Chapter 1

Introduction

The fundamental changes due to processes of deregulation concept in many countries during the past few decades have transformed structure of electric power industry from a single vertically integrated company to the unbundled structure implementing a free market deregulated concept. These activities result in competitive environment in power industry that increases number of transactions and competition among market participants. However, no matter how the market is operated, "power system security" is still undoubtedly important since it is the fundamental of power system operation ensuring quality of service.

In order to maintain security of power system under the deregulated environment, a new tool identifying secure operating point from insecure operating point is required. Therefore, a newly introduced term, Available Transfer Capability (ATC) is developed and widely accepted as an important tool to maintain power system security issued by independent system or transmission providers. This quantity notifies market participants the amount of electricity transactions they could accomplish with their counterparts through the transmission network. Therefore, it is foreseeable that ATC is a vital quantity necessity to all stakeholders; any future transactions in the system must refer to ATC value at that specific path and time.

This dissertation focuses on the algorithm to calculate real-time Available Transfer Capability (Real-time ATC) in a large-scale power system during the operation period. This dissertation shows a practical method to determine maximum power that can be safely transferred from a source to sink via transmission network in addition to existing load in both normal and n-1 contingency situations. This dissertation establishes a fast and reliable tool with a clear concept to determine ATC values of large-scale power system.

This chapter introduces the basic concepts of power industry deregulation, the motivation of ATC concept and the overview of ATC calculation. Chapter 2 discusses the information of assumptions and test system used in this dissertation. Chapter 3 explains concept and methodology of transfer capability and margin while chapter 4 investigates factors that affect transmission capability. Chapter 5 initiates the first step of real-time ATC calculation by determining reliability must run (RMR), must run capacity and must take units in order to explicit them from scheduling processes. Since these units are necessary to maintain security level of the system, these units are required to be available or at least available to supply reliability must run generation capacity once ISO requests. When reliability must-run units, reliability must-run capacity and must take units are selected, ATC interfaces can be defined for transactions. Afterward, chapter 6 describes a new method to rank the severity of emergency cases when n-1 contingency is occurred based on severity scoring concepts. Results from this chapter are required in ATC calculation since preventive control is mandatory according to NERC's ATC framework [1]. Chapter 7 proposes a practical method to determine Total Transfer Capability, Transmission Reliability Margin and Capacity Benefit Margin in practical power system. Finally, Available Transfer Capability values are obtained in chapter 8. The last chapter, chapter 9, directs future works and other possible techniques for ATC calculation.

1.1 Motivation

Deregulation of power system around the world causes a significant transition in power system planning, operation and control [2] since it changes both structure and concepts of power system. When transmission network is opened for nondiscriminatory accesses, theoretically, customers will purchase electricity from any sources that are connected to the system. Similarly, generation companies may prefer purchasing electricity from other utilities to serving their load instead of constructing a new power plant. These concepts and examples lead to several questions regarding the capability of transmission system when power system is deregulated. The most simple questions but difficult question to explain are:

"What is the maximum power can be delivered from location A to location B in the system while security standards are still maintained"

"What is the available power can be delivered from location A to location B compared to existing loading commitment"

"If utility A needs to deliver electricity to utility B, which elements in the system will limit this transaction"; and

All of these common questions lead to a requirement to develop a new tool to determine maximum allowances of transaction between utilities in the system.

1.2 Deregulation of Power Industry

Deregulation of power industry has initially implemented in Chile in 1982 [3-4], followed by the United Kingdom in 1988 when UK Department of Energy issued a white paper which set out the proposal to deregulate power industry of England and Wales [2]. A more concrete structure of UK system was written in legal framework for the electricity industry 1989.

Main purpose of power industry deregulation is to promote competition in generation industry. Mostly, transmission and distribution system are not the main purpose of deregulation or expected to be the second or third stage of deregulation. Therefore, this business is usually seen as regulated business under supervision of non-profit organization or nondiscriminatory transmission providers that are responsible for security of the system since the nature of transmission system is not suitable to be deregulated.

There are several structures widely used for deregulated power systems. United Kingdom develops the pool model that sellers and buyers have to submit their bids and offers to the pool. National Grid Company (NGC), a non-pool member company, manages the pool by providing services such as operation, maintenance and central clearing system for pool members. Members of UK market connected to the pool by transmission system and are required to making transactions with pool. Structure of pool model is shown in figure1-1.

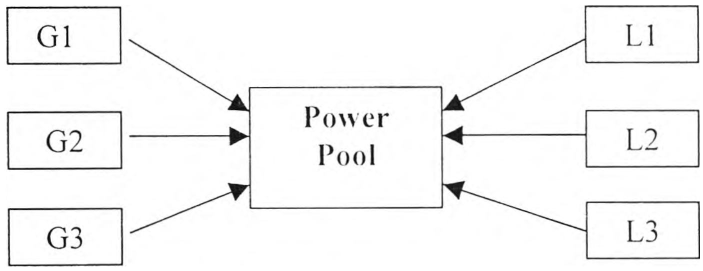

Figure 1-1. Structure of power pool model

In addition to the pool model. the United States has developed two different types of market structure that are different from UK power pool. The first, operated on March 31,1998, California Electricity Market is similar to UK system in structure but different in details. Based on pool model. California Power market is operated by two non-profit organizations, Independent System Operator (CalISO) and Power Exchange (CalPX) that have unique responsibilities [4-5].

California Power Market is composed of three sub-markets; Day-Ahead and Hour-Ahead energy market are similar in trading processes but operate in different time frames. Day-Ahead market operates on the day prior to energy delivery while Day-off market operates close to the delivery hour. The third market, Ancillary Service market, is designed to handle the uncertainties in the real-time system. Ancillary market supplies and absorbs imbalance energy in order to provide reliable operation of the systems. Structure of California Power Exchange is shown in figure 1-2 [6].

Main responsibility of CalPX is to be a Scheduling Coordinator. CalPX will not concern with security of power system but will try to set up the transaction scheduling based on bids and offers prices submitted by market participants for day-ahead and hour-ahead market. Scheduling results are passed to CalISO in order to decide by considering security issues in power system would approve transactions scheduling. Decision of CalISO based on the fact that a transaction will be approved if it complies with security standards. Once a transaction is approved by ISO, seller is eligible to dispatch electricity to buyer in the market. It is seen that functions of two non-profit organizations in California power system are decoupled which is different from UK system. Scheduling result from Cal PX does not guarantee the eligibility to be certified the bid/offer price of participants or even the right to make a transaction. CalISO may reject unacceptable scheduling from CalIPX and request for an alternative scheduling to be reconsidered.

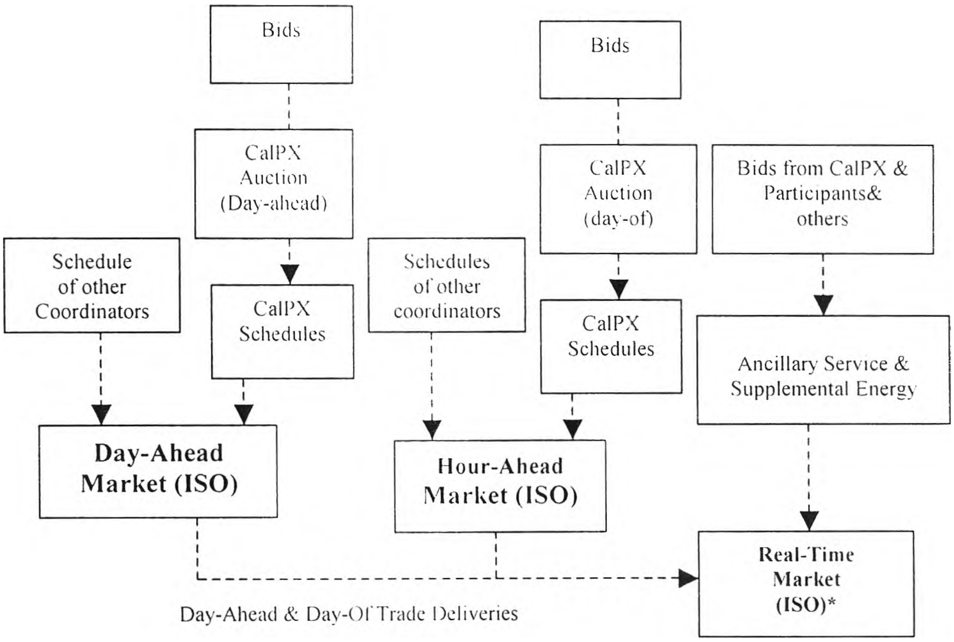

Figure 1-2. Structure of California Power Market

Since the process of deregulation in California Power Market is just begun (the first phase of operation is between 1998-2002), details of market operation rules are subjected to change. As seen from example of the U.S. Federal Energy Regulatory Commission (FERC)'s order on November 1, 2000 to force a complete re-design of the California market during the next two years. The proposed remedies include a $150 soft price cap, widely recognized as unworkable, and widely approved of dissolution of the ISO & PX boards [7]. This announcement was decided due to several price spikes, abnormal electricity price and event blackouts after the operation of the market.

The second structure of power market that is currently used beside the pool model and power exchange model in The United States is the Bilateral Contract structure [2]. Under this structure, sellers and buyers are obligated to contact each other in order to establish their transactions. Consequently, Independent System Operator in this structure has less responsibility than the pool-based structure since it's not the responsibility of ISO be a scheduling coordinator or directly control system's security. Generally speaking, ISO to takes care of inter-area power flow monitoring and calculates the transmission tariff that belongs to ISO. Structure of bilateral contract model is shown in figure 1-3.

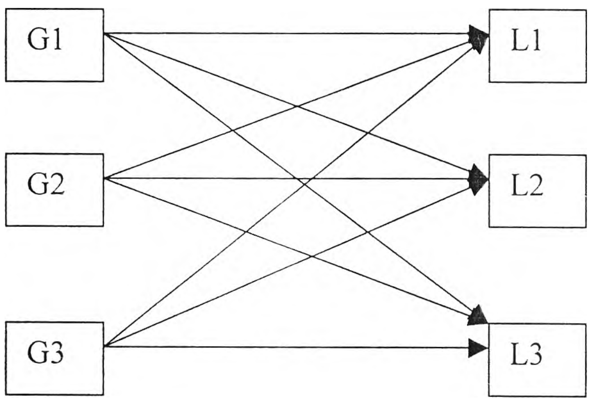

Figure 1-3. Structure of bilateral model

Thailand decided to take the Pool model as the main structure with limited bilateral contracts capability of power system after the deregulation of its utility industry in 2003 [8]. Deregulation processes encompassing both generation and distribution level when three stages of deregulation processes have been completed. When the system is fully implemented, market participants may establish an optional transaction in bilateral contract market in addition to the spot market depended on their strategy. Generation utilities, company formerly owned by a single state enterprise, will be split into several small companies competing in the competitive market. Transmission system is still a regulated business operated by a non-profit organization and Distribution system is marginally deregulated providing more distribution companies. In the final phase, customers in Thailand power system may purchase electricity from SupplyCo or RetailCos (if available). Following are definitions of market participants in Thailand power system after deregulation processes.

a) Generation Companies (GenCos): GenCos are competitive generators composed of former regulated generators and new power producers such as independent power producers (IPPs) or small power producers (SPPs).
b) Transmission Grid Company (GridCo): A regulated company who manages the transmission system under supervision of Independent System Operator

c) Power Traders (Traders): Power Trader is a broker company who does not own generation units. Traders may purchase contracts from RetailCos (Load aggregators) and sell to GenCos.

d) Supply Company (SupplyCo): Supply Companies are regulated local companies who sell electricity to those customers that are not allowed to choose retail supplier.

e) Retail Company (RetailCos): Retail companies are deregulated companies who sell power directly to the customer that can choose the supplier. Competitors of Retail Companies are other retail companies and Supply companies.

f) DistCo: DistCo is the regulated company of low voltage distribution system.

g) Market Operator (MO) and Settlement Administrator (SA): These two non-profit organizations manage the settlement processes of day-ahead market.

h) Independent System Operator (ISO): ISO is responsible for system security analysis. ISO will not be involved in settlement and operation processes.

Organization and structure of Thailand deregulated power system are given in figure 1-4.

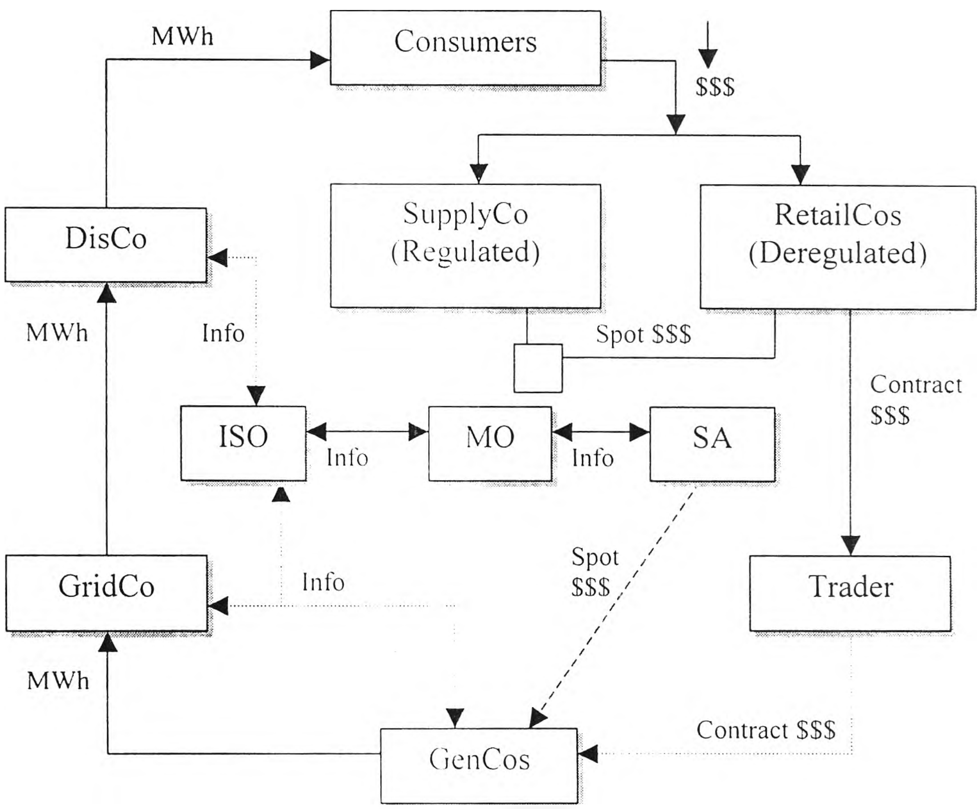

Figure 1-4. Functional Entities of Participants in Thailand Power System

In addition to information of participants and possibility of transaction provided in figure 1-4, Thailand deregulated power system can be structured in several parts depend on voltage level and functions. Firstly, Power pool is managed by three organizations ISO, MO and SA respectively. DistCo and SupplyCO govern distribution system. Generation companies and Traders are involved in generation level. Figure 1-5 shows the structure of Thailand power system by grouping similar participants.

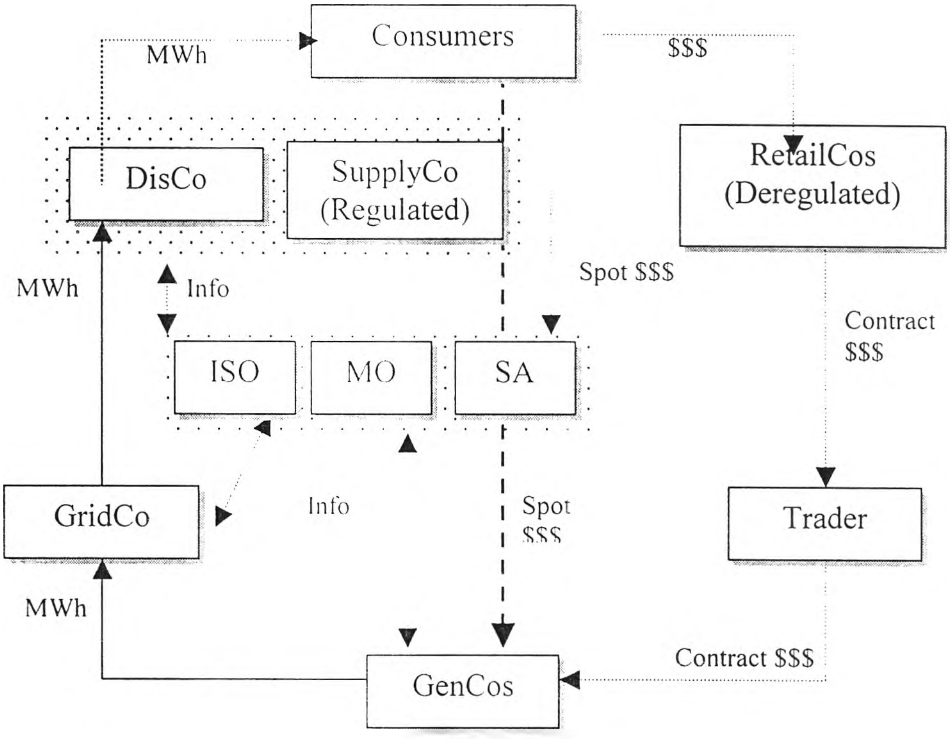

Figure 1-5. Structure Entities of Participants in Thailand Power System

1.3 Available Transfer Capability

The term Available Transfer Capability is relatively new in electric industry. It is firstly described in the U.S. Federal Energy Regulatory Commission's (FERC) in March 29, 1995 – Notice of Proposed Rulemaking (NOPR), Docket RM95-8-000, Section III-E4f [ATC NERC] [9]. These terms have been later developed to include the capability to cope with the occurrence of n-1 contingency in the system (First Contingency Total Transfer Capability – FCTTC and First Contingency Incremental Transfer Capability – FCITC) as recommended in NERC's publication May, 1995 – Transmission Transfer Capability reference document [10].

Since power system in each country, region or sub region has its unique characteristics, structure, and limitations; each individual system will have to consider the best ATC principles according to their circumstances. This dissertation will concentrate on the algorithm to calculate real-time ATC in Thailand deregulated power system. For Thailand's purposed deregulated structure, transmission system is regulated by TransCos. Independent System Operator (ISO) has full authority to control the system including calculating and posting ATC values in order to maintain security level and commercial viability.

According to documentations provided by NERC, algorithms to calculate ATC in a power system must satisfies the following principles [9].

a) ATC calculations must produce commercially viable results. ATC produced by the calculation must give a reasonable and dependable indication of transfer capabilities available to the electric power market.

b) ATC calculations must recognize time-variant power flow conditions on the entire interconnected transmission network.

c) ATC calculations must recognize the dependency of ATC on the points of electric power injection, the directions of transfer across the interconnected transmission network and the points of power extraction.

d) Regional or wide-area coordination is necessary to develop and post information that reasonably reflects the ATCs of the interconnected transmission network.

e) ATC calculations must conform to system reliability planning and operating policies, criteria or guides.

f) The determination of ATC must accommodate reasonable uncertainties in system conditions and provide operating flexibility to ensure the secure operation of the interconnected network.

From the concepts of power system deregulation, increasing of transactions among market participants due to the deregulation of transmission system is likely to move the system to operate in more stress conditions [11]. Generation utilities have more options to sell or purchase electricity with direct customers, pool or other sellers such as generation companies or power marketers. The deregulation open a new era of transactions not restrict to suppliers inside their area but from almost everywhere that transmission capability is available and the price is attractive compared to their generating cost. Similarly, customers (direct customers or distribution companies) may purchase electricity from other utilities. This behavior leads to the sharply increase in electricity transferred across the network that finally ends with a question that what is the maximum capability of transmission system (Total Transfer Capability- TTC) and the available power that can be transferred over transmission system in addition to current operation level (Available Transfer Capability – ATC) between locations. Basically, TTC is a property of transmission network while ATC is an optimum solution between security requirement and commercial viability. Generally, Independent System Operator (ISO) is responsible for determining TTC and ATC values between a selected pair of transaction and post these values for public in less than one hour (real time), hourly, daily, weekly and annually basis. However, this dissertation will concentrate on a method to determine real-time ATC since Thailand market is designed to operate up to thirty minutes bidding [8] that requires speedy ATC calculation. Furthermore, ATC is important for both market participants to arrange their scheduling and Independent System Operator to maintain security of the system.

In addition to the above contexts, ATC is recognized as a tool to stabilize deregulated power market since it can be used to control several activities of market gaming that apparently abuse the system as seen from recently price spike or surprisingly high electricity cost in California power market [12-NWEEK]. Example of price dynamics in California power market is shown in figure 1-6.

From the experiences in UK, California and other deregulated markets, market gaming is usually seen as a major reason behind price spikes incidents since generator will not sell electricity at the marginal price that causes a major distortion in their market-clearing price (MCP). Typical examples of market gaming that distorts market behavior from a perfectly competitive market as shown in items a) – d).

a) Marginal Price Gaming

Market price gaming occurs when only a few generators determine the market-clearing price. If this situation always occurs in the system then it will shortly predictable by other sellers. This will result in behavior of bidding at slightly less price below the last plant in the merit order to be dispatch of other sellers which is much higher than their marginal price. Example of this situation is when the old power plants must compete with new power plants in deregulated market. These old power plants with poor heat rate usually have higher marginal cost and determine market-clearing price. This situation was happened in UK power pool where two main power companies, National Power and PowerGen, determined 85% of market clearing price [15]. Similarly, price for the replacement power of California Power Exchange, CalPX, ranged from $500 to $9,999 per MWh since they have too few bidders [16].

b) Capacity Withholding Gaming

This market gaming starts from the exponential relationship between the reserve margin and the capacity payment. Since the change in reserve and price are highly nonlinear as seen from 20% reserve decrease in UK market may result in up to 1,000% capacity payment increased [15]. This would attract generators to withhold their capacity to boost the capacity payment before they re-declaring their availability. Example of this tactic is when sellers off-line their units or bid at very high price to make sure that they will be rejected from the merit order during the off-peak period. Then these sellers bid again when they satisfy the price. It is foreseeable that start-up cost and shutdown cost must be carefully considered in this tactic.

c) Gaming the Load Following Unit

Gaming of load following unit is important since loads in power system are dynamic. Fast acting power plants, Gas and Oil power plants, which are designed as load following units can bid much higher than the market-clearing price. Example from UK system shows that a 95 MW load following unit earned £60 - £120 /MWh compared to normal price of £25 /MWh [17].

d) Transmission Constraint Gaming

This scheme occurs with an area containing insufficient generation capacity, it is so called local area, but imported electricity is restricted by transmission system congestion. Generally, ISO will try to supply internal load of this area by including generation units inside that area in the merit order since sufficiency is the very important issue in power system operation. Therefore, if this situation exists, local generation facilities can bid at very high price since they dominate that area especially during peak load.

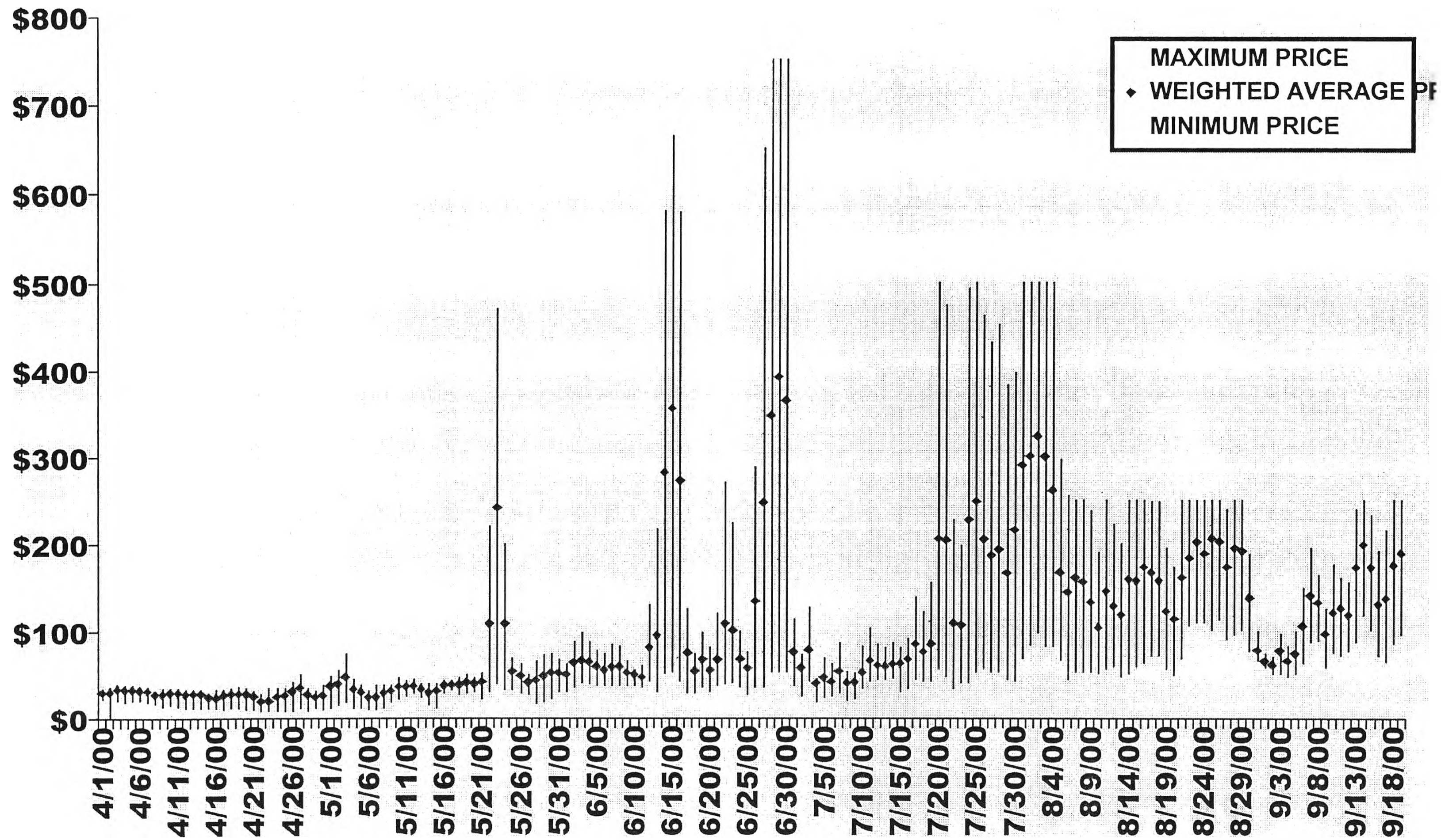

Figure 1-6. Day-ahead price dynamics in California power market during April – September 2000

Example of a local area in UK system illustrates that when demand exceed 430 MW in this area, every plant are compulsory to operate with incredible benefits [18].

According to the four major categories of market gaming explained above, providing information to participants is an important mitigation strategy to subside the market gaming. The information of ATC at each ATC interface will stabilize market price and decrease generation capacity speculation by informing amount of electricity can be delivered at any moment. Buyers may consider purchasing electricity from other sellers if they anticipate insufficient generation in their areas. Otherwise, market gaming and lacking of sufficient information may distort market-clearing price and suffer customers in the system.

As mentioned above, under the market operation viewpoint, ATC values play very important role in supplying information of the available generation capacity from other sources to market participants. With ATC values market price gaming may be diminished since buyers may consider purchasing electricity from other sellers beside their local generators if they know exactly that how much imported electricity will be allowed by ISO. Similar to marginal price gaming, buyers can estimate their reserve margin from other sellers which result in closer relationship between reserve margin and reserve capacity payment. Load following units inside the area may have more competitors since buyers may be supplied by from external fast-acting units. Finally, sellers may act properly if they realized that they are located in a local area by considering ATC values of each path connected them to the rest of the system that informs the amount of feasible imported electricity. Load management program from buyers such as Demand Side Management (DSM), Peak Shaving Method, the construction of new transmission lines or the construction of new power plants in the local areas due to price incentive will help to reduce price spike and abnormal price in these areas. However, these remedial actions will be done if only ATC values are known.

For ATC calculation procedure, although detailed ATC calculations in each area are different, the development of ATC procedure in each system must abide the ATC umbrella framework defined by NERC as the following principles.

In technical aspect, ATC equals to the difference between TTC, existing load and transmission margins. General equation of ATC can be expressed with the following equation.

$$ATC = TTC - ETC - TRM - CBM \quad (1)$$

where

TTC = Total Transfer Capability
ETC = Existing Transmission Commitment (existing load)
TRM = Transmission Reliability Margin (Transmission Margin)
CBM = Capacity Benefit Margin (Transmission Margin)

TTC is determined when a limit of the system is reached while power transfer is increasing. Generally, there are 4 key factors to be considered in TTC calculation:

a) Thermal limits

b) Voltage limits
c) Voltage Stability limit

d) Transient Stability limit

In general, Transmission margins (TRM and CBM) are determined by deterministic approach. An amount of transmission capacity and rating are deducted and reserved as transmission margins. Purposes of these transmission margins are to guarantee security of the system and continuation of services. Alternatively, probabilistic approach can be used to determine transmission margins. This method is based on the needed reliability level for the system requiring reliability information such as outage rate of each element. Since the probabilistic approach requires much more system performance data and it is difficult to obtain at this moment, this dissertation adopts the deterministic approaches for transmission margin calculation.

Generally, ATC has been used in many purposes. Power system planner can use long-term ATC values as a factor to identify vulnerable components in transmission system and use this information to solve the problem. In contrast, real time ATC can be used to determine marketing strategy of utilities as well as to be an indicator to maintain system security for the control center.

This dissertation will consider the real-time ATC calculation algorithm. A key technical challenge of real-time ATC is that available time for ATC calculation is very limited. Since hourly ATC must be posted to public every hour, all calculation processes must be finished less than one hour.

1.4 Survey of ATC Calculation

This section summarizes the most updated ATC calculation/coordination procedures in electric reliability councils all over the United States (geographically shown in figure 1-7). Since ATC concept was originated and compulsory in the United States, regional councils are required to design, develop, customize and perform a standard ATC calculation for their system based on the ATC umbrella program defined by NERC. Then, calculated ATCs are published for public access through Open Access Same Time Information System (OASIS). This section will concisely explain the concept, strategy and methodology for ATC calculation employed in nine reliability councils all over the United States as follow:

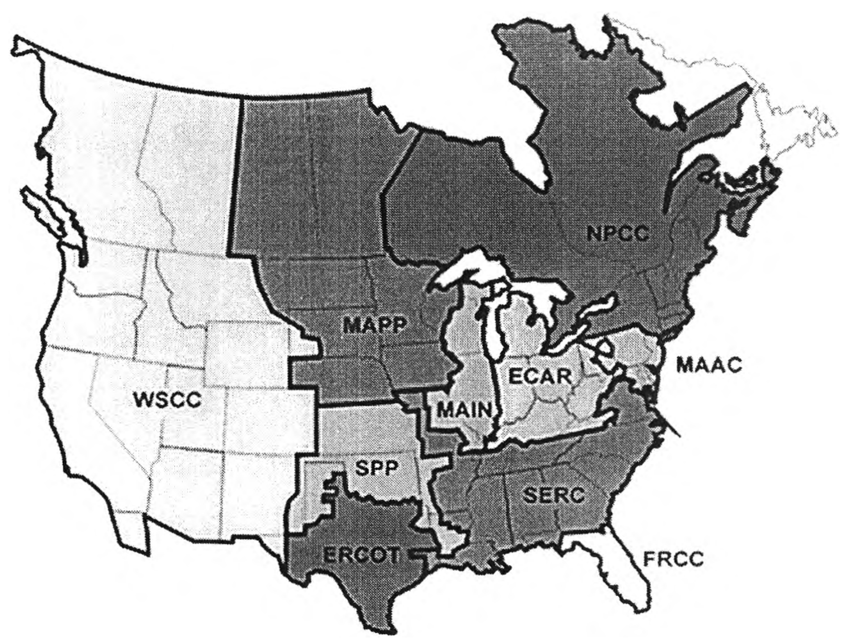

Figure 1-7 Electric Reliability Councils in the United States

1.4.1 East Central Area Reliability Coordination Agreement (ECAR) [19]

The ECAR Coordination Review Committee has charged the Joint Panel Available Transfer Capability Task Force (JPATF) with developing an ATC Coordination Plan for ECAR in conformance to the principles of ATC framework defined by NERC. Due to the character of ECAR power system, individual transmission providers are obligated to calculate, coordinate then followed by posting ATC of their entities.

According to the ATC implementation method performed by JPATF, ATC calculation in ECAR is structured into two-step Distributed Calculation / Coordination Method (DCCM) and ATC Posting Conflict Advisory Procedure as follows:

1.4.1.1 Distributed Calculation / Coordination Method (DCCM)

During this process, each transmission provider is required to calculate TTC/ATC for the following platforms of ATC interfaces (Example of each platform is shown in figure 1-8)

a) Directly interconnected systems: ATC between direct transmission paths between systems e.g. ATC of transactions between system A and system B

b) Commercially viable "through paths" across the transmission provider's system (indirect transaction) e.g. transactions between system X and system Y. In this case, system A, B and C are affected from the transactions and required to recalculate their internal limitations. Differ from direct transmission path, through paths are paths between non-contiguous systems.

c) Other "commercially viable paths" besides the first two platform of transaction such as the calculation of internal limitations inside system B for the transaction between system D and system Y. Commercially viable paths are recognized as the transfers that likely to be commercially desirable.

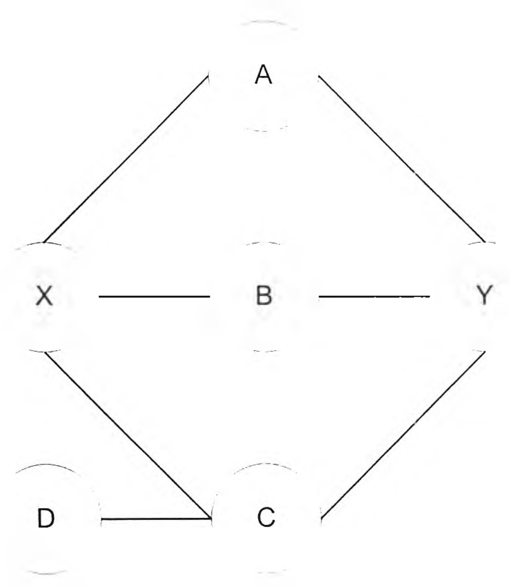

Figure 1-8. Typical power system simulating electricity transactions

With the platforms provided above, transmission providers must be able to supply the ATC quantity, firm and non-firm, of the critical transmission path based on its physicals limitation (thermal limit) in both normal and contingency conditions for coordination process.

ECAR's JPATF does not specify detailed calculation procedures but simply provide recommendation for transmission providers to reserve appropriate TRM and CBM for their entities to accommodate the Automated Reserve Sharing (ARS) second-tier assistance through-flows across the system and commercial viable. As a result, the rating reduction method is commonly used by transmission providers to determine TRM since it supply the exact amount TRM and is tradable in ECAR system as a non-firm reserve.

Once ATC quantities have been received, coordination is achieved by comparing these individually calculated values and then determine the lowest value as ATC. Basically, ATCs of the network, wide-area ATCs, will be posted on the OASIS but transmission provider may post the scheduling/reservation limitations such as interconnection capacity, joint ownership or contractual limitations instead of ATC if they are more restrictive.

During the first phase of ATC implementation (1996 -), ECAR employs manual coordination and posting method to complete ATC calculation. Currently, following coordinations are necessary to be available on the OASIS.

a) Next Thirteen Calendar Months Coordination: Annually firm, peak/off-peak ATCs for planning horizon starting from the month 2 to month 13)

b) Next Calendar Week Coordination: Weekly firm/non-firm, peak/off-peak ATCs starting from hours 49 through 168.

c) Next Day Coordination: The next calendar firm/non-firm, peak/off-peak ATCs starting from hours 24 through 48.

d) Unscheduled Updates: ATCs for the near-term operational horizon to produce values that reasonably reflect the wide-area ATCs of the network.

Example of coordination worksheet from a transmission provider (firm ATC at peak load conditions) is shown in table 1-1.

Table 1-1. A sample coordination worksheet for some generic sources and destinations

COORDINATION SPREADSHEET EXAMPLE FOR FIRM PEAK LOAD CONDITIONS											
		SYSTEM ATC									**NETWORK**
	TRANSFER PATH	**AP (MW)**	**AEP (MW)**	**A (MW)**	**B (MW)**	**C (MW)**	**D (MW)**	**E (MW)**	**F (MW)**	**LIMITING SYSTEM**	**ATC (MW)**
1	AEP-AP	1,000	1,100		1,500			5,000		AP	1,000
2	AEP-PJM	3,000	2,500	2,700			2,700			AEP	2,500
3	AEP-CP&L	1,000	1,500			1,200	1,100			AP	1,000
4	AEP-DUKE	1,000	4,000		500					B	500
5	AEP-TVA	2,100	3,000		2,100		2,000			D	2,000
6	AEP-VP	2,200	2,300					2,000		E	2,000
7	AP-BGE/PEPCO	1,200				1,000		900	950	E	900
8	AP-GPU	700					800			AP	700
9	AP-PJM	800			900		900			AP	800
10	AP-VP	1,050	1,000	1,200			1,200			AEP	1,000
11	A-Z					2,000				C	2,000
12	GROUP A-D		1,200		1,700					B	1,200
13	A-E			1,700			1,500			D	1,500
14	B-E				1,100	1,200		1,000		E	1,000
15	D-E	1,100	1,200					1,000		E	1,000

1.4.1.2 ATC Posting Conflict Advisory Procedure (APCAP)

This procedure is founded to resolve the posting conflicts and disputes in the qualification and coordination of a wide-area ATC. APCAP provides a mechanism to obtain the "second opinion" on the controversy in a timely fashion (one working day after the dispute is filed). APCAP will create a database of delegates from transmission providers who can be called upon to serve on an advisory board. Persons in this database will be selected to serve as advisory board by the appropriate technique to solve the arising future disputes.

1.4.2 Electric Reliability Council of Texas (ERCOT) [20]

The Electric Reliability Council of Texas (ERCOT) comprises of ten interconnected control areas, 25 ATC zones and single Independent System Operator (ISO). ERCOT maintains no closed interconnection with any other reliability council except two HVDC ties to the Southwest Power Pool (SPP). According to the unique character of the system, ERCOT requires minimal coordination with other regions and ERCOT ISO will fully responsible for ATC calculation with the cooperation with ERCOT members and control areas.

ATC procedure in ERCOT is divided into two major steps, calculating ATC/TTC and posting respectively. Information of ATC calculation is explained below

1.4.2.1 ATC/TTC calculation

ERCOT defines ATC interfaces in their system as the paths connected between zones, non-simultaneous ATC calculation is performed in these interfaces by accounting for the thermal limit violation of base cases and the adjustment within the appropriate horizons. Similarly to ECAR ATC calculation, ERCOT scheduled two-phase ATC calculation that purposed to implement the automatic calculation in the final phase. However, ERCOT is presently engaging in the first phase of ATC calculation examining 8 base cases ATC calculation representing peak/off-peak load of each season.

ATC and TTC calculations in ERCOT compose of two significant steps, base cases calculation and adjustments. The adjustment process is intended to increase the accuracy of results from load dynamics and n-1 contingency. The adjustment algorithm is a simple function of changes in the net zonal boundary flows (NZBF) in the sending and receiving zones as expressed in the equation below.

$$ATC_{adj} = ATC_{calc} + \min\left[(NZBF_{calc} - NZBF_{act})_{send} - (NZBF_{calc} - NZBF_{act})_{rec}\right] \quad (2)$$

Where

ATC_{adj} = Adjusted ATC value which will be post

ATC_{calc} = Calculated first incremental transfer capability

$NZBF_{calc}$ = Sending/receiving zone generation less the sending/receiving zone load and loss in the base case

$NZBF_{act}$ = Sending/receiving zone generation less the sending/receiving zone load and loss in the daily operation plan

For the TTC calculation, ERCOT has issued a simple expression which will be used for the calculation of TTC as given below

$$TTC = ATC_{calc} + 0.5\left[(NZBF_{calc})_{send} - (NZBF_{calc})_{rec}\right] \quad (3)$$

Equation (3) based on a conservative assumptions which is assumed to be valid for ERCOT system.

ERCOT has chosen not to incorporate TRM in its ATC determination. This decision based on the significant reasons that equipment rating used in ERCOT ATC study are summer emergency ratings anticipating continuous operation in high ambient temperature that that typically occurs in very short period in each year. Therefore, the ATC calculation in ERCOT system is already included reserved transmission capability that substantially equal or greater than TRM.

Similar to TRM, ERCOT also ignore the reservation of CBM since this concept is incompatible with the Public utility Commission of Texas (PUCT) rules. In

Texas power system, PUCT rules require the redispatch of generation when and to the extent necessary to relieve transmission constraints. This means that generation to serve a deficient load-serving entity (LSEs) can be obtained to the extent physically possible whether or not CBM has been reserved. In other word, the redispatch scheme declines the utilization of CBM in the system.

1.4.2.2 Posting

Following the ATC calculation and adjustment, ERCOT by the ATC Task Force posts inter-zonal ATC values on the Electronic Transmission Information Network (ETIN) in several different time frames as summarized below.

a) Hourly ATC for the next 7 days*
b) Two values per day (peak and off-peak) for the following 23 days
c) Two values per month (peak and off-peak) for the next 12 months
d) Additional ATC values if information is available

* Purposed to be available in the second phase of ATC calculation.

1.4.3 Florida Reliability Coordinating Council (FRCC) [21]

In response to the NERC initiative for all reliability regions to develop procedures for the determination and posting transfer capabilities, FRCC formed ATC Task Force to develop the "FRCC Methodology for ATC Calculation" on both operating and planning horizons. This committee has responsibility in planning, developing and implementing ATC procedure in FRCC inter-control areas and interfaces with neighboring regional council.

Transmission providers in FRCC are required to perform ATC calculation and posting within a specific time frame. ATC procedure developed by FRCC ATC Task Force incorporates commercial services, recallable / non-recallable, TRM and CBM with ATC calculation. Therefore, an ATC interface will contain two ATC values for each posting.

FRCC ATC procedure employs three-step process, calculation, coordination and posting that resembling to ECAR. Detailed information of each step is summarized as shown below.

1.4.3.1 ATC Calculation

Base on a network respond method, considering thermal limit, voltage limit and stability limits, accompanying with FRCC Databank loadflow base cases, FRCC determine ATC of interfaces by the following procedures.

a) Collecting data: FRCC generates loadflow Databank from peak demand (summer, winter), tables of interchange assumptions for existing interchange commitments (EC) and Non-Recallable Reserved (NRES) commitments at a variety of anticipated system load level. In addition, each utility should provide the information of all Non-recallable Scheduled (NSCH), Recallable Scheduled (RSCH), import and export electricity commitments and Recallable Reserved (RRES).

b) Calculating TTC for ATC interfaces: Using the database from a), Total Transfer Capability of commercially viable pathways between control areas can be determined.

c) Calculating NATC: Non-recallable Available Transfer Capability is the result from the different between TTC and summation of NRES, EC, CBM and TRM. Generally, transmission provider computes TRM values while utilities determine CBM of their entities that will become TRM of the system.

d) Calculating RATC: Recallable Available Transfer Capability (RATC) is calculated from the same procedure as NATC. The difference between NATC and RATC is likely to be RSCH and RRES are used instead of NSCH and NRES.

1.4.3.2 Coordination

FRCC transmission providers share information necessary for ATC calculation twice a day. Scheduling interchange, generation, transmission facility outages and planned switching actions are examples of shared information for coordination. Following the process of information interchanging, transmission providers will post ATC values on their OASIS node in a regular basis.

1.4.3.3 Posting

FRCC transmission providers are obligated to post TTC, NATC and RATC on the OASIS for public accesses. Since FRCC establishes an interconnection with southern subregion of SERC, both intra-regional and inter-regional values are compulsory in FRCC OASIS.

1.4.3 Mid-Atlantic Area Council (MAAC) (PJM International LLC.) [22]

PJM Interconnection, L.L.C. operates the largest wholesale electric market in the world. ATC procedure in MACC complies with NERC framework to determine ATC between control areas connected to their system by considering the most limiting facilities in the system as the stopping criteria for ATC calculation. Entire procedure for PJM's ATC calculation is summarized below.

1.4.3.1 ATC Interfaces

Generally, PJM posts ATC values of the following point-to-point transmission service paths:

a) ATC interface between sources in each control area directly interconnected with PJM to sinks in PJM.

b) ATC interface between sources in PJM to destinations in each control area directly interconnected with PJM.

c) Any valid contract path for which transmission service was denied, curtailed or subject to interruption during any hour for a total of 24 hours in the last 12 months

1.4.3.2 ATC calculation and Time frames

PJM employs a standard procedure to calculate ATC in the interconnected system. However, ATC calculation has been divided in a specific set of assumed operating conditions as follows:

a) Near-Term ATC: Near-term ATC is calculated by Operation Planning Department in hour 0 to hour 168. It is calculated by so-called "on-line ATC program" based on state estimation. PJM expects that hours 1 through 36 will be analyzed every 2 to 3 hours, hours 36 through 72 will be analyzed every 8 hours and hours 72 through 168 will be analyzed every 24 hours. Thermal limit, voltage limit or stability limit are constraints to be studied by the process. This process results in Non-Firm ATC values with the appropriate margin in "contract paths" ATC.

b) Mid-Term ATC: Operations Planning Department utilizes off-line AC power flow to calculate Mid-Term ATC including TTC, Firm/Non-Firm ATC for days 8 through 30 and weekly transfer capabilities (the most limiting daily ATC for the week). Calculation procedure of Mid-Term ATC is similar to Near-Time ATC except the "online" and "off-line" approaches.

c) Long-Term ATC: Long-Term ATC is calculated by PJM System Planning Department utilizing an off-line power flow. The study includes monthly TTC, Firm/Non-Firm ATC recalculating every month. For the first two months, recalculation is done monthly with the expected system conditions. For the remaining 22 months, monthly recalculation is performed at summer peak, winter peak, fall peak and light load model and conditions. Non-Firm ATC is calculated and posted only upon request after the first two months.

As a summary, PJM's ATC calculation at each time frame is given as tabulated below.

Table 1-2 PJM ATC Process Timeline

	Near-term	**Mid-Term**	**Long-Term**	
Time Frame	Hour 0-168	Day 8 to 30 Week 2 to 4	Month 1-2	Month 3 to 13
Department	Operations Planning	Operations Planning	System Planning	
Calculation Values	Hourly, Daily	Daily, Weekly	Monthly	
Base Case Origin	State Estimator*	Operating Study**	MMWG***	
Base Case Conditions	Forecast Loads, Generation Topology	Historical Load UC Dispatch Planned Actual Maintenance		LAS Loads PROMOD Dispatch Planned Maintenance
Base Case Transfers	Firm Scheduled, Non-Firm Scheduled	Firm Reservations, Non-Firm Scheduled	Firm-Firm Scheduled, CBM Non-Firm – Firm Sched Non-Firm Scheduled	Firm-Firm Reserved, World Circ., CBM Non-Firm – Firm Res'd. World Circ.

Notes:
* Real-time EMSstate estimator program
** Operating study with real-time adjustments.
*** NERC Multi-Regional Model Working Group power flow base case.

1.4.5 Mid-America Interconnected Network (MAIN) [23-24]

MAIN performs two separate frameworks for ATC calculation based on their transmission services, firm and non-firm ATC/TTC calculation methodology. MAIN assigns MAIN Coordination Center (MCC) as the command center to calculate and coordinate ATC calculation. The ATC methodology in MAIN power system comprises of three major steps as the following:

1.4.5.1 Preparing the Base Case Model:

This step sets up base case for ATC calculations by gathering necessary information. Peak conditions of the current and the upcoming four seasons, load data, firm and non-firm transmission reservations, scheduled and forced outages, line and transformer rating and generation dispatch are reported to MCC by transmission providers. This information is required to by update at least on a daily basis in order to ensure accuracy of the study.

1.4.4.2 ATC/TTC Calculation

This is the main process to calculate ATC/TTC in MAIN system requiring following data which are not included in the base case power flow data

a) Participation Points: List of sources and sinks along with participation factors

b) Contingency Lists: List of single contingency (n-1 contingency) consistent with ATC framework defined by NERC

c) Cutoff Values for Outage Transfer Distribution Factors (OTDF): Specific numbers are defined as cutoff values for ATC calculation as follows: 2% for limits of the first 48 hours, 3% for the period 2 days and 3% for all time periods outside MAIN

d) Monitored Equipment: All lines, transformers and tie lines 115 KV and above in MAIN and adjacent regions.

e) Transfer Directions: Transfer directions submitted by transmission providers and control areas.

Once the basic information has been provided, TRM and CBM are two significant quantities before the calculation of ATC as shown below.

Transmission Reliability Margin (TRM)

MAIN uses a two-step rating reduction approach for TRM calculations. Appropriate rating reduction for each transmission provider is selected to create the Contingency Incremental Transfer Capability (CITC) at a system condition. In addition, transmission provider will select a multiplier for each transfer direction. TTC values will be given by observing thermal limit violation inside the system.

Capacity Benefit Margin (CBM)

During the calculation of Firm ATC, CBM can be determined by using one or a combination of the following methods:

a) Capacity of the two largest units in the transmission provider area
b) Capacity of the largest plant in the transmission provider area
c) Result of a LOLE calculation
d) Historical capacity deficiency and the largest unit

1.4.4.3 Review and Posting of ATC/TTC values

After an ATC/TTC study, MAIN reviews the output and determines the appropriate posting according to the following criteria

a) Thermal limits

b) Voltage limits

c) Stability limitations

d) Thermal, Voltage or stability limitations

The MCC posts ATC, TTC, TRM, CBM values and limiting element and contingency for each transfer direction.

1.4.6 Mid-Continent Area Power Pool (MAPP) [25]

MAPP processes shares the ATC calculation to both transmission providers and MAPP center using a flow-based approach to determining the committed use of each constrained interface for the ATC calculation. ATC calculation is classified to NATC and RATC depend on transmission services available in MAPP system. Detailed ATC calculations in MAPP system are summarized as follows.

1.4.6.1 ATC Interfaces

"Service Point Model" is an alternative name for ATC interfaces in MAPP. There are two types of service point model considered in MAPP as follow.

a) Ultimate Service Points correspond to generation or load buses in the system
b) Intermediate Service Points are control areas or company boundary that are not mapped to any bus in the power flow model

1.4.6.2 ATC calculation

TTC, TRM, TRM coefficient*, NCBM, RCBM and ETC are calculated and submitted by transmission providers where NRES, RRES, NSCH and RSCH are calculated at the MAPP center. MAPP posts wide range of ATC values from hourly (168 hours) to 3 years ATC for different purposes of study.

Capacity Benefit Margin (CBM)

Two common guidelines as shown below are used for the determination of NATC and RATC.

a) The amount of Operating Reserve that must be delivered or emergency energy received over the constrained interface for the greatest single contingency

b) The frequency bias obligation for a 0.05 Hz deviation

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* A constant differentiates between planning and operating horizons

Transmission Reliability margin (TRM)

The same TRM is used for both RATC and NATC. However, in the RATC calculation, a coefficient is multiplied by the TRM. The coefficient may be used in one of two ways:

a) Rely on a fixed value between zero to one applied to the TRM in the RATC

b) Toggled coefficient between zero and one depending on the operating point of a controlling interface.

Existing Transmission Commitment (ETC)

ETC is determined by transmission providers to account for load serving, loop flows, losses, parallel path flows and pre-existing transmission commitments.

1.4.5.3 ATC Posting

MAPP center posts ATC values in both regular and irregular basis. Information of posting frequency is listed below

Regular Posting

Following time horizon are regular time frames for ATC posting

a) Hourly ATC for 168 hours
b) Daily ATC for 3 years

Irregular Posting

Irregular posting occurs whenever the following events occur

a) A base power flow model changes
b) The transmission outage schedule changes
c) A constrained interface definition changes
d) A new constrained interface is added
e) Any ATC components change
f) Energy schedules are collected at 15.00 each day
g) A reservation in withdrawn

1.4.5.4 Scenario Analyzer

Since MAPP employs a flow-based ATC calculation, it may not be obvious what the limiting interface might be for a specific transmission request that may lead to an dispute from MAPP members. Therefore, MAPP provides a Scenario Analyzer that may used to resolve this dilemma without submitting a real request to OASIS. The appealer is requested to complete and submits a request form and the respond will be replied by email based on the most current ATC posting. The purpose of scenario analyzer is to allow customers to analyze many scenarios without requiring intervantion of the MAPP center or transmission providers.

1.4.6 Northeast Power Coordinating Council (NPCC) [26]

Northeast Power Coordinating Council comprises of five control areas (excluding the Maritimes) planning to post ATCs on their interfaces with an approach that is similar to the rated path method described by NERC. The developing of ATC procedure in NPCC is purposed to ensure that ATC calculation and posting are coordinated on a wide area basis such that the interactions of electric power flows are identified and parallel flow impacts are adequately addressed. In NPCC interconnected system, control areas are responsible in calculating and posting ATC values of a number of transmission interfaces (ATC interfaces) within and between control areas. NPCC ATC methodology and procedure submitted by the NPCC Ad Hoc ATC Working Group is summarized below.

1.4.6.1 TTC and ATC determination

All control areas in NPCC are encouraged to conduct joint operating studies on a regular basis to determine inter-Area total transfer capabilities. On a short-term basis, the weekly conference call provides a vehicle for inter-area TTC coordination among NPCC control areas, PJM and ECAR are not required to attend this weekly conference.

For ATC calculation, control areas will apply a TRM and CBM based upon their respective operating practice to calculate ATC. Therefore, it has an opportunity of inconsistent ATC values addressed by two control areas. This issue is considering to be solved in Regional coordination procedure.

1.4.6.2 ATC Allocation and Posting

Due to specific character of NPCC, various member companies might own transmission facilities. To resolve this difficulty, ATC entitlement on a number of interfaces is divided according to agreements among owners and can be posted by single or multiple ownerships.

1.4.6.3 Actual Flow Predictions

Presently, all control areas rely on the "contract path" approach to schedule the inter-area transfer. This approach allows transfer between two non-directly connected areas through a willing intermediary area. However, this concept is slightly different in reality since the actual power flow follows the least resistive paths. This may result in the following conditions:

a) The actual flow across the direct interconnect is less than the scheduled flow

b) Some of the scheduled parallel path flow may be additive or subtractive that increase or decrease transfer reliability and capability of the unscheduled paths.

In order to facilitate the prediction of actual flows, a set of Interface Response Factor (IRFs) for specific transactions involving NPCC areas and surrounding areas in the nearby regions will be provided.

1.4.8 Southeastern Electric Reliability Council (SERC) [27]

SERC pursues the ATC calculation efforts accordance with the six principles for calculating and applying defined by NERC. Transmission providers in SERC are obligated in calculating and posting ATC values on their OASIS nodes for public awareness purpose. SERC has issued both coordination procedures and guidelines for transmission providers to calculate and develop ATC procedure as the following.

1.4.8.1 Common Base Assumptions:

SERC defines three discrete time horizons for commercial ATC calculation as common base assumptions as listed below.

a) Operating Horizon occupies the time period from next hour to 31 days. Both off-line and on-line (depend on availability) will be used to perform the calculation. In addition, transmission providers will share almost real-time information regarding generation outages, changes in transmission topology, reservation and scheduling.
b) Operational Planning Horizon takes place from month two through month thirteen (1 year ahead). Seasonal power flow models will be developed and used as the base case for ATC calculation.
c) Planning Horizon is from one to ten years. This ATC study focuses on the future construction projects and policy. Appropriate reliability group will be assigned to responsible for planning ATC calculation.

1.4.8.2 Transmission Provider Calculation Requirements

SERC transmission providers will calculate RATC and NATC on their facilities and then post on the OASIS. These values will be determined using conventional linear analysis, AC power flow analysis or other industry methodologies.

1.4.8.3 The Coordination Process

During the first phase of ATC implementation, manual coordination of the individual ATC value is the standard method for transmission providers in SERC. In the future, automatic coordination procedure is the prime purpose of ATC calculation

The coordination among the SERC transmission providers is as follows:

a) At least once a day, SERC transmission providers will directly exchange information to support the calculation of ATC values.

b) When a transmission service schedule is submitted to transmission provider, the transmission provider will determine the sufficient ATC in compliance with "NERC Operating Policy 3 – Interchange".

c) The SERC transmission providers will establish a process to notify each other and neighboring regions when ATC values have change significantly in addition to the regular scheduled ATC exchange.

d) ATC values will be coordinated on a monthly basis. This coordination applies to all components of the ATC calculation including TRM, CBM, reservation, schedules and TTC.

1.4.7.4 Dispute Resolution Procedures

The responsibility for dispute resolution resides with the transmission provider that should resolve most of disputes arising during the transaction. However, unsolved disputes will be referred to a contract or tariff dispute resolution process or the SERC Dispute Resolution Process.

1.4.8 Southwest Power Pool (SPP) [28]

SPP integrates the ATC calculation of interfaces between direct interconnection of transmission providers or path requested by transmission provider at a central control center. The seasonal calculation of ATC/TTC will be made using rolling seasonal models the produce an update for the upcoming five seasons. Components and terminology for SPP ATC calculation are summarized below

1.4.8.1 Power Flow Models

The seasonal power flow models will be based on the models developed annually by the SPP Model Development Working Group. Peak/Off-peak, summer, winter, spring and fall are basic power flow models for ATC calculations

1.4.8.2 Calculation Parameters

Two types of parameter are supplied to transmission providers to perform ATC calculation.

a) Parameters supplied by the transmission providers composing of participation points of MW increase/decrease, the participation factor of these points, the transfer level, contingency list, contingencies suspect of causing voltage limitations and transfers, additional facilities below 100 kV to be monitored, high and low voltage limits, contractual limitations, TRM and CBM margins, multiplier a and b for allowing partial usage of TRM for non-firm contract and the additional interfaces.

b) Default parameters such as list of direct interconnected, unused generating capacity, participation factor, transfer limit, etc.

1.4.8.3 Calculation Methodology

Four steps of ATC calculation are as follows.

a) Total Transfer Capability Calculation: SPP employs DC linear analysis to determine FCITC. This transfer capability will be AC verified for voltage constraints and overload conditions on specific interfaces.

b) DC Linear Analysis and AC Verification: Calculating on each transmission provider, DC linear analysis and AC verification are used to estimate the import and export limits of a transmission provider's area.

c) Voltage Analysis: A full AC analysis will be performed on any specified contingency/transfer on transmission providers to ensure valid limit violation.

d) Operating Procedures: The investigation if the next limit can be reached may be available in some cases to lift up their transfer capability

1.4.8.4 Determination of FATC and NATC

With the information provided by utilities, Firm Available Transfer Capability and Non-Firm Available Transfer Capability can be calculated by considering the appropriate transmission services.

After transmission providers calculate ATC/TTC values, SPP members may review these values to ensure the correctness. If there is any discrepancy between SPP member results and transmission providers, the question should be submitted to SPP or transmission providers.

1.4.9 Western Systems Coordinating Council (WSCC) [29]

Transmission providers in Western Interconnection will determine ATC in accordance with the NERC documents and WSCC standards based on the Rated System Path for determining Total Transfer Capability (TTC). In order to conclude the ATC determination procedures, three steps ATC calculation within WSCC system is summarized as follows:

1.4.9.1 Determination of Total Transfer Capability (TTC)

A wide area approach is used to determine TTC on a path basis using the RSP method of WSCC. This calculation must conform to the WSCC "Procedures for Regional Planning Project Review and Rating Transmission Facilities" and NERC ATC framework.

Since the case of multiple ownerships of transmission rights may exist on a path or parallel path inside WSCC, special allocation technique of TTC in this area must be addressed by referring to agreement on the allocation of transmission rights in order to determine and report ATC.

1.4.9.2 Determination of Committed Uses

This section describes the principles for the determination of Committed Uses that will be recognized as TRM, ETC and CBM in ATC calculation. Generally, committed uses in WSCC ATC formula is shown as the relationship between the five components of committed uses (CU1-CU5) as list below.

a) Native Load Uses (CU1)
b) Prudent Reserves (CU2)
c) Existing Commitments for purchases/exchanges/deliveries/sales (CU3)
d) Existing Commitments for transmission service (CU4)
e) Other Pending Potential Uses of transfer capability (CU5)

Classification of committed uses CU1 – CU5 is explained in the Western Regional Transmission Groups (RTG) Governing Agreements.

1.4.9.3 Determination of TRM

NERC TRM is a part of Prudent Reserves (CU2). TRM may include allowances for unscheduled flow, simultaneous limitations associated with the operation under the nomogram, a graphic representation that consists of several lines marked off to scale and arranged in such a way that by using a straightedge to connect known values on two lines. An unknown value can be read at the point of intersection with another line [29], uncertainty in load forecast and unplanned transmission outages. WSCC TRM does not include allowances for planned outages and other known transmission conditions that should be included in TTC.

1.4.9.4 Determination of ETC

WSCC defines NERC ETC, a part of ATC calculation, as the combination of the four RTG committed uses categories given below

a) Native Load (CU1) including reservation for native load growth, loss of native load, native load forecasts, ancillary services required to serve native load and reservation beyond reliability-based needs such as the import of power which is beyond the amount reserved for reliability needs of their native customers.

b) Existing Commitments for purchases/exchanges/deliveries/sales (CU3) and Existing Commitments for transmission service (CU4) composing of existing commitments and Non-Recallable Transmission Reservations for Energy Transactions

c) Other Pending Potential Uses of transfer capability (CU5) such as good faith requests that comply with general principles outlines in this document.

1.4.9.5 Determination of CBM

CBM, reservations required to maintain reliability of service in accordance with a tariff's term and conditions that may be sold on a recallable basis comprise of the following committed uses:

a) Native Load (CU1) covering ancillary services to accommodate operating reserves (spinning and supplemental) and reservations of transmission for purposes other than energy deliver for example, to provide a path for the import of ancillary services from another control areas; or to allow imports on a different paths.

b) Prudent Reserves Uses (CU2) that equivalent to the reservations of additional transfer capability for resource contingencies.

c) Generation Patterns and Generation Outages resulting in deductions from ATC associated with these uncertainties.

Based on the given guidelines for determining each term in ATC formula, Transmission providers in WSCC can determine ATC between control areas and post to the OASIS in a regular basis.

As a conclusion for ATC calculation in the United States, every regional council is likely to employs the similar processes for TTC calculation. By the way, methodology for TRM, CBM and detailed ATC implementation seem to be different in each system as summarized in table 1-3.

Table 1-3 Summary of ATC Calculation in the United States

Reliability Council	Processes	Authority*	Interfaces	Margin Components	Posting Frequncy
ECAR	1. Calculation 2. Coordination 3. Dispute Advisory	Transmission Providers	1. Direct Paths 2. Through Paths 3. Commercial Paths	TRM CBM	1. Next Day 2. Next Week 3. Next 13 Weeks 4. Unscheduled
ERCOT	1. Calculation 2. Adjustment	ISO	Among 25 zones	CBM	1. Hourly (next 7 days) 2. Daily Peak/Off-peak (23 days)
FRCC	1. Calculation 2. Coordination 3. Dispute Resolution	Transmission Providers	1. Direct 2. Inter-regional 3. Commercial	TRM CBM	1. Twice Daily (08.00/16.00) 2. Summer/Winter Peak
MACC	Integrated Calculation	ISO	1. Direct 2. Inter-regional 3. Other valid paths	TRM CBM	1. Hourly 0-168 2. Daily 8-30 3. Monthly 1-13
MAIN	Integrated Calculation	ISO (MCC)	1. Specified Source & Sink 2. Available Source & Sink	TRM CBM	1. Hourly 0-168 2. Daily for 3 years 3. Significant conditions changed
NPCC	1. Calculation 2. Coordination 3. Provide Interface Response Factors (IRF)	Control Areas	Selected contract paths	TRM CBM	Daily
SERC	1. Calculation 2. Coordination	Transmission Providers	1. Direct 2. Commercial	TRM CBM	1. Hourly 0-31 2. Monthly (12 months) 3. Annually (10 years)

Table 1-3 Summary of ATC Calculation in the United States (cont.)

Reliability Council	Processes	**Authority**	**Interfaces**	**Margin Components**	**Posting**
SPP	1. Calculation 2. Review 3. Coordination	Transmission Providers	1. Direct 2. Upon request	TRM	1. Next five seasons (peak) 2. Next season (off-peak) 3. Next summer (shoulder)
WSCC	1. TTC Calculation 2. TTC Allocation (Transmission right) 3. Defines committed uses	Transmission Providers	Contract paths	TRM CBM	1. Hourly (Peak/Off-peak next 168 hours) 2. Upon request

Remark

* Authority obligated to calculating/posting ATC values to OASIS node.

1.5 Summary

Deregulation brings new innovation and movement to power system generation, operation and control by an objective that the competition will lower the price of electricity. This concept, introduced by people live in area that electricity cost is higher than neighboring area, accepts the fact that size of power system has tendency to be bigger and cost is the key factor to determine everything in the system. However, it is important to notice that deregulation may result in insecure operation of power system since philosophy of power system operation has changed. This is the motivation to introduce Available Transfer Capability term which is balanced by two countering forces, security level and commercial viable.

Security of power system can be increased if more transmission and generation capability have been reserved. In contrast, this action decreases opportunity to deliver power from one point to another point in power system. From this reason, determination of ATC must be carefully considered. It must be certain that for a proper ATC calculation, no security constraints are violated as well as non unnecessary transmission capacity has been reserved