EVALUATING THE POTENTIAL IMPACT OF TRANSMISSION CONSTRAINTS ON THE OPERATION OF A COMPETITIVE ELECTRICITY MARKET IN ILLINOIS

APPENDIXES

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APPENDIX A
OVERVIEW OF THE POWERWORLD® MODEL

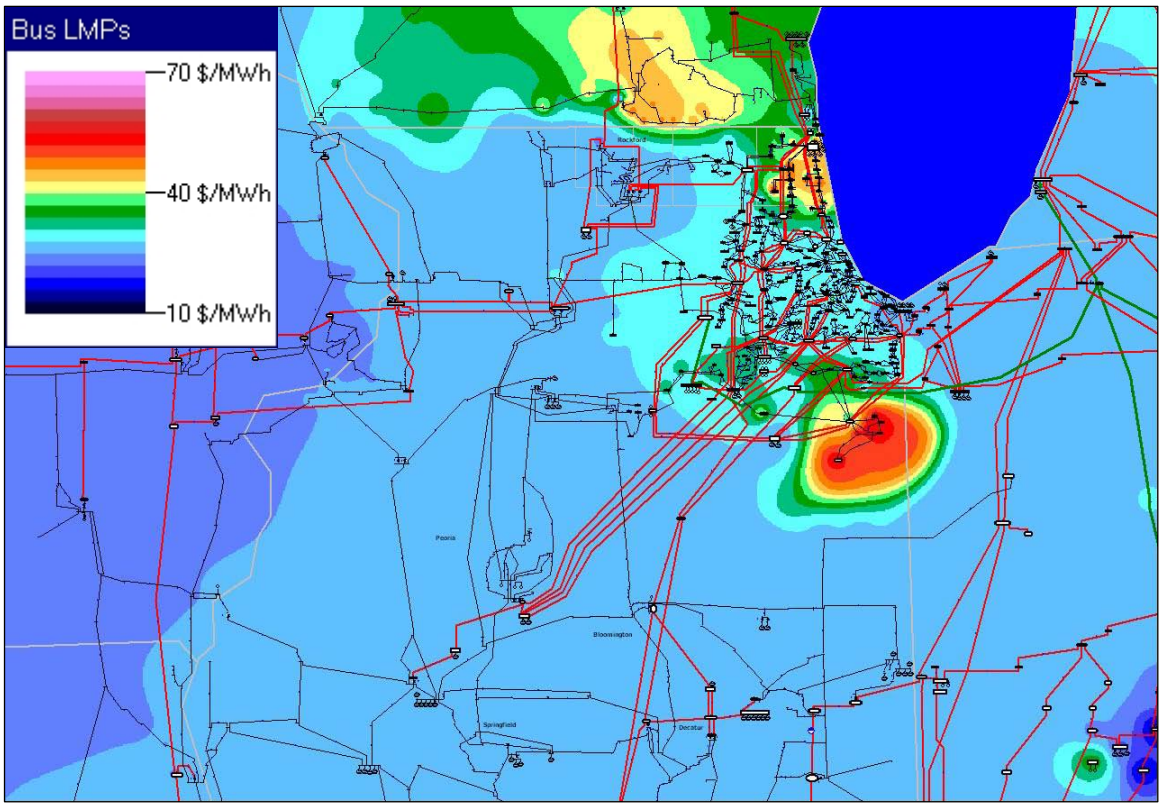
PowerWorld® Simulator is an interactive power system simulation package designed to simulate high voltage power system operation on a time frame ranging from several minutes to many days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 buses. Powerful visualization techniques are used on an interactive basis, resulting in an extremely intuitive and easy-to-use graphical user interface (GUI). The GUI includes animated one-line diagrams with support for panning, zooming, and conditional display of objects.

One of the add-ons available with Simulator is the Security Constrained Optimal Power Flow (SCOPF). The advantage of having a security constrained optimal power flow embedded into Simulator is that it is now possible to optimally dispatch the generation in an area or group of areas while simultaneously enforcing the transmission line and interface limits both for the base case and for a set of statistically likely contingencies. Simulator SCOPF can then calculate the marginal price to supply electricity to a bus (also known as the locational marginal price [LMPs]), taking into account transmission system congestion. The advantage with Simulator is that these values are not just calculated; they can also be shown on a one-line diagram, on a contoured map, or exported to a spreadsheet. An example contour of bus LMPs is shown in Figure A-1.

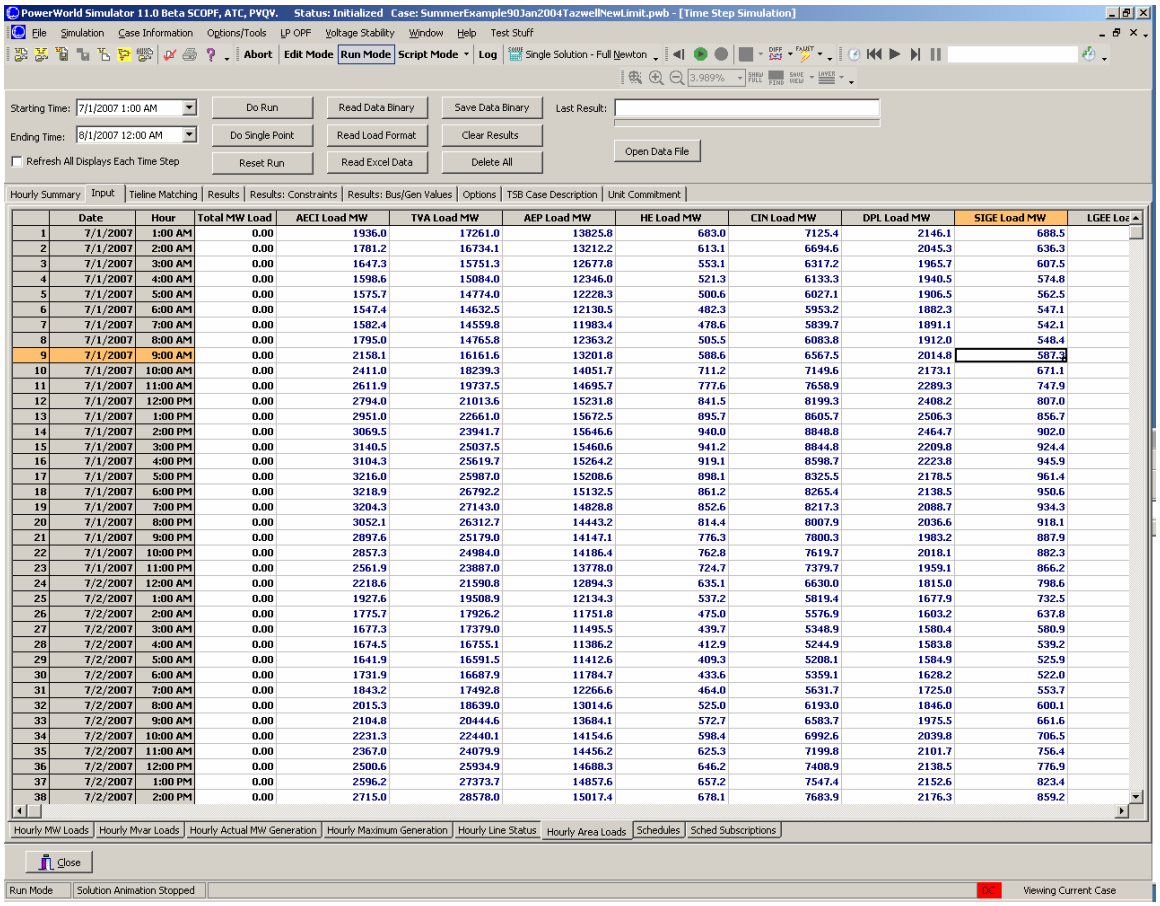
The purpose of an SCOPF is to minimize an objective (or cost) function by changing system controls taking into account both equality and inequality constraints. These constraints are used to model the power balance constraints and various operating limits. In Simulator SCOPF, the algorithm determines the optimal solution by iterating between solving a standard power flow with contingency analysis and then solving a linear program (LP) to change the system controls to remove any limit violations. In solving a constrained optimization problem, such as the SCOPF, there are two general classes of constraints, equality and inequality. Equality constraints are constraints that always have to be enforced. That is, they are always "binding." For example, in the SCOPF the real and reactive power balance equations at system buses must always be satisfied (at least to within a user specified tolerance); likewise the area MW interchange constraints are equality constraints. In contrast, inequality constraints may or may not be binding. For example, a line MVA flow may or may not be at its limit, or a generator real power output may or may not be at its maximum limit.

The version of Simulator used for this project also included the time step simulation enhancement. This enhancement allowed easy hour time step simulations of the power system over relatively long periods of time, such as a month. When run in the time step mode, Simulator sequentially solved the SCOPF for each hour in the time period, taking into account time-specific conditions, such as the total system load and any scheduled generator outages. The time step simulation enhancement also included many features for presenting the results of each study. Figure A-2 shows a sample page from the Time Step Simulation Control Form.

PowerWorld Simulator was originally developed at the University of Illinois at Urbana-Champaign (UIUC) by Professor Thomas J. Overbye beginning in 1994. PowerWorld Simulator is now marketed exclusively by PowerWorld Corporation. PowerWorld Corporation has no direct UIUC affiliation and was not involved with this study. However, since a gratis site license for PowerWorld Simulator (including all add-ons) has been provided by PowerWorld Corporation to UIUC, PowerWorld Simulator was used extensively for the UIUC portion of this study. Additional information about PowerWorld Simulator can be found on the PowerWorld Corporation website, available at www.powerworld.com.



Example LMP Contours for Northern Illinois



	Date	Hour	Total MW Load	AECI Load MW	TVA Load MW	AEP Load MW	HE Load MW	CIN Load MW	DPL Load MW	SIGE Load MW	LGEE Loa
1	7/1/2007	1:00 AM	0.00	1936.0	17261.0	13825.8	683.0	7125.4	2146.1	688.5	
2	7/1/2007	2:00 AM	0.00	1781.2	16734.1	13212.2	613.1	6694.6	2045.3	636.3	
3	7/1/2007	3:00 AM	0.00	1647.3	15751.3	12677.8	553.1	6317.2	1965.7	607.5	
4	7/1/2007	4:00 AM	0.00	1598.6	15084.0	12346.0	521.3	6133.3	1940.5	574.8	
5	7/1/2007	5:00 AM	0.00	1575.7	14774.0	12228.3	500.6	6027.1	1906.5	562.5	
6	7/1/2007	6:00 AM	0.00	1547.4	14632.5	12130.5	482.3	5953.2	1882.3	547.1	
7	7/1/2007	7:00 AM	0.00	1582.4	14559.8	11983.4	478.6	5839.7	1891.1	542.1	
8	7/1/2007	8:00 AM	0.00	1795.0	14765.8	12363.2	505.5	6083.8	1912.0	548.4	
9	7/1/2007	9:00 AM	0.00	2158.1	16161.6	13201.8	588.6	6567.5	2014.8	587.3	
10	7/1/2007	10:00 AM	0.00	2411.0	18239.3	14051.7	711.2	7149.6	2173.1	671.1	
11	7/1/2007	11:00 AM	0.00	2611.9	19737.5	14695.7	777.6	7658.9	2289.3	747.9	
12	7/1/2007	12:00 PM	0.00	2794.0	21013.6	15231.8	841.5	8199.3	2408.2	807.0	
13	7/1/2007	1:00 PM	0.00	2951.0	22661.0	15672.5	895.7	8605.7	2506.3	856.7	
14	7/1/2007	2:00 PM	0.00	3069.5	23941.7	15646.6	940.0	8848.8	2464.7	902.0	
15	7/1/2007	3:00 PM	0.00	3140.5	25037.5	15460.6	941.2	8844.8	2209.8	924.4	
16	7/1/2007	4:00 PM	0.00	3104.3	25619.7	15264.2	919.1	8598.7	2223.8	945.9	
17	7/1/2007	5:00 PM	0.00	3216.0	25987.0	15208.6	898.1	8325.5	2178.5	961.4	
18	7/1/2007	6:00 PM	0.00	3218.9	26792.2	15132.5	861.2	8265.4	2138.5	950.6	
19	7/1/2007	7:00 PM	0.00	3204.3	27143.0	14828.8	852.6	8217.3	2088.7	934.3	
20	7/1/2007	8:00 PM	0.00	3052.1	26312.7	14443.2	814.4	8007.9	2036.6	918.1	
21	7/1/2007	9:00 PM	0.00	2897.6	25179.0	14147.1	776.3	7800.3	1983.2	887.9	
22	7/1/2007	10:00 PM	0.00	2857.3	24984.0	14186.4	762.8	7619.7	2018.1	882.3	
23	7/1/2007	11:00 PM	0.00	2561.9	23887.0	13778.0	724.7	7379.7	1959.1	866.2	
24	7/2/2007	12:00 AM	0.00	2218.6	21590.8	12894.3	635.1	6630.0	1815.0	798.6	
25	7/2/2007	1:00 AM	0.00	1927.6	19508.9	12134.3	537.2	5819.4	1677.9	732.5	
26	7/2/2007	2:00 AM	0.00	1775.7	17926.2	11751.8	475.0	5576.9	1603.2	637.8	
27	7/2/2007	3:00 AM	0.00	1677.3	17379.0	11495.5	439.7	5348.9	1580.4	580.9	
28	7/2/2007	4:00 AM	0.00	1674.5	16755.1	11386.2	412.9	5244.9	1583.8	539.2	
29	7/2/2007	5:00 AM	0.00	1641.9	16591.5	11412.6	409.3	5208.1	1584.9	525.9	
30	7/2/2007	6:00 AM	0.00	1731.9	16687.9	11784.7	433.6	5359.1	1628.2	522.0	
31	7/2/2007	7:00 AM	0.00	1843.2	17492.8	12266.6	464.0	5631.7	1725.0	553.7	
32	7/2/2007	8:00 AM	0.00	2015.3	18639.0	13014.6	525.0	6193.0	1846.0	600.1	
33	7/2/2007	9:00 AM	0.00	2104.8	20444.6	13684.1	572.7	6583.7	1975.5	661.6	
34	7/2/2007	10:00 AM	0.00	2231.3	22440.1	14154.6	598.4	6992.6	2039.8	706.5	
35	7/2/2007	11:00 AM	0.00	2367.0	24079.9	14456.2	625.3	7199.8	2101.7	756.4	
36	7/2/2007	12:00 PM	0.00	2500.6	25934.9	14688.3	646.2	7408.9	2138.5	776.9	
37	7/2/2007	1:00 PM	0.00	2596.2	27373.7	14857.6	657.2	7547.4	2152.6	823.4	
38	7/2/2007	2:00 PM	0.00	2715.0	28578.0	15017.4	678.1	7683.9	2176.3	859.2	

Figure A-2 An Example Input Page from the PowerWorld Simulator Time Step Control Form

APPENDIX B
OVERVIEW OF THE ELECTRICITY MARKET COMPLEX ADAPTIVE SYSTEMS (EMCAS)© MODEL

B.1 INTRODUCTION

Electricity markets around the world are changing. The traditional vertically integrated electric utility that operated as a regulated monopoly that controlled all aspects of electricity service is giving way to new organizational structures. At a minimum, the electricity services are being unbundled with separate companies handling generation, transmission, and distribution services. In markets with the most restructuring, there are multiple companies competing to provide services.

Recent situations have shown the difficulties of understanding the operation of these new markets. The experience in California in 2000/2001 shows the potential pitfalls of not thoroughly analyzing market design, operating rules, business practices, and system operation. Traditional modeling techniques using global optimization approaches and equilibrium analysis have shown to be inadequate to deal with the new electricity markets. The complex interactions and interdependencies among electricity market participants have become much like those studied in game theory. Unfortunately, the strategies used by many electricity participants are often too complex to be conveniently modeled using standard game theoretic techniques. In particular, the ability of market participants to repeatedly probe markets and rapidly adapt their strategies adds additional complexity.

Computational social science includes the use of agent-based modeling and simulation (ABMS) to study complex social systems such as markets (Epstein and Axtell, 1996). An ABMS approach consists of a set of agents and a framework for simulating their decisions and interactions. ABMS is related to a variety of other simulation techniques, including discrete event simulation and distributed artificial intelligence or multi-agent systems (Law and Kelton, 2000; Pritsker, 1986). Although many traits are shared, ABMS is differentiated from these approaches.

In an ABMS model, an agent is a software representation of a decision-making unit. Agents are self-directed objects with specific traits. Agents typically exhibit bounded rationality, meaning that they make decisions using internal decision rules that depend only on imperfect local information. Emergent behavior is a key feature of ABMS. Emergent behavior occurs when the behavior of a system is more complicated than the simple sum of the behavior of its components.

A wide variety of ABMS implementation approaches exist. Live simulation where people play the role of individual agents is an approach that has been used successfully by economists studying complex market behavior. General-purpose tools such as spreadsheets, mathematics packages, or traditional programming languages can also be used. However, special-purpose

tools such as Swarm, the Recursive Agent Simulation Toolkit, StarLogo, and Ascape are among the most widely used options (Burkhart et al., 2000; Collier and Sallach, 2001).

Several electricity market ABMS tools have been constructed, including those created by Bower and Bunn (2000), Petrov and Sheblé (2000), as well as Nicolaisen (2001). These models have hinted at the potential of ABMS to act as electronic laboratories, or "e-laboratories," suitable for repeated experimentation under controlled conditions.

The Electricity Market Complex Adaptive System (EMCAS) model was developed by Argonne National Laboratory, a U.S. Department of Energy facility, to improve the ability to analyze restructured (often referred to incorrectly as "deregulated") electricity markets. It is designed for use both in regional U.S. markets and in markets that are undergoing restructuring in other countries.

B.2 OVERVIEW OF THE EMCAS FORMULATION

The EMCAS formulation can be described in terms of three components: agents, interaction layers, and planning periods. The agents represent the participants in the electricity market. The interaction layers represent the environment in which the agents interact with each other. The planning periods represent the different time horizons in which the agents make decisions regarding their participation in the market.

Figure B-1 shows the agents and the interaction layers that are included in the EMCAS formulation. Some agents appear in more than one layer.

B.2.1 PHYSICAL LAYER

The physical layer at the bottom of the figure represents the agents that are involved in the physical generation, transmission, distribution, and consumption of electricity. The *Consumers* represent the final users of electricity that create the demand or load. They can be residential, commercial, industrial, or any other type of electricity user. *Generators* represent the physical generation equipment. They can be driven by thermal (e.g., coal, oil, gas, nuclear), hydro, or renewable energy (e.g., wind, solar, biomass) technologies. The *transmission nodes* represent the points in the power system where consumers and generators are attached to the grid and where elements of the transmission network are connected. The *transmission links* represent the high-voltage lines that connect nodes. It should be noted that in the EMCAS formulation, the transmission nodes and links can represent actual transmission network buses and lines or they can represent a reduced-form network where buses and lines have been aggregated for computational efficiency. Consumers, Generators, and Transmission Nodes and Links together make up the physical part of the electricity market. Note that in EMCAS, the distribution system is generally not modeled in detail. While it is structurally possible to include the details of the distribution network (i.e., by adding distribution nodes and links), in practice this is not done to maintain a reasonable model size and run time for the simulation.

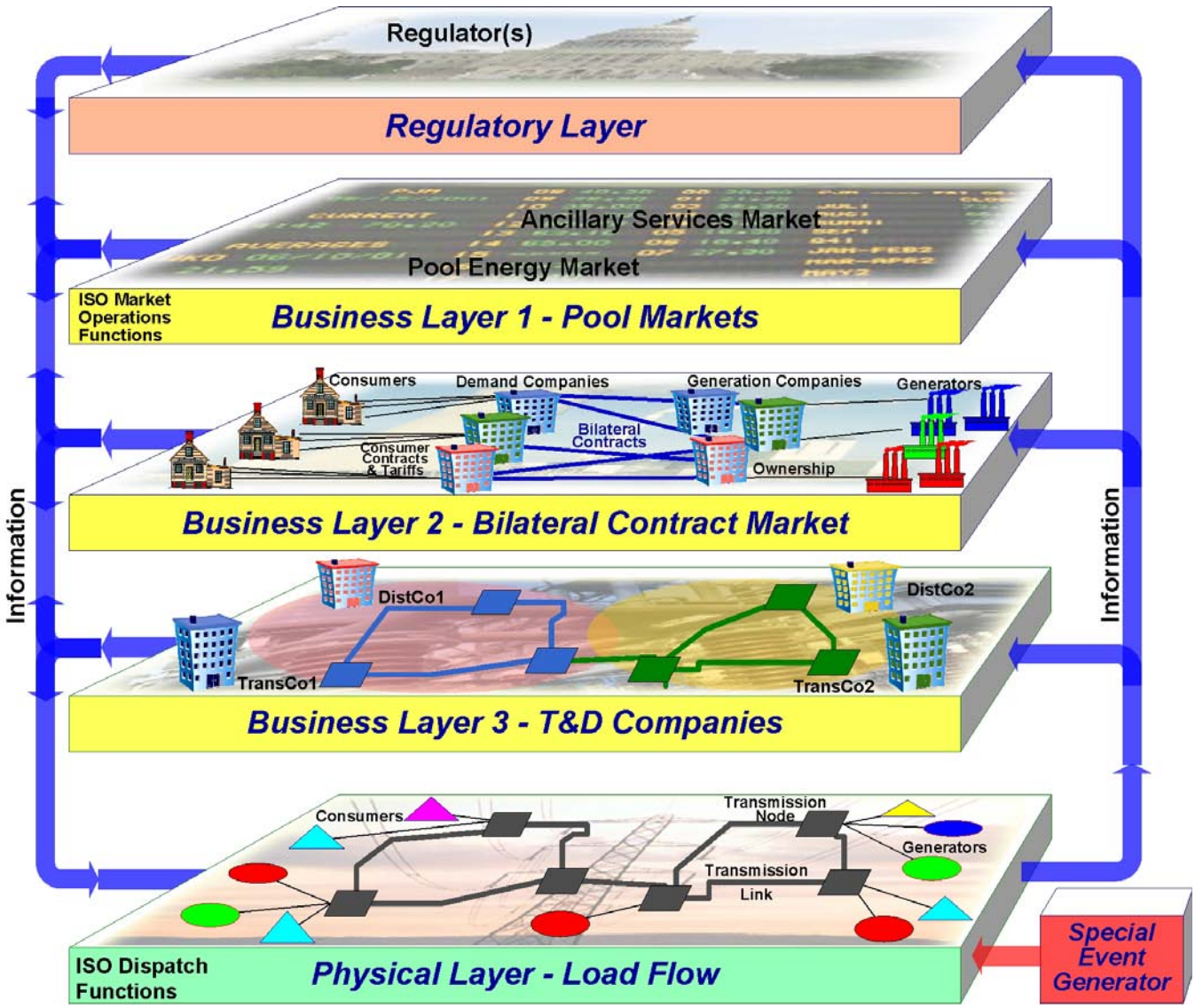


Figure B-1 EMCAS Formulation and Layers

The *independent system operator* (ISO) represents the entity that operates both the transmission system and the electricity markets. This agent could represent an independent system operator, regional transmission organization (RTO), or an independent transmission provider (ITP), depending on what organizational structure is in place. In the physical layer, the ISO exercises its dispatch function to operate the system to match load and generation and to adjust to unscheduled load, generator or transmission outages, and other unplanned events.

B.2.2 BUSINESS LAYERS

Figure B-1 also shows three business layers that represent the business side of the electricity market. The *generation companies* (GenCos) represent the business units that own the generators. It is these agents that make decisions about how to participate in the electricity

market and operate the equipment to meet company objectives. The *demand companies* (DemCos) represent the business units that sell electricity directly to consumers. In the EMCAS formulation, all consumers purchase their electricity from a demand company. It is the demand company that buys electricity from generation companies to serve its customer load. It should be noted that in actual practice, a generation company and a demand company might, in fact, be part of the same corporate parent. This can be accounted for in EMCAS.

Generation companies and demand companies can engage in *bilateral contracts* for the sale and purchase of electricity. These contracts are negotiated privately between two agents. In some market structures, the ISO is involved in these contracts only to the extent of determining that there is adequate transmission capacity to accommodate the contractual power transfers.

Pool markets (or spot markets) for energy and ancillary services serve as central clearinghouses for buyers and sellers. The ISO operates these markets by receiving bids from generation companies and demand companies. It selects bids based on price and system security considerations and prepares a generation schedule. In some areas, there is no pool market operating. EMCAS can simulate this situation as well.

The *transmission company* (TransCo) is the business unit that owns the transmission system. There may be more than one transmission company in an EMCAS simulation. The *distribution company* (DistCo) is the business unit that owns the distribution system. In EMCAS, the details of the distribution system generally are not modeled explicitly. This layer is designed to account for the ownership of the transmission and distribution systems and for the fees charged by these companies for the use of their facilities. The transmission and distribution companies may be part of a single corporate parent, along with a generation company and demand company. EMCAS can account for this corporate connection while maintaining a separate accounting of each business unit.

B.2.3 REGULATORY LAYER

The *regulator* is the agent in the regulatory layer that sets the market rules and monitors market performance. In EMCAS, the user provides input as the regulator.

B.2.4 SPECIAL EVENTS

The *special event generator* is a component of EMCAS that allows for the introduction of unplanned events that can affect market performance. The types of events include generator outages, transmission outages, and load forecast errors. The user inputs the specific special events to be tested in the simulation, which may be produced by external routines.

B.3 AGENT DESCRIPTIONS

This section describes each of the agents used in this EMCAS simulation, the manner in which their behavioral characteristics can be described, and the information that needs to be input for each agent.

B.3.1 GENERATORS

Generators included in an EMCAS simulation can represent single units (e.g., a single gas turbine), a plant that has several units at the same location (e.g., a multi-unit coal-fired power station), or an aggregate of several plants. The input data required for each generator include the following:

Generator Identification Information

- Name;
- Ownership;
- Location – geographic coordinates;
- In service date – on-line, retirement;
- Unit type;
- Fuel type; and
- Associated transmission bus.

Technical Performance Information

- Capacity – nameplate, summer rating, winter rating;
- Blocks – size of capacity blocks that the unit can be divided into;
- Heat rate – average, incremental;
- Minimum capacity;
- Spinning reserve capability;
- Maximum hourly ramp rates – up and down;
- Startup time;
- Minimum down time; and
- Outage rates – planned and forced.

Economic Information

- Fuel cost;
- Operating and maintenance cost – fixed, variable;
- Startup cost – cold start, warm start; and
- Shutdown costs.

The generator agents do not have any decision-making capability in the EMCAS formulation. All of the decisions on how and when to operate generators are made by the generation company agent that owns the unit.

B.3.2 TRANSMISSION NODES AND LINKS

The configuration of the transmission system is input into EMCAS as a set of nodes and links that represent buses and links, respectively (Figure B-2). The representation may be an aggregate of buses and links to simplify the analysis. Data input include:

- From-bus identification;
- To-bus identification;
- Line voltage, kV;
- Number of circuits;
- Circuit reactance;
- Line capacity, MW; and
- Line status (i.e., closed or open).

The transmission network data may be input point-by-point or may be read in from common format files such as those used by the National Electric Reliability Council (NERC).

The transmission nodes and links do not exercise any decision-making capability in an EMCAS simulation. The operation of the transmission system is governed by decisions made by the ISO agent and the transmission company agent that owns the facilities.

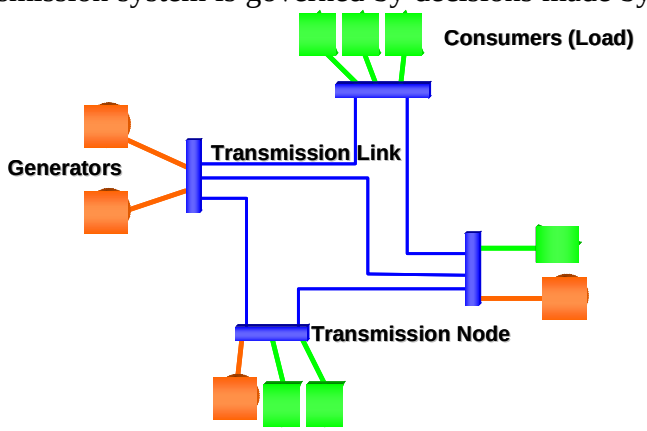


Figure B-2 EMCAS Transmission Components

B.3.3 CONSUMERS

Consumers are the agents in an EMCAS simulation that create the demand for electricity. Consumers may be residential, commercial, industrial, or any other type of electricity user. In theory, an EMCAS simulation may represent individual consumers (e.g., a single household, a single industrial facility). In practice, the number of consumer agents included in a simulation is limited by available data and by computational time. The input for consumer agents includes:

Consumer Identification and Characteristics

- Consumer type – residential, commercial, industrial, other;
- Start and end dates – the times when the agent is on-line and when it is shut down; this allows new consumers to enter the system and old ones to exit a market; and
- Node connection – the point in the transmission network where the consumer is connected.

EMCAS consumer agents have individual identification tags that allow the behavior of each to be tracked during the simulation. In addition, the consumer agent is tagged as to whether

it represents a single user (e.g., a single household) or is an aggregate representation of a number of users (e.g., all residential users in a specific area).

Load Information

Hourly load information is input for each consumer agent. The input load represents the basic load pattern in the absence of any unusual events (e.g., unusually higher or lower electricity usage for a short period), random variability in load, or response to electricity prices. All of these can be handled by separate algorithms in an EMCAS simulation.

Price Response

There has been considerable research on consumer response to electricity prices. Studies have shown that consumer reduction in electricity consumption in response to prices, particularly residential customers, is very inelastic in the short term; that is, even high price increases produce only small changes in usage. For this reason, the current version of EMCAS does not simulate consumer price response. However, work is under way to incorporate consumer behavior that would allow agents to switch between different contract types, resulting in changes in load pattern (e.g., load-shifting from peak to off-peak). Contract structures will include fixed pricing, time-of-day pricing, and real-time pricing.

B.3.4 GENERATION COMPANIES

In an EMCAS simulation, the GenCo agents represent the business units that own generators. GenCos may own a single unit and operate like an independent power producer. They may also own multiple plants and be part of a larger corporate parent that offers several products (energy and capacity in spot and bilateral contract markets) to the electricity market (Figure B-3). Decisions on how and when to operate its generation equipment and what prices to charge for its output are made separately by each GenCo agent in EMCAS using a decision process that will be described in more detail later. The GenCo input information includes:

Generation Company Identification

Each GenCo is given a unique identifier. Where a GenCo is part of a larger corporate parent, the generation division of the parent company is identified as the GenCo.

Generation Company Business Strategy

Each GenCo in an EMCAS simulation employs a business strategy that determines how it will behave in the market. An initial version of the strategy is input by the user and specifies the initial techniques

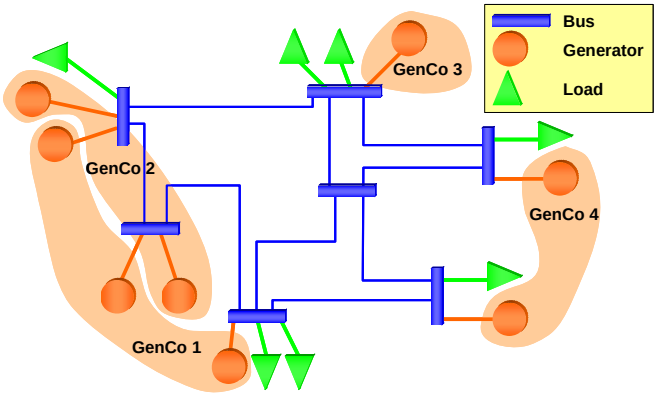


Figure B-3 EMCAS Generation Company Agents

that the GenCo will use in an effort to maximize its utility function. This initial strategy is modified as the simulation progresses and the GenCo agent learns and adapts. The business strategy is used by each GenCo to make the following decisions:

- Capacity and pricing for bilateral contracts,
- Capacity and pricing for pool energy market,
- Capacity and pricing for ancillary services market, and
- Maintenance schedule.

The following examples show the types of GenCo business strategies that can be included in an EMCAS simulation:

- Designate capacity to be offered under bilateral contracts to ensure a profitable return;
- Incrementally increase the offer price for bilateral contracts to seek higher returns;
- Offer capacity into the pool energy market at production cost to maximize the probability of acceptance;
- Bid the last blocks of capacity at a high price in an attempt to raise the marginal price in the market (referred to as "hockey stick" bidding);
- Withhold capacity from the market to force the utilization of higher priced units, thus driving up the market price; and
- Bid capacity located at points of transmission congestion at higher prices.

There are many more strategies that can be included in the simulation. The EMCAS approach allows for a wide variety of strategies to be tested for their effectiveness.

The GenCo business strategy is specified by two basic functions: the capacity allocation function and the capacity pricing function. The capacity allocation function determines where the company's available capacity will be bid, taking into account that some capacity is not available due to outages, and is given by the vector:

$$Capacity_{gbh} \ [Bilateral\ Contracts,\ Pool\ Energy,\ Pool\ Ancillary\ Services,\ Uncommitted]$$

The elements of the vector indicate the portion of the capacity, in MW, of block *b* of generator *g* that is to be committed to each of the markets in hour *h* of the simulation period. The portion that is designated *Uncommitted* is be allocated to a market based on price expectations and expected returns calculated during the simulation. The capacity pricing function of the GenCo business strategy is specified by the equation:

$$Bid\ Price_{gbh} = A_h*(Production\ Cost_{gb})+B_h*(Correlated\ Price)+C_h*(Specified\ Price)$$

where:

Bid Price$_{gbh}$ is the bid price that will be offered for block *b* of generator *g* in hour *h*;

Production Cost$_{gb}$ is the production cost of block *b* of generator *g*;

Correlated Price is some price to which the bid may be related (e.g., market price from the day before, projected market price for the next day, price with 50% probability of being accepted, etc.);

Specified Price is a specific price that is user-specified; and

A_h, B_h, C_h are constants for each hour.

This general form provides a means to specify a wide range of pricing strategies. For example, if the business strategy to be simulated is to bid production cost, then A=1.0 and B=C=0. If the business strategy is to bid the projected market clearing price for the next day, then B=1.0, the Correlated Price is the day-ahead price projection for the pool energy market, and A=C=0. If the business strategy is to bid $20/MWh for all situations, then C=1.0, the Specified Price = 20.0, and A=B=0. Various combinations of pricing strategies with each of the coefficients being non-zero can also be specified in this form.

The capacity allocation function and the capacity pricing function uniquely define the GenCo's business strategy. The details of how each GenCo applies its business strategy at each of the planning levels are described in the next section.

Learning and Adaptation

In EMCAS, the business strategy for each GenCo is not static. Rather, it changes as learning and adaptation occurs. The learning and adaptation by each GenCo includes the following (Figure B-4):

- Look Back – an evaluation of past performance of the company's business strategy;
- Look Ahead – a projection of the future state of the electricity markets; and
- Look Sideways – a determination of what competitors have done.

As a result of these evaluations, a GenCo agent can elect one of three basic courses of action:

- *Maintain the current business strategy*. If the evaluation shows that the current business strategy is very successful at

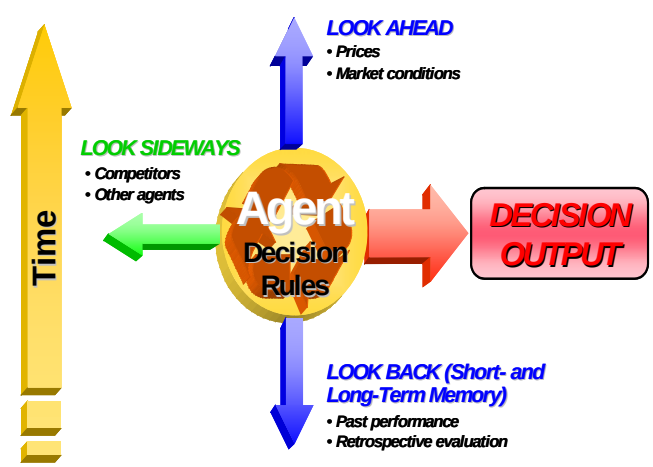


Figure B-4 Agent Adaptation Process

meeting company objectives (i.e., providing a high level of utility) and is likely to remain so under projected market conditions, it is maintained. A GenCo that is experiencing good returns and is somewhat risk-averse would adopt this approach.

- *Adjust the current business strategy*. If the evaluation shows that the current business strategy is only moderately successful and is likely to remain so under future market conditions, a company may elect to adjust it somewhat in an attempt to increase its utility. A GenCo that has small returns and that is risk-averse to risk-neutral might take this approach.

- *Switch to a new business strategy*. If the evaluation shows that the current business strategy is not successful or is not providing adequate returns, a company may elect to make a major change in business strategy in an attempt to improve the situation. A company that is not doing well may choose this course. Also, a company that is risk-prone may elect this option in an attempt to probe the market to find a strategy that significantly increases returns.

To illustrate this learning and adaptation process, day-ahead planning can be used as an example. A GenCo's initial business strategy might consist of the following:

- Commit 25% of generation capacity to day-ahead bilateral contracts;
- Offer 75% into the pool energy market; and
- Price the pool energy market bids for each generator at 20% above production costs.

If this strategy results in a modest profit for the GenCo, it would be maintained by a risk-neutral or risk-averse company. If this strategy resulted in the company's bids not being accepted in the pool energy market with a resulting financial loss, the same risk-neutral company could seek to adjust the pool energy market bids down to 15% above production cost in an attempt to gain bid acceptance in the market. If this were still too high for the bids to be accepted, the bids could be adjusted further down to 10% above production cost in the next bidding cycle. Should this still result in unacceptable losses, the company could switch to an entirely new strategy. One of the possibilities would be to commit 75% of the generation capacity to bilateral contracts with a guaranteed return and offer only 25% into the pool energy market.

This simple illustration shows the magnitude of the complexity of simulating how the energy markets will operate. Clearly, there are a large number of possible strategies that could be tried by a GenCo. Further, the strategies employed by other GenCos would impact the success or failure of any one company's approach. It is this level of complexity that cannot be handled by conventional optimization or simulation techniques and where the agent-based modeling approach used by EMCAS can provide insight into market behavior.

B.3.5 DEMAND COMPANIES

In an EMCAS simulation, the demand company (DemCo) agents represent the business units that sell electricity to consumers. The DemCo purchases this electricity either by entering into a bilateral contract with a GenCo or by buying electricity from the pool market. In the

EMCAS formulation, a DemCo does not need to have a specific service territory and may serve consumers from anywhere in the study area (Figure B-5). The DemCo makes decisions on how much electricity to buy, what price it is willing to pay, and what to charge its consumers. The input information for DemCo agents includes:

Demand Company Identification and Business Profile

Each DemCo is given a unique identifier. When a DemCo agent is part of a larger corporate parent, it represents the electricity sales division of the parent.

The DemCo's business profile is described in the same manner as that of a GenCo. That is, the profile consists of objectives, risk preference, and a utility function. The objectives and risk preferences can be different for each DemCo. Throughout a simulation each DemCo seeks to maximize its own utility.

Demand Company Business Strategy

As with the GenCos, each DemCo in an EMCAS simulation starts with an initial business strategy that is modified and adjusted as the simulation progresses. The DemCo business strategies are used to make the following decisions:

- Load to be committed to bilateral contracts;
- Price acceptability for bilateral contract bids;
- Supply to be sought from the pool energy market;
- Price acceptability from the pool energy market; and
- Consumer contract price offerings.

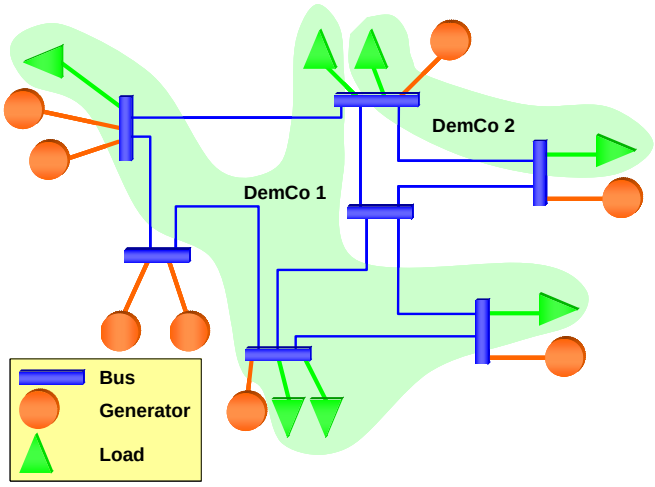


Figure B-5 EMCAS Demand Company Agents

The following examples show the types of DemCo business strategies that can be included in an EMCAS simulation:

- Offer all projected load to potential suppliers under bilateral contracts to secure fixed prices;
- Seek all projected load from the pool energy market;
- Establish price limits above which load will be dropped rather than paying high prices; and
- Reduce consumer contract charges to increase market share.

There are many more strategies that can be included in a simulation. The DemCos have a two-sided structure that they must deal with. On one side, they must interact with the GenCos

and the pool energy markets to optimize electricity purchases. On the other side, they must deal with consumers to offer competitive prices for their sales of electricity while maintaining an acceptable level of their own utility (e.g., profit). Their business strategy must address both parts in order to be effective.

The business strategy is specified by three basic functions: the load allocation function, the load price acceptance function, and the consumer contract pricing function. The load allocation function determines where the company will seek supplies to meet its projected load and is given by the vector:

$$Load\ Allocation_{nh}\ \ [Bilateral\ Contracts,\ Pool\ Energy,\ Uncommitted]$$

The elements of the vector indicate the portion of the company's load, in MW, at node *n* of the network that will be sought from bilateral contracts or from the pool energy market. The portion that is designated as *Uncommitted* will be sought from the best source based on price expectations calculated during the simulation.

The load price acceptance function of the DemCo business strategy is specified by the vector:

$$Load\ Price\ Acceptance_{bnh} = [Load\ Fraction_{bnh}\ ,\ Price_{bnh}\ ]$$

where:

Load Fraction$_{bnh}$ is the portion or block *b* of load at node *n* in hour *h* that will be accepted at the projected price of *Price*$_{bnh}$; if *Load Fraction* is 1.0, the DemCo will seek to meet all of its load as long as the price is less than *Price*$_{bnh}$. If *Load Fraction* is less than 1.0, then the DemCo will not seek to meet all of its load because of high prices. Consumer load will be shed by the DemCo.

The consumer contract pricing function is specified by the equation:

$$Consumer\ Charge_{cnh} = D_h*(Supply\ Cost_n) + E_h*(Correlated\ Price) + F_h*(Specified\ Price)$$

where:

Consumer Charge$_{cnh}$ is the charge that will be levied on the different consumers *c* connected to node *n;*

Supply Cost is the cost paid by the DemCo for power withdrawn from node *n;*

Correlated Price is some price to which the charge to consumers may be related (e.g., average market price in the zone where the consumer is located, annual average price paid by the DemCo for its supplies, etc.);

Specified Price is a specific price that is user-specified; and

D_h, E_h, F_h are constants for each hour.

This general form allows for a wide variety of contract prices that the DemCo can use to charge its customers. It is analogous to the GenCo bid pricing strategy in its application.

The load allocation function, the load pricing function, and the consumer contract pricing function uniquely define the business strategy of the DemCo. The details of how each DemCo applies its business strategy at each of the planning levels are described in the next section.

Learning and Adaptation

Learning and adaptation by DemCo agents in EMCAS occurs in a manner analogous to what is experienced by GenCo agents. That is, the DemCos employ an initial business strategy that is evaluated by a Look Back, Look Ahead, and Look Sideways process. With the results of the evaluation, the DemCo agents have the option to maintain, adjust, or switch business strategies.

B.3.6 TRANSMISSION COMPANIES

In EMCAS the transmission companies (TransCos) provide transmission services to GenCos and DemCos, but do not engage in strategic business practices. Instead, they charge a fee for the use of the transmission lines. The input for each TransCo includes the following:

Transmission Company Identification and Line Ownership

Multiple TransCos can be included in an EMCAS simulation. Each TransCo is given a unique identifier. Where the TransCo is part of a larger corporate parent, the transmission division is identified as the TransCo.

Each transmission line and bus in the network is assigned to a TransCo owner. Note that some buses/nodes may have lines attached to them that belong to different TransCos.

Transmission Fee Structure

In EMCAS, the TransCo agents are the owners of transmission lines but do not operate the system. Operation is left to the ISO, which is described in Section B.3.8. TransCos do, however, collect fees for the use of their transmission lines. In practice, these fees would be used to maintain the system and to expand the network to accommodate growth. By convention in EMCAS, the transmission use fee is collected from DemCos and is added to the price they

charge consumers. The *Transmission Use Rate* at node *n* for hour *h* is input as a $/MW charge. The *Transmission Use Charge (TUC)* in absolute dollars for a given transmission service at node *n* for hour *h* is calculated as follows:

$$TUC_{nh} = TUR_{nh} \times LOAD_{nh}$$

where:

TUR_{nh} is the Transmission Use Rate [$/MW], and

$LOAD_{nh}$ is the load [MW] at node *n* in hour *h*.

The *TUC* is charged to the DemCo that serves the consumer at node *n*. The DemCo can pass the *TUC* to the consumer and may or may not add a fee to it. The TransCo owning node *n* receives the *TUC* as revenue. Currently, the TUR_{nh} is set by the user.

Transmission Congestion Charge

Consumers pay an implicit transmission congestion charge by paying a price that is based on the node they are attached to. The *Transmission Congestion Charge (TCC)* for hour *h* is calculated as follows:

$$TCC_h = \sum_n Load_{nh} \times Node\ Price_{nh} - \sum_m Generation_{mh} \times Node\ Price_{mh}$$

where:

n are the nodes where load is attached to;

m are the nodes where the generation is attached to;

$Generation_{mh}$ is the generation [MW] at node *m* in hour *h*;

$Node\ Price_{nh}$ is the price at nodes *n* in hour *h*; and

$Node\ Price_{mh}$ is the price at node *m* in hour *h*.

The *TCC* is collected by the ISO and is distributed to the TransCos based on the distribution of load at the nodes owned by the TransCo.

B.3.7 DISTRIBUTION COMPANIES

Distribution companies (DistCos) own and operate the lower-voltage distribution system. They provide distribution services to GenCos and DemCos but do not engage in strategic business practices. In effect, the DistCos in EMCAS take the form of regulated monopolies. The information that is input for DistCos includes:

Distribution Company Identification and Service Territory

Multiple DistCos can be included in EMCAS, each with a specific service territory. Each DistCo is given a unique identifier. As with other agents, when a DistCo is part of a larger corporate parent, the division that operates the distribution system is identified as the DistCo.

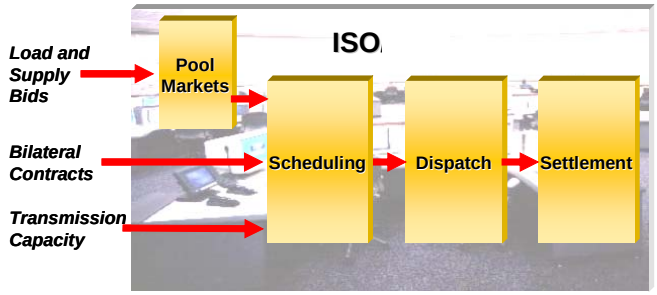


Figure B-6 EMCAS ISO Agent

To identify the service territory of each DistCo, each bus in the network where load is attached is identified as a delivery point in a DistCo's network. All consumer agents at that bus are identified as being served by that DistCo. Network buses that have only generation attached or that are transmission connection points with neither load nor generation attached are not assigned to a DistCo.

Distribution Charge Structure

The distribution charge structure is input. The DistCo levies the distribution charge to all consumers it serves. The charge may be different for different consumer types (e.g., residential, commercial, industrial). The charge may be different for different nodes in the DistCo's service territory. The charge may differ from one DistCo to another. The *Distribution Charge (DC)* in absolute dollars is:

$$DC_{cnh} = DCR_{cnh} \times LOAD_{cnh}$$

where:

DCR_{cnh} is the distribution charge rate [$/MW] for consumer type c at node n and for hour h.

The distribution charge is paid by consumers to DistCos and is tabulated as revenue to the DistCo.

B.3.8 ISO

The ISO follows market rules defined by the regulatory layer and exercises several functions in an EMCAS simulation (Figure B-6) including the following:

- Operation of the day-ahead market for energy,
- Operation of the day-ahead market for ancillary services,
- Confirmation of bilateral contracts,
- Dispatch of the physical system, and
- Computation of settlement payments to market participants.

The ISO does not engage in any strategic behavior but seeks to operate the power system in the most efficient, lowest cost manner given the information it receives from the market participants and the physical characteristics of the system. The ISO is the "honest broker" that seeks to optimize operations from an overall system-wide perspective. The following information is input for the ISO:

ISO Identification

Currently, only one ISO is used in EMCAS. Future enhancements will allow for multiple agents to be included in the simulation.

System Reliability Parameters

The ISO sets the parameters that will be used for system operations including the following:

- Day-ahead regulation reserve margin,
- Day-ahead spinning reserve margin,
- Day-ahead non-spinning reserve margin,
- Day-ahead replacement capacity margin,
- Transmission line overloading limits, and
- Load-shedding priority list.

Day-Ahead Market Parameters

The ISO sets the procedures that are used in the operation of the day-ahead market including:

- *Market order* – In the current version of EMCAS, the day-ahead bilateral contract market completes first, then the pool energy market, and finally the pool ancillary services market;
- *Bilateral contract treatment* – In the current version of EMCAS, bilateral contracts are treated as financial instruments and are subject to the limitations of the transmission system.

Settlement Accounting

The ISO handles the settlements at the completion of the hourly dispatching. This includes the following:

- Payments to GenCos,
- Charges to DemCos, and
- Transmission use and congestion charges.

B.3.9 REGULATOR

The regulator agent in EMCAS sets the market rules that apply. In the current version of EMCAS, the regulator does not adapt or change its behavior. Rather, it relies on input from the user who can take the position of the regulator by changing and testing different market rules. The input information for the regulator includes the following:

Market Structure

- Bilateral contracts (if none allowed, then all energy is provided via the pool market);
- Day-ahead pool market for energy (if none exists, then all energy is provided via bilateral contracts); and
- Day-ahead pool market for ancillary services (if none exists, then all ancillary services are included in the pool energy market).

Market Pricing Rules

- Day-ahead pool energy market payment (e.g., pay locational marginal price, pay as bid); and
- Bid caps.

Tariffs and Taxes

- Tariffs – limitations on prices; and
- Taxes – consumers, GenCos, DemCos, TransCos, DistCos.

B.3.10 SPECIAL EVENT GENERATOR

The special event generator provides the EMCAS user with the ability to inject events into the simulation that force the system to deviate from the procedures developed at the planning levels. Currently, the special event generator can be used to inject unplanned incidents at the hourly dispatch level. The unplanned events that can be input are:

- Load forecast errors – increases or decreases in the load that deviate from the load projections used in the planning periods;

- Generator outages – unplanned outages of generators for varying periods of time ranging from hours to days; and

- Transmission link outages – unplanned loss of transmission lines for varying periods of time ranging from hours to days.

B.4 EMCAS DAY-AHEAD MARKETS

The EMCAS modeling system operates at different time scales or decision levels. Dependent on user-defined rules, different types of markets are available to agents at each time scale. The types of markets available and the specific rules under which each operates will influence decisions made by market participants. This section describes the markets available at the day-ahead decision level.

At the day-ahead level, EMCAS simulates three types of markets that include bilateral contract markets, energy pool markets, and ancillary services markets. Generally, bilateral contracts are agreements between a single GenCo agent and a single DemCo agent. These contracts have time scales that range from hours and days to several years. In the pool markets, EMCAS agents submit buy and sell bids to a central clearinghouse that is operated by the ISO. The pool markets are typically conducted at the day-ahead time scales and include both energy and ancillary services markets.

Figure B-7 shows the sequence of market activities that are carried out in the day-ahead planning level. In the EMCAS simulation, the only agents that participate at this level are the ISO, DemCos, and GenCos. Consumers do not exercise any decision-making at the day-ahead level. Most electricity users do not have access to daily market price information; therefore, there is no basis on which they can adjust their planned consumption for the next day in response to market conditions. Only a few large users (e.g., large industrial facilities) might be considered to have access to daily price information and be in a position to react on a day-by-day basis.

ISO Day-Ahead System Status Projections

The initial step in the day-ahead planning simulation is for the ISO to develop a projection of the next day's load and system conditions. This includes any known outages of generators and transmission lines. The information is made available to all the DemCos and GenCos, analogous to the process used by several operating electricity markets currently posting public information.

DemCo and GenCo Market Price Projections

Each DemCo and GenCo prepares its own projections of the day-ahead situation for the company's system. For the DemCos, the focus is on the expected load from the consumers they are serving and the expected prices in the day-ahead energy market and for bilateral contracts. For the GenCos, the focus is on the status of their own generation equipment, the prices that bilateral contracts might bring, and expected prices in the day-ahead energy and ancillary services markets.

The market price projections are unique for each company and form the basis of how they will bid into the day-ahead markets. The projections include hourly prices in the pool energy market, hourly prices in the ancillary services market, and hourly projections of bilateral contract prices. The price projections are developed by DemCos and GenCos in one of several ways:

- Correlation to previous day(s),
- Next day forecast, and
- Price probability distribution.

The correlation to previous day(s) is the simplest price projection method. It assumes that the day-ahead prices will be the same as the previous day. In the simulation, the average price of the previous five weekdays (or two weekend days) is used to avoid unrealistic fluctuations from one day to the next. This type of "myopic hindsight" is the simplest form of price projection.

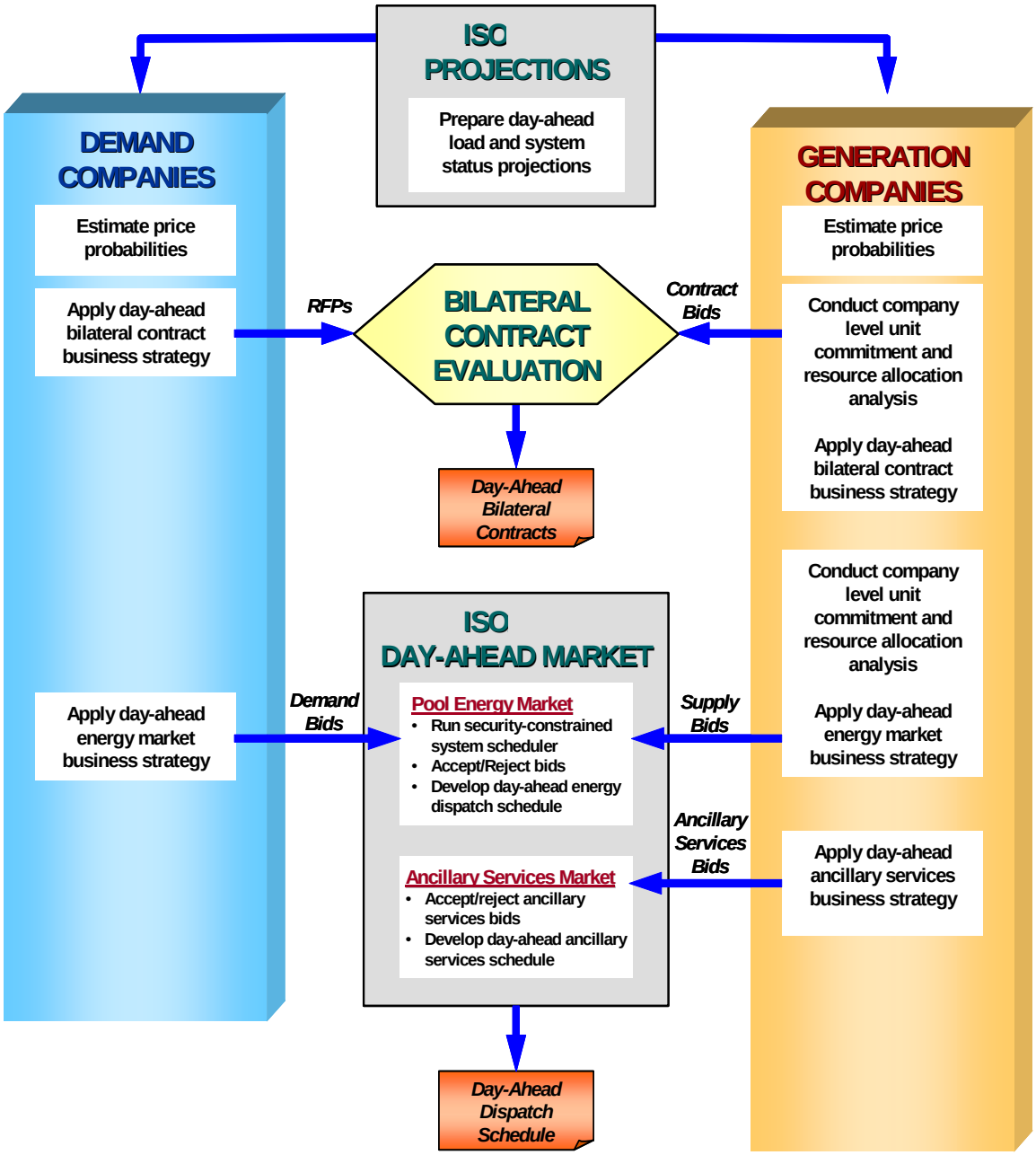


Figure B-7 Day-Ahead Planning Sequence

The next day forecast method of price projection is a type of "myopic foresight" approach. GenCos and DemCos using this method look at the forecasted load and system status for the day ahead and use this to project what the prices will be in the markets. The method uses a very simple projection technique that relates prices to system conditions.

The most sophisticated price projection technique is to use a price probability distribution. The price probability distribution gives the probability that a bid for a specific generator at a given node will be accepted in any of the available markets (i.e., energy, ancillary services, bilateral contracts), given system conditions.

Day-Ahead Bilateral Contracts

The day-ahead bilateral contract market operates next in the simulation. The process begins with DemCos developing requests for proposals (RFPs) for day-ahead bilateral contracts for energy (Figure B-8). Included in each RFP are load for each hour and points of withdrawal. The load quantities in an RFP account for demand that is already under a longer-term bilateral contract and include only the additional demand that must be met for the next day. The points of withdrawal indicate the node(s) at which the load will occur. The RFPs are sent to all GenCos participating in the bilateral contract market.

In the next step of the simulation, the GenCos prepare their responses to the RFPs. Using the price projections for the next day, which include projections for the pool energy market and for bilateral contracts, each GenCo conducts a company-level unit commitment and resource allocation analysis (CLUCRA). This analysis seeks to maximize the company's utility by assigning generation that (a) will be bid in response to bilateral contract RFPs, (b) will be reserved for bidding into the pool energy market, or (c) will be bid into the ancillary services market. The CLUCRA objective function is:

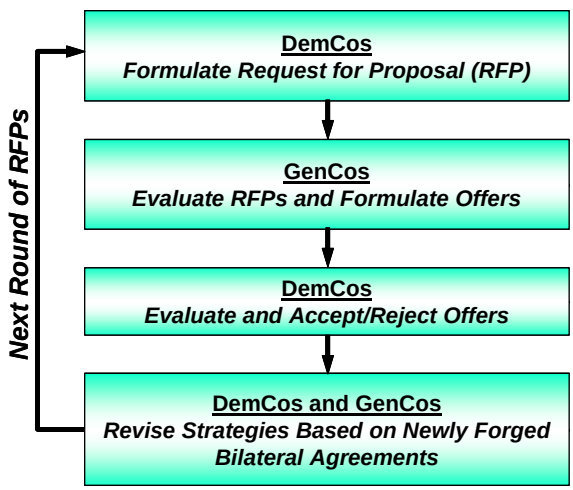


Figure B-8 Sequence of Events for Modeling Bilateral Contracts

$$
\begin{aligned}
\textbf{MaxCorporate_Objective} \; = & \sum_{n=1,n} \sum_{h=1,24} [Projected_Price_{nh} \; * \; \sum_{b=1,n} Production_Level_{hb}] \\
& + \sum_{h=1,24} \sum_{c} Bilateral_Revenue_{hc} \\
& - \sum_{h=1,24} \sum_{b=1,n} Production_Cost_{hb} \; * \; Production_Level_{hb} \\
& - Startup_Cost_{g} \; * \; Number_Starts \\
& - Shutdown_Cost_{g} \; * \; Number_Shutdowns
\end{aligned}
$$

The constraints imposed are the physical limitations of the generation equipment including:

- Start-up time,
- Minimum run time,
- Minimum capacity, and
- Shut-down time.

In maximizing its individual utility in this manner, each GenCo determines whether the projected prices for bilateral contracts or the pool markets will provide an adequate return to warrant the operation of each generation unit. The result of this analysis is a decision on whether to commit the unit to a bilateral contract, to offer the unit into the pool energy market, or to shut it down.

After the completion of the day-ahead CLUCRA, each GenCo applies its day-ahead bilateral contract business strategy. The use of the business strategy at this point accounts for the fact that each company's CLUCRA analysis is based on limited information. It has only its own price projections and its own record of success or failure from previous bids. It does not have access to similar information for other companies. The application of the business strategy allows the company to test other approaches that may be more beneficial (i.e., increase its utility) than one based solely on its own limited information.

As described in an earlier section on GenCos, the day-ahead bilateral contract business strategy is made up of two parts. The first is the use of the capacity allocation function to allocate resources in response to RFPs. In its simplest form, the capacity allocation function would set all the available capacity to the *Uncommitted* category, thus allocating capacity according to the company's CLUCRA results. That is, capacity would be offered in response to those RFPs that maximized the company's utility for the next day. Alternative strategies that can be applied include forcing a portion of capacity to be offered in response to RFPs independent of the CLUCRA result, forcing a response to an RFP from a particular DemCo, and other variations. These would be implemented by changing the capacity allocation function. This capability in EMCAS allows a GenCo to try different resource allocation strategies that may prove more beneficial to the company.

The second part of the GenCo's day-ahead bilateral contract business strategy is the pricing of its bids using the capacity pricing function, as described earlier. The general form of the function provides a means to specify a wide range of pricing strategies. Since the GenCos have the ability to try business strategies that do not rely solely on the outcome of the CLUCRA optimization results, they can explore for solutions that increase their utility.

When the GenCo bid responses to the RFPs are received by the DemCos, they go through a process to determine which bids to accept or whether to rely on the pool energy market to meet their requirements. The process used is the Demand Company Resource Allocation (DCRA). In applying the DCRA, each DemCo seeks to maximize its own utility function. The price bids received in response to the RFPs and the projected prices for the day-ahead energy market are compared and the best mix of bilateral contracts and planned purchases from the day-ahead pool energy market is determined. The EMCAS algorithm that simulates a demand company's bilateral contract purchase portfolio uses an "intelligent" heuristic to test various purchase portfolios (solution states) and selects the one that maximizes the corporate utility functions. The

algorithm is based on a methodology that combines “greedy adding” and “pair-wise substitution” techniques. The initial portfolio state assumes that all energy purchases would be from the day-ahead energy market. Individual bilateral contract offers from GenCos are then tested in the portfolio mix, and the one that yields the highest objective function value is temporarily added to the mix. The process of adding bilateral contracts into the mix using this greedy-adding method continues until no additional bilateral contract increases the corporate utility.

Other portfolios are then tested by swapping one or previous rejected bilateral contract offers with one that has been accepted. This includes a fictitious “null” contract that contains no capacity or energy. If swapping rejected bilateral offer(s) into the portfolio mix in place of an accepted offer increases the corporate utility, the swap is implemented. Swapping of contracts into and out of the corporate mix continues until a better utility function cannot be found.

After completion of the DCRA, each DemCo applies its day-ahead business strategy to the result. As described earlier, the DemCo business strategy includes the application of the load allocation function and the load price acceptance function. The strategy can include decisions to force a portion of the load to be under a day-ahead bilateral contract independent of the DCRA result, force a response to an RFP from a particular GenCo, and other variations. In a manner analogous to that used by the GenCos, this capability in EMCAS allows the user to try different resource allocation strategies for DemCos that may prove more beneficial to the company.

In EMCAS, the bilateral contract market can consist of multiple rounds of DemCo RFP / GenCo Bid / DemCo selection. This allows for an iterative process of contract negotiations to be simulated. In general, one to three bilateral contract bidding rounds are used in a simulation. At the completion of the last round, the day-ahead bilateral contract market is considered closed, and the simulation proceeds to the day-ahead pool markets.

Day-Ahead Pool Energy Market

The day-ahead pool energy market represents the operation of a pool market for wholesale electricity sales and purchases. In certain applications where no such market exists, this may be bypassed. The day-ahead pool energy market operates by accepting supply bids from GenCos and demand bids from DemCos.

GenCos begin the preparation of their supply bids in a manner similar to what was done for the day-ahead bilateral contract market. Beginning with the prices that they have projected for the market, the CLUCRA optimization analysis is run. At this point, decisions are made concerning the day-ahead pool energy market, the ancillary services market, and the withdrawing of capacity in situations when the projected market prices are below production costs. The same objective function and constraints that were used in the bilateral contract analysis are used in the pool energy market analysis.

With the CLUCRA results, each GenCo applies its day-ahead energy market business strategy, which consists of two parts, similar to what was used in the bilateral contract market: the capacity allocation function and the capacity pricing function. As with the bilateral contract

market, this capability in EMCAS allows the user to try different resource allocation strategies that may prove more beneficial to the company.

DemCos also submit bids to the day-ahead pool energy market. These demand bids specify the quantity of electricity the DemCo is willing to accept at a specified price. The DemCo demand bids show a decreasing purchase quantity with increasing price. A DemCo can reduce its purchase of electricity if the price is too high by not serving a portion of its projected load. This means that the load will be curtailed voluntarily (e.g., by exercising service interruption provisions of agreements with consumers, mostly large industrial or commercial users) or involuntarily (e.g., by load shedding). In either case, by the way in which its demand bids are submitted to the pool energy market, the DemCo can set a limit on the price it is willing to pay for electricity. Of course, a DemCo can submit a demand bid with no price limits, in which case it is indicating that it will pay any price to meet its load. The bid is then considered to be price inelastic.

The supply bids from the GenCos and the demand bids from the DemCos are on an hour-by-hour basis for the next day. In addition, the bids specify the point of injection (for supply bids) into the transmission network and the point of withdrawal (for demand bids). The ISO must balance the system based on these bids. In the EMCAS simulation, the bids are first rank-ordered by price, as illustrated in Figure B-9. Bids from all GenCos and all DemCos for each hour are included.

The ISO then runs a transmission-constrained system scheduler (TCSS) analysis to determine if the supply and demand can be balanced while maintaining the security and stability of the transmission system. TCSS uses a direct current Optimal power flow (DCOPF) algorithm. The algorithm consists of an objective function and a set of constraints that place limits on generation levels, load curtailments, and power flows. Constraints also ensure that at each bus there is an energy balance at all buses. Linear programming (LP) techniques are used to find the best solution to the problem.

The TCSS objective function is to minimize the overall costs, supply purchases, and load reductions (e.g., variable payment for hourly demand side management measures). Supply costs are those incurred when a block of energy is purchased at a specified price from the market. The objective function also accounts for the cost of unserved energy, power transport costs, penalties for transmission line overloads, and the cost of calling spinning reserves into service.

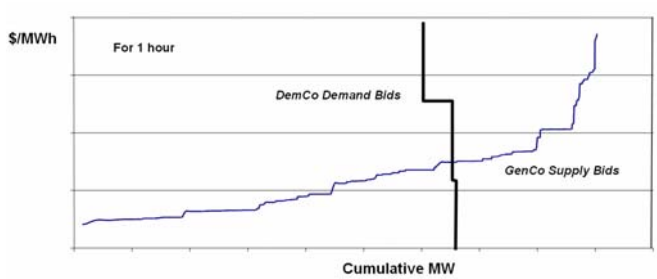


Figure B-9 Ranking of Day-Ahead Supply and Demand Bids with No Transmission Congestion

The TCSS cost minimization objective function is subject to several constraints. On the supply side, the amount of energy purchased at a specific bus cannot exceed the block amount offered by a GenCo. Likewise, the amount of load reduction that is accepted cannot exceed the

block-amount offered by a DemCo.

The flow of power from generators (power injections) to loads (power sinks) is governed by a set of physical constraints. Injections include power from both accepted energy offers and spinning reserves that are called into service. One transmission flow constraint requires that there is an energy balance at all buses. As shown in the equation below, the amount of power flowing on all power lines (branches) into a bus must exactly equal the amount of power that is flowing out of a bus.

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}} \left(\theta_i - \theta_j \right)$$

where:

P_i sum of generation (+) and load (–) at bus i (MW);
P_{ij} power flow from bus i to bus j (MW);
x_{ij} line inductive reactance;
θ_i phase angle at bus i (radians); and,
θ_j phase angle at bus j (radians).

Power flows on a transmission line connecting bus i to bus j are given by:

$$P_{ij} = \frac{1}{x_{ij}} \left(\theta_i - \theta_j \right)$$

Real power flows on lines, measured in MW, are limited. Currently the model includes three line rate limits, namely, rate A, rate B, and rate C. Typically, costs for line usage up to rate A are minimal, but very rapidly increase for any flows above that level.

The TCSS determines the supply and demand intersection points in the network. In the absence of any transmission congestion, the TCSS load flow analysis will show that the initial rank ordering of supply and demand bids of Figure B-9 and will provide the least cost way to dispatch the system. However, when congestion of the transmission system appears, such as during high load periods, it may not be possible to utilize the least cost generators without violating thermal limits of transmission lines or contingency situations. Lower-cost generators may need to be bypassed in favor of more expensive units that can be used without creating transmission problems. The supply curve is then shifted as shown on Figure B-10.

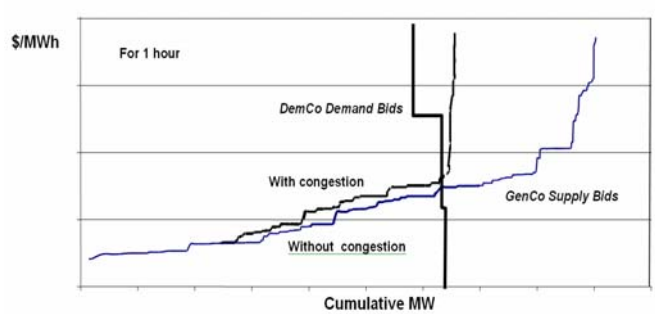


Figure B-10 Shift of Supply Bids Due to Transmission Congestion

The ISO will accept or reject bids from GenCos and DemCos based on the results of the TCSS analysis. Notification of acceptance or rejection is sent back to the GenCos and DemCos and the day-ahead energy market is closed.

Day-Ahead Pool Ancillary Services Market

Ancillary services are functions provided to maintain the reliability of the power system in response to both normal and unplanned variability in supply and demand. Some of the key ancillary services are:

- Regulation/automatic generation control (AGC) services,
- Spinning reserve,
- Non-spinning reserve, and
- Replacement reserve.

Regulation or AGC services are designed to match the output of generators to variations in load on a very short time frame, usually seconds. This requires the ability to adjust generator output on an almost instantaneous basis. Not all generator equipment is capable of this type of fine control. Spinning reserve is the ability of units that are in operation at a level below their maximum output and synchronized to the grid to increase their output generating capacity in response to changes in system demands. Typically, the criterion for this capacity increase is that it must be fully available within 10 minutes. Non-spinning reserve, frequently called non-synchronous or supplemental reserve, consists of capacity that is not operating but that can be started and fully available within 10 minutes. In some places, interruptible loads that can be shut down within the 10-minute window can also be included as a non-spinning reserve. Replacement reserve is a standby capacity that must be fully available within 30 to 60 minutes and then maintained until substitute capacity from the market is available.

EMCAS provides an explicit modeling of the ancillary services for spinning reserve, non-spinning reserve, and replacement reserve. The modeling of regulation/AGC services is handled in an approximate way. In an EMCAS simulation, the day-ahead pool ancillary services market for spinning reserve, non-spinning reserve, and replacement reserve is run after the closing of the day-ahead pool energy market. In this market, GenCos apply their company ancillary services business strategy to determine how they will participate. As with the bilateral contract and energy markets, the strategy has two parts. The first is a determination of how much capacity to commit to the various components of the ancillary services market: spinning reserve, non-spinning reserve, or replacement reserve. This analysis is based on the company's projections of day-ahead prices for each of these reserve markets. GenCos may consider offering any capacity that has not been committed to bilateral contracts or to the energy market into the ancillary services market, provided the particular units being considered can meet the technical start-up requirements for each of the reserve categories. In EMCAS, the company analysis is done by a simple comparison of the projected revenue in the market to the cost of operating the unit, should it be called upon. The market payment for having the capacity available, even if it is not needed, is factored into this comparison.

The second part of the GenCo's day-ahead ancillary services market business strategy is the pricing of its bids. The formulation of the bid price accounts for the probability that it will be called upon and follows the same structure that was used for bilateral contracts and the pool energy market. That is, the bid can be related to production cost, can be correlated to some other price, or can be a specified price as was shown earlier.

The ancillary service for regulation/AGC is modeled in EMCAS in an approximate manner. Additional capacity that would be needed to meet the need for regulation/AGC services is selected as part of the pool energy market. It is made available for dispatch as needed.

Day-Ahead Dispatch Schedule

After the closing of the day-ahead bilateral contract, pool energy, and pool ancillary services markets, the dispatch schedule for the next day is established. This schedule specifies which units are to be run in each hour of the next day to meet expected loads. Variations to this schedule due to changes in load or generator or transmission outages are dealt with at the hourly dispatch time line.

B.5 EMCAS HOURLY DISPATCH

Figure B-11 shows the operation of the hourly dispatch in EMCAS. Hourly simulations are the smallest time step used in EMCAS. In actual practice, dispatching is adjusted in periods of minutes and seconds. This level of detail is not used in EMCAS.

In some electricity markets, there is an hour-ahead market (sometimes called a "real time market"). This is a bit of a misnomer in that this market generally operates two to four hours in advance of the actual dispatch time. For simplification, this market is not currently included in an EMCAS simulation. Rather, the variation between actual demand and the day-ahead schedule for the dispatch of generators is handled by using the ancillary service capacity that is available.

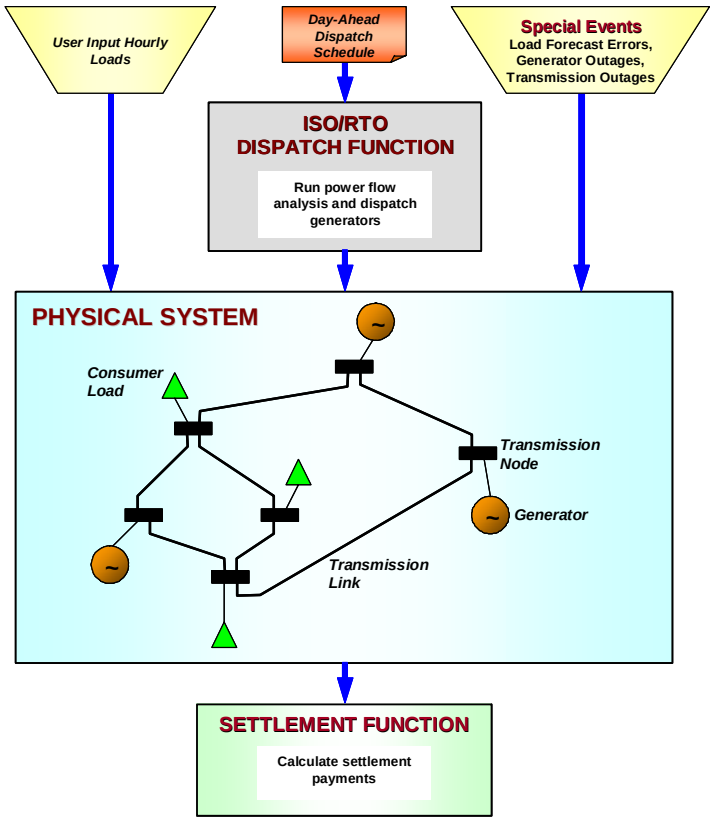


Figure B-11 Hourly Dispatch Sequence

User Input Loads

As the EMCAS hourly dispatch simulation begins, the load from each of

the consumers for each hour is determined from user-input load data. The simulation can be run with no load forecast error, in which case the load information that was used at the day-ahead planning level is identical to what is experienced in the hourly dispatch. Alternatively, at the user's discretion, the load can be allowed to include a random variability.

ISO Dispatch Function

The dispatch schedule of which generators are planned to operate in each hour to meet the load is available from the day-ahead planning level. Using this schedule as a starting point, the ISO operates the power system to balance supply and demand and to maintain the integrity and security of the overall system. In the real world, power system operation involves balancing a number of critical variables simultaneously including power flow, frequency, voltage, and other parameters. EMCAS uses a DC-OPF formulation, the same TCSS that was used in the day-ahead pool energy market segment of the simulation described earlier. If there were no variations in load, generator availability, or transmission system topology from the information used in the day-ahead planning, the results of the hourly dispatch would be identical to the results of the day-ahead TCSS and would follow the dispatch schedule developed there.

Special Events

The EMCAS user can specify several unplanned events to simulate how the system will respond to variations is load, generator outages, and transmission outages using the *Special Event Generator* described earlier. Each of these events will require that the system operation be adjusted from what was included in the day-ahead schedule. In general, these adjustments will result in increased costs in the system. In some cases, it may not be possible for the system to adjust and some load will not be served. EMCAS tracks these conditions.

Locational Marginal Prices

One of the primary focuses of this type of analysis is the locational differences in electricity prices across the network. The locational marginal price (LMP), expressed in $/MWh, is defined as the cost of serving one additional MW of load at any point in the network. The LMP has three components: (1) the marginal cost to produce the last MW of power, (2) a transmission congestion charge, and (3) the cost of marginal transmission losses. In situations where there is no transmission congestion, LMPs at all buses in a network are similar, varying only by a relatively small amount to cover small transmission losses. An uncongested state only occurs when power units can be dispatched according to an economic merit order dispatch without overloading transmission lines and violating security measures. The economic merit ordering of units or blocks of units is typically based on marginal production costs such that generators that are the least expensive to operate are dispatched first while the most expensive units are utilized only during times of highest demand. However, the actual dispatch of units must often deviate from the economic merit order to keep the transmission system operating within a stable and secure state. This change in the order of dispatch of units when transmission congestion occurs leads to variations in LMPs across a region. In some cases, the variation in LMPs among network nodes can be significant.

In simulating the hourly dispatch, EMCAS calculates the LMP for each node in the network. The LMP is set equal to the dual value computed for the energy balance constraint in the TCSS. These dual values are computed by the DCOPF/LP routine. Essentially, the dual value is a measure of the cost saving, in $/MWh, associated with relaxing the bus energy balance constraint by a very small amount. For load and generation buses, it can also be interpreted as the change in the objective function value if the net power injection at a bus is increased by 1 MWh.

Settlement Function

At the completion of the dispatch for each hour, the information needed to settle the charges and payments to each of the market participants is tabulated. In principle, these settlements can be displayed for each hour of a simulation. In practice, they are displayed as monthly or annual aggregations. Table B-1 summarizes the settlements that are calculated.

All of the settlement payments are calculated using the market rules that have been established. For example, if there is a tariff on consumer electricity purchases, the tariff value is used to calculate their payment for purchases.

Table B-1 Settlement Payments Calculated in EMCAS

Agent	Revenues	Expenses
Consumers	• N/A	• Payments to DemCos for electricity purchased • Payments to DistCos for distribution charges • Payments to TransCos for transmission use charges
DemCos	• Payments from consumers for electricity purchased	• Bilateral contract payments to GenCos • Energy payments to pool market based on actual purchases
GenCos	• Bilateral contract payments from DemCos • Energy payments from pool market; based on actual generation • Ancillary services payments: capacity charge for units on standby plus energy payment if unit is actually dispatched	• Generator fuel costs • Generator variable operating costs • Generator fixed operating costs • Off schedule charges to make up supply for generators that were scheduled to operate but were out of service; based on market price
DistCos	• Distribution charges for use of distribution system; paid by consumers	• N/A
TransCos	• Transmission use charges for use of transmission lines; paid by consumers through DemCos • Transmission congestion charge from differences in LMPs	• N/A

B.6 MODEL OUTPUTS

An EMCAS simulation can produces a substantial amount of output information. The simulation is done on an hour-by-hour basis for any period from days to years. At each step of the simulation, EMCAS can output the behavior of each component of the physical system (e.g., output of each generator unit, loading of each transmission line) and each agent (e.g., bids by each GenCo, bid acceptance/rejection by ISO, revenues, costs). Summaries and aggregations of information (e.g., by company, by geographical area) are available to provide an overview of results. EMCAS provides both tabular and graphical output at the user's choice and can output its information to spreadsheets or other data processing software.

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APPENDIX C
COMPARISON OF POWERWORLD® AND EMCAS© RESULTS

This appendix briefly discusses a comparison of the model results from EMCAS and PowerWorld. The comparison focused on the hourly LMPs and was conducted for February and July for buses located in the IP and all NI zones; that is, NI-A to NI-G. The EMCAS results used in the comparison were the LMPs from the Production Cost case. PowerWorld results were based on an assumed production cost-based bidding.

Figure C-1 shows hourly LMPs for February for bus 32271 located in the IP zone. As can be seen, EMCAS LMPs were consistently higher (on average $5.5/MWh) than LMPs projected by PowerWorld. An initial assessment concluded that this was based on several differences in the modeling approach as well as some of the underlying data assumptions, including:

- Differences in assumed unit production costs – the EMCAS results included a fixed O&M cost component, while PowerWorld did not;
- Differences in derating of out-of-state units to account for outages;
- Unit commitment – EMCAS included a unit commitment algorithm, while PowerWorld did not; and
- Unit heat rates – EMCAS used heat rates by block (up to 5 blocks per unit), while PowerWorld used only one heat rate (full-load heat rate) per unit.

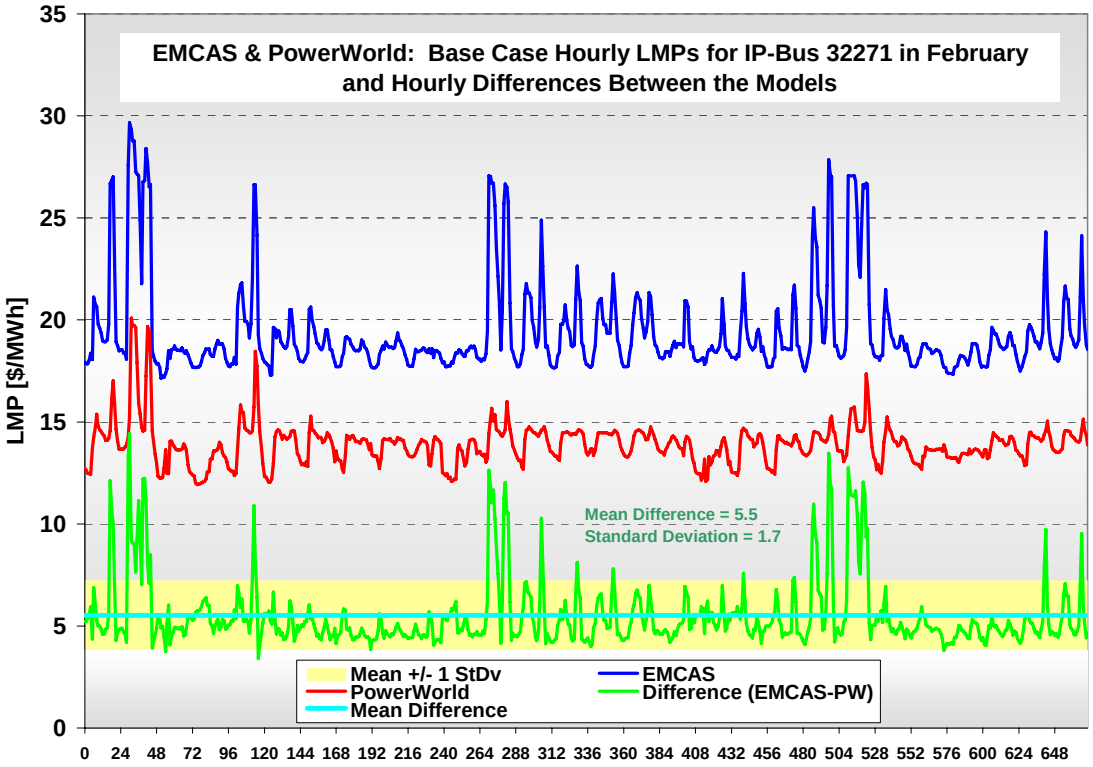

Figure C-1 Differences in Hourly LMPs for IP-Bus 32271 (February)

After identifying the main factors leading to the differences in LMP results, an EMCAS case was created that included the same production cost assumptions, the same out-of-state derating factors, and the same unit-level heat rates. In addition, the unit commitment algorithm was disabled. The following graphs show a comparison of PowerWorld results with the original EMCAS results (Original Case) and with the modified case (Modified Case). It can be seen that these four changes explained most of the differences in model results.

Figure C-2 shows that the differences typically dropped from around 4–6 $/MWh to less than 1 $/MWh in the Modified Case. (EMCAS results were slightly lower than PowerWorld in this case.) Expressed in relative terms, Figure C-3 shows that while the Original Case had LMPs to be around 25–30% different, the Modified Case reduced this to less than 5%. Figure C-4 shows that the hourly LMPs from both models varied well together; that is, they showed very similar daily fluctuations. In general, the Modified Case slightly improved the correlation between the data sets.

Figure C-5 shows the comparison for July. For the most part, the Modified Case leads to a significant reduction in differences, except for buses in the NI-D zone (Chicago). However, even in this zone, average differences for the month of July are still less than 5 $/MWh. Figure C-6 shows July differences in percent. Again, except for buses in NI-D, differences drop from around 20–30% to about –5% to +5%. Figure C-7 shows very good correlation for July, except for NI-D. The reason for the noticeably different behavior of NI-D buses is likely a result of the more detailed modeling of phase shifters by PowerWorld. This is discussed in Appendix E.

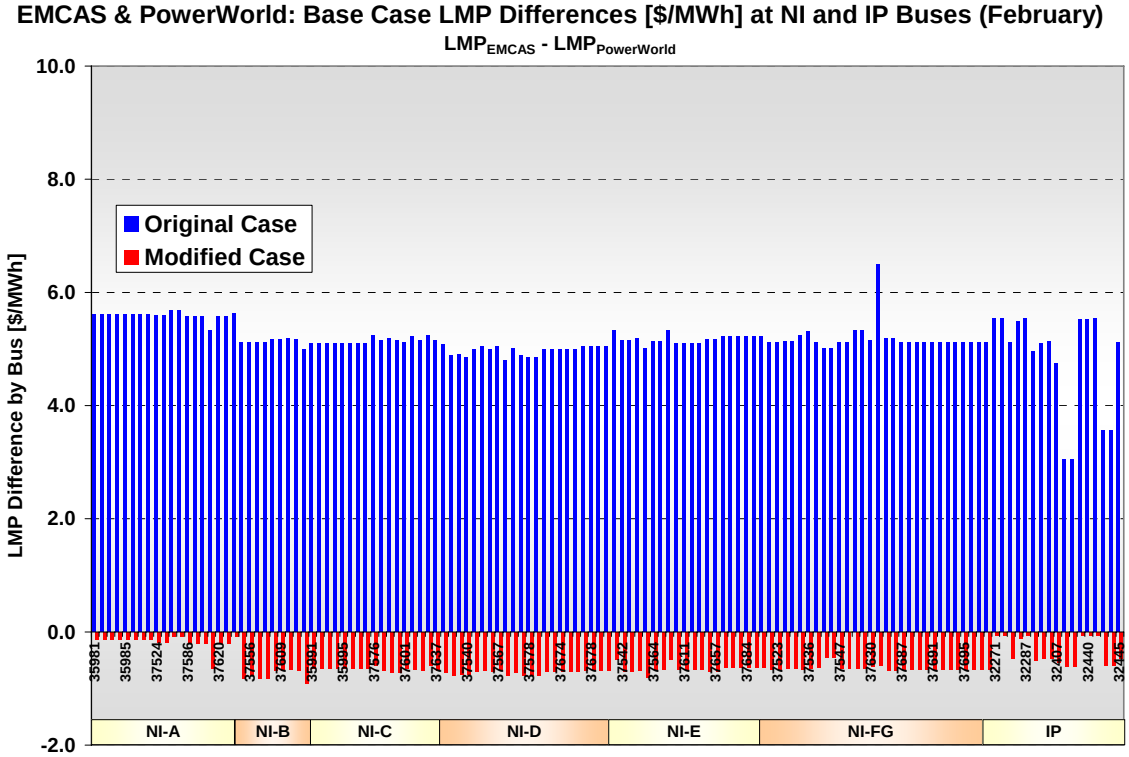

Figure C-2 Average Monthly Differences (February) by Bus for all IP and NI Buses

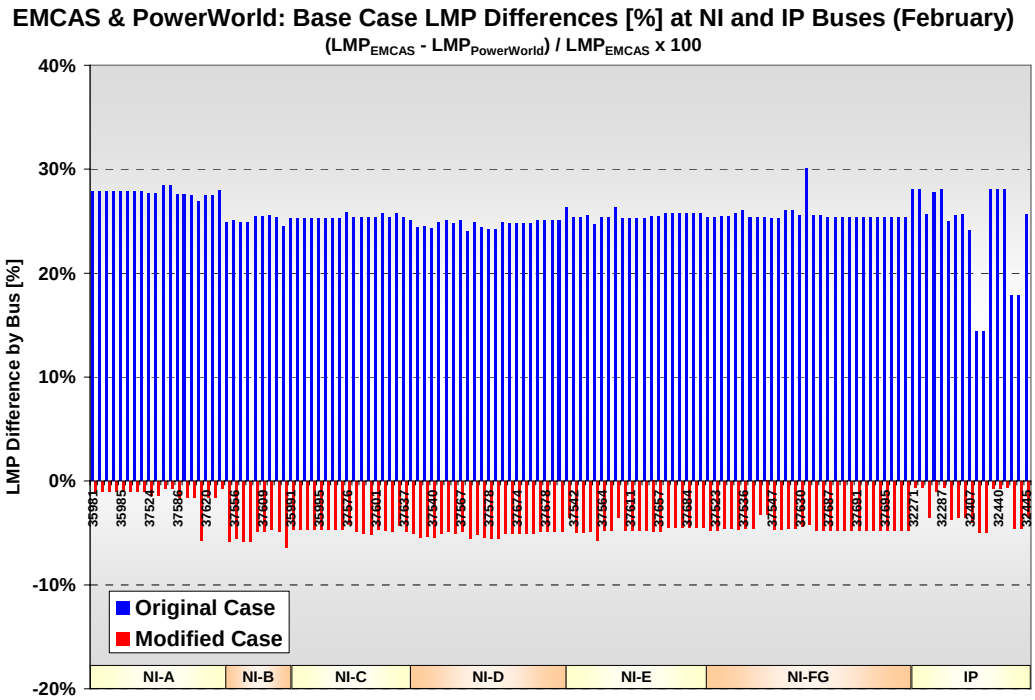

Figure C-3 Average Monthly Differences (February) by Bus for all IP and NI Buses in Percent

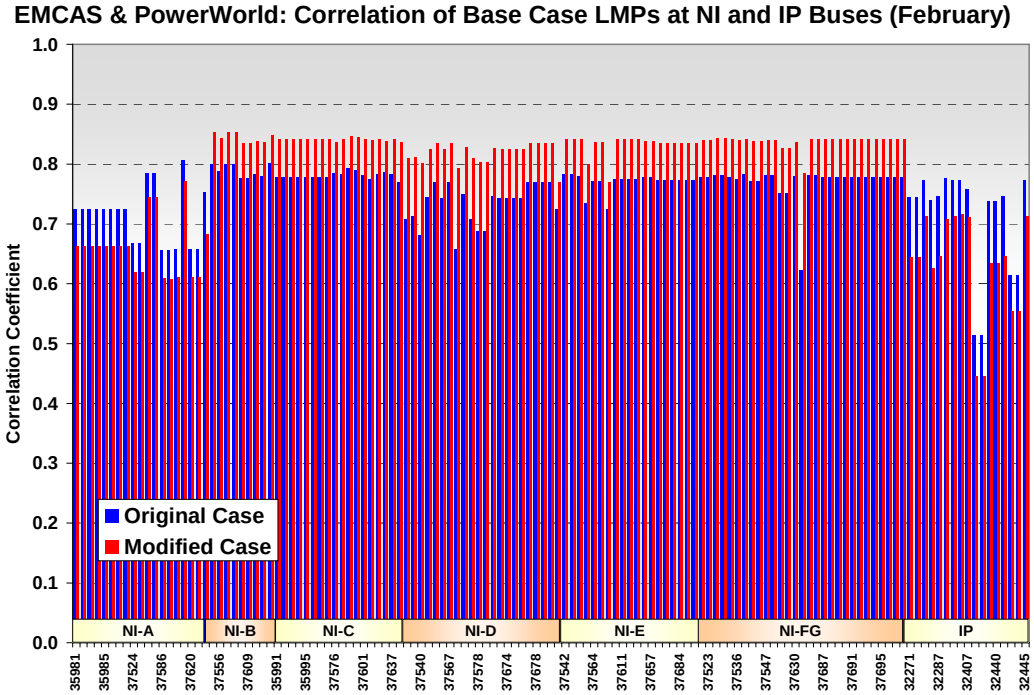

Figure C-4 Correlations between EMCAS and PowerWorld Results (February)

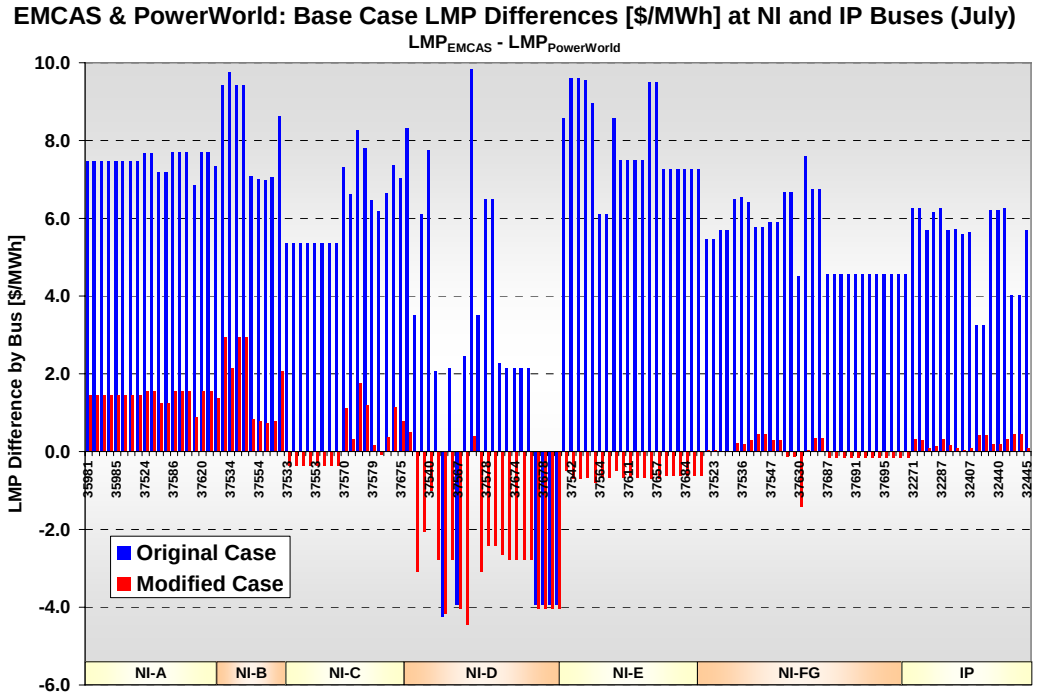

Figure C-5 Average Monthly Differences (July) by Bus for All IP and NI Buses

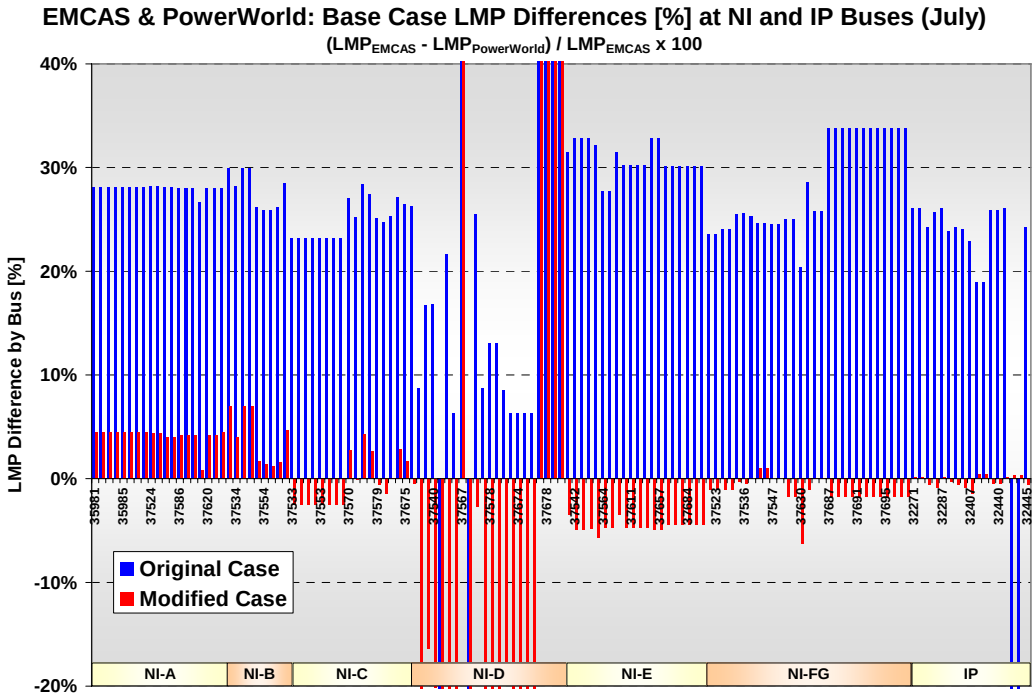

Figure C-6 Average Monthly Differences (July) by Bus for All IP and NI Buses, in Percent

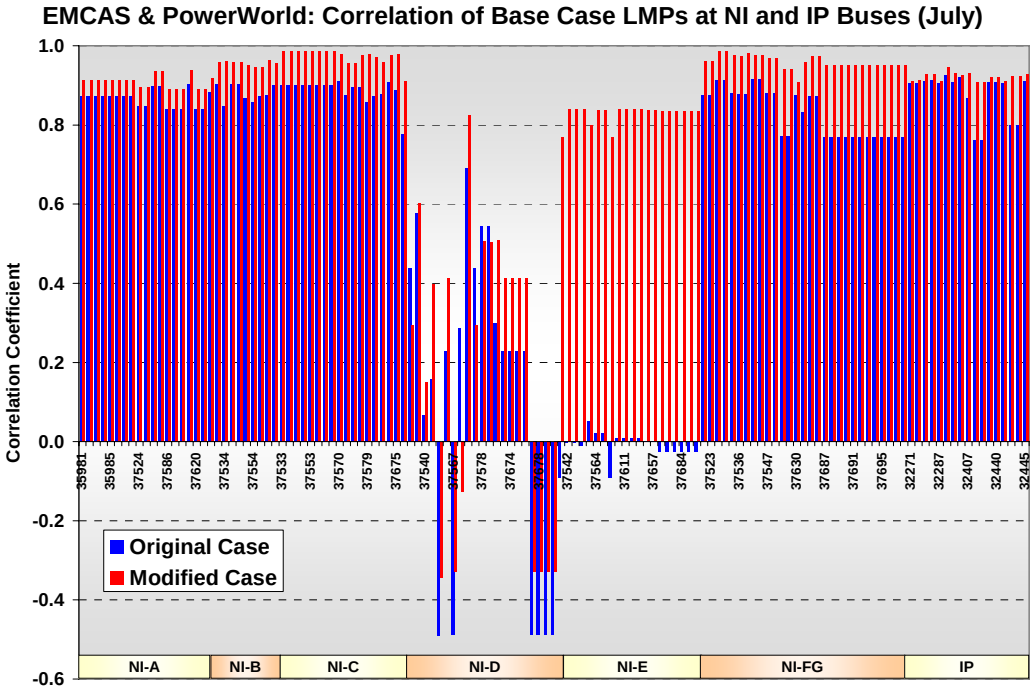

Figure C-7 Correlations between EMCAS and PowerWorld Results (July)