Recent ISO Software Enhancements and Future Software and Modeling Plans

STAFF REPORT

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Federal Energy Regulatory Commission Staff Team
Richard P. O'Neill, Team Lead
Thomas Dautel
Eric Krall

ISO Software Enhancements of The Last Decade and Future Software and Modeling Plans

Introduction

This paper provides a summary of the various market designs, and the components of each of these markets, utilized by the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) subject to the jurisdiction of the Federal Energy Regulatory Commission (Commission), and provides an overview of the current practices and future plans of these RTOs/ISOs with respect to the software and modeling used to implement their markets, including the real-time and day-ahead markets for energy and ancillary services, as well as certain transmission and planning functions.[1]

In 1999, the Commission and Rutgers University sponsored a conference entitled *The Next Generation of Electric Power Unit Commitment Models* (1999 Conference).[2] At the time, Lagrangian relaxation (LR) and linear programming (LP) were the dominant algorithmic approaches used to solve day-ahead and real-time market problems. Because they are approximations to the physical market problem, these approaches generally yield suboptimal results. On the other hand, mixed integer programming (MIP) allows for better modeling of, and is theoretically capable of finding a better solution to, these problems. The modeling of the problem is limited by the robustness of the software, and, as a result, MIP had been abandoned earlier because it was generally found to be incapable of finding a good solution in the time required. One of the papers in the book presented computational advances and test results on unit-commitment problems, and, given its theoretical benefits, encouraged the RTOs/ISOs to test using MIP.[3]

Following the 1999 Conference, PJM tested MIP by solving the day-ahead market problem with both its existing software and MIP. Based on this test, the PJM Interconnection, LLC (PJM) found that the production (bid) cost savings on an annual basis were approximately $60 million. In 2004, PJM implemented MIP in its

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[1] This paper was prepared by Commission Staff and based primarily on information provided by representatives of the various RTOs and ISOs, and reflects conditions as of the time such information was provided. The opinions and views expressed in this staff report do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission. This staff report contains analyses, presentations and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

[2] The 1999 Conference resulted in a book with the same title. *See The Next Generation of Electric Power Unit Commitment Models*, Hobbs, Rothkopf, O'Neill and Chao, eds. Boston, Dordrecht, London: Kluwer Academic Publishers, 2001.

[3] R. P. O'Neill, B. Hobbs, W. Stewart, R. Bixby, M. Rothkopf and H.P. Chao "Why This Book? New Capabilities and New Needs for Unit Commitment Modeling", *The Next Generation of Electric Power Unit Commitment Models*, Hobbs, Rothkopf, O'Neill and Chao, eds. Boston, Dordrecht, London: Kluwer Academic Publishers, 2001.

day-ahead market. Subsequently, in 2006, PJM tested, and then implemented, MIP in its real-time market look-ahead, with savings estimated at $100 million/year.

On April 1, 2009, the California ISO (CAISO) implemented its Market Redesign and Technology Update (MRTU), which modified the pre-existing market design by establishing a nodal market model, locational marginal prices (LMP), a residual unit-commitment (RUC), and a day-ahead market. As part of MRTU, the CAISO also introduced MIP as the solution technique for the new market design. CAISO estimated savings from implementation of MIP in connection with MRTU to be $27 million/year. After April 2010, the CAISO further reduced the MIP gap tolerance[4] to achieve an additional $25 million/year annual estimated savings. Therefore, the ISO is currently achieving an estimated $52 million in annual estimated savings by using MIP.

In 2009, Southwest Power Pool (SPP) also announced that it would add a day-ahead market to its existing market design, and would use MIP as the solution approach. SPP estimated that implementing the day-ahead market and other enhancements would result in benefits of $103 million/year.[5]

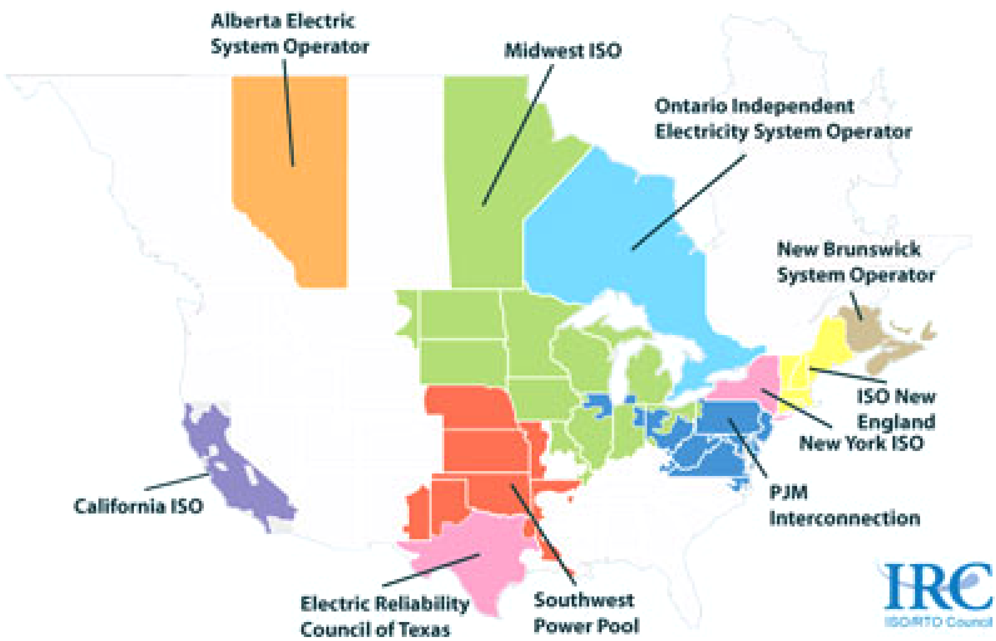
This paper reports on the results of the 2010 surveys, including reported estimated cost savings, current plans for future implementation of MIP, and other market modeling and software improvements.

[4] The gap tolerance is the difference between the best known feasible solution and a known bound on the optimal solution.

[5] http://www.spp.org/publications/Economies_of_Scale_Market_Benefits.pdf

Background

Figure 1. ISO Map

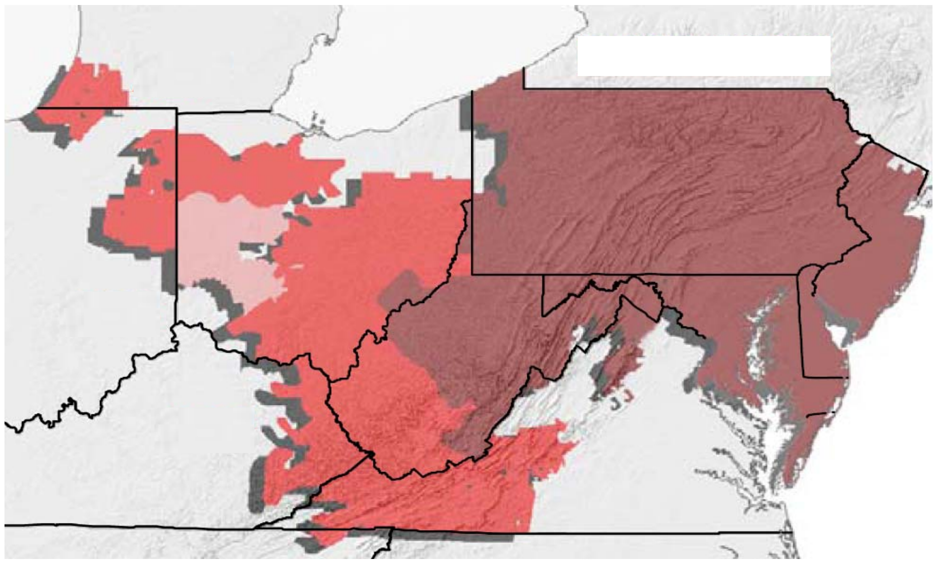


RTOs and ISOs cover a large portion of the U.S. (see Figure 1). Depending on the metric used, RTOs/ISOs serve between one-half and two-thirds of the U.S. electric power market. The remainder of the U.S. operates under bilateral open access transmission tariff (OATT) markets. The RTOs/ISOs have adopted a variety of market designs and services. For example, PJM, New York ISO (NYISO), ISO New England (ISO-NE), Midwest ISO (MISO), and CAISO all provide transmission service on the facilities owned by their members, and operate financial transmission rights, day-ahead, hour-ahead, and real-time markets for energy and ancillary services. Market settlement is based primarily on locational marginal pricing. SPP currently provides transmission service on the facilities owned by its members, and operates the region's real-time energy imbalance service (EIS) market. PJM, ISO-NE, and NYISO also operate capacity markets, and the MISO is developing a capacity market. CAISO and SPP, however, have no plans for a capacity market at this time.

The configuration of the RTOs/ISOs has changed over time. On October 1, 2004, for example, PJM expanded west (see Figure 2) to include parts of Illinois, Ohio, West Virginia and Kentucky at a (one-time) expansion cost of approximately $40 million. Post-expansion, the annual gains from trade increased by about

$180 million (over 20 years, about $1.5 billion in net present value efficiency gains), demonstrating the ability of better coordination through better software modeling to achieve efficiency gains.[6]

Figure 2. Pre and post expansion of PJM on Oct 1, 2004



Market Survey

In September 2010, Commission staff issued a data request to the jurisdictional RTOs/ISOs requesting information on current practices and future plans for proposed software and/or modeling improvements to the real-time market, day-ahead market, and planning models. This document summarizes the results from that data request.

Real-Time Market Look-Ahead

The real-time market look-ahead is a tool that operates in the real-time, up to four hours prior to the real-time dispatch, which provides the market operator the ability to anticipate the need to start-up or shut-down generators with long lead times. Not all of the RTOs/ISOs currently utilize this tool.

In a 2007 Commission staff survey, PJM stated that implementation of MIP in connection with its real-time market look-ahead tool and short term commitment models produced a time-coupled resource dispatch trajectory with estimated savings of $90 million to $130 million/year (including savings from its "Perfect Dispatch" program).

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[6] Erin T. Mansur and Matthew W. White, "Market Organization and Market Efficiency in Electricity Markets," March March 31, 2009, Draft. http://www.industrystudies.pitt.edu/Chicago09/docs/Mansur%203.5.pdf

Since 2009, CAISO has used MIP to improve the co-optimization of its energy and ancillary services, and to include a larger number of transmission constraints.

MISO has an intra-day commitment process that looks out several hours before the real-time market. In the real-time market, MISO currently only dispatches already-committed units using an LP-based security constrained economic dispatch (SCED). MISO is currently implementing a real-time look-ahead commitment model using MIP with 15 minute intervals for up to a three hour period.

NYISO currently has no real-time look-ahead market, but is planning to implement MIP in their market software.[7] The ISO-NE intra-day look-ahead is a reliability unit-commitment process to facilitate risk management and to pre-position generators for expected system changes. ISO-NE is investigating using MIP for its two-to-four hour look-ahead unit-commitment process. SPP also does not currently utilize a real-time look-ahead market.

Residual Unit Commitment

The residual unit-commitment (RUC) is a process that strips out virtual bids, inserts the RTO's/ISO's forecasts of demand and variable energy resources, and commits any additional units needed for reliability. As of 2010, PJM, CAISO, ISO-NE, and MISO all were using MIP in their RUC processes.

The NYISO currently uses LR in its RUC processwhich is integrated within the forecast pass optimization of the day-ahead market. NYISO is evaluating MIP as part of that process and expects MIP to provide incremental production cost benefits in the forecast pass of the day-ahead market. SPP plans to use MIP as part its RUC process in connection with its ongoing market re-design.

. ISO-NE reports that uncertainties caused by wind power generation, load forecast, external transactions, and intermittent resources are being considered for future improvements. For example, ISO-NE reports that a robust optimization based approach is under investigation.

MISO's forward reliability assessment commitment (RAC) model is run soon after the close of the day-ahead market and serves as its RUC process. The RAC minimizes the cost of committing the resources as measured by start-up, no-load, and the incremental energy costs of operating at minimum output. MISO also is investigating revised objective functions and other modeling changes.

Day-Ahead Market

[7] Personal communication with Rana Mukerji, Vice President, Market Structures, NYISO.

The day-ahead market is a 24-hour market that operates a day before real-time to commit, de-commit, and schedule generators with long start-up times, minimum run time and minimum down time. Until 2004, LR and LP were the dominant approaches to solving the day-ahead market. According to PJM, the implementation of MIP-based commitment in the PJM day-ahead market has reduced total production costs between $60 and $100 million annually and significantly reduced day-ahead market uplift. PJM reports that MIP is performing well and has no plans for additional algorithm upgrades at this time.

Prior to the start of MRTU, the CAISO did not conduct a day-ahead market and relied on balanced schedules based on the bilateral forward market. Under MRTU, CAISO estimates operations are saving $23 million/year. By 2010, ISO-NE, MISO and CAISO also had implemented MIP, and NYISO is targeting implementation of the MIP by 2013. In NYISO, the initial evaluation of MIP in the day-ahead market indicated an expected reduction in total system production cost and an improved selection of near marginal cost resources.

Capacity Markets

Of the 3 RTOs/ISOs that have capacity markets, PJM and ISO-NE use MIP; NYISO uses LP. ISO-NE reports an estimated savings from MIP of $45 million.

MISO is investigating a forward-looking capacity market with possible zonal requirements with simple import and export limits for the zones.

Co-optimization of Energy and Ancillary Services

Co-optimization is the simultaneous optimization of all products and services in the market over both time and space. Limitations of software currently prevent full co-optimization of all products and services in the RTO/ISO energy and ancillary services markets. As software improves, greater co-optimization is possible.

NYISO, MISO, and CAISO co-optimize energy, contingency reserves, and regulation. In CAISO, real-time energy and ancillary services currently are co-optimized on a 15-minute interval basis in the real-time unit-commitment (RTUC) process. The ancillary service awards are binding in the RTUC, but the energy dispatch in the RTUC is not. CAISO is considering co-optimizing on a five-minute basis to make both ancillary services and energy binding on the same interval.

ISO-NE and PJM co-optimize energy and reserves only. ISO-NE is conducting cost/benefit analysis of co-optimization of energy with regulation. PJM co-optimizes energy and reserves to make reserve/regulation assignments 30 minutes before the hour. The real-time five-minute dispatch will then incrementally modify reserve and regulation assignments, which is a limited form of co-optimization. However, PJM does not actually simultaneously optimize energy and reserves every five minutes. PJM currently plans to upgrade to a five-minute co-optimization of energy, contingency reserves, and regulation in 2011.

SPP is planning to co-optimize energy, contingency reserves, and regulation service as part of its ongoing market re-design efforts.

Ramp Rate Modeling

Ramp rate is the speed that a generator, or load, can change its output, or consumption, respectively. For generators, ramp rates vary depending on the power output. In the past, full ramp rate modeling was difficult due to non-convexities of ramp rates and subsequent computational difficulties. The fastest ramp 'down' is the dropping of load.

CAISO allows multi-segment ramp rate bid curves for generators within integral multi-interval look-ahead optimization in both day-ahead and real-time markets. ISO-NE has a single ramp rate in the real-time dispatch that is taken from one point of the multiple-ramp rate curve. The average ramp rate for the dispatch interval will be implemented in the real-time dispatch.

MISO uses a single ramp rate in the day-ahead market and allows resources to submit a ramp rate curve, and different ramp up, ramp down, and bidirectional ramp rate limits in the real-time market.[8] MISO is considering allowing resources to submit different ramp up, ramp down, and bidirectional ramp rate limits in the day-ahead market. MISO is also considering including emergency ramp limits.

NYISO uses a three-segment ramp rate for energy in both day-ahead and real-time. Multi-stage thermal units have indicated potential complications with both maintaining a constant ramp rate across their output ranges for regulation, and with regulating in ranges requiring supplementary (duct) burner firing. The NYISO is undertaking a project to evaluate the need and practicality of multi-segment ramp rates for ancillary service products.

PJM uses up to 10 different ramp rates for different MW operating ranges. PJM is working to implement enhancements to allow ramp rates to differ depending on whether the unit is ramping up or down.

SPP uses multiple ramp rates for dispatch purposes only. Futures plans include MW based ramp rate curve per generator for commitment, and multiple ramp rate curve types (ramp up, ramp down, and bidirectional ramp), for dispatch.

Transmission Switching

[8] The bidirectional ramp rate limit is only for AGC capable units.

Transmission switching (that is, taking out and inserting transmission elements into the transmission topology) is a widely used technique in power systems operations, but is not used in market optimization due to computational limitations. Specific instances of transmission switching are sometimes called “special protection schemes.”

ISO-NE, NYISO, CAISO and PJM all use “special protection schemes” for transmission switching. NYISO, for example, captures transmission switching operations in the commitment and dispatch optimization processes to ensure the most efficient resource utilization is available prior to, during and after the outage. PJM, on the other hand, uses a semi-automated on-line powerflow analysis, with confirmation by engineering staff, when considering available switching options and/or bus reconfiguration to alleviate overloads, to avoid off-economic dispatch, and/or to avoid emergency load management. In 2011, PJM expects that a new energy management system will allow further automation of the process.

MISO and SPP have not established any ‘‘special protection schemes.” CAISO is currently investigating using optimization to perform post-contingency corrective actions.

Combined-Cycle Generator Modeling

Combined-cycle generators and some other generators can operate in several different configurations. Without MIP, the different configurations are difficult to model. With MIP, however, a much improved representation is possible. In PJM, there are several modeling approaches available to combined-cycle resource owners, and optimization can accommodate multiple/conditional offers in the PJM markets. In CAISO, the bid function is the same for all generators. In December 2010, CAISO implemented its new multi-stage generation modeling approach, which optimally selects the appropriate configuration to be used. Each configuration in a plant is modeled as a separate resource accounting for the time and cost dependencies between the different configurations.

In MISO, each market participant must specify which combined-cycle plant configuration it is offering into the market. Only a single plant configuration may be offered for a combined-cycle generator. MISO is investigating enhanced modeling of the combined-cycle generators in which the unit-commitment model will select which configuration to use. In ISO-NE, resources are divided into approximate aggregate configurations. In SPP, each combined-cycle plant configuration is modeled as a unit and transition between configurations are modeled.

The NYISO modeling utilizes a gas turbine/steam turbine coupled model(s) to represent the operating modes of the plant for commitment and dispatch of combined-cycle generation units. The model allows for the representation of individual gas turbine commitment costs to the optimization processes, and captures the combined unit operating characteristics for the dispatch tools. NYISO will be moving towards an MIP methodology by 2013. As part of the evaluation and implementation process, the NYISO is reviewing the potential for individual unit configuration for combined-cycle generators.

Dispatchable Load Modeling

A significant element necessary for greater participation of demand response resources in the RTO/ISO markets is the need for enhanced market software computational capability.

In the MISO, CAISO, PJM, and SPP markets, dispatchable loads are modeled on a basis similar to a generator with similar parameters. CAISO is currently considering further modeling enhancements for demand response. In ISO-NE, dispatchable loads do not currently have commitment parameters, such as minimum up and down time, but ISO-NE is considering introducing such commitment parameters into its market design.

The NYISO approaches dispatchable load modeling in three methods. First, the day-ahead demand response program allows for the same full functionality as generator bidding to schedule economic demand reductions in the day-ahead market. Second, price cap functionality allows market participants to schedule their load purchases using predetermined limits. Third, NYISO allows dispatchable load the same full functionality as generator bidding to schedule economic demand reductions in the real-time market.

In PJM, dispatchable loads can choose to be modeled nodally (*i.e.,* as a single substation) and enter a complete set of offer parameters comparable with generators. Aggregated loads across multiple substations are also permitted, but the distribution of the load across the substations must be specified and all substations in the aggregate must be in the same transmission zone. PJM plans to upgrade load forecast and power flow optimization to accommodate widespread development of distributed price-responsive demand, and alternative technology such as storage and plug-in hybrid electric vehicles. Most of the effort is focused on upgrading system performance of the load model.

Storage Modeling

The RTOs/ISOs are evaluating the optimal use of storage and environmentally constrained resources. Certain RTOs/ISOs have already implemented measures to permit energy storage facilities to participate in both the real-time market and day-ahead markets. Some believe that storage facilities require more bidding options to allow greater market efficiency.

The NYISO market offers the capability to economically schedule the production and recharge cycles of pumped storage facilities based upon the market clearing prices. The NYISO is targeting a project to evaluate a full co-optimization of physical and financial offers from storage devices, including recharge time, minimum cycle time and arbitrage spreads.

In MISO, a pumped storage market participant can decide in which intervals the resource can be scheduled to generate, and in which intervals it can be scheduled to pump. In the intervals in which it can be scheduled to generate, the participant can submit an offer like any other generator. In intervals in which it can be scheduled to pump, the participant can submit a price sensitive demand bid.

In ISO-NE, bids for pumping and generating from a pumped storage unit are optimized independently. The CAISO is considering further modeling enhancements for different types of storage. SPP's new market design also will support pumped storage bidding.

Modeling of Flexibility in Resource Limits

Many constraints on power system assets are "soft," meaning that such constraints are both a function of time and intensity of usage. Often, though, constraints that are actually "soft" are modeled as "hard," or inviolate, in part due to a lack of understanding of the time and intensity function, and in part due to computational issues. For example, an excursion from a steady-state thermal constraint may be modeled as a "hard" violation even though this type of an excursion may, in fact, be more properly characterized as "soft." The consequence of characterizing such an event as a violation may include the assessment of a high penalty price, which may create suboptimal market results. On the other hand, flexibility in resource limits can include relaxation of violation limits on flowgates, and in the determination of the economic minimum and/or economic maximum output of a resource. Additional examples of constraint modeling, and the consequences of such modeling, include the following.

In CAISO, all resource-related limits are "hard" limits, except for daily energy use limits. Flowgate constraints are "soft" constraints. According to CAISO, it currently has no future plans to address these issues.

Going forward, MISO provides that it plans to simply use the penalty price in trying to enforce transmission limits. Moreover, MW limits for resources such as generators depend upon operating conditions. For example, one set of limits may be used during normal operations, whereas Emergency Maximum limits may be employed during maximum demand situations, during which MISO is experiencing difficulty satisfying demand. Similarly, Emergency Minimum limits may be used when MISO experiences difficulty satisfying minimum operating limits. Such Emergency conditions allow operation beyond economic limits used in normal operations and are based on emergency offer segments of resources. The resource limits selected based on these operating conditions are enforced by setting high penalties on violations.

In NYISO, demand curves for operating reserve, regulation, and transmission constraints that incorporate the assigned product shortage cost into the applicable market clearing prices were implemented in 2005. Such shortage values need to reflect the value of reserves during shortage conditions, consistent with operational practice and reserve scheduling requirements. With appropriate shortage values, shortage pricing ensures appropriate pricing and scheduling results when the desired amount of reserves or regulation is unavailable. NYISO is re-assessing the operation of the current reserve and regulation shortage values and examining the continued applicability of the current set points.

In PJM, the penalty adaptation has the objective of setting the resource's limit at the upper bound of seasonal physical dispatch alternatives and is semi-automated (*i.e.*, it is a function of distribution factors and resource offers relative to the unconstrained dispatch marginal price). "Economic" resource MW limits are dependent on operating conditions. On the other hand, "Emergency" limits allow resource operations beyond its economic limits based on emergency offer segments, which can include negative offers for minimum limits. PJM employs adaptive generation modeling, which modifies economic operating range dynamically based on unit dispatch trajectory and other parameters.

With respect to transmission facilities, PJM adapts its transmission constraints based on dispatch conditions. Generally, lower voltage level facilities have higher penalty levels because there are fewer resource dispatch options. According to PJM it is working on an adaptive transmission constraint model, which will adapt penalties based on a comparison of the rate of change of flow to the limit of the transmission facility.

In ISO-NE, the relaxation of transmission constraints includes high penalties. Adaptive transmission line rating is being considered for future implementation.

In SPP, dispatching of resources includes penalty factors for violation of resource limits on flowgates, ramp rates, and balancing. The SPP market model includes a very high penalty parameter for relaxing resource limits. Penalties for different constraints will be determined during the implementation of the market design. A few on-going prototyping activities for transmission constraint pricing are under review, including adopting a MW dependent penalty price curve, sub-gradient base transmission pricing, and a convex-hull approach.

AC Power Flow Models

AC power flow models describe the actual physics of the power system (at least to the extent that the power system parameter and configuration data are accurate), and include variables describing not only the real power (P) and voltage angles (θ) considered in the DC power flow models, but also variables describing reactive power (Q) and voltage magnitudes (V). AC power flow models can be used in at least the following two ways.

First, AC power flow models can be used to check the feasibility of a dispatch from a DC optimal power flow (DC OPF) model. In this process, the dispatch values for real power from the DC OPF are provided as inputs to an AC power flow model, which attempts to find a feasible solution given the restrictions on voltage and reactive power generation limits. Such a feasibility check does not attempt to further optimize the system on its own, although it is often used in an iterative, quasi-optimization process. In such a process, (1) a real power dispatch is obtained using a DC OPF, (2) that dispatch is fed into an AC power flow model that identifies constraint violations, (3) branch flow constraints (or other constraints) of the original problem are modified in an attempt to resolve the constraint violations observed in the AC power flow model, (4) the problem is re-solved in the DC OPF with the updated constraints, and the process repeats starting at step (2). The process typically ends when a dispatch from the DC OPF is found that does not violate any constraints in the AC power flow model.

Second, AC power flow models can be used as the mathematical basis for a model optimizing real and reactive power dispatch, known as an AC optimal power flow (AC OPF) model. The AC OPF model includes voltage as a direct constraint, and can much more accurately express the branch thermal constraints. Historically, AC OPF models have not been used in power markets, in part because of limitations on software to handle the nonlinear functions contained in the AC power flow model. In addition, the application of AC OPF models in power markets have been limited based on a dispute over whether the relatively low cost of reactive power generation implies that reactive power can be ignored during system dispatch without significant effects on efficiency.

Examples of the manner in which DC OPF and AC OPF are utilized by the RTOs/ISOs includes the following.

AC Power Flow Models in Real-Time Economic Dispatch

Currently, the ISO-NE employs a DC OPF with AC feasibility, and is reported to be conducting research on the risk-based security in SCED. PJM employs a DC-AC iteration and a decoupled AC model. The CAISO employs a decoupled AC model based on last 15-minute linearized loss and shift-factors. If a contingency or an event is declared, the AC model is based on the current state of the system. MISO employs a state estimator that incorporates an AC power flow model. The real-time market uses a linearization of the real power part of the power flow model with a correction of the limits for reactive flows. SPP employs a DC optimization interacted with AC real-time contingency analysis.

NYISO has indicated that it uses an approach other than a DC OPF, with AC feasibility check, DC-AC iteration, decoupled AC model or AC OPF. Rather than implementing an OPF, NYISO operates the system to high target voltage levels resulting in higher transmission voltages across the transmission system and reduced losses. NYISO states that an OPF technology could be used to aid in loss reductions on the transmission system, but such an approach would come with significant infrastructure and recurring costs. The transmission system should normally be operated within the highest operating levels allowable by equipment ratings and reliability.

AC OPF and Real-Time Market Look-Ahead

PJM employs a DC OPF (an approximation to the AC OPF) with an AC feasibility check, a DC-AC iteration approach, and a decoupled AC model with no future plans to modify this approach. CAISO has "fast decoupled"[9] its AC power flow analysis, producing linearized loss and shift-factors for optimization in a successive iteration approach, to include the non-linearity impact of the power flow model on the optimization results. ISO-NE employs a decoupled AC power flow and will deploy a future look-ahead process using MIP with an AC feasibility check. MISO reports that it is working on a look-ahead unit-commitment model and plans to work on a look-ahead dispatch model. The power flow models will be similar to real-time economic dispatch model. SPP uses DC optimization iterating with simultaneous feasibility test.

AC OPF and Residual Unit-Commitment

PJM uses a DC OPF with AC feasibility check, a DC-AC iteration, and a decoupled AC model. CAISO uses a fast decoupled AC power flow, producing linearized loss and shift factors for optimization in a successive iteration approach to include the non-linearity impact of the power flow model on the optimization results. ISO-NE's optimization iterates between MIP and DC power flow. MISO's residual unit-commitment uses a watch list for linearized real-power flow transmission constraints. SPP employs a DC optimization with sensitivity based on watchlist constraints.

AC OPF and Day-Ahead Market

CAISO uses a fast decoupled AC power flow producing linearized loss and shift factors for optimization in a successive iteration approach to include the non-linearity impact of the power flow model on the optimization results. MISO employs a DC power flow model for the base case conditions. It also employs a simultaneous feasibility test to check other power flow constraints (*e.g.,* contingencies). The simultaneous feasibility test model is a real power flow model with the real part of the admittance set to zero. If it finds a

[9] *See* Bergen, A. R., and V. Vittal, *Power System Analysis*, Prentice Hall, New Jersey, 2000.

violated constraint, it returns a linearized constraint to the optimization problem. PJM employs a DC OPF with AC feasibility check, a DC-AC iteration and a decoupled AC model. SPP uses DC optimization iterating with simultaneous feasibility test.

AC OPF and Capacity Market

CAISO and SPP have no capacity markets; MISO has plans for a capacity market. NYISO has no AC analysis in its capacity market. ISO-NE states that it uses a zonal model in the capacity market auction. PJM states that it uses transmission limits, in the form of import limits on a limited number of import limited regions of the market, as part of its capacity market model.

AC OPF and Planning

CAISO, MISO and NYISO employ an AC OPF as part of their planning processes. NYISO also has utilized a full AC OPF in performing its losses study, which optimized reactive power resources in the New York control area with the objective of minimizing losses in the planning horizon system and identifying optimal locations for additional reactive compensation. In the future, the NYISO planning department may use the ACOPF for further reactive power optimization, as well as developing generation dispatch scenarios and determining interface transfer limits.

ISO-NE and PJM employ a full AC power flow without optimization.

Reactive Power Pricing

Suppliers providing reactive power are compensated using various pricing methods in the RTOs/ISOs. PJM compensates suppliers of reactive power using a call option (or demand charge) payment, which is based on a fixed cost allocation method.[10] NYISO provides voltage support service (also using a call option or demand charge) payments to resources that can be called upon to provide support in real-time market operations. ISO-NE employs a cost-based call option payment through its transmission service tariff. SPP and MISO currently have no reactive power pricing.[11] CAISO is considering measures to minimize active power loss as part of the market optimization and a market mechanism for procurement of reactive power. All resources are required to be able to meet the power factor range. If the CAISO has to back down a resource's MW to get MVAR, the resource is eligible for opportunity cost.

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[10] *See American Electric Power Service Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999).

[11] MISO's reactive power rate design was vacated. *See Dynegy Midwest Generation v. Federal Energy Regulatory Commission*, D.C. Circuit, February 11, 2011.

Flexible AC Transmission (FACTS) System Settings

FACTS are used by the RTOs/ISO to control the system. In PJM, various FACTS device settings are based on real-time and forward looking AC power flow analysis. Phase angle regulators (PARs) are generally set in coordination with neighbors to hold schedule flows within a deadband. PARs adjustments are not continuous, and PARs are limited because of equipment and maintenance limitations. Static VAR compensator (SVC) settings are set to maintain desired 765 and 500 kV voltage profiles and to optimize reactive transfer limits.

In CAISO, DC cable flows (for example, the Trans Bay cable) are optimized based on price differentials between terminals and eventually the CAISO may migrate to an explicit DC line model. In ISO-NE, FACTS settings are jointly determined by the ISO and transmission owners through offline studies. In MISO, the market models do not control or adjust FACTS settings. FACTS such as PARS are set in coordination with neighbors. In NYISO, PARs optimization is integrated in the current NYISO unit commitment process in both the day-ahead and real-time markets to provide the optimal PAR settings. In SPP, the phase shifter settings can be optimized.

Appendix. Compilation of Survey Results.

The information in the below tables is taken directly from survey responses.

2a) Type of Unit Commitment Models

Real-Time Market Look-Ahead

	Current Approach				Future Plans	Estimated Annual Benefits from MIP
	LR	MIP	LP	Notes (below)		
CAISO		•		(A)	MIP is performing well. No plans to change models/algorithm.	N/A
ISO-NE		•	•	(B)	ISO NE is investigating a MIP based 2-4 hour look-ahead unit-commitment process. The main purpose of this process is to facilitate the risk management practice in the real-time operation, and preposition generators for system trending. The unit-commitment solution technique is MIP.	Not specified
MISO				(C)	MISO is currently implementing a real-time look-ahead commitment model. It is mixed integer programming based. It models 15 minute intervals for up to a three hour period. As such commitment decisions can be made as close as 15 minutes to the real-time period.	N/A
NYISO	•				The NYISO has performed an initial evaluation of a MIP Unit Commitment engine in the Day Ahead Market. The NYISO is targeting implementation of the MIP unit-commitment process within the 2011-2013 timeframe for use across all optimization horizons.	N/A
PJM		•			The short term commitment models are evolving to produce a time-coupled resource dispatch trajectory. This is accomplished using MIP-based optimization engines that are synchronized in time.	\$90 million to \$130 million (including savings from Perfect Dispatch)
SPP			•	(D)	Future market look-ahead will use MIP.	N/A

Notes:

(A) Prior to April 1, 2009 CAISO used the lagrangian relaxation method based on a zonal model. Under its new LMP-based market, in place since April 1, 2009, CAISO uses MIP. This was done to improve the quality of the co-optimization of energy and ancillary services, and to allow CAISO to include a larger number of transmission constraints in the formulation instead of the fewer and more limiting zonal constraints possible using the lagrangian relaxation method.

(B) ISO-NE dose not have an intermediate look-ahead unit-commitment process. It has an intra-day reliability unit-commitment process, which adopts the mixed integer programming technique. The commitment of fast start units in real time is based on the linear programming technique.

(C) MISO does not at present have real-time market look-ahead unit-commitment software. MISO has an intra-day commitment process, but it runs several hours before the real-time market. In the real-time market, MISO currently only dispatches already committed units using an LP based SCED.

(D) No real-time market look-ahead in SPP’s current market.

Residual Unit Commitment

	Current Approach				Future Plans	Estimated Annual Benefits from MIP
	LR	MIP	LP	Notes (below)		
CAISO		•		(A)	MIP is performing well no plans to change models/algorithm.	N/A
ISO-NE		•			Uncertainties caused by the wind power generation, load forecast, external transactions, and intermittent resources are being considered for the future improvement. A robust optimization based approach is under investigation.	Not specified
MISO		•		(B)	We plan to investigate revised objective functions in the RAC models. We are also considering investigating other modeling changes.	
NYISO	•			(C)	The current Residual Unit Commitment process at the NYISO is integrated within the Forecast Pass optimization of the day ahead market. This process will be included in the implementation of the MIP unit-commitment process as detailed below.	N/A
PJM		•			MIP is performing well. No plans for additional algorithm upgrades at this time.	$90 million to $130 million (including savings from Perfect Dispatch)
SPP				(D)	Reliability unit commitment (RUC) will be using MIP.	N/A

Notes:

(A) Prior to start of CAISO operations under the new LMP-based market design, CAISO did not conduct a residual unit-commitment process.

(B) MISO has a forward reliability assessment commitment (RAC) model that is run soon after the close of the day-ahead market and an intra-day RAC model that is run throughout the day. The cost considered in the RAC models is the cost of committing the resources as measured by start-up and no-load costs for committed resources as well as the incremental energy costs of running the newly committed resources at minimum output.

(C) (NYISO) The majority of generation commitment is achieved in the bid pass of the day ahead market. The change to a MIP algorithm will provide small incremental production cost benefits in the forecast pass of the day ahead market.

(D) Not applicable in the current SPP market.

Day-Ahead Market

	Current Approach				Future Plans	Estimated Annual Benefits from MIP
	LR	MIP	LP	Notes (below)		
CAISO		•		(A)	No current plan to change the MIP approach.	$52 million
ISO-NE		•			Not specified	Not specified
MISO		•			Not specified	Not specified
NYISO	•			(B)	The NYISO has performed an initial evaluation of a MIP Unit Commitment engine in the Day Ahead Market. The initial evaluation provided promising results to both the unit-commitment process and improved production cost. The NYISO is targeting implementation of the MIP unit-commitment process within the 2011-2013 timeframe. In addition, the NYISO is currently undertaking several initiatives to enhance the performance of the day ahead processes both with software and hardware enhancements.	Not specified
PJM		•		(C)	MIP is performing well. No plans for additional algorithm upgrades at this time.	$60-$100 million
SPP				(D)	Day-ahead Market will use MIP for unit-commitment and LP for dispatch and pricing.	

Notes:

(A) Prior to start of ISO operations under the new LMP-based market design, the ISO did not conduct a day-ahead market and relied on balanced schedules based on the bilateral forward market. For comparison purposes, based on a typical industry experience of one percent for the Lagrangian duality gap, one can estimate $52 million per year in savings, based on a $15 million ISO daily objective costs and the current 0.05 percent MIP gap. Recently reduced MIP Gap from .5 to .05%. Estimated annual production costs improved efficiency = $7million.

(B) The evaluation of the MIP unit-commitment process indicated a modest reduction in total system production cost and an improved selection of near marginal cost resources. The MIP solution tools offer additional flexibility to support enhanced market functionality.

(C) The implementation of MIP-based commitment in the day-ahead market has significantly reduced day-ahead market uplift and had reduced total production costs by between $60 - $100 million annually.

(D) Not applicable in the current SPP market.

Capacity Market

	Current Approach				Future Plans	Estimated Annual Benefits from MIP
	LR	MIP	LP	Notes (below)		
CAISO				(A)	No current plans to develop a centralized capacity market	N/A
ISO-NE		•		(B)	The capacity market is being redesigned, and the future market clearing may adopt the mixed integer linear programming technology.	Not specified
MISO			•	(C)	MISO is investigating a more forward looking capacity market with possible zonal requirements. Zones will have import and export limits.	N/A
NYISO			•		Continue with LP approach; no issues with execution time or accuracy.	N/A
PJM		•			MIP is performing well. No plans for additional algorithm upgrades at this time.	N/A (original design)
SPP				(D)	Not in scope for future market.	N/A

Notes:

(A) CAISO does not have a centralized long-term capacity market.

(B) The methodology for the ISO-NE capacity market clearing is the mixed integer nonlinear programming that searches for the global optimal solution.

(C) The MISO capacity market is a simple auction model with a single period and zone. It is a simple intersection of the supply offer curve with the demand. As such it can be viewed as a simple LP.

(D) Not applicable in the current SPP market.

2b) Unit Commitment Characteristics

Modeling of Flexibility in Resource Limits (e.g. Violation Relaxation Limits on Flowgates, Eco Min, Eco Max, etc)

	Current Approach	Future Plans
CAISO	All resource-related limits are hard limits except for daily energy use limits. Flowgate constraints are soft constraints.	No future plans to change the process.
ISO-NE	In ISO-NE, the relaxation of transmission constraints is being done in a separate process, but does include very high penalties.	Adaptive transmission line rating is being considered for future implementation.
MISO	MISO software uses high penalty prices on constraint violations to enforce limits. Presently, some transmission limits that cannot be enforced are relaxed to just over the flow that can be achieved prior to a second run to develop shadow prices in these constraints. . MW limits for resources such as generators depend upon operating conditions. One set of limits may be used during normal operations. During maximum demand situations in which MISO experiences difficulty satisfying demand, Emergency Maximum limits may be employed. Emergency Minimum limits may be used when MISO experiences difficulty satisfying minimum operating limits. Emergency operations allow operation beyond economic limits used in normal operations and are based on emergency offer segments of resources. The resource limits selected based on conditions are enforced by setting high penalties on violations.	MISO plans to remove the constraint relaxation on transmission constraints that cannot be enforced and simply use the penalty price in trying to enforce the limit and developing the shadow prices.
NYISO	In February 2005, as part of the SMD 2.0 implementation, NYISO implemented demand curves for Operating Reserve, Regulation, and Transmission Constraints that incorporate the assigned product shortage cost into the applicable market clearing prices. Shortage values need to reflect the value of reserves during shortage conditions, consistent with operational practice and reserve scheduling requirements. With appropriate shortage values, shortage pricing ensures appropriate pricing and scheduling results when the desired amount of reserves or regulation is unavailable.	NYISO has a project underway to re-assess the operation of the current reserve and regulation shortage values and to confirm the continued applicability of the current set points In addition, it will consider the need for additional shortage values to determine prices during shortage conditions.
PJM	PB constraint penalty= $1000/MWh; Ramp constraint penalty = $50,000/MWh; Emergency MW constraints= $5,000/MWh. Economic MW limits are dependent on operating conditions. Normal operations = $5,000/MWh; emergency	Moving toward adaptive transmission constraint model where penalties are adapted based on rate of change of flow vs. limit

	operations will allow economic limits to be violated based on emergency offer segments of unit which can include negative offers for min limits. Transmission constraints default to $1000/MWh but are adapted based on dispatch conditions. The penalty adaptation is semi-automated and has the objective to set limit at the upper bound of seasonal physical dispatch alternatives (i.e. it is a function of DFAX and resource offer relative the unconstrained dispatch marginal price) Generally lower voltage level facilities have higher penalty levels because there are fewer resource dispatch options.	Also moving toward adaptive generation modeling which modifies economic operating range dynamically based on unit dispatch trajectory, etc.
SPP	Dispatching of resources includes penalty factors for violation of resource limits on flowgates, ramp rates, balancing.	Market model includes a very high penalty parameter for relaxing resource limits. Penalties for different constraints will be determined during the implementation. A few on-going prototyping activities for transmission constraint pricing are under review: - MW dependent penalty price curve - Sub-gradient base transmission pricing - Convex-Hull approach

Ramp Rate Modeling

	Current number of ramp-rates per generator	Future Plans
CAISO	Multiple (dynamic rates based on MW output of generator)	No future plans to change the process.
ISO-NE	Single - The ramp rate in the real-time dispatch is taken from one point of the multiple-ramp rate curve.	The average ramp rate for the dispatch interval will be implemented in the real-time dispatch.
MISO	Single in day-ahead. In real-time, allows resources to submit a ramp rate curve, and different ramp up, ramp down and bidirectional (the latter is only for AGC units) ramp rate limits.	MISO is considering allowing resources to submit different ramp up, ramp down and bidirectional ramp rate limits in the day-ahead market. MISO is also considering modeling emergency ramp limits.
NYISO	Three segment ramp rate for energy in day-ahead and in real-time.	The NYISO is undertaking a project to evaluate the need and practically of multi-segment ramp rates for ancillary service products. Multi stage thermal units have indicated potential complications with both maintaining a constant ramp rate across their output ranges for regulation, as well as complications regulating in ranges requiring duct firing. This project will evaluate and determine the exact needs of resources for this ability.
PJM	Up to 10 different ramp rates for different MW operating ranges.	We are working to implement enhancements to allow ramp rates be different depending on whether the unit is ramping up or down.
SPP	Multiple ramp rates for dispatch purposes only.	MW based ramp rate curve per generator for commitment. Multiple ramp rate curve types (ramp up, ramp down, ramp bidirectional), for dispatch.

Co-optimization of Energy and Ancillary Services

	Current approach	Future Plans
CAISO	Co-optimization of energy, contingency reserves, and regulation.	Currently, in the real-time Energy and A/S is co-optimized on a 15 minute interval basis in the real-time unit commitment (RTUC) process. The A/S awards are binding in the RTUC, but the energy dispatch in the RTUC is not. Instead, the RTUC energy dispatch is re-optimized on 5 minute basis in the real-time market. In the future we may consider co-optimizing on 5 minutes basis to make A/S and energy binding on same interval.
ISO-NE	Co-optimization of energy and reserves only.	Cost/benefit analysis of co-optimization with regulation will be conducted in the future.
MISO	Co-optimization of energy, contingency reserves, and regulation	No response
NYISO	Co-optimization of energy, contingency reserves, and regulation: The NYISO unit-commitment process performs a simultaneous co-optimization solution for energy, reserves and regulation which is performed in the day ahead market and in the real-time market. This practice has been in place for the day ahead market since 1999 and for the real-time market since 2005.	No response
PJM	Current process performs co-optimization of energy and reserve to make reserve/regulation assignments for each hour, 30 minutes before the hour. The real-time 5 minute dispatch will incrementally modify reserve and regulation assignments which is a limited form of co-optimization however we do not actually do simultaneous optimization of energy and reserves every 5 minute period	Current plan is to upgrade to a 5 minute Co-optimization of energy, contingency reserves, and regulation on May 1, 2011
SPP	N/A to current market	Co-optimization of energy, contingency reserves, and regulation.

Transmission Switching

	Current approach	Future Plans
CAISO	Currently some special protection schemes that do not affect generation or load are considered in the security constrained unit-commitment (SCUC)/security constrained economic dispatch (SCED) optimization.	The ISO is in initial stages of investigating using optimization to perform post-contingency corrective actions.
ISO-NE	Special protection schemes	No response
MISO	None	No response
NYISO	Special protection schemes. NYISO captures transmission switching operations in the commitment and dispatch optimization processes to ensure the most efficient resource utilization is available prior, during and after the outage.	No response
PJM	Special protection schemes. Also, semi-automated on-line powerflow analysis with confirmation by engineering staff considers available switching options and/or bus reconfiguration to alleviate overloads to avoid off-economic dispatch and/or to avoid emergency load management.	New EMS in 2011 will allow further automation of the process.
SPP	N/A in current market	Not planned for future markets

Combined-Cycle Generator Modeling

	Current approach	Future Plans
CAISO	On December 7, 2010 the CAISO implemented testing its new multi-stage generation modeling approach, which models each configuration in a plant as a separate resource accounting for the cost/time dependencies between the different plant configurations.	No response
ISO-NE	Resource divided into approximate aggregate configurations	No response
MISO	Participants with combined cycle generators can model different configurations as generators with characteristics that depend upon the configuration. The participant must specify which configuration it is offering into the market. Only a single configuration may be offered for a combined cycle generator.	MISO is investigating enhanced modeling of the combined cycle generators in which the unit-commitment model will select which configuration to use. In essence additional integer variables will be used to model such decisions.
NYISO	The NYISO modeling utilizes a gas turbine/steam turbine coupled model(s) to represent the operating modes of the plant	NYISO will be moving towards a MIP methodology in the 2011-2013 timeframe as part of the evaluation

	for commitment and dispatch of combined cycle generation units. The models allows for the representation of individual gas turbine commitment costs to the optimization processes and captures the combined unit operating characteristics for the dispatch tools.	and implementation process the NYISO will review the potential for individual unit configuration for combined-cycle generators.
PJM	Several modeling approaches are available to resource owners. Optimization can accommodate multiple/conditional offers.	MIP is performing well. No plans for additional algorithm upgrades at this time.
SPP	Same as all generators	Each configuration modeled as a unit and transition between configurations are modeled.

Dispatchable Load Modeling

	Current approach	Future Plans
CAISO	Modeled similar to a generator, with similar parameters.	Considering further modeling enhancements for demand response.
ISO-NE	The dispatchable loads are modeled similar to generators without commitment type of parameters such as minimum up and down time.	Commitment type of parameters for dispatchable loads may be introduced.
MISO	Modeled similar to a generator, with similar parameters.	No response
NYISO	The NYISO approaches dispatchable load modeling in three methods. First, our day ahead demand response program allows for the same full functionality as generator bidding to schedule economic demand reductions in the day ahead market. Second, it allows for price cap functionality allowing market participants the ability to schedule their load purchases using predetermined limits. Third, allows dispatchable load the same full functionality as generator bidding to schedule economic demand reductions in the real time market.	No response
PJM	Modeled similar to a generator, with similar parameters. Note that loads can choose to be modeled nodally (i.e. single substation) and enter complete set of offer parameters comparable with generators. Aggregated loads across multiple substations are also permitted but the distribution of the load across the substations must be specified and all substations in the aggregate must be in the same transmission zone.	Plan to upgrade load forecast, powerflow, optimization, etc. to accommodate widespread development of distributed price-responsive demand and alternative technology (i.e. storage, PHEV). Most of the effort is in upgrading performance. The load model and fundamental MIP algorithm is to be able to support widespread distribute resource penetration based on current assessment.
SPP	Modeled similar to a generator, with similar parameters.	No response

Dispatchable Load Modeling

	Current Approach			Future Plans
	Pumped Storage Bidding	Endogenously Optimized	Other	
CAISO	•			Further modeling enhancements for different types of storages are being considered.
ISO-NE			Bids for pumping and generation from a pump-storage unit are optimized independently.	No response
MISO			For pumped storage, the participant can decide in which intervals the resource can be scheduled to generate and which intervals it can be scheduled to pump. In the intervals in which it can be scheduled to generate, the participant can submit an offer like any other generator. In intervals in which it can be scheduled to pump, the participant can submit a price sensitive demand bid.	No response
NYISO	•		NYISO market offers the capability to economically schedule the production and recharge cycles of pump storage facilities based upon the market clearing prices.	The NYISO is targeting a project to evaluate a full co-optimization of physical and financial offers from storage devices, including: recharge time, minimum cycle time arbitrage spreads, etc.
PJM	•			No response
SPP				Will support pumped storage bidding

2) Unit Commitment Characteristics

Modeling of Flexibility in Resource Limits (e.g. Violation Relaxation Limits on Flowgates, Eco Min, Eco Max, etc)

	Current Approach	Future Plans
CAISO	All resource-related limits are hard limits except for daily energy use limits. Flowgate constraints are soft constraints. No future plans to change the process.	
ISO-NE	In ISO-NE, the relaxation of transmission constraints is being done in a separate process, but does include very high penalties.	Adaptive transmission line rating is being considered for future implementation.
MISO	MISO software uses high penalty prices on constraint violations to enforce limits. Presently, some transmission limits that cannot be enforced are relaxed to just over the flow that can be achieved prior to a second run to develop shadow prices in these constraints.	MISO plans to remove the constraint relaxation on transmission constraints that cannot be enforced and simply use the penalty price in trying to enforce the limit and developing the shadow prices.
NYISO	In February 2005, as part of the SMD 2.0 implementation, NYISO implemented demand curves for operating reserve, regulation, and transmission constraints that incorporate the assigned product shortage cost into the applicable market clearing prices. Shortage values need to reflect the value of reserves during shortage conditions, consistent with operational practice and reserve scheduling requirements. With appropriate shortage values, shortage pricing ensures appropriate pricing and scheduling results when the desired amount of reserves or regulation is unavailable.	NYISO has a project underway to re-assess the operation of the current reserve and regulation shortage values and to confirm the continued applicability of the current set points In addition, it will consider the need for additional shortage values to determine prices during shortage conditions.
PJM	PB constraint penalty= \$1000/MWh; Ramp constraint penalty = \$50,000/MWh; Emergency MW constraints= \$5,000/MWh. Economic MW limits are dependent on operating conditions. Normal operations = \$5,000/MWh; emergency operations will allow economic limits to be violated based on emergency offer segments of unit which can include negative offers for min limits. Transmission constraints default to \$1000/MWh but are adapted based on dispatch conditions. The penalty adaptation is semi-automated and has the objective to set limit at the upper bound of seasonal physical dispatch alternatives (i.e. it is a function of DFAX and resource offer relative the unconstrained dispatch marginal price) Generally lower	Moving toward adaptive transmission constraint model where penalties are adapted based on rate of change of flow vs. limit Also moving toward adaptive generation modeling which modifies economic operating range dynamically based on unit dispatch trajectory, etc.

	voltage level facilities have higher penalty levels because there are fewer resource dispatch options.	
SPP	Dispatching of resources includes penalty factors for violation of resource limits on flowgates, ramp rates, balancing.	Market model includes a very high penalty parameter for relaxing resource limits. Penalties for different constraints will be determined during the implementation. A few on-going prototyping activities for transmission constraint pricing are under review: - MW dependent penalty price curve - Sub-gradient base transmission pricing - Convex-hull approach

4 AC Power Flow Models

4a AC Power Flow Models in Operation

AC OPF and Real-Time Economic Dispatch

	Current Approach							
	DC OPF with AC feasibility check	DC-AC Iteration	Decoupled AC model used	AC OPF	Other	None	Notes (below)	Future Plans
CAISO			•				(A)	None
ISO-NE	•							ISO NE is conducting research on the risk-based security in SCED.
MISO					•		(B)	None
NYISO					•		(C)	None
PJM		•	•					None
SPP					•		(D)	None

Notes:

(A) AC based on last 15 minute linearized loss and shift-factors unless there is a contingency or an event is declared, in which case the AC is based on the current state of the system.

(B) The state estimator model has an AC power flow model incorporated. The real-time market uses a linearization of the real power part of the power flow model with a correction of the limits for reactive flows.

(C) The NYISO states that rather than implementing an OPF, NYISO operates the system to high target voltage levels resulting in higher transmission voltages across the transmission system and reduced losses. Pursuing loss reductions through target voltage levels complements existing NYISO and transmission owner reliability practices. An OPF technology could be used to aid in loss reductions on the transmission system but would come with significant infrastructure and recurring costs. The expected outcome of OPF technology is that the transmission system should normally be operated at the highest operating levels allowable by equipment ratings. (D) DC optimization interacted with AC real-time contingency analysis.

AC OPF and Real-Time Market Look-Ahead

	Current Approach							
	DC OPF with AC feasibility check	DC-AC Iteration	Decoupled AC model used	AC OPF	Other	None	Notes (below)	Future Plans
CAISO			•				(A)	None
ISO-NE						•		Future look-ahead process will use MIP with AC feasibility check.
MISO						•		Working on look-ahead unit-commitment model and plans to work on a look-ahead dispatch model. The power flow models will be similar to real-time economic dispatch model.
NYISO					•		(B)	None
PJM	•	•	•					None
SPP					•		(C)	None

Notes:

(A) Fast decoupled AC power flow producing linearized loss and shift-factors for optimization in a successive iteration approach to include the non-linearity impact of the power flow model on the optimization results.

(B The NYISO states that rather than implementing an OPF, NYISO operates the system to high target voltage levels resulting in higher transmission voltages across the transmission system and reduced losses. Pursuing loss reductions through target voltage levels complements existing NYISO and transmission owner reliability practices. An OPF technology could be used to aid in loss reductions on the transmission system but would come with significant infrastructure and recurring costs. The expected outcome of OPF technology is that the transmission system should normally be operated at the highest operating levels allowable by equipment ratings.) (C) DC optimization iterating with MW only simultaneous feasibility test.

AC OPF and Residual Unit-Commitment

	Current Approach							Future Plans
	DC OPF with AC feasibility check	DC-AC Iteration	Decoupled AC model used	AC OPF	Other	None	Notes (below)	
CAISO			•				(A)	None
ISO-NE					•		(B)	None
MISO					•		(C)	None
NYISO					•		(D)	None
PJM	•	•	•					None
SPP						•		DC optimization with sensitivity based on watchlist constraints.

Notes:

(A) Fast decoupled AC power flow producing linearized loss and shift-factors for optimization in a successive iteration approach to include the non-linearity impact of the power flow model on the optimization results.

(B) Optimization iterates between MIP and DC power flow.

(C) Residual unit-commitment uses watchlist transmission constraints. The constraints are linearized real-power flow constraints.

(D) The NYISO states that rather than implementing an OPF, NYISO operates the system to high target voltage levels resulting in higher transmission voltages across the transmission system and reduced losses. Pursuing loss reductions through target voltage levels complements existing NYISO and transmission owner reliability practices. An OPF technology could be used to aid in loss reductions on the transmission system but would come with significant infrastructure and recurring costs. The expected outcome of OPF technology is that the transmission system should normally be operated at the highest operating levels allowable by equipment ratings.

AC OPF and Day-Ahead Market

	Current Approach							Future Plans
	DC OPF with AC feasibility check	DC-AC Iteration	Decoupled AC model used	AC OPF	Other	None	Notes (below)	
CAISO			•				(A)	None
ISO-NE			•					None
MISO					•		(B)	None
NYISO					•		(C)	None
PJM	•	•	•					None
SPP						•		DC optimization iterating with MW only simultaneous feasibility test

Notes:

(A) Fast decoupled AC power flow producing linearized loss and shift-factors for optimization in a successive iteration approach to include the non-linearity impact of the power flow model on the optimization results.

(B) The day-ahead market contains a DC power flow model for the base case conditions. It also employs a simultaneous feasibility test to check other power flow constraints (e.g. contingencies). The simultaneous feasibility test model is a real-power flow model with the real part of the admittance set to zero. If it finds a violated constraint, it returns a linearized constraint to the optimization problem.

(C) NYISO states that OPF technology could be used to aid in loss reductions on the transmission system but would come with significant infrastructure and recurring costs. The expected outcome of OPF technology is that the transmission system should normally be operated at the highest operating levels allowable by equipment ratings. Operating the system to high target voltage levels results in higher transmission voltages across the transmission system and reduced losses. NYISO states that pursuing losses reductions through target voltage levels complements existing NYISO and transmission owner reliability practices.

AC OPF and Capacity Market

	Current Approach							Future Plans
	DC OPF with AC feasibility check	DC-AC Iteration	Decoupled AC model used	AC OPF	Other	None	Notes (below)	
CAISO						•		None
ISO-NE					•		(A)	None
MISO						•		None
NYISO						•		None
PJM					•		(B)	None
SPP						•		None

Notes:

(A) A zonal model rather than detailed network model is considered in the capacity market auction.

(B) Reduced form transmission limits produced in the form of import limits are created on a limited number of import limited regions of the market.

AC OPF and Planning

	Current Approach							Future Plans
	DC OPF with AC feasibility check	DC-AC Iteration	Decoupled AC model used	AC OPF	Other	None	Notes (below)	
CAISO				•				None
ISO-NE					•		(A)	Will consider AC OPF
MISO				•				None
NYISO				•			(B)	None
PJM					•		(A)	None
SPP			•					None

Notes:

(A) Full AC model without optimization.

(B) The NYISO has utilized a full AC OPF in performing the NYISO losses study. That study optimized reactive power resources in the New York control area with the objective of minimizing losses in the planning horizon system and identifying optimal locations for additional compensation.

In the future, the NYISO planning department may use the AC OPF for further reactive power optimization as well as developing generation dispatch scenarios and determining interface transfer limits.

4b Pricing and Operations Related to AC Power Flow Markets

Reactive Power Pricing and/or Payments

	Current Approach							Future Plans
	Opportunity cost	Options payment based on AEP method	Other options payment	Reactive LMP	Other	None	Notes (below)	
CAISO					•		(A)	Considering market mechanism for procurement of reactive power
ISO-NE					•		(B)	
MISO						•		None
NYISO					•		(C)	None
PJM		•						None
SPP						•		None

Notes:

(A) All resources are supposed to be able to meet power factor range. If the ISO has to back resource MW to get MVAR, the resource is eligible for opportunity cost. Utilize reliability-must-run resources for this purpose.

(B) Cost-based payment through transmission tariff.

(C) Provides voltage support service payments to resources that can be called upon to provide support in real-time market operations.

Flexible AC Transmission System Settings

	Describe how FACTS settings are determined	Future Plans
CAISO	DC cable flows are optimized based on price differentials between terminals (i.e.,Trans Bay cable)	May eventually migrate to an explicit DC line model versus current implicit DC model.
ISO-NE	FACTS settings are jointly determined by the ISO and transmission owners through offline studies.	None
MISO	The market models do not control or adjust FACTS settings.	None
NYISO	Phase angle regulator (PAR) optimization is integrated in the current NYISO unit commitment process which is used in day-ahead and real-time markets and provides the optimal PAR settings to aid in the reduction of congestion. This process will be retained as the NYISO moves towards a MIP unit-commitment process.	None
PJM	Various FACTS device settings are based on real-time and forward looking AC power flow analysis. PARs are generally set in coordination with neighbors to hold schedule flows within a deadband. Note PAR adjustments are not continuous as there are limited PAR moves available throughout the operating day because of equipment and maintenance limitations. SVC settings are set to maintain desired 765 and 500 kV voltage profile and to optimize reactive transfer limits.	None
SPP	Phase shifter settings can be optimized	None