing and Deploying Ancillary and Reliability-Related Services

Tariff Domain – Requirement for Ancillary Services. The FERC open access (pro forma) tariff requires the Transmission Provider to provide the following Ancillary Services to all customers taking basic transmission service (Figure 6):

1. Scheduling, system control, and dispatch
2. Reactive supply and voltage control from generation

And the FERC pro-forma tariff requires that the Transmission Provider offer to provide the following services to customers serving loads within the Transmission Provider's own area who do not purchase or self-provide:

3. Energy imbalance
4. Regulation and frequency response
5. Operating reserve – spinning
6. Operating reserve – supplemental

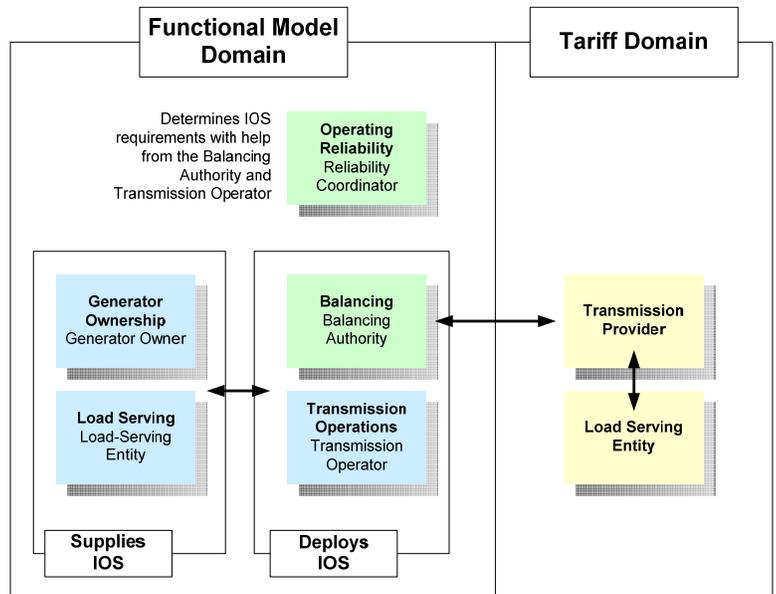


Figure 6 - Supply and Deployment of Ancillary Services and Reliability-Related Services.

Functional Model Domain – Reliability-related services. Version 2 of the Model used the term Interconnected Operations Services (IOS) to describe reliability services that may be considered building blocks of Ancillary Services. In Version 3 it is recognized that IOS as a defined term is not in use in reliability Standards, and hence it has been replaced by the term "reliability-related services" to mean those services other than the supply of energy that are physically provided by generators, transmitters and loads in order to maintain reliability

Reliability-related services include voltage control and reactive power resources from generators, transmitters and loads. Certain transmission facilities can provide reactive support but are not considered an Ancillary Service in the open access tariff, rather they are considered part of basic transmission service. In addition, loads may provide reserves through load-shedding or demand-side management, and may also provide frequency response.

Figure 7 shows how Ancillary Services in the “tariff domain” could be served by reliability-related services in the reliability domain or “Functional Model domain.” The Functional Model explains that the Balancing Authority, alone or in coordination with the Reliability Coordinator, determines the amount required and arranges for reliability-related services to ensure balance.

- The Balancing Authority determines regulation, load following, frequency response, and contingency reserves, etc., and deploys these as reliability-related services.
- The Transmission Operator determines the reliability-related services necessary to meet its reactive power requirements to maintain transmission voltage within operating limits, and deploys these as its set of reliability-related services.
- The Reliability Coordinator, working with the Transmission Operator, determines the need for Black Start capacity. The Transmission Operator cannot do this alone, because it may not have a wide enough picture of the transmission system.

Through its standards, NERC will hold Responsible Entities (the Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Service Providers) responsible to comply with every applicable standards requirement. The quantity of and processes used to deploy those reliability-related services depends on the Regional and local system characteristics of each entity, as well as on the Regional and local regulatory requirements.

NERC establishes Reliability Standards and related compliance measures. The Responsible Entities establish the quality and quantity of their own reliability-related services using processes and procedures that will ensure that they comply with the NERC standard.

Any or all of a Responsible Entity's reliability-related services may be delegated to a Market Operator to provide. A Market Operator is not subject to NERC standards – only a registered NERC functional entity is subject to NERC standards. The reliability-related services, the methods and the deployment used by Market Operators may vary from market to market, but the consequences of results will be imposed on the Responsible Entity using the respective Market Operator. A Delegation Agreement between the Responsible Entity and the Market Operator may allocate non-compliance penalties, but from the NERC perspective the Responsible Entity is held responsible for compliance.

6. Managing Bilateral Transactions – Basic Concepts

Interchange Transactions that cross multiple Balancing Authority (BA) Areas can be broken down daisy-chain fashion into individual Balancing Authority-to-Balancing Authority Interchange schedules, with the sink Balancing Authority designated as the “manager” (the “Tag Authority”).

Version 3 of the Functional Model recognizes this Interchange process as the current Industry practice and includes BA-to-BA “after hour” checkout for net Interchange between adjacent Balancing Authorities. Also, the Interchange Authority function “coordinates” and “communicates” Interchange Transactions (“deals”) that are ready for physical implementation between Balancing Authorities. The IA receives ramping capability confirmations rather than verifying it as prescribed in Version 2. The IA also communicates the Interchange transaction information to all involved parties (Figure 7).

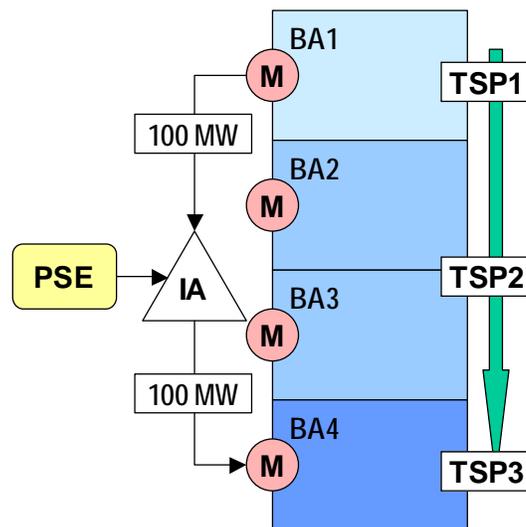


Figure 7 - The Interchange Authority manages transactions between the source and sink Balancing Authorities.

Managing Bilateral Transactions- Allowable Concept

Version 3 of the Functional Model does not prevent Balancing Authorities from scheduling Interchange with Interchange Authorities (IA). The IAs would ensure that the schedules are balanced (equal and opposite) between the Source and Sink BAs. In the example in Figure 8, the IA manages a transaction from BA1 to BA4. The schedule is

BA1 → IA → BA4

and the transmission service path is

TSP1 → TSP2 → TSP3.

The tables on the following page compare the Interchange checkout procedures that the Balancing Authorities use today with the procedures that the Balancing Authorities would use if this type of Interchange concept were applied.

Transactions within a Balancing Authority Area. A bilateral transaction within a Balancing Authority Area does not require Interchange Authority authorization. In the example in Figure 10, the Purchasing-Selling Entity submits the 100 MW Interchange Transaction to the Balancing Authority who will inform the Resource Dispatcher (or Market

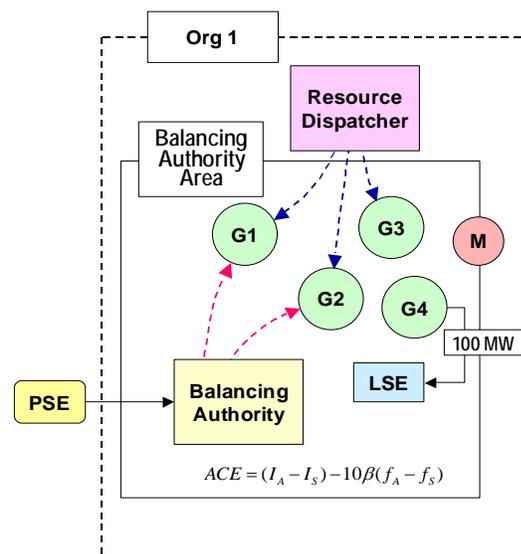
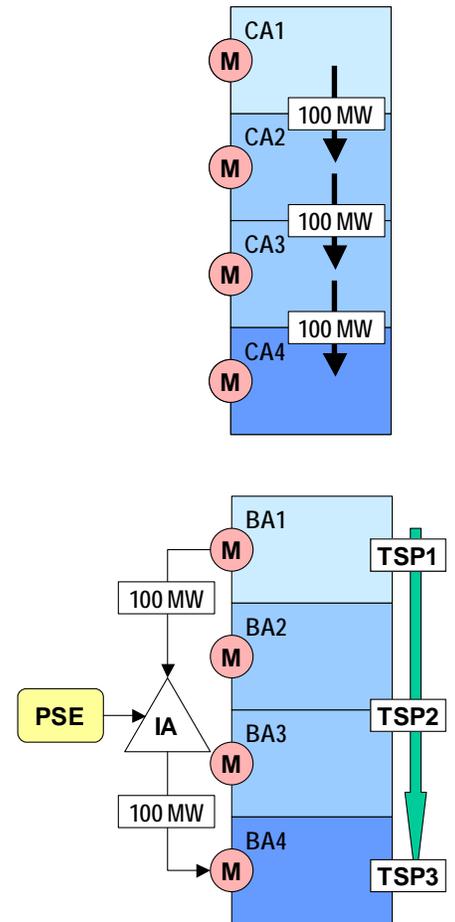


Figure 8 - The Purchasing-Selling Entity submits the bilateral transaction to the Balancing Authority for intra-BA transactions.

Operator) if the Resource Dispatcher needs to know which generators are committed to the Transaction, and to the Reliability Coordinator for reliability assessment.

Checkout under Existing NERC Practice			
Control Area	Actual from Tie Meters	Schedule with CA	Inadvertent
CA1	+100 to CA2	+100 to CA2	0
CA2	-100 from CA1 +100 to CA3	-100 from CA1 +100 to CA3	0
CA3	-100 from CA2 +100 to CA4	-100 from CA2 +100 to CA4	0
CA4	-100 from CA3	-100 from CA3	0

Potential Future Checkout			
Balancing Authority	Actual from Tie Meters	Schedule with IA	Inadvertent
BA1	+100 to BA2	+100 to IA	0
BA2	-100 from BA1 +100 to BA3	0	0
BA3	-100 from BA2 +100 to BA4	0	0
BA4	-100 from BA3	-100 from IA	0



7. Managing Bilateral Transactions – Scheduling Agents

Some Transmission Providers provide a Scheduling Agent service for their Balancing Authority members. The Scheduling Agent provides a single point of contact for all Interchange Schedules into or out of those Balancing Authorities. For example, the Southwest Power Pool serves as a Scheduling Agent for its members, and any Balancing Authority external to SPP will schedule to any SPP Balancing Authority by way of the SPP as the Scheduling Agent. This simplifies Interchange scheduling for parties both internal and external to SPP.

In the example in Figure 11, two Interchange Authorities schedule a total of 225 MW with the Scheduling Agent for a group of four Balancing Authorities as follows:

IS1 = 100 MW into BA1

IS3 = 50 MW into BA3

IS4 = 75 MW into BA4

IS2 = 0

The Scheduling Agent must ensure that the sum of the Interchange Schedules from all Interchange Authorities is exactly equal to the sum of the Interchange Schedules from the

Scheduling Agent to its Balancing Authorities:

$$ISA1 + ISA2 = IS1 + IS2 + IS3 + IS4$$

If the Balancing Authority(ies) use a Scheduling Agent, then the Interchange Authority will request ramp confirmation from the Scheduling Agent – not the Balancing Authority(ies) – during the Interchange Transactions authorization process. The Interchange Authority will also notify the Scheduling Agent of any Interchange Transaction curtailments.

Because Interchange scheduling is an integral function of the Balancing Authority, the Functional Model Working Group believes that the Scheduling Agent is actually an agent of the Balancing Authorities. The Balancing Authorities would still be the Responsible Entities for ensuring that the Interchange schedules from the Scheduling Agent were incorporated into the BAs' energy management systems. Some have argued that the Scheduling Agent would need to be certified and monitored to ensure that it handled the interchange schedules properly.

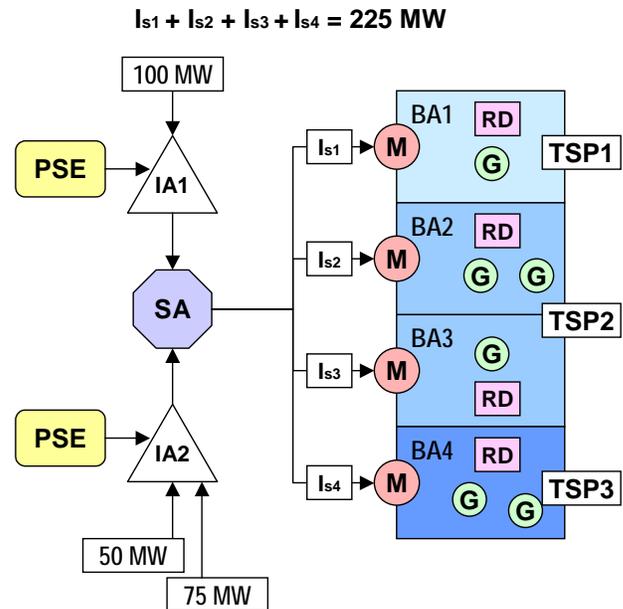


Figure 9 - The Scheduling Agent divides a 100 MW transaction among a group of Balancing Authorities.

8. Non-coincident Resource Dispatch and Balancing Authority Areas

Bilaterals between Resource Dispatch Areas. In the Balancing Authority Area was the same as the Resource Dispatch Area. When a Resource Dispatcher or Market Operator dispatches generation (either cost-based or bid-based) over several Balancing Authority Areas, we may be faced with a bilateral Transaction whose source or sink is the entire Resource Dispatch or Market Area, and can not be identified with any particular Balancing Authority within that area. In this situation, the Interchange Authority schedules with the Scheduling Agent for the Resource Dispatch Area. Then the Scheduling Agent, working with the Resource Dispatcher, will determine how the bilateral Transaction is allocated among the Balancing Authority Areas within the organization.

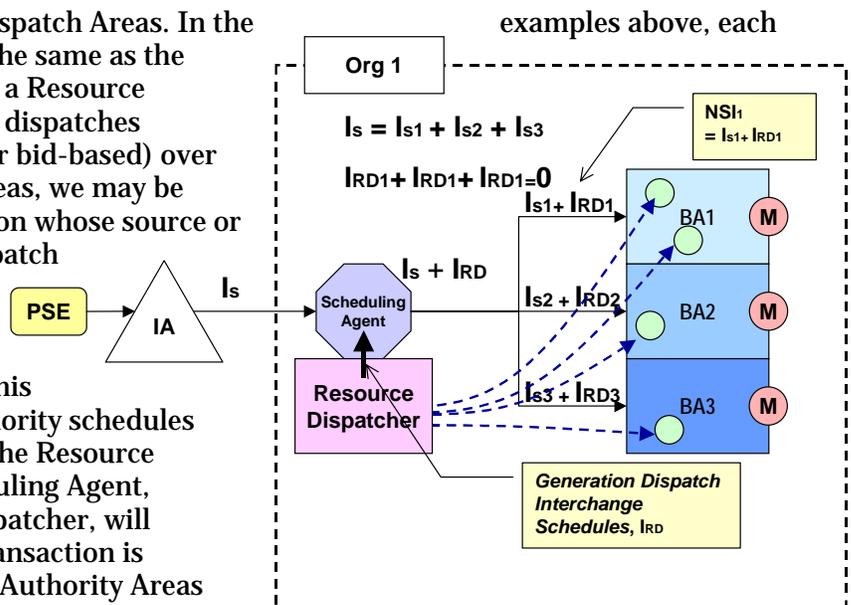


Figure 10 - The Scheduling Agent manages bilateral transactions in to or out of the Resource Dispatch Area as well as the Resource Dispatch Interchange Schedules that result from the economic dispatch or market operations.

As was explained in the technical discussion on Load Following and Regulation, the Scheduling Agent ensures that the RDIS are properly allocated to the Balancing Authorities. Now we can combine the Scheduling Agent's management of RDIS with bilateral transactions as shown in Figure 10.

Bilaterals between Balancing Authorities within the same Resource Dispatch Area. A bilateral Transaction between two Balancing Authorities within the same Resource Dispatch Area does not require Interchange Authority management because the Resource Dispatch Area is under a common tariff, and the Resource Dispatcher would have a close relationship with the Reliability Coordinator. In the example in Figure 11, the Purchasing-Selling Entity has submitted a 100 MW bilateral Transaction from BA1 to BA3 directly to the Scheduling Agent, who would then coordinate the transaction between the source and sink Balancing Authorities. The Scheduling Agent then submits the resulting interchange schedule to the Source and Sink Balancing Authorities, and inform the Resource Dispatcher if the Resource Dispatcher needs to know which generators are committed to the transaction.

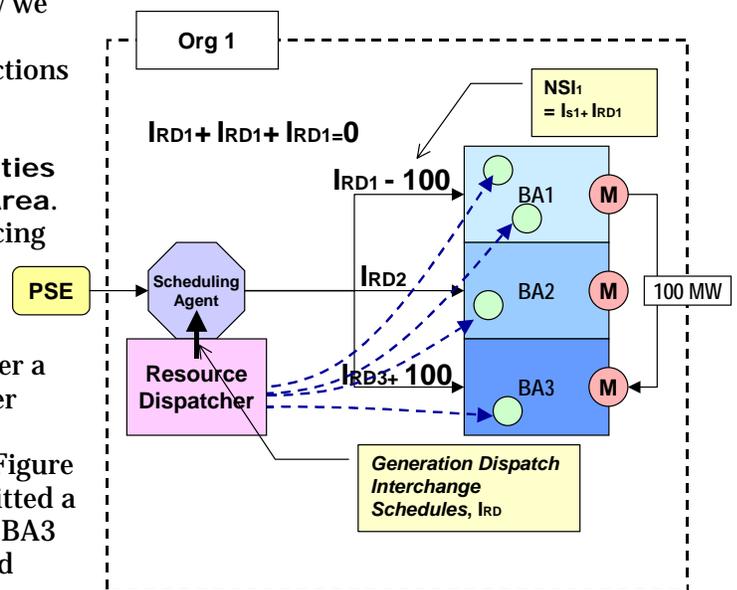


Figure 11 - The PSE submits its transaction information directly to the Scheduling Agent when the bilateral transaction is within the same Resources Dispatch Area.

9. Implementing the Interchange Authority Function

An important question for many within industry is “how do you implement the concept of an Interchange Authority (IA) so that it operates within the Functional Model”?

The initial step of the implementation requirements have been met with the NERC Board adoption of the Version 1 Interchange standards, which contain concepts and functions of the IA outlined in section 5.a. above. During NERC’s transformation to the “Electric Reliability Organization (ERO)”, organizations performing the Tag Authority functions will register as the Interchange Authority. The Electronic Tagging Function Specification assigns the Tag Authority requirements to the entity responsible for Balancing Authority operations (i.e., Sink BA).

To implement this concept, the Electronic Tagging Functional Specification (E-tag Spec.) will need revised to map the Tagging Service requirement from the Balancing Authority to the entity performing the Interchange function for the Sink Balancing Authority’s organization (still allows the Sink BA to use third party to fulfill the tasks of the requirements).

Additionally, NERC will need to update the Transmission Service Information Network (TSIN) registry and make E-tag modifications required to implement the IA.

If industry foresees a change is needed to the Interchange Authority function such that the duties of the IA would be performed on an interconnection-wide basis, NERC should consider a cost benefit analysis of the tool changes required to implement the expanded IA duties. Additionally, the modifications necessary to the E-tag Specification should be considered. The type of tool that has been discussed thus far for the implementation of an interconnection-wide IA include OASIS II and major modifications to OASIS 1A.

10. Task Assignment Options

Delegation

An organization, such as an RTO, can delegate Tasks to one or more organizations. In this example (Figure 12), the organization is the NERC-certified Transmission Operator, but has delegated some of the Transmission Operator Tasks to its members. In this situation, NERC would expect that the organization would be the Responsible Entity, and that its members are carrying out certain Tasks under that organization’s direction.

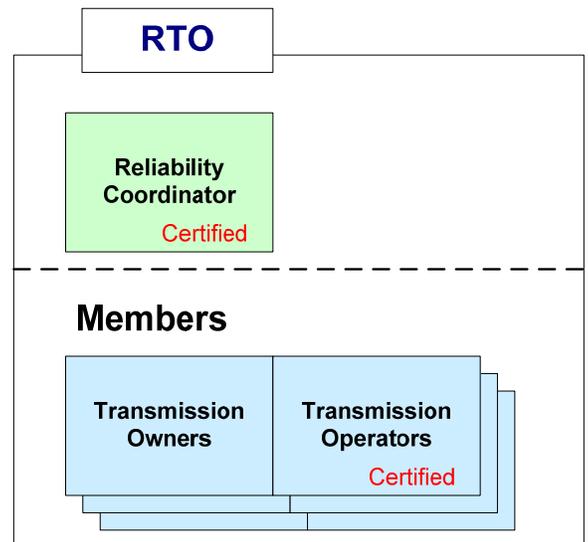


Figure 12 - In this example, Organization 1 has delegated certain Transmission Operations Tasks to its members. It retains the *responsibility* for ensuring those Tasks are performed.

Organization Pact

In the example shown in Figure 13, the two organizations have assumed the Tasks that must be performed by the Balancing Authority. One of these organizations (in this case, Organization 2) registers with NERC as the Balancing Authority, and from NERC’s perspective is the designated Responsible Entity responsible for compliance requirements and penalties. It would have an agreement with Organization 1 on how penalties would be assigned between these two organizations.

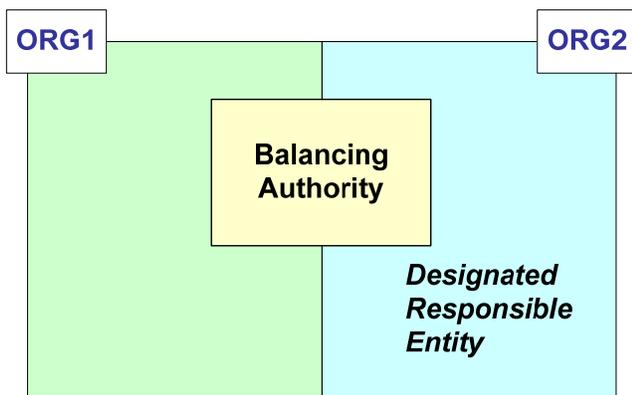


Figure 13 - An organization "pact" allows the Balancing Authority’s Tasks to be shared, but one of the organizations must register with NERC as the Balancing Authority (“Responsible Entity”) for that Function.

The certification audit team may have to visit both organizations to establish that each has the capability to perform its respective Tasks. Likewise it may be necessary for both organizations to be monitored.

This sharing of Tasks may also arise by statutory or regulatory authority. Therefore whether sharing of tasks arises by delegation, organization pact, or statutory or regulatory authority, the outcome is essentially the same. One organization is responsible to NERC for the performance of all tasks and meeting all standards requirements for the Responsible Entity. However, where judged necessary, the non-Responsible Entity will still be subject to NERC certification and compliance requirements.

11. Planning Functions

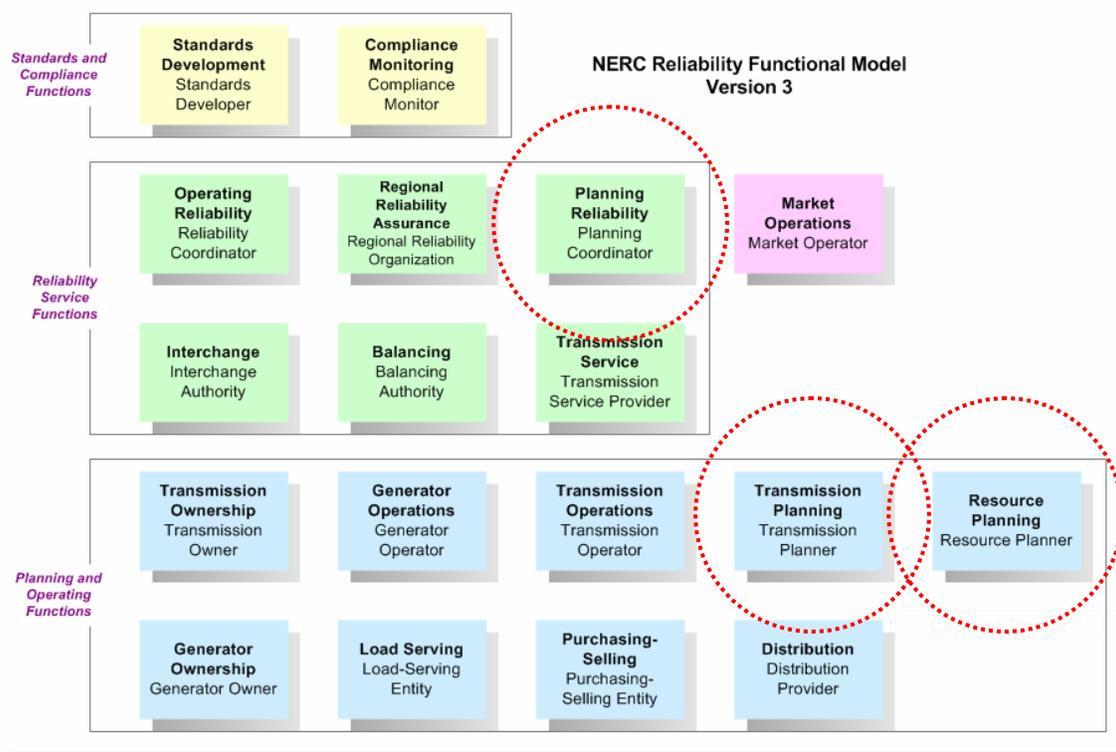


Figure 14 - Planning Functions.

Based on work of the NERC Planning Committee and its Planning Reliability Model Task Force (PRMTF), Version 2 of the NERC Functional Model was expanded to include the planning functions (Figure 14). The Operating Committee’s Control Area Criteria Task Force had previously developed the operational portion of the Functional Model (Version 1), which was approved by the NERC Board of Trustees in June 2001. Adding the planning functions completed the NERC Functional Model, and allows it to serve as the framework for the Reliability Standards that cover resource planning and transmission planning.

The PRMTF and Functional Model Review Task Group (FMRTG) added three planning functions to the model: Planning Reliability, Transmission Planning, and Resource Planning. The Planning Coordinator, who is the responsible entity for the Planning Reliability Function, resides at the “highest” planning level, with the Transmission Planners and Resource Planners within their respective Planning Coordinator Area reporting to the Planning Coordinator.

Planning Reliability Function

The Planning Coordinator, who is responsible for the Planning Reliability Function, integrates and assesses the plans from the Transmission Planners and Resource Planners within its Planning Coordinator Area to ensure that their plans comply with Reliability Standards and meet future needs, or develops and recommends revisions to plans that do not meet Reliability Standards or future needs. The Planning Coordinator also ensures that a long-term (generally one year and beyond) plan is available for adequate resources and

transmission within its Planning Coordinator Area. The Planning Coordinator is not responsible for implementing the transmission and resource plans. However, it helps to ensure that adequate resources and transmission facilities are placed into service in a timely manner through the Resource Planners, Transmission Planners, and possibly others through open solicitations for facilities.

Like the Resource Planners and Transmission Planners at the “local” level, the Planning Coordinator maintains system models and performs the necessary studies to evaluate whether the composite resource and transmission plans of its Resource Planners and Transmission Planners are in compliance with reliability standards.

Calculates transfer capabilities. The Planning Coordinator reviews the transmission transfer capability determined by Transmission Planners and also determines future (generally one year and beyond) transfer capabilities between and among the Transmission Planners and other Planning Coordinators based on the transmission and resource plans. These longer-term transfer capabilities are used in determining long-term ATCs and assessing requests for long-term transmission service. These values are provided to the Reliability Coordinator and Transmission Operator(s) for their use as a reference in developing operating limits.

Evaluates plans for customer requests. The Planning Coordinator evaluates responses for long-term (generally one year and beyond) transmission service requests developed by its Transmission Planners and provides the resulting plans to the Transmission Service Providers, Transmission Owners, and Transmission Customers. The Planning Coordinator also reports on system development trends for customer demand, transmission expansion, and resources within its Planning Coordinator Area. It also provides, as appropriate, plan assessments and reports to regulatory authorities and government agencies, and tracks capacity, demand programs, and transmission in-service dates. Finally, the Planning Coordinator evaluates the impact of revised generation and transmission in-service dates on the long-term reliability of the bulk transmission systems.

Resource Planning Function

The Resource Planners, who are the responsible entities for the Resource Planning Function, develop long-term (generally one year and beyond) resource adequacy plans necessary to supply specific customer demands within the Planning Coordinator Area. These plans can also be provided by the Load-Serving Entities or Generator Owners, or both, within the Planning Coordinator Area.

Develops resource plans. The Resource Planners maintain resource models to develop and evaluate resource plans in conjunction with Reliability Standards. These models also are coordinated with the Resource Planner’s related Planning Coordinator. The Resource Planners also identify areas of resource deficiency and provide potential alternative solutions to meet resource requirements.

The Resource Planners also evaluate, in conjunction with the Transmission Planners and Transmission Owners, the deliverability of the planned resources to the customer demands.

Provides resource plans to Planning Coordinator. The Resource Planners provide their resource plans to the Planning Coordinator for assessment and review for compliance with Reliability Standards. They also track capacity and demand program in-service dates,

and evaluate the impact of revised generation and transmission in-service dates on resource adequacy.

Transmission Planning Function

The Transmission Planners, who are the responsible entities for the Transmission Planning Function, provide long-term (generally 1 year and beyond) transmission plans for the areas under their purview, called the Transmission Planning Areas. A Transmission Planning Area may be smaller than or equal to the Area of its related Planning Coordinator. Every existing and proposed transmission line, or portion thereof, must be within the boundary of a Transmission Planning Area.

The Transmission Planners coordinate with other Transmission Planners to include the impacts of transmission plans on both on an intra- and inter-area basis. The Transmission Planners also maintain the system models and perform the necessary steady-state, dynamic, and short-circuit studies to ensure that their transmission plans meet Reliability Standards. These models are also coordinated with the Transmission Planner's related Planning Coordinator.

Evaluates customer requests for transmission service. The Transmission Planner evaluates long-term (typically longer than one year) requests for transmission service (as compared to the Transmission Service Provider who evaluates and provides transmission service for the shorter term (generally less than one year)), and identifies the facilities that will be needed to integrate new generation, transmission, and end-use customers into the bulk electric systems). Requests for transmission service will usually come from Transmission Owners, Generator Owners, Load-Serving Entities, and Transmission Service Providers.

Develops planning procedures and protocols. The Transmission Planners develop the planning procedures and protocols that are necessary to ensure that a reliable transmission system is developed within their respective Transmission Planning Areas. These procedures and protocols include specifications for transmission data, system protection and control and special protection systems as needed, and voltage and stability limits to meet reliability standards. They also coordinate these procedures and protocols with neighboring Transmission Planners and their related Planning Coordinator.

Develops transmission expansion plans. Based on customer requests for transmission service, the planning procedures and protocols established for their Transmission Planning Areas, plus the reliability standards, the Transmission Planners will develop transmission plans to accommodate long-term firm transmission service requests. While developing these plans, they may provide alternate solutions and evaluate alternatives suggested by the transmission customers.

Provides transmission plans to Planning Coordinator. The Transmission Planners provide their transmission plans for their respective Transmission Planning Areas to their Planning Coordinator for assessment and review for compliance with Reliability Standards.

12. Reliability Areas and Boundaries

Assets versus Geography as the Basis for Defining Areas and Boundaries

Under the Functional Model, it is useful for many of the Responsible Entities to specify an associated Area, which defines the portion of the bulk electric system that is applicable to an organization that becomes such a Responsible Entity. Moreover, by reviewing all of the Areas for a particular Responsible Entity, it is possible to establish whether there are overlapping responsibilities or gaps, which can then be eliminated. The concept of Areas and boundaries (the interfaces between adjacent Areas) is therefore important in establishing clear responsibilities for compliance with reliability standards.

The previous version of the Model (Version 2) referenced boundaries and Areas as being both physical (i.e., geographic) and electrical in nature. However, the FMRSCF, in reviewing the Model, concluded that the most logical building block for defining boundaries and Areas, and ultimately responsibility for compliance with reliability standards, is the individual bulk electric system asset. That is, the building blocks are the individual transmission, generation and customer equipment assets that collectively constitute the bulk electric system. Accordingly, the FMRSCF report recommended that assignment of Responsible Entities should be on the basis of particular bulk electric system assets, not geography.

This will enable any given bulk electric system asset to be associated with a single organization, with respect to the Responsible Entity for a given function. This will therefore provide the basis for clear assignment of responsibility for managing the potential reliability impacts of the asset.

The physical/geographic definition of Areas and boundaries corresponds to our intuitive understanding of these concepts. However, it becomes complex or impossible to apply in a situation where there are, for example, two Transmission Operators in a given geographic footprint, differentiated by the voltage level of the assets under their respective control. The use of bulk electric system assets as the basis for Areas/boundaries avoids this problem.

Boundaries for Operations and Planning

The Version 2 Technical Document examined boundary conditions and reached certain conclusions, including:

- Each Balancing Authority Area must be within an Reliability Coordinator Area
- There shouldn't be gaps or overlaps between adjacent Areas of the same type

The FMRSCF, by adopting a definition of Area based on electric assets, has removed the need for some of the conclusions reached in the Version 2 Technical Document. More fundamentally, the FMRSCF concluded in effect that boundary conditions are intrinsic to effective standards, and therefore any specification of boundary conditions should arise in the standards development process, i.e., in response to a perceived reliability need, not in response to the needs of the Model. Specifically, the FMRSCF report stated:

Mandatory boundary constraints between responsible entities should be set at the minimum threshold necessary for the reliability of the interconnections. Otherwise there should be no

restrictions on boundary conditions between responsible entities. These criteria should be set through an open process and adopted into organization certification standards.

This is the recommended approach of Version 3. It does not refute the broad and intuitively reasonable conclusions on matters such as the need to avoid gaps and overlaps, but leaves this as a matter to be addressed in the Reliability Standards, not the Model.

Boundaries for Operations

NERC requires that every generator, load (customer), and transmission facility be within an area having a metered boundary. This ensures that within the area:

- All resources are balanced with demand, including transmission system losses, and
- All transmission facilities are operated within their operating limits.

The Functional Model groups the reliability Tasks into Functions, but we must still ensure that all generation, load, and transmission facilities be physically located within certain boundaries to ensure generation-load balance and reliable transmission operations. NERC will need to incorporate these boundary conditions into its Reliability Standards.

Boundary Conditions for Transmission Reliability

The boundary conditions for transmission reliability deal with generators, transmission facilities, and customers.

- The Reliability Area must include all transmission facilities within the Area's metered boundaries, and all load and generation physically connected to those transmission facilities.
 - The transmission facilities within the Reliability Area are defined as those within the transmission metered boundaries of the Balancing Authority Areas under the Reliability Coordinator's purview.
 - The Reliability Area will therefore include all load and generation physically connected to those transmission facilities.

Boundary Conditions for Balancing

The boundary conditions for balancing deal with where generators and customers are defined in terms of electric assets, not geographic location.

- Every generator must be metered into a Balancing Authority Area.
- Every load (customer) must be metered into a Balancing Authority Area.
- Every transmission facility must be within the metered boundary of a Balancing Authority Area.
- Every Balancing Authority must designate a Reliability Coordinator.

Considered together, these boundary conditions mean that:

- A Reliability Area is defined by the metered boundaries of the Balancing Authority Area.
- A generator or customer falls within the purview of the Reliability Area.
- The Regional Reliability Plan will specify the Areas with which each organization is associated.

Boundaries for Planning

The Planning Reliability Functions and the associated Transmission Planning Functions and Resource Planning Functions apply to specific defined Areas that may or may not have a direct correlation with the corresponding operating areas (Reliability Coordinator Area or a Balancing Authority Area). The planning areas and their boundary relationships with other areas are defined below.

Planning Coordinator Area

The Planning Reliability functional Tasks that must be performed by a Planning Coordinator include an integration and assessment of the resource and transmission plans of others to ensure that an adequate long-term (generally 1 year and beyond) resources and transmission plan is available for an area called the Planning Coordinator Area. The Planning Coordinator Area is a defined area for which the Planning Coordinator has responsibility and includes the generators, transmission facilities, and customer demands in that area.

Unlike the operating functions, which must be uniquely defined so that each facility is in one and only one area, the Planning Reliability Areas can overlap. In some cases a Planning Coordinator Area may even be nested inside of a larger Planning Coordinator Area. However, there cannot be any gaps such that proposed or existing facilities are not included in at least one Planning Coordinator Area. This analysis will be part of the Regional Reliability Plan.

Transmission Planning Area

The Transmission Planning Area is a defined area within a specific Planning Coordinator Area. The Transmission Planning Area is the designated Area for which a Transmission Planner has the responsibility for developing a long-term (generally 1 year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric systems within its portion of the Planning Coordinator Area. The Transmission Planning Area may be an area smaller than, equal to, or greater than its related Planning Coordinator Area(s).

Existing and proposed transmission lines, or portions thereof, must be within the boundary of at least one Transmission Planning Area. The Transmission Planners must agree on how transmission between Transmission Planning Areas will be addressed.

A given Transmission Planning Area may encompass an area smaller than, equal to, or larger than its related Reliability Coordinator Area.

Resource Planning Area

The boundaries for the Resource Planning function are difficult to define as a Resource Planner developing a long-term (generally 1 year and beyond) resource adequacy plan for specific loads (customer demand and energy requirements) within a Planning Coordinator

Area may consider generation capacity both within and outside of the Planning Coordinator Area.

The loads addressed by a Resource Planner may encompass customer demands smaller than or equal to its related Planning Coordinator Area, but these customer demands must be within the Planning Coordinator Area. It may take one or more Resource Planners to cover all of the customer demands within a given Planning Coordinator Area.

Size Considerations Relating to Area

The Functional Model does not specify a minimum or maximum size for a Reliability Area. From the perspective of the Model, an organization qualifies to be the Responsible Entity for a particular Function solely on the grounds of whether it is responsible for the performance of the Function's Tasks.

Size is also not a consideration in the distinction between local-area versus wide-area reliability. Local-area reliability is the responsibility of the Transmission Operator in the sense of considerations relating to the Transmission Operator's local system or area, regardless of how large that area may be. Similarly, wide-area reliability is the responsibility of the Reliability Coordinator in the sense of considerations relating as well to the systems and areas of neighboring Reliability Coordinators, regardless of how small the Reliability Coordinator's own area may be.

13. Rollup Examples

Organizations will “roll up” the Functions they intend to perform and register with NERC as Responsible Entities. Here are several examples.

