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THE FRANZ EDELMAN AWARD
Achievement in Operations Research

MISO Unlocks Billions in Savings Through the Application of Operations Research for Energy and Ancillary Services Markets

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Over the past few years, the Midwest Independent Transmission System Operator, Inc. (MISO) has transformed the electric utility industry in 13 Midwestern US states through the development and implementation of energy and ancillary services markets. MISO uses mixed-integer programming to determine when each power plant should be on or off. Operations research methods set energy output levels and establish the prices at which energy trades. These new markets increased the efficiency of the existing electric infrastructure (power plants and transmission lines) in the Midwest, improved the reliability of the grid, and reduced the need for future infrastructure investments. These advances enabled the MISO region to realize between $2.1 billion and $3.0 billion in cumulative savings from 2007 through 2010. We expect additional savings of $6.1 billion to $8.1 billion through 2020.

Key words: energy; electricity; transmission; reliability; planning; OR in a region; supply; demand; values; optimization; performance; linear programming; integer programming; dynamic programming; Lagrangian.

The Midwest Independent Transmission System Operator, Inc. (MISO) is a nonprofit organization formed in 1998 by several electric transmission owners (companies owning high-voltage electric transmission) in the Midwestern United States. MISO exists to create greater efficiencies in the production and transportation of electricity, essential to deregulation of the wholesale electricity industry in the Midwest. Initially formed to facilitate unbiased access to the electric transmission lines (which we refer to as transmission), MISO quickly undertook the development and implementation of robust, centrally administered energy and ancillary services markets. These markets provide immense value to the region MISO serves.

Industry Overview

In this section, we review the electric industry growth and fundamental changes that occurred over time, making the implementation of these markets viable.

The industry started as companies (utilities) formed to meet the electric needs of specific cities in which the economics of serving densely populated areas allowed for the construction of power plants and distribution networks. Over time, these utilities became larger and served territories specified by state regulatory agencies. These utilities built the infrastructure—power plants, high-voltage transmission, and low-voltage distribution lines—to serve their larger regulated service territories.

Each utility served the electric demand in its service territory, using its own power plants and transmission lines to transport the electricity to its customers. In addition, each utility held enough capacity to manage operational risk. This business model resulted in utilities optimizing the use of their assets while carrying extra investment to manage their risk, but often at the expense of the larger electrical system. Other changes in the industry included the following.

- As the US population density grew, electrical needs grew even more quickly. Natural boundaries between service territories became less of a barrier as population centers expanded. Utilities interconnected their transmission systems with one another, primarily to assist with emergency energy transfers, but also to enable some limited economic-based wholesale energy transactions. The interconnections eventually grew substantial enough to create three distinct interconnected regions (see Figure 1).
- Many utilities with interconnected service territories built jointly owned transmission assets to reduce the costs of meeting their needs.
- Some more-populous regions of the country introduced power pools to enable neighboring utilities to afford to build large power plants, taking advantage of the resulting economies of scale and sharing the output to serve their customers' needs.
- In other areas of the country, independent power producers built power plants and sold the output to utilities, which in turn could sell that output to customers without incurring the expense of building their own power plants.
- Regulation of each utility was centered in the states, and each utility was regulated with respect to how it best built and operated the infrastructure to serve its specific service territory in each state.

This long period of growth, which started with Thomas Edison in the 1880s and extended through the 1990s, resulted in a complex network of transmission and power plants, typically called the electric grid.

By the 1990s, grid management continued in a decentralized (or localized) manner despite the growing regional demands on its use. Drivers for this included regulatory policies and the business interests of the incumbent utilities. Congress began deregulating the wholesale electricity market with the Energy Policy Act of 1992, which gave the Federal Energy Regulatory Commission (FERC) authority to implement wholesale deregulation.

Through a series of landmark regulations, FERC ordered open access to the transmission system to enable broad wholesale power competition (Federal Energy Regulatory Commission 1996a, b). The open-access order required transmission owners to provide open, nondiscriminatory access of their portion of the interconnected transmission system to customers; this transmission was crucial for facilitating competition in wholesale electric markets. These orders gave rise to the formation of regional transmission organizations (RTOs) in the late 1990s.

Established in 1998, MISO became the first FERC-approved RTO to serve as an independent administrator over access to the electric transmission systems

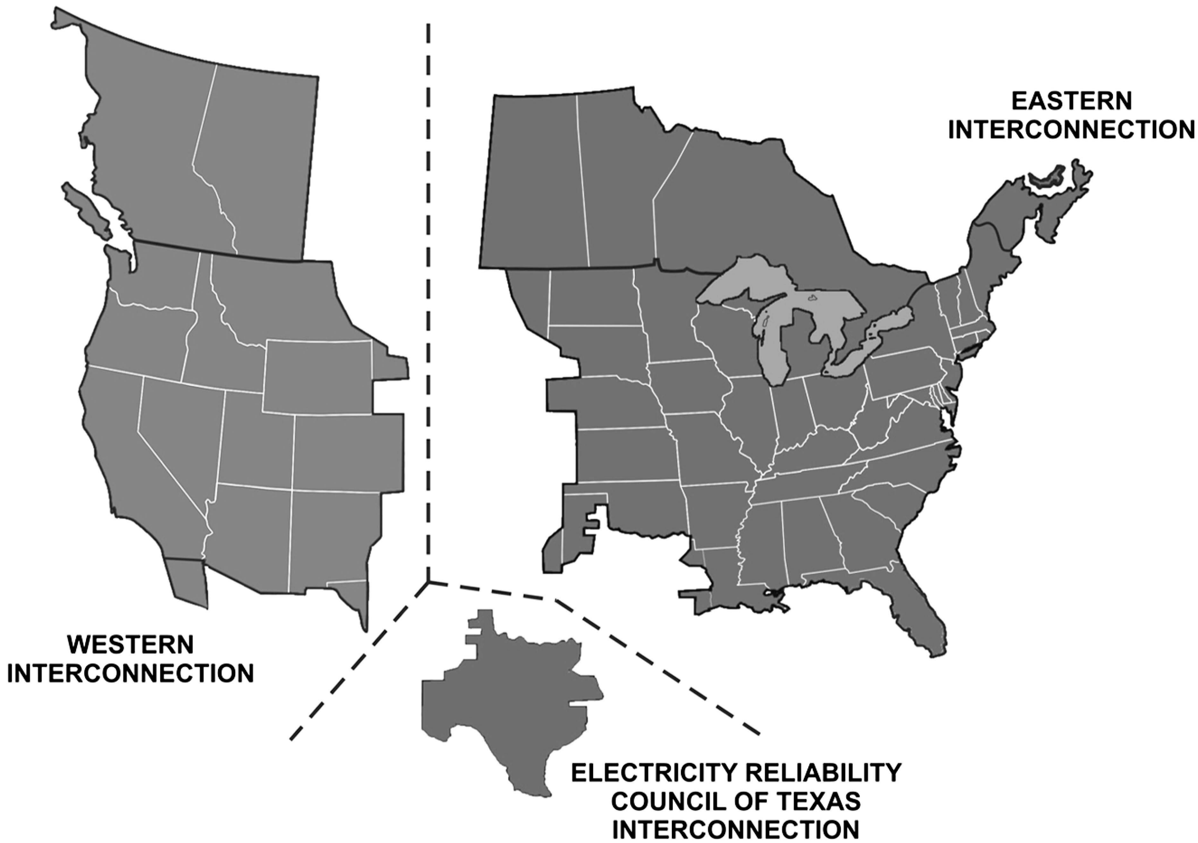

Figure 1: Each interconnection in the United States is electrically tied together during normal system conditions and operates at a synchronized frequency of 60 Hz.

of its members. This action began a series of steps aimed at improving coordination of the integrated grid. Initially, MISO assured unbiased access to and maximized use of the transmission system while monitoring the system to ensure the highest level of reliability given the electrical system's physical constraints. To maintain reliability and avoid overloading or damaging expensive equipment, transmission facilities (e.g., lines and transformers) can only carry electrical flows within their physical limitations.

Independent system operators (ISOs) are similar to RTOs and the terms are often used interchangeably. In this paper, we use the term RTO to refer to both RTOs and ISOs.

Commodities Markets

Although MISO's formation as an independent administrator of the transmission grid represented a major step for the industry, MISO's next move—the introduction of centrally administered commodities markets for wholesale energy and ancillary services to increase the efficient use of both existing and future assets—stunned the industry.

Commodity markets may be commonplace, but one characteristic makes electricity especially complex—electricity is consumed the instant it is generated. No commercially viable methods of storing electricity exist, except on a relatively small scale. Consequently, grid operators must accommodate the instantaneous generation and consumption of electricity. To reliably serve customers, MISO created markets to maximize the efficient use of the region's existing generation and transmission while planning for increased consumption. Three primary products comprise these markets:

- Energy: This product serves the electrical needs of end-user customers such as factories, businesses, and neighborhoods.

• Regulation: This product is an ancillary service with one main objective—to constantly keep frequency of the grid at 60 hertz or cycles per second by fine-tuning the moment-to-moment changes that affect supply and demand. Many appliances and machines are engineered to run at 60 hertz. If this frequency dramatically changes, equipment runs unpredictably or not at all. Frequency changes minutely with each flip of a light switch or largely with the cycling of a large industrial application such as an electric aluminum smelter. To help fine-tune these moment-to-moment changes, many power plants are equipped with automatic generation control (AGC), which adjusts energy output up or down every few seconds. When a power plant provides regulation, it is committing to provide the capability to increase or decrease the level of energy it provides in near real time. This regulation—similar to a safety stock—protects against short-term fluctuations in supply and demand so that frequency is maintained at 60 hertz.

• Contingency reserves: Contingency reserves refer to power plant capacity set aside to respond to major disruptions such as the sudden loss of a large power plant or transmission line. Upon a major supply loss, MISO's control systems immediately increase the energy output of power plants providing these reserves. Without these reserves, a loss of a power plant or transmission line could result in a local power outage or a widespread blackout. Contingency reserves are ancillary services comprising spinning reserves and supplemental reserves. Spinning reserves represent additional capacity from online power plants that can provide energy within 10 minutes. A power plant is considered online when it produces energy or can produce energy on demand. Supplemental reserves represent additional capacity from online or offline power plants that can provide energy within 10 minutes. The contingency reserve market compensates companies for having a portion of their capacity on standby, ready and available in case of a major supply loss. Regulation and contingency reserves are also referred to as operating reserves.

Energy reserves are so important to our society that state and federal regulators may impose significant monetary penalties for failure to comply with performance standards for these services (North American Electric Reliability Corporation 2005, 2008).

With the development and implementation of the energy and ancillary services markets, MISO not only improved how electricity was bought and sold, it also improved reliability in the region. MISO launched its energy-only market on April 1, 2005, and introduced its energy and ancillary services markets on January 6, 2009.

MISO Overview

MISO serves the electrical energy needs of more than 40 million end users, providing independent transmission system access, delivering improved reliability through efficient market operations, and coordinating regional planning that benefits all customers. Headquartered in Carmel, Indiana, with control centers in Carmel, Indiana, and St. Paul, Minnesota, MISO acts as an air traffic controller for the electric grid; it controls nearly 60,000 miles of high-voltage transmission lines and more than 1,000 power plants capable of generating 146,000 megawatts (MWs) of electricity. This infrastructure spans 13 Midwestern US states plus the Canadian province of Manitoba (see Figure 2), and is owned by more than 750 companies, each of which has turned over operational control of its transmission and generation equipment to MISO.

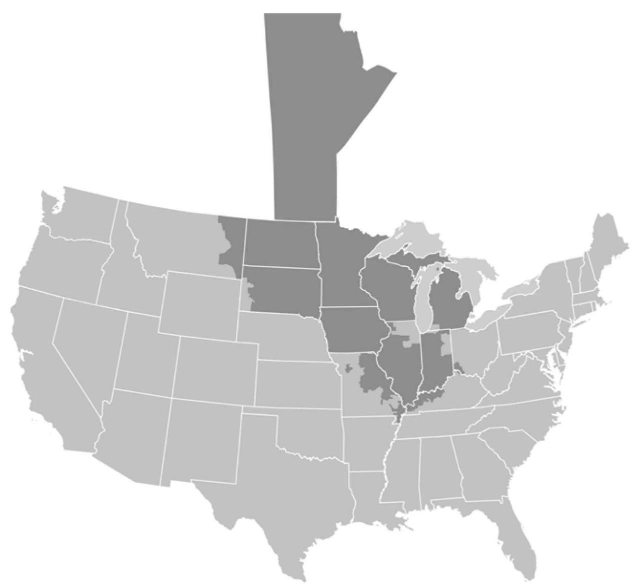

Figure 2: MISO is geographically the largest RTO in the United States.

The Challenge

MISO's mission was clear when developing the energy and ancillary services markets—add significant value to the Midwest region by improving reliability and increasing the efficiency of the region's power plants and transmission assets.

Although the technological challenges seemed formidable, working through the human element of many stakeholders proved to be an even greater challenge. As with the energy markets, MISO needed to break down the barriers and incentives of its members, market participants, consumer groups, and state and federal regulatory agencies so they would accept a major paradigm shift of operating the electrical system regionally. With the energy markets, stakeholders had to be convinced to dispatch energy on a regional basis. With the energy and ancillary services markets, MISO painstakingly persuaded stakeholders to dispatch ancillary services on a regional basis and consolidate the region's collective 27 balancing authorities into a single MISO balancing authority. Balancing authorities represent subregions of the transmission grid in which electricity production is balanced with local demand and electrical energy flowing between subregions. MISO educated many of its stakeholders on the foundation of the markets and how the markets work. This involved explaining complicated operations research (OR)-based market processes to a diverse audience with varying degrees of technical expertise. In addition, MISO market participants had to agree to a common set of market rules and procedures, and control room operators had to learn the basics of economic and market theories and the new economic impact of operations. Finally, MISO persuaded stakeholders to accept the financial risk of launching the energy and ancillary services markets. The development and launch of the original energy market in 2005 cost $245 million; replacing the original energy market with the energy and ancillary services markets in 2009 cost $71 million. MISO's steadfast determination and faith in an OR solution eventually overcame the genuine doubt of members and regulators as to whether MISO could master the daunting technological and business process challenges to successfully launch the markets.

From a technological perspective, no energy market system had ever been built to dispatch the number of power plants and miles of transmission the size and scale of MISO's region. Significant concerns surfaced as to whether OR techniques could handle the enormous scale and performance requirements. To appreciate the technological challenges MISO faced, consider the following properties of the electrical system.

- Energy generation by power plants and use of that energy by consumers must be kept in constant balance at all times.
- Consumers do not schedule their use of electricity, but count on electricity to be there immediately, whenever requested.
- Power plants have diverse operating characteristics that affect their dispatch (e.g., nuclear power plants cannot quickly start or shut down).
- The transportation of energy across the transmission grid follows the laws of physics; electricity flows at the speed of light along the path of least resistance.
- The transmission system can transport only a limited amount of energy. Attempting to operate the transmission system beyond its rated capacity likely results in line faults and electrical fires. To avoid capacity overload, the system must be dynamic enough to quickly dispatch other power plants to meet high demand. In addition, the system must be robust enough to handle the failure of a power plant or transmission line, and not cause a cascading failure of other devices on the system when the electricity finds alternative routes to travel.
- In addition to electrical energy, power plants provide ancillary services that the markets must manage, adding to the system's complexity.

Prior to joining MISO, utilities might have considered several options as they evaluated potential approaches to unlocking the value of more efficiently using the grid. Rather than join MISO, a utility could have elected to merge with another utility to create a larger company that covered a larger geographical area. The new utility could use economies of scale to operate its portion of the grid more efficiently, or the utility could have joined other existing energy markets.

In designing centralized energy and ancillary services markets, MISO members could choose from a variety of less-efficient market designs, including separate or sequential optimization of energy and ancillary services. Although those designs would reduce the risk of market launch, they would not maximize the value created.

The assets under MISO's operational control consist of power plants and transmission previously operated by the local utility companies. When a utility joins MISO, it agrees to several conditions. First, the utility retains physical control and operation of its power plants and transmission, but it no longer has functional control of its assets. MISO uses dispatch signals to tell the power plant when to produce energy and how much to produce. Additionally, the utility agrees to participate in the wholesale electricity market. It offers to supply energy (supply offers) reflective of the capabilities and costs to run its power plants and (or) the utility bids into the market to buy energy needed to meet demand (demand bids). Supply offers and demand bids clear and financially settle at the locational marginal price (LMP) determined by the OR model. The LMP is the cost to serve the next unit (MW) of energy at a specified location.

As an RTO, MISO performs two primary functions. As the market administrator, it does market clearing—it determines which power plant supply offers and demand center bids are accepted and at what price. The accepted offers and bids represent an energy production and consumption schedule that incurs the least societal cost. As the system operator, MISO also operates the grid's physical system by managing the real-time balancing of energy supply and demand, a critical task for system reliability. Through its actions, MISO ensures that energy cleared is delivered securely without overloading the transmission system. MISO manages transmission congestion by appropriately dispatching energy output levels of the power plant fleet. Transmission congestion occurs when the path-of-least-resistance flow of electrical energy approaches the limits of the transmission system's ability to transport it.

Strategically, MISO pursued development and operation of the markets in two phases:

1. design and implementation of the energy-only market, deployed in 2005 (Midwest Independent Transmission System Operator, Inc. 2009);

2. design and implementation of the energy and ancillary services markets, deployed in 2009 (Midwest Independent Transmission System Operator, Inc. 2010, 2011).

The Energy Market (2005–2008)

The overall objective of MISO's energy market is simple: reliably dispatch energy generation through economic-based incentives to minimize the total production cost of operating power plants through the cost-optimized scheduling of their energy output. The production costs include parameters such as:

- start-up costs (costs to heat up a specific offline power plant and bring it online to produce power),
- no-load costs (hourly costs to operate a specific power plant without regard to energy output level), and
- variable costs (costs to operate a specific power plant per unit of energy produced).

To run the energy market, MISO elected to form both day-ahead (DA) and real-time markets. MISO's DA market enables utilities that operate power plants to offer energy into the market based on their willingness (reflected in offers to sell) and ability to produce energy the following day. The DA market is financially binding, providing an incentive for power plants to perform as scheduled the next day. It also allows power plant operators to plan for the next day so the utilities know the amount of energy they have committed to generate. This is especially useful for large plants that require advanced notice to start operating.

Because anticipated demand, available power plant capacity, and system conditions change throughout the day, MISO also operates a real-time market in which it uses technology to precisely analyze moment-to-moment conditions of the system. Based on this information, our operators balance generation and demand to keep the system reliable and economically efficient.

Optimization Algorithms

The energy market clears through two sequentially solved optimization algorithms. The first optimization algorithm, security-constrained unit commitment (SCUC), involves committing the power plants to be on or off over time. The second optimization algorithm, security-constrained economic dispatch (SCED), determines power plant output levels and prices. The DA and real-time markets contain both.

The unit-commitment portion of SCUC determines the optimum set of power plants needed online over time to meet demand at a minimized production cost. Commitment refers to the power plant's obligation to operate. The SCUC process determines the commitment schedule of the power plant fleet, taking into account plant start-up and no-load costs. The security-constrained portion of SCUC ensures that the output of the committed power plants will not violate the transmission system's physical constraints (or capacity limitations). Therefore, SCUC is an optimization problem in which the primal decision variables are both binary and continuous. The security-constrained portion of SCUC is enforced as part of the optimization constraints. SCUC solves a single optimization problem for multiple periods rather than sequentially on an hour-by-hour basis. Besides the market-clearing processes, SCUC is also solved multiple times a day for planning purposes. This is to evaluate the adequacy of online power plant capability against updated demand forecasts for different time horizons.

The economic-dispatch portion of SCED determines the optimal economic-dispatch schedule—the energy output levels of the power plants at a minimized production cost. The security-constrained portion of SCED ensures that the energy dispatched will not violate the transmission system's physical constraints. The SCED problem is solved after the SCUC process determines the commitment schedule of the power plant fleet. In SCED, the start-up and no-load costs are not considered because these costs only impact the SCUC decisions; they are sunk costs for the SCED decisions.

SCED also determines the LMPs for all nodal locations of the system. LMPs are calculated for each node that represents either a power plant or transmission substation. The LMP represents the incremental cost to supply energy at that location. Energy prices vary from location to location because of transmission congestion and energy losses. As energy travels through transmission wires, some of it is lost; therefore, the amount produced at a power plant is not necessarily equal to the amount of energy that reaches a utility's substation for distribution to the end user—the longer the transmission line, the greater the losses.

In the DA market, the SCED algorithm produces hourly output levels and LMPs. These output levels match the forecasted demand for each hour. For DA, dispatching for the hourly periods can be solved independently once the SCUC algorithm has run. In the real-time market, the SCED algorithm solves every five minutes. Every five minutes, power plants receive dispatch instructions on how much they should change their output during the next five minutes. Technically, MISO's greatest economic-dispatch challenge was achieving an optimal solution in about a minute, necessary so that power plants can adjust their energy output before receiving the next dispatch signal.

In both SCUC and SCED, the locational impact of a power plant to a congested transmission line is modeled by the sensitivity factor (i.e., the percentage portion of the power plant output that flows through the transmission line). The flow through a transmission line is estimated as the total sum of the flow impact from all individual plants to the transmission line (as plant output times sensitivity factor). SCUC and SCED incorporate constraints that ensure that the transmission line flows are within their capacity limits.

The energy markets project team chose Paragon Decision Technology's AIMMS as the development platform for implementing SCUC and SCED, primarily because of its modeling capabilities to build, solve, and visualize large optimization models. AIMMS incorporates the most advanced commercial solvers in the market (e.g., CPLEX). Solving these two optimization problems is essential to MISO's business. Each day, MISO's energy markets accept or reject offers and bids based on these optimization algorithms.

Implementing SCUC required solving a large model with binary variables. Although the problem was best formulated as a mixed-integer programming (MIP) problem, the project team designed an optimization algorithm based on the Lagrangian relaxation (LR) method because the commercially available MIP solvers could not solve such large-scale problems at that time.

The LR engine first computed a relaxed economic dispatch of energy from all power plants, in which the relaxed economic dispatch did not enforce minimum output limit constraints for online power plants. The relaxed economic dispatch used a linear programming (LP) solver to minimize production costs and calculate hourly LMPs. The LMPs were then fed into a single-unit dynamic programming (SUDP) module that attempted to maximize the profit of each individual power plant over the commitment period, considering the hourly LMPs and constraints associated with each power plant. The output was a commitment flag (on or off) for each hour of the commitment period for each power plant. The SUDP decoupled the commitment problem into many smaller problems (one for each power plant). Once the SUDP was executed, the commitment schedule was fed into a constrained economic dispatch LP in which the commitment flags from the SUDP determined when the power plants were online or offline. A revised set of LMPs was calculated and fed back into the SUDP module. This iteration was performed four or five times until convergence toward an optimum commitment solution occurred.

For the SCED implementation, the project team designed an optimization algorithm that calls an LP solver to determine energy dispatch and LMPs, given that the on (off) decisions are fixed to the values determined by SCUC. All decision variables in the dispatch engine are continuous, representing power plant output levels. Two sets of output are obtained from the engine's LP solution—the primal solution and the dual solution. The primal solution represents the power plant output levels; the dual solution or shadow costs represent the LMPs. Because of transmission constraints and transmission losses, LMPs can vary based on the power plant or demand location. The market participants financially settle their offers and bids at the LMPs determined by the SCED solution.

Next, the project team designed a business process to integrate operation of the power system under a market structure. The SCUC and SCED processes provide the foundational data to support operational decisions that take place seven days to 10 minutes prior to real-time operations. The multiday reliability-assessment commitment process (MDRAC) runs a seven-day look-ahead SCUC process for power plants that require advance start-up notification (see Figure 3). SCUC and SCED are also key elements in the

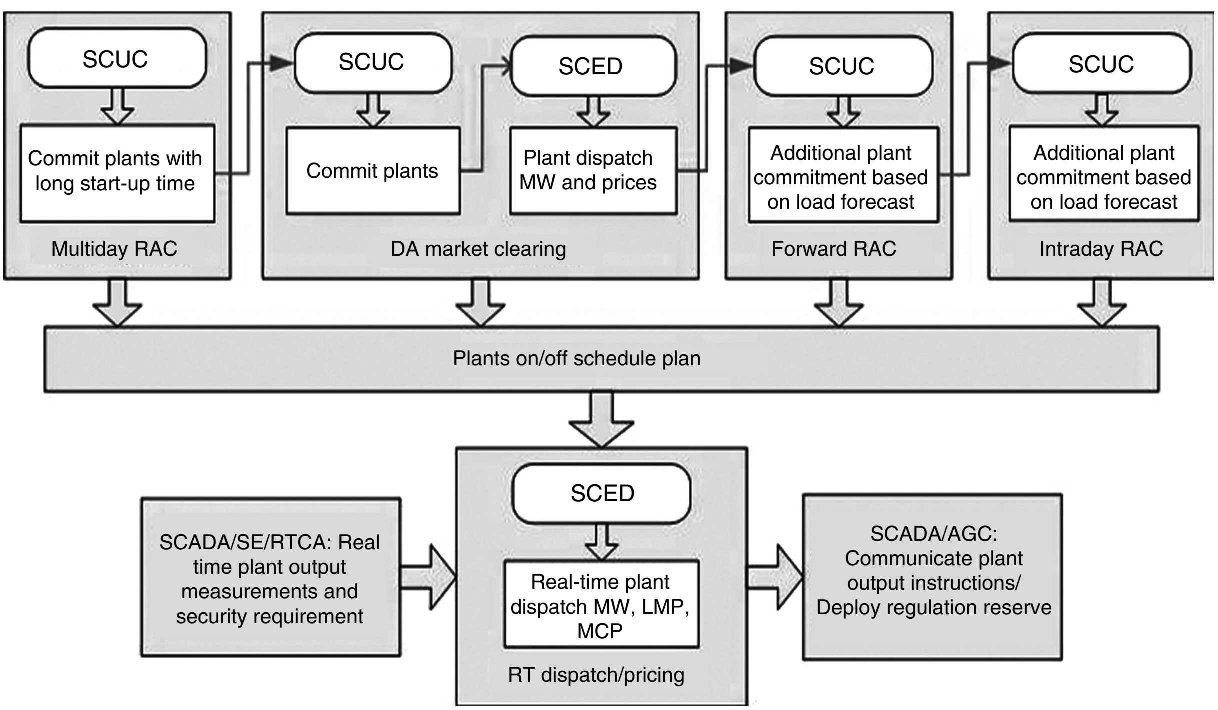

Figure 3: Because demand fluctuates, demand forecasts are dynamic, MISO's market-clearing process uses OR for many time horizons to aid system operators in determining appropriate least-cost dispatch levels. Note the following abbreviations in the flowchart: SCADA: supervisory control and data acquisition; SE: state estimator; RTCA: real-time contingency analysis.

DA market-clearing and reliability-assessment commitment (RAC) processes. Forward-day RAC (FRAC) processes are conducted one day prior to energy delivery and the intraday RAC (IRAC) processes are conducted on the day of operation. These processes evaluate the adequacy of the current energy production plan against a constantly changing demand forecast, and to call on or off power plants to meet the demand forecast.

On April 1, 2005, MISO successfully launched the Midwest energy market. The scope and scale of the problem posed tremendous OR challenges, including repetitive solving within a short period. Solving the SCUC and SCED problems in 2005 was a milestone achievement for both MISO and the power industry.

The Energy and Ancillary Services Markets (2009–Present)

In January 2009, MISO built upon its success, revamping the energy markets to include markets for ancillary services such as regulation and contingency reserves. MISO's cost-benefit analysis served as the catalyst for this project. Previously, 27 entities in the MISO region managed ancillary services. MISO's members recognized that consolidating these entities under MISO would provide more market efficiencies. They reasoned that scope and scale would create greater cost efficiencies for reserve services just as the regional model had accomplished for MISO's energy-only markets.

With the ancillary services market, the goal was to minimize total production cost by scheduling both power plant output and operating reserves at the same time. Power plants can submit operating reserve offers in addition to their energy offers. MISO designed the ancillary services markets in such a way that energy and operating reserve offers are cleared in a single optimization problem.

Two Design Approaches

The project team debated two general design approaches. The first approach, in use by some RTOs, was to establish the ancillary services markets separate from the energy market. When separated, each problem is smaller and thus easier to solve. However, this approach is globally suboptimal because of the interdependence of energy and operating reserves planning. Energy output and operating reserves together share the physical capacity of a power plant:

- energy output + regulation reserve + contingency reserve $\leq$ maximum output limit
- energy output − regulation reserve $\geq$ minimum output limit

Therefore, energy and ancillary services are interdependent and should be optimized as one problem. When a power plant's energy output level is higher, its ability to carry reserves is less, and vice versa.

The second approach chosen by MISO was to clear both energy and ancillary services in the same market as one optimization problem. Some other RTOs used this approach, but on a much smaller scale than we did. Although this approach would achieve greater cost reductions, it posed tremendous OR challenges because of the problem's large scale. Simultaneously optimizing both energy and operating reserves is more complex than optimizing energy alone. The number of decision variables and constraints can be several times more than in the energy-only problems.

Optimization Methods

Run-time performance was MISO's greatest concern. For the initial energy-only market, MISO used the decoupled and iterative LR method to solve the SCUC problem. This type of engine was too slow for simultaneous optimization of energy and ancillary services. Fortunately, advances in computing technology and OR since the 2005 launch of the energy-only market helped. Computing technology had advanced significantly, and ongoing work in OR had significantly improved optimization algorithms. With stronger modeling capabilities and faster convergence rates, MISO proposed using MIP for solving the SCUC problem for the energy and ancillary services markets.

In early 2007, the project team made a prototype using MIP for a realistic MISO model; this work showed promising results. In the next 18 months, the team formulated and implemented the SCUC problem as an MIP problem, but retained the LP method for the SCED process.

Optimization Formulation

The objective function includes power plant production costs such as start-up costs, no-load costs, and variable costs to produce energy or provide operating reserves. Both energy and operating reserves require capacity; therefore, the energy and operating reserves markets assign specific levels of capacity for each online power plant to produce: energy, regulating reserves, spinning reserves, and supplemental reserves. Supplemental reserves may also be assigned to offline power plants if they can produce energy starting from an offline state within 10 minutes. Similar to the energy market, energy and operating reserves' costs are determined based on supply offers and demand bids.

SCUC's objective function was expanded to include regulating reserves, spinning reserves, supplemental reserves, and their costs. SCUC decision variables include binary commitment and regulation variables and continuous energy and operating reserves variables. However, the binary variables used to feed the downstream SCED economic dispatch process are the only output used from the SCUC.

When a power plant is committed online to produce energy, a decision is made on whether the plant will supply regulating reserves. Supplying regulating reserves may reduce a power plant's maximum output limit and output ramping rates while increasing minimum output limits. For example, if the nominal output range is 100–200 MW, deciding to provide regulating capability could change the output range to 110–190 MW. Ramping refers to a power plant's ability to increase or decrease its energy output over a given period. Placing a power plant in regulating mode reduces the power plant's flexibility to ramp and produce energy. Therefore, additional binary decision variables are required to represent its regulating or nonregulating mode. For the SCUC implementation, we formulated the optimization problem as an MIP problem and solved it with a CPLEX solver (see the appendix).

The LP formulation of SCED is similar to SCUC; however, one major difference is that SCED's binary variables are fixed to the values determined by SCUC. SCED also determines LMPs for energy for specific locations based on the incremental cost to supply energy at that location and market-clearing prices (MCPs) for each class of operating reserve in specific geographic zones. Unlike the energy LMPs that vary by the power plant or transmission location, operating reserve MCPs vary by reserve zones that are geographical aggregates of many power plants and transmission locations. The SCED primal solution determines the energy and operating reserves output levels, and the dual solution determines the LMPs and MCPs (Ma et al. 2009a, b).

Performance Requirement

Initially, the primary concerns were the solution performances of the MIP and LP in solving SCUC and SCED. Adding ancillary services involved significantly more decision variables and constraints. Moreover, the business process allowed limited time to reach an optimal solution (see Table 1).

Among all the required runs, the most challenging is the MDRAC SCUC, which solves an MIP problem for unit commitment decisions involving more than 900 power plants (a typical number of power

Business process	OR algorithm	Solve frequency	Required solve time	Time horizon
MDRAC SCUC	1 MIP	Daily	Three hours	Seven days or 108 time intervals of varying duration
FRAC SCUC	1 MIP	Daily	One hour	48 hourly intervals
IRAC SCUC	1 MIP	Bi-hourly	20 minutes	24 hourly intervals
DA market SCUC	MIP	Daily	40 minutes	36 hourly intervals
DA SCED	24 LPs	Daily	One hour	24 hourly intervals
Real-time economic dispatch SCED	1 LP	Five minutes	~One minute	One 10-minute interval with the first five minutes fixed based on previous run's target

Table 1: OR supports energy and ancillary services markets (2009–present).

plants that offers into the market on a daily basis) over 108 periods. Each period includes more than 100 transmission constraints, which are dense in nature. One constraint may contain thousands of nonzero coefficients. The typical MIP model size includes 3,300,000 continuous variables, 450,000 binary variables, and 3,900,000 constraints. The binary variables include the on (off) state, the hot-cold-intermediate start-up state, shutting-down state, and regulation mode.

The real-time economic dispatch SCED (RT-SCED) presented another challenge. The RT-SCED solves an LP problem to clear the real-time market. Its solution represents the energy levels, operating reserves procurement, and pricing for all online power plants during real time. The LP solution of RT-SCED must complete in one minute so that market participants can adjust energy output to follow moment-to-moment changes in demand. RT-SCED's consistent performance is critical to the grid's reliability.

Reducing Run Time and Improving Solution Convergence

MISO pursued performance improvement in the following four areas: preprocessing, strong model formulations, model-specific cuts, and solver tuning.

Preprocessing reduces the number of unit commitment decision variables. Some commitment decisions are derived from analyzing the physical operating constraints. For example, if a generator requires a minimum downtime of eight hours and has been off for three hours at the beginning of the SCUC process, preprocessing determines whether the generator should stay offline for five more hours. Some generating units choose to commit or decommit without MISO's central authority. For example, a power-generating unit may declare that it must be operational from 5 PM through 7 PM and must be off from 1 AM through 4 AM. These self-commitments are preprocessed to remove them from the model as decision variables.

Another form of preprocessing avoids infeasibilities. When the solver encounters an infeasibility because of conflicting inputs, the optimization algorithm typically relaxes some of the constraints by formulating and solving an auxiliary problem. MISO designed SCUC and SCED so that most problem infeasibilities are identified prior to the initial solution attempt. These infeasibilities are removed either by adjusting some parameters or by directly formulating an auxiliary problem. This reduces the solution time by avoiding the unnecessary first-solution run that would result in the case of an infeasibility.

Formulating Strong Models

There is usually more than one way to formulate a constraint involving binary decision variables. Certain formulations, known as "strong models," can be solved more quickly. MISO identified strong models for all major constraints that impact performance. In the case of the minimum run-time constraint, the most obvious formulation would state that if a power generator started at time t, then it must remain operating until at least time $t + minruntime$. A stronger (and less obvious) model formulation would state that if a generator is not operating at time t, then there must be no start-ups of the generator in the previous minruntime number of periods. Also, if a generator is operating at time t, then the number of start-ups in the previous minruntime number of periods cannot exceed 1. In this case, experimental results showed that the stronger model formulation solved about 15 percent faster than the more obvious formulation.

Model-specific cuts reduce run time by tightening the constrained linear region without losing the integer feasible points.

The team also fine-tuned the solver parameters. CPLEX 11.0 solves the SCUC MIP formulation. Typically, CPLEX's standard parameter settings work well on a broad set of models. For SCUC, MISO investigated alternative parameter settings and tested for better solution convergence and run time. MISO consulted the CPLEX solver vendor (ILOG/IBM) and even CPLEX creators for insight and recommendations. After intensive testing, MISO implemented most of the parameter-setting recommendations.

Operations Research Unlocks Value

After launching the energy-only market in 2005, the value MISO was adding to the region through its OR-based energy markets became apparent. To quantify this value, MISO—in collaboration with its stakeholders—conducted a first-of-its-kind study in 2007 to measure the value that MISO provided to the entire region, including all market participants and customers. MISO's value proposition breaks the organization's business model into categories of benefits and calculates a range of dollar values for each defined category. The value proposition study is updated annually.

The value proposition studies conducted for 2007 through 2010 revealed that the MISO region realized between \$2.1 billion and \$3.0 billion in cumulative savings of which OR was a major driver. MISO estimates that an additional \$6.1 billion to \$8.1 billion of net value will be achieved through 2020.

"MISO is able to provide this value by applying new, complex analysis and optimization techniques on a broad regional basis," said John R. Bear, president and CEO of MISO. "This enables both improved use of existing electric system assets as well as a reduced need for future assets."

The value proposition's open and transparent process greatly increases the credibility of the results. Stakeholder input is requested and received throughout the study process. In addition, stakeholder review meetings are conducted to confirm facts and assumptions. The process is open to all stakeholder groups including regulators, transmission owners, market participants, and the general public. Finally, the value proposition and its calculations, assumptions, and supporting information are publicly available on MISO's website (https://www.misoenergy.org/).

MISO also provides qualitative benefits to the region, including price and information transparency, planning coordination, seams management (i.e., energy interchange and power congestion management with bordering RTOs and other nonmarket utilities), and regulatory compliance.

Price and informational transparency in MISO's markets benefit customers. Every market participant can see pricing and information produced by the markets, which results in increased market efficiencies. Price signals sent by MISO's energy markets provide investors in power plant assets with the basis for market-driven investments and with underlying data upon which they can anchor forecasts for future wholesale prices. MISO enhances reliability by informing all market participants on the state of grid conditions and market operations through the public posting of wholesale electricity prices and other key system information. High market prices in the MISO energy markets provide specific signals on where more power plants and transmission lines are needed, while lower market prices indicate the reverse.

Lessons Learned

MISO learned several lessons in launching its energy market in 2005 and its energy and ancillary services markets in 2009.

- Building confidence takes time. Building confidence in the new business processes took time, determination, and persistence. MISO and its stakeholders participated in many tests of the new software to verify that their systems and processes were ready. Market participants updated their business processes, software, and control systems. Tests allowed stakeholders to prepare their systems and gain experience interacting with energy and ancillary services markets.
- Widespread dedication led to success. Success resulted from the commitment of MISO, market participants, transmission owners, balancing authorities, vendors, and regulatory support to create a market-based congestion-management system. For the ancillary services markets, MISO's cost-benefit analysis galvanized support to create market mechanisms for energy and ancillary services. An open stakeholder process resulted in design choices vetted with market participants, transmission owners, balancing authorities, and regulators. Compromises added value throughout the project. MISO and participant development occurred in parallel. A series of parallel operations tests provided the validation that the new system would work. Everyone worked together to complete the programming, implement the systems and processes, and accomplish other day-to-day activities.
- OR played a critical role. OR made a huge impact in the initial deployment of the energy market. OR created even greater societal benefits with the success of the ancillary services markets. MISO has begun exploring how stochastic and robust optimization concepts might be applied to this large-scale problem.

Other lessons learned include (1) communicate frequently to keep all parties informed through all stages of the project, (2) perform smaller test implementations before spending money on full-scale projects, (3) involve everybody in the solution through an open stakeholder process, and (4) use centralized control, which adds value by improving the reliability of the transmission system and managing transmission congestion in real time.

Appendix. The MIP Formulation of SCUC

The SCUC problem with regulation and contingency reserves is modeled as a mixed-integer program with a large number of binary variables. As a key output of SCUC, these binary variables determine:

- whether a power-generating unit is committed to operate in a specific period, and
- whether a qualifying generating unit is scheduled to provide regulation service in a specific period.

The term "generation unit" is an equivalent to "power plant" in the main text. We also simplified some MISO-specific business logic in the formulations.

Sets and Parameters

$I = \{1, 2, \dots, |I|\}$ is the set of power-generating units i.

$L = \{1, 2, \dots, |L|\}$ is the set of critical power transmission lines l.

$H = \{1, 2, \dots, |H|\}$ is the set of periods h (time horizon).

$J = \{1, 2, \dots, |J_i|\}$ are indices for the "generation cost-power" curve approximation for generating unit $i \in I$.

δ_h is the length [hours] of period $h \in H$. Normally, $\delta_h = 1$ hour. Any positive number is valid.

t_h is the ending time [hours] of period $h \in H$.

By a recursive definition

$$t_h = t_{h-1} + \delta_h, \quad h = 1, 2, \dots, |H|,$$

where t_0 is starting time of the first period. $t_i^{\min up}(t_i^{\min down})$ is the minimum duration-generating unit $i \in I$ must remain up (down) once it is started up (turned off); it is positive.

$t_i^{begin\text{-}up}(t_i^{begin\text{-}down})$ is the duration the generating unit $i \in I$ was up (down) at the beginning of the time horizon; it is nonnegative.

$t_i^{end\text{-}up}(t_i^{end\text{-}down})$ is the duration the generating unit $i \in I$ is supposed to be up (down) after the end of the time horizon; it is nonnegative.

$H_i^{begin\text{-}up}$ are periods with predetermined commitment because of the initial minimum uptime restriction:

$$H_i^{begin\text{-}up} = \{h \in H \mid t_i^{begin\text{-}up} + t_h - t_0 \le t_i^{\min up}\}.$$

$H_i^{begin\text{-}down}$ are periods with predetermined decommitment because of the initial minimum downtime restriction:

$$H_i^{begin\text{-}down} = \{h \in H \mid t_i^{begin\text{-}down} + t_h - t_0 \le t_i^{\min down}\}.$$

$H_i^{end\text{-}up}$ are periods with predetermined commitment because of the terminal minimum uptime restriction:

$$H_i^{end\text{-}up} = \{h \in H \mid t_i^{end\text{-}up} + t_{|H|} - t_h \le t_i^{\min up}\}.$$

$H_i^{end\text{-}down}$ are periods with predetermined decommitment because of the terminal minimum downtime restriction:

$$H_i^{end\text{-}down} = \{h \in H \mid t_i^{end\text{-}down} + t_{|H|} - t_h \le t_i^{\min down}\}.$$

Because the unit cannot be up and down at the same time, at least one of $H_i^{begin\text{-}up}$ or $H_i^{begin\text{-}down}$ is empty. Similarly, at least one of $H_i^{end\text{-}up}$ or $H_i^{end\text{-}down}$ is empty. $[a_{ih}^{rr}, b_{ih}^{rr}]$ is the operating range [Mw] for generating unit $i \in I$ during period $h \in H$. $[a_{ih}^{rr}, b_{ih}^{rr}]$ is the operating range [Mw] for generating unit $i \in I$ during period $h \in H$ when i provides a regulating reserve:

$$0 < a_{ih} \le a_{ih}^{rr} \le b_{ih}^{rr} \le b_{ih}.$$

μ_{ij}, η_{ij} are cost coefficients for the "generation cost-power" curve approximation $i \in I$, $j \in J_i$. $c_{ihp}^{startup}$ is the start-up cost [\$] for generating unit $i \in I$ when the unit starts at period $h \in H$, while being down from period p to period $h - 1$. We calculate these cost parameters in the preprocessing stage based on the "start-up cost downtime" curve. We assume that

$$c_{ihp}^{startup} \ge c_{ih,p+1}^{startup} \ge \cdots \ge c_{ih,h-1}^{startup}.$$

c_{ih}^{rr} is the cost of regulating reserve [\$/Mwh] for generating unit $i \in I$ during period $h \in H$.

c_{ih}^{on} is the cost of an online contingency reserve cost [\$/Mwh] for generating unit $i \in I$ during period $h \in H$.

c_{ih}^{off} is the cost of an offline contingency reserve cost [\$/Mwh] for generating unit $i \in I$ during period $h \in H$.

d_h is the power demanded during period $h \in H$, $d_h \geq 0$.

d_h^{rr} is the minimum requirement for regulating reserve during period $h \in H$, $d_h^{rr} \geq 0$.

d_h^{cr} is the minimum requirement for contingency reserve during period $h \in H$, $d_h^{cr} \geq 0$.

$e(h, \Delta t) \in H$ is the earliest period staying no more than Δt apart from $h \in H$:

$$e(h, \Delta t) = \min\{p \in H \mid t_p \geq \max(t_h - \Delta t, t_0)\}.$$

We calculate this $e(h, \Delta t)$ function for $\Delta t = t_i^{\min up}$ and $\Delta t = t_i^{\min down}$.

$f_l^{\max}$ is the maximum allowable power flow [Mw] through transmission line $l \in L$, $f_l^{\max} \geq 0$.

g_{il} is the impact per 1 Mw injection by generating unit $i \in I$ on transmission line $l \in L$.

$k_i^{rr}(k_i^{cr})$ is the portion of the regulating (or contingency) reserve for generating unit $i \in I$ considering the ramping constraints.

r_{ih} is the maximum allowable ramping up or down [Mw/hour] for generating unit $i \in I$ during period $h \in H$; it is positive.

$z_{ih}^{off\max}$ is the maximum allowable offline contingency reserve provided by generating unit $i \in I$ during period $h \in H$.

The initial and terminal values for all variables described below ($h = 0$ and $h = |H| + 1$) are in the list of parameters.

Variables

x_{ih} = power [Mw] generated by unit $i \in I$ during period $h \in H$.

y_{ih} = amount of regulating reserve [Mw] provided by unit $i \in I$ during period $h \in H$; it is nonnegative.

$z_{ih}^{on}(z_{ih}^{off})$ = amount of contingency reserve [Mw] provided by an online (offline) unit $i \in I$ during period $h \in H$.

$u_{ih} = 1$ if unit i is committed to be on during period $h \in H$, 0 otherwise.

$v_{ih} = 1$ if unit i is committed for reserve commitment during period h, 0 otherwise.

$s_{ih}^{up} = 1$ if unit i starts up during period $h \in H$, 0 otherwise.

$s_{ih}^{down} = 1$ if unit i is shut down during period $h \in H$, 0 otherwise.

σ_{ih}^{gen} = generation and no-load cost of unit $i \in I$ during period $h \in H$.

$\sigma_{ih}^{startup}$ = start-up cost of unit $i \in I$ during period $h \in H$.

Objective Function

Minimize total cost: generation and no-load cost, start-up cost, regulating, and contingency reserve cost:

$$\sum_{i \in I} \sum_{h \in H} [\sigma_{ih}^{gen} + \sigma_{ih}^{startup} + c_{ih}^{rr}\delta_h y_{ih} + c_{ih}^{on}\delta_h z_{ih}^{on} + c_{ih}^{off}\delta_h z_{ih}^{off}].$$

Constraints

Power balance: power produced must be instantaneously consumed:

$$\sum_{i \in I} x_{ih} = d_h, \quad h \in H.$$

Regulating reserve requirements: total regulating reserve must honor the minimum requirements:

$$\sum_{i \in I} y_{ih} \geq d_h^{rr}, \quad h \in H.$$

Operating reserve requirements: total operating reserve must honor the minimum requirements:

$$\sum_{i \in I} (y_{ih} + z_{ih}^{on} + z_{ih}^{off}) \geq d_h^{rr} + d_h^{cr}, \quad h \in H.$$

Power-flow restrictions for transmission lines: the power flow at every transmission line is restricted:

$$f_l^{\min} \leq \sum_{i \in I} g_{il} x_{ih} \leq f_l^{\max}, \quad l \in L,\ h \in H.$$

Relationship between commitment and regulating reserve-commitment: commitment is a necessary condition for regulation reserve commitment:

$$v_{ih} \leq u_{ih} \quad i \in I,\ h \in H.$$

Dispatch, regulating, and contingency reserves relationship:

$$a_{ih}u_{ih} - (a_{ih} - a_{ih}^{rr})v_{ih} + y_{ih} \leq x_{ih}$$
$$\leq b_{ih}u_{ih} - (b_{ih} - b_{ih}^{rr})v_{ih} - y_{ih} - z_{ih}^{on}, \quad i \in I,\ h \in H.$$

Regulating reserves restrictions: the regulating reserve is restricted by half of the corresponding operating range:

$$y_{ih} \leq (1/2)(b_{ih}^{rr} - a_{ih}^{rr})v_{ih}, \quad i \in I,\ h \in H.$$

Offline contingency reserves restrictions:

$$z_{ih}^{off} \le (1-u_{ih}) z_{ih}^{off\,\max}, \quad i \in I,\ h \in H.$$

Start-up, shutdown, and commitment relationship:

$$s_{ih}^{up} - s_{ih}^{down} = u_{ih} - u_{i,h-1}, \quad i \in I,\ h \in H.$$

Start-up and shutdown relationship: no start-up and shutdown at the same time:

$$s_{ih}^{up} + s_{ih}^{down} \le 1, \quad i \in I,\ h \in H.$$

Ramping-up restrictions: ramping up includes power change and portions of regulating and contingency reserves:

$$x_{ih} - x_{i,h-1} + k_i^{rr} y_{ih} + k_i^{cr} z_{ih}^{on} \le (1-s_{ih}^{up}) r_{ih}\delta_h + s_{ih}^{up} a_{ih}, \quad i \in I,\ h \in H.$$

Ramping-down restrictions: ramping down includes power change and a portion of regulating reserve:

$$x_{i,h-1} - x_{ih} + k_i^{rr} y_{ih} \le (1-s_{ih}^{down}) r_{ih}\delta_h + s_{ih}^{down} b_{ih}, \quad i \in I,\ h \in H.$$

Minimum uptime constraints: if a unit is down, no start-ups are allowed in the previous periods inside of the minimum uptime:

$$\sum_{p=e(h,t_i^{\min up})}^{h} s_{ip}^{up} \le u_{ih}, \quad i \in I,\ h \in H.$$

Minimum downtime constraints: if a unit is up, no shutdowns are allowed in the previous periods inside of the minimum downtime:

$$\sum_{p=e(h,t_i^{\min down})}^{h} s_{ip}^{down} \le 1 - u_{ih}, \quad i \in I,\ h \in H.$$

Generation and no-load cost restrictions: approximation of the convex "generation cost-power" curve:

$$\sigma_{ih}^{gen} \ge \mu_{ij} x_{ih} + \eta_{ij} u_{ih}, \quad j \in J_i,\ i \in I,\ h \in H.$$

Start-up cost restrictions: approximation of the "start-up cost downtime" curve:

$$\sigma_{ih}^{startup} \ge c_{ihp}^{startup}\Big(s_{ih}^{up} - \sum_{k=p}^{h-1} u_{ik}\Big), \quad i \in I, h \in H, p = 1, \ldots, h-1.$$

Initial conditions: a unit must remain committed (decommitted) if it was up (down) at the beginning of the time horizon:

$$u_{ih} = 1, \quad i \in I,\ h \in H_i^{begin\text{-}up}.$$

$$u_{ih} = 0, \quad i \in I,\ h \in H_i^{begin\text{-}down}.$$

Terminal conditions: a unit must remain committed (decommitted) if it is supposed to be up (down) after the end of the time horizon:

$$u_{ih} = 1, \quad i \in I,\ h \in H_i^{end\text{-}up}.$$

$$u_{ih} = 0, \quad i \in I,\ h \in H_i^{end\text{-}down}.$$

Nonnegativity constraints for energy dispatch, reserves, downtime:

$$x_{ih} \ge 0, \quad i \in I,\ h \in H.$$

$$y_{ih} \ge 0, \quad i \in I,\ h \in H.$$

$$z_{ih}^{on} \ge 0, \quad i \in I,\ h \in H.$$

$$z_{ih}^{off} \ge 0, \quad i \in I,\ h \in H.$$

$$\tau_{ih}^{downtime} \ge 0, \quad i \in I,\ h \in H.$$

Range constraints for start-ups and shutdowns:

$$0 \le s_{ih}^{up} \le 1, \quad i \in I,\ h \in H.$$

$$0 \le s_{ih}^{down} \le 1, \quad i \in I,\ h \in H.$$

Integrality constraints for commitment and regulating reserve commitment:

$$u_{ih} \in \{0,1\}, \quad i \in I,\ h \in H.$$

$$v_{ih} \in \{0,1\}, \quad i \in I,\ h \in H.$$

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