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US STUDY TOUR
PRESENTATION MATERIALS
(ENGLISH LANGUAGE)

NIS Institutional Based Services Under the Energy Efficiency and Market Reform Project
Contract No. CCN-Q-11-93-00152-00

CAR Regional Energy Trade, Electricity Contracting and Pricing Reform
Delivery Order No. 11

Final Report

Prepared for:

U.S. Agency for International Development
Bureau for Europe and NIS
Office of Environment, Energy and Urban Development
Energy and Infrastructure Division

Prepared by:

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PN ACH-427

MEETING OF THE CENTRAL ASIA ELECTRICITY WORKING GROUP

SPONSORED BY

USAID PROJECT
ON
ELECTRICITY CONTRACTING AND PRICING REFORM

9-11 FEBRUARY, 1998
TASHKENT, UZBEKISTAN

USA STUDY TOUR

PRESENTATION MATERIALS

Prepared by:

U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT
Bureau for Europe
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Energy and Infrastructure Division
Washington, DC 20523

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A LIST

of

USAID STUDY TOUR PRESENTATION MATERIALS

1. NEPOOL/ISO Background
2. ISO Staff Organization
3. NEPOOL old organizational structure
4. Rate-Setting Process Presentation by the Massachusetts Department of Public Utilities
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8. MAPP Communications Network (MCN)
9. Reform of the Federal (All-Russian) Wholesale market of Electric Energy and Capacity (FOREM)
10. Implementation of Tariff Reform and Economic Dispatch
11. Wholesale Power Markets. Presentation by Carlos Yermoli, Hagler Bailly

NEPOOL/ISO New England Seminar

Peter K. Wong

December 2, 1997

USAID Central Asia Program

NEPOOL

New England Power Pool (NEPOOL)

- Formed in 1971
- Voluntary association of more than 100 business entities participating in electric power markets in New England
- Represents both public and private electric utilities, independent power producers, power marketers and brokers, and load aggregators
- Objective is to ensure the reliable and economical operations of the bulk power

Overview of NEPOOL

- NEPOOL Agreement
- Membership
- Organizational Structure

NEPOOL Agreement

- September 1, 1971
- Amended 32 times
- Objectives:
  - Reliability
  - Economy
  - Equity

MEMBERSHIP, cont'd

- Definition of Entity Allows for:
  - Federal or state political subdivisions or agencies;
  - Private corporations;
  - Partnerships;
  - Individuals;
  - Electric Cooperatives

MEMBERSHIP, cont'd

- Definition of Entity:
  - Generate and/or transmit and/or distribute electricity for consumption by public;
  - Purchase, as principal or broker, electricity for resale at wholesale;
  - Generation, transmission, or distribution must not be primarily for own or for affiliate's use.

Why NEPOOL ISO

Influencing Events

- The National Energy Policy Act of 1992
  - created exempt wholesale generators
  - increased FERC's power to order transmission access
  - resulted in FERC's Regional Transmission Group Policy
- Emergence of many independent generators
- Strong regulatory preference for open access to the transmission system
- Formation of any new entities in the utility industry
- Likelihood of increased competition and potential for further deregulation

Phase 1
Report Recommendations

- Membership
  - Voluntary
  - Open to any entity that transacts
  - Bulk power within NEPOOL
  - Voting Rights in relationship to their respective responsibilities
- Maintain system reliability - regional/national rules entities to support adequate capacity
- Members' bulk power system should remain a single control area
- Central Dispatch in some form should continue
- Accommodate bilateral transactions of various forms
- Determine price option for Central Dispatch

NEPOOL RESTRUCTURING ACTIVITIES

1996

- NEPOOL Plus (January)
- NEPOOL Restructuring Proposal (August)
- Restated NEPOOL Agreement and Transmission Tariff (December)

Independent System Operator Structure

- Non-Profit corporation to be formed in 1997
- independent board of Directors (no affiliation with market participants)
  - Directors to be selected by a 10-member nominating committee composed of two from:
    - large investor-owned utilities (more than 3% share)
    - small investor-owned utilities (less than 3% share)
    - municipally-owned and cooperatively-owned utilities
    - non-utility generators
    - power marketer, brokers and load aggregators

ISO STRUCTURE Cont.

- Advisory Committee (20 members) to assist the Board of Directors on matters relating to the operation of the ISO Agreement and the NEPOOL Market.
  - no oversight responsibility
  - serves as an information resource
  - provide a broad viewpoint of parties with an interest in the NEPOOL Market

NEPOOL ISO Resolution

- On May 3, 1996, the NEPOOL Executive Committee adopted the following additional elements to be included in the already approved NEPOOL Plus concept.

NEPOOL ISO Resolution

1. The NEPOOL functions and infrastructure will be transformed in accordance with NEPOOL Plus into an independent system operator (ISO) with FERC Order 888.

2. Such an ISO will have employees that are independent from any of the NEPOOL participants.

3. Such an ISO will have an independent governance board that will not be controlled by any single participant or participants.

Proposed Market Provisions

- Installed Capability
- Operable Capability
- Energy
- 10-Minute Spinning Reserve
- 10-Minute Non-Spinning Reserve
- 30-Minute Operating Reserve
- Automatic Generation Control (AGC)

Regional Transmission Provisions

- Five Year Transition Period
  - Regional Network Service
  - Tie Benefit Service
  - Other
- Congestion - Cost shared by generators in congested areas (for next 18 months)

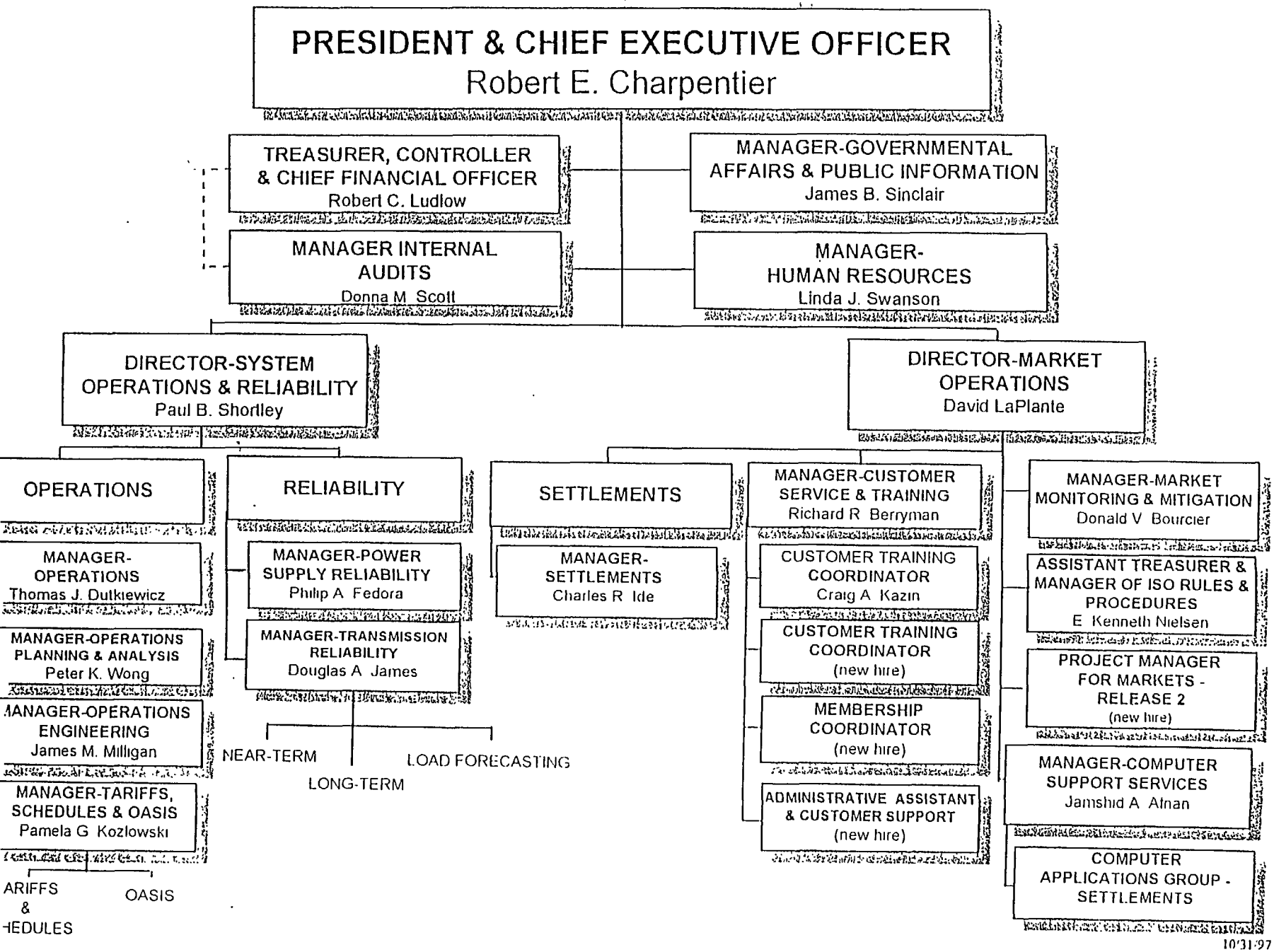
RESTATED NEPOOL OBJECTIVES

- to assure the bulk power supply of the NEPOOL control area conforms to proper standards of reliability;
- to create and maintain open, non-discriminatory, competitive, unbundled markets for energy, capacity, and ancillary services that function efficiently in a changing electric power industry and have access to regional transmission at rates which do not vary with distance;
- to attain maximum practical economy, consistent with proper standards of reliability and the maintenance of competitive markets, in such bulk power supply;

RESTATED NEPOOL OBJECTIVES, Cont.

- to provide access to competitive markets within the NEPOOL Control Area and to neighboring regions; and
- to provide for the equitable sharing of the resulting responsibilities, benefits and costs.

ISO STAFF ORGANIZATION



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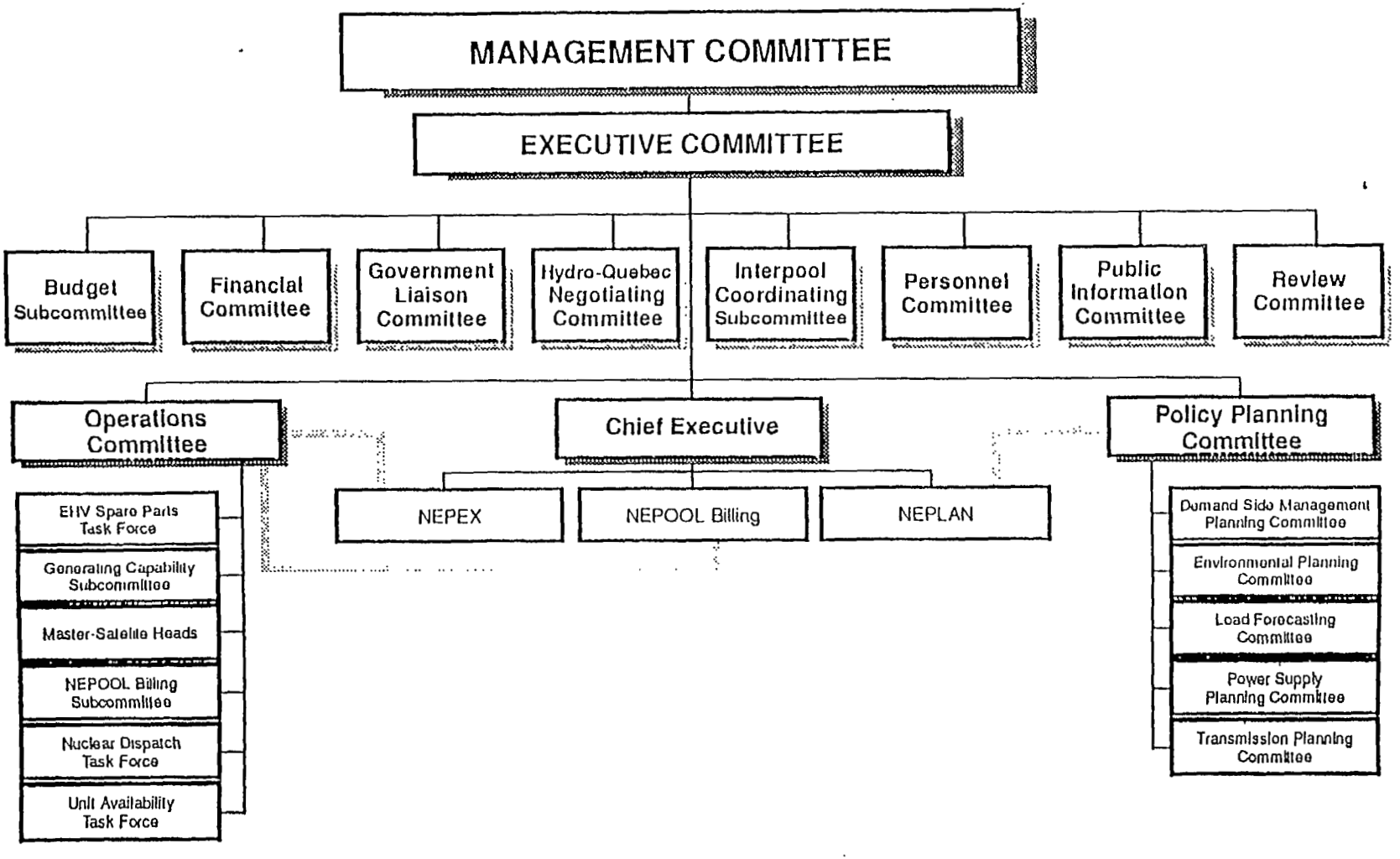
NEPOOL


MANAGEMENT COMMITTEE
EXECUTIVE COMMITTEE
Budget Subcommittee
Financial Committee
Government Liaison Committee
Hydro-Quebec Negotiating Committee
Interpool Coordinating Subcommittee
Personnel Committee
Public Information Committee
Review Committee
Operations Committee
Chief Executive
Policy Planning Committee
EHV Spare Parts Task Force
Generating Capability Subcommittee
Master-Satelite Heads
NEPOOL Billing Subcommittee
Nuclear Dispatch Task Force
Unit Availability Task Force
NEPEX
NEPOOL Billing
NEPLAN
Demand Side Management Planning Committee
Environmental Planning Committee
Load Forecasting Committee
Power Supply Planning Committee
Transmission Planning Committee

The Commonwealth of Massachusetts
Department of Public Utilities
Leverett Saltonstall Building, Government Center
100 Cambridge Street, Boston 02202

Presentation before the
Central Asian Delegation

on the

Rate-Setting Process and the
Legal Requirements of the Rate-Setting Process

December 5, 1997
Kevin M. Brannelly,
Director, Rates & Revenue Requirements

I. Fundamentals of the Utility Industry

A. Monopoly

1. Because utilities are very capital intensive, it had been thought until recently that only one utility can cost-effectively serve within a given area

B. Role of Regulation

1. Substitute for Competition- i.e., balance supply and demand by setting prices at a level at which a firm is willing and able to provide service and customers are willing and able to take service

2. Provide Revenues Sufficient to Allow Utility to Meet its Public Service Obligation
   a. Recovery of Reasonable Expenses
   b. Provide an opportunity to earn a Fair Return for Investors
   c. Failure to Allow Adequate Revenues Constitutes Unlawful Confiscation of Property

C. Fuel Charge

1. Governed by statute G.L. c. 164, § 94G

2. Approximately 25% of an electric utility's total costs are recovered through the fuel charge
3. Fully reconcilable, dollar-for-dollar pass-through of fuel costs.
4. Filed and reviewed quarterly
5. Separately itemized on the ratepayers bill

D. Base Rates

1. Governed by Statute G.L. c. 164, § 94
2. Represents approximately 75% of an electric utilities costs
3. Present system utilizes an historic test-year, cost-based, rate of return methodology
4. Separately itemized on a ratepayers bill as a customer charge, an energy charge and a demand charge
5. Filed less frequently, usually every few years

E. Circumstances Leading to Request for Base-Rate Relief

1. Reduced Revenues
   a. Economy
   b. Weather

2. Increased Costs
   a. New Plant
   b. Large Unanticipated Maintenance or Outage Expenses- e.g., Storm Expense
   c. Change in Taxes
   d. Inflation

F. Policy/Goals in Rate Setting

1. Minimize the cost of service- e.g., reduction of costs and encourage increased productivity
2. Cost Allocation- identification of "cost drivers," or, usage patterns that contribute toward increased costs
3. Rate Design- balance among factors such as:
   a. Efficiency- marginal cost-based rates permit accurate price signals
   b. Continuity- avoids rate shock
   c. Fairness- equalized rates of return. Eliminate Cross-class subsidization
   d. Earnings Stability
   e. Simplicity

II. Rate-Setting Process (Base Rates)

A. Administrative Procedures

1. Utilities may file a rate case at any time-- it's up to their discretion
2. Rates cannot take effect before 14 days after filing
3. DPU may suspend for up to 6 months, or for 9 months in the case of water companies
4. Utilities are required to issue public notice that:
   a. describes rate proposal
   b. invites petitions to intervene
   c. invites public comment
   d. publicizes the public hearings
5. Public Hearing
6. Discovery
7. Evidentiary Hearings.
8. Briefing by parties.
9. Final Order.

III. Description of Typical Intervenors; Regulation state that the Petitioners must demonstrate they are "substantially and specifically" affected.

A. A.G.- on behalf of ratepayers

B. CLF- on conservation matters

C. DOER- on energy policy matters

D. Public Interest Groups- e.g., MassPIRG

E. Ratepayer Groups- e.g., Industrial Intervenors, IRATE, mainly on issues of cost allocation and rate design

IV. Overview of Settlements

A. Benefit all parties and ratepayers by reducing administrative costs of litigation

B. Reflects a balancing of divergent interests of parties and consistent with the public interest

V. Performance-based Ratemaking ("PBR")

A. Incentive Regulation, D.P.U. 94-158 (1995)

1. Examined various types of mechanisms
   a. price caps
   b. revenue caps
   c. rate of return bandwidths
   d. benchmarking regulation

2. no one mechanism superior to another
3. flexibility among companies
4. Department strongly encouraged all jurisdiction gas and electric utilities to devise and propose incentive plans
5. set out ten criteria and standards to review incentive mechanisms proposed by electric and gas companies

B. Electric Industry Restructuring, D.P.U. 95-30 (1995)

1. required electric companies to include in their restructuring plans an incentive plan
2. currently reviewing these plans

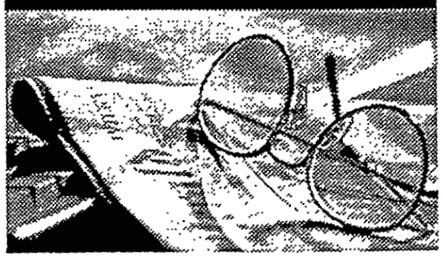
C. NYNEX, D.P.U. 94-50 (1995)

1. approved a price cap plan to be in effect for six years
2. basic formula for calculating a price cap index ("PCI"), such as NYNEX's is PCI = P - X + Z, where P is an inflation factor, X is a productivity factor, and Z is an exogenous factor

D. Massachusetts Electric Company, D.P.U. 95-40 (1995)

1. rejected MECo's proposal (benchmarking) because it did not meet the criteria set out in D.P.U. 94-158

A MAPP WHITE PAPER



A Synopsis of the

Restated Agreement and Regional Transmission Service

Produced by:

Mid-Continent Area Power Pool
1111 Third Avenue South, Suite 430
Minneapolis, MN 55404-1008

612-341-4600
www.mapp.org

September 1, 1997

NUMBER

1

Mid-Continent Area Power Pool (MAPP)
A Synopsis of the Restated Agreement and Regional Transmission Service

The Mid-Continent Area Power Pool (MAPP) is an association of electric utilities. Its membership includes investor-owned utilities, cooperatives, municipals, public power districts, independent power producers, power marketers, a federal agency, Canadian Crown Corporations and state and provincial regulatory bodies. The MAPP organization oversees these important regional functions: it is a regional transmission group, a regional reliability council, and a power and energy market.

The MAPP region includes the North Central region of the United States and two Canadian provinces, which is approximately 890,000 square miles.

On September 12, 1996, the Federal Energy Regulatory Commission accepted for filing the MAPP Restated Agreement. The Agreement went into affect on November 1, 1996.

This synopsis of the MAPP Restated Agreement and Regional Transmission Service is intended to introduce the reader to the basic concepts contained in the document.

This synopsis is not intended as an operating guide for implementation of the Restated Agreement or as a reference for specific applications. The Committees provided for in the Restated Agreement may at a later date provide guidelines for implementation and interpretations for case-specific applications.

This synopsis has been prepared by MAPP staff. It is not an approved document of the membership. The Restated Agreement shall govern where there may be differences or conflicts with this synopsis. Where such differences may exist they are unintentional and likely to be the result of seeking brevity.

MAPP RESTRUCTURED

The MAPP membership criteria within the Restated Agreement is open to a broad mix of entities. The Restated Agreement describes these important regional functions:

1. a NERC Regional Reliability Council with a Generation Reserve-Sharing Pool;
2. a Regional Transmission Committee conforming to FERC's Regional Transmission Group Principles, and
3. a Power and Energy Market establishing a wholesale energy market.

Membership

Membership eligibility is very broad (Section 4.1). Any entity selling or transmitting electric energy is eligible. The application procedure (Section 4.2) is intended to be expedient. A three-year notification is required to withdraw membership. A special class of membership is provided for Regulatory Participants for state or Canadian provincial agencies with authority over matters concerning the Restated Agreement. Members in other NERC Regions or other power pools can obtain selective membership in MAPP functional areas while retaining their regional reliability council affiliation in another NERC Region and maintaining their reserve-sharing commitments with their respective power pool. Some Members of other NERC Regions elect to hold membership in MAPP while retaining their full membership and obligations in the other NERC Region. Dual or multiple membership in regional associations is becoming more commonplace.

Region" every two years. The Restated Agreement addresses the obligations to build transmission facilities specified in the plan subject to appropriate contracts and financing (Section 8.7). Members not in the MAPP Region would not include their facilities in the plan, which would be the case for a Member of another NERC Region who also elects to be a MAPP Member.

Alternate Dispute Resolution

A comprehensive alternate dispute resolution procedure has been adopted so that FERC will not be the first recourse for dispute settlement. The process includes the right of appeal to full membership committees for reconsideration, non-binding mediation, and then the option of binding arbitration or FERC action if the issue is a FERC jurisdictional matter.

REGIONAL TRANSMISSION SERVICE SCHEDULE

Members are obligated to provide comparable service to other Members and may obtain comparable service from other Members. Each Member agrees to provide service for Coordination Transactions in accordance with the regional Service Schedule F - Transmission Tariff for Coordination Transactions. To receive transmission service under the region-wide service schedule an entity must be willing to take on the responsibilities and obligations of MAPP membership (Exhibit C, Section 2.6).

Coordination Transactions

MAPP defines Coordination Transactions as: "Any sale for resale of power and/or energy between Members, for a period not to exceed two years, using existing generation and transmission facilities. Any transaction where the seller is obligated to sell, or has an option to sell, power and/or energy, or the buyer is obligated to take or pay, or has the option to take or pay, for power and/or energy, for more than two years shall not qualify for service under this Service Schedule for any portion of the duration of the transaction."

Transmission System and Reciprocity

The transmission system applicable to Service Schedule F is not limited to the MAPP Region. A transmission providing Member of MAPP located outside of the MAPP Region must agree to provide service to other MAPP Members under terms and conditions of Service Schedule F over transmission facilities owned or controlled by it or its affiliates, that are a part of the transmission system. The transmission system is the composite of all contiguous, networked, synchronously operated 115 kV and above transmission facilities owned or controlled by MAPP Members. Such contiguous facilities shall include (i) networked facilities in the MAPP Region, (ii) facilities that are directly interconnected with those within the MAPP Region, and (iii) facilities that are interconnected with those within the MAPP Region through the facilities of another MAPP Member or Members (Exhibit C, Section 1.38).

Scope of Application

Service Schedule F - Transmission Tariff for Coordination Transactions must be used for coordination transactions between Members instead of the individual tariffs of the Members (Exhibit C, Section 2.1). This transmission service schedule is available for coordination transactions whether the coordination transaction is under a MAPP service schedule or not. Service Schedule F cannot be used to deliver power or energy directly to a non-member. This service schedule cannot be used in place of long-term transmission arrangements by generators or loads for interconnection with the host transmission provider (Exhibit C, Section 2.1).

- Directs Line Loading Relief
- Administers Loss Repayment Procedures
- Performs billing, collection, payment and accounting services

MEGAWATT-MILE METHODOLOGY

The MAPP region-wide transmission service schedule for coordination transactions uses a megawatt-mile rate formula for compensation. The megawatt-mile technique, adopted by MAPP, is a distance-based method of calculating payment for transmission use considering that power will, to some extent, flow over all available paths from the generating source to the load. The flow over each and every facility above 115 kV due to a transaction is calculated. This flow is then multiplied by the monthly MAPP pool average cost per megawatt-mile of owning the facility. The sum of all the individual use charges is the total transmission service charge for the transaction.

The Computer Models

The megawatt-mile method of calculating transmission service charge utilizes sophisticated computer programs known as the Megawatt-Mile Software to perform the necessary computations. A commercially available power systems analysis package, Power Technology Incorporated's PSS/E, performs the necessary network flow calculations through activity MWMI, which was specifically written for this application. MWMI also keeps track of cost information, and branch, load and generation ownership. Another program, called MWMIRPT, reads the output of MWMI and provides the distribution of payments for transmission service, given a set of power transactions.

The Megawatt-Mile Analysis

The megawatt-mile analysis starts from a solved loadflow model of the system. Transactions are modeled between utilities by changing generation on the sending, or seller end, and changing the load on the receiving, or buyer end. The distribution of flows on each branch is then determined. Individual branch charges are then calculated given the flow on the branch due to the transaction, the line mileage and the facility costs. The sum of all individual charges is calculated in appropriate units (i.e., $/MW-month, $./MWh, etc) for all necessary combinations of buyers and sellers.

Adjustment Factors Applied to the Rate

Adjustment factors are applied to the basic rate. The Effective Operating Capacity Ratio (EOC) is an adjustment which recognizes total regional transmission capacity beyond that required to serve load and is available to accommodate coordination transactions. The transmission reserve is defined as the difference between the Members' total megawatt-miles of transmission capacity and the megawatt-miles required to serve load. The EOC is then defined as the total megawatt-miles of transmission capacity divided by the total megawatt-miles of transmission reserve. The magnitude of the EOC factor is on the order of 1.5, but varies form one season to another, and as new Members are added to the model.

A discount factor is also applied to the basic rate. The rate for any transaction is multiplied by this factor. The multiplier for firm rates is 0.6 and for non-firm rates is 0.5 for on-peak hours and 0.25 for off-peak hours.

MAPP Service Schedules

Presented by Kevin Burns
MAPP Administrator of
Business Services

1650

Power & Energy Market

Provide the MAPP Market with identifiable products to transact electrical capacity and energy

Committee Responsibility
- PEM Committee
- Market Development Subcommittee

7 Interim PEM Schedules
- A, E, G, J, K, L, M

PEM

1650

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Schedule "G"

Operational control to improve electric system control

110% of the incremental cost when initiated by the purchaser for its benefit or 90% of the decremental cost of the purchasers when the transaction is initiated by the seller for its benefit

Third-Party purchaser and resale of this rate are limited to recover no more than the FERC Order 84 addresses

PEM

1850

Schedule "J"

Firm Power

Seven Days or Longer

Peaking Power

Mutually agree on a minimum or maximum limit

Negotiated Rate

PEM

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Schedule "M"

General Purpose Energy

Used to improve the economy or the systems

PEM

Regional Transmission Committee

Schedule "F"

Provides Transmission Service for Coordination Transactions

Period of no more than two years

RTC

25

Schedule "C"

Emergency Energy

- Supplies emergency energy by any pool participant to any other pool participant during emergency outages of generating or transmission facilities or both
- Firm Energy Transmission Service under Service Schedule "F"
- Cost is 3.0 cents per kilowatt-hour or 110% of supplying pool participants incremented cost

RRC

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Schedule "C1"

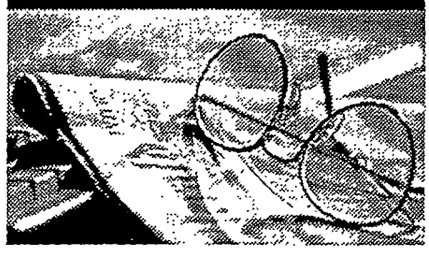
Scheduled Outage Energy

- Provides for the supply of energy by an pool participant during scheduled outages of generation or transmission facilities or both
- Cost of SO is greater of:
  - 110% of the increcemental cost of producing or
  - 110% of the average production cost
- Firm Energy Transmission under Service Schedule "F"

RRC

1850

A MAPP WHITE PAPER



A Synopsis of the

Energy Trading System

Produced by:

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September 1, 1997

NUMBER

2

Energy Trading System

I. Slutsker, K. Nodehi, S. Mokhtari
Open Access Technology International, Inc.
Minneapolis, Minnesota

K. Burns, D. Szymanski, P. Clapp
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Minneapolis, Minnesota

BACKGROUND

The Energy Policy Act of 1992 by Congress was a key event in the development of competitive bulk power markets for more efficient electrical supply. It mandated the electric utility industry to become deregulated and ordered the U.S. Federal Energy Regulatory Commission (FERC) to facilitate this transition. On April 24, 1996, FERC issued final rules on Open Transmission Access (Orders 888 and 889) facilitating the transition and requiring the transmission companies to allow non-affiliated selling/buying organizations to access utilities' transmission systems in a non-discriminatory manner.

In the past, electric utilities were strictly vertically integrated organizations with electricity being viewed as a single product paid for in a single tariff. FERC's Transmission Open Access initiatives broke up the traditional vertical utility model into various organizations composed of generation, transmission and distribution entities and required such organizations to operate independently of each other. In addition to restructuring of electric utilities, many new entities, such as power marketers, independent power producers, independent system operators and power exchanges, were born.

The open access to transmission promotes wholesale competition. The distribution system, however, remains a monopoly for the time being under the current model. In the future, the open access to transmission and distribution systems will promote the retail wheeling under which customers have direct access to the suppliers.

In order to facilitate the non-discriminatory access to the transmission grid and to make the vital transmission grid information available to all users, an unbiased transmission reservation mechanism was created. The Open Access Same-Time Information System (OASIS nodes), installed by transmission providers or their designated agents, enable any transmission user to view available grid capacity and reserve transmission rights.

The true deregulation of the utility industry cannot happen without the creation of vibrant energy trading markets which allow buyers and sellers of energy to freely engage in trading activities over a wide range of energy sources, products and geographies. The creation of such markets is impeded by the absence of adequate trading tools. Unfortunately, the trading facilities from other industries (such as the stock and commodity trading) cannot be easily applied to power markets, due to the peculiar technical characteristics of energy trading.

TRADING SYSTEM REQUIREMENTS

The development of sophisticated energy trading tools is of paramount importance to the electric power industry. In order to facilitate vigorous energy trading and to support various types of users, the energy trading product must meet the following requirements:

- **Variety of trading markets.** A trading product must support all mainstream trading market models.

- Trader efficiency/support tools
- Analytical tools

Trading Subsystem

ETS provides flexible trading options to market participants by supporting four different market models:

- **Bulletin Board - Open market.** In this market model traders place open buy and sell bids on an electronic bulletin board. The bids are available for viewing and purchase to any authorized trader. The buyer assistance facility, which utilizes an advanced market analysis algorithm, is provided to allow buyers to choose best buy opportunities out of many posted sell bids. The bulletin board software monitors bid placement and registers created transactions.
- **Bid Matching - Closed Market.** Traders who choose not engage in active trading for whatever reason may place closed buy and sell bids for bid matching services. At market clearing time, the bid matching software, based on a sophisticated decision-support methodology, is executed at the server site to optimally pair buyers and sellers. Bid matching software registers all transactions created in the matching process.
- **Auction Market.** Sellers of energy products willing to spend time to extract a higher price for their merchandise can place bids for an auction. Their bids are visible to all traders who may elect to place counteroffers to auction bids. The auctioneer can view counteroffers as they arrive and select the one deemed best or not select any if none is acceptable.
- **Bilateral Negotiations.** Energy traders can engage in direct bilateral negotiations using the ETS messaging facility. A trader can start an informal negating session by sending a message to an owner of any posted buy or sell bid (solicited negotiations) or by sending a message containing a trading proposal to any trader (unsolicited negotiations).

ETS supports trading in hourly, daily, weekly and monthly energy schedules. Both hourly (hourly segments) and day-of-week profiles are allowed. Profiling is independent from schedule length allowing users to enter complex, long term energy schedules with a single mouse click.

ETS supports trading in all NERC-defined energy commodities as well as pool-specific energy products. Auxiliary services can be traded in ETS as well.

ETS quotes transmission adjusted prices for all posted buy and sell bids (bids and offers) depending on viewer's geographical location. For each viewer, the transmission cost of every posted bid and every posted offer is automatically computed on-the-fly including an appropriate selection of the pool-wide or individual company tariffs and the selection of an optimal transmission path. ETS supports coast-to-coast trading.

Both bids and offers are presented side by side on the ETS Market Monitor display, which is refreshed in real-time, providing traders with the ability to monitor all aspects of trading. A complete information on any bid, offer or transaction is available with a click of a mouse button.

ETS usage is based on simple point-and-click operations with a wide use of dropdowns and popup windows. No user typing (except for entering price and amount data) is required. User data entries are preserved and can be reused in repeated operations. ETS provides a comprehensive data entry validation, essentially eliminating the possibility of data entry errors.

in the transaction tag template minimizing user effort and emails the created tag to all parties in the transaction.

Analytical Tools

Automatic Bid Matching

ETS provides state-of-the-art bid matching services which optimize the trading process by selecting best sellers for each buyer depending on buyer preferences. The Bid Matching application takes into account a number of goals and constraints in finding an optimal seller for a given buyer. It will also use available transmission data from MAPP OASIS to create transactions with high approval probability.

Impact Calculation

The cheapest deal is hardly the best if it creates violations in the transmission network and can not implemented. Unfortunately, and this is what separates the energy trading from any other form of trading, one can not easily see the consequences of a potential transaction without a computationally intensive and complex analysis. To evaluate a potential transaction, to assess its chances for being approved, the user must be able to simulate its impact on the transmission system over the entire time span of the transaction.

Normally, such an analysis requires an heavy duty power flow processing of 5,000 to 10,000 bus networks for many switching configurations. It is not uncommon for such processing to take several hours even with modern computers. OATI has developed a sophisticated sparse matrix methodology which reduces the computational time required for the transaction impact analysis down to few seconds. This enables ETS to perform on-the-fly transaction impact studies for many simultaneous users. With a click of a button traders can activate the scenario analyzer feature of ETS and perform a "what-if" analysis, evaluating the impact of potential transactions on LLR interfaces as well as on ATCs, and selecting those deals that have a high probability of survival, should LLR go in effect.

ARCHITECTURE

ETS is implemented in Windows NT environment using the modern client-server technology. ETS clients, located at trader offices, communicate with the central server over a private TCP/IP network as well as over the Internet. ETS uses a two server configuration: a Web server for client connections and a supporting data base server. The server machines house the single central operational Relational Database Management System (RDBMS) database, data communications and application components. All key processing and storage functions are performed at servers with no software required at the client site leading to a low overall cost.

Client access through Web browsers over the private network (Intranet solution) delivers the highest speed and security and is used for current MAPP members already connected to the MAPP private network. The remaining users access ETS through the Internet. The use of Web browsers for client access makes ETS appealing to a wide range of traders, since Web browsers are supported on most hardware/software platforms already in existence at client sites resulting in, essentially, a no-cost form of client access to ETS.

In the six month of ETS operation, new users have been added on-line almost daily with no trading disruptions and with no perceptible user effort. ETS software has been upgraded several times during this period, as new releases were installed. Again, these upgrades required no user activity and did not

MAPP Communications Network (MCN)

Providing First Class Connectivity Across North America

The MAPP Communications Network (MCN) provides high-speed, reliable access to the MAPP Intranet, connecting users at approximately forty-five locations throughout North America. One of the primary applications of the MCN is supporting MAPP Control Center Services (MCCS). MCCS is used by power system dispatchers for the communication of power system transaction information, outage information, emergency condition notification, and many other necessary information and data exchanges. Other services accessible through the MCN include Message Switch (Msw), five minute power system data, OASIS, the Internet, MAPP/OATI Energy Trading System™ (ETS), and Dow Jones Information Services.

Ensuring High Availability and Dependability

The MCN is a high availability network, with an availability of above 99%. Dedicated, high-speed communication services from AT&T connect the remote sites with the MAPP central site. MAPPCOR has installed a Cisco router at each remote site and Cisco routers at the MAPP central site. These routers are capable of supporting multiple wide area serial links and LAN connections. The MCN computer hardware consists of approximately 35 digital VAX computers, four Digital Alpha computers, and many personal computers and UNIX workstations. These computers are configured with the VMS operating system, MS Windows or UNIX, and are interconnected via DECnet links or TCP/IP. DEC MicroVAX II computers and VT series terminals are located at each of MAPP's 30 member sites. The MAPP central site consists of two DEC Alpha 2100 server computers configured in a OpenVMS VAXcluster environment. The Message Switch software and other MCCS software processes are served by these systems. The first Alpha is considered the primary host, while the other is configured as a back-up and will take primary responsibility if needed.

Future Upgrades

The remote site locations will replace the MicroVAX computers with Sun workstations during 1997. In addition, MAPPCOR intends to install redundant communication links to all MAPP control areas during 1997 to continue our effort of increasing the integrity of the network.

For more information on the MAPP Communications Network, contact Kevin Burns at (612) 341-4600.

MAPP Control Center Services (MCCS)

The MAPP Control Center Services (MCCS) are part of the MAPPnet Services applications family. MCCS is a group of applications designed to provide greater efficiency and flexibility to transmission providers and others in submitting, accessing, and maintaining the information that is essential to power grid reliability and operations. MCCS applications are targeted for the control center or similar type of customer.

MCCS includes the following:

- **Message Switch** – Message Switch (Msw) is a customized email messaging system designed for the Open Access electric industry, making it a critical communications component of power system operations and the marketplace.
- **Area Control Error (ACE) Survey** – The Area Control Error Survey application is used to submit a system's integrated ACE value.
- **After-the-Fact-Maintenance (ATFMTC)** – The After-the-Fact Maintenance application is used to submit the actual daily total generation your system had out for maintenance and the amount of that total which was forced out.
- **Automatic Time Error Notification (ATEN)** – The Automatic Time Error Notification application allows you to print the time error value whenever desired.
- **Combined Maintenance Outage Schedule** – The Combined Maintenance Outage Schedule application is used to update estimated generator down time.
- **File Access Utility** – The File Access Utility application is where files may be copied, printed, deleted or edited.
- **Line Loading Relief Procedure (LLR)** – The Line Load Relief Transitional Procedure is used to reduce the loading on transmission facilities that are heavily loaded or are loaded above their permissible limit on an operating guide under the Restated MAPP Agreement effective November 1, 1996.
- **Loss Repayment/Transmission Service Charge Transmissional Procedure (LRPTSC)** – MAPP Members use the Loss Repayment/Transmission Service Charge Transmissional Procedure to submit data needed to determine loss repayment responsibility and transmission service charge.

- **Mandatory Schedule Outage Search (SO)** – A system having difficulty in attaining needed scheduled outage may initiate a voluntary search via MCCS.
- **Emergency Replacement Request Program (EM)** – The Emergency Replacement procedure allows you to request power from other MAPP companies.
- **Inadvertent Interchange Summary (INAD)** – The Inadvertent Interchange Summary application has two functions: the first is to submit metered and scheduled Inadvertent Interchange data and produce a summary of results; the second is a bulletin board used to advertise Inadvertent accumulations for purposes of scheduling payback with another member.
- **Generator Outage Report (GENOUT)** – Informational report concerning the operating status of generators in the MAPP Region.
- **Transmission Outage Report (XMSOUT)** – Used to distribute current information on the status of the transmission grid facilities. This report is also available on the OASIS.

* Please note that program availability may change to conform with functional separation defined in FERC orders 888 and 889.

For more information on MCCS, contact Kevin Burns at (612) 341-4600.

Reform of the Federal (All-Russia) Wholesale Market of Electric Energy and Capacity (FOREM)

by

Anatoly Lazebnik

and

Bahman Daryanian

Hagler Bailly Wholesale Market Implementation Team

General Issues Affecting Reform

- Politics of Reform:
  - Absence of Consensus
  - Lack of Political Will for Reform
  - Multitude of Power Centers
  - National Versus Regional Control
  - Electricity is Not (yet) an Export Money Earner To Attract More Attention
  - Ineffectiveness of Decrees and Laws
  - Not yet fully developed FEC

- Prevalent Mind Set:
  - Electricity is a Social Good for All
  - Unified System Preserves Russia
  - Too Many Players Results in Loss of Reliability
  - Why do Foreigners Want Change? System Worked Well for Many Years
  - Change brings Anxiety and Chaos
  - Don't Need Lectures from Foreigners: They Should Learn from Russia

Specific Issues Affecting Reform

- Perseverance of Command Management Structure:
  - Absence of Business/Financial Manager Class
  - Lack of Motivation and Incentive for Change
  - Fear of Failure and Reprimand

- What is Missing in terms of Institutional Infrastructure:
  - Comprehensive Electricity Law
  - Legislation On Definition of Legal Authority and Determination of Jurisdictions
  - Functioning Court Systems for Resolution of Disputes or Assignment of Damages
  - Enforceable Contract Laws
  - Modern Banking System for Efficient Transactions

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Principal Problems of the Power Sector

- Sever Nonpayment Problem
- Absence of Mechanisms for Enforcement of Collections
- Cross-subsidies at National and Regional Levels
- Dispatch Based on Planning
- Inconsistent Pricing Rules
- Arbitrary Settlements Procedures
- Non-transparent Accounting Procedures
- Lack of Incentives for Operations as a Business

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Recommendations for FOREM Structure

- Wholesale Market Members:
  - Sellers: WM Generators, NPP's, AO Energos, IPP's, Importers
  - Buyers: AO Energos, Direct Access Customers, Exporters
  - RAO EES Rossii Transmission Network
- Wholesale Market Supporting Organizations:
  - Wholesale Market Operator
  - Market Settlements Administration
  - Market Funds Administration
  - Market Dispatch Administration
  - Market Planning Administration

Wholesale Market Governance and Supervision

- Wholesale Market General Membership
- Wholesale Market Supervisory Council of Members
- Federal Energy Commission (FEC)
- Regional Energy Commissions (RECS)

- All Members and Supporting Organizations Subject To:
  - Wholesale Market Governing Documents
  - Formal Rules of Membership
  - Governance by Membership
  - Decisions Voted in Wholesale Market General Meetings
  - Supervision by Supervisory Council
  - Final Oversight by FEC

General Meetings and Supervisory Council

- Wholesale Market General Meetings
  - Organized Annually or as Needed
  - Final Decisions Subject to FEC Approval
  - Members with Right to Attend and Vote
- Wholesale Market Supervisory Council
  - Comprised of Member Representatives
  - Supervision and Enforcement of the Rules
  - Development and Assessment of New Rules
  - Settlement of Disputes

Economically Efficient System Operations

▸ Least-cost Operations in 3 Time Scales:

(1) Annual Capacity Provisions: Capacity & Availability Payments

(2) Weekly or Monthly Unit Commitments: Demand Payments

(3) Real-time Economic Dispatch: Energy Payments

- Two or Three-Component Prices Applied to Both Sellers and Buyers
- Energy Payments Based on Time-Differentiated and Location Dependent Nodal or Zonal Pricing
- Operations and Reserves Optimized Across All-Russia

Market Pricing Rules

Type I: Existing Generators: Regulation of Capacity Component and Competition on Energy Component

Type II: New and Refurbished Generators: Longer-Term Competitive Capacity and Energy Bids

Type III: New and Refurnished Generators: Shorter-Term Spot Market Competitive Capacity and Energy Bids

- Principal Short-Term tasks:
  - Reform of Two-Part and Time-Differentiated Tariffs
  - Implementation of Least-Cost Economic Dispatch
  - Reform of Settlements and Market Funds Procedures
- Accommodation of Bilateral Financial Contracts
- Voluntary Participation of AO Energo Generation
- Direct FOREM Access to Large Customers Through Wheeling

WM Supporting Organizations

(A1) Wholesale Market Operator

(A2) Market Settlements Administration

(A3) Market Funds Administration

(B1) Market Dispatch Administration

(B2) Market Planning Administration

- Organized from Existing Departments of RAO EES Rossii, CDU, and RDTz
- Functionally Independent from Each Other and Other RAO EES Rossii Departments
- Operating under Transparent Rules and Procedures and Accountable to and Supervised by the Wholesale Market Supervisory Council

Role of Federal Energy Commission (FEC)

- Responsible For:
  - Oversight of the Competitive Sectors
  - Regulation of National Natural Monopolies
  - Issuance of "Operating Licences"
  - Approval of Market Governing Documents
  - Approval of Wholesale Market Amendments
  - Last Recourse to Appeal for Settling of Unresolved Disputes

Regional Energy Commissions (RECS)

- Responsible For:
  - Regulation of Regional Natural Monopolies
  - Protection of Rights and Interests of Retail Customers
  - Enforcement of Separate Costing of AO Energo Distribution and Generation
  - Enforcement of Guidelines for AO Energo Obligations to Serve Load and Prudent Investment Policies by AO Energos
  - Regulation of AO Energo Retail Tariffs and Distribution Charges

Transmission, Generation, and AO Energo Reorganization

- Separate Transmission from Generation and Distribution
- Organization of Generators + Market Structure ⇒ Affects Economic Viability & Competition
  - Therefore, Organization of Generating Companies First Requires Development of FOREM Market Rules
  - Implementation of Pricing Reform and Economic Dispatch Do Not Require Immediate Reorganization
  - Unlike the UK and Ukraine System, Each Generator Can Be Initially Treated as Single Profit Center
  - Proper Pricing Rules, Will Give the AO Enrgos Generation the Economic Incentive to Participate Voluntarily in the FOREM
- Long-Term Ownership Separation of Generation and AO Energos from RAO EES Rossii is better accomplished by "Stock Split", i.e., redistribution of shares to RAO Share Holders, Instead of Direct Sale of RAO Shares

Wholesale Market Operator

(1) Execution of Standard Contracting Procedures for the Wholesale Market Entities

(2) Implementation of Bidding Procedures on the Wholesale Market

(3) Coordination of Activities of Wholesale Market Supporting Organizations

(4) Dissemination of Pricing Information to All Wholesale Market Entities.

Market Settlements Administration

(1) Collection of Settlements Data

(2) Calculations of Payables and Collectable of Members Subject to Market Rules

(3) Billing and Invoicing of Market Buyers and Sellers

Market Funds Administration

(1) The administrator of Wholesale Market Funds and Accounts

(2) Collections from Wholesale Market Buyers

(3) Payments to Wholesale Market Sellers

(4) Payments to Supporting Organizations

- Market Funds Administration:
  - Empowered to Propose Sanctions to Collect Funds from Buyers
  - Liabilities Will Be Limited to What it Can Collect

Market Dispatch Administration

(1) Determination of Least-Cost Annual Capacity Provisions

(2) Determination of Monthly/Weekly Unit Commitment Decisions

(3) Implementation of Real-Time Economic Dispatch

Market Planning Administration

(1) Development of a Long-Term Load Forecast for Russia.

(2) Forecasting of Long-Term Capacity and Energy Requirements of the Wholesale Market Entities and the Overall Power Sector.

(3) Development of Requirements for System Reliability, Security, and Stability Criteria.

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Implementation of Tariff Reform and Economic Dispatch

by

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Hagler Bailly Wholesale Market Implementation Team

1. Economic Dispatch

1.1 Principal Interrelated Short-Term tasks:

- Improvement of Two-Part and Time-Differentiated Tariffs
- Implementation of Least-Cost Economic Dispatch
- Reform of Settlements and Market Funds Procedures

1.2 What Is Economic Dispatch and Why it Is Important:

- Economic Dispatch is the "short-run least-cost" matching of generation with load and losses subject to system reliability requirements.
- Economic Dispatch is only concerned with "variable costs". By definition, fixed costs don't change with dispatch (ignoring for now "unit commitment costs" such as "start-up fuel" and "no-load heat" costs).
- Economic Dispatch is not performed in Russia since dispatch and settlements are based on "planned energy balance" and generators' "average fuel costs" (energy tariffs).

- Analyses by ENIN, Hagler Bailly, and McKinsey & Co. predict that Economic Dispatch in Russia would result in $1 to $5 billion Savings in Annual Fuel Costs in Russia.

1.3 Implementation of Economic Dispatch:

- Approximate Economic Dispatch can be achieved in Russia rather easily with the coordination of activities at FEC, CDU, and RDTs.

- FEC should improve tariff setting methodology.

- CDU (and UDUs) should apply optimal dispatch techniques.

- RDTs should reform the settlements procedures.

- Steps Required for Implementation:

  (i) Decouple energy and capacity parts of the two-part tariff, in order to provide the correct pricing for the wholesale market energy to AO Energos.

  (ii) Apply marginal cost pricing for energy, which should be differentiated by time and territory (market area).

  (iii) Apply day-ahead (for now), and real-time (future) optimal economic dispatch using incremental fuel cost (now) or bids (later) of generating units.

(iv) Reform the settlements procedures by creation of a market funds administration and transparent application of the rules

1.4 Evolutionary versus a Revolutionary Process:

- Implementation will be based on the modification of established practices in Russia, without the need for foreign models, and based on purely Russian solutions.

- This modification effort will set in motion a natural evolutionary process that will culminate in a competitive bid-based dispatch of generation.

- Transition will be smooth and will proceed in a non-disruptive manner, with minimal effort in training, and no drastic changes in operational procedures.

- The proposed methodology will provide lowest average tariff for the wholesale market customers, but recover sufficient revenues to cover the generation costs.

- In the long-term, two other major efforts will be required:

  (i) Updating of "incremental fuel cost curves" (XOP) of all power plants.

  (ii) Upgrading of hardware and software for dispatch, control, communication, and metering.

2. Problems of Current Two-Part Tariffs

2.1 The present two-part tariff methodology is inherently inconsistent, for a number of reasons.

- Capacity tariff is coupled with energy tariff, because it is applied based on a measure of net power flow instead of a fixed capacity measure.

- Energy tariff is based on "average variable costs" of each power plant. This average variable cost is calculated from a non-optimal "quarterly planned dispatch".

- Quarterly planned dispatch is non-optimal because it is not based on total system least fuel cost optimality considerations. Based on optimality considerations, some inefficient power plants may not even be scheduled for generation.

- Actual required generation is always different from planned generation, because "forecast is always wrong". Therefore energy tariff determined based on forecasts and plans at the beginning of the quarter is always different from actual average cost at the end of the quarter.

2.2 Inconsistencies Introduced by Setting Energy Tariff Based on Average Fuel Costs:

- Optimal day-ahead dispatch schedule (calculated by the V2 program) is based on merit order loading of power

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plants according to their "incremental fuel cost curves" (XOP).

- The incremental fuel costs of a power plant is not a fixed number. It increases with the output of the power plant.

- Generally, a unit's average fuel cost is higher than its marginal fuel cost when the unit is generating at low output, because a unit's average fuel cost contains a fixed component: the unit's "no-load heat" and "start-up fuel" costs.

- Generally, a unit's average fuel cost rate is much lower than its marginal fuel cost rate when the unit is generating at its full capacity. Currently, each unit's energy tariff rate is a set constant number.

- Actually, a unit's marginal fuel cost rate is a variable -- a low number when the unit is generating at low output, a number that rises when the unit increases its generation, and a number that reaches a high value when the unit is generating at its full capacity.

- Since we cannot make a constant equal to a variable, there seems to be no hope of avoiding the contradiction by making each unit's energy tariff rate equal to its marginal fuel cost rate.

2.3 There are two possibilities: Either a plant follows dispatch order, or decides for itself.

- If power plants followed day-ahead dispatch schedule (such as a RAO plant), their actual average and marginal fuel costs will be different from the planned energy tariff. Therefore, RAO plants revenue from energy payments may have no direct relationship to its variable costs.

- If power plant decides for itself (such as an AO Energo), based on economic principles, if a power plant is faced with an energy tariff, it will set its load level at point where its marginal fuel cost is equal to the energy tariff. This means that its "actual average fuel costs" will be different from its "planned average fuel costs".

2.4 Relationship Between Loading of Plants and System Lambda:

- Some units will be loaded at a point between their minimum and maximum load. The marginal costs of all such plants at their loading point will equal the system lambda adjusted by a loss factor for their point of connection. These are usually load-following thermal units.

- Some units will operate at their maximum load. For these units, their marginal cost at the maximum load would be lower than system lambda. These are the inexpensive base load plants.

- Some units will operate at their minimum load. For these units, their marginal cost at their minimum load will be greater than system lambda. These are usually expensive

units, ready to produce more as the peak period approaches. These are the peaking plants.

- All plants not loaded at their maximum or minimum load will operate at a loading point where their marginal fuel cost is equal to system lambda. These are the load following plants.

- In Economic Dispatch, thermal units are dispatched according to their marginal costs, with least expensive plants loaded first, and then next expensive, and so on.

- Hydro-electric and pumped storage units are done by a different method.

- By conducting our dispatch in this way, we minimize the system's variable costs — which also minimizes the system's total costs.

- Furthermore, there is no direct relationship between "quarterly planned dispatch" and the "optimal least-cost day-ahead dispatch" schedule determined by the V2 program of CDU and UDU.

2.5 The Overall Result of Current Methodologies Are:

- Some inefficient RAO plants are scheduled for generation when they should not.

- Some AO Energos fully load their inefficient generations, even if there may exist more efficient RAO plants.
- Energy payments have no relationship to actual fuel costs of plants.
- Overall generation of the Russian power sector is economically suboptimal.

3. Problems of Current Time-Differentiated Tariff

3.1 Current time-differentiated tariff has three fixed levels depending on the period of the day.

- Price level at each period is fixed for a large region and has no clear relationship to system generation costs for that period.

- Hence, revenues based on time-differentiated tariff may be more or less than total system costs.

3.2 Time-differentiated tariff gives the wrong economical incentive to AO Energo generation:

- Time-differentiated tariff combines capacity (fixed) and energy (variable) components into a single number.

- At any moment in time, for dispatch purposes, AO Energos only compare their variable costs to the wholesale market's rate which Combines Capacity and Energy Costs Into One Component.

- Therefore, in most occasions, AO Energos will fully dispatch their own generation instead of buying from the wholesale market.

4. Recommended Methodology Under Discussion

4.1 Initial Approach:

- The most rational method of dispatch at present time is to use power plant XOP curves, even though they are outdated.

- It is recommended that initially, capacity tariffs be regulated by a simplified "price-cap methodology", which is gradually modified to introduce elements of efficiency.

- It is recommended that at first step, energy tariffs be directly linked to each power plant's XOP curves.

- It is recommended that in the next step, energy tariff be based on the regional market area marginal costs (determined for marginal XOP curve), and capacity tariffs be adjusted such that expected total payments remain as before.

- In the long-run, move to a system of energy pricing based on market area marginal costs (based on bid or reported XOP curves), and uniform capacity tariffs based on plant types. Short term capacity bids is another option.

4.2 First Quarter Wholesale Market Generator's Tariffs

- For each power plant use the capacity tariff for a similar quarter from the previous year adjusted for inflation.

- Pay each power plant, pay its capacity tariff on a daily basis, if it demonstrates its availability for the day, even if does not get dispatched.

- For each power plant, assign a three level energy tariff based on three load levels determined from a piece-wise linear presentation of its present XOP curve (adjusted for current fuel costs).

- For each power plant, assign a start-up cost based on historical data, and assign an hourly no-load heat costs based on historical data.

- Use each power plant's XOP curve in the V2 program for daily scheduling.

- For each power plant at each hour, if it is dispatched, pay its energy tariff based on its dispatch load level and its no-load heat cost (part of unit commitment costs).

- For each power plant at each hour, if it is started by dispatch command, pay its start-up cost (part of unit commitment costs). This means that at each hour of the day, the power plant will get paid a different price for each load level.

4.2 Second Quarter Wholesale Market Generators' Tariffs:

- Use last quarter's data (or if justified, the planned data), and do a calculation for the whole quarter, assuming that each power plant in each market areas (unified dispatch zone), was paid for energy at each hour at the marginal cost of the plant on the margin.

- Compute the total energy payment based on the above assumption. Subtract from the above the actual energy payments for the quarter. Call this the surplus energy payments.

- For each power plant use its total capacity payment from a similar quarter of the previous year, and adjust it for inflation and subtract 0.25% efficiency factor (about %1 reduction per year -- but this factor should be decided by the FEC). Call this the interim capacity payment

- Subtract from the interim capacity payment the surplus energy payment. Call this value the new capacity payment. Based on this value, compute the new capacity tariff.

- To each power plant, pay its new capacity tariff on a daily basis, if it demonstrates its availability for the day, even if does not get dispatched.

- For each power plant, assign a three level energy tariff based on three load levels determined from a piece-wise linear presentation of its XOP curve (which should be updated to account for inflation in fuel costs).

- For each power plant, assign a start-up cost based on last quarter's value adjusted for inflation in fuel costs. For each power plant assign an hourly no-load heat costs based on last quarter's value adjusted for inflation.

- Use each power plant's XOP curve in the V2 program for daily scheduling.

- For each power plant at each hour, if it is dispatched, pay the energy price of the marginal plant in the market area plus its no-load heat cost.

- For each power plant at each hour, if it is started, pay its start-up cost.

- This means that at each hour of the day, the a power plant will get paid a different zonal marginal price for each load level.

- This method will still result in economic dispatch.

4.3 Third and Future Quarter Wholesale Market Generator's Tariffs

- Use previous quarter's capacity tariff plus inflation minus efficiency.

- Allow power plants to report their own XOP curves.

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- This method introduces "competitive bidding" on energy, combined with price cap regulation for capacity.

4.5 Wholesale Market Customer's Tariffs

- Energy and Capacity Tariffs:
  - Set a "time-differentiated energy tariff" (three periods of the day), equal to the expected "average marginal costs" of marginal thermal power plants in the market area for the quarter.
  - "Average marginal costs" can be calculated from simulation of typical days of the planned period.
  - Set "total customer capacity payments" applied to buyers equal to the "full planned payments to generators" minus "total planned payments of buyers for energy"
  - Set "capacity tariff for each customer by prorating the "total customer capacity payments" by the "total planned energy requirements to be purchased from the wholesale market"
- Adjustments for quarterly "deficit" or "excess" in revenue Recovery:
  - Calculate last quarter's total collections from buyer's and total generator's payment.

- Compute the discrepancy and call it collections deficit or collections surplus.

- Add the collections deficit or excess to the expected total generation capacity payments, and prorate it to buyers based on their agreed level of capacity. This will result in capacity tariff for buyers.

/end

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Power Pooling Study Tour for the Representatives of the Countries of Central Asia

Wholesale Power Markets

Hagler Bailly

Carlos Yermoli

December 12, 1997

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Wholesale Power Markets

- **Competition in Bulk Power Supply**

  Objectives of a Power Market
  Organization of a Competitive Power Sector

- **Pricing of Generation in a Wholesale Market**

  Marginal Cost Payments for Energy and Capacity
  Marginal Cost Payment Bundled into a Market Clearing Price

- **Ancillary Services and Bulk Transmission**

- **Linking Wholesale Supply to Regulated Retail Supply**

  Seasonal Wholesale Tariffs
  Value Added of Distribution
  Retail Wheeling

- **Success Stories**

Objectives of a Power Market

- **Primary Objectives in Most Countries**

  Private Sector Investment in the Power Sector

  Improvement in the Availability and Quality of Power Supply

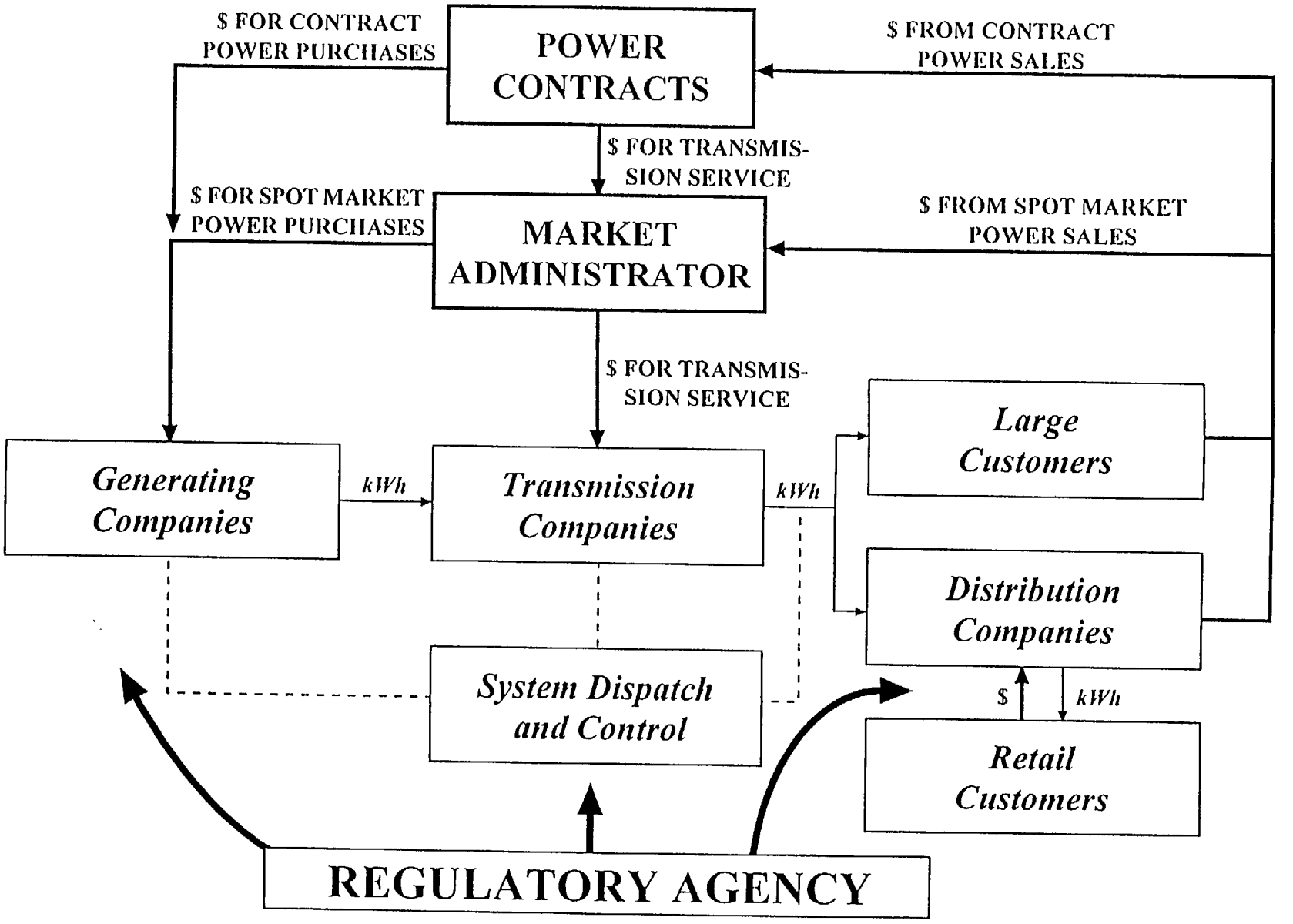
  Economic Efficiency Through Elimination of Subsidies

- **Primary Objectives in Some Countries**

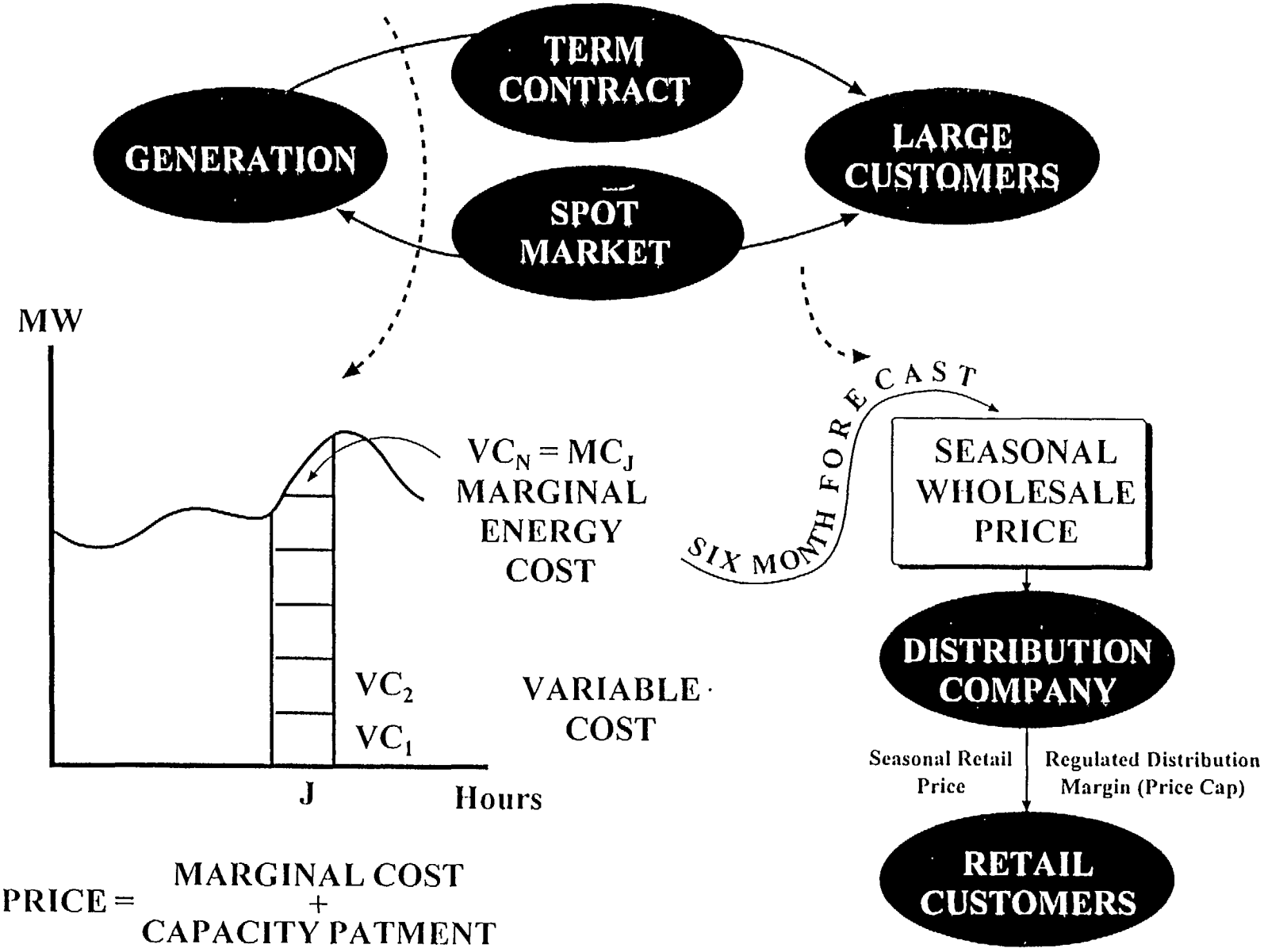
  Lowering Prices Through Competition

  Simplification of the Regulatory Process

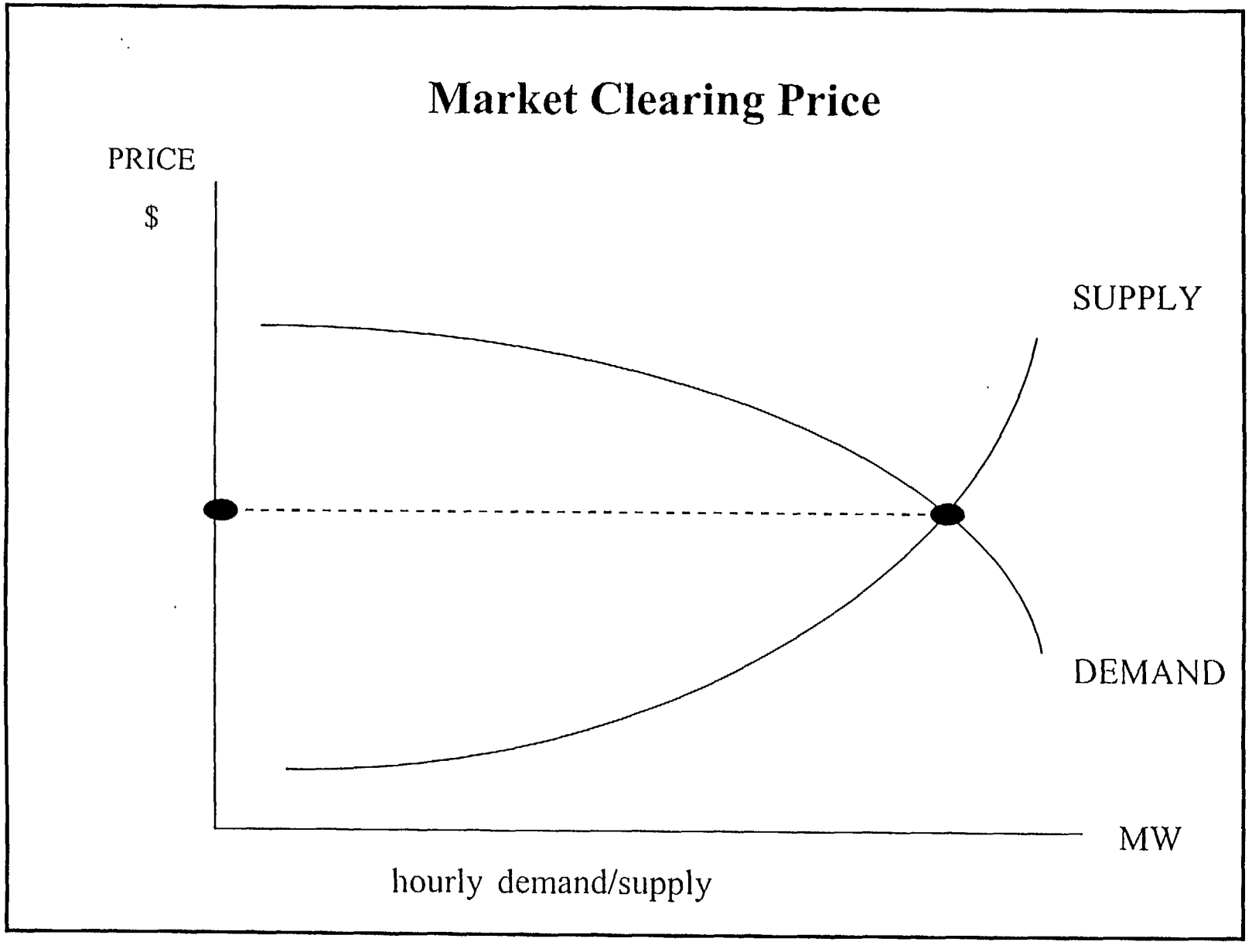
Organization of a Competitive Power Sector



Typical Pricing Mechanism in a Competitive Power Market



SPOT PRICE = MARGINAL COST + CAPACITY PATMENT


Market Clearing Price
PRICE
$
SUPPLY
DEMAND
MW
hourly demand/supply

Ancillary Services and Bulk Transmission

- **Ancillary Services**

  Capacity Reserves
  Primary Control
  Voltage Support
  Reactive Compensation

- **Transmission Pricing**

  Access Charge
  Node Factors

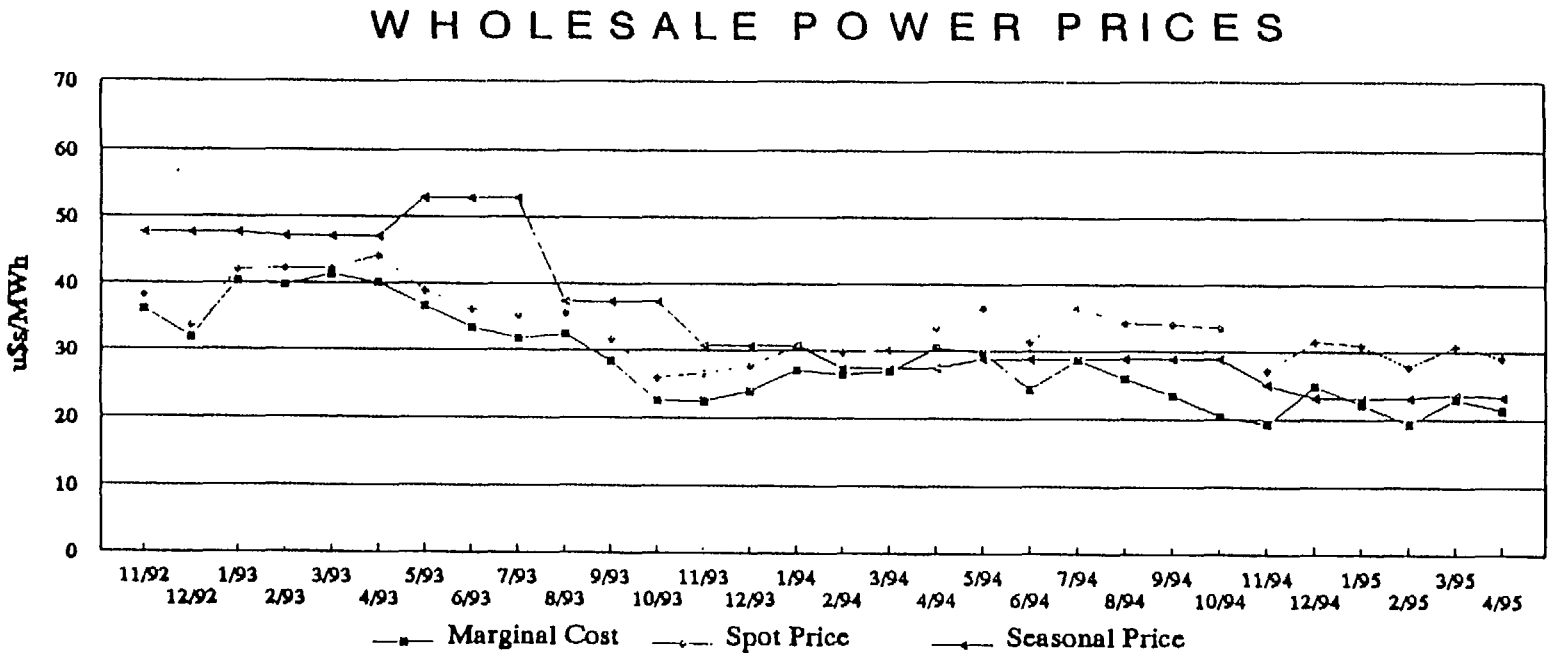
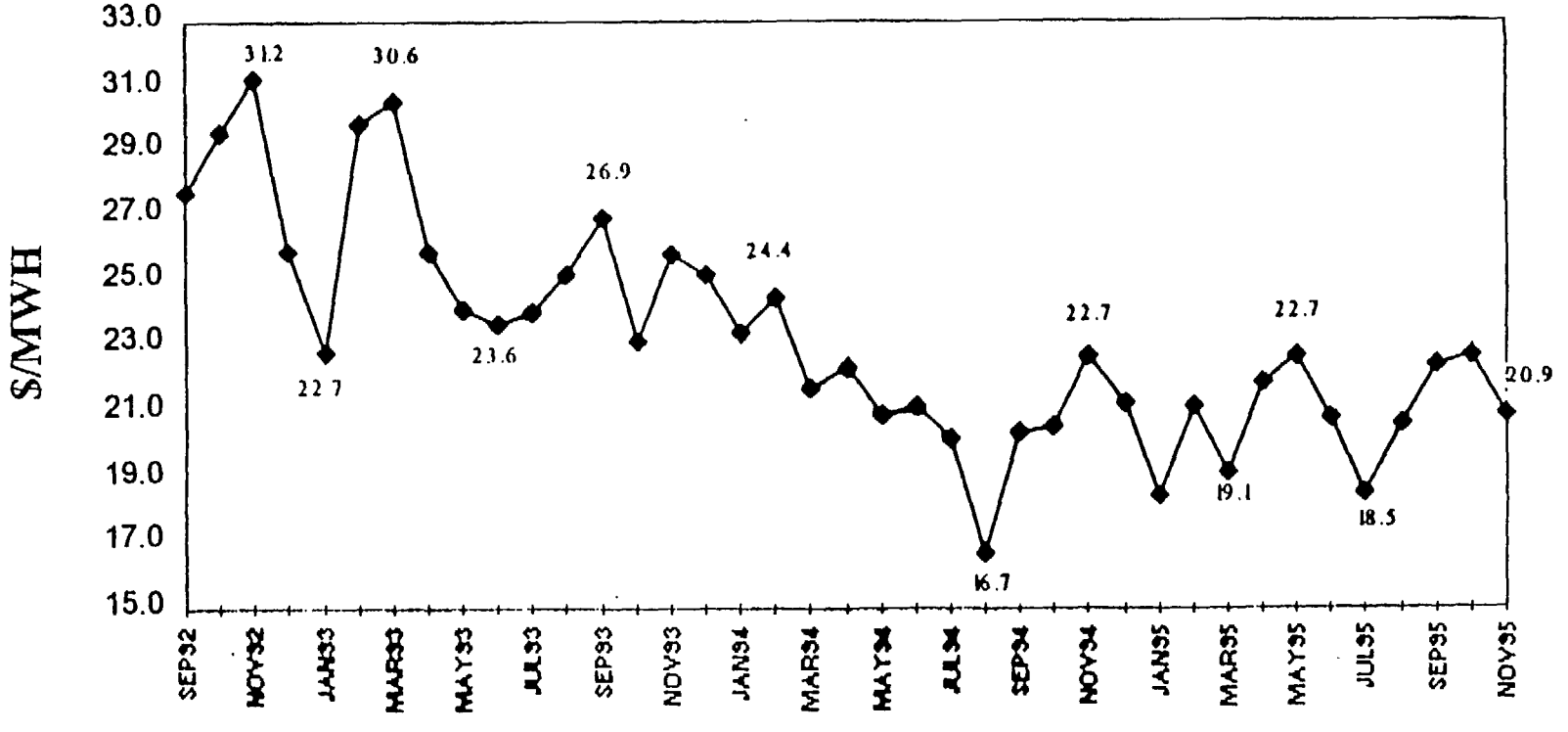
- **Transmission Expansion**

  The Most Difficult Aspect of a Market Based Bulk Power Supply System

LAC Region

MEXICO
BAHAMAS
CUBA
DOM REP.
JAMAICA
HAITI
Puerto Rico (U.S.)
St Thomas
St Croix
BARBUDA
Guadeloupe (FRANCE)
DOMINICA
Martinique (FRANCE)
ST LUCIA
ST VINCENT AND THE GRENADINES
Netherlands Antilles (NETH.)
GRENADA
TRINIDAD AND TOBAGO
BELIZE
GUATEMALA
HONDURAS
EL SALVADOR
NICARAGUA
COSTA RICA
PANAMA
VENEZUELA
GUYANA
SURINAME
FRENCH GUIANA
COLOMBIA
ECUADOR
PERU
BRAZIL
BOLIVIA
HBQ-E
CHILE
PARAGUAY
ARGENTINA
HBQ
URUGUAY
MALVINAS

Success of Competition in Lowering Wholesale Power Prices



Success of Price Cap in Lowering Distribution Cost