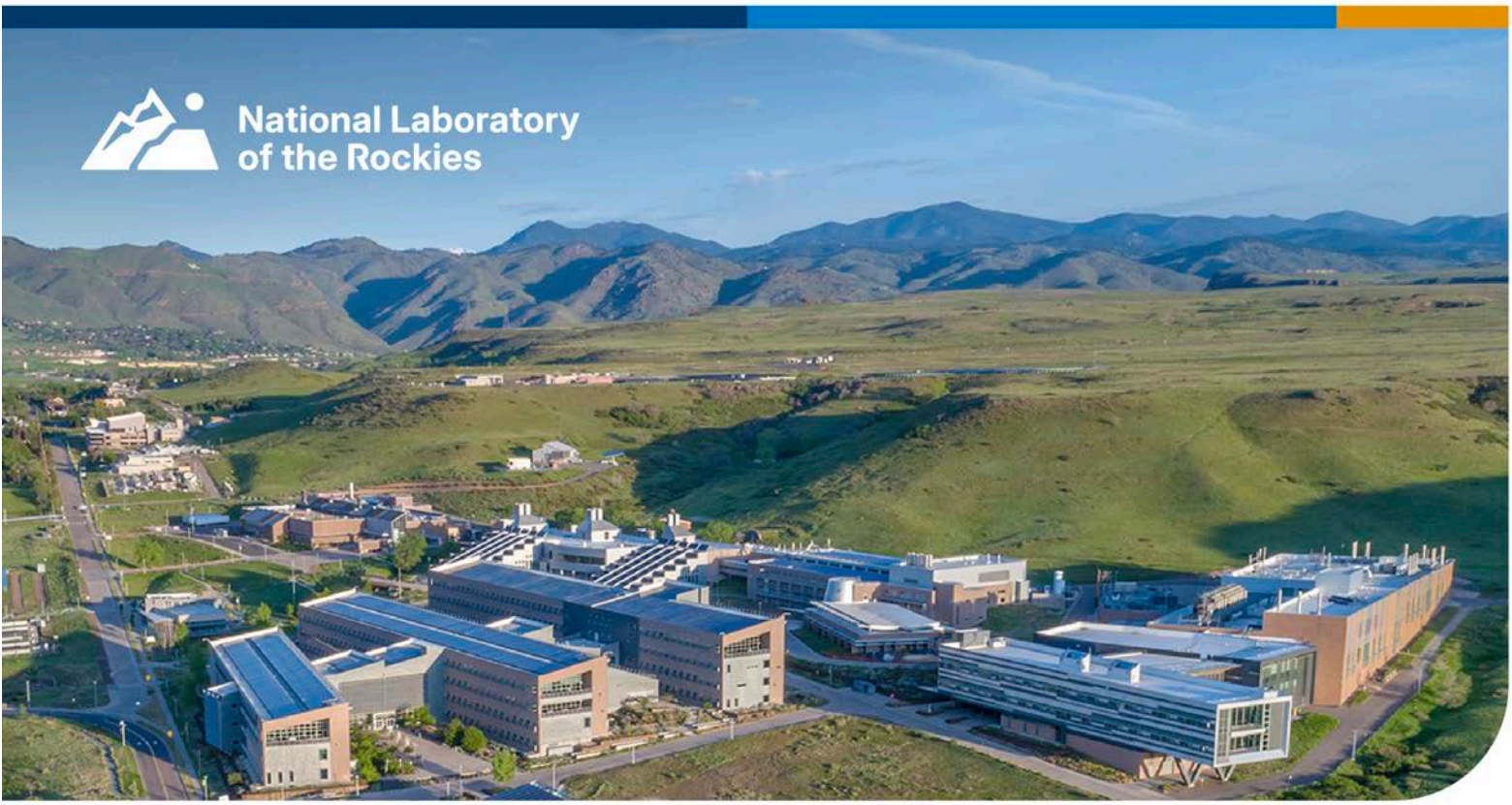

Interregional Transmission Operational Coordination (IRTOC)

Yonghong Chen, Jose Daniel Lara, Haotian Chen, Matthew Bossart, Sebastian Manrique Machado, and Jarrad Wright

National Laboratory of the Rockies

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List of Acronyms

AC	alternating current
ADMM	alternating direction method of multipliers
EI	Eastern Interconnection
GMLC	Grid Modernization Lab Consortium
HVDC	high-voltage direct current
IRTOC	Interregional Transmission Operational Coordination
ISO	independent system operator
ISO-NE	Independent System Operator–New England
JOA	joint operating agreements
M2M	market-to-market
MISO	Midcontinent Independent System Operator
MRTO	monitoring regional transmission organization
NERC	North American Electric Reliability Corporation
NMRTO	nonmonitoring regional transmission operator
NYISO	New York Independent System Operator
PTDF	power transfer distribution factor
RT-SCED	real-time security-constrained economic dispatch
RTOs	regional transmission organizations
RTS	Reliability Test System
SCED	security-constrained economic dispatch
SCUC	security-constrained unit commitment
SPP	Southwest Power Pool
TLR	transmission loading relief

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Executive Summary

This report summarizes the framework developed through the **Interregional Transmission Operational Coordination** project to study market-to-market congestion management across day-ahead and real-time markets. Although U.S. nodal wholesale electricity markets have delivered significant regional benefits, coordination across regions remains limited and uneven across operational stages.

The project advances both methodology and software to enable rigorous and systematic comparisons of alternative coordination designs:

- **Sienna Decomposition**, an extension to the open-source Sienna platform for large scale grid scheduling simulations using production cost modeling (National Laboratory of the Rockies n.d.), enables users to define areas, coordinated subsystems, and synchronous regions; configure coordination structures by market stage; and flexibly enforce monitored transmission constraints, including energy flows and post-reserve-deployment flows under defined generation outage contingencies.

- **A multistage evaluation framework** links day-ahead and real-time market outcomes and includes an emulation stage to systematically calculate pre- and post-contingency transmission flows. This framework quantifies transmission limit violations and aggregates production and violation costs to provide consistent performance metrics.

- **A loop flow representation and data passing scheme** that captures key interactions across regions during market-clearing processes.

Beyond baseline coordination, the study incorporates two operational features that affect reliability and efficiency:

- **Intra- and interregional reserve deliverability constraints**, which ensure procured reserves can be deployed without violating monitored transmission limits following generation contingencies. The framework allows contingency events to be modeled by area and by market stage.

- **High-voltage direct current (HVDC) optimization for alternating current transmission congestion management**, enabling HVDC schedules—either within or across areas under fixed net interchange—to relieve alternating current transmission constraints.

For real-time distributed coordination, three algorithms are designed and implemented:

- **Method 1 (single shadow price exchange):** Uses the most recent state estimator flows and prior-period shadow prices from both regions to determine relief or relaxation targets within each market-clearing optimization. This approach minimizes information exchange and implementation changes.

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- **Method 2 (relief cost curve exchange):** Extends Method 1 by exchanging piecewise-linear relief cost curves that better capture marginal congestion relief costs across multiple flow levels. This approach improves convergence and scalability to multiple lines and more than two regions.

- **Method 3 (alternating direction method of multipliers):** Provides convergence through updating dual variables but can exhibit larger interim flow violations. It is included primarily for comparison to highlight operational implications.

Case studies on a three-area IEEE Reliability Test System (RTS) modified by the Grid Modernization Lab Consortium and a large-scale Eastern Interconnection model demonstrate the framework can systematically evaluate different market coordination structures. The analysis emphasizes methodological development rather than monetized benefit estimates; comprehensive benefit quantification will require expanded datasets and additional scenarios.

The study demonstrates that the Sienna Decomposition framework can be used to evaluate operational strategies for market coordination across different stages, assess new coordination methods, and analyze future intra- and interregional HVDC integration, as well as reserve product and deliverability design.

Future work will focus on:

- Extending datasets and contingency definitions to incorporate forecast errors and uncertainties between day-ahead and real-time operations, including intra-hour variability

- Exploring interchange optimization and reserve sharing across regions

- Advancing interregional HVDC optimization for both interchange scheduling and congestion management.

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1 Multiregional Market-to-Market Coordination Overview

1.1 Market-to-Market Coordination on System-Wide Constraints

In North America, wholesale electricity markets have delivered significant benefits to their regions. Midcontinent Independent System Operator (MISO) and PJM—the two largest independent system operators (ISOs)—have reported annual regional benefits of approximately $4 billion to $5 billion from integrated planning and market operations (MISO n.d.; PJM n.d.).The nodal market design explicitly accounts for generation and transmission physical constraints through security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) market-clearing processes.

Within these market-clearing formulations, four categories of system-wide constraints are typically enforced: (1) power balance constraints, (2) reserve requirement constraints, (3) transmission flow constraints under energy dispatch, and (4) transmission flow constraints accounting for post-contingency events and reserve deployment. Incorporating these constraints into the market-clearing co-optimization enables regional transmission organizations (RTOs) to achieve welfare maximization, price transparency, and the efficient and reliable utilization of transmission capacity.

However, significant opportunities remain to improve coordination across seams between different operational entities (Simeone and Rose 2024). In control room operations, power balance and reserve procurement fall under the balancing authority function, whereas transmission congestion management is handled through the reliability coordination function. These functions are governed by separate coordination agreements involving different entities. For example:

- New York Independent System Operator (NYISO) and Independent System Operator–New England (ISO-NE) have implemented coordinated transaction scheduling for interchange to support power balance (ISO-NE and NYISO 2011).
- MISO and PJM have implemented market-to-market joint operating agreements (M2M-JOAs) for coordinated congestion management (PJM 2008; “Joint Operating Agreement” 2008).
- In many cases, North American Electric Reliability Corporation (NERC) transmission loading relief (TLR) procedures are used to manage congestion through transaction curtailments (NERC n.d.).

Negotiating and implementing coordination agreements typically require substantial effort. It is therefore important to evaluate the benefits of coordination across different constraint categories and to study methods for achieving convergence under various coordination mechanisms.

The examples of seams coordination agreements in the Eastern Interconnection are summarized in (Staff Whitepaper 2025).

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1.2 Coordination Across Multiple Operational Stages

Market operations are conducted through a multistage process spanning multiday, day-ahead, intraday, and real-time dispatch. In North America, coordination during the operational planning stages—from multiday through intraday—remains limited; coordinated transaction scheduling andM2M-JOA are implemented primarily in real time.

In the United States, nodal markets have demonstrated high efficiency in power balance, congestion management, and reserve procurement. Among U.S. ISOs, MISO has the largest installed generation capacity, totaling 203 GW (MISO 2025).

In principle, forming a fully coupled nodal market across the continental United States could achieve a globally optimal solution. However, doing so would require addressing substantial computational challenges and overcoming institutional and business-structure barriers. Prior to such an evolution, it is essential to develop a systematic framework to evaluate coordination methods across different operational stages. Without effective coordination across these stages, the industry may be unable to realize the full benefits identified in the planning studies such as the National Transmission Planning Study (U.S. Department of Energy n.d.).

1.3 Study Framework

For four categories of system-wide constraints, there are 12 possible coordination configurations (Table 1).

Coordination may vary across operating stages—for example, there is, in general, limited coordination (C0) in the day-ahead stage, and in some ISO seams M2M-JOA is used for energy flow coordination (C2). This report focuses on congestion-management configurations C2 and C8.

Real-time coordination, such as M2M-JOA, is implemented in a distributed fashion along seams among several Eastern ISOs. Paired RTOs exchange shadow prices and adjust relief requests to achieve flow and shadow price convergence. As demonstrated by Potomac Economics (2020), this method may exhibit convergence issues or converge to suboptimal solutions.

Through the Interregional Transmission Operational Coordination (IRTOC) project, the team at the National Laboratory of the Rockies has developed methodologies and software tools to systematically study multistage market-to-market (M2M) coordination. Under the IRTOC project, the team developed Sienna Decomposition under the open-source Sienna modeling framework (National Laboratory of the Rockies n.d.) to evaluate the impacts of different coordination configurations at different operational stages. Its functions include:

- Areas, subsystems, and islands to model balancing authorities, coordinated areas, and the synchronized grid, with flexibility to define coordination entities and coordinated transmission constraints
- Benchmark mathematical optimization formulations for each coordination configuration
- Multistage simulation with flexibility to study different configurations at different stages
- Reserve deliverability constraints for predefined generation contingency events and response areas in the market-clearing formulation

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- High-voltage direct current (HVDC) optimization and its impact on alternating current (AC) transmission-constraint coordination
- An emulator stage that mimics state estimation and evaluates pre- and post-contingency flows under generation outage events with reserve deployment
- Consistent economic and reliability metrics; production costs from multiarea simulations and flow violation costs from the emulator enable consistent evaluation of different coordination structures

In this report, the term *area* is used interchangeably with *region*, representing the entity responsible for balancing authority functions.

Table 1. Coordination Configurations

Coordination Configurations	C0	C1	C2	C3	C4	C5	C6	C7	C8	C9	C10	C11
Power balance	0	1	**0**	1	0	1	0	1	**0**	1	0	1
Transmission constraint (energy flow)	0	0	**1**	1	0	0	1	1	**1**	1	1	1
Reserve requirement	0	0	**0**	0	1	1	1	1	**0**	0	1	1
Transmission constraint (post-contingency with reserve deployment flow)	0	0	**0**	0	0	0	0	0	**1**	1	1	1

0: without coordination, 1: with coordination

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2 Multistage Market Coordination Study Framework

The market-clearing processes differ across the multiday, day-ahead, intraday, and real-time time frames.

- In the multiday and day-ahead markets, ISOs solve a single optimization problem spanning multiple intervals. In the multiday time frame, operators typically commit only units with startup and notification times longer than 1 day (i.e., long-lead units), deferring commitment decisions for shorter-lead units to the day-ahead market or intraday commitment. In the day-ahead market, clearing results for all intervals are determined and published simultaneously.
- In the intraday time frame, unit commitment is performed on a rolling basis (e.g., every 15 minutes) by solving a multi-interval SCUC problem. Operators make ongoing commitment decisions based on the updated SCUC results.
- In real time, some ISOs solve a single-interval real-time security-constrained economic dispatch (RT-SCED), whereas others solve a multi-interval SCED, both on a rolling basis (e.g., every 5 minutes). In either case, only the dispatch results for the first interval are typically published.

Given the complexity associated with intraday commitment and multi-interval RT-SCED, this report focuses on the day-ahead market and single-interval RT-SCED in the context of interregional transmission operational coordination.

2.1 Day-Ahead Forward Process

In the day-ahead time frame, each RTO solves a multi-interval SCUC, some followed by more granular SCED, and the process may take several hours (Chen et al. 2018). Two potential approaches—centralized and distributed—can be used to coordinate AC transmission congestion management across regions. In this report, we use a system with three regions designated here as $a, b,$ and c to illustrate the coordination models.

2.1.1 Centralized Day-Ahead Coordination

For centralized day-ahead coordination, the two RTOs may jointly clear the markets using a centralized M2M coordination model. This approach represents the mathematically optimal solution, as it optimizes the two areas simultaneously. The centralized M2M coordination models are therefore developed as benchmarks. The nodal day-ahead benchmark model for coordinated energy flow ($C2$, represents configuration "$C2$" in Table 1) is formulated as follows.

In this model, region a and region b are coordination entities that jointly optimize transmission flow constraints in $C2^{DA,ab}_{Central}$. Region c is not part of the coordination. The flow contributions from noncoordinating entities may create loop flow impacts on the transmission constraints. Loop-flow is defined as power transfers from adjacent, noncoordinating regions that unintentionally affect monitored transmission constraints within another region.

In this formulation, the entities do not coordinate on interchange scheduling or reserve procurement. Therefore, the power balance equations and reserve requirement constraints are

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enforced separately by each region based on predetermined regional net scheduled interchange and reserve requirements.

Here we define subsystems to represent the sets of coordination entities. Each subsystem includes one or multiple regions. The subsystem ab includes the coordinated region a and region b. The subsystem c includes only region c.

The $C2^{DA}_{Central}$ configuration includes two optimization problems ($\{C2^{DA,ab}_{loopflow}, C0^{DA,c}_{loopflow}\}$), the first one representing the coordination entities (a, b) that jointly optimize transmission flow constraints (Configuration "$C2$" in Table 1), and the second one related to the uncoordinated entity (c), which corresponds to the configuration "$C0$" in Table 1. In this model, the loop flow impacts are estimated and incorporated in the transmission constraints.

$$C2^{DA,ab}_{loopflow} = Min_{g_{a,t},g_{b,t},s_t,rsv_{a,t},rsv_{b,t}} \sum_{t\in T}[c^T_{a,t}g_{a,t} + c^T_{b,t}g_{b,t} + \alpha 1^T_t s^{l_{ab}}_t]$$

Subject to:

$$f^{l_{ab}}_t = ptdf^{l_{ab}}_{a,t} \cdot [g_{a,t} - d_{a,t}] + ptdf^{l_{ab}}_{b,t} \cdot [g_{b,t} - d_{b,t}] + loopflow^{l_{ab}}_{c,t} \quad \text{(d1)}$$

$$f^{l_{ab}}_t - s^{l_{ab}}_t \le \overline{f^{l_{ab}}_t} \quad \text{(d2)}$$

$$1_{a,t} \cdot [g_{a,t} - d_{a,t}] = Ich_{a,t},\ 1_{b,t} \cdot [g_{b,t} - d_{b,t}] = Ich_{b,t} \quad \text{(d3)}$$

$$1_{a,t} \cdot [rsv_{a,t}] \ge Req_{a,t}, \quad 1_{b,t} \cdot [rsv_{b,t}] \ge Req_{b,t}, \quad \text{(d4)}$$

$$\begin{bmatrix} g_{a,t} \\ rsv_{a,t} \end{bmatrix} \in X_{a,t}, \qquad \begin{bmatrix} g_{b,t} \\ rsv_{b,t} \end{bmatrix} \in X_{b,t}, \quad \text{(d5)}$$

$$\forall\, t \in T, l_{ab} \in L_{ab}$$

$$C0^{DA,j}_{loopflow} = Min_{g_{j,t},s_t,rsv_{j,t}} \sum_{t\in T}[c^T_{j,t}g_{j,t} + \alpha 1^T_t s^{l_j}_t]$$

Subject to:

$$f^{l_j}_t = ptdf^{l_j}_{j,t} \cdot [g_{j,t} - d_{j,t}] + \sum_{j1\notin j} loopflow^{l_j}_{j1,t} \quad \text{(d6)}$$

$$f^{l_j}_t - s^{l_j}_t \le \overline{f^{l_j}_t} \quad \text{(d7)}$$

$$1_{j,t} \cdot [g_{j,t} - d_{j,t}] = Ich_{j,t} \quad \text{(d8)}$$

$$1_{j,t} \cdot [rsv_{j,t}] \ge Req_{j,t} \quad \text{(d9)}$$

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$$\begin{bmatrix} g_{j,t} \\ rsv_{j,t} \end{bmatrix} \in X_{j,t} \quad \text{(d10)}$$

$$\forall\, t \in T, l_j \in L_j, j = c$$

where

t, T are the index and set of intervals

$c_{j,t}$ is the generation cost vector in region j at interval t

α is the transmission flow violation penalty

1_t is the vector of ones

l_s, L_s are the index and set of monitored transmission constraints in subsystem $s \in \{ab, c\}$

$\overline{f_t^{l_s}}$ is the limit of monitored transmission constraint l_s at interval t

$ptdf_{j,t}^{l_s}$ is the vector of power transfer distribution factor for transmission constraint l_s to buses in region j

$d_{a,t}$ is the demand in region j at interval t

$Ich_{j,t}$ is the net scheduled interchange for region j in interval t

$Req_{j,t}$ is the reserve requirement for region j in interval t

$X_{j,t}$ is the resource feasible region for region j in interval t

$loopflow_{j,t}^{l_s}$ is the loop flow on transmission constraint l_s from region j in interval t

$g_{j,t}$ is the vector if generation dispatch variable in region j at interval t

$rsv_{j,t}$ is the vector of reserve capacity variable in region j at interval t

$s_t^{l_s}$ is the transmission constraint violation variable for transmission constraint l_s at interval t

$f_t^{l_s}$ is the expression of transmission flow on constraint l_s in interval t.

Constraints (d1) and (d6) calculate flows of transmission constraints monitored by each subproblem. Constraints (d2) and (d7) enforce transmission limit constraints. Constraints (d3) and (d8) are power balance equations for each of the areas. (d4) and (d9) are reserve requirement constraints by area. (d5) and (d10) represent generation resource constraints.

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Even though the centralized model can provide the best solution on managing congestion on coordinated regions (a and b in this example), it has two main challenges:

1. It will require overcoming business-structure barriers to allow the coordinated regions to share market inputs and models for centralized coordination.
2. It may be computationally expensive to optimize two or more markets together.

The European Union has established processes for day-ahead and intraday market coupling. These processes rely on simplified, zonal aggregated models (Estermann et al., 2025), which may require less computational time but are generally less efficient in managing congestion than nodal approaches.

2.1.2 Distributed Day-Ahead Coordination

For distributed day-ahead coordination, each RTO clears its own day-ahead market. Then the coordination partners exchange clearing results, such as the binding transmission constraints and shadow prices. The coordination partners then revise their SCUC/SCED model to incorporate the information from the partners and re-solve their own SCUC/SCED. This distributed solution approach can be challenging and unrealistic for the following reasons:

- The day-ahead market-clearing problem is large and subject to strict time constraints, making iterative approaches computationally challenging.
- The SCUC problem is nonconvex and may not warm-start effectively. As a result, solving subsequent iterations may not be significantly faster than the initial SCUC, potentially increasing the total solution time.
- In the day-ahead time frame, the number of binding transmission constraints can be large, making convergence difficult to achieve.

For these reasons, we do not study distributed day-ahead coordination approach under this project.

2.1.3 Other Day-Ahead Configurations

In this subsection, a few other typical day-ahead multiregional clearing models are listed.

2.1.3.1 Day-Ahead Configuration Without Market-to-Market Transmission Constraints

The mathematical formulation for this configuration neglecting loop flow influences is developed as follows:

$$C0^{DA}_{no-loopflow} = \{C0^{DA,a}_{no-loopflow}, C0^{DA,b}_{no-loopflow}, C0^{DA,c}_{no-loopflow}\} \text{ with}$$

$$C0^{DA,j}_{no-loopflow} = Min_{g_{a,t}, g_{b,t}, g_{c,t}, s_t, rsv_{j,t}} \sum_{t \in T} [c^T_{j,t} g_{j,t} + \alpha 1^T_t s^{l_j}_t]$$

Subject to:

$$f^j_t = ptdf^{l_j}_{j,t} \cdot [g_{j,t} - d_{j,t}] \qquad \text{(d6.1)}$$

Constraints $(d7) - (d10)$

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$$\forall\, t \in T, l_j \in L_j, j \in \{a, b, c\}$$

In this model, each region solves its own market clearing problem where transmission flows are calculated based on (d6.1), which reflects only the impacts of generators and loads within that region.

2.1.3.2 Day-Ahead Configuration Without Coordination But With Consideration of Loop Flows

In this configuration, each monitoring region is responsible for its own transmission constraints. The monitoring region has estimation on loop flow from other regions:

$$CO_{loopflow}^{DA} = \{CO_{loopflow}^{DA,a}, CO_{loopflow}^{DA,b}, CO_{loopflow}^{DA,c}\}$$

2.2 Real-Time Market

Even if RTOs can commit units to adequately manage congestion in day-ahead market, real-time operations may encounter unexpected transmission violations because of uncertainty. However, effective coordination in forward operational processes, such as the day-ahead market, can reduce the likelihood and severity of real-time flow violations. Real-time coordination can similarly be implemented in either a centralized or a distributed manner. Although it is unlikely that multiple markets would be jointly cleared for congestion management in real time, a centralized real-time model is developed in this study to serve as a benchmark for evaluating the performance of distributed coordination algorithms.

Real-time markets are solved on a rolling basis. Generation and load from all regions inject into and withdraw from the grid, and their actual impacts on transmission flows are observed in state estimation results in control rooms. In North America, grid operators generally have good visibility of neighboring transmission systems. In this study, we assume the coordinating regions can observe similar state estimation flows on the M2M coordinated transmission constraints.

2.2.1 Centralized Real-Time Coordination

For centralized real-time M2M transmission coordination, the two RTOs may jointly clear the markets using a centralized M2M coordination model. This approach represents the mathematically optimal solution, as it optimizes the two areas simultaneously. The centralized M2M coordination models are therefore developed as benchmarks. The nodal real-time benchmark model for coordinated energy flow (C2) is formulated as follows.

In this model, region a and region b are coordination entities jointly optimizing transmission flow constraints in $C2_{loopflow}^{RT,ab}$. Region c is not part of the coordination. The flow contributions from noncoordinating entities may create loop flow impacts on the transmission constraints.

In this formulation, the entities do not coordinate on interchange scheduling or reserve procurement. Therefore, the power balance equations and reserve requirement constraints are enforced separately by each region based on predetermined regional net scheduled interchange and reserve requirements.

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The $C2^{RT}_{Central}$ configuration includes two optimization problems $\{C2^{RT,ab}_{SE}, C0^{RT,c}_{SE}\}$. Here, "SE" denotes that the transmission flow constraints are linearized around the observed state estimator flows.

In real-time models, each region uses state estimation as the starting point to calculate linearized transmission flow. As shown, this is equivalent to assume that loop flow impacts stay the same as previous interval.

$$C2^{RT,ab}_{SE} = Min_{g_{a,t},g_{b,t},s_t,rsv_{a,t},rsv_{b,t}} \left[c^T_{a,t}g_{a,t} + c^T_{b,t}g_{b,t} + \alpha 1^T_t s^{l_{ab}}_t\right]$$

Subject to:

$$f^{l_{ab}}_t = \widehat{f^{l_{ab}}_{t-1}} + ptdf^{l_{ab}}_{a,t} \cdot \left[g_{a,t} - d_{a,t} - (\hat{g}_{a,t-1} - \hat{d}_{a,t-1})\right]$$

$$+ptdf^{l_{ab}}_{b,t} \cdot \left[g_{b,t} - d_{b,t} - (\hat{g}_{b,t-1} - \hat{d}_{b,t-1})\right] \quad \text{(r1)}$$

Constraints $(d2) - (d5)$

$\forall\, l_{ab} \in L_{ab}$

$$C0^{RT,j}_{SE} = Min_{,g_{j,t},s_t,rsv_{j,t}} [c^T_{j,t}g_{j,t} + \alpha 1^T_t s^{l_j}_t]$$

Subject to:

$$f^{l_j}_t = \widehat{f^{l_j}_{t-1}} + ptdf^{l_j}_{j,t} \cdot \left[g_{j,t} - d_{j,t} - (\hat{g}_{j,t-1} - \hat{d}_{j,t-1})\right] \quad \text{(r2)}$$

Constraints (d7)-(d10)

$$\forall\, l_j \in L_j \; for \; j = c$$

where

$\widehat{f^{l_s}_{t-1}}$ is the state estimator (SE) flow for transmission constraint l_s at the end of interval $t-1$.

$\hat{g}_{j,t-1}$ is the vector of SE generation in megawatts (MW) in region j at the end of interval $t-1$.

$\hat{d}_{c,t-1}$ is the vector of SE load MW in region j at the end of interval $t-1$.

Constraints (r1) and (r2) represent transmission flow calculation linearized around SE flow. The linear approximation of SE flow is as follows in (r3):

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$$\widehat{f_{t-1}^{l_{ab}}} = ptdf_{a,t}^{l_{ab}} \cdot \left[\hat{g}_{a,t-1} - \hat{d}_{a,t-1}\right] + ptdf_{b,t}^{l_{ab}} \cdot \left[\hat{g}_{b,t-1} - \hat{d}_{b,t-1}\right] + ptdf_{c,t}^{l_{ab}} \cdot \left[\hat{g}_{c,t-1} - \hat{d}_{c,t-1}\right] \quad \text{(r3)}$$

From (r1) and (r3),

$$f_t^{l_{ab}} = ptdf_{a,t}^{l_{ab}} \cdot \left[g_{a,t} - d_{a,t}\right] + ptdf_{b,t}^{l_{ab}} \cdot \left[g_{b,t} - d_{b,t}\right] + ptdf_{c,t}^{l_{ab}} \cdot \left[\hat{g}_{c,t-1} - \hat{d}_{c,t-1}\right]$$

This is equivalent to assume loop flow from external region c is equal to its contribution to state estimation flow: $ptdf_{c,t}^{l_{ab}} \cdot \left[\hat{g}_{c,t-1} - \hat{d}_{c,t-1}\right]$. If we further assume generators perfectly follow the dispatch from $t-1$, then (r1) and (r2) assume loop flow equal to the external flow impact from previous interval $t-1$.

2.2.2 Distributed Real-Time Coordination

Real-time markets are solved on a rolling basis. Usually there is no time to exchange information and achieve convergence within one interval. Existing real-time coordination usually exchanges information from interval $t-1$ to adjust RT-SCED in interval t. Gradually the two RTOs aim to achieve convergence in multiple real-time intervals.

Section 6 discusses several algorithms developed under IRTOC for real-time M2M coordination on congestion management (C2).

2.2.3 Uncoordinated Real-Time Configuration

Without coordination on transmission constraints, each region needs to manage its own monitored lines within its own market-clearing optimization model. All regions may have impact on SE flow. SE flow is used as the starting point for flow constraint in (r2) for all regions. The market structure is represented by the following optimization problems:

$$C0_{SE}^{RT} = \{C0_{SE}^{RT,a}, C0_{SE}^{RT,b}, C0_{SE}^{RT,c}\}.$$

2.3 Multistage Multiregional Market Structure Evaluation Framework

With multistage multiregional coordination, it can be challenging to systematically evaluate the outcome. For example, the constraint flows shown in the RT-SCED of each region may not match the actual state estimation flow. Therefore, an emulation component is developed to systematically evaluate production cost, reserve violation cost, and pre- and post-contingency transmission violation costs.

Different coordination in day-ahead and real-time stages may result in different commitment and dispatch plans. In Figure 1, the day-ahead and real-time market can be configured with different formulations presented in Section 2. The commitment and dispatch plan can be fed into an emulator to calculate the actual transmission flow. For the cases with reserve products, the emulator can also calculate the flow post contingency and reserve deployment. The commitment cost, dispatch cost, and pre- and post-contingency flow violation costs from the emulator are added to form the total cost for consistent comparison. The implementation of the emulator is discussed in Section 5.

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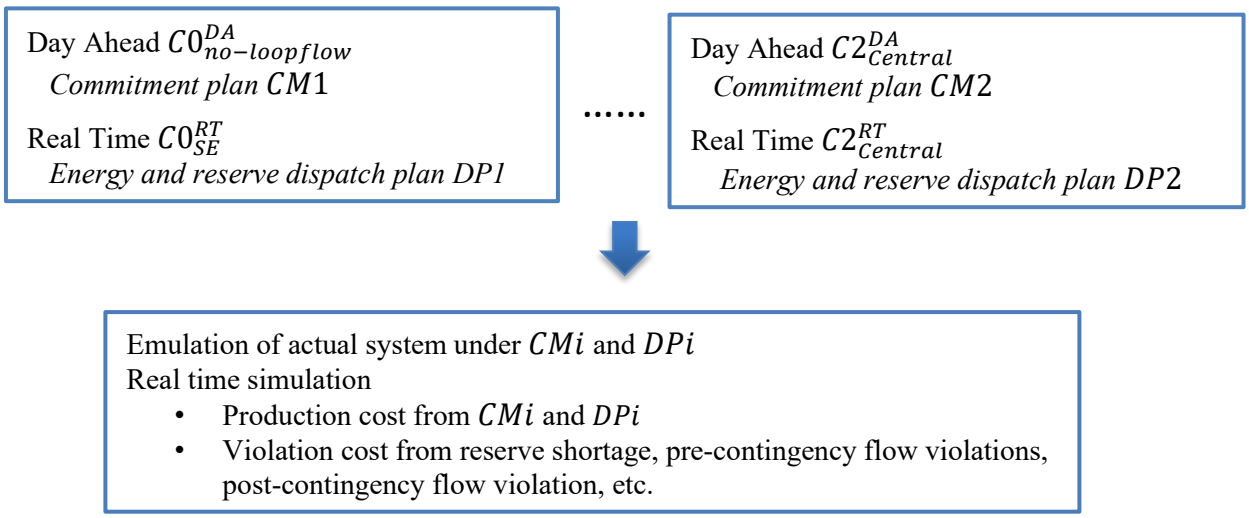

Figure 1. Evaluation framework with emulator

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3 Intra- and Interregional Reserve Deliverability

Reserves are defined for two main purposes: (1) managing uncertainties under normal operating conditions, such as regulation and flexible ramping products and (2) responding to post-contingency events, such as contingency reserves.

The purpose of reserve deliverability constraints is to ensure transmission limits are not violated after reserve deployment. Reserves can be deployed in many ways, and it is generally impractical to formulate all possible deployment scenarios. For contingency reserves, the most severe events—such as the loss of the largest generating unit—are typically considered (Chen et al. 2014).

In this project, we focus on contingency reserves to illustrate constraints that ensure reserve deliverability across both intraregional and interregional transmission constraints. We assume reserve sharing is not allowed; therefore, a generation contingency in one region must be covered by contingency reserves within the same region.

In the market-clearing model, each region monitors only its own contingency events and the associated reserve deployment impacts on transmission constraints monitored by that region. Post-reserve-deployment transmission flow constraints and post-reserve-power-balance constraints are enforced similar to Wang and Chen (2021).

The formulation for $C2^{DA}_{Central}$ is revised to $C2^{DA,RsvDeliv}_{Central} = \{C2^{DA,ab,RsvDeliv}_{loopflow}, C0^{DA,c,RsvDeliv}_{loopflow}\}$ as follows:

$$C2^{DA,ab,RsvDeliv}_{loopflow} = Min_{g_{a,t},g_{b,t},rsv_{a,t},rsv_{b,t}} \sum_{t\in T}[c^T_{a,t}g_{a,t} + c^T_{b,t}g_{b,t} + \alpha 1^T_t s^{l_{ab}}_t + \sum_{e\in E_a\cup E_b} \beta 1^T_t s^{l_{ab}}_{e,t}]$$

Subject to:

Constraints (d1), (d2), (d3), (d4), (d5)

$$f^{l_{ab}}_t - ptdf^{l_{ab}}_{e,t}\cdot g_{e,t} + ptdf^{l_{ab}}_{a,t}\cdot \Delta rsv_{e,a,t} - s^{l_{ab}}_{e,t} \le \overline{f^{l_{ab}}_t} \quad for\ e \in E_a \qquad (dr1)$$

$$1_{a,t}\cdot[\Delta rsve_{e,a,t}] = g_{e,t} \qquad for\ e \in E_a \qquad (dr2)$$

$$\Delta rsv_{e,a,t} \le rsv_{a,t} \qquad for\ e \in E_a \qquad (dr3)$$

$$f^{l_{ab}}_t - ptdf^{l_{ab}}_{e,t}\cdot g_{e,t} + ptdf^{l_{ab}}_{b,t}\cdot \Delta rsv_{e,b,t} - s^{l_{ab}}_{e,t} \le \overline{f^{l_{ab}}_t} \quad for\ e \in E_b \qquad (dr4)$$

$$1_{a,t}\cdot[\Delta rsve_{e,b,t}] = g_{e,t} \qquad for\ e \in E_b \qquad (dr5)$$

$$\Delta rsv_{e,b,t} \le rsv_{b,t} \qquad for\ e \in E_b \qquad (dr6)$$

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$$C0_{loopflow}^{DA,c,RsvDeliv} = Min_{g_{c,t},s_t,rsv_{c,t}} \sum_{t\in T}[c_{c,t}^T g_{c,t} + \alpha 1_t^T s_t^{l_c} + \sum_{e\in E_c} \beta 1_t^T s_{e,t}^{l_c}]$$

Subject to:

Constraints (d6), (d7), (d8), (d9), (d10)

$$f_t^{l_c} - ptdf_{e,t}^{l_c} \cdot g_{e,t} + ptdf_{c,t}^{l_c} \cdot \Delta rsv_{e,c,t} - s_{e,t}^{l_c} \le \overline{f_t^{l_c}} \qquad for\ e \in E_c \qquad \text{(dr7)}$$

$$1_{c,t} \cdot [\Delta rsve_{e,c,t}] = g_{e,t} \qquad for\ e \in E_c \qquad \text{(dr8)}$$

$$\Delta rsv_{e,c,t} \le rsv_{c,t} \qquad for\ e \in E_c \qquad \text{(dr9)}$$

where

e, E_j are the index and set of generation contingency events in region j

$g_{e,t}$ is the generation dispatch variable for contingency event e at interval t

$\Delta rsve_{e,j,t}$ is the vector of region j reserve deployment variables for contingency event e at interval t

$s_{e,t}^{l_s}$ is the violation variable for post reserve deployment for event e on transmission constraint l_s at interval t

β is the post-reserve-deployment transmission constraint violation penalty.

Constraints (dr1), (dr4) and (dr7) are post reserve deployment flow constraints under contingency event $g_{e,t}$. Constraints (dr2), (dr5) and (dr8) are post reserve deployment power balance equations, i.e., the deployed reserve should equal to the size of the event. Constraints (dr3), (dr6) and (dr9) ensure reserve deployment is within the cleared reserve capacity.

For certain events and reserve products, emergency transmission flow limits may be used in (dr1), (dr4), and (dr7).

In this formulation, reserve deployment variables $\Delta rsv_{e,j,t}$ are defined for each loss of a generation event $e \in E_j$ in region j. Without reserve sharing, only reserves in region j can respond to an event in E_j. Hence, the total reserve deployment for event e should match the size of the generation loss in post-reserve-deployment power balance constraints in (dr2), (dr5), and (dr8).

The post-reserve-deployment flow constraints are formulated for each event in (dr1), (dr4), and (dr7). It has three main components: flow from energy dispatch, flow impact from loss of generation event, and flow impact from reserve deployment.

Together these constraints can ensure reserves are procured at the proper location to minimize post event transmission flow violation. Without coordination, reserve deployment from one region may cause flow violation in another region.

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The National Laboratory of the Rockies' open-source Sienna modeling framework (National Laboratory of the Rockies n.d.) has created the largest representation of a power system ever simulated through the National Transmission Planning Study. It has capabilities for power system data management and assembly, large-scale power flow calculations, network analysis, and massive scale grid scheduling simulations using production cost modeling.

Through the IRTOC project, Sienna is enhanced to analyze contingency events in multiregional market clearing. The new functionality provides flexibility to evaluate post-reserve-deployment transmission constraints across all coordination configurations.

- When the reserve deployment model is enabled and generation outage events are defined, post-reserve-deployment constraints are added to the optimization model on monitored transmission constraints.
- This can be disabled globally by turning off the reserve deployment model or disabled for a specific area by not defining a generation outage in that area.
- Different outages can also be defined for different simulation stages.

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4 Intraregional and Interregional HVDC Optimization for Alternating Current Congestion Management

In this report, we assume lossless HVDC. Intraregional lossless HVDC does not affect the regional power balance. The AC line flow sensitivities at the "from" and "to" ends of an HVDC line can differ; therefore, HVDC can be scheduled to relieve AC transmission congestion, including M2M AC line constraints. Although interregional HVDC may have its "from" and "to" buses located in different regions, its schedule must maintain consistent megawatt injection and withdrawal at the two ends. As a result, it needs to be scheduled by a single entity. In this study, we assume the receiving region is responsible for optimizing HVDC.

The focus of this work is on congestion management for M2M AC transmission constraints. We assume the net interchange, which equals the sum of HVDC and AC tie-line flows, is fixed. HVDC can be scheduled by the scheduling entity to relieve M2M AC congestion as well as other internal AC transmission congestion.

The model can be extended in the future to represent HVDC as a dynamic schedule, where the net interchange can be adjusted based on the HVDC schedule. This extension would allow HVDC to be scheduled to simultaneously optimize the interchange and AC transmission flows.

The formulation for $C2_{Central}^{DA,RsvDeliv}$ is revised to $C2_{Central}^{DA,RsvDeliv,HVDC} = \{C2_{loopflow}^{DA,ab,RsvDeliv,HVDC}, C0_{loopflow}^{DA,c,RsvDeliv,HVDC}\}$ as follows:

$$C2_{loopflow}^{DA,ab,RsvDeliv,HVDC} = Min_{g_{a,t},g_{b,t},s_t,rsv_{a,t},rsv_{b,t}} \sum_{t\in T}[c_{a,t}^T g_{a,t} + c_{b,t}^T g_{b,t} + \alpha 1_t^T s_t^{l_{ab}} + \sum_{e\in E_a\cup E_b} \beta 1_t^T s_{e,t}^{l_{ab}}]$$

Subject to:

Constraints (d2), (d3), (d4), (dr1), (dr2), (dr3), (dr4), (dr5), (dr6)

$$f_t^{l_{ab}} = ptdf_{a,t}^{l_{ab}} \cdot [g_{a,t} - d_{a,t} + h_{a,t}^{to} - h_{a,t}^{from}] + ptdf_{b,t}^{l_{ab}} \cdot [g_{b,t} - d_{b,t} + h_{b,t}^{to} - h_{b,t}^{from}] + loopflow_{c,t}^{l_{ab}} \quad \text{(dh1)}$$

$$\begin{bmatrix} g_{a,t} \\ rsv_{a,t} \\ h_{a,t}^{to} \\ h_{a,t}^{from} \end{bmatrix} \in XH_{a,t}, \qquad \begin{bmatrix} g_{b,t} \\ rsv_{b,t} \\ h_{b,t}^{to} \\ h_{b,t}^{from} \end{bmatrix} \in XH_{b,t}, \quad \text{(drh2)}$$

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$$C0_{loopflow}^{DA,c,RsvDeliv} = Min_{g_{c,t},s_t,rsv_{c,t}} \sum_{t\in T}[c_{c,t}^T g_{c,t} + \alpha 1_t^T s_t^{l_c} + \sum_{e\in E_c} \beta 1_t^T s_{e,t}^{l_c}]$$

Subject to:

Constraints (d7), (d8), (d9), (dr7), (dr8), (dr9)

$$f_t^{l_c} = ptdf_{c,t}^{l_c} \cdot \left[g_{c,t} - d_{c,t} + h_{c,t}^{to} - h_{c,t}^{from}\right] + loopflow_{a,t}^{l_c} + loopflow_{b,t}^{l_c} \qquad \text{(dh3)}$$

$$\begin{bmatrix} g_{c,t} \\ rsv_{c,t} \\ h_{c,t}^{to} \\ h_{c,t}^{from} \end{bmatrix} \in XH_{c,t}, \qquad \text{(dh4)}$$

where

$h_{j,t}^{from}$ is the vector of monitored HVDC "from" bus withdraw in region j at interval t

$h_{j,t}^{to}$ is the vector of monitored HVDC "to" bus injection in region j at interval t

$XH_{j,t}$ is the feasible region for generator and HVDC in region j at interval t.

Constraints (dh1) and (dh3) are energy flows including HVDC impact. Injections and withdrawals from HVDC facilities not monitored by region j are reflected in its loop flow contribution. Without coordination, the monitoring region may optimize HVDC for its own benefit, potentially increasing AC congestion in other regions.

Constraints (dh2) and (dh4) are feasible regions for generators and HVDC in each of the areas.

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5 Sienna Decomposition Development

Through the IRTOC project, the team expanded the National Laboratory of the Rockies' open-source Sienna software (National Laboratory of the Rockies n.d.) by introducing a new Sienna Decomposition functionality.

5.1 Operational Structure

To represent operational entities and their collective impacts on the power system, the model incorporates combinations of balancing areas, synchronous regions, and coordinated subsystems as illustrated in Figure 2.

Area represents a balancing authority responsible for maintaining scheduled interchange and reserve procurement. In this report, the term *area* is used interchangeably with *region*.

In Sienna, a subsystem consists of a subset of the full system components. For this project, subsystems are used to represent coordinated operational entities—several areas that coordinate for interchange, transmission congestion management, and/or ancillary services. All areas within a subsystem have some level of visibility in each other's operations.

The IRTOC project focuses on the coordination of transmission congestion management. Therefore, interchange schedules and reserve requirements are maintained within each area. However, multiple areas within a subsystem can jointly optimize their operations to manage M2M transmission constraints. Each subsystem defines a set of coordinated transmission constraints, which may or may not coincide with physical tie-lines.

Areas may span multiple asynchronous regions that are connected via HVDC links. Properly representing synchronous regions is important to ensure power transfer distribution factors (PTDFs) are calculated properly. PTDFs must be computed separately within each synchronous region to ensure correct line flow calculation in the optimization.

This structure increases the complexity of model construction and simulation. With the new framework, Sienna supports different operational configurations across multiple simulation stages. The emulator can also mimic state estimation and generation contingency analysis to simulate the resulting impacts on the interconnected power system.

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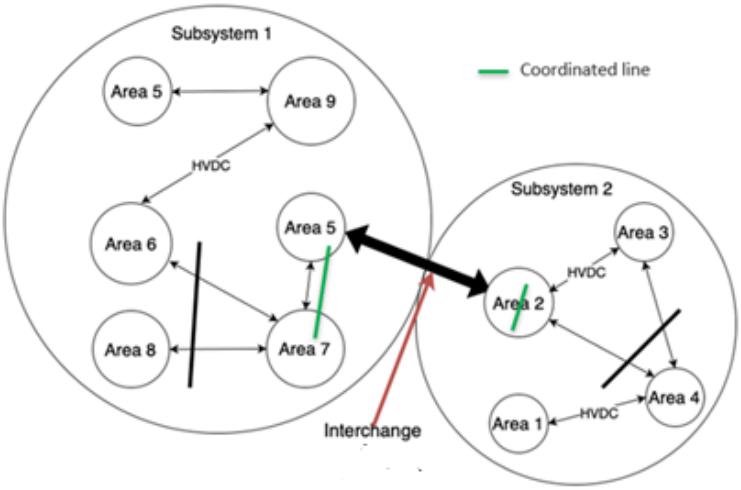

Figure 2. Illustration of area, subsystem, and coordinated lines

5.2 Multistage Multiregional Simulation Framework

5.2.1 Optimization Model

Sienna provides different formulations for modeling the power network of varying complexity. The AreaPTDF formulation uses the PTDF matrix to compute the fraction of power transferred in the network across the branches, and simultaneously balances the power by area (instead of system-wide). Sienna Decomposition extends this formulation to include the SplitAreaPTDF, allowing for the decomposition of the network model by subsystem according to the coordination structure of interest. These templates offer flexibility to configure different subsystem structures across different simulation stages.

- Power balance constraints

  In both AreaPTDF and SplitAreaPTDF, power balance is enforced at the area level, similar to constraint (d3).

  - The net interchange $Ich_{j,t}$ for region j is the sum of the interchange flows between region j and its neighboring areas.
  - The interchange flow between two areas is defined as the sum of the modeled tie-line flows between the two areas. It can be modeled as a variable in Sienna with upper and lower bounds to limit the allowable interchange between the two areas. If these limits are set sufficiently wide, the formulation becomes equivalent to a global power balance constraint.

- Reserve requirement constraints

  Sienna allows users to define reserve products, the responding devices, and the associated requirements. This structure provides flexibility for different areas to define and enforce their own reserve products.

- Transmission constraints

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In the AreaPTDF model, transmission constraints are jointly optimized by all areas. The flow constraint for the three-region example in Subsection 1.1.1 is:

$$f_t^{l_{AreaPTDF}} = ptdf_t^{l_{AreaPTDF}} \cdot [g_{a,t} - d_{a,t}] + ptdf_t^{l_{AreaPTDF}} \cdot [g_{b,t} - d_{b,t}]$$

$$+ptdf_t^{l_{AreaPTDF}} \cdot [g_{c,t} - d_{c,t}]$$

In SplitAreaPTDF, multiple subsystems can be defined, with each subsystem having its own optimization model. Within a subsystem, transmission constraints can be enforced as in (d1)–(d2) and (d6)–(d7). Loop flows from external subsystems are incorporated using the methods described in Section 5.2.2.

- Post-reserve-deployment transmission constraints

  One or more generation outages and corresponding reserve responses can be defined for each area. For subsystems with defined generation outages, post-reserve-deployment transmission constraints, similar to (dr1)–(dr6), are enforced.

5.2.2 Multistage Data Passing and Loop Flow Model

The Sienna Decomposition multistage simulation framework allows users to configure AreaPTDF or SplitAreaPTDF models, define subsystems, and specify monitored transmission constraints and generation outages at different stages.

This subsection describes how data is passed between stages and how this affects area interchanges and loop flows.

- Area interchanges

  The day-ahead and real-time models in Section 1 assume fixed interchange schedules. In practice, interchanges are largely driven by physical transactions scheduled by scheduling entities.

  In this study, a network model without any enforced transmission constraints (i.e. a copperplate model) is used in Stage 1 to determine economically efficient interchanges. Interchange flow limits are set sufficiently wide, representing unconstrained economic interchange across all areas.

  The resulting interchange schedules from Stage 1 are passed forward and fixed in subsequent stages.

- External injections and withdrawals

  External subsystem data is passed between individual optimization problems depending on the stage and coordination approach. In some cases, results are passed from a previous stage for the same time ("vertical passing"). In other cases, results are passed from a previous time step of the same stage problem ("horizontal passing"). Figure 3 Illustrates an example of a multi-stage, multi-configuration simulation which employs both approaches.

  In Stage S1, regions A1 and A2 in the example in Figure 3 are jointly optimized using the AreaPTDF model with multi-interval optimization. This stage produces estimated interchange schedules, which are then fixed in Stages S2 and S3.

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Stage S2 simulates the day-ahead market with fixed interchange schedules. Although dispatchable transactions may be allowed in practice, they typically represent a small portion of total interchange. Dispatchable transactions and interchange optimization will be studied in the future. S2 also uses multi-interval optimization but adopts the SplitAreaPTDF formulation to simulate two separate markets, A1 and A2.

For the A1 optimization model, external injections and withdrawals at A2 buses are taken from the Stage S1 solution. Similarly, for A2, the external injections and withdrawals at A1 buses are taken from Stage S1.

This vertical passing of external net bus injections effectively sets loop flows based on the external solution from Stage S1.

Stage S3 simulates real-time market clearing of two markets A1 and A2 using a single-interval rolling optimization. External net bus injections are passed horizontally from interval t to $t + 1$, except for the first interval where they are taken from Stage S2.

As discussed in Section 1.2.1, the loop flow calculated from the horizonal passing of external net injections is equivalent to constraints (r1)–(r2), where transmission flows from the new dispatch are linearized around the observed state estimator flows.

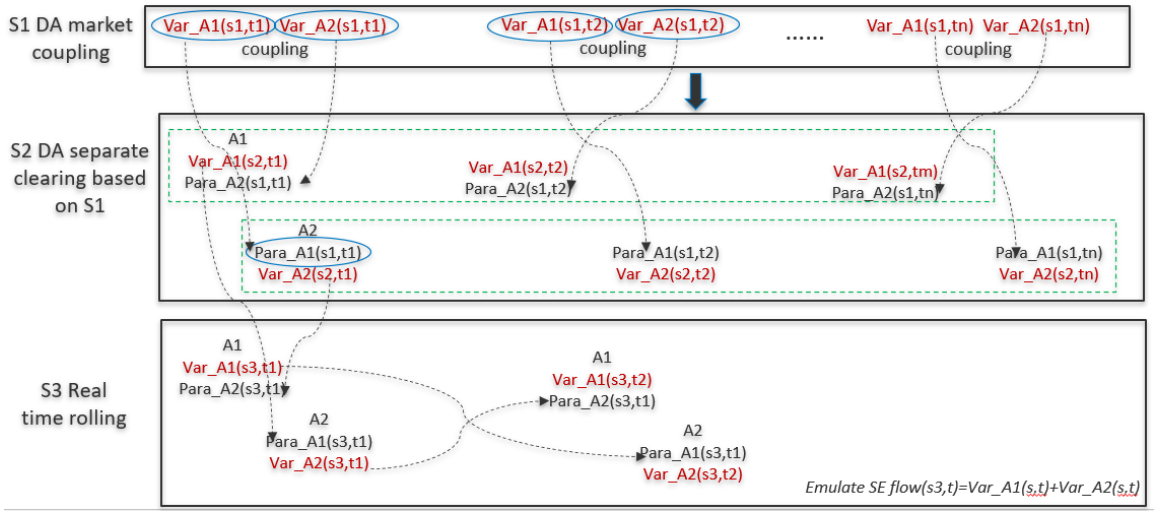

Figure 3. Sienna Decomposition multistage data passing.

Var_Aj represents flow determined by the dispatch variables in region j; Para_Aj represents flow determined by the fixed net injections in region j.

5.2.3 Emulator

An emulator model in Sienna can be added as the final simulation stage to represent the realized behavior of the system subject to the previous decision models. The emulator uses the AreaPTDF model. Commitment and dispatch variables for all generators, HVDC schedules, and reserve clearing variables can be fed forward from the real-time market stage.

The state estimator energy flows are calculated in the emulator based on the fixed dispatch variables. The resulting state estimator flow violations represent pre-generation contingency violations under the given market design.

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Generation outage events can also be modeled in the emulator, even if they are not defined in the day-ahead and/or real-time simulation stages. For the three-region example, post-reserve-deployment transmission constraints are enforced for all monitored lines and all contingency events as shown in (em1), (em2), and (em3). The corresponding violation slack variables represent post-generation contingency flow violations under the given market design.

By feeding forward and fixing the commitment and dispatch variables, the commitment and dispatch costs calculated in the emulator represent the overall production cost under the given market design.

$$f_t^l - ptdf_{e,t}^l \cdot g_{e,t} + ptdf_t^l \cdot \Delta rsv_{e,j,t} - s_{e,t}^l \le \overline{f_t^l} \qquad for\ e \in E_j \qquad \text{(em1)}$$

$$1_{a,t} \cdot \left[\Delta rsve_{e,j,t}\right] = g_{e,t} \qquad for\ e \in E_j \qquad \text{(em2)}$$

$$\Delta rsv_{e,j,t} \le rsv_{j,t} \qquad for\ e \in E_j \qquad \text{(em3)}$$

$$for\ j \in \{a, b, c\}$$

The sum of the total production cost, state estimator flow violation cost, and post-generation contingency flow violation cost can be used as a metric to evaluate the economic and reliability performance of the market design.

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6 Real-Time Coordination Algorithm Development

Several real-time distributed coordination algorithms are developed and implemented in Sienna Decomposition and summarized in Chen et al. (2025). Chen et al. identifies shortcomings in existing M2M approaches, where coordinated regions exchange shadow prices and relief requests to optimize congestion relief allocations across interconnected regions. Two methods are proposed to enhance flow and price convergence.

The first method proposes both regions use state estimator flows directly to determine relief requirements, eliminating delays and potential oscillations caused by using market flows calculated from the prior period under the existing M2M approach.

The second method involves exchanging transmission relief cost curves, enabling each region to integrate relief cost curves from other regions into its RT-SCED. This method can effectively extend the coordination to multiple transmission lines and across more than two regions.

The alternating direction method of multipliers (ADMM) is also applied to the M2M coordination problem and compared with the proposed methods.

Case studies on small- and large-scale systems demonstrate the effectiveness of these approaches.

6.1 Method 1: Single Shadow Price Exchange

Under the currently implemented M2M coordination processes (Luo et al. 2015), each transmission line has a monitoring RTO (MRTO) responsible for managing and controlling its flow through market-clearing processes. Typically, transmission congestion is managed solely by the MRTO. If the MRTO cannot relieve the constraint independently, it may request TLR under NERC procedures (NERC n.d.). For RTOs with M2M operational agreements, the MRTO can request relief from the non-monitoring RTO (NMRTO).

Under the current M2M implementation (Chen et al. 2017; Yang et al. 2021), the MRTO calculates relief requests based on the solution from the previous period and exchanges shadow prices with the NMRTO. However, delays in these calculations and the use of piecewise-linear offer curves can lead to discontinuous dispatch adjustments, resulting in oscillations in shadow prices and transmission flows (Chen et al. 2017; Baldick and Chatterjee 2014).

For large RTOs in the United States, coordinated transmission constraints are typically observable in the state estimation of both RTOs. For simplicity, we assume both RTOs observe the same state estimation flow for the coordinated transmission lines at time $t-1$. The Sienna Emulator is used to calculate the equivalent state estimation flow based on generation dispatch results and load levels from all regions.

In Method 1, the M2M process is improved by eliminating the need for the MRTO to calculate and send relief requests based on previous solutions. Instead, the two RTOs use the latest observed state estimation flows and the previous-period shadow prices from both regions to determine the amount of relief or relaxation through SCED. Each RTO uses shadow prices as

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indicators to estimate the cost of providing or receiving congestion relief from the neighboring region.

This method requires minimal information exchange and only minor updates to the SCED formulation. However, it assumes shadow prices remain constant and do not change with variations in flow contributions. As a result, it may require more iterations to converge and may be more difficult to extend to multiple transmission constraints or coordination among more than two regions.

6.2 Method 2: Relief Cost Curve Exchange Method

The relief cost curve method extends the single shadow price exchange approach by exchanging a piecewise-linear cost curve that quantifies the marginal cost at each level of relief. This cost curve better represents the cost variation across different relief levels, allowing each region to optimize its relief actions based on more detailed cost information provided by neighboring regions.

After solving SCED, each RTO generates relief cost curves by adjusting the right-hand side of the coordinated transmission constraints (d2) and (d7) and re-solving SCED to obtain the corresponding shadow prices (i.e., relief costs) for the adjusted flow contributions.

The generated relief cost curves are then exchanged and incorporated into the SCED run for the next interval. Additional computation time is required to generate these curves. In the Eastern Interconnection case study in Chen et al. (2025), generating the curves requires approximately 10% of the SCED dispatch solution time, and this overhead can be further reduced through parallel computing.

The case study in Chen et al. (2025) demonstrates this method can coordinate multiple transmission constraints with coordination across two or three regions. It also converges faster than Method 1.

6.3 Method 3: Alternating Direction Method of Multipliers

In Ren et al. (2025), an ADMM-based coordination method is proposed to address the M2M congestion management problem with convergence guarantees, in which relief requests are obtained through iterative updates of dual prices. Because ADMM adjusts dual variables iteratively to guide convergence, transmission flow violations can remain large before convergence is achieved. To compare the operational implications of different approaches, the ADMM-based method is also implemented and evaluated on a large-scale, real-world Eastern Interconnection model.

By contrast, the two new proposed methods explicitly enforce flow limit constraints, enabling faster reduction of flow violations during the coordination process. These methods exchange either shadow prices or relief cost curves. Each RTO incorporates the received shadow prices or relief cost curves directly into its market-clearing model to determine the economically efficient relief contribution from the coordinating RTOs.

Operational implications are critical when developing M2M coordination methods. In practice, when a transmission constraint violation exceeds a specified threshold (e.g., 125% of the

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emergency rating at MISO), it is classified as a violation of interconnection reliability operating limits (Midcontinent Independent System Operator 2024). Failure to operate within interconnection reliability operating limits—or to mitigate violations within the required time frame—may constitute a violation of NERC reliability standards and may result in substantial penalties ("Top–001-5–Transmission Operations" n.d.).

Case studies on a large-scale Eastern Interconnection system demonstrate the two proposed new methods more effectively address operational flow violation risks while maintaining coordination efficiency.

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7 Case Studies

7.1 Multistage Coordination Study

This section summarizes the case studies on multistage coordination for M2M transmission constraints and the distributed real-time coordination algorithms. This project focuses on developing foundational tools and methodologies for M2M transmission studies. The case studies are intended to demonstrate the methodology rather than to quantify the benefits. A comprehensive benefit analysis would require additional data collection.

Because of data availability limitations, the study includes the following simplifications:

- Day-ahead and real-time markets are assumed to use the same forecast time series. Therefore, the results primarily reflect the impact of market structure. Future work will consider uncertainties between day-ahead and real-time operations.
- All stages use hourly intervals. Intra-hour variability and its impact on coordination will be studied in future work.

7.1.1 Reliability Test System_Grid Modernization Lab Consortium (RTS_GMLC) Test Case

The Sienna multistage coordination framework is first tested on the RTS_GMLC test case (Sienna RTS-GLMC Test Data n.d.).

This system has three regions: area 1, area 2, and area 3. In this study, three generation outages are considered:

Area 1: "121_NUCLEAR_1"	(OU1)
Area 2: "221_CC_1"	(OU2)
Area 3: "317_WIND_1"	(OU3)

In all configurations, Stage 1 (S1) is solved using AreaPTDF without enforcing transmission constraints. The interchange flow limits are set sufficiently wide so that they are nonbinding. The resulting area interchange therefore reflects the economically optimal interchange under an unconstrained system.

- **Sim_1 to simulate existing operations where there is no M2M coordination and M2M constraints are managed by the MRTO in real-time only**

  In this configuration, there is no M2M coordination in either the day-ahead stage (S2) or the real-time stage (S3), as shown in Table 2.

  The M2M coordinated lines "A28" and "B28" are not considered in the S2 day-ahead clearing, mainly because it is difficult to estimate loop flows accurately at this stage.

  In real-time S3, each region monitors its own transmission constraint(s) under both pre- and post-generation outage contingency conditions. Each RTO considers only its own contingency events.

  The column "Feed Forward" indicates the variables that are passed to and fixed in the subsequent stage. In the emulator stage (S4), all variables except the reserve deployment

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variables are fixed. This setup allows evaluation of the state-estimated flows and post-reserve-deployment flows under the defined outage scenarios.

Table 2. RTS Sim_1 Configuration

Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve-Deployment Constraint	Feed Forward
S1	AreaPTDF	SCUC (1X24h)	N/A	No	No	Area interchange HVDC schedule
S2	SplitAreaPTDF	SCUC (1X24h)	a = {1} b = {2} c = {3}		No	Area interchange Commitment HVDC schedule
S3	SplitAreaPTDF	SCED (Rolling 24X1h)	a = {1} b = {2} c = {3}	"A28" in a "B28" in b	"A28" under OU1 "B28" under OU2	Area interchange Commitment Generation dispatch Cleared reserve HVDC schedule
S4	AreaPTDF	Emulator (24X1h)	N/A	"A28" and "B28"	"A28" and "B28" under all three outages: OU1, OU2, and OU3	

- **Sim_2 to simulate no M2M coordination, but M2M constraints are managed by the MRTO in both day-ahead and real-time stages**

  In this configuration, there is no M2M coordination in either the day-ahead stage (S2) or the real-time stage (S3).

  The M2M coordinated lines "A28" and "B28" are **considered** in the S2 day-ahead clearing. The external loop flows are based on the bus injections from S1. It may provide better day-ahead commitment to feed to real-time S3.

  Similar to Sim_1, in real-time S3, each region monitors its own transmission constraint(s) under both pre-contingency and post-contingency conditions. Each RTO considers only its own contingency events. The configuration detail is shown in Table 3.

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Table 3. RTS Sim_2 Configuration

Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve-Deployment Constraint	Feed Forward
S1	AreaPTDF	SCUC (1X24h)	N/A	No	No	Area interchange HVDC schedule
S2	SplitAreaPTDF	SCUC (1X24h)	a = {1} b = {2} c = {3}	"A28" in a "B28" in b	"A28" under OU1 "B28" under OU2	Area interchange Commitment HVDC schedule
S3	SplitAreaPTDF	SCED (Rolling 24X1h)	a = {1} b = {2} c = {3}	"A28" in a "B28" in b	"A28" under OU1 "B28" under OU2	Area interchange Commitment Generation dispatch Cleared reserve HVDC schedule
S4	AreaPTDF	Emulator (24X1h)	N/A	"A28" and "B28"	"A28" and "B28" under all three outages: OU1, OU2, and OU3	

- **Sim_3 to simulate M2M coordination in the day-ahead stage but not in the real-time stage**

  In this configuration, there is M2M coordination in the day-ahead stage (S2). But in the real-time stage (S3), there is no M2M coordination, and transmission constraints are managed by the MRTO.

  The M2M coordinated lines "A28" and "B28" are jointly managed by the coordinated RTOs in subsystem *ab* in S2 day-ahead clearing. The external loop flows are based on the bus injections from S1. The formulation is similar to $C2^{DA}_{Central}$ in Section 1.1.1. It provides better day-ahead commitment to feed to real-time S3.

  Similar to Sim_1, in real-time S3, each region monitors its own transmission constraint(s) under both pre- and post-generation outage contingency conditions. Each RTO considers only its own contingency events. The detailed configuration is shown in Table 4.

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Table 4. RTS Sim_3 Configuration

Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve-Deployment Constraint	Feed Forward
S1	AreaPTDF	SCUC (1X24h)	N/A	No	No	Area interchange HVDC schedule
S2	SplitAreaPTDF	SCUC (1X24h)	ab = {1,2} c = {3}	**"A28" and "B28" in ab**	**"A28" and "B28" under OU1 and OU2**	Area interchange Commitment HVDC schedule
S3	SplitAreaPTDF	SCED (Rolling 24X1h)	a = {1} b = {2} c = {3}	"A28" in a "B28" in b	"A28" under OU1 "B28" under OU2	Area interchange Commitment Generation dispatch Cleared reserve HVDC schedule
S4	AreaPTDF	Emulator (24X1h)	N/A	"A28" and "B28"	"A28" and "B28" under all three outages: OU1, OU2, and OU3	

- **Sim_4 to simulate M2M coordination in real time but not in the day-ahead stage**

  In this configuration, there is M2M coordination in real time (S3). But in the day-ahead stage (S2), the M2M transmission constraints are ignored.

  The M2M coordinated lines "A28" and "B28" are jointly managed by the coordinated RTOs in subsystem *ab* in S3 real-time clearing. The formulation is similar to $C2^{RT}_{central}$ in Section 1.2.1. The detailed configuration is in Table 5.

Table 5. RTS Sim_4 Configuration

Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve-Deployment Constraint	Feed Forward
S1	AreaPTDF	SCUC (1X24h)	N/A	No	No	Area interchange HVDC schedule
S2	SplitAreaPTDF	SCUC (1X24h)	a = {1} b = {2} c = {3}	No	No	Area interchange Commitment HVDC schedule
S3	SplitAreaPTDF	SCED (Rolling 24X1h)	ab = {1,2} c = {3}	**"A28" and "B28" in ab**	**"A28" and "B28" under OU1 and OU2**	Area interchange Commitment Generation dispatch Cleared reserve HVDC schedule
S4	AreaPTDF	Emulator (24X1h)	N/A	"A28" and "B28"	"A28" and "B28" under all three outages: OU1, OU2, and OU3	

The four configurations are simulated for the following 2 weeks: January 8, 2020–January 14, 2020 and August 8, 2020–August 14, 2020. The results are shown in Figure 4.

In Figure 4, the production cost, violation cost, and total cost are compared relative to the corresponding Simu_1 results.

- The production cost includes startup, shutdown, and incremental energy costs.

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- The violation cost includes reserve shortage (penalty $1,000/MWh), emulator energy flow violation (penalty $2,000/MWh), and post-reserve-deployment transmission violation ($800/MWh).
- The total cost is the sum of production cost and violation cost.

In this study, only two transmission constraints, "A28" and "B28," are considered. Under the original 500-MW line ratings, neither line is binding in any of the simulation scenarios. To demonstrate the impact of different market configurations, the ratings of these two lines are reduced from 500 MW to 350 MW and 150 MW, respectively.

Overall, **Sim_3**, which includes day-ahead coordination between area 1 and area 2, provides the largest reduction in total cost, even though there is no coordination in real time.

Sim_1 and **Sim_4** do not include the two monitored lines in the day-ahead market. In **Sim_4**, Areas 1 and 2 coordinate on congestion management in real time, which reduces the total cost in the summer week; however, the reduction is smaller than that achieved through day-ahead coordination in **Sim_3**. In the winter week, real-time total cost in Sim_4 is slightly higher than Sim_1.

In **Sim_2**, the two lines are considered by the NMRTO without coordination between the regions. The loop flows from Stage 1 (copperplate) are relatively accurate given the limited number of transmission constraints in this study. As a result, **Sim_2** produces results similar to those of **Sim_3**. This indicates that if regions can estimate loop flows accurately in the day-ahead stage, it can be highly beneficial for managing M2M congestion.

Figure 4. RTS simulation results

7.1.2 Eastern Interconnection Test Case

The Sienna Eastern Interconnection (EI) model is used to study MISO and SPP M2M transmission coordination. A total of 11 M2M transmission constraints, including 3 MISO lines and 8 SPP lines, are selected based on the top M2M settlement payment constraints (Organization of MISO States n.d.).

In this study, two generation outages are considered:

- The largest generator outage in MISO (OU1)
- The largest generator outage in SPP. (OU2)

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In this study, we use a 10-min spinning reserve to illustrate post-reserve-deployment constraints. In reality, 10-min offline supplemental reserve can also be deployed for contingency events. MISO and SPP also have other products, such as 30-min or 60-min products. More detailed reserve deployment constraints will be studied in the future.

In all configurations, Stage S1 is solved using AreaPTDF without enforcing transmission constraints. The interchange flow limits are set sufficiently wide so that they are nonbinding. The resulting area interchange reflects the economically optimal interchange under an unconstrained system.

- **Sim_1 to simulate existing operations in which there is no M2M coordination and M2M constraints are managed by the MRTO in real time only**

  In this configuration, there is no M2M coordination in either the day-ahead stage (S2) or the real-time stage (S3).

  The 11 M2M coordinated lines are not considered in the S2 day-ahead clearing, mainly because it is difficult to estimate loop flows accurately at this stage.

  In real-time S3, each region monitors its own transmission constraint(s) under both pre- and post-generation outage contingency conditions. Each RTO considers only its own contingency events.

  The column "Feed Forward" indicates the variables that are passed to and fixed in the subsequent stage. In the emulator stage (S4), all variables except the reserve deployment variables are fixed. This setup allows evaluation of the state estimation flows and post-reserve-deployment flows under the defined outage scenarios.

  In the EI study, different configurations of HVDC feed forward and reserve deliverability are also evaluated. Table 6 shows the configuration for **Sim_1_RvD1_hff1**, in which the HVDC schedule is fed forward from the day-ahead to the real-time stage (hff1), and post-reserve-deployment transmission constraints are enforced under the defined outage scenarios.

Table 6. EI Sim_1_ RvD1_hff1 Configuration

Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve-Deployment Constraint	Feed Forward
S1	AreaPTDF	SCUC (1X24h)	N/A	No	No	Area interchange
S2	SplitAreaPTDF	SCUC (1X24h)	MISO = {MISO} SPP = {SPP} OTHER = {all other EI areas}	No	No	Area interchange Commitment HVDC schedule
S3	SplitAreaPTDF	SCED (Rolling 24X1h)	MISO = {MISO} SPP = {SPP}	3 lines in MISO	3 MISO lines under OU1	Area interchange Commitment

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Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve-Deployment Constraint	Feed Forward
			OTHER = {all other EI areas}	8 lines in SPP	8 SPP lines under OU2	Generation dispatch Cleared reserve HVDC schedule
S4	AreaPTDF	Emulator (24X1h)	N/A	All 11 lines	All 11 lines under outages OU1 and OU2	

Table 7 shows the configuration for **Sim_1_RvD0_hff1**, in which the HVDC schedule is fed forward from the day-ahead to the real-time stage (hff1), and post-reserve-deployment transmission constraints are not enforced.

Table 7. EI Sim_1_ RvD0_hff1 Configuration

Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve-Deployment Constraint	Feed Forward
S1	AreaPTDF	SCUC (1X24h)	N/A	No	No	Area interchange
S2	SplitAreaPTDF	SCUC (1X24h)	MISO = {MISO} SPP = {SPP} OTHER = {all other EI areas}	No	No	Area interchange Commitment HVDC schedule
S3	SplitAreaPTDF	SCED (Rolling 24X1h)	MISO = {MISO} SPP = {SPP} OTHER = {all other EI areas}	3 lines in MISO 8 lines in SPP	No	Area interchange Commitment Generation dispatch Cleared reserve HVDC schedule
S4	AreaPTDF	Emulator (24X1h)	N/A	All 11 lines	All 11 lines under outages OU1 and OU2	

Table 8 shows the configuration for **Sim_1_RvD0_hff0**, in which the HVDC schedule is not fed forward from the day-ahead to the real-time stage (hff0), and post-reserve-deployment transmission constraints are not enforced. The HVDC schedule is optimized in real time by the monitoring region that is assumed to be the receiving area in this study.

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Table 8. EI Sim_1_ RvD0_hff1 Configuration

Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve-Deployment Constraint	Feed Forward
S1	AreaPTDF	SCUC (1X24h)	N/A	No	No	Area interchange
S2	SplitAreaPTDF	SCUC (1X24h)	MISO = {MISO} SPP = {SPP} OTHER = {all other EI areas}	No	No	Area interchange Commitment
S3	SplitAreaPTDF	SCED (Rolling 24X1h)	MISO = {MISO} SPP = {SPP} OTHER = {all other EI areas}	3 lines in MISO 8 lines in SPP	No	Area interchange Commitment Generation dispatch Cleared reserve HVDC schedule
S4	AreaPTDF	Emulator (24X1h)	N/A	All 11 lines	All 11 lines under outages OU1 and OU2	

- **Sim_2 to simulate no M2M coordination, but M2M constraints are managed by the MRTO in both the day-ahead and real-time stages**

  In this configuration, there is no M2M coordination in either the day-ahead stage (S2) or the real-time stage (S3).

  The M2M coordinated lines are **considered** in the S2 day-ahead clearing. The external loop flows are based on the bus injections from S1. It may provide better day-ahead commitment to feed to real-time S3.

  Similar to Sim_1, in real-time S3, each region monitors its own transmission constraint(s) under both pre- and postgeneration outage contingency conditions. Each RTO considers only its own contingency events.

  Table 9 is the configuration for **Sim_2_ RvD1_hff1. Sim_2_ RvD0_hff1 and Sim_2_ RvD0_hff0** can be configured similarly to Table 7 and Table 8 on HVDC feed forward and reserve deliverability constraints.

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Table 9. EI Sim_2_ RvD1_hff1 Configuration

Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve Deployment Constraint	Feed Forward
S1	AreaPTDF	SCUC (1X24h)	N/A	No	No	Area interchange
S2	SplitAreaPTDF	SCUC (1X24h)	MISO = {MISO} SPP = {SPP} OTHER = {all other EI areas}	3 lines in MISO 8 lines in SPP	3 MISO lines under OU1 8 SPP lines under OU2	Area interchange Commitment HVDC schedule
S3	SplitAreaPTDF	SCED (Rolling 24X1h)	MISO = {MISO} SPP = {SPP} OTHER = {all other EI areas}	3 lines in MISO 8 lines in SPP	3 MISO lines under OU1 8 SPP lines under OU2	Area interchange Commitment Generation dispatch Cleared reserve HVDC schedule
S4	AreaPTDF	Emulator (24X1h)	N/A	All 11 lines	All 11 lines under outages OU1 and OU2	

- **Sim_3 to simulate M2M coordination in the day-ahead but not in the real-time stage**

  In this configuration, there is M2M coordination in the day-ahead stage (S2). But in the real-time stage (S3), there is no M2M coordination, and transmission constraints are managed by the MRTO.

  The 11 M2M coordinated lines are jointly managed by the coordinated RTOs in subsystem *MISOSPP* in S2 day-ahead clearing. The external loop flows are based on the bus injections from S1. The formulation is similar to $C2^{DA}_{Central}$ in Section 1.1.1. It provides better day-ahead commitment to feed to real-time S3.

  Similar to Sim_1, in real-time S3, each region monitors its own transmission constraint(s) under both pre- and post-generation outage contingency conditions. Each RTO considers only its own contingency events.

  Table 10 is the configuration for **Sim_3_ RvD1_hff1. Sim_3_ RvD0_hff1 and Sim_3_ RvD0_hff0** can be configured similarly to Table 7 and Table 8 on HVDC feed forward and reserve deliverability constraints.

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Table 10. EI Sim_3_RvD1_hff1 Configuration

Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve-Deployment Constraint	Feed Forward
S1	AreaPTDF	SCUC (1X24h)	N/A	No	No	Area interchange
S2	SplitAreaPTDF	SCUC (1X24h)	MISOSPP = {MISO,SPP} OTHER = {all other EI areas}	All 11 lines in MISOSPP	All 11 lines under OU1 and OU2	Area interchange Commitment HVDC schedule
S3	SplitAreaPTDF	SCED (Rolling 24X1h)	MISO = {MISO} SPP = {SPP} OTHER = {all other EI areas}	3 lines in MISO 8 lines in SPP	3 MISO lines under OU1 8 SPP lines under OU2	Area interchange Commitment Generation dispatch Cleared reserve HVDC schedule
S4	AreaPTDF	Emulator (24X1h)	N/A	All 11 lines	All 11 lines under outages OU1 and OU2	

- **Sim_4 to simulate M2M coordination in the real-time stage but not in the day-ahead stage**

  In this configuration, there is M2M coordination in real time (S3). But in the day-ahead stage (S2), the M2M transmission constraints are ignored.

  The M2M coordinated lines are jointly managed by the coordinated RTOs in subsystem *MISOSPP* in S3 real-time clearing. The formulation is similar to $C2^{RT}_{central}$ in Section 1.2.1.

  Table 11 is the configuration for **Sim_4_ RvD1_hff1. Sim_4_ RvD0_hff1 and Sim_4_ RvD0_hff0** can be configured similarly to Table 7 and Table 8 on HVDC feed forward and reserve deliverability constraints.

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Table 11. EI Sim_4_RvD1_hff1 Configuration

Stage	Model Template	Model	Subsystems	Transmission Constraints	Post-Reserve Deployment Constraint	Feed Forward
S1	AreaPTDF	SCUC (1X24h)	N/A	No	No	Area interchange
S2	SplitAreaPTDF	SCUC (1X24h)	MISO = {MISO} SPP = {SPP} OTHER = {all other EI areas}	No	No	Area interchange Commitment HVDC schedule
S3	SplitAreaPTDF	SCED (Rolling 24X1h)	MISOSPP = {MISO,SPP} OTHER = {all other EI areas}	All 11 lines in MISOSPP	All 11 lines under OU1 and OU2	Area interchange Commitment Generation dispatch Cleared reserve HVDC schedule
S4	AreaPTDF	Emulator (24X1h)	N/A	All 11 lines	All 11 lines under outages OU1 and OU2	

The 12 configurations are simulated on the EI model for the following dates: January 15, 2023, July 15, 2023, and October 15, 2023. The simulation results are shown in Figure 5. For each day, the graph presents the differences in production cost, violation cost, and total cost relative to the corresponding values under **Sim_1_RvD0_hff0**.

Key takeaways from the EI simulation:

- **Sim_3**, with day-ahead coordination, provides the largest reduction in violation cost and total cost, especially when the violation cost is high on January 15, 2023.
- **Sim_2**, which models M2M constraints in the day-ahead market using approximated external loop flows, also helps reduce violation costs. The total cost reduction is smaller than that in **Sim_3** but is significantly larger than the reduction achieved by coordinating only in real time when the violation cost is high on January 15, 2023.
- **Sim_4**, with M2M coordination only in real time, may reduce violation and total costs; however, the reductions are smaller than those achieved in **Sim_2** and **Sim_3** in most cases.
- Feeding forward HVDC schedules (hff1) and enforcing reserve deliverability (RvD1) in **Sim_2** and **Sim_3** may further reduce total costs.
- Under **Sim_1** and **Sim_4**, where M2M constraints are not considered in the day-ahead market, feeding forward HVDC schedules from the day-ahead to the real-time stage may

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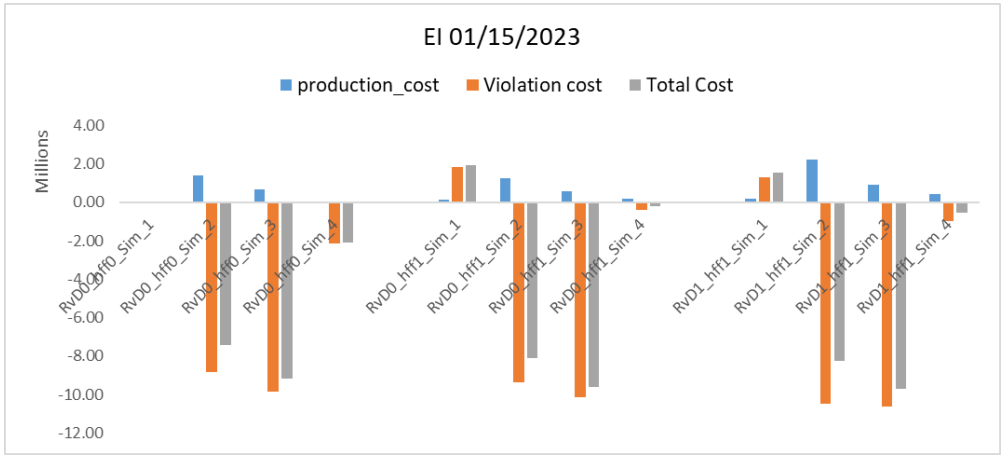
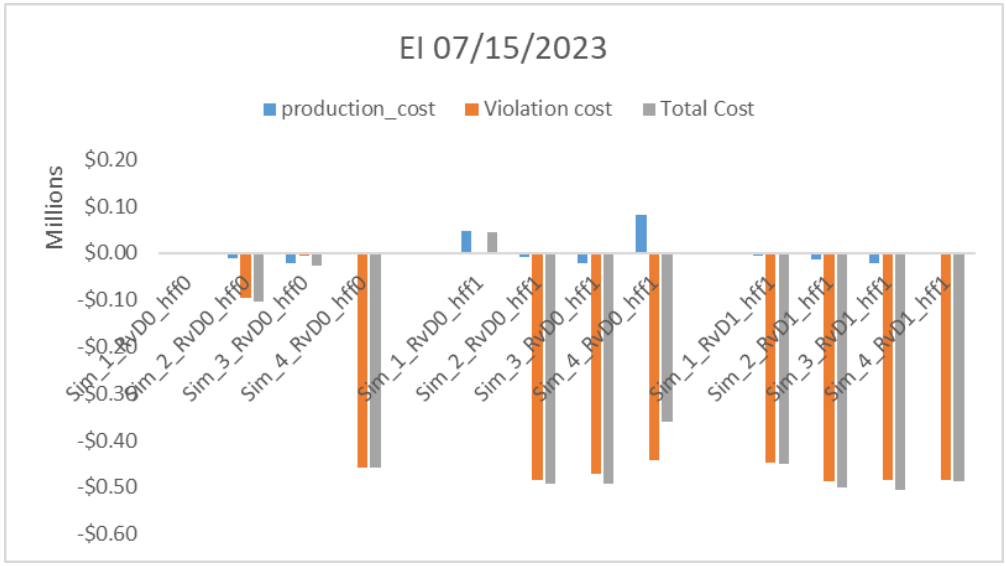
not be beneficial (hvff1 versus hvff0 on Sim_1 and Sim_4). Not feeding forward HVDC allows the monitoring region to optimize HVDC in real time and may help relieve M2M constraints.

There is no interregional HVDC between MISO and SPP in existing EI model. Therefore, the impact of HVDC scheduling on interregional AC congestion is relatively small. However, preliminary results suggest that, when AC transmission constraints are adequately represented in the market-clearing process, HVDC can be dispatched to help alleviate AC congestion. The study also demonstrates that the Sienna Decomposition framework can be used to evaluate operational strategies for future intra- and interregional HVDC integration.

In summary, without accounting for uncertainties between day-ahead and real-time operations or intra-hour variability, this study shows that day-ahead coordination may deliver significant value. Real-time coordination alone may be insufficient; effective day ahead and real time coordination—incorporating HVDC optimization and reserve deliverability modeling—is essential for managing interregional transmission congestion.





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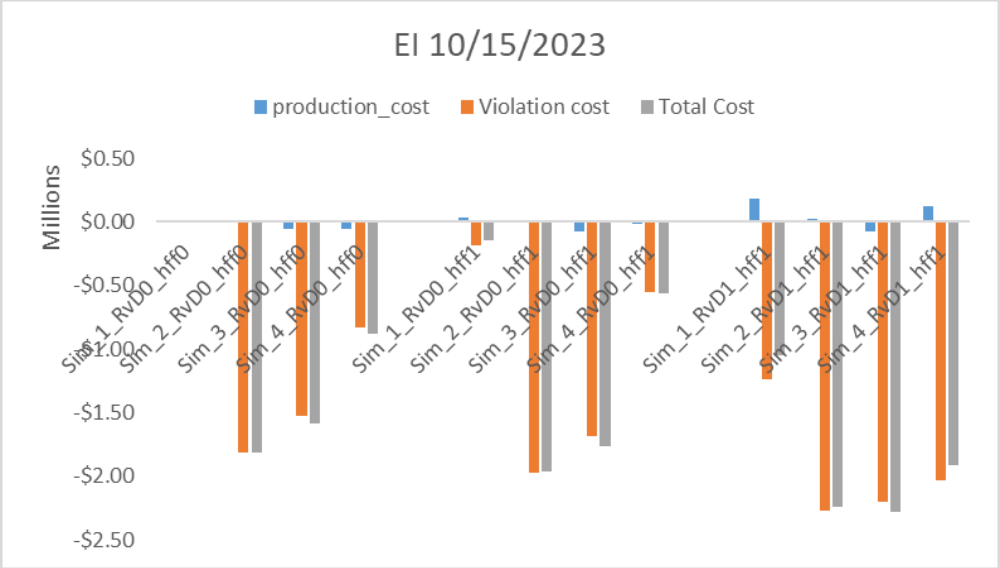

Figure 5. EI simulation results

7.2 Real-Time Distributed Algorithms

Real-time distributed algorithm case studies are presented in Chen et al. (2025).

First, a small system with three regions and nine generators is used to compare coordination based on single shadow price exchange (Method 1), relief cost curve exchange (Method 2), and a benchmark centralized congestion management approach. The comparison focuses on key metrics such as transmission line flows and congestion shadow prices. The results show the cost curve exchange method enables generator outputs to converge more rapidly toward the benchmark solution compared to the single shadow price exchange method. This analysis demonstrates the effectiveness of both methods for M2M congestion management, with the cost-curve-based method exhibiting faster convergence.

The relief cost curve exchange method is further extended to scenarios involving three-region coordination on a single transmission line and two-region coordination on two transmission lines, both of which demonstrate fast convergence.

Second, a large-scale EI study is performed. In this case, Method 1 and Method 2 are compared with an ADMM-based coordination approach (Method 3) for two-region coordination on a single transmission line. The results show the monitored line flow under ADMM initially deviates significantly from the optimal solution and converges only after multiple iterations. In contrast, both the shadow price exchange and the relief cost curve exchange methods achieve flow convergence within a single interval. In addition, the shadow prices under ADMM converge more slowly than those obtained using the relief-cost-curve-based approach.

Finally, the effectiveness of the relief-cost-curve-based method is further evaluated on the EI model for three-region coordination and for coordination across two monitored transmission lines.

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In summary, Method 1 is a practical enhancement to existing real-time M2M coordination in Eastern ISOs, requiring relatively modest software changes. Method 2 is more effective for coordinating across multiple regions with more transmission constraints, but involves greater implementation complexity. Both methods outperform ADMM in achieving flow convergence.

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8 Conclusion and Future Work

The IRTOC project develops a modeling and evaluation framework to study IRTOC and assess alternative M2M congestion management designs across day-ahead and real-time markets. The framework extends the Sienna platform with Sienna Decomposition, a multistage evaluation framework to enable flexible representation and systematic assessment of market coordination design.

Additional modeling capabilities developed through this project include reserve deliverability constraints and HVDC optimization for AC congestion management, and several real-time distributed coordination algorithms.

Case studies on both the RTS-GMLC test system and a large-scale EI model demonstrate the framework can systematically evaluate alternative coordination structures and analyze their economic and operational impacts.

Without accounting for uncertainties between day-ahead and real-time operations or intra-hour variability, this study shows that day-ahead coordination can deliver significant value, while real-time coordination alone is insufficient. For real-time coordination, the framework evaluates different distributed algorithms and demonstrates that the proposed methods are effective in achieving flow and price convergence.

Future work will focus on expanding datasets and scenarios to better capture forecast uncertainty and operational variability between day-ahead and real-time markets. Additional research will explore interregional interchange optimization, reserve sharing mechanisms, and enhanced interregional HVDC coordination strategies. Further development of scalable coordination algorithms for large multiregion systems will also be pursued to support practical implementation.

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