Functional Description of a Consolidated Control Area Operated by Regional Independent Entity

Summary

Under the Regional Proposal[1], parties who wish to obtain the benefits of control area consolidation may contractually assign operational responsibilities to the regional independent entity in order to gain the efficiencies that result from consolidation. This paper provides a functional description of an approach to operation of a consolidated control area by a regional independent entity. The approach described here is a work in progress with a number of questions yet to be resolved and is offered as a starting point for further discussions.

In this paper, the independent entity is viewed as a provider of services, those provided to all members of the independent entity and additional services required for operation of a control area for those members electing to consolidate their existing control areas. For the purpose of this discussion, the services provided are divided into five service families:[2] (1) market procured generator services, (2) scheduling and rights administration, (3) reliability, (4) system expansion and (5) line operations. The generator services family contains the services that are required for control area operation (balancing-regulation and contingency reserve) as well as redispatch which is provided across the independent entity's footprint. The scheduling, reliability and expansion families are provided to all members. The last service family, line operation, will remain with transmission owners with the independent entity providing coordination services.

There are three service bundles within the market procured generator services family – balancing-regulation, contingency reserves and redispatch. The balancing-regulation bundle contains the conceptual core that defines a control area, i.e., the ancillary services that include regulation and frequency response, load following (up and down), balancing energy and regulation reserve. The independent entity will obtain the interconnected operations services needed to provide ancillary services through a market, with the consolidating parties having an obligation to offer, or to have offered on their behalf, an amount into that market which is greater than or equal to their own needs.[3] A market for contingency reserve would also be operated for the consolidated control area. It is perceived to be in the interest of the consolidating parties to permit other parties to offer resources into these markets and to purchase from the market to the extent there is surplus available to meet needs beyond those of the consolidated control area. Under the Regional Proposal, the cost of operating these

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[1] See RTO West Regional Representatives Group, "Narrative Description Of RRG Platform Group Regional Proposal", December 24, 2003, http://www.rtowest.com/Doc/FinalNarrative_RegionalProposal_Dec242003.pdf

[2] The five families described here are not unlike to the NERC functional model, however the bundling of services in this paper is adapted to fit the organizational structure envision by the Regional Proposal. For more detailed discussion, see reference in footnote 4 below.

[3] Offers amounts in excess of mandated requirements are voluntary offers to sell.

markets is to be borne by the consolidating parties; however, if others utilize these markets they should contribute to the cost of market operations through appropriate fees.

A decision to consolidate control areas will depend upon the ability of the new operational structure to produce benefits that cannot be obtained by continuing to operate as independent control areas. This paper describes these expected benefits, but their quantification is beyond the scope of this paper and is left for future work. In describing the expected benefits, an attempt has been made to separately list the benefits that arise from independent operation of the transmission system and the benefits that arise primarily as a result of consolidating control areas. This separation is intended to clarify the discussion, however, the distinction is imprecise because operational issues are naturally interdependent.

Introduction

During the discussions that led to the development of the Regional Proposal in the fall of 2003, several of the filing utilities expressed an interest in consolidating control areas at the time an independent entity is formed, even if the adopted regional approach deferred regional consideration of control area consolidation until a later date. The Regional Proposal accommodates this expressed interest by permitting the independent entity to operate a control area under contract with those parties who wish to consolidate. To further describe how a consolidated control area might operate and how its operation would relate to the independent entity's role, the filing utilities held a series of technical discussions of the applicable issues. This paper reports on those discussions and the concepts developed by the filing utilities' work group representatives.

To better understand the activities of a control area today and in the future, the NERC functional model was considered as a vehicle for describing the relationship between the control area operation activities and the other activities of the independent entity. Under this model, NERC separates the roles of a traditional control area, as operated by a vertically integrated utility today, into component functions. These functions are grouped as Service or Operating Functions, with a subset of Merchant Functions within the Operating Function. Within the service functions, there are three "Authorities" (Balancing, Interchange and Reliability). To be called an Authority for a given function, an organization must be the ultimate decision maker, i.e., there is no higher "authority" taking care of that responsibility.[4]

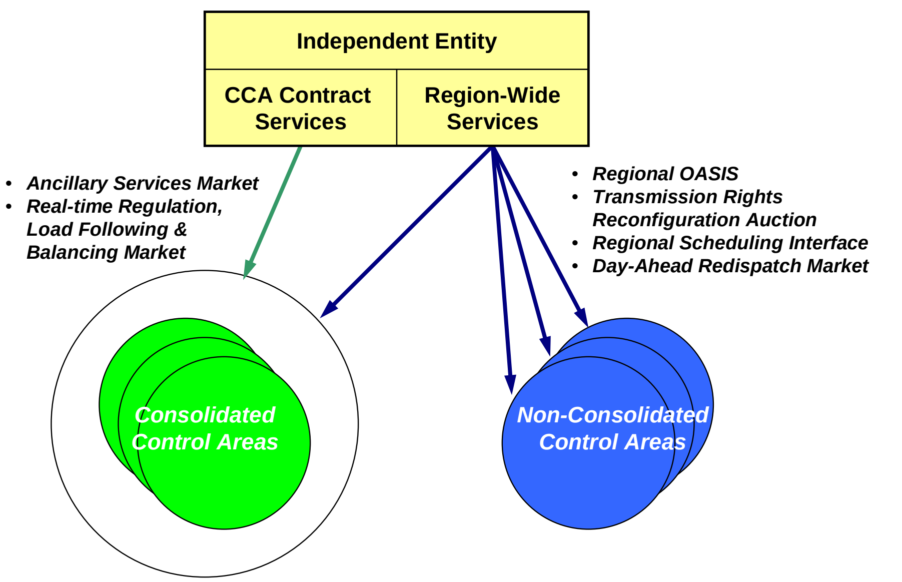
All of the functions described in the NERC model are required, however not all functions must be performed by the same entity. Rather, functions may be divided among a set of organizations, which together meet all the model requirements. Each of these operating organizations is to be identified by the functions it provides within the functional

[4] North American Electric Reliability Council, "The NERC Functional Model, Functions and Relationships for Interconnected Systems Operation and Planning", June 12, 2001 with updates January 20, 2002, pp. 5-6. (ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Functional_Model.pdf)

model.[5] For instance, in today's northwest regional system, all of the control areas are Balancing, Interchange and Reliability Authorities. Further, while the PNSC supports the control areas in their role as Reliability Authorities, it is not a Reliability Authority in its own right.

While useful for determining whether and by whom all functional requirements are to be met, the NERC functional model by itself provides no guidance on possible organizational structures for the provision of service. The work group found it useful to consider the independent entity as a service provider and to explore the nature of the services it would provide as a control area operator. This approach addresses the same questions as the NERC functional model, but looks at operation from the consumer rather than the provider point of view. Figure 1 is a conceptual portrayal of the independent entity as provider of services to the consolidated control area, including those provided across the full footprint of the independent entity and those supplied only to the consolidated control area.

Figure 1
Control Area Service Relationships



To facilitate discussion and consideration of relationships among regional parties, the functions associated with each of the families of service functions are listed below and more detailed descriptions follow:

[5] Ibid, p. 5.

1. Market Procured Generator Services:
    a. Balancing-regulation – regulation and frequency response, load following both up and down, balancing energy and replacement reserve.
    b. Contingency reserve – both spinning and non-spinning reserve.
    c. Redispatch.

2. Scheduling and Rights Administration:
    a. OASIS.
    b. Commercial availability of transmission capacity, i.e., what is today called available transmission capacity (ATC) under current open access transmission tariffs.
    c. Final-day scheduling including E-Tag processing.
    d. Rights administration.

3. Reliability:
    a. System monitoring
    b. Authority for operational changes.
    c. Physical capacity of transmission system, i.e., the total transmission capacity (TTC) and operational transmission capacity (OTC).
    d. System voltage and VAr control.

4. System Expansion:
    a. Planning.
    b. Interconnections.
    c. Expansion and construction.
    d. Financing.

5. Line Operation:
    a. Switching.
    b. Maintenance.
    c. Local voltage management.

Discussion of Services

The following discussion of families of services compares the provision of services today with their possible provision by a consolidated control area. Appendix I provides a summary of this discussion of services in tabular form. The potential benefits from control area consolidation are discussed in each section. A broader list of benefits is provided in Appendix II, including those that arise from independent, regional provision of transmission services.

1. "Market" Procured Generator Services

This family of services is acquired from generators through auction markets. Two of these markets, the balancing-regulation and contingency reserve markets, are required to meet the needs of the independent entity's control area[6], however it is envisioned that other parties may also participate in these markets, subject to development of market operational details. The redispatch market is a service available across the full footprint of the independent entity.

a. Balancing-Regulation

A control area's most basic function is the real-time minimization of control error, measured as the difference between the scheduled and actual interchange across the control boundary. To meet this obligation, a control area must have at its disposal generating capacity that it can dispatch to match changes in load and generation within the metered control boundary. The balancing-regulation services are therefore the family of ancillary services needed to exercise control, namely regulation and frequency response, load following (up and down), balancing energy, and replacement reserve. These services represent the conceptual core that describes what a control area is and does.

In order to provide these ancillary services, the independent entity will facilitate organized markets for procurement of these interconnected operation services from generators. These markets will be appropriately coordinated with the contingency reserve and redispatch markets. Bidding of resources will be open to all generators who meet technical requirements.

Provision Today. While there are some bilateral sales of these services today, balancing and regulation requirements are usually met by control area operators using their own resources (or those of an affiliated merchant function) that are mostly internal to their control areas:

- Each company computes and carries its own capacity for regulation and load following based on regional criteria.
- Each control area has metering and AGC, and it controls its generators to match generation to load in real time.
- A mismatch between generation and load within a control area causes an "inadvertent interchange"; when a control area mismatch occurs, as the energy is supplied by other control areas in the interconnection as a result of ; governor action (to maintain frequency) or time error correction. Inadvertent interchange is returned in-kind between control areas.

Provision Within Consolidated Control Area. Within a consolidated control area, there must be a framework for insuring that adequate resources are available, a method for determining which of the combined resources can best meet the needs of the control area and a method for sharing savings realized and costs incurred. To do this within the independent entity's control area:

[6] That is the consolidated control area operated by the independent entity.

- A new control area Metered Boundary will be established. It is likely that this can be done using existing control area boundary meters, but some new meters at generators may be needed.
- Regulation capacity will be obtained through a cash market administered by the independent entity, who will buy the entire regulation requirement for its control area from that market on a full requirements, full-time basis on behalf of parties who chose to consolidate.
- Each consolidator will be required to bid into this market an amount of generation capacity that is equal to its share of the control area's requirement for balancing-regulation and may offer additional amounts for sale to others participating in this market.
- Both incremental and decremental bids will be accepted.
- Day-ahead, the independent entity will run an auction market for regulation capacity. This process commits and pays for capacity and sets bid prices for energy supply. The committed capacity stands by to produce energy as instructed in real-time to provide balancing-regulation services.
- In real-time, any actual energy deliveries associated with balancing-regulation are settled at energy prices derived from accepted bids.[7]
- The balancing-regulation markets must be integrated or coordinated with the markets for contingency reserve and redispatch to avoid creating artificial price discrepancies for identical energy or capacity provided at the same time to support different services. Without such consistency of pricing, artificial price differentials are created that have proven to be invitations to inappropriate trading activities that create market distortion while doing nothing to improve efficient resource use.

<u>Market Participation by Non-consolidators</u>. This description of the balancing-regulation markets obligates the consolidating parties to a minimum level of contribution to the market that is equal to their own needs absent consolidation. This adequacy requirement is important to insure that the market will function well, with depth of resources, price discovery and stable performance.[8] Participation in the balancing-regulation market by others, whether non-consolidating members or parties outside of the independent entity, can provide additional market depth. It is expected that others' participation would have the following features:

- Resources may be bid into the balancing-regulation markets by parties who are not participants in the independent entity's control area.
- Purchases from the balancing-regulation market by non-consolidating members of the independent entity might be allowed, however the conditions

[7] If needed, an hour-ahead market could be established to facilitate changes conditions and schedules between day-ahead and real-time.

[8] The requirement described here is intended to insure that the market functions appropriately at start-up. As the balancing-regulation market matures and experience in using it grows, the form of the adequacy requirement should be considered and adapted to needs of a fully functional market.

for participation need additional discussion as market design details are further developed.

- Dynamic scheduling will be required to enable the provision of these services on a real-time basis.
- It is not anticipated that parties outside the independent entity's footprint will use these markets to enable purchase of balancing-regulation services. Such arrangements would likely occur on a bilateral basis or through generators bidding into other regions' balancing-regulation markets.

Potential Benefits of Consolidation. From a practical point of view, consolidation of control areas requires the presence of an independent party to insure that selection of resources and allocation of costs is efficiently and equitably administered. While independence is a precondition, the following potential benefits arise out of consolidation of control functions:

- When a large aggregation of load is created, the variation in load across a time period will be statistically smoother than for smaller collections of loads. This provides an opportunity to reduce the total capacity requirement needed for load regulation.
- By procuring regulation capacity for the combined requirements of the control area, a lower overall cost can be obtained, i.e., a reduced per-unit cost, over that which would have occurred had each company carried its own regulation.
- The geographical location of the regulation capacity should be easier to control when its impact on transmission constraints is explicitly considered in procurement.
- Over time, economies of scale should be achieved in staffing and capital investment in control systems equipment.

b. Contingency Reserve

The contingency reserve service bundle includes both the spinning and non-spinning reserve used to allow the interconnected system to withstand the loss of generating units while maintaining system frequency and avoiding loss of load.[9] In order to function efficiently the independent entity's control area will need a market in which the lowest cost reserve can be obtained from among the resources available to it.

The work group considered the possibility that today's regional sharing of contingency reserve could be converted from an in-kind sharing program to a centralized market through a modification of the Northwest Power Pool (NWPP) pro-rata reserve sharing program (PRRS). Conversion could include using market mechanisms to select and price reserve capacity as well as to establish a protocol for the price of energy supplied under the program. At this point, there have only been conceptual discussions of these ideas, and there are differing views about what features would be included and how they might be

[9] Today contingency reserve requirements are specified as 5% of hydro-electric and 7% of thermal-electric generation used to meet system load. The consolidated control area's contingency reserve requirements would be converted to newer forms of contingency reserve when new standards are adopted by WECC.

implemented. The idea is offered here as a possibility for future discussions of possible modification of existing practices to better meet regional needs.

Adoption of a regional market for contingency reserve would obviate the need for the creation of a separate contingency reserve market; however, if such a conversion does not occur, the independent entity will need to create a contingency reserve market within its control area. This market might later be extended or be adapted for region-wide application.

Provision Today. Today contingency reserve obligations are shared through the NWPP program, which has these characteristics:

- Each company computes[10] and carries its own share of the total regional requirement. Each participant's contributed reserve is available to any member of the NWPP to respond to a loss of resource contingency. This amounts to an in-kind pro-rata sharing of the regional reserve among the program participants.
- Each participant can request, and is entitled to receive, capacity from other NWPP control areas to the extent it experiences a contingency that exceeds its own contingency reserve obligation and sufficient transmission is available from other control areas.
- Energy deliveries are settled financially, using a suitable market index. (There are currently some outstanding issues in the region with this approach.)

Provision Within Consolidated Control Area. Within a control area operated by the independent entity in the absence of broader regional market:

- The independent entity will become a signatory to the NWPP PRRS program for its control area, using a market to obtain it pro-rata share of the regional requirement.
- Contingency reserve capacity will be acquired through a cash market for contingency reserve administered by the independent entity.
- The independent entity will buy the entire contingency reserve requirement for the consolidated control area from that market. (The consolidating parties will no longer have their own, separate reserve obligation.)
- Each consolidator will be responsible to bid (or to have bids submitted on its behalf) into this market generation capacity equal to a pro-rata share of the control area's contingency reserve requirement and may offer additional amounts for sale to others participating in this market.
- Only incremental bids apply.
- Day-ahead, the independent entity will run an auction market for contingency reserve. This process selects and pays for capacity, and it sets energy supply bids. The committed capacity stands by to produce energy as instructed in real-time to meet system contingencies., but no energy commitment is made day-ahead.

[10] The computation is not entirely up to the company; the pool sets criteria based on WECC Minimum Operating Reliability Criteria (MORC).

- In real-time, actual energy deliveries associated with contingencies are paid energy prices derived from bids, with the energy bid being locked-in when a capacity bid is accepted. The details of setting prices and settlement will need to be developed in further work on control area consolidation.
- For the reasons cited above in the description of balancing-regulation services, the contingency reserve market must be integrated or coordinated with the markets for balancing-regulation and congestion redispatch to avoid creating artificial price discrepancies for identical energy or capacity provided at the same time to support different services.

Market Participation by Non-consolidators. The expansion of the contingency market to include participation by non-consolidating parties produces the same general benefits as described above for balancing-regulation markets, i.e., market depth, price discovery, stability and potentially lower costs. Absent a regional conversion of the NWPP program, a contingency reserve market established for the independent entity's control area, could allow other parties to participate as follows:

- Bids may be submitted to supply capacity for contingency reserve.
- Purchases of contingency reserve by non-consolidating members of the independent entity might be allowed if there are resources in excess of the needs of the consolidated control area. However, the conditions for participation need further discussion as the details of the market are developed.
- It is not anticipated that parties outside the independent entity's footprint will use these markets to enable purchase of balancing-regulation services. Such arrangements would occur on a bilateral basis or through generators bidding into other regions' contingency reserve markets.

Potential Benefits of Consolidation. As with balancing-regulation services, consolidation of control areas requires the presence of an independent entity to insure that selection of resources and allocation of costs is equitably administered. Again, independence is a precondition to obtaining the following potential benefits that arise out of consolidation of control area functions:

- Determining the quantity for the aggregate consolidated control area may be done in a way that produces a smaller total reserve capacity requirement than the combined reserve for today's individual company calculations.
- Procuring reserve capacity for the aggregate consolidated control area should assure a lower overall cost, even for the same quantity of reserve, since reserve will be carried on the most economical generators from the combined resources supplied. The potential exists for more efficient use of generation. For instance, energy limited parties may bid in low cost reserves above their need and receive payments they would otherwise not realize. At the same time, those who are capacity constrained can obtain lower cost reserves and use capacity otherwise held in reserve to produce lower cost energy.
- The geographical location of the reserve should be easier to control when its impact on transmission constraints is explicitly recognized in the procurement process rather than approximated by the zonal approach used today.

- The utilization of the reserve during a contingency should be more efficient recognizing energy costs that are consistent with the cost of reserve.

c. Redispatch

Redispatch of scheduled generation is done during day-ahead pre-schedule process for the purpose of accommodating energy transfers that would otherwise cause transmission overloads and to produce a lower overall operating cost by making full use of uncommitted capacity in the transmission system. This is a simultaneous process that includes clearing potential congestion, and it is part of the scheduling function described in Item 2.c below.

Provision Today. Today, control area operators change schedules[11] or arrange generation redispatch to resolve transmission overloads. They primarily redispatch their own (or their merchant's) generation in order to support network service agreements.[12] There is no compensation for the cost of most redispatching today.[13]

Regional Provision by Independent Entity. In the Beginning State of the Regional Proposal, the independent entity will provide congestion redispatch services over its entire footprint:

- Prior to running redispatch, schedules will be received day-ahead and checked for consistency with transmission service contracts.
  - Initially the transmission owners, who originally issued those rights, will make this check with a transition of this function to the independent entity over time.
  - If necessary to honor contracts, transmission owners will adjust their desired dispatch to meet their obligations.
- The independent entity will then run a day-ahead inc/dec market for redispatch.[14]
  - Based on the needs of the additional schedules[15], purchase commitments are made for incremental generation production changes. These are energy commitments made by the accepted bidders.

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[11] When schedules are curtailed by a transmission provider, it causes redispatch by indirect means, since the sending and receiving parties to a schedule much alter their plans for meeting load or selling energy.

[12] Some network service agreements permit the transmission provider to redispatch the network resources of the transmission service customer, however, such redispatch is small compared to the redispatch of "own" resources by a today's control area operators today.

[13] There are provisions for redispatch charges in the FERC Order No. 888 open access transmission tariffs. However, those provisions are not often used, and they are difficult to implement on a single utility basis.

[14] The redispatch process will perform a simultaneous feasibility evaluation for both submitted schedules and additional requested service, i.e., voluntary inc/dec bids. If a feasible dispatch cannot be produced, when all rights checked schedules are combined and redispatch consider, curtailment of under the terms of original transmission rights may be required. Consideration of this kind of problem is among the issues to be addressed in further development of the Regional Proposal's Beginning State.

  - Both incremental and decremental bids are accepted.
  - Settlement will be made among the parties making redispatch commitments, with payments to parties increasing generation coming from payments made by those who decrease generation to acquire less costly energy than they would have produced absent redispatch.
- At real-time the independent entity will take redispatch energy as scheduled at predetermined prices. Any deviation from accepted redispatch bids will be billed as imbalance and potentially subject to penalties for non-performance.[16]
- As noted above for the balancing-regulation market, the redispatch market must be integrated or coordinated with the markets for balancing-regulation and contingency reserve in order to avoid creating artificial price discrepancies for identical energy or capacity provided at the same time to support different services.

Provision Within Consolidated Control Area. Redispatch will be the same for the consolidated control area as for any other control area within the independent entity's footprint.

Potential Benefits of Redispatch Market. Procuring redispatch capacity through a system-wide market will be more efficient than a redispatch based on today's limited contractual obligations. It will also be more effective because the independent entity is able to make adjustments directly with generators rather the indirect redispatch that occurs through only curtailing schedules. These are benefits that arise at least initially from the creation of an independent entity without the consolidation of control areas. The independent entity will develop its feasible dispatch using voluntarily bid resources and optimizing to take best advantage of transmission capacity not committed or otherwise reserved for schedule change flexibility by a right holder (i.e., scheduling headroom).

2. Scheduling and Rights Administration

This family of functions is not tied to control area consolidation, but rather is provided to all members of the independent entity. The regional platform contemplates injection/withdrawal scheduling with a means of purchasing inc/dec redispatch to accommodate additional requested schedules throughout the independent entity's footprint. Also new rights of intermediate and long-term duration will be sold as injection/withdrawal pairs rather than as contract paths. This function extends beyond the consolidated control area.

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[15] The form of requests for additional service, whether as added sets of bids, direct requests for transmission or some other option, have yet to be developed. The detailed scheduling protocol and timing will be addressed in further work on the Regional Proposal's Beginning State.

[16] This does not include changes in schedule that are within the existing rights of transmission user, but is specific to the voluntary offers made to redispatch which are accepted and relied upon in developing the independent entity's feasible dispatch.

a. OASIS

- The independent entity will provide a single OASIS for its entire footprint.
- It will have information about both day-ahead and forward or long-term rights.
- All participants in the independent entity's congestion management program must utilize the independent entity's OASIS.

b. Determination of Commercially Available Capacity (i.e., ATC)

- The determination of commercially available capacity is an issue common to the independent entity's entire footprint rather than to its control area.
- There may be a timing difference between when this function is transferred to the independent entity as opposed to the consolidated control area; however, the process should be the same.

c. Final Day Scheduling (E-Tag Processing Day-ahead through Real-time)

Provision Today. Control area operators execute the scheduling function and manage transmission overloads:

- Control area operators accept schedules that have prior rights and process e-tags.
- Control area operators check out interchange schedules.
- Each control area operator monitors its own transmission system for overloads.
- If the transmission is overloaded or is expected to be overload, the control area operator curtails schedules (non-firm first) and redispatches generation under its control. This includes the control area operator's own generation (or its merchant's generation) and sometimes generation under network service agreements, but is primarily the control area operator's own generation that is redispatched.
- There is no compensation for the cost of most redispatching.[17]

Regional Provision by Independent Entity. The Regional Proposal provides for scheduling of all of its members through the independent entity.

- Day-ahead, the independent entity will:
  - Accept balanced schedules that are covered by prior rights and run power flow studies to assure feasibility.
  - Receive nominations for additional schedules (as injection/withdrawal pairs) that do not have or need prior rights.
  - Run an inc/dec redispatch market, as described in section 1.c above.
- At real-time, redispatch energy will be delivered and taken as scheduled by the parties whose bids were accepted in the redispatch market. Deviations from scheduled production will be billed as imbalance.
- Redispatch energy will be settled financially; the payments for energy are settled among the parties who participate as buyers and sellers in the redispatch market.

[17] There are provisions for redispatch charges in the FERC Order No. 888 open access transmission tariffs. However, those provisions are not often used, and they are difficult to implement on a single utility basis.

Those whose schedules are accepted without rights will face the locational differential in energy prices.

Provision Within Consolidated Control Area. Redispatch will be the same for the consolidated control area as for any other control area within the independent entity's footprint. There does not appear to be an operational difference within the consolidated control area footprint. Those who participate in control area consolidation will be participants in the region-wide services provided by the independent entity.

Potential Benefits of Independent Scheduling. Providing independent regional scheduling should lower administrative costs for provision of transmission services and for the customers who use those services. Providing such a single point of contact is not a direct function of control area consolidation.

d. Rights Administration

- Independent entity issues, converts and administers intermediate and long-term rights including establishing the rights issuance enabled by system expansion.
- Reconfiguration auctions are provided to allow parties to trade transmission capacity and enable new medium to short-term requests from existing capacity.
- This function encompasses the entire independent entity's footprint, so there is no perceived difference between the consolidated control area and other parts of the region.

3. Reliability

This family of functions is not tied to control area consolidation. The independent entity's performance of the reliability function will cover its entire footprint and even beyond, to the extent possible.

a. System Monitoring

- The independent entity will monitor the entire system of its members and operate a state estimator to evaluate the reliability of the network. This will cover the entire independent entity footprint regardless of participation of its member systems in a consolidated control area. It will also likely need data from other neighboring systems to better understand system conditions.

b. Authority to Order Changes in Operation

- This should cover independent entity's entire footprint regardless of participation in the its control area.
- At least in the consolidated control area, the independent entity will be the Reliability Authority.
- This is a higher level of authority than PNSC has today.

c. Determine Physical Capability of System (i.e., TTC and OTC)

- The independent entity will determine both TTC and OTC for all participating systems, not just within its control area.

d. System Voltage and VAr Control

- Management of system voltage and VArs that affect system transfer capability and regional reliability. (See section 5.c below for local voltage management.)

4. System Expansion

This family of functions is not tied to control area consolidation. For these functions, the independent entity will provide service across its full footprint. While there is little operational relationship between control area consolidation and these planning/expansion functions, the consolidating utilities may view both together as a package that achieves a desired outcome of independence. This family of functions includes:

a. Planning

b. Interconnections

c. Expansion / Construction

d. Financing

5. Line Operation

This family of functions stays with the individual utilities with coordination or direction provided by the independent entity, which should have the same influence over these functions under its reliability or congestion management responsibilities regardless of a party's participation in a consolidated control area.

a. Switching

- Physical operation of switches and physical safety clearances remain with transmission owners, with reliability oversight through the independent entity.

b. Maintenance

- Coordination of maintenance outages provided through the independent entity.

c. Local Voltage Regulation

- Capacitor switching and tap changing in lower voltage transmission facilities where the bus voltages are not a significant factor in system transfer capabilities.

Appendix I
Conceptual Approach to Independent Entity Services Offerings

<table>
<tr><th rowspan="2">Description</th><th colspan="3">Level of Participation</th></tr>
<tr><th>CCA PTOs</th><th>Other PTOs</th><th>Non-PTO Party</th></tr>
<tr><td>1. Market Procured Generator Services</td><td></td><td></td><td></td></tr>
<tr><td rowspan="2">a. Balancing-Regulation
Regulation & Freq. Resp.
Load Following Up & Down
Balancing Energy
Replacement Reserve
(Capacity needs for services made prior to real-time and energy delivered as needed in real-time)</td><td rowspan="2">Sell: Obligation to submit offers ≥ to expected need.
Buy: Full Requirements met and settled by IE through CCA Market.</td><td>Sell: May submit voluntary offers, with accepted bids subject to penalties for delivery failure.
Buy: Further discussion is needed to determine the degree and conditions of participation by non-CCA parties.</td><td>Sell: May submit voluntary offers, with accepted bids subject to penalties for delivery failure.
Buy: Further discussion is needed to determine the degree and conditions of participation by non-CCA parties.</td></tr>
<tr><td colspan="2">Note: Non-CCA parties, who opt to participate in CCA markets, will contribute to the cost of market operation thru service fees. Inter-area dynamic scheduling will be required for both buyers and sellers.</td></tr>
<tr><td rowspan="2">b. Contingency Reserve
Spinning & Non-Spinning[18]
(Capacity needs arranged in day-ahead time frame)</td><td rowspan="2">Sell: Obligation to submit offers ≥ to expected need[19].
Buy: Full Requirements met and settled by IE through CCA Market.
Note: IE’s control area will be a participant in NWPP reserve sharing agreement.</td><td>Sell: May submit voluntary offers, with accepted bids subject to penalties for delivery failure.
Buy: Further discussion is needed to determine the degree and conditions of participation by non-CCA parties.</td><td>Sell: May submit voluntary offers, with accepted bids subject to penalties for delivery failure.
Buy: Further discussion is needed to determine the degree and conditions of participation by non-CCA parties.</td></tr>
<tr><td colspan="2">Note: Non-CCA parties, who opt to participate in CCA markets, will contribute to the cost of market operation thru service fees. Inter-area dynamic scheduling will be required for both buyers and sellers.</td></tr>
<tr><td>c. Congestion Redispatch
(Operates as part of day-ahead process. Real-time congestion managed as part of balancing energy acquisition.)</td><td colspan="3">Sell: May submit voluntary offers, with accepted bids subject to penalties for delivery failure.
Buy: Redispatch market optimizes feasible dispatch using voluntary bids of willing buyers and sellers.
Note: As described in the Regional Proposal, a two-stage process occurs during day-ahead scheduling – (1) schedules are verified for consistency with contractual rights and original control area physical feasibility and (2) system wide feasibility using congestion redispatch to resolve problems that may exist when schedules are combined.</td></tr>
</table>

[18] Converted to newer forms of contingency reserve when new standards are adopted by WECC.
[19] The contingency reserve obligation is based on the types of resources to be submitted to serve load.

Description	Level of Participation		
	CCA PTOs	Other PTOs	Non-PTO Party
2. Scheduling and Rights Administration			
a. OASIS	IE provides a single OASIS site for the entire IE footprint.		May use OASIS services of IE to meet needs.;
b. Determine Commercial Availability of Capacity (i.e. ATC)	Evaluates contractual commitments of IE members and identifies capacity available to meet new requests.		
c. Final Day Scheduling *E-Tag processing DA through RT*	Schedules submitted to IE who establishes day-ahead schedules, which are transmitted to member control areas for execution in real-time.		Interconnection (Interchange?) Coordination with IE
d. Rights Administration	Reconfiguration auctions provide purchase and sale opportunities to increase utilization of available capacity. Requests for LT service go to IE for coordinated evaluation and resolution. Determination of transmission rights available to expansion projects.		
3. Reliability			
a. System Monitoring	Monitors and provides state estimator evaluation of the regional system.		
b. Authority to Order Changes in Operation	Reliability Authority in the consolidated control area and emergency authority for the rest of the system within the IE's footprint.		
c. Determine Physical Capability of System (i.e., TTC & OTC)	Service provided on all facilities of all PTOs in the IE's footprint.		
d. System Voltage and VAr Control	Management of voltage profile and reactive margin which affects system wide transfer capability.		
4. System Expansion			
a. Planning	Region-wide services provided with participation by project sponsors, transmission owners, and all other regional stakeholders.		
b. Interconnections			
c. Expansion/Construction			
d. Financing			
5. Line Operation			
a. Switching	Reliability oversight through independent entity.		
b. Maintenance	Coordination of outages through independent entity.		
c. Local Voltage Regulation	Management of voltages in lower voltage facilities that do not affect system stability and transfer capabilities.		

Draft #3.3

Appendix II
Potential Benefits of Independent Operation and Consolidating Control Areas
(A Brainstorming Thought Piece)

The following is a list of potential benefits from independent operation of the regional transmission system and from consolidation of control areas. Those items related primarily to consolidated control area operation are shown in ***bold italic typeface*** while those benefits related primarily to independent operation are show in plain typeface.

A. Strategic Advantages of Consolidating Under a Single Entity

1. ***Central forum for debating and resolving issues relating to real time operations from a single utility perspective.***
2. Increased clout in dealing with FERC on reliability matters.
3. Increased clout in dealing with CAISO and West Connect on reliability and other matters.
4. ***Increased clout in dealing with suppliers of control area-related non-generation products and services (increased buyer power) (e.g., software, IT systems, metering, communications, RTU devices).***
5. Single voice for operating reliability issues.
6. Better coordination of planned outages across the region.
7. Unbundling services may promote increased efficiency through new business models focused on particular products or services.
8. Provide a broad, single market for new transmission products within the region.

B. Standardization of Business Practices

9. ***Uniform business practices for ancillary services, including reserve and imbalance, inadvertent within a consolidated control area, including tariff-related practices.***
10. Standardized TTC, OTC, and ATC calculations within the region.
11. Standard definitions of services.
12. Increased compatibility of region-wide data, performance measurement, system requirements, communication, and related IT issues.

C. Increased Efficiency

13. ***Lower costs from reduction in the amount of generation capacity required for load regulation and frequency response.***
14. ***Ability to use lowest cost resources for reserve and balancing (i.e., pooled through market bids).***
15. Potential to minimize transmission reserve margin (TRM) on system-wide basis.
16. Single point of service for generator owner communications.
17. Reduced capital costs going forward to implement design changes as a result of new reliability standards, changed industry practices, and new innovations.

18. ***Reduction (over time) in staff and control systems capital needed to perform real time operations.***
19. ***Buyers and sellers of control area related products and services will see a single, large market instead of multiple, smaller buyers.***
20. ***More efficient markets for ancillary services (integrated operations services) and imbalance energy.***

D. One Stop Shopping for Ancillary Services and Related Real-Time Products and Services

21. Single OASIS site for transmission reservations.
22. ***Single market for sellers of ancillary services, imbalance and related services within the IE control area.***

E. Price Discovery of Ancillary Services and Related Real Time Markets

23. ***Making ancillary service prices visible in a market***.
24. ***Attaching bids to reserve pooling will increase the efficiency in the use of generation to supply reserve.***
25. ***Higher visibility of the grid through price transparency; one-stop information source for consolidated control area market participants and project sponsors.***

F. System-Wide Perspective Promotes Improved Reliability

26. A system wide perspective should allow reliability to be maintained at lower cost.
27. Reduced exposure to large-scale grid outages.
28. ***Improved redispatch of generation in real time from single utility perspective within consolidated control area to lower costs and maintain reliability.***
29. ***Easier to obtain reserve geographically, taking into account transmission constraints within the consolidated control area.***
30. ***Simplified procurement process of control area related products and services.***
31. System-wide view makes it easier to restore service after an outage.

G. Reduced Gaming Opportunities

32. ***Settling ancillary services financially should reduce gaming opportunities.***
33. ***Inadvertent interchange eliminated and replaced with imbalance process which is settled at value of energy, eliminating value differences which occur with energy returns at a later date.***