Introduction to System Operation, Optimization, and Control

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1.0 Introduction

The energy control center (ECC) has traditionally been the decision-center for the electric transmission and generation interconnected system. The ECC provided the functions necessary for monitoring and coordinating the minute-by-minute physical and economic operation of the power system. In the continental U.S., there are only three interconnected regions: Eastern, Western, and Texas, but there are about 130 *balancing areas* (previously known as *control areas*), with each one having its own ECC. Figure 0.a illustrates the three interconnections, and Fig. 0.b provides a map of all balancing areas within the US.

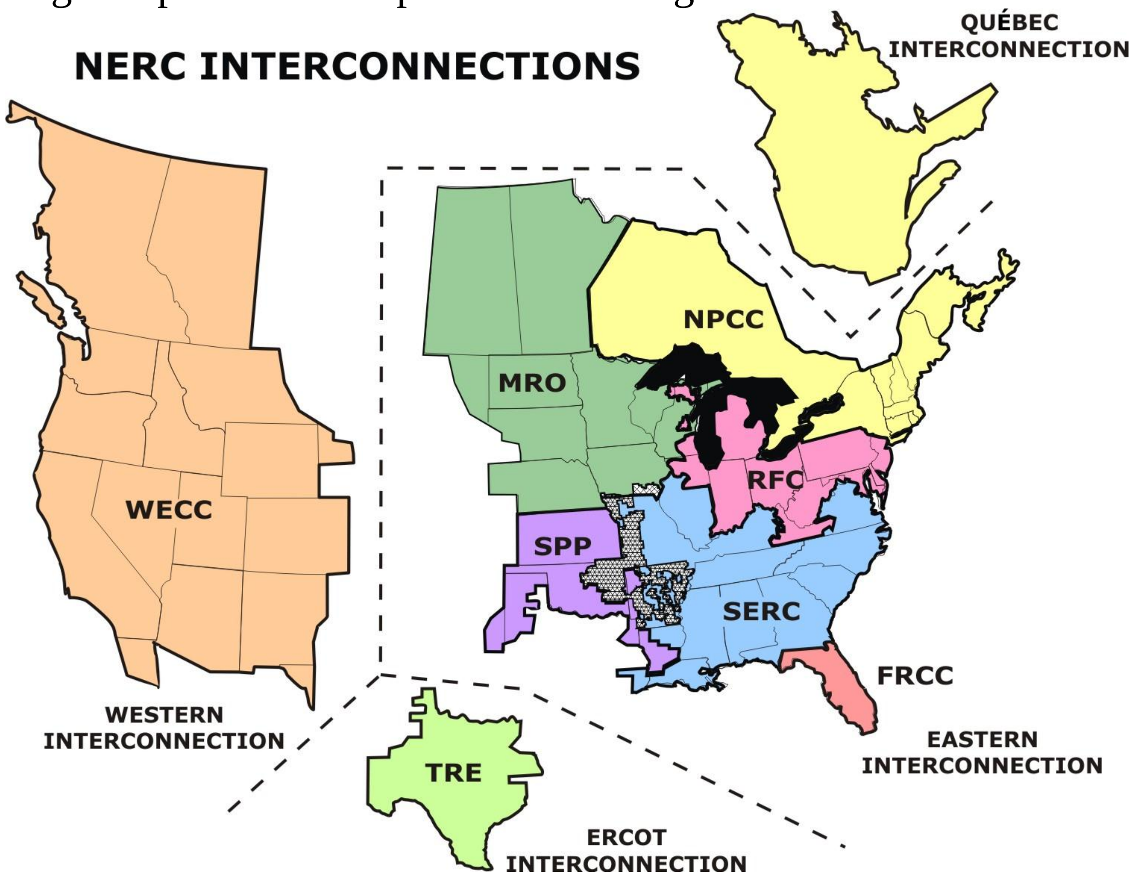


Fig. 0.a: The three North American interconnections

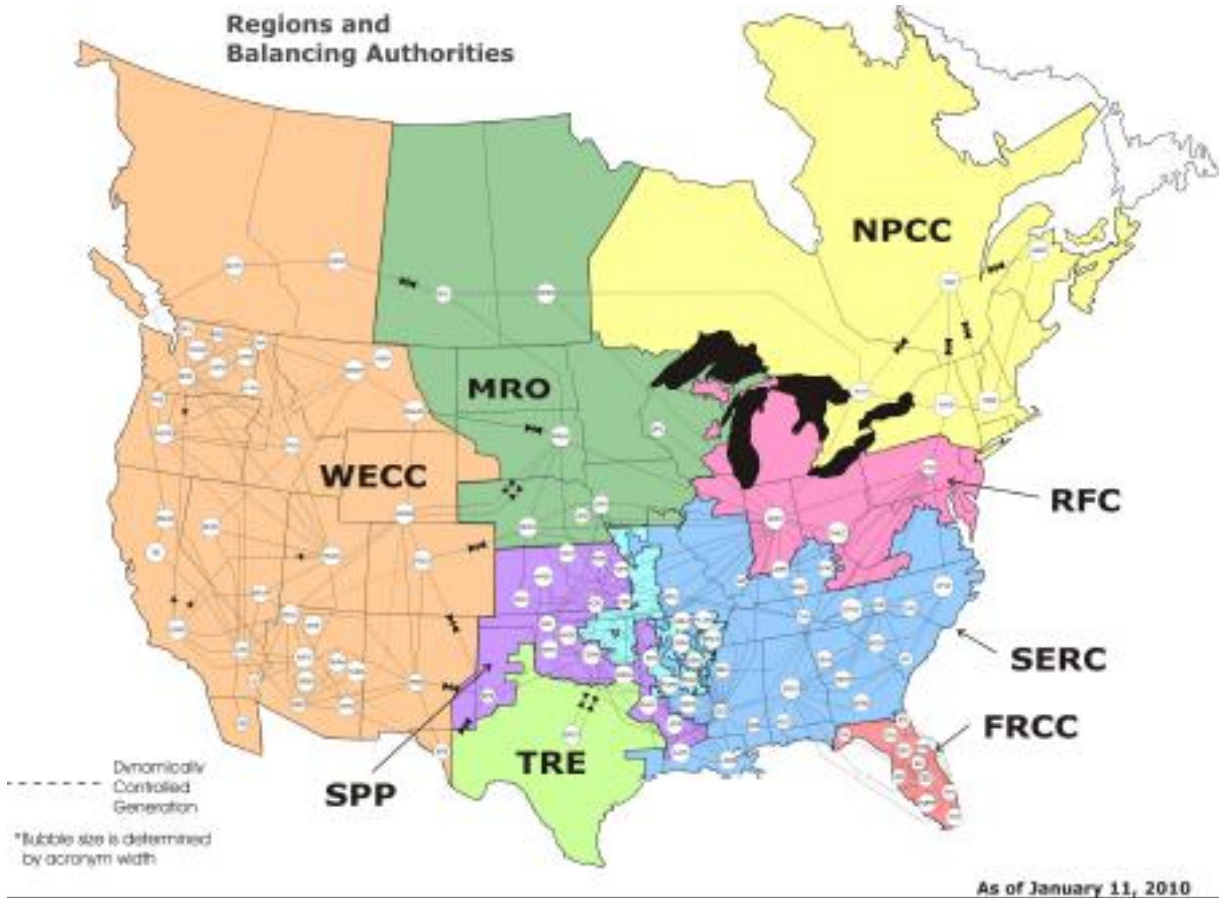


Fig. 0.b: North American balancing areas

Balancing areas should not be confused with regional transmission organizations (RTOs) indicated in Fig. 0.c (and are generally also independent system operators or ISOs).

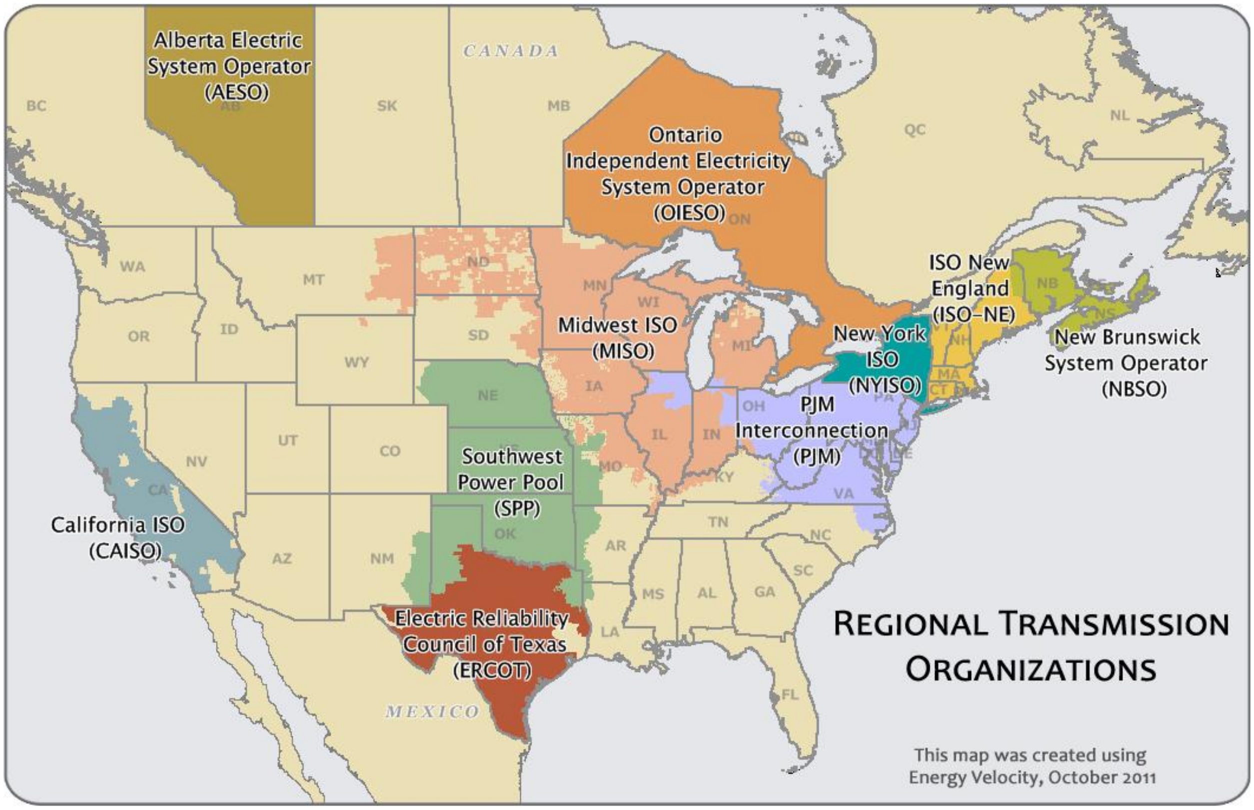


Fig. 0.c

A balancing area is an electric power system or combination of power systems bounded by interconnection metering and telemetering, which has automatic generation control and performs the following functions:

- Balance Supply and Demand within metered area
- Maintain Interchange Power with other Balancing Areas
- Maintain frequency of Interconnection within reasonable limits

Below are some pictures of ECCs.

Fig 0.d: Energy control centers

Generally, most utility companies that owned significant transmission and generation also owned and operated an ECC. This began to change during the latter half of the 1990's, however. A major part of the "deregulation" movement, perhaps better said as the "industry restructuring," consisted of changing the organizational structure of the regulated utility from a *vertically integrated*, single organization having responsibilities for generation, transmission, operation, and distribution, into a number of different organizations, each one with a separate function. Now, within what was a single balancing area operated by a single utility company, there may exist generation plants and transmission circuits having ownership from a variety of different organizations. The process by which this took place is sometimes called "functional disaggregation." The motivation for doing so was to create conditions conducive for competition within the electric power industry.

One of the reasons why the electric power and energy industry was regulated under a monopolistic organizational structure, with a single utility company responsible for each control area, was that maintaining the integrity and the economy of the interconnected system required significant coordinated decision-making. So a single organization, having unified and consistent objectives, could achieve this very well. In bringing marketplace competition to the industry, it was necessary to disaggregate these functions, in order to have multiple players to compete against one another without giving any one of them too much market power; yet the need for coordination remains. The independent system operator (ISO) and the real-time and day-ahead electricity markets have resulted from recognition of this need. The ISO function is to monitor and regulate the physical operation of the interconnected grid, and the electricity market function is to provide a fair way to facilitate competition while maintaining reliable and economic operation of the interconnected grid.

Our objective in this introduction to gain some perspective regarding system operation and energy trading as it is done in the industry today. In order to achieve this objective, it is useful to study the role of the ECC and associated technology used in the regulated, traditional industry. This we will do in Section 1.1, because many of these same technologies still exist today, and newer technologies are typically an evolution of the traditional ones. In Section 1.2, we identify the way the traditional system control functions have been distributed to accommodate the restructured industry, and we describe some of the technologies that have been developed to facilitate this distribution.

A final comment is in regards to the phrase *power systems operation* on which our course is focused. We will define it in two ways, what it is, and what it is not.

- Power systems operation *is* the decision-making associated with use of <u>existing equipment</u> to generate, transmit, and deliver energy. It typically revolves around the ECC and the electric energy markets. Associated decision horizons (the time between the moment the decision must be made and the time in which it takes effect) are from real-time (milliseconds to seconds) to as much as 1-2 years.
- Power systems operation *is not* the decision-making associated with the planning of <u>future new equipment</u>. This is an area that

more typically comes under the heading of *power system planning*. We have another course for this topic.

It should be said, however, that there are many inter-relationships between operations and planning, and there are some decisions that are not cleanly in just one area or the other, and there are some tools that are used in both areas. But the terms are used heavily (and many companies are organized accordingly) and you should have some appreciation of what these terms mean.

1.1 System control for a vertically integrated utility

The system control function traditionally used in electric utility operation consisted of three main integrated subsystems: the energy management system (EMS), the supervisory control and data acquisition (SCADA), and the communications interconnecting the EMS and the SCADA (which is often thought of as part of the SCADA itself). Figure 1 [1] provides a block diagram illustration of these three integrated subsystems. The SCADA and communications subsystems are indicated in the dotted ovals at the top left hand corner of the figure. The rest of the figure indicates the EMS. We will describe each one in the following subsections.

We should distinguish at the outset EMS from distribution management systems (DMS). Both utilize their own SCADA, but for different functions. Whereas EMS/SCADA serves the high voltage bulk transmission system from the ECC, the DMS/SCADA serves the low voltage, distribution system, typically from a distribution dispatch center. There are a number of similarities and differences between the two. We are addressing within this document the EMS/SCADA.

<u>Assignment</u>: Use Fig. 1 to write 1-2 sentence descriptions of:

• SCADA	• Power flow
• Telemetry	• Economic dispatch
• Energy management system	• Optimal power flow (OPF)
• Network topology program (topology processor)	• Security assessment
• State estimation	• Automatic generation control (AGC)

Also (but not in Fig 1):

• unit commitment, • fuel scheduling, • hydro-thermal coordination, • production costing.

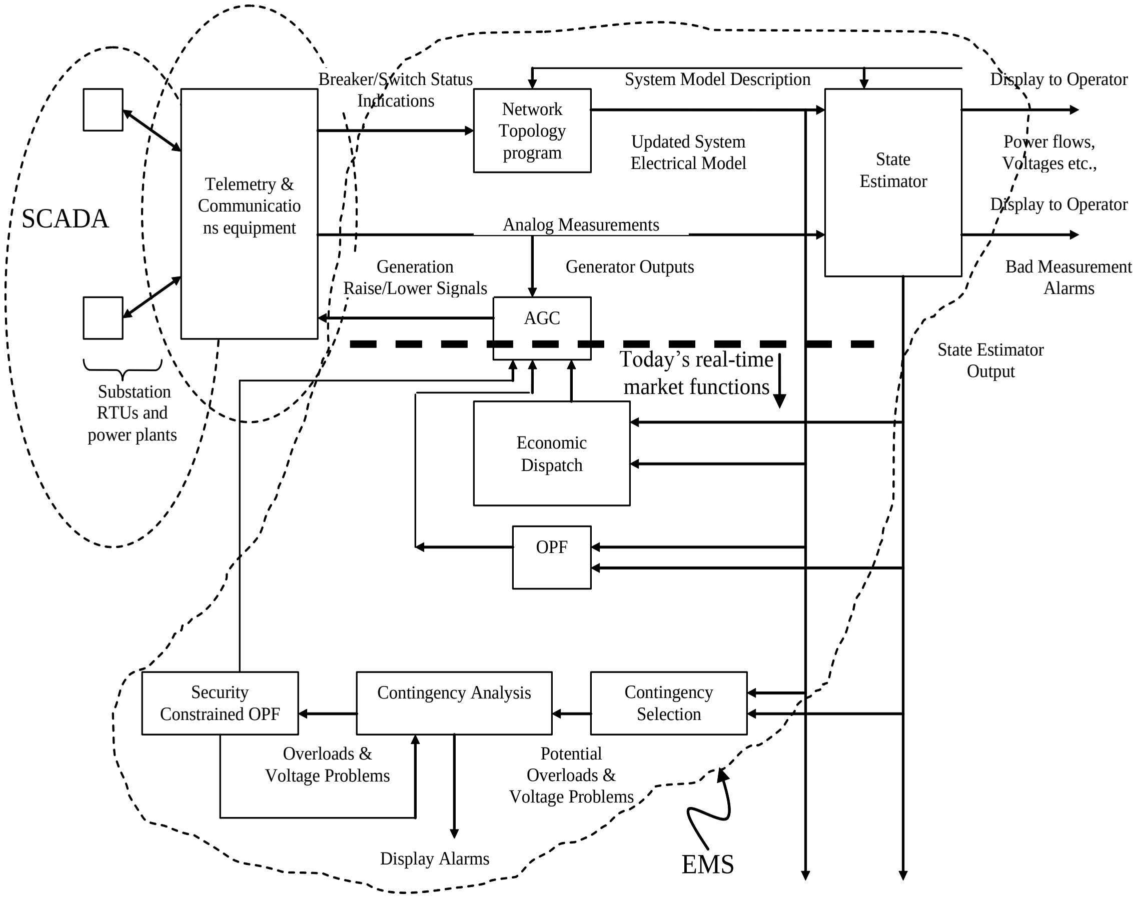


Figure 1: System control subsystems: EMS, SCADA, and Communications [1]

1.1.1 SCADA

There are two parts to the term SCADA [2-5]. *Supervisory control* indicates that the operator, residing in the energy control center (ECC), has the ability to control remote equipment. *Data acquisition* indicates that information is gathered characterizing the state of the remote equipment and sent to the operator for monitoring purposes. The monitoring equipment is normally located in the substations and is consolidated in what is known as the remote terminal unit (RTU). Generally, the RTUs are equipped with microprocessors having memory and logic capability. Older RTUs are equipped with modems to provide the communication link back to the ECC, where as newer RTUs generally have intranet or internet capability.

Relays located within the RTU, on command from the ECC, open or close selected control circuits to perform a supervisory action. Such actions may include, for example, opening or closing of a circuit breaker or switch, modifying a transformer tap setting, raising or lowering generator MW output or terminal voltage, switching in or out a shunt capacitor or inductor, and the starting or stopping of a synchronous condenser. Several security measures may be used to minimize false operations, including select-before-operate, check-back, and double-transmission. For example, in the check-back mode, when an operator desires to perform an action at a particular substation, the operator selects the substation, the RTU affirms, the operator selects the device on which to act, the RTU affirms, the operator requests the action, and then the RTU performs the action and affirms its completion. Such a procedure minimizes the likelihood of erroneous operations.

Information gathered by the RTU and communicated to the ECC includes both analog information and status indicators. Analog information includes, for example, frequency, voltages, currents, and real and reactive power flows. In addition, checks are made to verify telemetry integrity in case of failures and errors in the communication links. For these data, analog-to-digital converters change the quantity to digital form before the information is transmitted back to the ECC. Status indicators include alarm signals (over-temperature, low relay battery voltage, illegal entry) and whether switches and circuit breakers are open or closed. Such information is provided to the ECC through a periodic scan of all RTUs. A 2 second or 4 second scan cycle is typical. Some information reporting back to the ECC is minimized through a procedure known as *exception reporting*, whereby data is reported only if it changes. An important monitoring capability is sequence-of-event recording. This technology is driven by the fact that it is possible several events of interest take place in much less time that the scan cycle. For example, a breaker may open and then reclose several times. Protection engineers are very interested in the number of breaker closing operations as well as the timing of these kinds of operations. Yet, if these operations occurred within 1.5 seconds, all of the information would be lost. Sequence-of-events recorders provide the ability to capture these kinds of events and then report them back to the ECC in the next scan.

1.1.2 Communication technologies

The form of communication required for SCADA is *telemetry*. Telemetry is [6] the measurement of a quantity in such a way so as to allow interpretation of that measurement at a distance from the primary detector. The distinctive feature of telemetry is the nature of the translating means, which includes provision for converting the measure into a representative quantity of another kind that can be transmitted conveniently for measurement at a distance. The actual distance is irrelevant. Telemetry may be analog or digital. In analog telemetry, a voltage, current, or frequency proportional to the quantity being measured is developed and transmitted on a communication channel to the receiving location, where the received signal is applied to a meter calibrated to indicate the quantity being measured, or it is applied directly to a control device such as a ECC computer [2]. Forms of analog telemetry include variable current, pulse-amplitude, pulse-length, and pulse-rate, with the latter two being the most common. In digital telemetry, the quantity being measured is converted to a code in which the sequence of pulses transmitted indicates the quantity. One of the advantages to digital telemetering is the fact that accuracy of data is not lost in transmitting the data from one location to another [2]. Digital telemetry requires analog to digital (A/D) and possible digital to analog (D/A) converters, as illustrated in Figure 2 [2].

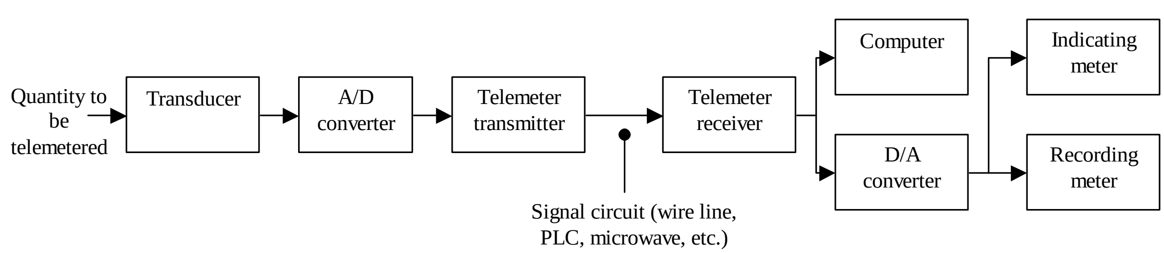


Figure 2: Block Diagram of Telemetering System [2]

The earliest form of signal circuit used for SCADA telemetry consisted of twisted pair wires; although simple and economic for short distances, it suffers from reliability problems due to breakage, water ingress, and ground potential risk during faults. Improvements over twisted pair wires came in the form of what is now the most common, traditional type of SCADA telemetry mediums based on leased-wire, power-line carrier, or microwave [7]. These are all *voice grade* forms of telemetry, meaning that they represent communication channels suitable for the transmission of speech, either digital or analog, generally with a frequency range of about 300 to 3000 Hz [6].

Leased-wire means use of a standard telephone circuit; this is a convenient and straightforward means of telemetry when it is available, although it can be unreliable, and it requires a continual outlay of leasing expenditures. In addition, it is not under user control and requires careful coordination between the user and the telephone company. Power-line carrier (PLC) offers an inexpensive and typically more reliable alternative to leased-wire. Here, the transmission circuit itself is used to modulate a communication signal at a frequency much greater than the 60 Hz power frequency. Most PLC occurs at frequencies in the range of 30-500 kHz. The security of PLC is very high since the communication equipment is located inside the substations. One disadvantage of PLC is that the communication cannot be made through open disconnects, i.e., when the transmission line is outaged. Often, this is precisely the time when the communication signal is needed most. In addition, PLC is susceptible to line noise and requires careful signal-to-noise ratio analysis. Most PLC is strictly analog although digital PLC has now become available.

Microwave radio refers to ultra-high-frequency (UHF) radio systems operating above 1 gHz. The earliest microwave telemetry was strictly analog, but digital microwave communication is now quite common for EMS/SCADA applications. This form of communication has obvious advantages over PLC and leased wire since it requires no physical conducting medium and therefore no right-of-way. However, line of sight clearance is required in order to ensure reliable communication, and therefore it is not applicable in some cases.

A more recent development has concerned the use of fiber optic cable. This technology is capable of extremely fast communication speeds. Although the cost was originally prohibitive, it has now decreased to the point where it is economically viable. Fiber optics may be either run inside underground power cables or they may be fastened to overhead transmission line towers just below the lines. They may also be run within the shield wire suspended above the transmission lines. Additional communication technologies include use of satellites, VHF and UHF radio, spread spectrum radio, and internet/intranet systems.

1.1.3 EMS

The EMS is a software system. Most utility companies purchase their EMS from one or more EMS vendors. These EMS vendors are companies that specialize in design, development, installation, and maintenance of EMS within ECCs. There are a number of EMS vendors in the U.S., and they are very active in hiring power system engineers with good software development capabilities and software development engineers with power system engineering background.

One can observe from Figure 1 that the EMS consists of 4 major functions: network model building (including topology processing and state estimation), security assessment, automatic generation control, and dispatch. These functions are described in more detail in the following.

Network Model Building (topology processing, state estimation, and power flow)

A network model is necessary in order to analyze it to determine whether operating conditions are safe under for the existing topology and also under the event that one or more components fail and are outaged. The network model must reflect the correct topology and the correct operating conditions relative to the actual network conditions. The information available to construct the network model includes the status indicators and the analog measurements available from the

SCADA. The result of the network model builder is a power flow model. Network model building takes place in two steps, topology processing and state estimation.

Topology Processing: The topology of the network characterizes the connectivity between buses (nodes), the shunt elements at each bus, and which generators are connected to each bus. This information comes to the EMS from the SCADA in the form of status indicators for each circuit breaker and switch at all buses. This information is referred to as the *bus section-breaker-switch data* and provides a mapping of individual *bus sections* at each substation and how they are connected. Different bus sections connected by closed breakers or switches are electrically a single node. A key step in topology processing is to recognize these situations in order to minimize the number of nodes in the resulting network model. Effectively, then, topology processing converts bus section-breaker-switch data into so-called *bus-branch data*. The bus-branch data is appropriate for modeling the transmission line and transformer connections between substations, rather than the precise bus-section connections at each substation [8]. The impedances of all network elements are stored in an EMS database, and this information, when combined with the output of the topology processor, is enough to establish the system topology.

State Estimation: Given the topology of the system, it still remains to determine the operating conditions, i.e., the bus voltages, load levels, and generation levels. At first glance, this appears to be an easy problem – just take the corresponding information from the SCADA. However, one must recognize the reality of data unavailability and of data error. Data unavailability comes from two sources. First, there may be some substations that have no SCADA. Second, there may be some substation RTUs or telemetry systems that are unavailable due to maintenance or unexpected trouble. Data error comes from the fact that all analog measurement devices contain some measurement error. Typically this error is small for any single device, but the use of many thousands of devices, each having small error, can result in significant inaccuracy in regards to the overall system analysis. The state estimator is a program that receives the SCADA measurement information and then uses statistical procedures to obtain the very best *estimate* of the actual state of the system. The result of state estimation is a power flow model that can be used for security assessment.

Power flow: The power flow problem is a very well known problem in the field of power systems engineering, where voltage magnitudes and angles for one set of buses are desired, given that voltage magnitudes and power levels for another set of buses are known and that a model of the network configuration (unit commitment and circuit topology) is available. A power flow solution procedure is a numerical method that is employed to solve the power flow problem. A power flow program is a computer code that implements a power flow solution procedure. The power flow solution contains the voltages and angles at all buses, and from this information, we may compute the real and reactive generation and load levels at all buses and the real and reactive flows across all circuits. The above terminology is often used with the word “load” substituted for “power,” i.e., load flow problem, load flow solution procedure, load flow program, and load flow solution. However, the former terminology is preferred as one normally does not think of “load” as something that “flows.”

Security Assessment

Security assessment determines first, whether the system is currently residing in an acceptable state and second, whether the system would respond in an acceptable manner and reach an acceptable state following any one of a pre-defined contingency set. A *contingency* is the unexpected failure of a transmission line, transformer, or generator. Usually, contingencies result from occurrence of a *fault*, or short-circuit, to one of these components. When such a fault occurs, the protection systems sense the fault and remove the component, and therefore also the fault, from the system. Of course, with one less component, the overall system is weaker, and undesirable effects may occur. For example, some remaining circuit may overload, or some bus may experience an undervoltage condition. These are called *static* security problems. *Dynamic* security problems may also occur, including uncontrollable voltage decline, generator overspeed (loss of synchronism), or undamped oscillatory behavior. Almost all EMS today are capable of performing static security assessment, because it only requires a power flow program to do so. Not many EMS are capable of performing dynamic security assessment, however, because the assessment tools are more complex and computationally intense. However, dynamic security assessment tools are rapidly becoming more prevalent in EMS with the continued growth in computational and algorithmic efficiency.

Automatic Generation Control

The purpose of AGC is to regulate the system frequency and power interchange between control areas. It is sometimes referred to as the secondary frequency control loop, with the primary frequency control coming from the governors located on each generator. We refer to the interconnecting circuits between control areas as tie lines. There are two SCADA measurement used by AGC: total net tie line flow and frequency. There also exist *scheduled* values for these two parameters. The scheduled net tie line flow depends on the total sales less purchases to other control areas. The scheduled frequency is always 60 Hz. The differences between actual and scheduled tie line flow and frequency can be denoted as ΔP_{tie} and Δf, respectively. These two values are combined in a weighted sum $\Delta P_{tie}+\beta\Delta f$ and provided as the AGC control actuation signal. If this signal is positive, it means that either our control area is selling too much power or the frequency is too high. In either case, the solution is to reduce generation within our control area, and "lower" command pulses are consequently sent to all generators. If the control actuation signal is negative, it means that either our control area is buying too much power or the frequency is too low. In either case, the solution is to increase generation within our control area, and "raise" command pulses are consequently sent to all generators. AGC typically sends the appropriate command pulses to the generators every 1-5 minutes.

It is important to recognize that the command pulses sent to each generator represent incremental changes only. This leaves the question: What should be the set point power levels at the generators?

Economic dispatch and optimal power flow

The function of the economic dispatch calculation (EDC) is to determine the set point power levels of all generators in order to supply the demand. The EMS program to do this solves an optimization problem having as its objective the minimization of the total generation cost. This objective quite naturally requires that the *generator cost-curves* (or generator offers to sell) be available. These cost curves or offers provide the cost per hour (to the owner, if cost-curves; to the market, if offer) of operating the generator as a function of its set point power level. One equality constraint requires total generation equal to total demand plus losses. A number of inequality constraints force the solution to be physically realizable, particularly in terms of respecting generator maximum and minimum power limits.

One also observes in Figure 1 the acronym “OPF,” which stands for *optimal power flow*. The OPF is also an optimization problem. It is similar to EDC in that it typically has the same objective of minimizing the total cost of generation in order to supply the demand. Yet it extends the EDC to account for the equality constraints governing the real and reactive power flowing out of each bus and therefore, its optimal solutions are more realistic. More important, it offers the capability to determine the effects of different electrical constraints on the system economic operation. The security constrained OPF extends the OPF to account for flow and voltage constraints imposed by security considerations identified through contingency analysis. It has only been recently that OPF has achieved the technical maturity necessary for application within an EMS.

Unit commitment

The unit commitment (UC) problem is the problem of identifying the generation units to be interconnected at any point in time, in order to achieve minimum total cost. It is typically solved for the next 2-6 hours, 1 day, or 1 week, and so it is dynamic (solved through time).

It is also integer, i.e., the solution must specify, for each unit, whether the unit is off-line (0) or on-line (1) during each time interval for which a solution is desired. One therefore sees that the number of possible solutions is 2^N where N is the number of units. For example, if N=50, a very modest-size power system, the number of possible solutions is 1.12E15, which is 1.12 quadrillion. Of course, feasibility constraints rule out many of these solutions, but still, this problem is a very high-dimension one.

The UC problem contains inter-temporal constraints, which causes what happens in one time period to possibly affect what happens in another time period. So we may not solve each time period independent of solutions in other time periods.

Finally, the UC problem is mixed integer. As already stated, it requires integers in its solution. In addition, it also requires continuous variables, in that, for interconnected units, the generation level should be determined in order to know the cost. This variable may be any number between the minimum and maximum generation levels for the unit. Thus, the economic dispatch problem, the optimal power flow problem (if transmission is included), or the security-constrained optimal power flow problem must be solved as a subproblem to UC. If the security-constrained optimal power flow problem is included in UC, the UC is referred to as the security-constrained unit commitment (SCUC).

1.1.4 Other operational needs

There are three other problems relevant to operations, optimization, and control that are not typically included in the EMS. However, they are all three very important to the operations of a power system. These are described below.

Fuel scheduling

Given a load forecast over the desired time interval (a month or a year), the fuel scheduling problem seeks to move an amount of fuel (coal and/or gas) to each power plant so that the cost of satisfying total demand over the time interval is minimized, subject to constraints on plant generation capacities, plant storage capacities, and specified (or potential) fuel contracts.

The fuel scheduling problem seeks to determine how much fuel to deliver to each plant in the specified time interval. The most important constraints are on energy, i.e., energy available (through contract), and energy possible for storage, are constrained. Thus, we refer to this problem as one of “generation with limited energy supply.”

Hydro-thermal coordination

Given a load forecast over the desired time interval (months or 1-2 years), the hydro-thermal coordination problem seeks to schedule the available hydro generation to minimize the cost of using the thermal generation and while satisfying constraints on reservoir capacity, flow rates, water release requirements (e.g., for recreational, navigational, or environmental purposes).

This problem deals with the fact that water reservoirs, which supply many of our hydroelectric facilities, are energy-constrained. In essence, then, this problem is one of “generation with limited energy supply.” But the unique nature of hydroelectric facilities requires specialized treatment. It should be clear that hydro-thermal coordination is necessary only for systems where significant hydroelectric capacity exists.

Production costing

The production costing program identifies the total production costs, or cost of producing the energy, over a time interval, typically months to a year. It also typically computes reliability indices that enable judging tradeoffs between cost and reliability. The operational decisions informed by production costing programs are when to have units available, and for what kinds of durations. Maintenance schedules are typically heavily influenced by the results of production costing programs.

The production costing program is also a heavily used tool for planning purposes. Here, one is able to determine how annual production costs will change under different facility plans. By summing annual production costs and investment costs for a specific investment plan, one can compute present worth as a good metric to use in comparing one investment plan to another. Organizations in the Eastern US are today heavily using production costing programs to determine the best transmission plan to move inexpensive wind energy from Midwestern US to the East.

1.2 System control for a competitive industry

The industry restructuring has considerably changed the system control paradigm [9]. A key aspect of this change has been the creation of the Independent System Operator (ISO) and the electricity markets. Most of the EMS functions remain with the ISO, although some go under the name of *ancillary services*. These include network model building, security assessment, and AGC. An additional function given to the ISO is congestion management. One very important function that required modification was the energy trading function. Figure 3 provides a conceptual illustration of the functional relationship between the ISO and the trading function and various features essential to accommodating this relationship. Figures 4, 5, and 6 provide alternative views.

Typically, the electricity market has responsibility for most of the trading functions. There are generally two trading functions: dispatch and transaction coordination. A significant difference between the traditional EDC and the new dispatch function is generator cost-curves are not made available. Rather, each generator owner sends *offers* to the electricity market on a periodic basis (hourly and/or daily). These bids minimally contain MW quantity and price. Buyers also submit *bids* to the electricity market, and then the electricity market conducts periodic actions resulting in identification of generation dispatch and purchase price. The functions used to perform this identification are the security-constrained unit commitment (SCUC) for the day-ahead market and the security-constrained optimal power flow (SCOPF) for the real-time or balancing market.

The second trading function is transaction coordination. A transaction is generally between two parties and therefore requires a bilateral contract. Such contracts must specify minimally quantity and price, sending and receiving nodes, and initiation time and duration as well. The system must have the capability of ensuring that requested transactions are in fact feasible and for identifying the price the parties will pay for obtaining the transmission service if the transaction is in fact feasible. The most important issue regarding transaction feasibility is the transmission capability, i.e., whether there is sufficient “room” for accommodating the transaction above what is already dedicated for other uses. Thus, transaction coordination requires the ability to compute available transmission capability (ATC). ATC is defined as a measure of the transfer capability, or available room in the physical transmission network, for transfers of power for further commercial activity, over and above already committed uses.

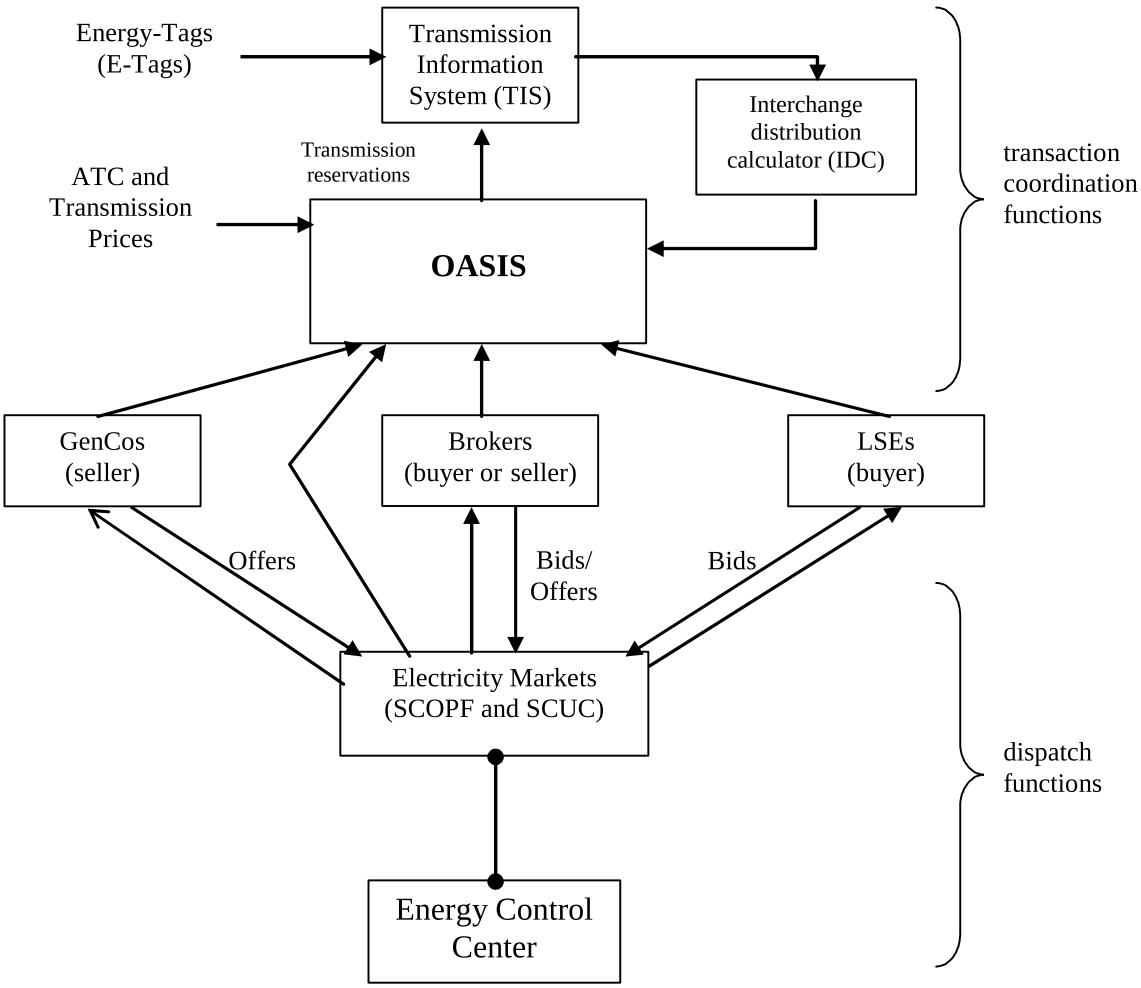


Figure 3: System Control Function for a Restructured Power Industry

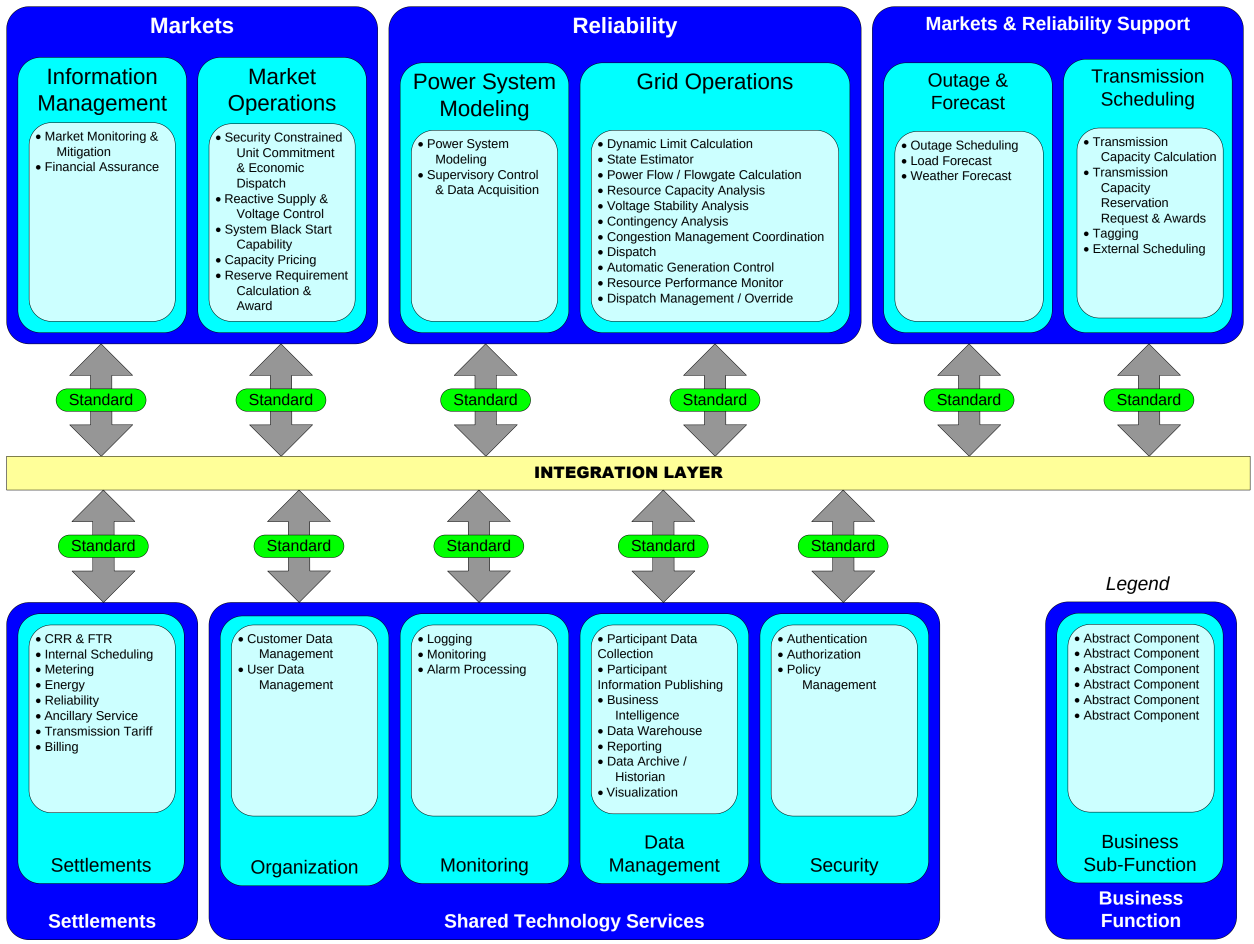


Fig. 4: IT Architecture for Markets and EMS Functionality [10]

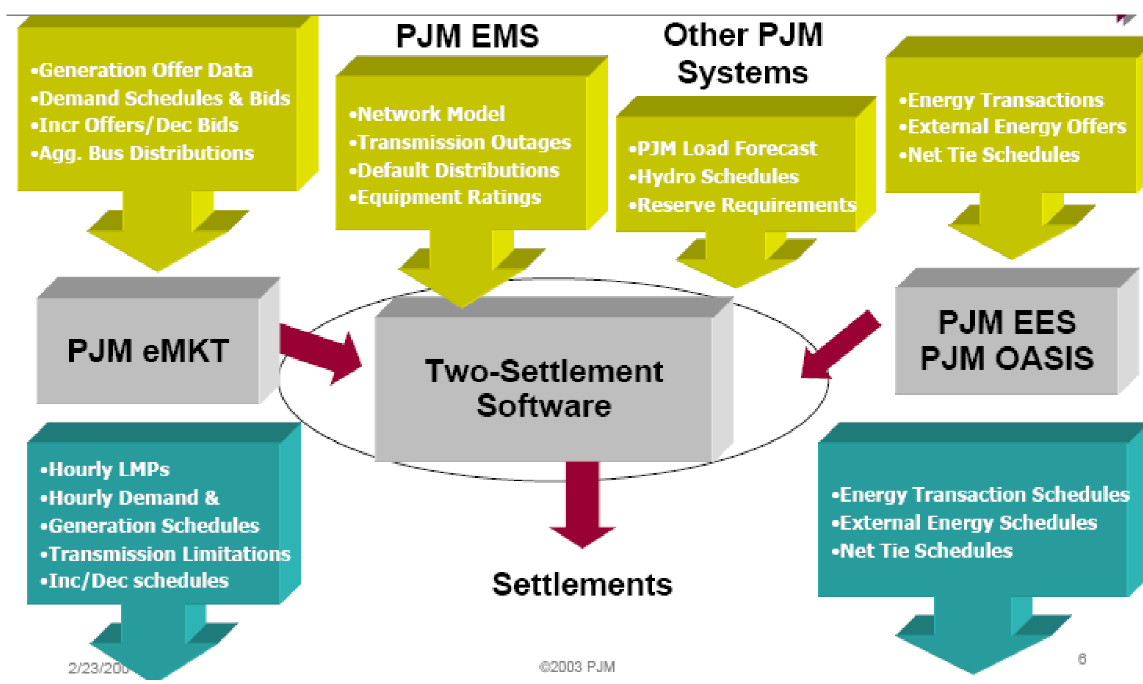


Fig. 5: PJM's Two-Settlement (day-ahead and real-time) System

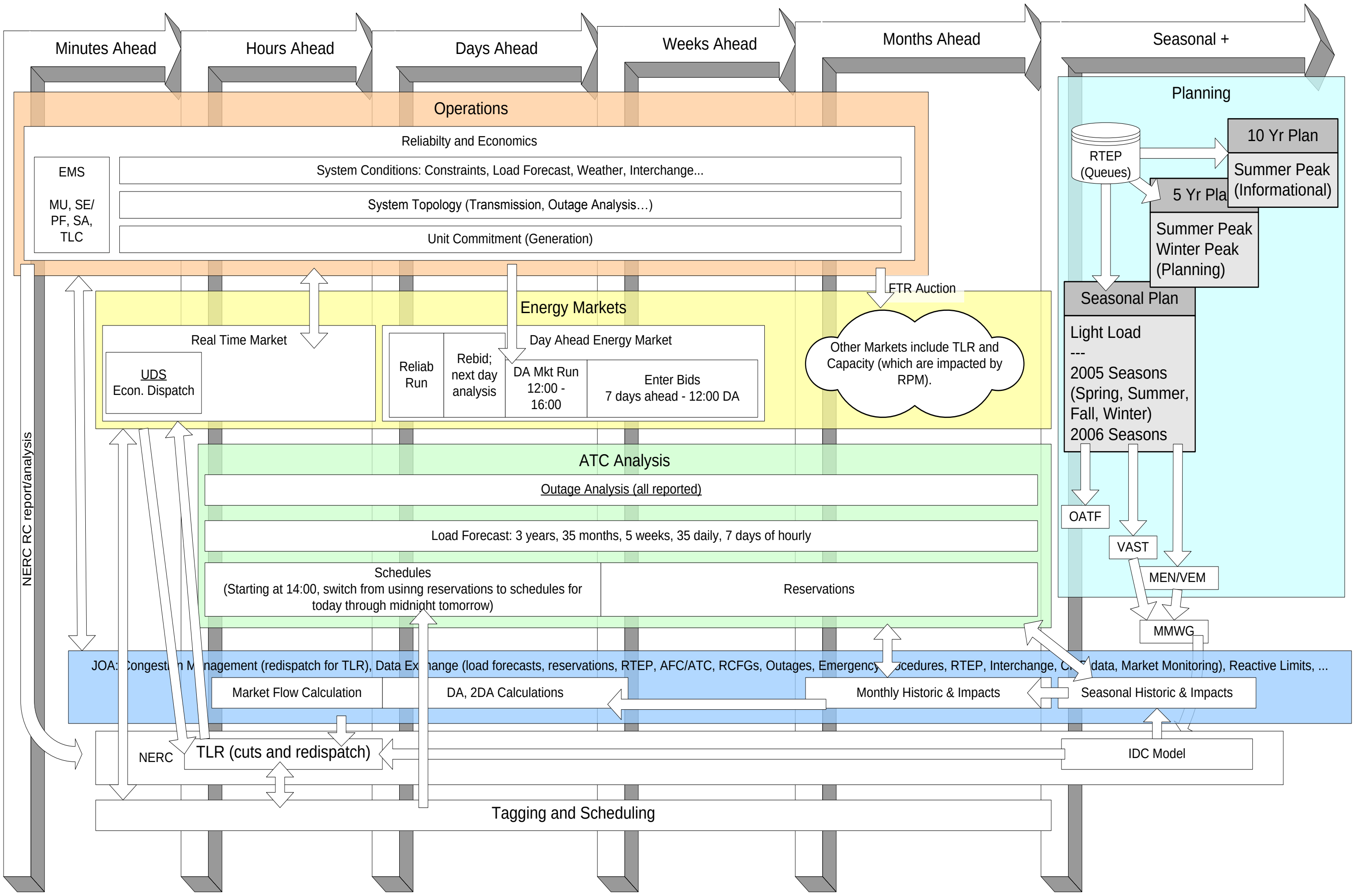


Fig. 6: PJM's Decision Processes

1.2.1 OASIS

A key requirement for any competitive economic system is that information be equally accessible by all competing entities. For example, participants of the farm produce markets must be able to equally identify price and quantity of the various commodities but also the availability of transportation for those commodities. Considering electric energy, the kW-hr, as a commodity, we easily recognize that transportation is provided by the transmission system. Therefore, having open information pertaining to the availability of transmission is essential for successfully operating an electricity market. Essentially, this means that *real-time ATC needs to be publicly available at all times*.

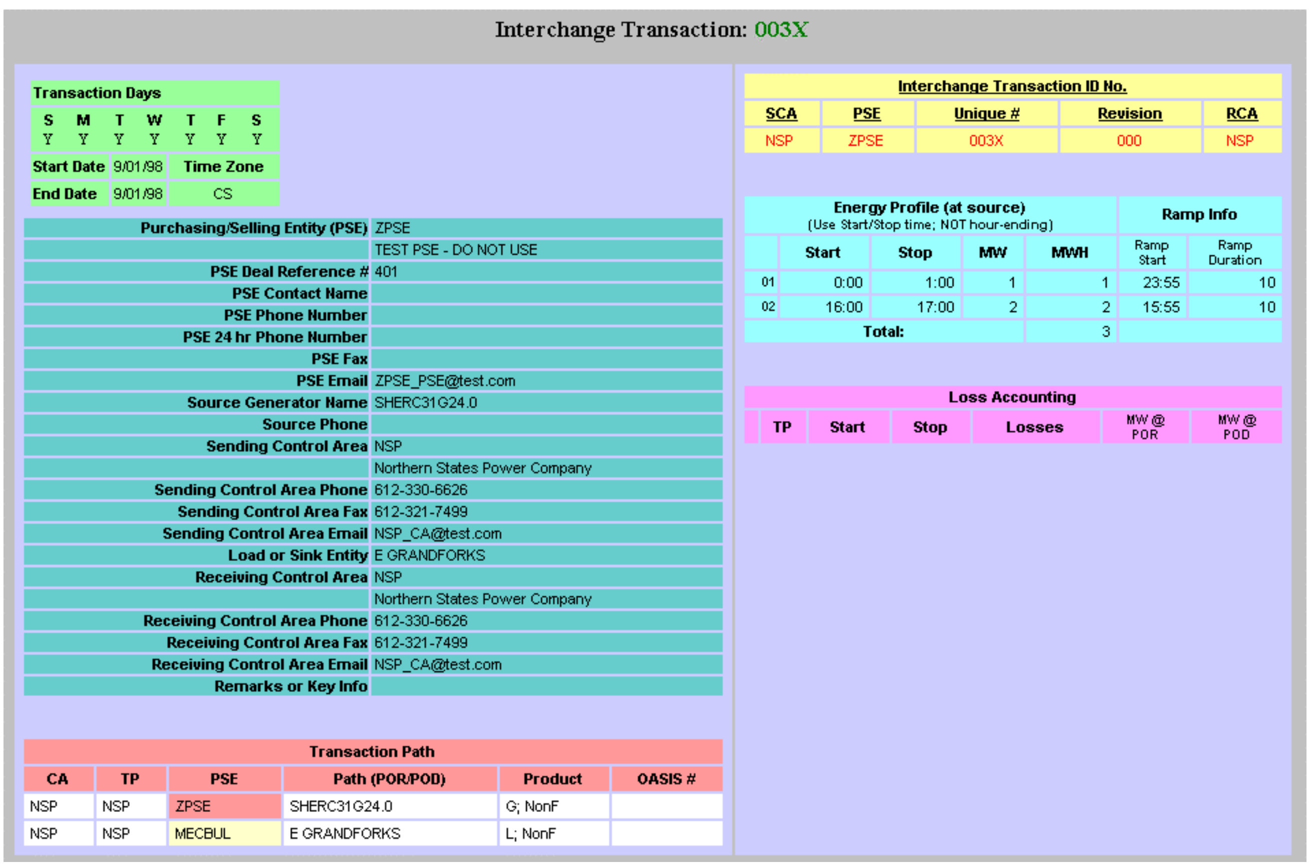
It has been difficult technically to compute ATC because the necessary tools are quite complex, and the data necessary to make the computation in real time has been available only at the ECCs; yet, it is necessary to make the results of the computation available to all of the different competing entities.

Recognizing the political difficulties, the US Federal Energy Regulatory Commission (FERC) gave a ruling in 1996 issuing Orders 888 and 889. One of the requirements from these rulings was that the industry had to maintain an information system that gives equal access to ATC and transmission prices to all competing parties. The industry began immediately to develop what has now become known as OASIS sites. OASIS is an acronym that stands for "Open Access Same Time Information System." In 1997, 21 OASIS sites began operation, and today there are more than 170 sites.

An OASIS site is an electronic ATC and transmission service pricing database and processing system that is available on the internet to registered participants. One uses an OASIS site to determine ATC, reserve transmission capability, arrange ancillary services, schedule energy interchange transactions, and to perform constraint management. A person can make a transmission request on OASIS and the request is then granted or not within minutes to hours, depending on the nature of the request. It is possible for the request to include a price and the service provider to counter with a different price. In this sense, OASIS provides negotiation capability. Reservations may be bumped if there are competing requests for the same, limited transmission. A "bumping protocol" exists that is based on a defined set of reservation tiers, ranging from tier 1 (long-term service, cannot be bumped) to tier 4 (non-firm point-to-point service, may be bumped by any lower tier reservation or a tier 4 reservation that is longer duration or same duration but higher price).

05.2.1 E-Tags

One may observe from Figure 3 that the transaction and dispatching functions of the trading function, and the ISO functions are not independent from one another. One essential requirement is that the appropriate ISOs be informed of any transmission requests made on the OASIS. The Transaction Information System (TIS) was developed to accomplish this. The TIS requires that every OASIS reservation have a corresponding "energy-tag" or "e-tag" as they have become known. The e-tag is an electronic internet tag for every energy transaction. The purpose of e-tags is to improve the exchange of information between marketing entities, security coordinators, and system operators, in order to provide a basis for curtailing transactions when necessary. Each transaction is described in the tag as an energy schedule to be transferred over a prescribed path for a specific duration and time frame, with an associated OASIS reference number. Figure 7 shows a sample e-tag.



Interchange Transaction: 003X

Transaction Days						
S	M	T	W	T	F	S
Y	Y	Y	Y	Y	Y	Y

Start Date	9/01/98	Time Zone
End Date	9/01/98	CS

Purchasing/Selling Entity (PSE)	ZPSE
	TEST PSE - DO NOT USE
PSE Deal Reference #	401
PSE Contact Name	
PSE Phone Number	
PSE 24 hr Phone Number	
PSE Fax	
PSE Email	ZPSE_PSE@test.com
Source Generator Name	SHERC31G24.0
Source Phone	
Sending Control Area	NSP
	Northern States Power Company
Sending Control Area Phone	612-330-6626
Sending Control Area Fax	612-321-7499
Sending Control Area Email	NSP_CA@test.com
Load or Sink Entity	E GRANDFORKS
Receiving Control Area	NSP
	Northern States Power Company
Receiving Control Area Phone	612-330-6626
Receiving Control Area Fax	612-321-7499
Receiving Control Area Email	NSP_CA@test.com
Remarks or Key Info	

Transaction Path					
CA	TP	PSE	Path (POR/POD)	Product	OASIS #
NSP	NSP	ZPSE	SHERC31G24.0	G; NonF	
NSP	NSP	MECBUL	E GRANDFORKS	L; NonF	

Interchange Transaction ID No.				
SCA	PSE	Unique #	Revision	RCA
NSP	ZPSE	003X	000	NSP

Energy Profile (at source) (Use Start/Stop time; NOT hour-ending)					Ramp Info	
	Start	Stop	MW	MWH	Ramp Start	Ramp Duration
01	0:00	1:00	1	1	23:55	10
02	16:00	17:00	2	2	15:55	10
	Total:			3		

Loss Accounting					
TP	Start	Stop	Losses	MW @ POR	MW @ POD

Figure 7: Sample E-tag

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