PN-ACD-180

ENERGY TRAINING PROGRAM

Transmission Access, Power Wheeling & Economic Dispatch

September 8-12, 1997

Manila, Philippines

Department of Energy
Republic of the Philippines
USAID Mission in Manila

USAID Center for Environment

Power Technologies, Inc.

Institute of International Education

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PROGRAM SUMMARY

Background of the Philippines' Power Sector

The current (1996) installed capacity is about 10,556 MW which includes 2,333 MW hydro, 1,414 MW geothermal, 1,460 MW coal and 5,349 MW oil To meet the growing demand for electricity, an additional capacity of 12,978 MW will be installed between 1996 and 2005, bringing the total nationwide installed capacity to 23,264 MW

The demand for electricity is projected to increase at an annual average of 12 per cent between 1996 and the year 2005 This translates into an increase in power demand from 5,855 MW in 1996 to 16,256 MW in 2005 Correspondingly, electricity sales are expected to increase to 93 313 GWhr in 2005 from 33,532 GWhr in 1996

With the implementation of energy conservation and demand-side management (DSM) programs, a significant reduction in energy consumption is projected A decline in the annual growth of electricity demand by an average of about 5 4 per cent shall be affected by the impact of energy efficiency and DSM programs

The need for reform of the Philippines' power sector came about by the power crisis of the early 1990's when it began experiencing brownouts of two hours per day By the summer of 1993, the daily brownouts had reached eight to ten hours a day thereby crippling the economic activities The national government and the National Power Corporation responded to the crisis by initiating and involving the private sector in financing, building and operating power plants The successful experience of this initiative resulted in the Department of Energy's (DOE) comprehensive power sector structural reform of 1996 to rationalize the power sector The main objectives of these reforms are

- to create an environment which permits and encourages sufficient investment to meet expected expansion of the power sector,
- to develop a competitive environment that will encourage efficiency and reliability in production and delivery of electricity to consumers at a reasonable price, and
- to establish a regulatory and policy structure that will protect the consumers, while maintaining the ability of the sector to finance necessary expansion projects by allowing participants to operate commercially

Under the proposed restructuring, DOE plans for the unbundling of the NPC into a series of Generation Companies (Gencos) and a regulated Transmission Company (Transco) The generation subsector, including new generation companies and existing Independent Power Producer (IPP) generation, will be responsible for power generation in a market-based, highly

competitive environment The Transmission Company will be responsible for operation and dispatch on a real time basis that will meet demand on a least cost basis, while maintaining system reliability The responsibility of providing power will be delegated to Distribution Companies (Discos) The Energy Regulatory Board (ERB) will be responsible for (1) setting and enforcing performance standards for Gencos based on reliability and efficiency to ensure fair and high competition between these Gencos, (2) regulating transmission service pricing and transmission system operations, and (3) setting and enforcing performance standards for distribution utilities, including financial management, based on reliability and system efficiency to ensure the lowest possible cost to consumers

ASEI Philippines Energy Training Program

The Asia Sustainable Energy Initiative (ASEI), developed under the Global Climate Change for the Philippines, Indonesia and India mandate, is set of activities to address the major obstacles to large-scale implementation of commercial sustainable energy project development schemes by focusing on policy and regulatory reform, planning and project development In the case of the Philippines understanding that the power sector is experiencing growth in demand for electricity, at the same time, undergoing a transition from state-owned power companies to an unbundled and competitive power industry, USAID/Mission in Manila directed the Energy Training Program (ETP) to develop the ASEI training component to support the Government of the Philippines' (GOP) plan of restructuring, regulatory reform, and privatization Providing training in support of a restructuring effort is expected to result in a market-oriented electricity sector, which will enable the adaptation of renewable energy and energy efficiency projects

Under ASEI Philippines, ETP is implementing the following courses in support of the GOP's training priorities

Power Sector Regulation	April 7-11 (1 week)
Tariff Structure and Rate Making	May 19-23 (1 week)
Environmental Management of Thermal Power Plants	July 21-August 1 (2 weeks)
Economic Management of a Distribution Company (Disco) - focus on IRP	August 25-September 5 (2 weeks)
Transmission Access, Power Wheeling and Economic Dispatch	September 8-12 (1 week)

BIOGRAPHIES OF COURSE INSTRUCTORS

Dr Hyde M Merrill

Dr Merrill is currently a senior consultant for Power Technologies, Inc (PTI) He joined PTI in 1980, where he carried out a project to assess usefulness of battery storage on the New York City subway system He is the principal developer of PTI's power plant maintenance scheduling (PP/MS) software and of PTI's trade off/risk (TO/R) computer program He conducted a fuel inventory study for one of the world's largest utilities He managed one major Electric Power Research Institute (EPRI) project to develop a methodology for setting transfer capability objectives, and another to develop a general methodology for least-cost and strategic planning in the presence of uncertainty and conflicting objectives He has led least-cost and strategic planning consulting assignments for a number of utility and non-utility clients One of these was an international effort involving assessment of markets and risks for power produced in one country and sold in another He has performed a number of studies on engineering, economic, and contractual issues in wheeling and transmission access

Dr Merrill teaches PTI short courses in transmission access and wheeling, power plant maintenance scheduling, utility economics and finance, strategic planning, corporate modeling, system operations, system planning, and least cost planning He is a registered professional engineer in New York State A Fellow of the Institute of Electrical and Electronic Engineers (IEEE), he is active in the Power System Planning Subcommittee and the Working Group on Long-Range Planning

Prior to joining PTI, Dr Merrill served as an independent consultant to power companies, engineering firms, and research organizations in the U S , Europe, and Latin America, mainly on real-time control of electric power systems and development of control centers

In 1979, he was a Senior Visiting Scientist at Massachusetts Institute of Technology (MIT) He helped teach a graduate course in strategic planning for energy and was technical director of a major research project to assess energy strategies He was instrumental in developing powerful new strategic planning methods

In 1972, he joined the American Electric Power Service Corp (AEP) He was later promoted to Senior Engineer and to Section Head He developed computer applications in engineering, planning, and management for the AEP System One of these was a pioneering power plant maintenance scheduling program He contributed to the development of state estimation for electric power systems, both as a graduate student and at AEP He was responsible for developing analytic tools to support the mining, storing, and shipping of coal at AEP

Dr Merrill earned degrees in mathematics from the University of Utah (B A , 1967) and electrical engineering from the University of Utah (M S , 1968) and MIT (Ph D , 1972), and was elected to membership in the Tau Beta Pi, Eta Kappa Nu, and Sigma Xi honor societies

John E Koehler

Mr Koehler is currently Manager of Operations Engineering at the New York Power Pool (NYPP) He has served in this capacity since 1993 He is responsible for supervision, direction and coordination of engineering studies to determine system transfer limits, the need for, and effectiveness of, computer programs and effective utilization of NYPP transmission and generation resources, in order to achieve reliable and economic operation of the Pool

From 1980 to 1993, he served as Manager of Pool Operations at NYPP In this capacity, he was responsible for supervision, direction and coordination of all activities in Pool System Operations including dispatching, scheduling, operations engineering, dispatcher training and system protection From 1978 to 1980, he was Supervisor of Pool Operations, where he was responsible for control and operation of all generation and major transmission facilities within the operating jurisdiction of the NYPP

From 1973 to 1978, he was Pool Computer Supervisor, where he directed and supervised the functions of the Pool Computer Systems and the Pool Computer Staff He was responsible for the operation, maintenance and security of the computer system as well as the design, evaluation, implementation, installation and documentation of computer hardware and software required to meet specified objectives From 1969 to 1973, he was a Pool Computer Applications Supervisor He was responsible for the direction and performance of computer programming functions and activities in the area of power systems analysis and simulation, economic dispatch and load-frequency control for all major generation and transmission facilities in the State of New York These functions and activities included the development, preparation and implementation of computer programs and studies for the following applications on-line and off-line load flows, economic dispatch and load-frequency control, unit commitment, generation and transmission outage studies, contingency studies, power system modeling, system security monitoring and evaluation, man-machine interface for dispatcher use of computer facilities through CRT's , and communications system for the receiving and transmitting of data between the NYPP and member companies

From 1956 to 1969, he was employed by the Long Island Lighting Company While there, he held various positions in operating, engineering and new business departments He has also worked as an independent consultant for ECC, Inc , Coopers & Lybrand, Power Technologies, Inc , and the Institute of International Education He has worked in other countries including Canada, India, Kazahkstan and Kyrgyzstan Mr Koehler earned degrees in industrial management from Long Island University (B S) and electrical engineering from Union College (M S) He also completed the General Electric Power Systems Engineering Course

U S AGENCY FOR INTERNATIONAL DEVELOPMENT

INSTITUTE OF INTERNATIONAL EDUCATION

ENERGY TRAINING PROGRAM

THE ENERGY TRAINING PROGRAM (ETP)

The Energy Training Program (ETP) of the United States Agency for International Development (USAID) trains energy and environmental professionals from A I D -assisted countries (AACs) in how best to assess, utilize, and manage their energy resources ETP supports the program plans and activities of USAID's Center for Environment, the regional Bureaus and the overseas Missions

The Institute of International Education (IIE) manages ETP ETP works with AACs' energy and environmental sectors to assess their capabilities and identify training needs In response to their needs, the program develops courses in conjunction with the U S energy and environmental industry ETP ensures that participants receive practical, skills-oriented training in every program and access to modern technologies, methodologies, and management techniques Its staff closely monitor each training program to guarantee excellence

ETP covers the full range of conventional and alternative energy options available to AACs, with an emphasis on energy efficiency, environment, renewable energy, and privatization ETP has developed a two-pronged approach to training the Management-Level Training Program (MTP) and U S -based courses The MTP provides short-term, in-country workshops for senior management and policy makers These workshops are designed to increase understanding and build support for energy and environmental issues among key decision-makers The U S -based courses provide more in-depth, practical training This integrated approach is designed to strengthen the institutional capacity to plan and implement sustainable energy projects

To further enhance the effectiveness of training, ETP has established an Alumni Network, uniting its over 5,000 graduates The Network is served by the *ETP Digest, a newsletter which provides information on individual alumni accomplishments and upcoming training opportunities*

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USAID's CENTER FOR ENVIRONMENT

The U S Agency for International Development (USAID) allocates a significant portion of its assistance efforts to the wise management of environment and natural resources USAID has further underscored the importance of environmental issues by creating the Center for Environment The Center's mandate is to provide technical and programmatic leadership and support to the Agency and its domestic and international development partners in addressing global environment and sustainable development problems

Specifically, the Center provides technical support to USAID field missions and regional bureaus, identifies and analyzes critical environmental problems and the constraints to their resolution, guides Agency strategy in specific environmental areas such s global climate change and biodiversity, helps to ensure consistent excellence in technical capabilities and Agency programs, and synthesizes and disseminates data from technical and scientific research

The Center for Environment also collaborates with a wide range of partners -- host countries, non-governmental organizations, other U S government agencies, international organizations, and other donor countries -- to solve environmental problems on local, regional and global levels

INSTITUTE OF INTERNATIONAL EDUCATION (IIE)

IIE is the largest privately-operated, international education and training agency in the United States Since 1919, IIE has promoted international understanding and furthered international development IIE currently administers over 270 programs for government and private sponsors worldwide The Energy Training Program, under which this course inTransmission Access, Power Wheeling and Economic Dispatch training program falls, is sponsored by the Office of Energy, Environment and Technology of the United States Agency for International Development (USAID)

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Transmission Access, Power Wheeling & Economic Dispatch

September 8 - 12, 1997
Manila, Philippines

Objectives

This one-week course will provide participants with an understanding of the latest developments in a competitive marketplace as it relates to operation and dispatch of a transmission company It will cover the technical and economic issues related to network access on system control, protection and security, interconnected operations, pricing, and power wheeling

Who Should Attend

This course is designed for policy decision-makers from the Energy Regulatory Board (ERB), Department of Energy (DOE), and generation, transmission and distribution companies who are or will be involved in the current development to expand transmission access

Course Schedule

		Instructor
September 8, Monday		
9 00 a m - 10 30 a m	Welcome and Opening Statements Department of Energy USAID/Manila IIE/Energy Training Program	
10 30 a m - 10 45 a m	Refreshment Break	
10 45 a m - Noon	Introduction and Overview Pretest Course Objectives Wheeling Defined	H Merrill
Noon - 1 00 p m	Lunch	
1 00 p m - 2 30 p m	Physics and Engineering Issues Two Transmission Models Transfer Capability	H Merrill
2 45 p m - 3 00 p m	Refreshment Break	
3 00 p m - 5 00 p m	The Busy Signal Transmission Services Reliability Effects of Wheeling	

September 9, Tuesday

9 00 a m - 10 30 a m	Economic Dispatch of Resources Overview of Commitment Process Economic Dispatch and Control	J Koehler
10 30 a m - 10 45 a m	Refreshment Break	
10 45 a m - Noon	Basic and Advanced Methods of Dispatch	
Noon - 1 00 p m	Lunch	
1 00 p m - 2 45 p m	Economic Dispatch with Security Constraints Dispatch Penalties, Incentives, Bilateral Contracts	
2 45 p m - 3 00 p m	Refreshment Break	
3 00 p m - 5 00 p m	Cost-based versus Market-based Dispatch Ancilliary Services	

September 10, Wednesday

9 00 a m - 10 30 a m	Contract and Regulation Issues Organizational Structure of the US Electric Power Industry NERC, Reliability Councils and Control Areas Today IOU's, Co-ops, TDU's, Muni's, and Pools	J Koehler
10 30 a m - 10 45 a m	Refreshment Break	
10 45 a m - Noon	Tomorrow Genco's, Transmission Providers, Load Servers Independent System Operators, Power Exchanges, Marketers	
Noon - 1 00 p m	Lunch	
1 00 p m - 2 45 p m	Types of Access and Wheeling Contracts	H Merrill
2 45 p m - 3 00 p m	Refreshment Break	
3 00 p m - 5 00 p m	FERC and State Regulations Alternative Evolution Scenarios	

September 11, Thursday

9 00 a m - 10 30 a m	Economic Issues- Costs and Prices Cost Elements	H Merrill
10 30 a m - 10 45 a m	Refreshment Break	

M

10 45 a m - Noon	Theoretical Basis for Costing Imbedded Marginal Incremental Opportunity External	
Noon - 1 00 p m	Lunch	
1 00 p m - 2 45 p m	Pricing Objectives Capital Recovery Economic efficiency Conflicts	
2 45 p m - 3 00 p m	Refreshment Break	
3 00 p m - 5 00 p m	Pricing Methods Network vs Point-to-point Postage stamp Red-line Megawatt mile	

September 12, Friday

9 00 a m - 10 30 a m	Interchange Transactions Contract Path versus Actual Flow Path Scheduling Impact of Loop Flow and Recent NERC Activities	J Koehler
10 30 a m - 10 45 a m	Refreshment Break	
10 45 a m - Noon	Transmission Capability and Access through OASIS Transmission Reservations, Energy Scheduling and Transaction "tagging"	
Noon - 1 00 p m	Lunch	
1 00 p m - 2 15 p m	Identifying the Source and Sink GAPP Experiment of Scheduling, Compensation and Cotrol	
2 15 p m - 2 30 p m	Refreshment Break	
2 30 p m - 3 30 p m	Interchange Transactions with Locational-based Marginal Pricing	
3 30 p m - 5 00 p m	Wrap-up Closing Ceremonies	

TRANSMISSION ACCESS

AND

POWER WHEELING

COURSE NOTES

Prepared by

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Revised September 1996

PRETEST

1 Please define "wheeling "

2 Please identify the statement which best describes each term below

__ stranded investment	A	Circulating flows, either clockwise or counter-clockwise, generally at sub-harmonic frequencies
__ obligation to serve	B	Currents in network elements parallel to a contract path
__ loop flow	C	A power plant whose access to the network is blocked because an IPP's wheeling uses up all the capacity of the local network
__ regulatory compact	D	The accretion of federal and state laws, judicial decisions, and regulatory rulings related to electrical energy
__ "no losers" test	E	The agreement that utilities will provide electricity to all comers
	F	No party, i e , the ratepayer, should pay more because of an action to benefit another
	G	Facilities that are no longer needed because other suppliers are satisfying the load

3 A wheeling utility sees costs which vary with power wheeled according to the following formula cost = 10,000 + 3Q + 0 05Q^2, where cost is in $/hour and Q (quantity wheeled) is in MW What are the marginal and incremental wheeling costs for a 100-MW wheel?

4 Given the bi-axis transfer capability polygon on page 2-17, if X imports 1000 MW from Y, what is the maximum possible simultaneous export from X to Z? Can this amount actually be transferred? Why or why not?

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COURSE OBJECTIVES

This course covers much of what someone who already has practical power system background needs to know in order to deal with transmission access and wheeling In particular, at the end of this course you will be able to

Information and Knowledge

- List four cost bases for pricing wheeling
- Identify four characteristics of an adequate measure of transfer capability or busy signal
- Select from a list the statements which best describe such terms as *stranded investment, obligation to serve, loop flow, regulatory compact, fixed cost, revenue reconciliation, "no losers" test,* etc
- Identify elements included in short-run marginal cost and postage-stamp rates

Skill

- Compute marginal and incremental costs of wheeling, for a lossless and unconstrained case, given a cost function for the wheeling system
- Compute transfer capability ranges, given a bi-axis diagram and a transfer level across one interface

Perspective

In addition, having taken this course you should

- Recognize that transmission access and wheeling is a complex arena encompassing **physics, economics**, and **regulation** -- and that some questions do not have simple answers

Approximately one-third of this course is devoted to each of the three main problem areas (**physics, economics**, and **regulation**) Each of these areas is described in its own section of these notes References and a glossary are found at the end Appendices include important original source material, as well as new material of current interest in this rapidly-evolving field

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WHEELING DEFINED

"*Wheeling* is a very imprecise term which, primarily for convenience, is loosely applied to a variety of transactions or occurrences which have too widely different characteristics to be accurately referred to by the same label In what we believe to be preferred and technically correct usage, 'wheeling' may be defined as the use of the electric transmission system of one utility for the simultaneous receipt at one point and delivery at another of power, of like quantity and characteristics (i e , the power delivered by the wheeling utility must be of like quantity and characteristics as the power it receives), of and for another utility or utilities "[1] **EEI #1**

"Wheeling, in its broadest sense, is the delivery of electric power from one party to another, utilizing the transmission facilities of a third party " [2] **EEI #2**

"There are two ways of defining wheeling The <u>contractual</u> definition is (informally) the simultaneous purchase and sale of electricity of non-adjoining parties Usually one or both of the parties are utilities, but this is not necessary What is important is that they are <u>not</u> <u>adjacent</u>, so that one or more utilities in between them must provide transmission services, which are referred to as wheeling **Schweppe**

The <u>physical</u> definition of wheeling which we adopt in this paper is different It is the change in the power flows in transmission lines owned by other parties, when S sells to B

The contractual and physical definitions of wheeling can be quite different It is possible for wheeling to be taking place contractually, yet no physical effect occurs It is also possible to have physical wheeling effects taking place when, under current contractual practices, no wheeling is happening'" [5]

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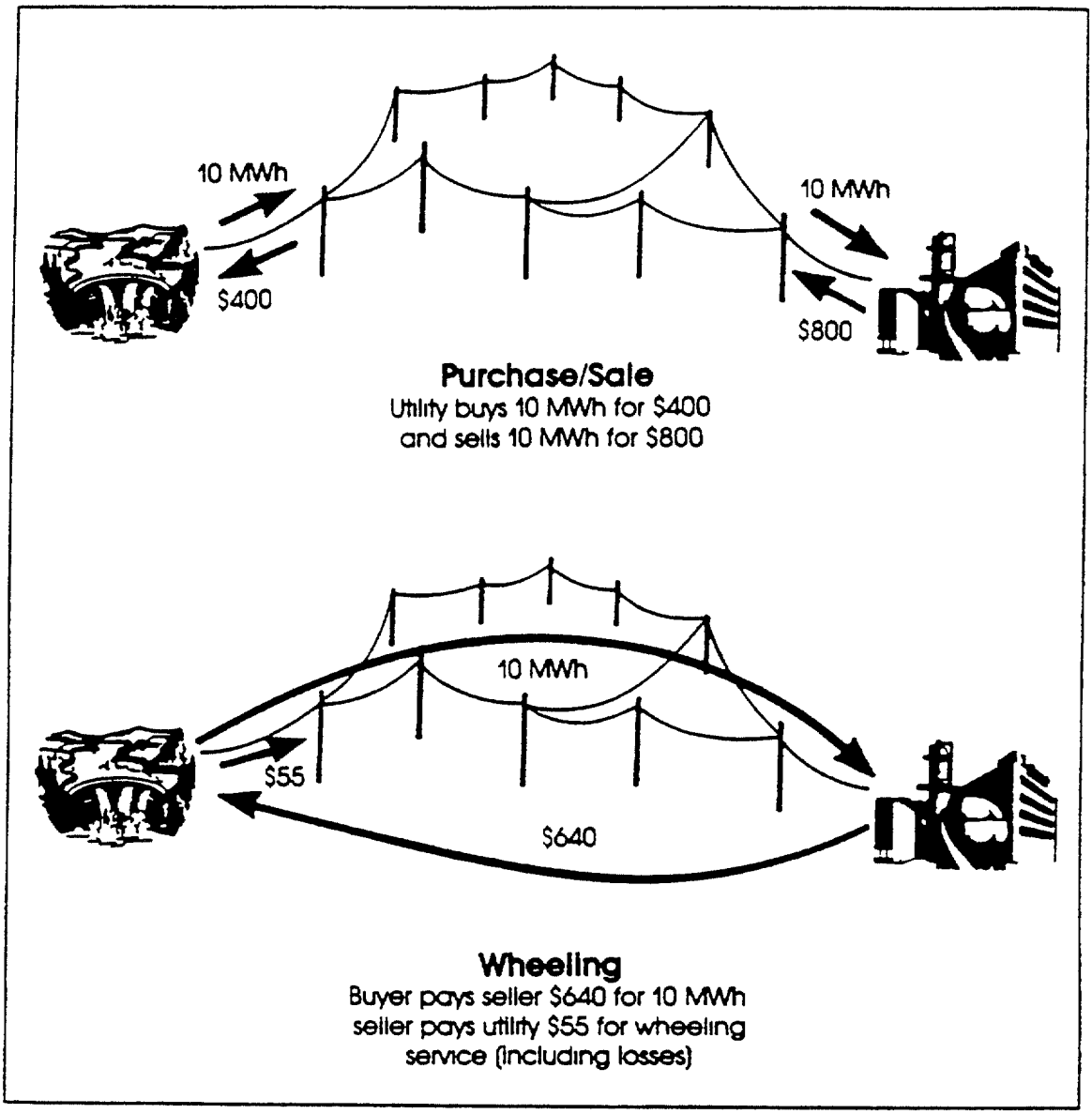

Wheeling is physically the same as a purchase/sale, so sometimes only money is wheeled [6]

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There are many types of wheeling, depending on the relationship between the buyer and the seller Four examples are

- Utility to utility,
- Utility to private customer,
- Private generator to utility, and
- Private generator to private user

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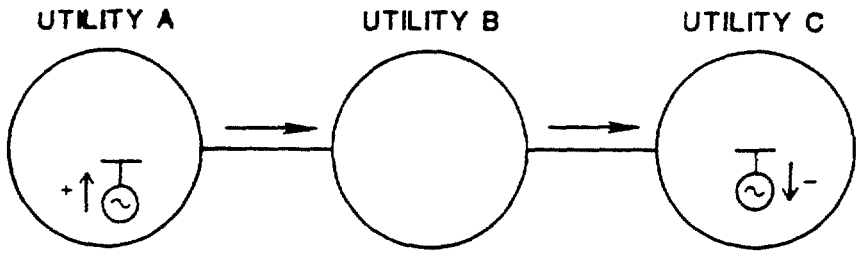
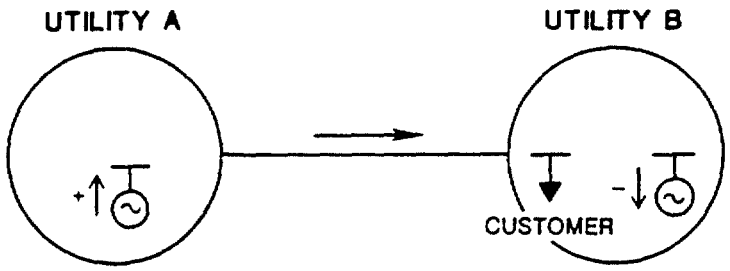
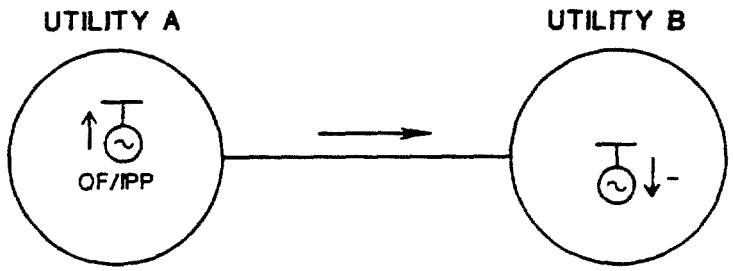


Utility to Utility



Utility to Customer



Private Generator to Utility

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This section covers network physics issues associated with transmission access and wheeling

Some fundamental facts about the transmission system are discussed first The transmission system is not a transportation system The diffences between the two are examined In particular, the transmission system cannot be separated from the generation system -- generation and transmission are closely coupled functions of an integrated energy conversion machine

We next discuss specific transmission services or functions An important one is allowing power to be injected into the network at one point and removed at another Transfer capability is today's best measure of the system's ability to perform this function The strengths and weaknesses of the transfer capability concept are discussed Specifications for a more useful measure of network strength are presented

Finally, we turn to the physical effects of wheeling and transmission access on the bulk power system There is no fundamental problem of physics which prevents increased wheeling or transmission access In fact, a recent ten-year analysis shows a dramatic increase in the amount of power that moves across company lines contractually in the US In 1983, for every $15 spent by US utilities on purchased power, $64 was spent on power production By 1992, these numbers had changed to $27 and $49, respectively [16]

Increased transmission access and wheeling does affect power system operations and planning, however We discuss these effects, some of which are surprising For example, we show that in retail wheeling the physical flows are rarely from the putative supplier to the customer, instead, the incremental power flows are to the wheeling utility's power plants

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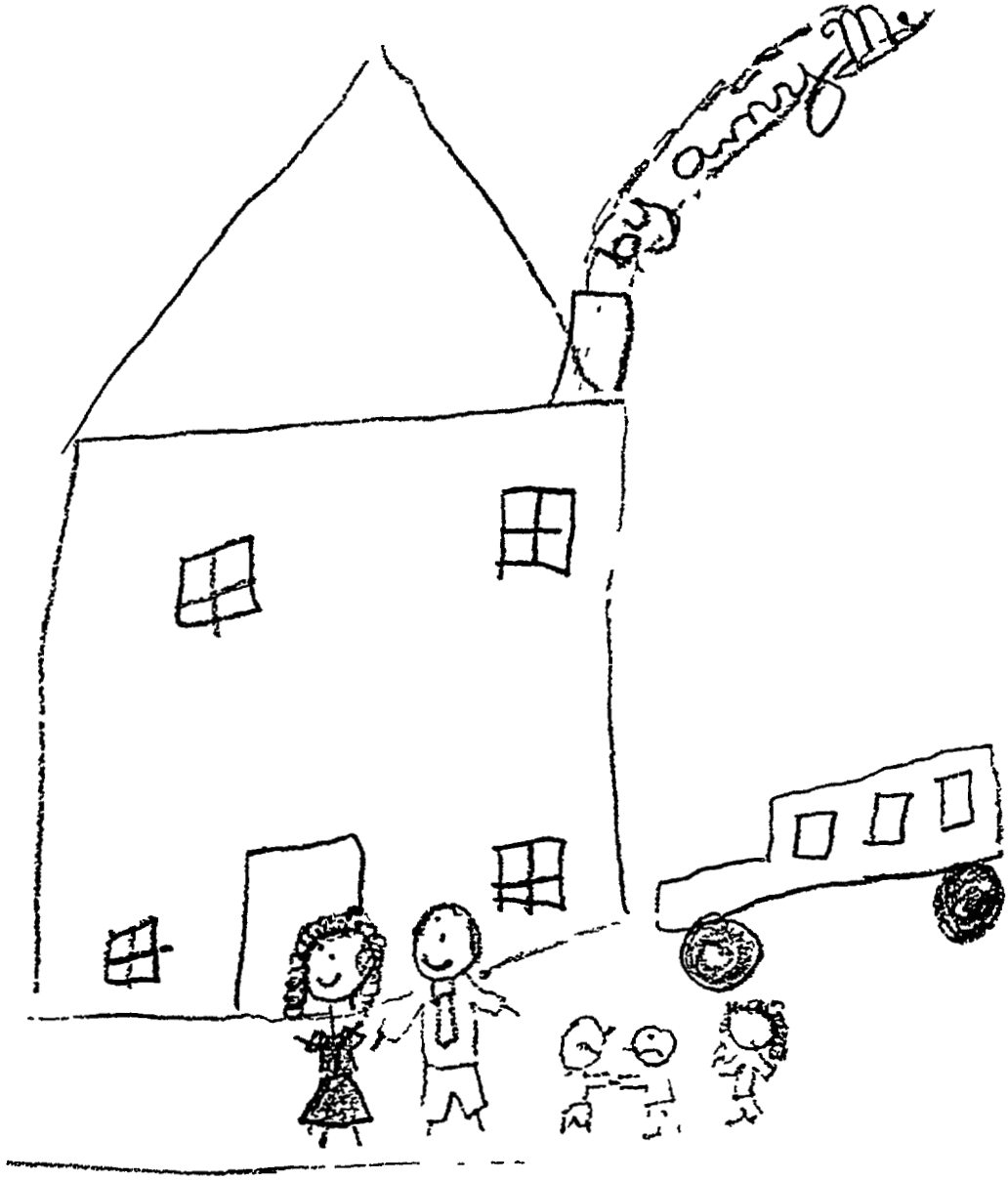

The Norman Ulysses Gigawatt Family

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THE TRANSMISSION SYSTEM - TWO MODELS

At this point it is useful to describe and differentiate between two models of a transmission system

Model 1 Transmission as Moving a Commodity

Model 1, which is almost everyone's implicit or explicit mental model, treats electrical energy as a commodity which is produced at point A, moved to point B, and used there In model 1, the three processes (generation, transportation, and use) are quite different and can be dis-integrated in terms of physical mechanics, ownership, regulation, costing, pricing, etc

Model 2 Transmission as a Function of an Integrated Machine

The physical reality which conflicts with model 1 is that transmission moves nothing from point A to point B Not even electrons (if there still is such a thing) move from A to B In model 2, transmission is a force-at-a-distance function which is part of an integrated energy-conversion machine One analog is the transmission of a car, which connects the engine to the wheels Another is a belt drive which couples a steam engine to a gear which raises or lowers an elevator In fact, it is instructive to think of a complicated belt system, driven by one or more steam engines, which runs a lathe in one room, a drill press in another, and an elevator at the end of the hall Voltage, VARs, electrical losses, etc , all have their analogs in this system

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THE PRACTICAL DIFFERENCES BETWEEN MODEL 1 AND MODEL 2

All of the challenges and difficulties associated with the busy signal problem are due to the differences between model 1 and model 2

In model 2, the operation of the transmission system cannot be separated from the operation of the engines and the wheels, lathes, elevators, etc In model 2, it is the transmission system as a whole, not a piece of the driveshaft or one of the idler wheels, which allows potential energy at one location to be transformed into kinetic energy elsewhere

Although it is the transmission system as a whole that makes this happen, in some sense some parts of the transmission system contribute more than others to this force-at-a-distance For example, if a weight is lifted by a hoist made of a rope and several pulleys, some parts of the rope move farther than others But if the rope is cut anywhere, the hoist fails

In model 2, there is little or no control over which portion of the system contributes the most leverage it is dictated by physics

Although model 2 is more consistent with physical reality than is model 1, much of the language and many of the concepts used in transmission engineering have their roots in model 1 Edison found the model 1 power flow concepts handy, and one of the important contributions of the pioneers was to develop a practical way of measuring and integrating flow -- the watthour meter We will use these existing constructs, but keeping in mind the fact that they are reflect reality only crudely

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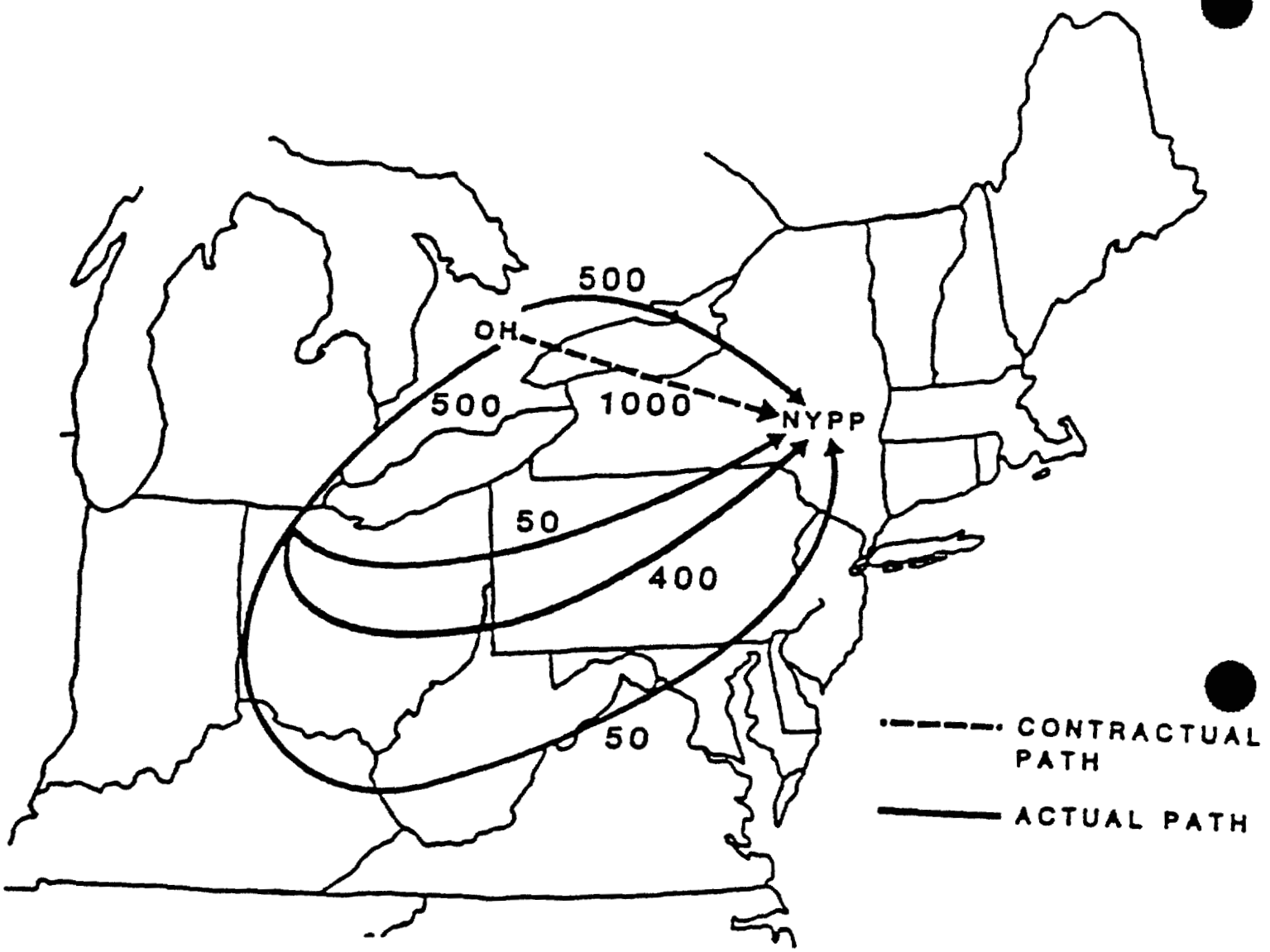

Loop flows when 1000 MW of Ontario Hydro (OH) Power is wheeled to Southeastern New York Power Pool (NYPP) [3]

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B TRANSMISSION SERVICES AND FUNCTIONS

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WHAT IS A TRANSMISSION SYSTEM?

- Current-carrying hardware
- Protection and control devices
- Operation and planning practices and procedures

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EXERCISES ON
TRANSMISSION SERVICES
AND
EFFECTS OF INCREASED TRANSMISSION ACCESS

1 What services are provided by the transmission system?

2 What elements of planning and operations would be affected by increased transmission access and wheeling? How would these elements be affected?

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SERVICES
PROVIDED BY
THE TRANSMISSION SYSTEM?

- Deliver power and energy from remote generation to load
- Allows optimization of generation operations
- Allows parallel operation
- Constitutes an element of frequency control
- Part of control of voltage
- Increases reliability at lower cost
- Allows interregional transfers
- Transfers pollution
- Transfers jobs

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"The Legal Mind at Work,"

by David Pope, P Eng
Sandwich West Hydro-Electric System, Ontario

WORMSLEY WRISTWRENCH Ltd vs Beaver Falls Light & Power

BEAVER FALLS, ONT AUG 3 -- Orville Onion, General Manager of Beaver Falls Light & Power, announced today that his company would appeal the decision handed down by Mr Justice Goldenrod in the Wormsley Wristwrench case

"We will fight it up to the Supreme Court if necessary", Mr Onion commented

In his judgement Mr Justice Goldenrod awarded Wormsley Wristwrench $185,000 for services rendered to Beaver Falls Light & Power

"The origins of this action", he wrote in his decision, "are to be found some three years ago when the Wormsley Wristwrench works was constructed and the company entered into a contract with Beaver Falls Light & Power for a supply of electric power

"Upon receiving his first power bill, Mr Wormsley noted that it included not only a charge for power actually used in the plant, but also a charge which was entered on the account as 'power factor penalty' Inquiring into the nature of this penalty, Mr Wormsley was advised that he was being supplied with a special kind of electricity known as 'reactive power' in addition to the ordinary electric power

"According to Mr Wormsley's testimony he then advised the company's representative that he had not asked for any reactive power, he did not want any and he requested they kindly refrain from delivering any more to his premises He added that if he changed his mind later on and decided it would be advantageous to have some he would let the company know In the meantime, and particularly in view of the uncertain state of the wristwrench market, he would try to get along with regular run-of-the-mill kilowatts

"Having, as he thought, made himself perfectly clear on this point, Mr Wormsley was understandably surprised when his next bill again included charges for reactive power and he again visited the company's offices to lodge this complaint This time he went directly to Mr Onion who informed him that his equipment consisting largely of induction motors, made it imperative that he take a supply of this so-called reactive power whether he wanted it or not

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"Details of this conversation and subsequent occurrences were given by Mr Wormsley during examination by his counsel, Mr Walter Writ, O C Parts of this testimony follow

MR WRIT Now Mr Wormsley, after Mr Onion informed you that you were required to accept reactive power, did he perhaps oblige you with an explanation of this remarkable product?

MR WORMSLEY He did He told me it could best be explained by the introduction of an operator, jay

MR WRIT And were you, in fact, introduced to Mr Jay?

MR WORMSLEY No, I wasn't I asked to be, but Mr Onion said that would be impossible He said jay was the square root of minus one

MR WRIT I see So jay is a number, then?

MR WORMSLEY Not exactly Evidently there isn't really such a number as the square root of minus one, not a real one, at any rate It's an imaginary number

MR WRIT An imaginary number, Mr Wormsley?

MR WORMSLEY Yes As Mr Onion explained it, reactive power is just like ordinary power except that it has been multiplied by an imaginary number Consequently it is often referred to as 'imaginary power'

MR JUSTICE GOLDENROD One question if I may, Mr Wormsley At the time of your conversation, did Mr Onion appear different in any way? Was he perhaps flushed?

MR WORMSLEY Not that I recall, sir Of course it's always a bit difficult to tell with Mr Onion

"Following the conversation, Mr Wormsley returned directly to his office and mailed two envelopes to the company Testimony concerning these envelopes makes it clear that one of them contained a cheque for the kilowatt portion of the power bill, but there appears to be conflicting evidence regarding the other Mr Onion has declared, under oath, that it was empty Mr Wormsley testified that it contained an imaginary cheque covering the imaginary power supplied to him

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"Faced with the threat of having all power, real and imaginary, cut off, Mr Wormsley finally paid in full and Mr Onion suggested that future difficulties could be avoided by the installation of devices called static capacitors at the factory He provided information relating to the required number and size of these machines and Mr Wormsley, anxious to be on the safe side, purchased twice as many as Mr Onion recommended

"These new capacitors did indeed eliminate the power factor penalty and when, after several months, the two men met at a social function, they greeted each other warmly

"'Good to see you, Wormsley,' Mr Onion is quoted as saying "Don't suppose I can sell you any imaginary power these days Matter of fact, with all those capacitors you've got, it's probably the other way round '

"'The other way round?' asked Mr Wormsley

"'I expect so,' Mr Onion replied 'You're producing more reactive than you need so we must be getting the balance of it '

"This remark, in Mr Wormsley's own words, 'got me to thinking' and, after some research and consultation with experts in the field, Mr Wormsley was able to establish not only that imaginary power was indeed flowing from his plant onto the lines of Beaver Falls Light & Power, but also that the exact quantity of this imaginary power could be accurately ascertained using billing meters already installed in his plant by the company

"Mr Wormsley thereupon commenced rendering the company monthly accounts for imaginary power, using the company's own rate schedules These accounts were evidently ignored by the company but Mr Wormsley persisted in sending them, carefully adding arrears and compounding interest quarterly He also installed additional capacitors to increase his output

"'This new venture,' he recalled in his testimony, 'was fortuitous in that it coincided with a sharp decline in the world demand for wristwrenches and so afforded us an opportunity to diversity our interest In my opinion, the generation of imaginary power has all the earmarks of a growth industry

"Mr Wormsley has entered suit for payment for imaginary power supplied to Beaver Falls Light & Power The company can think of no better defense than that it did not want the power and has indeed demanded the cessation of its delivery -- a position this court regards as a studied impertinence in view of the attitude taken by the company when the shoe was, so to speak, on the other foot

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"The law concerning this question is clear Using the established legal principle of *sausa goosa, sausum ganderum*, I award the plaintiff, Wormsley Wristwrench Limited, the sum of $185,000 for imaginary power supplied to Beaver Falls Light & Power with an additional $15,000 in special damages so as to bring the total up to a nice round figure

"Cost to be paid by the defendant and I further direct that the preposterous testimony of Mr Onion be reviewed for possible perjury "

Beaver Falls, Ont , Aug 4 -- William Wormsley, President of Wormsley Wristwrench Ltd , today announced plans for a 90,000 square foot expansion to the Beaver Falls plant The new addition will provide much-needed space for electrical capacitors

Mr Wormsley also announced that the name of his company is being changed to Imaginary Power Enterprises Ltd to identify it with its major product line

****

Power Transmission and Transfer Capability

One important transmission function is permitting power to be injected at one point in the network, with a like amount removed simultaneously at another We think of the power as having been transported between these two points, though what is truly occurring in this transmission function is a "force at a distance" effect, like pushing down on one end of a lever to make the other end rise

Especially in a competitive environment, it is important for a utility to be able to determine the amount of power that can be transmitted in this way -- how hard can we push down on one end of the lever before it breaks? In fact, the US Congress requires the Federal Energy Regulatory Commission to collect information about transmission capability annually from US utilities [17] Unfortunately, there is no known way of measuring transmission capacity adequately As of this writing, the best that can be done is to measure "transfer capability " The next few pages illustrate this concept and its shortcomings An excellent reference document on transfer capability is reproduced in one of the appendices

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C. TRANSFER CAPABILITY

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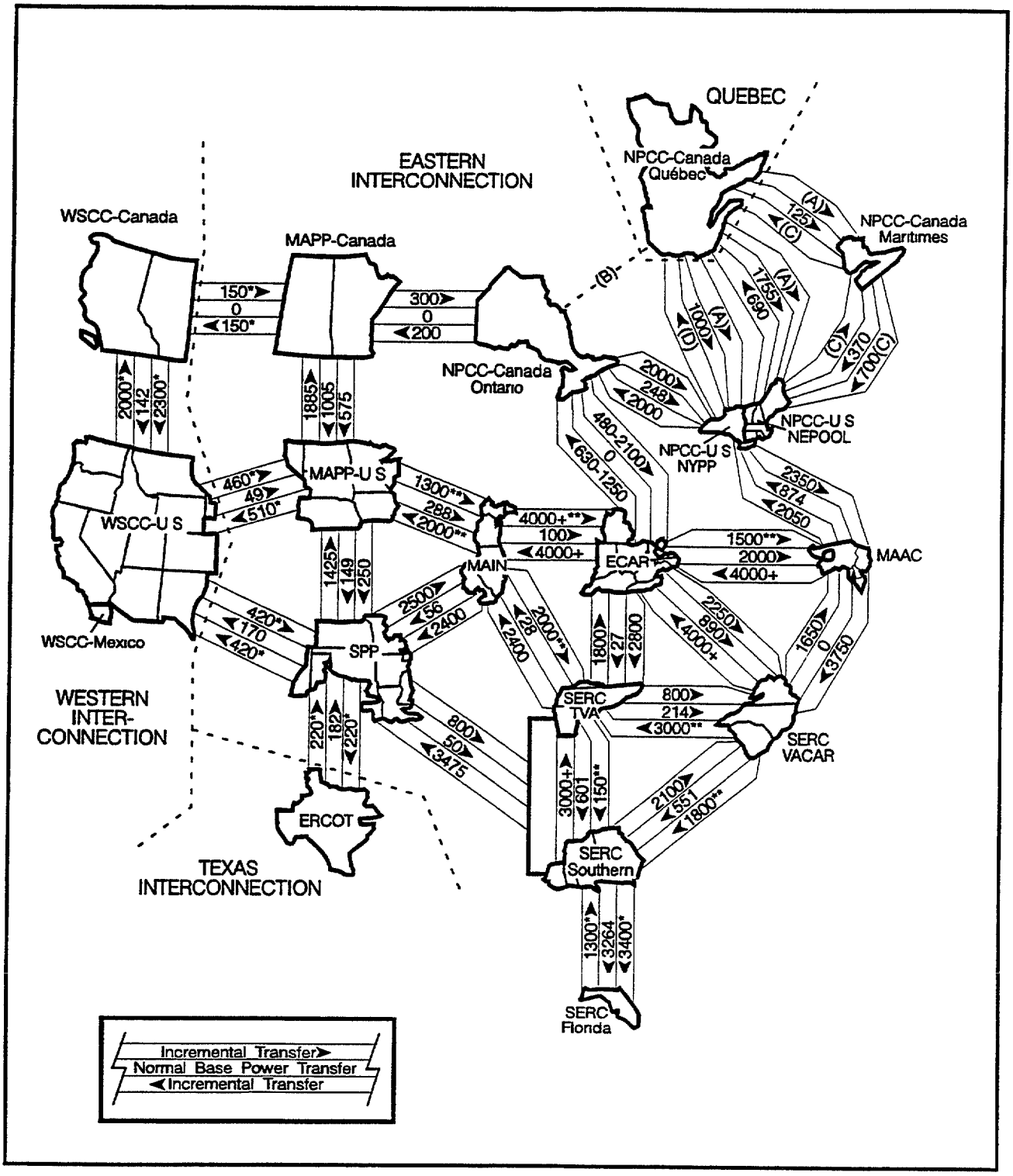
Summer 1991
Normal Base Electricity Transfers
and
First Contingency Incremental Transfer Capabilities
(Non-Simultaneous) — MW



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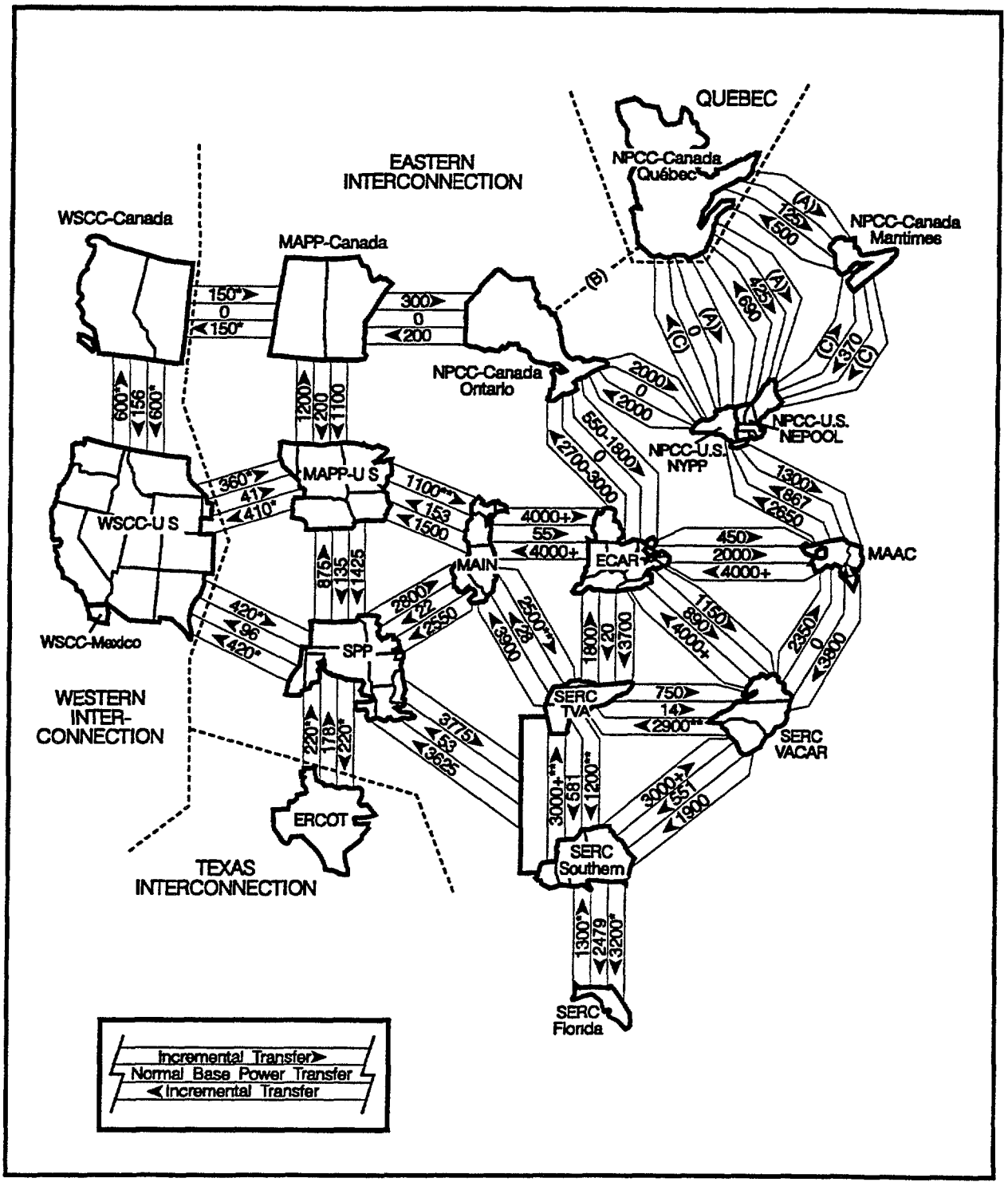
Winter 1990/91
Normal Base Electricity Transfers
and
First Contingency Incremental Transfer Capabilities
(Non-Simultaneous) — MW



Notes to Transfer Capability Diagram [14, 15]

The non-simultaneous transfer capabilities shown represent the ability of the transmission network to transfer electricity from one area to another for a single demand and generation pattern Different patterns of demand and generation cause variations in transfer capabilities on a day-to-day (or hour-to-hour) basis **The numbers given in this diagram should, therefore, be considered as representative, rather than definitive** The reader wishing more detailed information should refer to the several interregional studies for this peak demand season

The **FIRST CONTINGENCY INCREMENTAL TRANSFER CAPABILITY** is the amount of electricity, incremental above normal base electricity transfers, that can be transferred over the transmission network in a reliable manner, based on the following conditions

1 With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits

2 The bulk electric system is capable of absorbing the dynamic power swings and remaining stable following a disturbance resulting in the loss of any single generating unit, transmission circuit, or transformer

3 After the dynamic power swings following a disturbance resulting in the loss of any single generating unit, transmission circuit, or transformer, but before operator-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages within emergency limits

---

A The Hydro-Québec export is limited to a range of 1,700-2,200 MW on all HVDC interconnections due to the Hydro-Québec system contingency

B The only transactions between Ontario Hydro and Hydro-Québec consist of isolated load and generation, there are neither synchronous ac ties nor back-to-back HVDC interconnections between the two systems A maximum of 1,400 MW can be isolated onto the Ontario system by Quebec and 600 MW can be isolated to Quebec by Ontario

C The total transfer capability from the New Brunswick portion of the Maritime Area to NEPOOL is 700 MW The base flow of 370 MW from New Brunswick to NEPOOL is the net of all scheduled contracts between the two parties for the winter period In the reverse direction, a minimum transfer of 150 MW must be maintained from New Brunswick to NEPOOL in anticipation of the loss of the Point Lepreau unit at full output (630 MW)

* Those values shown with an asterisk (*) are First Contingency Total Transfer Capabilities — the total amount of power that can be transferred over the transmission network in a reliable manner based on conditions 1 2, and 3 in the definition above

** Indicates that an operating rule must be in effect to allow the noted capability to be used

(+) Indicates no significant transmission limit found at this level

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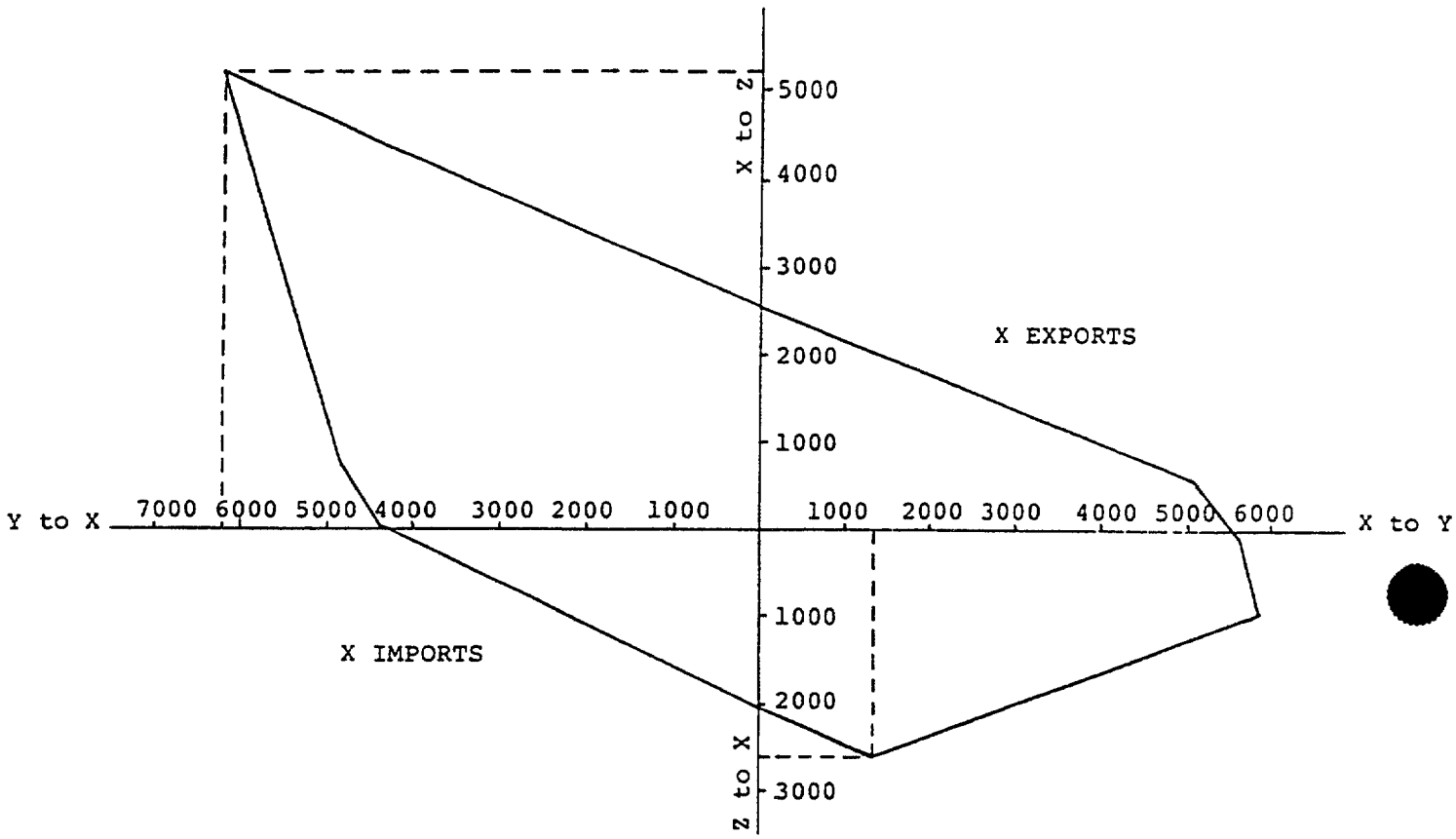

Typical bi-axis transfer capability polygon

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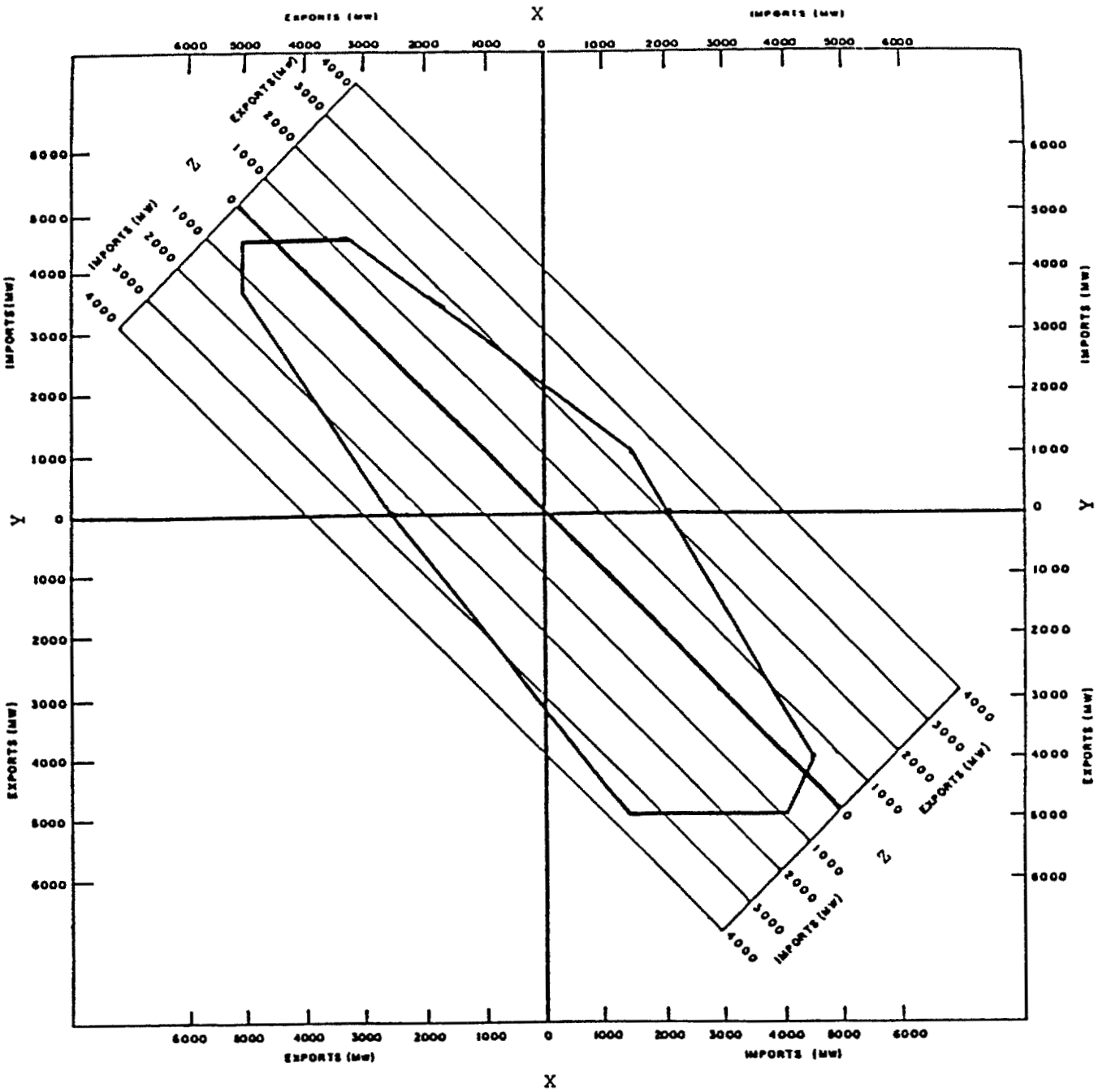

Typical tri-axis simultaneous transfer capability polygon [4]

Some Existing Programs for Determination of Thermal Transfer Limits

Program	
TLIM	PJM member utilities
CAP	New York State utilities
SLANT	Mid-western utilities
LINSUM	Texas utilities (ERCOT)
PSS/E TLT-G	
PSS/E Poly	
TPLAN TLIMIT	

OBSERVATIONS
ON THE TRANSFER CAPABILITY CONCEPT

Uncertainties

- Some uncertainties are handled with the contingency concept, and others (e g , load and dispatch) are somewhat arbitrarily assumed Modeling the probabilistic nature of transfer capability might change the transfer capability objectives

Complex Interconnections

- Transfer capabilities can be conveniently expressed in terms of bi-axis or tri-axis polygons for interconnections of up to three areas These are difficult to apply to more complex interconnections of systems A better way of representing dependencies and relationships among transfer capabilities for complex interconnections may prove useful to system planners

Time-Varying Conditions

- Recognition of the time-varying or condition-dependent nature of transfer capability would lead to more meaningful system reliability and economic assessments Planners think of transfer capability as an index of system strength, generally based on worst conditions Yet the production cost and reliability programs they use treat it as an actual MW value, valid 8760 hours per year For many planning studies it would be unacceptable to treat loads and power plant output as constant throughout a year Nonetheless, presently available production cost and reliability programs do not have the capability of representing transfer capabilities as dependent on other transfer, other loads, generation dispatch, etc [4]

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TRANSYLVANIA TRANSFER CAPABILITIES EXERCISE

System Description

The Transylvanian Interconnected System consists of four entities (see figure below)

- FLAPCO (Favorite Light and Power Company)
- GSP&L (Golden State Power and Light Company)
- TGIF (Turtle Gulch Iridium Facility, a major DOE-operated plant)
- TLC (Transylvania Light Company)

There is load and generation at every bus The rated capacity of each generating unit, and the thermal capability of each line, are given below

TABLE 1 Generating Capacity and Load				TABLE 2 Line Capacity and Base Flows		
Bus	Capacity	Load	Base Generation	Line (to-from)	Line Capacity	Base Flows
1	250	0	100	1 - 2	80	30
2	250	50	100	1 - 4	50	40
3	110	50	110	1 - 5	100	30
4	130	200	130	2 - 3	30	5
5	300	200	130	2 - 4	100	35
6	100	100	30	2 - 5	25	15
				2 - 6	50	25
				3 - 5	30	20
				3 - 6	50	45
				4 - 5	30	5
				5 - 6	50	0

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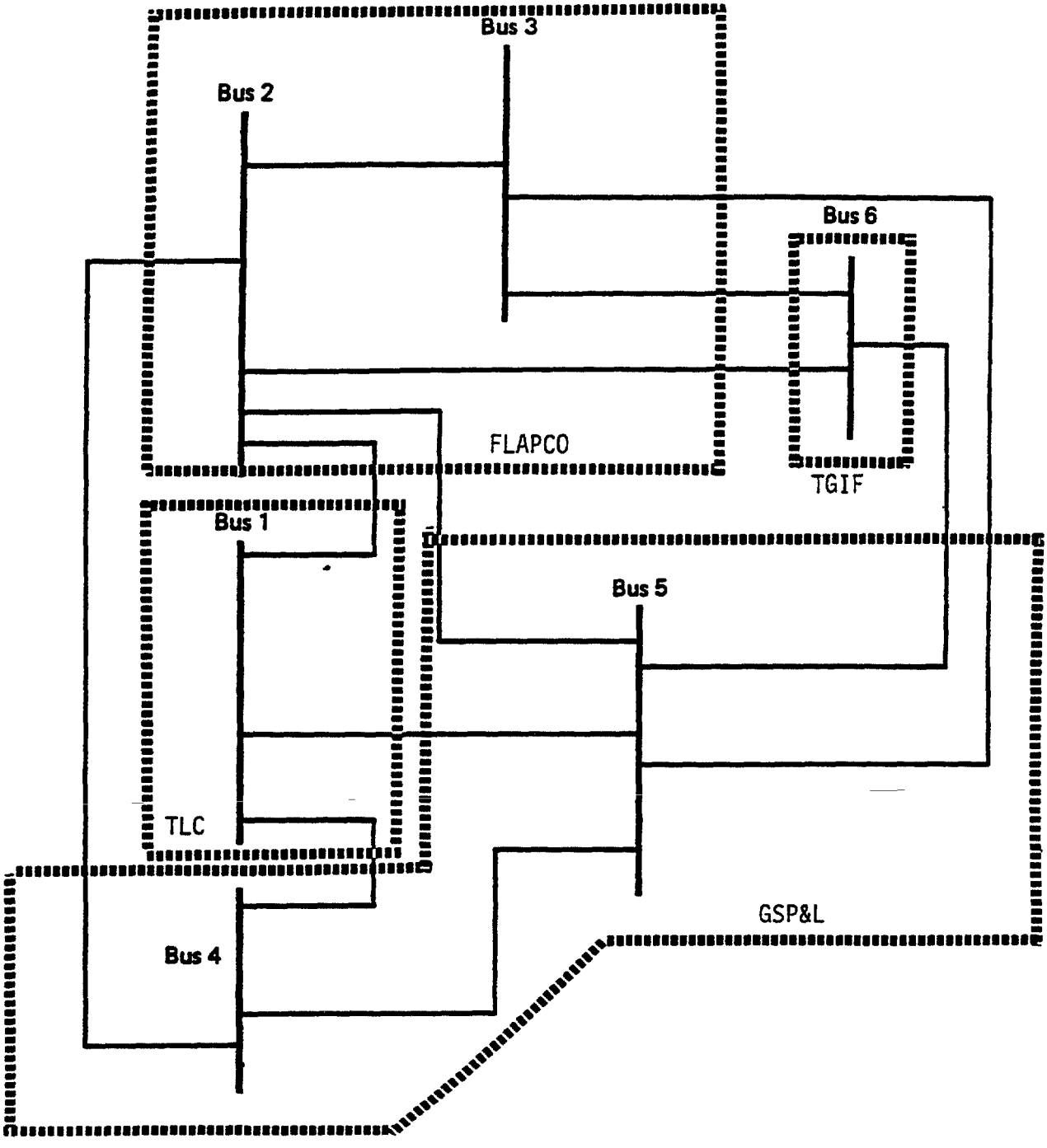

The Transylvania Interconnection

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Bi-Axis Transfer Capability Polygon

1 What are the "base case" transfers among the four companies? The sum of flows across each interface? Why are these different?

2 Considering only constraints on generation, the instructor will develop bi-axis transfer capability polygons for

- FLAPCO to TLC and FLAPCO to GSP&L (next page)

Please develop transfer capability polygons for

- GSP&L to FLAPCO and GSP&L to TLC
- TLC to GSP&L and TLC to FLAPCO

3 The instructor will add network constraints, using the computer and a dc-load flow model

$$\Delta Pline = GSF \times \Delta Pbus$$

where

$\Delta Pline$ = vector of changes in line flows

GSF = Generation Shift Factor matrix (below)

$\Delta Pbus$ = vector of changes in bus injections (generation, load)

To do this will require modeling the economic dispatch, assume that generation at bus 3 is cheaper than at bus 2, and that generation at bus 4 is cheaper than at bus 5

4 Which quadrants represent wheeling? Where is pure wheeling found -- that is, wheeling where the wheeling party delivers exactly what it receives, without any net sale or purchase?

5 Suppose FLAPCO wanted to wheel by buying from TLC and selling the same amount to GSP&L What is the maximum amount FLAPCO could wheel? In the other direction? How much would TLC and GSP&L wheel in the same way?

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6 According ing to these diagrams, is the following set of simultaneous transactions possible?

- TLC to FLAPCO 150 MW
- FLAPCO to GSP&L 60 MW
- TGIF to GSP&L 70 MW

What does the computer analysis say?

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DEVELOPMENT OF TRANSFER CAPABILITY POLYGONS

			Generation Shift Factors					
Line	From	To	Bus 1	2	3	4	5	6
1	1	2	0	-0 471	-0 403	-0 315	-0 322	-0 406
2	1	3	0	-0 315	-0 295	-0 504	-0 271	-0 296
3	1	4	0	-0 214	-0 303	-0 181	-0 407	-0 298
4	2	3	0	0 054	-0 342	0 016	-0 106	-0 191
5	2	4	0	0 311	0 215	-0 379	0 101	0 221
6	2	5	0	0 099	-0 034	0 029	-0 193	-0 027
7	2	6	0	0 064	-0 242	0 019	-0 125	-0 410
8	3	5	0	0 062	0 289	0 018	-0 121	0 153
9	3	6	0	-0 008	0 369	-0 002	0 015	-0 343
10	4	5	0	-0 003	-0 080	0 117	-0 170	-0 075
11	5	6	0	-0.056	-0.127	-0.017	0.110	-0.247

Transmission Lines						Buses				
Flag	From	To	Lower Limit	Trans-fers	Upper Limit	Min Shift	Gen Shift	Max Shift	Bus	Company
	1	2	-110	0	50	-100	0	150	1	TLC
XX	1	4	-90	0	10	-100	0	150	2	FLAPCO
	1	5	-130	0	70	-110	0	0	3	FLAPCOc
	2	3	-35	0	25	-130	0	0	4	GSP&Lc
	2	4	-135	0	65	-130	0	170	5	GSP&L
	2	5	-40	0	10	-30	0	70	6	TGIF
	2	6	-75	0	25					
	3	5	-50	0	10		0	Exports		
	3	6	-95	0	5		0	Imports		
	4	5	-35	0	25					
	5	6	-50	0	50		0			

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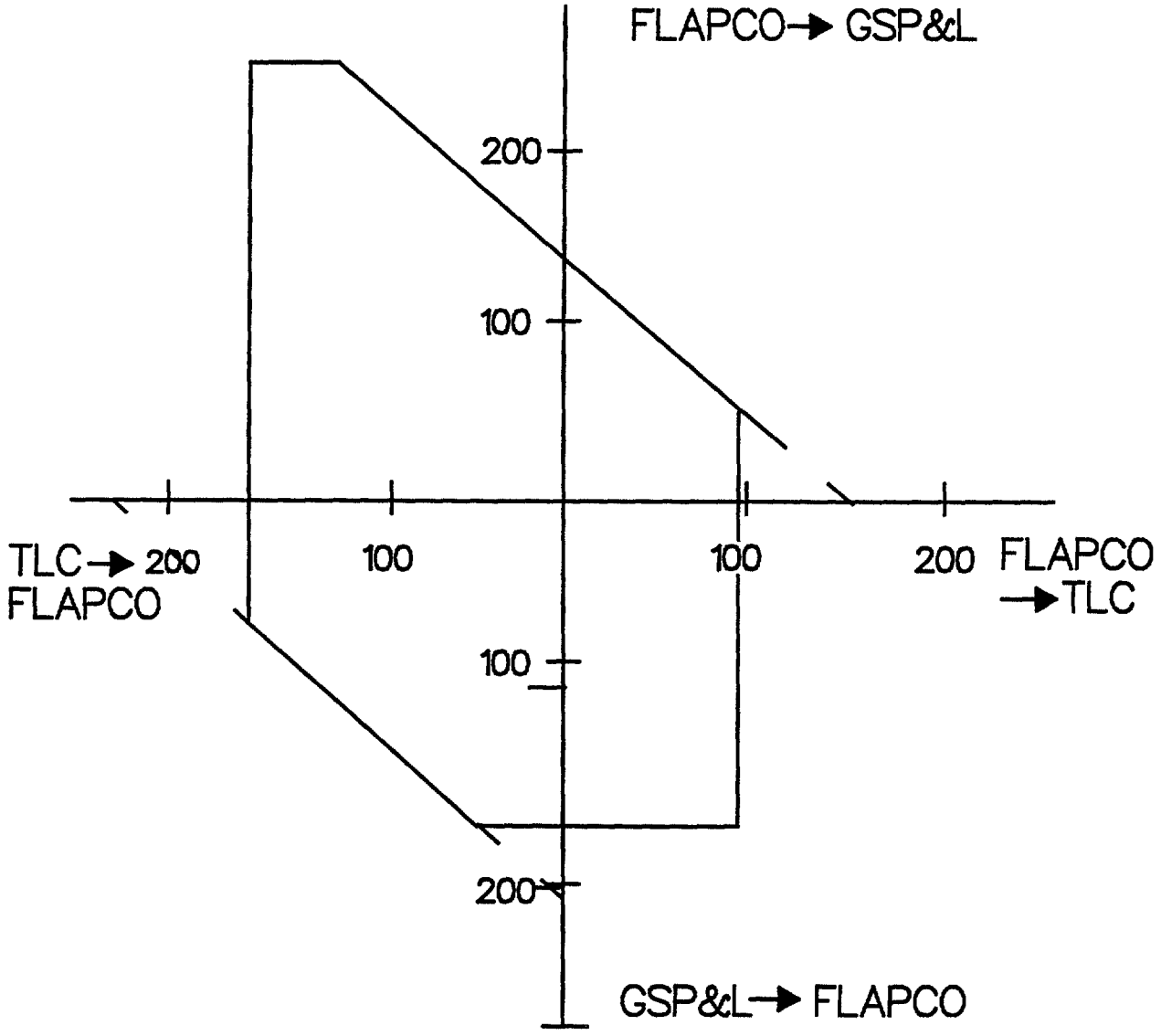

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A BUSY SIGNAL SPECIFICATIONS

Under deregulation and increased wheeling, a new method for defining transfer capacity is needed, with the following characteristics

- it should require straight-forward calculations,
- it should represent an objective, defensible, standard,
- it should be compatible with today's regulated industry structure, and with likely evolutions thereof,
- it should not be so conservative as to unduly limit wheeling,
- it should represent variations in operating conditions and network changes due to maintenance, switching, etc , and
- it should lend itself to on-line use in control centers as well as consistent application in planning

It is particularly important that this method be so clearly acceptable to all parties that the courts and commissions will not have to spend inordinate amounts of time reviewing and redefining transmission transfer capability Such a method is not available today

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BUSY SIGNAL THE GAS PIPELINE APPROACH

The first idea is to ignore all those (including PTI) who cry out that the transmission network is not a gas pipeline and pretend that it is This "model 1" approach is actually quite good in many radial situations where there is only one transmission path between A and B Radial lines in the US tend to be dynamic-stability limited or thermally limited rather than limited by transient stability, and contingency issues are irrelevant for radial lines Thermal and dynamic-stability limits are easy to calculate, so a busy signal based on them would satisfy all the specifications listed above

Unfortunately for this approach, most of the EHV network is not radial But maximum line capabilities might be reduced to something below thermal limits to provide a safety margin for voltage problems and dynamic limits plus leaving a margin to accommodate the fact that the analytical methods used to determine flow patterns will direct flows at will, using all available capacity Determining the appropriate limits for individual elements will be an exercise in itself But have no fear, even if we don't want to do it, some administrative law judge or regulator, will out of desperation, after listening to several hours of "expert testimony " (Similar things have already happened) We could then develop models of the acceptable flows and transfer limits based on linear-network-flow analysis The methods are available, fast, are simple to implement and provide a definite transfer limit They can reflect changes in system configuration and would be easy to implement in an on-line environment

This approach fails to meet at least two of the specifications given earlier First, there would have to be quite a margin of conservatism built into the individual line capacities, so the operation of the system probably would be far from optimal Second, determining the appropriate limits for individual elements will be quite difficult computationally, in the most general situations

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BUSY SIGNAL ENHANCING TODAY'S METHODS

Because of the concerns that power system engineers have about cascading failures and blackouts, one approach would be to keep the basic notions involved in today's techniques and search for simplifying methods to represent them These current analytical techniques consider the analysis of N-1 and N-2 cases (where one or two elements are considered to be out of service) to determine transfer limits Regions for safe operations are determined using some means for searching for limiting conditions (A linearized model using a dc load flow might use linear programming, an ac model might use an OPF)

One technique that might work and be a useful tool would be to develop the maximal regular sphere (or hypersphere) that could be enclosed in the region of safe operation This would mean that the region would be determined by the coordinates of the center and the length of the radius The behavior of this regular internal bounding sphere (RIBS) (UREKA! We've coined an acronym!) for different initial conditions might be studied to develop a way to make the RIBS a simple function of load, interchange, etc

If a RIBS could not be found, it would be possible to work with a transfer capability polyhedron (an extension of Figure 2) It is quite easy to use a linear program to determine if a particular operating point is inside or outside such a polyhedron The challenge is in finding the hyperplanes that define the sides of the polyhedron

This general approach is likely to be quite acceptable to experienced power engineers It represents no philosophical change from what they are doing Only incremental steps will be necessary to implement it

Unfortunately, it is not clear that significant simplification will be possible This means that these methods will continue to be too burdensome computationally, and too complex conceptually, to meet the specifications given above

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BUSY SIGNAL THE TRAFFIC COP

A third approach is to get around the first and second specifications by creating a totally independent, unbiased entity to control grid access in real time and to plan for transmission additions Whatever this entity says is the transfer capability of the network is, by definition true

At one extreme, the entity could use relatively simple methods in making its decisions This would lead to an under-exploited network At the other extreme, the entity could use very complex analysis, doing the same calculations as under "Enhancing Today's Methods " The difference in this approach is that the cop is given complete authority to say who can go and who must stop, so there is no need for other parties to understand or duplicate the analysis

This approach is quite simple conceptually A major difficulty is that it is inconsistent with today's US utility industry structure and with likely evolutions thereof

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BUSY SIGNAL INTEGRATED NETWORK APPROACH

The first three methods are based on model 1 of the transmission network Using model 1 to develop a busy signal is a source of significant difficulty This is reminiscent of what pre-Copernican astronomers had to do to make their earth-centered model agree with the astronomical data they were collecting

A model 2 method would not attempt to model flows through the network, but would treat it as an integrated system, with energy injected at some points and removed at others

Unfortunately, we do not have accepted models of this type available, nor do we know how to develop them More than the other three methods, developing a model 2 solution would require some very sensitive and basic research

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TRANSMISSION ACCESS AND WHEELING·
PHYSICAL EFFECTS

There is no fundamental problem of physics which prevents increased wheeling or transmission access Increased transmission access and wheeling does affect power system operations and planning, however Some of these effects are listed on the next page The rest of this section expands on some of these

The problem of loop or parallel flows was raised earlier One of the appendices contains a copy of the draft "General Agreement on Parallel Paths," a very thorough and interesting proposal for managing this problem

Several pages are devoted to the increased uncertainty associated with increased wheeling and transmission access, in particular, the effects of wheeling on the planning process

The final material in this section describes a modeling issue associated with retail wheeling

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EFFECTS OF INCREASED WHEELING
on
SYSTEM OPERATIONS
and
PLANNING

- Area Control
- Loop Flows
- Voltage Control
- Security and Operating Procedures
- Effects of Uncertainty
- Changes in the Planning Process
- Determination of Transmission Requirements
- Actual versus Planned Use of Networks
- Modeling

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"In 1986 Southern California Edison had contracts for 3900 MW of third party renewable and alternative energy But Edison estimated that only 60% of it would ever be built A year later, most of this (3500 MW) was still under contract, but the company lowered its expectation to 40% That is, the 1986 forecast was 50% higher than the 1987 forecast One important factor underlying this change in forecast was the changing policy of the California Public Utilities Commission (PUC) regarding avoided cost As the PUC policy changed, the amount of QF/IPP capacity which was economically viable also changed This illustrates the sensitivity of potential suppliers' plans to the policies of regulatory agencies and contributes to the overall uncertainty of the planning process If the amount of QF/IPP generation which is expected to be available in the future is highly uncertain, then the amount of wheeling services to be sought and the required transmission facilities needed to accommodate such wheeling is also uncertain, as are the wheeling utilities' own planned generation requirements " [2]

What does this imply for utility planners?

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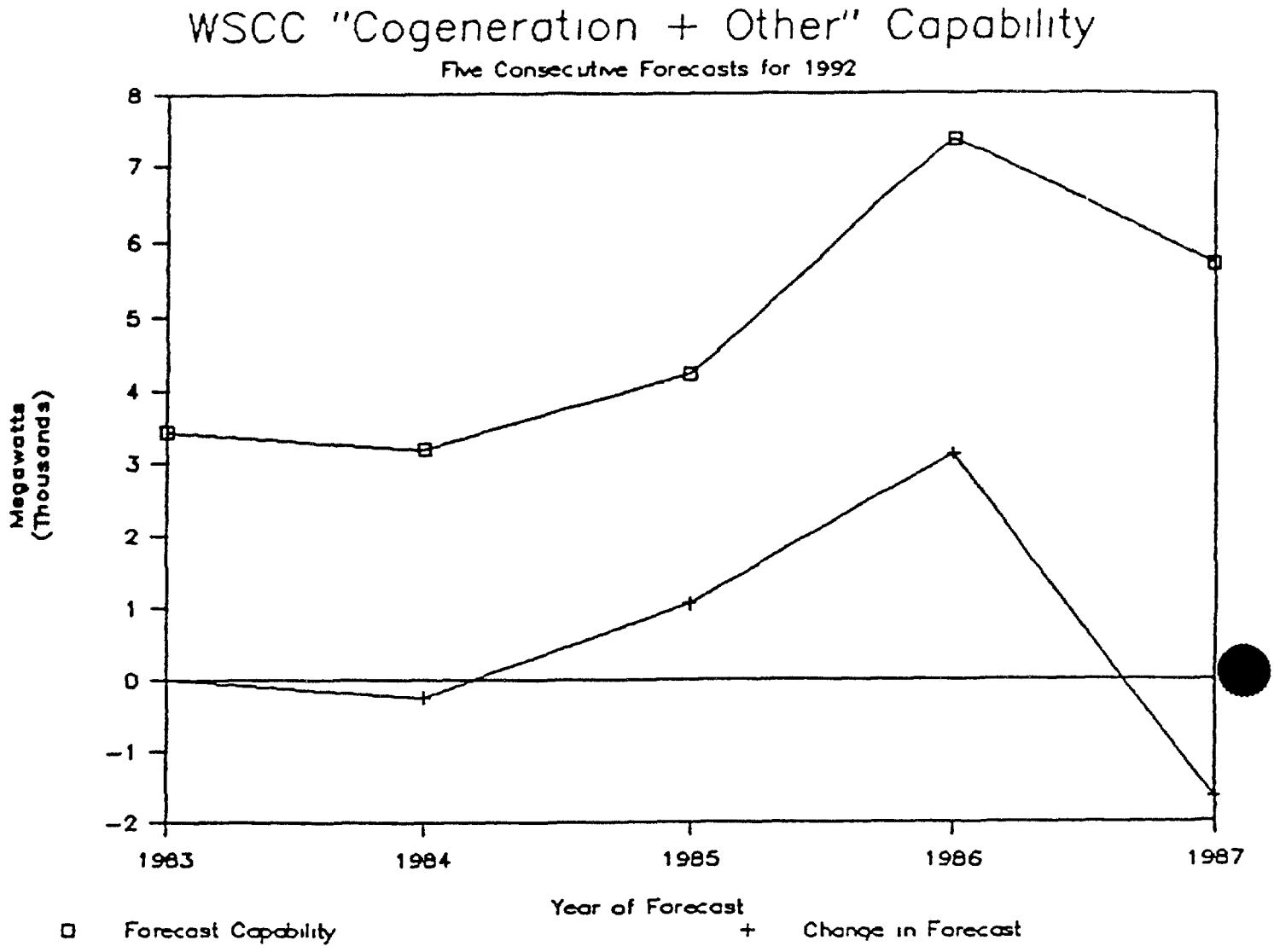

Annual forecasts of 1992 cogeneration, solar, wind, etc , capacity in the Western Systems Coordinating Council (WSCC) [2]

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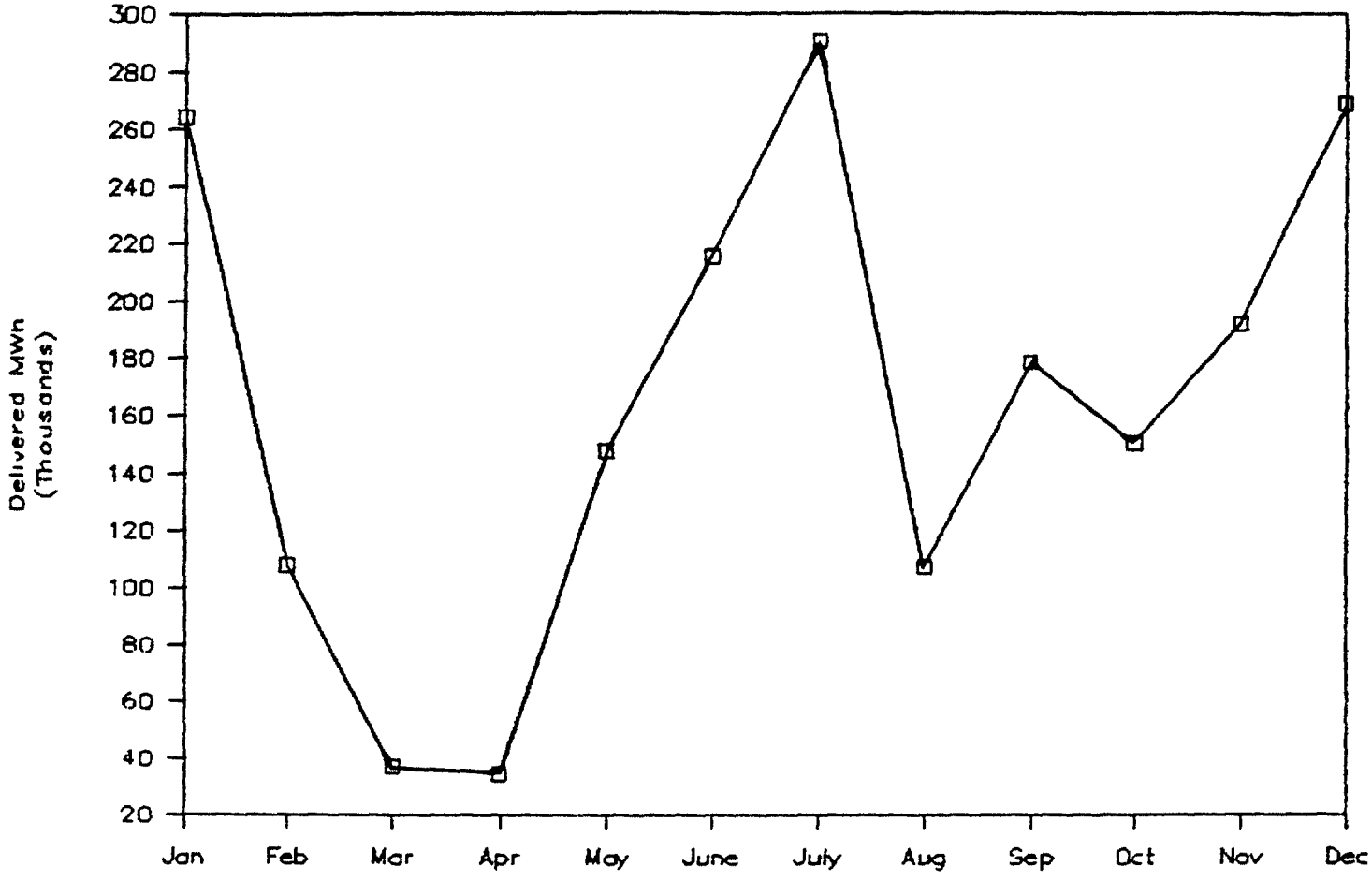

1986 transmission transactions for the American Electric Power Company [2]

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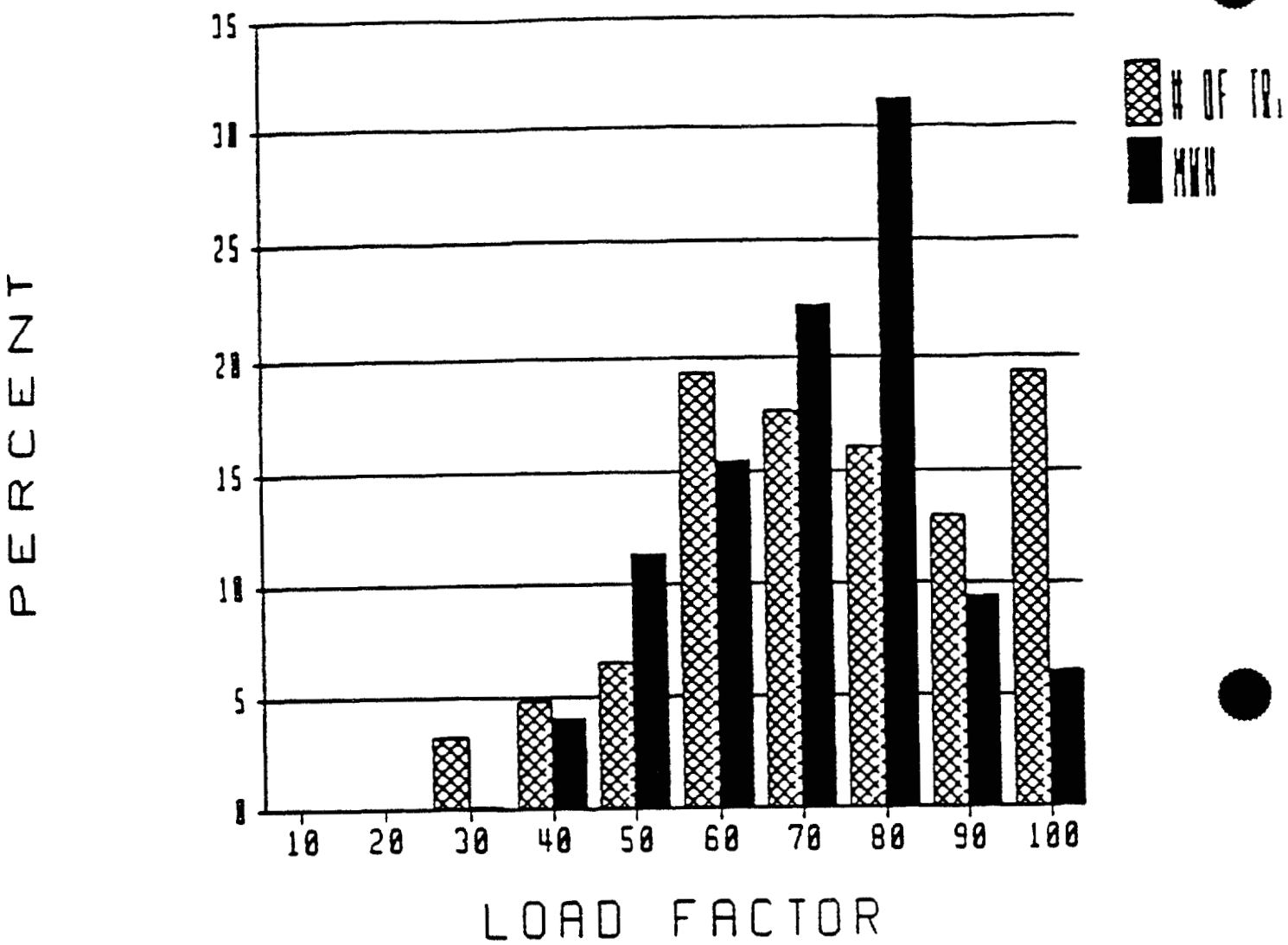

Load factor analysis of wheeling transactions [2]

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RETAIL VS WHOLESALE WHEELING

The Energy Policy Act of 1992 gave the FERC, for the first time, broad authority to order utilities to provide transmission services (wheeling) for wholesale providers of electricity The Act specifically denied the FERC authority to order retail wheeling, reserving action in that area to the states

The desirability of retail wheeling was a matter of debate before the passage of that act and has continued to be For example, a key report (1B) by the Department of Energy, a technical annex to the National Energy Strategy, questions whether retail wheeling offers any efficiency gains and points out that it could cause administrative and reliability problems, using words like "burdensome," "more complex," "far more difficult," etc On the other hand, experimental retail wheeling was the subject of a 1992-1993 proceeding before the Michigan PSC In that case the author provided testimony along the following lines on behalf of Detroit Edison

Much of this debate has overlooked the fact that retail wheeling (wheeling power to an end-user) is invariably only the wheeling of money to the end-user

- Contractually or legally the power is wheeled from the seller to the buyer

- Physically the power is wheeled from the seller to the host (wheeling) utility's power plants That is, physically, retail wheeling is a sham

Consider the next three figures Suppose an existing customer, B (buyer), decides that from 9 00 a m to 10 00 a m , instead of buying 2 MW from his host utility, he will buy it from S (seller), an independent power producer or another utility, and wheel it through his host utility This is legal or contractual wheeling from S to B

Suppose that at that hour the host utility's economic dispatch program has unit G2 operating at its upper limit, with G1 the marginal unit, which will

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respond to any change in load Then when the wheeling transaction is consummated, G1 will reduce its output by the amount of the transaction The changes in flows (physical wheeling) will be between S and G1, not between S and B

Similarly, if between 10 00 p m and 11 00 p m unit G1 is at its minimum, with G2 the marginal unit, then a contractual wheel from S to B would be consummated by reducing G2 by the amount of the transaction All of the physical effects would be between S and G2

This phenomenon does <u>not</u> accompany bulk or wholesale wheeling There, the buyer (B) has his own source of generation -- typically, his own power plants Then, when power is wheeled from S to B, it is B's generating units whose output is reduced, not the wheeling utility's, and the physical effects are from S to B, not from S to the wheeling utility's plants

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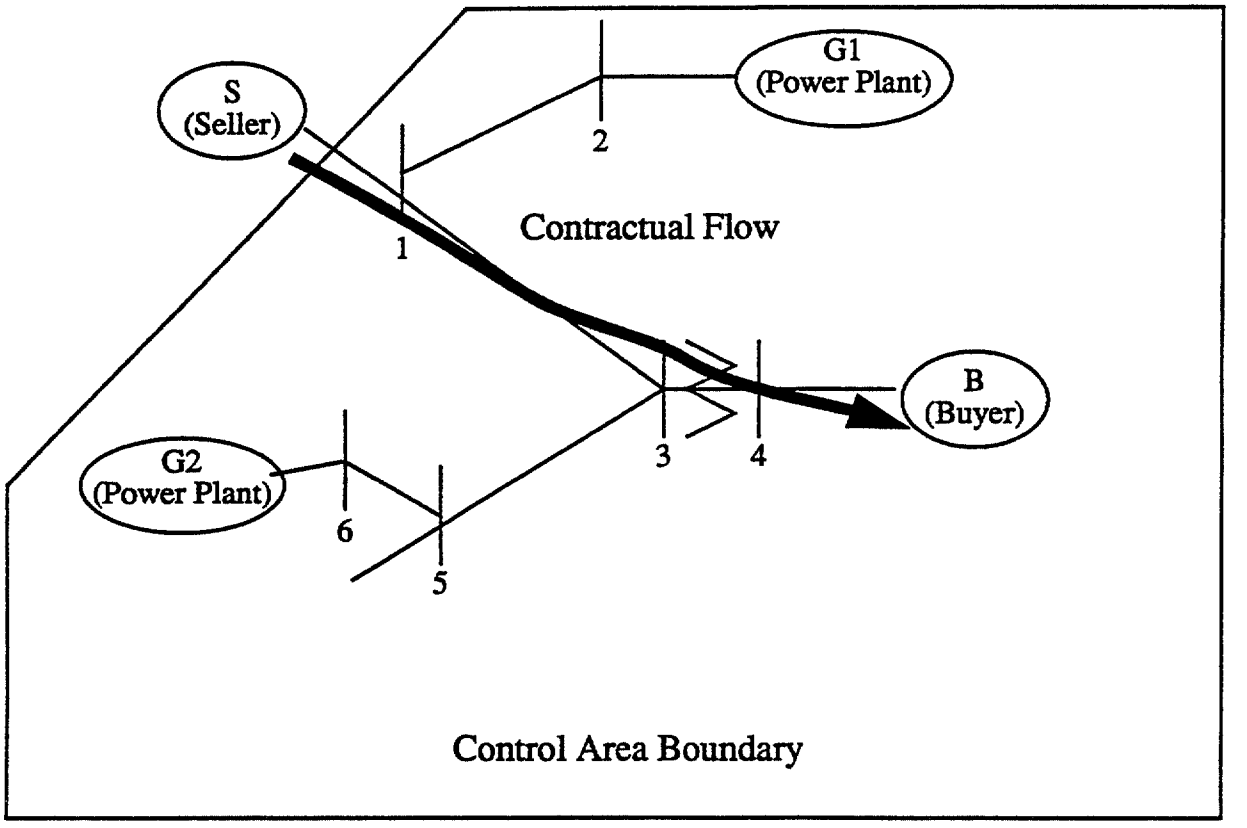

In retail wheeling, contractual flows are from seller to buyer The transformer between buses 3 and 4 is the physical link between the distribution system (bus 4 and the line to the buyer) and the transmission system

Retail Wheeling Contractual Flow

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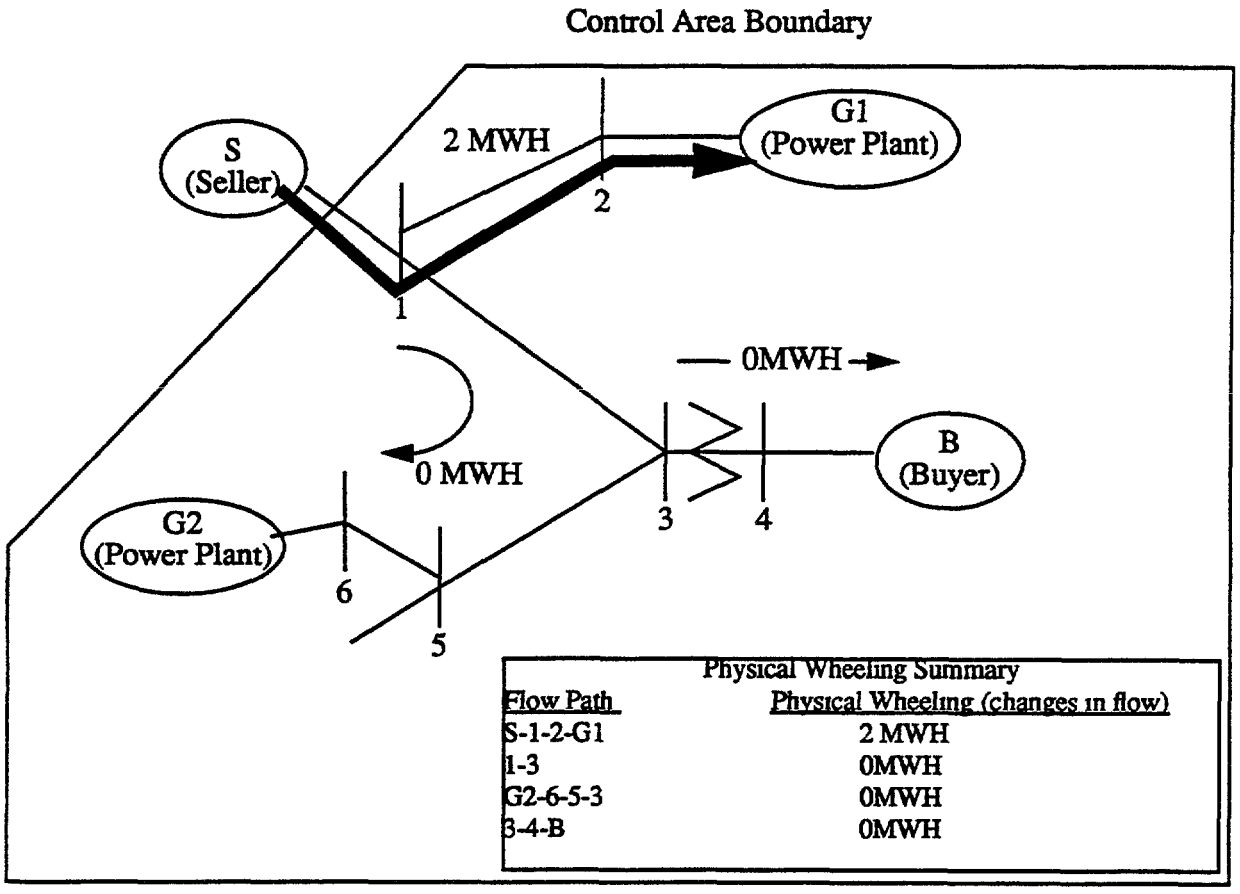

Physical Wheeling Summary

Flow Path	Physical Wheeling (changes in flow)
S-1-2-G1	2 MWH
1-3	0MWH
G2-6-5-3	0MWH
3-4-B	0MWH

Between 9 00 a.m and 10 00 a.m , G1 is the marginal plant. Its output is reduced by the amount the sellers increases (2 MW) causing changes in flows (physical wheeling) between seller and G1 Contractural wheeling is between seller (S) and Buyer (B)

Retail Wheeling Causes Physical Wheeling from Seller to G1.

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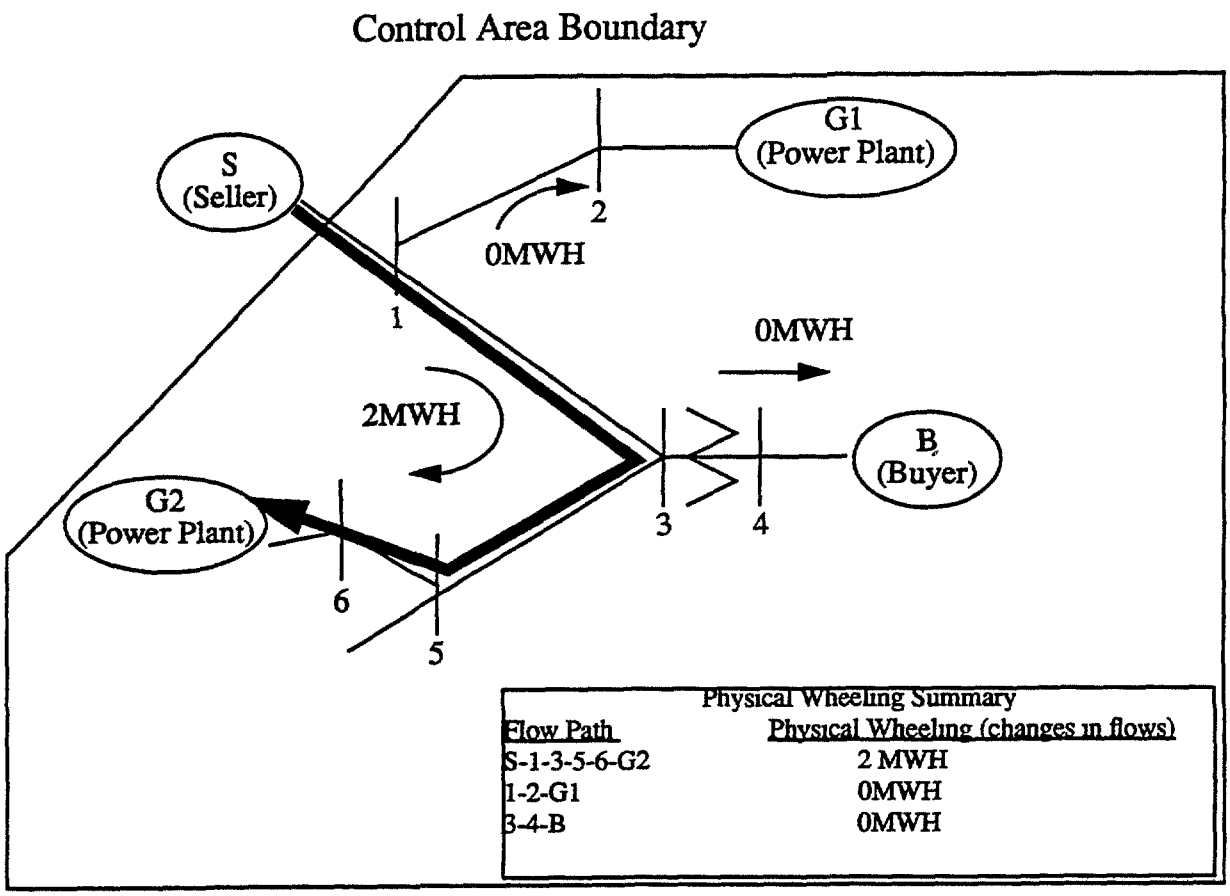

Between 10 00 p m and 11 00 p m , with G2 the marginal plant, the physical wheeling (changes in flows) is between S and G2 Contractual wheeling remains between the seller (S) and Buyer (B)

Retail Wheeling also Causes Physical Wheeling to G2.

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III ECONOMIC ISSUES -- COSTS AND PRICES

COSTS AFFECTED BY WHEELING

- Transmission facilities costs
- Transmission O&M costs
- Distribution facilities costs
- Distribution O&M costs
- Administrative and general costs
- Losses
- Cost of reactive power
- Cost of voltage control
- Cost of spinning reserve
- Cost of operating reserve
- Cost of flow regulation
- Cost effect on economic dispatch
- Opportunity cost
- Congestion cost
- Other external costs

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COST BASES

- Imbedded, average, fully-allocated
- Marginal
  (short-run, long-run)
- Incremental
- Opportunity
- External

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MARGINAL COST OF WHEELING

The marginal cost of wheeling to the wheeling utility (in cents/kWh) can be calculated via this formula.

$$\textit{Marginal Wheeling Cost} = \frac{\textit{Change in Wheeling Utility Costs}}{\textit{Small Change In Amount Wheeled}}$$

The marginal wheeling cost can be calculated using constrained economic dispatch and load-flow theory

Equation may include a term to reflect security or flow constraints In addition, the wheeling utility may not have enough transmission capacity to serve all the proposed transactions If it doesn't, this equation becomes still more complicated to reflect the cost of new facilities or to allocate the network to the most desirable transaction The marginal wheeling cost may be negative -- for example, if wheeling makes losses go down

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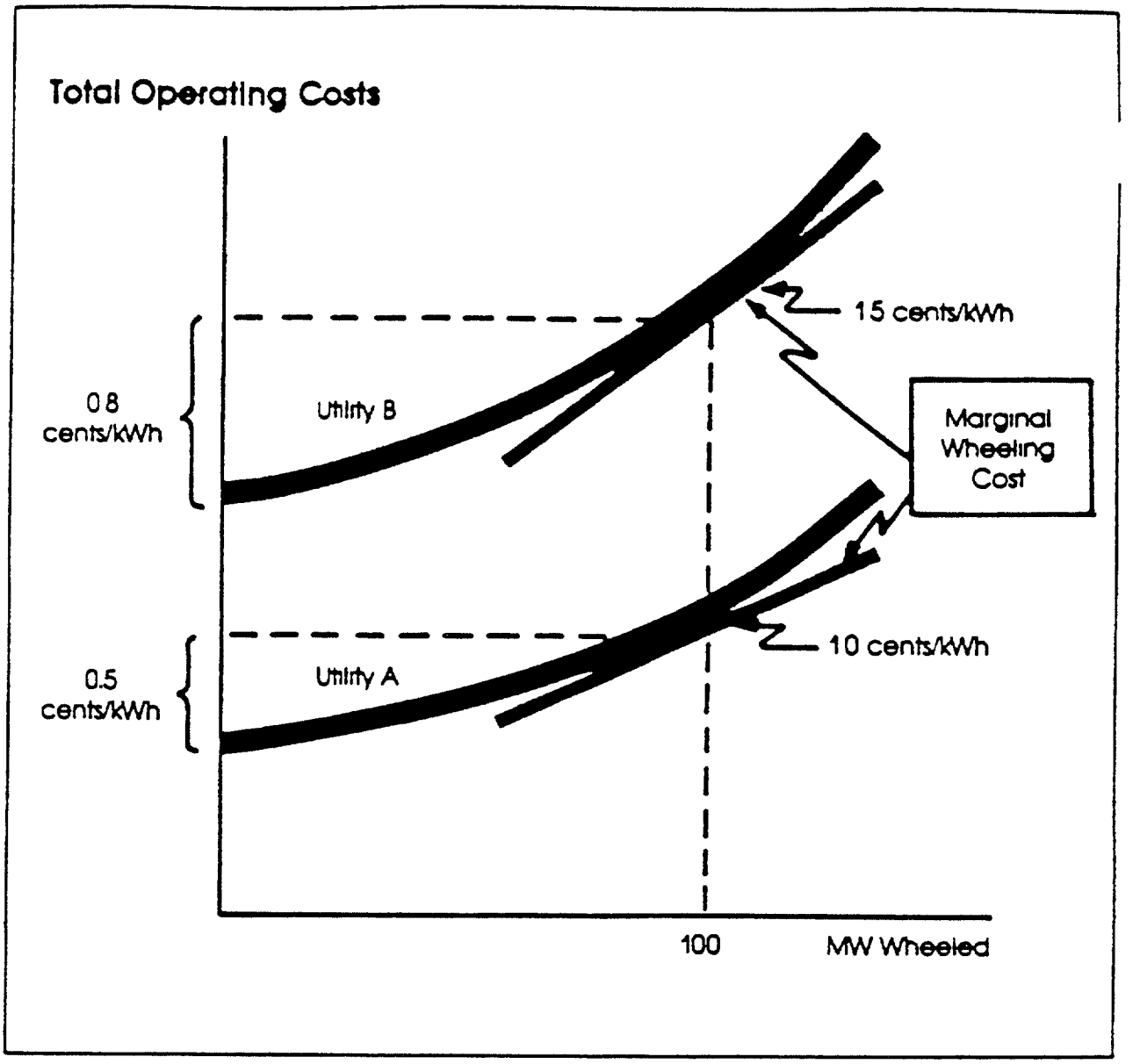

Marginal wheeling costs and incremental wheeling costs are shown for two hypothetical wheeling utilities

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Table 1

Transactions involving two different wheeling utilities

	Wheeling Through Utility A	Wheeling Through Utility B
Wheeling rate (marginal wheeling cost)	1 0 cents/kWh	1 5 cents/kWh
Less		
Total change in wheeling utility's operating costs	0 5 cents/kWh	0 8 cents/kWh
Change in net operating income to wheeling utility	+0 5 cents/kWh	+0 7 cents/kWh
Less		
Fixed capital costs	0 8 cents/kWh	0 5 cents/kWh
Change in total revenues to wheeling utility	-0 3 cents/kWh (under-recovery)	+0 2 cents/kWh (over-recovery)

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THE DIFFERENCES BETWEEN SHORT-RUN MARGINAL COSTS AND INCREMENTAL COSTS

The distinction between marginal and incremental costs is important The preceding figure illustrates marginal wheeling costs of 1 cent/kWh and 1 5 cents/kWh for two utilities But the incremental costs, or changes in total operating costs, are only 0 5 cents/kWh and 0 8 cents/kWh, respectively, for a 100-MW wheel The nature of power systems is such that marginal costs are generally greater than incremental costs SRMC pricing theory says that each transaction is priced at the <u>same</u> marginal cost For instance, if the 100 MW shown in the figure represented three simultaneous wheeling transactions, of say 10 MW, 60 MW, and 30 MW, in the same direction across the same wheeling utilities, each transaction would be priced at the same rate (1 cent/kWh or 1 5 cents/kWh), with no attempt to prioritize or assign lower marginal costs to the transaction which happened to hit the books first or which happened to be larger

From this description, it is obvious that short-run marginal costs and incremental costs, such as are traditionally developed by utilities using familiar cost reconstruction methods, are quite different Traditional cost reconstruction considers the incremental cost of a significant block of, in this instance, wheeling This cost is typically expressed in dollars, though it can be averaged over the transaction and expressed in cents/kWh wheeled, as it is in the figure SRMC, by contrast, is a rate, computed at the margin, and expressed in cents/kWh wheeled It cannot reasonably be expressed in dollars, since it represents the change in cost associated with an infinitesimally-small increment of wheeling

Which measure of cost is better? That question, as stated, is meaningless Both costs are correct, but incremental cost measures one thing, while marginal cost measures another The dashboard of a car provides an analogy

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Which is better -- the odometer, which measures distance traveled, or the speedometer, which measures speed? The answer, obviously, is that neither is better in any absolute sense while the quantities measured are related, they are different, and the information the two meters give is used for different purposes

The term "better" can be applied to incremental (or average incremental) versus marginal costs, but only if what is meant by "better" is defined This definition must recognize what use will be made of the data If the cost data is to be used for pricing of wheeling services, for instance, and if "better" has to do with optimizing the use of an existing system (maximizing the benefits to all participants), and with certain technical mathematical assumptions, then pricing on the basis of marginal costs is better than pricing on the basis of average costs -- and is, in fact, optimal [1] This is discussed by Kahn [7] A proof, specifically applied to wheeling of electric power, was developed by Schweppe *et al* [5] Rather than repeating Kahn's argument or Schweppe's proof, we will present a simple illustrative example

Suppose that a seller, a buyer, and a wheeler are considering a one-hour wheeling transaction, and that their cost structure is shown in the table below Suppose the decision on how much to wheel is to be made by the market, on the basis of prices alone (that is, without external regulatory compulsion) Then if the wheeler offers his services at a price which is equal to his marginal cost, the three will decide on a level of wheeling which minimizes their total costs

How much will they agree to wheel? At 0 MW, the marginal cost[2] to the wheeler is 3 mills/kWh The difference between the marginal costs of the buyer and seller is 53 mills/kWh The buyer and seller will gladly pay the wheeler 3 mills/kWh for his services At 50 MW wheeled, if the wheeler

---

1 If, on the other hand, the price is to be set so as to exactly recover incremental operating costs, then it is better to use average incremental cost to calculate prices

2 Note that in this example, marginal cost refers to the cost effect on seller, buyer, and wheeler of changes in wheeling For the seller, this reflects marginal cost of increasing generation For the buyer, this is the marginal (decremental) cost of reducing generation For the wheeler, it is the marginal cost associated with increasing the flows through his system

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prices his services at his marginal costs (8 mills/kWh), the other two will still want to buy The breakeven point is 100 MW At any level of wheeling below 100 MW, the wheeler's price will encourage the buyer and seller to wheel more At any level above 100 MW, his marginal-cost price will discourage wheeling

For each level of wheeling, the incremental cost portion of the table shows the difference between each party's costs and the costs he would have incurred with no wheeling This table shows that the 100 MW level to which this pricing structure will drive the market is, in fact, optimal Savings due to wheeling increase as the quantity wheeled increases, up to 100 MW If more than 100 MW is wheeled, savings decrease

At 100 MW of wheeling, with wheeling priced at short-run marginal costs, the wheeler is paid $1300 by the other two parties Since his incremental costs are $800, he makes $500 profit The total savings are $2500, so the remaining $2000 is shared by the buyer and seller

Suppose the price of wheeling were reduced so that the wheeler recovered only his costs, with all profits accruing to the buyer and seller At 100 MW, the wheeler would charge $800, or 8 mills/kWh, as the average incremental cost portion of the table shows But that price would induce the buyer and seller to wheel more power -- not as much as 150 MW, but certainly more than 100 MW This would reduce the overall savings to the three parties, which are maximized at 100 MW

Kahn's reasoning, and Schweppe's proof, are valid for more complex systems, which may include multiple wheelers, contending buyers and sellers, multiple simultaneous wheeling transactions, and constraints of various kinds

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TABLE

MARGINAL VS INCREMENTAL COSTS AS A BASIS FOR PRICING

Quantity Wheeled, MWh	0	50	100	150
Marginal costs, mills/kWh ($/MWh)				
Seller	20	30	40	50
Buyer	-73	-63	-53	-43
Wheeler	3	8	13	18
Total	-50	-25	0	25
Incremental Costs, $/h				
Seller	0	1250	3000	5250
Buyer	0	-3400	-6300	-8700
Wheeler	0	275	800	1575
Total	0	-1875	-2500	-1875
Average Incremental Costs, mills/kWh ($/MWh)				
Seller	0	25	30	35
Buyer	0	-68	-63	-58
Wheeler	0	5 5	8 0	10 5
TOTAL	0	-37 5	-25 0	-12 5

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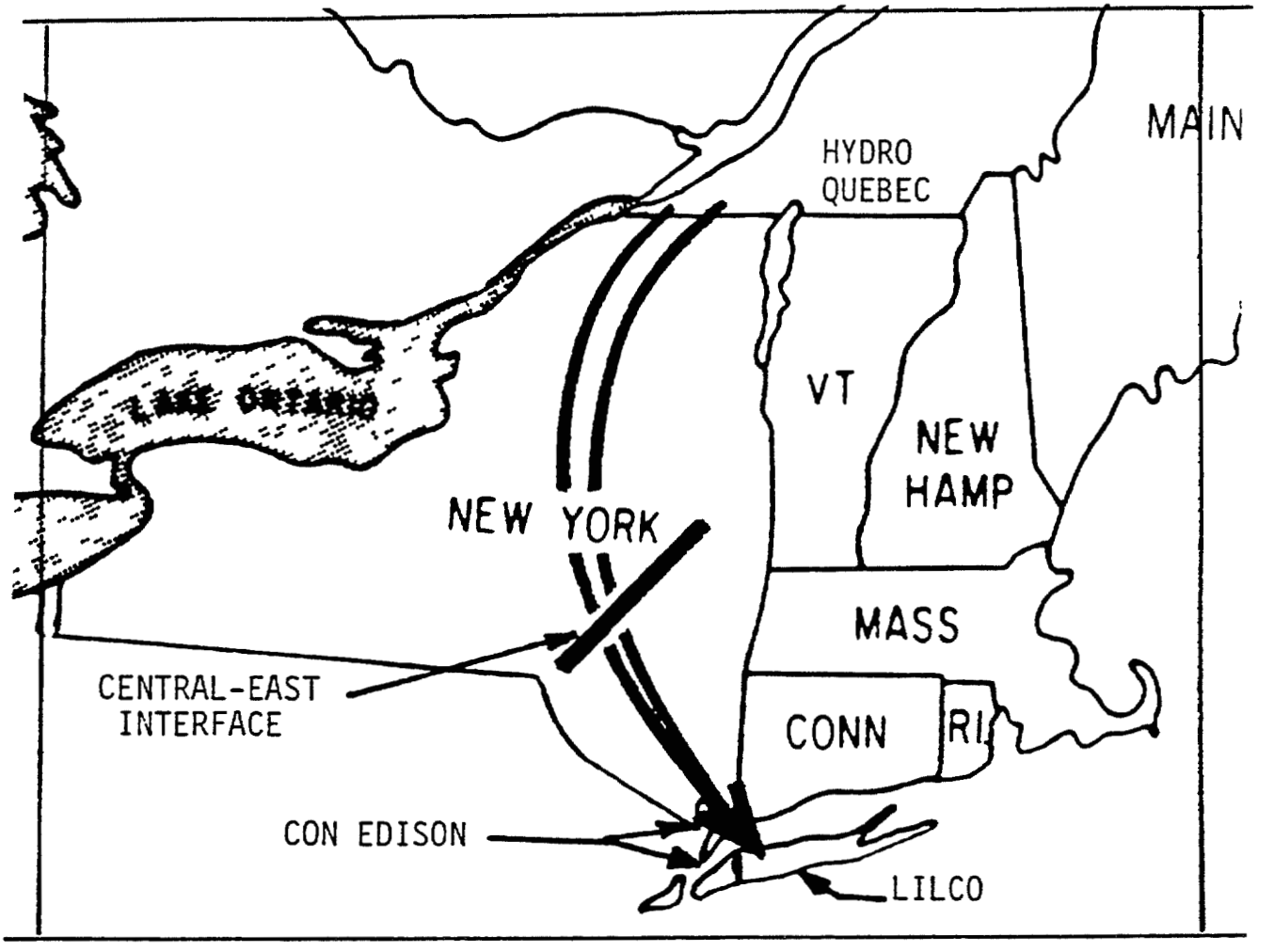

Wheeling from Hydro Quebec to LILCO [8]

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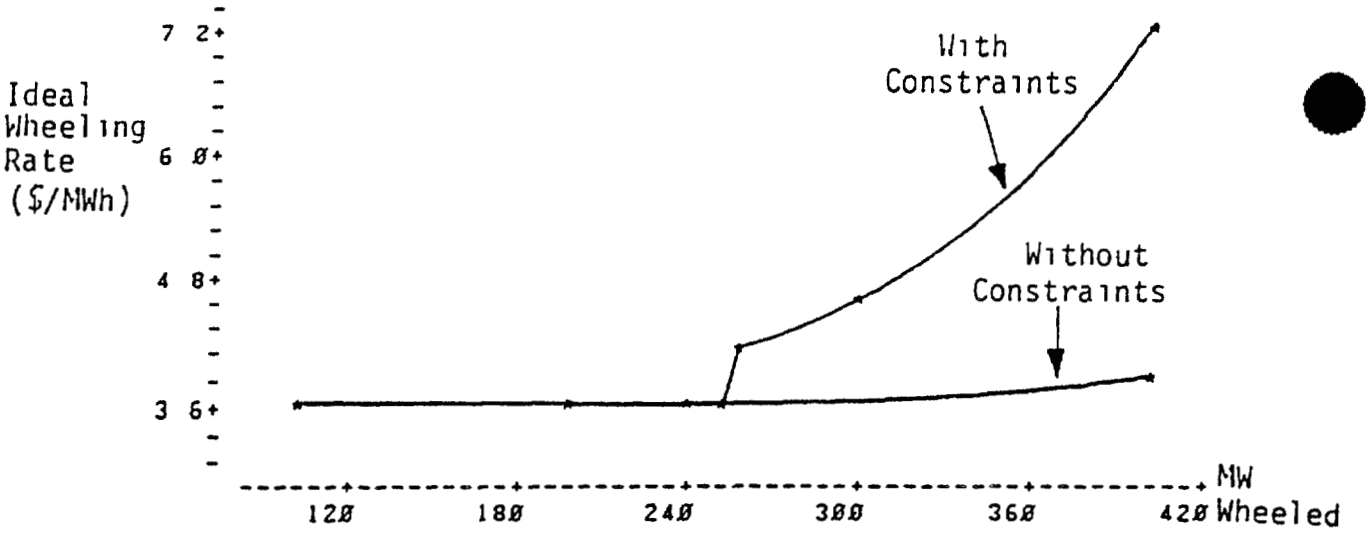
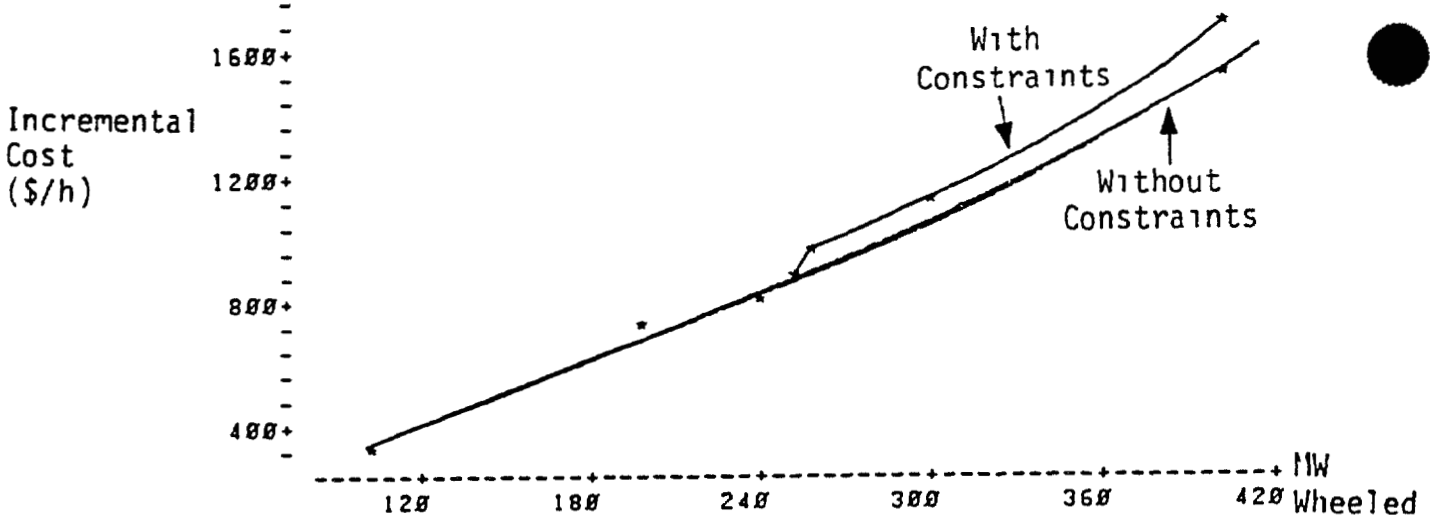


Ideal wheeling rates with and without flow constraints



Incremental (compared to no wheeling) wheeling cost, with and without constraints

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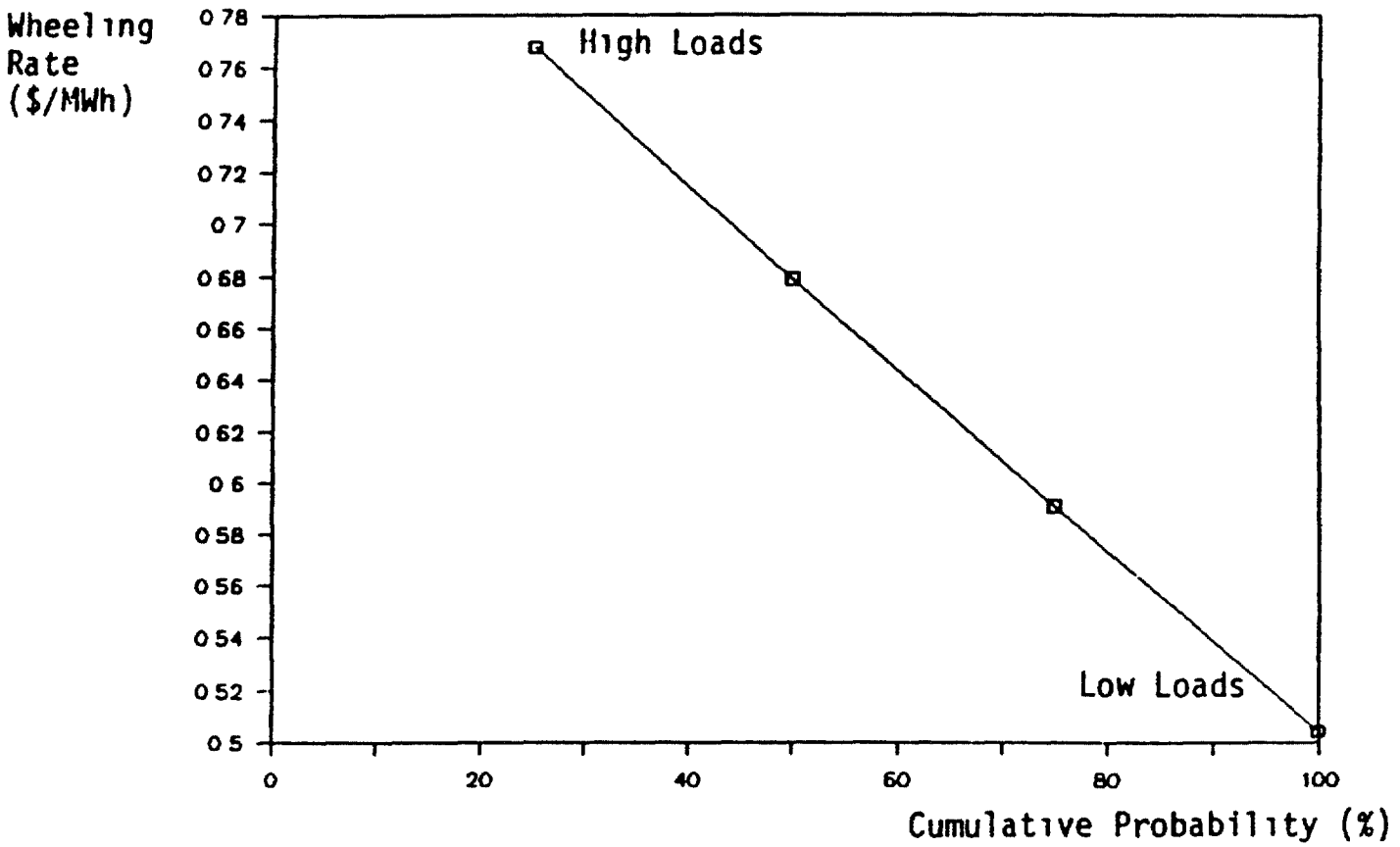

Wheeling-rate distribution curve, Kings Park to West Nyack wheeling case

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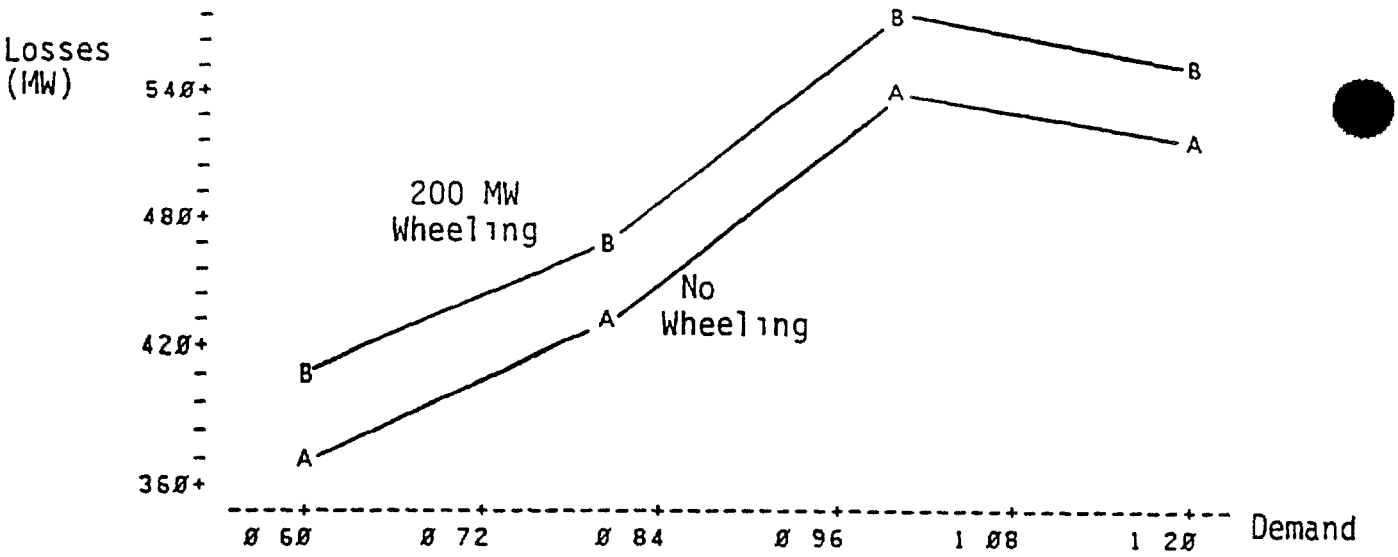
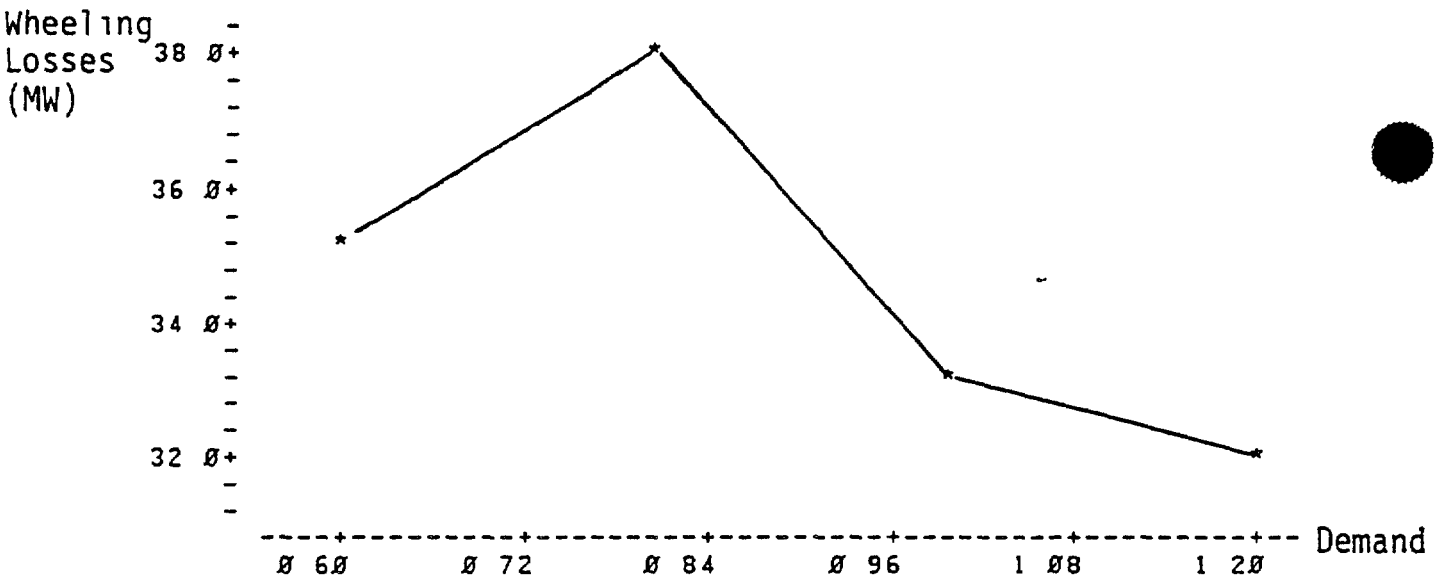


Total losses vs demand



Losses due to wheeling vs demand

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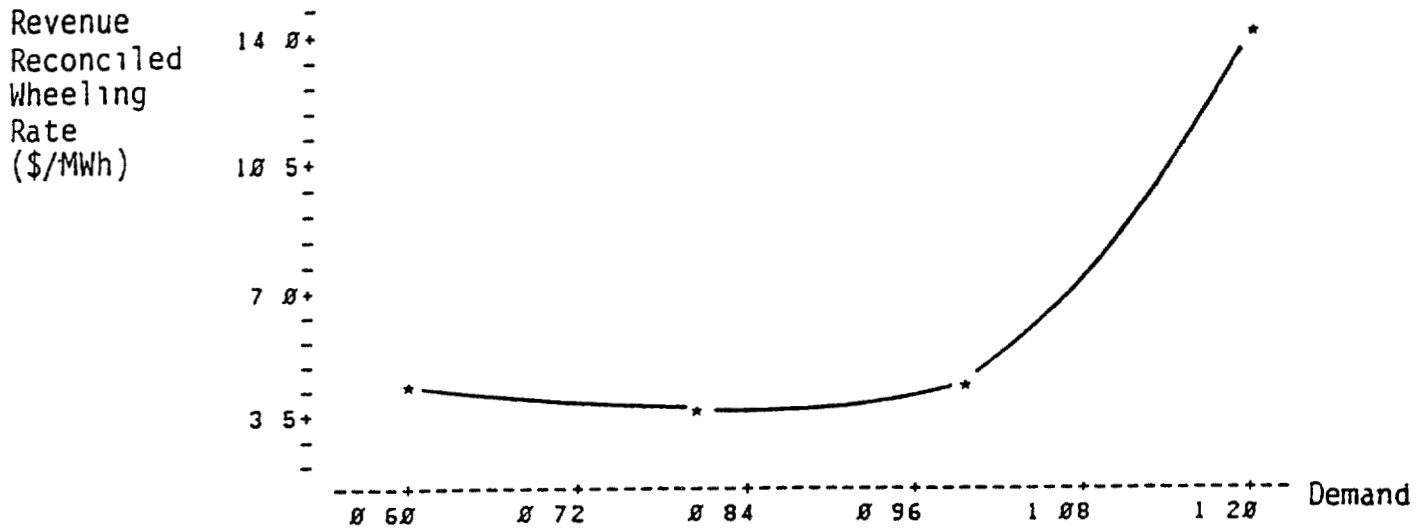
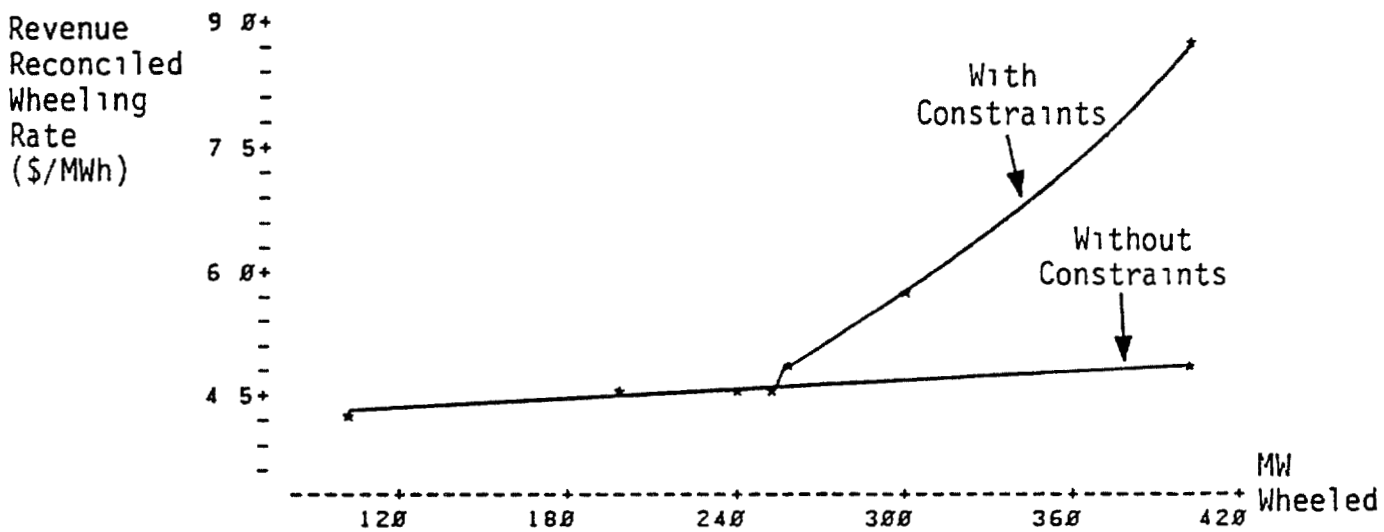


Revenue - reconciled wheeling rate vs demand



Revenue - reconciled wheeling rate vs MW wheeled

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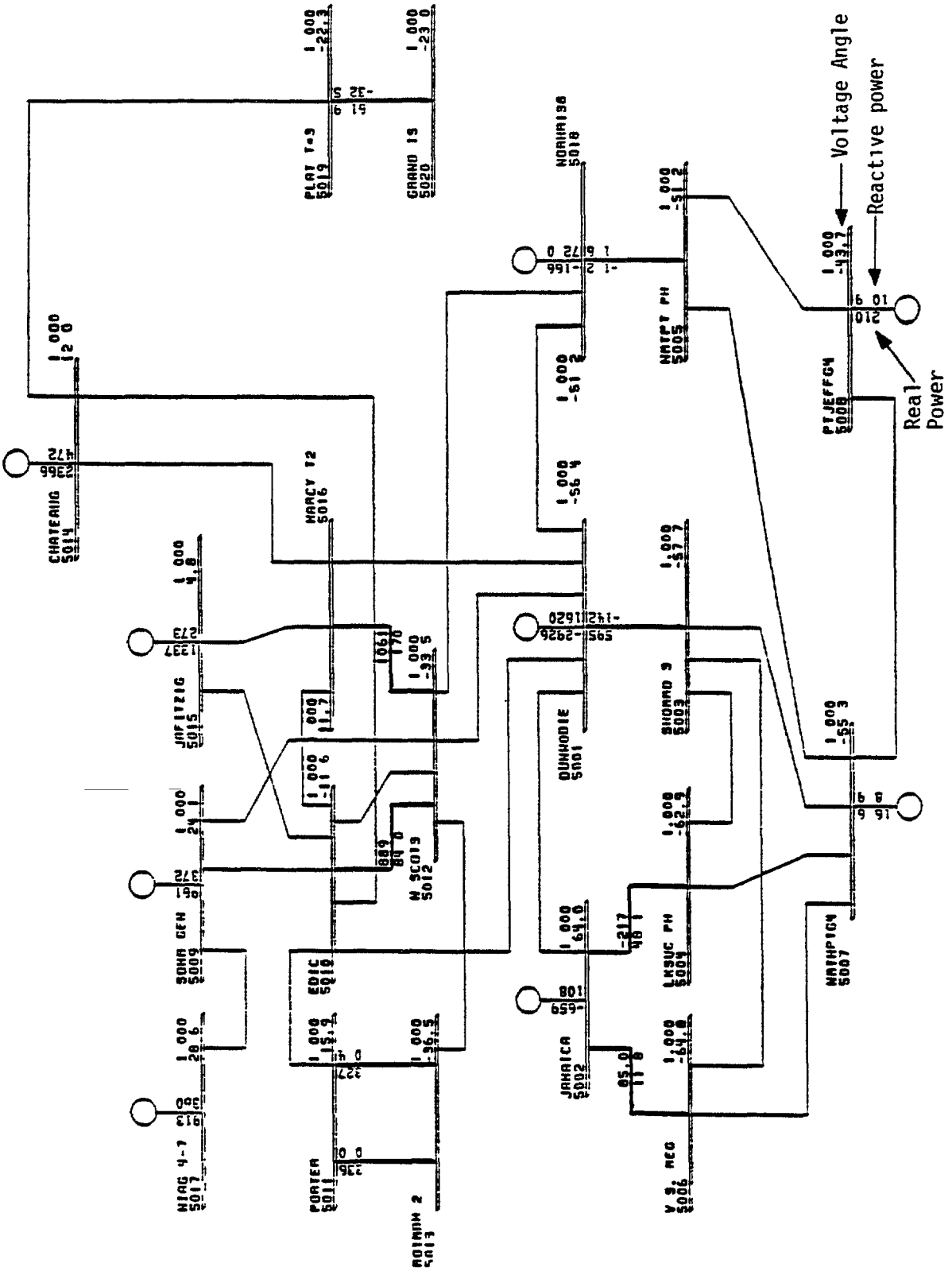

20-Bus Reduced Network

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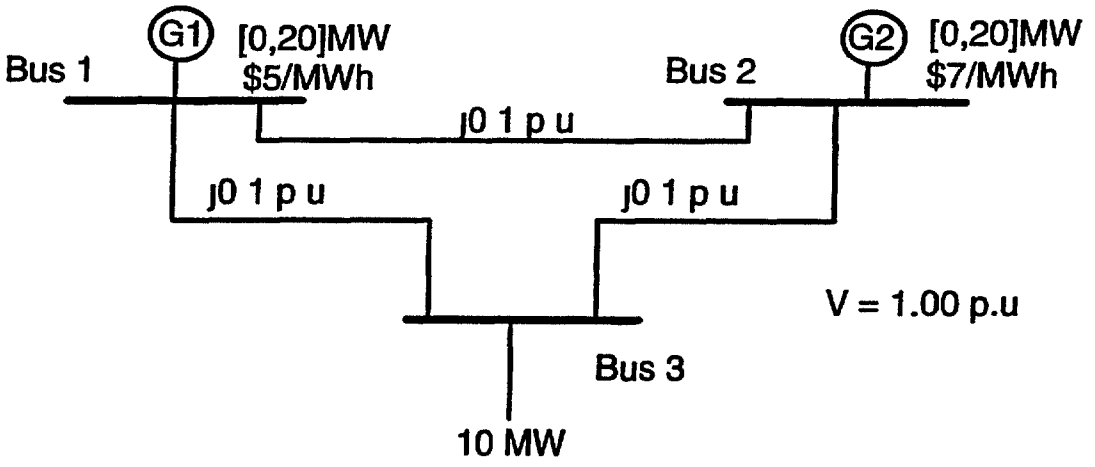
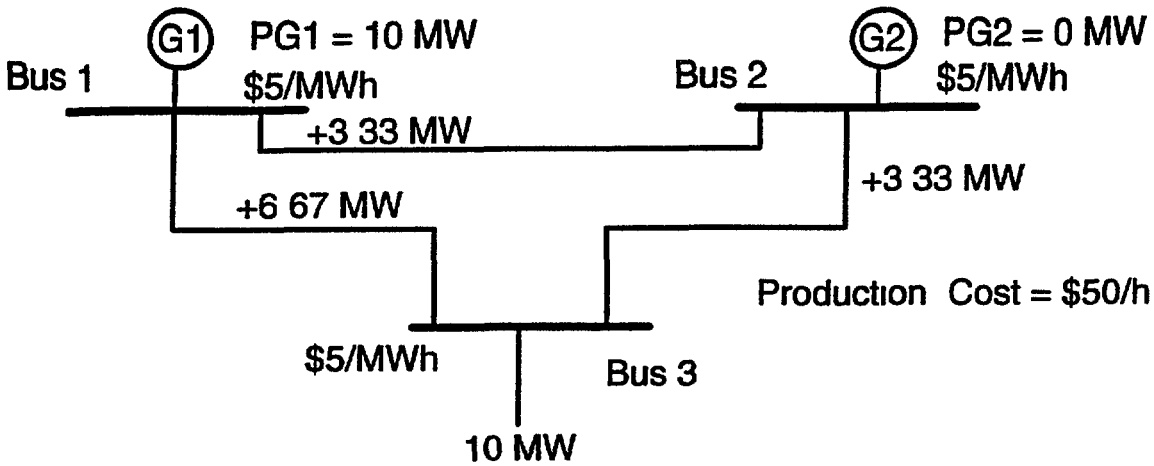


MARGINAL COSTS: EXAMPLE

Computed Using an OPF Program System



MARGINAL COSTS: EXAMPLE

Unconstrained Solution

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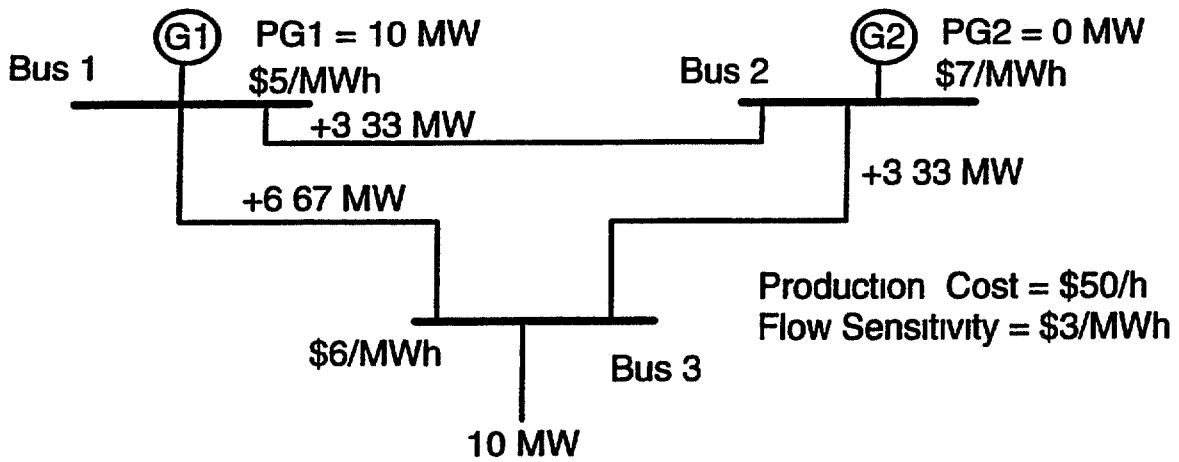

MARGINAL COSTS: EXAMPLE

MW Flow on Line 1-2 Limited to 3.33 MW

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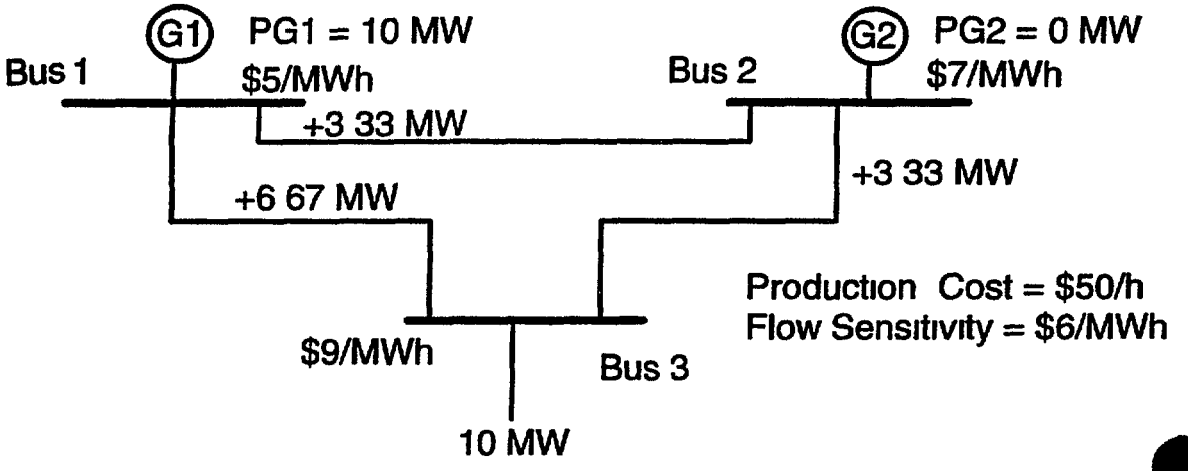

MARGINAL COSTS: EXAMPLE

MW Flow on Line 1-3 Limited to 6.67 MW

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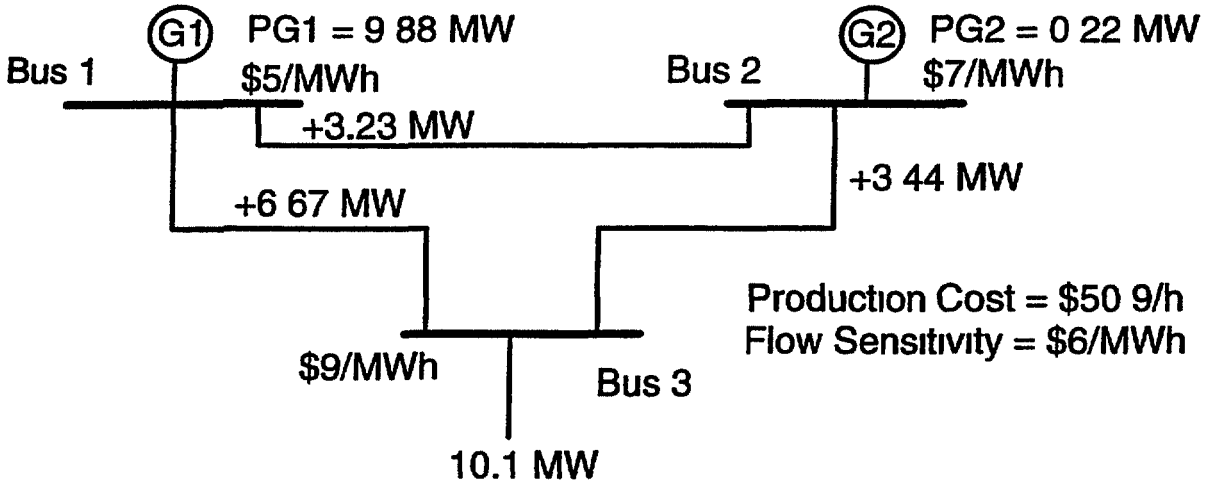

MARGINAL COSTS: EXAMPLE

MW Flow on Line 1-3 Limited to 6.67 MW

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C PRICING OBJECTIVES

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NOT ALL WHEELING IS GOOD

Buyers, sellers and wheeling utilities should be willing to cooperate to achieve "good" wheeling while discouraging "bad" wheeling Unfortunately, the difference between good and bad is not always clear Two objectives are to improve overall economic efficiency, and to recover the wheeling utility's costs Then, by definition, good wheeling satisfies both objectives, while bad wheeling does not

Note that bad wheeling may look good to both the buyer and seller[1] For example, suppose the buyer is an industrial customer in the wheeling utility's service territory and the seller is another utility The following costs are assumed

MARGINAL OPERATING COSTS
(mainly fuel)

Selling Utility	*4 cents/kWh*
Wheeling Utility	*3 cents/kWh*

Suppose the wheeling utility sells to the industrial customer at 8 cents/kWh (which includes fixed costs in the rate base) Here the selling utility and the industrial customer would be willing to deal instead, at say 6 4 cents/kWh Such a transaction would be bad as overall production efficiencies would decrease, the selling utility would increase its 4 cents/kWh generation and the wheeling utility would decrease its 3 cents/kWh generation

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Economic Efficiency	Wheeling parties should see wheeling rates which motivate them to behave in a socially desirable fashion, e g , ideally their wheeling levels should be as if they were "seeing" the Ideal spot wheeling price
Equity	The wheeling utility's own customers should not subsidize the wheeling
Freedom of Choice	Wheeling parties should have a high degree of freedom to choose their own patterns
Acceptance and Understanding	Wheeling parties should be able to understand the nature of the transactions and believe that they are fair
Utility Control	The wheeling utility's job of running the power system should not be compromised
Wheeling Parties' Control, Operation, and Planning	The wheeling parties' reaction to transactions should not have to be unwieldy or unnecessarily complex [5]

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CONFLICT BETWEEN
REVENUE RECONCILIATION
and
ECONOMIC EFFICIENCY (OPTIMALITY)

- Short-run marginal costs
  - Seller -- 4 cents/kWh
  - Buyer -- 6 cents/kWh
  - Wheeling Utility -- 1 cent/kWh wheeled

- Revenue reconciliation adjustment:
  - Case A. +1 cent/kWh
    - Wheeling rate =
  - Case B- 0 cents/kWh
    - Wheeling rate =
  - Case C -0 5 cents/kWh
    - Wheeling rate =

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EXAMPLE OF PRICING OBJECTIVES

- Inquiry Concerning FERC's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act (November 3, 1994)

- **Objectives:** (1) embedded cost revenue requirement, (2) comparable, (3) promote economic efficiency, (4) promote fairness (no subsidization by one customer class), (5) practical and easy to administer

- **Conforming** Tariffs (meet 1 & 2, balance 3, 4, and 5)

- **Non-conforming** tariffs (do not meet 1)

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D PRICING METHODS

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- **NETWORK SERVICE.**
  - Permits the applicant to fully integrate load and resources on an instantaneous basis in a manner similar to the transmission owner's integration of its own load and resources
  - Allows a transmission customer to distribute a given amount of transmission usage between specified resources and specified loads without having to pay multiple charges for each resource-load pairing

- **POINT-TO-POINT SERVICE**
  - "The reservation and/or transmission of energy from a specified point(s) of receipt to specified point(s) if delivery "
  - Coordination transactions (e g , economy energy transactions) often require point-to-point service

Rate structure elements reflecting type of service

- **FIRM CONTRACT** Wheeler guarantees to provide wheeling services Contract specifies conditions such as

  - Rate Renegotiation Interval (how often the rates are renegotiated, based on system conditions), for example

    - - Annual
    - - 24 hour
    - - 1 hour

  - Period Definition (when rate renegotiation interval is not specified)

    - - Flat Rate (no time differentiation)
    - - Time of Use Rate (hours within day, day of week, season of year)

- **INTERRUPTIBLE CONTRACT** Wheeler provides wheeling service subject to availability of network capacity Contract specifications include rate renegotiation interval or period definitions

- **RESERVATION CONTRACT** Wheeler agrees to provide wheeling service if buyer and seller want to use it

Rate structure elements which reflect time and operating conditions

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- **POSTAGE STAMP RATE** Rate does not depend on network flows or distances

- **CONTRACT PATH (RED LINE)** Rate depends on specified nominal path through network (sometimes drawn with a red pencil!)

- **MEGAWATT-MILE** Rate depends on line-by-line results of load flow analyses Three different approaches

  - Net Effects (consider both increases and decreases in line flows)

  - Positive difference (consider only increases in line flows)

  - Vector Difference (assume an empty system with no other flows)

- **MARGINAL COST** Rate based on marginal costs of wheeler as determined by load flows Include two types of costs

  - Losses

  - Quality of Supply (costs of system reliability)

    - - Line Overloads
    - - Cost of New Lines

Different ways of reflecting network flows into wheeling rates structure

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- **COSTS OF WHEELER**
  - Transmission Capital
    - Existing
    - Special Needed Construction
  - Generating Capital (if there is obligation to serve)
  - Operating
    - Losses
    - Re-dispatch (to prevent overloading lines)
    - Lost Opportunities (for other purchases or sales)
  - Possible Future (for Long Run Marginal Costs)
    - Capital
    - Operating
- **BENEFITS TO BUYER AND SELLER**
  - Operational Savings
    - Fuel
    - Reserves
    - Reduction in Unserved Demand
  - Capital Not Spent
    - Transmission
    - Generation

Costs and benefits to be considered when specifying a wheeling rate level

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POSTAGE STAMP RATES [11]

Cents/kWh	A flat rate per kWh generally measured at the point(s) of delivery This category includes rates stated in mills or cents per kWh, or dollars per MWH delivered
$/kW	A flat rate based on either contract or billing demand Billing demand is generally defined as the highest 30 or 60 minute integrated demand measured during the billing month In some instances a demand ratchet is employed
Demand and Energy	A two-part rate including flat rate per kWh delivered plus a demand charge expressed in kW based on metered demand
Mileage Component Rates	A rate wherein the charge is based in part upon distance, generally stated in dollars per kW per circuit mile Billing demand is generally calculated as the highest 30 or 60 minute integrated demand during the billing month

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OTHER

Formulary Rates

An average embedded cost rate calculated by a formula which varies the monthly charge with changes in demand and with changes in specified costs

Fixed Charges

This type of rate is customarily associated with the exclusive use of facilities (e g , transmission and/or substation facilities) by the wheeling customer or equalization charges for jointly-owned or pooled facilities The rate, generally stated in dollars per month, reflects the carrying charges associated with specific facilities

No Compensation

Wheeling services provided without charge in return for reciprocal services provided by the recipient of the wheeling service

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FIRM RATES [10]

Knowledgeable people at the FERC indicate that firm wheeling rates are almost always based on the total embedded costs of the transmission facilities of the wheeling utility These costs usually consist of (1) return on the transmission rate base, (2) depreciation of transmission facilities, (3) transmission operation and maintenance expenses, (4) allocated taxes, and (5) some share of administrative and general expenses The annual embedded costs assigned to the transmission function (EC_t) are then divided by a measure of the system peak (the single annual peak, an average of 12 monthly peaks, or some other measure of system peak) to derive an annual cost or charge per kilowatt.

$$\$/kW - yr = (EC_t) / (kW\ peak)$$

An annual figure may be adjusted to be a monthly, weekly, or daily charge

CONDITIONALLY INTERRUPTIBLE RATES [10]

Some utilities offer conditionally interruptible service Although the full details are not provided, the NEPCO tariff indicates that for Rate T-PTF, the numerator of the rate equation is based on embedded costs, as discussed for firm rates However, the denominator is based on system capability rather than system peak, as was the case for firm rates

$$\$/kW - yr = (EC_t) / (kW\ system\ capability)$$

System capability includes kilowatt capability of all generating units and may also include the kilowatt capability of interconnection points with other systems which could be used for importing power

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UNCONDITIONALLY INTERRUPTIBLE RATES [10]

Almost all of the rates for unconditionally interruptible service are stated in terms of a charge per kilowatt-hour The LILCO rate schedule states the methodology used to determine the rate It is derived by dividing the monthly firm rate (a per kilowatt charge) by 730 (the number of hours in a month)

kWh charge = (monthly kW charge) / (730)

The rate that results from this type of calculation is known as a 100-percent load factor rate It represents the charge per kilowatt-hour that would produce the same revenues as a specified demand per kilowatt, under the assumption that the same amount of power is wheeled 100 percent of the time

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Selected Features of Existing Wheeling Tariffs and Rate Schedules [10]

Wheeling Utility Tariff or Rate Schedule and Type of Service	Stated Rates ($)	Calculated Annual Rate ($/kW)	Line Loss Adjustment (%)
TARIFFS			
Bonneville Power Administration Rate Schedule IR-1 Firm			
Network Service	1749/kw/mo $ 00056/kwh		
Intertie Service	3024/kw/mo $ 00081/kwh		
Clev Elec Illum Co Vol No 1, Firm	$1 69/kw/mo	$20 28	2
Consumers Power Co Firm, Vol No 2	222/kw/wk 318/kw/wk	11 54 16 54	2 77 4 62
Interruptible, Vol No 3			
Weekly	172/kw/wk 248/kw/wk	8 94 12 90	2 77 4 62
Hourly	00125/kwh 0017/kwh		2 77 4 62
Economy Energy	15 0% of savings		
Florida Power Corp Vol No 1			
Firm	797/kw/mo extra charge	9 56 13 32 max	
Nonfirm	00109/kwh extra charge		
Florida Power & Light Co Vol No 2, Firm			System avg loss, but may use incremental loss
Firm (Schedule TD)	1207 25/mw/mo	14 49	
ST Firm (Schedule TB)	39 69/mw/day	14 49	
Emergency (Schedule TA)	1 65/mwh		
Economy Energy (Schedule TL)	1 65/mwh		
New England Power Co Vol No 3, Nonfirm			
Rate T-PTF	NEES cost/kw/mo	6 21	
Rates T-Non PTF 1,2 & 3	Extra charges	3 60 max	

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New England Power Pool Rate Schedule No 2 Firm Nonfirm	 formula/kw/mo formula/kw/mo		
Otter Tail Power Co Vol No 3, Firm	1 306/kw/mo	15 67	7%
Kentucky Utilities Schedule No 92, Nonfirm	001/kwh		
Long Island Lighting Co Schedule No 32 Firm Interruptible	 2 14/kw/mo ≥ 63/kw/mo 2 93/mwh	 25 68 12 00	System Average
Mississippi Power & Light Schedule E I T Firm ST Firm Nonfirm	 75/kw/mo ≥ 25/kw/wk 173/kw/wk ≥ 058/kw/mo 001/kwh ≥ 003/kwh	 9 00 12 00 9 00 12 00	3
Southern California Edison Schedule No 83, Interruptible	00122/kwh can increase if rate of return increases		3 3

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Prices for electricity determined for the purposes of the electricity pooling and settlement arrangements in England and Wales

1/2 hour period ending	Provisional Price for Trading on 09 12.92 Pool purchase price £/MWh	Final Prices for Trading on 11 11.92 Pool purchase price £/MWh	Final Prices for Trading on 11 11.92 Pool selling price £/MWh
0030	17 72	20 32	20 32
0100	22 92	23 52	25 46
0130	28 17	30 00	32 22
0200	28 17	30 00	32 16
0230	22 92	23 52	25 40
0300	22 92	23 52	25 41
0330	20 49	20 68	20 68
0400	18 43	20 32	20 32
0430	17 72	18 04	18 04
0500	18 16	18 04	18 04
0530	17 86	17 76	17 76
0600	17 72	18 89	18 89
0630	17 72	20 32	20 32
0700	23 03	23 23	25 14
0730	23 46	23 29	25 19
0800	26 87	23 29	25 17
0830	25 17	27 18	29 17
0900	26 87	27 58	29 56
0930	29 70	27 58	29 56
1000	29 70	27 59	29 55
1030	29 70	27 59	29 55
1100	26 87	27 59	29 56
1130	29 59	34 90	37 13
1200	26 87	34 90	37 11
1230	29 59	34 90	37 10
1300	26 87	34 89	37 12
1330	25 17	27 18	29 14
1400	20 72	27 18	29 15
1430	20 72	24 52	24 52
1500	20 62	27 18	29 16
1530	20 72	24 39	24 39
1600	28 37	27 08	29 06
1630	33 91	34 77	38 73
1700	39 47	53 41	59 56
1730	39 41	56 40	62 16
1800	33 47	50 20	55 08
1830	29 17	32 66	35 18
1900	27 95	29 13	31 11
1930	27 23	28 81	30 74
2000	26 87	27 77	29 69
2030	23 46	26 88	28 79
2100	23 46	23 29	25 11
2130	23 41	23 26	25 08
2200	23 31	23 23	25 06
2230	20 03	23 13	24 97
2300	18 13	20 68	20 68
2330	17 71	20 32	20 32
2400	17 71	18 35	18 35

Prices are determined for every half-hour in each twenty-four hour period Prices are in pounds per megawatt-hour rounded to two decimal places To convert prices to pence per kilowatt-hour the decimal point should be moved one place to the left eg £16 86/MWh becomes 1 686p/KWh Provision for the determination of pool prices is made in the Pooling and Settlement Agreements which govern the operation of the electricity pool in England and Wales The Pool Purchase Price is the basis of the majority of payments made to generators in respect of electricity traded through the pool The calculation of pool prices is a highly complex process the product of which is subject to revision or correction until final pool prices are determined approximately twenty-four days after the day of trading Accordingly due to the possibility of their revision and/or correction no reliance should be placed upon provisional pool prices for any day being the same as final pool prices for that day Final pool prices are also capable of revision Pool Selling Price is the price paid by purchasers of electricity under the pool trading arrangements It is dependent upon the determination of Pool Purchase Price Further information on pool prices is provided on behalf of the Pool by NGC Settlements Limited Anyone wishing to receive such information should telephone 0602-456789 between 8 30am and 5 15pm Monday to Friday

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Pool Pricing - England

Typical Bi-hourly prices published each morning in the "Financial Times"

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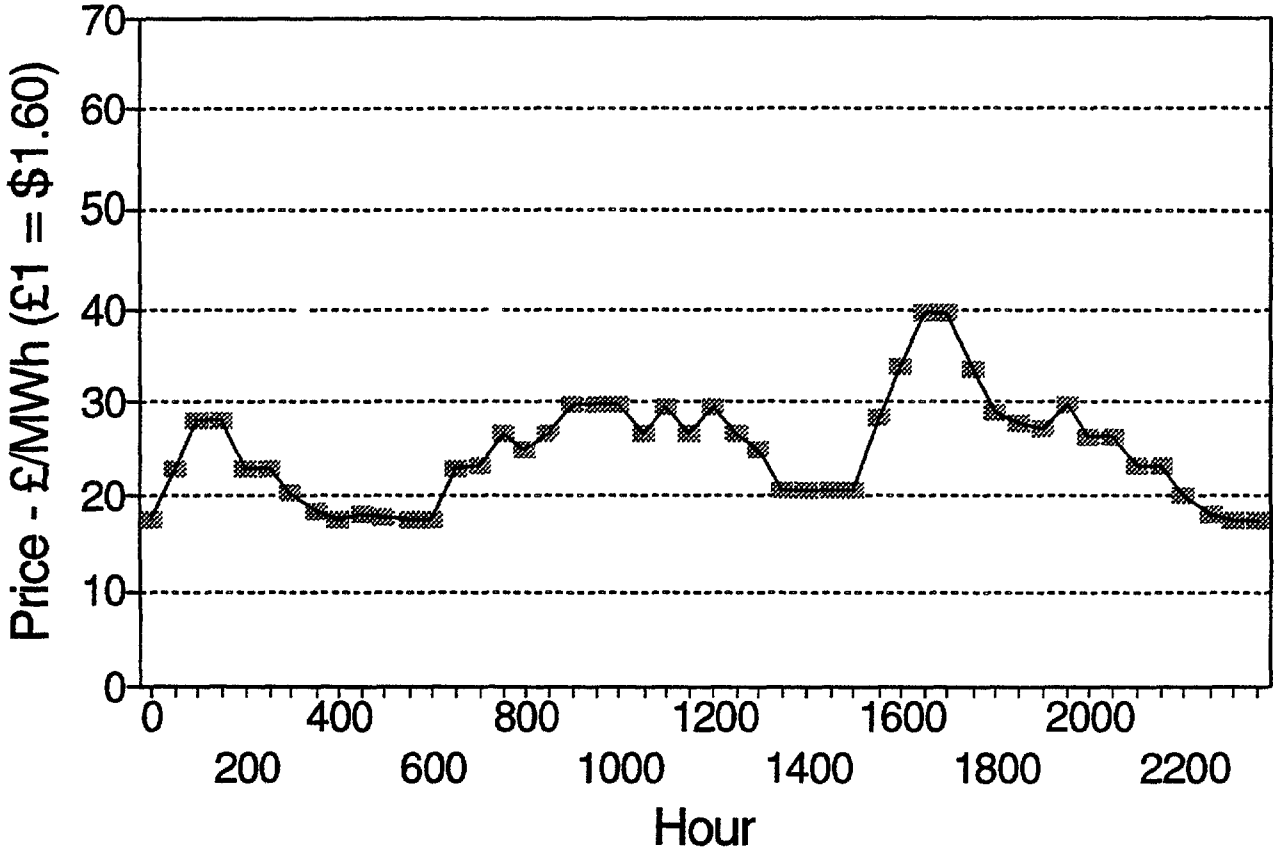
Provisional Pool Purchase Price
England & Wales - Wed., 12/9/92



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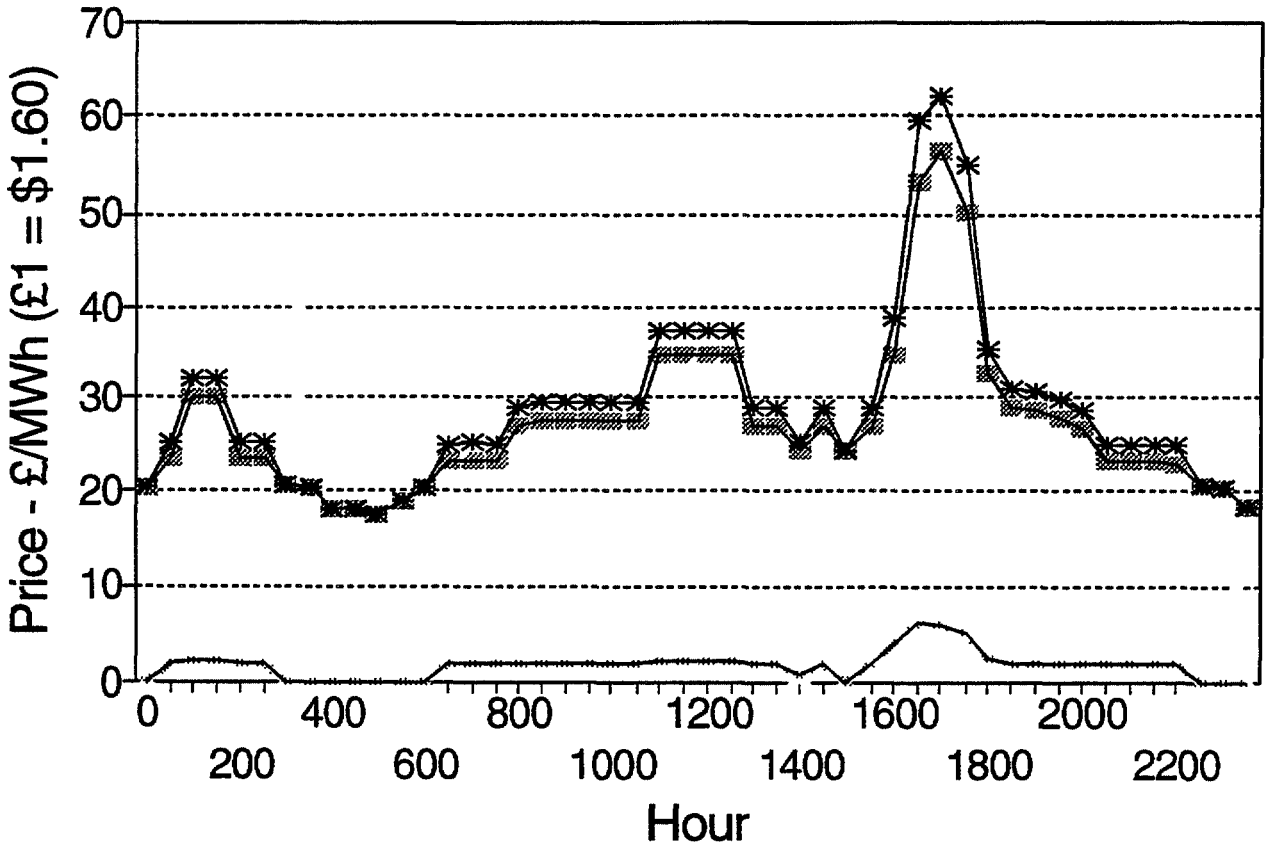
Final Buy & Sell Prices
Wednesday, 11/11/92



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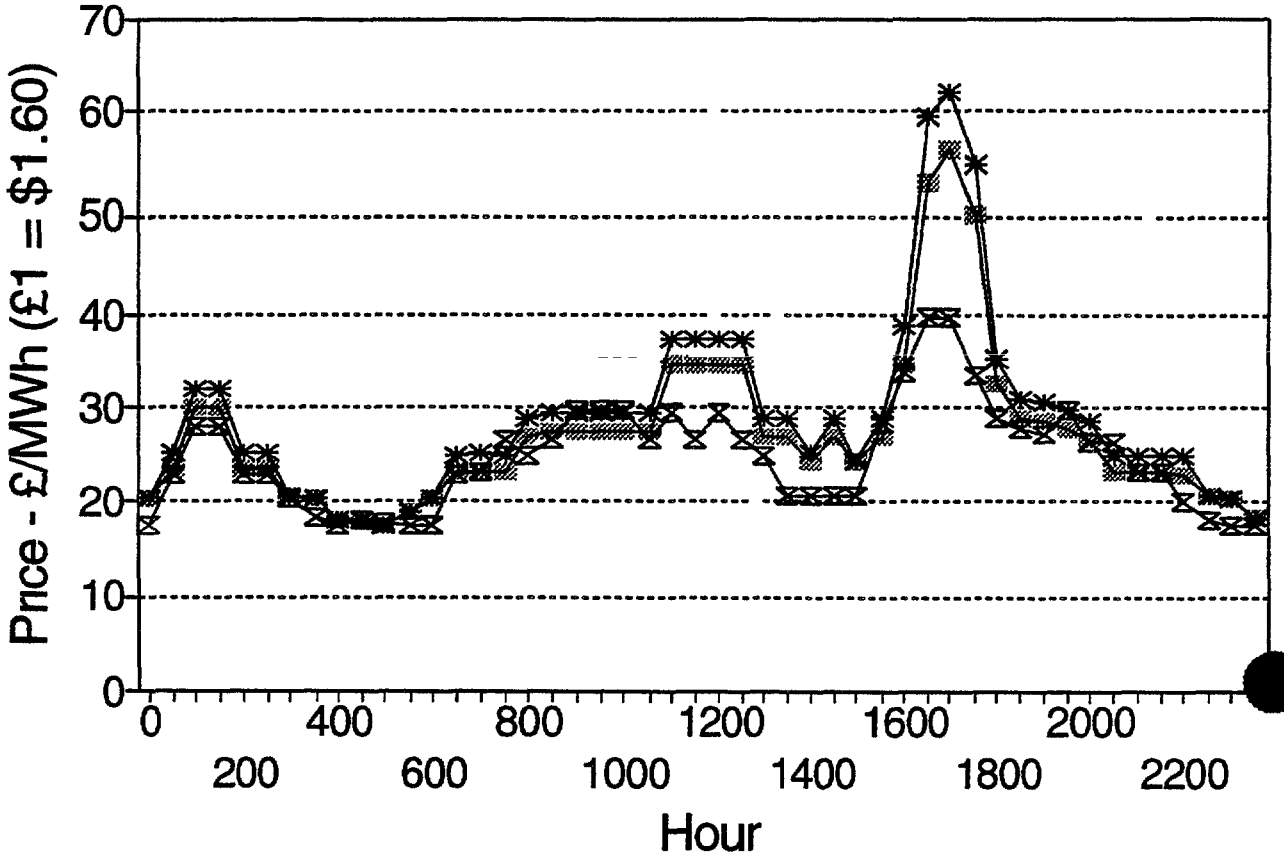
Wednesday Pool Prices
Provisional (12/9); Final Buy & Sell (11/11)



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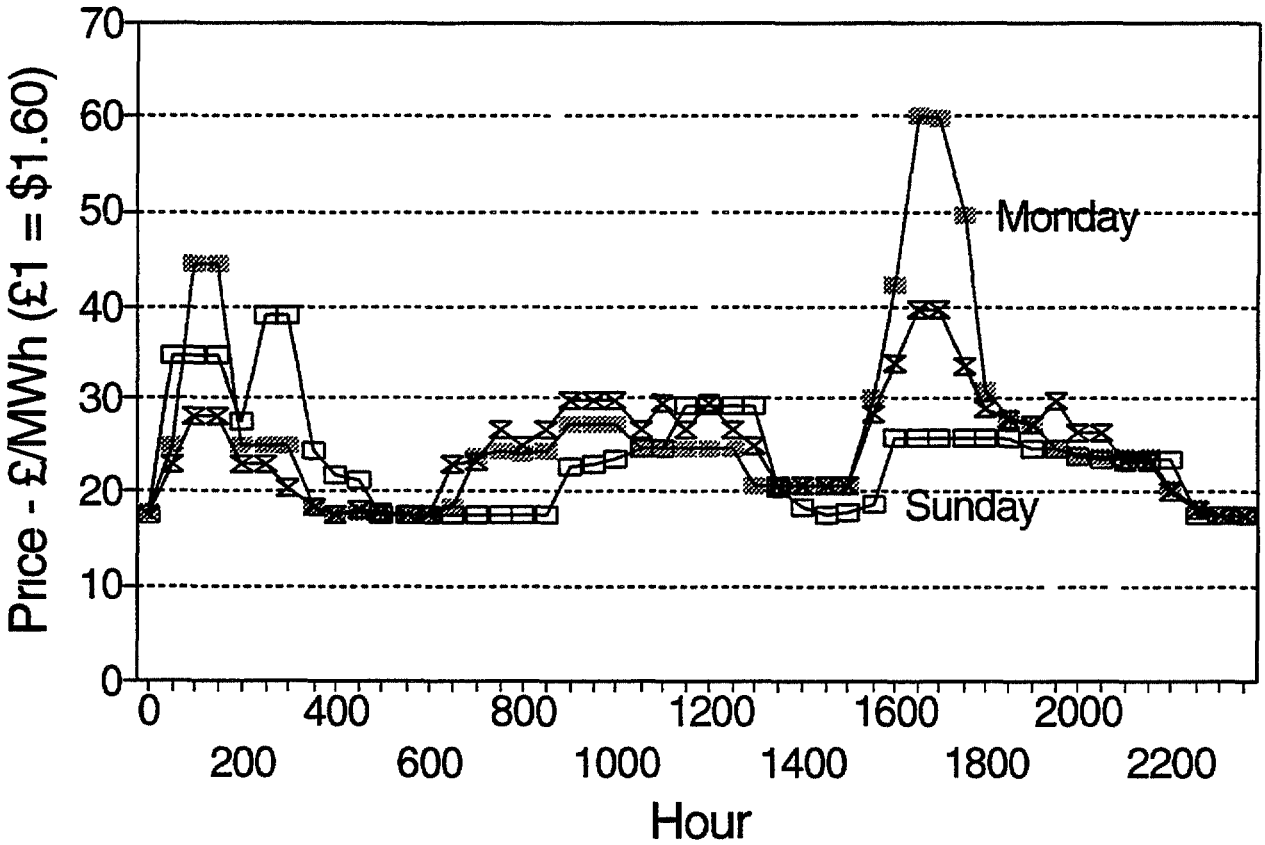
Provisional Pool Prices (1992)
Sunday 12/6, Monday 12/7, Wednesday 12/9



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EXERCISE -- RETAIL WHEELING PROPOSAL

Please read the excerpts from Maurice Brubaker's testimony on retail wheeling

1 On which of the cost bases listed in Section 3 does Brubaker build his proposed tariff? Which of the cost bases does he explicitly avoid?

2 What types of rate structure does Brubaker recommend?

3 How would you defend the cost bases and rate structure he advocates? How would you attack them? (Hint. what do you think his objective is? What other objectives might there be?)

4 Are there cost elements he excludes that you feel should be included? Why do you feel they should be included?

5 How does Brubaker's proposal deal with stranded investment, the obligation to serve, and the "no losers" test?

6 What services does Brubaker implicitly or explicitly plan to receive from the wheeling utility (Detroit Edison or Consumers Power)?

7 What would the wheeling utility have to do in order to provide retail wheeling if the purchaser chose to get 100% of his energy from an IPP?

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A TYPES OF WHEELING CONTRACTS

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DISTRIBUTION OF RATE STRUCTURES
EMPLOYED IN FIRM WHEELING ARRANGEMENTS ARRANGEMENTS
BY TYPE OF POWER WHEELED [11]

Type of Power	Postage Stamp Rates							
	$/kWh	$/kW	Demand and Energy	Mileage Compon -ent	Form-ulary Rate	Fixed Charge	No $ Compen-sation	To-tal
Entitlements	4	10	-	1	13	6	1	35
Unit Power	-	1	-	1	7	-	2	11
Full Requirements	4	7	-	-	1	-	1	13
Partial Requirements	10	33	1	-	4	3	4	55
Emergency Energy	-	1	-	-	2	4	1	8
Firm Power & Energy	15	13	1	-	-	-	1	30
Pumping Power	1	1	-	-	-	2	-	4
Other	-	1	1	-	-	-	-	2
Entitlements/Partial Requirements	-	1	1	-	-	-	-	2
Entitlements/Unit Power	-	1	-	-	-	-	-	1
Full & Partial Requirements	1	1	-	-	-	-	-	2
Partial Requirements/ Other	2	1	-	-	-	-	-	3
Entitlements/Other	-	-	-	-	-	1	-	1
Partial Requirements/ Firm Power & Energy	2	-	-	-	-	-	-	2
Partial Requirements/ Surplus Power	-	2	-	-	-	-	-	2
TOTAL	39	73	4	2	27	15	10	171

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DISTRIBUTION OF RATE STRUCTURES EMPLOYED IN NON-FIRM WHEELING ARRANGEMENTS BY TYPE OF POWER WHEELED [11]

Type of Power	Postage Stamp Rates							
	$ per kWh	$ per kW	Demand and Energy	Mileage Component	Formulary Rate	Fixed Charge	No $ Compensation	Total
Entitlements	2	-	-	-	-	-	-	2
Hydro Peaking Power	1	-	-	-	-	1	-	2
Surplus Power	2	3	-	-	-	-	-	5
Economy Energy	1	-	-	-	-	-	-	1
Emergency Energy	8	-	-	-	-	-	2	10
Short Term Power	1	1	-	-	-	-	-	2
Non-firm Power & Energy	7	2	-	-	1	1	1	12
Pumping Power	-	-	-	-	1	-	-	1
Other	5	3	-	-	1	1	2	12
Emergency Energy/Other	1	2	-	-	-	-	1	4
Maintenance Power/Replacement Power/Other	1	-	-	-	-	-	-	1
Maintenance Power/Emergency Energy/Short-term Power/Other	3	-	-	-	-	-	-	3
Economy Energy/Short-term Power	-	1	-	-	-	-	-	1
Short-term Power/Non-Displacement Energy	2	-	-	-	-	-	-	2
Emergency Energy/Short-term Power/Other	1	-	-	-	-	-	-	1
Hydro Peaking Power/ Economy Energy/Other	1	-	-	-	-	-	-	1
Economy Energy/Emergency Energy	5	-	-	-	-	-	-	5
Replacement Power/ Surplus Power	1	-	-	-	-	-	-	1
TOTAL	42	12	0	0	3	3	6	66

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SUMMARY OF WHEELING TARIFFS ON FILE AT THE FERC [11]

Company	Tariff Number	Eligibility Requirements	Type of Service	Rates & Charges	Treatment of Losses	Power Factor Requirements
Boston Edison Company	Orig Vol #3	Utilities interconnected with Boston Edison	Non-firm wheeling of unspecified types of non-firm power and energy	$14 64/kW/year The billing determinant is the greater of kW contracted to be wheeled or the largest billing demand in the previous 12 months An 80% demand ratchet is applied to both measures	Energy delivered less a percentage for losses determined by the New England Power Exchange	Customer must maintain a power factor of 92 percent lagging
Central Illinois Public Service Company	Orig Vol #5	Any party requiring the use of the company's transmission facilities to transmit long-term firm power acquired from supply sources interconnected with the company	Firm wheeling of long-term power (furnished continuously for at least 1 year)	$1 97/kW/month Billing determinant is the 60 minute maximum monthly coincident peak demand	Energy delivered less 4 percent for losses	None
Central Power and Light Co	Orig Vol #2	Utilities operating in ERCOT whose maximum load in the most recent 12 months is less than 1500 MW Also power to be wheeled must be generated by a utility other than Central Power & Light Co and West Texas Utilities Co	Firm wheeling greater than one month and short-term firm wheeling for less than one month of unspecified types of power	$1 39/kW times maximum transmission capacity (kW) reserved	A formula using an average system factor and average fuel loss cost (for each company) is applied to MWH delivered to arrive at a charge	Customer must supply reactive power to maintain a power factor near unity
Central Power and Light Co	Orig Vol #3	Utilities wishing to transmit energy over the DC facilities to and from delivery point on the combined systems of Central Power & Light Co and West Texas Utilities Co	Short-term and long-term firm wheeling of unspecified types of power and energy Non-firm wheeling of economy and emergency energy	$2 25/kW times maximum transmission capacity (kW) reserved	A formula using an average system factor and average fuel loss cost (for each company) is applied to MWH delivered to arrive at a charge	Customer must supply reactive power to maintain a power factor near unity
Cleveland Electric Illuminating Co	Orig Vol #1	Available to all cooperative and municipal utilities in the combined territories of CAPCO member companies	Firm wheeling of unspecified types of power and energy	$2 50/kW reserved per month	Power and energy delivered less one percent for losses	None
Comsumers Power Company	Orig Vol #2	Available to any neighboring utility located in all or part of Consumer Power Co s service area	Firm wheeling of unspecified types of power and energy	$0 34/kW/week @138 kV and above $0 47/kW/week @46kV and below The billing determinant is the contract capacity specified in each service agreement	Power and energy delivered less 2 5% at 138kV and above 4 45% at 46kV and below	None

SUMMARY OF WHEELING TARIFFS ON FILE AT THE FERC [11] - cont

Company	Tariff Number	Eligibility Requirements	Type of Service	Rates & Charges	Treatment of Losses	Power Factor Requirements
Consumers Power Company	Orig Vol #3	Same as above	Non-firm wheeling of economy energy and other unspecified types of power and energy	Weekly Rates $0 24/KW/week @138kV and above $$0 33/kW/week @46kV and below Hourly Rates Economy Energy-15% of gross savings 1 7 mill/KWh @138kV and above 2 3 mills/kWh @46kV and below	Same as above	None
Dayton Power and Light Co	Orig Vol #2	Utilities receiving partial wholesale requirements service from the company	Firm wheeling of partial requirements	$1 28/kW/month	None	Power Factor is maintained at 80% lagging by both the customer and the company
Florida Power Corp	Orig Vol #3	Available to cooperatives municipal utilities, or other electric utilities for service over the company s facilities between existing or future delivery points on the interconnected system	Firm and non-firm wheeling of unspecified types of firm and non-firm power and energy	Transmission Firm $0 946/kWh Non-firm 1 3 mills/kWh Subtransmission Voltage / Coops Firm / Municipals Firm 69kV / $ 37457/kW / $0 423/kW 12/25kV / / $1 121/kW below 12kV / / $1 232/kW Voltage / Coops Nonfirm / Municipals Nonfirm 69kV / - / 0 5mills/kWh 12/25kV / - / 1 54mills/kWh below 12kV / - / 1 69mills/kWh	Additional charges are assessed for any losses provided by the company	If the power factor falls below 97 percent the customer is charged for reactive power at $0 06/KVAR
Georgia Power Company	Orig Vol #3	Available to members of Oglethorpe Electric Coop and members of the Municipal Electric Authority of Georgia, as well as the City of Dalton All service is pursuant to the statewide integrated transmission system agreement	Firm wheeling of requirements power	Formulary Rate The product of the sum of each party s undepreciated investment in the integrated transmission system and each party s peak load responsibility ratios determined at the highest one hour coincident system peak	Losses are shared in proportion to peakload requirements	Power factor will be maintained at no less than 93 percent lagging No penalty charges specified
Idaho Power Company	Orig Vol #2	Available to any electric utility operating a control area The tariff solely for non-firm transmission over the company s System Transmission Facilities	Non-firm wheeling of unspecified types of non-firm power and energy	Priced in mills/kWh, the rate charged is the quotient of Annual System Transmission Facilities Costs divided by Idaho Power Co s Net Generating Capability (total nameplate rating expressed in kWh)	Losses shall be returned to the company with 168 hours after transmission service was provided	None

SUMMARY OF WHEELING TARIFFS ON FILE AT THE FERC [11] - con t

Company	Tariff Number	Eligibility Requirements	Type of Service	Rates & Charges	Treatment of Losses	Power Factor Requirements
Illinois Power Company	Orig Vol #2	Any customer in the company s service territory engaged in distribution and sale of electricity to the general public Service is for a minimum of 5 years	Firm wheeling of requirements power	138 kV $0 85/kVa/Month 34 5 & 69 kV $150/kVA/Month 7 2 & 12 47 kV $350/kVa/Month	Energy delivered less losses 130 kV 3 percent 34 5 & 69 kV 4 percent 7 2&12 47 kV 8 percent	Customer is responsible for supplying its own reactive power
Monaup Electric Company	Orig Vol #2	Available to any electric utility desiring to transmit power over the company s NEPOOL pool transmission facilities (PTF)	Firm and non-firm wheeling of unspecified types of firm and non-firm power and energy	Contract demand applied to formulary rates (firm and non-firm) rates based on the company s annual PTF costs in the preceding year If energy is transmitted over additional systems the monthly charge is reduced up to 50 percent by the amount charged by other utilities	Losses are paid by the customer in an amount determined by NEPOOL Agreement Procedures	None
New England Power Co	Orig Vol #3	Available to electric utilities including municipal utilities that (1) do not receive requirements service from NEPCO (2) have entitlements or unit contracts outside their service areas and (3) have arrangements which provide for delivery of power and energy to NEPCO	Non-firm wheeling of non-firm power and energy	Over NEES PTF ¼ X NEES PTF Cost X kW transferred Over Non PTF Non PTF-1 $09/kW Non PTF-4(69kV) $0 98/KW/MN Non PTF-4(MASS) $1 96/kW/MN Non PTF-4(RI) $2 57/kW/MN	Losses borne by customer in accordance with NEPOOL Agreement	None
Otter Tail Power Co	Orig Vol #4	Available to any wholesale customer in the company s normal service area	Firm wheeling of full and parital wholesale requirements	Transmission service $2 70/kW/MN Primary service $4 542/kW/MN The billing determinant is the highest 30 min monthly peak demand with an 11 month 90% ratchet applied	Customer delivers 106 percent of power to be wheeled to compensate for losses	None
Public Service Company of New Hampshire	Orig Vol #1	Available to municipals cooperative and investor-owned utilities for transmission service over the companies NEPOOL Pool Transmission Facilities	Non-firm wheeling of non-firm entitlements	$/kW-PSNH Annual PTF Costs divided by PSNH NEPOOL capability X 50 percent, if transmitted over PTF of other NEPOOL companies	Energy delivered less an unspecified percentage	None
Public Service Company of Oklahoma	Orig Vol #1	Utilities in the service area of PSO and Southwestern Public Service Co	Non-firm wheeling on South D C line	$2 16/kW/month times maximum kW reserved	A formula using average loss factors and average fuel costs on the PSO and SWEPCO systems	Customers supply their own reactive power

SUMMARY OF WHEELING TARIFFS ON FILE AT THE FERC [11] - con t

Company	Tariff Number	Eligibility Requirements	Type of Service	Rates & Charges	Treatment of Losses	Power Factor Requirements
Sierra-Pacific Power Co	Orig Vol #2	Non-firm transmission service at 120 kV and higher available to utilities snot served by Sierra-Pacific Power Co under firm rate schedule	Non-firm transmission of surplus power economy energy and exchange energy	$0 31/kWh	Energy delivered less 4 percent for losses	None
Southern California Edison Co	Orig Vol #1	Network Transmission Service Available to municipal utilities having Integrated Operating Agreements (IOA) with SCE, for the transmission of city-owned resources between substations on SCE s 220kV system	Firm wheeling of city-owned firm power	Terminal Facilities $0 254/kW Transmission Facilities $0 0437/kW-mile Switching Facilities $0 0152/kW mile Charges are based on Contract Capacity	Capacity and energy back delivered less 4 percent for losses	None
		Point to Point Transmission Service Available to municipal utilities having IOA s with SCE for the transmission of city-owned Resources over SCE s non-220kV system	Firm wheeling of city-owned firm power	Cities pay proportioned share of SCE s average costs and rate of return for on the shortest circuit mile path and the shortest separate right of way Charges are based on Contract capacity	Average system losses deducted from power delivered	None
Washington Water Power Co	Orig Vol #2	Utilities eligible are those defined in Pacific Northwest Planning Act PL88-552 Applicable to all transactions not performed under existing agreements	Non-firm wheeling of non-firm power and energy	0 75 mills/kWh	Customers pay for losses Method of compensation not specified	None
West Texas Utilities Co	Orig Vol #2	Utilities operating in ERCOT whose maximum load in the most recent months is less than 1500 MW Also power to be wheeled must be generated by a utility other than Central Power & Light for West Texas Utilities Co	Firm wheeling greater than one month, and short-term firm wheeling for one month or less of unspecified types of power	$1 39/kW times maximum transmission capacity (kW) reserved	A formula system using an average system loss factor and average fuel cost (for each company) is applied to MWH delivered to arrive at a charge	Customer must supply reactive power to maintain a power factor near unity
West Texas Utilities Co	Orig Vol #3	Utilities wishing to transmit energy over the North DC facilities to and from delivery point on the combined systems of Central Power & Light Co and West Texas Utilities Co	Short-term and long-term firm wheeling of unspecified types of power and energy Non-firm wheeling of economy and emergency energy	$2 25/kW times maximum transmission capacity (kW) reserved	A formula system using an average system loss factor and average fuel cost (for each company) is applied to MWH delivered to arrive at a charge	Customer must supply reactive power to maintain a power factor near unity

WHOLESALE TRANSACTIONS BY INVESTOR-OWNED UTILITIES [13]
1961-1987
(Billions of kWh)

Year	Sales For Resale	Interchange Out (1)	Transmission Delivered (2)
1961	87	37	10
1966	143	74	22
1971	209	178	50
1976	291	280	71
1981	349	352	119
1982	316	345	124
1983	332	331	129
1984	336	342	171
1985	359	373	197
1986	330	297	133
1987	338	291	141

(1) Received at one time, delivered at another

(2) Simultaneous receipt and delivery

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BULK POWER TRADE AND TRANSMISSION
AS A PERCENTAGE OF RETAIL SALES [13]
1961-1987
(Billions of kWh)

Year	Bulk Power Trade (1)	Transmission	Retail Sales	Bulk Power/ Retail (%)	Transmission/ Retail (%)
1961	124	10	545	23	2
1966	217	22	798	27	3
1971	387	50	1149	34	4
1976	571	71	1418	40	5
1981	701	119	1629	43	7
1982	675	123	1592	42	8
1983	655	129	1638	40	8
1984	678	171	1739	39	10
1985	732	197	1769	41	11
1986	627	133	1806	35	7
1987	629	141	1879	33	8

(1) Sales-for-resale and interchange out

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Five major types of wheeling service would be offered

- firm unconditional,
- firm conditional,
- conditionally interruptible,
- unconditionally interruptible, and
- emergency

"FIRM" generally means <u>except for</u>

1. Interruption due to factors reasonable beyond the control of the utility and not attributable to its neglect, such as lightning damage, a flood, labor strike, or civil war This condition is often referred to as the *force majeure* clause

2. Danger to the reliability and sound operation of the utility's electric system, in accordance with good utility practice

3. Maintenance, repairs, replacements, installation of equipment, or investigation and inspection

4. Failure of the wheeling customer to comply with the terms and conditions of the tariff or service agreement, such as nonpayment of bills [10]

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CONTRACTUAL ARRANGEMENTS

- Firm Versus Interruptible
- Transmission Reservation and Scheduling
- Frequency Control
- Back-up Power Arrangements
- Voltage Control

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B FERC EXPERIMENTS AND ANALYSES

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Box 5-E—Southwest Bulk Power Market Experiment [12]

In December 1983 FERC approved a 2 year experiment in bulk power marketing and transmission access involving six utilities in the Southwest [1] The experiment was intended to determine the economic efficiency gains and competitive impacts of modifying FERC s regulation of coordination transactions—transactions between utilities with their own generating capacity Transactions involving distribution utilities with little or no generation were not addressed There were no apparent concerns or problems with the technical feasibility of implementing the experimental power transactions and transmission access

In the experiment, the participants were allowed substantial freedom in setting prices for economy energy (for interruptible sales from hour to hour up to 30 days) and block energy (for sales extending at least one month) Prices were allowed to range from 0 9 ¢/kWh to 9 4 ¢/kWh The utilities were allowed to retain 25 percent of the resulting savings as profit with the remaining 75 percent flowed through to customers (Traditional regulation requires 100 percent of such savings to be passed on to customers) Further the utilities agreed to provide transmission access (up to technical limits) at a fixed price of 1.5¢ /kWh and thus not prevent trades involving other participants

FERC contracted with the Rand Corp for technical assistance in evaluating the experimental design proposed by the utilities assessing the usefulness of the data and analyzing the experimental results [2] Rand published first year results in October 1985 The analysis of economic efficiency impacts was inconclusive Our findings with respect to efficiency are decidedly mixed and vary depending on the analytic technique selected By some measures efficiency increases under the experiment by others it is unchanged or falls by a statistically significant amount [3] Rand noted that the *first year* findings were possibly unrepresentative for several reasons

According to Rand s first year report the second year was expected to be more representative of the efficiency gains resulting from the experimental regulatory changes Results of the experiment s second year have not been published to date

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[1] *Southwest Experiment* FERC Opinion No 203 Docket No ER84 155-000 Dec. 30 1983 The six utilities were Arizona Public Service the City of Farmington El Paso Electric Public Service Company of New Mexico Salt River Project, and Southwestern Public Service (which began participation in the final 3 months of the first year

[2] The Rand Corp provided an advisory report to FERC before the experiment was approved The Rand Corp *Issues in the Design of a Market Experiment for Bulk Electrical Power* December 1983

[3] J Acton and S Besen *Regulation Efficiency and Competition in the Exchange of Electricity First Year Results From the FERC Bulk Power Market Experiment* The Rand Corp October 1985 p vii

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Box 5-F—Western Systems Power Pool
A Current Experiment in Transmission Access and Bulk Power Pricing [12]

In March 1987, the Federal Energy Regulatory Commission (FERC) accepted another 2-year bulk power marketing experiment, called the Western Systems Power Pool (WSPP) [1] The WSPP experiment began on February 1, 1987 Like the Southwest Experiment, the WSPP experiment is intended to determine whether more flexible pricing and greater information sharing will promote more efficient use of generation and transmission facilities and reduce costs to consumers As with the Southwest experiment there have been no apparent concerns or problems with the technical feasibility of implementing any of the experimental power transactions including transmission access

There are several differences between the WSPP experiment and the Southwest Experiment One principal difference is transmission access The WSPP provides only for voluntary transmission service and gives substantial pricing freedom to the transmitting utilities Transmission access prices are allowed to range from 0 1 ¢/kWh to 3 3 ¢/kWh In contrast the Southwest Experiment provided mandatory transmission access (subject to availability) at a fixed price of 1 5 ¢/kWh Thus according to FERC the WSPP experiment will examine whether mandatory transmission access is a prerequisite to a competitive market.' [2]

WSPP also allows a much wider range of prices for generation than did the Southwest Experiment In the WSPP experiment s first year prices were allowed to range up to 24 5 ¢/kWh compared to the earlier experiment s cap of 9 4 ¢/kWh

Size is another difference between WSPP and the Southwest Experiment WSPP is very large including over 20 utilities in 10 Western States The utilities in this region produce about 12 percent (82 000 MW) of the total electric generating capacity of the United States That is substantially larger than the Southwest Experiment which was open to six utilities in three States with under 13 000 MW capacity To implement the experiment over this large group of utilities the WSPP experiment uses a computer bulletin board into which buy and sell offers are placed each day

The experiment is scheduled to conclude on May 1 1989 but the participants have requested a 2-year extension As a condition of FERC approval the participants are required to produce interim and final reports examining economic efficiency impacts and potential monopoly power The interim report does not draw conclusions on these issues due to a lack of data [3] However the report notes that some transmission owners are holding less transmission in reserve for their own uses resulting in increased availability to others

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[1] Order Accepting Experimental Rates for Filing FERC Docket No ER87 97-001 Mar 12 1987

[2] Ibid. p 3

[3] T W Keelin et al *Western Systems Power Pool Assessment Interim Report* (Menlo Park CA Strategic Decisions Group January 1989)

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Box 5-G—Innovative Transmission Access
Turlock Irrigation District [12]

In June 1988 FERC approved a novel agreement under which Turlock Irrigation District gained transmission access to a number of competing power suppliers [1] [2] In exchange Pacific Gas and Electric (PG&E) gained a pricing system allowing it to retain more of the savings from coordination transactions than were previously allowed PG&F also gained release from responsibility to provide power and transmission beyond which it committed itself contractually [3]

Turlock is a partial requirements utility with capacity of approximately 157 MW and peak loads of approximately 266 MW in 1988 According to FERC Turlock has always been a captive customer of PG&E due to its reliance on the PG&E transmission system [4] Under the new agreements Turlock will have reserved transmission service providing 176 MW of import access to three other northern California utilities and to Southern California Edison at cost-based prices Together with its own capacity and approximately 5 3 MW of firm capacity from PG&E this gives Turlock sufficient resources to meet its own load In addition the agreement allows PG&E and Turlock to negotiate coordination services The coordination services would allow Turlock to pursue short-term purchases with PG&E and other utilities when low-cost opportunities exist In addition the agreement covers such provisions as charges for unauthorized power flows voltage regulation scheduling and regulation services

FERC s order of approval noted uncertainty and some concern about whether PG&E may exercise any leverage over Turlock because of its control over Turlock s transmission access to other suppliers The agreement is not an experiment however and no formal mechanism has been instituted to determine whether such leverage is exercised

Finally, it s worth noting that neither FERC nor PG&E nor other intervenors expressed concern with the technical feasibility of reliably implementing the agreement

---

[1] *Pacific Gas and Electric* FERC Docket No ER88 219-000 Mar 31 1988

[2] *Pacific Gas and Electric* FERC Docket No ER88 219-001 June 1 1988

[3] FERC approved a similar transmission access and pricing agreement between Modesto Irrigation District and PG&E in July 1988 *Pacific Gas and Electric* FERC Docket No ER88 302 001 July 5 1988

[4] *Pacific Gas and Electric* op cit. Mar 31 1988 p 10

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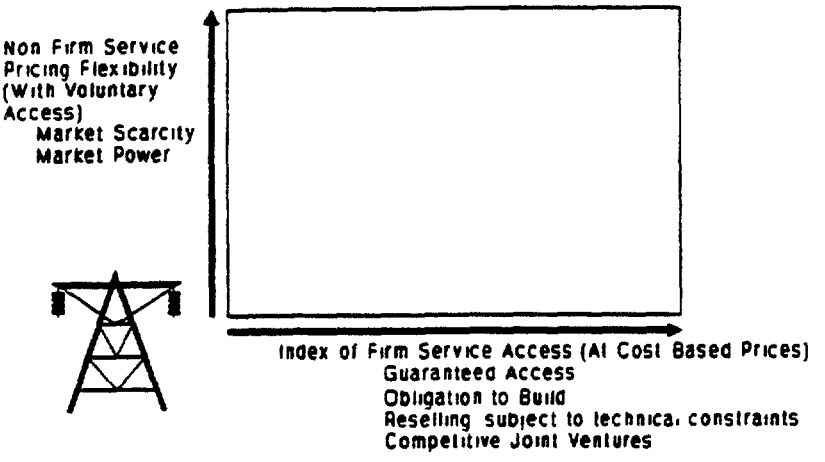
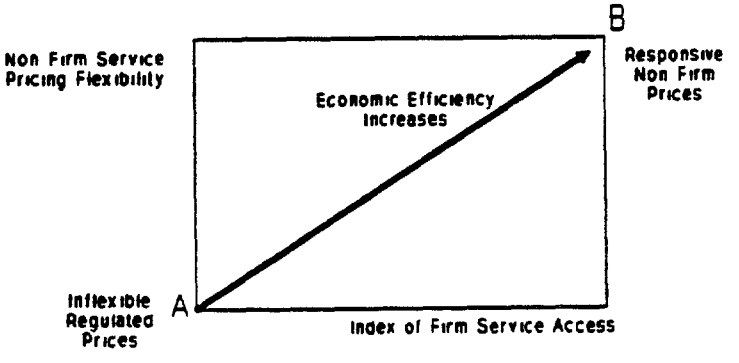
TRANSMISSION POLICY EVALUATION [13]
(Non-Firm Pricing vs Firm Service Access)



TRANSMISSION POLICY EVALUATION [13]
Economic Efficiency



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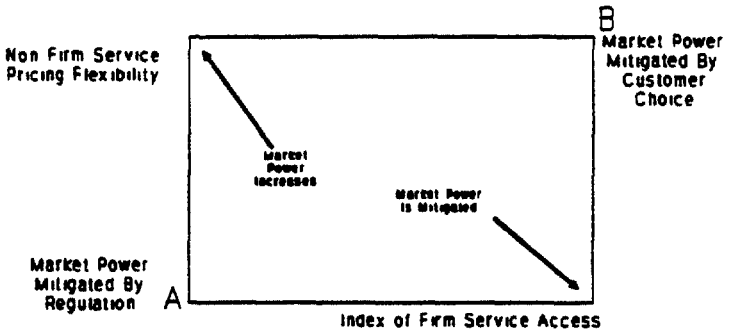
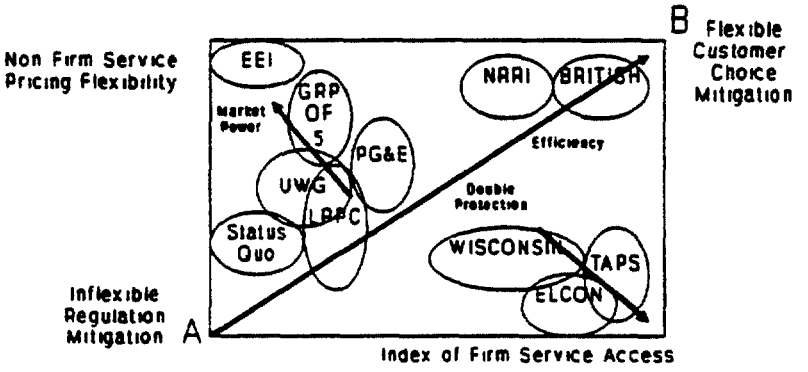
TRANSMISSION POLICY EVALUATION [13]
Market Power Mitigation



TRANSMISSION POLICY PROPOSALS [13]



BRITISH Spot Electricity Market
Open Access for Retail and Wholesale Users
Secondary Market for Capacity Contracts

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MAJOR POLICY DIMENSIONS OF THREE ALTERNATIVE TRANSMISSION PROPOSALS [13]

ISSUE/CONCERN	CONTRACT	PLANNING	BRITISH
1 Reliability	Owner's Duty	Owner's Duty	Owner's Duty
2 Stranded Investments/ Insufficient Transmission Capacity	Governed by Contract	Governed by Joint Plan	Governed by Central Plan
3 Environmental/Siting Issues	Duty of State PUC	Duty of State PUC	Duty of Transco
4 Structural Change	Small	Major	Radical
5 Quality of Service	Point to Point	System Wide	System Wide
6 Price Discrimination	Probably (Vintage Pricing)	No	No
7 Who Bears Future Price Risk?	Depends on the Design	Shared Through Joint Planning	Shared Through Joint Planning
8 Who Has Priority?	Core Customers	No One	No One
9 Method of Enforcement	Contracts	Joint Planning	Joint Planning
10 Parallel Flows	Contract Path	Real Flows in Region	Real Flows
11 Retail Bypass	Not Allowed	Not Allowed	Allowed
12 Accommodates IPPs	Yes	Yes	Yes
13 Requires Legislation	No	Yes, probably	Yes

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C MULTI-OBJECTIVE DECISION ANALYSIS

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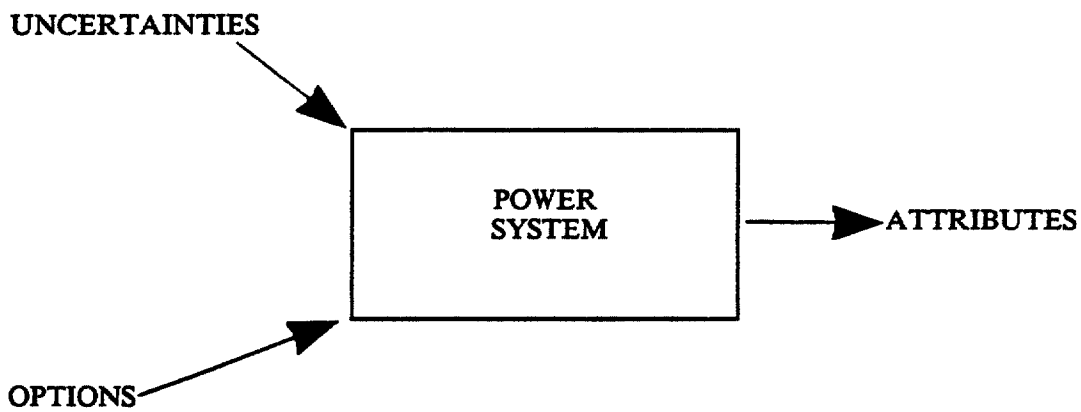

Attributes are Functions of Uncertainties and Options

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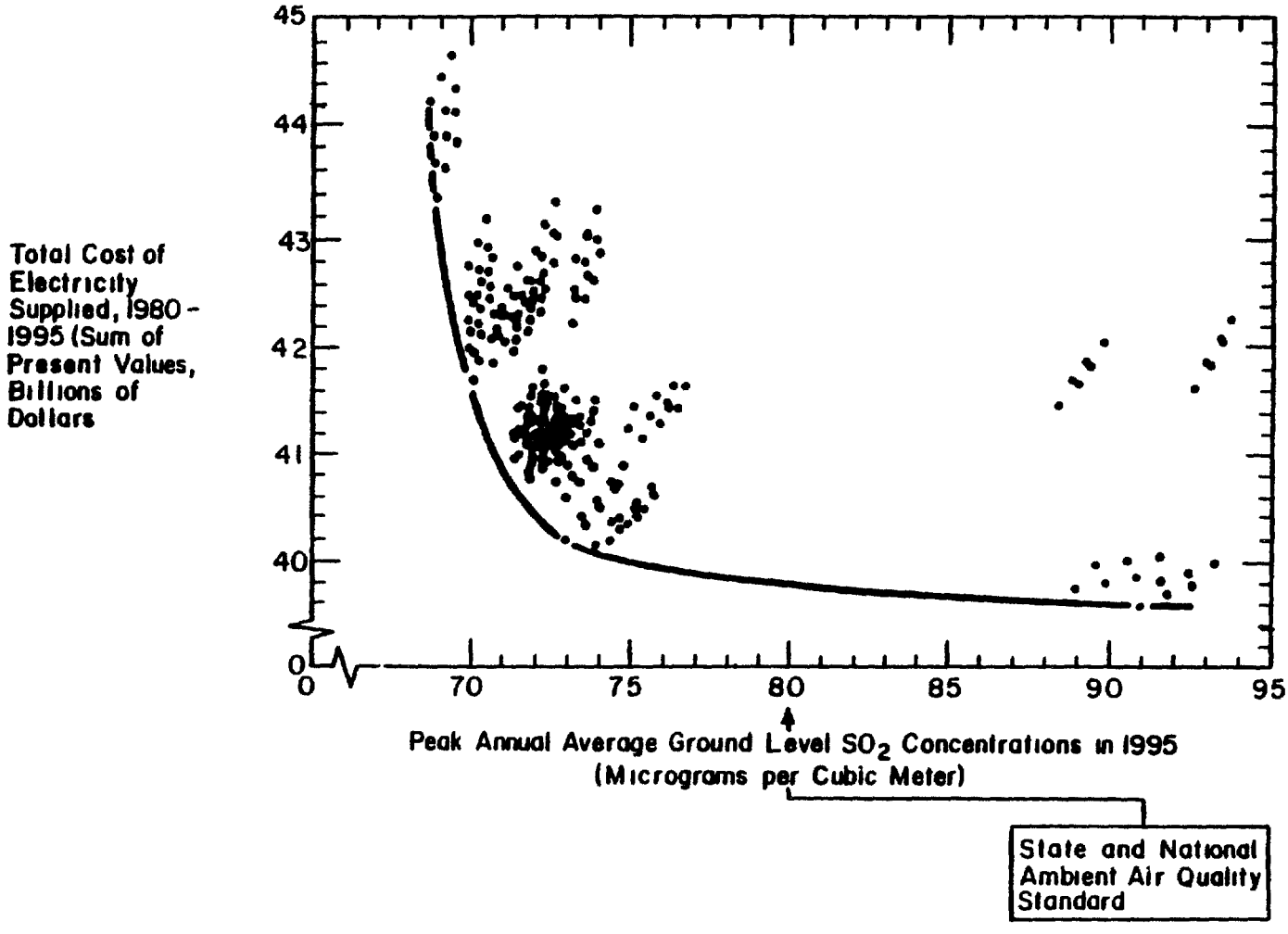

Cost Versus SO_2 Concentrations - Several Hundred Strategies Involving All Possible Combinations of Options (Coal Conversion, New Coal-Fired Plant, New Pumped Storage Plant, Power Imports) With Random Variables Held Constant

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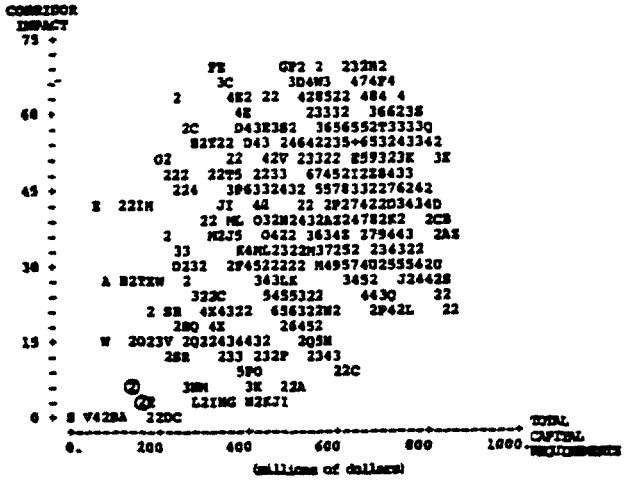
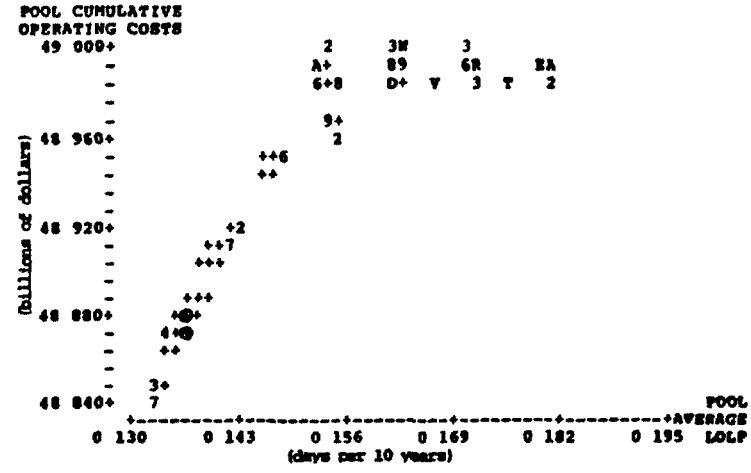
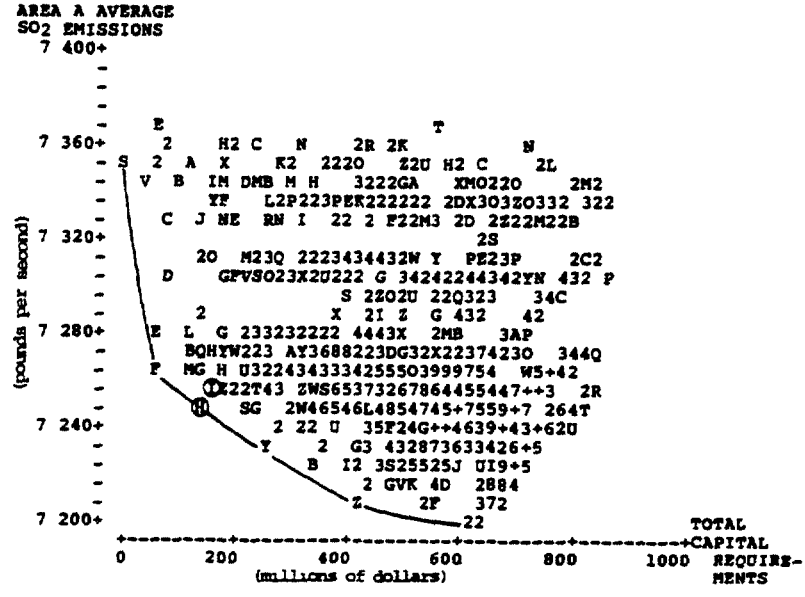


Corridor effect versus capital requirements for 1166 plans



Operating costs versus LOLP for 1166 plans



SO_2 emissions versus capital requirements for 1166 plans

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FICTIONAL POLICY STUDY: VARIATIONS IN WHEELING RATE AND TRANSMISSION ACCESS RULES

	Incremental Investment by All Parties (10^6)	Levelized Cost of Electricity (1995-2010) (c/kWh)	Oil Dependence (1995-2010) (%)	Impediments to NUG Transmission Access
Plan A	-	15.26	18 6	High
Plan B	-330	15 10	16.3	High
Plan B1	-420	15 07	15 0	Medium
Plan B2	-610	15 14	14 9	Medium
Plan B3	-260	15.29	15 8	High
Plan C	-460	15.21	16.2	High
Plan D	-70	15.25	18.5	Low
Plan D1	-90	15.24	18.2	Medium
Plan F	-50	15.26	20 0	High
Plan G	-250	15.32	18 8	Low
Plan G2	-410	15.24	16 6	Low
Plan H	400	15 60	24.2	Medium
Plan H1	410	15 60	24.2	Medium
Plan HX	-90	15 49	19 7	Medium
Plan I	60	15 44	24.2	Low
Plan J	120	15 46	23.2	High
Plan J1	100	15 46	23 0	Medium
Plan JX	-170	15 42	20.2	High
Plan K	-130	15.37	21.5	Low
Plan K2	-280	15.31	18 4	Low
Plan L	-370	15 31	18 6	High
Plan M	-40	15.25	16.3	Medium
Plan M2	-200	15 18	12 8	Medium
Plan N	-560	15.22	12 0	Medium
Plan O	-620	15 14	12 9	Low
Plan P	-670	15 12	13 0	Low

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D POSSIBLE EVOLUTION SCENARIOS

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Table 3-1—Summary of Alternative Scenarios [12]

Scenario 1 Strengthening the Regulatory Bargain	Scenario 2 Expanding Transmission Access and Competition in the Existing Regulated Utility Structure	Scenario 3 Competition for New Bulk Power Supplies	Scenario 4 Competition for All Bulk Power Supplies	Scenario 5 Common Carrier Transmission Services in a Disaggregated Industry Structure
• Industry consists of a mix of vertically integrated utilities IOUs public power cooperatives Federal power authon ties self-generators QFs and IPPs • Existing regulatory structure with State preapproval of new generating proj ects and periodic prudence reviews during planning and constr uction • Negotiated transmission access arrange- ments • Traditional system coordination and control by integrated utilities or con trol centers • Prices set by regulatory proceedings and cost of service Transmission prices and wholesale rates set by FERC (including approval of negotiated IPP power purchases) State over sight of retail rates and PURPA implementation • Federal and public power agencies and cooperatives affected only to the extent State law provides	• Industry consists of existing mix of entities • Existing regulatory structure with wider QF eligibility under PURPA including full utility ownership/control of QFs (may require amendment of PURPA) • New Federal wheeling authority under a public interest standard for whole sale and retail transmission access (requires amendment of the Federal Power Act) • Traditional system coordination and control by integrated utilities or con trol centers with contracts for un bundled services • Prices set by regulatory proceedings and cost of service Transmission prices and wholesale rates set by FERC (including approval of negotiated IPP power purchases) State over sight of retail rates and PURPA implementation • Federal and public power agencies and cooperatives affected only to the extent State law provides	• Existing mix of generating entities expanded by IPPs and unregulated utility generating subsidiaries • Existing regulatory structure with market based rates for new competitive gen eration Utilities use all source procure ment for new bulk power needs Contracts awarded to lowest cost supplier with consideration for non price factors • Transmission access provided by utili ties as a bidding condition, or by privately negotiated arrangements, or under new Federal public interest wheeling authority (no retail wheel ing) • Traditional system coordination and control by integrated utilities or con trol centers Unbundled bulk power dispatch control and transmission services provided through contracts • Retail and transmission prices set by regulatory proceedings Wholesale power prices set through competitive procurement except for cost base plants built by utility as last resort supplier State and Federal regula tors oversee terms and conditions of wholesale sales • Federal and public power agencies and cooperatives can participate in competitive generating sector to ex tent provided by Federal and State law and policy	• Industry structure Ownership of com petitive generating sector segregated from transmission and distribution sectors • New Federal and State regulatory systems Price and entry regulation of generation sector replaced with competitive market Continued regu lation of transmission and distribution utilities and retail sales • Revised Federal wholesale wheeling authority Transmission utility to plan for and provide nondiscriminatory ac- cess for bulk power supplies • Most of traditional utility system plan ning and coordination taken over by transmission and distribution entities Competitive generators plan and build generation Transmission operator as sumes responsibility for bulk power system control and operation Distribu tion utility retains retail obligation to serve Unbundled bulk power dis patch control and transmission serv ices provided through contracts • Bulk power prices set by market through bidding negotiation Transmis sion and retail prices are set by regulatory proceedings Some State and Federal oversight of competitive ness of generation markets and pru dence of bulk power contracts • Federal and public power agencies cooperatives can participate in competi tive generating sector to extent pro vided by Federal and State law and policy	• Ownership and control of existing integrated utility industry is disaggre gated into separate generation trans mission and distribution segments • New Federal and State regulatory system Price and entry regulation of generation replaced with competitive markets Distribution utilities serv ices and retail prices remain regu lated Transmission prices and activi ties are strictly regulated • Transmission sector operates as a common carrier providing nondiscrimina- tory access to all wholesale and retail customers Reasonable conditions on reserving transmission services may be imposed • Bulk system planning and coordina tion is split among generation trans mission and distribution entities Gen erators identify plan and build new generation in response to market signals Transmission utility assumes responsibility for reliability of bulk system operations Responsibility for estimating demand and securing ade quate power supplies rests with distri bution utilities Unbundled bulk power dispatch control and transmission services provided through contracts • Bulk power prices set by market Transmission and retail prices are set by regulatory proceedings Some State and Federal oversight of competitive ness of generation markets and pru dence of bulk power contracts • Federal and public power agencies cooperatives can participate in competi- tive generating sector to extent pro vided by Federal and State law and policy

SOURCE Office of Technology Assessment 1989

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Table 3-2—Alternative Scenarios Summary of System Operations, Planning, and Development [12]

Scenario	System operation: Reliability dispatch and coordination	System planning and development: Generation	Transmission	Distribution
1 Strengthening the regulatory bargain	Utility control center Control of nonutility generation set by contract	Utility obligation to plan build and purchase QFs market under PURPA IPPs negotiate contracts	Utility responsibility	Local utility responsibility
2 Expanding transmission access and competition in the existing regulated industry structure	Similar to 1 with greater reliance on contractual provisions for nonutility generation control and wheeling	Similar to 1 with expanded QF and IPP participation	Same as 1 but States may require utilities to plan and build adequate transmission capacity for regional needs including retail wheeling	Same as 1
3 Competition for new bulk power supplies	Same as 2	Utility obligation to plan and secure adequate new supplies through competitive means Generators include utilities, QFs IPPs and host utility affiliates	Same as 2 but no retail wheeling obligation	Same as 1
4 Competition for all bulk power supplies	Transmission utility assumes bulk system control Operational responsibilities of generators and distribution utilities set by contracts with customers and transmission utilities	Generators plan and build in response to perceived market needs and solicitations by transmission-distribution utilities	Transmission utility obligation to plan and build adequate capacity for instate/regional wholesale needs	Local retail utility obligation to plan and contract for adequate supplies Utility may participate in load management and conservation Transmission utility may provide brokering services
5 Common carrier transmission services in a disaggregated industry structure	Same as 4	Generators plan and build in response to perceived market needs and solicitations by local distribution utilities and transmission companies as brokers	Transmission utility obligation to plan and build adequate capacity for foreseeable needs as common carrier for regional wholesale and retail customers	Same as 4

SOURCE Office of Technology Assessment adapted from Power Technologies Inc *Technical Background and Considerations in Proposed Increased Wheeling Transmission Access and Nonutility Generation* OTA contractor report, Mar 30 1988

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FOUR PLANNING PROCESSES

The future structure of the utility industry - with wheeling a major issue - could lead to four distinct planning processes, with many variations, as follows

Traditional Utility Process

This was the standard procedure until recently The utility, when only minor regulatory oversight, assembled data, defined objectives, and planned accordingly

Parliamentary Process

Recently, other entities have insisted on being part of the planning process I hearings, proceedings, and lawsuits, they are becoming part of a process of compromise and accommodations, where data is shared and a joint decision is reached, involving both utility and nonutility participants

United Nations' Process

Some utilities have many years' experience with this model, as they carry out joint regional planning studies with their neighbors While data has been shared openly, each utility has reserved the right to make its own decisions and set its own plans In the future, independent power producers and other customers may share data, with each other and with utilities, while making independent plans

Unbridled Competition Process

Decisions and plans are made independently, with no shared information, as all parties view the others as competitors This was, of course, the planning process in the early swashbuckler days, it may return in a different context if one of the more extreme deregulation paths is followed

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	Single Attribute	Multiple Attribute
Unified Decision-Making	Optimization	Trade-Off Analysis
Independent Decision-Making	Zero-Sum Game	Non-Zero-Sum Game

Mathematical bases for planning

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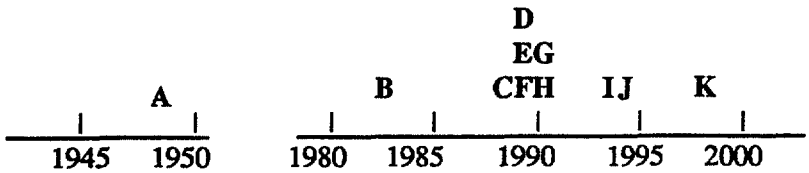
RESTRUCTURING AND PRIVATIZING IN ENGLAND (16,17)

Time Line



A 1948 - The Central Electricity Generating Board (CEGB) was organized

CEGB owned and operated the high-voltage transmission system and most of the power plants in England and Wales

Twelve area boards bought power at wholesale from CEGB and sold to retail customers

B 1983 - Energy Act required CEGB to buy from independent producers and to provide network access No takers (costs too high, prices too low)

C February 1988 - Her Majesty's Government published a white paper on restructuring It envisaged two pools -- one for sellers (generators), one for suppliers (buyers)

D 1989 - The Electricity Act created Regional Electricity Companies (distributors, successors of the area boards, privatized) and split the CEGB into four major companies

National Power (fossil-fueled generation, privatized)
PowerGen (fossil-fueled generation, privatized)
Nuclear Electric (nuclear generation, government-owned)
National Grid (transmission, owned by RECs)

The act allowed generation by independent players and provided open transmission access Special subsidies supported the British coal industry and funded nuclear decommissioning

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E 1 July 1989 – The two-pool approach was abandoned

F October 1989 – Basic principles of the single-pool system were agreed upon, followed by an intense and remarkable period of work on procedures, documentation, software, etc

G 1 April 1990 – CEGB was privatized and operation under the new structure began Large customers (> 1 MW) may change supplier

H Mid-April 1990 – prototype pool-settlement software was completed

I 1993 – Coal contracts to be renegotiated and nuclear levy to be reduced

J 1994 – Medium-sized customers (> 0 1 MW) may change supplier

K 1998 – All customers may change supplier Nuclear levy ends

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RESTRUCTURING AND PRIVATIZING IN ENGLAND (16,17)

Principles and Objectives of Privatization

- Decisions about electricity supply should be consumer–driven
- Competition is the best guarantee
- Regulation should promote competition, oversee pricing, and protect consumers (in monopoly situations)
- Security and safety must be maintained
- Customers should be given new rights, not just protection
- All who work in the industry should be given new opportunities, free of government interference

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RESTRUCTURING AND PRIVATIZING IN ENGLAND (16,17)

Pricing Through and Around the Pool

What is the pool?

The pool is a club of generators and suppliers (purchasers) As of September 1991 it had 27 members, dominated by National Power, PowerGen, and the Regional Electricity Companies The pool is not a company or part of National Grid, though National Grid performs functions for it

The Pool Purchase Price (PPP)

PPP = SMP(1 – LOLP) + VOLL•LOLP
SMP = system marginal price = marginal price of swing unit
LOLP = loss of load probability (usually zero)
VOLL = value of lost load = £2 (1990) + inflation

Generator Bidding and Provisional PPP

At 10 00 a m , all units > 100MW offer prices (startup, variable, etc) for each half hour of the next day, plus operating constraints (ramp rates, etc) National Grid's GOAL (generation, ordering, and loading) program uses this information plus load forecasts (ignoring transmission constraints) to schedule generation and to compute provisional half-hourly SMP for the next day These are published the next morning in the "Financial Times "

Table A periods capacity is tight, SMP includes fixed elements in the offers

Table B periods surplus of generating capacity, SMP is the incremental offer price

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Operation and Payments

On the day of operation, each unit is dispatched by National Grid in accordance with normal economic dispatch/unit commitment theory, recognizing transmission constraints Each generator is paid at the final PPP for each MWh, regardless of the generator's offer price They are also paid for reserve, ancillary services, the effects of transmission constraints and forecast errors, etc

Purchasers buy at the Pool Selling Price (PSP), which is set to exactly recover enough to cover costs of all purchases During Table B periods, PSP = PPP During Table A periods, PSP > PPP

Generators and suppliers are charged for the use of the grid in a zone-pricing system

It takes 28 days to sort all of this out, develop the final PPP, and settle up

Contracts

There is a very active futures market for power In addition, to protect National Power and PowerGen, who had to buy expensive British coal, the government initially set the PSP for RECs at a high level

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THE ENERGY POLICY ACT OF 1992

Overview

Title	Content
I	Energy efficiency – buildings, utility integrated resource planning, equipment
II–V	Fuels – natural gas and alternative fuels
VI	Electric vehicles
VII	Electricity
VIII–XI	Nuclear fuel and waste
XII–XV	Renewable energy, coal, petroleum
XVI	Global climate change (and least-cost strategy)
XVII	Miscellaneous Federal Power Act changes (fish, etc)
XVIII–XX	Oil and taxes
XXI,XXII	Energy and the environment and economy
XXIII–XXVII	Administrative, hydro, coal, oil, gas, Indians and islands
XXVIII,XXIX	Nuclear plant one-stop licensing
XXX	Miscellaneous

Summary of Details Relevant to this Course

Title I Energy Efficiency

Three new federal integrated resource planning standards are set, which are not mandatory on utilities or on state commissions, which may or may not enforce them (but which are mandatory for TVA and WAPA customers)

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1 to require utilities to engage in integrated resource planning,

2 to make energy efficiency programs at least as profitable as supply side options, recognizing revenue losses from reduced sales, and

3 to have rates encourage investments in efficiency in generation, transmission, and distribution

There is little discussion of uncertainty, risk, or non-monetary attributes

Title VII Electricity

Amends the Public Utility Holding Company Act of 1935 (PUHCA)

Creates "Exempt Wholesale Generator" (EWG) EWGs are exempt from all provisions of PUHCA and can be owned by utility holding companies An EWG may sell power that it has not generated itself Holding companies also can own PURPA "qualifying facilities "

Holding companies may own foreign utilities, which are unregulated

FERC may order utilities to provide transmission services for providers of wholesale power "Legitimate, verifiable, and economic costs" should be recovered from the beneficiaries of the service, not the wheeling utility's native rate-payer FERC is not authorized to order transmission services for retail consumers -- this issue is left to the states to handle

What the transmission services are is not defined!

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Regional Transmission Groups (RTGs)(19)

All major segments of the electric utility industry (investor-owned utilities, public power, cooperatives, IPPs, and environmental and conservation groups) developed an agreement on RTGs This was intended to be part of the Energy Policy Act of 1992 It was submitted too late to be included

FERC later used the agreement as the basis for a proposed rule Their objectives were to reduce regulatory burden and provide for negotiated agreements within regional organizations Specifically, the proposal

- Creates a formal structure for resolving transmission planning and wheeling issues
- Includes an arbitration system
- Provides for voluntary membership (non-members go to FERC)
- Considers planning needs of non-members

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TRANSMISSION SERVICES IN THE ENERGY POLICY ACT OF 1992

- BACKGROUND
  - SECTION 201 OF THE FPA AUTHORIZES FERC TO REGULATE THE TRANSMISSION OF ELECTRIC POWER (OR "WHEELING") IN INTERSTATE COMMERCE
  - AUTHORITY INCLUDES THE ABILITY TO INTERPRET AND MODIFY RATES, TERMS AND CONDITIONS
  - THE SUPREME COURT HAS INTERPRETED FERC'S JURISDICTION OVER INTERSTATE COMMERCE VERY BROADLY
  - VIRTUALLY ANY TRANSACTION INVOLVING THE TRANSMISSION OF ELECTRIC POWER OVER LINES THAT ARE CAPABLE OF TRANSMITTING POWER ACROSS STATE BOUNDARIES ARE SUBJECT TO FERC'S JURISDICTION
  - UNDER SECTIONS 205 AND 206 OF THE FPA ALL RATES, TERMS, AND CONDITIONS FOR THE TRANSMISSION OR SALE FOR RESALE OF ENERGY MUST BE JUST AND REASONABLE AND NOT UNDULY DISCRIMINATORY OR PREFERENTIAL

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TRANSMISSION SERVICES IN THE ENERGY POLICY ACT OF 1992

- BACKGROUND (CONT)
  - SECTION 206(a): FERC MAY NOT COMPEL THE TRANSMISSION OF ELECTRICITY BUT MAY MODIFY TERMS THAT ARE UNJUST, UNREASONABLE, UNDULY DISCRIMINATORY OR PREFERENTIAL
  - COURTS CONSISTENTLY REVERSED FERC WHEN MODIFICATIONS OF PROPOSED TRANSMISSION CONTRACTS RESULTED IN INVOLUNTARY WHEELING
  - PERMITTING INCREASED ACCESS TO THEIR TRANSMISSION SYSTEM HAS BEEN A CONDITION FOR FERC'S APPROVAL OF UTILITY MERGERS (MITIGATE MARKET POWER)
  - SIMILARLY FOR CHARGING MARKET-BASED RATES FOR POWER
  - FIRM TRANSMISSION TO THIRD PARTIES AT COST-BASED RATES

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TRANSMISSION SERVICES IN THE ENERGY POLICY ACT OF 1992

- MANDATORY WHEELING
  - TITLE VII OF THE EPACT EXPANDS FERC'S DISCRETIONARY AUTHORITY TO ORDER WHEELING
  - ANY ELECTRIC UTILITY, FEDERAL POWER MARKETING AGENCY, OR ANY OTHER PERSON GENERATING ELECTRIC ENERGY FOR SALE FOR RESALE MAY REQUEST/BE REQUESTED TO PROVIDE TRANSMISSION SERVICES (NOT DEFINED, THOUGH)
  - EPACT EXPANDS FERC'S JURISDICTION OVER TRANSMISSION ACCESS FROM "PUBLIC UTILITIES" AS DEFINED IN THE FPA TO "TRANSMITTING UTILITIES"
  - TRANSMITTING UTILITY: ANY "ELECTRIC UTILITY, QUALIFYING COGENERATION FACILITY, QUALIFYING SMALL PRODUCTION FACILITY, OR FEDERAL POWER MARKETING AGENCY WHICH OWNS OR OPERATES ELECTRIC POWER TRANSMISSION FACILITIES WHICH ARE USED FOR THE SALE OF ELECTRIC ENERGY AT WHOLESALE"

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TRANSMISSION SERVICES IN THE ENERGY POLICY ACT OF 1992

- CONSTRAINTS ON ORDERING WHEELING SERVICES
  - THE ORDER SHOULD NOT "UNREASONABLY IMPAIR THE CONTINUED RELIABILITY OF ELECTRIC SYSTEMS AFFECTED BY THE ORDER," UNDER "CONSISTENTLY APPLIED REGIONAL OR NATIONAL RELIABILITY STANDARDS, GUIDELINES, OR CRITERIA"
  - IF ENLARGEMENT IS REQUIRED AND NECESSARY APPROVALS ARE NOT OBTAINED, THE ORDER MUST BE MODIFIED
  - MANDATORY RETAIL WHEELING IS LEFT TO THE STATES (INCLUDING "SHAM" WHOLESALE TRANSACTIONS)
  - THE SERVICE MUST BE "IN THE PUBLIC INTEREST"

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TRANSMISSION SERVICES IN THE ENERGY POLICY ACT OF 1992

- PRICING TRANSMISSION SERVICES
  - TRANSMITTING UTILITIES MAY CHARGE JUST AND REASONABLE RATES THAT WILL RECOVER "ALL THE COSTS INCURRED IN CONNECTION WITH THE TRANSMISSION SERVICES AND NECESSARY ASSOCIATED SERVICES"
  - "AN APPROPRIATE SHARE, IF ANY, OF LEGITIMATE, VERIFIABLE AND ECONOMIC COSTS, INCLUDING, BUT NOT LIMITED TO, TAKING INTO ACCOUNT ANY BENEFITS TO THE TRANSMISSION SYSTEM OF PROVIDING THE SERVICE AND THE COST OF ANY ENLARGEMENT OF TRANSMISSION FACILITIES"
  - RATES MUST PROMOTE ECONOMICALLY EFFICIENT TRANSMISSION AND GENERATION
  - THE COSTS OF PROVIDING TRANSMISSION SERVICE MUST BE RECOVERED FROM THE APPLICANT FOR THE ORDER AND NOT FROM A TRANSMITTING UTILITY'S EXISTING CUSTOMERS

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TRANSMISSION SERVICES IN THE ENERGY POLICY ACT OF 1992

- INFORMATION REQUIREMENTS
  - FERC FORM 715 (1) BASE CASE POWER FLOWS,(2) MAPS AND DIAGRAMS, (3) TRANSMISSION PLANNING RELIABILITY CRITERIA, (4) TRANSMISSION PLANNING ASSESSMENT PRACTICES, (5) ANTICIPATED SYSTEM PERFORMANCE
  - THRESHOLD. 100kV
  - FERC BULLETIN BOARD (202) 501-7787

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TRANSMISSION SERVICES IN THE ENERGY POLICY ACT OF 1992

- PROCEDURE FOR REQUESTING TRANSMISSION SERVICES
  - CUSTOMER MAKES "GOOD FAITH REQUEST"
  - TRANSMITTING UTILITY HAS 60 DAYS TO RESPOND IN WRITING
  - CUSTOMER MAY GO TO FERC TO REQUEST AN ORDER

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G THE 1995 MEGA NOPR

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FEDERAL ENERGY REGULATORY COMMISSION'S MEGA NOTICE OF PROPOSED RULEMAKING

PROMOTING WHOLESALE COMPETITION THROUGH OPEN ACCESS NON-DISCRIMINATORY TRANSMISSION SERVICES BY PUBLIC UTILITIES (Docket No. RM95-8-000)

RECOVERY OF STRANDED COSTS BY PUBLIC UTILITIES AND TRANSMITTING UTILITIES (Docket No. RM94-7-001)

- **Issued** March 29, 1995
- "Sweeping changes in the wholesale electric industry
- New rules would require utilities to provide open access to the Nation's interstate transmission network
- Under the Commission's proposal

  1 all utilities under the Commission's jurisdiction would be required to file non-discriminatory open access transmission tariffs, available to all wholesale sellers and buyers of electricity,

  2 the utilities would be required to take service under the tariffs for their own wholesale sales and purchases of electric energy, and,

  3 the utilities would be allowed the opportunity to recover stranded costs

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- **Stated Goals**

  1 Facilitate the development of a competitive market

  2 Eliminate anti-competitive and discriminatory practices in transmission services

  3 Lower electric rates

- According to Chair Moler " foster competition in generation "

- Under the proposed rule, transmission utilities would have to offer point-to-point and network transmission services, including ancillary services, such as scheduling and dispatch Pro forma tariffs issued with the proposed rule spell out the minimum requirements for transmission service

- The Commission believes 137 utilities will be required to open up their lines Only 21 utilities have any form of open access today, the vast majority do not No public utility has on file a non-discriminatory open access tariff as defined by this rule (footnote, pp 65) The majority have offered only point-to-point services However, a few utilities have sought to comply with the non-discrimination (comparability) standard announced in AEP (footnote in pp 67)

- To be implemented in two stages In Stage 1, for every public utility that owns or controls transmission, the Commission proposes to put into effect--60 days after the effective date of the rule--generic pro forma tariffs In Stage 2--which would begin 61 days after a Final Rule went into effect--utilities and their customers could file to modify the tariffs and rates within the limits of non-discriminatory open access outlined in the rule

- The Commission established the principle that utilities are entitled to full recovery of legitimate and verifiable stranded costs at both the state and federal level

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- In a related action, the Commission said it will hold a technical conference to develop real-time information networks (RINs), i e , networks for ensuring that potential purchasers of transmission services under the open access tariffs have the necessary information

- The Commission said it plans to have standards in place (for the availability of simultaneous information to those trading electric power) when the open access transmission rule is finalized

- The Commission said it plans to have standards in place (for the availability of simultaneous information to those trading electric power) when the open access transmission rule is finalized

- The Commission seeks comments on these proposals

- The proposed rule includes two pro forma tariffs, one for network service and one for point-to-point service These set out terms and conditions, and specifically must address ancillary services such as

  1 Scheduling and dispatching
  2 Load following
  3 Imbalance resolution
  4 Reactive power support, and
  5 System Protection

- Public utilities are also required to enlarge transmission capacity and/or ancillary service facilities if necessary to provide requested transmission service

  Two key principles proposed to be used by the Commission in evaluating tariffs

  1 The terms and conditions must be clear and specific
  2 Any restrictions or limitations on service or procedures must be limited to technical or operational needs that **can be verified, and they must be the least restrictive way to meet those needs** (pp 103)

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- The proposed rule **does not** require corporate unbundling (i e , corporate separation of generation, transmission, and distribution functions)

- The proposal does provide for functional wholesale generation and transmission unbundling, meaning

  1 A public utility must obtain transmission services for all of its new wholesale sales and purchases of electric energy under the same tariff with which it offers such services to others

  2 A transmission owner's tariff must include separately stated rates for transmission and ancillary service components

  3 A public utility must rely on the same electronic network that its customers use to obtain transmission information about its system when buying or selling power

- The Commission believes that it can achieve its goals without disrupting existing contracts It proposes to apply the unbundling requirements only to transmission services under new requirements contracts and new coordination trade contracts The Commission would not disrupt any existing power or transmission contracts (Coordination transactions are voluntary sales or exchanges of specialized electricity services that allow buyers to realize cost savings or reliability gains that are not attainable if they rely solely on their own resources For sellers, these transactions provide opportunities to earn additional revenue, and to lower customer rates, from capacity that is temporarily excess to native load capacity requirements, pp 37)

- " the opportunity to recover stranded costs is critical to transition of the electric utility industry to a competitive environment"

- The Commission had issued a stranded cost NOPR on June 19, 1994 The mega NOPR consolidates the previous proposal with the open access initiatives and recognizes the vital link between the two A supplemental NOPR on stranded costs was therefore issued concurrently

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REGIONAL TRANSMISSION GROUPS

- DID NOT GET INTO THE EPACT DESPITE AN AGREEMENT AMONG INTERESTED PRIVATE PARTIES

- POLICY STATEMENT REGARDING REGIONAL TRANSMISSION GROUPS (AUGUST 5, 1993)

- **REGIONAL TRANSMISSION GROUP:** A VOLUNTARY ORGANIZATION OF TRANSMISSION OWNERS, TRANSMISSION USERS AND OTHER ENTITIES APPROVED BY THE COMMISSION TO EFFICIENTLY COORDINATE TRANSMISSION PLANNING (AND EXPANSION), OPERATION AND USE ON A REGIONAL (AND INTERREGIONAL) BASIS

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REGIONAL TRANSMISSION GROUPS

- FERC HAS EXPRESSED SUPPORT FOR THE DEVELOPMENT OF VOLUNTARY TRANSMISSION ASSOCIATIONS AND HAS ENCOURAGED THEIR FORMATION. "WE BELIEVE THAT RTGs CAN SPEED THE DEVELOPMENT OF COMPETITIVE MARKETS, INCREASE THE EFFICIENCY OF THE OPERATION OF TRANSMISSION SYSTEMS, PROVIDE A FRAMEWORK FOR COORDINATION OF REGIONAL PLANNING OF THE SYSTEM AND REDUCE THE ADMINISTRATIVE BURDEN ON THE COMMISSION AND ON MEMBERS OF RTGs BY PROVIDING FOR VOLUNTARY RESOLUTION OF DISPUTES. THE COMMISSION HAS STATED ITS WILLINGNESS TO GIVE DEFERENCE TO DECISIONS RESOLVED THROUGH RTG DISPUTE RESOLUTION PROCEDURES "

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REGIONAL TRANSMISSION GROUPS

- **REQUIREMENTS:**
  - BROAD MEMBERSHIP
  - ADEQUATE CONSULTATION AND COORDINATION WITH INTERESTED PARTIES
  - FAIR AND NON-DISCRIMINATORY VOTING PROCEDURES
  - PROVIDE SERVICES TO EACH OTHER
  - DEVELOP A COORDINATED TRANSMISSION PLAN
  - INCLUDE VOLUNTARY DISPUTE RESOLUTION PROCEDURES
  - INCLUDE EXIT PROVISIONS

A NUMBER OF ORGANIZATIONS HAVE FILED OR ARE PREPARING TO FILE FOR RECOGNITION BY FERC AS RTGs. AS OF APRIL 1996, THREE WESTERN ORGANIZATIONS HAVE BEEN APPROVED BY FERC. WRTA (WESTERN REGIONAL TRANSMISSION ASSOCIATION), AND SWRTA (SOUTHWEST TRANSMISSION REGIONAL ASSOCIATION), AND NRTA (NORTHWEST REGIONAL TRANSMISSION ASSOCIATION).

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THE EVOLVING MIDWEST ISO BASIC PRINCIPLES (20)

In recent months, 21 utilities* have agreed to propose an ISO which would control the transmission grid in the Upper Midwest So far, the utilities have agreed to 13 basic principles

1) ISO is independent of transmission owners
2) ISO has functional control of combined member transmission systems
3) Members retain ownership and operate and maintain transmission facilities, while existing control areas provide real-time data to the ISO
4) Bulk-transmission system managed by ISO includes facilities affecting transmission transfer capability and system security
5) Members will be electrically interconnected
6) ISO determines transmission capability and schedules transactions
7) Existing control areas will be retained
8) ISO responsible for regional system security
9) ISO administers regional transmission tariff and equitable revenue distribution procedure
10) ISO will be regulated by the FERC
11) ISO plans expansion of the regional bulk transmission system
12) ISO develops dispute resolution process
13) ISO ensures availability of ancillary services to support transmission services

**Members include American Electric Power, Big Rivers Electric Co-op, Centerior Energy, Central Illinois Public Service, CINergy, Commonwealth Edison, Detroit Edison, East Kentucky Power Co-op, Illinois Power Co , Hoosier Energy Rural Co-op , Indiana Municipal Power Agency, Indianapolis Power & Light, Kentucky Utilities, Louisville Gas & Electric, Michigan Public Power Agency, Northern Indiana Public Service, Southern Indiana Gas & Electric, Union Electric, Wabash Valley Power Assn , Wisconsin Electric Power, Wisconsin Public Service*

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ALTERNATIVE POOLING INSTITUTIONS

- INQUIRY CONCERNING ALTERNATIVE POWER POOLING INSTITUTIONS UNDER THE FEDERAL POWER ACT (OCTOBER 26, 1994)
- POOLCO AND BILATERAL MODELS RECEIVING A LOT OF ATTENTION (CALIFORNIA, NEW YORK, ETC)
- IMPACTS OF MODELS ON A NUMBER OF ATTRIBUTES BEING INVESTIGATED

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- **POOLCO**
  - U.K., AUSTRALIA
  - CENTRALIZED ENTITY WITH AUTHORITY OVER REAL-TIME SYSTEM OPERATIONS
  - DISPATCH TO MINIMIZE SYSTEM PRICE
  - MERIT ORDER DISPATCH IS ENFORCED
  - CONSTRAINTS ARE ENFORCED
  - INFORMATION ABOUT PRICES AT INDIVIDUAL GENERATORS IS REQUIRED

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- **BILATERAL**
  - NORWAY
  - CENTRALIZED ENTITY WITH AUTHORITY OVER REAL-TIME SYSTEM OPERATIONS
  - DISPATCH TO ENFORCE CONSTRAINTS, RESPECTING BILATERAL AGREEMENTS, IF POSSIBLE
  - SPOT MARKET FOR RELIABILITY AND SECURITY
  - INFORMATION ABOUT PRICES AT INDIVIDUAL GENERATORS IS NOT REQUIRED

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I FERC ORDER NO 888

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ORDER 888
TRANSMISSION SERVICES [21]

Point-to-point Transmission Service, based on reservations

Network Integration Transmission Service, based on load

Ancillary Services which Transmission Provider must provide and Transmission Customer must purchase

- Scheduling, system control, and dispatch
- Reactive supply and voltage control from generation sources

Ancillary Services which Provider must offer and Customer serving load in the provider's control area must purchase from Provider or acquire elsewhere

- Regulation and frequency response
- Energy imbalance
- Operating reserve -- spinning
- Operating reserve -- supplemental

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Basic point-to-point service tariff	Daily, weekly, monthly, or annual demand charge, based on reservation
Basic network service tariff	(Load ratio share) x (transmission revenue requirements), based on usage (load)
Losses	Made up in kind by customer using loss factors
Opportunity costs	May be used instead of but not in addition to embedded costs in determining rates
Resale of services	If the provider purchases services from others and sells them to the customer, the charges should reflect only a pass-through of costs
Energy imbalance	If within ± 1 5%, repay in kind within 30 days If not repaid, or if outside band, then pay in cash
System impact study	Customer pays for it, if necessary
New facilities	If serving a customer requires new facilities, then the customer pays for them
Redispatch costs	If redispatching allows a point-to-point customer to be served at lower cost than by adding new facilities, then the customer pays the redispatch costs A network customer pays a part of the total redispatch cost, based on his and the provider's respective load ratio shares

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ORDER 888
STRANDED INVESTMENT [21]

Transition issue Courts faulted FERC for ignoring stranded investments in deregulation of gas

The mantra *legitimate, prudent, and verifiable*

Applicable only to

- Existing wholesale requirements customers
- Retail-turned-wholesale situations
- Retail-wheeling situations where states do not have authority to permit recovery of stranded investment
- New requirements contracts which contain stranded investment clauses

Mechanism 100% recovery through

- Exit fee or
- Transmission services surcharge

Must demonstrate "reasonable expectation" that customer would continue to take service indefinitely

Calculation

$$SCO = (RSE - CMVE) \times L$$

SCO = Stranded cost obligation (present worth)
RES = Revenue stream estimate
CMVE = Competitive market value estimate
L = Length of obligation (reasonable expectation period)

Cap (RSE - CMVE) must be $\leq$ (RSE - variable costs)

Brokering option customer may reduce SCO by brokering the utility's stranded capacity and energy

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ORDER 889
OPEN ACCESS SAME-TIME INFORMATION SYSTEM (OASIS) [22]

Input from two industry working groups

- The "What" group (NERC)
- The "How" group (EPRI)

Three provisions

- Standards of conduct
- Requirement that an OASIS be set up
- Standards and protocols (draft)

Information to be posted must allow customers to

- Request transmission services
- Make business decisions
- View information about available products, desired services
- Identify degree to which their transmission service requests were denied
- Access data to support transmission capability calculations and historical requests and schedules

Posting transmission capability

- Constrained posted paths - hourly (168 hours), daily (30 days), monthly (12 months), seasonal (10 years)

- Unconstrained posted paths - daily (7 days), monthly (12 months)

There are rules on variations of the above reporting requirements, when reports have to be updated, what constitutes a posted path, etc

All offers, contracts, curtailments, etc , are to be transparent and public as to terms, conditions, prices, etc

Every transmission provider must participate in an OASIS and be in compliance with the standards of conduct by November 1, 1996

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CAPACITY RESERVATION TARIFF
(Proposed Rule) [23]

Inconsistency point-to-point tariff is based on reservation, network tariff is based on use Would it not be cleaner to charge everybody on one of these two bases?

> (In addition, network customers do not have to forecast usage in order to contract for service The transmission provider thus faces greater uncertainty with them than with point-to-point customers)

Purpose develop a single tariff approach which will work for both point-to-point and network service

Basic approach customers specify amount of power to be delivered and received at multiple delivery and receipt points, with flexibility in rearranging them Everyone pays on reservation basis, not load basis

> (Problem reservation-based contracting may over-state the demand on the system)

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GLOSSARY OF KEY TERMS

AGREEMENT/SUPPLEMENT TYPE

INTERCONNECTION

An arrangement between two or more electric utility systems to provide a variety of electric services (e G , Economy energy, emergency service) to each other

COORDINATION

An arrangement between interconnected electric utility systems to participate in joint planning of operations and to provide assistance to each other during periods of emergency or limited generating reserves

FACILITIES ONLY

An arrangement between parties in which one party provides electric facilities for use by the other The facilities most often involve transmission (substation) equipment

FULL REQUIREMENTS

A sale of power and energy by a utility to a purchaser in which the seller pledges to meet all of the purchaser's electric requirements

PARTIAL REQUIREMENTS

A sale of power and energy by a utility to a purchaser in which the seller provides only a portion of the purchaser's electric requirements

POWER POOL

An arrangement between interconnected utilities to provide for integrated operation of the utilities' systems, including central dispatch of member utility generating units and specified installed capacity and operating capacity obligations which must be met by each pool member

POOL TO POOL

An arrangement between power pools to provide electric services to each other

TRANSMISSION SERVICE

An arrangement to transmit power for another party over the transmission lines of the utility providing service

CERTIFICATE OF CONCURRENCE

A statement filed by a utility in lieu of submitting an agreement which concurs in the contractual arrangements (including rates and charges) filed by another party to the agreement The rates, charges, terms and conditions under which the party filing the certificate of concurrence will provide service are found in the other party's rate schedule

CHANGE IN CONTRACT DEMAND

The establishment or change in the contracted amount of power to be provided

CHANGE IN DELIVERY POINTS

The establishment, change, or deletion of specific points of delivery for electric power

CHANGE IN DELIVERY VOLTAGE

The establishment or change in the voltage at which electric power is to be provided

CHANGE IN TERM

A change in the term of a contract

RATES AND CHARGES

Specification of rates and charges for the electric service provided

SERVICE AGREEMENT

A contract for electric service under the rates, terms and conditions of tariff

SERVICE SCHEDULE

A portion of an agreement between parties which provides for a specific electric service to be rendered and includes the rates, terms and conditions for the service

TERMS AND CONDITIONS

Specification of operating arrangements and other special contractual items and conditions for the electric service provided

CLASS OF SERVICE

BANKED

Energy provided to a purchaser that entitles the supplier to receive energy in return

DIVERSITY

Capacity and/or energy which is exchanged between utility systems to take advantage of the difference in load patterns of the utilities' systems, that is, provided by one party to another during a specified period with the receiving party obligated to make an equivalent amount available to the other party during a different specified period

DUMP

Energy generated in hydroelectric plants by water that cannot be stored or conserved and which energy is in excess of the needs of the electric system producing the energy

ECONOMY

Energy produced from a source in one system and substituted for energy that could have been produced by a less economical (more costly) source in another system

FACILITIES CHARGE

A lump sum payment or periodic charge for the use of a specific facility

FIRM

Power and energy which is intended to have assured availability to the purchaser at all times

FIRM TRANSMISSION

Transmission of energy by a utility over its system for the account of another party with the service intended to be available at all times

FUEL CONSERVATION

Capacity and/or energy provided by a utility to enable the receiving party to avoid the use of generating capacity fired by fuels which are in scarce supply

INADVERTENT

An unplanned providing of energy by a utility to another due to the inadvertent flow of power over an interconnection point between the parties

INTERRUPTIBLE

Energy whose availability may be curtailed or canceled by the supplier under specific conditions

INVESTMENT EQUALIZATION CHARGE

A payment made by a utility to reflect an insufficient level of investment in facilities dedicated to a power pool arrangement

LIMITED TERM FIRM

Capacity and/or energy provided on a weekly or monthly basis, generally for periods not to exceed one year, with assured availability during the period or reservation

LIMITED TERM NON-FIRM

Capacity and/or energy provided on a weekly or monthly basis, generally for periods not to exceed one year, with limited or no assured availability during the period of reservation

NON-FIRM TRANSMISSION

Transmission of energy by a utility over its system for the account of another party with the service having limited or no assured availability

OTHER HYDRO

Energy generated by hydro electric plants not specifically described under other classes of service

OTHER NON-HYDRO

Energy generated by other than hydroelectric plants not specifically described under other classes of service

POOL CAPACITY

Capacity provided by power pool to a pool member in order for the member to meet installed or reserve capacity obligations

SCHEDULED MAINTENANCE

Capacity and/or energy provided by a utility during the period that generating facilities the receiving party are inoperative due to scheduled maintenance on the facilities

SHORT-TERM FIRM

Capacity and/or energy provided on a daily or weekly basis, generally for periods not to exceed one month, with assured availability during the period of reservation

SHORT-TERM NON-FIRM

Capacity and/or energy provided on a daily or weekly basis, generally for periods not to exceed one month, with limited or no assured availability during the period of reservation

SPECIFIED UNIT POWER

Capacity and associated energy provided from a specified generating unit

SPINNING RESERVE

Providing of generating capacity which is connected and ready to take load, including capacity available in generating units which are operating at less than full capability

STANDBY SERVICE

Capacity and/or energy provided or made available when the purchaser's generation is unable to meet its entire load or has dropped below a stated level of reserve capacity

STORAGE ENERGY

Energy provided by a utility to enable the receiving party to avoid discharging water through hydroelectric generators at a reservoir

Glossary

avoided cost
the cost which a utility would otherwise incur to provide its own generation sources if other options such as purchase from non-utility (QF) sources were not available

back-up power
power which a wheeling utility must provide by contract or by virtue of its control area responsibility to a customer as part of customer wheeling when that customer's normal external source of power is not available

cogeneration
the term applied to generating plants which utilize a single heat source for a dual purpose - generating electrical energy and some other unrelated use such as the production of process steam

contractual path
the physical transmission path(s) between interconnected utility systems defined by a contract covering the delivery of power from one system to the other

firm wheeling
wheeling service which by contract terms cannot be intentionally interrupted by the utility providing the wheeling service

"fly wheel" effect
the term used to describe the electromechanical interaction of the electrical power output and the mechanical power input to the turbo-generator whereby the rotating mass of the turbogenerator increases or decreases its speed (kinetic energy) to make up for the difference between instantaneous changes in electrical output and slower corresponding variations in mechanical input.

frequency
refers to the number of times per second that the voltage of an alternating current system varies from positive polarity to negative polarity and back to positive, each such variation being called a cycle, with frequency being measured in cycles per second or Hertz (Hz).

impedance (Z)
the electrical characteristic (measured in ohms) of an electrical network component, such as a transmission line or transformer, which quantifies that element's ability to hinder (or impede) the flow of electrical power

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interconnected systems
in the context of this paper, this term refers to individually owned and operated electric utility systems which are electrically connected to each other through transmission network components such as lines or transformers for the purpose of delivering and receiving electrical power

interconnection
in the context of this paper, the transmission network component which connects individually owned and operated electric utility systems together, often referred to as a tie line if the interconnection is a transmission line

interruptible wheeling
wheeling service which by contract terms may be interrupted under specified conditions by the utility providing the wheeling service

line charging
the reactive power produced by an ac transmission line or underground cable resulting from the alternating charging and discharging of the line or cable due to an alternating voltage

load factor
the sum of all hourly loads in a given period divided by the peak hourly load multiplied by the number of hours in the period

load following
as used in this paper, this term refers to the obligation of the wheeling utility to provide from its own generating sources any difference between the amount of power being wheeled and the instantaneous requirements of the customer receiving, or the supplier delivering, the wheeled power

load frequency control (LFC)
the control system by which a utility continuously balances the generation sources and loads within its control area so as to maintain the desired net area interconnection power flow and thereby keep frequency constant

mandated wheeling
wheeling service that must be provided under regulatory directive.

phase angle regulator
an electrical device which has the ability within certain physical limits to control power flow through a particular component of the transmission network.

power flow
the delivery of electrical power through any component of the transmission network

power interchange
the power flow which occurs between two interconnected electric utility systems

power transfer
often used interchangeably with "power interchange", but is more general in that it refers to movement of power by reducing one or more generating sources and increasing one or more sources a similar amount anywhere in the interconnected systems

relay
as used in the context of this paper, refers to a device which detects abnormal conditions on a power system and automatically initiates control action to protect endangered equipment, usually by activating other devices which will separate the endangered equipment from the rest of the system

right-of-way
the defined corridor under and to each side of a transmission line in which land use is restricted so as to permit safe operation of the line

rotational kinetic energy
the energy which must be transferred to and stored in a rotating mass by exerting a force on it to bring it from standstill to a constant speed

short circuit (or fault) current
the current which will flow when a conductor energized at one voltage level is inadvertently connected to another conductor which is energized at a different, or zero, voltage level, most commonly a connection between an energized line and a grounded conducting object

shunt capacitors
static electrical devices which may be connected to the power system to provide a source of reactive power

spinning reserves
the difference between the capability and actual output of generating units which are operating and connected to the electrical network.

static var system
a system of static capacitors and reactors using solid state electrical controls to provide a rapidly controllable source of reactive power

synchronism
the process of operating all ac generating units connected to the same electrical system at exactly the same frequency with their voltages having the same polarity at every instant

synchronizing power
that power which flows between generating units to keep them operating in synchronism

synchronous condenser
a machine which is designed to generate reactive power and to operate at synchronous speed

synchronous speed
the speed at which an alternating current generating unit must operate so as to generate power at the same frequency as all other generators connected to the same electrical system

transmission access
the ability of third parties to make use of existing transmission facilities owned by others (wheeling utility) to deliver power to the customers of the wheeling utility

transmission margin
the difference between actual loading and maximum capability of a transmission facility.

transmission services
the transport of power from one point to another and all of the ancillary functions which system operators must perform such as voltage control, load frequency control, etc. which make the transport of power possible

turbogenerator
the combined steam, hydro, or other type of turbine and mechanically connected electrical generator which are used to convert steam, falling water or some other form of energy into electrical energy.

turbogenerator rotor
the rotating part of a turbogenerator.

Wheeling — a primer for engineers

"Good" wheeling improves efficiency of operation.

By Fred C Schweppe, Professor of Electrical Engineering and Computer Science Massachusetts Institute of Technology and Hyde M Merrill Manager - Planning Power Technologies Inc

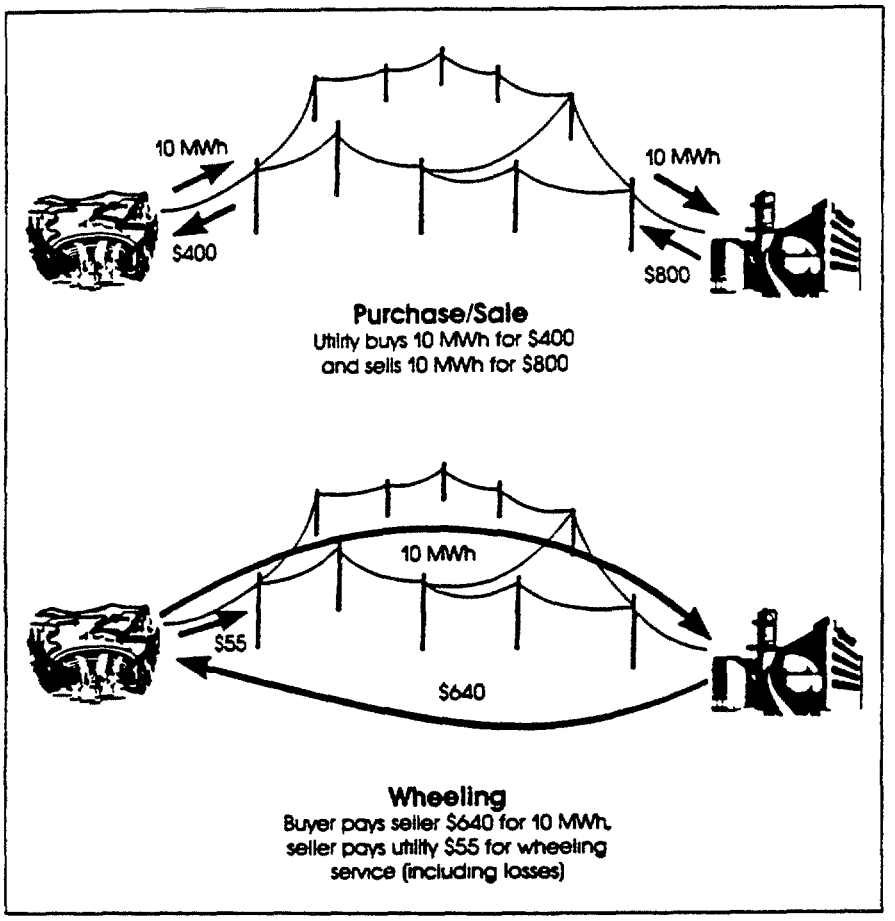

Fig 1. Wheeling is physically the same as a purchase/sale so sometimes only money is wheeled.

This article introduces wheeling from a practical point of view Emphasis is on understanding the issues and available options Two key issues include What costs should be recovered by the wheeling utility? and What rates should the wheeling utility charge?

There are many types of wheeling depending on the relationship between the buyer and the seller Four examples are

- Utility to utility,
- Utility to private customer,
- Private generator to utility and
- Private generator to private user

Wheeling usually involves changes in energy flows over a transmission system But it's possible to wheel money, ' with no change in transmission flow For example in Fig 1 independent buy sell transactions are replaced with a wheeling transaction This wheeling has absolutely no physical effect money is being wheeled energy is not Similar situations can occur in a large power pool with central dispatch

Not all wheeling is good

Buyers, sellers and wheeling utilities should be willing to cooperate to achieve good wheeling while discouraging bad" wheeling Unfortunately, the difference between good and bad is not always clear Two objectives are to improve overall economic efficiency, and to recover the wheeling utility s costs Then, by definition, good wheeling satisfies both objectives, while bad wheeling does not

Note that bad wheeling may look good to both the buyer and seller[1] For example, suppose the buyer is an industrial customer in the wheeling utility's service territory and the seller is another utility The following costs are assumed

Marginal Operating Costs (mainly fuel)	
Selling Utility	4 cents /kWh
Wheeling Utility	3 cents/kWh

Suppose the wheeling utility sells to the industrial customer at 8 cents/kWh (which includes fixed costs in the rate base) Here the selling utility and the industrial customer would be willing to deal instead, at say 6 4 cents/kWh Such a transaction would be bad as overall production efficiencies would decrease, the selling utility would increase its 4 cents/kWh generation and the wheeling utility would decrease its 3 cents/kWh generation

What costs should be recovered?

Almost everyone agrees that a wheeling utility should get revenues to cover the effects of the wheeling on its operating cost These costs represent electrical losses, generation redispatch (wheeling can force the utility to redispatch its generation to maintain acceptable line flows) and the transaction itself (metering billing communications and computations) The loss and redispatch costs can actually be negative — wheeling can reduce the losses on the wheeling utility s system or allow it to redispatch generation more economically

Capital costs

Network capital costs associated

with transmission lines transformers switches circuit breakers and variable reactances are relatively easy to evaluate A more elusive network capital cost is the VAr support provided by the generators it is hard to compute real and reactive components of a generator s cost[1]

Should capital costs associated with generation of real power be recovered from wheeling revenues? This question can have a major impact on wheeling revenues The key issue is whether the wheeling utility has an "obligation to serve" the buyer or seller If it does, then generation capital costs should be recovered from wheeling rates

For wheeling to take place, the buyer and seller must decide that it is to their economic advantage, and the wheeling utility must agree to wheel The rate structure should recover the wheeling utility s costs and send correct price signals' to the buyer and seller so their decisions will tend to improve overall production efficiency The best way to do this is to use wheeling rates that are based on marginal wheeling costs[1]

Marginal cost of wheeling

The marginal cost of wheeling to the wheeling utility (in cents/kWh) can be calculated via this formula

$$\text{Marginal Wheeling Cost} = \frac{\text{Change In Wheeling Utility Costs}}{\text{Small Change In Amount Wheeled}} \quad (1)$$

The marginal wheeling cost can be calculated using a production-cost program and a load-flow program More sophisticated tools make this easier a computer program (WRATES) is being developed with funding from DOE and New York State ERDA

Equation (1) may include a term to reflect security or flow constraints In addition the wheeling utility may not have enough transmission capacity to serve all the proposed transactions If it doesn t this equation becomes still more complicated to reflect the cost of new facilities or to allocate the network to the most desirable transaction[2] The marginal wheeling cost may be negative — for example, if wheeling makes losses go down

Recovering fixed costs

While wheeling rates based on marginal wheeling costs will allow a utility to recover all operating costs associated with a wheeling transaction the utility may make or lose money on the deal For example, Fig 2 compares marginal wheeling costs and total changes in the wheeling utility's operating costs for transactions wheeled through utility A and utility B But both A and B have fixed capital costs to recover These costs might be for facilities built just for wheeling (with 30-yr lifetime 70% capacity factor) Or they might be an allocated share of the cost of existing facilities

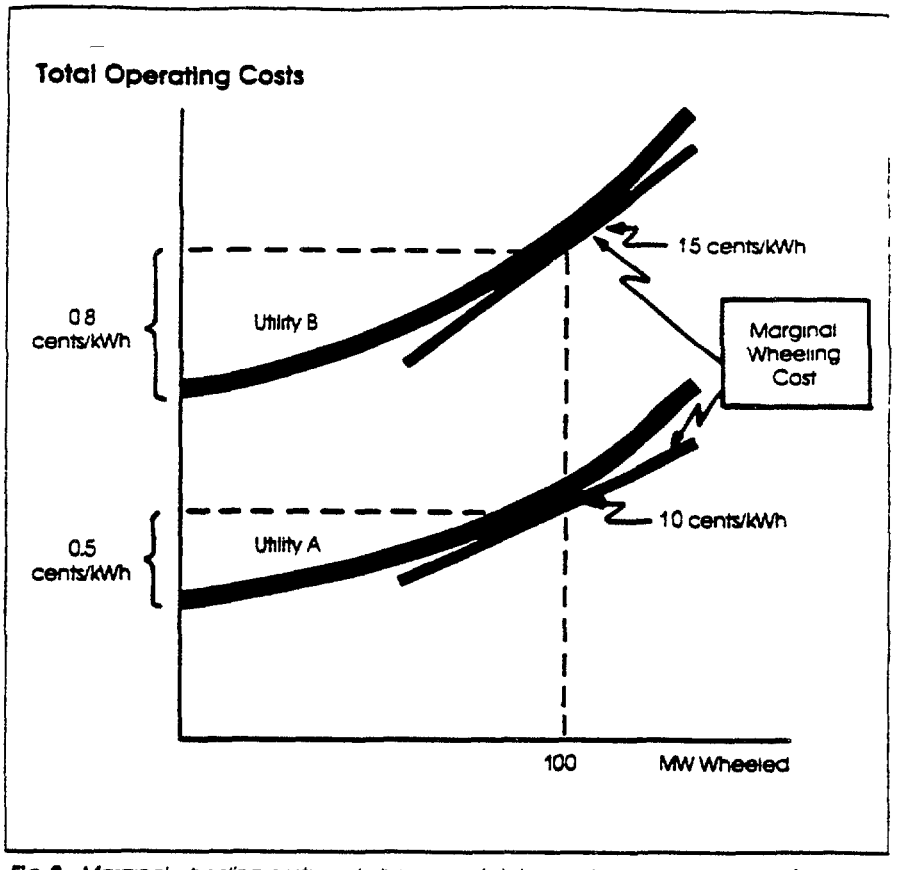

Fig. 2. Marginal wheeling costs and changes in total operating costs are shown for two hypothetical wheeling utilities.

Table 1 Transactions involving two different wheeling utilities

	Wheeling Through Utility A	Wheeling Through Utility B
Wheeling rate (marginal wheeling cost)	1.0 cents/kWh	1.5 cents/kWh
Less: Total change in wheeling utility's operating costs	0.5 cents/kWh	0.8 cents/kWh
Change in net operating income to wheeling utility	+0.5 cents/kWh	+0.7 cents/kWh
Less: Fixed capital costs	0.8 cents/kWh	0.5 cents/kWh
Change in total revenues to wheeling utility	−0.3 cents/kWh (under-recovery)	+0.2 cents/kWh (over recovery)

Table 1 shows that both transactions more than recover changes in operating costs caused by the wheeling However when fixed costs are included, utility A under-recovers, while utility B over-recovers This situation can be remedied by adding a 'revenue reconciliation term to equation (1) Unfortunately, this reconciliation gives wheeling rates that do not always encourage an increase in production efficiency For instance suppose equation (1) gives a one cent/kWh marginal wheeling cost The revenue

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reconciliation term can be either positive or negative Looking at both cases Wheeling Rate = 2 cents/kWh (Revenue reconciliation of +1 cent/kWh) or = 0 5 cents/kWh (Revenue reconciliation of −0 5 cent/kWh)

Suppose buyer and seller are both utilities with marginal operating costs of 6 cents/kWh and 4 cents/kWh respectively If the wheeling rate is the marginal wheeling cost of one cent/kWh the buyer and seller can afford a deal which would increase overall production efficiency and cover the wheeling utility operating costs That is good wheeling will occur If the wheeling rate is 2 cents/kWh the buyer and seller have no incentive to deal even though doing so would improve overall production efficiency If the wheeling rate is 0 5 cents/kWh the buyer and seller are encouraged to deal even though the wheeling utility s actual operating costs may not be recovered

A buyer and a seller will want a utility to wheel energy for them if there are savings or profits to be made The wheeling utility will usually want to share in these profits Who gets the profits needs to be solved reasonably as perceived by all parties, if wheeling is to occur

Conclusions

This article discussed wheeling transactions which differ because of the nature of the buyer and the seller We defined good and bad wheeling the former improves efficiency of operation and recovers the wheeling utility s costs If no capital is to be recovered by wheeling economic theory says that the marginal cost of wheeling is an optimal rate for wheeling services If capital is to be recovered this rate is not adequate it may be under or over-recover capital costs and will not necessarily apportion access to the network properly

Changing the price can take care of these problems but may distort the economics impeding good transactions or encouraging bad" ones So, in general there is no theoretically and practically perfect way to price wheeling services

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WHEELING RATES BASED ON MARGINAL-COST THEORY

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Abstract - Knowledge of what rates for wheeling electric power would be, if based on marginal costs, is vital in the debate on how wheeling should be priced This paper presents the first extensive computations of marginal costs of wheeling, and of rates based on these marginal costs Sensitivities to losses, constraints, load levels, amount of power wheeled, revenue reconciliation, etc , are examined in the context of two case studies

Keywords wheeling, power wheeling, wheeling rates, transmission access, marginal cost pricing

INTRODUCTION

Wheeling has been defined as

> "The use of transmission or distribution facilities of a system to transmit power of and for another entity or entities "

Schweppe has observed that "wheeling is a mongrel concept resulting from mating two inherently different economic concepts an ideal world of regulated utilities, and an ideal deregulated competitive market place Wheeling would not exist at either extreme " [1]

Historically, wheeling has not been an important issue Large blocks of power have been moved from one system to another to another as utilities interchanged power with their neighbors Sometimes intervening utilities have been involved formally as part of a "contract path" between a buyer and a seller In addition, unofficial wheeling occurs constantly as dictated by the laws of physics and the facts of parallel networks, such "loop flows" are generally recognized but usually do not cause problems because the networks were designed to handle them

Today's debates on deregulation recognize that network access is a key requirement of any meaningful form of a competitive market place And how network access will be priced has to be resolved

References [1] and [2] are introductions to wheeling which identify many of the key issues A complete exposition of wheeling rate theory is in [3] This includes development of marginal cost concepts and approaches to revenue reconciliation for capital recovery Reference [3] also includes an extensive bibliography A computer program called WRATES was developed to provide a practical means of computing the marginal cost of wheeling It is described in [4] and [5]

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The next section of this paper summarizes the marginal cost concepts of [3] and describes the WRATES program Then the two main sections of this paper describe extensive evaluations of marginal costs of wheeling, and of rates based on these costs Two case studies are outlined Losses, load levels, quantity of power wheeled, network constraints, locations and operating costs of power plants -- all affect the marginal cost of wheeling These effects are described Revenue reconciliation for capital recovery is also described briefly In the final section we summarize our conclusions

MARGINAL COST THEORY AND WRATES

Marginal Cost Theory [3]

The short-run costs of wheeling are the marginal (incremental) costs of the last MWh of energy wheeled Since wheeling is physically indistinguishable from a simultaneous purchase-sale by the wheeling utility, the short-run marginal wheeling costs can be computed from the marginal costs (spot prices) of electricity at the buses where it enters and leaves the wheeling utility, and

Ideal Wheeling Rate = Marginal Cost of Wheeling

The ideal wheeling rate varies as the spot prices of electricity change It recognizes transmission constraints -- if wheeling would cause an overload, the ideal wheeling rate rises to discourage it If wheeling causes a reduction in losses, the ideal wheeling rate will even be negative

This is simple, logical, and appealing Many words have been written about the desirability of wheeling rates based on marginal-cost theory But computations, showing what the marginal costs are, have not been made or results published This is important because the marginal costs can behave in ways which are at first counter-intuitive The main contribution of this paper is to present marginal costs for typical transactions based on real-world conditions

For instance, it is a characteristic of marginal cost pricing that the wheeling utility will at least recover its incremental operating costs, and will in fact usually make a profit But there is no guarantee that the profit will be sufficient to recover an appropriate share of the imbedded capital investment in facilities used for wheeling Nor is it guaranteed to provide the funds necessary to provide new facilities which may be needed for wheeling In fact the ideal wheeling rate may over-recover or under--recover capital See [2] for examples

It is therefore necessary to adjust the ideal wheeling rate to give the appropriate capital recovery

Revenue Reconciled Wheeling Rate	=	Ideal Wheeling Rate	+	Revenue Reconciliation Adjustment

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The revenue reconciliation adjustment concept is murky and messy There is no good theory which tells how much capital should be recovered, either to make the utility whole for past network investments or to give the proper incentive for future investments Arguments also can be made for including capital recovery for generating plant, if wheeling causes a utility to lose electricity sales for which it had constructed power plants, that is, if it has an "obligation to serve" the buyer or seller of the wheeled power

Once the amount of capital to be recovered has been decided, a revenue reconciliation adjustment can be made to recover it Several forms of this adjustment have been suggested A multiplicative approach is

$$\text{Revenue Reconciliation Adjustment} = m \times f$$

The quantity m is a multiplier The last term, f, is a function of the spot prices Its form depends on whether generation costs are included, whether wheeling is from a utility to a utility, or from a single bus to another bus, whether capital costs are computed line-by-line or aggregated, etc [4]

The WRATES Computer Program [4][5]

WRATES is public-domain software whose development was funded by the New York State Energy Research and Development Authority and by the US Department of Energy The software and its documentation are available for a nominal reproduction and handling fee from Meta Systems, Inc , of Cambridge, MA

WRATES (Wheeling Rate Evaluation Simulator) is an implementation of the marginal cost theory described above It runs on an IBM-compatible PC and can handle dc load-flow models of up to 25 buses and 200 lines It can also handle larger networks if the sensitivity matrix from an ac load-flow model is available The dc model can represent up to five separate control areas simultaneously, each with its own independent economic dispatch

The most complex part of WRATES is a module which computes a network-constrained economic dispatch It provides spot prices at each bus These spot prices are used to compute marginal wheeling costs WRATES also includes a module which computes the revenue reconciliation multiplier, m

It will be recognized that the dc network model is very small PTI applied standard network-reduction techniques in non-standard ways to develop small dc networks which are surprisingly-accurate mimics of large ac networks Details are in [5], errors are typically a few percent

CASE STUDIES

The purpose of this section is to discuss wheeling rates for two case studies done using WRATES Here we describe the two case studies In a later section, we describe the relationships among rates, constraints, losses, load levels, and divisions into subareas

Both case studies are based on network and generation data provided by the New York Public Service Commission This data was given to the Commission by New York utilities But the case-study assumptions made by the authors are hypothetical and are not intended to represent any actual or contemplated transactions

Utility-to-Utility Wheeling

In the first case study, up to 400 MW are wheeled from Hydro Quebec to the Long Island Lighting Company (LILCO) This is in addition to a 2000-MW base-case purchase by the pool from Hydro Quebec This power crosses a Central New York-East New York interface, which in recent years has been a constraint on New York Power Pool operations The power is also wheeled through the Consolidated Edison Company (Con Edison) service territory, an area of dense energy utilization See Figure 1

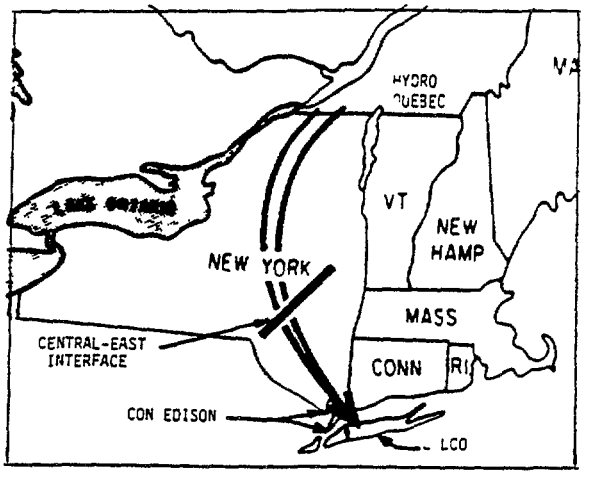

Figure 1

Wheeling from Hydro Quebec to LILCO

The wheeling flows are in the same direction as the normal flows, so they increase losses and exacerbate any problems with network constraints

Marginal-cost-pricing theory says that internal costs for Hydro Quebec and LILCO do not affect wheeling rates The rates are determined by the costs of the wheeling party (most of the New York Power Pool plus adjoining areas, in this example)

Flows were computed using WRATES and a 20-bus reduced network model They were also computed using PSS/E, PTI's nonlinear AC load-flow program, running a 2329-bus case The 20-bus DC and 2329-bus AC simulations matched quite closely

The economic-dispatch simulation imbedded in WRATES was compared to economic dispatch on a full-sized system using PTI's PSS/O program WRATES and PSS/O were in reasonably close agreement

Cogenerator-to-Customer Wheeling

The second case study considered two facilities of the New York State Office of Mental Hygiene It was hypothesized, without feasibility study, that perhaps 100 MW of cogenerated power could be available at Kings Park (Long Island) for wheeling to the Rockland Psychiatric Center in Rockland County, which is west of the Hudson River, just north-west of New York City

As in the first study, the wheeling is through the Con Edison service territory Since flows are opposite to New York's prevailing northwest-to-southeast power transfers, they can be expected to reduce network loading and losses

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This second situation is quite different from the first The first was from the Hydro Quebec system to the LILCO system, mainly through much of the New York Power Pool The second is from a single bus to a second bus, mainly through a southern portion of the New York Power Pool The Kings Park power enters the network at Northport and is taken by the Rockland Psychiatric Center at West Nyack

One surprising result is that total losses increased slightly with wheeling from Long Island to Rockland County Flows and losses in the network between New York City and West Nyack went down But the case included Long Island's Shoreham plant, some of whose output served loads in New York City and elsewhere The wheeling from Northport increased the loading and losses in some Long Island lines The reduction in losses north of the City, plus increase in losses east of the City, summed to a net increase in losses

Absence of Shoreham would increase flows into the downstate area, exacerbating any problems with transmission limitations and increasing system losses Wheeling against this tide would help relieve transmission constraints and would decrease system losses

WHEELING RATE SENSITIVITIES

Effect of Constraints

Without network constraints and ignoring revenue-reconciliation issues, the ideal wheeling rate from a marginal-cost perspective is determined by marginal losses and marginal generation costs When wheeling causes flows to exceed transmission limitations, corrective action must be taken -- at some cost, which is charged to the wheeling transaction

Figure 2 shows the WRATES-computed ideal wheeling rate for Hydro Quebec studies The amount wheeled caused transfers across the Central-East interface to exceed its capability For comparison, Figure 2 also shows the ideal wheeling rates assuming infinite transfer capability As expected, the constraints (which were reached with 250 MW of wheeling) cause the ideal wheeling rate to increase substantially

This can happen if the dispatch pattern is changed to force flows around the interface Or it can happen if upstate generation is backed off and downstate generation is increased to unload the interface For this example, the latter effect seemed to dominate Output of a coal-fired equivalent unit upstate (the marginal unit for the system) decreased, while generation at an oil-fired equivalent unit downstate increased

Figure 3 shows the incremental cost of wheeling, corresponding to Figure 2, as computed by WRATES The increment shown is the production-cost difference from the base (no-wheeling) case The ideal wheeling rate of Figure 2 is related to the slope of the curve in Figure 3

Effect of Changes in Load Levels

Figure 4 is a wheeling-rate distribution curve for a period where loads are at one of four arbitrary levels, with equal probabilities It was taken from a study of 100 MW of wheeling from Northport to West Nyack The loads are incremented by 10 MW at every load bus, including LILCO buses, for each load level

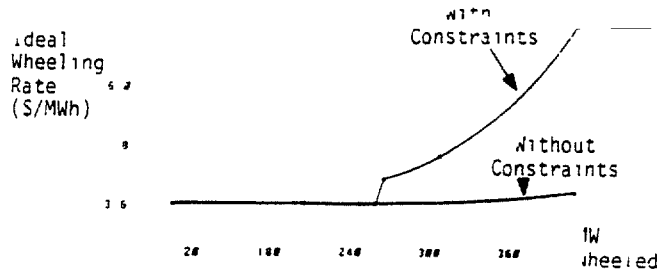

Figure 2

Ideal Wheeling Rates, With and Without Flow Constraints

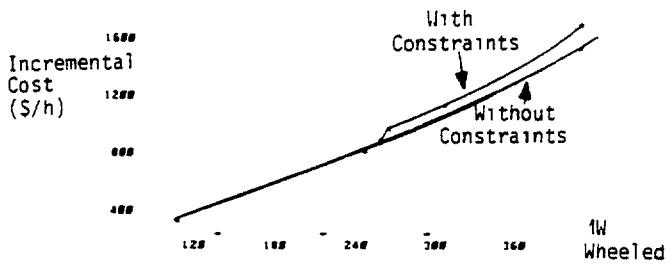

Figure 3

Incremental (Compared to No Wheeling) Wheeling Cost, With and Without Constraints

The higher load levels produced higher wheeling rates This figure is interesting because of the almost precise linearity between load levels and wheeling rates Although power systems are not linear, they often exhibit near-linear behavior In Figure 4, this was in part because the changes in load were minor and the network was not stressed, partially because of the Shoreham assumption Of course, if we had assumed Shoreham was not built, the wheeling rate would have been negative and Figure 4 would have been different

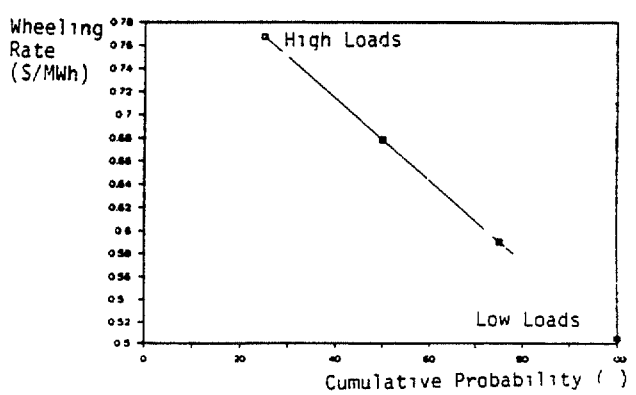

Figure 4

Wheeling-Rate Distribution Curve, Kings Park to West Nyack Wheeling Case

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To contrast, Figure 5 shows how wheeling rates for the Hydro Quebec example were affected by load levels In this figure, 200 MW is wheeled, with no network-flow constraints Demand at six pool (wheeling-party) buses was varied so that the total pool load ranged from 60% to 120% of nominal Figure 6 shows the incremental costs incurred by the wheeling party

The shapes of Figures 5 and 6 appear strange Without network flow constraints, the ideal wheeling rate and the incremental costs should depend on system losses Losses should be approximately quadratic functions of load levels, and incremental costs should go up with loads, so the curves in Figures 5 and 6 should be convex Instead, they are strongly concave

The flaw in this argument is that while losses are approximately quadratic functions of flows, increases in system load do not necessary cause increases in flows! In fact, just the opposite may occur

Suppose that most of a system's lowest-cost generation is in one region At low load levels, this may meet most of the demand, with relatively high flows from that region to the rest of the system At high load levels, local demand may soak up much of the lowest-cost generation Then higher-cost units near other load centers supply those loads, reducing the inter-regional flows and losses Even though the cost of a kWh of losses is higher at higher load levels (because the losses are made up from more expensive generation), the total cost of losses may even be lower than at low loads

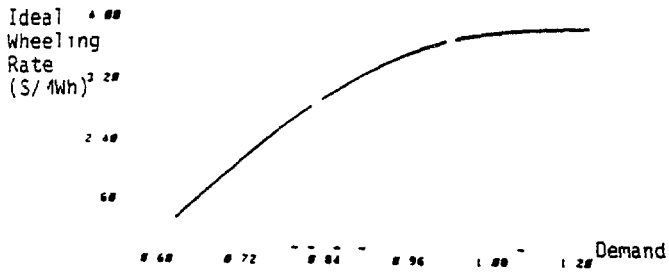

Figure 5

Ideal Wheeling Rate vs Demand (200 MW Wheeled)

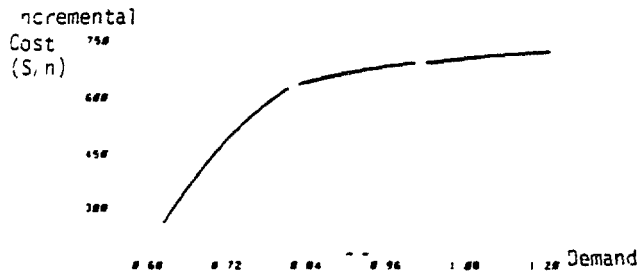

Figure 6

Incremental (Compared to No Wheeling)
Wheeling Cost vs Demand (200 MW Wheeled)

Effects of Losses

Figure 7 shows total system losses corresponding to the 200 MW wheeling transaction of Figures 5 and 6 As expected, the losses increase as load increases -- up to nominal load Then losses decrease

This decrease is due to the generation pattern As was discussed above, the cheaper generating units are upstate At low load levels, they supply most of the state's power, but with high losses because of distances At high load levels, all power plants are needed, so production is more uniformly distributed

The losses due to wheeling are the differences between these two curves These differences are plotted in Figure 8 For this situation, wheeling causes losses to increase

One would anticipate that wheeling losses would be higher for higher loads Figure 8 shows that that intuitive guess can be wrong, because wheeling losses are affected by the pattern of flows And we have just seen that that pattern is affected in a somewhat complex way by the relative load levels and the location of generating units

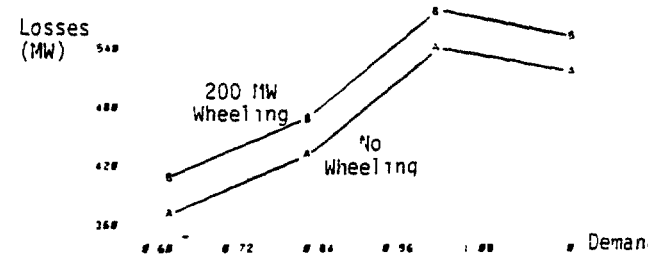

Figure 7

Total Losses vs Demand

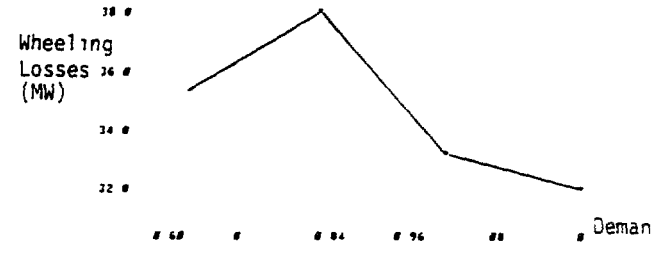

Figure 8

Losses Due to Wheeling vs Demand

Effects of Revenue Reconciliation

Figure 9 shows the revenue-reconciled wheeling rate for the wheeling transactions of Figures 5-8 The revenue-reconciliation multiplier, m, was set to 0 2 This value was chosen arbitrarily, not with the intention of recovering a specific amount of capital The objective was to see how the ideal wheeling rate changed with revenue reconciliation, not to tune m

There is no a priori theory for setting m It depends on network flows, on the number of inter-area interconnections, on fuel costs and capital investments, etc

The large difference between the ideal and revenue-reconciled wheeling rates (Figure 5 versus Figure 9) is at first surprising But the ideal wheeling rate is the sum of a number of positive and negative terms [4] The revenue-reconciled rate is

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computed by adding 20% (if m = 0 2) of the absolute value of each term If network conditions make the terms individually large in absolute value, but if in summing, the positive and negative terms almost cancel to give a small ideal wheeling rate, then the reconciled rate can be quite large compared to the ideal rate

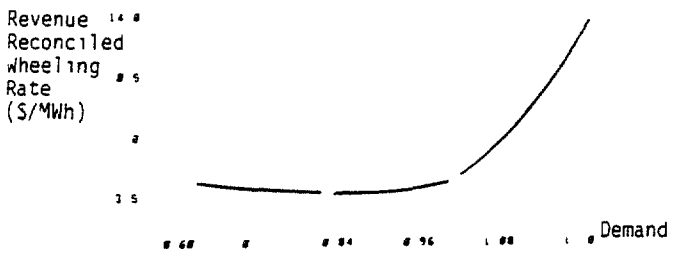

Figure 9

Revenue - Reconciled Wheeling Rate vs Demand

Figure 10 is the revenue-reconciled wheeling rate (m = 0 2) corresponding to the ideal rate of Figure 2 In Figure 10, this cancellation and amplification are less extreme than in Figure 9

In these figures the generation component of the wheeling rate was much smaller than the network component In other tests it was found that this amplification did not occur with the generation component of the wheeling rate This is because the generation component does not involve summing positive and negative terms

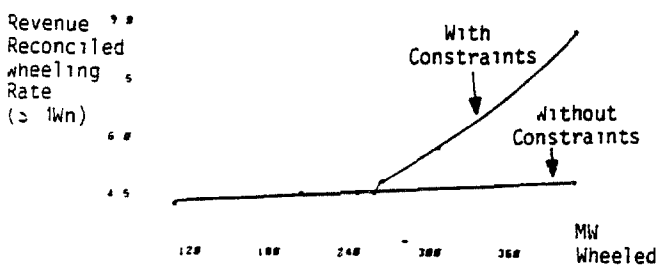

Figure 10

Revenue - Reconciled Wheeling Rate vs MW Wheeled

Effects of Subareas and Ties

The definition of wheeling areas can have a profound effect on wheeling rates

An important instance is where a wheeling transaction can be assumed to involve either one or several wheeling parties This occurs in New York, where Hydro-Quebec-to-LILCO wheeling, for example, could be done by the pool as an entity, or by the individual utilities operating in series and parallel with each other

Figure 11 is a five-area representation of this situation Each area can represent each area as an individual control area, each doing part of the wheeling An individual wheeling rate can than be computed for each area

It is reasonable to ask if the sum of the wheeling charges, considering three wheeling parties, is the same as the wheeling charge when the pool is considered the wheeling entity The answer is, "in general, it is not " Several reasons for this have been observed in our case studies

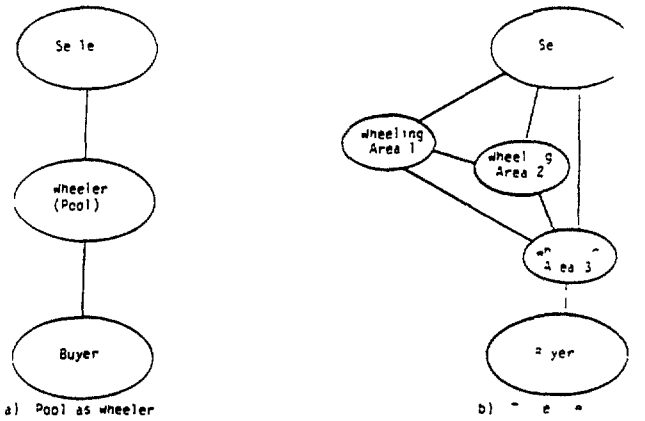

Figure 11

Alternative Representations of the Same Network

First, suppose the marginal unit for the entire system is in area 1 In the "pool-as-wheeler" model, this unit would make up all the incremental wheeling losses, and the ideal wheeling rate would be based on the marginal cost of this unit In the "three-wheeler" model, the marginal units for each area would make up the incremental losses for each area The ideal wheeling rate for each area would reflect each area's incremental losses and marginal unit costs

Second, suppose there is a transmission constraint Suppose that generation within the same area is redispatched to relieve this constraint The ideal wheeling rate is a function of the redispatch, so it will likely be different for a "pool-as-wheeler" model than for a "three-wheeler" model

Third, suppose the marginal costs and incremental losses happened to result in three ideal wheeling rates, for the three areas of Figure 11, that summed to the same ideal wheeling rate computed for the "pool-as-wheeler" model The revenue-reconciled rates would probably be quite different Cancellations of positive and negative terms that would occur in the ideal-wheeling-rate computation would be absent in the reconciled-rate computation This is a phenomenon of the revenue reconciliation method used It should not be assumed that wheeling rates can be added or disaggregated promiscuously In multiple-area situations, one needs to be very careful that the wheeling rates computed reflect true marginal costs, in the context of how the system is actually operated

CONCLUSIONS

Many papers advocate marginal-cost-based wheeling rates The case studies described here -- and others like them which the authors have carried out -- seem to be the most extensive effort to date to determine what marginal-cost-based wheeling rates would be These studies point out some important characteristics of such wheeling rates

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First, it would have been very difficult to do these analyses without a tool like the WRATES computer program These analyses require a load-flow program that is integrated with a constrained economic-dispatch simulation (including a loss formula)

Second, marginal wheeling costs can exhibit counter-intuitive behavior One illustration above was the decrease in incremental losses when loads increase It has been pointed out elsewhere that marginal wheeling costs, and hence wheeling rates, can even be negative if power is wheeled in the opposite direction to prevailing network flows

Third, marginal wheeling costs are quite sensitive to network conditions, including transmission constraints, transmission and generation outages, load levels, and locations and operating costs of generating units

Fourth, marginal wheeling costs are also quite sensitive to how interconnected utilities are operated -- for instance, if several wheeling utilities are jointly dispatched, the marginal cost of wheeling is in general different from what it would be were they dispatched as a single pool

Fifth, the very difficult topic of revenue reconciliation seems to need further thought In particular, capital recovery using a multiplicative revenue reconciliation method seems to be unduly sensitive to load levels and wheeling levels

To these conclusions, the authors would like to append a suggestion We understand the theoretical attractiveness of basing wheeling rates on marginal costs We are also painfully aware of the difficulty of defining marginal costs, particularly in view of long-run issues like construction of new facilities and capital recovery We suggest that policy debates on wheeling rates include a healthy content of experimental analyses such as, and even more extensive than, those described in this paper

ACKNOWLEDGEMENTS

This paper was to have been written with Professor Fred C Schweppe of MIT, whose innovative thinking and energy contributed so much to this field His death on July 8, 1988, prevented this He was a key participant in the development of WRATES and in the studies described here Natasha Roukos, of Meta Systems, Inc , was most supportive as we worked through WRATES Most of the funding for the work described in this paper was provided by the New York State Energy Research and Development Authority, under the direction of Dr W James Cole and Dr David R Wolcott

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BIOGRAPHIES

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Transmission Transfer Capability

A Reference Document
for Calculating and Reporting
the Electric Power Transfer Capability
of Interconnected Electric Systems

North American
Electric
Reliability
Council

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FOREWORD

The Engineering Committee of the North American Electric Reliability Council (NERC) established the Transmission Transfer Capability Task Force to review and revise, as appropriate, NERC's *Transfer Capability — A Reference Document*, published in 1980 This newly revised *Transmission Transfer Capability* report, approved by the Engineering Committee in November 1994 and accepted by the NERC Board of Trustees in January 1995, is the result of that effort

This report expands on electric system transmission transfer capability definitions and calculation and reporting practices It should be a useful reference document not only for electric utilities but for the new, expanding audience of potential transmission system users

NERC recognizes that strong and flexible electric transmission systems, capable of coping with a wide variety of system conditions, are necessary for a reliable supply of electricity To help ensure that the interconnected transmission systems in the United States, Canada, and the northern portion of Baja California, Mexico continue to be planned and operated in accordance with NERC and Regional Reliability Council (Regional Council) reliability criteria and guides, the NERC Engineering Committee requested a review of several planning related NERC reference documents, including its *Transfer Capability — A Reference Document*

Electric power transfers have a significant effect on the reliability of the interconnected electric transmission systems, and must be evaluated in the context of the other functions performed by these interconnected systems In some areas, portions of the transmission systems are being loaded to their reliability limits as the uses of the transmission systems change relative to those for which they were planned, and as opposition to new transmission prevents facilities from being constructed as planned Efforts by all industry participants to minimize costs will also continue to encourage, within safety and reliability limits, maximum loadings on the existing transmission systems

During the past several years, competition in wholesale electricity supply has been on the increase The enactment of the U S Energy Policy Act of 1992 established a new environment in the electric utility industry in the United States to further spur a competitive electric generation and wholesale electricity supply market This legislation also encourages the further development of nonutility generators by establishing a new classification — exempt wholesale generators — and recognizes that access to the nation's electric transmission systems will be essential to ensure competitive wholesale electricity supply

The new competitive environment will foster an increasing demand for transmission services With this new focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems — utilities as well as nonutilities — must understand the electrical limitations of the transmission systems and the capability of these systems to reliably support a wide variety of transfers The future challenge will be to plan and operate transmission systems so as to provide desired electric power transfers while maintaining overall system reliability

This report addresses transmission transfer capability from the perspective of the transmission systems physical characteristics and limitations It provides the technical basis for discussions about transfer capability Background information on industry practices related to transfer capability is also presented including definitions, concepts, technical issues, and simulation techniques used to calculate and report transmission transfer capability

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This report does not address issues of transmission ownership, allocation of transmission capacity, or the costs associated with providing transmission services It also does not establish guidelines for determining adequate or appropriate levels of transfer capability to support emergency and economy power transfers or to ensure reliable electric service These determinations are system specific and must be evaluated by individual electric systems

It is recommended that all users of the interconnected electric systems follow the approaches and industry practices for calculating and reporting transfer capability described in this report This report, however, does not preclude Regional Councils (or their subregions or member systems), power pools, individual electric systems, or groups of systems from amplifying these practices or developing more detailed procedures for determining transfer capability applicable to the unique system characteristics of their respective areas

All users of the transmission systems must also adhere to accepted planning and operating criteria and guides designed to maintain electric system reliability as described in NERC's *Policies, Procedures, and Principles and Guides for Planning Reliable Bulk Electric Systems,* its *Policies for Interconnected Systems Operation,* and its *Operating Guides*

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INTRODUCTION

The purpose of this report is to present a consistent set of definitions and guidelines for calculating and reporting the transmission transfer capability of interconnected electric systems Although the basic transfer capability concepts outlined in NERC's 1980 Transfer Capability report are still valid, this revised document includes additional clarifications and insights on transmission transfer capability calculations It also discusses various concepts and technical issues to aid in understanding the nature of transfer capability A glossary of terms has been added, and new issues, such as demand-side management and the extent to which operat ing procedures are used in determining transfer capabilities, are addressed This report does not deal with the availability of generation equipment to provide electric power for transfer, nor does it delineate how to plan transmission systems or the transmission facilities that may be needed to support the levels of electric power transfers that may be desired

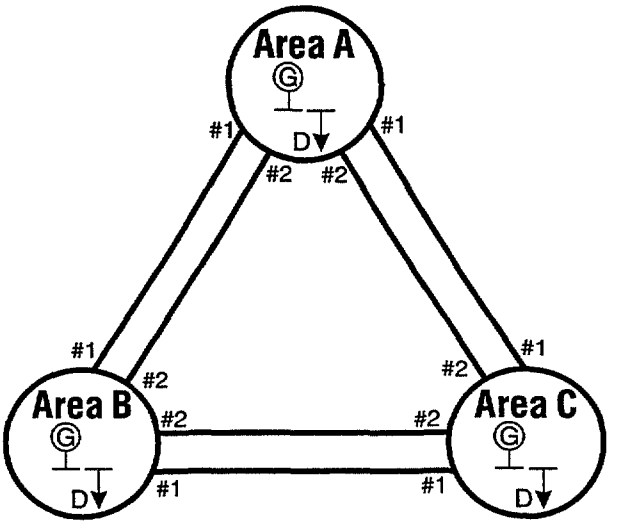
Transmission Transfer Capability

Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specified system conditions The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW) In this con text, area refers to the configuration of generating stations, switching stations, substations, and connecting transmission lines that may define an individual electric system, power pool, control area, subregion, or Region, or a portion thereof

Concept of Transfer Capability

The concept of transmission transfer capability may be explained in terms of a simplified interconnected systems network comprised of three Areas (or systems) — A, B, and C — interconnected by transmission paths A-B, A-C, and B-C, as shown in Figure 1

Figure 1
Simplified Interconnected Systems Network



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Each Area represents a configuration of generating stations, substations, and internally connected transmission lines that may define an individual electric system, power pool, control area, subregion, or Region, or a portion thereof The transmission paths or interconnections from Area A to Area B, Area A to Area C, and Area B to Area C may each represent one or more transmission lines In this example, two transmission lines comprise each transmission path.

The determination of transfer capability from Area A to Area B is achieved using com puter simulations of the interconnected systems network of Figure 1 To simulate an electric power transfer, Area A and Area B generation (and/or electrical demand) is adjusted so as to create a generation excess in Area A and a generation deficiency in Area B, thereby automatically resulting in an electric power transfer from Area A to Area B These differential adjustments in each Area's generation level are increased until an equipment or system limit is reached, or a transfer test level is achieved, taking into account the most critical single contingency (e g , generating unit, transformer, transmission line, etc) outage condition In those cases where an equipment or system limit is reached with all facilities in service at a transfer level below that of the single contingency outage condition, then that lower transfer level defines the transfer capability limit

To determine the transfer capability in the opposite direction, from Area B to Area A, the generation excess is created in Area B and the generation deficiency in Area A. As customer demands and transmission and generation facilities in Areas A and B will rarely be symmetrical, and as the critical facility outage condition will likely be different, the transfer capability in each direction, Area A to Area B or Area B to Area A, will also generally be different, and must be determined separately

As the generation levels in Areas A and B are modified to increase the electric power transfer from Area A to Area B, the loading level on transmission path A-B, as well as on all other interconnection and internal transmission facilities, will change but at different rates These different rates — called power transfer distribution factors — are determined according to the physical laws of electrical networks Thus, all transmission paths will not simultaneously reach their capability limits at the same transfer level However, the Area A to Area B transfer level at which a transmission path, system voltage, or system stability limit is reached for a single facility outage becomes the limiting transfer capability level for transfers from Area A to Area B In the interconnected systems, it is possible that the critical single contingency facility outage and the associated limiting facility may not be in Areas A or B, or at the interface (transmission paths) between Areas A or B, but in another Area (or Areas) altogether, such as Area C

The capabilities (or ratings) of the interconnecting transmission lines, lines A-B #1 and A-B #2, between Areas A and B cannot be added to derive the transfer capability from Area A to Area B or from Area B to Area A. In addition, the sum of the non-simultaneous transfer capabili ties from Area A to Area B and from Area C to Area B does not equal the total transfer capability to Area B Simultaneous transfer capability calculations from Areas A and C to Area B are required to determine that value

When transfer capabilities between areas or systems are determined, it must be under stood that these capabilities correspond to a specific set of system conditions for the intercon nected systems network The transfer capabilities can be significantly different for any other set of system conditions, such as a different customer demand level, a different network configura tion, or a different generation dispatch Also influencing the level of transfer capability between Areas A and B are any electric power transfers under way between other neighboring systems, such as transfers from Area A to Area C or from Area B to Area C

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Numerical examples of transfer capabilities among the interconnected Areas A, B, and C of Figure 1 are included in Appendix A. These examples illustrate the concept of incremental and total transfer capabilities, non-simultaneous and simultaneous transfer capabilities, associated terminologies, and reporting practices

Uses of Transfer Capability

In both the planning and operation of electric systems, transfer capability is one of several performance measures used to assess the reliability of the interconnected transmission systems, and has been used as such for many years

System planners use transfer capability as a measure or indicator of transmission strength in assessing interconnected transmission system performance It is often used to compare and evaluate alternative transmission system configurations

System operators use transfer capability to evaluate the real-time ability of the inter connected transmission systems to transfer electric power from one portion of the network to another or between control areas In the operation of interconnected systems, "transfer" is synonymous with "interchange"

Under the NERC *Operating Guides*, in scheduling transfers or interchanges between two control areas, system operators must limit electric power transfers so as not to exceed the lesser of either the total capacity of the owned or arranged-for transmission facilities in service between the two control areas or the first contingency total transfer capability between the two control areas as determined at that point in time Not exceeding the transfer limit is essential as electric systems must operate on the basis that the current system configuration can reliably withstand the next single contingency (facility outage) Exceeding that limit could subject the interconnected electric systems to facility overloads, voltage instability, or system dynamic insta bility Any of these situations could lead to cascading facility outages and widespread electricity supply disruptions, and even a system collapse or blackout, if transfer limits are exceeded and a critical facility outage occurs

Transfer Capability and Reliability

Reliable operation of the interconnected electric systems requires close coordination among the individual electric systems for monitoring, controlling, and scheduling inter-system or inter area electric power transfers The coordination of these transfers is one concern that led the electric utilities to establish the Regional Reliability Councils and, subsequently in 1968, the North American Electric Reliability Council (NERC) Much of the work regarding the development, calculation, and reporting of transfer capability has been done by study groups under inter-Council and intra-Council agreements

The electric systems in the United States and Canada are planned in conformance with NERC s *Policies, Procedures, and Principles and Guides for Reliable Bulk Electric Systems* and operated in compliance with NERC's *Policies for Interconnected Systems Opera tion* and its *Operating Guides* These NERC policies for electric system reliability provide the framework for the Regional Councils (Regions), subregions, power pools, or individual systems to develop their own more detailed planning and operating criteria or guides, including those for transfer capability, that reflect the diversity of individual system characteristics, geography, and demographics

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Purposes of Electric Transmission Systems

The interconnected transmission systems are the principal media for achieving reliable electric supply They tie together the major electric system facilities, generation resources, and customer demand centers These systems must be planned, designed, and constructed to oper ate reliably within thermal, voltage, and stability limits while achieving their major purposes These purposes are to

- **Deliver Electric Power to Areas of Customer Demand** — Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to continuously changing customer demands under a wide variety of system operating conditions

- **Provide Flexibility for Changing System Conditions** — Transmission capacity must be available on the interconnected transmission systems to provide flexibility to handle the shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages

- **Reduce Installed Generating Capacity** — Transmission interconnections with neighboring electric systems allow for the sharing of generating capacity through diversity in customer demands and generator availability, thereby reducing invest ment in generation facilities

- **Allow Economic Exchange of Electric Power Among Systems** — Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among neighboring systems when temporary surpluses in generating capacity are available Such economy transfers help to reduce the cost of electric supply to customers

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TRANSFER CAPABILITY DEFINITIONS

Several approaches are used in the electric utility industry to express "transfer capability" values Each of these approaches uses the same general definitions and simulation techniques in the calculation of transfer capability levels The differences lie in the statement of transfer capability results rather than in the underlying principles

Incremental and Total Transfer Capabilities

In 1974, NERC established definitions that refer to transfer capability as incremental above normal base power transfers Normal base transfers usually refer to representative electric power transfers between systems that are modeled in power flow base case simulations Therefore, incremental transfer refers to the additional amount of electric power, above the base level, that the interconnected transmission systems can support or transfer while continuing to maintain electric system reliability This incremental transfer approach provides an indication of the ability of the transmission systems to accommodate additional transfers after all normally scheduled transfers are considered, as well as an indication of the ability of these systems to cope with emergency conditions

The NERC definitions have been widely used and are generally accepted throughout the industry The basic philosophy supporting these definitions remains unchanged but the additional clarifications and examples in this report should provide an increased understanding of the nature of transfer capability

Today, the recommended basic NERC transfer capability measures are "First Contingency Incremental Transfer Capability (FCITC)" and "First Contingency Total Transfer Capability (FCTTC)" The FCTTC approach recognizes the effects of all electric power transfers, both normal base and incremental, and represents the total amount of electric power that can be transferred between two entities while continuing to maintain system reliability For consistency, it is recommended that transfer capabilities determined according to the definitions of FCITC and FCTTC be used in reporting to NERC and others The reported transfer capability values should be applicable to peak demand system conditions If reported transfers are for other than peak demand conditions, the conditions for which transfers are reported should be so stated

First Contingency Incremental Transfer Capability (FCITC)

FCITC is the amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions

1 For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,

2 The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and

3 After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits

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With reference to condition 1 above, in the case where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached Such a transfer capability is referred to as a normal incremental transfer capability (NITC)

First Contingency Total Transfer Capability (FCTTC)

FCTTC is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above

Other Definitions

The electric system terms and definitions that are key to understanding the above definitions of transmission transfer capability (FCITC and FCTTC) are described below These terms and related electrical terms and their definitions are also included in the "Glossary of Terms" of Appendix B

- **Normal Base Power Transfers** — Electric power transfers that are considered by the electric systems to be representative of the base system conditions being analyzed, and which are agreed upon by the parties involved Other transfers, such as emergency or economy transfers, are usually excluded

- **Normal Rating** — The rating as defined by the facility owner that specifies the level of electrical loading (generally expressed in megawatts or other appropriate units) that a facility can support or withstand through the daily demand cycles without loss of equipment life of the facility or equipment involved

- **Emergency Rating** — The rating as defined by the facility owner that specifies the level of electrical loading (generally expressed in megawatts or other appropriate units) that a facility can support or withstand for a period of time sufficient for the adjustment of transfer schedules or generation dispatch in an orderly manner with acceptable loss of equipment life, or other physical or safety limitations, of the facility or equipment involved This rating is not a continuous rating

- **Normal Voltage Limits** — The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable on a sustained basis

- **Emergency Voltage Limits** — The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance

- **Operating Procedures** — A set of policies, practices, or system adjustments that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational

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integrity of the interconnected electric systems These actions or system adjustments may be implemented in anticipation of or following a system contingency (facility outage) or system disturbance, and include, among others, opening or closing switches (or circuit breakers) to change the system configuration, the redispatch of generation, and the implementation of direct control load management or interruptible demand programs

- **Automatic Operating Systems** — Special protection systems (or remedial action schemes) or other operating systems installed on the electric systems that require no intervention on the part of system operators for their operation

- **Normal (Pre-Contingency) Operating Procedures** — Operating procedures that are normally invoked by the system operator to alleviate potential facility overloads or other potential system problems in anticipation of a contingency

- **Post-Contingency Operating Procedures** — Operating procedures that are invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred

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CONCEPTS AND TECHNICAL ISSUES

Certain concepts and technical issues that are necessary to an understanding of transmission transfer capability are described in each of the following sections

Actual and Simulated Transfer Capabilities

The calculation of transfer capability is generally based on a computer simulation of the operation of the interconnected electric systems under a specific set of assumed operat ing conditions Each simulation represents a single "snapshot" of the operation of the inter connected systems based on the projections of many factors Among these factors are the expected customer demands, generation dispatch, the configuration of the interconnected electric systems, and the electric power transfers in effect among the interconnected systems

Customer demand is influenced not only by season, time of the day, day of the week, and weather, but also by demand-side management programs Generation dispatch is affected by unit availability, economics, environmental and hydrological conditions or limitations, and available fuel supply Transmission line availability is primarily influenced by planned maintenance and changes less frequently than generation availability, but when it does change, it can have a major influence upon facility loadings Other factors that can vary are the number, direction, and amount of simultaneous electric power transfers among the interconnected systems These concurrent transfers influence the electrical loading patterns on the system or systems being analyzed

In real-time operation of interconnected electric systems, many factors are continuously changing As a result, the electric power transfers that can be supported on the transmission systems can vary from one instant to the next The actual transfer capability available at any particular time may differ from that calculated in simulation studies due to the fact that in the simulation studies only a limited set of operating conditions can be evaluated, whereas in real time, widely different conditions may exist For this reason, the transfer capabilities derived from simulation studies need to be viewed as indicators of system capability Several control areas can now calculate first contingency incremental and first contingency total transfer capability limits on a real time basis from the facility thermal rating perspective This on line capability allows these control areas to modify their transfer or interchange schedules throughout the day That is, the real time calculations could allow scheduled transfers to exceed previously determined off-line limits when it is safe and feasible to do so, or they could further limit transfers below previously determined off line limits, depending on actual system conditions

The transfer capabilities reported to NERC are generally the first contingency incremental (FCITC) or first contingency total (FCTTC) transfer capabilities for projected peak customer demand conditions Because of the variability of transfer levels and the complexity involved in their calculation, some electric systems prefer to report a range of possible transfer capabilities rather than a single transfer capability value When a range is reported, an appropriate brief explanation should accompany the reported transfer capabilities

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CONCEPTS AND TECHNICAL ISSUES

Parallel Path Flows

The transfer of electric power in ac interconnected transmission systems generally cannot be directed along specific transmission lines (or paths) or predetermined routes except in some limited applications where those routes are controlled by phase-shifting transformers, thyristor-controlled series capacitors, or the like Therefore, electric power transfers in ac systems will be distributed, in varying degrees, on all transmission paths between two areas The resultant transmission line loadings will be in accordance with known electrical network relationships, but may not be in accord with any contract or agreement that established the scheduled transfers between the two areas

When such electric power transfers between two areas distribute onto the facilities of other interconnected systems not contractually (or directly) involved in the agreement between the transacting parties, the unintended electric power flows on these neighboring or adjacent system facilities are known as "parallel path flows" In some cases, the parallel path flows may result in transmission limitations in the neighboring or adjacent systems, which can limit the transfer capability between the two contracting areas

Parallel path flow is a complex transmission system phenomenon that can affect many systems of an interconnected network, especially those systems electrically near the transacting systems As a result, transfer capability determinations must be sufficient in scope to ensure that neighboring or adjacent interconnected system limits are recognized

Non-Simultaneous and Simultaneous Transfers

As explained in the Introduction and Figure 1, transfer capability involves the movement of electric power from one area of the interconnected transmission systems to another Transfer capability from Area A to its interconnected neighbors (Areas B and C) is generally evaluated by simulating transfers from Area A to Area B independently, then from Area A to Area C only, and so on These independently derived transfer capabilities are not concurrent with any other (A to B, B to C, C to A, etc) area transfers Therefore, each of these independent transfer capabilities (Area A to Area B only, etc) is referred to as a "non-simultaneous" transfer capability from one area or system to the other

Another type of transfer capability reflects the capability of the interconnected systems to conduct simultaneous or multiple transfers concurrently (e g , from Areas A and C to Area B concurrently) This transfer capability is developed in a manner similar to that used for non simultaneous capability, except that the interdependency of transfers among the several areas is taken into account The transfer capability so derived is referred to as the "simultane ous" transfer capability from Areas A and C to Area B

No general numerical relationship exists between simultaneous and non simultaneous transfer capabilities A simple addition of the non-simultaneous transfer capabilities, Area A to Area B and Area C to Area B, is not appropriate to determine the capability for simultaneous transfers from Areas A and C to Area B In fact, an Area A to Area B transfer can significantly affect a coincident Area C to Area B transfer, particularly if both transfers are limited by a common set of facilities The simultaneous transfer capability may be lower than the sum of the individual non simultaneous transfer capabilities

The calculations of non simultaneous and simultaneous power transfers are generally performed on an interconnected system s configuration representative of the base system conditions being analyzed and which are agreed upon by the parties involved These base conditions may or may not include normal base power transfers The non simultaneous and simultaneous transfers would be additional to these normal base power transfers

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Transmission System Limits

The ability of ac electric transmission systems to reliably transfer electric power may be limited by any one of the following

- **Thermal Limits** — The flow of electrical current in a conductor or electrical facility causes heating of the conductor or facility Thermal limits, in the form of facility normal and emergency ratings, establish the maximum amount of current over a specified period that a transmission line or electrical facility can conduct before it sustains permanent damage by overheating or violates public safety ground clearance requirements due to conductor sag

- **Voltage Limits** — Adequate voltage must be maintained on the transmission systems at all times, including during and after a system contingency (facility outage) As electricity is transmitted along a transmission line, resistive and reactive power losses are incurred and a voltage drop occurs As an increasing amount of electricity is transferred, resistive losses increase and increasing amounts of reactive power are required to support system voltages Reactive power is needed throughout the transmission transfer paths, and, in particular, in the importing (receiving) area or area of generating capacity deficiency

  The reason for an electrical supply deficiency is often the outage of one or more generating units If the major portion of reactive power in the deficit area is normally supplied by the outaged generators, then the associated reactive power of these units will also be unavailable The result can be unacceptable system voltages at electric power transfer levels that may be lower than those transfer levels for which transmission facility thermal overloads would occur during single contingencies In addition, the nonlinear characteristic of reactive power can exacerbate the voltage decay of a deficit area As voltage declines in an area, the effectiveness of installed reactive support (shunt capacitors) and line charging is diminished by the square of the voltage Minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to electric system or customer facilities, or a "voltage collapse" A wide spread collapse of system voltage can result in a blackout of portions or all of the interconnected systems

- **Stability Limits** — A basic tenet of reliable system design is that the intercon nected systems should be capable of surviving disturbances, coincident with safe maximum electric power transfers, through the transient and dynamic time peri ods (from milliseconds to several minutes, respectively) following the disturbance

  All generators connected to ac interconnected transmission systems operate in synchronism with each other That is, they operate in lockstep with each other at the same frequency (nominally 60 cycles per second in the United States and Canada) Immediately following a system disturbance, generators begin to oscillate relative to each other, causing fluctuations in system frequency, line loadings, and system voltages If the disturbance is minor, the oscillations will diminish and damp out as the electric systems attain a new, stable operating point If a new, stable operating point is not quickly established, the generators will likely lose synchronism with one another, and portions or all of the interconnected systems may become unstable The result may be damage to equipment and the uncontrolled interruption of electric supply to customers

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SIMULATION TECHNIQUES

Transmission system transfer capability is calculated using computer network simulation software to represent anticipated system operating conditions Each such simulation reflects a "snapshot" of one specific combination of system conditions Transfers between two areas are determined by increasing transfers from a normal base transfer level until a system limit is reached, taking into account the most critical single contingency facility outage and its system loading, voltage, and stability effects

The difference between the normal base power transfer level and the total transfer level at a transmission system limit is known as the first contingency incremental transfer capability (FCITC) The transfer level at the limit is the first contingency total (base plus incremental) transfer capability (FCTTC) Several such representative snapshots are simulated yielding a range of transfer capability values that might be expected This approach is referred to as a deterministic approach to transfer capability It is the more common method of calculating transfer capability In more sophisticated techniques, probability values are assigned to each snapshot, yielding a probability distribution of transfer capability

The intent of a transfer capability calculation is to determine a transfer value having the following general characteristics

- Represents a realistic operating condition or expected future operating condition.
- Conforms with the requirements of the transfer capability definitions
- Considers single contingency facility outages that result in conditions most restrictive to electric power transfers

These characteristics are broad enough to be applicable to electric systems generally, but are also specific enough for consistent application and interpretation Specific recommendations for performing transfer capability calculations that are in accord with these characteristics are briefly discussed in the following sections

Power Flow Calculations

Transfer capability values may be based on alternating current (nonlinear) simula tions or direct current (linear) simulations of the interconnected transmission systems Direct current simulation techniques are an efficient means to screen the transmission systems for the most critical contingencies and their system effects, and to approximate the transfer level at which those contingencies are limiting Transfer values determined by such linear simula tions should be verified by alternating current simulations where voltage, reactive power supply, or stability problems exist, or to ensure that these problems do not exist at or below the transfer level identified by the direct current simulations Appropriate dynamic demand models should be used in these nonlinear simulations as they can have a significant effect on the results

System Configuration

The base case configuration of the interconnected systems should be representative of the systems being simulated, including any long term generation and transmission outages that are expected The activation of any operating procedures normally expected to be in effect should also be included in the simulations

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Generation Dispatch

The generation dispatch of the interconnected systems being simulated should generally follow the guidelines described below

- **Normal Base** — The generation dispatch should be realistic for the system con ditions being simulated This dispatch should be the same as that used for the base case for other studies of the same customer demand level and system configuration. The base case electric power transfers provide the reference for incremental values of transfer capability The net of base case transfers plus the incremental transfer at which a system limitation is reached is the total transfer capability

- **Nonutility Generators** — Nonutility generators, exempt wholesale generators, and qualifying facilities should be modeled and dispatched at their representative operating conditions for the system conditions under study

- **Exporting (or Sending) Area** — In the exporting area, the generation is increased on an economic, environmental, or other appropriate dispatch basis, up to the limit of the installed generating capacity Nonexistent generators should not be used to simulate electric power transfers If additional transfers are required to test the interconnected transmission systems' adequacy, transfers into the area from outside generating sources located in other adjacent systems can be simulated, or other generation dispatch adjustments can be made, provided the distribution of loadings among transmission facilities in the area of interest is realistic Customer demands in the exporting area may also be reduced so that additional transfers can be scheduled from actual generators provided the simulated conditions are realistic Further, the resulting transfer capability should be reported as being from generation sources outside or beyond the reporting area or for the reduced exporting area demand level

- **Importing (or Receiving) Area** — In the importing area, the generation is decreased on a realistic dispatch basis for the transfers being tested Generator reactive supply in the importing area should be modified for consistency with generator real power output levels System security, capacity margins, and voltage limits must be preserved. If additional transfers are required to test the intercon nected transmission systems' adequacy, customer demand in the importing area may be increased in reasonable amounts provided the distribution of loadings among transmission facilities in the area of interest is realistic Further, the result ing transfer capability should be reported as being for the increased importing area demand level

Voltage and Reactive Power

The computer simulations should verify the capability of the interconnected transmission systems to support acceptable voltage levels at the determined transfer capability level, including the effects of any reactive power supply limitations The reactive capability of all generators and reactive sources should be appropriately modeled within their respective limits

It is especially important in simulating the outages of generating units that reactive power output be removed along with the real power output It is equally important to have accurate reactive power limits in these simulations A generator s reactive capability may be significantly limited by the design of the auxiliary system, the generator step-up transformer, the minimum excitation limiter, minimum or maximum generation limits, or by other opera tional considerations

SIMULATION TECHNIQUES

The nonlinear relationship between reactive power requirements in the importing area and electric power transfers must be recognized Switched reactive devices or dynamic reactive sources should also be appropriately modeled for normal and transfer conditions

Demand Levels

Base case demand levels should be appropriate to the system conditions and customer demand levels under study and may be representative of peak, off-peak or shoulder, or light demand conditions Although transfer capabilities are generally reported to NERC for peak customer demand conditions, knowledge of transfer capability limits at other demand levels is also important for the reliable operation of the electric systems

Demand-Side Management

In the system simulations, the demand levels, especially the peak internal demand levels, should be net of indirect demand side management (DSM) programs In contrast, the direct control load management and contractually interruptible demands should generally be included in (not subtracted from) the internal demand levels However, the representation of direct control DSM programs depends on specific contract terms and the practices of the individual electric systems employing these types of direct control (load management and interruptible demand) DSM programs

System Contingencies

Sufficient generation and transmission system single contingencies should be selected for simulated testing to ensure that the facility outage most restrictive to the transfer being studied is included The contingencies studied should be consistent with individual electric system or Regional Council planning criteria or guides, and may in some instances include multiple contingencies, if appropriate, such as the outage of transmission circuits using common towers or rights-of way

Extrapolation of Transfers

A limited amount of linear extrapolation and interpolation can produce useful results if done judiciously, but transfer levels should be verified by alternating current simulations Where no limits are found at a test transfer level, the transfer capability should be reported as "X+" MW, where "X" is the highest test transfer level simulated

Excluded Limitations

Transfer capability limits are determined by the overall interconnected systems When the loadings of certain lower voltage electric facilities restrict calculated transfer capability, these transfer capabilities and their limiting facilities should be reported For consistency, it is recommended that such lower voltage limitations be excluded from the analysis only on the basis of one of the following two conditions

1 An established and documented operating procedure exists for eliminating the overload or restrictive condition. In addition, no restrictive conditions will be placed on the implementation of these procedures For these situations, transfer capability should be documented as having been calculated with the operating procedure in effect, or

2 The restrictive or limiting facility has minimal or no adverse effect on the reliability of the electric supply systems (i e , the outage of the facility is not likely to lead to widespread or cascading outages) System facilities having a very low distribution or response factor, as described in the "Distribution (or Response) Factor Cutoff" section below, should generally be excluded from the calculation of transfer capability

Where transfer capability values are based on the exclusion of such restrictions, this exclusion should be documented as a part of the study results

Dynamic Control Systems

The base and transfer conditions for continuous-acting dynamic control systems, such as static var compensators, synchronous condensers, portions of HVDC systems, phase-shifting transformers, and other similar devices, must be clearly defined for the system conditions under study

Distribution (or Response) Factor Cutoff

Distribution factors, used in the calculation of transfer capability and other system analyses, measure the electrical effects that an electric power transfer has on system facilities or that an outage (or removal from service) of one system element or facility has on the remaining system facilities Line outage distribution factors (LODFs), power transfer distribution factors (PTDFs), and outage transfer distribution factors (OTDFs) that can be used to estimate FCITC and FCTTC values are defined in Appendix B

A distribution (or response) factor cutoff is the suggested minimum level or magnitude of LODFs, PTDFs, and OTDFs considered significant and used in transfer capability calculations or other system analyses LODFs, PTDFs, and OTDFs below 2-3% are not generally considered in determining transfer capabilities

This suggested cutoff level may be more significant to a lower voltage facility with a lower normal or emergency rating than it is to a higher voltage facility with a higher normal and emergency rating For example, a 2% PTDF on a 138 kV line for a 1,000 MW transfer (or a 20 MW change in loading on the line) is a more significant portion of the emergency thermal rating of a 138 kV line than it is of an emergency thermal rating of a 345 kV line

The above suggested distribution factor cutoff should not be universally applied without good engineering judgment Any critical facility with a distribution (or response) factor below the cutoff should still be closely monitored in the analyses to ensure that its facility limits are not exceeded and that system reliability will be maintained

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Reliability Criteria or Guides

The NERC definitions for FCITC and FCTTC are intended to foster and promote consistency in calculating and reporting electric system transfer capability However, if Regional, subregional, power pool, or individual system calculation methods or reliability criteria or guides are more restrictive than the system conditions in the FCITC and FCTTC definitions, the more restrictive calculation method or reliability criteria or guides must be observed

The Regions, subregions, power pools, or individual systems have the primary responsibility for the reliability of bulk electric supply in their Regions or areas These entities also have the responsibility to develop their own appropriate or more detailed planning and operating reliability criteria or guides, including those pertaining to transfer capability, that reflect the diversity of individual electric system characteristics, geography, and demographics for their areas

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OTHER CONSIDERATIONS

The transfer capability calculation guidelines in this report are intended for general use and are designed to be flexible enough to be adaptable to the varying circumstances in different areas of the United States and Canada However, they are also specific enough to promote a common understanding and interpretation of transfer capability concepts The guidelines are based on sound technical considerations recognizing the electrical and opera tional characteristics of the interconnected transmission systems

Electric transmission systems have finite capabilities that are based on an expected use pattern and are governed by the laws of physics, and safety and reliability considerations These systems cannot provide unlimited transmission services for all parties at all times When transmission systems become loaded to their transfer capability limits, additional transmission services can only be accommodated by adjusting or curtailing some existing services or, in the longer term, by expanding the transmission systems

Transmission System Planning and Operation

Electric transmission systems are planned and designed to be responsive to a range of constantly changing operational parameters These parameters, among others, include changing customer demands, generation availability and dispatch, and the electrical characteristics of the transmission facilities Therefore, the determination of the capability of the interconnected transmission systems to support electric power transfers is complicated The transfer analysis requires a thorough understanding of the interrelationship of the operational parameters and their effects on the performance of the transmission systems

Transmission systems designed to serve a projected range of operational parameters may not be capable of supporting a large change in one or more of these parameters, or a significant change in the system uses that may be imposed upon them When the voltage or stability limits of the systems or the thermal limits of individual transmission facilities are reached, the capability of the interconnected systems to support additional transfers is also reached Additional transfers can only be accommodated by

- Reducing the loadings on the constrained facility(ies) by either changing some operating parameter, such as changing generation dispatch or reducing customer demand, or
- Modifying the configuration of the existing facilities or reconfiguring the interconnected systems by the addition of new transmission facilities

Adequate Transfer Capability

No comprehensive and universally applicable procedure exists for determining the "adequate' or "appropriate" level of transfer capability that will ensure reliable service at all times The adequate level of transfer capability for any individual electric system is a complex determination It involves analysis of a number of system performance and configuration issues, including an evaluation of the system benefits to be achieved System size and location, the size of installed generating units, the distribution of customer demands to be served, the strength of the transmission system configuration, and the anticipated use of the system are some of the key parameters that will affect transfer capability For each electric system or potential transmission user, the objectives and benefits to be achieved from different levels of transfer capability will be unique and must be evaluated by an analysis of the specific parameters appropriate to each system

OTHER CONSIDERATIONS

The development of interconnection lines among electric systems is pursued for a wide variety of reasons Some directly address reliability matters, while others address environ mental or economic concerns Each electric system must analyze and define its own transfer capability goals All significant uses of transfer capability must be adequately evaluated

Reliability of Interconnected Systems

As the electric systems evolve in a more competitive electric power market, demands for use of the transmission systems will increase The need to provide transmission services, for both utilities and nonutilities, raises a number of reliability concerns including increased transmission system loadings, parallel path flows, and increased coordination problems

The planning and operation of the interconnected electric transmission systems in the United States and Canada are conducted in accordance with NERC reliability criteria and guides The Regions and their member systems also have established additional criteria and guides designed to maintain the security of their transmission systems for the more probable contingencies Although there have been a few instances of localized interruption of electric supply to customers, widespread cascading transmission outages generally have been prevented

All users of the transmission systems must also adhere to accepted planning and operating criteria and guides designed to maintain electric system reliability as described in NERC's *Policies, Procedures, and Principles and Guides for Planning Reliable Bulk Electric Systems,* its *Policies for Interconnected Systems Operation,* and its *Operating Guides*

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APPENDIX A

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

Overview A-2

Example 1 Transmission Transfer Capability from Area A to Area B without Base Scheduled Transfers, and a Clockwise Loop Flow A-5

Example 2 Transmission Transfer Capability from Area A to Area B without Base Scheduled Transfers, and a Counterclockwise Loop Flow A-12

Example 3 Transmission Transfer Capability from Area A to Area B with a 500 MW Base Scheduled Transfer from Area A to Area C A-14

Example 4 Transmission Transfer Capability from Area A to Area B with a 500 MW Base Scheduled Transfer from Area B to Area A A-16

Example 5 Transmission Transfer Capability from Areas A and C to Area B without Base Scheduled Transfers, and a Clockwise Loop Flow A-18

Example 6 Transmission Transfer Capability from Area A to Area B with a 1,000 MW Base Scheduled Transfer from Area C to Area B, and a Special Protection System Installed A-22

APPENDIX A

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

Overview

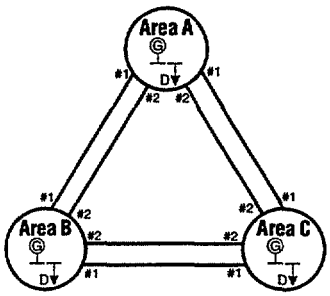
This appendix illustrates by means of a simplified interconnected electric systems network the key concepts and definitions of transmission transfer capability described in the main body of this document Specifically, six examples illustrate, in a simplified manner, how transfer capabilities are calculated and reported

This overview briefly describes the interconnected systems network, the general methodology, and the transfer capability definitions on which the examples are based It also includes a summary of the transfer capability results for each example A detailed description of Example 1 and summary descriptions of Examples 2 through 6 follow this overview

Description of the Interconnected Systems Network

The six examples all reference the same simplified interconnected systems network (Figure 1) Three electric systems, designated Area A, Area B, and Area C, are interconnected via three transmission paths, path A-B, path A-C, and path B-C Each transmission path, in turn, is comprised of two parallel interconnection transmission lines, line #1 and line #2 Each Area, in itself, is an electric system comprised of several generating units, dispersed customer demand, and transmission lines, none of which are explicitly shown on Figure 1 or used in the examples Rather, the internal electric system in each Area is symbolically designated by a generator (G) and a customer demand (D) arrow

Figure 1
Simplified Interconnected Systems Network



In the examples, it is assumed that the transmission lines connecting the Areas include both the critical single contingency (facility outage) as well as the limiting transmission facility or element for electric power transfers between and among these Areas In an actual interconnected network, the critical single transmission system facility that is out of service and the limiting transmission facility may be located anywhere in the entire interconnected network, including within the internal system in each Area.

In the six examples, it is assumed that each of the two interconnection transmission lines between Areas A and B (and which comprise path A-B) has a normal thermal rating of 950 megawatts (MW) and an emergency thermal rating of 1,100 MW Each of the two lines between Areas A and C, and Areas B and C has a normal thermal rating of 850 MW and an emergency thermal rating of 1,000 MW These ratings of the two transmission lines interconnecting the Areas are summarized below

TRANSMISSION TIE LINES

Facility	Normal Thermal Ratings (MW)	Emergency Thermal Ratings (MW)
Line A-B #1	950	1,100
Line A-B #2	950	1,100
Line A-C #1	850	1 000
Line A-C #2	850	1 000
Line B-C #1	850	1 000
Line B-C #2	850	1,000

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APPENDIX A

Overview

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

In general, the ability of the interconnected systems network of Figure 1 to reliably transfer electric power may be limited by any one of three conditions, namely, thermal limits, system voltage limits, or system stability limits For the purposes of these examples, it is assumed that only the thermal capability of the interconnection transmission lines will limit the electric power transfers and that voltage and stability limits, for simplicity, do not apply

The two methods generally used in reporting transmission transfer capability are also included for each example The first reporting method, used primarily in the Eastern Interconnection, presents transfer capability results in terms of electric power transfer capability between "Areas" (or electric systems) The second reporting method, used primarily in the Western Interconnection, presents transfer capability in terms of individual "transmission path" capabilities

Although the interconnected systems network of Figure 1 remains the same for the six examples, different assumed base system conditions in each example result in different transmission transfer capabilities among Areas A, B, and C

General Methodology

In each example, the base conditions are representative of a different set of specified generation, customer demand, and base scheduled transfer assumptions Computer simulations performed on those base system conditions determine the transfer capabilities between and among the Areas as well as the transfer capabilities of the transmission paths connecting the Areas under the First Contingency Incremental or First Contingency Total Transfer Capability (FCITC or FCTTC, respectively) definitions described in the main body of this report

Summary of Results

The transmission transfer capabilities for the six examples are summarized in the following table It includes the base conditions, the base scheduled transfers in effect, the critical single contingency transmission facility, the limiting transmission facility and its emergency thermal rating, and the transfer capability from Areas A and C to Area B for various assumed base conditions, as well as the transmission path transfer capabilities of paths A-B, A-C, and B-C These examples show how FCITC and FCTTC can vary for the same interconnected electrical network under different base system conditions They also illustrate that the calculated transfer capabilities are only "snapshots" of the transfer capability at a given moment for this network The key features of each example are described below

Example 1 – Shows the amount of electric power that can be transferred from Area A to Area B under a specified set of base system conditions

Example 2 – Illustrates for a different set of base conditions the effects on the Area A to Area B transfer capability of Example 1

Example 3 – Shows the impact on the Area A to Area B transfer capability of Example 1 when an existing base scheduled transfer is in effect between Area A and Area C

Example 4 – Shows the impact on the Area A to Area B transfer capability of Example 1 when a base scheduled transfer condition exists in the opposite direction, that is, a transfer from Area B to Area A.

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

Example 5 – Shows the maximum total simultaneous transfer capability from Areas A and C to Area B It illustrates that the maximum non-simultaneous Area A to Area B transfer capability and the maximum non-simultaneous Area C to Area B transfer capability cannot be added to obtain the maximum total simultane ous transfer capability from Areas A and C to Area B

Example 6 – Shows that, in certain circumstances and when system conditions permit, special protection systems (or remedial action schemes) may be used to increase transmission transfer capability These systems or schemes are automated and generally fast acting, responding to system contingencies much faster than system operator action They are not universally applicable to all electric systems

The six examples also illustrate that different transmission transfer capability values or levels can be reported to describe the same network conditions and transfer capability limits depending on the reporting method ("area interchange" basis or "transmission path" basis) used

SUMMARY OF TRANSMISSION TRANSFER CAPABILITY EXAMPLES

	Example 1	Example 2	Example 3	Example 4	Example 5	Example 6[a]
Base Conditions	200 MW clockwise loop flow (A-C-B-A)	200 MW counter-clockwise loop flow (A-B-C-A)	200 MW clockwise loop flow (A-C-B-A)	200 MW clockwise loop flow (A-C-B-A)	200 MW clockwise loop flow (A-C-B-A)	240 MW counter-clockwise loop flow (A-B-C-A)
Base Scheduled Transfers	None	None	500 MW from Area A to Area C	500 MW from Area B to Area A	None	1,000 MW from Area C to Area B
Critical Single Contingency (Facility Outage)	Line A-C #1	Line A-B #1	Line A-C #1	Line A-C #1	Line B-C #1	Line B-C #1 or #2
Limiting Facility (Emergency Thermal Rating – MW)	Line A-C #2 (1,000)	Line A-B #2 (1,100)	Line A-C #2 (1,000)	Line A-C #2 (1,000)	Line B-C #2 (1,000)	Line A-B #1 and #2 (1,100 each)
Transfer Capability (MW)	A to B	A to B	A to B	A to B	A and C to B	A to B
"Area Interchange" Basis[b]						
• FCITC	2,834	2,286	1,834	3,208	3,018	2,116[a]
• FCTTC	2,834	2,286	1,834	2,708	3,018	2,116[a]
"Transmission Path" Basis[c]						
• Path A-B FCTTC	1,500	1 572	1,000	1,374	1,548	1,770[a]
• Path A-C FCTTC	1,334	—[d]	1,334	1,334	—[d]	—[d]
• Path C-B FCTTC	—[d]	—[d]	—[d]	—[d]	1,470	1,346[a]

[a] Special protection system (or remedial action scheme) in effect.
[b] Both the FCITC and FCTTC concepts are used in reporting transfer capabilities on the area interchange basis in the Eastern Interconnection
[c] Only the FCTTC concept is used in reporting transfer capabilities on the transmission path basis in the Western Interconnection.
[d] In this example the transmission path is not at its FCTTC limit

Example 1

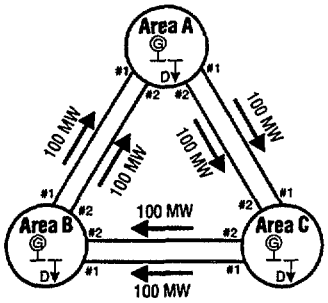
Transmission Transfer Capability from Area A to Area B without Base Scheduled Transfers, and a Clockwise Loop Flow

Base Conditions

In Example 1, under base conditions, each Area (or electric system) has dispatched its generation to satisfy its own customer demands, and no scheduled electric power transfers exist among the three Areas That is, inter area scheduled transfers from Area A to Area B, B to A, A to C, C to A, B to C, and C to B are zero

A computer simulation of these initial or base system conditions indicates that the interconnected systems network will have a net clockwise electric power flow, or loop flow, of 200 MW from Area A to Area C to Area B and back to Area A. This clockwise flow results from the configuration and generation dispatch within the three interconnected Areas as they serve their own native distributed customer demands These base conditions are shown in Figure E1-A.

Figure E1-A
Base Conditions – Example 1
Zero Scheduled Transfers Among Areas A, B and C



Calculation of Transfer Capability

Transfer capability values or levels may be based on alternating current (nonlinear) or direct current (linear) computer simulations (load flow studies) of the interconnected elec tric systems, and, as necessary, system voltage and system stability analyses Since it is assumed that only interconnection transmission line thermal ratings will limit the transfer capability of the interconnected systems network, simplified direct current simulations will be used in this Example 1 and the following examples These linear computer simulations can determine the network response to the various possible electric power transfers, in this case from Area A to Area B, the critical single transmission contingency, and the transmission facility that restricts or limits the transfer capability under the single contingency condition

The first step in determining the Area A to Area B transfer capability is to modify the base case computer simulation of Figure E1-A by increasing generation in Area A and decreasing generation in Area B This process continues until any single contingency (or facility outage) would cause one of the remaining transmission facilities in service to reach its emergency thermal rating Assume in this Example 1 that computer simulation identifies one of the two transmission interconnection lines between Areas A and C as the critical single transmission contingency and the remaining transmission line between Area A and Area C as the limiting facility

The computer simulation also shows, with all the facilities in service, for electric power transfers from Area A to Area B, 60% of a scheduled transfer will flow from Area A to Area B on transmission path A-B, or 30% on transmission line A-B #1 and 30% on transmission line A-B #2 The remaining 40% of the scheduled transfer from Area A to Area B will flow on the transmission path from Area A to Area C and then from Area C to Area B That is, 20% of the power transfer will flow on transmission lines A-C #1, A-C #2, C-B #1, and C-B #2 The simu lations also show that the outage of line A-C #1 will result in 50% of the pre-contingency load ing on line A-C #1 to immediately shift to line A-C #2 In addition, 25% of the pre-contingency loading on line A-C #1 will be shifted to each of lines A-B #1 and A-B #2, and 25% will shift to each of lines B-C #1 and B-C #2

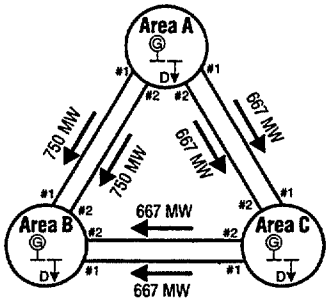
APPENDIX A

Example 1

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

When the transfer capability limit on the interconnected systems is reached, generation in Area A will have increased by 2,834 MW and generation in Area B will have been decreased by the same amount The loadings on the transmission paths for this transfer capability of 2,834 MW from Area A to Area B are shown in Figure E1-B Note also for this transfer limit, with all transmission lines in service, that the transmission line loadings are within their respective normal thermal ratings

Figure E1-B
Area A to Area B Transfer Capability Limiting Conditions
2 834 MW Transfer Limit from Area A to Area B

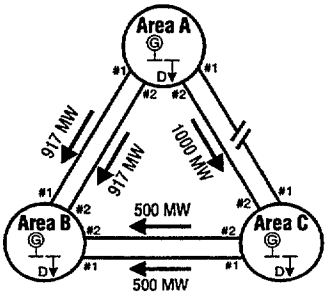


In comparing Figure E1-A with Figure E1-B, the simulated operating conditions show that of the 2,834 MW transferred from Area A to Area B, 60% of the transfer (or 1,700 MW) will flow over transmission path A-B, resulting in a net loading of 1,500 MW (-200 MW + 1,700 MW) on path A-B Forty percent of the 2,834 MW transfer (or 1,134 MW) will flow over transmission paths A-C and C-B, resulting in a net loading of 1,334 MW (200 MW + 1,134 MW) on paths A-C and C-B

Not exceeding the Area A to Area B transfer capability limit of 2,834 MW is essential as electric systems must operate on the basis that the current system configuration can reliably withstand the next contingency Failure to operate in this manner could subject the interconnected electric systems to facility overloads, voltage instability or collapse, or system dynamic instability Any of these situations can lead to cascading and widespread electricity supply disruptions, and even a system collapse or blackout, if transfer limits are exceeded and a critical facility outage occurs

The resulting network loadings under the outage of the critical transmission facility for the 2,834 MW capacity transfer from Area A to Area B are summarized in Figure E1-C At the transmission transfer capability limit conditions of Figure E1-B, transmission lines A-C #1 and A-C #2 are each carrying 667 MW An outage of transmission line A-C #1 will result in an immediate shift in flow of 333 MW (50% of 667 MW) to line A-C #2 For this critical outage condition, line A-C #2 will be loaded to 1,000 MW (667 MW + 333 MW), its emergency thermal rating No additional electric power transfers may be achieved from Area A to Area B under the conditions simulated because the interconnected systems network has reached a limiting transmission condition Under this single contingency condition, the remaining 50% of the pre-contingency loading of line A-C #1 (or 334 MW) will be transferred to paths A-B and B-C That is, each transmission line of paths A-B and B-C will carry an additional 167 MW in the counterclockwise direction

Figure E1-C
Area A to Area B Transfer Capability Under the Critical Contingency
2,834 MW Transfer Limit from Area A to Area B and Line A C #1 Out of Service



Reporting of Transfer Capability

Two approaches are used in the electric utility industry to express or report transfer capability values or levels depending on the purpose to be served They include the "Area Interchange" basis and the "Transmission Path" basis as described below Each of the approaches, however, uses the same general simulation techniques to calculate the electric power transfer limits The differences lie in the statement or reporting of results as described in the "Interpretation of Results" section, rather than in the underlying calculation principles

a) **"Area Interchange" Basis**
In Example 1, if the transfer capability values are reported on an "area interchange" basis, as in the Eastern Interconnection, the Area A to Area B transfer capability would be either the First Contingency Incremental Transfer Capability (FCITC) of 2,834 MW or the First Contingency Total Transfer Capability (FCTTC) of 2,834 MW FCITC and FCTTC from Area A to Area B are the same in this Example 1

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Example 1

FCITC is the amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected systems in a reliable manner As the base power transfer from Area A to Area B is zero, the maximum incremental power transfer above the normal base power transfer is 2,834 MW The total transfer capability or FCTTC from Area A to Area B is the net of the base power transfer (or zero) plus the incremental power transfer (2,834 MW) or 2,834 MW

b) "Transmission Path" Basis

Another approach, used in the Western Interconnection, would report only the total transfer capability (FCTTC) results of Example 1 but with a focus toward specific transmission path capabilities The First Contingency Incremental Transfer Capability (FCITC) concept is not used in the Western Interconnection. Under the limiting electric power transfer conditions of 2,834 MW from Area A to Area B and with all facilities in service (Figure E1-B), transmission path A-B has a loading of 1,500 MW For this operating condition, a higher transfer from Area A to Area B on path A-B cannot be achieved because the single contin gency outage of either transmission line A-C #1 or A-C #2 would cause the remaining A-C line to exceed its emergency thermal rating Therefore, the 1,500 MW loading on path A-B becomes the path A-B total capability, which is reported as the FCTTC for path A-B It is not permissible for net scheduled power transactions between Areas to exceed the capability of the direct paths between Areas In this example, scheduled transfers from Area A to Area B would be limited to 1,500 MW on the basis of path A-B

The corresponding FCTTC of path A-C is 1,334 MW However, the appropriate coordination arrangements must be made with Area C for the 1,334 MW transfer to be made from Area A to Area B over paths A-C and C-B If these arrangements are made, then Area A could transfer 2,834 MW to Area B

For the transfer levels simulated in this example, transmission path C-B is not loaded to its total transfer capability Therefore, an FCTTC for path C-B is not reported.

c) Interpretation of Results

Example 1 is intended to demonstrate how transmission transfer capability may be calculated and reported and the care that must be exercised in using transfer capability results On the "area interchange" basis, the FCITC from Area A to Area B would be reported as 2,834 MW The FCTTC from Area A to Area B on the "area interchange" basis would also be reported as 2,834 MW, while on the "transmission path" basis, the FCTTC for transmission path A-B would be reported as 1,500 MW

For each of these reporting methods, the responses are based on the same physical interconnected transmission system conditions and limitations However, the transfer values reported focus on different aspects of the intercon nected systems In the "area interchange" case, the focus is on the ability of the interconnected systems network to support the electric power transfer from Area A to Area B In the second case, the focus is on the ability of a specific transmission path to support a transfer

APPENDIX A

Example 1

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

Transfer Capability Calculation Details

Transfer capability values or levels should be based on alternating current load flow simulations of the interconnected transmission systems However, direct current or linear simulation techniques are often used to screen the interconnected transmission systems for the most critical single contingencies and their system effects, and to determine the transfer level at which those contingencies are limiting Transfer levels determined by such linear simula tions should be verified by alternating current simulations to ensure that no voltage or reactive power supply problems exist at or below the limiting transfer levels identified by the linear simulations Evaluations of the interconnected systems for stability limitations under the transfer levels identified in load flow simulations also need to be performed to ensure the stability of the interconnected systems under the transfer conditions and any single facility outage

For the simplified interconnected systems of Example 1, line outage distribution factors, power transfer distribution factors, and outage transfer distribution factors, as defined below, will be used to calculate in detail the FCITC and FCTTC values reported in Example 1 These distribution factors are determined from computer simulations of the interconnected electric systems and can be used to "estimate" transfer capabilities in systems with thermal lim itations These factors can also be used to calculate the FCITC and FCTTC values in Examples 2 through 6

Line Outage Distribution Factors

A line outage distribution factor (LODF) measures the redistribution of electric power on remaining system facilities as a result of an outage (or removal from service) of a single system facility or element The redistribution of the electric power is expressed in percent (up to 100%) of the pre-contingency electrical loading on the outaged facility LODFs for one line of each of the three transmission paths of Example 1 are shown below Because of the assumed symmetry in each of the interconnection transmission paths of this intercon nected network example, these distribution factors also apply, respectively, for the outage of lines A-B #2, A-C #2, and B-C #2

LINE OUTAGE DISTRIBUTION FACTORS (LODFs)

Line	Response (%) to Outages of		
	Line A-B #1	Line A-C #1	Line B-C #1
A-B #1	Outaged	25	-32
A-B #2	40	25	-32
A-C #1	30	Outaged	32
A-C #2	30	50	32
B-C #1	-30	25	Outaged
B-C #2	-30	25	36

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

Example 1

It is convention that transmission line flows are "positive" in the direction from the first named line terminal to the second named line terminal For an outage of line A-B #1, 40% of the pre-contingency loading on line A-B #1 will instantaneously shift to line A-B #2 As the 40% (of the distributed flow) is a positive response factor, the incremental loading on remaining line A-B #2 will be in the direction from Area A to Area B Similarly, 30% of the pre-contingency loading on line A-B #1 will be shifted to each of lines A-C #1 and A-C #2, and in the direction from Area A to Area C Thirty percent of the pre-contingency loading on line A-B #1 will also be shifted to lines B-C #1 and B-C #2 but in the direction from Area C to Area B

Power Transfer Distribution Factors

Computer simulations are also used to determine power transfer distribution factors (PTDFs) for an interconnected systems network PTDFs measure the responsiveness or change in the electrical loadings on system facilities due to a change in the electric power transfer from one area to another area. These distribution factors are expressed in percent (up to 100%) of the change in power transfer They apply only for the pre-contingency configuration of the interconnected systems under study That is, with all facilities in service

The PTDFs for the interconnected systems network of Example 1 are shown below These factors can be used to determine the responses to power transfers between any of the six possible combinations of the three Areas For example, for the network configuration and generation dispatches assumed, and with all facilities in service, 60% of the transfer from Area A to Area B will flow over path A-B and 40% will flow via Area C over transmission paths A-C and C-B

POWER TRANSFER DISTRIBUTION FACTORS (PTDFs)

	Line Response (%) to Transfers From					
Line	Area A to Area B	Area A to Area C	Area B to Area A	Area B to Area C	Area C to Area A	Area C to Area B
A-B #1	30	10	-35	-8	-15	13
A-B #2	30	10	-35	-8	-15	13
A-C #1	20	40	-15	8	-35	-13
A-C #2	20	40	-15	8	-35	-13
B-C #1	-20	10	15	42	-15	-37
B-C #2	-20	10	15	42	-15	-37

APPENDIX A

Example 1

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

Figure E1-D
Base Conditions - Example 1
Zero Scheduled Transfers Among Areas A, B and C

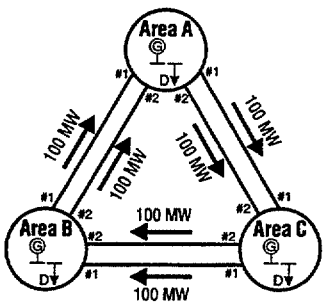
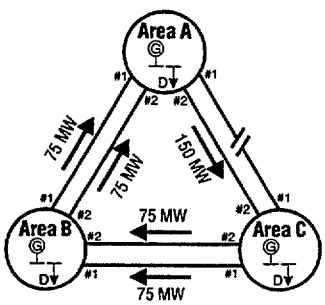


Figure E1-E
Base Conditions - Example 1 Under the Critical Contingency
Zero Scheduled Transfers Among Areas A, B and C, and Line A-C #1 Out of Service



Single Contingency and Limiting Facility

Computer simulations, which combine line outage distribution factors and power transfer distribution factors, are used to identify the critical single transmission facility outage and its effects on the remaining transmission facilities In Example 1, it was assumed that computer simulation identified that when Area A schedules a transfer to Area B, the transmission interconnection lines between Areas A and C are the most restrictive That is, for the outage of one of the two A-C transmission lines, the remaining line becomes the limiting facility for Area A to Area B transfers

These line outage and power transfer distribution factors can also be used in estimating the FCITC and FCTTC for electric power transfers between and among Areas A, B, and C The calculations of FCITC and FCTTC for electric power transfers from Area A to Area B using these factors are described below for the conditions of Example 1

Calculation of FCITC — Example 1

The base electric power flow conditions of Example 1 are shown on Figure E1-D (Same as Figure E1-A.)

If transmission line A-C #1 is out of service under base conditions, the resulting loading on line A-C #2 will be

(Flow on line A-C #2) + (LODF) (Flow on line A-C #1) = Flow on line A-C #2 with line A-C #1 out of service

$$100 \text{ MW} + (0\ 50)\ (100 \text{ MW}) = 150 \text{ MW}$$

Figure E1-E shows the electric power flows on the interconnected systems network following the outage of line A-C #1 under base conditions

A next step in the calculation of FCITC is to determine the fraction (or percent) of the electric power transfer from Area A to Area B that appears on line A-C #2 (which is the assumed transmission limiting facility) when line A-C #1 is out of service This fraction (or percent), also known as the Outage Transfer Distribution Factor (OTDF), can be calculated as follows

(PTDF of line A-C #2) + (LODF of line A-C #1) (PTDF of line A-C #1) = OTDF

$$0\ 20 + (0\ 50)\ (0\ 20) = 0\ 30 \text{ or } 30\%$$

This OTDF factor means that 30% of any power transfer from Area A to Area B will appear on line A-C #2 when line A-C #1 is out of service

To determine the FCITC for electric power transfers from Area A to Area B (assuming no voltage or stability system limitations), the difference between the emergency thermal rating (ETR) of limiting line A-C #2 (or 1,000 MW) and the flow on limiting line A-C #2 (or 150 MW) is divided by the above OTDF as follows

$$\frac{(\text{ETR of line A-C \#2}) - (\text{Flow on line A-C \#2})}{\text{OTDF}} = \text{FCITC}$$

$$\frac{1{,}000 \text{ MW} - 150 \text{ MW}}{0\ 30} = 2{,}834 \text{ MW}$$

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EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

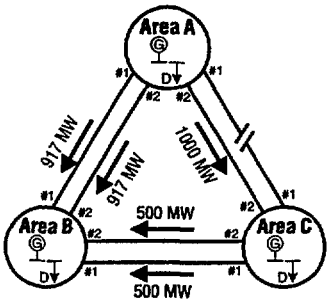
Example 1

Figure E1-F (same as Figure E1-C) shows the loadings on the interconnected systems network for the critical line outage condition (line A-C #1 out of service) with the 2,834 MW FCITC transfer from Area A to Area B in effect The loading on transmission line A-C #2 is at its emergency thermal rating of 1,000 MW

Figure E1-F

Area A to Area B Transfer Capability Under the Critical Contingency

2 834 MW Transfer Limit from Area A to Area B and Line A-C #1 Out of Service



Calculation of FCTTC — Example 1

FCTTC is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission systems in a reliable manner based on the three conditions in the FCITC definition

As no scheduled transfers are in effect between Area A and Area B under base conditions, the FCTTC is

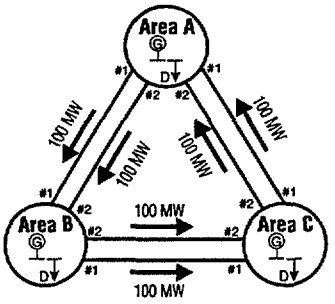
Base Scheduled Transfers + FCITC = FCTTC

0 MW + 2,834 MW = 2,834 MW

Example 2

Transmission Transfer Capability from Area A to Area B without Base Scheduled Transfers, and a Counterclockwise Loop Flow

Figure E2-A
Base Conditions – Example 2
Zero Scheduled Transfers Among Areas A, B and C



Base Conditions

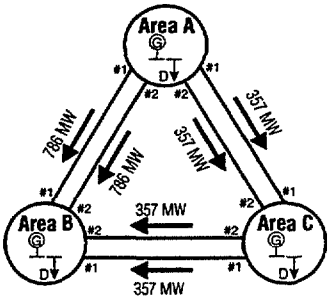
The network configuration of Example 1 applies to Example 2 However, in Example 2, changes have been made to the internal generation dispatch in each Area to meet a different level of customer demand such that a computer simulation of base system conditions indicates that the network will have a net counterclockwise electric power flow, or loop flow, of 200 MW from Area A to Area B to Area C and back to Area A These base conditions are shown in Figure E2-A All of the other interconnected network assumptions are similar to Example 1

Calculation of Transfer Capability

The method of determining transfer capability is the same as in Example 1 However, in this Example 2, computer simulation identifies one of the two interconnection transmission lines between Areas A and B as the critical single transmission contingency and the remaining transmission line between Area A and Area B as the limiting facility

When the transfer capability limit on the interconnected systems is reached, generation in Area A will have increased by 2,286 MW and generation in Area B will have been decreased by the same amount The loadings on the transmission paths for this maximum transfer capability of 2,286 MW from Area A to Area B are shown in Figure E2-B

Figure E2-B
Area A to Area B Transfer Capability Limiting Conditions
2,286 MW Transfer Limit from Area A to Area B



The resulting network loadings under the outage of the critical transmission facility, line A-B #1, for the 2,286 MW capacity transfer from Area A to Area B are summarized in Figure E2-C No additional power transfers may be achieved from Area A to Area B under the conditions simulated because the interconnected systems have reached a limiting condition of 1,100 MW on transmission line A-B #2

Reporting of Transfer Capability

The transfer capability results of Example 2 may be reported on an area interchange basis or a transmission path basis as follows

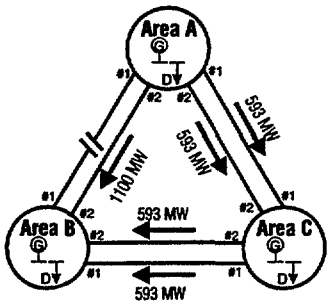
a) **"Area Interchange" Basis**
In the Eastern Interconnection, the Area A to Area B transfer capability would be reported either as a First Contingency Incremental Transfer Capability (FCITC) of 2 286 MW or a First Contingency Total Transfer Capability (FCTTC) of 2,286 MW FCITC and FCTTC from Area A to Area B are the same in this Example 2 as no scheduled transfers exist between Areas A and B under base conditions

Example 2

Figure E2-C

Area A to Area B Transfer Capability Under the Critical Contingency

2,286 MW Transfer Limit from Area A to Area B and Line A B #1 Out of Service



b) "Transmission Path" Basis

In the Western Interconnection, only the total transfer capability (FCTTC) results of Example 2 would be reported but with a focus toward specific transmission path capabilities The FCITC concept is not used in the Western Interconnection Under the limiting transfer conditions of 2,286 MW from Area A to Area B and with all facilities in service, transmission path A-B has a loading of 1,572 MW (Figure E2-B) For this operating condition, a higher transfer from Area A to Area B on path A-B cannot be achieved because the single contin gency outage of either transmission line A-B #1 or A-B #2 would cause the remaining A-B line to exceed its emergency thermal rating Therefore, on a transmission path basis, the 1,572 MW loading on path A-B becomes the path A-B total transfer capability, which is reported as the FCTTC for transmission path A-B

For the transfer levels simulated in this example, transmission paths A-C and C-B are not loaded to their total transfer capability Therefore, FCTTCs for these paths are not reported

c) Interpretation of Results

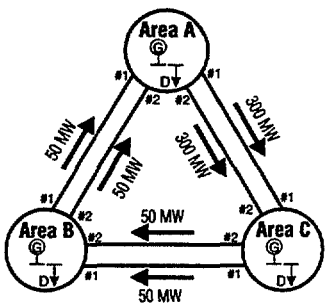
Example 2 demonstrates the effect of a different set of base conditions on the transmission transfer capability from Area A to Area B By comparing Examples 1 and 2, a 400 MW shift in electric power circulation or loop flow (200 MW clockwise to 200 MW counterclockwise because of a change in internal generation dispatch in the Areas) results in a 548 MW reduction in the Area A to Area B FCITC and FCTTC transfer capabilities on an area interchange basis The 400 MW change in base conditions results in an increase of 72 MW in the FCTTC of transmission path A-B

Example 2 also illustrates that transmission transfer capability between areas or systems is not one number, but a range of numbers that varies with system operating conditions, the critical single contingency (or facility outage), and the limiting system facility under the single contingency condition

Example 3

Transmission Transfer Capability from Area A to Area B with a 500 MW Base Scheduled Transfer from Area A to Area C

Figure E3-A
Base Conditions - Example 3
500 MW Base Scheduled Transfer from Area A to Area C



Base Conditions

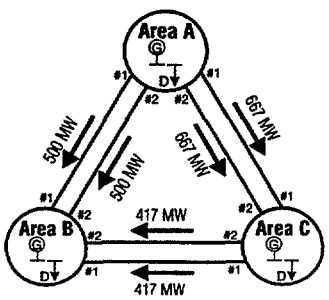
The network configuration of Example 1 applies to Example 3 Under base conditions, however, a 500 MW scheduled power transfer exists from Area A to Area C Computer simulation of these base system conditions results in the transmission line loadings of Figure E3-A. All of the other interconnected network assumptions are similar to Example 1

Calculation of Transfer Capability

The method of determining transfer capability is the same as in Example 1 However, in this Example 3, computer simulation identifies one of the two interconnection transmission lines between Areas A and C as the critical single transmission contingency and the remaining transmission line between Area A and Area C as the limiting facility

When the transfer capability limit on the interconnected systems is reached, generation in Area A will have increased by 1,834 MW and generation in Area B will have been decreased by the same amount The loadings on the transmission paths for this maximum transfer capability of 1,834 MW from Area A to Area B are shown in Figure E3-B

Figure E3-B
Area A to Area B Transfer Capability Limiting Conditions
1,834 MW Transfer Limit from Area A to Area B with a 500 MW Base Scheduled Transfer from Area A to Area C



The resulting network loadings under the outage of the critical transmission facility, line A-C #1, for the 1,834 MW transfer from Area A to Area B are summarized in Figure E3-C No additional power transfers may be achieved from Area A to Area B under the conditions simulated because the interconnected systems have reached a limiting condition of 1,000 MW on transmission line A-C #2

Reporting of Transfer Capability

The transfer capability results of Example 3 may be reported on an area interchange basis or a transmission path basis as follows

a) **"Area Interchange" Basis**
In the Eastern Interconnection, the Area A to Area B transfer capability would be reported either as a First Contingency Incremental Transfer Capability (FCITC) of 1,834 MW or a First Contingency Total Transfer Capability (FCTTC) of 1,834 MW FCITC and FCTTC from Area A to Area B are the same in this Example 3 as no scheduled transfers exist between Areas A and B under base conditions

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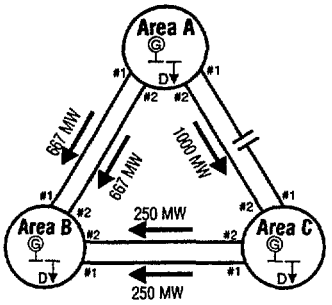
Example 3

Figure E3-C

Area A to Area B Transfer Capability Under the Critical Contingency

1,834 MW Transfer Limit from Area A to Area B with a 500 MW Base Scheduled Transfer from Area A to Area C, and Line A-C #1 Out of Service



b) "Transmission Path" Basis

In the Western Interconnection, only the total transfer capability (FCTTC) results of Example 3 would be reported but with a focus toward specific transmission path capabilities The FCITC concept is not used in the Western Interconnection Under the limiting transfer conditions of 1,834 MW from Area A to Area B and with all facilities in service, transmission path A-B has a loading of 1,000 MW (Figure E3-B) For this operating condition, a higher transfer from Area A to Area B on path A-B cannot be achieved because the single contingency outage of either transmission line A-C #1 or A-C #2 would cause the remaining A-C line to exceed its emergency thermal rating Therefore, the 1,000 MW loading on path A-B becomes the path A-B total transfer capability, which is reported as the FCTTC for transmission path A-B

The corresponding FCTTC of path A-C is 1,334 MW However, the appropriate coordination arrangements must be made with Area C for the 1,334 MW transfer to be made from Area A to Area B over paths A-C and C-B If these arrangements are made, then Area A could transfer 1,834 MW to Area B

For the transfer levels simulated in this example, transmission path C-B is not loaded to its total transfer capability Therefore, an FCTTC for this path is not reported

c) Interpretation of Results

Example 3 demonstrates the effect of a base scheduled transfer of 500 MW from Area A to Area C on the transmission transfer capability from Area A to Area B A comparison of Examples 1 and 3 shows that the base transfer reduces the FCITC and FCTTC from Area A to Area B by 1,000 MW on an area interchange basis

On the transmission path basis, the 500 MW scheduled transfer from Area A to Area C reduces the FCTTC of transmission path A-B by 500 MW In Examples 1 and 3, under contingency conditions, the transmission lines of path A-C are limited by their emergency thermal ratings, therefore, the FCTTC of path A-C is 1,334 MW in both examples

Example 4

Transmission Transfer Capability from Area A to Area B with a 500 MW Base Scheduled Transfer from Area B to Area A

Figure E4-A
Base Conditions – Example 4
500 MW Base Scheduled Transfer from Area B to Area A

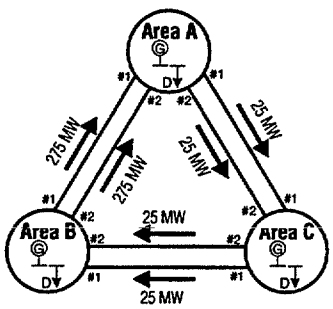
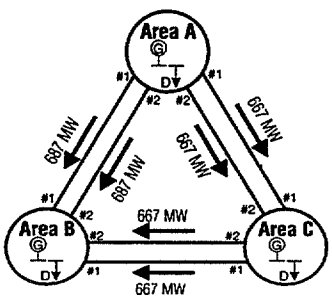


Figure E4-B
Area A to Area B Transfer Capability Limiting Conditions
3,208 MW Transfer Limit from Area A to Area B with a 500 MW Base Scheduled Transfer from Area B to Area A



Base Conditions

The network configuration of Example 1 applies to Example 4 Under base conditions, however, a 500 MW scheduled power transfer exists from Area B to Area A. Computer simulation of these base system conditions results in the transmission line loadings of Figure E4-A All of the other interconnected systems network assumptions are similar to Example 1

Calculation of Transfer Capability

The method of determining transfer capability is the same as in Example 1 However, in this Example 4, computer simulation identifies one of the two interconnection transmission lines between Areas A and C as the critical single transmission contingency and the remaining transmission line between Area A and Area C as the limiting facility

When the transfer capability limit on the interconnected systems is reached, generation in Area A will have increased by 3,208 MW and generation in Area B will have been decreased by the same amount The loadings on the transmission paths for this transfer capability of 3,208 MW from Area A to Area B are shown in Figure E4-B

The resulting network loadings under the outage of the critical transmission facility, line A-C #1, for the 3,208 MW transfer from Area A to Area B are summarized in Figure E4-C No additional power transfers may be achieved from Area A to Area B under the conditions simulated because the interconnected systems have reached a limiting condition of 1,000 MW on transmission line A-C #2

Reporting of Transfer Capability

The transfer capability results of Example 4 may be reported on an area interchange basis or a transmission path basis as follows

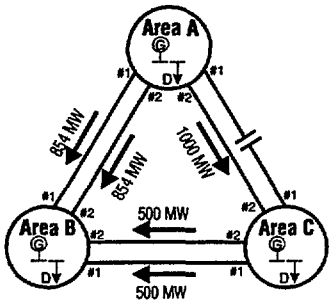
a) **"Area Interchange" Basis**
In the Eastern Interconnection, the Area A to Area B transfer capability would be reported either as a First Contingency Incremental Transfer Capability (FCITC) of 3,208 MW or a First Contingency Total Transfer Capability (FCTTC) of 2,708 MW The FCTTC is the net of the base power transfer from Area A to Area B (or -500 MW) plus the incremental power transfer (3,208 MW) from Area A to Area B or 2,708 MW

Example 4

Figure E4-C

Area A to Area B Transfer Capability Under the Critical Contingency

3,208 MW Transfer Limit from Area A to Area B with a 500 MW Base Scheduled Transfer from Area B to Area A, and Line A-C #1 Out of Service



b) "Transmission Path" Basis

In the Western Interconnection, only the total transfer capability (FCTTC) results of Example 4 would be reported but with a focus toward specific transmission path capabilities The FCITC concept is not used in the Western Interconnection. Under the limiting net transfer conditions of 2,708 MW from Area A to Area B and with all facilities in service, transmission path A-B has a loading of 1,374 MW (Figure E4-B) For this operating condition, a higher transfer from Area A to Area B on path A-B cannot be achieved because the single contingency outage of either transmission line A-C #1 or A-C #2 would cause the remaining A-C line to exceed its emergency thermal rating Therefore, the 1,374 MW loading on path A-B becomes the path A-B total transfer capability, which is reported as the FCTTC for path A-B

The corresponding FCTTC of path A-C is 1,334 MW However, the appropriate coordination arrangements must be made with Area C for the 1,334 MW transfer to be made from Area A to Area B over paths A-C and C-B If these arrangements are made, then Area A could transfer 2,708 MW net to Area B

For the transfer levels simulated in this example, transmission path C-B is not loaded to its total transfer capability Therefore, an FCTTC for this path is not reported

c) Interpretation of Results

Example 4 demonstrates the effect of a base scheduled transfer of 500 MW from Area B to Area A on the transmission transfer capability from Area A to Area B A comparison of Examples 1 and 4 shows that the existence of a base transfer in the opposite direction (Area B to Area A) increases the incremental transfer capability from Area A to Area B by 374 MW (from 2,834 MW to 3,208 MW)

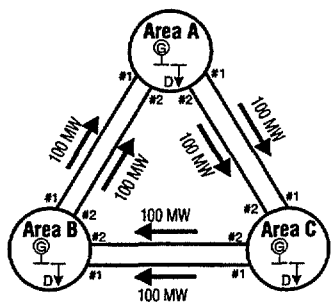
A comparison of the FCTTC values of these examples shows a decrease of 126 MW in the Area A to Area B FCTTC of Example 4 because the power transfer distribution factors are not identical in both directions (Area A to Area B and Area B to Area A) FCTTC values may give a truer picture of the changes in the overall strength of interconnected systems when base transfer schedules are different

A comparison of Examples 1 and 4 on a transmission path basis shows that the FCTTC of transmission path A-B is reduced by 126 MW, while the FCTTC of path A-C remains unchanged at 1,334 MW

Example 5

Transmission Transfer Capability from Areas A and C to Area B without Base Scheduled Transfers, and a Clockwise Loop Flow

Figure E5-A
Base Conditions - Example 5
Zero Scheduled Transfers Among Areas A B and C



Base Conditions

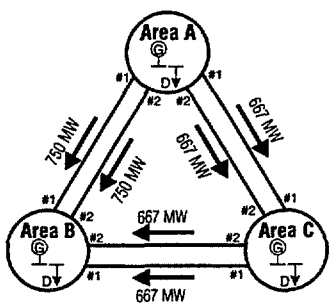
Example 5 shows that the non-simultaneous transfer capability from Area A to Area B cannot be added to the non-simultaneous transfer capability from Area C to Area B to obtain the maximum total simultaneous transfer capability from Areas A and C to Area B

The network configuration and assumptions of Example 1 apply to Example 5 These base conditions are shown in Figure E5-A (same as E1-A)

Maximum Non-Simultaneous Transfer Capability to Area B

The calculation of the maximum non-simultaneous transfer capabilities from Area A to Area B and from Area C to Area B are described below

Figure E5-B
Area A to Area B Transfer Capability Limiting Conditions
2 834 MW Transfer Limit from Area A to Area B



a) **Non-Simultaneous Area A to Area B Transfer Capability**
Example 1 indicates that the maximum non simultaneous transfer capability (FCITC or FCTTC) from Area A to Area B is 2,834 MW on an area interchange basis The limiting or maximum network loadings for that transfer, including the FCTTC for transmission paths, A-B and A-C, are shown in Figure E5-B (same as E1-B) Example 1 also identifies one of the two interconnection transmission lines between Areas A and C as the critical single transmission contingency and the remaining line between Area A and Area C as the limiting facility

b) **Non-Simultaneous Area C to Area B Transfer Capability**
Similar to Example 1 and using the system response characteristics (LODFs, PTDFs, and OTDFs) in Example 1, the maximum non-simultaneous transfer capability (FCITC or FCTTC) from Area C to Area B can be determined as 1,716 MW on an area interchange basis The limiting or maximum network loadings for that transfer are shown in Figure E5-C In this case, the critical single transmission contingency is one of the two interconnection transmission lines between Areas B and C, and the limiting facility is the remaining line between Area B and Area C

c) **Combined Non-Simultaneous Transfer Capabilities**
The non-simultaneous transfer of 2 834 MW from Area A to Area B and the non simultaneous transfer of 1,716 MW from Area C to Area B <u>CANNOT</u> be added to obtain the maximum simultaneous transfer capability to Area B If these non simultaneous transfers are added, the resulting network loadings would be as shown in Figure E5-D Clearly, the transmission lines of path C-B at 1,302 MW each would exceed their normal thermal rating of 850 MW and their emergency thermal rating of 1,000 MW prior to any single contingency Similarly, the transmission lines of path A-B at 973 MW each exceed their normal thermal rating of 950 MW prior to any single contingency These facility loading conditions are unacceptable from a transmission reliability perspective and do not meet NERC, nor any NERC member system, planning or operating reliability criteria and guides

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

Maximum Simultaneous Transfer Capability to Area B

To determine the maximum simultaneous transfer capability from Areas A and C to Area B, the base case computer simulation of Figure E5-A is modified by increasing generation in Areas A and C and reducing generation in Area B This process continues until a single con tingency causes one of the remaining transmission facilities in service to reach its emergency thermal rating In this Example 5, the computer simulation identifies one of the two interconnection transmission lines between Areas B and C as the critical single transmission contin gency and the remaining transmission line between Area B and Area C as the limiting facility

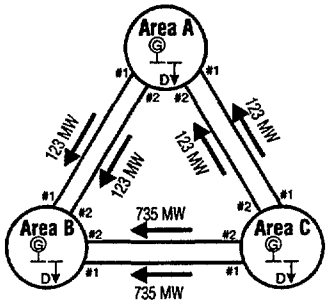
When the transfer capability limit on the interconnected network is reached, genera tion in Area A and Area C will have increased by 2,834 MW and 184 MW, respectively, and gen eration in Area B will have decreased by this total amount The loadings on the transmission paths for this maximum 3,018 MW simultaneous transfer to Area B from Areas A and C are shown in Figure E5-E

The resulting network loadings under the outage of the critical transmission facility, line B-C #1, for the total simultaneous transfer of 3,018 MW from Areas A and C to Area B are summarized in Figure E5-F No additional power transfers may be achieved from Areas A and C to Area B under the conditions simulated because the interconnected systems have reached a limiting condition of 1,000 MW on the remaining B-C line in the direction from Area C to Area B

Figure E5-C

Area C to Area B Transfer Capability Limiting Conditions

1 716 MW Transfer Limit from Area C to Area B



Reporting of Transfer Capability

The maximum simultaneous transfer capability results of Example 5 may be report ed on an area interchange basis or a transmission path basis as follows

a) **"Area Interchange" Basis**
In the Eastern Interconnection, the maximum simultaneous transfer capability from Areas A and C to Area B would be reported either as a First Contingency Incremental Transfer Capability (FCITC) of 3,018 MW or a First Contingency Total Transfer Capability (FCTTC) of 3,018 MW

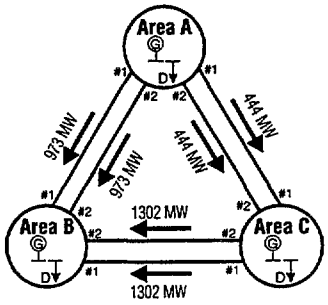
b) **"Transmission Path" Basis**
In the Western Interconnection, the simultaneous total transfer capability (FCTTC) results of Example 5 would be reported with a focus toward specific transmission path capabilities The FCITC concept is not used in the Western Interconnection Under the limiting transfer conditions of 3,018 MW from Areas A and C to Area B and with all facilities in service, transmission path A-B has a loading of 1,548 MW (Figure E5-E) For this operating condition, a higher combined transfer from Areas A and C to Area B on path A-B cannot be achieved because the single contingency outage of either transmission line B-C #1 or B-C #2 would cause the remaining B-C line to exceed its emergency thermal rating Therefore, the 1,548 MW loading on path A-B becomes the path A-B total transfer capability, which is reported as the FCTTC for path A-B

The corresponding FCTTC of path C-B would be 1,470 MW However, the appropriate coordination arrangements must be made with Area C for the 1,470 MW transfer to be made over paths A-C and C-B If these arrangements are made, then Areas A and C could transfer 3,018 MW to Area B

Figure E5-D

Network Loadings for Combined Non-Simultaneous Area A and Area C Transfers to Area B

2 834 MW Transfer from Area A to Area B and 1 716 MW Transfer from Area C to Area B



EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

For the transfer levels simulated in this example, transmission path A-C is not loaded to its total transfer capability Therefore, an FCTTC for this path is not reported

c) Interpretation of Results

Example 5 shows that non simultaneous transfers from several Areas (Areas A and C) to a common Area (Area B) CANNOT be directly added to obtain the total simultaneous transfers to that common Area (Area B)

The table below summarizes the "maximum non-simultaneous" transfer capability from Area A to Area B (Case 1) and from Area C to Area B (Case 2) along with the "maximum simultaneous" transfer capability from Areas A and C to Area B (Case 3) Included in this table are two other (Cases 4 and 5) of the many combina tions of simultaneous transfer capabilities from Areas A and C to Area B that are possible in a reliable manner That is, within the constraints of the normal and emergency thermal ratings of the interconnection transmission lines of the inter connected systems network

Figure E5-E

Network Loadings for Maximum Simultaneous Area A and Area C Transfers to Area B

2 834 MW Transfer from Area A to Area B and 184 MW Transfer from Area C to Area B

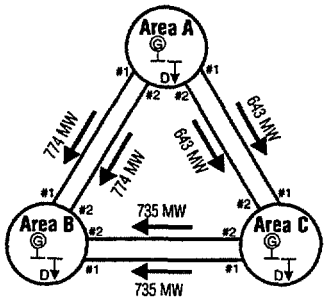
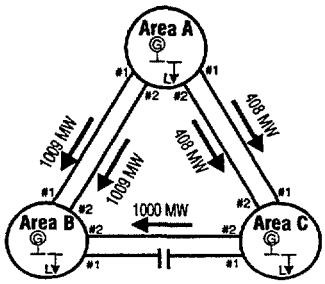


Figure E5-F

Maximum Simultaneous Transfers to Area B Under the Critical Contingency

2 834 MW Transfer from Area A to Area B 184 MW Transfer from Area C to Area B and Line B-C #1 Out of Service



SIMULTANEOUS TRANSFER CAPABILITIES FROM AREAS A AND C TO AREA B

Case	Transfer from Area A to Area B MW	Transfer from Area C to Area B MW	Critical Contingency Facility	Limiting Facility	Transfers from Areas A and C to Area B MW
1[a]	2,834	0	Line A-C #1	Line A-C #2	2,834
2[b]	0	1,716	Line B-C #1	Line B-C #2	1,716
3[c]	2,834	184	Line B-C #1	Line B-C #2	3,018
4[d]	2,249	500	Line B-C #1	Line B-C #2	2,749
5[d]	500	1,447	Line B-C #1	Line B-C #2	1,947

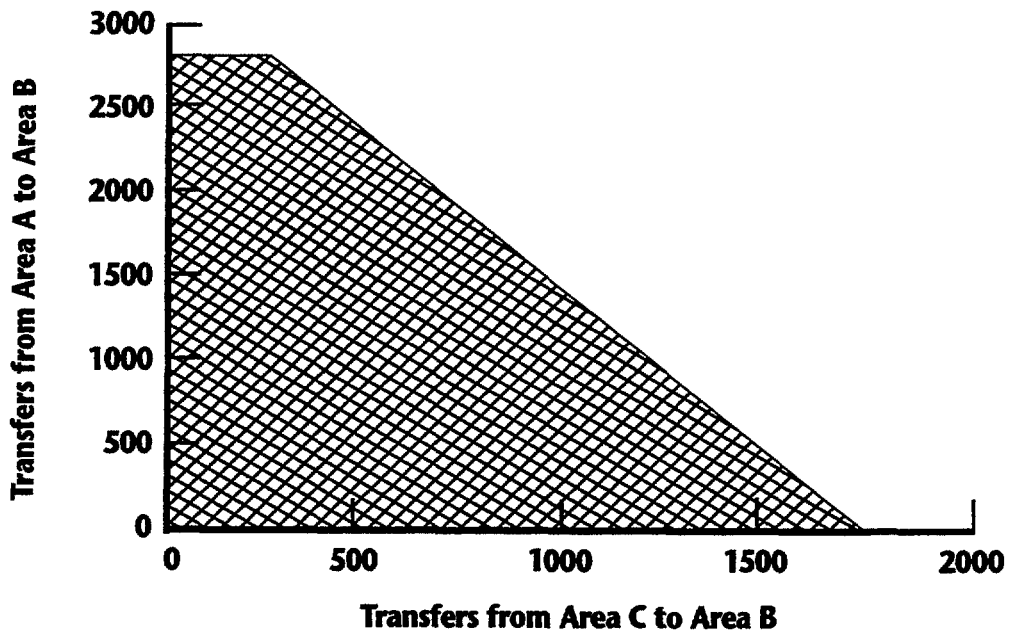
[a] Maximum non-simultaneous transfer capability from Area A to Area B
[b] Maximum non-simultaneous transfer capability from Area C to Area B
[c] Maximum simultaneous transfer capability from Areas A and C to Area B
[d] Only two of the many combinations of simultaneous transfers from Areas A and C to Area B that are possible in a reliable manner under the interconnected systems network s constraints

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

The possible simultaneous transfer capabilities from Areas A and C to Area B are shown graphically in Figure E5-G to illustrate that simultaneous transfer capabilities are multi-dimen sional quantities The textured area represents those combinations of Area A to Area B and Area C to Area B transfers that can be scheduled simultaneously without exceeding the FCITC criterion Because of this characteristic, simultaneous transfer capabilities are more difficult to quantify and describe than non simultaneous transfer capabilities

FIGURE E5-G

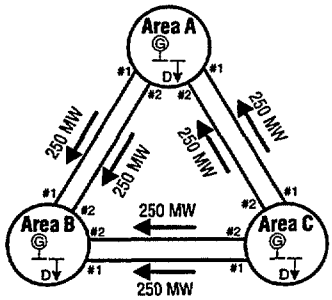
SIMULTANEOUS TRANSFER CAPABILITIES FROM AREAS A AND C TO AREA B (MW)



Example 6

Transmission Transfer Capability from Area A to Area B with a 1,000 MW Base Scheduled Transfer from Area C to Area B, and a Special Protection System Installed

Figure E6-A
Base Conditions – Example 6
1 000 MW Base Scheduled Transfer from Area C to Area B



Base Conditions

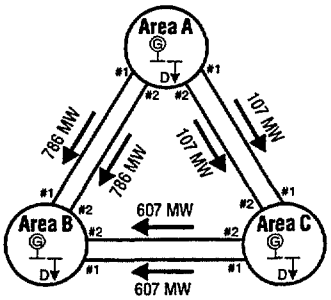
The network configuration of Example 1 applies to Example 6 Under base conditions, however, changes have been made to the internal generation dispatch and the level of customer demand in each Area such that the network will have a net counterclockwise electric power flow, or loop flow, of 240 MW from Area A to Area B to Area C and back to Area A. In addition, a 1,000 MW scheduled power transfer exists from Area C to Area B The resulting base conditions are shown in Figure E6-A. All of the other interconnected systems network assumptions are similar to Example 1

Calculation of Transfer Capability

The method of determining transfer capability is the same as in Example 1 However, in this Example 6, the computer simulation identifies one of the two interconnection transmission lines between Areas A and B as the critical single transmission contingency and the remaining transmission line between Area A and Area B as the limiting facility

When the transfer capability limit on the interconnected systems is reached, generation in Area A will have increased by 1,786 MW and generation in Area B will have been decreased by the same amount The loadings on the transmission paths for this maximum transfer capability of 1,786 MW from Area A to Area B, with the scheduled transfer of 1,000 MW from Area C to Area B in effect, are shown in Figure E6-B

Figure E6-B
Area A to Area B Transfer Capability Limiting Conditions
1 786 MW Transfer Limit from Area A to Area B with a 1 000 MW Base Scheduled Transfer from Area C to Area B



The resulting network loadings under the outage of the critical transmission facility, line A-B #1, for the 1,786 MW transfer from Area A to Area B are summarized in Figure E6-C No additional electric power transfers may be achieved from Area A to Area B under the conditions simulated because the interconnected systems have reached a limiting condition of 1,100 MW on transmission line A-B #2

Special Protection Systems

Special protection systems (SPSs), also known as remedial action schemes, are designed to automatically perform system protection functions other than the isolation of electrical faults For example, some SPSs are designed to trip (or remove from service) generators, pumped storage units, or transmission facilities under a set of carefully defined system conditions

Example 6

If it were feasible to apply and install an SPS on the interconnected systems network in Example 6, it might be possible to increase the level of transfer capability on the network. For example, if an SPS were installed to prevent, under the outage of either line A-B #1 or A-B #2, the interrupted power flow on either line A-B #1 or line A-B #2 from immediately shifting to the other remaining A-B line, the transfer capability from Area A to Area B could be increased until lines A-B #1 and A-B #2 each reached their normal thermal rating (assumed to be 950 MW) or some other single contingency in the network resulted in another transmission facility reaching its emergency thermal rating

To eliminate the potential overload on the limiting transmission line A-B #1 or line A-B #2, the SPS would need to be designed to readjust system conditions immediately following the outage of line A-B #1 or line A-B #2 so that the remaining A-B transmission line does not exceed its 1,100 MW emergency thermal rating

If such an SPS could be appropriately applied to the example network, the transfer capability from Area A to Area B could be increased by 330 MW from 1,786 MW to 2,116 MW, with the 1,000 MW scheduled transfer from Area C to Area B in effect The loadings on the transmission paths for this maximum 2,116 MW transfer from Area A to Area B are shown on Figure E6-D Lines A-B #1 and A-B #2 would increase to 885 MW each from the 786 MW level shown in Figure E6-B

Under the increased transfer conditions, the outage of either transmission line B-C #1 or B-C #2, with a loading of 673 MW each, would result in an immediate shift in flow of 215 MW (32% of 673 MW) to lines A-B #1 and A-B #2, respectively For this critical outage condi tion, transmission lines A-B #1 and A-B #2 would each be loaded to 1,100 MW (885 MW plus 215 MW), their emergency thermal rating, as shown in Figure E6-E

Under the conditions of Figure E6-D, the outage of either transmission line A-B #1 or A-B #2 would result in an immediate shift in flow of 354 MW (40% of 885 MW) to the remain ing A-B transmission line For this critical outage condition, the remaining A-B line will be loaded to 1,239 MW (885 MW plus 354 MW), or 139 MW above its emergency thermal rating However, an SPS has been assumed to have been installed for the outage of either transmission line A-B #1 or A-B #2 The SPS is designed such that under these transfer conditions and with the outage of either line A-B #1 or A-B #2, 330 MW of generation in Area A would be automati cally tripped (or removed from service) and 330 MW of pumping load in Area B would be simultaneously removed from service These SPS control actions will bring the network back to its transfer limit of 1,786 MW from Area A to Area B, and will reduce the loading on the remain ing A-B transmission line to its 1,100 MW emergency thermal rating All other facilities will also be within their respective emergency thermal ratings The resulting loadings on the transmis- sion paths when the SPS has been activated are shown in Figure E6-C

Figure E6-C

Area A to Area B Transfer Capability Under the Critical Contingency

1 786 MW Transfer Limit from Area A to Area B with a 1 000 MW Base Scheduled Transfer from Area C to Area B and Line A-B #1 Out of Service

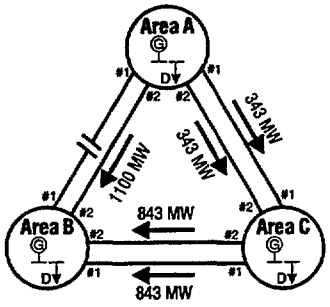
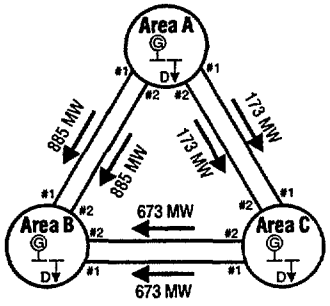


Figure E6-D

Area A to Area B Transfer Capability with a Special Protection System

2 116 MW Transfer Limit from Area A to Area B with a 1 000 MW Base Scheduled Transfer from Area C to Area B, and an SPS Installed



Reporting of Transfer Capability

The transfer capability results of Example 6 may be reported on an area interchange basis or a transmission path basis as follows

a) **"Area Interchange" Basis**
In the Eastern Interconnection, for the base conditions assumed and with a special protection system in effect, the Area A to Area B transfer capability would be reported either as a First Contingency Incremental Transfer Capability (FCITC)

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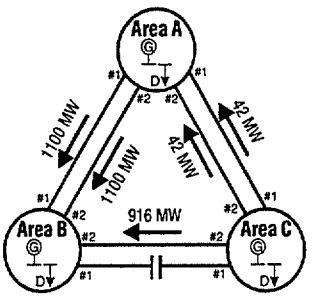
Example 6

Figure E6-E

Area A to Area B Transfer Capability with a Special Protection System and Under the Critical Contingency

2 116 MW Transfer Limit from Area A to Area B with a 1 000 MW Base Scheduled Transfer from Area C to Area B and Line B C #1 Out of Service



of 2,116 MW or a First Contingency Total Transfer Capability (FCTTC) of 2,116 MW Use of the SPS would be noted in the reporting of these transfer capabilities

b) "Transmission Path" Basis

In the Western Interconnection, only the total transfer capability (FCTTC) results of Example 6 would be reported but with a focus toward specific transmission path capabilities The FCITC concept is not used in the Western Interconnection Under the limiting transfer conditions of 2,116 MW from Area A to Area B and with all facilities in service, transmission path A-B has a loading of 1,770 MW (Figure E6-D) For this operating condition, a higher transfer from Area A to Area B on path A-B cannot be achieved because the single contingency outage of either transmission line B-C #1 or B-C #2 would cause lines A-B #1 and A-B #2 to exceed their respective emergency thermal ratings Therefore, the 1,770 MW loading on path A-B becomes the path A-B total capability, which is reported as the FCTTC for path A-B Again, use of the SPS would be noted in the reporting of these transfer capabilities

The corresponding FCTTC of path C-B would be 1,346 MW However, the appropriate coordination arrangements must be made with Area C for the 1,346 MW transfer to be made from Area A to Area B over paths A-C and C-B If these arrangements are made, then Area A could transfer 2,116 MW to Area B

For the transfer levels simulated in this example, transmission path A-C is not loaded to its total transfer capability Therefore, an FCTTC for this path is not reported

c) Interpretation of Results

Example 6 demonstrates the use of an SPS to increase the transmission transfer capability from Area A to Area B On an area interchange basis, the SPS increases the transmission transfer capability from Area A to Area B by 330 MW (from 1,786 MW to 2,116 MW) It also increases the A-B transmission path total transfer capability by 198 MW (from 1,572 MW to 1,770 MW)

SPSs are highly sophisticated and complex schemes that depend on multiple data inputs, good communication channels, and reliable equipment Their applications are limited and electric system specific Operators must be alert to the conditions that create the need for SPSs, the consequences of SPS misopera tion, and the established criteria and guidelines under which SPSs were designed and are to be operated

APPENDIX B

GLOSSARY OF TERMS

Control Area

An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling its generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the Interconnection. A control area must be able to

- Directly control its generation to continuously balance its actual interchange and scheduled interchange, and
- Help the entire Interconnection regulate and stabilize the Interconnection's alternating current frequency

Demand-Side Management

The term for all activities or programs undertaken by an electric system or its customers to influence the amount and timing of electricity use

- **Indirect Demand-Side Management** — Programs such as conservation, improvements in efficiency of electrical energy use, rate incentives, rebates, and other similar activities to influence or indirectly control electricity use
- **Direct Control Load Management** — The magnitude of customer demand that can be interrupted by direct control of the system operator by interruption of the electric supply to individual appliances or equipment on customer premises This type of control, when used by utilities, usually involves residential customers Direct Control Load Management as defined here does not include Interruptible Demand
- **Interruptible Demand** — The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator In some instances, the demand reduction may be initiated by the direct action of the system operator (remote tripping) with or without notice to the customer in accordance with contractual provisions Interruptible Demand as defined here does not include Direct Control Load Management

Distribution Factors

Measures of the electrical effects of an electric power transfer on system facilities or an outage (or removal from service) of a system facility or element on the remaining system facilities

- **Line Outage Distribution Factor (LODF)** — A measure of the redistribution of electric power on remaining system facilities caused by an outage (or removal from service) of another system facility, expressed in percent (up to 100%) of the pre-contingency electrical loading on the outaged facility
- **Power Transfer Distribution Factor (PTDF)** — A measure of the responsive ness or change in electrical loadings on system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer The PTDF applies only for the pre-contingency configuration of the systems under study
- **Outage Transfer Distribution Factor (OTDF)** — The electric power transfer distribution factor (PTDF) with a specific system facility removed from service (out aged) The OTDF applies only for the post-contingency configuration of the systems under study

- **Distribution (or Response) Factor Cutoff** — The suggested minimum level or magnitude of the line outage distribution factor (LODF), the power transfer distribution factor (PTDF), or the facility outage transfer distribution factor (OTDF) considered significant and used in transfer capability calculations or other system analyses LODFs, PTDFs, or OTDFs below 2-3% generally should not be considered in determining transfer capabilities The suggested distribution (or response) factor cutoffs should not be universally applied without good engineering judgment Any critical facility with a distribution (or response) factor below the cutoff should still be closely monitored in the analyses to ensure its limits are not exceeded and that system reliability will be maintained

Electric System

The generation, transmission, distribution, and other facilities operated as an electric utility or a portion thereof

Facility Ratings

The operational limits of an electric system facility or element under a set of specified conditions

- **Normal Rating** — The rating as defined by the facility owner that specifies the level of electrical loading (generally expressed in megawatts or other appropriate units) that a facility can support or withstand through the daily demand cycles with out loss of equipment life of the facility or equipment involved

- **Emergency Rating** — The rating as defined by the facility owner that specifies the level of electrical loading (generally expressed in megawatts or other appropriate units) that a facility can support or withstand for a period of time sufficient for the adjustment of transfer schedules or generation dispatch in an orderly manner with acceptable loss of equipment life, or other physical or safety limitations, of the facility or equipment involved This rating is not a continuous rating

Forced Outage

An unplanned facility failure or other system condition that requires that the failed facility (or portion of the system) be disconnected or removed from service to maintain the operational integrity of the remaining electrical system facilities and to limit damage to the failed facility

Interchange

Operational term for electric power that flows from one control area to another "Inter change" is synonymous with "transfer"

- **Actual Interchange** — Metered electric power that flows from one control area to another

- **Scheduled Interchange** — Electric power scheduled to flow between control areas, usually the net of all sales, purchases, and wheeling transactions between those areas at a given time

- **Inadvertent Interchange** — The difference between a control area s actual interchange and scheduled interchange

GLOSSARY OF TERMS

Interconnection

When capitalized (Interconnection), any one of the four major interconnected areas of NERC, which are comprised of one or more of the electric systems in the United States and Canada the Eastern Interconnection, the Western Interconnection, the Quebec Interconnection, and the ERCOT Interconnection When not capitalized (interconnection), the facilities that connect two electric systems or control areas

Maintenance Outage

The planned removal of an electrical facility from service to perform work on that facility so it can continue to adequately perform its system function

Nonutility Generator

Facility for generating electricity that is not exclusively owned by an electric utility and which operates connected to an electric utility system

Operating Procedures

A set of policies, practices, or system adjustments that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected electric systems These actions or system adjust ments maybe implemented in anticipation of or following a system contingency (facility outage) or system disturbance, and include, among others, opening or closing switches (or circuit break ers) to change the system configuration, the redispatch of generation, and the implementation of Direct Control Load Management or Interruptible Demand programs

- **Automatic Operating Systems** — Special protection systems (or remedial action schemes) or other operating systems installed on the electric systems that require no intervention on the part of system operators for their operation
- **Normal (Pre-Contingency) Operating Procedures** — Operating procedures that are normally invoked by the system operator to alleviate potential facility over loads or other potential system problems in anticipation of a contingency
- **Post-Contingency Operating Procedures** — Operating procedures that are invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred

Parallel Path Flow

The flow of electric power on an electric system's transmission facilities resulting from scheduled electric power transfers between two other electric systems

Peak Internal Demand

The peak hour integrated demand that includes the demands of all customers that a system serves, the peak demands of the organization providing the electric service, plus the losses incidental to that service Internal Demand is also the sum of the metered (net) outputs of all generators within the system and the metered interconnection line flows into the system, less the metered interconnection line flows out of the system The demand of station services or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of generating units) is not included

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Internal Demand represents actual customer demand and, therefore, is net of (reduced by) utility indirect demand side management (DSM) programs In contrast, Internal Demand is generally not reduced by direct control DSM programs such as Direct Control Load Management or Interruptible Demand However, the representation of direct control DSM programs depends on specific contract terms and the practices of the individual electric systems employing these types of programs

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating current equipment Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers It also must supply the reactive losses on transmission facilities Reactive power is provided by generators, synchronous condensers, or electrostatic equipment, such as capacitors, and directly influences electric system voltage

Reliability

Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — adequacy and security

- **Adequacy** — The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities
- **Security** — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities

Single Contingency

The sudden, unexpected failure or outage of a system facility or element (generating unit, transmission line, transformer, etc)

Special Protection Systems (or Remedial Action Schemes)

Fast acting, automated relay configurations designed to perform system protection functions other than the isolation of electrical faults These systems may be used to increase transmission transfer capability under specified conditions They may also be used to permit higher loading levels on the interconnected transmission systems in those instances where additional facilities cannot be built or have been delayed Their application is system specific

Study Criteria

The planning and operating reliability criteria or guides that are used in determining the amount of electric power that can be reliably transferred

System Facility (or Element)

Any generating unit, transmission line, transformer, or other piece of electrical equipment comprising an electric system.

Transfer Capability

The measure of the ability of interconnected electric systems to reliably move or transfer electric power (generally measured in megawatts) from one area to another area by way of all transmission lines (or paths) between those areas under specified system conditions In this context, area refers to the configuration of generating stations, switching stations, substations, and connecting transmission lines that may define an individual electric system, power pool, control area, subregion, or Region, or a portion thereof

- **First Contingency Incremental Transfer Capability (FCITC)** —The amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions

  1 For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,

  2 The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and

  3 After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contin gency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits

- **Normal Incremental Transfer Capability (NITC)** —The amount of electric power, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-contingency loadings reach the normal thermal rating of a facility prior to any first contingency transfer limits being reached When this occurs, NITC replaces FCITC as the most limiting transfer capability

- **First Contingency Total Transfer Capability (FCTTC)** —The total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the intercon nected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above

- **Simultaneous Transfer Capability** —The amount of electric power that can be reliably transferred between two or more areas of the interconnected electric systems as a function of one or more other electric power transfers concurrently in effect

- **Non-Simultaneous Transfer Capability** —The amount of electric power that can be reliably transferred between two areas of the interconnected electric systems when other concurrent normal base power transfers are held constant

- **Economy Transfers** — Electric power that is scheduled and reliably transferred between two areas or entities in the short term, or on the spot market, to take advantage of the disparity in the cost of electric power between the entities, thereby reducing operating costs and providing mutual benefit

- **Emergency Transfers** — Electric power that is scheduled and reliably transferred from an area with sufficient generating capacity margin to an area that has a temporary deficiency of generating capacity or other deficit system condition

- **Scheduled Transfers** — Electric power that is scheduled, by or through control areas, to be reliably transferred between buying and selling areas or entities

- **Normal Base Power Transfers** — Electric power transfers that are considered by the electric systems to be representative of the base system conditions being analyzed, and which are agreed upon by the parties involved Other transfers, such as emergency or economy transfers, are usually excluded

Transmission Path

An electrical connection, link, or line consisting of one or more parallel transmission elements between two areas of the interconnected electric systems, or portions thereof

Transmission System

A network of transmission lines and the switching stations and substations to which the lines are connected

Transmitting Utility

Any electric utility (e g , investor-owned, cooperative, municipal or state agency), qualifying cogeneration facility, qualifying small power production facility, or federal power marketing agency that owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale

Voltage Limits

The voltages within which the interconnected electric systems are to be operated

- **Normal Voltage Limits** — The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable on a sustained basis

- **Emergency Voltage Limits** — The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance

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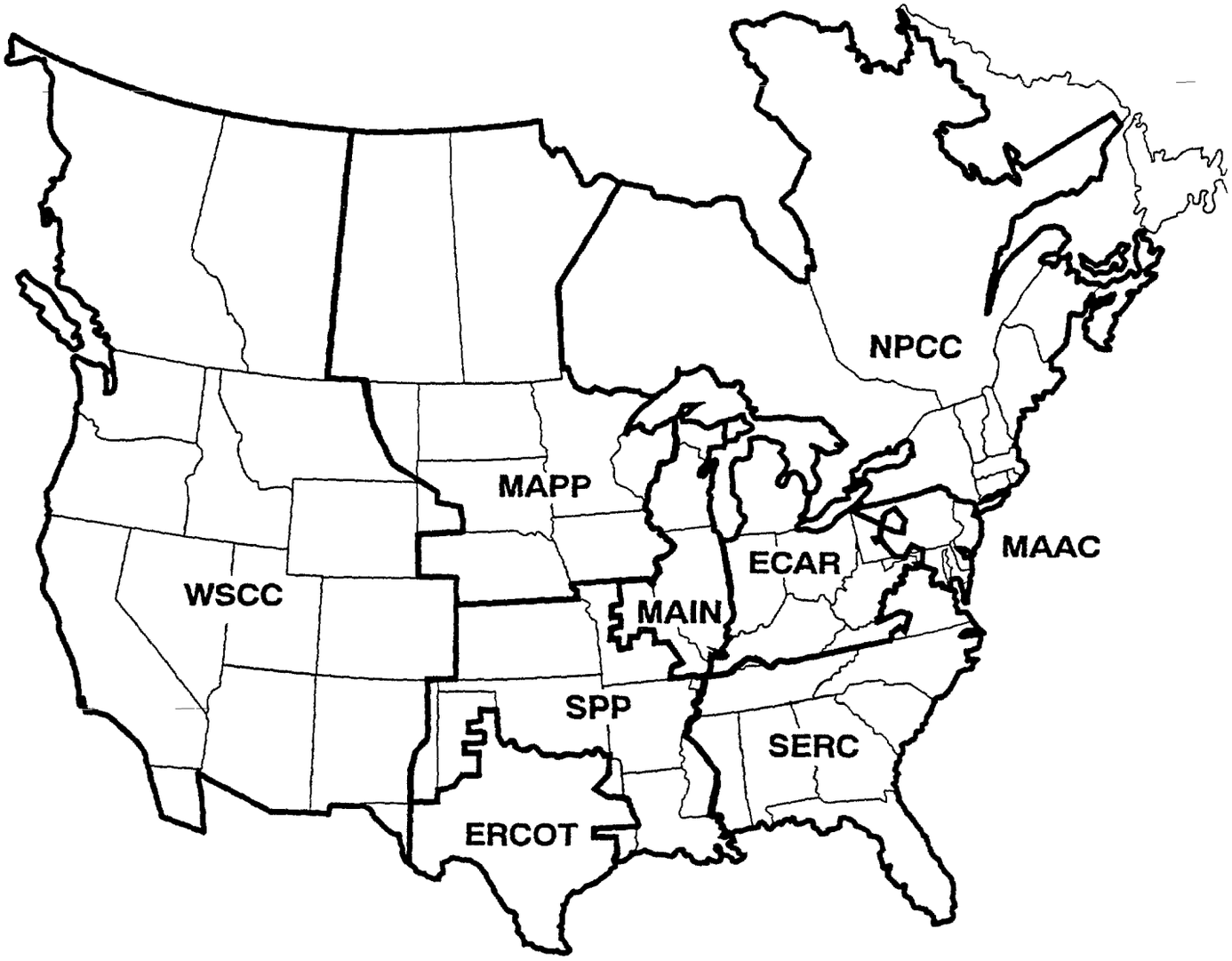

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid Atlantic Area Council

MAIN
Mid America Interconnected Network

MAPP
Mid Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

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April 1990 Volume 3, Number 3

the Electricity JOURNAL

Transmission: The Center of Things

Transmission—Heart of the Matter
With Charles G Stalon and Roger Odisio

STATE INITIATIVES TO OPEN TRANSMISSION

A Proposal to Broaden Transmission Service in New England
By Hon Susan F Tierney

Wisconsin's Integrated Planning Order Making Love, Not War
By Michael Arny and Barbara James

Need for a Transmission 'Busy Signal'
By Hyde M Merrill and Allen J Wood

Ute and Tri-State Ambushed by Regulators

Midland on a Roll

A Run on Utility Limited Partnerships?

The Dark Side of Bidding in Virginia

Entergy's Plant Sales Raise Eyebrows

In Coming Issues:

Greenhouse Strategies for Agnostics

Pretend We Wanted a Nuclear Power Program

DOE's National Energy Strategy

Source Courtesy of "The Electricity Journal"

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In This Issue . . .

For everyone interested in either reforming the electric utility industry or keeping it as it is, there are three things to remember: transmission, transmission, transmission.

All visions of the future that promise a more competitive and diverse industry seem to hinge on some type of transmission access restructuring, i.e., wresting access from the transmission "haves" and giving it to the "have-nots." The strategies for how to do this (or avoid having it done) make for lively reading. In many ways, the transmission debate serves as a proxy for much larger, more fundamental differences about the industry's future. In this sense, it is not unlike the somewhat related debate over the Public Utility Holding Company Act.

This month, **Roger Odisio** concludes his insightful two-part interview with former FERC commissioner **Charles Stalon**. Stalon's views about the regulatory process, competition, and the role of transmission in both are good and challenging reading. The interview also delves into concepts central to the recent FERC Transmission Task Force report, current target in the transmission debate.

Following this essentially federal view, we turn to examine two approaches that demonstrate the ingenuity of two states in addressing some of the same problems that drove the FERC Task Force Report team.

First, Massachusetts DPU Commissioner **Susan Tierney** explains a proposal she has put forth which seeks to reform an existing utility pooling agreement—the NEPOOL Agreement—to expand transmission services available in New England. In spite of NEPOOL's "integrated pool" character, many transactions and projects do not qualify for service under the agreement as it stands. Her proposal would remedy that situation.

Michael Arny and **Barbara James**, both of the Wisconsin Public Service Commission staff, argue that there is ample room for states to address transmission issues under state law without stepping on federal toes. Drawing on their experience in Wisconsin, they believe states have authority to bridge the access gap in a way that advances legitimate state interest, while incidentally advancing federal goals.

Hyde M. Merrill and **Allen J. Wood** spin a yarn about the misfortune of one Norman Ulysses Gigawatt, a man with power to sell but no one to wheel it. They say a proper "busy signal" for transmission access, analogous to a telephone busy signal, would make the need to deny transmission access (when the need to do so occurs) more credible to non-utility generators and policy makers. In a world with a transmission busy signal, they say, everyone lives happily ever after and drives Porsches.

Finally, our "Wheeling, Dealing, and Data" department this month focuses on the transmission issue, offering some graphics that sort out some of the proposals that have been put on the table, while providing other views about this central, highly charged topic.

Good reading!

Robert O. Marritz

the Electricity JOURNAL

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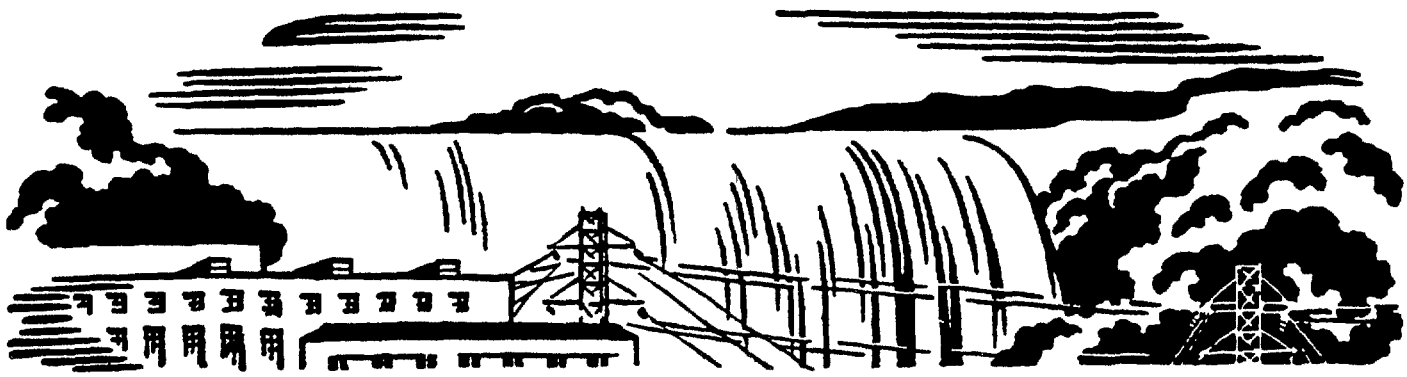

Short Takes

NARUC's Surprising Acid Rain Consensus, Next Stop Transmission?

It seemed laughably remote, a few months ago, to think that state regulators—divided as they were by "clean" and "dirty" views of the acid rain problem—could possibly forge a consensus position on the issue

But the persistence of Maryland's Bill Badger (Electricity Committee chair) and Ohio's Ashley Brown (vice-chair) paid off at the regulators' winter meeting last month in passage of a focused NARUC Executive Committee resolution that has made the commissioners a player, albeit still a minor one, in the increasingly "inside" process that is shaping the complex legislation

The NARUC position addresses emissions trading and nontrading issues, with emphasis on the former Key provisions make sure the trading market is liquid, support for an emission rights auction (5% or more of the total allowances), allow "clean" plants to overcontrol and trade, reward utilities that practice least-cost planning; permit utilities to select alternate baseline periods, specifically preserve rights of utility regulators

The Electricity Committee meeting also hosted a debate of sorts on transmission policy, in which the principal focus was the FERC Transmission Task Force Report and the principal participants were FERC commissioner Charles Trabandt and former commissioner Charles Stalon The structure of the discussion was useful, if predictable Stalon setting forth his vision of needed industry changes and how FERC could facilitate them under existing authority (see page 14, this issue), and Trabandt doubting the wisdom and lawfulness of those changes

To avoid what Yogi Berra called making "the wrong mistake," Stalon said he was prepared to take the utilities at their word that they are not committed to building new capacity and suffering another round of disallowances To protect the integrity of the system, he said there is needed a new risk allocation model which is capable of developing the needed capacity by nonutilities, if not utilities It is that model that the FERC Task Force Report proposes to foster—through FERC s ability to condition approvals that utilities seek—to induce utilities to open the transmission system to permit a competitive bulk power market to develop

Trabandt, reflecting what he characterized as an engineer's perspective, found strong reason *not* to take the path the Task Force Report suggested ("Even if it s legal, it's terrible policy"), noting that the only commissioners to endorse the report—Stalon and Hesse—were no longer at the commission One observer noted "It seemed he was saying to Stalon, 'I'm here and you're not'"

As he had at last November's NARUC meeting in Boston, Trabandt raised state preemption concerns, questioning the fairness

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of one of the Task Force's key ideas giving utilities providing transmission pricing flexibility, but only if they provide firm transmission service to others on a priority basis, something to which utility "haves" take strong umbrage

This concern is addressed more comprehensively in the National Regulatory Research Institute's analysis for NARUC of the FERC Task Force Report, which both Stalon and Trabandt referred to with approval

The next tough issue to be tackled by the state regulators may well be transmission NARUC's Staff Subcommittee on Electricity has been instructed to undertake a preliminary analysis of the issue and report to the Electricity Committee at its July meeting in Los Angeles With states ever more active trying to find ways to improve markets and system performance (see pages 24 and 40, this issue), the transmission ball could well be shifting to the states' arena

Musical Chairs at DOE

The last two Reagan appointees in the Energy Department have been replaced by Secretary James Watkins Donna Fitzpatrick, assistant secretary for management and administration, was pushed out by Watkins in order to create an assistant secretary slot for his long-time crony and special assistant Leo Duffy Duffy is an expert in nuclear waste According to sources close to the agency, Fitzpatrick was very bitter about her ouster, which was done with the lack of tact that has so badly damaged Watkins' image inside the Forrestal Building She was offered the opportunity to stay on for a face-saving period, but declined and left immediately Soon after Fitzpatrick's firing, DOE announced a reorganization that split up management and administration, parcelling out the pieces to various DOE offices That opens up a slot for Duffy

The second departure, much more amicable, is that of Helmut Merklein as head of the Energy Information Administration He had been at EIA since 1985 Merklein told reporters his departure was a "mutual" agreement between himself and Watkins Watkins wanted new blood at EIA, and Merklein was ready to return to academic life he will stay on until a successor is found, which could be as late as May

'Transition' a Concern at ABA Conference

At the ABA Conference on Electricity Law and Regulation in Denver last month, Massachusetts Commissioner **Susan Tierney** caught the attention of the predominantly male audience when she likened the present state of flux of the industry to that "short period of intense discomfort right before a baby is born, known euphemistically as transition' " Tierney said the '80s were a gestation phase, and that the '90s would likely see the birth of the new industry

Steve Herod, Director of FERC's Office of Electric Power Regulation, pressed by a member of the audience for some indication of FERC's case-by-case approach, said "We're like tennis linesmen, as long as we call all the balls in, no one's going to care whether or not there are any lines on the court It's when we call the first ball out that they'll start to complain "

Mark Sholander, general counsel for Kansas City Power and Light, said competition in bulk power markets will hurt consumers big Overreliance on IPPs will impose these costs, he said (1) increased capital costs for utilities who buy too much from highly leveraged IPPs, (2) costs for negotiation, enforcement and monitoring of contracts, (3) threats to reliability posed by the adversarial relationship of the parties, (4) potential for vendors to claim inability to perform due to *force majeure*, and (5) loss of economies of scale presently achieved through industry coordination

Better for the consumer, said Sholander, would be a few, good, well-regulated, vertically-integrated utilities

Least-Cost Doing, not Least-Cost Planning! ' was the message put forth by the **Ralph Cavanagh**, senior attorney for the Natural Resources Defense Council Utility earnings should be tied to utilities success in delivering least-cost energy services to

Donald Kendall, managing partner of Kendall Capital Partners, said there will be more creative financing to address the impending huge need for capital expenditures for new supply and Clean Air Act costs To share the "burden of blame," joint ventures will increase Financing will be based heavily on cash flow and long-term contracts Evidence of need for power will be critical

Mike Oldak, regulatory counsel for the National Rural Electric Cooperative Association, characterized what proved to be an incendiary restructuring panel as "contestants in the 'custody dispute' of the industry" Economic consulting whiz **Jerry Pfeffer** recommended reading Sam Insull's biography, since "he's the reason PUHCA exists " As long as there are undervalued assets, said Pfeffer, the pace of mergers and acquisitions will continue not because of junk bonds, conglomerates, or Japan, but because of other utilities **George Galloway**, PacifiCorp's chief counsel, caused a minor ruckus when he proposed the "Public Utilities Reform Act of 2005" (no PUHCA, no public power, no tax exemptions) Moderator Oldak waved the 'time's up' sign vigorously, but thanked Galloway for securing his job for the indefinite future Morgan Stanley's **John Beatty**, calling the U S the most socialized electric utility country in the world, said the Eastern Bloc would go heavily for market solutions, auctioning off transmission lines in Czechoslovakia, for example He observed that "the two Germanies will combine before San Diego and SCE do "

—*Amalie B Schuck*

The PUHCA Game

Partnerships and the Doswell Project

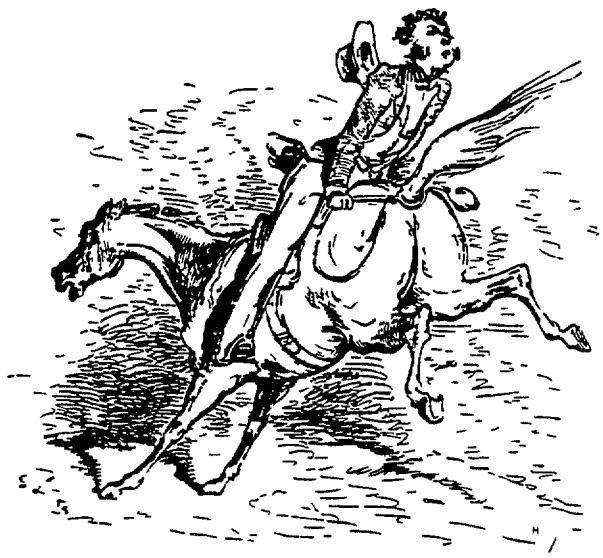
When is a holding company not a holding company? For purposes of the Public Utility Holding Company Act, the answer may well be when it is a limited partnership

The issue has come to the fore with the recent decision by the Federal Energy Regulatory Commission to approve the wholesale rates for the Doswell Limited Partnership project, a 600 MW two-unit combined cycle generator to be built in Virginia to supply Virginia Power According to several lawyers familiar with ways to avoid the net that PUHCA casts, Doswell presents a classic example of how a limited partnership can work to prevent a project from falling afoul of the act

What makes Doswell a classic is the simplicity of its organizational structure Doswell Limited Partnership consists of just two partners The general partner is Doswell Limited I, incorporated in Delaware The only limited partner is Doswell Limited II, incorporated in Delaware

Doswell I and Doswell II are wholly-owned subsidiaries of Diamond Energy Inc Diamond, in turn, is a wholly-owned subsidiary of Mitsubishi Corp , the U S subsidiary of the Japanese industrial and trading giant Diamond Energy Inc also is developing three other nonutility generating projects These are

—Diamond Paris Cogen Inc , a 213 MW plant under construction in Texas Diamond Paris Cogen Inc is one of the general partners in the partnership



Doswell birthplace of Secretariat and an intriguing limited partnership

Inc is one of the general partners in the partnership
—Dexzel, Inc, a 29 MW cogeneration project in Kern County, California
—Moose River Energy, Inc, a wholly-owned Diamond Energy subsidiary, which is the general partner in a project to develop a 19 MW wood-fired cogeneration plant in upper New York state

According to Eric Silverman, who represents Doswell on PUHCA issues for Milbank, Tweed, Hadley & McCloy in New York, "You have to use these kinds of structures to try to comply with the Holding Company Act" The limited partnership, he said, is a mechanism "to separate voting control from economic interest"

Says another PUHCA expert, the trick in a limited partnership is to vest the general partner with less than 10% of the voting securities The limited partner, who has the bulk of the voting stock, does not have management control over the project "Except for certain extraordinary events," said Silverman, the limited partners can't call the shots in the limited partnership The Ocean State Power project in Rhode Island, in which J Makowski and Associates is general partner, also uses the limited partnership structure

In Doswell's case, said one PUHCA practitioner, the limited and general partners are, in essence, the same "It is meaningless to argue that Diamond Energy won't be calling all the shots," he said "They *are* Doswell, both I and II"

Doswell Limited Partnership came into existence after a December 1986 solicitation from Virginia Power, seeking 700 MW of intermediate and peaking capacity One successful bidder was Intercontinental Energy Corp, which proposed to build two 300 MW gas-fired combined cycle units The project was going to be a cogeneration deal, and Virginia Power signed an agreement with Intercontinental in 1987 But Intercontinental's steam host arrangement fell through and Intercontinental assigned its purchase agreements with Virginia Power

to Doswell last June

Doswell applied to FERC for approval of initial rates late last year, as an independent power producer, not a cogenerator That distinction is important, according to Steven Burton, general counsel for Sithe/Energies, a French-backed New York independent power producer Cogeneration project are exempt from PUHCA by statute

The limited partnership is ' pretty unsatisfactory for most investors," said a Washington lawyer familiar with PUHCA cases "They don't want to put their money in unless they have management control It is a bizarre way to do business"

Nevertheless it is a structure that is increasing in popularity Of the six developers Virginia Power selected from its 1986 auction, one (NB Partners Limited, a 73 MW coal waste facility) started life as a limited partnership and three others, including Doswell, became limited partners

According to Burton, the limited partnership arrangement has advantages beyond protection from PUHCA "It protects liability, and has favorable tax consequences," he said Burton added that 90% of the recent nonutility generating projects he had seen recently were set up as limited partnerships

Unless the 1935 Holding Company Act is changed, said Milbank, Tweed s Silverman, you have to use these kinds of structures to comply"

—*Kennedy P Maize*

The Color PURPA

Midland Gets FERC's Blessing

Midland Cogeneration Venture, the nation s largest cogeneration plant, has started out the decade on a roll with FERC, receiving recertification in January of its QF status over the objections of Michigan's municipal utilities, and assurance in

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March that its QF status will remain after it completes a sale-leaseback transaction FERC-watchers disagree on whether the Commission's actions are designed to boost the morale of the cogeneration industry, bankers on Wall Street, or both

Not feeling uplifted are the State of Michigan and the Michigan Municipal/Cooperative Group, who have asked FERC to revisit the question of whether MCV is really a QF, contending that the cogeneration plant is controlled by CMS Energy, parent of Consumers Power, and that it is a "fiction" that Midland is now an independent plant

Independence a 'Fiction'

They argue recertification means FERC is accepting "the transfer of what should be a Consumers Power rate base plant to an affiliated company, and the sale back to Consumers Power of electricity at rates that are plainly excessive under the Federal Power Act" They go on to say "by ignoring the limitations of PURPA, which prevent utilities from owning or controlling cogeneration facilities and collecting PURPA rates, the Commission discourages new independent generation, invites severe adverse consequences to the Michigan and national economies, and ignores its Congressional mandate to protect consumers against monopoly power and excessive rates"

Late last year, the Midland Cogeneration Venture asked FERC to recertify its 1,340 MW gas turbine-fired cogeneration facility, constructed in part from Consumer Power's abandoned Midland nuclear plant, as a QF under PURPA MCV also asked for a temporary waiver of certain operating and efficiency standards

FERC granted the waiver and recertified the facility on a 4-0 vote, saying that since Congress charged the Commission with encouraging qualifying facilities,

"we cannot ignore the fact that this facility is the largest cogeneration facility ever to seek certification from the Commission in the 10 years since our PURPA regulations have been effective," and that "an unfavorable decision here could realistically affect the capital markets' perception of the risk of this industry" That could mean, according to FERC, "capital costs for alternate energy projects would rise to compensate for the additional risk," which "in turn could result in efficient qualifying facility projects not being built"

While FERC acknowledged there were issues associated with the plant that might be worth scrutinizing, such as whether Consumers Power would obtain profits it might not obtain without the existence of MCV, the Commission limited its review to determining whether, under the ownership and technical regulations, the MCV facility qualified for PURPA benefits The Commission said, "we do not mean to suggest that by virtue of finding these matters irrelevant to this proceeding that we are casting a blind eye to the situations noted by the intervenors" It is, said FERC, "a question of pursuing any potential remedies in another forum"

No Blind Eye

FERC says in its order that the plant was originally proposed as a rate base plant, but "pursuant to its desire to effect what it freely acknowledges is in effect a salvage operation, and subject to the constraints imposed by the Michigan Commission, Consumers Power via MCV constructed a partnership and facility that complies with the Commission's regulations," and that ' the fact that qualifying status will relieve the facility of regulation that Consumers Power might otherwise face were it a part of the utility's rate base is irrelevant That is a benefit conferred on such facilities by section 210 of PURPA," says FERC

The Commission's order also states

we cannot ignore the fact that this facility will make productive use of assets intended to be used in a cancelled nuclear unit

Whether the value is between $1.2-$1.5 billion as determined by the non-Consumers Power partners, or some lesser value, there can be no argument with the fact that the value of these assets is significant

FERC Couldn't Waste Assets

FERC says "we simply do not see how the waste of these assets can be in the interest of this Nation," and while there is no assurance denying the waiver for MCV would lead to unproductive use of the assets, the Commission indicates "we are unwilling to take this risk given our responsibilities to ensure the Nation a reliable supply of power" The Commission goes on to note a "modest positive effect" on employment during plant operation and that MCV will burn "an environmentally clean fuel"

Consumers Power said the Commission's decision "vindicated" the way it had structured the MCV project (see *TEJ*, October 1989 for background) MCV President and CEO Rodney Boulanger called the action "important for financing reasons"

But the Michigan munis see grave consequences from FERC's decision They charge "legitimate cogenerators in Michigan have claimed that Consumer Power's economic desires to further MCV have resulted in its refusals to deal with them, thereby freezing out legitimate alternative generation, and that FERC s approval of MCV is likely to "lead other utilities to seek to spin off existing plants to affiliates, add steam facilities, and claim that they are entitled to treatment similar to that accorded MCV The result would be to siphon off capital, which otherwise could be used to develop legitimate cogeneration, and to encourage market manipulation"

As for the part of the transaction through which Consumers receives $1 5 billion in cash from MCV for the Midland nuclear facilities, the state and the munis

complain that money "is nothing more than a lump sum payment to Consumers Power of anticipated profits from sales at PURPA rates," a cost that ' will ultimately be borne by industry and residents of the state of Michigan" They add "Given the bonanza to Consumers Power inherent in the recertification approval, this decision will not be an encouragement to additional, alternative generation to that constructed by utilities Rather, it will likely pave the way for economic windfalls as utilities seek to create affiliates to buy existing, depreciated generation and sell that generation back to themselves under contractual guarantees at above regulated rates" "Nothing less is at stake," say the state and the municipals, "than a *de facto* deregulation of a major part of electricity generation"

"De Facto Deregulation"

They argue that FERC's MCV order "will give encouragement to utilities to give up corporate opportunities to affiliates in order to avoid both federal and state regulation of utility activities" and that FERC "has now written a road map, an open invitation, for such regulatory avoidance behavior and market manipulation" Unless rehearing is granted, the Commission s decision will invite other utilities to interfere improperly with the development of independent QFs" and will send ' purchasing utilities the message that form, rather than substance, will govern the Commission's findings on ownership and control"

FERC's order in early March recertified the plant in light of a proposed ownership change as a result of a leveraged-lease arrangement for permanent financing of MCV Investors, including two affiliates of electric utilities and an affiliate of Consumers Power, would purchase the facility and lease it back to MCV

Boulanger said MCV was pleased' with FERC s ruling on the proposed sale-leaseback transaction Commercial operation of the MCV is expected in late March

Meanwhile the Michigan PSC, which in 1989 barked about self-dealing in two separate orders, but did not, according to critics, follow up with much regulatory bite, ruled late last year that CMS could purchase up to 870 MW of power from MCV instead of the 638 MW limit previously imposed That ruling provoked positive comment from Wall Street analysts and raised CMS stock prices It was a change from previous PSC policy which had restricted the amount of cogeneration capacity a single project could supply to Consumers Consumers has appealed parts of the order dealing with a backloading requirement for gas-fired plants and a PSC decision not to raise the payments to MCV any higher than 3 77 cents per kilowatt-hour

—*Susan L Whittington*

Troubles in Bidville?

Ripples in Virginia's New Wave Bid Lab

Virginia's competitive bid laboratory is churning out regulatory dilemmas Groundbreaking rulings on Doswell, the state's first IPP, issued from both the Virginia State Corporation Commission (SCC) and FERC earlier this year, and the state's regulators are now pondering a hearing examiner's recommendation that they increase their oversight of Virginia Power's avant-garde capacity planning and acquisition process

The SCC in February approved a request by Doswell Limited Partnership to build a 650 MW gas-fired generating plant near Doswell, Virginia, the output of which will be sold to Virginia Power In that proceeding, the Commission had to consider for the first time what reporting requirements to impose on an IPP

The SCC decision, which requires Doswell but not its general partners to file financial information like other public utilities, will apply also to Commonwealth Atlantic, the Long Lake Energy and

Mission Energy partnership that aims to build a 240 MW generator in Chesapeake, Virginia, an SCC spokesman said The application to build that project, one of those selected in Virginia Power's 1988 solicitation for generating proposals, will be considered in May

Virginia Power has been at the forefront of the trend to secure power supplies from nonutilities through competitive bid But what appeared to be the panacea for high-risk, capital-intensive utility construction programs may have some unpleasant side effects for long-term system reliability and cost, according to a hearing examiner's report, which was spawned in hearings on Virginia Power's application to build some CTs of its own

"The Company's decision to rely mainly on nonutility generation for capacity additions has reduced the Commission's oversight of Virginia Power's capacity planning and acquisition process," the report states According to a staff witness in the proceeding, Virginia Power has contracted for over 3,900 MW "without a public hearing and intervention by interested parties " Of paramount concern is what the hearing examiner called "the Company's adamant refusal to admit, at least publicly, that its capacity planning and acquisition process is experiencing problems " The report said the Commission needs to consider the appropriate mix of utility versus nonutility resources

—*Sonya Bruce*

Grand Canyon Days

Blowing Smoke Over Park Visibility

The little-noticed issue of visibility in national parks is picking up steam in Washington, driven by two ambitious congressmen, two warring agencies inside the U.S Department of Interior, and a recent General Accounting Office report The issue could represent a multi-billion-dollar headache for electric utilities

Just ask Salt River Project, the Phoenix-based public power agency that operates and owns a piece of the 2,250 MW coal-fired Navajo power plant in Page, Ariz , some 50 miles north of the Grand Canyon If Salt River is unable to persuade the Environmental Protection Agency and the National Parks Service that the plant is not polluting the pristine canyon, Salt River will have to retrofit the giant plant with a flue gas scrubber Salt River estimates the scrubber will cost $1 6 billion EPA says the cost will be more like $4 4 billion

The Park Service push for EPA to regulate the plant is not without irony, since its sister agency, the Bureau of Reclamation, owns the biggest single hunk of the plant, 24 3% BuRec disputes the scientific experiment the Park Service has used to support controls on the the Navajo plant, called the WHITEX experiment Salt River is funding its own study, to the tune of $10 million, in an attempt to prove WHITEX wrong The answer to the scientific dispute should be in by early next year, including a National Academy of Sciences review of the issue

The dispute between the two Interior agencies has caused considerable embarrassment at the department and mirth among its many critics in the West For example, a recent BuRec letter to EPA on Department of Interior letterhead, bore a disclaimer "Some material included in the Navajo Generation Station information package may not necessarily reflect the views of the United States Department of Interior"

The broader issue of visibility impairment in other parks got a boost in early March when the GAO issued a study done for Rep Mike Synar (D-Okla), chairman of a House oversight subcommittee The study found EPA has done a bad job implementing the ' prevention of significant deterioration" program to protect pristine ("Class I") areas The report said the Parks Service has done the best job with the PSD program, while EPA has performed poorly at best

Synar is a tough, smart young lawmaker who is moving up in the House Democratic leadership At his March hearing on park visibility, Synar was joined by Rep Ron Wyden (D-Ore), another savvy young lawmaker who is eyeing a Senate bid one of these days Wyden has an amendment on park visibility he wants to introduce during House deliberations on the Clean Air Act Both Synar and Wyden are members of the committee In a statement accompanying his amendment, Wyden indicated he has in mind a broad attack on park visibility, not just targeting specific point sources

EPA's program, Wyden complained, "deals only with 'plume blight'—pollution that can be directly traced to one or two sources EPA put off attacking the more pervasive problem of regional haze " Wyden is expected to slip his amendment into the House version of the Clean Air Act with little controversy There is no companion provision in the Senate version, which, in fact, re-

The seductive promise of clean air in national parks—a matter of perspective

peals the PSD program at the behest of Western lawmakers If both versions pass, it will be up to a House-Senate conference committee to decide the issue

—*Kennedy P Maize*

PUC Deals Setback to Ute

A Long and Winding Road to Merger For Colorado G&Ts

The proposed merger between Tri-State Generation & Transmission Association and Colorado-Ute Electric Association has run aground on the rocky shoals of a preliminary rate decision from the Colorado Public Utilities Commission

While the G&Ts were negotiating a merger agreement to send to their boards for a vote in April, the PUC was determining that Ute should be denied a rate increase needed to make the deal hold water Recent efforts by the two G&Ts to work with Colorado's principal investor-owned utility, Public Service of Colorado, could yet bear fruit and rescue the merger Public Service has an agenda in the possible co-op reshuffle and could well end up a winner itself, with the PUC's help

At a special public meeting on March 8, Commissioners Arnold Cook and Ron Lehr directed PUC attorneys to prepare an order setting Ute's rates at 42 24 mills per kWh (the G&T was seeking 48 36 mills) The commission also said it would hold Colorado-Ute's feet to the financial fire to force a sale of excess capacity It denied all costs associated with surplus generation, and both commissioners admonished Colorado-Ute and its members for seeking a hefty rate hike without demonstrating a willingness to put their own money into solving the G&T's enormous financial problems

A source at the meeting said Lehr told Colorado-Ute attorneys that the testimony of their witness, Ed Grange, had helped him determine the G&T deserved no relief Grange, who manages Holy Cross Electric in Glenwood Springs, testified that he would not put more equity into Colorado-Ute, despite the fact his co-op had the reserves to do so Lehr said Colorado-Ute "is losing its shirt," and it should sell assets even if that means "a fire sale" Cook told those present he would not be held hostage by the threat the Commission's action could throw a monkey-wrench in the merger discussions with Tri-State or send Colorado-Ute into bankruptcy

The commissioners warned Colorado-Ute not to come back for more revenue before it put its house in order and said they would call an immediate hearing if the G&T attempted to raise rates again Under Colorado law, the PUC has no authority to suspend a G&T rate, an increase may be imposed at the co-op's discretion, but can be investigated by the PUC

Commission spokeswoman Barbara Fernandez counted Colorado-Ute s largest member, Intermountain Rural Electric of Sedalia, and Southeast Colorado Power of LaJunta among those who agreed with the PUC's announced rate decision Stan Lewandowski, manager of Intermountain since 1974, has been a vocal opponent of the merger and of Colorado-Ute's rate increases Intermountain bought power from Public Service of Colorado until 1981, when studies indicated a switch to Colorado-Ute would be advantageous The PUC announcement tracked with Lewandowski's assessment of what should happen to the distressed G&T

Ute's problems stem from "substantial mismanagement and deception," Lewandowski contends While erroneous growth forecasts and the downturn in Colorado's economy in the early 1980s

played a role in Colorado-Ute's problems, he argues that the G&T's former management deliberately withheld information from the board and played "accounting gymnastics" to try to cover the problems that have now brought Colorado-Ute to the brink of bankruptcy The directors are not to blame for what they didn't know, Lewandowski said, but once the situation was uncovered they still dragged their feet "It appears Colorado-Ute is attempting to keep things just as they've been—spend money, not cut staff, not sell assets They want their cake and to eat it too," he said

Intermountain and Delta Montrose Electric, which has been neutral on the merger, are pressing a lawsuit that would force the G&T into receivership and liquidate its assets The case, which is scheduled for trial in July, is one of three legal actions Intermountain has taken to try to put Colorado-Ute out of business and recover some damages "It s like shooting a bear,' Lewandowski said of the coterie of lawsuits challenging the G&T ' You keep filling it with bullets, but it won t go down '

Enter Public Service of Colorado The PUC may just have had a big enough gun to put a trophy up on the wall of Public Service Co once the commission puts ink to its rate order The company, which at one time made an offer to buy Colorado-Ute, was talking to Colorado-Ute about acquiring the Craig 3 coal-fired plant until late February Sources say the company was aiming to buy the plant, but Colorado-Ute interjected terms for a 10-year lease which caused Public Service of Colorado to end the discussions

The company has said it would enforce its $200 million contract for a power sale to Colorado-Ute, which includes a $31 million take-or-pay capacity requirement, split between 1990 and 1991

The company told Denver newspapers after the commission's tentative rate decision was announced that it would be interested in resuming discussions with Colorado-Ute, but only if Ute is ready to talk turkey

The merger between Colorado-Ute and Tri-State was on track until the Commission lowered the boom A feasibility analysis by Stone & Webster delivered at the end of January, concluded the consolidation would save members of both G&Ts $293 million from 1990 through 2004, compared to what it would cost if the two continued to operate individually Tri-State's members, however, would get the short end of the benefits stick if the merged entity used an average wholesale power rate for all customers, and the consultant suggested an alternative such as a split rate for the first several years

The G&T's eight merger task forces have completed their work and none of the final reports uncovered any fatal flaws in the proposed coupling Eleven of 14 managers in the Colorado-Ute system supported the merger "I've been negotiating this as our future," said Dave Potter of LaPlata Electric, who chairs the G&T

The Colorado PUC order dealt Ute s merger hopes a blow

managers group and is a member of the merger rate task force "I figured if we can't cut a deal better than bankruptcy, why merge? But what's on the table is better," he said, noting the Stone & Webster study projects rates would go down over the next decade for Colorado-Ute's members if the two G&T's merge And the figures in the analysis appear to be conservative, Potter said

Despite lousy weather, 150 of Tri-State's managers and directors journeyed to Denver February 20 for a full membership meeting on the merger The five-hour session was reportedly dominated by frank talk and tough questions, but ended on a positive note Ron Carey, general manager of Tri-State's largest member system, Poudre Valley REA in Fort Collins, Colorado, said his board was leaning toward merger after the membership meeting, although not all members were willing to call the union a done deal That sentiment has proved prophetic

The consultant's conclusions and estimated benefits were predicated on a rate increase for Colorado-Ute The PUC directive, which a Commission spokeswoman said rolls rates back to the July 1, 1989 level, isn't a "merger killer," according to Tri-State's Jim Van Someren, but it sends the G&Ts back to the drawing board to refigure economic benefits, if they still exist

Colorado Ute has operated with a loan from Tri-State while the merger was being explored Without higher rates, Colorado-Ute cannot cover its expenses A spokeswoman at Colorado-Ute acknowledged "we don't know" where things stand in light of the PUC action After the flaying at the PUC, members of both G&Ts were reportedly headed straight to Washington, DC to talk to the Cooperative Finance Corporation and REA, Ute's major creditors

By mid-March, discussions with Public Service Co had also recommenced, this time with both Ute and Tri-State involved If Colorado parties are skilled in the 20th century art of pursuing win-win solutions, everyone could get the essence of what they want

Public Service could get Craig 3 without Ute's earlier time restrictions, as well as the recalcitrant piece of Ute's wholesale load Ute and Tri-State could get the merger they've been pursuing and, with an asset sale, lower rates in the bargain

—*Sonya Bruce*

The commission's order suggests Colorado-Ute has been a bit fast and loose

Integrated System, or No?

Probing the Bounds of Entergy Prerogatives

The Entergy holding company system is recovering from the blues of its Grand Gulf nuclear construction program, with plant 1 finally allocated to its affiliates and plant 2 terminated and written off But a little noticed proceeding at FERC is stirring up new dust

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Last October, Entergy Services filed a coordination agreement with the commission in Docket No ER 90-38 The agreement is predicated on a transfer of two generating units (one coal-fired, one oil- and gas-fired) from Entergy's Arkansas Power & Light affiliate to a new "independent power" affiliate—Entergy Power, Inc —but the FERC filing does not seek FERC's approval for the transfer In fact, Entergy asserts that FERC has no authority with respect to the asset transfer If anyone does, it's the Arkansas Commission or the Securities and Exchange Commission, says Entergy

The FERC filing has drawn interventions from the City of New Orleans and the Arkansas and Louisiana commissions, among others There is also a parallel proceeding at the Arkansas Public Service Commission on the asset transfer issue

"It's a question of fairness," says Paul Nordstrom, who represents New Orleans, served by Entergy affiliate New Orleans Public Service, Inc (NOPSI) Though the city, Entergy, and NOPSI are said to be deep in discussions over selling NOPSI to the city on some mutually agreed basis, New Orleans has a concern about the impact of removing the AP&L coal plants from the integrated holding company's resource "stack."

"There's a short-run and a long-run problem," says Nordstrom "In the short run, with these plants out of the stack, other more costly plants will drop in The transferred plants would be available to the system only to the extent Entergy Power [the new "independent power" affiliate] couldn't make a bigger profit selling the energy elsewhere

"In the longer run, these resources are going to have to be replaced and there will be a cost connected with that We don't think the consumers come out of

this very well," says Nordstrom

FERC had been scheduled to take up the matter at its March 15 meeting, but the item was pulled from the Commission agenda at the last minute

Section 201 (b) of the Federal Power Act denies FERC jurisdiction over facilities for the generation of electric energy, "except as specifically provided" in Parts II and III of the Act Section 203 of the Act gives FERC jurisdiction over disposition of property

FERC's general counsel seems ready to approve a hands off posture for the Commission, in spite of the ambiguous language of Sections 201 (b) and 203

Nordstrom says if the Commission goes along with the filing and disclaims jurisdiction over the transfer, New Orleans will consider its remedies on appeal and in other forums

There's at least one more piece of the puzzle Arkansas Public Service Commission approval of the plant transfers This is by no means a settled issue, since Arkansas Power & Light proposes to sell the units to fellow Entergy affiliate Entergy Power, Inc at depreciated book value Arkansas industrial consumers are concerned that this is a steal, and that AP&L should get the far greater market value they believe the plants could command in the open market Entergy says there is little market for the plants and that the Public Utility Holding Company Act requires that interaffiliate transfers be made at actual cost

These issues cut deeply into ground many utilities want to plow in a less structured, more competitive bulk power industry Whether this proposed transfer makes good public policy or not and who will get the final word about it—FERC, the Arkansas commission, or the SEC—remain to be seen

—Robert O Marritz

Transmission—the Heart of the Issue

In the second and final portion of our interview, Charles Stalon expresses some strong views about transmission and its central place in the bulk power picture, and suggests a surprising alternative for the industry to ponder

Charles G Stalon, interviewed by Roger Odisio

***Charles G Stalon** is a Director of Putnam, Hayes & Bartlett, Inc Prior to that, he served as a commissioner on the Federal Energy Regulatory Commission from 1984 to November 1989 and as a commissioner on the Illinois Commerce Commission from 1977 to 1984 Dr Stalon holds a B A degree in economics from Butler University and M S and Ph D degrees in economics from Purdue University **Roger Odisio** holds a B S in business administration from Duquesne University and a Ph D in economics from the American University For the past 11 years he has been a staff economist with the Federal Energy Regulatory Commission*

RO: The FERC Transmission Task Force Report emphasizes that without access to long-term firm transmission service competitive markets for electricity will not get a full chance to develop

CS: That is correct There is a possibility of some constructive rivalry among generators without transmission access But I don't see that it could ever amount to very much Surely we could not talk about a competitive generating industry without transmission access

RO: Let's talk about sequence Would you go so far as to say that transmission access—I am using the term "access" when I mean both access to the current grid and building additional capacity on demand—is a "prerequisite" for general deregulation of prices? Is that too strong a term? What sequence do you see as preferable?

CS: I made a cut at that, but it was not entirely an analytical cut To some extent I made a strategic cut that access has to precede complete price deregulation in bulk power markets

In fact, I went a little further on the strategic point For a regulated monopolist, access has to precede great *flexibility* in pricing

I call that a strategic cut because analytically I can imagine creating intense enough competition among established utilities with access for themselves, but not for independent power producers, where one could make an argu-

ment that no one utility has any control over price A market dominates the price But strategically I found it difficult as a public policy maker to say that I could ever repose the public confidence in that situation, without the possibility of entry

It is fundamentally entry that is the key to disciplining prices No matter how intense competition is between established players, if they are sophisticated enough to say that it is too difficult to collude on price—we aren't going to collude on price, but we can collude on expansion—it is only entry that can block that

You may even have perfect competition in the pragmatic sense that each player is a price taker, but price remains above that level necessary to squeeze out monopoly rents because firms can operate in a consciously parallel manner to limit capacity expansion

RO: In the Transmission Report, you said that firm transmission should be thought of as a multidimensional service that includes guaranteed access rights, an obligation of the utility to build additional capacity, customer rights to resell the service, and perhaps a customer right to joint ownership of the grid Concerning particularly the first two, given the limitations on FERC's ability to order access or require a utility to build transmission, how do you see these things being accomplished?

CS: Under current laws, the only way I can see that the FERC could accomplish its objectives is with conditioning power The electric utilities want some things that FERC can refuse to grant unless it simultaneously gains something in exchange

That is a well-established policy on the gas side, though the courts have mixed feelings about it But on the electric side we haven't done as much of it

Utilities want pricing flexibility I think the Commission ought to get something in exchange for giving it to them That was part of the strategic element in my decision that competition could not be adequate without access The other, more defensible part in terms of abstract logic, was the point I made earlier Unless you can assure entry, it is very hard to persuade yourself that you are going to have a competitive generating sector

It is fundamentally entry that is the key to disciplining prices No matter how intense competition is between established players, if they are sophisticated enough, only entry can discipline the market

The FERC could condition the granting of pricing discretion on access As we suggested in the Transmission Report, the FERC could condition a utility's right to make off-system sales or purchases on its *ability*, not just willingness, to provide transmission access and services to other parties

In short, tell a utility that your priorities and preferences for capacity go to the bottom of the list. If you want capacity for off-system sales and purchases, you have to grant the demands of everybody else, and you take what is left That is a great exercise of conditioning power, although I could not say for certain that the courts would tolerate it The question, in fact, comes down to the Commission's ability to defend before the courts a substantial departure from past practice

I was encouraged by the court's response to FERC's Order 436 I have been very depressed by the court's response in some other areas But in the last decade, in those areas where there is a broad mandate, I see the court saying, "Commission, you must be able to defend what you are doing"

The court is thinking of the reasoned decision-making standard, not the objective evidence standard I think that is very desirable, although most regulatory agencies would fail the test badly

It is very difficult for a multimember body to pass that test because it means you must not only agree about what you are going to do, but why you are doing it

If the Commission can survive that test—and I think it can in this

area—and the court will accept that, I think the Commission can pull this off It could condition It could bring about some open access

I have a feeling, however, that this will end up as a battle in the legislature This is an important issue and the utilities who are opposed are making it an important issue

RO: What do you think they will do?

CS: Part of their strategy is to argue that this question is much too important to be decided by a regulatory agency We have a great irony in our society Congress says this is much too complex for us to handle, we are passing it over to FERC And the industry says this is much too big for FERC to handle, we think Congress must decide

I see the argument somewhat the way I see the old states' rights argument There are parties who want the states to take over everything they know the states can't handle, and therefore it won't be done Then there other parties who want the states to take over things they believe the states can do

States' rights has nothing to do with it, the issue is the substance And I think that is true here

Those who argue that this is too important for the FERC may succeed in blocking FERC action, but they have no intention of having the Congress make this decision They just want to block the FERC

RO:

The New York Power Authority chairman, Richard Flynn, suggested recently that a national study should be done to see if new or different transmission linkages are needed to enable more efficient transactions. But to do that you must first investigate existing constraints That seems to be something we know very little about

We have a great irony in our society Congress says this is much too complex for us to handle, we are passing it over to FERC And the industry says this is much too big for FERC to handle; we think Congress must decide

CS: I think it *is* something we know very little about

RO: The FERC had a unique opportunity in the PacifiCorp merger to look at that company's transmission system and determine how it was being used, how it could be used, what is this thing called "excess capacity" that was going to be made available to other utilities Instead it let the company designate its excess capacity Why?

CS. First, if commissioners have little technical ability and don t believe there is much technical ability on the staff as well, or if there is they can't understand it, there is a tendency not to try technical solutions

RO: Couldn't they hire somebody?

CS: Yes, but what are you going to get when you get information back and what are you going to do with it?

So the tendency is to try to work on the company itself

In one sense, the important issue in *PacifiCorp* was not whether there were bottlenecks in the system The important question was, what are the necessary conditions for creating discipline on the merging company so that it will not be able to abuse its control over crucial assets, whether they are in short supply now or in the future?

A survey of crucial capacity shortages would not have gained us very much All we knew at that point, which was important, was we didn't have control of rectifying a shortage if one existed That was a state and utility problem

Our problem was how do we bring regulatory constraints to bear on the utilities and states that drive them to remedy that situation? We have known for quite some time, known in the sense

that we have been told by utilities, that there are bottlenecks in the system

Somebody once pointed out to me that one of the problems in parallel flows of Northwest power coming into southern California is the shortage of certain kinds of capacity in the Idaho area That person insisted that what we really need is more capacity built in Idaho for the benefit of California But its immediate objective would be to alleviate the overloading of lines in Arizona

So what we have is a failure of a regulatory system California has no reason to volunteer to pay for that capacity Arizona is already being forced to build extra capacity Idaho has no incentive to build it There is no mechanism for getting it built

What we chose to do in *PacifiCorp* was say to the company, and indirectly to the regulatory agency with siting authority, you must build capacity to meet demand If you don't, you will have to cut off your off-system sales We conditioned

Many states didn't like that one bit because they saw that we recognized there was a parallelism of interest between the PUC and the utility in the exercise of the utility's monopoly power We were saying, "We are going to get at that parallelism," and we did And I think we did it pretty well

But at that point it didn t make any difference whether there was any excess capacity or not We would have ended up with the same argument, I believe, if the system would have been tightly strained, or whether there had been a lot of excess capacity

RO: Don't you make the question of whether to build, where to build, or how much to build that much more difficult by relying solely on that as the remedy, rather than first trying to determine how the current system can be better used, and to what extent excess capacity exists?

In the transmission area, we have the failure of a regulatory system California has no reason to volunteer to pay for the additional capacity that's needed Arizona is already being forced to build extra capacity Idaho has no incentive to build it There is no mechanism for getting it built

CS: Yes we do And in the Transmission Report we were very conscious of the limited power of the FERC and how the FERC was going to use its limited power to move the industry forward If FERC had greater powers, yes, a different strategy would have been preferred

On the basis of assertions that have been made to me, there is a shortage of capacity in certain parts of the country There is a need for transmission lines There almost certainly are some utilities that know this and are not building because they have a vested interest in not building

In other cases it is not so clear because they have very good arguments "This shortage is temporary and in a few years we are going to equalize generating capacity and we are not going to need the transmission capacity we now have"

While I was there, the FERC never had a majority that could make a long-term plan The majorities were fragile and likely to fall apart at any time You wondered how you were going to make the next step You were very limited in the abilities and power you had You had to do whatever you did within that framework of power

The FERC is a fallback agency The FERC operates in default The system has been in default for much of the time I was there

Moreover, in the DOE Reorganization Act, Congress seemed to suggest that in the future DOE would take the lead in long-term planning DOE would have most of the strategic policy responsibilities But DOE wasn't going to do anything like that So by default it came back to the FERC

Given the structure Congress

has created, however, DOE can resume that kind of power at any time, or Congress could give the FERC that kind of power

Under existing law, the power of the FERC is extremely limited The only real power that FERC has flows from its job of protecting transmission networks under Section 202 of the Act

That instrument could give the FERC a lot more power But FERC has chosen to turn that power over to the utilities to exercise through NERC, the reliability councils It let the utilities create a system of self-regulation

RO: But on the other hand, because of its FPA §203 (corporate reorganization) and §205 (pricing) responsibilities, mustn't FERC take the lead, as it did in the PacifiCorp merger, to see that actions it approves serve the public interest?

CS: Yes But I am reluctant to put too much weight on a merger case because it is something that somebody else initiates You may create a precedent But it is not an adequate instrument for policy making

RO: What is the potential for federal-state cooperation on transmission, as opposed to federal action by either the FERC or Congress? Can a regional body be created that could handle this problem?

CS: It's possible But I don't see it as a likely outcome If we had started thinking about this problem earlier, it might have been a possible solution I say might have been because I still don't know Let me tell you the pattern I am thinking about

In preparing the Transmission Report, I was never able to get to the heart of one important debate I find it difficult to believe that the eastern network and the Texas network—ERCOT—can both be optimal But the people in Texas are very emphatic that ERCOT is the optimal size for an interconnected network The ideal world would be an interconnected network about the size of ERCOT, then connected to those around it with direct current lines

In that case, they argue, you can create mathematically a very quick, real-time model for scheduling and dispatching, you can have everything And while they haven't quite gone that far, they believe they could if they wanted to

They have gone so far as to model a system for an average peak period and an average off-peak period Now suppose we impose transaction A on the system between point A1 and A2 They can tell you almost immediately the losses that will occur in every utility in the system It doesn't take much to go beyond that to get a real-time system

We are a long way from a real-time system on the eastern grid It is such a giant thing So I find it difficult to imagine in the foreseeable future that we are going to break the eastern grid into small units

If we don't, I find it difficult to imagine how you are going to get a regional body to regulate the eastern grid region It has got to be the FERC And even then you have problems because the grid extends into Canada

The same is true of the western grid although we may get a little closer to finding another agency there

RO: Do you see any other organizational possibilities?

CS: Yes I think it's worthwhile to contemplate another possibility which I have proposed for the utilities, not always with dead seriousness since I haven't been able to think through all of the consequences maybe the utilities should be allowed to create their own regulatory body

They have a problem coordinating among regional reliability councils and dispatching centers They are scared to death to have the FERC get involved in that because they understand the appointment process and the technological ignorance of the decision process at the FERC

So maybe they ought to create their own regulatory agency, just as the baseball leagues created their own commissioner because they realized they had disputes among clubs

The baseball leagues had no mechanism for resolving disputes They didn't want them resolved in courts They didn't want them to get into state legislatures

They needed an agency whose first loyalty was to the owners, yet who had power over those owners—under normal circumstance, a king to regulate the barons, created by the barons

History shows that is an unstable circumstance Yet it has worked, although sooner or later you have a battle over who is going to be boss So far in the baseball leagues it has always turned out that the barons have been the boss But they have made very good use of the commissioner

In this case, the utilities may need a commissioner of the eastern network and a commissioner of the western network, who can be very technical, who can hire very technical staff, and who can create ways to escape the appointment process and procedures that cripple the FERC

Moreover, if the utilities who are going to deal with IPPs are smart, they should want to work with a skilled regulator who is not politically appointed—a commissioner of their own After all, a key element in transactions with IPPs is implementing broadly termed contracts With such a commissioner, you don't make him decide things in accordance with judicial models, you *create* the kind of expertise needed to interpret that contract for the benefit of, say, the end user

Let them create their own regulatory scheme and I think utilities would find that a very large number of the tools created by regulators are of value

RO: What limits would you place on the powers of such a commissioner?

CS: Traditional antitrust constraints would have to be imposed That is, where society has said it prefers competition, perhaps in the sale of electric power, the commissioner would not be able to establish prices or even terms of sale

The role of the commissioner would be limited to certain technical areas where established commissions have proven to be deficient For example, the transmission system is complex and we know that established commissions are not good at dealing with technical, complex issues Even when they do have the expertise to deal with them, they do not have procedures that allow efficient use of that expertise

A commissioner could use greater expertise in determining the technical rules for operating a transmission grid, for cooperation among control units, for cooperation among reliability councils, and so on

Perhaps I would also go a little further than that Where prices established by regulatory agencies do not effectively ration capacity,

Those who want to use the transmission systeem should consider creating their own commissioner

so that demand exceeds capacity, maybe such a commissioner should be allowed to enunciate rules for rationing that capacity That is a questionable idea, but at least it strikes me as something that is feasible

RO: Currently, some states are acting on their own with respect to transmission issues For example, Wisconsin has asserted that transmission in that state constitutes a state-wide system and it directed utilities to provide access on that system, as well as to build additional capacity How do you view that kind of an approach?

CS: With great skepticism The division of labor between states and the federal government clearly needs to be rethought The old Federal Power Act "bright line" division doesn't make a lot of sense anymore We have subverted that

I think the division that makes the most sense is for the states to retain firm control over distribution, the feds to take control of transmission and let generation become competitive

That division of labor is neat and clean But it grossly reduces the significance of both federal and state regulation by removing approximately two-thirds of the value added in the industry—the generating sector-from regulation entirely

RO: What you are suggesting—if I could put it in terms of jurisdiction rather than regulation to eliminate the problem of how strictly sectors are regulated—seems to be exactly what the states were opposing in FERC's NOPRs That is, the creation of an IPP industry that would sell to utilities and therefore bring generation under the jurisdiction of FERC in addition to transmission costs State commissions would end up simply regulating distribution costs Didn't that generate a lot of the heat over the NOPRs?

It's possible, though I wouldn't want to bet on it, that some division of labor, even on transmission access, could be worked out between the FERC and the states

CS: It did The states are aware that they are vitally interested in regulating not merely the source of the natural monopoly, but also the source of value added

If one believes that regulation—and I am almost stealing a phrase from Alfred Kahn—has a prime purpose of serving "illegitimate economic demands"—i e , demands that would not be served in a competitive market—then it is not surprising to see regulators defending the preservation of a vertically integrated firm That is where they get the ability to cross-subsidize classes, services, or whatever

Losing the generating sector leaves them with so little value added to play with that those "illegitimate demands"—I wish I had a better phrase—simply can't be met

There are two things that ought to be kept separate, but get intermixed in the debates In addition to the problem I just described, which describes the largest number of regulators, but not the largest states, there is massive distrust of the FERC as an institution

As a state regulator, I had no confidence in the FERC I was hostile to and suspicious of the FERC It was an animal with no sense of direction

It was clearly not going to be working for the interests of the citizens of my state It was very likely to be working for the interests of the states that had important members on the powerful Senate committees Or who knew what? But it was clearly not going to be working for what I considered important Interestingly, I was willing to tolerate a similar performance out of my fellow commissioners, but not out of the FERC because I could get them to line up with me against the FERC

Mix those two things together, the lack of credibility of and the hostility towards FERC, with the desire to retain control of as much value added as possible, and you

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get almost every state commissioner in the game

I think that problem needs to be brought out in the open and debated I fear that more damage will be done to the kind of partnership that has to be created by refusing to talk about this problem than by bringing it out in the open

It may well be that if you bring it out in the open, I would find my position beaten I don't know

But I have a feeling that the conflict between the FERC and the states is going to be unnecessarily intense because it is not going to be talked about

RO: Do you see any possibilities at all for federal-state cooperation?

CS: I think it's possible, though I wouldn't want to bet on it, that some division of labor, even on transmission access, could be worked out between the FERC and the states

Let me give the old, tired example We had a division of labor between the states and the federal government over long distance telephone calls If a call was placed from Chicago to Springfield, Illinois it was an intrastate call Nobody pretended that the call went over lines within the state of Illinois It may have been routed through San Francisco and back We knew that AT&T was routing the call according to patterns at the time, however they routed it But the division of labor facilitated regulation and it worked moderately well

If you have a single agency in control of large areas, you might be able to create a division of labor where the states could regulate certain transactions and the FERC others and make the system work

The difficulty is you need a monopolist with efficiency objectives that don't pay much attention to price signals because, in order to make this shared system work, you have to have a cost allocation system that is pure fiction

The FERC usually uses the words "fairness" and "equity" as a cover for preserving the status quo

But if a compromise between the states and the federal regulatory agencies is absolutely essential, I would not rule out one like that

RO: Perhaps one of the problems too is that state and federal regulators seem to have different views about both the kind of competition likely to result from implementation of ideas in the NOPRs, and perhaps the Transmission Report, and its likely benefits The states can see very clearly some of the problems that might result, but they don't see as many benefits

CS: I think you are correct If I were to focus on one unending source of conflicts between state and federal regulators, it would be the fact that they have different objectives

As a state commissioner, I had a great deal of knowledge that I didn't have, and never would have, as a federal regulator That is, I could predict with greater confidence the consequences of my decisions on the various classes of citizens in the state—poor versus rich, whatever

And once one can do that, it is very tempting to modify a narrowminded pursuit of efficiency with equity considerations

The example I have used repeatedly was a decision of the Illinois commission to order utilities not to cut off people during a couple of cold months in the year for failure to pay their utility bills

We did that on very simple humanitarian grounds As a commission, we were not willing to impose on utilities a set of rules which required them to cut off those people And so in effect we said, postpone the cutoff until the weather warms up in the spring

It was a very inefficient way to accomplish a social objective We recognized that and we called on the legislature to do something to deal with this massive social problem The legislature finally did act It ordered us to continue doing the same thing In effect the legislature was saying we can't do any better than you are doing There are political realities beyond our control that we must

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bow to, so go ahead

As a FERC commissioner, I never had any temptation to do anything like that I never had a choice where I could say I am helping the poor or the rich.

FERC decisions were made in the abstract with no real understanding, and no capability of knowing, the income distributional consequences

Consequently, as a FERC commissioner I found it very easy to take a narrow view "This process should seek efficiency"

That is the only objective that I can find defensible I can't think of an equity argument here that is not hypocritical and really nothing more than an attempt to preserve the status quo

The FERC usually uses the words "fairness" and "equity" as a cover for preserving the status quo That is, they define equity as not depriving anybody of a beneficial interest in the status quo without elaborate due process

That tendency is going to last forever The states are always going to give equity considerations a higher priority than will the FERC

RO: To the extent a commission substitutes competition for regulation, control can be lost over equity questions Are you saying, then, that this is a basic reason the states are less enamored with competition?

CS: Yes, I think that's right, because many of them do have equity considerations Many states have no choice

There is a law in Illinois that no citizen can be required to pay more than X percent of his annual income for utility services There is a law in California that lifeline rates shall be established Many of these purported equity considerations written into law assume the existence of strong monopoly power and large value added If you take away the value added

and monopoly power, they collapse

RO: Transmission pricing is a very tricky concept What direction would you want to go with it?

CS: That question should be divided in two spot pricing of services versus long-term pricing

I am convinced that in the long term, for risk bearing purposes, it is desirable to have two-part tariffs, where the person who demands service bears some of the risk of expanding capacity

Those prices ought to reflect the marginal social cost of providing those services, which is probably going to be higher than embedded cost, although it need not be

Then for short-term energy transactions, we need essentially a spot market price, or something that approximates it (it doesn't have to be all that precise, but the better, the better)

Having said that, it is not clear how you approximate the long run marginal social cost Nor is it clear how you approximate short run market prices

There are difficult conceptual problems, which boil down, as we tried to state in the Transmission Report, to "to what extent does incremental cost approximate long run marginal social cost?" And if it doesn't, under what circumstances might you argue that it is a better approximation?

I recall an example from my teaching days many years ago There is an old canal which is still in use After it folded as a transportation system, the city water company took it over and used it to carry water from a reservoir north of the city to a processing plant in the city Many years later, the city sold the water company to a private company

The private company insisted that the appropriate valuation of the canal was reproduction cost

It raises an interesting question What is the marginal social cost of moving water? Even if you conclude that a canal would be the optimal technology, should you recognize the cost of the canal in

the replacement cost? Or should you treat the canal as a river, a gift of nature, and treat it differently

I think those are very serious questions and we have posed a few of them in the Transmission Report, but we didn't really try to come to much of an answer

Utilities' concept of incremental cost or embedded cost, whichever is higher, may turn out to be a tolerable approximation I don't know That problem needs a great deal more work.

RO: That is very interesting If an asset has a particular life, that is, if it depreciates and needs to be replaced, it would be hard to argue that you don't need to consider the cost of the asset

CS: Then I think you have to consider the cost of the asset That is exactly right

But you get into a difficult problem What is the lifetime of the asset? In a world of positive discount rates, something that lasts a hundred years is forever It is no different from an act of nature

You get into some very sticky areas, and while in principle, as an economist, you can lay out an optimal solution, in many cases I don't know how you can reconcile some of those principles

RO. There is an interesting statement in the Transmission Report that perhaps *transmission* pricing is a little too flexible, allowing owners to capture some monopoly rents, but the pricing of *wholesale power* is not flexible enough, because there is more opportunity for competition

CS: That is correct and I think that is an important distinction to make If we are correct, there is going to be a multiplicity of power suppliers Yet, there is a sense in which the supplier of transmission service is still a natural monopolist Especially where it is big enough, it internalizes most of the externalities

A logical monopolist is sooner or later going to recognize that the real rents are in transmission services It can get them one of two ways through a bundled service if it is buying and selling, or in an unbundled transmission rate

As its ability to discriminate is limited, it may turn out the only way it can really get them is through control of the transmission service That is where the monopoly is

RO And the ability to require building on demand, if you ever get to that point for the industry, will not eliminate the natural monopoly quality of transmission

CS. No It won't eliminate the natural monopoly, but it ought to discipline it It ought to limit its exercise In a sense the natural monopoly comes from the technology It is the exercise of it that we are trying to discipline and constrain

Mistakes in pricing may not be very serious in an allocation sense if they are random and correctable in time They become noise in the system that we would like to get rid of, but tolerable They are systematic mistakes, that bring in expensive assets at the wrong place or at the wrong time

To some extent we had this problem in the electric utility industry in the 70s, although there were other things at work The utilities were systematically *underpricing* energy—they still are—and inducing forecasts of 7% growth

They saw the costs rising, they just assumed there would be no demand elasticities associated with it I don't know whether you call that stupidity, but it was certainly mispricing because if you saw that costs were going up, then it made sense to raise your rates to reflect marginal social cost

However, that was very hard to do politically because of the regulatory scheme and its embedded cost-based revenue requirements ■

Using Existing Tools to Pry Open Transmission—a New England Proposal

Despite New England's "tight" NEPOOL arrangement, most new resources lack readily available access to buyers on a regional basis This proposal would plug a gap in the NEPOOL agreement by providing needed transmission service on a regional basis

Susan F Tierney

***Susan Tierney** is a commissioner of the Massachusetts Department of Public Utilities and chairman of the transmission task force of the New England Governors Conference Power Planning Committee Dr Tierney holds a Ph D and a Masters degree in regional planning and public policy analysis from Cornell University She is a member of the NARUC Conservation Committee She previously served as director of the Massachusetts Energy Facility Siting Council and as assistant professor at the University of California at Irvine The views expressed in this article are those of the author alone*

The national debate on electric transmission policy is intensifying This is in part because the traditional terms of pricing and access to the bulk power transmission system are frequently inadequate to the task of broader integration of utility and nonutility electric generation into the bulk power market

This debate is in especially high gear in New England, where the need for new power resources is more immediate than in other parts of the country Calls for reform of existing transmission rules have come from the region's regulators, who have recently put forward a simple but sweeping proposal intended to open access to the region's transmission system at cost-based rates

This article describes this proposal, how it fits regional needs, and what New England regulators are doing to see that it—or something better—is imple-

mented in our region While the proposal builds upon existing concepts in our region's power pooling agreement, the same general tools and concepts may be applied elsewhere

I The Transmission Debate

Along with the developing movement to restructure certain aspects of the electric industry by promoting bulk power competition, transmission issues have begun to draw the attention of regulators, utilities and nonutility developers

Transmission access and pricing problems have become increasingly apparent and thorny as various states and the federal government have taken initial steps to ensure that fair competition develops in electric energy markets As a starting point, most parties agree that transmission demonstrates the essential features of a monopoly service [1]

Many key players—certain transmission-owning utility companies among them—also recognize that lack of nondiscriminatory access to transmission as well as pricing problems impede competition in electric supply markets [2] These are not the only impediments, however Perhaps the greatest underlying impediment is the fact that control over transmission increases the value of generation for those transmission owners that have excess power to sell and gives great leverage to those that want to buy

The economic value of these effects is very large in relation to the cost of transmission This means that regulators will need to set rules so that transmission is properly priced and made available to various parties on a nondiscriminatory basis and not be used to distort workings of potentially competitive parts of the business

Who are "the regulators" in this case? Neither states nor the federal government has unambiguous authority to ensure the elements of transmission service fair access to the grid, reasonable pricing of its use, and ability to effect its expansion [3] Until such authority is clarified or changed, states and the federal government must use the tools available to them to try to effect fair terms and conditions for wheeling transactions undertaken today

Neither states nor the federal government has unambiguous authority to ensure the elements of transmission service.

Various tools are being used and tested [4]

—The Federal Energy Regulatory Commission imposed conditions on the Utah Power & Light Company/PacifiCorp merger to try to improve transmission access in the inland West [5]

—Vermont regulators filed a complaint at FERC under Section 207 of the Federal Power Act alleging that Northeast Utilities may be rendering inadequate or insufficient interstate service [6]

—The Wisconsin Public Service Commission has used its certification and planning authorities to bring about coordinated transmission services through, among other things, a requirement that each Wisconsin utility file a wheeling tariff at FERC [7]

—States have used their authority to require wheeling as a service necessary to implement the Public Utility Regulatory Policies Act (e g, Massachusetts' PURPA regulations) [8]

Until legal challenges regarding use of some of these tools are resolved, or until there is legislative resolution of the gaps and ambiguities in lines of authority between state and federal jurisdictions, considerable risk and uncertainty will surround access to cost-based transmission services—a situation likely to chill the development of a competitive electricity supply market [9]

Absent clearer authority and jurisdictional boundaries, the national debate on transmission access and pricing is being played out in miniature in New England in various arenas First, utilities in the region have themselves been trying to negotiate resolution of some of the thorny access priority and pricing issues, this effort has gone on for several years without resolving the toughest issues [10] Second, scores of interested parties are participating actively in

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the FERC and SEC proceedings reviewing Northeast Utilities' proposed acquisition of Public Service of New Hampshire, for most parties, transmission is the key issue in the cases [11] Finally, New England's regulators have joined together to push for resolution of regional transmission problems, this avenue seems to hold considerable promise [12]

This article describes these activities, focusing on the latter transmission reform proposal Although the particulars of the transmission reform proposal are cast in terms related to New England's coordination agreements, the broad concepts and the consultative process underway in New England may provide models for other regions considering ways to improve the transmission underpinnings of electricity markets in their own areas

II Regional Structure

The New England region is made up of six states with a 1989 summer electric peak load of about 20,000 MW [13] New England's economy, robust during much of the 1980s, has spawned record-breaking demand for electricity even in recent years Though load growth has slowed lately, the industry estimates that New England needs to add new generating or demand-management resources to meet expected needs in the next few years New generating additions have fallen behind demand growth, however [14]

While the six New England states are linked in critical ways, the states are diverse economically, geographically and politically Each is served by various individual retail electric companies, subject to the jurisdictions and policies of separate public utility commissions In fact, New England has an unusually high number of electric companies for a region of its size Even so, New England tends to behave more like a region than certain other parts of the country

This is true for several reasons The states have interrelated economies and energy markets Several utilities serve customers in more than one state New England is joined in NEPOOL, a 'tight power pool,' [15] and New England state regulators and energy officials have worked together for some time as a regional power planning committee

A The Industry

While there are about 90 utility companies in New England—some of them very small municipal systems—a few companies are so large that they tend to dominate the region, especially with regard to bulk-power transmission facilities [16] Mid-sized companies, as well as the very small ones, rely to a large extent on the transmission services of a few transmission-owning companies [17]

The utilities in New England operate together via the New England Power Pool (NEPOOL), set up in 1971 to provide reliability and economic benefits to the region through economic dispatch of the region's generating facilities and coordinated planning and operation of the transmission and generation system

Virtually every investor-owned electric company, municipal electric system and electric cooperative in New England is a member of NEPOOL, in which voting authority is largely a function of the size of each entity's annual peak load NEPOOL's coordination arrangements are governed by the NEPOOL Agreement, which falls under the jurisdiction of FERC

B Regional Structure of Government Energy Officials

Utility regulators and energy officials in the six New England states are organized together as members of the Power Planning Committee (PPC) of the New England Governors Conference, Inc The PPC was established over a decade ago to provide a mechanism for sharing information about regional energy problems and developments, for discussing ways to achieve regional solutions to shared energy problems, and to oversee and influ-

ence the activities of NEPOOL

The PPC has no governmental authority However, its adopted resolutions and informal investigations have a sort of *de facto* authority When its positions are undertaken unanimously and unambiguously, with the support of the New England governors and the six states' public utility commissions, its positions have the potential to influence NEPOOL activities

Over the years, the PPC has worked actively on various regional energy matters, such as New England's purchase of energy from Hydro Quebec, reliability issues, and development of an energy plan for the region PPC is now very much involved in the transmission issue

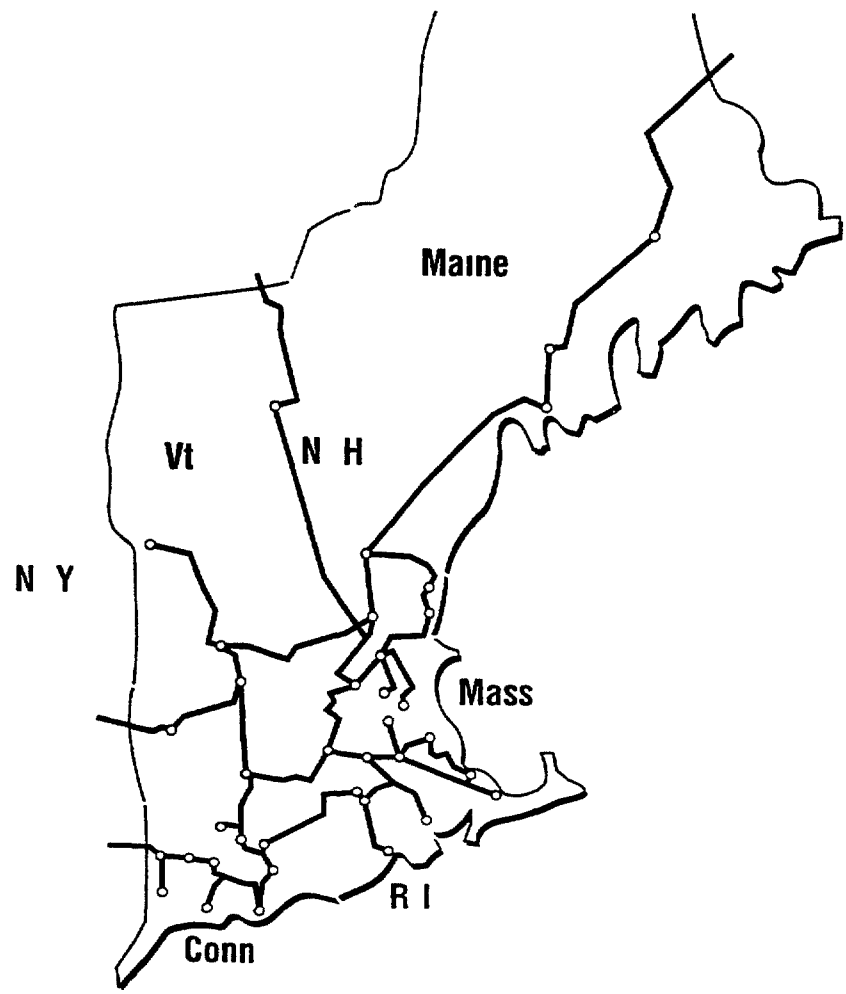
C Transmission Practices in New England

Transmission service in New England is furnished under NEPOOL, as well as pursuant to individual companies' transmission policies However, neither avenue—alone or taken together—adequately addresses current needs for transmission The proposal outlined at Section III below is intended to fill in some of these gaps

Under the NEPOOL coordination agreement, New England's utilities operate on an integrated basis, with a high degree of reliance on jointly-owned or jointly-supported generation and transmission facilities dispersed across the region NEPOOL members have a long history of buying and selling power from one another, including participating together in large generation and transmission projects The region's backbone transmission system links the major generating units and load centers and interconnects with major tie lines to New York to the west, and Quebec and New Brunswick to the north Although each transmission line is owned by individual or groups of electric companies, the entire system is interconnected and operated in a centrally coordinated fashion by NEPOOL to provide economical and reliable power within the region Some of the wheeling arrangements between buyers and sellers of wholesale power within New England are governed by the NEPOOL Agreement, others not covered by NEPOOL provisions are subject to the individual policies and practices of transmission-owning utilities in New England

D NEPOOL Transmission Policies

1 Historical Strengths One of the historical strengths of



The New England transmission grid at 230 kv and above is essential to moving firm or nonfirm power around the region as well as for transactions with utilities to the South West and North

NEPOOL is its transmission rules that made joint ownership of power projects a reality by enabling all participants to have equal, low-cost and high-priority access to any economical source of power in the region Prior to NEPOOL's formation, wheeling practices in New England were governed by the policies and practices of each utility New England utilities had come to realize that the economies of scale of large plants would be unavailable to even the region's larger utilities unless mechanisms were devised to facilitate joint ownership

Under the NEPOOL Agreement, two designations for energy facilities—"pool-planned unit" ("PPU") status for electric companies' generating units and the accompanying "pool transmission facility' ("PTF") status for transmission—offered opportunities for NEPOOL members to develop and participate in economical sources of power in New England [18] The only real criterion imposed by the NEPOOL Agreement was that the pool-planned facility meshed well with regional needs

The theory behind the PPU and PTF provisions was that all NEPOOL members should have equal access to participate in the economies afforded by large regional generation projects, and to wheel power from them over the high-voltage transmission system based upon "postage stamp' price terms that are indifferent to distance and reflect embedded costs of the PTF system

Large projects, such as the 1000 MW nuclear projects undertaken during the 1970s and NEPOOL s new 2000 MW interconnection with Hydro Quebec, were conferred PPU status, thus providing all NEPOOL members the chance to participate and to have high priority transmission access at a cost-based PTF postage stamp rate

NEPOOL participants have met the challenge of planning and arranging for the transmission requirements of these "mega-projects," dedicating both NEPOOL's and the utilities' engineering and planning staffs to the task of moving power from the projects to many users [19]

2 Contemporary Weaknesses

NEPOOL transmission access and terms may be "better' than in some other areas, but serious problems remain

NEPOOL's transmission provisions were designed for certain types of transactions—to connect large utility projects to their joint owners located throughout the region Drafters of the NEPOOL Agreement did not anticipate accommodating the other kinds of wheeling transactions required today

Most of the resources that have been proposed and constructed in the last few years—i e , qualifying facilities (QFs) and independent power producers (IPPs)—are not the sort of large, central station baseload projects originally envisioned to gain PPU status While the only condition the NEPOOL Agreement places on projects seeking PPU status is consistency with regional need, the actual designation of PPU status is gained only by vote of NEPOOL members, with a significant majority being needed for passage This means that most new plants are not given PPU status

continued on page 33

The Northeast Utilities/PSNH merger case at FERC with its 60-plus parties is a large new force in the New England transmission picture

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Special Segment Transmission

The participants in the struggle to define the future of the electric utility industry find much to disagree about On one point, however, there is complete accord competing versions of the industry's future depend sensitively on provisions for transmission access and wheeling All participants in the debate, whatever their views on such issues as competition, privatization, and deregulation, thus have a keen interest in transmission policy

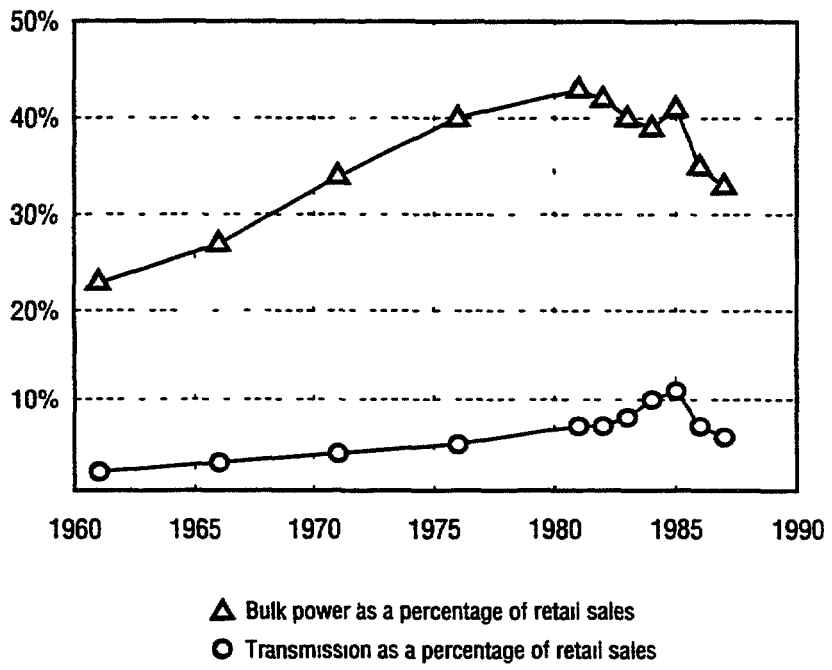
In this issue, Wheeling Dealing and Data focuses on this pivotal topic and some of its many facets

Growth in Wheeling Service Agreements Filed with the FERC

Recipient of Service	Number of Agreements on File		% Increase
	1976	1985	1976-1985
Investor-owned utilities only	322	563	75
Municipal & cooperative utilities	263	475	81
Joint public and private	20	256	1180
Other	51	86	69
Total	**656**	**1380**	**110**

(Source L Weiss and S Spiewak The Wheeling and Transmission Manual 1989)

Growth of Transmission



Left· This graph depicts bulk power sales and transmission as a percentage of total energy delivered to ultimate customers for major investor-owned utilities Growing interconnection large fuel price differentials and/or excess capacity could explain the observed growth in bulk power sales up to 1985 The decline after 1985 may be due in part to the way utilities are reporting these transactions Utilities used to supply actual or contract amounts, beginning in 1986 however FERC began collecting annual fees based on the total kilowatt-hours of transactions reported This appears to have led utilities to supply the data in a way that minimizes the fees

(Sources Financial Statistics for Selected Electric Utilities Energy Information Administration and The Transmission Task Force s Report to the Commission Federal Energy Regulatory Commission 1989)

Some Aspects of the Twelve Transmission Policy Proposals Evaluated by FERC

Status Quo
- Embedded cost pricing firm
- Voluntary access
- Some shared savings
- Purchase and resale

Edison Electric Institute
- Voluntary access
- Flexible pricing for non-firm
- Cost-based pricing for firm

Pacific Gas & Electric
- Voluntary access
- Cost-based pricing for firm
- Flexible pricing for non-firm
- Build new capacity on request
- No reselling

TAPS (Transmission Access Policy Study Group) and APPA
- Mandatory access at cost-based prices
- Joint ownership
- Consider some pricing flexibility

ELCON
- Mandatory access at cost-based prices

Wisconsin PSC
- Mandatory joint use and cost-sharing
- Mandatory joint planning
- No retail access

NRRI (National Regulatory Research Institute)
- Administered marginal cost pricing for non-firm
- Regulatory oversight of capacity expansion

Group of Five
(AEP, Duke Power, Southern Co , Entergy, Baltimore G&E)
- Liberal cost-based price caps for long-term, firm service
- Customer choice of interruption risk
- Flexible pricing for short-term service

LPPC (Large Public Power Council)
- Cost-based pricing for long-term service
- No obligation to build
- Arbitration of pricing disputes

UWG (Utility Working Group)
- Cost-based pricing for long-term
- Flexible pricing for short-term
- No obligation to build limited resale

British
- Spot electricity market
- Open access for retail and wholesale users
- Secondary market for capacity contracts

(Source Transmission Task Force Report FERC)

Bottom, page 31 *The pricing and access provisions of the above proposals are summarized on the chart at right The vertical axis represents the degree of pricing flexibility allowed for non-firm transmission services in each of the proposals If a proposal is placed near the origin this indicates that no flexibility is authorized and price must equal cost as determined by regulation Conversely complete deregulation would correspond to the highest point on the vertical scale*

The horizontal axis represents the extent of firm service access guarantees at cost-based prices, in each of the proposals Access provisions come in many forms such as (1) obligations to build new transmission capacity, (2) guarantees to provide firm service at cost-based prices, (3) willingness to allow the transmission capacity purchased under a firm service contract to be resold at times when the buyer does not need it (4) willingness to enter into competitive joint ventures that allow the participants to market transmission services independently of one another and also to expand capacity unilaterally or (5) willingness by a utility to agree to displace its own short-term coordination trades to the extent necessary to accommodate a request for long-term firm transmission service from a third party In effect the horizontal axis represents several things each of which serves to improve access among the transmission have nots '

The diagonal arrow thus points from regions of low pricing flexibility and low access to high flexibility and high access The size and shape of the ovals reflects the degree of uncertainty in the placement of the proposals

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A L P H A

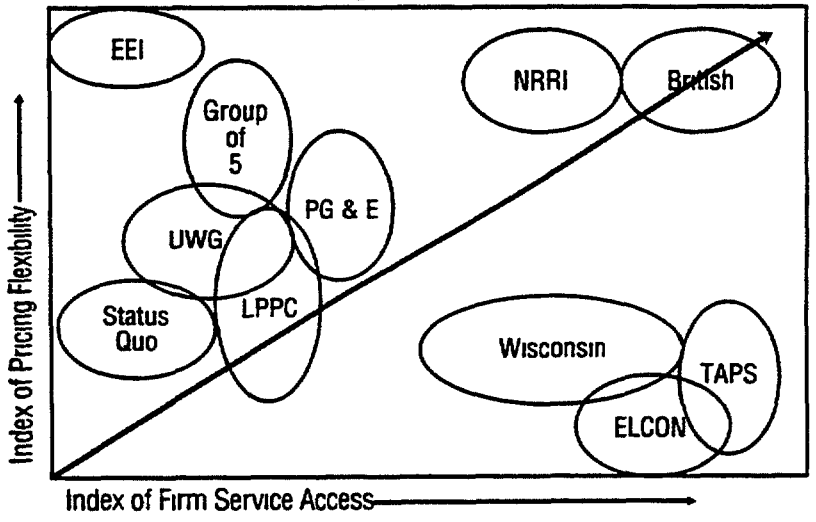
Below *Along with the all-important pricing and access provisions summarized earlier FERC looked at 13 other policy dimensions for the various proposals To keep the task manageable the 12 proposals were condensed and discussed in terms of two general transmission policy alternatives and the British model The two alternatives are called (a) the Contract Model, represented by PG&E the Group of Five, and other transmission owner groups and (b) the Planning Model, advocated by groups such as TAPS APPA and the Wisconsin PSC These correspond to the three clusters of proposals on the chart at the bottom of this page*

Major Policy Dimensions of Three Categories of Transmission Proposals

Issue/Concern	Contract	Planning	British
Reliability	Owner's Duty	Owner s Duty	Owner's Duty
Stranded Investment/ Inefficient wheeling	Governed by Contract	Governed by Joint Plan	Governed by Central Plan
Environmental/ Siting Issues	Duty of State PUC	Duty of State PUC	Duty of Transco
Structural Change	Small	Major	Radical
Quality of Service	Point to Point	System-Wide	System-Wide
Price Discrimination	Probably (Vintage Pricing)	No	No
Who Bears the Future Price Risk?	Depends on the Design	Shared through Joint Planning	Shared through Joint Planning
Who Has Priority?	Core Customers	No One	No One
Method of Enforcement	Contracts Enforcement	Joint Planning	Joint Planning
Parallel Flows	Contract Path	Real Flows in Region	Real Flows
Retail Bypass	Not Allowed	Not Allowed	Allowed
Accommodates IPPs	Yes	Yes	Yes
Requires Legislation	No	Probably	Yes

(Source Transmission Task Force Report FERC)

Non-Firm Pricing vs Firm Service Access



(Source Transmission Task Force Report FERC)

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Perspectives on Transmission

National Regulatory Research Institute, Kevin Kelly, Robert Burns, and Kenneth Rose

Some states claim the authority to order wheeling within the state using existing transmission facilities Depending on whether the courts eventually uphold this claim, there may be a "regulatory vacuum" in that neither federal nor state authorities might have the power to enforce an obligation to provide transmission service (Today's regulatory vacuum is reminiscent of the vacuum in regulatory authority over interstate power sales that led Congress to pass the Federal Power Act in 1935) It is in this sense that the regulatory rules for overseeing monopoly behavior are incomplete

David Owens, Edison Electric Institute

Perhaps the clearest example of the potential conflicts the Report creates for state regulators is its arbitrary preference for wheeling of long-term wholesale transactions even at the expense of economy trade which benefits a wheeling utility's own customers While this may lead to increased competition for new generation, it will not necessarily lead to increased efficiency

Transmission Access Policy Study (TAPS)

The current balkanized system of transmission ownership is inefficient In its place, regulators should seek the development of shared regional systems planned and built on a single system basis to serve all regional end-user load

The objective is to foster maximum hourly coordination among utilities and other generators so that [there is] vigorous competition in wholesale power supply and all utilities regardless of size and market power can pursue least-cost sources of supply

The FERC Transmission Task Force Report is a thorough analysis of transmission policy issues and provides a valuable survey and comparison of the competing models presented in the policy debate

Jeanine Hull, Hadson Power Systems

The FERC Task Force Report has identified legitimate issues that must be addressed in this process Along with the [Office of Technology Assessment] report, it puts more nails in the coffin of transmission red herrings which had earlier confused the issue

The Task Force Report also highlights efforts some utilities are undertaking to understand how to use their transmission sytems as a profit center, which will have a positive effect on the competitive power market We are watching to make sure that the access and pricing that results are equitable

Utility Working Group (includes 22 major investor-owned utilities and holding companies)

We applaud [the Task Force Report's] overall conclusion that voluntary transmission access coupled with price incentives can support a competitive wholesale electric supply industry However we have [some] serious reservations

First, the discussion of market power is confusing and incorrect Second in defining the relevant market the report incorrectly separates generation and transmission Third the report incorrectly links ownership of transmission facilities with market power

[T]he UWG encourages the FERC to hold public hearings on its transmission report [T]he Commission must assure the electric utility industry that the basic elements of the contract model, as expressed in the UWG principles submitted to the Commission in June will be the preferred approach to electric transmission policy reform

NRECA Transmission Task Force

All utilities should have an opportunity to participate in system planning through voluntary cooperation Participants should provide load and resource data pay their allocated share of system costs and participate in system upgrades as needed Participation would entitle utilities to access on a priority basis at cost-based rates Access would also be available to utilities which chose not to participate in the planning process on a non-priority basis

National Independent Energy Producers

Although competitive bidding has advanced in many states without an obligation to provide transmission access for winning and losing bidders, there is evidence that the lack of transmission access is limiting the ability of some projects to compete and has even contributed to the failure of some winning bidders In Virginia Power's March 1988 solicitation for example three winning projects later withdrew in part because of the inability to arrange for wheeling from an adjacent service territory

State regulatory commissions should require that transmission access within the state be incorporated into every bidding program

Greg Rueger, Pacific Gas & Electric

The Task Force Report leans away from point-to-point ' transmission service and suggests that purchasers of long-term firm transmission service should be allowed to use or broker service they never purchased in the first place

The report suggests that short-term economy transactions which benefit retail and requirements customers should be curtailed whenever long-term firm transmission service is requested and needed transmission upgrades cannot be built within an unspecified period of time Applying the same 'guilty unless proven innocent approach [as used by FERC in the Utah/PacifiCorp merger] on a generic basis clearly violates the subsidy principle

continued from page 28

In recent years, the apparently far-sighted transmission provisions of the NEPOOL Agreement have been found wanting Of late, most new transmission transactions have had to be worked out outside the framework envisioned by the NEPOOL's PPU and PTF pricing provisions [20] Lack of PPU status has denied the developers of such projects the opportunity to wheel their power under the priority and price terms associated with NEPOOL's PTF facilities Instead, power from such projects is subject to the access and pricing policies of the individual utilities that wheel such power, which vary from utility to utility as described below

Transmission-related planning for these QF and IPP power projects has also suffered, not just because the projects were offered by nonutility developers who were not members of NEPOOL, but also because the smaller scale and geographically dispersed character of these projects differs from NEPOOL s typical experience with megaprojects [21]

E The Jungle Wheeling Outside the NEPOOL Umbrella

For smaller, dispersed resources, current wheeling policies of the individual companies that own transmission facilities typically have not afforded either transmission service or planning for such service on an efficient basis [22]

There is considerable uncertainty and variability among transmission-related costs Most New England utilities charge new power developers for direct and indirect costs associated with new transmission construction, but such charges and practices vary greatly for such critical matters as the portion of the facility's costs charged to a new power project

Many utilities have recently joined QFs and IPPs in asserting that the price and restrictive access terms of certain New England utilities are too onerous to allow wheeling on a reasonable basis This is especially true where there is wheeling over any significant distance or across multiple service territories, or even across certain systems [23]

Sometimes the actual cost of moving power over a long distance does outweigh the apparent benefits of purchasing power from a distant source However, in other cases onerous pricing and access policies impose an artificial barrier to a transaction This can result simply from the exercise of monopoly power, for example, in cases where the utility from which wheeling is sought is also a competitor of the hopeful seller and is in a position to restrict others' access When markets are characterized by a monopoly in transmission, buyers' and sellers' options are reduced In such cases there is greater likelihood that the transmission-owning utility may demand monopoly rents for sale of its own excess capacity [24]

The incentive for restricting wheeling services as a way to promote utility generation sales ahead of transmission service is powerful revenues from wheeling services are simply picayune in comparison to those to be derived from generating capacity and energy sales [25]

This fact, along with a regulatory paradigm that values transmission at embedded cost, gives a utility with excess generation and control over tight transmission corridors a powerful incentive to position its own sales ahead of competitors sales and a strong disincentive to fill up its transmission corridor with others transmission capacity [26]

Some transmission-owning utilities always place their own power sales on a higher priority' or "preference,' so that others power flows are always on the margin, causing the need for new transmission facilities if such expansion is necessary to carry all requested power flows on the system

Some utilities will provide firm, long-term transmission service to all comers on a tariffed basis as long as transmission capacity exists, others will agree to do so via contracts that require compensation based on lost opportunity costs "[27]

Many are reluctant to provide firm transmission services that depend on expanded transmission capacity for fear that entering into such agreements will require them to meet such commitments if licensing constraints prevent addition of transmission facilities

Some companies will sign transmission contracts only if the transmission user commits to make a "balloon payment"—of unknown size and date—to cover transmission system expansion costs if such expansion is ever necessary during the life of the wheeling contract [28]

These policies are discriminatory In my view, they also raise the risk that needed and economic power supplies will not be developed They also fail to reflect policy directives advocated by New England state officials with respect to electric energy planning

The New England governors have encouraged the creation within NEPOOL of a formal marketplace to facilitate the purchase and sale of generating capacity within the region and between the region and its neighbors, and the governors' Power Planning Committee has urged the utilities to adopt marginal-cost-based wheeling prices for new transmission facilities [29]

III The New England Transmission Proposal

The Transmission Task Force of the Power Planning Committee has been examining transmission issues in New England for some time and has begun to identify a number of problem areas As chair of this task force, I offered a proposal in September 1989 to amend the NEPOOL Agreement—a proposal that attempts to retool long-established NEPOOL principles to meet the changing needs of the region in ways that are consistent with the policies adopted by the New England governors to ensure an equitably supported, reliable and cost-effective electricity supply system The proposal has been forwarded by the PPC to NEPOOL and the industry

The New England governors have encouraged the creation within NEPOOL of a formal marketplace to facilitate the purchase and sale of generating capacity

A Mechanics of the Proposal

The proposal would update certain provisions of the NEPOOL Agreement in two essential ways to facilitate a more competitive electric generation market

1 Market Test First, the proposal would change the method by which NEPOOL designates power projects as "Pool Planned Units"—by utilities voting for or against PPU status There should be a more market-oriented way to determine whether a project fits regional needs

The proposal would allow both utility and nonutility projects located inside and out of New England to use a "market test" (by way of a formal offering to all NEPOOL members) to determine how well a project fits with regional needs Projects that pass the market test (by being fully subscribed by buyers who are members of NEPOOL) would be designated Pool Planned Units [30] *Buyers and sellers*—rather than a majority of utility votes—*would determine what projects make sense for the region*

Once a project had PPU status, it could use the high voltage transmission system to transmit power on a high-priority basis and pricing terms currently available under the NEPOOL Agreement—that is, using the Pool Transmission Facility postage stamp rates which are insensitive to the distance of transmission [31]

2 Incremental Cost Rates The current embedded cost approach for setting the PTF rate would be replaced with an incremental cost approach, based upon the direct dollar-per-kilowatt cost to construct and operate new transmission facilities in New England today [32] The new charges—perhaps in the range of $30 per kW, compared to the embedded PTF cost of about $4 per kW today—would apply to all new wheeling contracts to transfer power from a new PPU to the NEPOOL mem-

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ber utilities purchasing power from it The revenues collected from such rates would go into the current NEPOOL transmission fund, from which owners of existing PTF lines would be reimbursed at their actual costs, the remainder would provide a fund to pay the full costs of siting, constructing and operating new bulk power transmission facilities for the New England region [33]

These proposed changes to the NEPOOL Agreement would expand choices for all players and improve the quality of competition By broadening the availability of wheeling, it would open vastly the range of transactions available to any utility or area both from sources within or outside the region All the current ways in which utilities now obtain power resources from others (through bidding or negotiation) and transact wheeling arrangements (through contract or tariff provisions) would otherwise remain intact

Except for the need to obtain FERC approval for the proposed changes to the NEPOOL Agreement itself, the proposal would not affect the types of approvals that proposed power projects and transmission facilities would need to obtain from the state agencies

B Objectives of the Proposal

The aim of this proposal is to afford equal high-priority access to transmission services for any utility or nonutility resource deemed to be consistent with the region s needs, as determined through a market mechanism

The proposal would price such services fairly and efficiently, according to postage stamp rates based on incremental cost It would allow the wheeling of utility or nonutility generation and even ' negawatts" (i e , measurable conservation or load management resources) on an equal basis

The proposal s inclusion of incremental cost-based wheeling rates is intended to provide a more efficient pricing signal to users of transmission services than now exists This aspect of the proposal is also intended to overcome some of the present disincentives to construct new transmission facilities through the fund mechanism, the utility constructing transmission, its ratepayers, and the residents who live next to a new transmission facility would be reimbursed for their costs by the users of wheeling services, and the local utility would retain ownership of and use the new facility

The proposal's inclusion of incremental cost-based wheeling rates is intended to provide a more efficient pricing signal and to overcome present disincentives to construct new transmission

IV The Process for Reform

The Power Planning Committee formally transmitted the proposal for industry comment in late 1989 [34] The common thread of responses to date is that the proposal deserves serious attention, which it is indeed receiving

Work is underway to sort out the complicated policy and technical issues raised by the proposal This involves joint working meetings with representatives from the regulatory agencies, utilities, and nonutility developers to discuss the technical and policy issues and develop needed modifications to the concepts originally proposed Issues raised by the proposal are seen as both complex and important,[35] and debate is on the fast track.

If anything, the pace of transmission reform discussions has been accelerated by the Northeast Utilities proposal in late 1989 to acquire PSNH, and NU s subsequent January 1990 application for FERC approval of the acquisition In this proceeding a principal issue clearly is the relationship of the merged company s control over transmission to the future of the region s generating markets [36]

The proposal described here has already succeeded in one of its objectives it has kick-started the debate on transmission reform in New England Just having a credible proposal on the table is moving the region closer to the needed

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change

The Transmission Task Force of the Power Planning Committee has asked NEPOOL either to develop a refined version of the proposal we circulated to them last year or to offer a counterproposal it believes is superior[37] My hope is that shortly after the industry responds, NEPOOL and New England regulators will ask FERC to approve new provisions in the NEPOOL Agreement that support nondiscriminatory access and cost-based pricing of regional transmission service ■

Footnotes

1 *See* THE TRANSMISSION TASK FORCE S REPORT TO THE COMMIS SION, ELECTRICITY TRANSMIS SION REALITIES THEORY AND POLICY ALTERNATIVES 73 165 (FED ENERGY REG COMM 1989) (hereinafter Transmission Task Force Report or Task Force Report") A C Brown *State Power Over Transmission Access and Pricing The Giant Will Not Sleep Forever* PUB UTIL FORT, Nov 9 1989 at 21-23 K KELLY J S HEN DERSON P NAGLER SOME ECO NOMIC PRINCIPLES FOR PRICING WHEELED POWER Ch 6 (NAT REG RES INST 1987)(hereinafter NRRI Report 1) L WEISS S SPIEWAK eds THE WHEELING AND TRANS-MISSION MANUAL 115-119 (1989)(hereinafter Wheeling Man ual)

2 *See e g* Transmission Task Force Report, *supra* note 1 at 57, 67, NRRI Report, *supra* note 1, Executive Summary and chs 6 10, R BURNS *et al*,ed , NON-TECHNICAL IMPEDIMENTS TO POWER TRANSFERS (NAT REG RES INST 1987)(hereinafter "NRRI Report 2) Wheeling Manual *supra* note 1 at 81-108, OFFICE OF TECH-NOLOGY ASSESSMENT, ELECTRIC POWER WHEELING AND DEALING (1989)

3 *See generally* Brown *supra* note 1 at 21-23 Task Force Report *supra* note 1 at 185-187

4 *See e g* Brown at 21-23

5 Utah Power & Light Co Opinion No 318 45 FERC ¶61 095 (1988)

6 Vt Dept of Pub Serv and Vt Pub Serv Bd v Conn Light and Power Company *et al* FERC Docket No EL90 13-000 @FOOTNOTE = 7 Wisc Pub Serv Comm Order 05-EP 5 April 1989

8 Mass Dept of Pub Util 220 CMR 8 03(5)

9 Task Force Report *supra* note 1 at 67 77
Increasingly, the transmission system will begin to separate the evolving competitive market in power generation and the traditional electric power franchise monopoly at retail Transmission or the lack thereof can be a barrier to entry in the emerging competitive portion of this industry *Id* at 67

10 *See* NEPOOL Review Committee Study of Priority of Use of Transmission System, 1988

11 Northeast Utilities Service Company (Re Public Service Company of New Hampshire) FERC Docket Nos EC90-10-000 ER90-142-000 ER90-144 000 ER90-145-000 EL90-9-000 *See* initial pleadings of New England Power Co United Illuminating Co Boston Edison Co American Public Power Assn /National Rural Electric Cooperative Assn Commonwealth Electric Co and Cambridge Electric Light Co *See also* Northeast Utilities *et al* SEC File No 70 7695

12 S Tierney A Transmission Pro posal for New England Mass Dept of Pub Util Sept 28 1989

13 NEPOOL Forecast Report of Capac ity Energy Loads and Transmission (CELT Report) 1989 2004 April 1 1989 at 1

14 *Id* at 1 2

15 A tight power pool is one in which a group of utilities agrees to have its power plants centrally dispatched Task Force Report at 11-17 NRRI Report 1 at 290 91

16 Several of the largest electric com panies in New England—e g Northeast Utilities and New England Electric System—are holding companies with retail electric company affiliates serving customers in more than

Regulators could play honest broker to open the New England grid

one state

NU the largest electric utility in the region currently serves most of Connecticut and a portion of western Massachusetts—together representing approximately 25% of New England s summer peak load With NU s proposed acquisition of PSNH NU will also serve most of New Hampshire and will then make up approximately 31% of the region s summer peak

The second largest utility NEES, serves much of Massachusetts and Rhode Island, along with a small portion of New Hampshire—representing 21% of the region s summer peak These two utilities (after NU s expected acquisition of PSNH) would own or control virtually all the major transmission pathways linking load and generation sources in southern New England and northern New England New York and Canada (Load date source NEPOOL)

17 *See e g* the initial pleadings of New England Power Co Boston Edison Co United Illuminating Co and Commonwealth Electric Company in the NU/PSNH proceeding at FERC *supra* note 11

18 The NEPOOl Agreement currently contains the following provisions regarding Pool Planned Unit status

Section 10 1 states that PPUs are all units designated by the NEPOOL Management Committee (NMC) for inclusion in NEPOOL s expansion plan In theory these are units that are economical for the region Section 10 1 states that the NMC may not unreasonably withhold PPU designation for any particular unit however it is through voting—rather than through application of any particular set of objective criteria—that PPU designation is obtained In some instances votes have not been taken because the project proponent knew that the numbers needed to support PPU status were lacking Section 10 1(a) provides that all NEPOOL participants should have an opportunity to share in the types of units being built in the region and accorded PPU status Section 11 1 provides that all participants should have an opportunity to meet their needs from PPUs

19 The FERC Transmission Task Force recognized this circumstance when it noted

> capacity planning under uncertainty is somewhat easier when a utility can deal with a small number of customers each of whom is large Such customers can provide the utility with direct estimates of their future needs Such a process is akin to a joint planning exercise in which prices play a minor role in the capacity expansion decision

Task Force Report *supra* note 1 at 88 note 24

20 According to United Illuminating Co 80 % of current wheeling transactions in New England do not fall under the protections and privileges associated with NEPOOL s Pool Planned Units See Motion of United Illuminating Company for Leave to Intervene in Northeast Utilities FERC Docket No EC90-10-000 at 17

21 *See* S Angle *Recovering the Incremental Costs of New Facilities* WHEELING AND TRANSM N MONTHLY Dec 1989 at 1

22 As an example of a recent change from this trend *see* New England Power Co Discussion Paper Transmission Upgrades for North Shore Generation Projects February 9 1990 In this document NEPCo proposes to batch generation projects willing to commit to participate by a date certain in joint transmission upgrade studies in order to establish an orderly and equitable process to accommodate new generation on portions of NEPCo s transmission system *See also* the reference to NEPOOL s new transmission study of the effects of multiple additions of small generators described in Freudmann, *Small Power Plants Complicate New England Transmission* Energy Daily February 1, 1989

23 See *e g* NRRI Report 1, *supra* note 1 at 1 2 and ch 1 for a discussion of various technical and cost reasons why utilities are reluctant to wheel

24 *See e g* note 17 *supra*

25 Task Force Report *supra* note 1 at 72 196

26 Regarding incentives to restrict transmission in order to make more lucrative generation sales, *see* K Kelly R Burns K Rose An Evaluation for NARUC of the Key Issues Raised by the FERC Transmission Task Force Report NRRI January 31 1990 Wheeling Manual *supra* note 1 at 81 82 115-166

27 A situation where a utility has transmission policies stating that native load customers should benefit from wheeling transactions and receive a reduction in the price of their service, is

> an excellent example of market power—it is not possible to transfer benefits from outsiders to favored ratepayers in the absence of monopoly power

Task Force Report *supra* note 1 at 124 125

28 *See e g* policies and practices of Northeast Utilities as described in letter from W Schultheis Northeast Utilities to C Morris Mass Dept of Pub Util September 25 1989

29 *See* Resolution of the New England Governors Conference Inc Urging Enactment of Additional Policies to Strengthen the Region s Electricity Supply and Demand Situation Dec 15 1987 *See also* Resolution of the NEGC s Power Planning Committee Concerning Revisions to the

NEPOOL Rules Re Transmission Policies Feb 17 1988

30 *As originally proposed* the following features would be required of any resource that sought to obtain PPU status

(1) The developer/owner would make a formal offering of its power through a central market place overseen by NEPOOL The resource offering could be for short or long-term power contracts or entitlements, and for power from new or existing generating projects owned by either utility or nonutility companies

(2) The offering would have price and non-price terms that would be subject to a menu of standard contract provisions to permit a timely orderly and fair process

(3) The offering would likely require reasonable deadlines for NEPOOL participants to decide whether to subscribe to the project offering and for subscribing companies to receive contract approvals from regulatory agencies

(4) All NEPOOL participants would have an opportunity to buy power from the project

(5) The proposal could be drafted to allow NEPOOL participants in the host state (where the project is located) to elect to have an exclusive option to participate in some percentage of the project s total offering (e g , 50% available on a first-priority basis to in-state utilities), and leave the remaining portion of the offering available for subscription by both out-of-state and in-state utilities

(6) Fully subscribed or oversubscribed projects would be deemed to have met the market test consistent with regional need and would receive designation as a Pool Planned Unit This would be the case even if only one NEPOOL participant elected to participate in the offering as long as all NEPOOL participants had had the opportunity to participate

(7) Oversubscribed projects would result in pro rata scaling back of the shares or purchases in the project undersubscribed projects would not become Pool Planned , however, nothing would prevent such a project from attempting to negotiate power purchase agreements with individual utilities or from submitting bids in individual utility solicitations subsequent to the failed PPU offering

(8) The requirement that all NEPOOL participants have the opportunity to buy power from a project being offered through the proposed mechanism is consistent with the objective stated in Section 11 of the NEPOOL Agreement that all NEPOOL members have an opportunity to meet their ca-

pability responsibility from Pool Planned Units As stated in Section 10 1(a) this objective is in place so that all NEPOOL members have access to an equitable distribution of desirable resources that are reasonably comparable to the economics and types of generation resources being developed for New England

At present the NEPOOL Agreement includes these terms relating to the nature of rights of access to and pricing of EHV pool transmission facilities (EHV PTF)

(1) Section 13 1 defines Pool Transmission Facilities as those transmission facilities owned by NEPOOL participants and required to move energy freely on the New England transmission network

(2) Under Section 13 2 NEPOOL participants are entitled to use the PTF owned by other NEPOOL participants for various purposes including wheeling to a participant s system of its ownership interest or contract purchase entitlement in a Pool Planned Unit located off the purchasing participant s system

(3) The rate that NEPOOL Participants pay for wheeling energy from Pool Planned Units over the PTF system is on a dollar-per-kilowatt basis and is insensitive to the distance of the transaction between the PPU and the utility power purchaser This wheeling rate is paid by the utility purchaser only once, regardless of the number of utility companies that wheel the power between the PPU and the purchaser

(4) Under Section 13 4 the PTF rate is based on a formula reflecting the embedded costs of PTF facilities The rate for any calendar year is obtained by dividing (a) the aggregate costs incurred by participants with respect to EHV PTF for the prior calendar year by (b) the NEPOOL Objective Capability or the actual NEPOOL Capability whichever is less as of June 30 of the prior year

(5) Section 13 4 also includes a funding mechanism reimbursing utilities for their investment in PTF facilities One-half of the funds collected from these NEPOOL EHV PTF participant wheeling rates is paid to a Pool Transmission Fund and distributed monthly among the participants in proportion to the relative amounts of their embedded costs relating to EHV PTF for the month The other half of the funds collected from these wheeling charges is paid to the participant on whose system the transfer originates (the utility in whose service territory the PPU is located)

31 Under the proposed change to the NEPOOL Agreement all transmission service to wheel power from new Pool Planned Units would pay a new PTF rate which would be calculated based on the full incremental (or replacement) cost of EHV PTF facilities

32 The new NEPOOL participant PTF

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wheeling rate would be based upon today s total direct and indirect costs of constructing and operating new EHV PTF system transmission facilities in New England divided by the load carrying capability of the system This is the same approach used to establish the original EHV PTF rate Like the present approach the rate would apply to the amount of the purchase in the PPU entitled to be wheeled over the PTF system

To avoid complex reviews of the utilities plans to expand the transmission system the incremental cost in $/kw would be based on the generic cost to construct transmission line in New England today at the voltage level appropriate for wheeling the power from a project This rate would be relatively certain in any year It would be based on standard industry estimates and would change over the time largely as a function of inflation

33 Funds collected from NEPOOL Participants using the new PTF wheeling rate would go into the Pool Transmission Fund and would be disbursed in two parts

(a) The average embedded portion for preexisting PPU wheeling services on the PTF system would be paid out of the Fund as it is now one-half to the owners of PTF facilities according to their proportionate share of total PTF investment and the other half to the participant in whose service territories the PPU is located

(b) The remainder would be maintained in an interest-bearing account and paid out to participants that construct new PTF facilities in the future Funds would be paid out in relation to new transmission investment capped at full annual cost of any member s transmission investment and operation and maintenance expense Any funds not paid out (e g during the period prior to commencement of new construction or where funds collected exceed the amounts paid out for actual new construction) would continue to accrue in the account

34 In October 1989 the PPC sent the proposal to NEPOOL to the individual public and private utilities that comprise NEPOOL to the New England Cogeneration Association to major developers of QF and IPP projects to customer groups representing large end users in New England to eastern Canadian utilities and to the New York Power Pool

35 Among the issues under active discussion are the following grandfathering of existing PPU Wheeling under existing embedded cost rates development of zoned parcel post rates rather than uniform postage stamp rates methodology for calculation of the rate based upon replacement cost of new transmission facilities direct cost allocation of interconnection costs attributable to a new plant states siting criteria for regional transmission lines the requirement that a project be fully subscribed to gain PPU status the possibility that any power sales agreement signed between any NEPOOL buyer and a seller might be wheeled according to the proposed PTF provisions the revenue-generating potential of the new PTF wheeling rate and whether the fund will be sufficiently large to cover the costs of constructing and operating new facilities the priority level of power wheeled from new PPUs relative to existing PPUs native load needs exports and other firm and non-firm wheeling services under tariff or contract

36 NU s acquisition of PSNH would result in control of a transmission system that spans an area from the periphery of New York City on the south to the Canadian border on the north and from the western border of New England to the Atlantic Ocean Virtually all bulk power transactions in the region would cause power flows into out of or through the merged company s service territory

At this writing, there were more than 60 intervening parties in the FERC case examining NU s acquisition of PSNH Many pleadings at FERC regarding intervention petitions and NU s request for an expedited review schedule allege that NU has historically displayed restrictive transmission policies

NU currently has no transmission tariffs on file to date it prefers to use only negotiated contracts to provide wheeling services NU declines to offer firm long term transmission service except if the transmission customer agrees to provisions such as paying lost-opportunity costs and staying on the margin relative to NU s sales of its own excess capacity which are generally agreed to be burdensome

Given NU s own claim that it will possess generating capacity in excess of NU/PSNH s customers requirements for as long as ten years the potential and motive clearly exists for NU/PSNH to use transmission pricing and access terms to influence potential customers to purchase its own excess capacity *See e g* the pleadings of Boston Edison New England Power Company United Illuminating the states of Massachusetts Rhode Island and Vermont in the NU/PSNH acquisition case *supra* notes 11 and 17

See also Schultheis letter *supra* note 28

37 Letter from Peter Boucher Conn Dept of Pub Util Control and Chairman Power Planning Committee to G Edwards United Illuminating and Chairman of NEPOOL Executive Committee February 26 1990

State Transmission Planning and Federal Power Policy: Turf War to Alliance?

The purposes of state and federal regulation are different, but potentially complementary The Wisconsin Public Service Commission believes there is room for it to act in a way that benefits both systems

Michael Arny and Barbara James

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1 Introduction

Relations between the FERC and state public utility commissions have been somewhat strained of late, both on the ratemaking front, with the *Nantahala* and *Mississippi Power & Light* cases,[1] and on the transmission front, with FERC s Florida Power & Light[2] decision Given the prohibition on exercise of state authority these cases stand for, some analysts suggest there may be no role for states to order or facilitate transmission access

There is wide agreement, however, that in order to attain the promise of the new competitive era in which utilities and nonutilities vie for bulk power sales there must be more open access to the transmission grid [3] It is next to impossible for FERC to order access directly, as *Otter Tail* and the *Kentucky Utilities* cases make clear [4] However, in the context of the recent Utah Power / PacifiCorp merger, it has become clear that FERC can impose transmission service as a condition to its approval of, for example, a merger [5] Of course, FERC retains jurisdiction over the price and terms of transmission services that are offered

But if the states cannot order transmission service and FERC

cannot—except in the rarest of circumstances—then who can? Did Congress intend such a transmission gap?

This article assumes Congress had no such intention and that there is ample room for the states to address transmission issues in a way that advances essential governmental interests If movement toward a system of more open bulk power markets is desirable, it is time to recognize the important, constitutionally permitted role of the states in regulating transmission and to reassess whether the transmission access gap can be bridged using state authority The first step is to identify the differences between the authority and responsibilities of the states and the FERC

The Public Service Commission of Wisconsin (PSCW) has recently acted to open transmission facilities in the state to broader use as part of its evolving planning process PSCW's 1989 planning order used its prior development of planning principles and techniques as a foundation for its next step, commonly known as Advance Plan 5,[6] which includes broadened access to the transmission system

The order increases transmission access in two ways First, the major utilities were ordered to develop transmission joint use and cost-sharing agreements with neighboring large utilities and small utilities[7] These use and cost-sharing agreements are required to be compatible with 20 principles also specified in the order[8] Second, the major utilities were ordered to file wheeling tariffs at the FERC[9]

Only the planning order requirement that use and cost sharing agreements be developed has been challenged by the major Wisconsin utilities at the FERC When and if FERC will decide this case is not known

Both the requirement for development of joint use and cost-sharing agreements and for filing of wheeling tariffs at FERC have been challenged by utilities in Wisconsin State Court In February 1990 the court ruled on a request by the utilities for a stay of these two aspects of the order The court agreed to stay the cost- and use-sharing requirement and to defer to the FERC for six months, but did not stay the requirement that wheeling tariffs be filed at FERC

If the states cannot order transmission service and FERC cannot—then who can?

Since the 1989 Advance Plan 5 order, there have been several developments in the area of wheeling tariffs Wisconsin Power and Light Co has filed a general wheeling tariff at the FERC, and Wisconsin Public Service Co has said it intends to do so in the near future Northern States Power Co divisions in Wisconsin and Minnesota have said they will file a general wheeling tariff that covers the transmission systems of both companies

The transmission access provisions included in the Wisconsin planning order will create a more open transmission system in Wisconsin that will facilitate transmission transactions both for Wisconsin utilities and those in surrounding states

These provisions are designed to meet the state s needs, but also to bridge the access gap without trespassing on FERC's authority In fact, the Wisconsin approach provides an opportunity for the FERC and a state to move from a turf war (or perhaps more aptly a no man's land) to an alliance in creating a more open market for generation, as well as fulfilling other important state and federal responsibilities

II What Does the Wisconsin Order Do for Federal Interests That FERC Cannot Do?

The Wisconsin order advances federal interests by accomplishing two things that the FERC would like to see but cannot do itself it requires utilities to provide transmission access and it provides a process to get necessary facilities constructed Both actions facilitate interstate as well as intrastate transactions

The FERC has broad public interest responsibilities which are set forth throughout the Federal Power Act[10] This paper will

focus on those interests particularly highlighted in the recent FERC Transmission Task Force Report

The first interest expressed in the FERC report is that access to the transmission system be more open The Wisconsin planning order uses three mechanisms to open the transmission system (1) it requires joint transmission use and cost-sharing agreements between neighboring large utilities,[11] (2) it requires each large utility to develop transmission joint use and cost-sharing agreements with the smaller utilities it surrounds, (3) and it requires each large utility to file a wheeling tariff with the FERC

Each of these provisions advances the federal interest in a more open transmission system and allows increased competition for Wisconsin wholesale markets among suppliers both inside and outside Wisconsin

Another interest expressed in the Task Force Report is that sufficient transmission exist or be constructed to permit optimum use of resources This is a legitimate concern, since FERC lacks authority to require the planning or construction of transmission facilities

States do have authority to approve or disapprove construction of transmission facilities, whether or not this power has been delegated to the public utility commissions Where this authority is exercised by the state commission, it is usually granted through issuance of a certificate of public convenience and necessity or its equivalent

In Wisconsin, authority to determine which facilities go into rate base was given to the commission in 1907, along with the power to compel interconnections and joint use In 1931, the legislature gave the PSCW authority to approve transmission facilities In 1971, these powers were extended to include explicit consideration of the environment, and in 1975 to include long-range planning Wisconsin has delegated a very broad array of powers to the PSCW

All states have the underlying authority, under their police power authority, to confer equally broad powers on their utility commissions, and some have already done so The basic mechanism for providing an adequate grid is in place at the state level There are good policy reasons why it should stay there

III State and Federal Responsibilities and Resources Differ

The states have a fundamental interest in the construction and use of electric transmission within their borders The states are responsible for insuring that retail service is adequate and reliable, which requires a properly planned and built transmission system They also are responsible for the quality of the environment within their borders and for regulating the cost of power to retail customers This means that the states have the responsibility to ensure that enough transmission is built to provide reliability, but that duplicate transmission facilities, with their attendant costs and environmental degradation, are not built

The key factor in these considerations is system requirements and benefits, with emphasis to a long-term perspective The existing transmission system was built by utilities which used—directly or indirectly—the states' eminent domain power This grant of power is itself an indication of the strong state interest in electric transmission The federal government s recognition of state interests underlies the freedom of state regulated public utilities from *de facto* violation of the antitrust laws, if it were not for the states approval, the monopoly character of utility operations would make them unlawful

In more and more states, responsibility for ratepayer, property owner, and societal interests over the long term has moved utility commissions toward comprehensive least-cost planning for the electric system, including generation, transmission, and demand-side measures to improve efficiency[12]

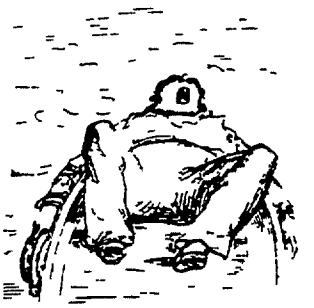
These are matters of local interest, best suited to local regulation and control

The FERC, on the other hand, is not responsible for service to retail customers, or for impacts on local landowners or the environment Rather, its focus is interstate transactions between utilities, which, as it has come to be interpreted by the federal courts, means all wholesale transactions It has authority over rates, terms and conditions upon which utilities may sell bulk power or transmission service Its major interest is that interstate coordination be maximized for the benefit of reliability, economy, and conservation of natural resources[13] and that interstate commerce not be impeded

FERC also lacks responsibilities or resources to do transmission planning, which involves enormous detail on the capacity and characteristics of myriad lines and related equipment, as well as generation and load data By contrast, most states have responsibility to plan and authorize construction of facilities and are close enough to the local situation to plan or oversee utility planning intelligently

Wisconsin's transmission planning and use directives are grounded in a very detailed analysis of the state s transmission system as a whole This analysis has taken the engineers at Wisconsin utilities and the PSCW some six years to develop It involved extensive measurement and modeling both of the existing system and projected additions Without this deep understanding of the physical transmission system, the Wisconsin PSC would not be able to take steps toward more open use of the system without risking degradation of reliability or actions which would make no sense in the real world If planning is to result in real efficiency, the agency and the utilities must have done their system analysis homework

The responsibilities and re-



sources of the states and the FERC are different, but they need not be incompatible The Wisconsin approach takes account of the interests and statutory basis for FERC and state regulation and treats them as complementary

IV Evolution of Wisconsin Transmission Planning

The Wisconsin Commission has broad authority over the electric utilities in Wisconsin The 1975 Wisconsin siting law established a two-step preconstruction approval process for major electric generation and transmission facilities The siting law applies to all three types of utilities investor-owned, municipal, and cooperative

The 1975 siting law established a two-step process because the prior one-step process had several drawbacks [14] It had frustrated environmentalists because the construction review stage was too late to address important planning questions Farmers felt they were not getting enough say about need for facilities and routes

Utilities were also unhappy They faced attempts by local units of government to stymie construction projects through local zoning measures Condemnation procedures were difficult Long construction lead times for large plants presented problems because they required major capital commitments before a utility had any certainty a plant would be certified This carried the risk of a cost disallowance due to later imprudence findings

The siting law addressed these problems by making several changes to the previous process (1) the construction certificate now preempts local zoning, (2) the need showing made in a construction case does not have to be repeated in the condemnation procedure, and (3) the planning review now occurs before the construction certificate procedure, so a utility can be sure its planning expenditures will not be disallowed once its plans have been approved at the planning level

The two-step review process works this way first, there is review of long range plans on a two-year cycle, second, there is review of specific facilities and routes in

construction proceedings Both generation (plants over 12 MW) and transmission facilities (lines over 100 kv and one mile long)[15] must be approved in the planning proceeding before they can be approved in a construction proceeding To concentrate on the facility before more basic planning questions are answered would let the tail wag the dog

Both review steps—planning and construction—include public involvement, determination of need, evaluation of alternatives, environmental review, and review of costs The planning level review is more general and the construction case level review is more detailed The review process under the siting law has evolved toward a integrated least-cost approach

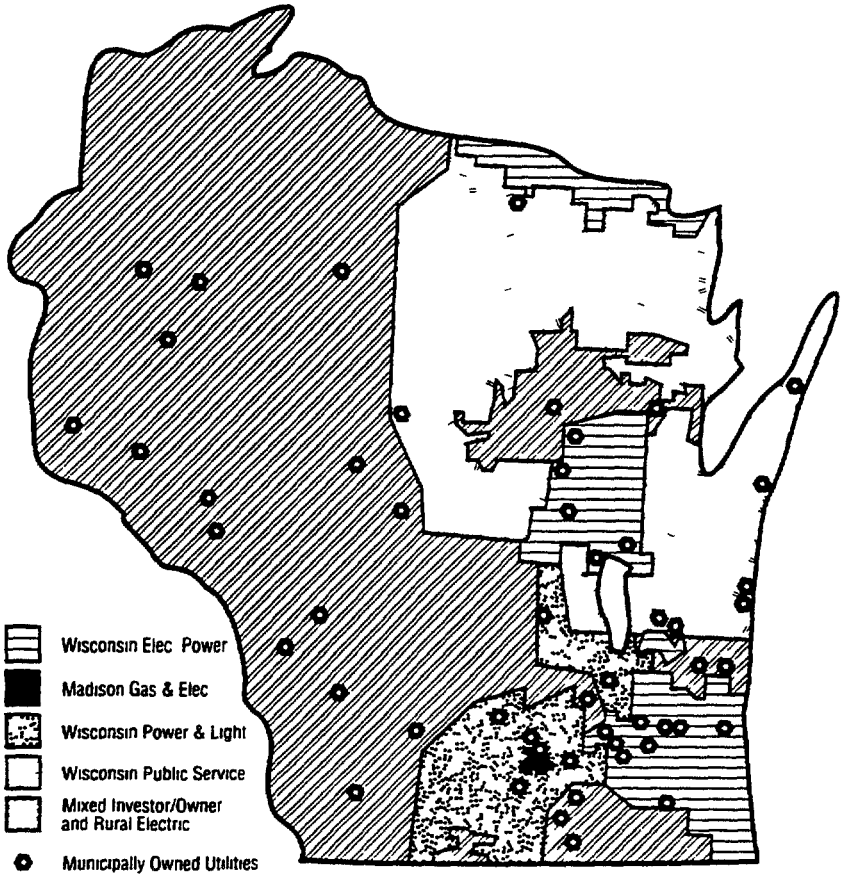
This process provides an effective mechanism for planning and siting major transmission lines in Wisconsin It provides a smooth process for the identification of future system planning problems, evaluation of alternative solutions, authorization of construction, and getting facilities constructed and into rate base

Transmission planning under the 1975 law has evolved and improved The fourth planning order, issued by the PSCW in August 1986,[16] formalized the comprehensive method for transmission planning developed by the utilities and the PSCW staff This order specifies criteria for the analysis needed as the basis for approval of transmission plans The analysis is used to identify system problems, evaluate solutions, and to demonstrate that those solutions will work for at least 15 years into the future

This analysis is carried out on a single-system basis, which means looking at the transmission system for the whole area without consideration of utility boundaries or transmission line ownership This is necessary because the electrons flowing on the system are indifferent to both transmission line ownership and utility boundaries

Analysis on a company-by-company basis would fail to identify problems on the boundaries between utilities, it would not identify solutions that rely on the strength of a neighboring utility system, it would not identify combined solutions that may solve several problems for neighboring utilities The Wisconsin transmission planning process avoids these inefficiencies, which would impose unnecessary costs on ratepayers and unnecessary impacts on land owners and the environment

Use of the transmission planning criteria has facilitated both transmission planning review and construction case review In planning proceedings there is now much less controversy over transmission plans because they are well substantiated In construction cases there is much less controversy because of the foundation provided by thorough planning Land use, environmental and NIMBY (not in



The interleaved service territories of Wisconsin s investor-owned and consumer-owned utilities make joint transmission planning logical if not absolutely necessary

my back yard) concerns do not go away, but they are easier to deal with when not clouded by uncertainty over the need for a project

V Why Did the PSCW Address Transmission Access?

The rationale for Advance Plan 5 developed quite naturally As the PSCW was developing its integrated, least-cost approach to supply-side and demand-side planning concurrent with the above improvements in transmission planning, it became apparent that these activities were fundamentally interrelated the impact of demand-side measures on loads affects the transmission and generation that will be required, likewise, the cost of transmission and generation affects which demand-side measures are chosen

Duplicate transmission facilities are costly, inefficient, and unnecessarily degrade the environment Consequently, where the transmission system is electrically adequate, Wisconsin law does not allow construction of new facilities Given this situation, the absence of equitable arrangements for access available to all utilities causes several problems utilities lacking access may seek approval for additional facilities in order to reach suppliers, or vice versa, deciding who gets to build when there are many affected utilities may be difficult; and not all rate payers may be getting a fair share of transmission system benefits

Since the PSCW does not allow duplicate facilities, it is stuck with the task of making sure institutional arrangements are in place to make the transmission system available on an equitable basis to all utilities that participate in the planning process

Wisconsin approaches the opening of its transmission grid from the perspective of joint system planning, which is founded on a clear understanding of how the grid actually functions Because of this understanding, the PSCW is able to take the step from a systematically planned and constructed transmission grid, to one in which

costs and benefits are shared on a joint system basis, as simply the next logical step in an existing continuum

There are other benefits of increased access to the transmission system Increasing access promotes competition at the generation level It also promotes competition on the demand-side by increasing the market for sale of any capacity or energy made available by demand-side measures

VI Joint Use and Cost-Sharing Solution to a Practical Problem

The transmission system is an interconnected network made up of pieces owned by many different entities Because of the network nature of the system, a transaction does not affect just the flow along one particular path, but flows throughout the network. As a result, every utility is constantly using the transmission lines of others, whether or not there are formal arrangements for such use

The adoption of transmission joint use and cost-sharing agreements, instead of relying on wheeling, avoids a number of the difficulties which plague the latter approach Joint use and cost-sharing facilitates dealing with the transmission system as it actually works, rather than relying on various fictions For instance, if the power seller and the purchaser are linked by a transmission system covered by a joint use and cost-sharing arrangement that includes the other utilities in the area, there is no reason to pretend that the electrons flow over a contract path' Most wheeling arrangements rely on this fiction, even though power flows not over a given line but over the whole network.[17]

The joint use and cost-sharing approach also avoids the need to wrestle with the 'excess capacity' concept that arose in the Pacific Corp/Utah Power and Light merger case There is no need to attempt to assess excess capacity on the system or speculate about its costs Indeed, there is no necessity to pin a cost on *the transaction* at all

VII The FERC Task Force Report and the Wisconsin Approach to Access

FERC's Transmission Task Force Report sets forth many of the issues involved and evaluates alternative approaches or models These approaches are grouped into categories the contract approach, the planning approach and the British approach The Wisconsin approach is one of those discussed under the "planning" category

A Effect on Interstate Transactions

The Task Force Report expresses concern about the impact of the Wisconsin approach on interstate transactions [18] The PSCW planning order does not address this issue directly However, far from restricting interstate transactions, the order includes a number of provisions that will facilitate interstate transactions It will do so because, by requiring development of transmission joint use and cost-sharing agreements and filing of wheeling tariffs with FERC, transmission access will be more readily available to suppliers and utility buyers, both interstate and intrastate transactions

The PSCW supplemental order also states that including out-of-state portions of Wisconsin utilities in the planning process is to be encouraged This is important because five out of the six major Wisconsin utilities either serve outside the state or are affiliated with utilities outside Wisconsin

The PSCW order requires the eastern Wisconsin utilities to investigate the potential benefits of joining the Mid-Continent Area Power Pool (MAPP), which is a power pool as well as a reliability council [19] MAPP includes the provinces of Saskatchewan and Manitoba and all or part of the states of Montana, North Dakota, South Dakota, Nebraska, Iowa, Wisconsin and Minnesota This provision also takes a regional point of view and is intended to facilitate increased interstate transactions

Far from restricting interstate transactions, the order includes a number of provisions that will facilitate interstate transactions

Finally, in February 1990 the PSCW determined that an existing Shared Transmission System (STS) agreement between Dairyland Power Cooperative (DPC) and the Western Wisconsin Municipal Power Group (WWMPG)[20] was in compliance with the 20 principles for joint use and cost-sharing agreements which is an important part of the PSCW planning order This agreement allows the participating municipal utilities to use the entire DPC transmission system, which extends into Iowa and Minnesota as well as Wisconsin

The agreement allocates future costs of the transmission system on the basis of peak loads To buy into the Shared Transmission System, the municipal utilities paid 104 percent of what would have been their peak load responsibility share of the embedded cost of the existing system This shows that transmission joint use and cost sharing agreements which are not based on embedded costs can be compatible with the 20 principles for these agreements spelled out in the PSCW planning order The PSCW also noted that

> the STS Agreement not only responds to the 20 principles, but does so for all municipal customers of DPC, including those in Iowa All the municipal participants are given the opportunity to make transactions on the same basis that DPC can make them in all three states in which DPC serves, which facilitates efficient movements of power on a regional rather than on a strictly Wisconsin basis This feature of the STS Agreement is a good foundation for planning and use of transmission facilities on a regional basis, which this Commission is interested in moving toward, as stated in the AP-5 order [21]

B Incentives for Access

The analysis in the FERC Report seems to assume that incentives must be provided to induce both transmission access and the

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construction of adequate transmission facilities This assumption may be appropriate for FERC, given its limited authority However, this sort of inducement is not necessary if state authority can be used directly to accomplish both transmission access and the construction of adequate transmission facilities

Wisconsin addresses both of these matters directly The PSCW has the authority and an effective process for ensuring that necessary facilities are both planned and built The PSCW requires transmission joint use and cost-sharing agreements and the filing of wheeling tariffs with the FERC Taking these state powers and actions into account in the evaluation of policy alternatives appears to move the performance of the Wisconsin planning approach much closer to the Task Force Report's view of the British approach.

The Report s concern about allocation of transmission use, should short term congestion occur, is not addressed by the PSCW order However, the order does not restrict development of allocation mechanisms to address any such short term congestion

C Workability

The Task Force Report s concern about having too many cooks stirring the broth—i e , too many players involved in the planning process—has not proved a problem in Wisconsin Our experience is that smaller players have banded together in groups for the sake of organizational efficiency For example, three municipal utility joint action agencies greatly reduce the effective number of players, environmental groups have used an umbrella group in the same way

D Independent Power

The FERC Report's concern about providing increased transmission access to facilitate transactions between utilities and IPPs is addressed by the PSCW planning order Requirements in the order for the development of transmission joint use and cost-sharing agreements and for the filing of wheeling tariffs with the FERC should facilitate utility use of the transmission system to make deals with IPPs outside their own service territory

All states have broad authority under the police power to minimize power costs, minimize power facility impacts on landowners, and protect environmental values

E Interstate Coordination

The Task Force Report also raises question about how much coordination with surrounding states is necessary to stimulate more coordinated transmission planning To date, Wisconsin's interaction with surrounding states on transmission issues has occurred on an *ad hoc* basis when projects of mutual interest arise If a more formal mechanism is needed in the future, closer cooperation can be pursued

Wisconsin's geography, with Lake Superior as part of its northern boundary and Lake Michigan to the east, tends to limit the extent of such planning with adjacent states States with more neighbors may find that closer cooperation—or even the development of multistate compacts[22]—is necessary to carry out transmission planning and siting more effectively

VIII Conclusion

The states have an important role to play in the regulation of transmission The states and FERC have different authorities and responsibilities regarding the transmission system, which provide opportunities for development of mutually beneficial approaches to transmission access Both state and federal responsibilities should and can be fulfilled

While the statutory delegation of power to utility commissions varies from state to state, all states have broad authority under the police power to minimize power costs, consistent with a reasonable return to utility investors to minimize power facility impacts on landowners, and to protect environmental values

This reservoir of state authority

can be used as it has been in Wisconsin to bridge the transmission access gap between state and federal transmission regulation The transmission access provisions included in the Wisconsin order are designed to meet the state's needs and bridge the access gap without trespassing on FERC's authority In fact, the Wisconsin approach advances federal as well as essential state interests

The State of Wisconsin has delegated to its commission broad responsibilities and authority Transmission planning is but one component of the least-cost planning approach which has been developed to meet these responsibilities We hope our efforts are helpful to other states and utilities who are confronted with similar problems However, we are aware that what works in Wisconsin may not be the right solution for every area or jurisdiction.

Approaches which permit opening the transmission system without damaging it, which improve electric service at lowest cost, and which carry out the public's interest in a quality environment should be encouraged ■

Footnotes

1 Nantahala Power and Light Co v Thornburg 476 U S 965 106 S Ct 2349, 90 L Ed 2d 943 (1986)

2 Florida Power and Light Co 40 FERC ¶ 61 045 (1987)

3 Otter Tail Power Co v U S 410 U S 366, 93 S Ct 1022 35 L Ed 359 (1973) *See also* Southeastern Power Administration v Kentucky Utilities Co 26 FERC ¶61,127 In this case, which tested FERC s authority to order wheeling under sections 211 and 212 of the Federal Power Act the Commission refused to order the wheeling sought on the basis that to do so would not "reasonably preserve existing competitive relationships a key finding under the statute Later FERC members have suggested FERC may have construed the statute s requirements too strictly but the matter has not been revisited in any proceeding since that time

4 Public Service Commission Docket 05-EP-5, Order dated April 6, 1989 and Supplemental Order dated April 19, 1989 (hereinafter the ' Advance Plan 5 Order) 102 PUR 4th 245 (1989)

5 Utah Power & Light Co 45 FERC ¶61 095 (Order 318) 47 FERC ¶61,209 (Order 318-A), and 48 FERC ¶61,035 (Order 318-B) *See also* THE TRANSMISSION TASK FORCE S REPORT TO THE COMMISSION ELECTRICITY TRANSMISSION REALITIES THEORY AND POLICY ALTERNATIVES (Oct 1989)(hereinafter Transmission Task Force Report, or Task Force Report)

6 For simplicity this article will refer to cost- and use-sharing agreements but the Advance Plan 5 order allows utilities to comply by instituting other arrangements that accomplish the same thing There is a broad array of institutional possibilities The order requires only that such agreements or arrangements be compatible with the 20 principles spelled out in the order

7 The 1989 planning order provision requiring the development of transmission use and cost sharing agreements reads as follows

71 Transmission system use and cost sharing agreements (either bilateral or multilateral) or other institutional actions that achieve the same result and are compatible with the principles included in Appendix H shall be developed between all major utilities (WEPCO WP&L WPS, NSP MG&E SWL&P and DPC) which share a border, and between each of those major utilities and all municipal utilities, small investor-owned utilities, and cooperatives that share a border with the major utility and choose to enter such an agreement Each municipal utility small investor-owned utility or cooperative desiring an agreement may choose to do this on an individual basis or as a member of a group Each of the investor-owned utilities or DPC that is connected to WPPI members shall develop transmission use and cost sharing agreements with WPPI on behalf of its members

8 Several of the Transmission System Use and Cost Sharing Principles from Appendix H of the 1989 planning order are listed below

2 The transmission system is a single interconnected system which must be planned and built on a state wide single system basis for the general public good

4 If a particular transaction which can be handled physically by the existing system is prevented by institutional problems, it is necessary to solve the institutional problems rather that to build duplicative facilities

5 Ownership and/or use of the transmission facilities should not unduly enrich one group of ratepayers and/or stock holders at the expense of another group

6 Utilities that use or intend to use the transmission system need to participate either directly or through a representative in the advance plan transmission planning process and in the least cost planning process in order to develop an approved least cost plan and

implementation program

8 Broadening the use of the transmission system must not be allowed to degrade retail service reliability

10 In view of the utilities legal obligation to serve it is inappropriate for retail customers to be allowed to use the transmission system to make their own transactions

16 Fair allocation of coordination and reliability benefits of the transmission system must be assured All users should be able to dispatch economically to meet their loads by being able to use a full range of transmission

18 Owners of transmission facilities must be fairly compensated for their use Fair compensation does not include any amounts for value created by the owning utility s monopoly position

9 The provision of the PSCW order requiring the filing of wheeling tariffs reads

77 All major investor-owned utilities shall file wheeling tariffs with the Federal Energy Regulatory Commission (FERC) within one year of the date of this order

10 *See e g* section 202 (a) of the Federal Power Act under which FERC is required to divide the country into voluntary coordination districts so as to better provide an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources

16 U S C §824a(a)

11 For simplicity this article will refer to cost- and use sharing agreements but the order allows utilities to comply by instituting other arrangements that accomplish the same thing There is a broad array of institutional possibilities The PSCW order requires that these agreements or arrangements be compatible with 20 principles spelled out in the order

12 *See* C Mitchell *Lagging in Least Cost Planning—Not As Far Along As We Thought* THE ELEC J Dec 1989 at 24 26 showing that nine states have implemented substantial least-cost planning regimes

13 *See e g* note 10 *supra*

14 In early years problems arose at the planning stage because plans lacked adequate documentation What documentation existed was often inconsistent and underlying assumptions unclear Even data on the existing system were inadequate As a result planning questions were addressed in the construction cases This resulted in delays and denials because construction cases are too focused on one facility to be a useful forum for overall system planning The transmission system must be planned as a whole because of the interactions of all the interconnected facilities

15 In practice even the transmission system down through 69 kv has to be planned because the entire system is a network For example an outage of a 345 kv transmission line can cause overloads on lower voltage lines

16 Order Public Service Commission of Wisconsin Docket 05-EP-4 August 5 1986 (generally referred to as Advance Plan 4 Order)

17 This divergence of the contract path fiction from the network reality causes problems Utilities not included in the contract path arrangement experience changes in the power flowing on their transmission lines Such third party impact problems can only be addressed by getting the utilities whose transactions or transmission lines are affected to address the problem together They all need to be involved because each of their own supply loads and transactions affects how power will actually flow on the network

18 Task Force Report *supra* note 5 at 131 note 9

19 The utilities in western Wisconsin already belong to the Mid-Continent Area Power Pool (MAPP) the eastern Wisconsin utilities belong to the Mid-America Interpool Network (MAIN) MAIN is only a reliability council and not a power pool The eastern Wisconsin utilities will meet the MAPP membership requirement that a utility have at least two transmission interconnections with MAPP utilities once an interconnection currently under construction is completed in 1991

20 The transmission joint use and cost sharing approach provides the opportunity to use simple mechanisms to share costs and benefits of the system For example the DPC/WWMPG Shared Transmission System agreement simply allocates responsibility for new transmission costs among the participants on the basis of non-coincident peak loads The joint use and cost sharing approach can also incorporate more complex mechanisms for sharing costs and benefits if that is seen as desirable For example the MAPP power pool is testing a complex power flow modeling method for compensating members for losses caused by transactions within the pool

21 *See* Docket No 05-EP-6 letter order Feb 6 1990 the Shared Transmission Agreement between DPC and WWMPG was entered into in 1984 and is discussed on page 206 of the FERC Task Force Report *supra* note 5

22 *See e g* F Frankfurter and J Landis *The Compact Clause of the Constitution—A Study in Interstate Adjustments* 34 YALE L J 685 (1924) *see also* R Marritz *A Safety Net for State Regulation?—The Compact Clause of the Constitution* THE ELEC J May 1989 at 26

A Busy Signal for Electric Power: A Day in the Life of N. U. Gigawatt

An analog to a telephone busy signal for transmission networks would make them more efficient and reliable, from the perspective of nonutility generators, while promoting freer access to wheeling

Hyde M Merrill and Allen J Wood

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Norman Ulysses Gigawatt lives a life like yours and mine Home in a respectable suburb Adoring wife Great job managing a cogeneration facility at a local pulp mill Approximately 2 4 children (rounded up, in his case, to an even three) He drives a two-year-old Chevy wagon and a seven-year-old VW And therein lies the rub He dreams of trading his VW for a Porsche

On this particular typical day Norman had a typical breakfast—almost A cursory exploration of the refrigerator revealed it to be unusually juiceless But he accepted this as an unambiguous annoyance He had no doubt that there was no juice, and the lack of his matutinal libation was merely an annoyance—it threatened neither life nor fortune

Six blocks from the office Norman U Gigawatt hit a red light The wait was not onerous He knew from experience what that intersection had been like before the light was installed One day a year or two back the light had gotten stuck It slowed things down a bit but since it was an obvious malfunction, people eventually had proceeded cautiously through the intersection By the time he had returned home that evening, it was working again

Later that morning Norman U Gigawatt tried to call home to remind his wife to pick up orange juice The

line was busy He knew that there was only one line going into his house, and that only one conversation could be carried on at once With no teenagers, and knowing his wife s habits, he figured that if he tried again in ten minutes he had a good chance of getting through And sure enough, he did

Incidentally, he had little doubt that, if he got a busy signal, the line was truly busy several times, when it seemed to be tied up for an inordinate time, he'd had the phone company verify it They usually reported that, yes, someone was talking Once, when he hadn't been able to get through for hours, they told him that there was something wrong with the line It was fixed that afternoon But that had only happened once, so he believed the busy signal unless he had evidence to the contrary

N U Gigawatt ate lunch at McDonald s The milk shake machine, the kid told him, was kaput, so he had a Sprite instead He had no reason to disbelieve the kid After all it was in McDonald s interest to sell him a milk shake

That afternoon Favorite Light and Power Company (FLAPCO) one of N U Gigawatt s best customers, called and asked for 75 MW from his cogeneration plant for two weeks FLAPCO was willing to pay a good price — a few more like this and he could afford the down payment on the Porsche

Unfortunately, NUG would have to wheel through Big Bad Power Company (BBP), and he d had problems making those arrangements in the past Dealing with BBP was always a hassle Sometimes they told him that they didn't have capacity available to do the wheeling He got the impression they were worried about overloading lines He was aware of occasional local blackouts in his area, but they were always caused by tree limbs on low-voltage lines or drunks hitting distribution circuit poles, and he knew that his power would be moving on the high voltage network This made NUG wonder how real BBP's concerns really were

When he tried to press BBP on how much of what they called "transfer capability" there really was, he could never get a straight answer The BBP engineers started by throwing jargon around and ended by telling him that it was too complicated and difficult to explain to a layman He had a cousin who worked for a power company out west who once told him that his company used different reliability and operating criteria than eastern utilities like BBP, and that there was a lot of 'engineering judgment involved in defining and applying measures of network capacity In his darker moments, NUG wondered if BBP wasn t freezing him out so that they could sell their own power to outfits like FLAPCO

NUG was thinking about the Porsche — a red 911 — as he dialed BBP After he explained what he wanted, he got a lot of hemming and hawing about contingencies that might happen and VAR support (that s imaginary power — why should he care about imaginary power?) and voltage collapse — all stuff that never happened and never will They finally told him they d have to make a couple of load-flow runs and a stability study before they could say yes or no That s when he hung up and called his attorney (who, by the way was on another line

When he tried to find out how much "transfer capability" there really was, he could never get a straight answer

when he called, but got back to him promptly) to discuss a lawsuit against BBP—probably a long and costly lawsuit Norman Ulysses Gigawatt wasn't thinking about Porsches anymore

The moral of the story is this unexpected service interruptions are more tolerable if their causes are clearly understood Of the various interruptions experienced by Mr Gigawatt on this typical day, Big Bad Power Company's unwillingness to wheel power for him was by far the most disturbing, primarily because of his unconfirmed suspicion that the transmission network wasn't truly at capacity In contrast, the other signals of service interruption, such as the telephone busy signal, were clear and unambiguous, allowing him to adjust his routine accordingly

Unexpected service interruptions are more tolerable if their causes are clearly understood

Unfortunately, instituting a "busy signal" for electric power transmission is a very difficult, and as yet unsolved, problem But it is the key to making the most efficient use of our transmission networks One need only consider how much less efficient our telephone system would be if the phone company regulated the number of outgoing calls to lower the probability of simultaneous calls to the same number, rather than letting customers find out for themselves that the lines were busy

Given the importance of transmission access to the future success of deregulation, privatization, and competition, developing a busy signal for transmission access is an issue of premier importance Utilities need it to maintain the security of the network, regulators need it to know how much capacity the network really has, and nonutility generators (NUGs) and purchasers need it to know how much power they truly can move

The remainder of this paper describes why present methods of determining network capacity are inadequate for both operational and planning purposes We then precisely state the busy signal problem and present the required characteristics of a practical and acceptable solution

I The Transmission Network

At this point it is useful to describe and differentiate between two models of a transmission system

A Model 1 Transmission as the Movement of a Commodity

This model, which is almost everyone s implicit or explicit mental model, treats electrical energy as a commodity which is produced at point A, moved to point B, and used there In Model 1, the three processes (generation, transportation, and use) are quite different and can be viewed independently in terms of physical mechanics, ownership, regulation, costing, pricing, etc

B Model 2 Transmission as a Function of an Integrated Machine

The physical reality which conflicts with Model 1 is that transmission moves nothing from point A to point B Not even electrons move from A to B in an AC

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circuit In Model 2, transmission is a force-at-a-distance phenomenon which is part of an integrated energy-conversion machine One analog is the transmission of a car, which connects the engine to the wheels Another is a belt drive which couples a steam engine to a gear which raises or lowers an elevator In fact, it is instructive to think of a complicated belt system, driven by one or more steam engines, which runs a lathe in one room, a drill press in another, and an elevator at the end of the hall Voltage, VARs, electrical losses, etc , all have their analogs in this system

C Practical Differences Between Model 1 and Model 2

All of the challenges and difficulties associated with the busy signal problem are due to the differences between Model 1 and Model 2 In Model 2, the operation of the transmission system cannot be separated from the operation of the engines and the wheels, lathes, elevators, etc In Model 2, it is the transmission system as a whole, not a piece of the drive shaft or one of the idler wheels, which allows potential energy at one location to be transformed into useful energy elsewhere Although Model 2 is more consistent with physical reality than is Model 1 much of the language and many of the concepts used in transmission engineering have their roots in Model 1 Edison found the Model 1 power flow concepts handy, and one of the important contributions of the pioneers was to develop a practical way of measuring and integrating flow — the Watt-hour meter We will use these existing constructs, but keep in mind that they reflect reality only crudely

II Measuring Transmission Capacity

A How Capacity Is Measured Today

Transfer capacity is not the rating of a single line or a few lines It is a function of the strength of the network as a whole It is defined in terms of reliability criteria, which are subjective and somewhat imprecise It varies as switching operations occur and as demand, generation, and wheeling patterns change Even loop flows and actions taken by operators of other systems affect the available transfer capacity Given these realities, transmission capacities can be extremely difficult to establish even in simple cases

To get a flavor of the complexity involved, consider three interconnected systems X, Y, and Z The amount of power that X, say, can transfer simultaneously to Y and Z can be represented on a 2-dimensional graph, where the vertical axis represents power transfers between X and Z and the horizontal axis represents transfers between X and Y (negative values on the graph represent power imported by X, positive values indicate power exported by X) Each combination of transfers involving X is then represented by a point on the graph

Not all combinations are possible however In general, there will be some bounded region on the graph, the interior of which

Transfer capacity is not the rating of a single line or a few lines It is a function of the strength of the network as a whole

Developing sets of transfer capability diagrams for even a three-area system takes a lot of engineering time and cooperation

represents the set of allowed power transfers The perimeter of this region is called the Transfer Capability Polygon (TCP), which represents maximum allowed transfers A typical example of a TCP for the three system case is shown in Figure 1 In this diagram, if X is transmitting 1300 MW to Y, then the transfer capability between X and Z is 2000 MW (X to Z) or 2600 MW (Z to X) All transfers between these maximum values are also allowed

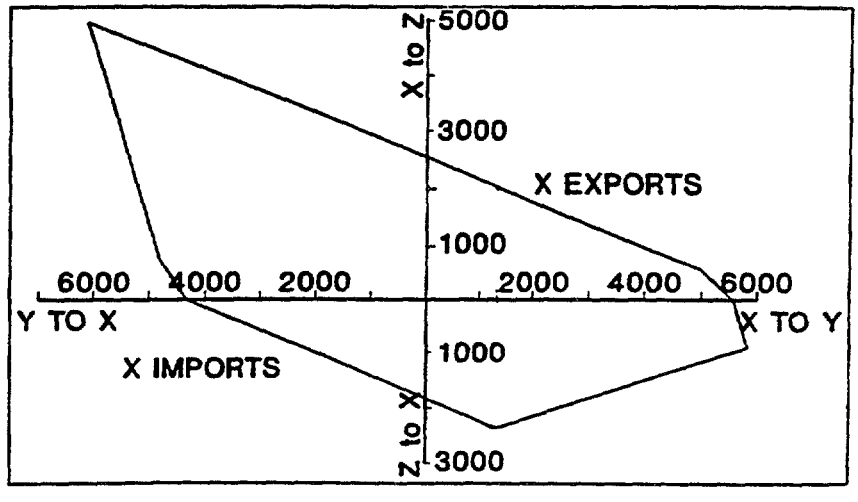
Three such diagrams are used to represent transfer capabilities for a three area (X, Y, and Z) system Each diagram is valid for one specific operating condition and a particular set of reliability criteria These diagrams are developed using load flow programs, which simulate the flows on the network. Developing sets of these diagrams for even a three-area system, for a spectrum of operation conditions, takes a lot of engineering time and inter-utility cooperation Transfer capabilities for systems with more complications (due to a variety of possible wheeling transactions, for instance), are much harder to model

Reliability and security issues are closely related to transfer capacity Today's recommended criteria are developed by NERC, by each reliability area, and in some cases by power pools The criteria are interpreted and applied by each individual utility These criteria are different for different parts of the system For example, the reliability of a utility's set of power plants is expressed as loss-of-load probability, expected unmet demand, reserve margin, etc The reliability of the transmission network is defined in terms of the number and type of contingencies it is designed to withstand There is no accepted method for expressing generation reliability and transmission reliability in equivalent terms

Today's methods for measuring transmission capacity work, but only because

—the parties all have large engi-

FIGURE 1 Typical Bi-Axis Transfer Capability Polygon



neering staffs,
—they are willing to exchange data and cooperate in studies, and
—they are not in serious competition, so utility-to-utility differences in defining transfer capabilities are not seen as competitive ploys

Under evolving conditions when NUGs play a larger role, only the first of these conditions is likely to hold, and only for the large NUGs The cooperative nature of today's environment will be lost

Since the entity owning the transmission may compete with NUGs who want to wheel, the definition of transfer capacity may be a bone of contention Accordingly, today's methods for measuring transmission capability probably will not work under deregulation Signs of this are already occurring

B A New Method for Defining Transfer Capacity

Under deregulation and increased wheeling, a new method for defining transfer capacity is needed, with the following characteristics
— it should require straight-forward calculations,
—it should represent an objective, defensible, standard,
—it should be compatible with today s regulated industry structure and with likely evolutions thereof,
—it should not be so conservative as to unduly limit wheeling,
—it should represent variations in operating conditions and network changes due to maintenance, switching, etc , and
—it should lend itself to on-line use in control centers as well as consistent application in planning

It is particularly important that this method be so clearly acceptable to all parties that the courts and commissions will not have to spend inordinate amounts of time reviewing and redefining transmission transfer capability Such a method is not available today The Norman Ulysses Gigawatts' of the world do not get busy signals—they receive irritating dissertations on transfer capability calculations

III Toward A Busy Signal

We will suggest four possible busy signals, each with its own unique development path Others, of course, are possible

A The Gas Pipeline Approach

The first idea is to ignore all those (including the present authors) who cry out that the transmission network is not a gas pipeline and pretend that it is This 'Model 1' approach is actually quite good in many radial situations where there is only one transmission path between A and B Radial lines in the US tend to be dynamic-stability limited or thermally limited rather than limited by transient stability, and contingency issues are irrelevant for radial lines Thermal and dynamic-stability limits are easy to calculate so a busy signal based on them would satisfy all the specifications listed above

Unfortunately for this approach, most of the extra high

The Norman Ulysses Gigawatts' of the world do not get busy signals—they receive irritating dissertations on transfer capability calculations

voltage (EHV) network is not radial But maximum line capabilities might be reduced to something below thermal limits to provide a safety margin for voltage problems and dynamic limits plus leaving a margin to accommodate the fact that the analytical methods used to determine flow patterns will direct flows at will, using all available capacity Determining the appropriate limits for individual elements will be an exercise in itself But have no fear even if we don't want to do it, some administrative law judge or regulator will set these limits, out of desperation, after listening to several hours of "expert testimony" (Similar events have already occurred) We could then develop models of the acceptable flows and transfer limits based on linear-network-flow analysis The methods are available, fast, simple to implement and provide a definite transfer limit They can reflect changes in system configuration and would be easy to implement in an on-line environment

Even if we don't want to do it, some administrative law judge or regulator will set these limits, out of desperation, after listening to several hours of "expert testimony"

This approach fails to meet at least two of the specifications given above First, there would have to be quite a margin of conservatism built into the individual line capacities, so the operation of the system probably would be far from optimal Second, determining the appropriate limits for individual elements will be quite difficult computationally, in the most general situations

B Enhancing Today's Methods

Because of the concerns that power system engineers have about cascading failures and blackouts, one approach would be to keep the basic notions involved in today s techniques and search for simplifying methods to represent them

This general approach is likely to be quite acceptable to experienced power engineers It represents no philosophical change from what they are doing and only incremental steps will be necessary to implement it Unfortunately, it is not clear that significant simplification will be possible This means that these methods will continue to be too burdensome computationally, and too complex conceptually, to meet the specifications given above

C The Traffic Cop

A third approach is to get around the first and second specifications by creating a totally independent, unbiased entity to control grid access in real time and to plan for transmission additions Whatever this entity says is by definition, the transfer capability of the network.

At one extreme the entity could use relatively simple methods in making its decisions This could lead to an under-exploited network At the other extreme, the entity could use very complex analysis, doing the same calculations hinted at in the previous section The difference in this approach is that the cop is given complete authority to say who can go and who must stop, so there is no need for other parties to understand or duplicate the analysis

A major difficulty with this approach is that it is inconsistent with today's U S utility industry structure and with likely evolutions thereof

D Integrated System Approach

The first three methods are based on Model 1 of the transmission network. Using Model 1 to develop a busy signal is a source of significant difficulty, reminiscent of what pre-Copernican astronomers had to do to make their earth-centered model agree with the astronomical data of the day A Model 2 method would not focus myopically on flows through the network Instead, it would treat the network as part of an integrated system, with power injected at some points and withdrawn at others

Unfortunately, we do not yet have accepted models of this type available The closest such models are optimal power flow (OPF) programs, which include

—AC representations of the network,

—generating unit cost characteristics, and

—power flow and generating unit constraints

These have not yet proven to be capable of automatically representing contingencies and the system s response to them But this capability may be achievable If an OPF with contingency analysis could be achieved, with fast run times, it would be the best-available technically-adequate solution The calculations, however, would not be straightforward This requirement would need to be addressed in order to find a truly useful busy signal

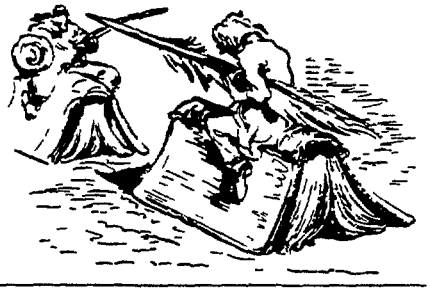
IV Conclusions

With the growth of a competitive generation industry, and as electric utilities compete with each other, there is a need to develop a simpler and more understandable approach to the determination of transfer capability The method should be simple to understand and apply and should provide unambiguous answers It must be conservative enough to accommodate concerns over system security and yet must not unnecessarily restrict the flow of wheeled power

This paper has suggested four possible evolutionary approaches to developing a usable busy signal for power Each of these approaches faces significant problems Probably the most promising is an extension of today's optimal power flow methods, but transient stability issues must be resolved as well ■

Using Model 1 to develop a busy signal is reminiscent of what pre-Copernican astronomers had to do to make their earth-centered model agree with the astronomical data of the day

Book Review



Unraveling the Mysteries of Planning

—by Jim Litchfield

To most individuals, the art and science of electric power planning and regulation are matters confined to the inner sanctum of utilities or the structured processes of a regulatory hearing

Ed Kahn's book, *Electric Utility Planning and Regulation*, does a superb job in helping unravel the mystery of how the electric power industry has evolved from its beginnings to its current structure It also translates the esoteric dialect of electric power into clear English

Kahn, a staff scientist at Lawrence Berkeley Laboratory, sets the stage for an electric power industry wrestling with awesome changes Change is endemic in every level and facet of the industry, including the regulatory environment Regulation is becoming an increasingly important component of the industry's decision making structure, on which society depends more and more

***Jim Litchfield** is director of power planning for the Northwest Power Planning Council*

During the late 1800s, electric power began to emerge as one of the highest quality and most versatile forms of energy During its early development, the electric power industry took advantage of tremendous opportunities for improvements in efficiency, a challenge now facing it again in different guise

One figure in the book charts the cost of electricity over nearly a century, from 1892 to 1982 From a nominal price of more than 20 cents/kWh (and a real price that is hard to imagine), the chart depicts the "golden era" of the industry during the first 40 years of this century, the nominal cost of electricity was reduced tenfold

Electric Power Planning and Regulation
by Edward Kahn
American Council for an Energy-Efficient Economy, 339 pp

Kahn sets the stage nicely for the industry we see today with conservation now widely recognized as a resource, competition a fact, environmental concerns and values increasing; regulators beginning to involve themselves in resource planning through least-cost planning and bidding; and further mergers or takeovers likely

Kahn also tells us how utility planning has evolved and changed, beginning with simple decision processes derived from the economic literature on capital budgeting, which emphasized levelized life-cycle cost as the primary decision rule, and moving on to the increasing complexity of modern decision making, which explicitly address uncertainties Kahn concludes

> [T]he financial upheavals of the 1970s have been sorted out in neither theory or practice With declining productivity of investment, there is clearly less incentive for capital intensity than in the past But quantitative measures of this incentive are difficult to come by, and theoretical models only somewhat suggestive All that can be said with certainty is that the application of the Jeynes decision rule [a decision rule based on maximizing a firm's earnings per share for given revenue increases as the appropriate objective for investment decisions] is gone

From discussing reliability aspects of planning, Kahn moves on to analyze the complex world of regulation From the basics on how regulatory commissions go about setting prices to real world case studies of a particular rate case in California, the reader gets a sometimes too graphic description of the inner workings of regulation But for anyone interested in joining the regulatory wars, this book offers a good description of the economic theory of regulatory decision making and helps to illustrate the significant policy judgments which play a part in it

Readers will also be pleased to find material addressing indepen-

dent power production and demand-side utility programs Real world experiences, largely from California, are offered to help clarify the role these two new resources play in utility planning Related material dealing with bidding as a means to acquire new resources and a discussion of the industry restructuring that could evolve from the decentralized nature of both demand-side and independent power producer resources is also helpful

Kahn believes power pools are still very much needed to provide benefits of increased coordination and the economies of scale beyond the scope of individual utilities, also, that there are still forces driving toward increased centralization of power markets, along with decentralizing forces

In this, he sees a significant issue for public power

A distribution company which is too small to negotiate with suppliers effectively is not likely to benefit from a competitive bulk power market Thus, individual municipalities or agricultural cooperatives might have to merge operations to cope with the competition among purchasers for the cheapest power supplies The whole system of public power may not be easily compatible with unregulated bulk power markets

Electric Utility Planning and Regulation is interesting reading for anyone associated with the electric power industry Perhaps more importantly, it would serve as a very good text for new employees or students contemplating joining the electric power industry

As one of the most important elements of the nation's economic well-being, the electric power industry deserves the best trained and most talented new employees society has to offer This book can help turn on the light for the next generation of engineers and analysts ■

Kahn s book is helpful for the experienced analyst as well as the new

continued from page 60

agreed goals, to see if, as Wisconsin tantalizingly claims, the two jurisdictional levels can have an alliance rather than a turf war

Already, at the last NARUC meeting, there was talk of a joint FERC-state workshop to explore possibilities

This may be a good idea someday, but not yet For now, we suggest the states and FERC continue to pursue their responsibilities independently Let their respective creative processes and, yes, their rivalry continue for a while The states must first determine where they want to go They are not all as far along as Massachusetts or Wisconsin, and may want to consider other options

And let Mr Allday assess where his commission wants to be Has the air gone out of the "reform" balloon, now that Stalon and Hesse are gone, as Trabandt suggests? If so, it s the states next move anyway

Even if FERC is interested, little of use could be accomplished until positions and goals of the various players are better developed A FERC-NARUC summit on transmission at this early date would produce at best warm fuzzies, or at worst, the rasp of peeling velcro The commissioners, utilities and other camp followers such a meeting would attract do not deserve such a fate

The transmission issue, as Massachusetts Commissioner Susan Tierney has said, is in ' transition,' but its head isn t crowning just yet

EDITORIAL

Transition for Transmission

"A watched pot never boils" When people long for a particular result, it seems to take forever This is true with the trivial—children on car trips asking, "Aren't we there yet?"—and the poignant—homeless families hungering for their own roof, Lebanese longing for peace

Such is the case with those who have urged opening of the nation's electric transmission system to wider use For years it seemed that those who owned the nation's electric power highways also owned the debate

Most recently, FERC has been inhibited by the perhaps worse-than-useless wheeling provisions of sections 211 and 212 of the Federal Power Act, enacted as part of the Public Utility Regulatory Policies Act These provisions, which on their face set out the basis under which FERC may order transmission service, in fact present the most formidable barrier imaginable to such an order They are prolix testimony to a lobbyist's skill and deviltry, and a warning of what twisted visions can be wrought into law amid complex legislation (Clean Air Act watchers, beware!)

As just one example, these FPA sections require that transmission service not be granted if doing so would "unreasonably disturb existing competitive relationships" Yet *some* disturbance of relationships is essential if competition and choice are to be promoted What does "unreasonably" mean?

This situation is now changed In its Transmission Task Force Report, FERC has explored what can be done under its existing authority As Commissioner Trabandt has noted, the principal supporters of the Task Force Report and the approach it suggests have left the Commission But FERC will continue to search for solutions to the transmission dilemma, if only defensively they cannot abandon the field to the states or the Department of Energy And FERC has seen what open access unleashed in natural gas markets

The proposals urged in by state regulatory interests in this issue have two central goals

1 ***To use the transmission system to develop more competitive power markets*** Policy makers have seen what force a little competition can unleash Questions raised by transmission-owner spokesmen like American Electric Power's Dick Disbrow about the complexity of power flow and stability issues can be addressed

But there is no disputing that power markets can operate much more competitively, and there appear to be no insuperable technical obstacles to wider transmission service for utilities or nonutilities, as the Congressional Office of Technology Assessment found in its 1989 study

2 ***To have a transmission system adequate for use by all suppliers and utilities in an area, while protecting environmental values*** Even if it were economically feasible for each user to build its own lines, this would be environmentally undesirable As Wisconsin regulators have seen, this fact alone forces transmission line siting agencies to see to it that service is available to all users over a network that is at least minimally adequate

Let's be candid If policy makers were to structure a power system today, starting from scratch, they would not design the transmission ownership pattern we have now

We would not put the transmission system in the sole hands of the principal buyers and sellers Rather, the transmission system—the paths of commerce—would be owned and operated by an independent utility corporation or a public body for the benefit of the various buyers and sellers, a model Great Britain and other countries are now turning to

We would devise a better process for siting transmission lines—one that does not allow a single jurisdictional body veto power over the decision where other interests are at stake We would find some way to compensate a jurisdiction for costs which facilities impose on it

And we would harness the expertise that exists in the utilities and the research community to find better ways to design and operate the system to meet the needs of all those who use it

FERC Chairman Martin Allday appears to be more committed than his predecessor to work with the states to pursue mutually

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Editorial Advisory Board

The members of *The Electricity Journal's* Editorial Advisory Board listed below are not and will not be responsible for what appears in these pages They have, however, graciously agreed, time permitting, to suggest articles and authors we should consider publishing, and to try to comment on articles in advance of publication when asked We and our readers will be enriched by their generosity, their ideas, and their critical comments

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Merribel S Ayres, Executive Director
National Independent Energy Producers

Douglas C Bauer, Executive Vice President
ERC Energy and Environmental Services

Steve Brobeck, Executive Director
Consumer Federation of America

Ralph Cavanagh, Senior Staff Attorney
Natural Resources Defense Council

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Energy and Power Subcommittee,
U S House of Representatives

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Public Utility Institute, University of Wisconsin

William C Walbridge, Executive Vice-President
and General Manager,
Seminole Electric Cooperative

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PSI ENERGY, INC

Transmission Service Tariff

A. **DEFINITIONS**

The following words and terms as used herein shall be understood to have the meanings set forth below

1 "Bulk Transmission System" means the transmission facilities operated by PSI at or above 138 Kilovolts ("KV) pursuant to the Transmission and Local Facilities Agreement dated November 5, 1985, among PSI, Wabash Valley Power Association ("WVPA"), and Indiana Municipal Power Agency ('IMPA"), filed with FERC in Docket No. EC86-3-000, as it may be amended from time to time

2 "Commission" or "FERC" means the Federal Energy Regulatory Commission or such successor federal regulatory agency as may have jurisdiction over this Tariff

3 "Coordination Transmission Service" means Transmission Service provided for periods of less than five years, and may include both Firm and Non-Firm Transmission Service

4 "Contract Demand" means the maximum amount of capacity in megawatts, specified in the Service Agreement, that the Company has agreed to schedule to transmit over its Bulk Transmission System from a specified Point of Receipt to a specified Point of Delivery

5 "Delivering Party" means the entity supplying the capacity and energy being transmitted to a Point of Receipt with PSI

6 'Electric Control Area' means the self-contained set of generating units and electrical loads managed and overseen by a utility that is responsible for matching generation with such loads on a second-by-second basis

7. "Eligible Utility" or "Utility" means a private or public corporation, governmental agency or authority, municipality, rural electric membership corporation or cooperative, person, or lawful association of any of the foregoing, which engages in the generation, transmission or distribution of electric energy at wholesale or retail and which is subject to regulation with respect to rates or services under the laws of the state where such entity renders electric utility service, or pursuant to the Federal Power Act, or is legally exempted from such regulation; provided, however, that the term "Eligible Utility" shall not include ultimate consumers of electric utility service. "Eligible Utility" shall include qualifying small power production facilities and qualifying cogeneration facilities under sections 3(17)(C) and 3(18)(B), respectively, of the Federal Power Act, independent power producers; and PSI Energy, Inc., but PSI shall be an Eligible Utility only for purposes of sales pursuant to PSI s Rate Schedule FS-1.

8. "Firm Transmission Service" means Transmission Service which is provided by PSI on an all reasonable efforts basis and can only be curtailed or interrupted due to events and circumstances specified in Section H of this Tariff Firm

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Transmission Service does not include ancillary services, including but not limited to, load following and voltage control, or back-up or reserve transmission services

9 "Long-Term Firm Transmission Service" means Firm Transmission Service provided for a minimum term of five (5) years

10 "Native Load Customer(s)" means PSI's retail customers and its customers under PSI's FERC Electric Tariff Original Volume No 1 (9th Revision) Rate MUN, PSI's FERC Electric Tariff Original Volume No 2 (7th Revision) Rate REMC-1, PSI's FERC Rate Schedules No 233, 234 and 236, or such amended or successor rates or agreements as may be filed with and accepted by the Commission from time to time.

11 "Non-firm Transmission Service" means Transmission Service that may be curtailed or interrupted at the sole option of PSI

12. "Parties" means PSI and one or more Eligible Utilities who have entered into a Service Agreement.

13 "Point of Delivery ("POD")" means a point of interconnection on the Company's Bulk Power Transmission System between the Company and the Receiving Party or the Receiving Party's authorized agent where capacity and energy to be transmitted by the Company will be made available to such Receiving Party The POD shall be specified in the Service Agreement

14 "Point of Receipt ("POR")" means a point of interconnection on the Company's Bulk Power Transmission System

between the Company and the Delivering Party or the Delivering Party's authorized agent where capacity and energy not originating on PSI's system to be transmitted by the Company will be made available to the Company by such Delivering Party The POR shall be specified in the Service Agreement

15 "Prudent Utility Practice" means any of the practices, methods and acts engaged in or adopted by a significant portion of the electric utility industry, or any practices, methods and acts which, in the exercise of reasonable judgment in the light of the facts known at the time, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety, expedition and the requirements of governmental agencies having jurisdiction. Prudent Utility Practices are not intended to be limited to any particular set of optimum practices, methods or acts to the exclusion of all others, but rather are intended to include a range of possible practices, methods or acts consistent with the above stated criteria

16 "PSI" or "Company" means PSI Energy, Inc

17 "Receiving Party" means the entity receiving the capacity and energy being transmitted by PSI pursuant to this Tariff Receiving Parties and authorized agents of Receiving Parties may not be retail customers of PSI, either in whole or in part

18 "Service Agreement" means the initial agreement and any supplements thereto entered into by the Eligible Utility and PSI for service under this Tariff.

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19 Transmission Service" means either Long-Term Firm or Coordination Transmission Service at 60 Hertz, alternating current, three phase, and at or above 138 KV

20 'Valid Request" means a request for Transmission Service made and maintained consistent with the provisions of Section D. herein

B. **AVAILABILITY**

Service under this Tariff is available to Eligible Utilities that have Valid Requests for Transmission Service pending with PSI and with whom PSI has entered into a Service Agreement A Service Agreement must be executed and filed with the FERC prior to the commencement of any Transmission Service by PSI for an Eligible Utility

C. **OFFER OF SERVICE**

PSI will provide Transmission Service to any Eligible Utility that has a pending Valid Request for Transmission Service through PSI's Bulk Transmission System from a designated POR to a designated POD Transmission Service provided pursuant to this Tariff shall be subject to the engineering and reliability limitations of PSI's Bulk Transmission System, the obligations of PSI to provide firm service to its Native Load Customers and to fulfill its obligations under previously executed contracts to provide firm service, and PSI's obligations to IMPA and WVPA under the

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Transmission and Local Facilities Agreement By undertaking to provide Transmission Service to Utilities pursuant to this Tariff PSI does not assume the obligations of a common carrier

D. PROCEDURES FOR OBTAINING SERVICE

1. Initial Requirements

(a) A Valid Request for Transmission Service under this Tariff shall be made by providing the following information in writing to PSI, attention Executive Director, Power System Engineering/Operations, 1000 E Main Street, Plainfield, Indiana 46168:

- the identity, address and telephone number of the Eligible Utility requesting transmission service
- the title of the contact person at the requesting Eligible Utility,
- a statement that the entity requesting Transmission Service is, or will be upon commencement of service, an Eligible Utility
- the location of the POR and POD, and the identity of the Delivering Party and the Receiving Party,
- the identity of the initial source of the power to be transmitted pursuant to the request,
- the identity of the Electric Control Area in which the ultimate consumer of the power is located;
- the proposed dates for initiating and terminating Transmission Service,
- a description of the requested Transmission Service, including whether it is Firm or Non-Firm
- the Contract Demand and expected load profile,
- a showing of credit worthiness

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(b) PSI must file a Valid Request for Transmission Service pursuant to this Section D 1 to be eligible to use the Bulk Transmission System to make long-term firm power sales pursuant to Rate Schedule FS-1

(c) PSI may request the Eligible Utility to identify the ultimate consumer of the power to be transmitted if such information is necessary for PSI to determine pursuant to Section G 1 hereof whether adequate capacity will be available on its Bulk Transmission System to provide the service initially and for the full term of the transaction requested by the Eligible Utility

(d) In order to determine whether Valid Requests for Firm Transmission Service are duplicative or mutually exclusive of Valid Requests filed by other parties, PSI may request further information, including, by way of illustration, a statement whether the request is being made in response to a competitive solicitation, and whether the requesting party has in fact submitted a bid in response to the solicitation If certain Valid Requests for Transmission Service give PSI a reasonable basis to believe that such requests are mutually exclusive, PSI may ask the Eligible Utility making such a Valid Request to identify the ultimate purchaser of the power and, if appropriate under the circumstances, PSI may contact the ultimate purchaser to determine whether transmission requests are mutually exclusive

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(e) If the Eligible Utility objects to a request by PSI under (c) or (d) above that it provide the name of the ultimate consumer, then PSI shall have the right to seek an order from the Commission allowing PSI to require the Eligible Utility to provide PSI with the identity of the ultimate consumer.

(f) A Valid Request for Firm Transmission Service also must include a deposit by the Eligible Utility of an amount that is the lesser of $10,000 or one month's Reservation Charge as shown in Section 3 of Service Schedule A of this Tariff. This amount will be credited against the Eligible Utility's first month's Reservation Charge.

(g) If the Eligible Utility is either insolvent or unable to demonstrate credit worthiness to PSI's satisfaction, then PSI may require the Eligible Utility to demonstrate its ability to pay for three (3) months of Transmission Service

2. **Subsequent Requirements Where No New Facilities Are Needed**

(a) When, pursuant to Section G.1 hereof, PSI determines that adequate capacity will be available on its Bulk Transmission System to provide the requested service initially and for the full term of the transaction requested, PSI shall notify the Eligible Utility in writing and tender a Service Agreement to the Eligible Utility

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(b) Within ninety (90) days after receipt of such written notice and Service Agreement, the Eligible Utility must either (1) execute the Service Agreement and begin payment of the Monthly Reservation Charge and rates as required by Section L hereof, or (2) withdraw its Request for Service Failure to execute the Service Agreement within such ninety (90) days will be deemed to be a withdrawal of the Request for Service Nothing herein limits the right of the Eligible Utility to file another Valid Request for Transmission Service immediately upon such withdrawal If PSI has not received any Valid Requests from any other Eligible Utility during the period between the date the Eligible Utility filed its initial Request for Service and the date of such withdrawal, the deposit required under Section D 1 (f) will be waived

3. **Subsequent Requirements When New Facilities Are Needed**

(a) When, pursuant to Section G.1 hereof, PSI determines that a Valid Request for Long-Term Firm Transmission Service will require initially or during the term of the transaction upgrades, improvements, additions or other modifications ("modifications") to the Bulk Transmission System, PSI shall inform the Eligible Utility in writing and tender a form of agreement ("Study Agreement") under which the Eligible Customer would agree to compensate PSI for the cost of conducting a study of the

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modifications needed to provide the requested Transmission Service ('Facility Study') The Facility Study also will include an estimate of the cost of such modifications and the time required to complete the modifications and initiate the requested service At the time PSI tenders the Study Agreement, PSI also shall provide the Eligible Utility with an estimate of the cost of conducting the Facility Study

(b) For the Valid Request to remain valid and pending, within ten (10) days of the receipt of the Study Agreement, the Eligible Utility must execute such Study Agreement and return it to PSI along with a deposit of 50% of the estimated cost of the Facility Study

(c) Upon receipt of such deposit and the executed Study Agreement, PSI shall commence the Facility Study Promptly upon completion of the Facility Study, PSI shall present the results to the Eligible Utility and tender an invoice for the cost of the Facility Study, reduced by the amount of the deposit PSI also shall tender a Service Agreement under which the Eligible Utility would agree to receive service upon completion of the facility modifications and to compensate PSI for the incremental costs of the facility modifications, as determined pursuant to Section L 1 (b) herein

(d) For the Valid Request to remain valid and pending, within sixty (60) days of the receipt of the

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invoice, the Facility Study results and the Service Agreement, the Eligible Utility must reimburse PSI for the cost of the Facility Study and execute the Service Agreement The Eligible Utility also must provide PSI with a security deposit, or other form of security acceptable to PSI, in such amount and for such term as sufficient to protect PSI against the risk of non-payment by the Eligible Utility for the estimated incremental costs of the facility modifications, as determined pursuant to Section L hereof

(e) Upon receipt of reimbursement for the Facility Study, the executed Service Agreement and the security deposit, PSI shall use due diligence to complete the necessary modifications within a reasonable time PSI shall give the Eligible Utility ninety (90) days' written notice prior to completion of the facility modifications and the commencement of service ("Advanced Notice") Promptly upon completion of such modifications, PSI shall notify the Eligible Utility in writing that service can commence ("Final Notice')

(f) Within ten (10) days of the receipt of the Final Notice, the Eligible Utility shall commence paying the Monthly Reservation Charge and rates required by Section L 1 hereof Failure to do so will result in forfeiture by the Eligible Utility of all deposits and security provided under this Section D , and the Utility s Valid Request no longer will be considered valid or pending

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4 <u>Service Agreements</u>

(a) Subject only to the provisions of Section D 4 (e) herein, PSI is obligated to provide Transmission Service under this Tariff only to Eligible Utilities that have signed a Service Agreement with PSI for the requested service The Service Agreement shall contain a statement of service specifications including, without limitation, the amount of capacity reserved for Transmission Service, the term of such service, identification of PORs, PODs, and any Delivering Party or Receiving Party, the conditions under which service may be interrupted, the rates and charges for such service; and where applicable the agreement to reimburse PSI for the cost of necessary facilities.

(b) At the time of execution of the Service Agreement, the Eligible Utility shall provide PSI with the identity of the ultimate consumer, if it has not already done so

(c) PSI will file the executed individual Service Agreement with the Commission

(d) Requests to modify the terms or conditions of a Service Agreement must be submitted to PSI in writing PSI will determine the capacity availability for such requested modifications only after it has determined the capacity availability, pursuant to Section G herein, of all Valid Requests pending as of the date that PSI

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receives the written request to modify the Service Agreement

(e) If PSI and an Eligible Utility requesting service pursuant to this Tariff cannot agree on the terms of the individual Service Agreement, PSI commits to commence the requested service as soon as reasonably practical after receipt of the Utility's Valid Request subject to the engineering and reliability limitations of its Bulk Transmission System and Prudent Utility Practice Such service will be provided under terms and conditions deemed appropriate by PSI for the requested service and filed with the FERC as a proposed Service Agreement PSI commits to continue providing the requested service under whatever terms and conditions are ultimately determined by the Commission to be just and reasonable under sections 205 or 206 of the Federal Power Act, within the constraints imposed by engineering and reliability limitations.

Notwithstanding any other provision of this Section D 4 (e), PSI is not obligated to provide Transmission Service to an Eligible Utility until such Utility provides PSI with a binding written commitment (i) to pay for any facility modifications determined by PSI under Section G hereof to be reasonably necessary to provide the requested services and (ii) to receive and pay for such service under the terms, conditions and rates determined to be just and reasonable by the FERC

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(f) Acceptance of service by an Eligible Utility pursuant to a Service Agreement filed under this Tariff commits the Eligible Utility both to the provisions of this Tariff and to the terms of the individual Service Agreement

(g) PSI reserves its right to cancel the Service Agreement of a Utility and to terminate service under this Tariff to that Utility consistent with the provisions of the Commission's regulations governing notices of cancellations or termination

(h) PSI may also curtail service to an Eligible Utility that is delinquent in its payments under its Service Agreement and this Tariff subject to the following conditions

(i) PSI shall give the Eligible Utility at least twenty (20) days advance written notice of its delinquency and of PSI's intent to curtail if the delinquency is not remedied within thirty (30) days of the date of such notice, and then only after giving written notice thereof to the Commission; and

(ii) PSI shall not curtail, or shall cease curtailing, under this provision if and when the Eligible Utility cures the delinquency

E. PRIORITY OF REQUESTS FOR FIRM SERVICE

1. Capacity Determination

If at any time more than one Valid Request is pending, PSI shall assign a priority to each request pursuant to Section

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E 2 hereof for all such requests received during the sixty-(60) day period commencing the day after the Commission accepts for filing this Transmission Service Tariff ("Open Season) or pursuant to Section E 3 hereof for all such requests received after the Open Season In determining whether adequate capacity will be available on its Bulk Transmission System to provide a requested service, PSI shall determine capacity availability pursuant to Section G.1 hereof for the Valid Request that has the highest priority and shall not take into consideration any other pending Valid Request If PSI determines that adequate capacity will be available on its Bulk Transmission System to provide service for the highest priority Valid Request, the Company will notify the requesting Utility and tender a Service Agreement pursuant to Section D.2

If PSI determines that it will not have adequate capacity available on its Bulk Transmission System to satisfy the full amount of the requested service, PSI will allow the Eligible Utility to either (a) sign a Service Agreement pursuant to Section D 2 hereof for the amount of Transmission Service that can be provided immediately, and receive the remainder of the requested service pursuant to Section D 3 hereof after the necessary facility upgrades and modifications have been installed, (b) sign a Service Agreement pursuant to Section D 2 hereof for the amount of Transmission Service that can be provided immediately and withdraw the request for the remainder of the service, (c) sign a Service Agreement to

receive all the requested Transmission Service pursuant to Section D 3 hereof after the necessary facility modifications are completed, or (d) withdraw the request for Transmission Service

After PSI has offered Transmission Service to the highest priority Eligible Utility with a pending Valid Request pursuant to the above described method, PSI then will apply the same procedures to determine whether adequate capacity will be available on its Bulk Transmission System to provide service for the Valid Request that has the next highest priority This procedure will be repeated until all pending Valid Requests have been processed Should an Eligible Utility withdraw all or part of its Valid Request, or should an Eligible Utility fail to execute a Service Agreement within the required time period, the Company will re-evaluate the capacity availability for lower priority Valid Requests in light of the additional capacity that might be made available PSI shall re-evaluate such Valid Requests in the order of their assigned priority Should the Company determine that additional transmission capacity is available for any Eligible Utility, PSI shall allow such Utility an option, to be exercised within ten (10) days, to modify its Service Agreement to receive additional service under Section D 2 hereof and a corresponding reduction in service under Section D 3 hereof, provided, however, such Utility shall remain responsible for compensating PSI for the costs, determined pursuant to Section L hereof, of any

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facility upgrades or modifications already made by PSI to accommodate the service requested under Section D 3 hereof prior to the exercise of the option by the Eligible Utility to reduce such request

2. **Requests Received During the Open Season**

The priority ranking of Valid Requests for Firm Transmission Service received by PSI during the Open Season shall be determined by lottery The lottery shall be conducted by an independent certified public accounting firm, to be named by PSI on or before the first day of the Open Season. All Eligible Utilities that file Valid Requests for Firm Transmission Service during the Open Season shall be assigned a priority that is higher than such requests received after the Open Season Rates for Firm Transmission Service provided in response to requests received during the Open Season will be determined according to Section L 2 hereof

3. **Requests Received After the Open Season**

Valid Requests for Firm Transmission Service received after the Open Season shall be assigned a priority according to the date on which they are received, with the earliest in time receiving the highest priority

4. **Mutually Exclusive Requests**

Should PSI confirm that particular Valid Requests for Firm Transmission Service are mutually exclusive (e.g., the ultimate purchaser will buy from one but not all of the Eligible Utilities requesting service), PSI reserves the right

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to process all such Valid Requests as though they were a single Valid Request for Transmission Service, with the Transmission Service awarded to the Eligible Utility that is selected by the ultimate purchaser

5. Requests by PSI

Valid Requests filed by PSI pursuant to Section D 1 hereof will be treated in the same manner as any other Valid Request and assigned a priority for determining capacity availability according to the provisions of this Section E

F. SCHEDULING

All capacity and energy to be transmitted by PSI under this Tariff shall be scheduled in advance pursuant to the terms of the Service Agreement It shall be the responsibility of the Eligible Utility requesting service pursuant to this Tariff to make any necessary arrangements for delivery of capacity and energy to or beyond the points of interconnection of PSI's transmission system with those of other electric systems designated as the Delivering Party or the Receiving Party in the individual Service Agreement. Any scheduling arrangements including compensation for any associated costs, losses or parallel flows, that may be required by other electric systems shall be the responsibility of the Utility requesting service The Utility shall provide written notification to the Company identifying such systems and authorizing such systems to schedule all capacity and energy to be transmitted by the

Company pursuant to the Service Agreement on behalf of the Receiving Party at the POD or the Delivering Party at the POR All scheduling of capacity and energy to be transmitted by the Company shall be in accordance with Prudent Utility Practice

G. DETERMINATION OF CAPACITY AVAILABILITY AND OBLIGATION TO EXPAND CAPACITY TO ACCOMMODATE REQUESTS FOR SERVICE

1 Determination of Capacity Availability

Upon receiving a Valid Request for Transmission Service, PSI will determine whether adequate capacity will be available on its Bulk Transmission System to provide the service initially and for the full term of the transaction requested by the Eligible Utility Such determination will be made within sixty (60) days from the date of receipt, unless the number or complexity of requests reasonably requires additional time. If additional time is needed, PSI shall notify the Eligible Utility on a timely basis and provide an estimate of the time needed to reach a final determination Such determination will be made in accordance with Prudent Utility Practice and PSI's operating and engineering standards historically applied to its system, and shall be subject to the engineering and reliability limitations of the PSI Bulk Transmission System In determining whether capacity will be available on its Bulk Transmission System for the requested service both initially and for the full term of the transaction

requested Valid Requests for Firm Transmission Service shall take priority over all Non-Firm Transmission Services provided by PSI, whether such Non-Firm services are being provided to third-parties or are being provided for the benefit of PSI's Native Load Customers, provided that PSI shall not jeopardize or restrict lawful use of the system by the parties to the Transmission and Local Facilities Agreement, dated November 5 1985, filed with the Commission in Docket No EC86-3-000, as it may be amended from time to time

2. **Treatment of Valid Requests for Transmission Service Requiring Expansion of PSI's Bulk Transmission System.**

Where a determination is made by PSI that a Valid Request for Long-Term Firm Transmission Service pursuant to this Tariff will require, during the term of the transaction upgrades, improvements, additions or other modifications to the Bulk Transmission System, or when an Eligible Utility requests specific upgrades, PSI commits to use due diligence to make such modifications to its system within a reasonable time, provided, however, that the Eligible Utility requesting service agrees to compensate PSI for the costs of all modifications to the Bulk Transmission System reasonably required to provide such service PSI will not increase or upgrade the capacity of its existing or planned transmission facilities in order to provide service under this Tariff if doing so would impair system reliability or otherwise jeopardize firm service to its Native Load Customers Unless otherwise agreed to by PSI and

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the other parties to the Transmission and Local Facilities Agreement and the Utility requesting service, ownership of any additional transmission facilities or upgrades constructed pursuant to this Tariff will be determined by the Transmission and Local Facilities Agreement The requesting Utility shall cooperate with PSI in construction of the required facilities and shall take all reasonable steps to assist the Company in obtaining any necessary permits, authorizations and rights-of-way

H. **INTERRUPTIONS**

PSI will use due diligence to furnish the Firm Transmission Services available under this Tariff, but it does not guarantee uninterrupted transmission of electricity PSI shall not be liable for any claim of damage attributable to any interruption or reduction of service due to (1) force majeure, including unavoidable accident or casualty, extraordinary action of the elements, strikes, actions of any governmental authority or litigation; (2) any cause which PSI could not reasonably have foreseen and made provision against, (3) any operating decisions, which, in PSI s judgment, are necessary to maintain reliable service or to protect PSI s generation or transmission facilities and (4) necessary or routine maintenance, repairs, replacements, or installations of equipment, or the investigation and inspection of such equipment To the extent practicable, PSI will provide

reasonable advance notice to a Utility receiving service of any scheduled interruptions, reductions or other impairments of the Transmission Service as specified in the individual Service Agreement

I **INDEMNIFICATION**

Each Party to a Service Agreement under this Tariff assumes all liability for injury or damage to persons or property arising from the acts or neglect of its own employees agents or contractors and shall indemnify and hold the other harmless from any liability arising therefrom

J. **SALE OR ASSIGNMENT OF TRANSMISSION SERVICE**

Subject to the approval of the FERC, a Utility may sell, assign or transfer all or a portion of its rights under the Service Agreement negotiated pursuant to this Tariff, but only to another Eligible Utility If the second Utility so purchasing or taking an assignment does not request any change in the POR(s) or the POD(s), or a change in any other term or condition set forth in the original Service Agreement, the second Utility will receive the same services as did the first Utility If the second Utility purchasing, or taking an assignment of, such services requests a change in the POR(s) or POD(s), or a change in any other term or condition set forth in the original Service Agreement, PSI will consent to such change subject to the provisions of Section D 4 (d) herein, but only

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if to do so will not impair the operation and reliability of PSI s generation, transmission, or distribution systems, and on the condition that the second Utility agrees to compensate PSI for any additional costs resulting from such change The original Utility requesting service shall remain liable for the performance of all obligations under the Service Agreement except as specifically agreed to by the parties through an amendment to the Service Agreement

K. COORDINATION TRANSMISSION SERVICE

PSI agrees to provide Coordination Transmission Service at the request of an Eligible Utility, subject to capacity availability and a determination by PSI of the effects of each transaction on the reliability of the Bulk Transmission System PSI does not commit to construct facility upgrades, improvements or additions to provide Coordination Transmission Service, unless the requesting Utility agrees to reimburse PSI for all costs incurred in providing such additions or upgrades. Coordination Transmission Service will be non-firm interruptible service unless firm service is specifically provided for in the price and other terms and conditions of the individual Service Agreement

L. RATES

1. Firm Transmission Service -- General Rule

(a) For Firm Coordination Transmission or for Long-Term Firm Transmission Service to Eligible Utilities

where, pursuant to Section G 1 hereof, PSI determines that no upgrades, improvements, additions, or other modifications to the Bulk Transmission System are necessary to initiate the service or to maintain the service during the term of the transaction requested, the rate for such Transmission Service shall be in accordance with Service Schedule A appended to, included in and made a part of this Tariff In addition, should the Transmission Service require the use of facility modifications or upgrades determined to have been necessary to provide Transmission Service for another Utility and reflected in the rate for service paid for by another Utility, the subsequent Eligible Utility receiving service shall also pay a contribution to cover a portion of the cost of such facility upgrades or modifications The amount of the contribution shall be based on the subsequent Eligible Utility's pro rata use of the facility modifications and on the period of time over which the joint use occurs

(b) To ensure that PSI's Native Load Customers do not subsidize any Firm Coordination Transmission Service or Long-Term Firm Transmission Service provided under this Tariff, in those instances described in Section G 2 hereof where PSI determines that upgrades, improvements, additions or other modification to the Bulk Transmission System are necessary to initiate service or to maintain service during the term of the transaction requested, the Eligible Utility

will pay the rate required by Section L 1 (a) and the cost of the modifications to be computed as the net differential in the present value of PSI's revenue requirements calculated with and without the modifications

Should the facility modifications paid for by the Eligible Utility subsequently be used to provide Firm Transmission Service to another Utility, the Eligible Utility that paid for such facility modifications will receive compensation for such use in the form of a credit against its rates The level of compensation will be based on the pro-rata use of the facility modifications and on the period of time over which the joint use occurs

2. **Firm Transmission Service -- Open Season**

If PSI determines pursuant to Section G.1. hereof that there is sufficient available capacity to accommodate all Requests for Firm Transmission Service received during the Open Season, the rates for such service will be determined according to Section L.1. above If PSI determines that facility modifications are needed to provide all the Firm Transmission Service requested during the Open Season, the rates for all Utilities receiving such Firm Transmission Service shall also include a pro rata share of costs of all such facility modifications

3 **Non-Firm Transmission Service**

Rates for Non-firm Coordination Transmission Service shall be based on PSI's applicable losses, plus (one) 1 mill

per kilowatt-hour for difficult to quantify costs incurred by PSI in providing such service, plus a negotiated amount of up to one-third of the total net savings (after reflecting the costs of the applicable losses) resulting from the transaction calculated as the difference between the incremental cost(s) of the seller(s) of the power and the decremental cost(s) of the buyer(s) of the power, however, in no case will the rate for service under this section exceed the rate for firm service pursuant to Section L 1 hereof The requesting Utility shall if required by PSI, provide PSI with certificates from the seller(s) and the buyer(s) setting forth such estimated incremental and decremental costs, respectively, such certificates also shall contain the agreement of the seller(s) and the buyer(s) to make available to PSI such information as is reasonably necessary to confirm such estimates

M. RATE CHANGES

Nothing contained in this Tariff or any Service Agreement shall be construed as affecting in any way the right of the Company to unilaterally make application to the FERC for a change in rates, charges, classification or service, or any rule, regulation or Service Agreement related thereto, under section 205 of the Federal Power Act or any successor statute and pursuant to the Commission's Rules and Regulations promulgated thereunder

Nothing contained in this Tariff, any associated Service Schedule or any Service Agreement shall be construed as

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affecting in any way the right of any party receiving service under the Tariff to exercise its rights under the Federal Power Act or any successor statute and pursuant to the Commission's Rules and Regulations promulgated thereunder

N. **BILLING**

PSI shall invoice the Utility each month for services provided under this Tariff, pursuant to the terms of the Service Agreement If not paid within thirty (30) days of the due date thereof as stated in the bill, the amount due shall be subject to a charge for interest computed at the average prime rate from said due date until the date of payment. The applicable average prime rate for each calendar month or any part thereof shall be the arithmetic mean, to the nearest 100th of 1%, of the prime rate values published in the Federal Reserve Bulletin for the fourth, third and second months preceding the due date The interest required to be paid hereunder shall be compounded monthly

O. **ARBITRATION TO RESOLVE SCHEDULE DISPUTES**

1. **Disputes Subject to Arbitration**

(a) For purposes of determining the effective date of a suspension of the Company's authority under Rate Schedule FS-1 to make long term firm power sales at negotiated rather than cost-based rates, if the Company and the Eligible Utility are unable to agree upon a "reasonable

time to construct any new facilities determined by PSI to be necessary to provide the requested Transmission Service then either party may submit this 'Schedule Dispute' to binding arbitration in accordance with the provisions herein.

(b) Except as provided in paragraph (c) below, the Schedule Dispute resolution provisions herein provided shall be the exclusive method to resolve such disputes, provided the parties may at any time agree to settle between themselves the Schedule Dispute.

(c) Nothing in this Tariff requires any party to waive any rights it may have under section 206 of the Federal Power Act.

2. **Arbitration**

(a) The arbitration shall be conducted by a panel of three arbitrators, one selected by the Company, one by the Eligible Utility, and the third to be selected by the two arbitrators selected by the parties Each arbitrator so selected shall be appropriately professionally trained, experienced and knowledgeable in the areas of the permitting, construction, and operation of high voltage electric transmission lines.

(b) The scope of the arbitration shall be expressly limited to the issue of the "reasonableness of the time frame necessary for PSI to provide the Eligible Utility the Firm Transmission Service it has requested and

shall not include other issues such as the cost of or need for such facilities, the route selection, or the facility configuration The arbitrators may not change any term or condition of this Tariff, deprive either party of a remedy expressly provided for hereunder, or provide any right or remedy that has been excluded hereunder

(c) Within ten (10) days after the selection of the arbitration panel, each party shall submit to the arbitration panel its estimate of the "reasonable" time for PSI to commence transmission service to the Eligible Utility and provide any supporting material it deems appropriate Within thirty (30) days after submission of the parties' estimates and supporting material, the arbitration panel shall determine which of the two estimates is "reasonable," and they may set forth their reasoning for the selection of the "reasonable" period Within such 30-day period, the arbitrators may request the parties to provide more information and also may request that the parties answer written interrogatories, produce documents, and/or present witnesses to be subjected to cross-examination

(d) The arbitrators decision regarding the "reasonableness" of the time frame necessary for PSI to commence Transmission Service shall be limited to selecting either the construction time estimate submitted by PSI or the construction time estimate submitted by the Eligible

Utility The arbitrators shall not have discretion to find reasonable" any other time period

(e) Each party shall bear the cost of the arbitrator it selects. The costs of the third arbitrator shall be borne by the parties equally

3. **Binding Arbitration**

(a) Subject to the provisions of (b) herein, for purposes of suspension of Rate Schedule FS-1 as set forth in Section O 1 (a), the decision of the arbitrators regarding the construction time estimate deemed "reasonable" shall be binding upon the parties

(b) The right of either party to challenge or appeal the decision of the arbitrators is expressly limited to asserting that the decision was arrived at in bad faith or that the arbitrators exceeded their authority Such appeal or challenge may be presented to the FERC

P **SPECIAL PROCEDURES TO RESOLVE TRANSMISSION COMPLAINTS**

1. **Disputes Subject to Special Complaint Procedures**

(a) If an Eligible Utility believes that PSI has not accommodated or will be unable to accommodate a request for transmission service within a "reasonable time," then the Utility may file a Transmission Complaint ("Complaint) with the Commission in accordance with the provisions herein

(b) Except as provided in paragraph (c) below the Complaint resolution provisions herein provided shall

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be the exclusive procedure to determine whether to suspend the Company's authority under Rate Schedule FS-1 to make long-term firm power sales at negotiated rather than cost-based rates, provided the parties may at any time agree to settle between themselves the matters in dispute, provided further such settlement does not amend or modify Rate Schedule FS-1

(c) Nothing in this Tariff requires any party to waive any rights it may have under section 206 of the Federal Power Act.

2. <u>Scope of and Procedure for Transmission Availability Complaints</u>.

(a) Eligibility to file a Complaint shall be limited to Utilities having, as of the date of the filing of the Complaint, a Valid Request for Transmission Service pending with PSI To have such a Valid Request pending, the complaining Utility shall have timely and fully satisfied each requirement for a Valid Request for transmission set forth in Section D of PSI's filed Transmission Service Tariff

(b) The scope of a Complaint shall be expressly limited to the issue of whether Firm Transmission Service has been or will be unavailable from PSI after a "reasonable period of time," and shall not include other issues such as the route selection, the facility configuration, or "Schedule Disputes" which are to be resolved as provided for in Section O of this Tariff

A complaining Utility may assert claims in a Complaint alleging only the following specific grounds

1 an absence of any need for new facilities,

2 discrimination by PSI in the allocation of capacity,

3. the failure to provide Transmission Service within the agreed to, or adjudicated pursuant to Section O herein, "reasonable" time; and

4. the occurrence of an event or the expiration of time which indicates that PSI will not provide the requested service within the "reasonable" time period

(c) If the Commission notices the Complaint for hearing, within ten (10) days after the date of the notice, PSI shall admit or deny in whole or in part the allegations of the Complaint

(d) Any decision by the Commission on the merits of the Complaint shall determine whether PSI's authorization to make sales under its Rate Schedule FS-1 should be suspended and whether a refund condition triggered by the filing of the Complaint should continue or should be terminated

Q. RECIPROCITY

In order to maximize opportunities for efficient trade in bulk power services, a Utility requesting Long-Term Firm or Coordination Transmission Service under this Tariff agrees to provide upon request by PSI, comparable service to PSI on similar terms and conditions, and over comparable facilities controlled by the requesting Utility, to the degree such

service can be provided by the requesting Utility consistent with the engineering and reliability limitations of its own bulk transmission system and those of other interconnecting systems

R. APPLICABILITY OF TARIFF TO FACILITIES ACQUIRED BY PSI SUBSEQUENT TO THE FILING OF SERVICE AGREEMENTS

The bulk transmission facilities of any entity acquiring, or acquired by, PSI or any successor or assign of PSI, as a result of consolidation, merger, or other corporate acquisition shall not be subject to the terms of this Tariff, nor will such facilities be recognized in the determination of the available transmission capacity of the Bulk Transmission System, the need to upgrade, improve, or add to such facilities to accommodate any request for transmission service hereunder, or for calculating the rates to be charged for such service

S. EXPIRATION

No new requests for Transmission Service hereunder shall be accepted after December 31, 2016, and no service under any Service Agreement filed pursuant to this Tariff shall extend beyond December 31, 2016

PSI shall have no obligation to build any new facilities or upgrades necessary to accommodate requests received after December 31, 1996, except to meet requests of Receiving or Delivering Parties with ongoing Long-Term Firm Transmission Service, or a Valid Request for such service that

was pending on December 31, 1996, and then only to the extent that the total capacity of Long-Term Firm Transmission Service for the applicable Receiving or Delivering Party does not exceed the total transmission capacity under contract with PSI or requested of PSI by December 31, 1996

T. **SEMI-ANNUAL REPORTS**

PSI shall submit to the FERC semi-annual reports of requests for Firm Transmission Service The reports shall include the following information for both ongoing service and for pending requests for service·

- the identity of the requesting Utility,
- the delivering and receiving control areas,
- the contract demand and expected load profiles,
- a brief description of any facility upgrades installed or expected to accommodate the service, and
- the date service was requested

For pending requests for service, PSI shall provide the following additional information·

- the date service is proposed to begin, and
- the proposed termination date

The information required to be reported for pending requests shall be reported with a six-month lag to protect commercially sensitive information In addition, a requesting utility may request that PSI not report that utility's request for up to two additional years

SERVICE SCHEDULE A
TRANSMISSION SERVICE THROUGH
THE BULK TRANSMISSION SYSTEM

1 **Availability**

Available to any Eligible Utility who enters into a Service Agreement pursuant to this Transmission Service Tariff

2 **Offer of Service**

The Company will provide Firm Transmission Service as required by this Transmission Service Tariff through the Company's Bulk Transmission System from a designated Point of Receipt to a designated Point of Delivery

3 **Rate**

Reservation Charge (Monthly)

Each kw of Reserved Capacity from
Bulk Transmission System . ...$1 05 per kw

4 **Reserved Capacity**

Reserved Capacity shall be the Contract Demand applicable to the Eligible Utility in accordance with the terms and conditions of the Service Agreement Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60)-minute interval (commencing on the clock hour) basis

5 **Losses**

The Eligible Utility shall schedule sufficient capacity and energy to cover applicable losses from the designated Point of Receipt to the designated Point of Delivery

6 **Other Facility Cost**

The Eligible Utility shall be responsible for the cost of any applicable sub-transmission and distribution facilities required to connect such Eligible Utility to Company's Bulk Transmission System Rates to recover such costs shall be included in the Service Agreement The rate shown in Item 3 above does not include any cost associated with upgrades, improvements, additions, or other modifications to the Bulk Transmission System due to a request for Transmission Service under this Tariff Such additional costs shall be treated in accordance with Section G.2 of this Tariff

DOE/S-0085P

NATIONAL ENERGY STRATEGY

Technical Annex 3

Electricity Transmission Access

A series of technical papers developed to support the National Energy Strategy
First Edition
1991/1992
Washington, DC 20585

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Executive Summary

Increased access to electricity transmission lines for sellers and buyers of wholesale power could encourage competition in the industry, lower electricity costs, and enhance environmental quality The generation sector of the industry has recently become more competitive, with much of the new capacity ordered in the 1980's supplied by nonutility generators However, achievement of the economic benefits potentially available through increased competition in generation of electricity could be constrained by the absence of adequate access to transmission Calls for more open transmission have increased for this reason and because price differentials among utilities have caused wholesale buyers that cannot satisfy all of their own generating needs to seek alternative suppliers of electric power

Complex questions of economics, equity, and reliability are embedded not just in the concept of transmission access, but also in the issues surrounding access—such as pricing, dispute resolution, joint ownership of lines, and planning for future additions to transmission capacity Utilities' obligations under State laws and regulation add an additional layer of complexity The purpose of this analysis is to explore these issues and suggest appropriate Federal options

Transmission of electricity has the characteristics of a natural monopoly This is in contrast to electricity generation, where competition is an economic alternative to exclusive reliance on local utilities constructing generating units Owners of transmission systems can deny access to those who wish to make economic sales or purchases A transmission owner with market power could do this to protect his wholesale sales from competition

While increased transmission access for wholesale sellers and buyers of electricity can enhance efficiency by opening the wholesale generation market to more competition, it is not clear that access for retail customers would produce any additional economic gains Moreover, there could be a significant strain on system reliability if all retail customers were allowed unlimited access Increased wholesale access will not degrade reliability, provided access increases at a rate that does not outpace the technical capabilities of control systems and that allows system control centers to remain in control of system operation

Three options for Federal action on transmission are considered. The first is to allow the present pattern of case-by-case determination of transmission access policy to continue The second is to examine existing laws for authorities that could be used to expand wholesale transmission access while making the terms and conditions governing that access more predictable and orderly Both these options would ideally involve rulemaking on transmission access, pricing, contracting, and capacity-expansion planning to define more clearly "just and reasonable" utility policies that are consistent with systemwide efficiency and reliability and with utilities' obligations under State law and regulation The third option is to enact new Federal legislation which, among other things, could create an obligation for utilities to provide transmission service for wholesale customers

1. Introduction

Purpose of This Paper

The electricity industry today is changing rapidly These changes are creating pressures for new operational procedures and policies One such pressure is for increased access to the transmission system by various categories of sellers and buyers Prominent among the many reasons cited by proponents of increased transmission access are the emergence of increased competition in the electricity generation sector, reduced capacity surplus in many regions, difficulty in siting new generating facilities in some regions, and the increase in geographic size of regional electricity markets, made possible by the development of regional high-capacity transmission grids

The purpose of this paper is to explore, first, the principal issues raised by calls for new transmission access policies and, second, the possible Federal policy options that might address these concerns The remainder of this introduction is intended to give the reader the background necessary to appreciate the later discussion of issues and options

Increased Competition and Transmission Access

Electricity is delivered to end-use customers by local monopolies, as it has been since the industry began in the early 1880's From the earliest days of the industry until the late 1960's, economies of scale in construction and operation of new generating units caused prices of utility-provided generation to decrease steadily As electricity production costs bottomed out and started to rise in the late 1960's, the question of whether generation of electricity is in fact a natural monopoly was raised more and more frequently

Greater visibility and controversy for the industry began with the cost and price increases that first occurred in the 1970's These industry-wide cost increases had many causes Fuel prices rose, most notably with the oil embargoes of the 1970's The price of natural gas also rose, in response to the partial wellhead-price deregulation of the late 1970's Coal prices rose, due in part to labor settlements that allowed wage increases in excess of inflation

In addition, the inflation that started in the early 1970's and peaked about 1980–81 drove financing costs up New environmental and regulatory requirements increased both fuel and capital costs The costs of nuclear powerplants under construction at the time of the Three Mile Island accident, for example, rose to levels several times higher than originally projected. Finally, new economies of scale in generating electricity were hard to achieve in the 1970's, substantially reducing or eliminating the decades-long trend of reductions in costs when new plants came into service and allowed service to be expanded at reduced unit costs

This maturity of the electricity generation system called into question the economic rationale for the traditional assumption that new plants should be built only by local utilities The rising costs of the 1970's prompted much closer and more contentious regulatory oversight than utilities had experienced previously The cost increases, together with the recession following the 1979 oil embargo, left many utilities with excess capacity that regulators were reluctant to include in the rate base One consequence of the increased oversight has been a decade of regulatory decisions that, according to industrial credit rating services, many analysts, and the testimony of many utility executives, have made utilities reluctant to invest capital in new generating units because they fear they may not fully recover their costs

Concurrently, the Public Utility Regulatory Policies Act of 1978 (PURPA) created a new class of electricity generating entities known as qualifying facilities (QF's) To be a QF under PURPA, a generator must either cogenerate electricity and steam or use a waste or renewable resource for at least 75 percent of its primary fuel To promote this type of generation, PURPA freed these generators from much of the rate base and other financial regulation that utilities face—for example, the

Public Utility Holding Company Act of 1935 QF's were also given a guaranteed market Electric utilities are required by PURPA to purchase electric energy offered by QF's at a price equal to the purchasing utility's avoided cost, rather than at the QF's cost of service Efficient QF's can thus earn potentially large profits by selling power to electric utilities Further consideration of PURPA and a discussion of proposed changes to the act can be found in a separate technical annex.

The most visible results of PURPA and the regulatory climate of the last decade are the emergence of new entrants in the wholesale generation sector of the industry and competition between the new entrants and traditional utilities for the opportunity to meet new electricity demand.

While most of these new entrants are QF's, recently another class of new entrants, independent power producers (IPP's), has appeared.[1] The use of competitive bidding mechanisms has emerged in approximately 20 States as the preferred method of choosing which sources of new power are least expensive, partly as a result of the abundance of QF's responding to administratively determined avoided-cost prices for QF power in some areas In several areas of the United States, much of the recent growth in demand for electricity has been met mostly by QF's and recently by some IPP's, rather than by traditional utility construction, as utility proposals or avoided-cost projections have been underbid by QF's or IPP's

The term "transmission access" refers to the ability of a seller or buyer of power to use high-voltage transmission lines owned by one or more utilities to purchase or deliver electricity to markets distant from the point of generation Transmission access issues have been debated in the electric utility industry for many years The emergence of competition in wholesale power markets, however, has given the subject new importance

Many of the new suppliers in the wholesale electricity generation market have called on the Federal Government or State governments to institute transmission access policies that would enable suppliers to locate generating units where they would be most economical, taking into account environmental and other siting constraints Significant cost differences among utilities have motivated wholesale purchasers, notably public power utilities with little generating capacity of their own, to seek transmission access that would enable them to purchase power that is less expensive than power supplied by their local utility Other entities, such as the National Governor's Association, have taken notice of the inability to transmit the surplus power from some areas to areas that need additional sources of power

Advocates of increased transmission access argue that local utilities, through their control of transmission lines, may reduce competition and increase their own profits at the Nation's economic expense Many utilities disagree, suggesting that they are already allowing considerable transmission access and that to do more could harm the reliability of the system and increase the likelihood of blackouts They also argue that because competitive bidding has been vigorous, and because wholesale buyers have locally available alternatives to purchases from distant utilities (such as self-generation, conservation, or continued purchase from the local utility), more transmission access is not needed. They point out that, in conjunction with the traditional obligation of the utility to serve, transmission access could cause inequities such as "stranded investment"—that is, investment in generating equipment that was built in part to serve customers that now seek other suppliers These and associated issues are explored in detail in the body of this paper

Changes in the Industry

In the early decades of this century, the electric power industry was predominantly local in nature Each local utility served the immediate area, usually with a city of some size at its core Gradually, as cities grew, larger utilities formed from mergers and eventually served several cities However, the degree of interconnection between utilities was weak by today's standards, and each utility depended mostly on its own generation sources, usually located close to load centers

Since the 1920's, however, utilities have become more strongly interconnected over large regions Generating plants became larger and were located farther from load centers as the technology developed for longer transmission lines of higher volt-

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age Utilities recognized the economic benefits of interconnection, in particular because interconnection could increase system reliability at lower cost than could building more generating facilities A possible shutdown of a local generating unit can be backed up by the generating capacity of neighboring utilities instead of by building additional units locally

New transmission technologies eventually allowed the use of much larger lines—230-kilovolt (kV), 345-kV, 500-kV, and finally 765-kV lines Each of these can carry correspondingly more power per construction dollar, and can do so with greater efficiency than the smaller lines In the United States, 345-kV lines were first built commercially in the early 1950's, 500-kV lines in the mid 1960's, and 765-kV lines in the late 1960's About 1,000 circuit-miles of extra-high-voltage lines (230 kV and up) existed in the United States in 1950 By 1987, approximately 130,000 circuit-miles of these lines were in use, and now great amounts of electricity can travel up to a thousand miles in many parts of the Nation

Transmission is now regional, rather than local, in scale Just four large, interconnected grids cover the continental United States and the highly populated areas of Canada. The coordination of electricity interchanges is managed by about 150 "control areas," many of which are multistate power pools dispatching the generating units of several utilities

Because the industry's transmission network is now often regional in scale, large amounts of power can often be transmitted long distances, without this capability, there would be fewer calls for increased transmission access However, wheeling (that is, the transfer of power by a utility that is neither the generator nor the ultimate purchaser of the power) does not necessarily entail the transmittal of power over long distances A wheeling transaction could and often does involve a buyer and seller within close proximity of one another

Institutional Structures and Transmission Issues

Construction and transmission access decisions, siting approvals, and regulatory oversight all have effects that extend over large regions However, these decisions are often made by local or State bodies, or by local utilities Thus the potential for decisions to be made in the interest of the locality exists, and this interest may conflict with broader regional or national interests Regional or national economic efficiency may suffer

Some voluntary regional bodies do exist Some are power pools that use central dispatching systems to ensure the lowest short-run production cost and that, in some cases, help coordinate future construction decisions There is also the North American Electric Reliability Council and its nine regional reliability councils, which take steps to ensure the reliability of electricity service However, these groups were not formed to facilitate the most efficient use of regional transmission facilities and have not tried to do so

Yet, many parties are calling for changes in transmission policies For instance, the National Governor's Association 1987 report, *Moving Power*, states

> Even when a transmission project would clearly generate net total benefits, regulatory or institutional factors affecting the distribution of those benefits can result in at least one affected group concluding that the line is "uneconomic" or undesirable In short, *the way the utility industry is organized and regulated* can create a disparity between the total economic value of a project (including its social costs and benefits), and its "accounting value" which reflects whether, and by whom those benefits can be realized [italics added]

Moving Power then concludes (in part)

> The task force also found that, by and large, long range planning (by both states and utilities) focuses on and is driven by generating capacity needs This focus seems to result from an institutional and regulatory framework which promotes consideration of needs within rather than between utility systems *In particular, the fact that transmission lines are generally developed and owned by the utility within whose service territory they reside, but will be used by non-owners as part of the whole system, creates*

> *economic and regulatory disincentives to the optimal development of the transmission grid.*
>
> Larger-scale transmission projects, which better reflect the needs of the overall system rather than its individual components, *may only be achievable if regulatory requirements actually promote greater inter-utility coordination and cooperation on transmission development* [italics added]

Considering the status and diversity of interests represented by the National Governor's Association, these are strongly stated findings The next section lays the groundwork for a further discussion of the issues and potential policy options

Notes

1 As yet, relatively few IPP projects have been undertaken The success of the future IPP industry will depend upon whether the Public Utility Holding Company Act is amended to reduce regulatory barriers now faced by IPP's For more detail, see the technical annex on options to amend the Public Utility Holding Company Act.

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2. Barriers to Increased Wholesale Transmission

Implications of Lack of Transmission Access

Electricity transmission is a textbook case of a natural monopoly Natural monopolies are characterized by decreasing unit costs over the entire extent of the relevant market and are normally characterized by relatively large fixed investments [1] When a natural monopoly exists, society's total costs for providing the service in question are minimized when a single facility is built, rather than having several providers each build duplicative and more expensive (per unit of service) facilities In the case of transmission lines, society's total expense is reduced if one set of lines is built, with the large economies of scale achievable in transmission service, rather than two or more sets of less efficient, more expensive (per unit of energy shipped) lines [2] Furthermore, there are environmental benefits in minimizing the number of transmission lines For these reasons, it has been both efficient and traditional to grant only one entity the right to build transmission capacity in any particular jurisdiction In some cases, which can be identified by the application of modern antitrust analysis, that entity thereby acquires significant monopoly power in the market for transmission services

All firms strive to maximize profitability A utility monopolist can be expected to utilize its monopolistic position to maximize its profitability A monopolist maximizes profits by reducing the output of the good in question or the amount of service provided, thereby raising its price In the utility industry, that would mean constructing less transmission capacity than is optimal for society's overall benefit while also charging too high a price for the use of existing lines A simple numerical example of how a utility might do this, and in so doing prevent an economical project from being built, is provided in Appendix A.

The electric utility industry exhibits a high degree of vertical integration, that is, virtually all owners of transmission lines in the industry also own generating capacity This introduces the possibility that firms could use their control of transmission facilities to reduce competition in wholesale markets, particularly when firms are restricted in the price they can charge for transmission For instance, a utility might want to submit a bid to sell power in a competitive procurement It therefore might want to block potential competitors from access to this market Alternatively, a utility might want to protect its existing wholesale sales by restricting transmission access to competition from alternative suppliers

Finally, to retain market share, utilities want low rates Utilities are regulated, and it is important for them to have good relations with their ratepayers and regulators Thus, they might also use their transmission facilities first to minimize their retail rates, even if in the long term this might prevent power transfers through the system at lower regional costs

Owners of transmission lines object to contentions that they abuse their monopoly position and argue that expanded transmission access would cause inequities and reliability problems These owners have made the following generic arguments

- Reliability of service will suffer because control will be more difficult when more users or providers of generating capacity can make demands on the transmission grid.

- With regard to "captive" wholesale buyers who wish access to other sources of supply, both stranded investment and "prodigal son" issues are raised.

  The stranded investment argument arises when the local utility has constructed generating capacity to serve its customers but then finds that some wholesale customers want to leave the system, thus requiring stockholders or other customers to pay for these investments

  The "prodigal son" issue arises when a wholesale customer has left its traditional electric utility supplier for a source offering lower cost and then, when costs on the other system become higher, returns and again demands

service as a right from the local utility Here the utility may not have adequate capacity or may have to increase rates to other customers to meet the returning demand. Allowing wholesale customers to move on and off a utility's system generally would make the already difficult job of load forecasting even more difficult

- If transmission access is made mandatory rather than voluntary, then either courts or governments might have to decide which entities should have access and under what terms and conditions that access should be provided.

- Some have urged *retail* transmission access If retail access were allowed, however, the stranded investment and prodigal son issues would be far more difficult to manage than if access were limited to wholesale customers, the same applies to the planning and forecasting problem Reliability problems would be much more likely, given the much larger number of independent users of a system that requires a high degree of coordination among all participants

  System accounting would become more complex under retail access Because of the numerous potential buyers, dispatch centers and utilities would have to ensure that blocks of power are matched with the correct customers Because the number of sellers within a control area also could become quite numerous, the accounting could become even more burdensome

- Because transmission lines are paid by and built for the utility's customers, it would be inequitable, it is argued, to allow other users to have priority for the use of the lines

Most of these issues are addressed in later chapters In this chapter, though, with its focus on market barriers, we examine next the arguments of some utilities that lack of *mandatory* transmission access does not create economic inefficiencies

Does Lack of Transmission Access Cause Economic Inefficiencies in the Electricity Industry?

A typical argument presented by owners of transmission lines is as follows

> Transmission owners do not abuse their monopoly power Instead, their policy of voluntary access is working well, resulting in increased wholesale trade Competition in new wholesale markets is substantial, therefore transmission access appears not to be a barrier for new entrants such as independent power producers (IPP's) and qualifying facilities (QF's) Furthermore, power purchasers may have alternatives to transmission access for meeting their energy needs

Four points to consider in evaluating this argument are presented below

Contention: IPP's and QF's are thriving. Therefore, expanded transmission access for IPP's and QF's would not produce additional benefits

Most competitive procurements have been oversubscribed by a factor of 5 to 10 However, some of the winners in these procurements have been unable to build their plants because of the lack of transmission service For example, in Virginia Power's 1988 solicitation, four of the winning bidders, located in West Virginia, could not obtain transmission service [3] Other, more efficient competitors might have entered this and other bidding contests had they been assured of access at reasonable rates

Transmission service would also enable QF's or IPP's to sell to several utilities Thus they could build larger plants and take advantage of economies of scale, thereby lowering the cost per kilowatt of new generating capacity over a larger area

Increased access would also enable utilities in areas where siting new powerplants is very difficult or expensive to purchase power from remotely sited plants at lower costs

Another type of potential entrant in the generation market, a "merchant IPP," could also be prevented or discouraged by lack of transmission access A merchant IPP is a company that owns generation

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but sells only part of its power under long-term contract, reserving the remainder to sell on the spot market as economy power There are no merchant IPP's today, but some argue that such IPP's could perform useful functions in wholesale power markets by simultaneously providing price signals for potential builders about when to build new generating capacity and shifting some of the "demand risk" of building new plants from buyers to sellers of power The existence of merchant IPP's could increase transmission reliability difficulties if power flows for spot-market sales are not carefully controlled. However, according to a recent study by the Office of Technology Assessment,[4] there are no institutional, engineering, or economic reasons why satisfactory arrangements with control centers and reliability councils cannot be reached to ensure reliability

Thus, the multitude of bidders responding to competitive procurements does not mean that lack of transmission access is not inhibiting more vigorous competition The issue is whether expanding transmission access would cause bidding programs to be even more successful in terms of lower prices and higher quality bidders

Contention. An entity requesting access has alternatives that largely prevent the transmission owner from exercising monopoly power.

The argument here is that a wholesale buyer can build its own plant, invest in energy efficiency, or in some cases use another firm's transmission facilities, and thus circumvent any attempt to exercise market power by denying transmission access on reasonable terms While this argument may have some merit, increased access is nevertheless important for at least three reasons

First, while alternatives exist, they may not be least-cost alternatives This is why buyers request access Modern antitrust analysis will correctly detect significant monopoly power when differences in economic cost are substantial. The cost of a new plant, especially for a small utility, may be higher than the market price of electricity that can be acquired through the best use of transmission lines Cost-effective conservation resources may be limited or uncertain In short, the fact that some alternatives exist does not prove that market power is absent any more than the mere ownership of transmission facilities proves that it is present The existence of alternatives does not prevent economic inefficiencies from occurring as a result of the exercise of market power

Second, where significant market power exists, to argue that the presence of imperfect alternatives negates the need for action to prevent the exercise of that power is to argue that monopolies should not be regulated. By analogy, industrial users of electricity can in many cases shift from electricity to oil-based or gas-based technologies, and homeowners can use gas or oil instead of electricity for heat, however, few policymakers would argue that these alternatives warrant deregulation of electric retail service

Third, while it is important for the wholesale buyer to have a number of alternative supply sources, it is also important that a utility seller not be able to restrict the buyer's choices An ability to restrict access to markets is likely to be used by a seller to its own advantage If this is not the seller's intention, the seller should have little interest in maintaining an ability to restrict access in the first place

Contention: Voluntary access is working.

The argument that transmission access is not a barrier to efficient electricity transactions is often based on the premise that the significant increase in coordination sales between utilities in the last two decades demonstrates that access is given liberally to those who desire it

The volume of short-term wholesale electricity transactions between utilities has increased substantially in the past two decades An increase in transfer capacity, excess generating capacity at some utilities, and increased disparity in production costs among utilities, due in part to increases in the cost of oil relative to coal for much of the past 17 years, have all contributed to this trend. The amount of electricity being sold in power pools, also considered wholesale trade, also has increased because of these factors

In most spot-market, or economy, transactions, an owner of transmission lines will lose revenues if a potential sale, perhaps between two utilities on

either side of the transmission-owning utility, does not take place Consequently, a transmission owner with excess capacity has a short-term incentive to accommodate economically beneficial trades In addition, transmission owners in power pools typically allow other pool members to use their lines in exchange for the substantial economic benefits generated by the pool A 1981 report by the Federal Energy Regulatory Commission (FERC), *Power Pooling in the United States,* found that only 1 to 2 percent of possible short-term savings were not achieved at that time, indicating that most opportunities to displace units with higher operating costs with units with lower operating costs were taken However, a nationwide gain of 1 to 2 percent in short-term savings is equivalent to more than $1 billion annually

Two issues must be considered here First, while it is true that many efficient short-term trades are consummated in today's "spot market" for economy energy, the market itself is imperfect Individual transactions are priced at widely different prices because FERC sometimes allows split-savings pricing for economy transactions This pricing practice has arguably improved the utilization of existing generation assets and heretofore has been an appropriate part of FERC's policy However, it may become an impediment to the development of more efficient arrangements because different sellers could face significantly different prices for similar transmission service, thus distorting the delivered cost of power

Second, it is important to distinguish between transmission access for short-term trade and transmission access for long-term trade In the long term, the issue is whether long-term access is available on reasonable enough terms and under reasonable enough conditions to allow a distant competing generator to provide service to local utility systems

For potential long-term transmission agreements, an economically rational transmission owner would examine a range of issues, including the revenue stream those requesting access might provide, the possibility of brokering power at a markup greater than allowed transmission rates, the revenues to be derived from using the transmission for his own uses (for example, selling power from his own generating units), and how best to minimize his own retail rates The rational decision sometimes will be to deny long-term access or to charge high transmission rates that would discourage construction of competing new generating units

Thus, the large gains in short-term wholesale electricity transactions do not mean that the exercise of monopoly power over transmission lines cannot result in economic inefficiencies for long-term trade

Contention: Many groups are calling for increased access for the wrong reasons.

The American Public Power Association, the National Rural Electric Cooperative Association, the National Independent Energy Producers, the National Coal Council, and many others are calling for increased transmission access It is difficult to conclude that voluntary access is working well when so many potential transmission users assert that access is inadequate

Some of the demands for opening the Nation's transmission system are undoubtedly self-serving These users want service at low embedded-cost rates and seek transmission access to avoid the sunk capital costs of generating units, shifting these costs onto other users Many of the proposals, however, would entail acceptance of higher incremental-cost rates and cannot be summarily dismissed as self-serving and contrary to the public interest

Discussion

On the whole, it seems unlikely that the voluntary access policies in place today will provide sufficient and economical transmission access for wholesale sellers and wholesale buyers of electricity—especially those needing long-term contracts However, some promising incremental changes have begun to occur in the industry recently The more prominent of these are discussed below

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Recent Transmission Access Agreements

Few utilities grant long-term open access to all entities that request it In some recent FERC cases, however, some utilities have agreed to provide transmission access, generally as a condition for FERC approval of a utility proposal or action (for example, a merger or proposal to sell power at market-based rates) Several of the more important cases, both completed and pending, are discussed in some detail in Appendix B and are briefly summarized here

Turlock and Modesto

In 1988, FERC approved transmission agreements between Pacific Gas & Electric Company (PG&E) and two of its captive wholesale customers the Turlock and Modesto Irrigation Districts In both cases, the Commission approved a 20-year regulatory bargain whereby the wholesale customer would receive certain firm transmission and power services at embedded cost-based prices while PG&E would be authorized to charge "market-based" prices for certain coordination services The Commission approved PG&E's request for market-based pricing because it judged that the company had sufficiently mitigated its market power, in general, by its offer of cost-based services and, in particular, by its transmission commitments

Neither agreement allows the captive customer to resell reserved transmission service, and in both cases the transmission service is provided between specific receipt and delivery points Both these features restrict the market activities of the wholesale customers and help to insulate PG&E from competitive pressures that might otherwise be exerted against it

PSI Energy

In 1990, FERC approved a proposal by PSI Energy (formerly Public Service Company of Indiana) to sell up to 450 megawatts of long-term, firm power at market-based rates in exchange for a commitment by PSI to open its transmission grid. FERC approved PSI's program on the basis, first, that PSI is not a dominant firm in its region and consequently lacks market power over generation and, second, that PSI derives no market power from its transmission assets because of its commitment to provide open-access transmission service to all utilities, IPP's, and QF's

FERC required PSI to back up its obligation to provide transmission service by agreeing to suspend its market-based power pricing should FERC receive and uphold a third-party complaint about the lack of timely transmission service

PacifiCorp-Utah Power & Light Merger

FERC conditioned its approval of the merger of PacifiCorp and Utah Power & Light on the company's acceptance of an absolute obligation, over the long term, to provide firm transmission service to any power producer, not including QF's, at cost-based rates

FERC's conditions were accepted by the two companies and the merger was consummated in 1989 In so doing, the company agreed to place its coordination transactions at risk. This aspect of FERC's conditions is viewed as particularly onerous by many companies in the industry Whether it is burdensome in practice remains to be seen In any case, such a commitment satisfies the Federal interest in ensuring that efficient interstate electricity transactions are not unnecessarily impeded by utilities or local authorities However, this "Utah condition" is not the only means of doing this

Wisconsin Power & Light Transmission Tariff

In 1990, FERC accepted a transmission tariff under which Wisconsin Power & Light Company (WP&L) effectively became an open-access provider of transmission services No regulatory bargain was involved at the Federal level The Wisconsin Public Service Commission, however, established a policy that required its jurisdictional utilities to implement joint transmission planning and to file transmission service tariffs

This State policy raises the possibility of joint Federal-State partnerships to establish adequate transmission access FERC has authority over transmission rates, but cannot (except in a few unlikely circumstances) order nondiscriminatory access Here, the State, which has no authority

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over the pricing of transmission service, is in essence ordering access If Wisconsin's action passes judicial scrutiny, the groundwork for possible Federal-State cooperation will have been laid.

Under the tariff, WP&L will provide both firm and nonfirm transmission service to any utility, including QF's and IPP's, from existing facilities at embedded-cost rates If new facilities are needed, WP&L will provide service under separate, negotiated agreements approved by FERC Although the tariff does not specify the transmission price to be charged if new facilities must be built, it must ultimately be "just and reasonable" under the Federal Power Act Thus far, FERC has required a cost basis for the price of firm transmission service under this standard.

The WP&L tariff allows transmission between flexible receipt and delivery points, but does not allow the service to be resold. The flexibility offered to customers by the first condition is somewhat offset by the restrictiveness of the second

Pending Cases

Several cases are pending at FERC, including the Western Systems Power Pool extension and the Southern California Edison-San Diego Gas & Electric merger These cases suggest that the trend toward voluntary offers of transmission service is continuing Issues related to mergers, market power in nonfirm transmission pricing, and FERC's authority to order transmission under Section 207 of the Federal Power Act are also raised by these cases

FERC actions in these pending cases will substantially affect the evolution of transmission policy The current strategy at FERC appears to rely on case-specific developments No generic action on access or pricing has yet been proposed or announced by FERC, thus it is not yet clear where the Commission intends its case-specific actions to lead or what principles will guide its actions in future cases As discussed below, there would appear to be significant benefits from the development and articulation of a more general transmission policy

Notes

1 See Alfred E Kahn, *The Economics of Regulation,* Vol II, p 119

2 See *Report of the Federal Energy Regulatory Commission Transmission Task Force,* Table 2–5, p 47, for cost per kilowatthour of transmitting power over different sized lines

3 After these projects were canceled, Virginia Power and American Electric Power reached agreement on the construction of new extra-high-voltage transmission lines that will make it possible for projects in this part of West Virginia to sell power into Virginia starting in the mid-1990's

4 Congress of the United States, Office of Technology Assessment, *Electric Power Wheeling and Dealing Technological Considerations for Increased Competition,* May 1989

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3. Pricing and Related Terms for Transmission Access

The Relationship Between Pricing and Monopoly Power

As noted in Chapter 2, the critical transmission issue facing the industry is how to deal with the potential exercise of market power by some owners of transmission facilities In this regard, both price and priority of use are crucial to determining whether access to transmission lines is in fact meaningful to an independent power producer, qualifying facility, or other wholesale seller If the price of service for a long-term contract is not specified with a reasonable degree of certainty, a prospective wholesale seller cannot know if a candidate powerplant is economically feasible, especially because in many cases the seller would have no transmission alternative If the service is not firm (or is firm for only a part of the contract), the seller would not know if it could always get its power to market

The National Independent Energy Producers, which represents nonutility generators, states the issue in greater detail

> In specific competitive situations, utilities which own and control transmission facilities may exercise market power over competitors if they·
>
> - Make transmission access available to affiliates while denying access to competitors
> - Deny transmission access to favor competing proposed rate-based plants
> - Refuse to make public transmission capacity or availability information
> - Delay signing letters of intent to provide wheeling service to suppliers which prevents those suppliers from meeting bidding deadlines or other bidding requirements
> - Make access available to all, but impose prices, terms or conditions on transmission service for nonaffiliated entities that make projects unfeasible or uneconomic [1]

Of these five points, the first two relate to how a transmission owner could block competition in generation markets (addressed in Chapter 1), the third and fourth points indicate how a transmission owner might indirectly avoid providing access, and the last addresses the focus of this chapter, namely the relationship of pricing and the use of market power

What examples are there of transmission owners actually using their market power? Few cases of outright refusal to either wheel or otherwise provide service exist The most celebrated is the two-decade-old *Otter Tail* case, in which a utility that denied access was penalized on antitrust grounds [2] The more recent cases described below illustrate the difficulty of separating access from pricing issues Specifically, these cases demonstrate how the utility owning the lines can use pricing and prioritization to limit use of transmission lines by wholesale buyers or sellers of power

1 The Geneva, Illinois, municipal electric system in 1986 exercised its contractual right to drop its local supplier, Commonwealth Edison, and obtain only transmission services from Edison, upon 1 year's notice However, Geneva was unable to arrange for access at a transmission price that would make it economical to purchase power from its new supplier In a 1986 decision, the Federal Energy Regulatory Commission (FERC) found

> By the terms of the agreement, Edison was to enable any of its wholesale customers to pursue alternative power supply options under reasonable parameters *Implicit in such an arrangement must be an agreement that transmission service will be priced reasonably relative to existing services being provided by the utility* [3] [italics added]

FERC noted that Edison proposed a rate approximately four times the price that had been quoted to Geneva during its evaluation of suppliers The FERC decision continued.

> Whatever ultimate findings the Commission might make with regard to the merit of Edison's pricing structure or, conversely, its anti-competitive effects, we know at this point that the filing will immediately subject Geneva to an observable prejudice or

disadvantage in the power supply market that will not be remedied through later refunds [4]

2 In the Northeast Utilities (NU)/Public Service of New Hampshire merger case currently before FERC, similar issues are raised by the Vermont Public Service Board, a wholesale purchaser of electric power

> *NU's policy that a customer in need of transmission service receive such service only under terms dictated by NU—the largest electric utility in New England and often the only utility with the facilities to provide such transmission—and receive such service only on the condition that the customer does not challenge the terms of service* [before FERC or the courts]—is patently unreasonable and renders inadequate much of the essential interstate service available in New England
>
> Under the terms of [contractual conditions] the customer is obligated, for the life of its transmission agreement, *to pay all, or a pro rata portion, of the costs of new construction or modification of transmission facilities which NU determines are [required]*, whenever NU makes that determination *NU's practice holds potential transmission customers hostage* to indeterminate future charges as a condition of service *[T]his practice is unduly discriminatory in that NU's sales customers, particularly its native load, are apparently not subject to this condition for continued service, although continued service to them may also "contribute to the need for such new or modified facilities"*[5] [italics added]

NU's view is quite different

> Vermont complains that NU's transmission service practices are discriminatory in two respects First, NU's long-term transmission service contracts disclaim any obligations "to construct or modify its transmission facilities" to ensure continuation of the transmission service If new or modified transmission facilities are required in order to continue the service, the transmission service customer has the option of either contributing to the costs of these facilities or discontinuing the service Second, *NU currently follows the practice of not committing to provide transmission service to another utility where to do so would interfere with NU's ability to use its transmission system to make off-system sales from its generation capacity to reduce the cost of service to NU's native load customers, and to sell the output of its own generation to its own native load customers*[6] [italics added]

This dispute raises a key issue NU, quite reasonably from its viewpoint, wants to minimize its own customers' rates (and maximize shareholder returns) and therefore will give its own uses priority over the uses of others, including those who seek firm service contracts If a transmission user with a long-term contract to use the lines wants to continue using them for firm service, it must pay some or all of the costs of expanding the capacity of the lines

3 The Wisconsin Public Service Commission, in a recent order, addressed similar issues when it stated

> The monopoly control of "bottleneck" facilities has also permitted the owning utilities to allocate the benefits of the transmission system optimally for their own ratepayers without consideration of statewide least-cost planning, or statewide efficiency of use Allocation on this basis is unlikely to be equitable or to provide the statewide efficiency for which the system is being planned and built[7]

It should be noted, of course, that even policies designed to maximize statewide efficiency (or to minimize statewide average rates) may reduce efficiency on a regional or national basis Individual State commissions cannot be expected to applaud policies that have the potential to raise their constituents' rates in the service of broader efficiency goals

An important corollary issue is whether a utility must sacrifice its own short-term sales in order to provide long-term access Such a policy might require the user to pay for any upgrades needed to accommodate use of the transmission system in the near term, when the user is brought on line Under this policy, a utility also would charge a reasonable (perhaps embedded-cost) rate for the use of lines that do not need upgrading, but would then treat the user as an existing part of the system If the "reasonable rate" went up over time, it would go up the same amount as for other system users, including retail customers, and thus all would share on a *pro rata* basis in the costs of system upgrades needed to provide continued service

Would this kind of policy cause losses to the transmission-owning utility by making it forgo economic transactions? This type of policy would

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cause a utility to forgo economy transactions only if the utility could not provide upgrades needed to serve all users in a timely manner Then, a choice would have to be made for priority of use

PacifiCorp (in its merger with Utah Power & Light) and PSI Energy (in its recently approved market sales program) both agreed that firm transmission will have priority over nonfirm uses of the grid, even those that might otherwise benefit native-load customers This priority applies equally to expansion planning and operational uses of the grid. The fact that some members of the industry can arrange to operate their grids under rules of priority that apply equally to the industry and its customers suggests that problems of priority of use are not viewed uniformly across the industry and may be particularly difficult to solve

The question of whether utilities could reasonably be expected to provide needed upgrades is discussed further below

Transmission Pricing in the Absence of Market Power

The reasoning thus far is that in cases where transmission owners have significant market power over firm transmission service, their conduct must be constrained by regulation Ensuring that transmission services are priced in an economically sound fashion and provided under reasonable contractual conditions while improving the access conditions in the industry is a significant challenge for FERC and other interested parties at present Economically sound pricing of transmission services promotes good decisionmaking in the generation and transmission sectors of the industry by promoting trades that are economically efficient and discouraging trades that are not

A report issued by the National Regulatory Research Institute (NRRI) finds that marginal-cost pricing for transmission would tend to promote good decisionmaking and would be more appropriate than embedded-cost pricing [8] In this view, long-term incremental-cost pricing will give the correct signals about real resource costs to users of long-term firm transmission service

Similarly, short-term marginal-cost prices will give correct price signals to users of nonfirm transmission service, where short-term marginal costs include a measure of congestion costs if transmission facilities are constrained in the short term The NRRI concept of short-term marginal costs corresponds closely to that advocated by the so-called MIT group, which favors a form of spot-market pricing for short-term, nonfirm transmission service [9]

As the NRRI report points out, not only is it important to get the prices for individual transmission services right, but it is also critical for the overall functioning of the market that customers have a viable choice between firm and nonfirm services In that way, when the spot price of transmission rises because of congestion, customers who do not wish to pay the resulting higher prices for nonfirm service will be able to subscribe to firm service instead The spot market, then, will provide signals that affect the demand for firm transmission service, which, if the service is priced at expansion costs, will signal that additional transmission capacity is needed

The report of the FERC Transmission Task Force took this reasoning a step further and addressed the possibility of so-called "vintaged pricing" in which, among other things, native-load customers and off-system customers would be treated differently This concept involves native-load users paying embedded costs for the transmission service that they receive bundled together with generation service With this concept, off-system customers would pay incremental costs for firm service and each customer would in addition pay the incremental cost of the grid at the time the long-term, firm transmission contract is initially negotiated and approved.

Former FERC Commissioner Stalon has carefully examined four alternative pricing regimes for long-term, firm transmission service involving various combinations of policies concerning incremental versus embedded-cost pricing, and whether or not vintage pricing is permitted for off-system users [10] All of Stalon's alternatives have embedded-cost pricing for the native load. He concludes that, of the four alternatives considered, incremental-cost pricing for all off-system users would best promote the Nation's economic efficiency objective

He points out, however, that embedded-cost pricing is familiar to regulators and is politically attractive In addition, discriminating among off-system users with vintage pricing can also be politically attractive to regulators and can be thought of as a form of "grandfathering," an acceptable regulatory practice in many instances Consequently, while the efficient choice in Stalon's view is nondiscriminatory incremental-cost pricing, he expects that a less efficient embedded-cost standard or a vintaging standard is likely to be adopted. Given the importance of making efficient use of the Nation's energy resources, a politically driven standard could be extremely costly

These pricing issues are complicated matters that may require several years to sort out completely The sorting-out process could be accelerated if FERC were to move forward with a rulemaking process concerned with transmission issues related to access, pricing, contracting, and capacity expansion planning In the meantime, the industry has proposed some interesting approaches that FERC has found to be just and reasonable PSI Energy's program, described in more detail in Appendix B, involves embedded-cost pricing for service from existing assets and incremental-cost pricing when new facilities must be built PSI Energy and FERC were able to move forward on PSI's basic proposal by acknowledging that PSI's calculation of incremental costs, if and when new facilities are needed, must meet the Commission's "just and reasonable" standard. The Wisconsin Power & Light (WP&L) transmission tariff envisions a similar regulatory solution to the need for new facilities

The WP&L transmission tariff is also an example of an industry-sponsored approach for dealing with one aspect of the quality-of-service issue It permits systemwide transmission service as opposed to point-to-point service Systemwide transmission was also a feature of the Gulf States Utilities settlement with Sam Rayburn Cooperative PSI Energy's recently approved program does not have systemwide access, but does allow receipt and delivery points to be adjusted if the buyer agrees to pay any incremental costs These examples suggest that the industry is capable of addressing the quality-of-service issue in productive and innovative ways

Another aspect of service quality of interest to transmission customers is whether firm transmission service can be resold In the PacifiCorp-Utah Power & Light merger, FERC required that customers be allowed to resell firm transmission service In this instance, reselling was seen as one way of checking the merged company's market power over nonfirm transmission—a flexibly priced service Similarly, PSI Energy also allows transmission service to be resold, although the market power issue does not arise to the same degree in this case because PSI offered to cap nonfirm prices at cost The Large Public Power Council, an association of transmission-owning municipal utilities, has called for reselling in its transmission reform proposal In contrast, the WP&L transmission tariff does not allow reselling, although this restriction is tempered by the systemwide character of the service in the first instance These industry-sponsored initiatives suggest that reselling can be dealt with in the context of current institutions

The recent regulatory experience strongly suggests that FERC has adequate authority to deal with pricing and other terms and conditions of transmission service, including such issues as whether to allow reselling and whether systemwide or point-to-point service is appropriate The unanswered question is whether FERC can address the transmission owner's obligation to serve within its current authority—a topic discussed below

Will Adequate Transmission Capacity Be Provided?

In this section, we return to the issue of whether it is reasonable to expect a utility to provide adequate capacity at reasonable prices over time for both existing and potential transmission users The reader will recall that some utilities have recently accepted such a proposition in cases before FERC Three factors affect the capacity expansion issue (1) the ease of building new lines, (2) new technologies for upgrading existing lines, and (3) a historical perspective

Regarding new lines, the FERC Transmission Task Force found that in the 1980's, more than 29,000 circuit-miles of extra-high-voltage transmission lines were built while only about 100 circuit-

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miles were on the "troubled line" list published by the North American Electric Reliability Council There is no question that the public is increasingly aware of environmental issues, and that this awareness makes it more difficult and expensive to build new lines The FERC Transmission Task Force concluded, however, that "the barriers to building new transmission lines do not seem formidable when viewed from a national perspective Some difficulties may exist in densely populated regions, however " The fact that several new intrastate and interstate 500-kilovolt lines have been proposed in the East in the last several months suggests that the industry believes that environmentally sensitive, carefully planned lines can still be constructed. It remains to be seen whether these lines can actually be constructed Problems in siting transmission lines may well increase as concern about the health effects of electromagnetic fields increases

As for existing transmission lines, new technological improvements, collectively known as Flexible AC Transmission Systems (FACTS), could significantly increase the capability of existing transmission lines if used on a widespread basis

For example, an April 1990 General Electric publication, *Systems Innovations*, presented the results of a study of an application of one of the FACTS technologies, a thyristor-controlled series capacitor Under present conditions, a certain critical transmission corridor is capable of transmitting 5,000 megawatts while withstanding the loss of a 500-kilovolt line However, with the addition of the FACTS technology, the interface is capable of transferring an additional 1,200 megawatts, or 6,200 megawatts in all. The Electric Power Research Institute (EPRI) has found that application of several different FACTS technologies on a particular transmission corridor of 5,000 megawatts can almost double the power-carrying capacity

EPRI gives several other examples of how this and other FACTS technologies, some of which are still a few years away from commercialization, can increase transmission capacity on existing lines Combined with data demonstrating the number of new lines built in the 1980's, FACTS suggests that needed capacity increases can be provided.

From a historical perspective, utilities have been able to provide transmission for the needs of their native-load customers without apparent exception For most of the post-World War II period, electricity demand was growing at about 7 percent yearly, much higher than the average national growth rate today of about 2 to 3 percent Given their historical success, it does not seem unrealistic that utilities could meet a requirement for transmission service that includes some new firm users, provided that the utility is given adequate time to build or upgrade capacity However, simply imposing the obligation to provide this service without ensuring adequate returns from doing so puts captive-customer rates at risk and creates incentives for delay However, given an adequate amount of time to add capacity, an economic pricing regime, and contract terms that set reasonable service priorities, there should be no reason to sacrifice future national efficiency

Notes

1 W Harrison Wellford and Nancy H. Sutley, "Our Views on Transmission Policy," *Public Utilities Fortnightly*, July 19, 1990, pp 35–36

2 See Douglas G Green, "The Antitrust Laws and Transmission Access in The Electric Utility Industry An Outline of Basic Principles," presented at the Annual Meeting of the American Bar Association, August 1990, pp 32–34

3 FERC Docket No ER86–76

4 *Op cit*

5 Motion of the Vermont Department of Public Service and Vermont Public Service Board to Amend Complaint and for Partial Summary Judgement, FERC Docket No EL90–13–000, March 19, 1990, pp 3–4

6 Answer of Northeast Utilities Service Company to Amended Complaint, FERC Docket No EL90–13–000, April 18, 1990, p 9

7 Wisconsin Public Service Commission Order in Advance Plan 5 (Docket 05–EP–5)

8 See Kevin Kelly, J Stephen Henderson, and Peter A. Nagler, *Some Economic Principles for Pricing Wheeled Power*, National Regulatory Research Institute Report 87–7, August 1987

9 The "MIT group" has written extensively on spot transmission pricing; for example, see Roger E Bohn, Michael C Caramanis, and Fred C Schweppe, "Optimal Pricing in Electrical Networks over Space and Time," in *The Rand Journal of Economics* 15 (Autumn 1984) 360–376

10 See Charles G Stalon, "A Pricing Regime to Achieve Economic Efficiency and Equity in the Provision of Transmission Services," Presentation to Keystone II Project on Transmission, Keystone, Colorado, March 1990

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4. Reliability, Dispute Resolution, and Planning

Reliability Is Crucial

The importance of the transmission system's reliability cannot be overemphasized Reliability here means the ability to ensure that power is delivered to customers and that power outages are infrequent The costs of large-scale, extended outages (for example, the blackouts in the Northeast in 1965 and in New York City in 1977) can be great An accumulation of smaller outages also imposes significant costs

There have been debates over what constitutes an adequate level of reliability in the electricity industry The industry's typical standard for planning purposes has been that there should only be 1 day in 10 years during which electricity would not be available due to insufficient generation This rare outage would be caused by a lack of adequate generating capacity, lack of adequate interconnection to import power, or some combination of the two (Not included would be outages caused by acts of nature, such as tornadoes, hurricanes, or violent thunderstorms, these outages affect distribution lines more often than larger transmission lines and are generally localized in nature)

Given the costs of new generating and transmission capacity, some commenters have wondered if a somewhat less stringent standard, perhaps 1 day in 5 years, might not be more cost-effective Alternatively, some utilities are beginning to experiment with "product differentiation," offering different degrees of reliability to customers at different rates Some large users have the ability to reduce operations or to generate power with backup equipment, and so could accept interruptible rates that entail an occasional loss of service, others require continual high-quality electricity service to avoid large economic losses

This analysis will not attempt to assess what constitutes a cost-effective level of reliability It will simply assume that whatever the appropriate level is, an increase in transmission access ought not to change the level

Assuming the control and operation of the transmission system stays exactly as it is today, how might transmission access decrease reliability? One must understand the nature of electricity transmission to appreciate the technical issues associated with increased transmission access

Electricity does not flow along a defined, predictable path from the generator to the ultimate end-user Instead, it flows along multiple paths This means that contractually prescribed transmission paths are largely a fiction because bulk power transactions simultaneously affect many lines in a transmission network. The actual division of power over the various lines depends on the loadings on those lines and can vary widely over time The summation of the flow over the various paths can cause an effect known as loop flow Thus, a power transaction between two utilities often will affect the transmission system of other utilities that are not parties to the transaction

Therefore, little insight into the power transfer capability of a utility is gained by evaluating the available capacity on a single transmission circuit What needs to be determined is the amount of power that can be safely carried by the portion of the network under consideration

The amount of power that can be transferred between parts of the network is also subject to reliability constraints Reliable system operation requires that there be some excess capacity in the system to handle contingencies—loss of a generator or transmission line System loading will generally be kept below a limit that is expected to be safe for at least a 30-minute period if any single component is lost [1] Thus, one or more circuits will intentionally be loaded at less than full capacity so that the system can respond to contingencies

Coordination of power flows is handled by the previously mentioned control areas Currently, there are about 150 control areas within the lower 48 States and interconnected southern Canada Each control area is responsible for matching generation (plus purchases from other control areas, minus sales to other control areas) with

load. To accurately match generation and load, automatic control of generation is required within the area and each area controller must know about scheduled power flows into, out of, or across the region and must be able to plan for them Unscheduled flows could cause economic harm (for example, by forcing the use of less economic plants than would have been used if the flow had been properly scheduled) and in the extreme could cause loss of service because of changes in system conditions such as line overloading or undervoltage

In addition to possible problems caused by unscheduled power flows through control areas, area controllers must also be able to control emergencies by being able, at a minimum, to turn generating facilities—including qualifying facilities (QF's) and independent power producers (IPP's)—on or off or otherwise disconnect them from the system Being able to dispatch generating facilities to a greater or lesser extent also can improve system stability Utilities generally will not sign contracts with QF's and IPP's unless they meet minimum reliability standards such as a willingness to be disconnected in emergencies In the last few years, the ability to dispatch has become either a requirement or a major nonprice factor in competitive bidding for power

The challenges posed to transmission area controllers by greater numbers of QF's and IPP's are in principle not much different from those posed by the tremendous expansion of the system over the past several decades Loop flows could increase, but utilities have heretofore managed either to ignore or to reach voluntary agreements on loop flows, and pertinent new accounting methods and technologies are being examined. New equipment, new software, and new training procedures might all be needed. However, given adequate time to adjust, and without a very large increase in the number of entities seeking transmission access, there seems to be no reason why increased transmission access should cause decreased reliability This is the conclusion of both the Office of Technology Assessment (in *Electric Power Wheeling and Dealing,* May 1989) and of the Large Public Power Council (LPPC), a group of publicly owned utilities, most of whom own large transmission systems For instance, the March 15, 1990, LPPC Transmission Access Task Force paper states

> Additional supplier and wholesale customer access can be provided *without jeopardizing reliability*
>
> LPPC's transmission policy supports increased access to suppliers and wholesale customers and LPPC believes this can be accomplished without jeopardizing reliability However, it is imperative that certain actions be taken by the industry to ensure that these new players will not jeopardize reliability [italics added]

The LPPC paper then lists a number of such actions These would include the enforcement of technical requirements so that new generating and transmission equipment conforms with utility standards The ability of new suppliers and wholesale customers to be dispatched or curtailed must be compatible with economic and emergency use of existing utility generating systems Operational control of the network must be retained by utilities and power pools because, to protect the transmission system, they ultimately have the responsibility and physical ability to control transactions between nonutility suppliers and wholesale customers with no generating capacity

Dispute Resolution and Planning Procedures

Wholesale trade and interregional transfers may continue to increase, thereby creating a need for new or upgraded lines within and between geographic regions As more new entrants press for access, there will inevitably be disagreement about how much capacity might be available, for what timeframe, at what cost to the existing system, and at what prices The result will be an increasing need for ways to resolve disputes and for closely related new planning procedures

Dispute Resolution

As we have seen, maintaining reliability in a regime of more open access means that the network will have to accommodate a larger number of buyers and sellers A larger number of participants creates more opportunities for disputes over access and the terms of access If these disputes cannot be settled in a timely manner, system operation and hence reliability could suffer as multiple parties stake claims for a limited amount of transmission capacity

Hence, the inevitable disagreements regarding the amount of available transmission system capacity must be resolved by some entity These could include regulators, groups whose primary qualification is technical knowledge about how the grid operates, or as a last resort the courts (arguably the least qualified to interpret technical issues)

Given the surge of interest in increased access to the grid, and given the precarious balance between monopoly ownership of the grid and potential antitrust difficulties if those who desire to use the grid cannot get access, there may be significant reason to worry that courts might in the end be the arbiter of terms and conditions of access This worry should be shared not just by utilities, which would have to live with the decisions of the courts, but also by others interested in maximizing economic efficiency [2] Although it goes without saying that the arbiter of such disputes must be neutral, an arbiter without adequate technical knowledge could make decisions that unnecessarily cause significant economic harm.

The extent to which the Federal Energy Regulatory Commission (FERC) might be able to encourage access and associated terms and conditions is explored in Chapter 6 of this analysis However, several proposals for voluntary dispute resolution have been made recently For instance, a group of proposals with some common characteristics include those of the National Rural Electric Cooperative Association, the Consumer Energy Council of America (CECA), and the Large Public Power Council

The LPPC proposal would allow investor-owned and publicly owned utilities and QF's and IPP's to join a voluntary association that would utilize the talents of people intimately familiar with the grid to resolve transmission access disputes Members would be bound by the decision of the arbitration panel The LPPC sees this voluntary method as far superior to relying on the courts and points to other voluntary industry organizations, such as the Institute for Nuclear Power Operations and the North American Electric Reliability Council and its regional councils, as precedents for its proposal

CECA recently released a new study, *Transmission Planning, Siting and Certification in the 1990s Problems, Prospects and Policies,* which calls for the creation of an arbiter to "resolve impasses among the states in planning, siting or certifying multistate transmission lines " CECA's large advisory committee for this study included the executives of several investor-owned electric utilities as well as representatives from most other groups interested in the electricity industry, including regulators, public utilities, environmentalists, consumer bodies, and government officials

The CECA proposal would attack a problem different from but related to the problem addressed by the LPPC proposal The LPPC proposal would referee issues related to the terms and conditions of access, while the CECA concept would attempt to deal with the closely related issue of how to ensure that the transmission capacity needed to implement greater access and transfers of power will be built It would do so by providing a forum for resolving disagreements of planning and siting of new lines in the context of binding arbitration CECA's arbitration mechanism would be established as part of an agreement among States to form Regional Transmission Planning and Certification Coordination Boards (RCB's), the full purpose of which is explained below If binding arbitration within an RCB agreement or as a result of other agreements among States did not occur, CECA recommends a Federal "court of last resort," created by new legislation, in which the burden of proof would be on the complainant, whether the complainant was proposing or opposing a proposed new line

Another important factor in siting transmission lines is the clear and growing public concern about the possible health effects of electric and magnetic fields (EMF's) The CECA proposal calls for a vigorous Federal research effort into EMF effects, to resolve uncertainties about the possible health impacts of these fields CECA also suggests establishment of an international clearinghouse to compile and disseminate research, with costs shared between the government and private sectors Finally, the RCB's would be a useful forum through which States could adopt uniform standards for dealing with EMF emissions

Planning

Planning and dispute resolution are closely related because new planning procedures could remove or mitigate the need for dispute resolution by enabling transmission "have nots" to become transmission "haves"

At the outset, it is useful to consider mergers as a particular type of solution that may help to facilitate planning, although mergers are not planning tools in themselves Mergers may be important because they could help reduce one disincentive to economic provision of transmission the balkanization of ownership that allows a transmission owner to block highly beneficial transmission capacity that must go through several utility territories Thus certain mergers could help remove bottlenecks, in that a merger could "internalize" the net economic benefits from wholesale transactions within one system

Clearly, however, mergers can have the opposite effect For example, in the merger of PacifiCorp and Utah Power & Light, FERC was concerned that the merger would decrease the number of competing corporate transmission corridors in the western Rocky Mountain area from two to one, thereby harming those in need of transmission and decreasing economic efficiency It was for this reason that FERC conditioned its approval of the merger on, among other things, firm transmission access for wholesale buyers and IPP sellers

New planning possibilities can be characterized as falling in four areas statewide planning, regional regulation and planning, joint ownership of transmission lines, and FERC activities FERC activities in this context are not strictly planning measures They are included here, however, because they can have effects on efficiency similar to some of the other measures proposed. These activities could include continuation of the present policy of conditioning mergers and utility power sales at market-based rates on transmission access as well as exploration of potentially existing but unused powers in the Federal Power Act

Statewide planning can also help solve the balkanization issue, in the sense that any bottlenecks *internal* to the State would presumably be removed to maximize efficiency gains within the State for those entities with rights to use the transmission grid. In most cases, one would expect for this reason alone that statewide planning with a goal of maximizing efficiency would likely be better than not having statewide planning In this context, statewide planning means having the regulators provide incentives for jurisdictional utilities to conduct joint resource planning It does not mean having regulators do the actual system planning Regulators would maintain their traditional role of reviewing and approving utility resource plans

Whether statewide planning would solve the economic inefficiencies that would exist because a wholesale seller, such as an IPP, might not be able to sell into markets other than its host utility would depend on several factors States do not have authority to set prices for transmission services, and their power to order wheeling appears to be quite limited. FERC normally asserts jurisdiction over wholesale transactions even when all the utilities involved are within a single State FERC's rationale, which has been supported by the U S Supreme Court, is that any power transaction involving at least one utility interconnected with a utility in another State, or with a utility that has an interstate connection, constitutes an interstate power flow Because of the highly interconnected nature of the electricity system, nearly all wholesale transactions meet this criteria and thus are subject to FERC's jurisdiction [3]

Yet, State regulators have powers of persuasion that are relevant, even if explicit authorities are lacking It is therefore possible that statewide planning could include "voluntary" provisions for statewide wheeling at reasonable cost for wholesale sellers without previous rights to use the system, if the State regulators want such a policy and potential legal obstacles are resolved.

A test case of this approach is already under way in Wisconsin As noted in Chapter 2, in 1989, the Wisconsin Public Service Commission issued an order calling for establishment of a statewide transmission system based on single-system integrated planning and operated pursuant to long-term joint use and cost-sharing agreements [4] The order also requires transmission-owning utilities to file wheeling tariffs with FERC The Wisconsin Commission's view is that efficiency

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gains will result from providing all of the State's utilities, public and private, the opportunity to jointly take part in the planning, operation, and ownership of a statewide transmission system All but one of Wisconsin's major investor-owned utilities are currently challenging provisions of the order before State court and FERC

An important issue regarding statewide planning is whether such planning could increase *intra*state efficiency but harm, or at least not help, *inter*state efficiency Suppose that construction or upgrade of a certain line within a certain State would allow two in-State utilities to minimize their joint costs of production, considering only the resources within the State Suppose also that still greater efficiency would result if the utilities build or upgrade a different, *inter*state line and share the benefits with several out-of-State utilities In this case, the statewide plan would conflict with efficient cost minimization, and could even prevent cost minimization, because once the line is built or upgraded the utilities would be much less likely to build the second, interstate line

Alternatively, suppose that the most economic potential market for an IPP is in a neighboring State, but that the only utilities to which it could sell its output under a given statewide plan, other than its local utility, are other in-State utilities Here, the State, through its plan, has helped the IPP and promoted efficient use of energy by broadening the IPP's potential market But the absence of regional planning has prevented the most economic use of this resource

Regional planning and regulation potentially could achieve some of the multistate benefits that could elude statewide planning For instance, if such planning and regulation were effective, bottlenecks that affect efficiency across several States, not just one, could be dealt with IPP's and other wholesale sellers could have access to a larger market, and purchasing utilities could have access to a greater number of sellers Regional planning could resolve the possible difficulty posed by statewide planning whereby a transmission or generation project that maximizes efficiency within one State might impede an even more efficient solution

Regional planning, however, also could cause inefficiencies If it becomes simply a burdensome regulatory hurdle on top of existing regulation in several States, it could hinder the already difficult process of getting needed facilities built However, if it provides a process that not only helps achieve regional efficiencies, but also reduces the regulatory hurdles faced by these economical new projects, then regional planning or regulation would be beneficial CECA's recent proposal to establish RCB's to coordinate the planning, siting, and certification of new lines seems to promise movement in this direction In addition to encouraging regional planning, the RCB's would simultaneously offer a mechanism for dispute resolution

Another proposal that could achieve regional efficiencies is that of former Commissioner Susan F Tierney of the Massachusetts Department of Public Utilities Her proposal to create a formal marketplace for generation within the New England Power Pool (NEPOOL) has four principal features

- All utility or nonutility projects inside or outside NEPOOL that pass a market test would become "Pool Planned Units"
- All such units would be eligible for the access and transmission pricing terms currently available under the NEPOOL agreement (for example, pool transmission facility rates, which do not vary with distance)
- The current embedded-cost transmission rates would be replaced with marginal-cost rates based upon the full costs of building new transmission facilities
- The revenues from these new rates (applied to all new wheeling contracts) would provide a fund to pay the full costs of all new bulk power transmission facilities in the region

Joint ownership of transmission lines would allow transmission "have nots" (who today are often wholesale buyers) to have greater access to potential markets A policy of greater joint ownership would certainly help those who would be new members of the transmission owners' "club," and in that way would enhance competition significantly

However, joint ownership probably would give only limited help to entities that do not become joint owners For example, a wholesale buyer who for one reason or another does not or cannot become a joint owner of transmission capacity would be helped only to the extent that the additional owners would provide the potential for competition among transmission sellers Wholesale sellers would be helped by joint ownership either by becoming joint owners or by being able, through greater numbers of transmission owners, to access markets that were formerly closed to them

Turning from actions that can be taken at State or regional levels to actions at the Federal level, there are two types of possibilities for increasing transmission access, although both are not strictly planning procedures These options are (1) continuation of FERC's policy requiring transmission access as a *quid pro quo* for approval of particular utility proposals that might not be "just and reasonable" or otherwise legal without transmission access to mitigate market power and (2) a reexamination of FERC powers under Sections 205, 206, and 207 of the Federal Power Act

Continuation of FERC's case-by-case, *quid pro quo* policy, as in several mergers and proposals to sell power at market-based rates, will inevitably be a slow process While this approach has the virtue of increasing understanding of the effects of departure from traditional ways of doing business, it may not lead naturally to the development of a coherent and workable framework. Development of a comprehensive policy, possibly including legal reform, would be desirable and would have the advantage of avoiding the creation of a patchwork of different and possibly conflicting approaches Continuation of the current case-by-case approach is likely to create a patchwork that depends on which utilities come before FERC with requests that motivate FERC to require transmission access as a *quid pro quo*, on the specific facts in each such case, and on the details of each such decision In addition, uncertainty regarding case-specific outcomes may inhibit companies from coming to FERC with mergers and other proposals that would themselves enhance efficiency

The common theme of the five nongeneric approaches above—mergers, the three State or regional ideas for statewide planning, regional planning, and joint ownership, and the continuation of FERC's present policies—is that each can contribute something to decreasing the transmission owner's ability to exercise market power by increasing transmission access, but each represents only part of a comprehensive solution

Looking further out in time, a more comprehensive policy would establish a less balkanized regulatory solution to a problem that itself is partly caused by industry balkanization FERC could move in this direction by initiating a rulemaking process on transmission access, pricing, contracting, and capacity expansion planning, taking into account the importance of avoiding conflicts between laws and obligations at the State and Federal levels There may be unused powers in the Federal Power Act that FERC could use to increase transmission access in a more broadly applicable manner Alternatively, there might be ways in which State authorities, with their ability to influence utilities to offer transmission access, could be combined with FERC authorities to establish prices and terms for the use of transmission lines These concepts are explored further in Chapter 6

Notes

1 John A. Casazza, "Understanding the Transmission Access and Wheeling Problem," *Public Utilities Fortnightly,* October 31, 1985, pp 35–42.

2 See Richard J Pierce, Jr, "Who Will Mandate Access to Transmission. FERC or the Courts?" in *Public Utilities Fortnightly,* March 29, 1990

3 See Robert E Burns, "Legal Impediments to Power Transfers," in *Non-Technical Impediments to Power Transfers* (National Regulatory Research Institute, Kevin Kelly, ed.), September 1987, p 74

4 See George R. Edgar, "Wisconsin Lines," in *Public Power,* July-August 1989

5. Which Entities Should Have Access?

As noted in earlier chapters, three types of firms want a greater degree of access to the integrated transmission system These are wholesale sellers (utilities, qualifying facilities, and independent power producers), wholesale buyers (generally utilities that want to purchase all or part of their needs from other parties), and retail users (generally large industrial customers)

To judge the appropriateness of greater access for each of these groups, *economic efficiency*, *equity*, and *reliability* criteria are discussed.

Economic Efficiency

Four effects related to economic efficiency should be considered. Two of these are large and positive, leading to gains in efficiency, and two are relatively small, possibly leading to losses in efficiency

Potential Economic Efficiency Gains in Wholesale Transactions

As discussed in Chapters 1 and 2, transmission access for wholesale *sellers* of power will most likely lead to a more efficient electricity generation market This is the first type of gain in economic efficiency Wholesale sellers would include utilities with excess capacity that have been unable to get their power to buyers as well as new facilities that have demonstrated in competitive bids that they are among the least expensive options available

Potential efficiency gains also can result from access for wholesale *buyers* The possibility of losing wholesale customers would arguably make utilities more cost-conscious and more flexible with respect to rate design and service by enhancing market discipline, which currently exists only to the extent that large customers might be able to self-generate Today, wholesale power markets generally (with the exception of sales to "captive" wholesale customers) involve neighboring or nearby utilities selling firm or economy power to one another or participating in a power pool Such markets are active, especially in times of excess capacity, but it is also true that such wholesale markets would likely be significantly more competitive if many "captive" wholesale buyers, in most cases purchasing from the local utility in whose service area they are located, were actively purchasing on the open market

This analysis does not attempt to determine how many wholesale buyers are needed within a region to create a workable, competitive market However, to the extent that increased access facilitates an expansion in the number of wholesale customers purchasing on the open market, there is reason to believe that, over time, wholesale power might be substantially more cost-efficient For these efficiencies to be realized, however, open transmission access would be required

These efficiencies would come about because utilities would have to compete more strenuously not only to retain their own (no longer captive) wholesale customers, but also to expand their sales to other wholesale buyers The likely result would be substantial cost reductions such as those seen in highly competitive industries where there are no captive customers Utilities would have new incentives to conduct their business more efficiently Regulators would be able to observe which utilities are able to sell power at the lowest cost, an impetus to lower costs at all utilities

Sometimes this potential cost reduction is referred to as the gain to be had from "pencil sharpening," for example, by reducing the costs of one's operation In fact, the gains may be more substantial

In the short term, a utility with excess generating capacity could offer a "discount rate" to retain a wholesale customer, much as utilities with excess capacity have offered discount rates to large industrial customers during the 1980's However, over time only those utilities that could build or acquire new sources of power at low cost would expand their base of wholesale customers Thus, if a utility designed a power-purchase auction poorly or did not minimize the cost of new powerplants, it would sell less power and would therefore build less The same would be true of a utility that fails to build plants economically

Would these same efficiency gains also be present if retail buyers, in addition to wholesale buyers, have access for purchases on the open market? Although the answer cannot be known with certainty, it seems unlikely that much added efficiency would be gained Presumably, over time, the ability of wholesale buyers to choose among many wholesale sellers would weed out the less efficient builders and operators Most utilities would have reduced costs in other ways in response to the increase in competition Access for wholesale sellers such as qualifying facilities and independent power producers should bring the most efficient nonutility generators to market Thus, the added benefits of retail transmission access are likely to be small

Potential Economic Efficiency Losses in Wholesale Purchasing

Transmission access will not always engender improved efficiency Some transactions may "wheel money" rather than wheel power This phenomenon occurs when the transaction is motivated by differences in average, embedded-cost rates between utilities rather than differences in marginal production costs An individual utility may experience a sharp increase in its average cost of service following incorporation of an expensive new generating plant into its rate base The near-term increase is exacerbated by the "front-end loading" of the capital cost of new plants Wholesale buyers will naturally seek to purchase power from a neighboring utility with lower embedded-cost rates However, if the two utilities are members of a centrally dispatched power pool, the composition of plants actually producing the power might remain unchanged, even though there has been a change in contractual arrangements If there is no physical change in plant dispatch within a region, there are no savings in aggregate regional production costs Thus, there is no efficiency benefit

Alternatively, in a few cases costs could actually increase For example, suppose the new seller sells firm power, based mostly on older coal plants, at a total price of $0 05 per kilowatthour, but at a short-term marginal production cost of $0 03 per kilowatthour Suppose the previous seller's price was $0 07 per kilowatthour, but with short-term marginal production costs of $0 023 per kilowatthour In this example, economic efficiency is harmed because short-term costs have increased from $0 023 to $0 03 per kilowatthour (The fixed costs, reflected in the $0 05 and $0 07 per kilowatthour total costs, are sunk—already spent—and so do not enter a calculation of economic efficiency today) Whether such inefficiencies occur depends in part on Federal Energy Regulatory Commission power-pricing rules

A special subcase of the generic problem of "wheeling money instead of power" would involve public power-generating plants Often, these plants are built with low-interest Federal loans, and their owners have no obligation to pay income taxes Both of these cost reductions, everything else equal, give public power projects a cost advantage over plants built by other entities, even taking into account the deferral of income tax payments and other tax incentives for investor-owned utilities Currently, some public power builders have excess capacity The potential economic efficiency problem might come about if a public power utility were to appear to be lower in cost than an investor-owned utility for a power sale only because of the Federal subsidies available to public power utilities There would be an efficiency gain if the short-term costs of the public power utility were lower than those of the investor-owned utility However, if the lower total costs of the public power entity disguised the fact that it had higher short-term costs, economic efficiency would be harmed

Even though there may be some cases where efficiency could decrease in the manner described, the net impact of transmission access for wholesale buyers on efficiency is likely to be quite positive

The second possible type of efficiency loss has to do with the "prodigal son" issue, and again the potential efficiency loss is small relative to the potential efficiency gain In the utility context, a "prodigal son" is a wholesale customer that deals with other suppliers when lower price alternatives are available, but then seeks to return to its original supplier, at embedded-cost rates, when those alternatives disappear If the utility has an obligation to provide power to the prodigal son, it might be required to build new plants on short notice when the prodigal son returns Any generating resource that cannot be constructed in a short time period—such as coal and nuclear technologies—could not be considered, even if it might

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have been the most economical with a longer planning horizon

Ways to deal with cases where new wholesale transactions might increase short-term costs need to be investigated. Regulators need to examine pricing policies carefully to ensure that they do not facilitate inefficiencies in regional dispatch If, as we expect, regulators can find such solutions, then the possibility of these limited efficiency losses could be minimized, while the potential efficiency gains indicated above could be achieved

Equity Issues

The equity question arises most prominently with both the stranded investment and the prodigal son issues

Stranded Investment

Suppose a utility has built generating capacity to serve not just its retail customers, but also a long-time wholesale customer located entirely within its service area. For each of these classes of customers, the utility has the legal obligation to provide the amount of power requested. The utility therefore builds enough capacity to serve both

Suppose then that the wholesale customer finds, in a time of general excess capacity such as occurred in the 1980's, that it can get wholesale power at a lower cost elsewhere, most likely in the form of a multiyear contract If the buyer then leaves its original supplier, that supplier is left with excess capacity—capacity that must be paid for by remaining (mostly retail) customers or by shareholders, or marketed through off-system sales If the original supplying utility had known the buyer was going to "leave the system," it would not have built this capacity The excess capacity caused by the decision of the buyer to leave the system is called "stranded investment" While stranded investment occurs in unregulated industries as well, and can be thought of as an inducement to make good investment decisions, the utility's obligation to serve means an obligation to invest and thus creates an equity issue not faced by unregulated firms

Rate reform could reduce the incentive for wholesale customers to leave the system Traditional utility ratemaking exacerbates the rate differentials resulting from the incorporation of costly new generating capacity into the rate base because it is heavily front-loaded, that is, the plant's capital cost is loaded more heavily onto its earlier years of operation. (State commissions somewhat moderated front-loading during the 1980's by using rate phase-ins Phase-ins lessened the degree of front-loading, but rarely eliminated it)

Prodigal Sons

Suppose that the wholesale buyer in the above example finds another seller and signs a firm 7-year contract with that seller However, during the 7 years the amount of excess capacity in the area diminishes to the point that few utilities, including both the original seller and the new seller (with the 7-year contract), have much excess capacity When the contract expires, the wholesale purchaser cannot find a new arrangement to its liking It might then go back to the original utility in whose service territory it is located, and demand that it be provided power at a (presumably) low-embedded-cost wholesale rate

The original selling utility asserts that it has no capacity to sell on a firm basis because its reserve capacity is low Notwithstanding the logic of this argument, utilities fear that political pressure on State and Federal regulators would enable the wholesale buyer, the returning "prodigal son," to force the original seller to sell power at embedded-cost wholesale rates In turn, the selling utility would have to embark on a crash construction program or purchase costly firm power on the open market to meet its obligation to serve all its customers, including the prodigal son In all likelihood, the cost of the construction or purchase program would not be fully compensated by the embedded-cost rates paid by the returning wholesale buyer Once again, the extra costs—here, the difference between the embedded-cost rate paid by the prodigal and the extra costs the utility must spend to satisfy its service obligation—would be borne largely by the retail customers or the shareholders A policy that would allow a prodigal utility to return to its original supplier at rates that would impose increased costs on others is considered by most parties to be inequitable

Efficiency issues are at stake as well. The ability of a wholesale customer to return to its host utility and receive embedded-cost service, for example, may encourage excessive risk-taking by the customer, since the customer knows that it has a "safety net" if its supply plans do not turn out well Risk-taking of this sort by wholesale customers may facilitate insufficient risk-taking on the part of utilities that will be discouraged from undertaking long-lead-time projects with more risk in favor of projects with low risk and short lead times, even though the latter projects may be less efficient

Potential Solutions

Two observations emerge from this discussion First, of the entities seeking transmission access, only wholesale *sellers* do not necessarily cause stranded investment or prodigal son equity difficulties (that is, sales to utilities conducting power auctions do not create such problems) Second, transmission access for wholesale buyers should emphasize development of equitable resolution of the stranded investment and prodigal son issues

Two trends seem likely to reduce the importance of the stranded investment problem over time First, as generation services become more competitive, price differentials among utilities are likely to become smaller These smaller differentials, in turn, will reduce the incentive for wholesale customers to seek off-system supplies Second, most utilities can be expected to have less excess capacity within a few years as demand continues to grow Generally, if a selling utility has little excess capacity today, the stranded investment problem will be diminished to an extent The selling utility might even have no objection to losing the customer if that would allow the utility to avoid building a plant Under these circumstances, a wholesale purchaser might be able to leave without penalty

Ameliorative strategies are available to deal with the prodigal son problem For example, the prodigal could return if it were willing to pay the *incremental* costs it imposes on the selling system Alternatively, if there were enough transmission access to allow the prodigal to choose from a large number of potential suppliers, there would be no need to require the original seller to supply power on anything but a voluntary basis, because there would be a competitive market for wholesale power

Finally, it may be possible in contracts between wholesale buyers and sellers to establish a system of "exit" and "entrance" fees that could provide a market solution to the stranded investment and prodigal son problems

Reliability Impacts

As discussed previously, reliability would be affected by the number of new players, the frequency of their transactions, the degree of central control required or allowed for such transactions, and the institutional arrangements worked out to accommodate more open access The 1989 Office of Technology Assessment report, *Electric Power Wheeling and Dealing*, found that the transmission system could accommodate greater competition However, it also found that

> The greatest challenge will be to maintain the coordination of the bulk power system as an integrated whole when many different entities are involved. *Rapid change will entail the greatest risk* If implemented unwisely, competition easily could result in higher costs and *lower reliability* because crucial functions such as economic dispatch would not work as effectively [italics added]

Some analysts have noted that the roughly 30,000 megawatts provided by qualifying facilities (QF's) entering service in the 1980's do not seem to have adversely affected reliability, in the sense of increasing the possibility of blackouts They conclude from this that transmission access will not cause reliability problems, and they note that several electric utilities have testified to that effect

There are several reasons for the lack of adverse impact One appears to be contractual conditions, for example, QF's must meet certain reliability criteria. Another reason is probably that, in most sections of the country, the amount of QF capacity is still relatively small and utilities and power pools have had the time to adjust to the newcomers in their midst A third is that many or most QF transactions take place within one control area and involve scheduled sales to the control area operator; they do not require wheeling through

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another utility's system Finally, many bidding auctions for new power sources implicitly or explicitly take into account the location impacts of proposed generating facilities on the transmission system

In the future, greater transmission access may mean more transfers between control areas, involving transactions where one or more parties to the transaction will not themselves be control-area utilities This could mean, absent explicit agreements between the control areas and the new entities, and absent continued adherence to North American Electric Reliability Council operational criteria, that unscheduled power transfers could take place, possibly upsetting the operation of the grid. While there is no obvious reason why such agreements could not be forged, it is important to note that these agreements must be reached or mandated in order to maintain reliability

In summary, it seems clear that to maintain high standards of reliability—standards crucial not just to minimizing costs, but also to ensuring against blackouts with great economic consequence—any opening up of the transmission grid to new users should proceed at a measured pace This would give transmission owners and controllers adequate time to develop the capability to deal with the issues that would be raised by the presence of new users without jeopardizing reliability in any sense

Conclusions

In summary, increased access for wholesale sellers and buyers can lead to long-term efficiency gains

Access for wholesale buyers raises equity issues If these issues can be resolved, there is promise of significant economic gain Reliability issues would not be overly difficult if reasonable agreements between control area and non-control area entities can be reached.

With retail access, equity problems are far more difficult than with wholesale access The reliability issues are much more difficult because of the huge number of potential retail buyers that could want access Efficiency gains would be questionable, except perhaps for the largest of retail buyers willing to pay appropriate entry and exit fees Given the crucial need to maintain the reliability of the transmission system and the unexplored cost accounting problems, retail access is not a recommended policy at this time

6. Transmission Policy Options

This chapter discusses options for transmission policy These options are considered at the level of a national energy strategy; that is, we treat only broad issues that can command the attention of the Administration and perhaps the Congress, and leave to regulators the resolution of the many issues that will surely arise as broad policy is implemented Because we are concerned with government policy, an important option not considered here is that of industry forming a voluntary association to solve transmission disputes without government action

As the previous chapters have indicated, much is changing in the electric power industry These changes are occurring for many reasons, and the theme running throughout these reasons is efficiency and competition Many now believe that greater access to transmission can make the wholesale market for electricity more competitive

Some observers of the industry believe that, absent significant progress toward a greater degree of nondiscriminatory access, lawsuits calling for access to transmission may be brought and be successful In essence, this would put the terms of access and use in the hands of juries and judges Many industry observers contend that juries and judges would be unlikely to design efficient terms and conditions for transmission access and use This task is better left to those with a solid technical understanding of the transmission system Thus the worst outcome for increased transmission access might be a series of court decisions not solidly grounded in engineering and economics

If this kind of outcome is to be avoided, progress should be made through government policy leadership The options below encompass three broad approaches to increasing nondiscriminatory wholesale transmission access

The Case-by-Case Approach

Option 1. Continue the present case-by-case approach at the Federal level and at the State and regional levels (including voluntary proposals for access and use)

Even without any generic regulatory or legislative action, many incremental changes are occurring At the State and regional level, there are Wisconsin's statewide plan and the proposal for equalizing New England Power Pool (NEPOOL) terms and conditions for wholesale sellers to enable independent power producers (IPP's) and qualifying facilities (QF's) to wheel power across several utilities for the same rates as NEPOOL member utilities

There are various other proposals for regional action These would include the proposals of the Large Public Power Council, the National Rural Electric Cooperative Association, and the Consumer Energy Council of America, and other proposals that cover a wide range of issues, from regional planning and regulation to dispute resolution (for siting of transmission lines or for deciding terms and conditions for access)

At the Federal level, the Federal Energy Regulatory Commission (FERC) has made it clear that transmission access is a key concern in providing a remedy for the anti-competitive effects of proposed mergers and market-based pricing proposals FERC has indicated that utilities that desire market pricing for generation sales must be willing to allow other entities to use their transmission systems under nondiscriminatory conditions

In the recent Terra Comfort, PSI Energy, and Entergy Services cases, FERC indicated that a utility that owns transmission lines that could be used by competitors and that wants to sell power to an adjoining utility at *market* rates (as opposed to traditional, embedded-cost rates) will be much more likely to obtain FERC approval if, at the time competition for a sale takes place, it makes transmission capacity available to potential competitors Such an offer would demonstrate that the utility has mitigated its market power over competitors (that is, the power to prevent them from competing by denying them use of transmission facilities) Having made such an offer at

reasonable transmission rates, the utility could make a credible claim that a market rate for its power sales is a competitive rate Without allowing others to use its transmission lines, a lack of sellers might be an indication not of lack of interest in selling power, the reasoning goes, but of inability of potential competitors to secure necessary transmission service

As mentioned, in some cases FERC has required utilities to commit to building or upgrading capacity for those requiring firm transmission service and, after a length of time deemed appropriate to secure added capacity, provide firm service to others before they can use the system for their own economy transactions FERC has justified this condition on the ground that it encourages utilities to construct needed transmission Insofar as generic transmission policy is considered, this approach is problematic First, it depends on a utility wanting something unusual, such as a merger approval, from FERC before access can be achieved. Second, it may be inefficient An efficient approach would always assign the highest transmission priority to the trade of greatest value, but the FERC approach could halt coordination trades, including those of higher value, to meet the firm transmission needs of others This happens when transmission cannot be expanded to meet the needs of others because legitimate environmental or other obstacles prevent transmission expansion

Third, this approach raises fairness concerns and the potential for conflict with State regulators because the utility's retail customers typically must pay for these transmission lines in the absence of wholesale trades by other users Frequently, the extra capacity on these lines was installed to permit economy transactions that lower retail rates It may be unfair for others to have first call on the use of these assets while retail ratepayers have the ultimate liability to cover their costs, depending on the price at which access is provided.

If FERC had clear authority to order wholesale transmission access, as provided in options 2 and 3, this "condition" approach would be unnecessary FERC would be better able to achieve uniformity of result and to coordinate its efforts with those of State regulators

Despite the considerable amount of case-by-case change, it is not clear whether the movement toward increased transmission access is being or will be reasonably coordinated. Partly because of the patchwork character of the various efforts, progress may be slow under option 1 and perhaps eventually incomplete The "patchwork problem" could be mitigated considerably, however, if FERC were to develop general policies toward transmission access and pricing, most naturally through the rulemaking process

As an example of the patchwork problem, consider that analyses of market power in electric bulk power markets and its effect on competition are conducted by the FERC staff, the Department of Justice, State commission staffs, State attorneys general, and the antitrust courts, among others The analyses often yield conflicting results, creating tension among these agencies Results differ in part because of differences in analytical approach Significant differences between the FERC staff's approach to the analysis of market power in the electricity industry and the approach followed in modern antitrust analysis has been a source of concern to some observers Progress under option 1 would be enhanced if FERC were explicitly to strive for greater uniformity of approach, perhaps by adopting the analytical approach used by the antitrust courts to evaluate mergers in other sectors Inconsistent Federal and State policies for transmission access, pricing, contracting, and capacity planning are also a problem Greater consistency among case-specific decisions could be ensured by FERC's adoption of general policies

Pros and Cons of Option 1

Pros

- Requires no new FERC authority
- Allows gradual evolution of new mechanisms and institutions for an industry in transition

Cons

- May take a long time to achieve the benefits of increased competition in generation, indeed, such benefits may never be realized.

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- Will result in inconsistent and uneven evolution of access around the country
- May be overtaken by events if court decisions result in inefficient outcomes
- May discourage utilities from bringing efficiency-enhancing proposals before FERC because of aggressive pursuit of the *quid pro quo* approach, with results that vary from case to case

Potentially Available Authorities

Option 2: Explore present law for potentially unused or underused authorities, including antitrust law. Encourage FERC to explore maximum use of authority under the Federal Power Act to establish an affirmative policy of moving the Nation's transmission systems toward open access for wholesale entities.

There are at least three areas where existing law might be examined to see the extent to which greater amounts of nondiscriminatory access might be granted to wholesale buyers and sellers

- Antitrust law
- Sections 205 and 206 of the Federal Power Act (regarding undue discrimination)
- Section 207 of the Federal Power Act (regarding State petitions to FERC concerning inadequate transmission service)

Antitrust Law

The *Otter Tail* case, decided by the U S Supreme Court in 1973, established that electric utilities are subject to antitrust law If a violation of antitrust law occurs, in this case in the denial of use of available transmission facilities under particular circumstances, then courts may compel wheeling as a remedy for the violation

Antitrust law, however, appears to have some deficiencies as a remedy for correcting abuses of monopoly power in transmission access and use First, there may be no antitrust violation if a line is fully used by the owner Second, antitrust law as applied to utilities may have no provision for expanding capacity The combination of these two characteristics of antitrust provisions produces different results from those in FERC's PacifiCorp-Utah Power & Light merger decision, which was accepted by the utilities in that case The decision called for expansion of transmission capacity if necessary, within a reasonable timeframe, to accommodate firm transmission service to other users, including wholesale purchasers and IPP's

Is it possible that antitrust law, applied to the unique technical and economic landscape that now exists in the electricity industry, would be sufficient to achieve economic efficiency in wholesale power markets? Although utilities expand transmission capacity for their own use, will they do so for others? If they expand their capacity by minimal amounts, without offering to build enough capacity for others when they build for themselves, they will not have enough capacity to offer to others Could this in some sense be interpreted as an antitrust violation? Alternatively, if a utility does not have enough capacity for an entity desiring it, and refuses to expand capacity, would this in itself be an antitrust violation? Or must there be a regulatory obligation to serve the wholesale market, which exists apart from antitrust law?

Undue Discrimination: Sections 205 and 206 of the Federal Power Act

Section 205 of the Federal Power Act requires that utility transmission rates subject to FERC jurisdiction not be unduly preferential to any entity, nor subject any entity to any undue prejudice or disadvantage Section 206 requires that whenever FERC finds undue preference or discrimination in any rate, contract, practice, or regulation under its jurisdiction, it must determine and enforce a nondiscriminatory rate, contract, practice, or regulation Together, these two sections appear to offer promise for providing increased transmission access to achieve greater economic efficiency

Consider, for example, an 11-year-old case involving Section 205 and 206 powers In 1979, the D C Circuit Court upheld a FERC decision—the *Central Iowa* case In this case, several utilities had formed a power pool A power pool's proposed methods for accounting for interpool sales are in

essence rates for wholesale sales, so they require FERC approval In this case, FERC found that the proposed rates were unduly discriminatory because some utilities were excluded from the pool without good reason and were therefore subject to higher transmission rates than pool members

In 1979, there were no QF's or IPP's Can the *Central Iowa* reasoning now be applied to IPP's, or can similar logic be applied to wholesale purchases and sales? Consider two theoretical examples

Example 1

Utilities A and D are members of a multistate power pool, and an IPP is located within A's service area. Both are competing in an auction to sell power to utility D Utility A, as a member of the power pool, will pay "postage stamp" rates of 3 mills per kilowatthour for transmission to D The IPP, not a member of the pool, would have to pay a wheeling charge to utilities A, B, C, and possibly D, amounting to 9 mills per kilowatthour

Question Is it undue discrimination to have these two competitors, Utility A and the IPP, pay such different rates for transmission if the units are similarly situated and would essentially use the same transmission capacity? The IPP might have significantly lower generating costs and might clearly be more efficient, but could lose the bid to A because of the difference in transmission costs

The question can be put another way Is there a cost basis for charging different transmission tariffs for Utility A and the IPP? Is this basis reflected in the tariffs?

Example 2

Captive municipal utility M is located inside Utility A's service area Utility M needs power, and utility A is willing to wheel power at nondiscriminatory rates Utility D (a member of the same power pool as A) and utility E (just beyond D, but not a member of the pool) both want to sell to M Utility E's price is significantly lower than D's Utility D, however, pays the low postage stamp transmission rate, while E, not a member of the pool, must pay each intervening utility a separate rate, as in the first example, and therefore loses the sale

Again, the question is Does E face undue price discrimination? What is the cost justification for different transmission rates?

Avoiding Undue Discrimination

There are several ways for possible undue price discrimination to occur in rates that FERC must approve The suboption here is for FERC to closely examine such rates to determine whether changes in the electricity industry may have rendered discriminatory transmission pricing practices that in the past may have been reasonable

Complementary Federal and State Jurisdiction: Section 207 of the Federal Power Act

Section 207 of the Federal Power Act states that if FERC, upon complaint of a State regulatory commission and after notice and opportunity for a hearing, finds that any interstate service of a public utility is inadequate, it shall determine and order the proper or adequate service

On its face, the authorities of Section 207 appear to be strong However, because the ability of FERC to order increased transmission access to improve efficiency is apparently limited by Sections 211 and 212, the strength of Section 207 to improve transmission access is uncertain. A Section 207 case is now before FERC, so a decision, likely to be appealed, may be forthcoming This decision ultimately should tell us much about FERC's Section 207 powers in this area

To prevent the owner of a monopoly from exercising monopoly power, two authorities are required an ability to establish an obligation to serve and an ability to regulate the rates, terms, and conditions of service One without the other is inadequate For instance, if a utility must serve a customer but can charge what it desires, it can exercise monopoly power If rates are regulated but the utility can choose not to serve particular customers, again it can exercise monopoly power

It is generally believed that, under current authority, FERC cannot order utilities to serve the transmission needs of others, except in very limited circumstances However, if State regulators have, in essence, the power to require utilities

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within their States to serve transmission needs, this authority, exercised in coordination with FERC's authority to approve transmission rates, terms, and conditions, could be used to substantially increase transmission access Thus, as alluded to in the earlier discussion of the Wisconsin Public Service Commission's order to Wisconsin utilities to file open-access transmission tariffs with FERC, the existing bifurcated powers between State and Federal regulators could be used cooperatively to expand transmission access

Regardless of State regulatory authority, FERC, under this and the previous suboption, would explore its Section 205, 206, and 207 powers and also work with States to examine the extent to which complementary Federal and State authorities might be used to increase transmission access and provide greater economic efficiency FERC's powers under Sections 205 and 206 may prove to be the more promising basis for these efforts because FERC has such a strong statutory mandate to remedy undue discrimination

To develop general policies on transmission access, pricing, and contracting, and to address complicated issues of reliability, economic efficiency, and expansion planning that will arise as the grid becomes more heavily used, FERC may find it necessary to develop its technical expertise The additional staff expense should be small compared to the potential improvements in power markets

Pros and Cons of Option 2

Pros

- Requires no new legislation
- More likely than option 1, even with the development of general policies toward transmission access and pricing, to result in consistent national policy and foster a meaningful increase in competition in generation
- Would relieve FERC from the need to rely on imposition of undesirable conditions to achieve policy objectives

Cons

- FERC may not have sufficient existing authority to implement an efficient open-access policy
- FERC actions would likely be appealed, uncertainty would be created and decisions might be overturned, several years may be needed to gauge the effectiveness of this option
- State authorities to establish a utility obligation to provide interstate transmission service might be limited, hindering an effective Federal-State partnership

New Legislation

Option 3: Develop new legislation that would give FERC explicit authority to require open-access transmission for wholesale entities when it is in the public interest to do so.

The prior options may fail to provide adequate, nondiscriminatory transmission access Another option is to create an explicit Federal obligation for transmission owners to provide wholesale transmission service to eligible sellers and buyers FERC would enforce this obligation Such enforcement would complement existing FERC powers to regulate transmission pricing, thus ensuring that both authorities needed to adequately address the exercise of monopoly power—the obligation to serve and the ability to regulate prices—are unified in one regulatory agency Adoption of this option would of course require FERC to develop detailed policy principles for regulating transmission access and pricing

Pros and Cons of Option 3

Pros

- Would permit FERC to develop a consistent national policy to maximize the benefits of competition in generation
- Would relieve FERC of the need to rely on imposition of undesirable conditions to achieve policy objectives

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Cons

- Would require new legislation, prospects for which are unclear
- Could result in inappropriate legislation, especially if the experience with the current case-by-case approach is an insufficient basis for designing appropriate legislation
- Might be interpreted by States as a kind of Federal preemption, unless or until it is determined that States themselves are unable or unwilling to establish a utility obligation to provide regional wholesale transmission service

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7. Cost-Benefit Analysis

The costs and benefits of more open transmission access are difficult to quantify However, to be responsive to an Economic Policy Council request to examine whether costs or benefits are greater for each National Energy Strategy option, in this chapter we present crude estimates of the minimum likely benefit of more open transmission access and the maximum likely cost of such a policy The actual benefit could be much greater than the minimum, and the actual cost may well be much less than the maximum, the purpose of the calculation is merely to see if benefit exceeds cost, however approximate our estimation of each of these quantities may be

Introduction

Several types of benefits could result from increased transmission access The benefits of greatest concern here are economic, both short term and long term The short-term benefits are improved use of existing generating resources The long-term benefits include the operational cost-cutting measures that occur when a vertically integrated industry experiences more competition Additional long-term benefits include the efficiency gained through acquisition of new generating units These would include economies in the newly emerging generating sector (qualifying facilities and independent power producers) as well as among traditional utilities

The efficiencies for new generating units would come about as more efficient plants displace less efficient competitors With or without competitive bidding, benefits would come from displacement of higher cost local plants that would have been built in the absence of transmission access by lower cost plants built elsewhere

There are other benefits of transmission access Due to siting constraints in many areas, it is increasingly difficult to construct new electricity generating plants Depending on assumptions, some 200 to 275 gigawatts of new capacity will be needed by 2010 Without transmission access, many utilities face unnecessarily high costs to locate powerplants in their service areas With transmission access, power can be moved from locations where siting is easier and cheaper This benefit can be thought of as a special case of the long-term efficiencies in acquisition of new resources noted above Here the gains would be from avoiding alternatives that by their very nature would be more expensive, even if efficiently constructed.

Finally, there are benefits to the Nation from flexibility in plant siting, flexibility in fuel choice, and flexibility in response to energy emergencies Transmission can, for example, be used to facilitate switching from oil to other fuels in those relatively few areas that still rely on oil-generated electricity to a significant degree The benefits here would come from two sources Primarily, increased transmission access would allow displacement of remaining oil-fired generation As a secondary effect, if transmission access lowers electricity prices, it could facilitate displacement of oil used elsewhere in the economy, including industrial processes, personal transportation, and space heating in the industrial, commercial, and residential sectors

Benefits

Short-Term Benefits

To estimate the short-term benefits of transmission access, one can use recent studies of improved economic dispatch procedures In particular, the Indiana Economic Dispatch Study (*Decision Focus*, 1989) is a representative analysis

The State of Indiana is already engaged in substantial interutility trade, including a formalized brokerage system To examine the potential for further gains, a State task force commissioned a study The results estimated potential annual production cost savings in the range of $13 million to $37 million, with an expected value of $24 million This is a small number relative to the State's 1988 annual electricity revenues of about $4 billion [1] Suppose that roughly half the expected

savings, or $12 million, could be realized under improved transmission access This result can be scaled to a national level. Proportional scaling assumes that these benefits are achievable everywhere to the same degree In some regions, where pooling arrangements are strong, this may not be true In other regions, greater savings may be obtained, especially if displacement of more expensive oil is possible Indiana accounts for about 2 8 percent of U S electricity sales, if equal savings were achievable proportionally, the result at a national level would be annual savings of $432 million from 1991 through 2000 [2] The net present value of these savings is $2 654 billion [3] For comparison, a 1981 Federal Energy Regulatory Commission study of power pooling estimated additional benefits of coordination at 1 to 2 percent of national electric revenues This corresponds to $1 44 to $2 88 billion annually While our lower estimate contains an implicit assumption (without corroboration) that much of this potential has already been captured in the 1980's, this may not be the case

Long-Term Benefits

Long-term efficiency gains from transmission access include cost-cutting measures and savings in resource acquisition We will first examine cost-cutting efficiencies

Transmission access will increase competitive pressures in the utility sector A typical response of any industry to increased competition is increased productivity This is often accomplished by reducing staff and overhead. Suppose all productivity improvements were accomplished by reducing staff. According to the Edison Electric Institute (EEI) *Statistical Yearbook of the Electric Utility Industry/1988* (p 99), the investor-owned segment of the industry employed 513,742 people in 1988 The publicly owned sector represents one-third of the industry, estimated by sales, but proportionately less by employment Let us assume the publicly owned sector adds another 20 percent to the EEI figure This would make total industry employment approximately 615,000 The EEI data show an employment decline of 16,000 from the peak level of 1986 We assume that an additional decline of 5 percent, or about 31,000, is a reasonable response to competitive pressure We will conservatively attribute roughly half the decline, or 15,000 jobs, to transmission access (This workforce reduction can be achieved largely through attrition) In support of the assertion that this estimate is conservative, we would note that several utilities have cut employment by more than 5 percent in the last 2 years

The estimated cost decrease from eliminating 15,000 jobs over a 10-year period is based on the assumption that the full cost (including benefits) per position is $100,000 per year We assume that these reductions are spread evenly over the decade The first year's savings are $150 million, and savings grow by that amount each year The present value of that stream is $4 354 billion

This is, admittedly, a crude estimate of productivity gains Gains could also be achieved by improving heat rates and capacity factors, and by more aggressively lowering fuel expenses through improved acquisition practices Many of these improvements could require addition, not depletion, of staff and would, of course, be made only if the operating cost savings outweighed the extra staffing cost Our calculation of staff reductions then can be considered a surrogate for such larger savings

A second long-term benefit comes from proportionately greater reliance on lower cost powerplant builders and sites This can occur either under traditional utility supply or under a competitive bidding scenario

An important example of the effect of transmission access on long-term costs in the unregulated sector comes from the recent experience of Virginia Power in attempting to purchase capacity from out of State A very efficient project was canceled, after being selected by Virginia Power in its 1988 solicitation, because the project could not obtain transmission into Virginia. Estimated cost savings for this project compared to the alternative choice made by the utility were approximately $70 per kilowatt-year starting in 1994 [4] The capacity associated with this project represented 15 percent of the total capacity selected by the utility in the solicitation

On the regulated side, benefits can be estimated by examining the distribution of construction costs for new coal plants built in the 1980's The stan-

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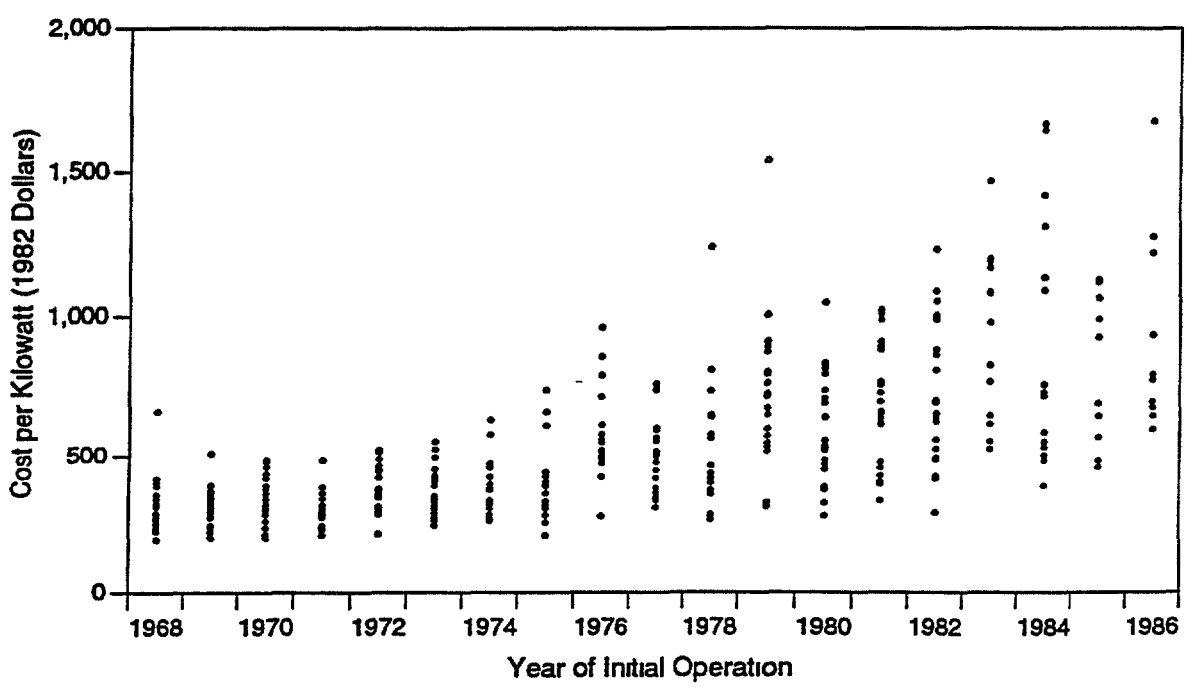
dard deviation of construction cost has typically been one-third of the average value (Utility Data Institute, 1989) A typical estimate of the cost per kilowatt of new coal-fired capacity today is about $1,200 without capitalized interest and $1,500 with capitalized interest If broader markets were available through transmission access, the high-cost end of this cost distribution is apt to be eliminated. The benefit can then be estimated by truncating the high-cost end of the cost distribution

For the purpose of this analysis, let us assume that, with transmission access, more efficient builders would construct plants or plants would be built in better locations so as to displace higher cost plants that would have been built locally by the local utility From the data above, saving 25 percent of the cost of the plant with the highest cost seems reasonably achievable Figure 1 shows the cost distribution of new coal plants from 1976 through 1986 In most years, the plant with the highest cost was 2 5 to 3 times more expensive than the plant with the lowest cost Cost differences of this magnitude, often in the same parts of the United States, imply that cost savings of the magnitude discussed here are justified by the historical record. Suppose the higher cost plants, at $2,000 per kilowatt, could be replaced by plants that cost only $1,500 per kilowatt, a savings of $500 per kilowatt The annualized equivalent of $500 per kilowatt is roughly $50 per kilowatt-year Under standard ratemaking treatment, the present value of future revenue requirements is approximately 1 6 times the rate base, thus establishing an annuitized value that includes overheads of roughly $80 per kilowatt-year

For this exercise, we assume conservatively that 15 percent of the total market for new capacity can achieve this saving through a policy of increased transmission access (This is also the percentage of Virginia Power's needs lost in the cancellation of one plant due to lack of access) The Current Policy Base for the National Energy Strategy (September 1990) projects capacity additions of 54 gigawatts of coal capacity and 20 gigawatts of renewables in the 1990–2000 period. These largely capital-intensive technologies are the market that

Figure 1. Capital Costs of Coal Units
(1968–1986)



Source Utility Data Institute, *Construction Costs, U S Steam Electric Plants, 1966–1986,* October 1987

would potentially be most affected by transmission access This results in an estimate of $83 million per year starting in 1990 and increasing by that amount every year until 2000 The net present value of that stream is $2 416 billion

Another potential benefit from any competition enhanced by transmission access, which we have not attempted to quantify, is that of technological innovation Recent experience with heightened competition in other sectors of the economy suggests that introducing competition in areas long subject to cost-of-service regulation results in unanticipated technological and organizational innovations, with major economic benefits for consumers [5]

It is reasonable to assume that open access could hasten development and use of technical improvements in electricity transmission Chapter 3 mentions the technological improvements currently being developed by the Electric Power Research Institute In some cases, these technologies could double the transfer capability of a transmission corridor Greater demand on the existing transmission network coupled with the difficulty in siting new lines in some cases should create a powerful incentive for owners of transmission systems and builders of transmission technologies to find and implement innovative ways to upgrade the power-transfer capability of the existing network.

Costs

The basic costs of increased transmission access would be either decreased reliability of the bulk-power transmission network or increased mitigation costs to maintain reliability The proposition that reliability would decrease if transmission access increases significantly without adequate mitigation has been discussed in the professional literature [6]

The concern with reliability arises from the complexity of coordination among large numbers of control centers When disturbances occur on the transmission network, the coordinated response of more than one control center is often required to maintain system security The power grid of the United States and lower Canada has about 150 control centers The computational, communication, and human complexities of real-time coordination among these control centers are the sources of difficulty in confining and limiting the impact of transmission disruptions

As the Office of Technology Assessment study and the Large Public Power Council proposal (discussed in Chapter 4) indicate, the reliability of transmission can be maintained as access increases, provided the process proceeds in an orderly manner and that control area requirements are strictly followed and maintained. There will be increased software development and hardware costs, as well as manpower and training costs These costs are difficult to quantify, but they are unlikely to be of the order of magnitude of the benefits One approach is to make a rough estimate of the costs associated with reduced reliability of the transmission system and treat these costs as a proxy for the real costs of administrative adjustments required to ensure reliability as access increases

Estimating the costs of power outages is a complicated problem that involves both engineering and economics We used the limited literature on this subject to estimate the transmission-related cost of unserved energy The estimate has two parts the amount of energy unserved due to transmission system outages and the costs of outages to consumers Using these figures, we place a dollar value on the cost of unserved energy

To estimate the amount of unserved energy due to transmission outages, we rely on statistical data reported in a comprehensive national study administered by the Department of Energy in response to the requirements of Section 209 of the Public Utilities Regulatory Policy Act of 1978 In particular, we use data summarized in "Analysis of Bulk Power System Failures and Review of Utility Security and Restoration Procedures" [7] Although the data reported here cover only the 1967–79 period, it is not unreasonable to extrapolate them, because there appears to be no particular time trend in the occurrence of outages over the period covered.

The amount of energy unserved due to transmission outages is the product of (1) the average number of outages per year due to the transmission system, (2) the average duration, in hours per

transmission outage, and (3) the average load lost per transmission outage The averages are (1) 45 3 outages per year, (2) 5 6 hours per outage, and (3) 177 megawatts lost per outage The product of these factors is 44 9 million kilowatthours lost annually due to transmission system failures

The economic literature on the value of service reliability is summarized in a special issue of *The Energy Journal* (v 9, 1988) devoted to this subject Conventional studies of this type develop separate estimates for residential and nonresidential customers The value estimated for residential customers is approximately $4 per kilowatthour [8] For nonresidential customers, the value estimated is about $7 per kilowatthour [9] If we assume that the amount of interrupted load corresponds to annual sales, then roughly one-third of the interrupted load will be residential and two-thirds will be nonresidential This proportion will result in a weighted average outage cost of about $6 per kilowatthour

The transmission outage cost, then, is the product of the unserved energy (44 9 million kilowatts per year) and its consumer value ($6 per kilowatthour), or about $270 million per year

This estimate can be interpreted as an upper bound on the costs of transmission access under several scenarios A worst-case scenario would be one in which consumers incurred an additional $270 million in outage costs due to decreased reliability

Our cost estimate is based on the reasonable assumption that current outage costs would no more than double due to increased transmission access About half or more of the outages reported in the source document are related to weather or other factors that would be relatively unaffected by system disturbances that might be caused by increased transmission access Thus, to assume a $270 million increase in outage costs is to assume implicitly that outages caused by degraded system reliability would increase by at least a factor of four

Alternatively, we can think of this estimate as an upper bound on the mitigation costs required to maintain current reliability levels These mitigation costs would include research and development, software development, incremental hardware, additional manpower, and manpower training

Summary

It must be reemphasized that our analysis has attempted to maximize potential costs and minimize potential benefits We have not quantified all benefits of more open access The potential for decreased reliability or the cost of mitigating that potential may well be overstated

Let us now compare the costs and benefits over the 1991–2000 period. All estimates are in 1990 dollars, with future estimates discounted at a 10-percent real discounted rate

We assume that the short-term benefits persist over the entire 10-year period. The present value of these benefits is $2 654 billion The long-term cost-cutting benefit is estimated at $4 354 billion The long-term construction-efficiency benefit is assumed to grow over the 10-year period. We assume it begins at $83 25 million per year and increases by that amount every year as the market for new capacity grows The present value of this growing stream is $2 416 billion The sum of the three benefits is $9 424 billion

The reliability cost (either direct or its mitigation equivalent) is assumed to be constant at its maximum over the whole period The present value of $270 million per year for 10 years is $1 659 billion

The benefit-cost ratio we estimate for transmission access, therefore, is 5 68 (9 424 divided by 1 659)

This benefit-cost ratio applies to a sudden, substantial, and national increase in transmission access If access and its attendant competition come about more slowly or one region at a time, both cost and benefits would be correspondingly lower However, in this model we would still expect benefits to exceed costs, and we would not expect the ratio to change

Notes

1 Energy Information Administration, *Electric Power Annual 1988*, 1990, p 42.

2 *Ibid*, p 40

3 All NPV calculations in this report use a 10-percent real discount rate

4 Testimony of Larry W Ellis, Virginia Electric and Power Company, before the State Corporation Commission of Virginia, 1989, Case No PUE 89051

5 An example would be the long-distance telephone industry In the 1970's, it was predicted that easier entry would have little effect because entrants would have to rely on small-scale, inexpensive microwave technology, as opposed to fiber optics, which is economical only at very high volumes However, the cost of fiber optics has fallen faster than anticipated, largely because of greater than expected demand for it from new entrants, so that entrants have found it economical to build extensive fiber optic networks This illustrates the creative ability of new entrants and the ability of competitive markets to make the most of new technologies and unfilled market niches

6 See F Wu and A. Montecelli, "Analytical Tools for Power System Restoration. Conceptual Design," in *IEEE Transactions on Power Systems*, v 3, no 1 (1988) 10–16 It is also prominent in industry study groups (see Electric Power Research Institute, *Proceedings Power System Operations-Research Needs and Priorities*, EPRI EL–6659, 1990)

7 See Chapter 5 of *The National Electric Reliability Study Technical Study Reports*, DOE/EP 0005, April, 1981

8 See M Doane, R. Hartman, and C Woo, *Households' Perceived Value of Service Reliability An Analysis of Contingent Valuation Data*, pp 135–149

9 See C Woo and K. Train, *The Cost of Electric Power Interruptions to Commercial Firms*, pp 161–172

APPENDICES

APPENDIX A

Profiting From Constrained Capacity: A Simple Example

A monopolist, like economic actors in fully competitive markets, will attempt to maximize profits Textbook economics, derived from many real-world examples, indicates that a monopolist will maximize profits by selling less of a good or service at a higher price than would occur in a fully competitive market Economic efficiency is then harmed because fewer economic transactions take place under the monopoly

Some may dispute whether a monopoly owner and seller of transmission services acts as a traditional monopolist The argument seems to be that if there is an opportunity to make an economic transaction, the transaction will take place, and the only argument is over who gets the rents This may be the case in a short-term period of days or months, where the worst outcome for the monopolist would be excess capacity going unused and a profit opportunity being missed, and where the transaction costs of achieving the efficient outcome are small Thus a power pool with central dispatch may not exercise market power in its day-to-day operations

To examine this argument as it applies in the long term to the independent power industry, let us posit a utility that is centrally located with regard to a number of inexpensive fuel sources (for example, a southwestern utility for gas and a midwestern utility for coal) Potential independent power producers (IPP's) or qualifying facilities (QF's) would likely find it economically attractive to build inside this service area and sell power, over two decades or more, to several potential buyers through a combination of long-term and shorter contracts To do this, they would need to know that transmission services would be available at reasonably predictable rates from the host utility

Let us assume that five such potential sellers exist, each 100 megawatts in size, and that their minimum selling costs are 6 2, 6 4, 6 6, 6 8, and 7 0 cents per kilowatthour, respectively Several buyers willing to pay 7 35 cents per kilowatthour are at various locations just outside the service area. The embedded cost of transmission services is 0 3 cents per kilowatthour, this embedded cost is greater than the short-term marginal costs of transmission incurred, and the host utility can make 500 megawatts of transmission available with some minimal difficulty Our final assumption is that the utility may have some degree of flexibility in pricing its transmission services, either because of relaxed regulation allowing such flexibility or for other reasons

In a fully efficient market, any of the five IPP's and QF's could build its plant and sell its power because the cost of the most expensive plant, plus the cost of transmission, would be 7 3 cents, less than the 7 35 cents that the buyers are willing to pay The host utility receives no economic gain from the sale of transmission beyond the normal profit built into embedded-cost rates

Suppose the utility, seeing that the IPP's and QF's are not able to build new transmission lines themselves, holds out for 0 6 cents per kilowatthour for transmission services Let us assume, for the sake of argument, that the host utility points to a number of technical difficulties that, while not expensive or difficult to solve, allow the utility to delay reaching agreements with the IPP's and QF's for some time Let us also assume that, to avoid losing contracts, the IPP's and QF's eventually agree to the 0 6-cent wheeling charge Only the first three will be able to make a deal (the fourth, with a selling cost of 6 8 cents, plus the 0 6-cent transmission adder, can sell power at a total cost of 7 4 cents, which is above the 7 35-cent offer)

In this case, only three of the five economic IPP's and QF's are built and sell power The utility receives 0 3 cents per kilowatthour in economic rents While the utility loses only the small amount of normal profit in the 0 3-cent wheeling charge it does not recover from the lost sales of transmission services, the 6 8- and 7 0-cent IPP's and QF's will more than make up this amount in

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the large gain in rents on transmission sales to the three remaining sellers

Thus, a monopoly owner of transmission services could increase profits by restricting output and increasing prices for the monopolized service These actions lead to fewer economic transactions, with a loss to the Nation of economic efficiency

APPENDIX B

Recent and Pending FERC Transmission Decisions

This appendix describes some recent and pending Federal Energy Regulatory Commission (FERC) decisions regarding innovative transmission proposals offered by the industry, and some transmission conditions ordered by the Commission In addition, a few of the more important pending transmission cases are listed.

Transmission Commitments for Market-Based Pricing

Turlock-Modesto

In 1988, FERC approved two transmission agreements between Pacific Gas & Electric Company (PG&E) and two of its captive wholesale customers the Turlock and Modesto Irrigation Districts [1] Both cases are 20-year regulatory bargains in which the wholesale customer receives certain services, notably firm transmission service, at cost-based prices while PG&E is authorized to charge "market-based" prices for certain coordination services FERC concluded that market-based pricing is appropriate because PG&E had sufficiently mitigated its market power by its offer of cost-based services in general and its transmission commitments in particular

In the Turlock agreement, PG&E agreed to provide three services at cost-based rates (a) partial-requirements generating service that Turlock may request initially, (b) firm, reserved transmission service to four specific receipt points, and (c) contract firm power service that acts as a safety valve for Turlock to return to PG&E's system in the event that Turlock's suppliers cannot perform All other power and transmission services are voluntary and flexibly priced. FERC based its finding that PG&E lacked market power over Turlock on the grounds that

- Reserved transmission service can be used for all types of transactions, including short-term coordination trades
- PG&E is obligated to provide additional reserved transmission service, upon request, at embedded-cost prices if capacity is available and at incremental cost prices if capacity must be built
- Turlock can return to PG&E for contract firm power service in the future and thereby has a safety net

The Modesto agreement is similar to that struck by Turlock, except that the contract firm power safety net is missing and Modesto is not restricted to selecting among four specific delivery points as was Turlock. The safety net is replaced in the Modesto contract by the following, showing that PG&E lacks market power

- Evidence that Modesto had arranged for sufficient reserved transmission, along with purchased and owned generation services, to cover its requirements for the first 3 years of the agreement
- A FERC requirement that PG&E would lose its flexible pricing authority in the event that Modesto cannot meet its requirements because of an inability to obtain reserved transmission service from PG&E

Neither agreement allows the captive customer to resell reserved transmission service In both cases, the transmission service is provided between specified receipt and delivery points that can be rearranged upon negotiation Both of these features somewhat restrict the market activities of the wholesale customers and help to insulate PG&E from competitive pressures that might otherwise be exerted by them

PSI Energy

In 1990, FERC approved a proposal by PSI Energy (formerly Public Service Company of Indiana) to sell up to 450 megawatts of long-term, firm power

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at market-based rates in exchange for a commitment by PSI to open its transmission grid. FERC approved PSI's program on the basis, first, that PSI is not a dominant firm and consequently lacks market power over generation and, second, that PSI derives no market power from its transmission assets due its commitment to provide open-access transmission service to all utilities, independent power producers, and qualifying facilities

PSI owns several low-cost coal plants that are designed for base-load service but will be underutilized in the future PSI intends to sell its base-load capacity to a utility that can fully utilize it and build new peaking facilities for itself. Such a trade enhances the economic efficiency of all the parties, however, it would most likely not be economically attractive for PSI if PSI were required to sell its power at cost-based rates—likely to be much lower than the prevailing market price PSI intends to keep the plants used to produce the market-priced power in the rate base of Indiana consumers and to more than compensate Indiana ratepayers by sharing the profits from the sales This portion of the regulatory bargain will be overseen by the Indiana Utility Regulatory Commission

To gain Federal approval of its plan, PSI included strong transmission commitments intended to demonstrate to FERC that PSI lacks market power over its proposed power sales These commitments include the following

- PSI will provide long-term firm transmission service to any utility at cost-based prices (embedded-cost prices if existing capacity is used and incremental-cost prices if new capacity must be added)
- PSI will provide nonfirm transmission service at rates capped by embedded costs
- For planning and operational purposes, all firm transmission service will have priority over nonfirm service, even that which would otherwise benefit native-load customers
- PSI has agreed to provide transmission service between specific points of receipt and delivery, and to allow changes in these points if the customer pays for any additional costs
- Firm transmission service may be resold or reassigned, with the new utility receiving the service paying for any additional costs imposed by the changes in receipt and delivery points

FERC required PSI to back up its obligation to provide transmission service by agreeing to suspend its market-based pricing authority for power if a third party complains about the lack of timely transmission service and the Commission subsequently upholds the complaint In addition, FERC will receive certain reports from PSI on the status of both the midwestern power market and PSI's transmission program that will assist FERC in any future review of the program.

PSI's open-access transmission program is likely to be an important factor in the development of a competitive power market in the Midwest for several years The most obvious weakness of PSI's commitments is its limited duration PSI asked FERC for market-based pricing authority until 1997 and also asked that its transmission-building obligation be similarly limited. After 1997, PSI's obligation to upgrade the transfer capability of its grid will be limited to new investment needed to accommodate rearrangements of levels of service that were existing or requested at the end of 1996 Whether this restriction will become important or will be overtaken by events is difficult to judge now

Transmission Conditions for Mergers

PacifiCorp-Utah Power & Light Merger

Each of the previous three agreements is a regulatory bargain in which FERC has granted market-based pricing in exchange for transmission commitments sufficiently strong to mitigate the market power likely to be wielded in the particular circumstances FERC has opportunities to reshape the regulatory bargain in other ways that promote the public interest One such instance was the merger between Utah Power & Light Company and PacifiCorp In that case, FERC conditioned its approval of the merger on the company's acceptance of an absolute obligation over the long term to provide firm transmission service to any utility, not including qualifying facilities, at cost-based rates

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FERC based its decision on the record in the case that showed that Utah Power & Light had exhibited a history of denying transmission service to utilities in the Northwest and Rocky Mountain regions who wished to sell inexpensive power into lucrative markets in the Southwest Instead, Utah Power & Light would buy the cheap power for itself and resell it into these markets at a markup This purchase and resell activity was more profitable than providing wheeling service The profits were mostly credited to Utah Power & Light's retail ratepayers and served to keep rates in Utah low FERC concluded that the merger would strengthen the company's ability to use its transmission assets in such anti-competitive ways and could therefore foreclose a significant amount of interstate trade between the Northwest and Southwest regions

To address these anti-competitive concerns, FERC fashioned two sets of transmission conditions

- **Transition Period** (First 5 years) The merged company was required to identify remaining transmission capacity (after setting aside capacity needed for native load) and to allocate it as follows 20 percent to transmission-dependent utilities, 30 percent to unaffiliated entities to the north and east of the company, and 50 percent to any company, including the merged company itself.

- **Long-Term Obligation to Serve.** The merged company must provide firm wholesale transmission service at cost-based prices to any utility requesting it FERC required the company to back up this commitment with an agreement to reduce its own coordination trade to whatever extent is necessary should the company not be able to meet this obligation within 5 years of a request

FERC also required that customers be able to resell or reassign firm transmission service As in the Turlock, Modesto, and PSI cases, PacifiCorp will provide point-to-point transmission service, with the customer responsible for paying the cost of any upgrades due to receipt point or delivery point changes

FERC's conditions were accepted by the two companies and the merger was consummated in 1989 In doing so, the company agreed to the condition that PacifiCorp must reduce its own coordination trade if such action is needed to accommodate a firm transmission request As discussed in Chapter 6, this condition is problematic

Open Transmission Access With No Federal Quid Pro Quo

Wisconsin Power & Light Transmission Tariff

In 1990, FERC accepted a transmission tariff under which Wisconsin Power & Light Company (WP&L) effectively became an open-access provider of transmission services No regulatory bargain was involved at the Federal level Instead, the bargain, if any, may reflect circumstances in Wisconsin In 1989, the Wisconsin Public Service Commission expressed a strong interest in statewide joint use or joint planning of the transmission grid as part of the a biennial regulatory review of integrated resource planning within the State As part of its interest in transmission, the Wisconsin Public Service Commission required Wisconsin utilities to file transmission tariffs at FERC within 1 year The WP&L initiative may be the utility's response to the State Commission's directive Alternatively, the tariff may be a way for WP&L to compete in a developing regional market for transmission service

In any case, the WP&L transmission tariff, called T–2, applies to all utilities, including qualifying facilities and independent power producers, outside of its service territory[2] Under the tariff, WP&L will provide both firm and nonfirm transmission service at embedded-cost rates from existing facilities If new facilities are needed, WP&L will provide service under separate, negotiated agreements approved by FERC Although the T–2 tariff does not specify the transmission price to be charged if new facilities must be built, it must ultimately be "just and reasonable" under the Federal Power Act Thus far, FERC has required a cost basis for the price of firm transmission service under this standard

The WP&L tariff is distinguished by the company's offer to provide transmission service between

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generalized interfaces that separate adjoining utilities, instead of between specific receipt and delivery points as in each of the aforementioned cases The additional flexibility allowed by such arrangements may be an important feature of the tariff to some market participants The most restrictive feature of the tariff is the inability of a customer to resell transmission service The inflexibility due to this restriction is offset to some extent by WP&L's concept of service between generalized interfaces

Pending Cases

In all, since 1988 FERC has dealt with five specific regulatory cases that have increased the availability of transmission service in parts of the Midwest and West Several cases are pending at the Commission, suggesting that this trend is continuing A few of the more important cases are listed below

- **Western Systems Power Pool.** FERC has ordered the pool to develop a method for mitigating the market power of the pool members or else lose the pricing flexibility that they seek for nonfirm transmission service, in particular

- **Southern California Edison-San Diego Gas & Electric Merger.** This merger is under consideration It involves the offer of certain transmission commitments by the merging companies

- **Northeast Utilities-Public Service Company of New Hampshire** This is another merger involving transmission commitments, with the added feature that the merger is intended to bring Public Service of New Hampshire out of bankruptcy

- **Kansas City Power & Light-Kansas Gas & Electric Merger** This is a hostile takeover that involves transmission commitments

- **Northeast Utilities-United Illuminating Company Nonfirm Transmission Pricing.** FERC has set for hearing the issue of whether opportunity cost pricing for nonfirm transmission service is appropriate in the presence of market power on the part of the transmission incumbent

- **Vermont Commission Section 207 Complaint.** The Vermont Commission, as part of its intervention in the Northeast Utilities-Public Service of New Hampshire merger case, has complained that the transmission service received by Vermont utilities from Northeast Utilities is inadequate and has asked FERC for relief under little-used Section 207 of the Federal Power Act

Notes

1 See Pacific Gas & Electric Company's agreement with Turlock (42 FERC ¶ 61,406, rehearing 43 FERC ¶ 61,403) and Pacific Gas & Electric Company's agreement with Modesto (44 FERC ¶ 61,010, rehearing 45 FERC ¶ 61,061)

2 A separate tariff, T–1, is available to utilities within WP&L's service territory and provides for transmission services under similar prices, terms, and conditions

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State of Michigan

Before the Michigan Public Service Commission

In the matter of the Application of the Association of Businesses Advocating Tariff Equity for approval of an experimental retail wheeling tariff for Consumers Power Company	Case No U-10143
In the matter on the Commission's own motion, to consider approval of an experimental retail wheeling tariff for The Detroit Edison Company	Case No U-10176

Direct Testimony of

MAURICE BRUBAKER

On Behalf of

Association of Businesses Advocating Tariff Equity

Project 5739
October 1992

Drazen-Brubaker & Associates, Inc
St Louis, Missouri 63141-2000

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1 Providers (TPP) to engage in a variety of transactions with individual
2 retail customers. It will also allow the collection of valuable infor-
3 mation concerning the administration of such a program, and other infor-
4 mation which may be important in designing permanent tariffs

5 Q **WHY IS IT IMPORTANT TO CONSIDER ALLOWING RETAIL WHEELING ON A PERMANENT**
6 **BASIS?**
7 A Retail wheeling is one of many options that may assist a utility in
8 meeting the energy requirements of its service territory in a least-cost
9 manner Most utilities currently consider utility-constructed supply-
10 side resources, power purchased from other utilities for system supply,
11 power purchased from QFs or other non-utility sources for system supply,
12 and demand-side management (DSM) as the primary options Retail wheel-
13 ing, which would allow an individual end-use customer to contract with
14 a TPP for a specific quantity of power over a defined term, has the
15 potential to be another least-cost option

16 Q **HOW COULD RETAIL WHEELING BE A LEAST-COST OPTION?**
17 A If a utility has identified a need for additional resources, retail
18 wheeling may be able to satisfy that requirement at a lower cost than
19 other more traditional options As is true for other options, the
20 specific facts of each circumstance must be considered to determine
21 whether this is the case Under a permanent (as distinguished from
22 experimental) tariff which allows retail wheeling, the associated supply
23 and price risk is transferred from the utility and its general body of
24 ratepayers to the specific end-use customer contracting with the TPP

1 This limits the exposure of the general body of ratepayers to the
2 uncertainties of load growth, construction cost overruns, fuel price
3 increases, resource performance, etc. To the extent that individual
4 customers are willing to assume these risks, they are transferred away
5 from the utility and its general body of ratepayers.
6 Not all utility customers have the same degree of risk-aversion,
7 so when the utility is the sole provider, it must consider its customers
8 in the aggregate, and plan in accordance with a level of risk, and with
9 a view toward a level of reliability, that is consistent with customers
10 in the aggregate If individual customers that have risk/reliability
11 preferences different from the aggregate are allowed to contract
12 separately for their requirements, the potential exists for a more
13 efficient employment of resources, and lower overall costs.
14 In a more general sense, allowing this additional option will
15 bring more competition to the electric utility industry This is
16 entirely consistent with integrated resource planning (IRP) which
17 requires a consideration of a variety of alternatives in resource plan-
18 ning, and this Commission's recent orders establishing a competitive
19 bidding framework for new supply-side resources

20 **SPECIFIC PARAMETERS**

21 Q TURNING NOW TO THE SPECIFIC DETAILS OF THE EXPERIMENTAL PROGRAM, DO YOU
22 HAVE RECOMMENDATIONS ON THE KEY PROGRAM PARAMETERS?
23 A Yes

1 **Size of Program**

2 Q SHOULD THE EXPERIMENTAL PROGRAM ALLOW UNLIMITED RETAIL WHEELING?

3 A No One of the purposes of conducting the program on an experimental
4 basis is to gain information in a controlled environment. The size
5 of the program must be established consistent with two competing con-
6 siderations First, the program must be large enough to accommodate
7 diversity in participants and transactions. At the same time, however,
8 considerations of manageability and potential impact argue for limiting
9 the program

10 In consideration of these factors, it is my recommendation that
11 the amount of load allowed to participate in the experimental program
12 be restricted to 1% of the annual peak of each utility This amounts
13 to approximately 60 megawatts for Consumers and 90 megawatts for Edison
14 The experiment would commence at the time the utility has a need for new
15 capacity, as evidenced through the IRP or a capacity solicitation I
16 will discuss this in more detail later in this testimony It is my
17 judgment that a program of this nature will allow the opportunity to
18 test a variety of transactions, under a number of different circum-
19 stances, while at the same time limiting potential impacts

20 Q WHAT ARE THE POTENTIAL IMPACTS?

21 A One potential impact is on the utility's transmission system loadings
22 By limiting the size of the program and making the provision of service
23 contingent upon the existence of adequate capacity in the utility's
24 transmission system, this potential impact is eliminated.

1 Second, there may be a limit to the number of transactions that
2 the utility's personnel and control facilities can accommodate The
3 restriction of the program size allows the relevant information to be
4 obtained, while limiting the number of transactions
5 Third, initiating the program at a time when there is a need for
6 new capacity mitigates any concerns about cost recovery or the potential
7 for stranded investment.

8 **Eligible Customers**

9 Q **WHAT IS YOUR RECOMMENDATION WITH REGARD TO CUSTOMER ELIGIBILITY?**
10 A This parameter should also be selected giving consideration to admin-
11 istrative feasibility and the objective of inducing participation in a
12 variety of transaction types It is my recommendation that all
13 customers with maximum demands of 5,000 kW or more be eligible The
14 minimum amount of capacity available at any customer location would be
15 2,000 kilowatts, and the maximum would be 10,000 kilowatts Given the
16 recommended size of the program, this should allow for a reasonable
17 variety of participants and transactions

18 **Eligible Suppliers**

19 Q **HOW BROADLY SHOULD THE CLASS OF TPPs BE DEFINED?**
20 A As broadly as possible The broader the class, the greater the variety
21 of transactions that will be expected to occur, and the greater the
22 level of experience gained TPPs should include investor-owned util-
23 ities, cooperatives, municipal utilities, utility pools, qualifying

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1 facilities (QFs), and other non-utility generators (NUG), without
2 restriction as to location Customers who generate and have multiple
3 facilities should also be allowed to wheel power from the generation
4 source to their other facilities

5 **Extent of Load Requirement Supplied**

6 Q **WHEN A TPP SUPPLIES POWER TO AN ELIGIBLE LOAD, IS IT NECESSARY THAT THE**
7 **ENTIRE LOAD OF THE ELIGIBLE CUSTOMER BE SUPPLIED?**
8 A No The customer could, of course, arrange for the TPP to supply the
9 entire load However, it is also possible to arrange for the TPP to
10 supply a portion of the load Under a partial supply scenario, the TPP
11 could either supply a base load block of power, with the balance of the
12 supply requirement being met by the utility, or, the utility could
13 supply a base block, with the balance of the requirement being supplied
14 by the TPP
15 In order to gain as much experience as possible about cost and
16 feasibility, I recommend that all three of the transaction types
17 described above be permitted in this experimental program

18 **Pooling of Requirements**

19 Q **FOR PURPOSES OF OBTAINING POWER SUPPLY, SHOULD INDIVIDUAL LOCATIONS BE**
20 **REQUIRED TO CONTRACT INDEPENDENTLY WITH A TPP?**
21 A No. Since the program contemplates eligibility of loads as small as
22 2,000 kilowatts, it is reasonable that customers be allowed to aggre-
23 gate their requirements for purposes of contracting with a TPP An

29x

1 service may be taken in conjunction with service under any other appli-
2 cable rate, including standby service under Rate CG-2.
3 The metering voltage discount, minimum charge, due date and late
4 payment charge, substation ownership credit, voltage level definition
5 and power factor provisions are consistent with Rate D

6 Q **PLEASE EXPLAIN THE SPECIAL CONDITIONS INCLUDED IN THE RATE.**
7 A Special Condition No 1 specifies that the customer is responsible for
8 making all arrangements with the TPP for delivery of the capacity and
9 associated energy to the utility, and that the utility shall not be
10 obligated to commence delivery service until all such arrangements have
11 been made This condition also provides that the utility will assist
12 the customer in making these arrangements, if it is requested to do so,
13 and that the utility will enter into suitable agreements with the TPP
14 and other involved parties, which are necessary to implement the trans-
15 actions
16 Special Condition No 2 specifies that the utility will enter into
17 agreements to purchase the TPP power for customer's account, and rebill
18 the charges to the customer, if the customer requests that the transac-
19 tion be structured in this fashion
20 Special Condition No 3 specifies that the quality of the service
21 provided is firm, and that the utility shall maintain necessary existing
22 equipment and facilities to deliver the capacity and associated energy

1 Q **WHAT IS THE REASON FOR THE "EXISTING FACILITIES" LANGUAGE?**

2 A The purpose of this language is to make it clear that the utility is not
3 required to expand its facilities to provide service hereunder. There-
4 fore, if a customer requests a particular transaction that the utility
5 is unable to accommodate with its existing system, the utility, if it
6 can establish its inability to provide the requested service from
7 existing facilities, would be under no obligation to do so.

8 Q **WHAT IS THE DEGREE OF FIRMNESS OF THE SERVICE PROVIDED?**

9 A Once delivery service begins it would be firm, with the same priority
10 as the utility's firm native load

11 Q **PLEASE EXPLAIN SPECIAL CONDITION NO. 4.**

12 A Special Condition No. 4 simply provides that the amount of power
13 delivered to the utility shall be reduced for expected system losses

14 Q **WHAT IS SPECIAL CONDITION NO. 5?**

15 A Special Condition No 5 provides that the customer shall give prompt
16 notification to the utility of any change in the scheduling of the
17 service to be provided For example, the customer may have scheduled
18 3,000 kilowatts in a given hour, and because of changed circumstances
19 needs to increase or decrease the amount scheduled. Or, if the customer
20 has been scheduling a 3,000 kW block of power from a TPP, and is plan-
21 ning to close its facility for maintenance, it is obligated to promptly
22 notify the utility

1 Q **PLEASE EXPLAIN SPECIAL CONDITION NOS. 6, 7 AND 8.**

2 A These provisions address partial and complete supply of customer's load
3 by a TPP, and the two options of partial supply discussed earlier in my
4 testimony They also define the billing parameters for the delivery
5 rate and the otherwise applicable rate under these different supply
6 options

7 Q **WHAT IS ADDRESSED IN SPECIAL CONDITION NO. 9?**

8 A Special Condition No 9 provides for the temporary or permanent re-
9 assignment of TPP power and delivery service

10 Q **WHAT IS ADDRESSED IN SPECIAL CONDITION NO. 10?**

11 A Special Condition No 10 allows the customer, at its option, to take
12 standby service under utility's standby rate CG-2 TPP-supplied power
13 is an alternative to utility-supplied power, just as power supplied from
14 a cogeneration facility is an alternative to utility-supplied power
15 Therefore, it is reasonable that the same standby options be made avail-
16 able Of course, since the customer would be paying maximum demand
17 charges under the delivery service rate, the maximum demand charges in
18 CG-2 would not be applicable

1 As a practical matter, implementation will shortly follow the con-
2 clusion of this case. For example, Consumers filed its new IRP showing
3 a need for 300 megawatts commencing in 1994 Under our proposal, the
4 needed amount of new resources would be reduced to 240 megawatts

5 **RETURN RIGHTS**

6 Q **WHAT RIGHTS SHOULD CUSTOMERS PARTICIPATING IN THE EXPERIMENTAL WHEELING**
7 **PROGRAM HAVE TO RETURN TO FULL SERVICE FROM THE UTILITY?**
8 A At the time a customer's delivery service contract expires, or the
9 experimental program concludes, participating customers should have a
10 right to take service from the utility under any available tariff for
11 which they qualify Given the experimental nature of the program, it
12 is essential that participating customers have this safeguard

13 Q **IF THE WHEELING PROGRAM BECAME PERMANENT, WOULD A PARTICIPATING CUSTOMER**
14 **HAVE THE SAME RIGHTS?**
15 A The specific details will need to be established if the Commission
16 decides to make wheeling a permanent option However, I would envision
17 that under a permanent program there would be a conditioning of the
18 utility's obligation to provide service, and that participating cus-
19 tomers requesting full service from the utility would be treated the
20 same as any new customer applying for service from the utility

21 Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**
22 A Yes

CONSUMERS POWER COMPANY

Cost of Service Study
Year Ending December 31, 1991
(Dollars in Thousands)

Line	Description	Consumers Allo Factor	TR\STR Allo Factor	Total Electric	Factor	Transmission & Subtransmission
	Plant in Service					
1	Production Plant	H5		2,245,519	0.00%	0
	Transmission Plant:					
2	Production Classified Substatns	H5		33,515	0.00%	0
3	Transmission Classified Substns	H5	100%	139,076	100 00%	139,076
4	Subtrans Classified Substations	H6	100%	86,577	100.00%	86,577
5	Distribution Classified Substns	A3		5,337	0.00%	0
6	Specific Class Assignment	F1	100%	3,157	100.00%	3,157
7	Meter Houses/Transclosures	F2	100%	6	100.00%	6
8	Transmission OH Lines	H5	100%	338,434	100.00%	338,434
9	Subtrans OH Lines	H6	100%	80,414	100.00%	80,414
10	Transmission UG Lines	H6	100%	4,325	100.00%	4,325
11	Total Transmission Plant			690,841		651,989
	Distribution					
	Account 361					
12	Subtrans Classified Plant	H6	100%	525	100 00%	525
13	Other			8,644	0.00%	0
	Account 362					
14	Subtrans Classified Plant	H6	100%	5,872	100 00%	5,872
15	Other			141,352	0.00%	0
16	Other Distribution			1,411,588	0.00%	0
17	Total Distribution Plant			1,567,981		6,397
	General Plant					
18	Production Related	49	F49A	21,938	0 00%	0
19	Transmission Related	31	F31A	1,483	94 38%	1,400
20	Distribution Related	48	F48A	10,590	0 41%	43
21	Customer Related	C5		10,305	0 00%	0
22	Total General Plant			44,316		1,443
	Common Plant:					
23	Production Related	49	F49A	22,365	0 00%	0
24	Transmission Related	31	F31A	1,510	94 38%	1,425
25	Distribution Related	48	F48A	10,795	0 41%	44
26	Customer Related	C5		10,506	0 00%	0
27	Total Common Plant			45,176		1,469
	Intangible Plant					
28	Organization/Intangible	64	F64A	96	3.25%	3
	Account 302					
29	Franchises & Consents	3		3	0.00%	0
30	Hydro Generation	4		4	0.00%	0
31	Intangible	64	F64A	225	3.25%	7
32	Miscellaneous	3		343	0 00%	0
33	Transmission-Ont Hydro Intercon	53		1,370	100.00%	1,370
34	Total Intangible Plant			2,041		1,380
35	Total Plant in Service			4,595,874		662,678

CONSUMERS POWER COMPANY

Cost of Service Study
Year Ending December 31, 1991
(Dollars in Thousands)

Line	Description	Consumers Allo Factor	TR\STR Allo Factor	Total Electric	Factor	Transmission & Subtransmission
	Other Utility Plant Items					
	Plant Held for Future Use					
1	Production	H5		1,121	0 00%	0
2	Transmission	50	100%	12,586	100.00%	12,586
3	Distribution	54		207	0 00%	0
4	Common	63	F63A	1,763	3.25%	57
5	Total PHFFU			15,677		12,643
6	Abandoned Midland Project Costs	H7		1,376,139	0.00%	0
	Construction Work in Progress·					
	Interest Bearing CWIP					
7	Production	2		24,370	0 00%	0
8	Transmission	50	100%	1,520	100 00%	1,520
	Non-Interest Bearing CWIP.					
9	Production	H5		59,457	0 00%	0
10	Transmission	50	100%	2,015	100.00%	2,015
11	Total CWIP			87,362		3,535
12	Total Utility Plant			6,075,052		678,857

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CONSUMERS POWER COMPANY

Cost of Service Study
Year Ending December 31, 1991
(Dollars in Thousands)

Line	Description	Consumers Allo Factor	TR\STR Allo Factor	Total Electric	Factor	Transmission & Subtransmission
	Operation and Maintenance Expenses					
	Production					
	Operation Expense					
	Fuel for Generation					
1	On Peak	B1		218,257	0.00%	0
2	Off Peak	B2		124,222	0 00%	0
	Purchased & Net Interchange Power					
3	Capacity	H5		375,761	0.00%	0
4	On Peak Energy	B1		128,647	0.00%	0
5	Off Peak Energy	B2		115,139	0.00%	0
	Other Operation Expense					
6	Production	H5		102,325	0 00%	0
7	Acct 556-Systm Cntrl & Ld Dsp	49	1/3	9,683	33.33%	3,228
8	Interconnection Equalization	50	100%	1,832	100 00%	1,832
9	Total Operation			1,075,866		5,060
	Maintenance Expense					
10	Capacity Related	H5		31,538	0 00%	0
11	Energy Related	B6		95,405	0.00%	0
12	Total Maintenance			126,943		0
13	Total Production			1,202,809		5,060
	Transmission					
	Operation Expense					
14	Transmission Substations	18	F18A	2,821	85 49%	2,412
15	Overhead & Underground Lines		100%	1,333	100.00%	1,333
16	Superv, Engineering & Misc	96	F96A	1,936	90 14%	1,745
17	Rents	25	100%	203	100 00%	203
	Maintenance Expense					
18	Structures & Station Eqpt	18	F18A	5,203	85 49%	4,448
19	Overhead & Underground Lines		100%	3,737	100 00%	3,737
20	Superv, Engineering & Misc	97	F97A	104	91 55%	95
21	Total Transmission			15,337		13,973

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CONSUMERS POWER COMPANY

Cost of Service Study
Year Ending December 31, 1991
(Dollars in Thousands)

Line	Description	Consumers Allo Factor	TR\STR Allo Factor	Total Electric	Factor	Transmission & Subtransmission
	O & M Expenses (Continued)					
	Distribution:					
	Operation Expense:					
22	Station Equipment	45	F45A	2,931	3 99%	117
23	Other			16,739	0.00%	0
24	Superv, Engineering & Misc	98	F98A	13,673	0.59%	81
25	Rents	55		3,118	0.00%	0
	Maintenance Expense.					
26	Structures	43	F43A	206	5.73%	12
27	Station Equipment	45	F45A	3,979	3 99%	159
28	Other			30,668	0.00%	0
29	Superv, Engineering & Misc	99	F99A	2,748	0 49%	13
30	Total Distribution			74,062		382
31	Customer Accounts			48,947	0.00%	0
32	Customer Service			8,192	0.00%	0
33	Sales Expense	C5		4,918	0.00%	0
	Administration & General:					
34	Production	H5		75,978	0.00%	0
35	Transmission	31	F31A	5,131	94 38%	4,842
36	Distribution	48	F48A	36,676	0 41%	150
37	Customer	C5		35,690	0.00%	0
38	Admin & General			153,475		4,992
39	Other O&M - DSS Program	C8		3,453	0.00%	0
40	Conservation (Incl DSM Program)	H10		8,498	0.00%	0
41	Total O & M Expenses			1,519,691		24,407

CONSUMERS POWER COMPANY

Cost of Service Study
Year Ending December 31, 1991
(Dollars in Thousands)

Line	Description	Consumers Allo Factor	TR\STR Allo Factor	Total Electric	Factor	Transmission & Subtransmission
	Depreciation and Amortization Expenses					
	Depreciation Expenses:					
1	Production			79,867	0.00%	0
	Transmission					
2	Production Classified Substatns	H5		695	0.00%	0
3	Transmission Classified Substns	H5	100%	2,835	100 00%	2,835
4	Subtrans Classified Substations	H6	100%	1,785	100 00%	1,785
5	Distribution Classified Substns	A3		111	0 00%	0
6	Specific Class Assignment	16	100%	29	100 00%	29
7	Transmission OH Lines	H5	100%	4,715	100.00%	4,715
8	Subtrans OH Lines	H6	100%	1,398	100.00%	1,398
9	Transmission UG Lines	H6	100%	129	100 00%	129
10	Total Transmission			11,697		10,891
	Distribution					
11	Account 361	43	F43A	218	5 73%	12
12	Account 362	45	F45A	4,072	3 99%	162
13	Other			48,133	0 00%	0
14	Distribution			52,423		175
15	General	62	F62A	1,306	3 26%	43
16	Common	63	F63A	1,331	3 25%	43
17	Total Depreciation			146,624		11,152
	Amortization Expenses:					
18	Franchises & Consents	65	F65A	7	3.16%	0
19	Common Plant	63	F63A	86	3 25%	3
20	Other Plant	66	F66A	62	79 98%	50
21	Abandoned Midland Project Exp	H7		86,610	0.00%	0
22	Total Amortization			86,765		53
23	Total Depreciation & Amortization Exp			233,389		11,204

CONSUMERS POWER COMPANY

Development of Unit Costs for Transmission and Subtransmission Service (Dollars in Thousands)

Line	Description	Transmission and Sub-transmission (1)	Transmission Only (2)
1	Total Revenue Requirement	$108,336	$82,010 a
2	Annual Peak, at Meter Level in MW	5,116	5,932
	Cost per kW.		
3	Annual	$21.18	$13.83
4	per Month	$1.76	$1.15

a. $108,336 x .757

DELIVERY SERVICE RATE FOR CUSTOMER-PROCURED POWER (EXPERIMENTAL)

Availability

This rate is available for the delivery of capacity and associated energy separately procured by customer from a source other than the Company Service is available only at subtransmission and transmission voltage levels Service is restricted to a minimum of 2 000 kW and a maximum of 10 000 kW at each customer location The Company may limit the amount of service provided hereunder to 60 000 kW

Service under this rate may be taken in conjunction with service under any other applicable rate including standby service under Rate CG 2

Nature of Service

Alternating current 60 hertz three-phase at a nominal voltage above 25 000 volts the particular nature of the voltage in each case to be determined by the Company

Where the Company elects to measure the service at a nominal voltage above 25 000 volts 1% shall be deducted for billing purposes from the demand measurements thus made

Monthly Rate

Customer Charge

$150 00 per customer per month

Delivery Charge

For Subtransmission Level Service

$1 76 per kW of maximum demand

For Transmission Level Service

$1 15 per kW of maximum demand

General Terms

Except as otherwise provided this rate is subject to all general terms and conditions shown on Sheet No E 1 00

(Continued on Sheet No E _____)

DELIVERY SERVICE RATE FOR CUSTOMER-PROCURED POWER (EXPERIMENTAL)

(Continued From Sheet No E-_____)

Monthly Rate (Contd)

Adjustment for Power Factor

Customers will have their bills determined based on the average power factor maintained by the customer during the billing period Such average power factor shall be determined through metering of lagging kilovar hours and kilowatt-hours during the billing period The calculated ratio of lagging kilovar hours to kilowatt-hours shall then be converted to the average power factor for the billing period using the appropriate conversion factor Whenever the average power factor during the billing period is above 899 or below 800 the delivery charge shall be adjusted as follows

(a) If the average power factor during the billing period is 900 or higher the delivery charge shall be reduced by 2%

(b) If the average power factor during the billing period is less than 800 the delivery charge shall be increased by the ratio that 800 bears to the customer s average power factor during the billing period

Maximum Demand

The maximum demand shall be the highest 15 minute demand created during the current month or previous 11 months

Substation Ownership Credit

Where service is supplied at more than 25 000 volts through customer owned equipment a substation ownership credit may be applicable in accordance with Rule D5 Substation Ownership Credit The credit per kW will equal the transmission level maximum demand charge in Rate D

Minimum Charge

The delivery charge plus the customer charge included in the rate

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing A late payment charge of 2% of the unpaid balance outstanding net of taxes shall be assessed to any bill which is not paid on or before the due date shown thereon

Term and Form of Contract

All service under this rate shall require a written contract with a minimum term of one year and a maximum term of five years No contract shall have an expiration date later than _____

(Continued on Sheet No E _____)

Issued _____
F W Buckman,
President & Chief Operating Officer,
Jackson, Michigan

Effective for service rendered on and after _____

Issued under authority of the Michigan Public Service Commission dated _____
in Case No U-_____

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DELIVERY SERVICE RATE FOR CUSTOMER-PROCURED POWER (EXPERIMENTAL)

(Continued From Sheet No E-_____)

Definition of Customer Voltage Level

Transmission Service

Transmission service is that service either supplied directly from the transmission system through a Company-owned substation where from the exits of the substation the distribution equipment for supplying service is owned and maintained by the customer

Subtransmission Service

Subtransmission service is that service either supplied directly from the subtransmission system or from the subtransmission system through a Company-owned substation where from the exits of the substation the distribution equipment for supplying service is owned and maintained by the customer

Special Conditions

(1) Customer is responsible for making all arrangements with the Third Party Provider (TPP) for delivery of the capacity and associated energy to the Company Company will assist customer in making these arrangements if requested to do so and will enter into suitable agreements with the TPP and other involved parties as necessary to implement the transactions The Company shall not be obligated to commence delivery service until all such necessary arrangements have been made Customer will be responsible for any charges imposed on Company by other parties as a result of the transactions hereunder

(2) If requested by customer Company will enter into agreements to purchase the TPP power for customer s account Company shall rebill to customer without markup the amounts billed to Company for capacity and associated energy received by the Company and delivered to customer

(3) The delivery service provided hereunder is firm The Company shall maintain the equipment and facilities necessary for the delivery of capacity and associated energy to any eligible customer from any point where capacity and associated energy may be generated within the Company s service territory or from any point of interconnection with another utility Company shall not be required to expand its existing facilities to make deliveries hereunder

(4) A reduction in the capacity and energy delivered to the customer shall be made to account for electrical losses on Company s transmission and subtransmission system For capacity and energy received and delivered by Company at transmission voltage the percentage reduction shall be 2 50% of the capacity and energy received by Company from the TPP for delivery to the customer For capacity and energy either received or delivered by the Company at subtransmission voltage the percentage reduction shall be 4 45% of the capacity and energy received by the Company from the TPP for delivery to the customer

(5) Customer shall promptly notify Company of any change in the scheduling of service to be provided hereunder

(Continued on Sheet No E _____)

DELIVERY SERVICE RATE FOR CUSTOMER-PROCURED POWER (EXPERIMENTAL)

(Continued From Sheet No E-____)

Special Conditions (Contd)

(6) Customer may elect to have part or all of the capacity and associated energy required by its load supplied by a TPP

(a) If customer's entire load is served by the TPP customer's load shall be telemetered to the TPP and the TPP shall be responsible for following customer's load with its generation resources

(b) Partial supply may be provided in one of two ways (i) the TPP provides a scheduled base block of power and the Company supplies the balance on an otherwise applicable rate schedule or (ii) the Company provides a base block of power on an otherwise applicable rate schedule, and the TPP provides the balance of customer's requirements Unless the TPP is providing the base power block the load following requirements shall be as specified in (a)

(7) If the TPP is supplying the base block of power the maximum demand billed under this rate schedule shall equal the amount of capacity contracted for hereunder The maximum demand billed on the otherwise applicable rate schedule shall equal the maximum demand determined as specified under the otherwise applicable rate schedule minus the maximum demand billed hereunder The on-peak demand for purpose of billing under the otherwise applicable rate schedule shall equal customer s on-peak demand as defined in the otherwise applicable rate schedule minus the average of the demands scheduled from the TPP at the times of the weekly demands used to calculate the on-peak billing demand in the otherwise applicable rate schedule For purposes of applying the on-peak billing demand ratchet provision during the first twelve months that service is taken hereunder customer's historic on-peak demands will be reduced by the amount of delivery service contracted for The amount of energy to be billed on the otherwise applicable rate schedule shall equal the total energy metered during on-peak and off-peak periods minus the amount of energy scheduled from the TPP in the on and off peak periods respectively

(8) If Company is supplying the base block of power the maximum demand under this rate schedule shall equal customer s maximum demand minus the demand contracted for billing under the otherwise applicable rate schedule The on-peak demand to be billed under the otherwise applicable rate schedule shall equal the on-peak demand for which customer has contracted under the otherwise applicable rate schedule but not more than the average of customer s actual weekly maximum demands occurring during the on-peak period of the month For purposes of applying the on-peak billing demand ratchet provision during the first twelve months that service is taken hereunder, customer's historic on-peak demands will be reduced by the amount of delivery service contracted for The amount of energy to be billed on the otherwise applicable rate schedule shall equal the amount of energy associated with the contracted demand on the otherwise applicable rate schedule during on and off peak periods respectively but not more than the actual amount of energy metered

(9) Consistent with the terms and conditions and limitations in this rate customer may temporarily or permanently reassign TPP power and delivery capacity under this schedule to another customer Such reassignment is subject to Company having sufficient capacity in the facilities required to provide the requested service to the other customer The customer originally contracting for service hereunder shall remain liable for the performance of all obligations under the contract except as specifically agreed to by the parties through an amendment to the contract

(10) At the option of the customer standby service for the TPP power delivered under this rate is available under Company s Rate CG 2 A customer electing this service shall pay the customer charge on-peak demand charge energy charges and maintenance energy charge (including the power supply cost recovery factor) and the surcharges shown on Sheet No E 2 00 for any standby service utilized The maximum demand charges in Rate CG 2 shall not be applicable

GENERAL AGREEMENT ON PARALLEL PATHS

FINAL REPORT

May 1992

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GENERAL AGREEMENT ON PARALLEL PATHS

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GENERAL AGREEMENT ON PARALLEL PATHS
DISCUSSION PAPER

1. EXECUTIVE SUMMARY

Bulk power transactions are now accomplished on the interconnected electrical system as a scheduled transaction or series of scheduled transactions between neighboring utilities All that is needed to effect long-distance transmission is the assembly of a willing chain of neighboring two-party transactions between individual companies The power is essentially handed-off from company to company according to the chain as described on paper (contract path)

The contract path may yield the ultimate buyer the lowest delivered power cost, but in many cases it partially or largely ignores the fact that electricity flows along the path of least resistance Therefore, companies experiencing a significant portion of the physical power flow but no contract recognition are faced with what amounts to unauthorized use of their transmission system Such parallel flows may jeopardize reliable customer service at worst, and at least result in an uncompensated use of transmission

The GAPP Committee was charged by the ITCF with the task of developing an effective method of resolving the problems associated with contract versus actual power flows (parallel flows) Progress in this area has become more imperative as the nature of bulk power dealings among companies trend towards longer distance, unidirectional power flows

After much discussion and weighing of the alternatives, the GAPP Committee has described in this discussion paper a method that will work to better control the imposition of parallel power flows on all participating companies Under the GAPP Method described herein, companies will also be compensated for what would previously have been an uncompensated parallel flow Under this method, parallel flow will largely become scheduled flow, and all scheduled flows will be priced by the providers of transmission service according to a public posting of their approved rates, whatever they may be

Power exchanges to meet urgent reliability needs will be exempt from certain aspects of the GAPP Method so that reaction to the situation is expedited

Computer based communications will be required for implementation of the GAPP Method and will be used for both operational control and billing purposes The GAPP Committee was mindful of the fact that companies will not implement a method that presents an unmanageable burden to operating staff whose primary responsibility it is to maintain reliable electricity supply

As complicated as the GAPP Method will be to implement, it remains rather simplistic in its treatment of certain issues If an implementation trial shows the method to be promising and worthy of additional effort, work should proceed on implementing necessary enhancements

Implementation of the GAPP Method will require the support of a significant number of the

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ITCF/GAPP representatives In addition, the GAPP Method will not be implemented without prior consideration and approval by FERC and other appropriate regulatory bodies

2. INTRODUCTION

Since early 1990, owners, operators and users of interconnected transmission systems in the eastern United States and Canada have been voluntarily convening to discuss interregional transmission issues with the intent of enhancing cooperation and coordination The participants refer to themselves as the Interregional Transmission Coordination Forum (ITCF)

One of the most significant issues regarding interconnected transmission system operation is that of unscheduled, or parallel power flows When power is transferred from one company to another, a single path is arranged by contract for delivery of the power However, a portion of the contracted power actually flows over other transmission lines and through other systems The difference between the contracted power scheduled over an interconnection and the actual flow is known as parallel flow (also called loop flow or circulating flow) The issue, while not new, has received increasing attention over the past decade during which time substantial power transfers between companies have routinely taken place, often to the reliable limit of transmission systems

The ITCF recognized that significant parallel flow between companies is inevitable and occasionally burdensome to transmission owners and operators who presently have little or no control over others' transactions and receive no compensation for parallel power flows across their systems To address this issue, the ITCF formed the General Agreement On Parallel Paths (GAPP) Committee Specifically, the ITCF requested GAPP to

> "Explore the practicability of replacing the single contract approach with a multiple contract path approach such that the transmission systems which are impacted by specific transactions are appropriately involved from a contracting, scheduling and operations perspective Prepare a discussion paper for the ITCF which compares the current single contract path approach to the implications of multiple contract paths, particularly with regard to scheduling and operational control The discussion paper should also address such considerations as the different types of transactions to which new contracting approaches should apply and any suggestions the committee has regarding how to transition to contracting for transactions on multiple paths "

The work of the GAPP Committee is consistent with statements by FERC recommending that interconnected entities develop practical solutions for the types of disputes which arise due to parallel flow This discussion paper presents a method which will largely solve the parallel flow problem It provides a summary of the GAPP Committee's investigation, together with discussion of related issues including some yet to be resolved

The GAPP Committee reviewed the approaches taken elsewhere in North America A brief summary of these other approaches can be found in Appendix C

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3. CURRENT METHOD – SINGLE CONTRACT PATH

Existing transmission systems principally have been designed by companies to carry power from generating units to load centers and to interconnect with neighboring companies in order to enhance overall system reliability and to permit emergency and economy transactions between neighboring companies The longstanding practice of the electric power industry has been to permit neighboring companies to contract to buy and sell power up to the reliable transfer capability of the interconnections between them At present, the "contract path" approach is employed in which only the contracting companies exercise control and are paid for the transmission service They are paid for the full contracted power transfer scheduled, regardless of whether the power is actually transported through the contracting companies or not Companies carrying parallel flows receive no compensation and have little or no control

Companies recognize that the many benefits they derive from interconnections outweigh the costs they sometimes incur to accommodate parallel flows as long as parallel flows are reciprocal In actual operation, companies cooperate and work closely together to address and mitigate parallel flows that would otherwise jeopardize any individual company's reliability

When parallel flows cause operating stresses on a company's transmission system, its operators take local actions such as generation shifts and power transaction adjustments in order of increasing cost Neighboring companies are advised of the problem When local controls are not sufficient, and reliability is threatened, a company will call on its neighbors to provide relief from the parallel flows Cooperation is the norm because all companies consider reliability of service to be paramount

One of the problems with this traditional approach to parallel flows is that in recent years, interregional transactions have become predominantly uni-directional for most companies in the eastern United States and Canada Therefore, the mutual interconnection benefit has, in some cases, become unbalanced due to persistent parallel flows such that some companies must make adjustments and incur costs more than others "Excessive" parallel flows are therefore increasingly seen as an unauthorized use of transmission, and the costs incurred to accommodate parallel flows are sometimes felt to be onerous

The application of the existing scheduling, control and compensation rules are not adequate when large quantities of power are transmitted over a complex network over long distances Although the traditional single contract path approach has been in place and accepted for many years, it is becoming increasingly impractical A new set of rules is desirable which compensates companies on the actual flow path for the power they are carrying and affords them some operational control over transactions

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4.0 OVERVIEW OF THE GAPP METHOD

The following is an overview of the GAPP Method which provides for the scheduling of power transactions along multiple contract paths which more closely correspond to actual power flows Details of the method are provided in Section 5 of this discussion paper

The GAPP Method builds on procedures now used between individual companies to effect a measure of control over transmission network conditions As an example, significant aspects of the control and system reliability philosophies developed for the Reliability Coordination Plan (RCP) co-authored and administered by the Allegheny Power System, Virginia Power and the Pennsylvania-New Jersey-Maryland Interconnection (PJM) have formed the foundation for many of the scheduling and control provisions detailed in Sections 5 1 and 5 2 Similar control arrangements between the Michigan utilities and within power pools such as New England, PJM and New York were referenced frequently during the GAPP Committee's deliberations

The GAPP Method is intended to apply to all normally-conducted power transactions involving at least one GAPP participant Examples of typical power transactions now most commonly taking place under various FERC-filed tariffs or schedules and to be governed by the GAPP Method in the future include (but are not limited to) long term capacity transactions, weekly-daily-hourly short term sales, economy transactions and banked power exchanges

There would be a limited number of cases exempt from the GAPP Method For example, when any company experiences operating conditions that in its judgment require emergency power from an external source or for which no reasonable internal accommodation is possible, the GAPP Method will be abridged The precedent for this kind of treatment can be found in the work accomplished by the ITCF members in the 1990-91 time-frame with respect to stressed transmission system conditions that prevailed at that time This is discussed more fully in Section 5 3 Also, the GAPP Method is not intended to apply, in whole or in part, to some existing generating units located outside a company's service area, to some existing transactions and to some aspects of transactions between directly connected companies Further details of the suggested exemptions can be found in Appendix A.2

4.1 TRANSMISSION TARIFFS

The GAPP Method requires that all transmitting companies have tariffs (or similar filed agreements) available for transmission service that are approved by the appropriate regulator(s) The method is not dependent upon the tariffs, although its acceptance by individual companies and/or the regulators might well depend on the tariffs intended to be used by the individual participants While the terms of reference of GAPP exclude compensation, the GAPP Committee has included discussion of some aspects of compensation in Appendices B 2 and B 3

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To date, most transmission tariffs have been routinely established according to a FERC standard which generally converts embedded costs of bulk transmission equipment (along with other miscellaneous activity) to a service charge per unit of power transmitted A newly emerging basis for transmission tariffs is reflective of the costs of relieving transmission constraints and may include items such as 1) the cost the transmitting company incurs to re-dispatch its generation away from optimum loading in order to support the requested transmission service, and 2) the cost of forgone economic power exchanges the transmitting company would have made itself were it not for the use of its system by others to transmit their power

Again, the GAPP Method does not require any specific derivation or establishment of a tariff structure on the part of GAPP participants and the GAPP Committee does not endorse any particular tariff basis

4.2 Transaction Matrix

The GAPP Method requires the derivation of a transaction matrix to show all paths involved in transactions between each and every pair of GAPP participants The matrix would be used to determine whether companies are transmitting sufficient power to qualify for compensation, and the extent to which they have control over any transaction

A load flow committee would be convened as an initial stage prior to the trial implementation of the GAPP Method This committee would be charged with constructing a matrix of load flow distribution factors applicable to all possible contracted power flows involving GAPP participants All distribution factors would be collected and displayed in the transaction matrix The transaction matrix would necessarily require many enabling assumptions concerning transmission network conditions, generation dispatch, load and generation distribution and new transactions and would be changed periodically to reflect changes in those conditions The study methodology would be approved by the ITCF before routine implementation or change

As a complement to the transaction matrix, all companies will post in some routine manner the rates from the tariffs which they have publicly filed with FERC and other appropriate regulatory bodies for the various transmission services they provide The rates would be in keeping with the companies' chosen tariff basis and may be changed from time-to-time Only posted rates may be charged, however, and changes in postings would only apply prospectively

The transaction matrix and the latest company rate postings would be made available to all GAPP participants for their easy access and review when completing, negotiating or assessing the impact of various power transactions

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4.3 Scheduling / Reservations

For a company to complete a power transaction under the GAPP Method, it must arrange a contract path(s) which carries 50% or more of the actual power flow as per the transaction matrix This contract path(s) must include the company(ies) transmitting the largest component of the transaction This requirement would be waived, however, if the generator of the power and its ultimate buyer are directly interconnected with sufficient unused transmission capacity to accommodate the entire transaction (See Appendix A 2[1] and A 3[3] for further discussion)

4.4 Threshold For Compensation

The GAPP Method specifies that all transmitting companies which carry 5% or more of any transaction be compensated according to the distribution factors in the transaction matrix at their posted rates This is a compromise in consideration of various factors (See Appendix A 3[1] for further discussion)

4.5 Threshold For Control

The GAPP Method provides some control to companies that transmit 20% or more of any transaction (as per the transaction matrix) by permitting the transmitting company to request that the transaction be reduced by an amount not more than the percentage flowing through its system when it experiences transmission capacity constraints When such a request is made (assuming the request is for a full reduction), the buyer would reduce the transaction by the requested amount and the requesting transmitting company would lose all transmission revenue for that transaction All other transmitting companies in the transmission path(s) would still receive compensation, albeit at a somewhat lower level reflective of the constrained company's cuts In the case of reductions of less than the full amount, reductions in compensation would be prorated accordingly to both the constrained transmitting company and others participating in the transmission path(s)

After any reduction, a portion of the remaining transaction would still flow through the system of the constrained transmitting company, of course, but this portion would then be an un-contracted parallel flow and would pose the same operational and economic problems as the current contract path method However, the transmitting company would have gained a measure of control over a transaction that may have been a parallel, uncontrolled flow prior to the GAPP Method (See Appendices A 3[2] and A 4)

4.6 Data Exchange

The GAPP Method requires each participating company to be linked to all other companies for purposes of exchanging data on transactions for control and billing

4.7 DISPUTES

The GAPP Method makes many simplifying assumptions and also establishes criteria and thresholds for participation, compensation and control These assumptions and criteria cannot anticipate all future methods of system operation or power transaction derivation Therefore, the ITCF would need to establish a dispute-resolving mechanism concurrent with the implementation of the GAPP Method

5.0 DETAILS OF SCHEDULING, OPERATIONAL CONTROL, COMMUNICATION AND BILLING

Detailed system operations under the GAPP Method outlined in Section 4 are provided below This method would apply to all power flows except those that may qualify for "grandfather" status (see Appendix A 2 for details) and some aspects of emergency operation (see Section 5 3 for details)

5.1 SCHEDULING / RESERVATIONS

Current procedures established between neighboring companies related to the timing of notifications for various transactions (weekly, hourly etc) would be unchanged by the GAPP Method

Under the GAPP Method, transactions would be allocated to companies which incur 5% or more of the transaction between the generator and ultimate buyer of the power The disaggregation of the power flow would be accomplished by application of the transaction matrix

A transaction reservation then can be made if

a) a continuous path(s) from seller to buyer carrying 50% or more of the actual flow according to the transaction matrix is (are) established, including the company transmitting the largest parallel component of the contract amount (see Exhibit I on page 8 and Appendix A 3), or

b) the generator and ultimate buyer are directly interconnected with sufficient unused transmission capacity to accommodate the entire transaction (See Exhibit II on page 8 and Appendix A 2[1])

Under the GAPP Method, the buyer would be responsible for notifying all involved transmitting companies carrying 5% or more of the transaction as per the transaction matrix Upon receiving that notification, all transmitting companies should notify the buyer of any expected operating problems that may impact this particular transaction once it begins The buyer then would have the opportunity to modify the transaction before it starts to reflect these operating problems and prepare to modify the transaction after it starts if such operating problems arise Through reference to the rate posting of all transmitting companies, the buyer has already been afforded the ability to select the level (if appropriate) and determine the cost of transmission service offered by all of the transmitting companies

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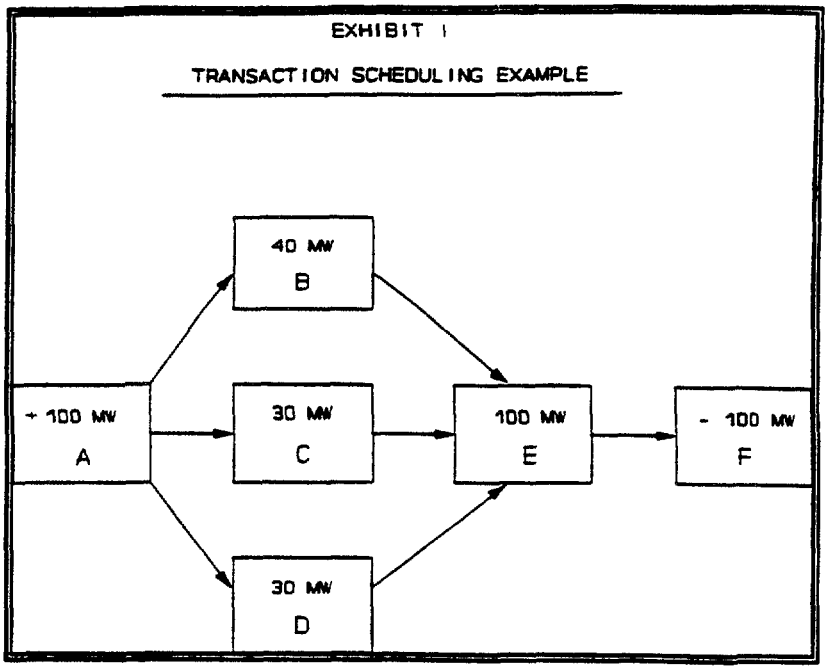
EXHIBIT I:



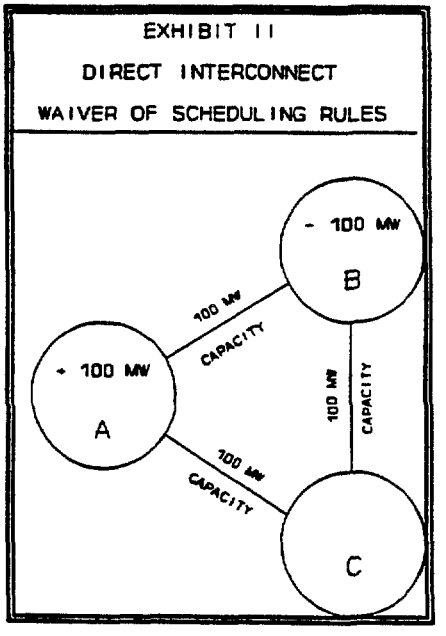
Premise

- System A sells 100 MW to System F
- System A over-generates by 100 MW System F under-generates by 100 MW, 100 MW flows from A to F through B, C, D and E as shown according to the transaction matrix

Consequence

- System F must reserve transmission service from systems E B and either C or D prior to the start of the transaction E because it carries over 50% of the scheduled flow B because it carries the largest portion of the flow between A and E, and either C or D because A needs permission from systems together comprising 50% of the flow between A and E before the transaction can start (and B represents less than 50%) Even though D is not on the contract path it receives compensation because it carries 5% or more of the flow Because they carry more than 5% B C D and E establish schedules for the appropriate amount

EXHIBIT II:



Premise

- System A is directly interconnected with Systems B and C C is directly interconnected with B All direct ties are assumed to have a rated capacity of 100 MW in one direction Scheduled power flows (parallel in this case) account for 50 MW of net pre-existing flow from A to B A wishes to sell 100 MW of its own power to B or wheel 100 MW of an un-pictured system s power to B or some combination of the two adding to 100 MW

Consequence

- Previously scheduled transactions in the direction A-to-B have used up 50 MW of their tie's rating A and B can schedule a maximum of 50 additional MW in the direction of A to B before C must be asked for schedule permission

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So, in accordance with timing procedures that have been established between neighboring utilities, all companies who participate in a prospective power transaction to a degree equal to or greater than the compensation threshold of 5% will receive a notification from the ultimate buyer of the power that it has received approval from a transmitting company or combination of transmitting companies to commence the intended transaction The notification will include a listing of the path(s) which granted approval of the transaction, and approval will have been granted in a manner which satisfies the scheduling threshold of 50% (a condition which should be easily verified by any company's reference to the transaction matrix) All companies involved in the transaction under the GAPP Method should then operationally include the notified transaction schedule as a part of the transactions managed over their system Consequently, parallel power flows which would have existed prior to the GAPP Method largely become scheduled flows after its application Remaining parallel flows should consist primarily of deviations between modeled distribution factors used in the transaction matrix and actual power flow, individual parallel flows imposed on companies who do not participate in transactions because they fail to meet the 5% compensation threshold, and parallel flows imparted on GAPP participants by transactions involving non-GAPP participants

5.2 Operational Control

As transactions are agreed and final confirmations are received, each of the transmitting companies will have been provided key data by the ultimate buyer on

1) The generating company and the ultimate buying company,
2) Scheduled interchange,
3) Start and stop times,
4) Priority and firmness (if appropriate) of transmission service purchased, and
5) The path(s) over which 50% or more of the transaction have been scheduled

As part and parcel of the five pieces of data provided above, all parties to the transaction (buyer, generator and transmitting companies) will know from the transaction matrix the amount of flow accruing from the proposed transaction and what relief is available or may be called for What would have previously been identified as a parallel flow pre-GAPP now becomes a scheduled flow in the post-GAPP era -- at least down to the application of distribution factors equal to or greater than 5%

Under normal system conditions (see Section 5 3 for a discussion of emergency conditions), if a reliability constraint (as determined by an individual transmission company's operating criteria) is encountered, the GAPP Method provides

A) Unilateral Relief Without Schedule Reductions.

A transmitting company should adjust its generation and/or switch transmission

facilities, if appropriate, which may alleviate, or at least minimize to the extent practicable, the effect of the constraint on its transmission system These are intended to be unilateral changes that a transmitting company can make without incurring significant additional costs

B) Relief Procedures With Schedule Reductions.[1]

If relief is still required, the transmitting company should notify the pertinent buyer(s) to stop loading any transactions not yet fully loaded and/or to avoid loading any scheduled transactions which have yet to start [2]

Upon the need for still further relief, a transmitting company may declare the need for reductions in transaction schedules and call for those reductions in transactions which exceed the 20% control threshold In so doing, the transmitting company should provide the following information to the appropriate buyers

1) Reliability limit encountered, severity of the problem, and its expected duration,
2) Scheduled transactions through the transmitting company segregated by category as to those above or below the 20% control threshold,
3) Total relief requested and transmission service priority categories affected by the requested relief (if applicable), and
4) Each individual buyer's share of the total relief which would be allocated to the service buyers on a pro-rata basis[3], cognizant of the transmitting company's service priority hierarchy (if any)

The buyer(s) will expediently provide the requested relief

C) Restoration Of Schedule Reductions

Once the reliability limit is no longer exceeded or in danger of being exceeded, the transmitting company will notify the buyer(s) when the transaction(s) can be reinstated, loaded to higher levels, and (in the event of companies carrying 50% of new transactions), new transactions can be scheduled

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[1] There may exist an intermediate step to be taken by transmitting companies which may alleviate or minimize the need for schedule reductions Refer to Section 2 of Appendix B.2 for further discussion of this potential step

[2] This may entail decreasing the loading of a lower priority transaction in favor of increasing the loading of a higher priority transaction which had not previously been fully loaded

[3] In no event shall the amount of relief apportioned to any single transaction exceed the product of the transmitting company's share of the transaction as per the transaction matrix times the total scheduled transaction between the generator and ultimate buyer

5.3 WAIVER FOR EMERGENCY SYSTEM CONDITIONS

Under emergency bulk power system conditions, the provisions of the GAPP Method pertaining to control will be suspended, and transmission system relief or emergency energy supply (as appropriate) will be provided to the company requesting such aid following existing industry guidelines Specifically, companies in need of such emergency aid and those responding to the request will not be required to observe the 50% reservation and 20% control thresholds as they make arrangements to address an emergency And, all transmitting companies experiencing parallel or scheduled power flows as a result of emergency-related power transactions will manage the provision of transmission services to all other customers in a manner that assures that higher priority is accorded the emergency-related transaction than any other transmission service transaction

The waiver of reservation and control thresholds under emergency system conditions does not extend to compensation The transaction matrix and records of companies who scheduled the emergency-related power transactions will be used as necessary to enable appropriate compensation of all companies (at their posted rates) whose systems were used to transfer power during the emergency

Companies who declare the need for such emergency aid will be required to keep records adequate to support their declaration after-the-fact to those companies who contributed (voluntarily or involuntarily) emergency services and support Inadequately supported declarations will be a matter to be addressed through the proposed ITCF dispute resolution process

5.4 COMMUNICATIONS

The reservations, schedules, transmission rates, transaction matrix, transmission limits and other data to be exchanged pursuant to Sections 5 1, 5 2 and 5 3 above, along with other generic data pertinent to system conditions (native loads, weather conditions, etc), will be exchanged on a real time, computer-based communication network

The initial concept of such a GAPP communications system revolves around a network of personal computers connected through controlling nodes of higher level computers with one another via dedicated telephone circuits This would allow the user in any one company's control center to send data/messages to and receive same from any or all companies connected to the network Also, the transaction matrix in effect at any particular time would reside on each control center's computer so that schedule apportionments could be confirmed, billing/revenue estimates could be performed, potential new transactions could be studied for system effect, etc

Implementation of this communications network would require the development of standardized computer software and, to a certain extent, hardware In addition, formats under which data and messages are to be exchanged between control centers, and provisions for data and hardware

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security/backup, will need developing The GAPP Committee believes that these requirements are not onerous

– The information exchange for the GAPP Method could be integrated with data exchanges now made or envisioned by ORNS[4] and IDEC[5] Members of those two groups now include Allegheny Power System, American Electric Power System, Centerior Energy System, Duke Power, Duquesne Light Company, Michigan Electric Coordinated System, New England Power Exchange, New York Power Pool, Ohio Edison System, Ontario Hydro, Pennsylvania-New Jersey-Maryland Interconnection and Virginia Power

5.5 BILLING / AUDIT

The GAPP Method should not require changes to normal practices for billing However, there will be a considerable degree of added complexity, first, because of the increased number of participants in many transactions, and second, because companies will conduct business dealings with companies well beyond their immediate interconnected neighbors

Companies will be required to keep records sufficient for audit purposes covering many more transactions than is currently the case

6.0 IMPLEMENTATION

The GAPP Method as outlined in this discussion paper is a major departure from current practice To demonstrate its efficacy, the GAPP Committee suggests that, subject to prior consideration and approval by FERC and other appropriate regulatory bodies, a trial of no longer than two years be conducted Some of the activities that will need to be undertaken to implement such a trial are provided in Section 6 1

During this trial, a number of problems and concerns will be identified which will need to be addressed in an ongoing way by the ITCF This will lead to the need to discuss possible enhancements to the basic GAPP Method and is discussed further in Section 6.2

At the end of the trial period, the ITCF will have to assess the outcome of the trial and whether the GAPP Method should be continued unchanged, enhanced or abandoned

6.1 TRIAL IMPLEMENTATION

Implementing the GAPP Method as outlined in this discussion paper will be a major undertaking

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[4] Operating Representatives Of The Northeast Systems

[5] Inter-Utility Data Exchange Consortium

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Even assuming rapid approval by the ITCF and regulators, it would be challenging to have the GAPP Method in place by June 1, 1993 Some of the actions that would need to be taken to accomplish this are briefly explained in this section Many of these can be conducted in parallel, but it must be recognized that many companies will want to know the outcome of these activities before they agree to adopt the GAPP Method

1 A significant number of the ITCF members must agree to participate because the GAPP Method cannot be implemented without the full cooperation of most of the companies participating at the ITCF (see Appendix B 4)

2 A committee must be formed to prepare a FERC filing and other appropriate regulatory filings requesting permission to implement the GAPP Method on a trial basis

3 Control areas that consist of more than one company will be required to make an election as to how they intend to participate (see Appendix B 1)

4 Individual companies and power pools will need to file appropriate transmission tariffs

5 A committee must be formed to derive distribution factors to be used in constructing the periodic transaction matrices The assumptions under which the committee performs its task must be presented to the ITCF for review and approval according to some procedure that the ITCF will need to specify During matrix development, special transmission system conditions caused by the introduction by individual companies of certain power flow control devices must be assessed and recognition given to the use of such equipment

6 A committee must be formed to work out the communication protocols necessary for implementation of the GAPP Method Each GAPP participant must acquire the appropriate computer hardware and software

7 A legal framework must be established for transmission tariffs and contracts under the GAPP Method to allow for compensation and control as envisioned (see Appendix B 4)

8 Transmitting companies will need to establish appropriate procedures for scheduling and control of transactions

9 A mechanism must be established by the ITCF to facilitate the resolution of disputes that will invariably arise among the participants however well-intentioned and committed they are to the GAPP Method A necessary companion to dispute resolution is the provision for and acceptance by all GAPP participants of a process whereby claims for emergency action, scheduled power flow reductions, etc can be audited

10 A review panel must be established to assess the credentials of "grandfather" candidates prior to the institution of the GAPP Method (see Appendix A 2) After the method

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starts, the panel will be required to rule on the continued pertinence of the "grandfather" criteria from time to time

– The GAPP Committee considered recommending a theoretical, "paper" exercise instead of a trial implementation, but concluded that this would be impractical and likely to be unrewarding The reason for this conclusion is that the results of the application of the GAPP Method are highly dependent on a number of factors including the assumptions used to develop the transaction matrix and the tariffs applied Therefore, as much work would be required to ensure the validity of any "paper" exercise as would be required for the proposed trial implementation There would likely be less interest in pursuing such a theoretical exercise than an actual trial Finally, there would be no point in pursuing a "paper" exercise if the legal and regulatory underpinnings are not known ahead of time

6.2 EVOLUTIONARY MODIFICATIONS TO THE GAPP METHOD

The GAPP Method for dealing with parallel power flow outlined in this discussion paper is a rudimentary solution meant to get at the crux of the parallel flow problem quickly with an acceptable level of effectiveness Almost by definition, the need for quick deployment of a manageable procedure has resulted in a deliberate inattention to several important considerations also associated with parallel flows and/or brought to the fore by the rudimentary solution the GAPP Committee devised

The inattention to those considerations in the name of expediency and simplicity does not demean their importance, and some of them might well prove to be so important that they cannot be overlooked during the trial implementation proposed in Section 6 1 It has always been the GAPP Committee's intention to devise an ultimate procedure which largely addresses conceptually the more global nature of the parallel flow problem, so the ITCF will need to establish an ongoing process to review the implementation trial and adapt the GAPP Method discussed herein as necessary In addition, the ITCF must address the issue of compensation of members experiencing untenable financial/operational harm through their exclusion from power flow scheduling via the 5% compensation threshold and other issues that might be addressed through the development of the pain pool (see Appendix B 3)

7. SUMMARY AND CONCLUSIONS

In consideration of such a significant change in the industry's approach to transmission system use as proposed in this discussion paper, one naturally asks - why should we change? The solitary contract path method has worked well for years The change will be inconvenient since operating procedures will be more complex Companies will incur fees and obtain revenues for certain operations where in the past there were none To every company represented on the ITCF, there are some apparent disadvantages involved in making the change

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In the view of the GAPP Committee, the central and overriding reason to make the change derives from a recognition that the bulk power supply market's trend towards becoming increasingly interregional may not coexist well with the need to maintain the reliability of the bulk power transmission network Bilateral power transactions among companies can no longer be assumed to be temporary and to "average out," rather, they are becoming more long term and unidirectional Also, non-utility generators are becoming significant power suppliers which, if they are not located within the host company's territory, generally require long-term and unidirectional transmission services from the bulk power network So, the conditions of the past which minimized the problems associated with the singular contract path approach no longer prevail to the same extent

In the multiple and diverse ownership structure that exists in the interconnected network, there is no way to carry out bulk power transactions without significant parallel flows, and hence significant burdens on the transmission systems of various companies Therefore, in consideration of the competitive industry environment that exists today and that can be expected to evolve in the future, a change in the way transmission transactions are arranged is highly desirable

The GAPP Method presented in this discussion paper provides a framework under which a majority of the problems attributable to parallel power flows can be managed It is intended to be as simple to implement as possible, while providing a measure of control over parallel flows larger than now available

Though conceptually simple, in practice the GAPP Method will impose a significant additional burden on personnel charged with the day-to-day management of the bulk transmission network It will also result in additional expense related to communication system development, load flow simulations, meetings and the like

Establishment of the GAPP Method, which affects both compensation for services as well as control of transactions, involves compromises among the various participants (see Appendix A 5) For any company, the GAPP Method represents a "mixed bag " Nevertheless, compromises are needed to reach an agreement among numerous parties to change the industry's current operating procedures The GAPP Method described in this discussion paper provides the minimum amount of control over the parallel flow problem sought by the ITCF while retaining the capability and economic incentive for the participants to continue to conduct bulk power transactions

APPENDICES

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APPENDIX A -- DISCUSSION OF ISSUES IMPLICIT IN THE GAPP METHOD

- Numerous issues are dealt with by the GAPP Method, many of which have various aspects that the GAPP Committee considered In evaluating the GAPP Method as presented, the ITCF will also need to consider these issues and their many facets For this purpose, the GAPP Committee is providing the discussion in this Appendix

A.1 APPLICATION FOR PAIN AND USAGE

The GAPP Method is intended to apply to all inter-company power transactions that significantly flow through a company's transmission system (usage), whether or not such flows necessitate that company operating in a manner different than it would have absent the transaction (pain) and thus incurring an economic burden

The GAPP Committee considered devising a method to apply just to parallel flows that cause transmitting companies pain so as to make them indifferent to such flows This would be more fair than the present contract path method because it would remove the financial penalties associated with actions transmitting companies now take to ensure reliable operation of the bulk power system under conditions of system stress compounded by high levels of parallel flows This might also result in interconnection transactions being maximized since there would be no parallel path charges for transmitting power unless constrained facilities were utilized

Such a method would result in no benefit to parallel path transmitting companies whose facilities are "un-painfully" used by others It would also provide compensation for companies with constrained transmission systems that do not expand to accommodate increasing usage

The alternative of devising a method for usage but not pain was also considered to be unattractive by the GAPP Committee It was ruled out because the very real problems that some companies have experienced and will continue to experience in the future as a result of parallel flow problems would not be directly addressed

The GAPP Committee concluded that it should devise a method that would apply to both pain and usage The GAPP Method presented in this discussion paper applies to usage through the provision for companies to be compensated for parallel flows greater than the 5% threshold It applies to pain through provision of control at or above the 20% threshold This would likely result in transmitting companies being indifferent to interconnection transactions that cause pain and would also result in fair compensation to transmitting companies for the usage of their transmission systems (See Appendix B 3 for further discussion of pain)

A.2 GRANDFATHERING - EXEMPTION OF DIRECTLY CONNECTED COMPANIES, SOME EXISTING TRANSACTIONS AND SOME EXTRA-TERRITORIAL GENERATION

1) Directly Connected Companies

As described in Section 5 1, the GAPP Committee agrees that transactions between directly connected companies should be granted dispensation from the need for a 50% aggregate flow path for an intended transaction between those two companies provided that there is sufficient unused capacity in the physical ties between them to accommodate the transaction It is understood that "sufficient unused capacity" means that the same capacity cannot apply to or enable more than one transaction in the same direction of flow That is, each transaction must be subtracted from any unused transfer capability, leaving a balance of unused transfer capability for a new transaction This waiver applies only to the requirement for a 50% path - it is not intended to exempt transactions between adjacent companies from being treated under the balance of the GAPP Method

Waiver of the 50% reservation threshold for directly connected companies erodes a measure of other companies' control over future transaction scheduling on the network in situations where there are significant resulting parallel flows The fact that companies are directly interconnected does not countermand the laws of physics The potential will exist for companies with relatively weak interconnections to use this exclusion with the result being little or no power flowing over the direct tie

This is a compromise The GAPP Committee felt that directly connected companies should be able to transact business over significant interconnections with their direct neighbors irrespective of actual flow The benefit of this would, on balance, outweigh the instances of loss of scheduling control over transactions claimed to be made over direct interconnections of dubious capacity or facility

The GAPP Committee intends this exclusion to be applicable only to power dealings which originate and terminate with those two directly connected companies The use of that path for power transactions which originate and/or end with a third company would be subject to all aspects of the GAPP Method

2) Some Existing Transactions

The GAPP Committee thought it undesirable and unfair, on balance, to retroactively apply the GAPP Method to all pre-existing transactions The Committee felt that certain FERC categories of transaction description could be used as the basis for consideration by the ITCF of

exempting pre-existing transactions from the GAPP Method The GAPP Committee feels that FERC categories RQ, LF and LU may be appropriate (A listing of known transactions as at 12/31/90 among current GAPP members in these categories, together with appropriate definitions, are provided in Table A 2 - 1)

The exempted - or "grandfathered" - transactions would be accommodated on the transmission systems of all of the appropriate GAPP participants without any change in control or compensation However, the GAPP Committee recognized the possibility that the effects of grandfathered transactions imposed on companies other than the contracting parties could be taken into account during negotiations between those companies as they individually and collectively enter into new, GAPP-governed transactions

The primary motivation for grandfathering is the simple recognition that certain transactions already exist, they have received regulatory approvals in many cases, and they have associated economic premises upon which they were justified Simply stated, retroactive application of the GAPP Method to these transactions might well be impossible

One obvious drawback created by grandfathering transactions is the potential for significant parallel flows to escape the scheduling and control procedures intended by the GAPP Committee Clearly, if a large number of transactions are grandfathered, new transactions would bear a disproportionate amount of the control responsibility necessary to alleviate transmission system constraints

The GAPP Committee concluded that the only way to deal with this would be to establish strict criteria for deeming transactions as "grandfathers", so as to keep the number of grandfathered transactions to a minimum For example, if the ITCF were to establish 12/31/90 as the cutoff date beyond which new transactions could not achieve "grandfather" status, Table A 2 - 1 would be a listing of prior transactions offered by the GAPP Committee as now meeting the grandfather criteria As part of the grandfather panel review suggested in Section 6 1 (10), the ITCF will need to give direction regarding the applicable cutoff date for candidates gaining acceptance as "grandfathers" The GAPP membership as at that date would then be polled for candidates

TABLE A 2-1
EXAMPLES OF GAPP "GRANDFATHER" CANDIDATES

BUYER	SELLER	MW	PARTY	TYPE	START	END	GEN PRIORITY	TRANSM PRIORITY	FERC CLASSIF
AMPOH	ELKEM	160	APS	UNIT	9/88	12/08	UNIT	(1)	LF
APS	AES/B V	135	DUQ	PURPA	7/87	12/17	NUG	(2)	RQ
CP&L	AEP	250	NONE	UNIT	1/90	12/09	UNIT	N/A	(3) LU
PEPCO	OE	450	APS	SYSTEM	6/87	12/05	Same As OE	(4)	LF
VP	AEP	500	NONE	UNIT	1/87	12/99	UNIT	N/A	LU
VP	HOOSIER	400	AEP	UNIT	3/84	12/99	UNIT	(5)	LU

(1) APS provides transmission priority just after OE-PEPCO transmission [see 4 below]
(2) Transmission priority right after DUQ native load
(3) Rockport Unit #2 -- Operating agreement w/APS AEP will adjust operation to protect 2800 MW of APS' eastern deliveries
(4) OE/PEPCO transmission thru APS has priority right after APS internal load
(5) Merom Units 1 & 2; transmission priority right after AEP native load

The examples above were selected by the GAPP Committee based on their FERC Form 1, Account 555 - Purchased Power, classification The ITCF will have to approve the final list The following summary shows the possible FERC classifications

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RQ for requirements service Requirements service is service which the supplier plans to provide on an ongoing basis (i e , the supplier includes projected load for this service in its system resource planning) In addition the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers

LF for long term firm service "Long term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e g , the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service) This category should not be used for long term firm service which meets the definition of RQ service For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract

IF for intermediate term service The same as LF service except that "intermediate term" means longer than one year but less than five years

SF for short term firm service Use this category for all firm services, where the duration of each period of commitment for service is one year or less

LU for long term service from a designated generating unit "Long term" means five years or longer The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit

IU for intermediate term service from a designated generating unit The same as LU service except that "intermediate term" means longer than one year but less than five years

EX for exchanges of electricity Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc and any settlements for imbalanced exchanges

OS for other service Use this category only for those services which cannot be placed in the above defined categories, such as all non firm service regardless of the length of the contract and service from designated units of less than one year

AD for out of period adjustment Use this code for any accounting adjustments or "true ups" for service provided in prior reporting years

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3) Extra-Territorial Generation (ETG)

Many companies presently operate systems that have generation sources located outside their service territory or control area Generation from such extra-territorial sources (ETG) is transmitted to the respective control areas or service territories generally over transmission facilities built by those companies for that express purpose However, even though the transmitting facilities are more than adequately sized to convey the ETG, portions of the power will still utilize facilities of interconnected neighboring companies in the process of serving the ETG owners' native load and therefore represent a parallel flow on those neighboring systems

The GAPP Committee acknowledged in its deliberations the fact that existing ETG installations and their associated transmission facilities were built, justified and accepted as part of the interconnected transmission network and should therefore be exempt from any retroactive application of the GAPP Method's treatment of parallel flows However, the GAPP Committee recommends that the ITCF establish some date as the cutoff beyond which member companies can no longer expect blanket absolution of ETG's they may be constructing or planning to construct (either themselves or through contract with non-utility generators) with regard to application of the GAPP Method

A.3 THRESHOLDS FOR COMPENSATION, CONTROL AND RESERVATIONS

1) Compensation Threshold - 5%

The GAPP Committee considered a range of alternatives from 0% to 20% before arriving at the 5% threshold The attractiveness of using the smallest possible threshold was that all companies whose transmission systems were used would be compensated The arguments against using a very low threshold were the inability to accurately model actual power flows, the increased burdens imposed on the system operators (more complex scheduling and accounting procedures) and potentially higher costs for transmission service Using a threshold as high as 20% would minimize these disadvantages, but in so doing, many companies that would experience significant parallel flows would not be compensated

The GAPP Committee compromised on 5% as an arbitrary balance among the various interests The Committee anticipated that should a transmitting company be disadvantaged significantly by a non-compensated parallel flow (or aggregation of flows), a concept such as the pain pool (discussed further in Appendix B 3) might provide a method of addressing the need for relief

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2) Control Threshold - 20%

The GAPP Committee considered a range of alternatives up to 50% as the threshold above which companies could exert control over transactions before eventually agreeing on 20% It was felt that too high a number would compromise the reliability of the bulk power network by preventing companies with substantial power flows through their systems from exercising some control over transactions that impose significant amounts of parallel flow A high threshold value for control over individual transactions could lead to repetitive declarations of emergency conditions by capacity constrained companies as the non-capacity constrained, controlling companies loaded their schedules

Conversely, the GAPP Committee felt that using a low control threshold would result in localized area problems impacting the operation of the interconnected network to an undesirable extent, that it would de-emphasize the need to add facilities to reduce local transmission bottlenecks, that it would grant a larger measure of control than necessary to achieve the required relief, and that it would be operationally complex

The GAPP Committee emphasizes that the amount of control afforded to companies carrying 20% or more of any transaction by the GAPP Method is not complete For a 25% path, for example, a company can have a transaction reduced by up to 25%, but 25% of the remaining portion of said transaction will still flow through that company which, having requested a reduction, has no more control In this example, the company would still have 25% of 75% of the original transaction flowing through it as a parallel flow To provide more control (say 100%) to companies providing a 20% path would have resulted in companies on relatively minor parallel paths having a "veto" over some transactions, a situation which the GAPP Committee agreed would be intolerable

Again, the 20% control threshold and the control procedures were compromises that the GAPP Committee feels best balances the above mentioned advantages and disadvantages

3) Transaction Reservations Threshold - 50%

In accepting the need to change from a single contract path scheduling of power transactions to the GAPP Method of multiple path scheduling, the GAPP Committee recognized that it would be unwieldy to give all participants in the multiple paths the same authority to sanction transmission transactions now accorded single path participants

A relatively high reservation threshold, while possibly more restrictive than the current contract path method, is necessary for reliable and secure operation of the bulk power system The GAPP Committee felt that too low a reservation control threshold (say 25%) would result

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in transactions being implemented that would not adequately consider the reliability of the interconnected network or the usage of and economic impact on the companies that transmit most of the transaction In effect, this would allow minor participants to a transaction to superimpose additional flow on major participants that could already be over-burdened with power flows

The GAPP Committee felt that too high a reservation threshold (say 80%) would effectively act as an unnecessary barrier to power transactions The higher the threshold, the larger the potential number of transmitting companies whose agreement must be gained before a transaction can take place

The GAPP Committee agreed on a reservation threshold of 50% as a reasonable compromise

A.4 CONTROL

The GAPP Method permits each company to consider a hierarchical method of allocating transmission service to its customers Customers in a post-GAPP era include those garnered by direct contract and those provided service as a result of the application of the GAPP Method to what would have previously been parallel flows In the event of transmission-limiting constraints on its system not manageable through its own actions, each transmitting company will reference its transmission service hierarchy (if any) to determine the amount of relief it will seek from each of its transmission service customers This relief will be manifest as curtailment of some or all of the overall scheduled flow between the generator(s) and ultimate buyer(s) Again, as indicated in Appendix A 3 [2], the control over parallel flows is not complete

It follows from the discussion of thresholds in Appendix A 3 that the hurt imposed by a company's call for curtailment of transmission activity over its system likely will be spread over several individual power transactions since the GAPP Method does not permit one company to completely curtail any one transaction of another company Two adverse consequences potentially arise from this treatment First, additional power transactions may be imposed on an already "tight capacity" transmitting company which then might be forced to reach near-emergency conditions before it can legitimately stop accepting new power transactions Second, new customers of transmission service may begin to request the lowest cost transmission service available from transmitting companies because there may not be much segregation of firmness among service classifications The latter consequence may cause providers of transmission service to react with nearly equivalent cost quotes for different classes of priority service, all at the highest justifiable cost

Providing some measure of control over transactions to companies above the 20% threshold effectively limits the exposure such transactions have to "nuisance" control A transmitting company

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carrying less than 20% of such overall transaction does not, in the GAPP Method, determine how or when such power should flow, although it receives compensation for its supporting role

The GAPP Committee believes that the benefits of limiting "nuisance" control outweigh the potential disadvantageous consequences discussed above However, much depends on (among other things) the presumed level of requested transmission service in the future, the potential for significant, timely capacity enhancing additions to the transmission network, the evolution of dominant geographic power flow patterns, and the rates which companies are authorized to charge for transmission service

It is this last area, compensation, which may hold the key to the benefits of the GAPP Method without incurring many of the offsetting drawbacks This is discussed further in Appendix B 2

A.5 NEED FOR TRADEOFFS AND COMPROMISES

As indicated earlier in this discussion paper, problems associated with a mismatch between the contract path and actual path(s) for transmission of electricity have existed ever since electrical systems were interconnected Clearly, the solution is not easy, or it would have been found and implemented long ago

Each company has a unique set of circumstances Each has generally built its system and installed facilities over time to meet its obligations in its own optimal manner and has done so in light of numerous considerations Each has interconnected with neighboring companies and arranged transactions with them to take advantage of the increased reliability and economic opportunities that such interconnections permit

The GAPP Committee is now proposing that the "rules" that have governed bulk power transactions be changed significantly

Given the unique circumstances of individual companies, each will be affected in a different way by implementation of the GAPP Method The GAPP Committee expects that some companies will achieve a net economic benefit from the GAPP Method in the short term, some will be indifferent, and some will incur net costs Those companies whose costs increase more than their revenues as a result of implementation of the GAPP Method will naturally want to make changes to some aspects of the GAPP Method so that they, too, can come out as a "winner "

The GAPP Committee cautions against the natural propensity of companies to advocate changing only one or two elements of the GAPP Method as presented in this discussion paper in an attempt to modify its economic impact on them The GAPP Method is a package that embodies dozens of tradeoffs and compromises on numerous issues that were made over more than a year of intensive discussions If one company insists on specific changes, then others will probably do likewise, since GAPP Committee members have evaluated the pros and cons of the package as a whole The balance of advantages and

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disadvantages afforded by the package cannot be subject to one company's fine-tuning without similar opportunity being offered to all other GAPP members

- The GAPP Committee believes that the GAPP Method contained in this discussion paper represents the best overall compromise that could be reached on all of the various issues

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APPENDIX B – ISSUES REQUIRING RESOLUTION

B.1 POOLS AND INDIVIDUAL COMPANIES

Members of power pools [notably American Electric Power System (AEP), Allegheny Power System (APS), Michigan Electric Coordinating System (MECS), New England Power Pool (NEPOOL), New York Power Pool (NYPP) and the Pennsylvania-New Jersey-Maryland Interconnection (PJM) who operate as single control areas] will be required to make an election as to how they intend to participate in GAPP collectively as pools or individually as independent companies The following are issues that might be considered in making this election

1 Thresholds

If pool members elect to participate as individual companies, many transactions may fall below the compensation (5%) and control (20%) thresholds

2 Transmission Tariffs

All GAPP participants will be required to have approved tariffs available for all transactions subject to the GAPP Method In some cases (both individual company and pool), these tariffs do not currently exist

3 Scheduling and Control

Scheduling and control will be more complex in pools that elect to participate as individual companies

4 Intra-Pool Operations (regarding GAPP Method)

If pool members elect to participate as individual companies, intra-pool transactions between pool members may require compensation to other companies outside the pool which experience parallel flows as a result of these transactions In effect, for GAPP purposes, the pool would no longer exist Conversely, although not specifically covered in Sections 4 and 5, transactions among pool members were acknowledged during GAPP Committee discussions as being exempt from the GAPP Method if the members elect to participate as a pool In effect, the pool becomes a company for GAPP purposes and the pool member companies lose their separate identities under the GAPP Method Regardless of how pools elect to participate, they will need to decide how the GAPP Method will affect transactions involving only pool members

B.2 NEED FOR APPROVED TRANSMISSION TARIFFS

Compensation under the GAPP Method will be the product of use of transmission as per the transaction matrix and rates approved by a regulatory body The GAPP Committee has concluded that

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rate design is a matter that should be left to individual participants Two factors that will influence rate design, however, bear discussion

1 "Postage Stamp" vs. "Distance-Related" Charges

The term "Postage Stamp" means one charge for a power transaction flowing through a transmitting company, regardless of source, destination and distance The term "Distance-Related" commonly means a charge per MW-mile of usage which is multiplied by the calculated MW-miles associated with a transaction flowing through a system The total charge is dependent on source, destination and distance

Postage stamp adherents point out that these charges recognize that a company's entire transmission system contributes to any individual transaction and that retail customers are charged on a postage stamp basis MW-Mile adherents point out that these charges more properly reflect cost causation and that they more appropriately mirror the nature of interregional transactions It is possible that FERC will be asked to review rates of both types or combinations thereof for use in the implementation of the GAPP Method

2 Compensation for Costs Incurred in Reducing Transmission System Constraints

When the GAPP Method is implemented, participants may be required to commit non-optimal cost sources of generation (operate off-cost) to respond to the effects of transactions below the 20% threshold They might also voluntarily operate off-cost to avoid imposing schedule reductions on transactions over which they can exert control in accordance with the 20% threshold Said participants would in effect judge which action would be less harmful economically -- operation off-cost or diminished revenue from curtailed transactions Recent FERC rulings seem to suggest that transmitting companies may be entitled to compensation for the increased costs incurred due to off-cost generation All of the above references to off-cost operation make this issue important in considering the proper treatment of constrained transmission interfaces

One alternative is to view the constraint as immutable, assign priorities to transactions and reduce the volume of transactions according to these priorities until the constraint is complied with

Another alternative is to relieve the constraint either by providing incentives to voluntarily curtail transactions (the volunteer recovers as his incentive the foregone benefit of his voluntarily curtailed transaction) and/or by running off-cost generation and being able to recover these costs This alternative views constraints as being changeable at some cost Taking actions to relieve

the constraints, rather than viewing the constraints as immutable, increases both the administrative and operational complexity of the transmission system and may also increase the cost of transmission services for some companies However, it provides all companies with additional choices regarding their transactions and it may increase the flexibility and efficiency of the transmission system

B.3 PAIN POOL

A company having a transaction matrix distribution factor lower than 5% applicable to any particular power transaction will not participate in the scheduling or revenue apportionment of the GAPP Method for that transaction But, that same company may very well experience significant operating cost impacts on its system as a result of either the parallel flow caused by that solitary transaction or perhaps the aggregate effects of a combination of many such "less than 5%" parallel flows Also, some companies may be aggrieved by parallel flows associated with scheduled power transactions such that they suffer monetarily beyond the amount of any compensation from application of the GAPP Method

The GAPP Committee considered creating an escrow account of funds - the "pain pool" - to be funded by contributions provided arbitrarily as a nominal levy on the revenue from all participants' transmission transactions A company aggrieved by the 5% threshold, or incurring other uncompensated extraordinary costs could then apply to a panel of its peers for compensation from the pain pool Any resulting disbursement of pain pool funds would be specific to the time period of "pain" claimed by the company and must be justifiable If the company is to be subjected to repetitive levels of "painful", uncompensated parallel flow, it would need to repetitively apply to the pain pool fund for redress

Those administering the pain pool would have to weigh the merits of each case, and take into consideration the fact that some parallel flows are the inevitable result of being interconnected, and that all companies accept some responsibility to bear some costs in order to gain the benefits of being interconnected

B.4 ACCEPTANCE

Issues of acceptance are raised by the GAPP Method with respect to three different groups GAPP participants, companies not participating in GAPP, and FERC

The GAPP Committee has made considerable progress, in fact producing what it believes to be an actionable proposal with substantial benefits to the electric industry This progress has been made in part because the GAPP Committee has agreed to defer issues of individual company acceptance until the nature of the entire "package" is known As the implementation phase is entered, the ITCF must consider how the proposal will be acted upon, and individual ITCF members must take a position with regard to

participation and implementation

FERC acceptance of individual rate filings is, of course, necessary In addition, FERC approval for a limited duration experimental implementation of the GAPP Method will be necessary Ultimately, assuming the experiment is successful, FERC approval of permanent arrangements will be required

All companies with a legitimate interest in wholesale power transmission are encouraged to participate in GAPP, regardless of whether they join the ITCF It is recognized that certain transmission owners and transmission-dependent entities (including non-utility generators and transmission-dependent utilities) may decline to become GAPP participants, although non-participants should be encouraged to accept the GAPP Method as a beneficial change to modern bulk power market operations Subject to final FERC (and other necessary regulatory) approval of the GAPP Method, GAPP participants which enter into sales transactions with non-participants will agree to comply with all applicable obligations arising from the GAPP Method as if the transaction had been between GAPP participants In addition, any GAPP participant entering into a sales transaction with a non-participant must comply, to the extent practicable, with any obligations (such as notification and compensation to third parties affected by parallel flows) to which the non-participant would have been subject if it were a GAPP participant Finally, no GAPP participant may refuse to transmit power on the ground that one or more of the participants to a given sales transaction is not a GAPP participant

APPENDIX C – OTHER SYSTEMS' EFFORTS TO ADDRESS PARALLEL FLOWS

A number of companies in the North American Electric Reliability Council (NERC) have addressed or are addressing various parallel path compensation and control provisions The following examples illustrate those efforts, summarized by NERC Reliability Council

C.1 MID-CONTINENT AREA POWER POOL (MAPP)

MAPP has developed an operating procedure to identify and relieve critical loading conditions of transmission facilities Their procedure depends on the use of transfer distribution factors and line outage distribution factors

When a transmission loading problem occurs, the MAPP center broadcasts power transaction schedule revisions necessary to relieve the problem and requests that those revisions be made effective if and when the monitoring participant requests relief Schedule revisions include only those which have a significant effect on loading (usually > 5%) and transactions are prioritized for schedule revisions Judgment is used to determine "significant "

MAPP has also investigated the use of a MW-Mile approach for transmission use compensation

C.2 MID-AMERICA INTERCONNECTED NETWORK (MAIN)

MAIN has established an operating guide which contains a procedure for monitoring loading on critical transmission elements and relieving overloads on such elements This operating guide calls for monitoring transactions daily and sometimes hourly, actively looking for problems This guide may be implemented prior to a problem occurring, not only after a problem occurs Power Transfer Distribution Factors (PTDFs), Line Outage Distribution Factors (LODFs) and power flows are used

When an actual or potential transmission loading problem occurs, the MAIN Coordination Center (MCC) determines which schedules significantly affect the loading on the critical element The intent and application of this operating guide is to be flexible and allow engineering judgment to prevail depending on the level of a PTDF and a scheduled transaction In practice, MAIN will not be limited to a specific minimum PTDF

C.3 ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)

The Texas PUC adopted a methodology to compensate transmission owners for parallel flows but not control them The Texas utility companies could not agree on a compensation

method and yielded decision to the PUC which considered Contract Path, Boundary Flow ("postage-stamp") and Line-by-Line (MW-Mile) compensation methods The PUC rule allows utilities to use a different method of compensation if all agree

For IPP's, the method is a combination of Contract Path and Line-by-Line (MW-Mile) IPP's choose the contract path and pay a contract path charge to the utility(ies) necessary to complete a physical transmission connection Non-contract path utilities charge IPPs for parallel flows based on a positive-only MW-Mile method

For transactions between utilities, transmission service is based on the positive-only MW-Mile method

C.4 WESTERN SYSTEMS COORDINATING COUNCIL (WSCC)

WSCC developed a set of parallel flow operating and compensation procedures which were implemented on a one year trial basis Participation in this trial was voluntary Participants were expected to accommodate parallel flows of up to 10% of their transfer limit without compensation

To receive compensation, energy schedules on a path either had to have been curtailed because of parallel flow for at least 100 hours, or the sum of the energy schedules curtailed due to parallel flow for less than 100 hours had to exceed the transfer path capability multiplied by a factor of three. Compensation was based on the costs incurred, or revenues foregone, as a result of curtailing schedules because of parallel flow Compensation was determined after the fact based on incremental and WSCC base case scheduling studies

After the one year trial, there was not sufficient interest on the part of WSCC members to implement compensating procedures on a permanent basis Although operating procedures are in place to curtail schedules when loop flows become excessive, a series of phase angle regulators were installed along the northern border of Arizona and New Mexico to provide for additional loop flow control

APPENDIX D – DEFINITIONS

Bulk Power Supply - The aggregate of electric generating plants, transmission lines, and related equipment The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission lines are interconnected

Contract Path - A scheduling arrangement for power transactions between two companies which may involve companies providing transmission service to transport the power The arrangement is supported by contracts and interconnections between, in many cases, adjacent participants

Control - The ability of a company to reduce or terminate interchange schedules which have an adverse effect on that company or on that company's transmission system

Control Area - A system (which may comprise one company or multiple companies) capable of regulating its generation in order to maintain its power interchange schedule with other systems and contribute its share of automatic network frequency restoration in response to network disturbances

Distribution Factors - A mathematical representation of the power flow through each of the companies comprising the interconnected transmission network as a result of a transaction between two companies or similar transmission of power from a generation source remote from its load

Economy Transactions - Sale by one company of lower cost power to permit another company to reduce higher cost generation, often priced to split the difference in generating cost and usually cancellable on short notice

Generation Shift - Increasing the output from one or more generating units while simultaneously decreasing the output from others in order to alleviate problems on the transmission system, most always to the detriment of economic operation

Grandfather - A power transaction which is excluded from application of the GAPP Method for a period of time to be determined

IDEC - Acronym for Interutility Data Exchange Consortium, a group of companies working to establish a dedicated communication network to share power system operating data

Interconnection Agreement - A document usually filed with the appropriate regulatory authorities which describes the facilities, understanding and compensation arrangements agreed by two or more companies for the transfer of power between them

Load Flow - A computer model of power systems used to represent power flows

ORNS - Acronym for Operating Representatives of the Northeast Systems, a voluntary organization which meets to discuss mutual concerns associated with power system operations

Parallel Flows - That portion of scheduled power transactions between two companies which actually flows over transmission lines owned by companies who are not a contractural party to those transactions Also called loop flows or circulating flows

Reliability Constraint (limit) - A level of power transfer which, if exceeded, would result in violation of an established maximum physical capability or contingency criterion

Reliability - The degree to which the performance of the elements of the bulk electric system results in electricity being delivered to customers within accepted standards and in the amount desired The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply (or service to customers)

Scheduling/Schedule - An agreement between the system operators of two companies, which are either directly interconnected or have arranged for appropriate transmission services, for one to over-generate and the other to under-generate in equal amounts and simultaneously for the purpose of transmitting power from one company to the other

Transfer Capability - The normal maximum amount of power that can be transmitted across an interface between companies, power pools or other entities, calculated in accordance with industry-accepted reliability principles

Transmission Tariff - A document including, among other things, a published schedule of pricing, approved by the responsible regulatory agency, covering transmission services

Wheeling - A term commonly used to describe the provision of transmission services

Power Pool - Two or more companies operating together in an integrated manner to achieve certain mutual benefits

APPENDIX E -- GAPP COMMITTEE

A R Garfield, Chairman	Ohio Edison System
D C Benson	Allegheny Power System
M Blake	Louisville Gas & Electric Company
F A Cassidy	Public Service Electric & Gas Company
C A Falcone	American Electric Power Service Corporation
T E Falk	Ontario Hydro
D Huff	Ohio Edison System
R A Irvin	Duquesne Light Company
G Jorgensen	Northeast Utilities Company
J Koehler	New York Power Pool
T J Kraynak	Centerior Energy Corporation
R McEacharn	New England Power Exchange
J McMahon	Detroit Edison Company
A F Mistr	Virginia Power
G E Timmons	Potomac Electric Power Company
T R Woodward	Pennsylvania-New Jersey-Maryland Interconnection

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THEORETICAL ASPECTS OF INTERUTILITY ELECTRICITY PRICING

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Abstract This paper is an explanation of theoretical aspects of interutility electricity pricing Various economic approaches to the pricing problem are described Their advantages and disadvantages are contrasted A procedure for developing interutility prices in developing countries is presented

INTRODUCTION: WHY SHOULD YOU READ THIS PAPER?

This paper will help you to understand the economic issues hidden in the pricing problem -- some of which are not obvious and not simple

Why do you care? Because bad prices can make it hard to operate an interconnected electric system Bad prices can cause inefficiencies in the operation of the system Bad prices can create distrust and prevent cooperation among professional and well-meaning electric utility managers and engineers Bad prices can reduce the reliability of all of the interconnected utilities in a region

This paper makes two contributions First, it is a simplified and illustrated explanation of an excellent but advanced and hard-to-read World Bank report on pricing [1] Second, it outlines a procedure for developing reasonable interutility prices, geared to international cooperation in developing countries

A word of background the electric utility industry was created as an "obvious" natural monopoly that could provide a wonderful new service plus make money for its owners It is a unique industry, and its success is based on a regulatory compact or agreement whose details differ from country to country, but whose basic elements are common

- The electric utility is protected against competition.
- It has the right to set commercial and technical terms and conditions for rendering service
- It has an obligation to serve without unreasonable discrimination.
- It can charge fair prices for its service but cannot exploit its monopoly position to charge extreme rates

Governments have intervened in a variety of ways to enforce this compact. In some countries, electricity is supplied by a government-owned utility that does not have profit incentive Others have varying degrees of independence and private sector ownership, but with government oversight.

There are two problems with this regulatory compact. First, it is being challenged and modified in many parts of the world, but this is irrelevant for this paper Second, and central to this paper, it evolved to define the relationship between the utility and its retail customers It does not apply to interutility or international energy interchanges And part of the difficulty in international energy interchanges is that we often think of them as though they were simply an extension of the supply of electricity to internal customers,

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which they are not. the circumstances and issues are different.

PRICING THEORIES. A SUMMARY

The following theories are discussed in [1], for normal tariffs or pricing in a competitive market inside a given country In the next section, we will talk about what they have to do with international and interutility pricing

Average-cost Pricing

This is the traditional basis for utility tariffs all of the costs incurred by the utility are added up, including, for privatized utilities, a reasonable profit for the shareholders These costs are then allocated among all kWh the utility sells and are billed to its customers This allocation is not a simple averaging Not everyone pays the same price for a kWh, for two reasons

- Classes of customers who are more expensive to serve may pay more
- By government policy, tariffs may be used to subsidize some customers

In some countries, the tariffs are deliberately set too low to recover all of the utility's costs, the government makes up the difference

Advantage: in keeping with the regulatory compact, the utility recovers its costs (including modest profit), no more, no less This takes away a big uncertainty that most businesses have to face will I make money? Without this uncertainty, planning is simplified Investors, confident that they will be repaid, are willing to provide capital at low interest and return rates

Disadvantages: tariffs may be too low Suppose a utility generates all of its electricity from old and inexpensive hydro plants at an average cost of 2 cents/kWh This low price may attract a chemical plant that requires a lot of power But to supply the chemical plant, the utility may have to build a new oil-fired station, with a bus-bar cost of 10 cents/kWh. If these costs are averaged in with the existing hydro costs, the cost of electricity might rise to, say, 2 1 cents/kWh. The chemical plant, which forced the utility to produce power at 10 cents/kWh, will pay only 2 1 cents/kWh for it.

Too-low tariffs may cause inefficient decisions Suppose the chemical plant could install a generator to make its own electricity, in part from by-product heat, at a cost of 5 cents/kWh. It would be cheaper for society as a whole for the chemical plant to spend 5 cents/kWh instead of for the utility to spent 10 cents/kWh But average cost pricing does not encourage this

In addition, average-cost pricing does not give the utility a direct incentive to reduce costs, since whatever the costs are, it recovers them In fact, a privatized utility may have the incentive to over-invest or gold-plate, since its profits are proportional to its investment.

Marginal-cost Pricing

In marginal-cost pricing, everybody's price for every kWh he uses is based on the cost to the utility of producing the last kWh, which is presumably the most expensive one See Fig 1 This is fair because everyone could have saved the utility that cost by reducing his demand by one kWh.

Marginal costs come in two flavors short-run and long-run The short-run marginal cost of power is the additional cost incurred if a small amount more (say a kWh) is produced, assuming that no new investments are made That is, short-run marginal costs include operating costs only Long-run marginal costs include the additional investments needed to supply a small increment of power "Marginal-cost pricing" usually means "short-run marginal-cost pricing "

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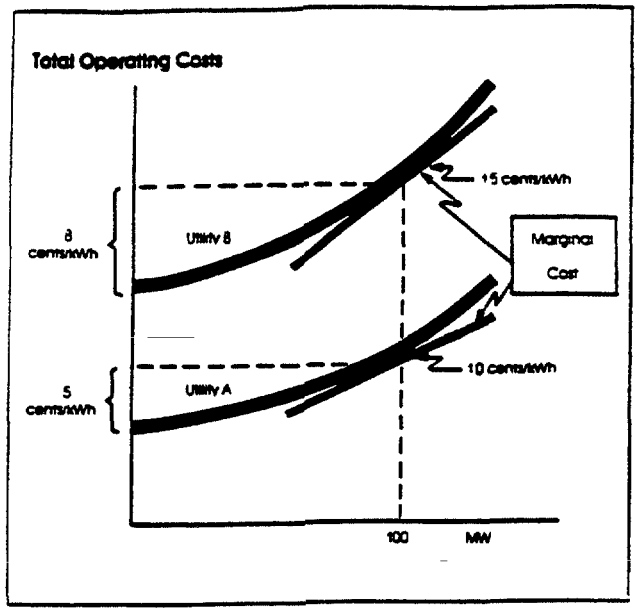

Figure 1 Marginal costs and changes in total operating costs are shown for two hypothetical utilities

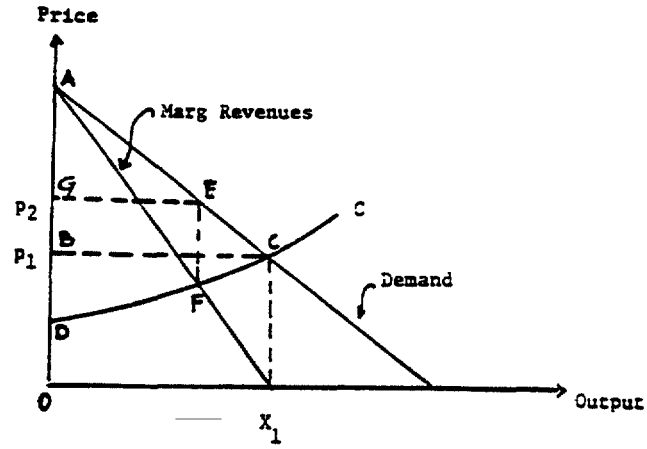

Figure 2 Demand and Supply Equilibrium Under Marginal Cost-Pricing

<u>Advantage:</u> economists love marginal-cost pricing With certain assumptions, it can be shown that if everything is priced on the basis of marginal costs, and if all decisions are made on the basis of prices, then the economy operates at minimum cost (maximum efficiency) See Fig 2

Fig 2 shows the consumer's demand curve and the utility's marginal cost curve The consumer's demand drops when price goes up, the utility's marginal cost increases as more expensive generation is used to meet higher demands At price P_1, the utility's operating profit is area BCD, and the consumer surplus is area ABC The consumer surplus is the maximum additional amount the consumers would have been willing to pay for the same power, under the most cleverly designed rate structure that exactly tracked the demand curve

At price P_2, the utility's operating profit is DGEF (which may be greater than ABC) But the consumer surplus is only AGE And the sum of DGEF and AGE is less than the sum of ABC and BCD That is, the aggregate benefit to society is reduced if electricity is priced above marginal cost. A similar argument shows that the aggregate benefit to society is also reduced if electricity is priced below marginal cost.

<u>Disadvantages:</u> tariffs based on marginal costs do not necessarily recover all costs (including profits) of a utility They may under-recover, in which case the utility loses money They may also over-recover See Table 1 and Fig 3

There are also theoretical problems with marginal cost pricing The assumptions referred to are crucial and are never met in real life This means that even if a utility's tariffs reflect marginal costs, the result may be a "second-best" situation that is not, in fact, optimal.

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Table 1

Transactions involving two different utilities

	Utility A	Utility B
Tariff (marginal cost)	10 cents/kWh	15 cents/kWh
Less		
Total change in utility's operating costs	5 cents/kWh	8 cents/kWh
Change in net operating income to utility	5 cents/kWH	7 cents/kWh
Less		
Fixed capital costs	8 cents/kWh	5 cents/kWh
Change in total utility revenues	-3 cents/kWh	2 cents/kWh

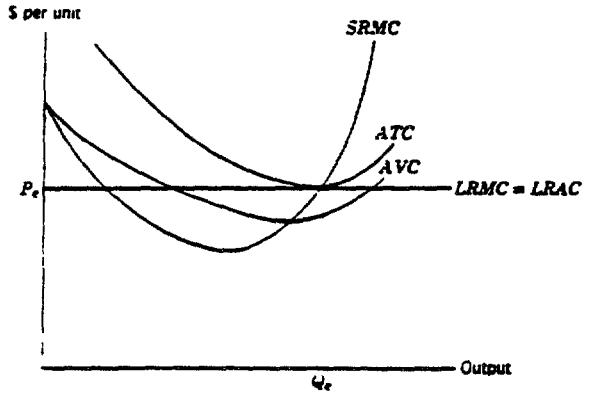

Figure 3 The unit costs of the firm under long-run constant returns (Source [2])

Ramsey Pricing

Here prices are set to minimize the sum of producers' and consumers' costs, subject to the constraint that the utility recovers all of its costs This constraint is absent in marginal cost pricing, so the Ramsey prices usually will not be the same as short-run marginal costs

How do they differ? Without going through the mathematics, Ramsey prices are higher for a customer whose demand is relatively "inelastic" and lower for one whose demand is relatively "elastic " A customer's demand is inelastic if he uses the same amount of electricity, no matter how much it costs It is elastic if he reduces consumption if the price is higher

Advantage: this method protects the utility against losing money (which no one wants it to do) while attempting to minimize the total costs of producer and consumers

Disadvantages: in order to apply Ramsey pricing, it is necessary to know the elasticity of demand of the customers This is generally not known.

Furthermore, Ramsey pricing does not work in a competitive market. The cross-subsidies (inelastic consumers paying more so that elastic ones can pay less) can make the utility vulnerable to inefficient competition. An inelastic customer, seeing high utility tariffs, would be tempted to switch to a lower-priced competitor, even if this increased the total costs of the system

Finally, since the utility gets to recover all of its costs, it does not have a built-in incentive to operate efficiently

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Sustainable Prices
As the theoretical pattern evolves, where there is a problem, another theory is developed to solve it. But mother nature is not necessarily cooperative, as the "fix" may have new problems of its own.

A "fix" to one of the problems of Ramsey pricing is called sustainable pricing Sustainable prices recover all costs, satisfy customers, and encourage efficiency, but eliminate cross-subsidies

Advantages: the utility's position in the market is sustained against entry by competitors who would be motivated by features of the otherwise-optimal Ramsey tariffs

Disadvantages: a sustainable price may not exist.

Furthermore, if it does exist and if it is different from the Ramsey price, then it must be less optimal than the Ramsey price This means that the consumers pay more in the aggregate in order to protect the utility's monopoly position. Someone needs to evaluate the trade offs between efficiency and the virtues of sustainable prices

Axiomatic Pricing
This approach begins with a set of objectives or criteria, based on cost accounting Depending on the objectives, axiomatic pricing may be equivalent to average-cost pricing or to time-of-use pricing, with the advantages and disadvantages of these methods

Price Capping
As noted, average-cost pricing, Ramsey pricing, sustainable pricing, and axiomatic pricing do not have built-in incentives for a utility to minimize its costs This is because each of these approaches guarantees that the utility will recover all of its costs

Where average-cost pricing is applied, which includes most of the world, the traditional fix for this lack of incentive has been for the government to oversee operation and investment to encourage low-cost operation.

Price capping is an alternative It has a built-in incentive to cut costs the utility can charge whatever it wants for electricity, as long as it does not exceed a price constraint.

Advantages: in addition to encouraging the utility to cut costs, price caps may result in utility pricing that is more efficient than the average-cost pricing now practiced

Disadvantages: finding fair price caps is almost as difficult as setting tariffs using any of the other methods The utility may have the incentive to minimize costs in the short term, at the expense of raising them in the long term or reducing the quality of service E g, maintenance may be postponed, saving money this year, but with reliability and cost exposure in the future

Priority Service Pricing
We usually think of electricity as a product with only one or two attributes kWh (energy) and kW (power) But electricity is an energy form with many additional attributes -- especially in interutility and international commerce

One important attribute, even at the retail level, is reliability Priority service pricing seeks to unbundle reliability from energy and power, and sell it separately Gentle Reader may protest that utilities have been doing this for many years by offering interruptible tariffs to industrial customers But priority service pricing seeks to expand the approach and to offer it to other classes of customers They would be allowed to select their reliability level, with higher reliability costing more than lower reliability There are many approaches, whose details vary

Advantages: this takes the guess-work out of determining how much reliability is needed and reduces the likelihood of utility over-investing Cross-subsidies are reduced because customers

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needing lower reliability do not have to pay for the high reliability others need

In industrialized countries with high rates of electrification, most customer outages are caused by distribution problems (e g , tree limbs falling on a feeder) Generation reserve levels would have to drop considerably before a retail customer would see his reliability change very much. But in developing countries, where generating capacity is more limiting, the effects would be immediate and obvious

Disadvantages: quite an investment in communication and control equipment would be needed if individual customers were allowed to select their reliability levels If the reliability was set area by area, then this equipment would be simpler and less extensive

Pilot studies have revealed that, unless such programs are carefully designed, they can fail in several ways

- People may decline to accept anything but premium reliability
- Free-loaders may contract for reduced reliability, while because of their load pattern (e g , if they have day-time valleys and night-time peaks) they are unlikely to see physical effects
- The incentives may be more expensive than the savings

Two-part and Non-linear Tariffs
A variety of other tariff approaches include such features as

- Separate demand and energy charges
- Time-of-use charges
- Discounts for high usage

All of these are designed to shape demand in one way or another, to encourage consumers to use electricity in such a way as to reduce the utility's costs They also are designed to shift costs to the type of usage responsible for incurring the costs

INTERNAL TARIFFS AND THE INTERUTILITY MARKET

Conclusions: Internal Tariffs
Today, the most-discussed of the methods above is marginal-cost pricing, because of its appealing theoretical efficiency But "worshipping the principle of [marginal-cost] pricing may do a disservice to economic efficiency pricing has to be relieved of sacrosanct efficiency objectives and should come to grips with more mundane and immediate commercial ends

"Generally speaking, responsive pricing or 'profane yet intelligent pricing' tends to rate better than strict or routine use of inflexible or unwieldy formulas that serve elusive efficiency goals or rest on ill-conceived arguments

"Finally, from a regulatory viewpoint, guidance, supervision, well-defined rules of the game, and arm's-length obligations (which should not be confused with armchair regulation) make more sense than putting the utility into the straitjacket of a particular pricing policy " [1]

In other words, there is no perfect pricing theory Regulation is still needed and cannot be replaced by a pricing algorithm (See [3], where this point is made again in a different context examining restructuring and competition in the electric power sector) Reasonable tariffs based on practical objectives will work better than theoretically-optimal prices based on idealized assumptions

The Interutility Market
The pricing approaches discussed mainly were for sales by a utility to its retail customers The market consists of a single monopoly seller and a large number of buyers

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The conference for which this paper was invited is on interutility transactions How does the conventional utility market differ from the interutility market, consisting of a small number of parties, each of whom may be a buyer and seller of electrical services?

The relationship between a utility and its consumers governed by a regulatory compact which does not apply to the relationship among utilities, particularly between utilities in different countries In particular

- In a multi-utility market, there are usually no natural monopolies [One exception. if three utilities, A, B, and C, are interconnected in such a way that power sold by A to C must flow through B, then B has a transmission or wheeling monopoly]
- Utilities do not have an inherent obligation to provide services to each other they do so only to the extent it is mutually beneficial
- Utilities are not necessarily obliged to price on the basis of costs

Because the regulatory compact is not in effect for interutility transactions, there is usually no government agency with the responsibility and authority to see that the regional power sector is optimized and that transactions are fair to all parties, particularly when the utilities are in different countries

In the US, the Federal Energy Regulatory Commission exercises some jurisdiction over interutility transactions, and some (but not all) states require joint planning among utilities within the state But in the US no agency has the responsibility and authority to control interutility operations to the same degree that an individual utility's relationship with its retail customers is regulated

In western Europe, the European Commission is attempting to create a unified electric market, which involves regulating the relationships among companies and, to an extent, within a particular country, but its control and authority are limited

Interutility Products and Services

In the internal market of a utility and its consumers, what is sold is mainly kWh and, to a lesser extent, kW In the interutility market, a much wider range of products and services is of interest These include

- Purchase/sale of kWh,
- Energy storage and borrowing,
- Energy transmission (wheeling),
- Reliability (reserves of various kinds),
- Operational interchanges (e g , to accommodate maintenance schedules or to mitigate environmental problems),
- Reactive support,
- Cooperation in regional projects to achieve economies of scale, etc

Some of these have important time dimensions For example, a kWh purchase for an hour may be motivated by savings in fuel costs, while a five-year purchase may enable a utility to postpone construction of a new unit.

The relationships between cost elements may be very different for these products and services than for internal kW and kWh sales For instance, marginal costs of wheeling are usually very much lower than average costs See [4] for an introduction to some of the specific problems in this area

DEVELOPING INTERUTILITY PRICES

Principles

Development of prices for interutility services should be based on the following principles, which differ dramatically from the utility compact which is the basis of internal tariffs

- There is no supranational regulator with responsibility and authority to maximize social welfare in a region.

- Prices must be negotiated between willing buyers and sellers

- All transactions must be "win-win" perpetually When a transaction benefits one party at the expense of another, the victim will find a way to cancel it. But parties must willingly accept imperfect arrangements that do not yield an exactly equal division of benefits

- Intergovernmental arrangements must allow utilities to honor their commitments, e g , by permitting payments

- Simplicity is important.

Procedure

Agreements based on these principles may be developed in the following steps

- Each utility analyzes its own needs and what it can offer to its neighbors

- Possible trading partners are identified and possible transactions are laid on the table

- Each party quantifies (privately) its transaction costs and benefits that can be measured monetarily The process will be different for different transactions and may draw on the theories developed earlier in this paper, as appropriate For instance, incremental or marginal operating costs make sense for casual short-term interchanges using existing physical plant. Total costs must be analyzed for joint development projects

- Other costs and benefits, not measurable in dollars, should be quantified in natural units, e g , reliability in LOLP

- The transaction should be structured, in price as well as terms and conditions, to maximize the benefit to all parties

- Risks should be analyzed and hedges developed All parties should realize that it is not practical for one of them to lose forever because of adverse outcome of an uncertainty with unequal risk.

- Contracts and treaties are finalized by the lawyers, who come in at the end of the process, not the beginning

These transactions differ from many common commercial transactions Bargaining for a car is a "zero-sum game" every dollar of price reduction goes straight from the seller's pocket to the buyer's, with no overall benefit to the two of them But interutility deals are often not zero-sum games They should benefit all parties

Although objectives often conflict, the nature of the conflicts can be managed. Often, trade-off compromises can be found that look good to all parties. For example, Fig. 4 shows the trade off as perceived by one utility between reliability and cost for a least-cost planning problem that included international energy purchases The maximum reliability solution was very expensive The minimum cost solutions were somewhat unreliable But a solution at the knee of the trade-off curve came close to minimizing both cost and LOLP

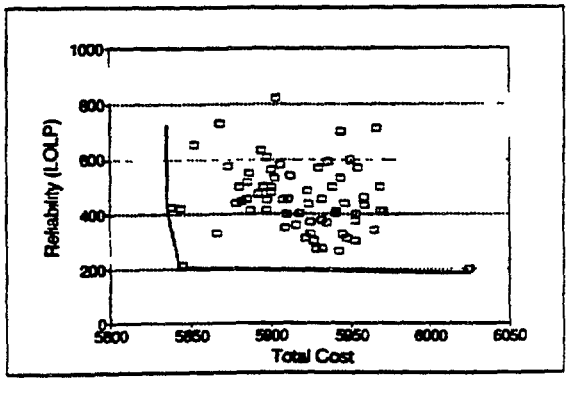

Fig 4 Illustration of trade off between two conflicting objectives Source [5]

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Trade-off analysis also includes very useful methods for measuring risks and developing protection against risk. [6]

Examples

Four examples -- two successful, two unsuccessful -- of interutility transactions will be given to illustrate these ideas

New York Parallel Flows when New York utilities purchased power from Ontario Hydro, perhaps 40% of it flowed east along parallel paths through the Pennsylvania-Jersey-Maryland (PJM) pool This used up network capability that PJM wanted to use to transfer coal-fired energy from western Pennsylvania to New Jersey After long and arduous debates, a creative solution was developed that included payments, installation of phase-shifting transformers, and repayment in kind by New York utilities for transfer capacity through PJM that they previously used

Energy Banking, Panama - Costa Rica: ICE (Costa Rica) and IRHE (Panama) developed a successful arrangement whereby either utility could store energy in the other's system Borrowing energy is allowed, too The agreement provides for losses, handling charges, repayment in cash instead of kWh, scheduling, etc [7]

Payment Problems: in one developing region, utilities want to interchange Though the normal mix of trust and distrust is evident, the main impediment has been governmental it is hard for the utilities to pay each other, because the finance ministries can't or won't release dollars The utilities have not been very successful in finding barter or other tricks to get around this problem

Operating/Reliability Problems: two interconnected utilities, in two countries, have a bit more than the usual level of distrust. Utility A thinks that utility B is operating in a risky way to reduce costs, by relying on A to save it in contingencies A's response has been to open the interconnection at a sign of trouble -- thereby negating the main value of the interconnection, which is to increase reliability

CONCLUSIONS

There are many theories on how sale of electricity to consumers should be priced These were presented in detail in [1] and were summarized above Each has strengths and weaknesses None is perfect, and none is a substitute for some degree of government regulation.

The interutility market, especially when utilities are in different countries, is different in many ways from the internal market -- in particular, both the rules and the products to be sold differ These differences were described in this paper

It is important that these differences be recognized as interutility transactions are looked at. This paper has also described a procedure for developing these transactions Following this procedure will increase the degree of interutility cooperation and will reduce distrust and other impediments to international energy trade

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He has published widely and is a member of several engineering and scientific honorary societies A Fellow of the IEEE, he is executive chairman of the 1995 Power Industry Computer Applications conference

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Restructuring the Electric Power Sector in Colombia

Manual I Dussan, General Coordinator, Commission de Regulation Energie, Ministero de Minas y Energie, Republic of Colombia

A major restructuring of the Colombian electric power sector is being implemented based on the improvement of sector efficiency through the promotion of a competitive energy market and the participation of private investment This short presentation highlights major events and difficulties in the restructuring process

The national interconnected power system has an installed generation capacity of about 10,000 MW, of which 80 percent is hydro and 20 percent is fuel-fired thermal The current generation expansion plan calls for the installation of about 4,000 MW during the next 10 years, of which 60 percent is in thermal plants

The present institutional structure shows 6 major generation companies and about 23 distribution companies, all of them state- owned enterprises (national and municipal governments) There are two vertically integrated municipal companies (generation transmission and distribution), serving 40 percent of demand

The development of the power sector has faced major problems, common to many countries in Latin America, related to centralized planning, poor regulation, pricing distortions, monopoly power over regional markets, and state participation as the major owner of energy enterprises, with a subsequent lack of efficiency incentives, the virtual disappearance of accountability, and deterioration of finances The problems were exacerbated by a prolonged power rationing during 1992 and 1993

Since the early 1990s, the government has been developing a power sector reform strategy based on the following key elements

- Introduction of indicative planning
- Establishment of competitive wholesale market, as a major instrument for improving efficiency
- Creation of independent and transparent regulation of the sector
- Promotion of private sector participation
- Financial rehabilitation of state-owned enterprises

Progress in Implementing Sector Reform

Progress has been made in implementing sector reform The government submitted to Congress two bills related to the electric power sector, which were approved by senate and will be considered by the lower chamber during the first semester of 1994 These bills, among other things

- Enable any private or public agent to develop generation projects
- Separate utility businesses in generation, transmission, distribution, and supply
- Deregulate wholesale prices for transactions between generators and suppliers
- Guarantee free access to transmission and distribution networks by third parties, at regulated use of system charges
- Create a new company responsible for the national transmission grid and dispatch

In late 1992, the government created an Energy Regulatory Commission (ERC), responsible for sector regulation, with the participation of three independent experts and three secretaries of state ERC is developing, with the assistance of international consultants, the key instruments and rules for sector regulation based on the principles outlined above, including the commercial arrangements for the wholesale market, the use of system charges for transmission and distribution, and the regulatory controls In late 1993, ERC issued a directive for the deregulation of prices for sales to industrial consumers with loads above 2 MW, as of April 1994 During 1994, the new rules for sector regulation will be gradually implemented

The government decided to offer to private generators under build/operate/own (BOO) arrangements the development of about 1,200 MW in thermal power plants by year 2000 So far, 250 MW in private projects have been commissioned, and bids for additional 630 MW are underway

The government implemented a major financial restructuring of the power sector During 1991 and 1992, the government contributed about US$1 5 billion to the sector through capitalization and debt swap schemes As a result, about 1,000 MW in generation assets are now in the hands of the government, and the Ministry of Finance has initiated the process to privatize about 700 MW

Difficulties in Achieving Efficiency Improvements

Notwithstanding the progress made, the restructuring program faces some difficulties in achieving efficiency improvements through competition These are cross-subsidies, vertical integration, and government's role

Subsidies Presently the pricing system includes substantial cross-subsidies For example, generators sell energy under contract at about 80 percent of their cost, residential tariffs on average cover 35 percent of the cost of supply, and high-voltage industrial costumers pay on average 135 percent of the cost of supply Obviously, competition and cross-subsidies cannot live together The government is implementing a 4-year tariff adjustment program that will eliminate cross-subsidies Therefore, in the meantime, cross-subsidies are a major constraint to the introduction of a competitive market

Vertical Integration About 40 percent of the market is presently served by municipal companies which provide generation, transmission, and distribution services In order to introduce a competitive market and reduce the regulatory burden, it would be necessary to separate these businesses However, at present, there are no legal instruments to enforce this requirement Therefore, as a last resort, it has been necessary to settle for a separation of accounts

Government Role By law, the government is responsible for ensuring a reliable electricity supply in the country Due to the 1992 power shortages, the government has become risk averse and is taking actions to ensure that new generation is commissioned on time to meet an adequate reliability criteria If the market is not driving the development of new generation, the operation of the wholesale market would be at risk, because the spot prices may collapse under a situation of excess capacity and it would not guarantee enough revenues to generators to pay for expansion costs

In summary the Colombian government is committed to the implementation of an ambitious restructuring program of the power sector to improve efficiency through competition and participation of private capital The program is now entering into a critical phase of introducing new rules and regulations for the operation of the sector, and of overcoming problems inherent of changing the status quo

About the Speaker

Manuel I Dussan was born in Bogota, Colombia in 1944 He obtained a BSEE from the Universidad de los Andes in Bogota in 1966 and an MSEE from Northwestern University in 1968 From 1968 to 1970, he was a member of the faculty of engineering at the Universidad de Los Andes, where he became head of the Electrical Engineering department

In 1970, he joined Interconexion Electrica SA For 10 years he was responsible for operational planning and dispatch of the national interconnected system, and was also responsible for power interchange negotiations

From 1980 to 1992, he was a staff member of both the Interamerican Development Bank and the World Bank, where he was responsible for preparation, appraisal, and supervision of power projects in Latin America, and also acted as a consultant for 4 years

Dussan is currently commissioner and general coordinator of the Energy Regulatory Commission in Colombia

Transformation of the Argentine Wholesale Electricity Market

Luis Maria Caruso, Director, Mercados Energeticos SA, Buenos Aires, Argentina

The electricity industry in Argentina has undertaken a very deep restructuring in recent years, from a 100 percent state owned, integrated activity to a true market of electricity, in which more than seventy free private agents (generators transmission companies, distribution companies, and big customers) operate in a framework of rules completely different from those in force at the beginning of the transformation

Today, almost 3 years later, an observer can notice a number of changes already in place As a consequence there is an increased interest from companies and government as well, in old and new issues such as electrical markets integration, or global business

The purpose of this presentation is to examine this emergent market, its rules, and its players, and to assess which of the patterns associated with the integration of business markets, and culture are for the benefit of final users

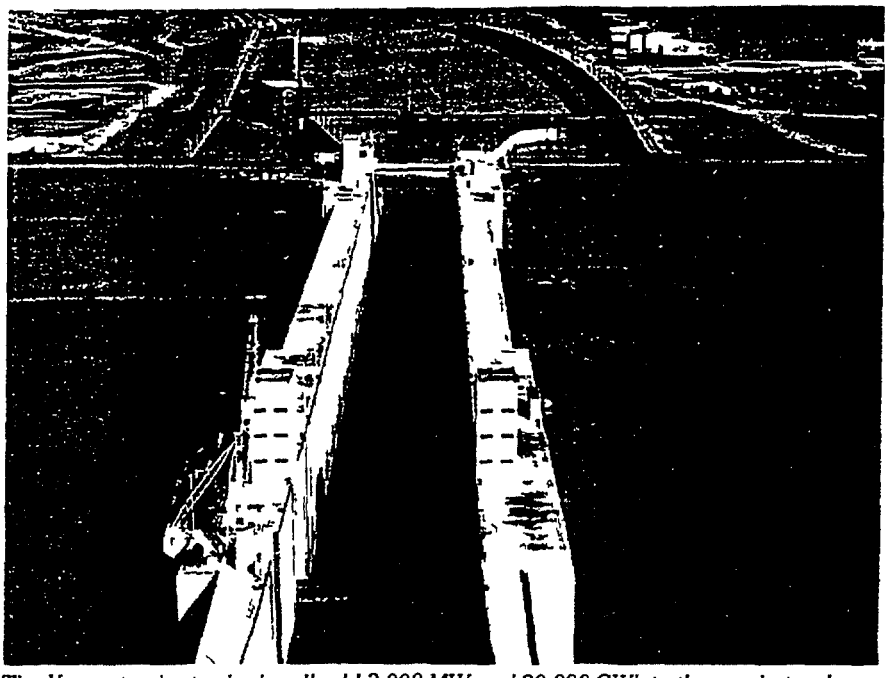
Beginning the Transformation

At the time of the electrical industry restructuring, Argentina had a very extensive 500 kV transmission grid covering most of the domestic territory and providing for 90 percent of the wholesale trading of electricity The grid, 90 percent of the generation installed capacity, and 50 percent of the distribution business was in the hands of three federal government owned integrated companies (Segba Hidronor and

Agua y Energia) while the rest of the industry was in the hands of 18 provincial governments

Since Argentina is embedded in a geographical area (the southern cone of South America) and is involved in an ambitious plan of economic integration called the southern common market (Mercosul) Argentina enjoys very strong commercial links with the six countries in the southern cone In the electric power sector the different countries have always had a long tradition of integration as demonstrated by big enterprises such as the hydroelectric power plants of Salto Grande Itaipu and Yacyreta are binational efforts As a federal country Argentina faces in this field as well as in many others the challenge of integration

There was therefore a specific goal when writing down the new rules Argentina wanted to encourage and facilitate a smooth and easy integration among the different electric power markets inside the country borderlines and as well as among the national markets of the southern end of the continent



The World Bank

The Yacyreta plant which will add 3 000 MW and 20 000 GWh to the market is being commissioned by a binational company

Transformation

The objective of the government when initiating this transformation was to set the basis for a new strong electric power industry and in doing so introduce a new culture (not only managerial but also technical) capable of supplying the necessary power at prices compatible with the economic cost of maintaining and expanding the power systems

The framework for this transformation a substantial change in the role of the government regarding industrial activities and utilities resulted in clearly separating administrative functions from regulatory ones

The means chosen to achieve this transformation in the shortest time were

- Clear segregation between functions subject to market conditions and those activities demanding regulation
- Establishment of a market price system as a set of consistent signals to encourage efficiency quality and security
- Reorganization of the preexistent vertically integrated state-owned companies creating a number of new specialized privatized ones
- Implementation of concession agreements for activities demanding regulation (distribution bulk transmission and hydroelectric generation) as a complement to the pricing system
- Creation of new institutions as required by the transformation model the Wholesale Electric Market Administration Company and the National Regulatory Agency
- Privatization of the newly created business units within the framework of the new rules

The Argentine electricity industry transformation was not merely a privatization On the contrary before privatizing there was a great deal of work and effort invested in restructuring the preexistent companies and in engineering the appropriate regulation

Most of this transformation has been successfully performed and it is possible to make some assessments about the main issues of this success

- Clear ideas and a good execution plan
- Strong executive team plus good experienced consultants
- Full political support along the whole process
- Trade unions that understood and participated in the transformation
- Decrease of country risk and increase in international banking confidence

Creating Competition

The new industry has been organized to encourage competition where possible and to introduce regulations where there is no chance to get competition or where the latter should still be developed

A competitive system in which producers are forced to resign a piece of their desired profit as a condition to having access to a fraction of the market means reduced costs for industrial and residential users provided that the new rules enable the transfer of reduced costs to customers

The rules put into practice in the Argentine market to encourage competition were the following

- Ownership in the generation activity was segmented limiting the cap participation in this industrial segment to a 15 percent of the capacity to be privatized by the federal government This policy gave way to more than 20 independent power producers born from the preexistent government owned monopoly
- A system of pricing signals based on the practice and procedures of centralized operation and economic dispatch During actual operation the available units are requested to generate following a priority list based on increasing variable costs until the demand is fulfilled The marginal cost of the last unit accepted by the demand represents the price that purchasers are ready to pay at a given time In this way cheaper units always displace expensive ones from the market, driving agents towards efficiency in operation and investment

In the Argentine electricity market there is a reference price (the Market Price) that reflects the present short run marginal cost of the system in each hour In the absence of contracts agreed to by parties every transaction is performed at that price The Market Price comes from the centralized operation activity there is no bidding process involved

Key Elements in the Organization of the Argentine Wholesale Electricity Market

The Market Three different kinds of companies are accepted as agents for operations in the wholesale electricity market generators, distributors, transmitters, and large customers

Each one has access to two different ways of selling and/or purchasing electricity through direct contracts freely agreed to by parties, and through the pool, at the hourly market price

While the contract price arises from a free negotiation, the market price basically reflects the short run marginal cost of the system (generation plus bulk transmission costs), and comes out from the procedures of economic dispatch and centralized operation, which are the main operational rules enforced by the new regulation

The market price, in addition to the mentioned basic energy item, includes a payment for running available capacity (generation plus transmission), and three different payments in exchange for services needed for reliable operation contribution to frequency and voltage control, and disposition to start and to stop thermal units as requested by the economic dispatch

There are two basic kinds of contracts *supply contracts*, in which a load curve is committed between parties, in general with a delivery-or-pay clause given by the seller, and *cold reserve contracts*, in which some units remain in standby at the disposal of the contract holder for a fee

The contracts are commercial relations between agents and are complied regardless of the actual generation program issued according to the economic dispatch principle The differences between both give room to trading in the spot market

Prices and Concession Agreements The joint action of market prices and obligations enforced by concession agreements is the key issue of the regulatory strategy chosen for the Argentine electric power market The system works as follows

- The distributors' concession contract provides the most important element for the development of the electric power market, the obligation to supply This forces the distributor to look for a reliable source of the power supply needed for subsequent distribution The tool provided by the electric power market to achieve this goal is the use of forward contracts for quantities, conditions, and prices freely agreed to by parties
- The need for distributors to "get the supply guaranteed" is the essential incentive for the development of the future supply contracts market Through contracts, generators ensure the supply requested by the client in conditions and prices agreed to in advance for long periods Contracts are, therefore, the actual price stabilizers of the wholesale electricity market
- The need for generators with contracts in the forward market in order to have access to the demand is the essential incentive for the expansion of the transmission capacity
- The transmission concession contract should provide complementary incentives to complete the cycle, the obligation to give open access to any user requesting transmission capacity to carry out the transportation The prohibition to trade electricity, the obligation of independence from distribution and generation companies is enforced by law
- A last condition was to be met by regulation Both key elements (pricing system and concession agreements) should facilitate the integration of neighbor electric power domestic markets among countries of the southern cone as long as their pricing system reflects the same criteria regarding economic costs as the one adopted by the Argentine wholesale electricity market

Other Key Decisions

An important strategic regulatory decision taken by the government was the creation of an independent company for the administration of the wholesale electricity market Cammesa This company has a number of characteristics to be mentioned

- The partners in Cammesa are the five different players in the wholesale electricity market generation companies, transmission companies, distribution companies large customers, and the government Each party has 20 percent of the votes on the board
- Its functions are to perform a centralized, real-time operation subjected to the economic dispatch principle to document transactions among agents in terms of physical units, transforming those transactions in economic results
- The kind of organization created pursues efficiency and transparency, giving nondiscriminatory service to every agent in the system

Cammesa is a regulated company, government is present but it is not dominant, and the same applies to industry In particular, the management of the company is not dependent on the generation industry

The second key decision was to organize a separate transmission activity Consider the following important issues

- In opposition to what had been done in the generation business, the restructuring here had the objective of concentrating the bulk transmission function in a single company (Transener) created from the merging of functions and assets present in the three preexistent government-owned transmission companies
- Additionally, several regional transmission companies were organized and given the responsibility to connect one to the other and to the national grid, all large users generation and distribution companies in the same geographical area

Besides these regulated companies, independent transmission companies are admitted They can build, operate and maintain new lines under the operational authority of the transmission concessionaire of the area They are not agents of the market, but as far as construction of new lines are concerned, they can compete with existing concessionaires for the expansion

While operation is a monopoly, construction of new lines is open to competition

The transmission activity is under federal regulation down to the level of 132 kV That means that every node in the system, regardless of ownership of assets there, has an associated cap price

These nodes are, therefore, the access to the market and to the market price for every agent, and particularly for the regulated agents (customers of installed capacity above 1 MW by now)

This activity, in which prices are regulated in the concession agreement and the concessionaire receives the obligation to give open access to every request at that price presents two significant issues

- These specialized companies represent the border of application of the principle of vertical separation
- The transmission system translates the market price deeply inside the network, to every node involved in the transmission regulation

We are convinced that these basic rules of transmission pricing, access, and expansion are a practical contribution to solving the problem of integration among neighboring domestic markets in the region

Towards Global Industry and Market Integration

From the Argentine experience, it is possible to draw some conclusions about which of the conditions inside the model are pushing towards globalization (and finding it unavoidable), and how the adoption of certain rules of the game facilitates the process of integration

In terms of the push towards globalization, consider the following

- Opening to foreign investors in nondiscriminating conditions
- Legal framework, giving enough stability to the rules of the game and to the policy of foreign investments
- Efficiency oriented pricing system allows for the appearance of excellent companies worldwide
- Familiar regulatory environment encourages the presence of global companies
- Global business ends up making room for a global culture in the specialized electricity business management and in the technical operation of it

In terms of market integration

- Compatible wholesale (at least) pricing concepts across state borderlines
- Consistent regulation and pricing for the bulk transmission activity
- Necessary institutional framework (federal laws, provincial laws, international agreements)
- Satisfactory solution for the administration, both technical and commercial, of the system and market under an integration process is in progress

How the New Industry Looks There are now 74 independent agents in the Argentine wholesale electricity market 26 generation companies, 26 distribution companies, 3 transmission companies, and 19 large customers New private companies born from restructuring of prior government owned monopoly are shown in Table 14

Conclusions

The Argentine wholesale electricity market and its new rules have enabled the gathering of a large number of excellent companies of the world in a competitive environment, and this is actually a key element of the Argentine process We can appreciate the importance and the variety of this contribution The degree of acceptance relies on some main issues

- Kind of rules enforced in the Argentine wholesale electricity market
- Nondiscriminatory opening to new investors
- Clear government role in the new business structure

Experience shows that

- Success in obtaining enough competition depends on the effort in the restructuring and in the careful design of the market price system, and the writing down the set of obligations and rules for regulated activities
- The way of organizing the transmission activity is the key for a fast and easy integration of neighboring markets, both inside and outside the countries' borderlines
- The change does not merely consist of a privatization of what existed before but of a sound transformation of the principles on which the whole industry is based
- The transfer of responsibilities in the supply from government to third parties does not deprive these activities of their character or public interest The exclusion of government from industrial or commercial activities does not mean it has no place in the new order The presence of government is essential to enforce the new rules, and to build up the necessary regulatory bodies

Consequently, there is a sustained interest from foreign investors to enter the Argentine wholesale electricity market and a new interest from several companies born from the transformation to intervene in the privatization of electricity

Table 14 New private companies

Company	Activity	Size	Partners from Abroad
Alicura SA	Hydro generation	1,000 MW	Southern Elec Int
Cerros Colorados SA	Hydro generation	450 MW	Dominion
Chocon SA	Hydro generation	1,320 MW	Endesa (Chile) CMS
Piedra de Aguila SA	Hydro generation	1,400 MW	Duke Chilgener Transalta
Transener SA (UK)	Transmission	7,000 km of 500 kV lines	Duke Entergy National Grid (UK)
Alto Valle SA	Thermal generation	100 MW	Dominion
Guemes SA	Thermal generation	245 MW	Duke Iberdrola (Spain)
San Nicolas SA	Thermal generation	650 MW	AES
Central Puerto SA	Thermal generation	1,000 MW	Chilgener
Costanera SA	Thermal generation	1 260 MW	Endesa (Chile) Entergy
Edenor SA	Distribution	10,000 GWh/yr	EDF (France) Endesa (Spain)
Edesur SA	Distribution	10 000 GWh/yr	Endesa (Chile) PSI
Edelap SA	Distribution	3 000 GWh/yr	Houston Ind

business abroad, to join the *global business* And, the is renewed interest in restructuring the industry following simi lar principles as a way towards market integration fron provincial governments inside Argentina as well as fron national governments across the South American continen

About the Speaker

Luis Maria Caruso was chairman of the National Coordi nation and Regulation Board, Energy Secretariat, and member of the Electric Sector Privatization Committee fron 1991 to April 1993 From these appointments, he had primar responsibility for the organization and launching of the Ar gentine Wholesale Electric Market (WEM), the creation o Compania Administradore del Mercado Mayorista (Cam mesa) of which he has been executive vice president and i drafting regulations that enforce the market

He has also been responsible for the Executive Unit cre ated by the Energy Secretariat to guide the organization o companies specialized in electric power transmission for mulate regulations for their activity, and for their privatiza tion

Between 1987 and 1991, he was manager of the Nationa Dispatch Center a predecessor of Cammesa, that was re sponsible for centralized operation and economic dispatc in the Argentine national interconnected system Betwee 1984 and 1987 he was director of the Working Group fo Planning the National Transmission Network which had th

task of designing the future extra-high-voltage bulk transmission system Between 1977 and 1987, he was head of the Operation Department in Hidronor SA, participating in the commissioning and operation of the Comahue hydro power plants and associated transmission system

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Reorganization of the Electric Transmission System in Argentina

Luis V Sbertoli, SIGLA SA, Buenos Aires

The Argentine electric system was developed from isolated local services, and, as the years went by, it became a well-integrated grid Except for some services in the southernmost region, the national interconnected system supplies electric power to final users throughout the country

Argentine Interconnected System

The Argentine national grid includes over 7,000 km of lines at 500 and 220 kV, and about 30 transformer stations

System Demand Electric power demand in the Argentine interconnected system is 49,000 GWh, with a peak load of 9,000 MW The geographical distribution of the energy demand is as follows Gran Buenos Aires (GBA), 45 percent, Buenos Aires Sur, 14 percent, Litoral, 13 percent, Centro, 9 percent, Cuyo, 6 percent, Noroeste Argentino (NOA), 6 percent, Comahue, 4 percent, and Noreste Argentino (NEA), 3 percent Isolated systems, mainly those in the southern Patagonia, demand about 5,000 GWh Demand is expected to grow at a rate of 6 percent per year By 1994, SIN will also add 1,000 GWh from presently isolated systems

Hydro Plants Hydro plants installed capacity is 7,000 MW with an average production of 16,000 GWh per year The Comahue region in the south provides 4,300 MW and 63 percent of global production, and it was formerly operated by Hydroelectrica Norpatagonica (Hidronor) Salto Grande, with 900 MW, produces 22 percent of the total hydro power The Comahue plants include a great capacity for regulation, and define the long range price of energy in the system Main generators are Chocon SA (1,320 MW), Cerros Colorados SA (450 MW), Alicura SA (1,000 MW), and Piedra de Aguila SA (1,400 MW) A number of minor private companies will be formed from plants presently owned by Agua y Energia Electrica (AYE) In the near future, it is expected to commission the Yacyreta plant, which will add 3,000 MW and 20,000 GWh to the market

Thermal Plants Thermal plant capacity is around 7,700 MW, with 5,000 MW conventional steam, 1,000 MW nuclear, 1,500 gas turbines, 100 combined cycle, and 100 diesel generators Steam plants are mainly fueled by natural gas from the Comahue and the NOA regions Main generators are Puerto SA (1,000 MW), Costanera SA (120 MW), both located in GBA, Eseba (1,100 MW), San Nicolas SA in the Litoral region (650 MW), and CNEA (1,000 MW)

In 1994, the thermal capacity in the Comahue will be increased by 500 MW in gas fueled gas turbines plants CNEA is constructing a third nuclear power plant in the Litoral, 750 MW, that is expected to be commissioned by 1999

Private Companies and Public Service

Private companies started the Argentine electric systems, however, the supply of electric power had become a public activity long ago, and a number of publicly owned electric utilities provided service

Public service in the Greater Buenos Aires Area was p formed by Segba, the greatest distributor and a big genera as well, with more than 4 million customers

Widely spread Agua y Energia Electrica was the natio company covering the rest of the country, and shared supply to regions other than the Greater Buenos Aires A with the provinces It was an integrated unit, devoted to fi distribution and generation as well Agua y Energia Electr was a pioneer in hydro resource exploitation

Major hydro power plant construction in southern Arge tina gave way to the creation of Hydroelectrica Norpatac nica (Hidronor) Remote hydro plants are linked with t market through a strong 500 kV transmission System

The Comision Nacional de Energia Atomica (CNEA) bu and operates two important nuclear power plants (abc 1,000 MW), and has a third one under construction

The hydro power plant of Salto Grande is shared w Uruguay, and is operated by a binational company, Comisi Tecnica Mixta de Salto Grande (CTM)

The Yacyreta hydro project (3,000 MW) is being comm sioned by another binational company, Entidad Binacion Yacyreta (EBY)

The national interconnected system was developed connect the regional systems and to route remote hydro ar nuclear energy to the market The national interconnecte network includes overhead lines covering over than 7,000 k and about 30 transformer stations, mainly at 500 kV Son lines operate at 220 kV The original major owners of th network were AYE and Hidronor Regional systems cover th rest of the country, typically at 132 kV, with some lines at 22 and 330 kV

Electric Power Sector Transformation

In mid-1991, the national government decided on th transformation of the electric power sector as part of a wide plan of public facilities privatization The plan included

- New definition for the role of the state in the electri power industry
- Plan for resizing and privatizing the national public owned utilities
- Guidelines for the extension of these principles to the provinces

This plan was carried out within the state reform definec by National Law 23696 and is almost completed The scope of this section is to describe the main characteristics anc results of the transformation process

With the reform, an in-depth transformation of the public sector began, with the aim of transferring productive anc commercial activities to the private sector, and keeping the responsibility for system regulation with the government

A Regulatory Framework Law for the electric power sector was passed This law states the main characteristics of sector activities, with two different types of regulation

- Energy production in power plants, organized as a competitive matter under a well-defined pricing system based on production costs (short range marginal cost of thermal units) and capacity costs needed to ensure system reliability (capacity and loss of load probability)
- Transmission and distribution, established as public services organized as monopolistic steps within an area and level, under specific regulation and subject to concession (license) contracts (transmission and distribution concessions)

In this way, the privatization of public-owned utilities was based on the segregation of production, transmission, and distribution activities This *vertical cut* was performed by creating different business units as commercial corpora tions, the controlling stake of which was to be offered to public bid

In order to achieve this, the former state-owned utilities (Segba, Agua y Energia Electrica, and Hidronor) were split into several specialized companies The government transferred to these companies the assets and functions, and the concession, when necessary Then the controlling stake and the managing of these companies was sold in public auction A minority stake, generally 10 percent, has been reserved for workers, and the remaining shares will be offered on stock exchanges

The privatization of the national utilities has been completed except for some minor power plants and regional networks that are to be sold early this year

The other key feature of the process was to set up a wholesale electricity market (WEM) that includes

- A unified marketplace where producers and customers buy and sell electricity and where a wholesale price is defined
- A transmission system that *carries* market prices and products, defining a nodal price for each delivery point (This is a monopolistic and federally regulated level)
- A distribution system as a monopolistic and federally regulated level in the Greater Buenos Aires area
- A regulatory body (ENRE) in charge of overseeing the observance of laws and codes and judging cases of disputes between market actors

ENRE is an autonomous body, its board of directors being appointed by the Executive Power ENRE is responsible for sector regulations and also plays a major role in concessions and the definition of rates

Electricity producers are selected according to location and production costs under a national dispatch program This program and overall market operation is in charge of Cammesa, a company formed by the government and the different market players, generators, distributors, transmitters, and large users

We can summarize the tasks of the state as follows reorganize, create a market with private producers and customers, and regulate the whole system

Transmission Network Privatization

Electric power networks in Argentina have developed from the beginning with two main goals

- Connect services so as to reduce power production costs by increasing unit sizes, reducing reserve requirements and allowing for general scale economies
- Link power plants, mainly remote hydro, with demand centers

While monopolistic state-owned agencies were in charge of services, the grid implied the creation of a commercially integrated system in which the state was both the producer and the final distributor

The *vertical cut* process produced a great number of new generation and distribution companies operating upon a previous matrix the Argentine interconnected transmission system Even the creation of the wholesale electricity market has been possible because that market was already in existence by means of the transmission networks

The Regulatory Framework Law defines power transmission as a monopolistic activity, to be performed under a license contract Power transmitters do not buy or sell energy and are paid as agents of a transmission service to the market

This feature is intended to preserve open access to the different players, thus increasing global efficiency over market priorities and constraints

With vertical cut, the transmission grid takes on a new function, namely to provide an open access to market players making power production effectively competitive, and allowing distributors and final customers to buy energy from producers not even directly connected to them

Transmission activity includes

- Transener, a company with a concession for the national high voltage grid (500 and 220 kV)
- A number of regionally organized companies operating typically 132 kV grids with a few transmission lines at 220 and 330 kV

All these companies have been created from previous Segba, AYE, and Hidronor grids, and with the potential addition of the provincial assets These companies operate under license contracts, the general regulation of the wholesale electricity market, and specific transmission regulation referring to grid utilization, expansion, connection and information

Transmission Rates

Transmission rates have been developed in such a way as to provide economic signals to grid users Each point of the network (node) becomes characterized by a factor expressing the relative cost in relation to market, an export node with a poor link will receive an income reduced by that factor while an import node will pay the energy increased by that factor

This principle tries to take into account the inefficiency derived from insufficient transmission capacity, and should encourage players to build new facilities

Economic theory indicates that in such cases, transmission should be paid according to marginal transmission losses Because of the nature of electricity networks, some scale economies appear that make it impossible to pay for new lines only with that remuneration, and some special charges must be added to pay for the transmission service

In the Argentine system, a mixed pricing method has been developed, based on marginal considerations and fixed costs as well The *variable charge* takes into account the incidence of marginal losses through a nodal factor Poor network reliability resulting in nonsupplied energy and out-of-merit dispatch is taken into account through an adaptation factor These factors cause the node price to change throughout the transmission grid and, with time, in accordance with power balance and network availability

The *fixed charge* represents the operation and maintenance costs of connecting users to the grid (connection charge) and transmission facilities (transmission capacity charge)

All these charges are computed for each user and are managed by Cammesa

Variable charges are calculated on an hourly basis for generators, but are stabilized each 6 months for customers Thus, transmission charges are an essentially changing amount, according to the transmission network and power dispatching

However, as the transmitter is an agent that does not have any influence on energy flows the remuneration has been stabilized on a 5-year basis according to the *ex-ante* mean value of charges for the period The stabilized annual income of Transener for the first 5-year period is 95 MU$ including 55 MU$ from variable charges and 40 MU$ from fixed charges This income will be reduced annually by a factor aiming to increase system efficiency, and will be adjusted every 6 months by a factor that takes into account dollar inflation Every 5 years annual income will be adjusted according to expected variable charges in the following 5-year period

The remuneration of the transmission companies in the first period is based on 100 percent availability Any time a facility is out of service whether planned or accidental a penalty will be applied to the company, its amount being computed according to outage duration and facility importance From the second period on a quality standard is to be established based on previous system performance Penal-

ties and bonuses will be applied to company income whenever a deviation from the standard occurs

The pricing system is designed to maintain economic signals to users and preserve system reliability as the transmission companies' main duty

Concession (License) Contract

Electric transmission companies operate under federal concession contracts stating their rights and duties The contract term is 95 years, with successive *management periods*, the first lasting 15 years and the following lasting 10 At the end of each management period, the controlling stake is to be offered in public auction, at which time the owner is asked to declare the value he or she assigns to the company Should any other bidder offer a higher price, he or she will became the new owner, and the price will be paid to the former Otherwise, the former owner will maintain the controlling stake

The main duties of the company are to keep its facilities in normal service and to avoid discrimination between network users, so as to allow free access within its field of operation Transmission companies will also comply with technical and environmental conditions

As stated, transmission companies are not allowed to buy or sell power They will not be allowed to own controlling stakes of generators or distributors or big customers

The transmission company is not obliged to make investments, except for operation and maintenance needs Network extensions are to be processed in a special way (described in the next section) However, the company will be in charge of overseeing construction, operation, and maintenance of its own network and the extensions being developed by third parties within its concession area as well

Extensions

The electric power sector in Argentina is no longer subject to centralized planning System design, operation, and tariffs are intended to promote economic decisions based on economic signals sent through prices As a consequence, transmission companies will not be asked to make new investments or to supply demands beyond their electrical network capacity

On the contrary, major extensions are to be promoted by interested agents and paid by those who benefit Extensions will also require a *need and suitability* certificate issued by ENRE after an analysis and public hearings process

Major extensions will always be the responsibility of an independent transmission company (ETI) through a Construct, Operate & Maintain Contract (COM contract) Transmission companies are allowed to act as ETI The specific access and extension code states two ways in which major extensions can be performed

- By agreement between a user or group of users and the ETI In this case, third users will pay ordinary transmission charges
- By public call for bids (auction) at the request of a group of users totaling 30 percent or more of those who will benefit from the extension, and barring opposition of 30 percent or more In this case, a competitive bidding is called to select an ETI, and a COM contract is to be signed The transmission company must give the ETI a technical license contract and oversee construction, operation, and maintenance The COM contract will have an amortization period during which ETI will be remunerated through the *canon* that was offered The rest of extension life ETI will collect normal transmission tariffs

The concessionaire will be in charge of overall supervision within its area being allowed to collect fees for the same as stated in the concession contracts This mechanism is already in operation for the Yacyreta hydro plant transmissio system (1,500 km, 500 kV) In the case of regional networks concessionaires are compelled to give ETI operation an maintenance services using the standard fixed remuneratio index

Other Transmission Concessions

The aim of electrical transmission regulation is to transmi an economic based remuneration from the wholesale marke to final customer Wholesale electricity market prices are established in points of demand, based on transmissior rules

This mechanism, referring to federal concessions given tc new companies, is supposed to be completed by provinces that own a variety of transmission grids The intention of general regulation is to encourage provincial utilities to perform a segregation process as done in connection with national assets

In so doing, wholesale prices will reflect economic conditions throughout the country, and global supply costs will be reduced

Such an organization will also provide services integration, with a great deal of operative decentralization and high regulatory consistency

About the Speaker

Luis Victorio Sbertoli graduated from the School of Engineering, University of Buenos Aires, in 1974 For more than 15 years, he has codirected and managed technical projects undertaken by SIGLA SA, with particular emphasis on new business in both the public and private fields He has been involved in many projects, including privatization of electricity transmission in Argentina (1992-1993) and electric distribution planning in Costa Rica (1993) In 1989-1991, he was national director of Energy Sector Planning, including both technical and institutional matters In 1987-1989, he was associate director of the Argentine consulting group Distrelec for the Engineering Project for National Electrical Distribution Systems In 1985-1987, he was director of the Energy Plan for the Province of Formosa and the organization of the Province Energy Utility He has also codirected the study outlining residential areas for the Corpus hydro project, and codirected electrification studies and programs for the provinces of Catamara, Tucuman, San Juan La Rioja Salta and Misiones

Chile: Pioneer in Deregulation of the Electric Power Sector

Hugh Rudnick, Pontificia Universidad Catolica de Chile, Santiago, Chile

Chile was the leader in Latin America in the restructuring of the electric power sector, and its case merits particular analysis Although a small system (70 percent of installed capacity is hydroelectric with 2,800 MW maximum demand in 1993), its development has been observed with interest by many institutions particularly by the World Bank and most recently by other Latin American countries, and several countries have followed its steps

The Chilean 1982 electricity law was a worldwide pioneer in deregulating the electric power sector to create market conditions where generators compete to provide electrical energy to large consumers, sharing a transmission system open to all and paying fees for that system The law formalized what had taken place in the country since 1978, several

years before market approaches were formulated in the United States and implemented in the United Kingdom [Margaret Thatcher published her white book, *Privatizing Electricity*, in March 1988, that lead to the restructuring of the UK electric power sector in April 1990, a development of worldwide interest At the time, Chile was already publishing some of the results of actions taken in 1978 that had lead to the new legislation of 1982 (S Bernstein, "Competition, Marginal Cost Tariffs, and Spot Pricing in the Chilean Electric Power Sector," *Energy Policy, August 1988, pp 369-377*)]

Energy Policies

The policies applied to the Chilean electric power sector have been directly linked to the general energy policies, formulated by the National Energy Commission, the basic regulatory institution The overall energy strategy aimed at maximizing the welfare of the community by establishing conditions of efficiency in the development and operation of the national energy system, and assigning the state a subsidiary role

Within this strategy, efficiency is connected to the recognition that market forces represent a basic mechanism in the correct allocation of resources The necessity of deconcentrating, decentralizing, and privatizing the activities and property of the energy sector companies was recognized as desirable for the stability of the system

On the other hand, subsidizing energy basically implies state support for the more deprived sectors of the population through direct subsidies, without distorting the prices of goods and services It also means that the state will perform entrepreneurial activities only when such activities cannot or will not be carried out by the private sector

Technical and Economic Characteristics of the Electricity Business

The electricity law assumes that there are distinct technical and economic peculiarities of the business of electric generation, transmission, and distribution that condition their development and operation Empirical information was used to demonstrate that there are no significant economies of scale in the generation business, nor in technology nor in organization On this assumption rests the conclusion that for, an electric power generator, full competition is possible The distribution business, given present-day technologies, tends to develop through geographic monopolies, although the assumption is that there are no clear economies of scale Transmission of electric power is seen as the single electric business in which important economies of scale are present and in which competition is not feasible, and natural monopolies develop, requiring government regulation

Specific Policies for the Electric Power Sector

The policies applied to the Chilean electric power sector were aimed at establishing an appropriate framework for decentralization, efficiency, and the establishment of competition and private participation in the sector The instruments designed to reach those objectives included

- Design of a new price system on the basis of marginal supply costs [The electricity law is based on the economic principle that the social optimum is achieve when in an economy, the goods and services are price at marginal costs and systems are economicall adapted Marginal costing is believed to provide th correct economic signals to system users] The syster establishes explicit generation to distribution sal prices, transfer prices between generating companie rates applicable by distributing companies to small enc users, and, finally, freedom of prices for large consum ers (over 2 MW)
- Division of the large state companies and explicit separation between generation-transmission and distribution activities
- Design and implementation of an Economic Load Dispatch Center ("a generators club") to coordinate th operation of the generating companies, to obtain th minimum overall operating cost of the system, and t assure equitable conditions in marketing the energ produced by the various generating entities (This Center was to be the key for competition in generation)
- Design of an open access system for the shared use o transmission systems
- Establishment of a new generation planning scheme with an indicative plan being developed by the regulatory agency
- New generation schemes to be undertaken by new companies by a consortia of the existing electric power facilities owners and the new private investors, plus state participation if necessary
- Clear definition of duties and rights of distribution companies
- Increased participation of consumers in financing the expansion of the electric power sector
- Full privatization of state-owned electric distribution companies and majority sale of state equity shares in the electric generating companies (actions were taken for a whole restructuring of the sector, with clear and stable defined rules and operational experience, before any extended privatization of the generating sector was achieved)

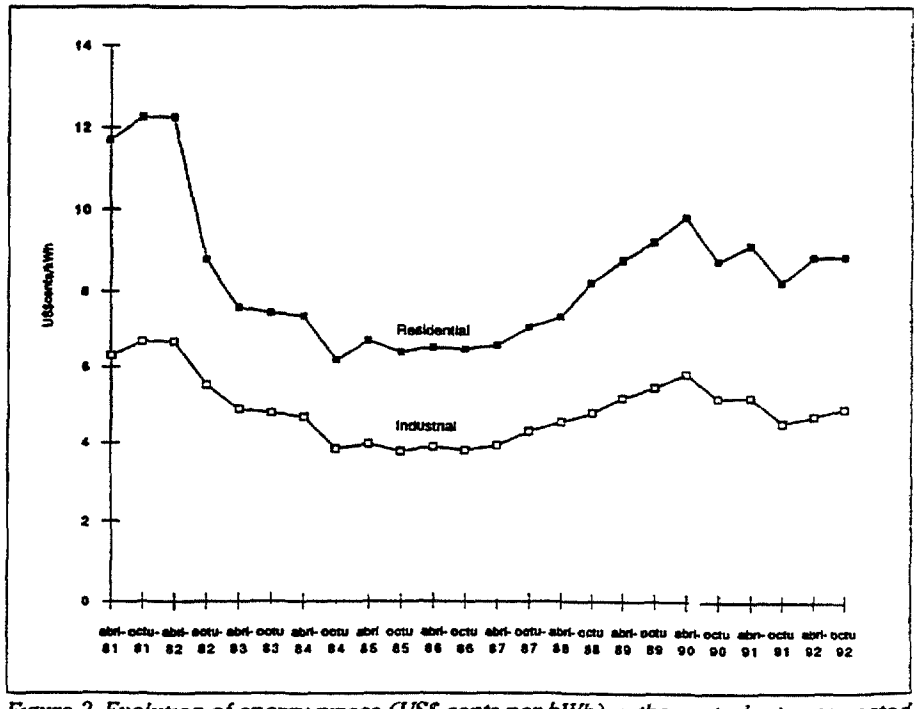

Figure 2 Evolution of energy prices (US$ cents per kWh) in the central interconnected system T

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Major Results of the Process

The Chilean restructuring process with the framework provided by the electricity law, has proved to operate adequately Electricity prices are relating closely to long run marginal costs, with what are thought to be correct market-based economic signals orienting the efficient decisions of participants Private capital is actively investing in the electric power sector development

Ownership of electric power sector companies is widely distributed across the population, and their stocks are traded daily on the local stock exchange The market is very dynamic, and the legislation has allowed the market to resist government political and special interest group pressures

Prices have remained relatively stable, with variatior depending mainly on hydro availability and fuel prices Fi ure 2 shows the evolution of energy prices (in US$cents/kWh in the central interconnected system, the residential tari (100 kWh load), and the prices for large industry

The process has promoted large investments by man private electric utilities with an annual average investment c US$400 million, with a system demand growing at a rate c 6 percent a year This private investment allows the goveri ment to concentrate its investment resources in other ec nomic areas of greater social urgency

Private electric utilities are making reasonable profit Endesa, with 2,500 MW installed capacity in 1993, has mac enough profits to sustain a continuou investment process of US$150 million year, with major investments in Arge tinean generating plants, and plans t invest in the future privatization of th electric power sector in Peru

The results of the restructuring pro ess are perceived as successful for th consumers and for the generation an distribution businesses The regulato and the electric utilities are looking fc some improvements to the law

A particular area in which problem have surfaced is that of the transmissic business Difficulties have been face with the open access tariff scheme pa ticularly in the allocation of the paymen among participating electric power ge erators The difficulties have created u certainty in the development of th transmission networks, with restricte investments taking place The regul tions dealing with transmission acce are being revised to deal with this matte

Another area where the parties a looking for improvements, to avoid is lated conflicts, is that of energy pricing the distribution level (where margin generation and transmission costs a added to average distribution costs a suming ideal model distribution comp nies) The incorporation of security ar quality concepts in electricity tariffs also being studied

About the Speaker

Hugh Rudnick was born in Santiag Chile He graduated as a civil electric engineer from the University of Chile ar received his MS and PhD degrees fro the Victoria University of Manchester Great Britain After a period of workir for local utilities, he joined the Univer dad Catolica de Chile, where be is a pr fessor of electrical engineering

His research interests include pow system economic operation, dynami and control, where he has published ov 100 technical papers He has been a co sultant to the National Energy Comm sion, software development companie industrial firms and several electric uti ties in Chile, Argentina, and Colombia

Stockholm Power Tech

International Symposium on Electric Power Engineering

Call for Papers

Abstract deadline: December 1, 1994

Meeting date: June 18-22, 1995

Location: Stockholm, Sweden

Stockholm Power Tech, an international symposium on electric power engineering, will be held June 18-22, 1995, at the Royal Institute of Technology, Stockholm, Sweden. Organized by Royal Institute of Technology and IEEE Power Engineering Society, the objective of Stockholm Power Tech is to provide an opportunity to exchange views on key areas of electric power engineering; to present progress in technology, and to discuss challenges for the future.

The symposium will be a meeting place for people from industry, utilities and universities who have an interest in power engineering research and development.

Subjects cover the main areas of electric power engineering:

- Electric power systems: analytical and computational techniques; operation, planning, and control, stability enhancement.
- Information and control systems: SCADA, EMS, and distribution management systems; protection; control system management.
- High-voltage technology: high-voltage apparatus development; diagnostic methods and condition monitoring; electrical insulation.
- Electrical machines and drives: industrial applications; traction and electrical vehicles; developments in high speed drives, generators etc.
- Power electronics: active and reactive power control; FACTS; HVDC; active filters.

The technical program includes a plenary session, invited speakers, sessions and paper sessions. Technical visits are planned at ABB and other industries, utilities, and universities. Post session tours will be organized.

Two-page extended abstracts are due by December 1, 1994. Details concerning submission of papers will be given upon receipt of the extended abstract. Notification of acceptance will be made by January 20, 1995. Conference program and registration forms will be issued in January 1995. Full manuscripts are due by May 1, 1995.

For further information, contact the Stockholm Power Tech Secretariat, Department of Electric Power Engineering, Royal Institute of Technology, S-100 44 Stockholm, Sweden, +46 8 790 60 00, FAX +46 8 20 52 68, E-mail stockholm95@ekc.kth.se.

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ORGANIZATIONAL STRUCTURE OF THE US ELECTRIC POWER INDUSTRY

ORGANIZATIONAL STRUCTURE OF THE US ELECTRIC POWER INDUSTRY

North American Electric Reliability Council- NERC

Interconnections

Regional Councils

Control Areas

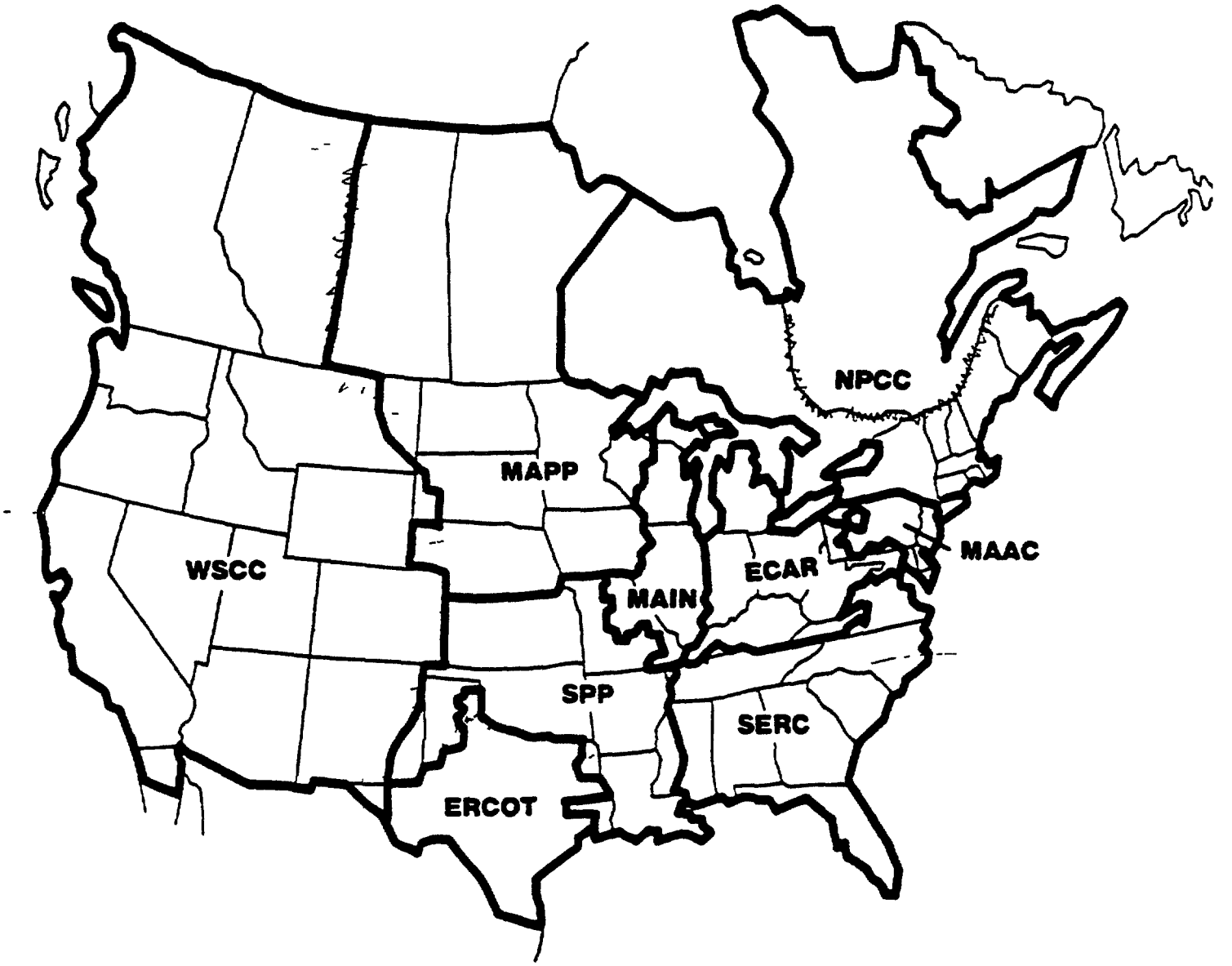
Power Pools

Investor Owned Utilities

Municipals, Co-ops, Power Authoritys

Federal and Provincial Organizations

North American Electric Reliability Council



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

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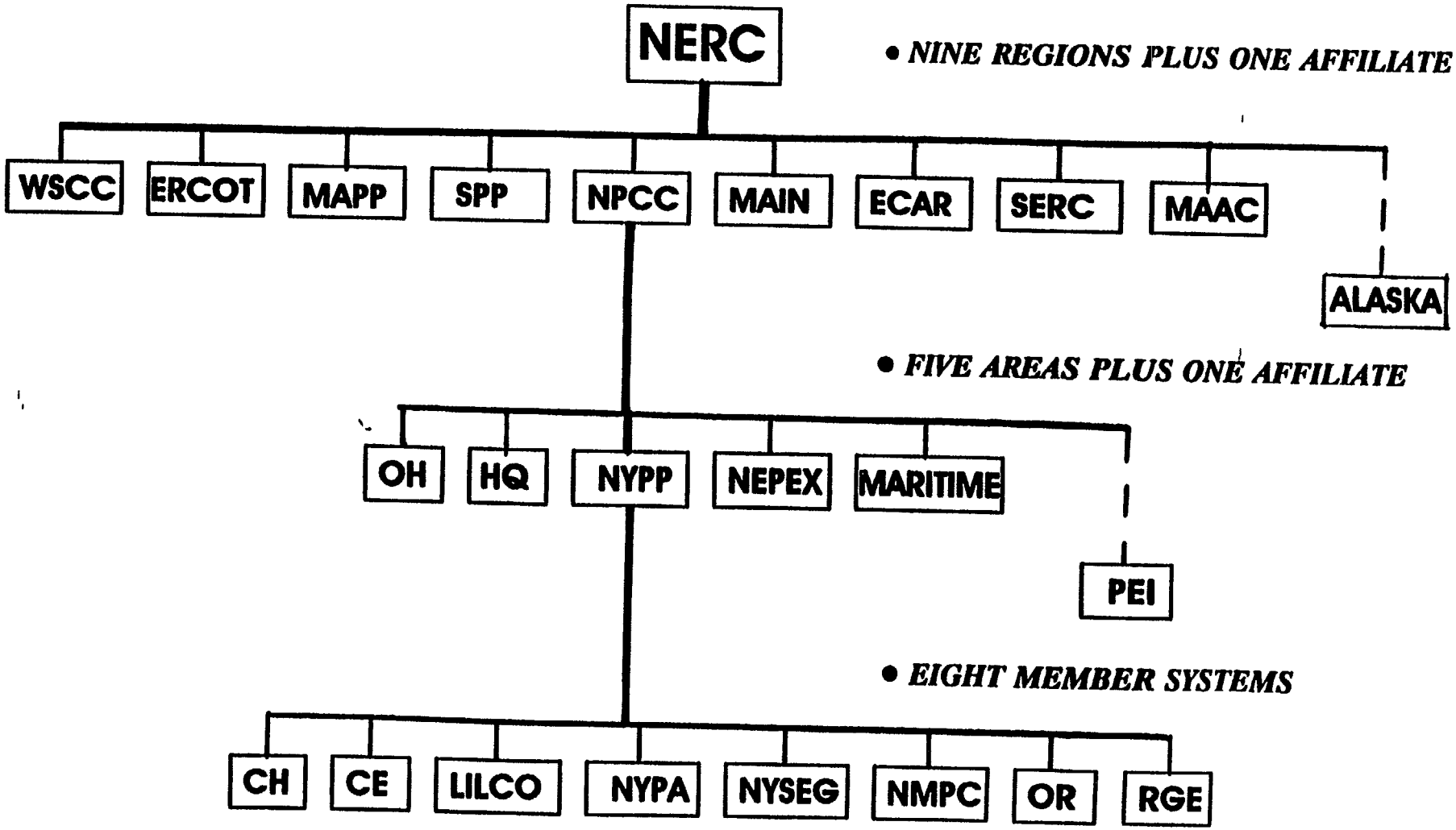

NERC
• NINE REGIONS PLUS ONE AFFILIATE
WSCC
ERCOT
MAPP
SPP
NPCC
MAIN
ECAR
SERC
MAAC
ALASKA
• FIVE AREAS PLUS ONE AFFILIATE
OH
HQ
NYPP
NEPEX
MARITIME
PEI
• EIGHT MEMBER SYSTEMS
CH
CE
LILCO
NYPA
NYSEG
NMPC
OR
RGE

North American
Electric
Reliability
Council

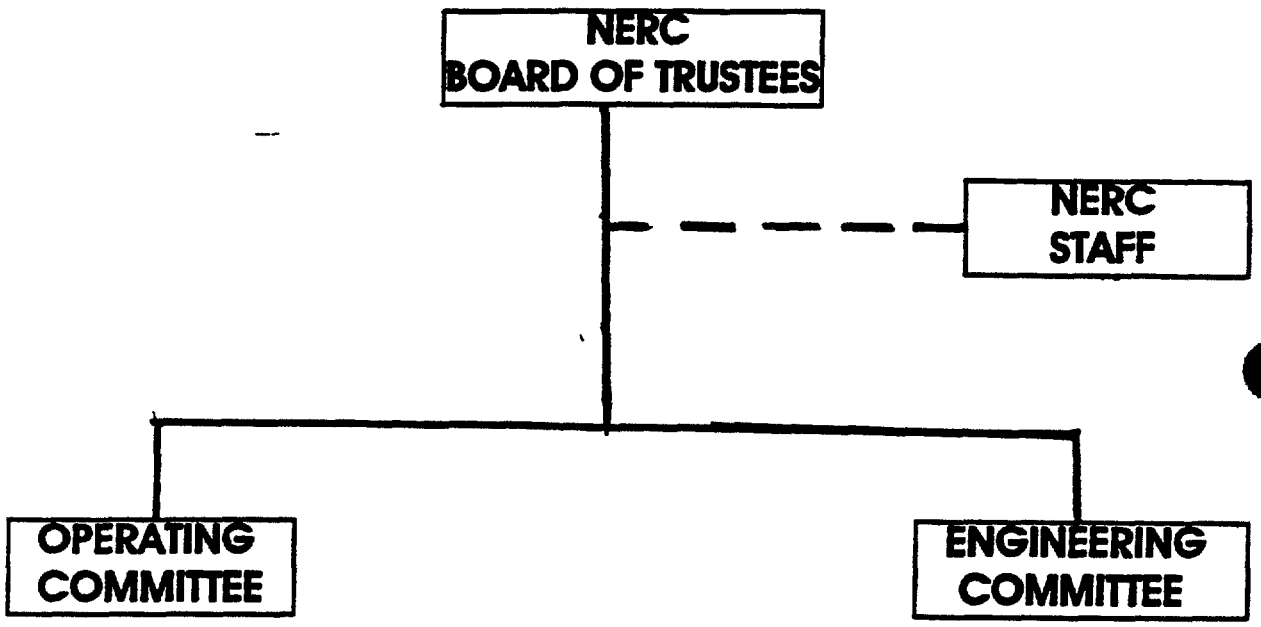
NERC

Purposes

- Promote the reliability and adequacy of bulk power supply by the electric systems of North America
- Conduct interregional studies which relate to the reliability and adequacy of the bulk power systems and to make information appropriately available
- Encourage and assist the development of interregional reliability arrangements among regional electric reliability councils and their members
- Exchange information with respect to planning and operating matters relating to the reliability and adequacy of bulk power supply
- Review periodically regional and interregional activities on reliability and adequacy
- Provide independent reviews of interregional matters referred to it by regional electric reliability councils

NERC

ORGANIZATIONAL STRUCTURE



North American Electric Reliability Council

NERC

BASIC OPERATING POLICY FOR INTERCONNECTED SYSTEMS CONTROL

- MW REGULATION
- VOLTAGE CONTROL
- TIME AND FREQUENCY REGULATION
- INTERCHANGE SCHEDULING
- CONTROL PERFORMANCE CRITERIA
- INADVERTENT INTERCHANGE MANAGEMENT
- CONTROL SURVEYS
- CONTROL EQUIPMENT REQUIREMENTS

E. CONTROL PERFORMANCE CRITERIA

Criteria Reference

The Control Performance Criteria define a standard of minimum control performance Each control area is to have the best operation above this minimum that can be achieved within the bounds of reasonable economic and physical limitations

Requirements

1 Two criteria shall be used to continually monitor control performance during normal conditions (See the "Control Performance Criteria Training Document," Section 2 1)

1 1 A1 Criteria - The ACE must return to zero within ten minutes of previously reaching zero Violations of this criteria count for each subsequent ten-minute period that the ACE fails to return to zero

1 2 A2 Criteria - The average ACE for each of the 6 ten-minute periods during the hour (i e , for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_4, that are determined from the control area s rate of change of demand characteristics See the "Control Performance Criteria Training Document," Section 2 1 2 1 for the methods for calculating L_4

2 Two criteria shall be used to continually monitor control performance during disturbance conditions (See the 'Control Performance Criteria Training Document," Section 2 2)

2 1 B1 Criteria - The ACE must return to zero within ten minutes following the start of the disturbance

2 2 B2 Criteria - The ACE must start to return to zero within one minute following the start of the disturbance

3 The ACE used to determine compliance to the Control Performance Criteria shall reflect its actual value, and exclude short excursions due to transient telemetering problems or other influences such as control algorithm action

4 All control areas shall respond to control performance surveys that are requested by the Performance Subcommittee

Recommendations

1 Each control area should be in compliance with the A1 and A2 Criteria at least 90% of the time

Background

Control performance is the degree to which a control area matches its generation to its demand plus scheduled interchange taking into account the effects of frequency bias The NERC Operating Committee has established the Control Performance Criteria (CPC) which include standards of acceptable control performance The CPC establish minimum standards for control performance and provide a means for measuring the relative control performance of each control area While these standards define the minimum acceptable performance, each control area shall meet and strive to exceed these standards

NORTHEAST POWER COORDINATING COUNCIL

NPCC

Statement of Purpose

To promote maximum reliability and efficiency of electric service in the interconnected systems of the signatory parties by extending the coordination of their system planning and operating procedures.

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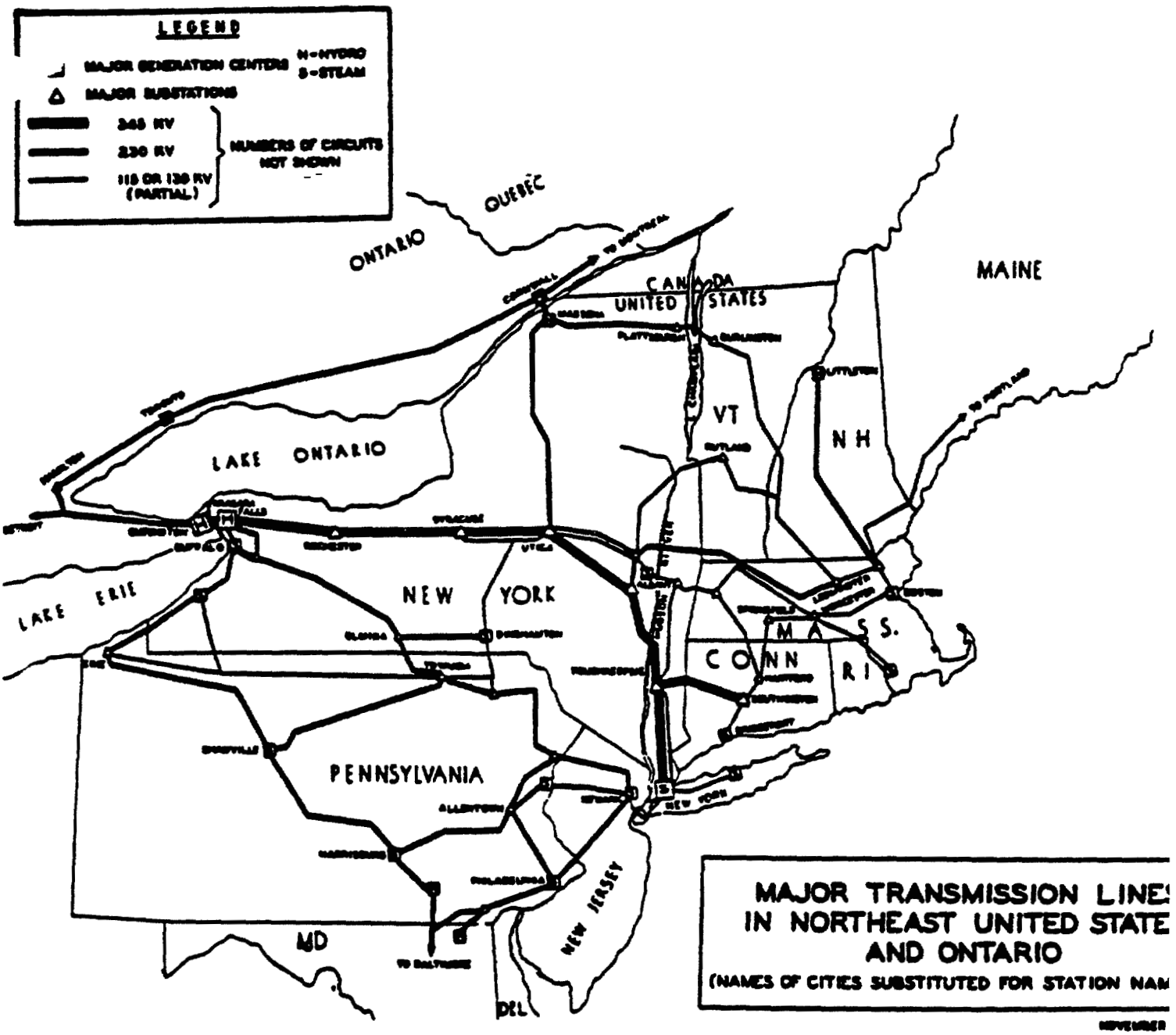
NORTH AMERICAN POWER SYSTEMS INTERCONNECTION COMMITTEE

- *Established January 1963*
- *Included:*
  - *ISG*
  - *CANUSE (NPCC)*
  - *PJM*
  - *RMPP*
  - *NWPP*
  - *AZ/NM*
  - *CA/NV*
  - *ERCOT (1979)*



CANUSE (formed from CANadian United States Eastern) is an organization of electric companies started in 1938 at a meeting of the operating representatives of Con-Edison and the upstate companies now known as Niagara Mohawk to coordinate operations and planning It has grown to a closely coordinated group of all the companies in the northeast (including government owned systems in Canada and the Power Authority of the State of New York) CANUSE operating procedures have since been adopted by the larger organization called NAPSIC (North American Power Systems Interconnection Committee) which includes the entire United States

THE BLACKOUT

NORTHEAST BLACKOUT

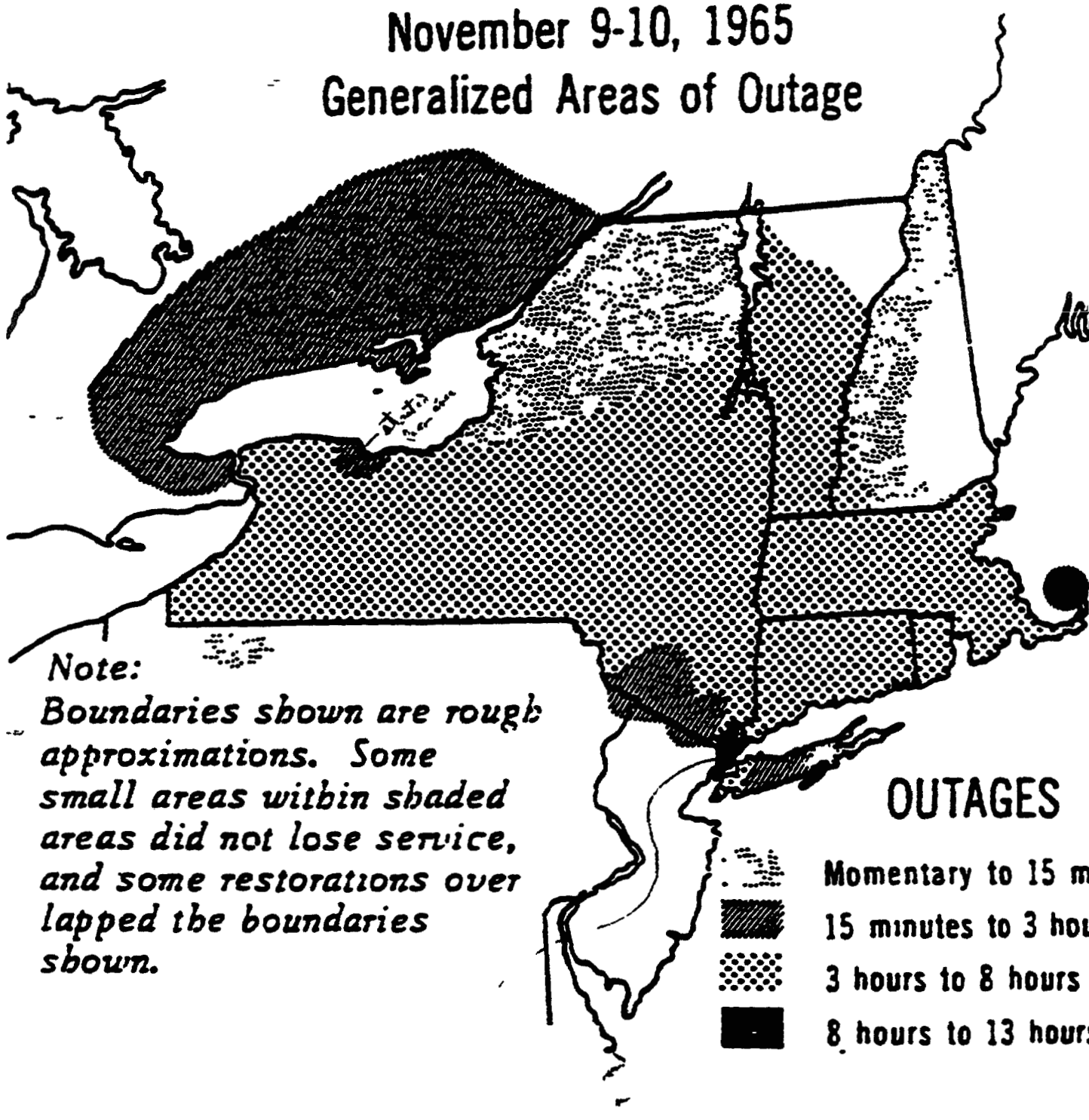
November 9, 1965 5:16 pm

- *Caused by*
  - *loss of load*
  - *inability to withstand first contingency*
- *President Johnson ordered study by Federal Power Commission*

POWER FAILURE IN THE NORTHEAST

November 9-10, 1965

Generalized Areas of Outage



Note:
Boundaries shown are rough approximations. Some small areas within shaded areas did not lose service, and some restorations overlapped the boundaries shown.

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PREVENTION OF POWER FAILURES

Volume I—Report of the Commission

A Report to the President
by the
Federal Power Commission
July 1967

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Formed in 1968

Promote the reliability of the bulk electric system in North America.

OBJECTIVE OF

POOL OPERATION IS TO

COORDINATE THE OPERATION

OF THE MEMBER SYSTEMS TO

IMPROVE RELIABILITY AND

EFFICIENCY

NPCC

POOL OPERATIONS IN A COMPETITIVE MARKET

INDEPENDENT SYSTEM OPERATOR

POWER EXCHANGE

No Longer Vertically Integrated Systems, Instead:

POOLCOs, GENCOs, TRANSCOs, DISCOs, RTGs, Marketers, Etc.

Market Based Pricing of Energy and Ancillary Services

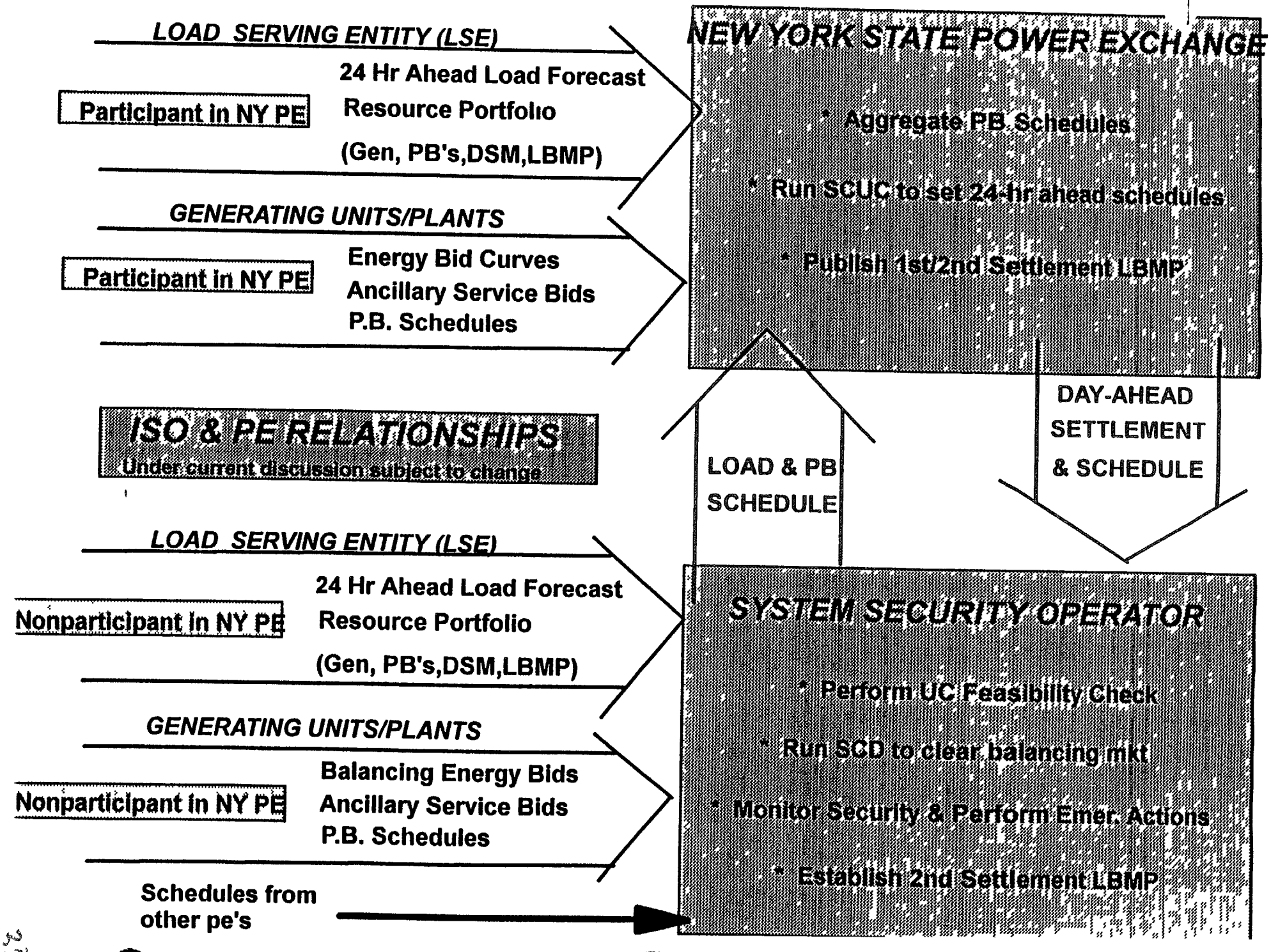
LBMP and Bilateral Transactions

RESPONSIBILITIES OF AN ISO

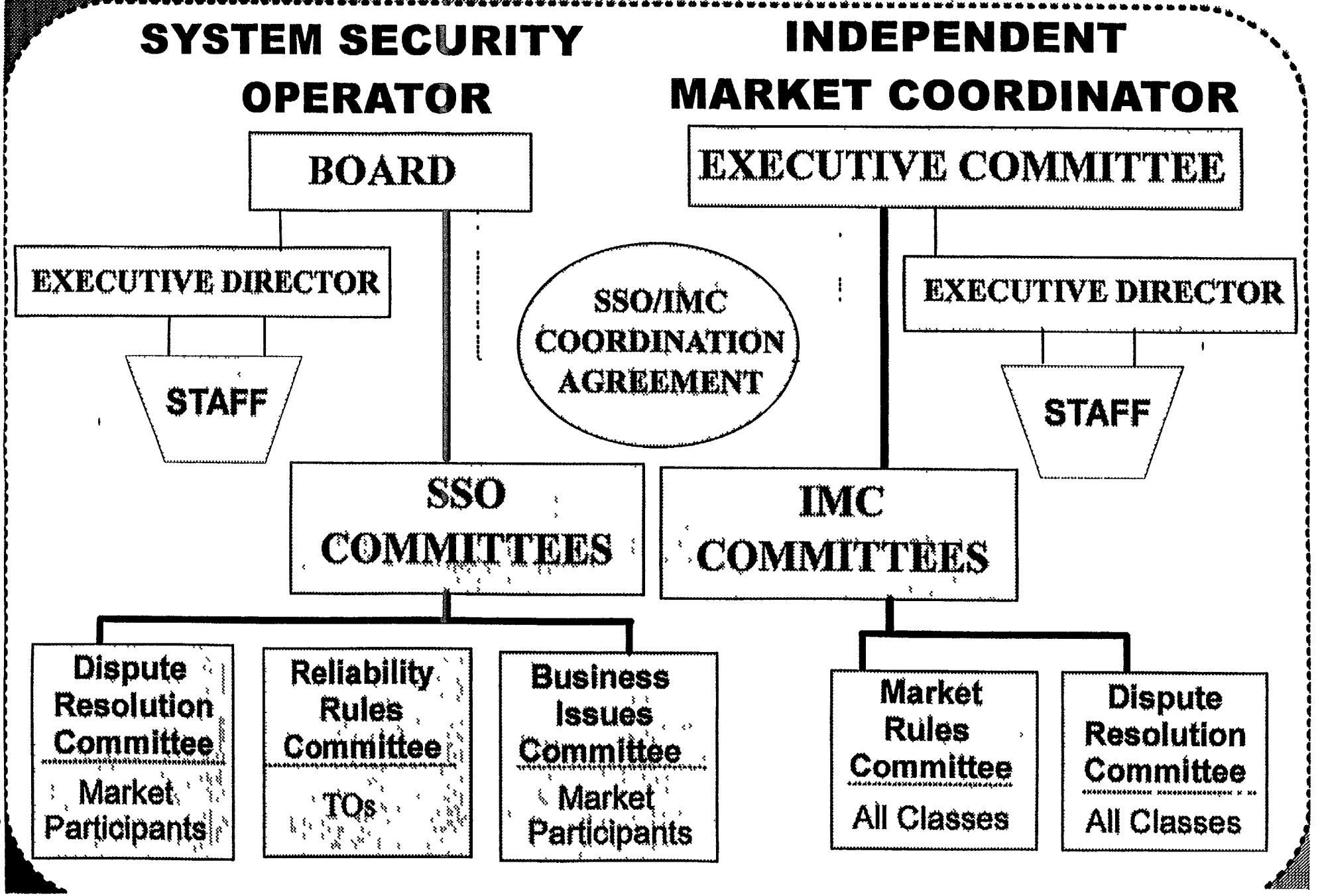
- Operate the Bulk Power System
  - Maintain Reliability (Meet NERC, NPCC & NY Criteria)
  - Maintain & Revise Operating Limits
  - Perform Daily, Weekly & Seasonal Studies
  - Verify LSE Load Forecasts
  - Coordinate Gen/Tran Maintenance
  - Procure Ancillary Services
  - Monitor System State
  - Initiate Emergency Actions
  - Maintain & Update OASIS (ATC, T. Rights/TCCs)

RESPONSIBILITIES OF THE PE

- Facilitate 1st & 2nd Settlement Markets
  - Accommodate Bilateral Transactions
  - Clear SCUC-Based 1st Settlement Forward Market
  - Provide Resulting Schedule to ISO for Verification
  - Provide unused bids to ISO
  - Publish 1st Settlement Spot Prices
  - Provide 1st Settlement Billing
  - Conduct Installed Capacity Auction
  - Conduct Transmission Congestion Contract Auction


LOAD SERVING ENTITY (LSE)
Participant in NY PE
24 Hr Ahead Load Forecast
Resource Portfolio
(Gen, PB's,DSM,LBMP)
GENERATING UNITS/PLANTS
Participant in NY PE
Energy Bid Curves
Ancillary Service Bids
P.B. Schedules
NEW YORK STATE POWER EXCHANGE
* Aggregate PB Schedules
* Run SCUC to set 24-hr ahead schedules
* Publish 1st/2nd Settlement LBMP
ISO & PE RELATIONSHIPS
Under current discussion subject to change
LOAD & PB SCHEDULE
DAY-AHEAD SETTLEMENT & SCHEDULE
LOAD SERVING ENTITY (LSE)
Nonparticipant in NY PE
24 Hr Ahead Load Forecast
Resource Portfolio
(Gen, PB's,DSM,LBMP)
GENERATING UNITS/PLANTS
Nonparticipant in NY PE
Balancing Energy Bids
Ancillary Service Bids
P.B. Schedules
Schedules from other pe's
SYSTEM SECURITY OPERATOR
* Perform UC Feasibility Check
* Run SCD to clear balancing mkt
* Monitor Security & Perform Emer. Actions
* Establish 2nd Settlement LBMP

NEW YORK WH


SYSTEM SECURITY OPERATOR
INDEPENDENT MARKET COORDINATOR
BOARD
EXECUTIVE COMMITTEE
EXECUTIVE DIRECTOR
STAFF
SSO/IMC COORDINATION AGREEMENT
EXECUTIVE DIRECTOR
STAFF
SSO COMMITTEES
IMC COMMITTEES
Dispute Resolution Committee
Market Participants
Reliability Rules Committee
TOs
Business Issues Committee
Market Participants
Market Rules Committee
All Classes
Dispute Resolution Committee
All Classes

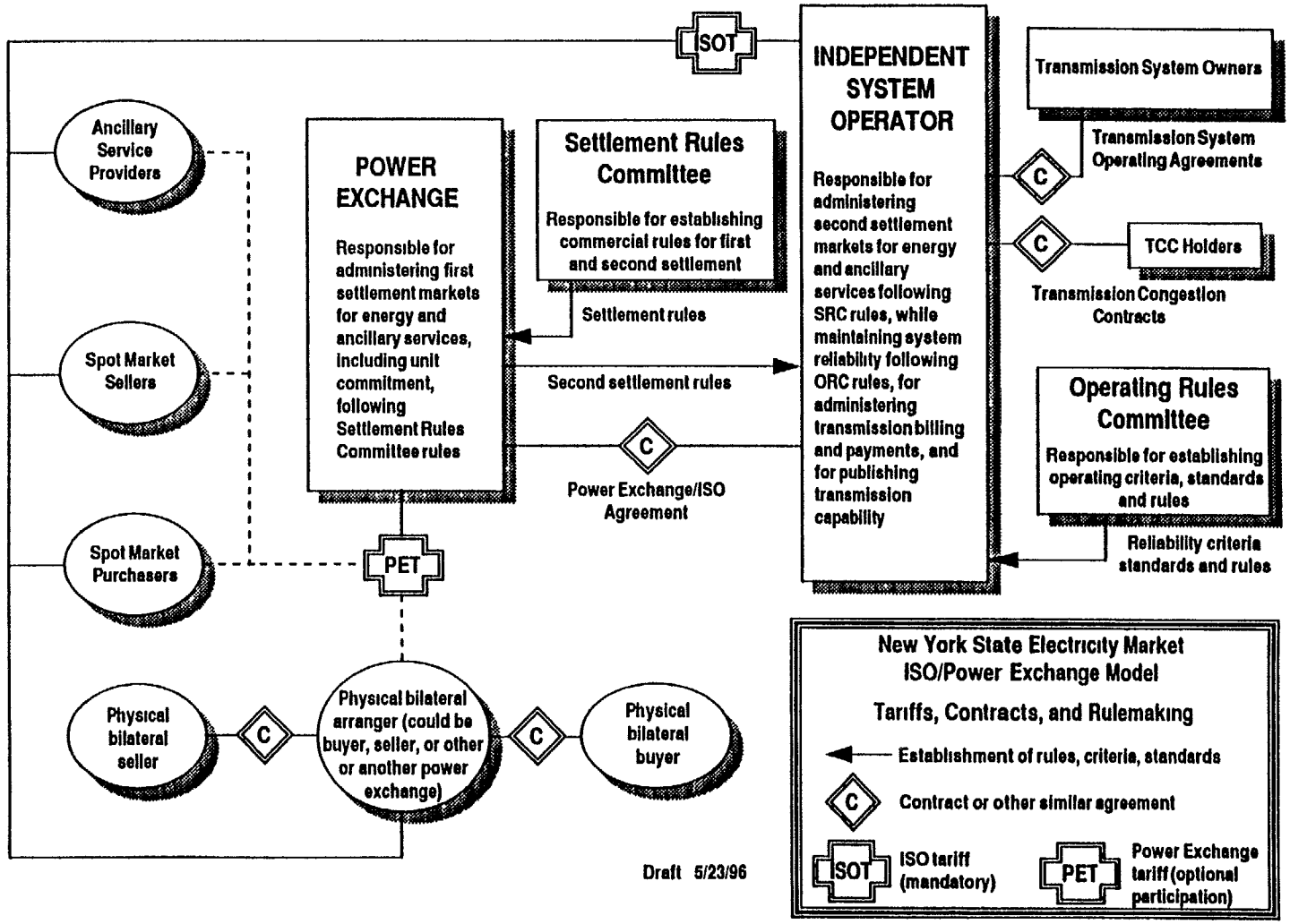
Interaction with the Competitive Market

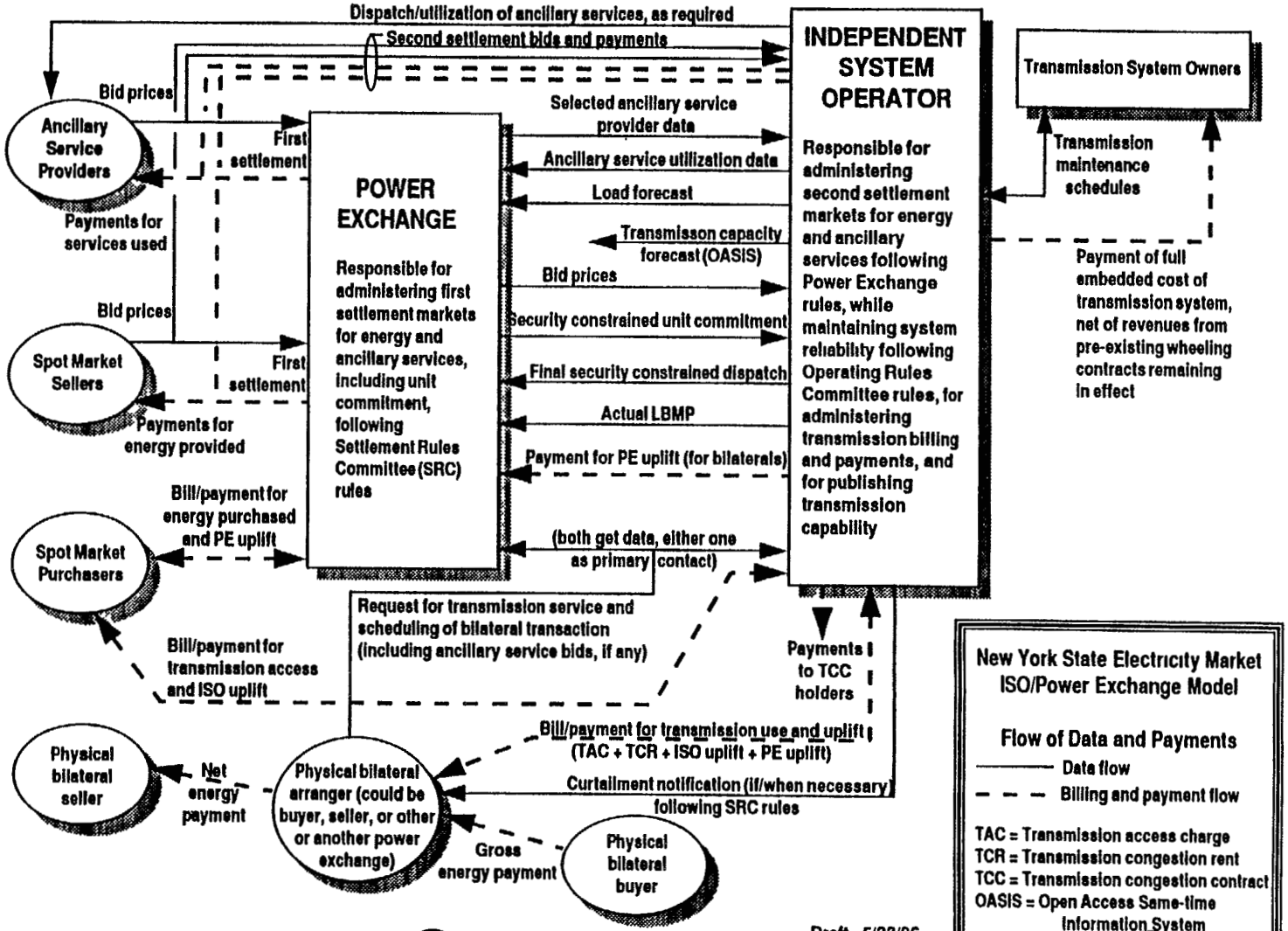
- Energy and Capacity Pricing
- Resource commitment Process
- Transmission Service and Pricing

Flexible Poolco Model

- Features

  - Full accomodation of Bilateral Transactions
  - Robust Central Dispatch / Spot Energy Market
  - Open Transmission Access


ISOT
INDEPENDENT SYSTEM OPERATOR
Responsible for administering second settlement markets for energy and ancillary services following SRC rules, while maintaining system reliability following ORC rules, for administering transmission billing and payments, and for publishing transmission capability
Transmission System Owners
Transmission System Operating Agreements
C
C
TCC Holders
Transmission Congestion Contracts
Ancillary Service Providers
Spot Market Sellers
Spot Market Purchasers
POWER EXCHANGE
Responsible for administering first settlement markets for energy and ancillary services, including unit commitment, following Settlement Rules Committee rules
Settlement Rules Committee
Responsible for establishing commercial rules for first and second settlement
Settlement rules
Second settlement rules
C
Power Exchange/ISO Agreement
Operating Rules Committee
Responsible for establishing operating criteria, standards and rules
Reliability criteria standards and rules
PET
Physical bilateral seller
C
Physical bilateral arranger (could be buyer, seller, or other or another power exchange)
C
Physical bilateral buyer
Draft 5/23/96
New York State Electricity Market
ISO/Power Exchange Model
Tariffs, Contracts, and Rulemaking
Establishment of rules, criteria, standards
C
Contract or other similar agreement
ISOT
ISO tariff (mandatory)
PET
Power Exchange tariff (optional participation)


Dispatch/utilization of ancillary services, as required
Second settlement bids and payments
INDEPENDENT SYSTEM OPERATOR
Responsible for administering second settlement markets for energy and ancillary services following Power Exchange rules, while maintaining system reliability following Operating Rules Committee rules, for administering transmission billing and payments, and for publishing transmission capability
Transmission System Owners
Transmission maintenance schedules
Payment of full embedded cost of transmission system, net of revenues from pre-existing wheeling contracts remaining in effect
Bid prices
Ancillary Service Providers
First settlement
Payments for services used
POWER EXCHANGE
Responsible for administering first settlement markets for energy and ancillary services, including unit commitment, following Settlement Rules Committee (SRC) rules
Selected ancillary service provider data
Ancillary service utilization data
Load forecast
Transmisson capacity forecast (OASIS)
Bid prices
Security constrained unit commitment
Final security constrained dispatch
Actual LBMP
Payment for PE uplift (for bilaterals)
Bid prices
Spot Market Sellers
First settlement
Payments for energy provided
Bill/payment for energy purchased and PE uplift
Spot Market Purchasers
(both get data, either one as primary contact)
Request for transmission service and scheduling of bilateral transaction (including ancillary service bids, if any)
Bill/payment for transmission access and ISO uplift
Payments to TCC holders
Bill/payment for transmission use and uplift (TAC + TCR + ISO uplift + PE uplift)
Physical bilateral seller
Net energy payment
Physical bilateral arranger (could be buyer, seller, or other or another power exchange)
Curtailment notification (if/when necessary) following SRC rules
Gross energy payment
Physical bilateral buyer
New York State Electricity Market ISO/Power Exchange Model
Flow of Data and Payments
Data flow
Billing and payment flow
TAC = Transmission access charge
TCR = Transmission congestion rent
TCC = Transmission congestion contract
OASIS = Open Access Same-time Information System
Draft 5/23/96

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ECONOMIC DISPATCH OF RESOURCES

ECONOMIC DISPATCH OF RESOURCES

Basic Objectives

The NYPP Process

ECONOMIC DISPATCH OF RESOURCES

THE COMMITMENT PROCESS

INTERCHANGE EVALUATION

DISPATCH AND CONTROL

ANCILLARY SERVICES

THE COMMITMENT PROCESS

OBJECTIVES

TIME FRAME

LOADS & RESOURCES

INTERCHANGE TRANSACTIONS

TRANSMISSION CONSTRAINTS

RESERVE REQUIREMENTS

ANCILLARY SERVICES

INTERCHANGE EVALUATION

TRANSACTION ORDERING

PRICING ALTERNATIVES

TRANSMISSION CONSTRAINTS

LOSSES

DOCUMENTATION & BILLING

DISPATCH AND CONTROL

LOAD AND LOSSES

INTERCHANGE SCHEDULES

FUNDAMENTAL DISPATCH

DISPATCH WITHOUT CONSTRAINTS

DISPATCH WITH CONSTRAINTS

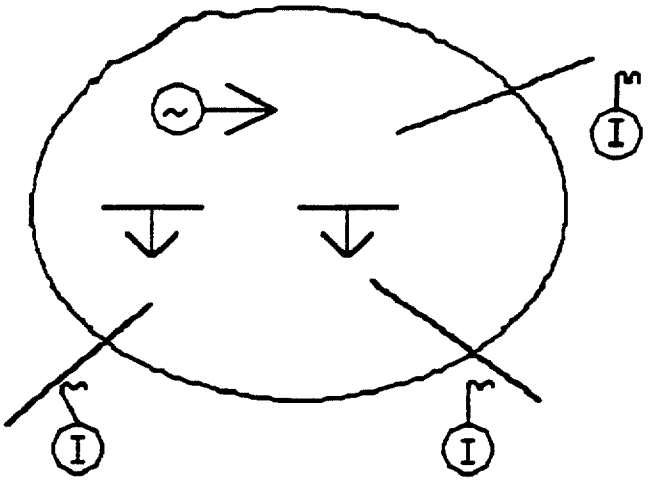
PRICING METHODS

PENALTIES AND INCENTIVES

COST VERSUS MARKET BASED DISPATCH

BI-LATERAL CONTRACTS

AUTOMATIC GENERATION CONTROL



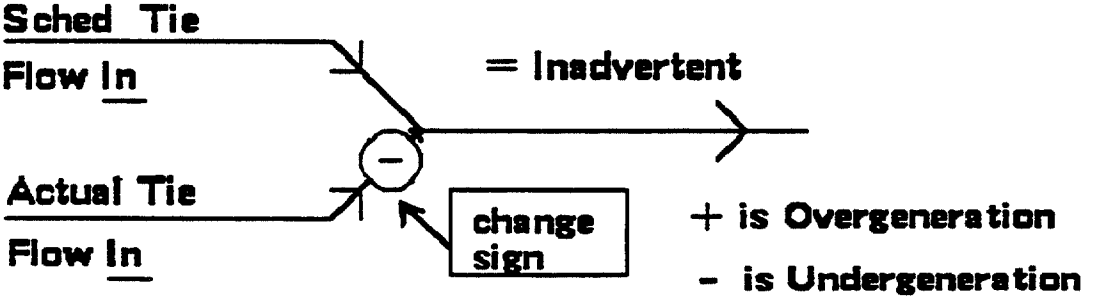
"MEETING SCHEDULE":

"Fixed Schedules"

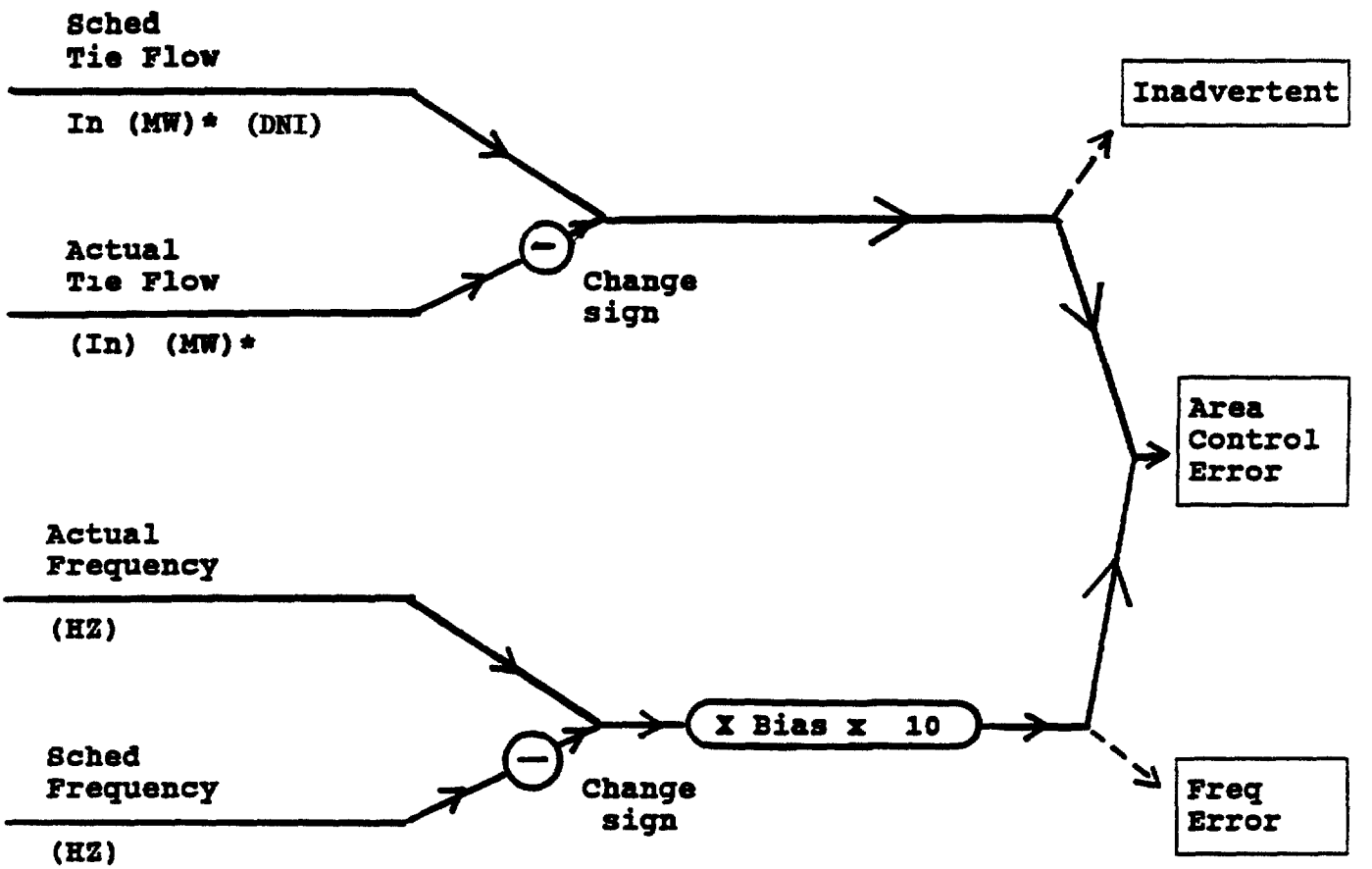
"DNI" - Desired Net Interchange

"fudge"

"INADVERTENT" MW:



THE AGC PICTURE



*NYPP convention - "into system" is a plus

NERC Criteria:

"A1" - Normally:

The ACE must equal zero at least one time in all 10 minute periods. Once zero is crossed, it must be crossed again within a 10 minute period.

"A2" - Normally:

The average ACE for all 10 minute periods must be within "L_D". An "L_D" is assigned to each system, and is based on that system's change of load characteristic.

"B" Criteria -

Disturbance Criteria:

"B1" - ACE must be returned to zero within 10 minutes.

"B2" - Corrective action must be forthcoming within 1 minute of a disturbance.

Policy 1 — Generation Control and Performance

Policy Subsections

A Operating Reserve
B Automatic Generation Control
C Frequency Response and Bias
D Time Control
E Performance Standard — Effective Beginning Feb 1, 1997; Compliance Expected Feb 1, 1998
F Inadvertent Interchange
G Control Surveys
H Control and Monitoring Equipment

General Criteria

Each system shall either operate a Control Area or make arrangements to be included in a Control Area operated by another system All load, generation, and transmission operating in an Interconnection must be included within the metered boundaries of a Control Area

A. Operating Reserve

[Appendix 1A – Area Control Error Equation]
[Performance Standard Training Document]

Criteria

Each CONTROL AREA shall operate its MW power resources to provide for a level of OPERATING RESERVE sufficient to account for such factors as errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity Following loss of resources or load, a CONTROL AREA shall take appropriate steps to reduce its AREA CONTROL ERROR to meet the Disturbance Control Standard (DCS) It shall take prompt steps to protect itself against the next contingency

Each Region, subregion or RESERVE SHARING GROUP shall specify its operating reserve policies, including the minimum reserve requirement for the group, its allocation among members, the permissible mix of SPINNING RESERVE and nonspinning reserve, and procedure for applying operating reserve in practice, and the limitations, if any, upon the amount of interruptible load which may be included

Requirements

1 **Operating reserve distribution** OPERATING RESERVE shall be dispersed throughout the system and shall consider the effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements

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2 **Contingency review** All Regions, subregions, RESERVE SHARING GROUPS, and CONTROL AREAS shall frequently review probable contingencies to determine the adequacy of operating reserve

3 **Operating reserve** Each Region, subregion, or RESERVE SHARING GROUP shall specify, and each CONTROL AREA shall provide, as a minimum, operating reserve as follows

3 1 **Regulating reserve** An amount ofSPINNING RESERVE, responsive to AGC, which is sufficient to provide normal regulating margin, plus

3 2 **Contingency reserve** An additional amount of OPERATING RESERVE sufficient to reduce AREA CONTROL ERROR to meet the Disturbance Control Standard following the most severe single contingency

3 2 1 **Spinning reserve** At least 50% of this operating reserve shall BeSPINNING RESERVE which will automatically respond to frequency deviations

3 2 1 1 **Jointly owned generation with dynamic schedules** CONTROL AREAS that share JOINTLY OWNED UNITS and incorporate DYNAMIC SCHEDULES or PSEUDO-TIES shall include only their share of the unit in their SPINNING RESERVE calculations

3 2 1 2 **Jointly owned generation with fixed schedules** CONTROL AREAS receiving their share of JOINTLY OWNED UNITS as fixed schedules should not include the jointly owned units' share(s) on which the schedules are based in their SPINNING RESERVE calculations The CONTROL AREA in which the jointly owned unit resides may include theSPINNING RESERVES for its share of the unit

3 2 2 **Reserve sharing group** Each RESERVE SHARING GROUP shall comply with the the Disturbance Control Standard as if it were a single CONTROL AREA A RESERVE SHARING GROUP shall be considered in a DISTURBANCE condition any time a group member is in a DISTURBANCE condition and calls for reserves Compliance may be demonstrated in either of the following two methods

3 2 2 1 **Group compliance to Disturbance Control Standard** TheRESERVE SHARING GROUP reviews group ACE (or equivalent) and demonstrates compliance

3 2 2 2 **Group member compliance to Disturbance Control Standard** The RESERVE SHARING GROUP reviews each member's ACE in response to a call for reserves, to be in compliance each member's ACE must return to zero or to its respective pre-disturbance level within ten minutes of the start of the DISTURBANCE

3 2 3 **RESERVE SHARING GROUP monitoring** Each RESERVE SHARING GROUP shall monitor operating reserve availability and actual response

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3 2 4 **Reduction in SPINNING RESERVE** The SPINNING RESERVE component may be reduced below 50% of the OPERATING RESERVE providing the Region, subregion, or reserve sharing group can demonstrate that with this reduction and upon its most severe single contingency, it will still be able to meet or exceed established Performance Standards, and not jeopardize the reliable operation of the Interconnection

3 2 5 **INTERRUPTIBLE LOAD** INTERRUPTIBLE LOAD may be included in the non-spinning reserve provided that it can be interrupted within ten minutes

3 2 6 **Disturbance Control Performance Adjustment** Each control area or reserve sharing group *not meeting the Disturbance Control Standard* during a given quarter, shall increase its Contingency Reserve obligation for the calendar quarter (offset by a month) following the evaluation The increase shall be directly proportional to the control area's or reserve sharing group's non-compliance to the Disturbance Control Standard (See the "Performance Standard Training Document," Section C)

3 3 **Jointly owned generation in another CONTROL AREA** CONTROL AREAS using fixed schedules for JOINTLY OWNED UNITS that reside outside their CONTROL AREA may include their share of the facility in their OPERATING RESERVE calculations The OPERATING RESERVE is constrained by their share of the unit(s) capability and their share of the unit(s) ramp capability achievable over a ten-minute period Included in the ten minutes is the time necessary to schedule the generation into the CONTROL AREA

3 4 **Reestablishing OPERATING RESERVE** An additional amount of reserve shall be made available as soon as practicable to aid in reestablishing this minimum OPERATING RESERVE after such reserve has been used

B. Automatic Generation Control

[Appendix 1A – The Area Control Error (ACE) Equation]
[Performance Standard Training Document]

Criteria

Each CONTROL AREA shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and INTERCHANGE schedules to its load It shall also provide its proper contribution toINTERCONNECTION frequency regulation

Requirements

1 **CONTROL AREA components** All load, generation, and transmission operating in an INTERCONNECTION must be included within the metered boundaries of a CONTROL AREA

2 **AGC calculation** AUTOMATIC GENERATION CONTROL (AGC) shall compare total net actual interchange to total net scheduled INTERCHANGE plus frequency bias contribution to determine the CONTROL AREA's AREA CONTROL ERROR (ACE)

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3 **Regulating capability** Each CONTROL AREA shall maintain generating regulating capability, synchronized to the INTERCONNECTION, that can be increased or decreased by AGC to provide for adequate system regulation and Control Performance

4 **Manual control** If AGC has become inoperative, manual control shall be used to adjust generation to maintain scheduled INTERCHANGE

5 **Regulation service** It is the responsibility of the CONTROL AREA providing REGULATION SERVICE to notify the entity for whom it is controlling if it is unable to provide the service

Guides

1 **AGC** All generating units of consequential size, including JOINTLY OWNED UNITS capable of regulating, should be equipped with AGC to ensure that the CONTROL AREA can continuously balance its generation with its demand plus net scheduled INTERCHANGE

1 1 **Data scan rates for ACE** Data acquisition for and calculation of ACE should occur at least every four seconds

1 2 **Data scan rates for joint control and regulation** For JOINT CONTROL andREGULATION SERVICES, the recommended update rates for data transmission is every four seconds If a four-second update rate is not possible, the rate should be at least as fast as the slowest scan rate of the participating CONTROL AREAS In all cases, data shared by the control participants must be identical at all times

2 **AGC operation** AGC should remain in operation as much of the time as possible

3 **AGC suspension** AGC may be suspended at frequencies above 60 2 Hz or below 59 8 Hz if continued control would result in generation changes that could endanger system reliability

4 **AGC verification** Turbine governors and control systems, including AGC, and HVDC control systems should be checked periodically to verify their correct operation

5 **Load-limiters** Load-limiting devices should be applied only to restrict the extent of LOAD change which might have an adverse effect on the generator or jeopardize transmission security

6 **Regulating margin** Regulating margin should be distributed over as many units as possible

7 **Control performance** Each CONTROL AREA should plan for future adequate control performance to meet expected changes in LOAD characteristics and daily LOAD patterns

8 **Response rates** The utility should establish normal and emergency rates of response for each generator and HVDC terminal

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C. Frequency Response and Bias

[Appendix 1A – The Area Control Error (ACE) Equation]
[Frequency Response Characteristic Survey Training Document]

Requirements

1 **Bias setting review** Each CONTROL AREA shall review its FREQUENCY BIAS SETTINGS by January 1 of each year and recalculate its setting to reflect any change in area frequency response characteristic

1 1 **Bias setting method** The FREQUENCY BIAS SETTING, and the method used to determine the setting, may be changed whenever any of the factors used to determine the current bias value change

1 2 **Bias setting reporting** Each CONTROL AREA shall report its FREQUENCY BIAS SETTING, and method for determining that setting, to the Performance Subcommittee

1 3 **Bias setting verification** Each CONTROL AREA must be able to demonstrate and verify to the Performance Subcommittee that its FREQUENCY BIAS SETTING closely matches or is greater than its system response

Standards

1 **Tie-line bias** Each CONTROL AREA shall operate its AGC on tie-line frequency bias, unless such operation is adverse to system or INTERCONNECTION reliability The Standards for tie-line bias control follow

1 1 **Bias setting to match frequency response** The CONTROL AREA shall set its frequency bias (expressed in MW/0 1 Hz) as close as practical to the CONTROL AREA's frequency response characteristic Frequency bias may be calculated several ways

1 1 1 **Fixed bias setting** A fixed frequency bias value may be used which is based on a fixed, straight-line function of tie-line deviation versus frequency deviation The fixed value shall be determined by observing and averaging the frequency response characteristic for several DISTURBANCES during on-peak hours

1 1 2 **Variable bias setting** A variable (linear or non-linear) bias value may be used which is based on a variable function of tie-line deviation to frequency deviation The variable frequency bias value shall be determined by analyzing frequency response as it varies with factors such as LOAD, generation, governor characteristics, and frequency

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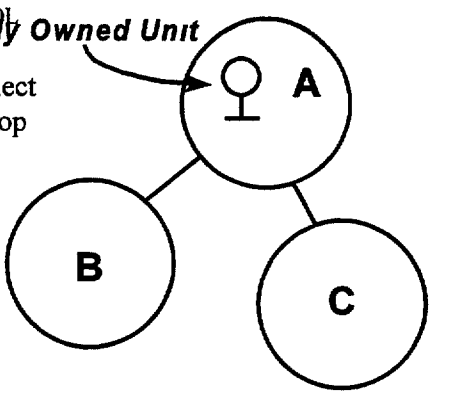
1 1 3 **Bias and jointly owned generation** CONTROL AREAS that use DYNAMIC SCHEDULING or PSEUDO-TIES for jointly owned units must reflect their respective share of the unit governor droop response into their respective FREQUENCY BIAS SETTING Fixed schedules for JOINTLY OWNED UNITS mandate that the CONTROL AREA (A) that contains the JOINTLY OWNED UNIT must incorporate the respective share of the unit governor droop response for any CONTROL AREAS that have fixed schedules (B and C) The CONTROL AREAS that have a fixed schedule (B and C) but do not contain the JOINTLY OWNED UNIT should *not* include their share of the governor droop response in their FREQUENCY BIAS SETTING



1 1 4 **Minimum bias setting for CONTROL AREAS that serve native LOAD** The CONTROL AREA'S monthly average FREQUENCY BIAS SETTING must be at least 1% of the CONTROL AREA'S estimated yearly peak demand per 0 1 Hz change as described in the Frequency Response Characteristic Survey Training Document

1 1 5 **Minimum bias setting for CONTROL AREAS that do not serve native LOAD** The CONTROL AREA'S monthly average FREQUENCY BIAS SETTING must be at least 1% of its estimated maximum generation level in the coming year per 0 1 Hz change as described in the Frequency Response Characteristic Survey Training Document

1 1 6 **Bias and overlap regulation** A CONTROL AREA that is performing OVERLAP REGULATION SERVICE will increase its FREQUENCY BIAS SETTING to match the frequency response of the entire area being controlled A CONTROL AREA that is performing SUPPLEMENTAL REGULATION SERVICE shall not change its FREQUENCY BIAS SETTING

Guides

1 **Governor installation** Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for frequency response unless restricted by regulatory mandates

2 **Governors free to respond** Turbine governors and HVDC controls, where applicable, should be allowed to respond to system frequency deviation, unless there is a temporary operating problem

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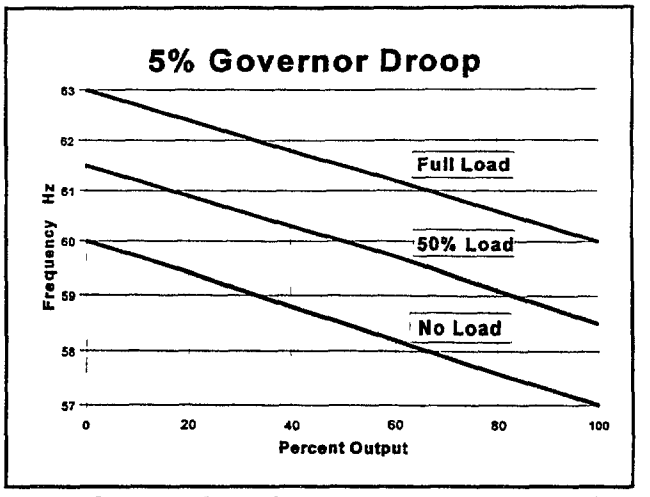
3 **Governor droop** All turbine generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions Governors should provide a 5% droop characteristic Governors should, as a minimum, be fully responsive to frequency deviations exceeding ± 0 036 Hz (± 36 MHz)

4 **Governor limits** Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics



Graph showing relation between generator output and Interconnection frequency at 0 50% and 100% LOAD for a 5% governor droop characteristic

D. Time Control

[Appendix 1A — The Area Control Error Equation]
[Appendix 1D — Time Error Correction Procedures]

Criteria

INTERCONNECTION frequency shall be scheduled at 60 Hz and controlled to that value except for those periods in which frequency deviations are scheduled to correct time error

Operating limits for frequency deviation and time error shall be established with Interconnection reliability as first priority

Each CONTROL AREA shall participate in Interconnection time error correction procedures

CONTROL AREAs which are operating in parallel shall select one CONTROL AREA to monitor time error for the Interconnection and to issue time error correction orders

Requirements

1 **Interconnection monitor** Each INTERCONNECTION shall designate an Interconnection Monitor who shall monitor time error and shall initiate or terminate corrective action orders when time error reaches predetermined limits as shown in Appendix 1D

2 **Time correction notice and commencement** Time error corrections shall start and end on the hour or half-hour, and notice shall be given at least 20 minutes before the time error correction is to start or stop

3 **Time correction serialization** Time error correction notifications shall be serialized alphabetically on a monthly basis

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4 **Time correction offset.** The time error correction offset shall be applied by either of the following two methods

4 1 **Frequency offset** The frequency schedule may be offset by 0 02 Hz, leaving the FREQUENCY BIAS SETTING normal, or

4 2 **Schedule offset** If the CONTROL AREAFREQUENCY BIAS SETTING cannot be offset, the net INTERCHANGE schedule (MW) may be offset by an amount equal to the computed bias contribution during a 0 02 Hz frequency deviation (i e , 20% of the FREQUENCY BIAS SETTING)

5 **Regional Monitor** A Regional Monitor shall be designated through which time error correction notifications originating with the Interconnection Monitor will be routed to each system in the Region by way of established Time Notification Channels

6 **Interconnection time error notification** The Interconnection Monitor shall periodically issue a notification of time error, accurate to within 0 1 second, to the Regional Monitors to assure uniform calibration of time standards

7 **Regional time error notification** Using the Time Notification Channels, the Regional Monitors shall, each hour, on the hour, notify all systems within their respective Regions of the accumulated time error within 0 1 second Time error notification shall be accompanied by the alphabetic designator if a time error correction is in progress

8 **Calibration of time and frequency devices** Each CONTROL AREA shall at least annually check and calibrate its time error and frequency devices against a common reference

9 **Time correction on reconnection.** When one or more CONTROL AREAS has been separated from the INTERCONNECTION, upon reconnection, they shall adjust their time error devices to coincide with the Interconnection by one of the following methods

9 1 **Time correction before reconnection** Before connection, the separated area may institute a Time Error Correction Procedure to correct its accumulated time error to coincide with the indicated time error of the Interconnection Monitor, or

9 2 **Device correction after reconnection** After interconnection, the time error devices of the previously separated area may be recalibrated to coincide with the indicated time error of the Interconnection Monitor A notification of adjusted time error shall be passed through Time Notification Channels as soon as possible after interconnection

Guides

1 **Automatic time correction** The CONTROL AREAS of an INTERCONNECTION may implement automatic time error control as a part of their AGC scheme

1 1 **Participation** If automatic time error correction is used, all CONTROL AREAS of the INTERCONNECTION should participate

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2 **Leap seconds** Systems using time error devices that are not capable of automatically adjusting for leap-seconds should arrange to receive advance notice of the leap-second and make the necessary manual adjustment in a manner that will not introduce a disturbance into their control system

E. Performance Standard

Effective Beginning Feb 1, 1997
Compliance Expected Feb 1, 1998

[Appendix 1H – Minimum Data Collection Requirements for Use in Monitoring NERC Performance Standards]
[Performance Standard Training Document]

Introduction

The Control Performance Standard (CPS) define a standard of minimum control performance Each CONTROL AREA is to have the best operation above this minimum that can be achieved within the bounds of reasonable economic and physical limitations

Standards

1 **Continuous Monitoring** Each control area shall monitor its control performance on a continuous basis against two Standards CPS1 and CPS2

1 1 **Control Performance Standard (CPS1)** Over a year, the average of the clock-minute averages of a control area's ACE divided by –10B (B is control area frequency bias) times the corresponding clock-minute averages of Interconnection's frequency error shall be less than a specific limit This limit, ε, is a constant derived from a targeted frequency bound reviewed and set as necessary by the NERC Performance Subcommittee

1 2 **Control Performance Standard (CPS2)** The average ACE for each of the six ten-minute periods during the hour (i e , for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10} See the "Performance Standard Training Document," Section B 1 1 2 for the methods for calculating L_{10}

2 **Disturbance conditions** In addition to CPS1 and CPS2, the Disturbance Control Standard shall be used by each control area or reserve sharing group to monitor control performance during recovery from disturbance conditions (see the "Performance Standard Training Document," Section B 2)

2 1 **Disturbance Control Standard (DCS)** The ACE must return either to zero or to its pre-disturbance level within ten minutes following the start of the disturbance

Requirements

1 **ACE values** The ACE used to determine compliance to the Control Performance Standards shall reflect its actual value, and exclude short excursions due to transient telemetering problems or other influences such as control algorithm action

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2 **Control Performance Standard (CPS) Compliance** Each CONTROL AREA shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90% (see the "Performance Standard Training Document," Section C)

3 **PS Surveys** All CONTROL AREAS shall respond to control performance surveys that are requested by the Performance Subcommittee

4 **Disturbance Control Standard Compliance** Each CONTROL AREA or RESERVE SHARING GROUP shall meet the Disturbance Control Standard (DCS) 100% of the time for reportable disturbances (see the "Performance Standard Training Document," Section C)

5 **Disturbance Control Surveys** Each control area or reserve sharing group shall submit a quarterly summary report to their Regional Performance Subcommittee representative of the respective control area's compliance to the DCS during the reporting quarter

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F. Inadvertent Interchange

[Appendix 1F – Inadvertent Interchange Energy Accounting Practices]
[Inadvertent Interchange Accounting Training Document]

Criteria

Each CONTROL AREA shall, through daily schedule verification and the use of reliable metering equipment, accurately account for INADVERTENT INTERCHANGE Recognizing generation and LOAD patterns, each CONTROL AREA shall be active in preventing unintentional INADVERTENT INTERCHANGE accumulation Each CONTROL AREA shall also be diligent in reducing accumulated inadvertent balances in accordance with Operating Committee procedures

Each CONTROL AREA interconnection point shall be equipped with a common MWh meter, with readings provided hourly at the control centers of both areas

Requirements

1 **Inadvertent calculation** INADVERTENT INTERCHANGE shall be calculated and recorded hourly and may accumulate as a credit or debit to the CONTROL AREA

2 **Including all interconnections** All interconnections shall be included in the INADVERTENT INTERCHANGE account Interchange served through jointly owned facilities and interchange with borderline customers must be properly taken into account

3 **Inadvertent payback.** INADVERTENT INTERCHANGE accumulations shall be paid back by one or both of the following methods

3 1 **Bilateral payback.** Method 1 — INADVERTENT INTERCHANGE accumulations may be paid back by scheduling interchange with another CONTROL AREA

3 1 1 **Other CONTROL AREA** The other CONTROL AREA must have an inadvertent accumulation in the opposite direction

3 1 2 **Agreement on schedule** The amount of inadvertent payback scheduled shall be agreed upon by all involved systems

3 2 **Unilateral payback.** Method 2 — INADVERTENT INTERCHANGE accumulations may be paid back unilaterally controlling to a target of non-zero ACE Payback may be made through an AGC offset of up to 20% of the CONTROL AREA's bias or 5 MW, whichever is greater

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4 **Payback with energy "in-kind "** INADVERTENT INTERCHANGE accumulated during "on-peak" hours shall be paid back during "on-peak" hours INADVERTENT INTERCHANGE accumulated during "off-peak" hours shall be paid back during "off-peak" hours

5 **Inadvertent account summary** Each CONTROL AREA shall submit a monthly summary of INADVERTENT INTERCHANGE as detailed in Appendix 1F, "INADVERTENT INTERCHANGE Energy Accounting Practices "

5 1 **Summary balances** INADVERTENT INTERCHANGE summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the "on-peak" and "off-peak" periods

5 2 **Summary submission** Each CONTROL AREA shall submit its monthly summary report to its Performance Subcommittee representative who will prepare a composite tabulation for distribution to all other Performance Subcommittee representatives

G. Control Surveys

[Area Interchange Error Survey Training Document]
[Frequency Response Characteristic Survey Training Document]
[Performance Standard Training Document]

Criteria

Periodic surveys of the control performance of the CONTROL AREAs shall be conducted These surveys serve the purpose of revealing control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic control, general control performance deficiencies, or other factors contributing to inadequate control performance

Requirements

1 **Surveys** The CONTROL AREAs in each INTERCONNECTION shall perform each of the following surveys, as described in the Performance Standard Training Document, when called for by the Performance Subcommittee

1 1 **AIE survey** Area Interchange Error survey to determine the CONTROL AREAs' INTERCHANGE error(s) due to equipment failures or improper SCHEDULING operations, or improper AGC performance

1 2 **FRC survey** Area Frequency Response Characteristic survey to determine the CONTROL AREAs' response to changes in system frequency

1 3 **CPS and DCS surveys** Performance Standard surveys to monitor the CONTROL AREAs' control performance during normal and DISTURBANCE situations

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H. Control and Monitoring Equipment

[Appendix 1H – Minimum Data Collection Requirements for Use in Monitoring NERC Performance Standards]

Criteria

The control equipment of each CONTROL AREA shall be designed and operated so that the CONTROL AREA can continuously and accurately meet its system and INTERCONNECTION control obligations and measure its performance The control equipment design and operation shall follow accepted industry techniques

All CONTROL AREA interconnection points shall be equipped to telemeter MW power flow to both area control centers simultaneously The telemetering shall be from an agreed-upon terminal utilizing common metering equipment

The system operator's displays and consoles shall present a clear and understandable picture of CONTROL AREA parameters This includes necessary information from facilities within other CONTROL AREAs in addition to internal information

Requirements

1 **Hourly verification of tie flows** Each CONTROL AREA shall perform hourly control error checks using tie-line MWh meters to determine the accuracy of its control equipment

2 **Adjustments for equipment error** The SYSTEM OPERATOR shall adjust control settings to compensate for any equipment error until repairs can be made

3 **Minimum data recording** SYSTEM OPERATORS shall be provided with a recording of those variables necessary to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance As a minimum, area control error (ACE), system frequency, and net tie-line INTERCHANGE data shall be continuously recorded

4 **Data filtering** The power flow and ACE signals that are transmitted for REGULATION SERVICE shall not be filtered prior to transmission except for anti-aliasing filtering of tie lines

5 **Metering for jointly owned generation** Common metering equipment shall be installed where DYNAMIC SCHEDULES or PSEUDO-TIES are implemented between two or more CONTROL AREAs to deliver the output of JOINTLY OWNED UNITS or to serve remote LOAD

6 **Tie flows in ACE calculation** All tie-line flows between CONTROL AREAs shall be included in each CONTROL AREA's ACE calculation

Guides

1 **Backup power for data recording** Adequate and reliable backup power supplies should be provided and periodically tested at the system control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply

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2 **Tie-line metering** All tie-line MW and MWH/Hr telemetry should be telemetered to both control centers, and should emanate from a common, agreed-upon terminal using common primary metering equipment

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Performance Standard Training Document

Training Document Subsections

A	**Area Control Error**
B	**Performance Standard**
C	**Calculation of Compliance**
D	**Survey Procedures**

This document provides the NERC Control Performance Compliance Survey coordinator with specific instructions on calculating the control performance of the control area and instructions to complete the survey forms contained in the document as CPS Form 1 and 2 and Form DCS

The control area is required to continuously monitor its control performance and report its compliance results at the end of each month This training document provides an explanation of the reporting requirements for the NERC Control Performance Standard

A. Area Control Error

[Appendix 1A — The Area Control Error Equation]

The control area's Area Control Error (ACE) is the basis for the calculation of control parameters used to evaluate control performance One part of the NERC Control Performance Standard (CPS) is defined by the control parameter

$$\left[\left(\frac{ACE_t}{-10B_t}\right)_1 \times \Delta F_1\right]$$

wherein the subscript 1 indicates one-minute clock averages This parameter is used to determine a control area's control performance with respect to the control area's impact on system frequency The values of ACE to be used throughout the calculation of the control parameter shall reflect its actual value and exclude short excursions due to transient telemetering problems or other influences such as control algorithm actions Erroneous readings such as "spikes" due to telemetering error or other false influences should be excluded from the calculations However, the computations should include ALL of the non-erroneous intervals (i e , do not exclude intervals that contains disturbance conditions) This ACE is defined as net actual interchange less net scheduled interchange less frequency bias contribution and meter error It does not include offsets (e g , unilateral inadvertent payback, WSCC's automatic time error correction, etc)

B. Performance Standard

[Appendix lA — The Area Control Error Equation]

The CPS is composed of two measures One measure is a statistical measure of ACE variability and its relationship to frequency error The second measure is a statistical measure designed to limit unacceptably large net unscheduled power flows These two measures define the NERC Control Performance Standard ***The NERC Control Performance Standard is the measure against which all control areas will be evaluated***

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The first measure of the CPS survey provides a measure of the control area's performance This control performance measure is defined in Section B 1 1 1 The measure is intended to provide the control area with a frequency-sensitive evaluation of how well the respective area met its demand requirements The measure is not designed to be a visual indicator that an operator would use to control system generation Nor is this measure designed to address the issue of unscheduled power flows, or minimization of inadvertent interchange

The second measure of the CPS survey is designed to bound ACE ten-minute averages and provides an oversight function to limit excessive unscheduled power flows that could result from large ACEs The measure to limit the magnitude of ACE is described in Section B 1 1 2

These measurements of control performance apply to all conditions (i e , both normal and disturbance conditions) The CPS is supplemented by a Disturbance Control Standard that establishes bounds for system recovery The following discussion expands the definitions of the criteria found in Operating **Policy lE — Control Performance** and defines the respective measurements and associated criteria

1 **Continuous Monitoring Requirements** The NERC Control Performance Standard defines a minimum acceptable control performance that a control area is expected to maintain over all operating conditions

1 1 **Parameters** The Control Performance Standard imposes two requirements

1 1 1 **CPS1** Over a given period, the average of the clock-minute averages of a control area's [ACE divided by ten times its bias] times the corresponding clock-minute averages of the Interconnection's frequency error shall be less than the constant on the right-hand side of the following inequality

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 \times \Delta F_1\right] \le \epsilon_1^2 \quad or \quad \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 \times \Delta F_1\right]}{\epsilon_1^2} \le 1$$

where ACE_i is the clock-minute average of ACE (as ACE is defined in Section A),

B_i is the frequency bias of the control area For those areas with variable bias, an area should accumulate ACE/(–10B) through the AGC cycles of a minute, and save the averaged value at the end of the minute as the clock-minute value of $ACE_i/(-10B_i)$,

ϵ_1 is a constant derived from the targeted frequency bound It is the targeted RMS of one-minute average frequency error from a schedule based on frequency performance over a given year The bound is the same for every control area within an Interconnection,

ΔF is the clock-minute average of frequency error from schedule, $\Delta F = F_a - F_s$, where F_a is the actual (measured) frequency and F_s is scheduled frequency for the Interconnection,

I is representative of the control area,

Period is defined as

a) one year for control area evaluation
b) one month for Performance Subcommittee review

1 1 2 **CPS2** Over a clock ten-minute period, the ten-minute averages of a control area's ACE shall be less than the constant on the right-hand side of the following inequality

$$AVG_{10-minute}(ACE_i) \leq L_{10}$$

where

$$L_{10} = 1\ 65\epsilon_{10}\sqrt{(-10B_i)(-10B_s)}$$

ϵ_{10} is a constant derived from the targeted frequency bound It is the targeted RMS of ten-minute average frequency error from schedule based on frequency performance over a given year The bound, ϵ_{10}, is the same for every control area within an Interconnection,

1 65 is a constant used to convert the frequency target to 90% probability It is the number of standard deviations from the mean of a statistical normal distribution (Gausian distribution) that will result in a probability of noncompliance of 10% (i e , compliance of 90%),

B_i is the frequency bias of the control area, and

B_s is the sum of the frequency bias settings of the control areas in the respective Interconnection, for systems with variable bias, this is equal to the sum of the minimum frequency bias settings

For those systems with variable bias, CPS2 becomes

$$AVG_{10-minute}(ACE) \leq L_{10}$$

where

$$L_{10} = 1\ 65\epsilon_{10}\left[-10AVG_{10-minute}(B_i)\right]\sqrt{\frac{B_s}{B_{minimum}}}$$

$B_{minimum}$ is the area's minimum allowed bias

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1 2 **Targeted Frequency Bounds** The Targeted Frequency Bounds, ϵ_1 and ϵ_{10}, are based on historic measured frequency error These bounds embody the targeted frequency characteristics used for developing the Control Performance Standard Each Interconnection will be assigned its own frequency bounds

The Targeted Frequency Bound for an Interconnection is computed as follows

1 2 1 NERC Performance Subcommittee (PS) defines a desired frequency profile This profile will be derived from the frequency experienced over a PS-selected one-year period

1 2 2 NERC PS collects the frequency data from designated providers within each Interconnection The frequency bounds are the RMS of the one-and ten-clock-minute averages of the frequency error from schedule These values are derived from data samples over a given year NERC PS calculates the targeted frequency bounds, ϵ_1 and L_{10}, to recognize the desired performance of frequency for each Interconnection

1 3 **Compliance for Control Areas** A control area that does not comply with CPS is not providing its required regulation service

1 3 1 If a control area does not comply with the CPS, the control area is not permitted to provide regulation or other services related to control performance for any other control area(s) or other entities Those services shall be determined by the NERC PS

1 3 2 A control area failing to comply shall take immediate corrective action and achieve compliance within three months If necessary, a control area shall buy sufficient supplemental regulation to achieve compliance

1 4 **Compliance for Control Areas Providing Regulation** A control area is not permitted to provide regulation or other services related to control performance (as determined by the NERC Performance Subcommittee) for (an)other control area(s) or other entities external to that control area, if the former control area does not comply with the CPS

1 5 **Compliance for Control Areas Participating in Supplemental Regulation** A control area providing or receiving supplemental regulation, either through dynamic schedules or pseudo-ties, will continue to be evaluated on the characteristics of its own area control error with the supplemental regulation service included The $\left[\left(\frac{ACE_i}{-10B_i}\right)_1 \times \Delta F_1\right]$ for each of the affected control areas will not change

1 6 **Compliance for Control Areas Participating in Overlap Regulation**

1 6 1 **Control Areas Providing Overlap Regulation** A control area *providing* overlap regulation shall continue to be evaluated on the characteristics of the combined areas' ACE The provider control area must calculate and use the

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combined limit using the sum of its own frequency bias setting, B_i and the frequency bias setting, B_j, of the control area for which it is providing the overlap regulation

1 6 2 **Control Areas Receiving Overlap Regulation** A control area *receiving* overlap regulation service shall not have its control performance evaluated

2 **Disturbance Conditions** During a disturbance, controls cannot usually maintain ACE within the criteria for normal load variation However, an area is expected to activate operating reserve to recover ACE within ten minutes This requires that a disturbance condition be defined For purposes of disturbance control compliance, a reportable disturbance is defined as an event whose magnitude is less than or equal to the magnitude of an affected control area's most severe contingency, or is greater than or equal to 80% of the magnitude of the control area's most severe single contingency loss Regional Reliability Councils may, at their discretion, require a lower reporting threshold

Normal load and generation excursions (e g , pumped storage hydro, arc furnace, rolling steel mill, etc) that influence ACE are not reportable disturbance conditions

2 1 **Control Area** A CONTROL AREA shall return its ACE either to zero or to its pre-disturbance ACE level within ten minutes following a disturbance A control area may, at its discretion, measure its compliance based on the ACE measured ten minutes after the disturbance, or based on the maximum ACE recovery measured within the ten minutes following the disturbance

2 2 **Reserve Sharing Group** The disturbance control compliance for a control area within a Reserve Sharing Group is based on the compliance of the Reserve Sharing Group (according to the compliance method chosen in section 3 2 2 of Policy 1A) A reserve sharing group area may, at its discretion, measure this recovery based on the combined ACE measured ten minutes after the disturbance, or on the maximum combined ACE recovery measured within the ten minutes following the disturbance

C. Calculation of Compliance

1 **Control Compliance Rating** Control area compliance will be determined by examining both CPS parameters One parameter (CPS1) measures control impact on frequency This parameter is calculated from a MW-Hz error value computed over a sliding 12-month period The second parameter (CPS2) is a function of the ten-minute ACE magnitudes over a one-month period Compliance to the two measures is outlined below

Control Compliance Rating = Pass if CPS1 $\geq$ 100% *and* CPS2 $\geq$ 90%

Control Compliance Rating = Fail if CPS1 < 100% *or* CPS2 < 90%

1 1 **Control Performance Standard 1 (CPS1)** The frequency-related parameter, CPS1, converts a compliance ratio to a compliance percentage as follows

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$$CPS1 = (2 - CF) \times 100\%$$

The frequency-related Compliance Factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the Target Frequency Bound

$$CF = \frac{CF_{12\text{-}month}}{(\epsilon_1)^2}$$

where $CF_{12\ month}$ is defined in Section C 1 1 1,

ϵ_1 is defined in Section B 1 1 1

Note that compliance percentages can be calculated for other bases (month, day, shift hours, etc) by simply replacing $CF_{12\ month}$ in the above formula with the appropriate CF value

1 1 1 **$CF_{12\ month}$ Calculation** The rating index is derived from 12 months of data The basic unit of data comes from one-minute averages of ACE, frequency error and frequency bias settings

1 1 1 1 **Clock-minute average** A clock-minute average is the average of the reporting control area's valid measured variable (i e , for ACE and for frequency error, as well as for the control area's frequency bias, as defined in section B 1 1 1) for each sampling cycle during a given clock-minute

$$\left(\frac{ACE}{-10B}\right)_{clock\text{-}minute} = \frac{\left(\dfrac{\sum ACE_{sampling\ cycles\ in\ clock\text{-}minute}}{n_{sampling\ cycles\ in\ clock\text{-}minute}}\right)}{-10B}$$

$$\Delta F_{clock\text{-}minute} = \frac{\sum \Delta F_{sampling\ cycles\ in\ clock\text{-}minute}}{n_{sampling\ cycles\ in\ clock\text{-}minute}}$$

The control area's clock-minute Compliance Factor (CF) becomes

$$CF_{clock\text{-}minute} = \left[\left(\frac{ACE}{-10B}\right)_{clock\text{-}minute} \times \Delta F_{clock\text{-}minute}\right]$$

1 1 1 2 **Hourly Average** Normally, sixty (60) clock-minute averages of the reporting area's ACE and of the respective Interconnection's frequency error will be used to compute the respective Hourly Average Compliance parameter

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$$CF_{clock\text{-}hour} = \frac{\sum CF_{clock\text{-}minute}}{n_{clock\text{-}minute\ samples\ in\ hour}}$$

1 1 1 3 **Accumulated Averages** The reporting entity can recalculate and store each of the respective clock-hour averages ($CE_{clock\ hour\ average\ month}$) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i e , HE 0100, HE 0200, , HE 2400)

$$CF_{clock\text{-}hour\ average\text{-}month} = \frac{\sum_{days\text{-}in\text{-}month} [\ (CF_{clock\text{-}hour})(n_{one\text{-}minute\ samples\ in\ clock\text{-}hour})\ ]}{\sum_{days\text{-}in\text{-}month} [n_{one\text{-}minute\ samples\ in\ clock\text{-}hour}]}$$

$$CF_{month} = \frac{\sum_{hours\text{-}in\text{-}day} [\ (CF_{clock\text{-}hour\ average\text{-}month})(n_{one\text{-}minute\ samples\ in\ clock\text{-}hour\ averages})\ ]}{\sum_{hours\text{-}in\text{-}day} [n_{one\text{-}minute\ samples\ in\ clock\text{-}hour\ averages}]}$$

The 12-month Compliance Factor becomes

$$CF_{12\text{-}month} = \frac{\sum_{i=1}^{12} [\ (CF_{month\text{-}i})(n_{(one\text{-}minute\ samples\ in\ month)\text{-}i})\ ]}{\sum_{i=1}^{12} [n_{(one\text{-}minute\ samples\ in\ month)\text{-}i}]}$$

Note that if data was not collected for all days of the month (or hours in day, or minutes in hour, etc), then the summations in the above formulas should be for "sample" days (or hours, minutes, etc)

At the end of the month, each of the respective hourly averages are used to calculate that month's Compliance Factor as follows

1 2 **Control Performance Standard 2 (CPS2)** The second parameter in the Control Performance Rating relates to a bound on the ten-minute average of ACE A compliance percentage is calculated as follows

$$CPS2 = \left[1 - \frac{Violations_{month}}{(Total\ Periods_{month} - Unavailable\ Periods_{month})} \right] \times 100$$

The $Violations_{month}$ are a count of the number of periods that $ACE_{clock\ ten\ minutes}$ exceeded L_{10} $ACE_{clock\ ten\ minutes}$ is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples

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$$\text{Violation}_{\text{clock ten minutes}} = 0 \text{ if } \left| \frac{\sum ACE}{n_{samples\ in\ 10\text{-}minutes}} \right| \le L_{10}$$

$$= 1 \text{ if } \left| \frac{\sum ACE}{n_{samples\ in\ 10\text{-}minutes}} \right| > L_{10}$$

Each area shall report the total number of Violations and Unavailable Periods for the month L_{10} is defined in Section B 1 1 2

1 2 1 **Determination of Total Periods$_{month}$ and Violations$_{month}$** Since the CPS2 Criterion requires that ACE be averaged over a discrete time period, the same factors that limit Total Periods$_{month}$ will limit Violations$_{month}$ The calculation of Total Periods$_{month}$ and Violations$_{month}$, therefore, must be discussed jointly

Each 24-hour period beginning at 0000 and ending at 2400 contains 144 discrete ten-minute periods (one more or less due to Daylight Saving Time) Each hour (HH) contains six discrete ten-minute periods, where period 1 spans HH 00 – HH 10, period 2 spans HH 10$^+$ – HH 20, period 3 spans HH 20$^+$ – HH 30, period 4 spans HH 30$^+$ – HH 40, period 5 spans HH 40$^+$ – HH 50, and period 6 spans HH 50$^+$ – (HH+1) 00 For a system that samples ACE every four seconds, for example, the average ACE over a ten-minute period would be defined by the algebraic sum of 150 ACE samples (starting at HH 00 04 and ending at HH 10 00) divided by 150

An incident of non-compliance is recorded for any ten-minute period where the absolute value of average ACE is greater than L_{10}

1 2 2 **Condition that Impacts the Calculation ofTotal Periods$_{month}$ and Violations$_{month}$** A condition may arise which may impact the normal calculation of Total Periods$_{month}$ and Violations$_{month}$ This condition is a sustained interruption in the recording of ACE

1 2 2 1 **Sustained Interruption in the Recording of ACE** In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that ACE remain uninterrupted for a period equal to or greater than five minutes during that ten-minute interval Should a sustained interruption in the recording of ACE due to loss of telemetering or computer unavailability result in a ten-minute interval not containing a consecutive five-minute sampling of ACE, that ten-minute interval is omitted from the calculation of CPS2

1 3 **Data Reporting** The control area is responsible for submitting the Control Performance Standard survey each month In addition (for post-reporting analysis by the Regional Performance Subcommittee representative), the control area is responsible for retaining sufficient CF and other pertinent data (see Appendix 1H)

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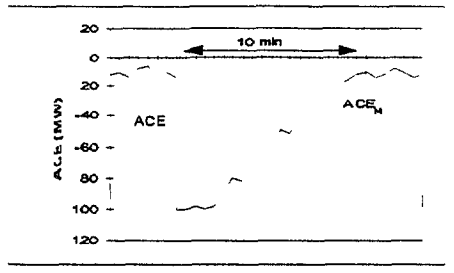
2 **Disturbance Control Standard** A control area or reserve sharing group must calculate and report compliance with the Disturbance Control Standard for all disturbances greater than or equal to 80% of the magnitude of the control area's or of the reserve sharing group's most severe single contingency loss Regional Reliability Councils may, at their discretion, require a lower reporting threshold Disturbance Control Standard is measured as the percentage recovery, R_i

For loss of generation

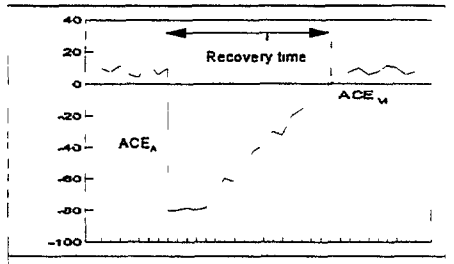
if $ACE_A < 0$

then $$R_i = \frac{MW_{LOSS} - \max(0, ACE_A - ACE_M)}{MW_{LOSS}} x100\%$$



if $ACE_A >= 0$

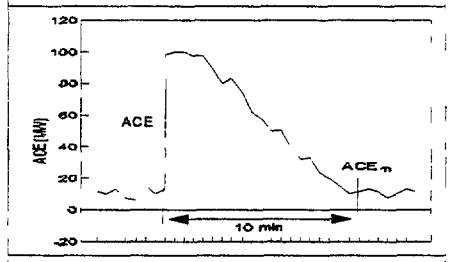
then $$R_i = \frac{MW_{LOSS} - \max(0 - ACE_M)}{MW_{LOSS}} x100\%$$



For loss of load

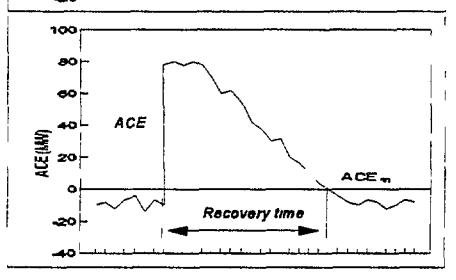
if $ACE_A > 0$

then $$R_i = \frac{MW_{LOSS} - \max(0\ ACE_m - ACE_A)}{MW_{LOSS}} x100$$



if $ACE_A <= 0$

then $$R_i = \frac{MW_{LOSS} - \max(0\ ACE_m)}{MW_{LOSS}} x100$$



where

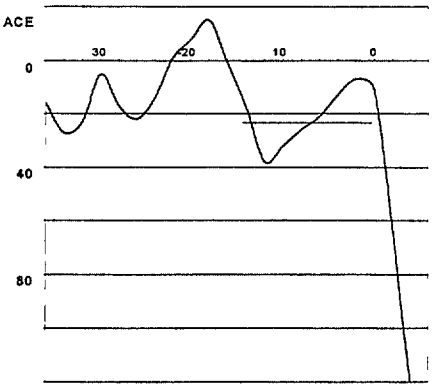
MW_{LOSS}	is the MW size of the disturbance as measured at the beginning of the loss,
ACE_A	is the pre-disturbance ACE,
ACE_M	is the maximum algebraic value of ACE measured within the ten minutes following the disturbance event A control area or reserve sharing group may, at their discretion, set $ACE_M = ACE_{10\ min}$, and
ACE_m	is the minimum algebraic value of ACE measured within the ten minutes following the disturbance event A control area or reserve sharing group may, at their discretion, set $ACE_m = ACE_{10\ min}$

2 1 **Determination of MW_{LOSS}**

Record the MW_{LOSS} value as measured at the site of the loss to the extent possible The value should not be measured as a change in ACE since governor response and AGC response may introduce error

2 2 **Determination of ACE_A**

Base the value for ACE_A on the average ACE over the period just prior to the start of the disturbance Average over a period between 10 and 60 seconds prior and include at least 4 scans of ACE In the illustration to the right, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the disturbance with a result of ACE_A= - 25 MW



2 3 **Determination of ACE_M or ACE_m**

ACE_M is the maximum value of ACE measured within ten minutes following a given disturbance At the discretion of the control area or of the Reserve Sharing Group, compliance may be based on the ACE measured ten minutes following the disturbance, i e , $ACE_M = ACE_{10\,min}$

ACE_m is the minimum value of ACE measured within ten minutes following a given disturbance At the discretion of the control area or of the Reserve Sharing Group, compliance may be based on the ACE measured ten minutes following the disturbance, i e , $ACE_m = ACE_{10\,min}$

3 **Examples**

Below is an example of the calculations required for CPS1 monitoring and compliance The example starts with the first hour of the first day of a month through to the end of the month Let's assume this area has a bias, B = –60MW/0 1 Hz

On Day 1, at the beginning of HE 0100, the area must calculate $CE_{clock\ minute}$ by multiplying the clock-minute average ACE (divided by ten times the area's bias) by the clock-minute average frequency error from schedule Subsequent products are calculated for the remaining clock-minutes of the hour

	HE 0100	Minute 1	Minute 2		Minute 60		
ACE/-10B	(Hz)	-20/-10(-60)	10/-10(-60)		40/-10(-60)		
ΔF	(Hz)	0 005	-0 005		0 005	Sum	$CF_{clock\ hour} = \Sigma(CF)/n$

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$CF_{clock\ minute}$ = (ACE/-10B) x ΔF n (# of samples)	(Hz²) (mHz²)	-0 000167 -166 667 1	-0 000083 -83 333 1		-0 000333 333 333 1	0 00525 5250 0 60	0 000088 87 5000

Note that n (# of samples) is based on the number of samples over the hour Since CPS1 requires minute averages of ACE and frequency error (and there were no data anomalies in this hour), n = 60 The procedure shown above is repeated for each of the 24 hour-periods of the day As the days of the month continue, the 24 hour-period $CF_{clock\ hour\ average\ month}$ values are averaged as shown below At the end of the month, a CF_{month} can be calculated

Hour		Day 1	Day 2		Day 31	Sum	$CF_{clock\ hour\ average\text{-}month}$ = [Σ(CF x n)]/Σ(n)
HE 0100	$CF_{clock\ hour}$ n (# of samples) $CF_{clock\ hour}$ x n	87 5 60 5250	93 5 59 5516 5		92 0 57 5244	 1842 166 742	90 5
HE 0200	$CF_{clock\ hour}$ n $CF_{clock\ hour}$ x n	90 0 58 5220	85 0 60 5100		89 5 60 5370	 1830 160 170	87 5
HE 2400	$CF_{clock\ hour}$ n $CF_{clock\ hour}$ x n	89 0 60 5340	92 0 59 5428		89 0 59 5251	 1830 163 787	89 5
		Total n Total $CF_{clock\ hour\ average\text{-}month}$ x n				44 208 3 930 888	
		CF_{month} = Σ($CF_{clock\ hour\ average\text{-}month}$ x n)/ Σ (n)				88 9	

A rolling $CF_{12\ month}$ can be calculated using the CF_{month} values

	Month					
	1	2		12	Sum	$CF_{12\ month}$ = [Σ(CF_{month} X n)/Σ(n)]
CF_{month} n CF_{month} X n	88 9 44,208 3 930 888	93 3 42 072 3,925,345		91 7 42 875 3,931 655	 515 030 47 022 239	91 3

Assuming this area has an ε_1 of 10 MHz, then its CPS1 compliance percentage would be calculated as follows (as described in section C 1 1)

$$CF = CF_{12\ month} / (\varepsilon_1)^2$$

$$= 91\ 3 / (10)^2$$

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= 91 3 / 100

= 913

CPS1 = (2 – CF) x 100

= (2 - 913) x 100

= (1 087) x 100

= 108 7% which is a "passing" grade (CPS1 must be greater than or equal to 100)

430

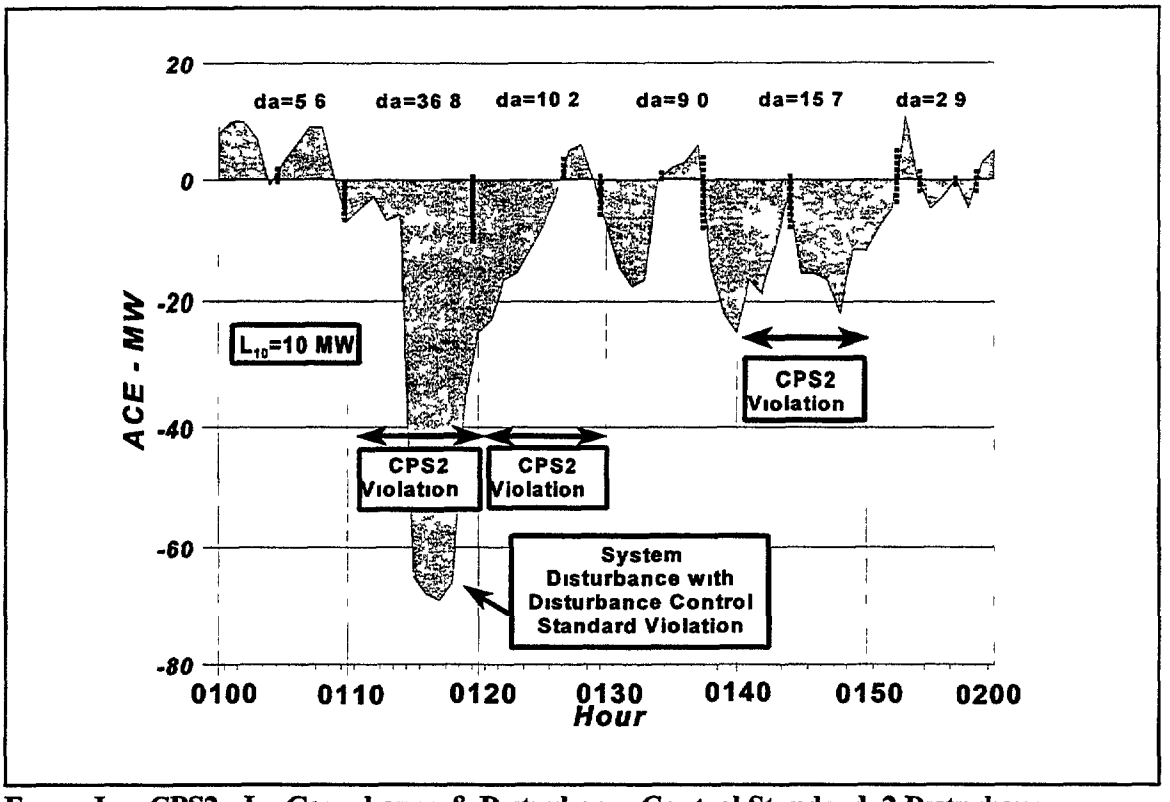

Figure I — CPS2 - L_{10} Compliance & Disturbance Control Standard, 2 Disturbance Examples

Figure I demonstrates various examples of L_{10} compliance (CPS2 Standard) and a disturbance condition (Disturbance Control Standard) Note that Figure I is separated into six distinct, cyclic ten-minute periods The absolute value of the algebraic mean of the ACE during each period, referred to as d_a, is compared to L_{10} (10 MW for this system) to determine a violation Note that the fifth interval (0140 – 0150) has recorded a violation because the absolute value of the algebraic mean of 15 7 MW exceeds the L_{10} of 10 MW Since disturbance conditions are included in the CPS2 calculation, violations are also recorded for the second and third intervals (0110–0120 & 0120–0130)

Note the pattern of the disturbance condition, which began at 0115 During this disturbance, the Disturbance Control Standard was violated ACE was not restored to its pre-contingency level until 0127 (a 12-minute interval which violates the Disturbance Control Standard)

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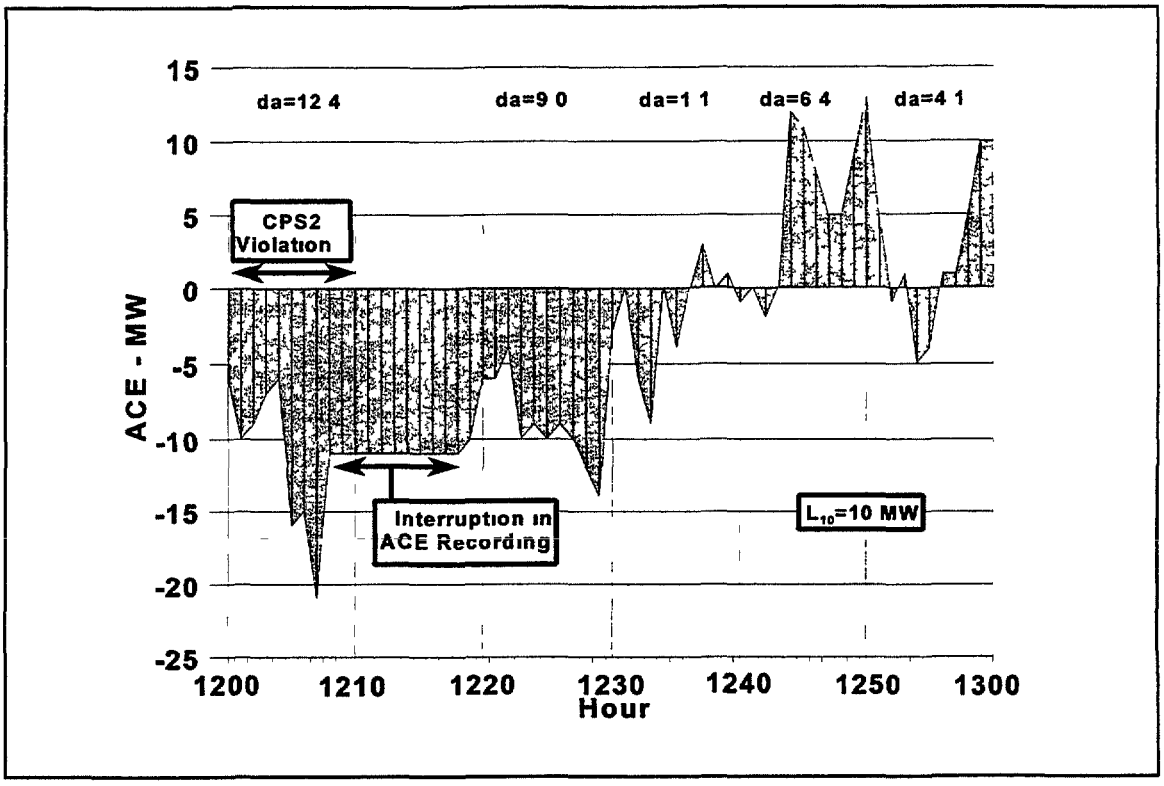

Figure II — L_{10} Compliance Examples

Figure II demonstrates various examples of L_{10} compliance coupled with an interruption in the recording of ACE At 1209, ACE recording was interrupted and not returned until 1218 Since the ACE recording for the interval 1210 – 1220 did not span a consecutive, uninterrupted period longer than five minutes, this period is eliminated from further CPS Standard analysis In contrast, the first ten-minute interval of 1200 – 1210 is included in the analysis because ACE recording was interrupted only for the last minute of the interval In fact, the first interval is in violation because the absolute algebraic mean of 12 4 MW exceeds the L_{10} of 10 0 MW This algebraic mean of 12 4 MW was calculated for the nine minutes during which ACE was not interrupted Thus, for this hour, there was one violation out of five intervals

D. Survey Procedures

Performance Standard surveys will be conducted monthly to analyze each control area's level of compliance with the CPS1 and CPS2 Control Performance Standards The surveys provide a relative measure of each control area's performance

1 **Issuance of Survey** Monthly averages are to be completed after the end of each month

1 1 Each control area shall return one completed copy of CPS Form 1, "NERC Control Performance Standard Survey — All Interconnections" to the Performance Subcommittee member representing the Region by the tenth working day of the month following the month reported

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2 **Instructions for Control Area Survey** Using data derived from digital processing of the ACE signal, a representative from each control area will complete CPS Form 1, "NERC Control Performance Standard Survey — All Interconnections "

2 1 **Hourly Table**

CPS1 Report the clock-hour average compliance factor (CF) for each of the 24-hour periods and the total number of samples in each hourly average (as described in section C 1 1 1 3)

CPS2 For each of the 24 hourly periods of a day, report the monthly total number of CPS2 violations and the number of unavailable ten-minute periods For example, if there was one violation for hour ending 0100 every day of a 31-day month, a 31 would be entered for the 0100 hourly period

2 2 **CPS1, CPS2 Standard Summary**

CPS1	CF_{month}	Report the monthly compliance factor and enter in this cell using the formulas and procedures described in Sections C 1 1 1 3
	$CF_{12\ month}$	Report the rolling 12-month compliance factor and enter in this cell using the formulas and procedures described in Sections C 1 1 1
	CPS1 (%)	Calculate the CPS1 percentage compliance and enter in this cell using the formulas and procedures described in Sections C 1 1
CPS2	TOTAL	Sum the clock-hour average compliance factors, the number of samples, the number of violations, and unavailable ten-minute intervals recorded on the hourly tables and enter the sums on this row for each column
	CPS2 (%)	Calculate the CPS2 percentage compliance and enter in this row using the formulas and procedures described in Sections C 1 2

3 **Instructions for Regional and NERC Surveys** From a review of the control areas' surveys, each Regional Survey Coordinator or PS member will complete CPS Form 2, "NERC Control Performance Standard — Regional Summary "

3 1 Review CPS Form 1 data received from each control area in the Region for uniformity, completeness, and compliance to the instructions Iterate with control area survey coordinators where necessary

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3 2 Transfer the data from each Form to the appropriate columns on CPS Form 2 Review the comments submitted and, if significant, identify them with the appropriate control areas

3 3 Forward a copy of the completed CPS Form 1 and 2 to the NERC staff

3 4 The NERC staff will combine the Regional reports into a single summary report and send one copy to each PS member

3 5 Each PS member is responsible for sending the summary report to the utilities in the Region

4 **Disturbance Control Standard**

Each Control Area or Reserve Sharing Group shall report its Disturbance Control Standard compliance quarterly The completed Disturbance Control Standard survey shall be supplied to NERC by the 20th day following the end of the respective quarter Where reserve sharing groups exist, the Regional Reliability Council shall decide either to report these on a control area basis or on a reserve sharing group basis If a reserve sharing group has dynamic membership, then it will be required for the Region to convert the disturbance reporting for the group to a control area basis before reporting to NERC If a control area basis is selected, each control area reports the reserve sharing group's performance only for disturbances occurring in their area

4 1 **Reportable Disturbance** The definition of a reportable disturbance shall be provided by the respective Regional Reliability Councils The definition shall include events that cause an ACE change greater than or equal to 80% of a control area's or reserve sharing group's most severe contingency The definition of a reportable disturbance must be specified in the operating Policy adopted by each Regional Reliability Council This definition may not be retroactively adjusted in response to observed performance

4 1 1 **Most Severe Single Contingency** A control area's most severe single contingency is defined as the magnitude of the single most credible event that would cause the greatest change in the control area's ACE or as defined by the respective Regional Council

4 2 **Excludable Disturbances and Average Percent Recovery** The control areas or reserve sharing group shall report both the number of reportable disturbances that occur in the given quarter, and the average percent recovery for that quarter The control area must also report the excludable disturbances that occurred in the quarter and the average percent recovery for those excluded events

4 2 1 **Excludable Disturbance** An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the control area's most severe single contingency

4 2 2 **Average Percent Recovery** The average percent recovery is the arithmetic average of all the calculated R_i's from reportable disturbances during the given quarter Average percent recovery is similarly calculated for excludable disturbances (See Section C 2 for calculation of R_i)

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4 3 **Contingency Reserve Adjustment Factor** The quarterly Contingency Reserve Adjustment factor shall include only those reportable disturbances with magnitudes less than or equal to the magnitude of the respective control area's most severe contingency

4 3 1 Contingency Reserve Adjustment factor The factor is defined as follows

when $n_{Quarter} \geq 0$, then

$$CRA_{Quarter} = 200 - \left[\frac{\Sigma R_i}{n_{Quarter}} \right]$$

when $n_{Quarter} = 0$, then $CRA_{Quarter} = 100$

where $n_{Quarter}$ is the number of reportable disturbances experienced during the reporting quarter

i = reportable disturbances

R_i is defined in section C 2

4 3 2 **Calculation Precision** The Adjustment Factor shall be rounded off to two decimal places

4 3 3 **Exemptions** Exemptions shall be granted in consideration of single events that cause multiple reportable disturbances (e g , hurricanes, earthquakes, islanding, etc) A control area or reserve sharing group shall request such exemptions through its Performance Subcommittee representative The chair of the Performance Subcommittee will rule on the request Until the ruling is received, the control area or reserve sharing group will consider the request denied If the request is from the chair's Region then a vice chair will issue the ruling

4 4 **Contingency Reserve Adjustment Period** Control areas shall revise their respective Contingency Reserve Requirement by their computed Contingency Reserve Adjustment factor The adjustments will be effective starting one month following the end of the reported quarter and remains in effect for three months

4 5 **Instructions for Disturbance Control Standard Survey** Each control area or Reserve Sharing Group shall report its Disturbance Control Standard compliance quarterly on Form DCS "NERC Disturbance Control Standard Survey "

4 5 1 Mail a copy of the completed Form DCS to the NERC staff

4 5 2 The NERC staff will combine the Regional reports into a single summary report and send one copy to each Subcommittee member

4 5 3 Each Subcommittee member is responsible for sending the summary report to the utilities in the Region

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NERC Control Performance Standard Survey
All Interconnections

CPS Form 1

Region			Control Area				
L_{10}			Date		Month & Year		
	CPS1				CPS2		
Hour Ending Central Time	Compliance Factor ($CF_{clock\text{-}hour\ average\text{-}month}$)		Number of Samples		Violations		Unavailable Periods
0100		Record the clock-hour average compliance factors for each of the 24 hour periods		Record the total number of samples for each of the 24 hour-averages		Record the total number CPS2 violations for each of the 24 hour periods during the month	Record the total number of unavailable ten minute periods during the month for each of the 24 hour periods
0200							
0300							
0400							
0500							
0600							
0700							
0800							
0900							
1000							
1100							
1200							
1300							
1400							
1500							
1600							
1700							
1800							
1900							
2000							
2100							
2200							
2300							
2400							
CF_{month}				Total			
$CF_{12\text{-}month}$				CPS2 (%)			
CPS1 (%)							

Notes _____

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NERC Control Performance Standard Survey
Regional Summary

CPS Form 2

Region	Month	Year	Date
Control Area		Control Performance Compliance	
		CPS1	CPS2
		Compliance %	Compliance %

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NERC Disturbance Control Standard Survey

Form DCS

Region	Control Area(s)*	
Year	Quarter	*Submit only one report for a reserve sharing group and list all areas comprising the group

	Number	Average Percent Recovery
Reportable Disturbances not greater than the most severe single contingency loss		(a)
Disturbances greater than the most severe single contingency loss**		

**Not a performance measure Completed for information only

Contingency Reserve Adjustment Factor (200 – (a), rounded to 2 decimal places)	

An area or reserve sharing group must increase their contingency reserve requirement by the contingency reserve adjustment factor Any increase takes effect one month following the end of the reported quarter and remains in effect for three months

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INTERCHANGE TRANSACTIONS

Contract Path and Parallel Flow

GAPP

OASIS

Available Transmission Capacity

Recent NERC Initiatives

A Brief Overview

GA PP

An evolving means to manage certain aspects of the interconnected electric transmission system which recognizes multiple parallel paths

January 1995

THE FUTURE (NOW!)

- NEW USERS OF AND USES FOR TRANSMISSION

- ACCESS REQUIREMENTS
  - PURPA
  - NEPA 92
  - THE FERC IMPLEMENTATION

- MARKET FORCES

SOLUTIONS

- A. FORCE POWER FLOW TO MATCH CONTRACT ($) FLOW

- B. PROVIDE A MULTIPLE CONTRACT ($) FLOW TO MATCH POWER FLOW

- GAPP IS A PROPOSAL TO EXPERIMENT WITH B.

(GAPP UNDER DEVELOPMENT BY A COMMITTEE OF THE ITCF TO ADDRESS, SPECIFICALLY, THE NEEDS OF THE EASTERN INTER)

GAPP COMPONENTS

- Reservations
- Schedules
- Equity compensation
- Reliability control
- Accounting, Billing, Auditing
- NERC Guides fully supported
- Certain exeptions
- GAPP Info System
- Manageable by Operators
- Experiment

TOPICS

- ***CHANGE!***
  - WHY, WHAT, WHEN, HOW
- THE CASE FOR EQUITY
- THE CASE FOR RELIABILITY

- ***GAPP***
  - CONCEPT, METHOD, INFORMATION

- ***GIS***
  - THE GAPP INFORMATION SYSTEM

GIS IS

Operating details of all entered transactions between control areas (C/A)

Including direct connects, third party, ETG

NOT internal transfers

NOT transfers between non-participants

Information includes seller, buyer, the transmitters, mW, reservations, schedules, times

Near real time

C/A to C/A interface data, graphical, tabular, and printed
- loading by reservation, schedule, adjusted schedule, contract path

How it might be used (to be determined by each system)

GIS ISN'T

An EMS

System security program
- It does provide information to assist in D/M
- It does provide data for a security program

No commodity details: $, etc

Not a live model
- Updated seasonally or on special demand
- Ideas here for future

Discuss impacts of
- Topology
- Load effect
- Non-participant transactions
- Internal dispatch

445

ELECTRIC POWER SYSTEM MODELS

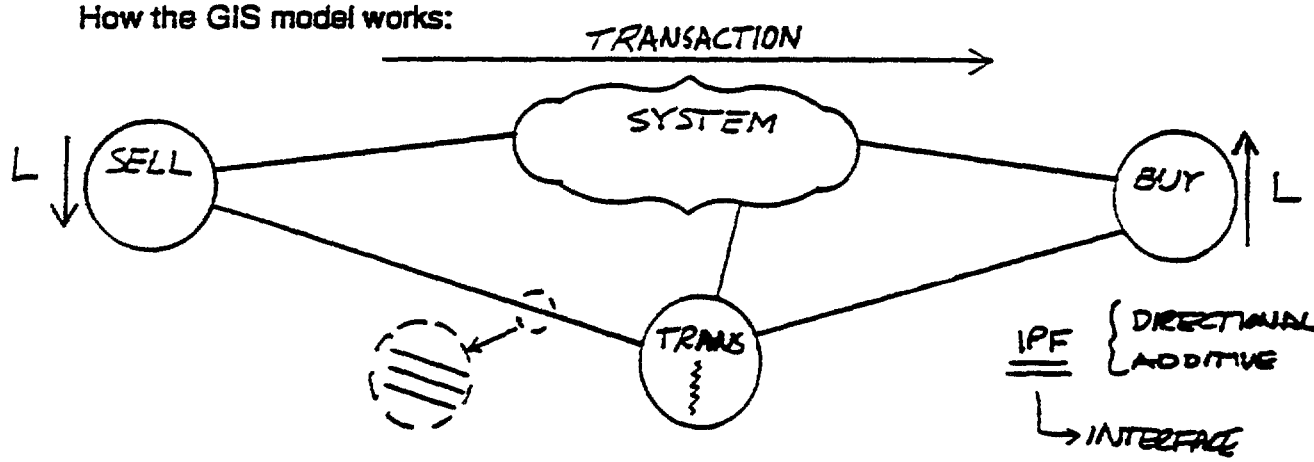
Marketer comments.

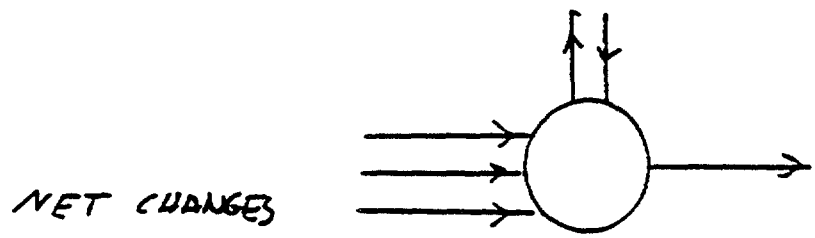
Models
Actuals

Models:

Sophisticated
Mathematical
Temporal
"Accurate"
Wrong

How the GIS model works:





$$\underline{\underline{TPF}} = \frac{\Sigma \text{ NET CHANGE IN} + \Sigma \text{ NET CHANGE OUT}}{2}$$

SYSTEM

NOT DIRECTIONAL
NOT ADDITIVE

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Nov.1, 1996 GAPP Information System (GIS) in Service

Feb. 13, 1996 GIS System Test - Results showed good comparison between predicted and actual flows in near term when all systems participated

Feb. 1996 Letter written to FERC requesting meeting to discuss GAPP experiment. Expect to meet with FERC staff after RIN Rules issued.

March,1996 Established Timetable for completion of first phase of GAPP Experiment.

April 1996 Began preparation of Final Report and specified requirements for Simulation Test

May 1, 1996 Begin one month Simulation Test

May 5, 1996 Begin 4 day test of ORNS information exchange on GIS. If successful, use GIS for ORNS requirements and cancel existing contracts with telephone company.

June, 1996 Results of Simulation Exercise, Final Report and draft FERC Filing to be distributed to GAPP Participants for review.

July, 1996 Participants indicate willingness to proceed with FERC Filing to conduct 2 year experiment. If a " core" of interested participants can be formed, proceed with filing

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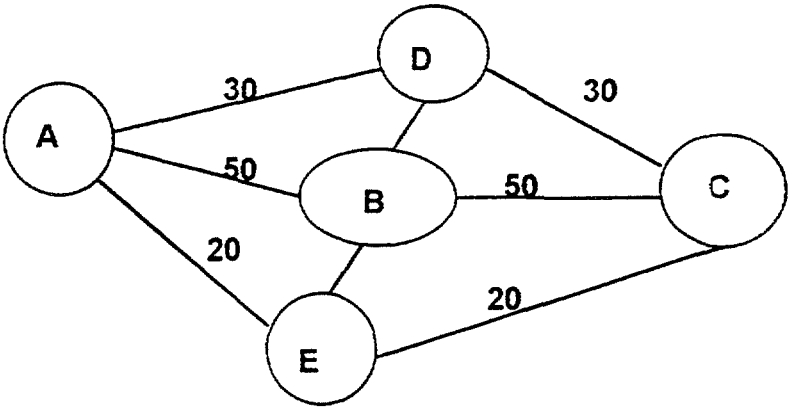
Scheduling Example

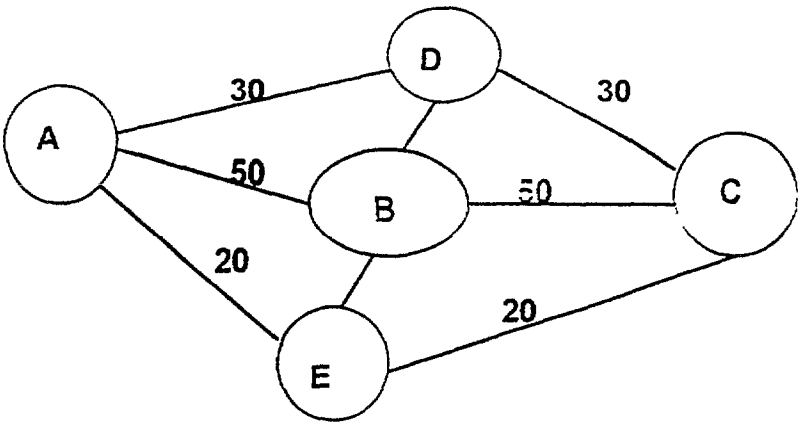


A sells 100 to D, 100 to B, 100 to C

Since sales to D and B are "direct connects" they are scheduled on the "contract path". The sale to C is distributed in accordance with the IPFs and compared to transfer limits in accordance with NERC policies. Assuming no limits were violated, the "schedules" would be:

A - D 130 mw
A - B 150 mw
A - E 20 mw

Compensation Example



Prime Path A-B-C

If Wheeling rates are· D-$4 B-$5 E-$3 and A sells 100 mw to C

Total Compensation is 100mw X $5 = $500

Allocation is calculated as:

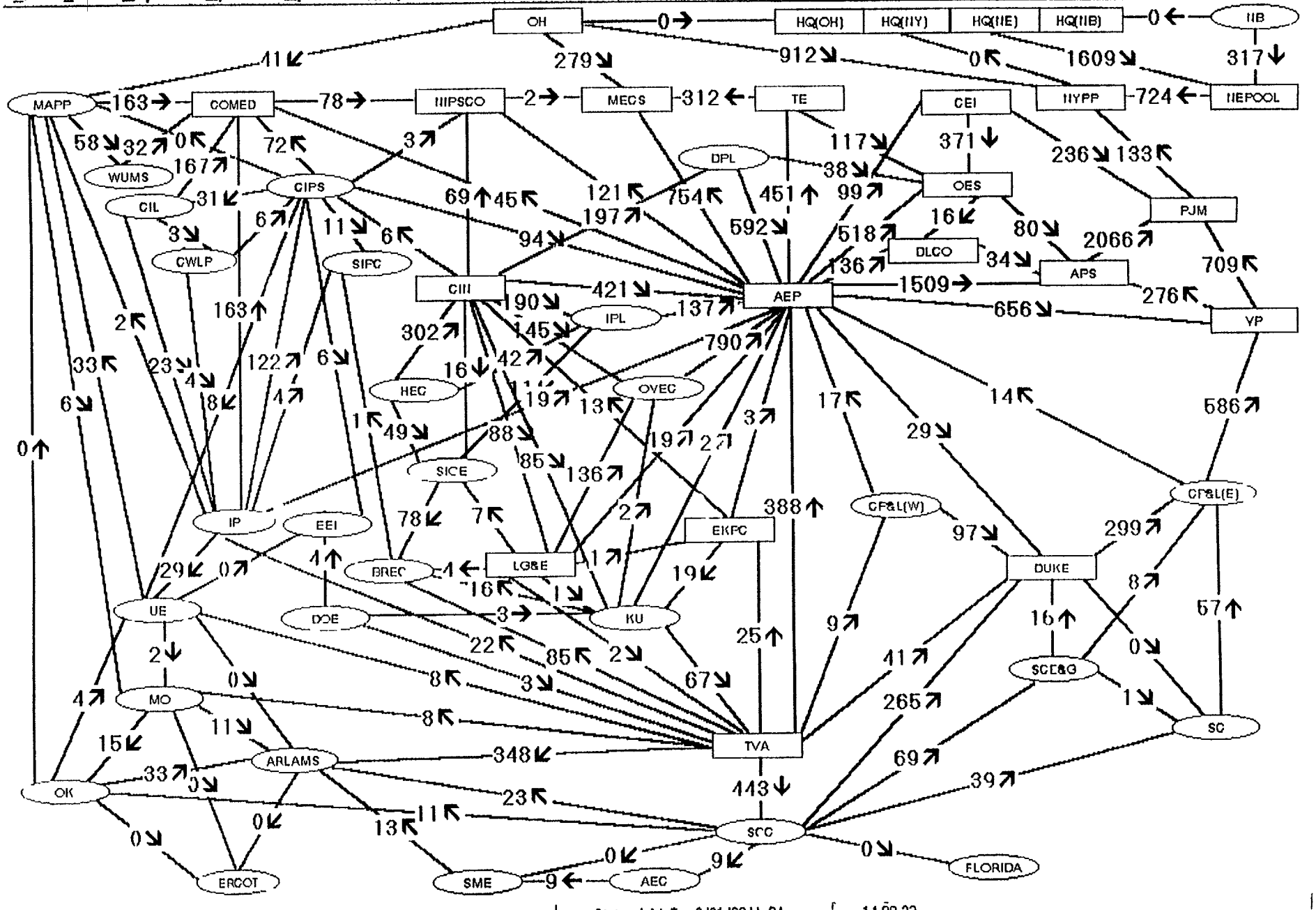
20 mw X $3.50 = $70
50 mw X $5.00 = $250
30 mw X $4.50 = $165

100	$485

A receives 70/485 X $500 = $72.17
B receives 250/485 X $500 = $257.73
C receives 165/485 X $500 = $170.10

GAPP Status Summary:Energy(MW)[2/13/96 Hr 14]

File View Reports Options Update! Help



12 Overloads | Status A/V To 3/31/96 Hr 24 | 14:00:33

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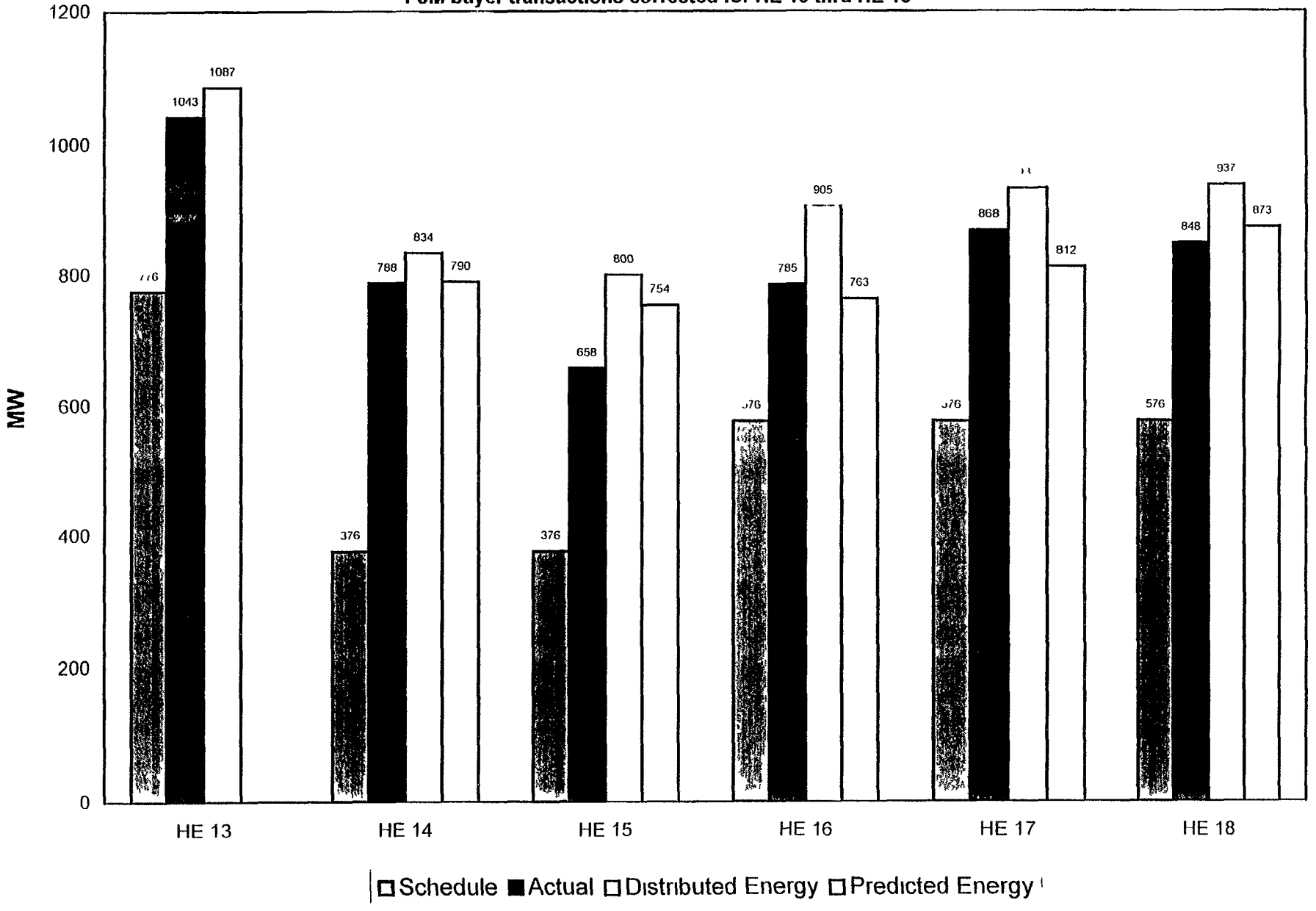
OH > NYPP

Homer City transactions corrected for HE 17 and HE 18
PJM buyer transactions corrected for HE 13 thru HE 18



25h

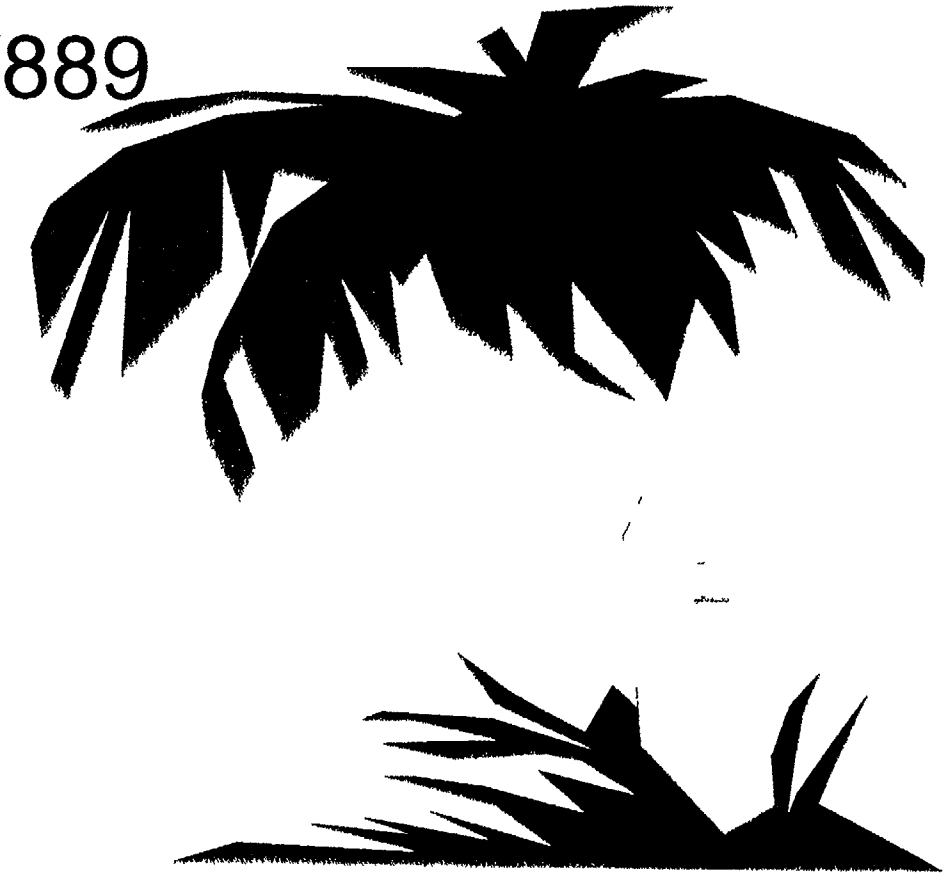
O.A.S.I.S.

Open Access SameTime Information System

Why...What...Where and How?!

O.A.S.I.S...Why:

- N. O. P. R.
- FERC Order's 888/889
- ProForma Tariff
- EPRI/NERC



O.A.S.I.S...What:

- Total and Available Transmission Capabilities. (TTC and ATC)

- Transmission Reservations.

- Personnel Transfers between Operations and Marketing entities affiliated with 'Providers'.

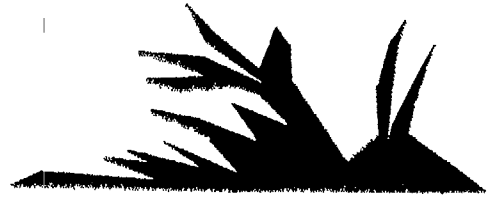
- General Informational Postings, Studies Information and Historical Reservation Data

O.A.S.I.S...Where:

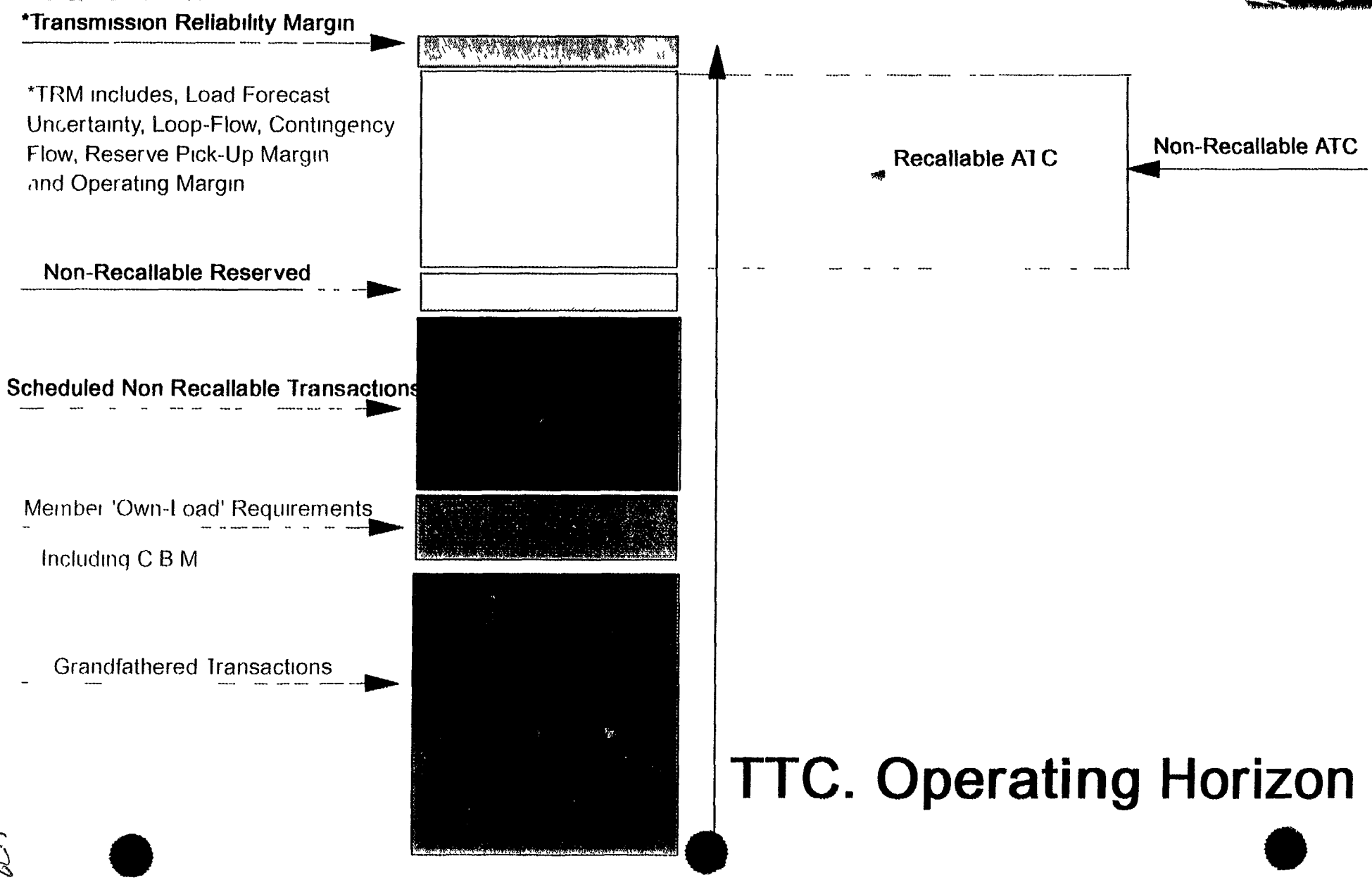
- NYPP will be the 'OASIS Node'?
- NYPP Processes?
- Member 'Provider' Processes?
- Transmission Customers.

O.A.S.I.S...How:

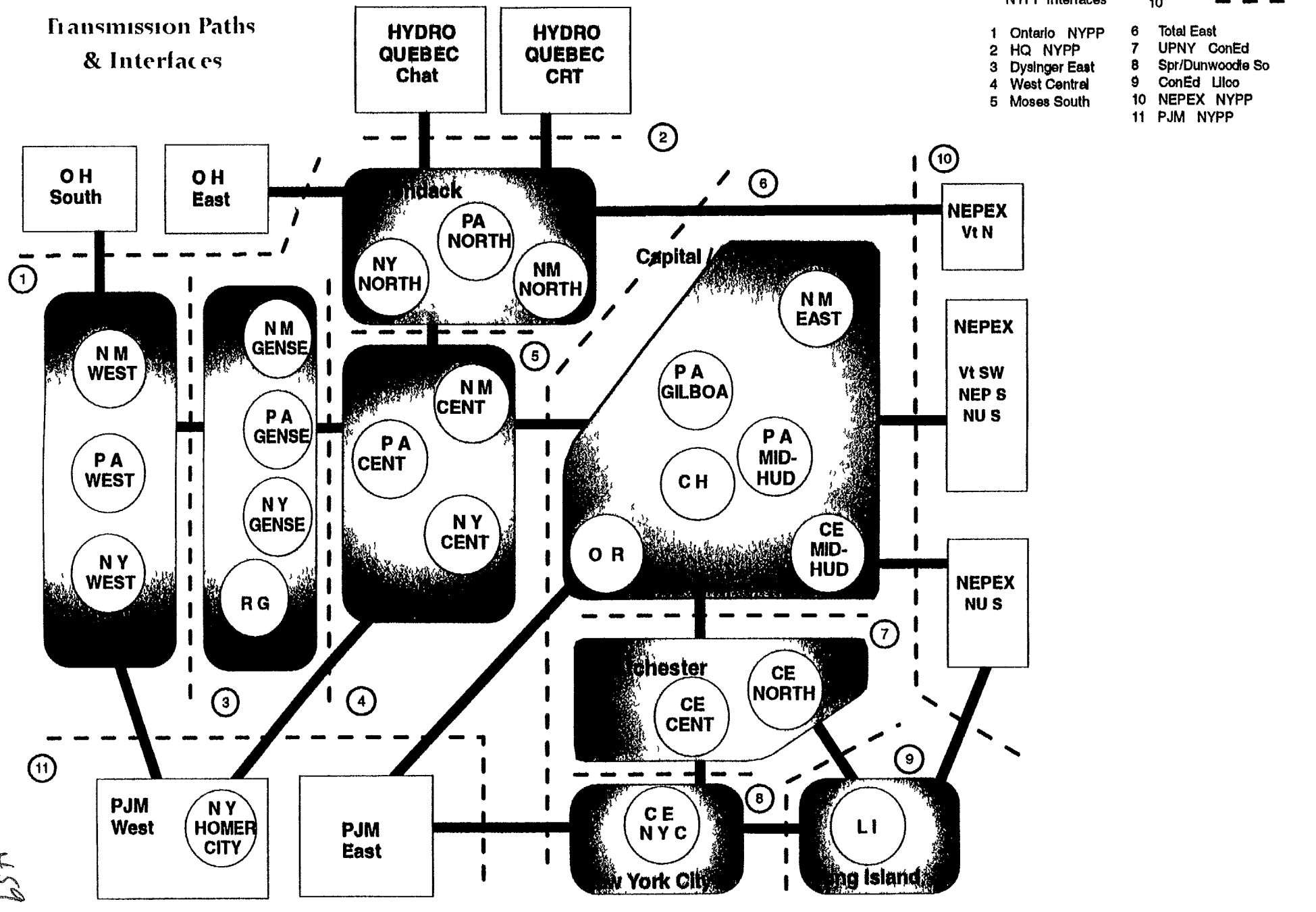
- Posting.
- Requests.
- Processing.
- Notifications/Communications.
- Result.
- Effect on Operations?



NYPP OASIS


*Transmission Reliability Margin
*TRM includes, Load Forecast Uncertainty, Loop-Flow, Contingency Flow, Reserve Pick-Up Margin and Operating Margin
Non-Recallable Reserved
Scheduled Non Recallable Transactions
Member 'Own-Load' Requirements
Including C B M
Grandfathered Transactions
Recallable ATC
Non-Recallable ATC
TTC. Operating Horizon

NEW YORK POWER POOL
OASIS Area & Transmission Paths & Interfaces



ATC Calculation Documents

- ATC Definitions and Determination - NERC

- Proposed Method of Calculation of ATC's on NYPP Paths
- Calculation of TTC's for NYPP Load Area Interconnection

Posted Transmission Paths

Any Path :

between two control area's

For which service has been denied, curtailed or interrupted for a 24 hr period over the last 12 months

requested by a transmission provider

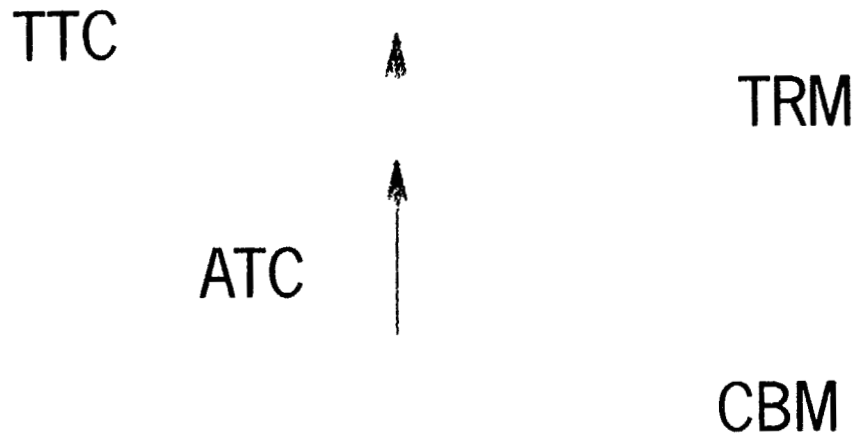
ATC Calculations

ATC Components

TTC - Total Transfer Capability

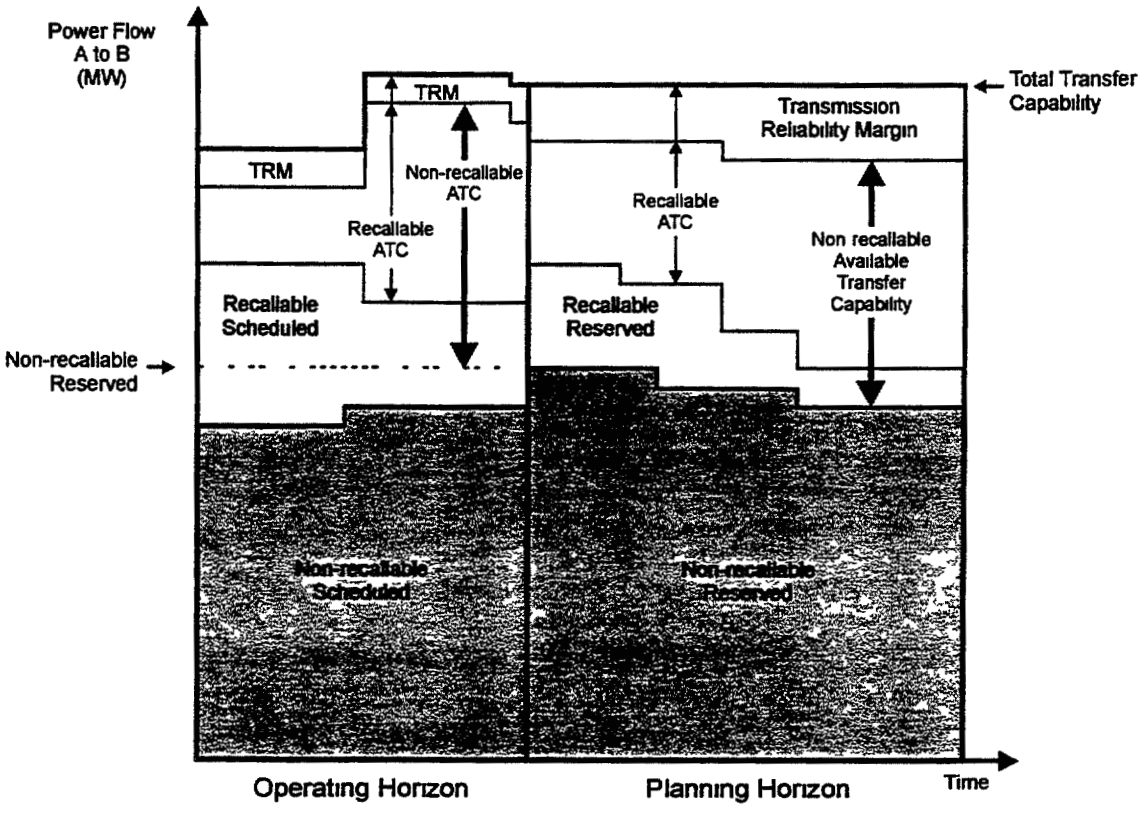
TRM - Transmission Reliability Margin

CBM - Capacity Benefit Margin



ATC AND RELATED TERMS

ATC and related terms are depicted graphically below They form the basis of a transmission service reservation system that will be used to reserve and schedule transmission services in the new, competitive electricity market



TTC, ATC, and Related Terms in the Transmission Service Reservation System

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ATC Calculations

- Total Transfer Capability
  - Monthly TTC's
    - NYPP Operating Study
  - Hourly, Daily and Weekly TTC's
    - NYPP Operations Planning

ATC Calculations

Transmission Reliability Margin (TRM)

- Operating Margin
- Reserve Pickup Margin
- Loop Flow
- Load Forecast Error

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ATC Calculations

Capacity Benefit Margin (CBM)

- Adequate Planning Reserve Margins
- Planning Time Frame

ATC Calculations

Additional Considerations

- Megawatts Reserved for Own Use
  "Grandfathered"

- Previously Reserved Transmission Capability

Transmission Paths

Determined By :

Free flowing unregulated transmission between two load areas

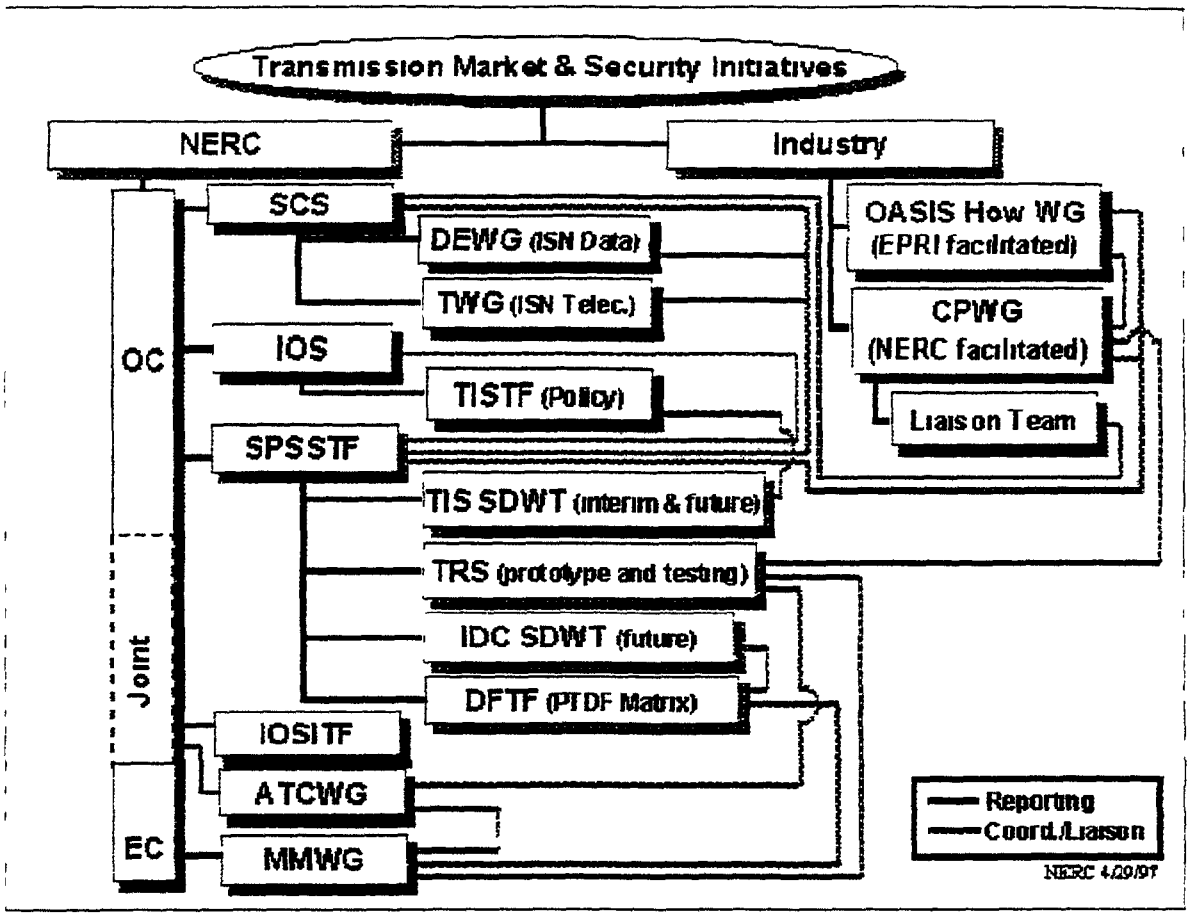
Phase angle regulators between two load areas

Paths which are expressed in positive values

ATC Calculations

General Concerns of ATC Implementation

- Line Outage Conditions
- Off Setting ATC's
- Posting of Unconstrained Paths
- Path Allocations
- Intra Area Paths



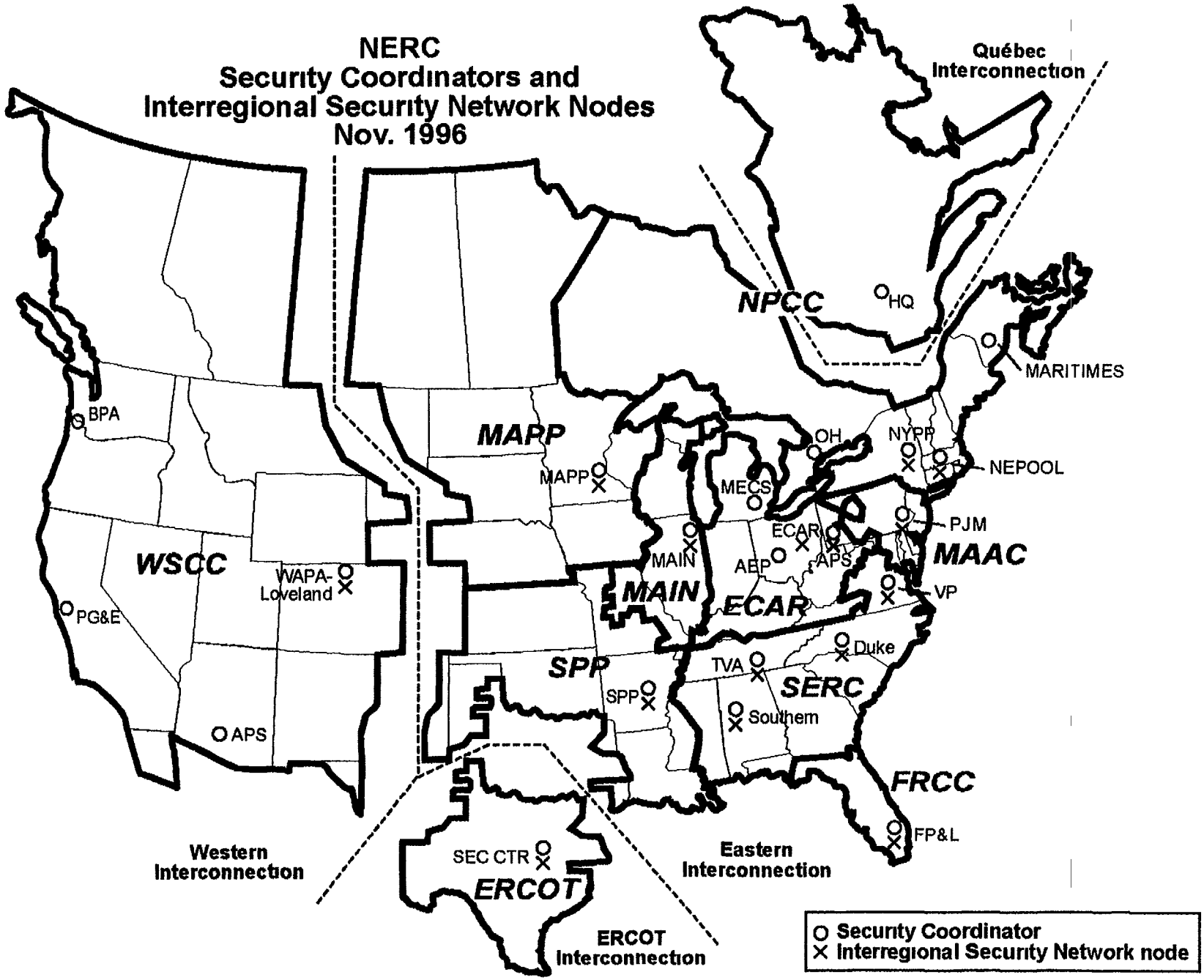
Transmission Market & Security Initiatives

NERC
Operating Committee
Security Coordinator Subcommittee (SCS)
- Telecommunications Working GroupTWG)
Data Exchange Working Group (DEWG)
Line Loading Relief Task Force (LLRTF)
Interconnected Operations Subcommittee (IOS)
Transaction Information System Task Force(TISTF)
Security Process Support System Task Force (SPSSTF)
Transaction Information System Self-Directed Work Team (TIS SDWT)
Transmission Reservation and Scheduling (TRS)
Interchange Distribution Calculator System Self-Directed Work Team (TIS SDWT)

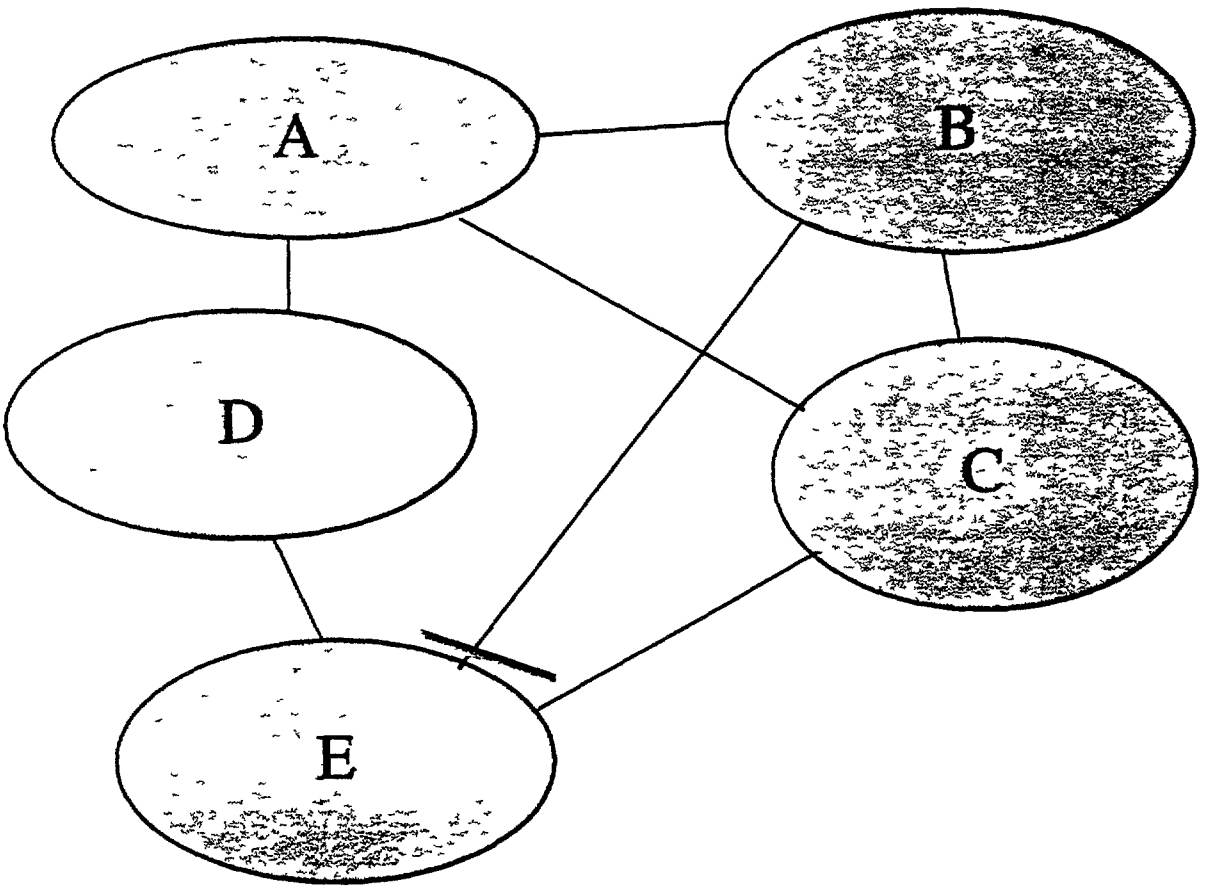
Distribution Factor Task Force (DFTF)
Joint Operating/Engineering Committees
Interconnected Operations Services Implementation Task Force (IOSITF)
ATC Implementation Working Group (ATCWG)
Engineering Committee
MMWG

Industry
OASIS "How" Working Group
Commercial Practices Working Group (CPWG)
CPWG Liaison Team

NERC
Security Coordinators and Interregional Security Network Nodes
Nov. 1996



NERC
Line Loading Relief Procedure



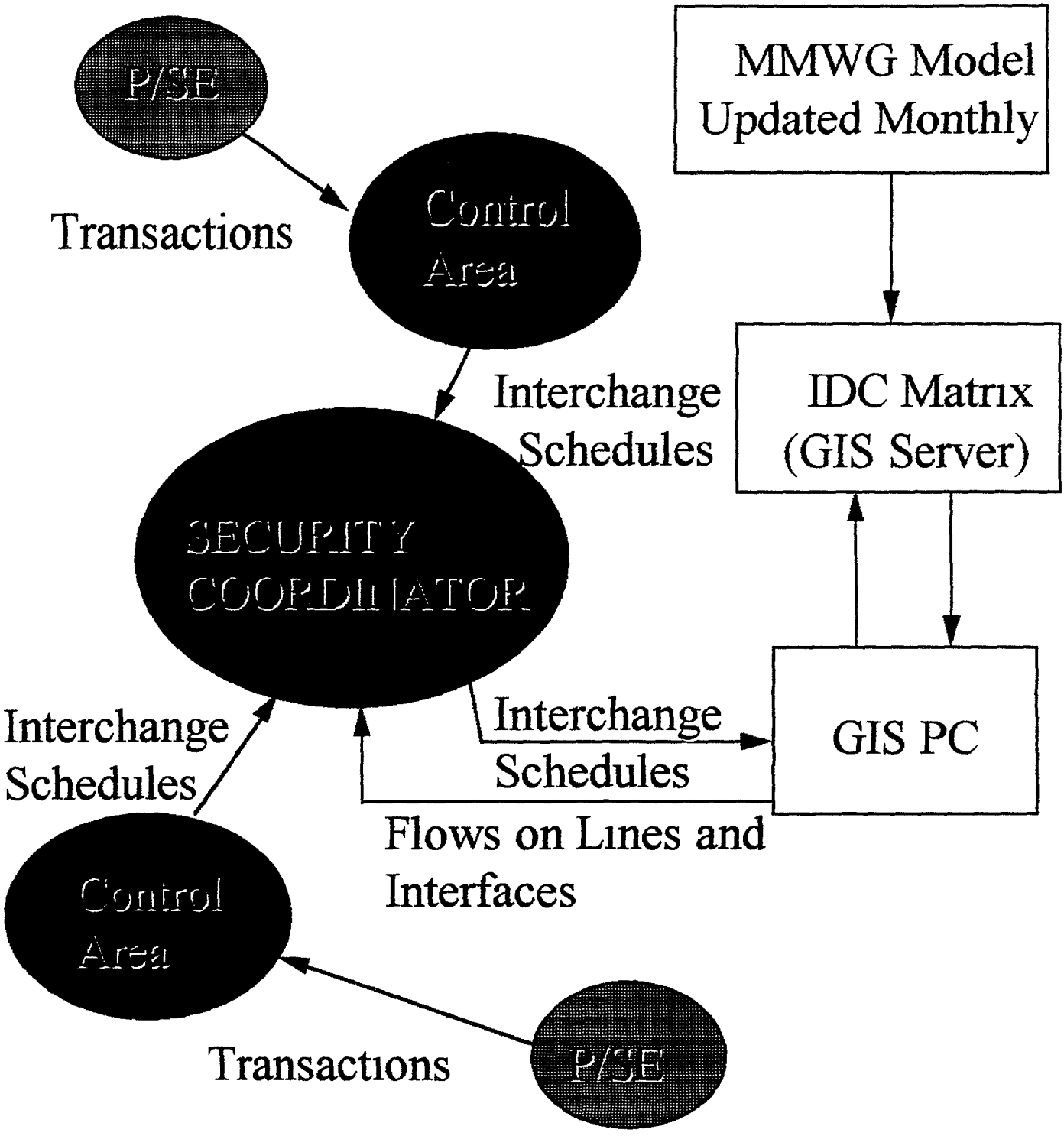
Transaction Matrix for ALL Control Area to Control Area Transactions

Example for Transaction from A to C

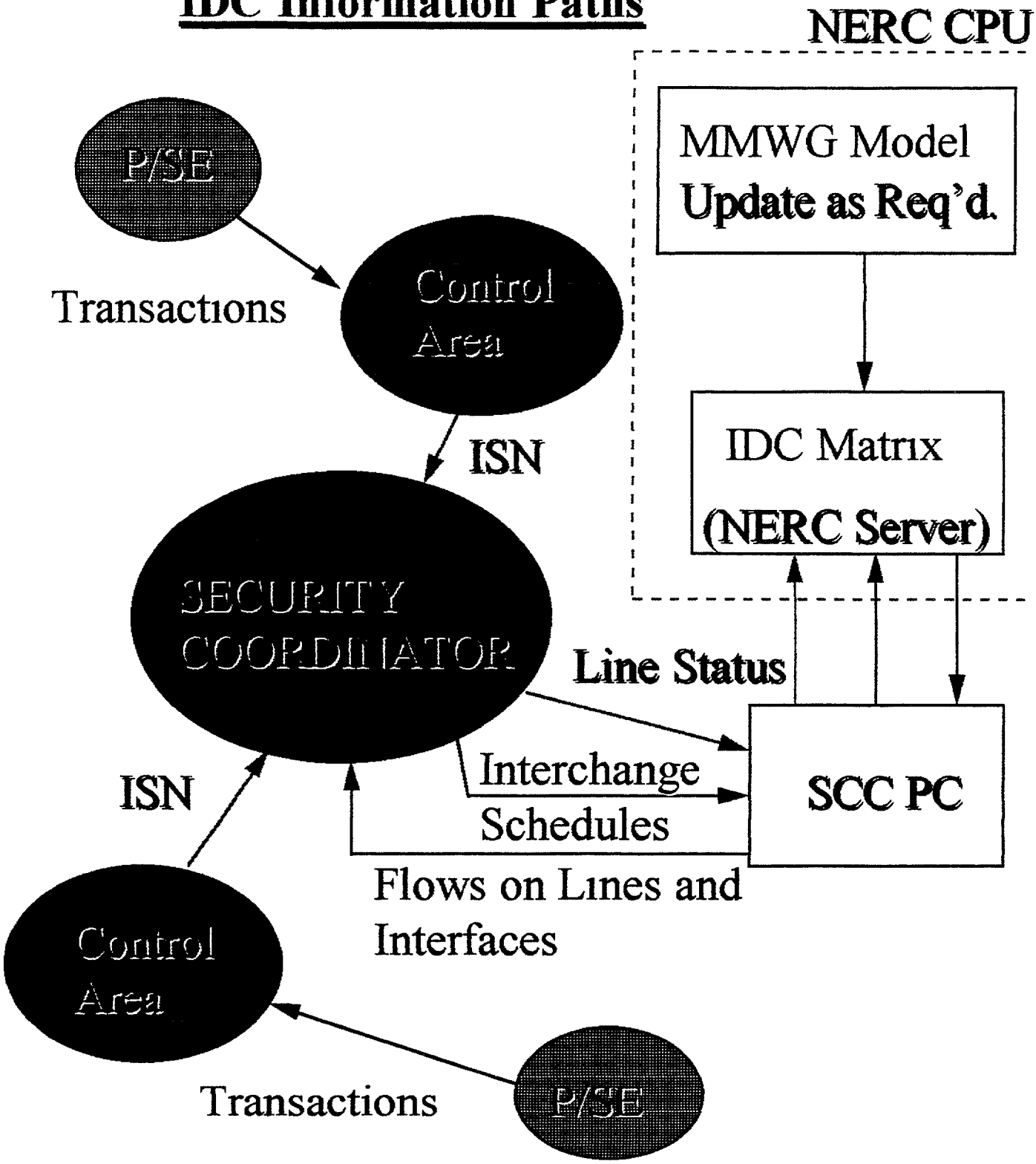
.PTDF

	A	B	C	D	E
A	-	.3	.5	.2	-
B	-.3	-	.35	-	-.05
C	-.5	-.35	-	-	-.15
D	-.2	-	-	-	.2
E	-	.05	.15	-.2	-

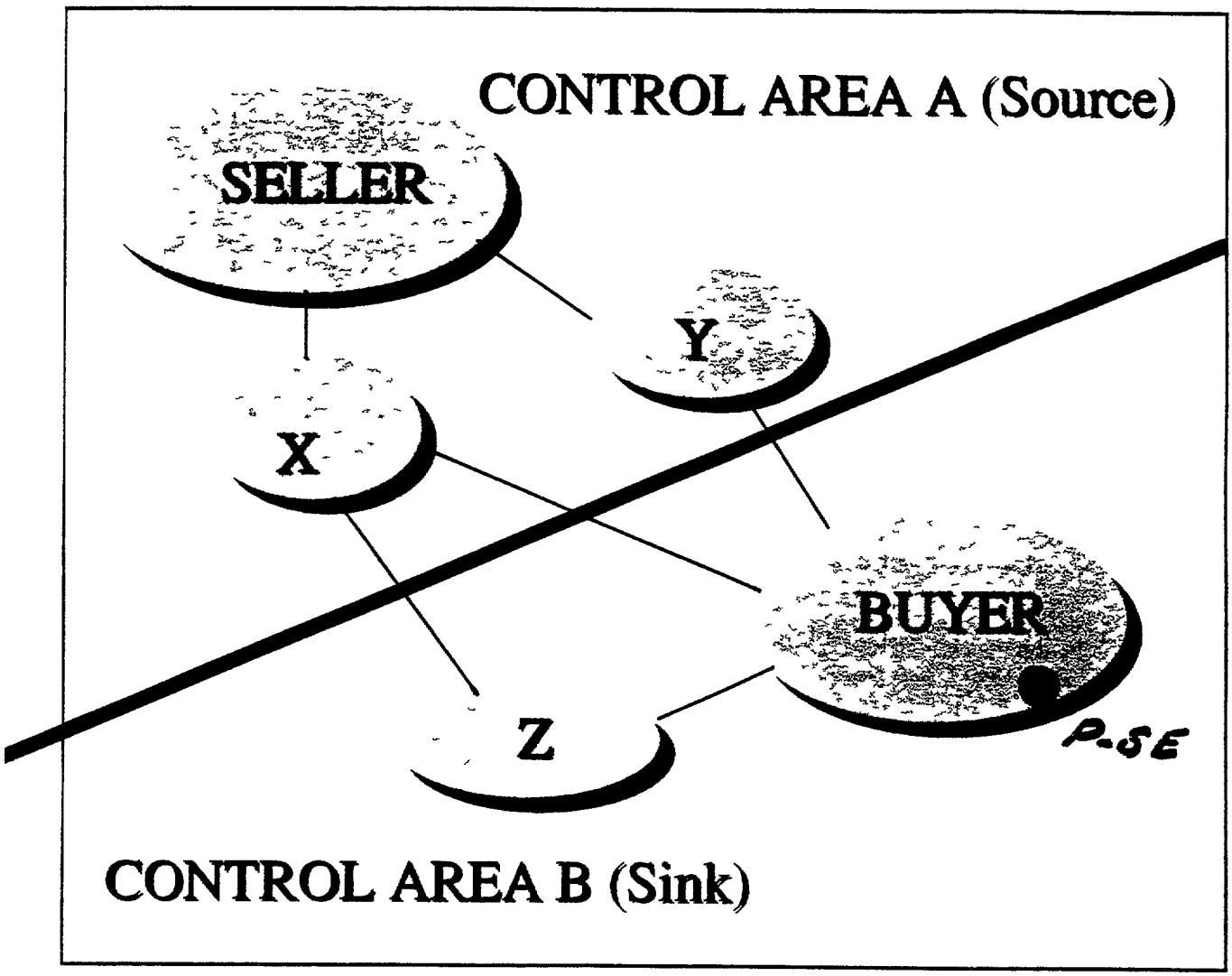
iIDC Information Paths



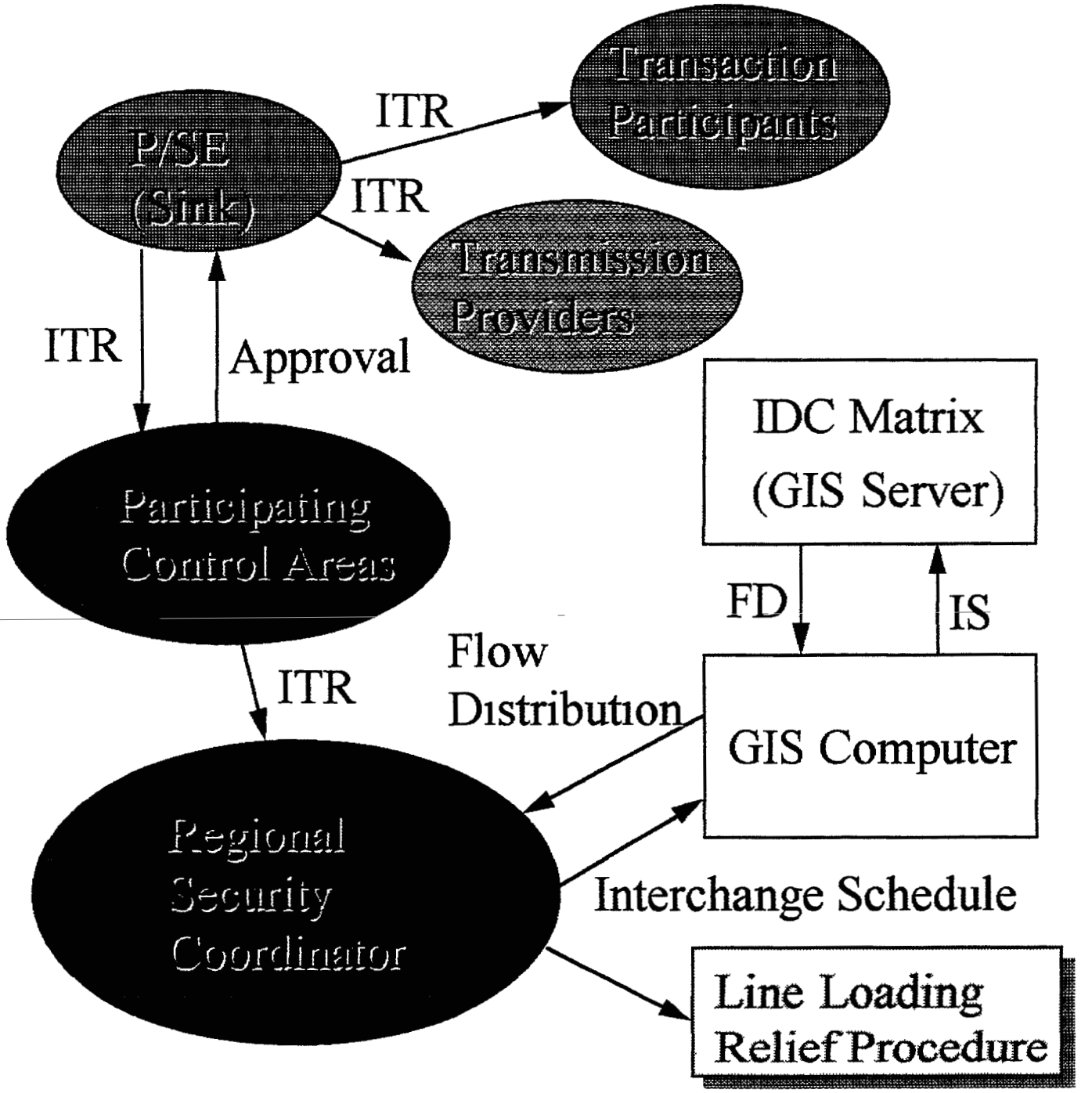
IDC Information Paths



Transaction Information System (TIS) (TAGGING)

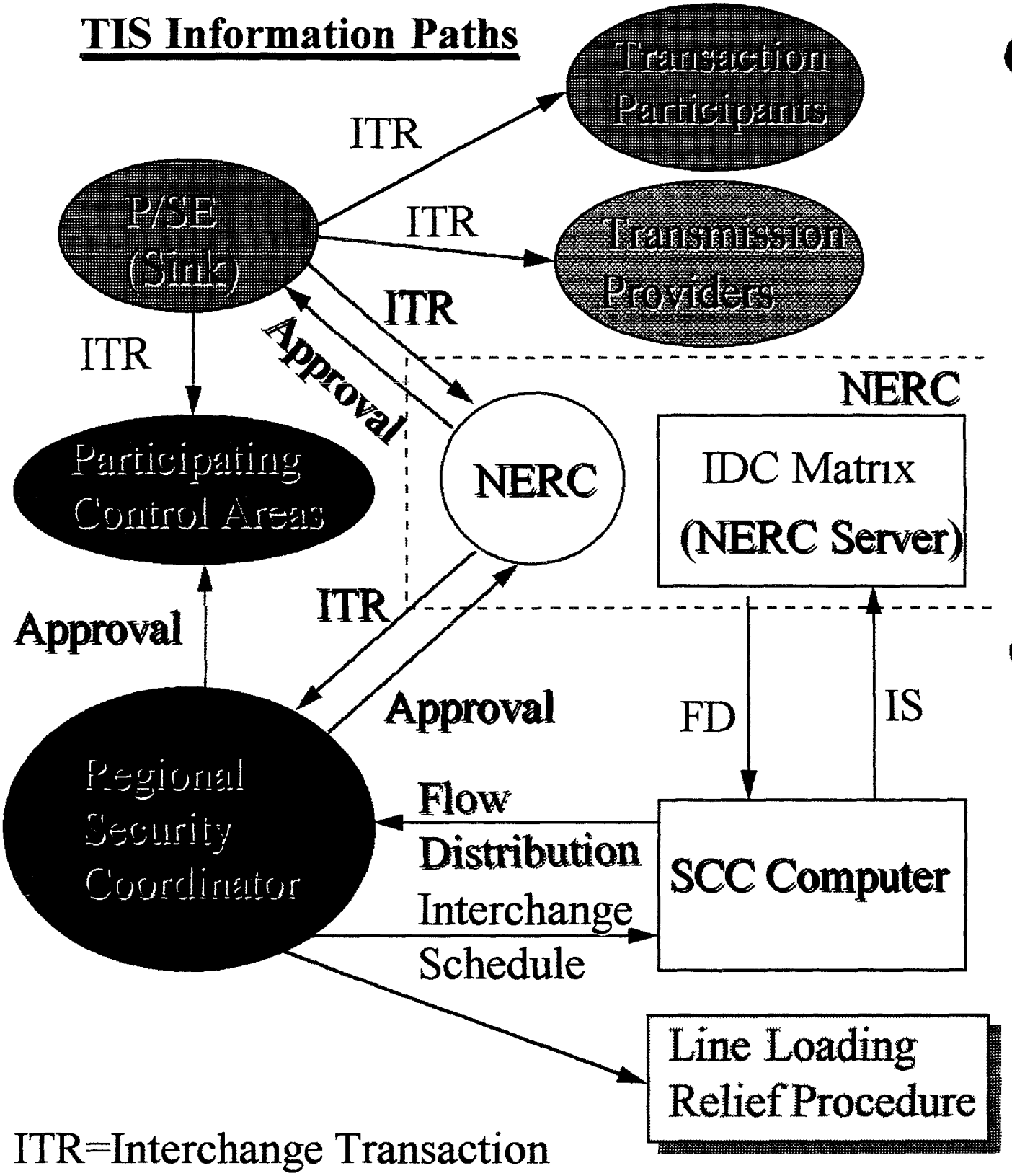


iTIS Information Paths



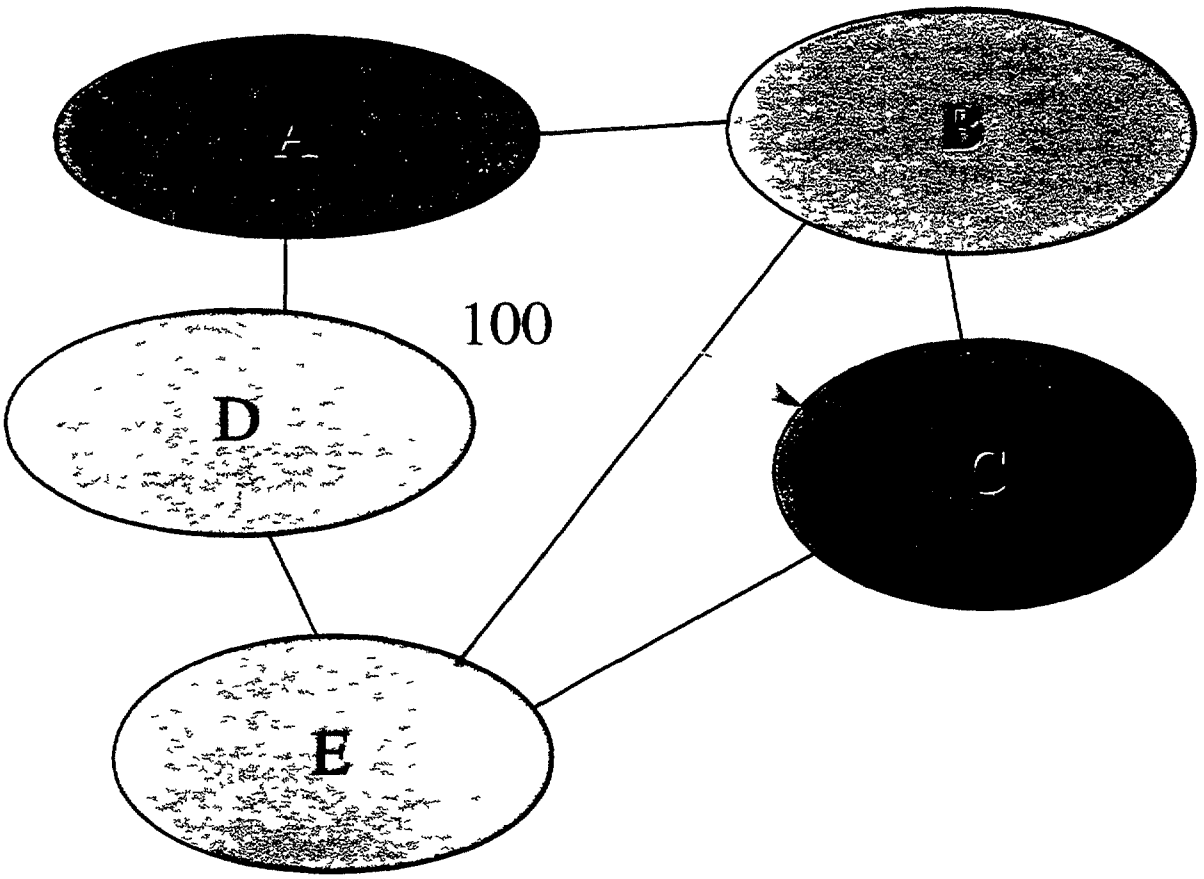
ITR=Interchange Transaction Request

TIS Information Paths

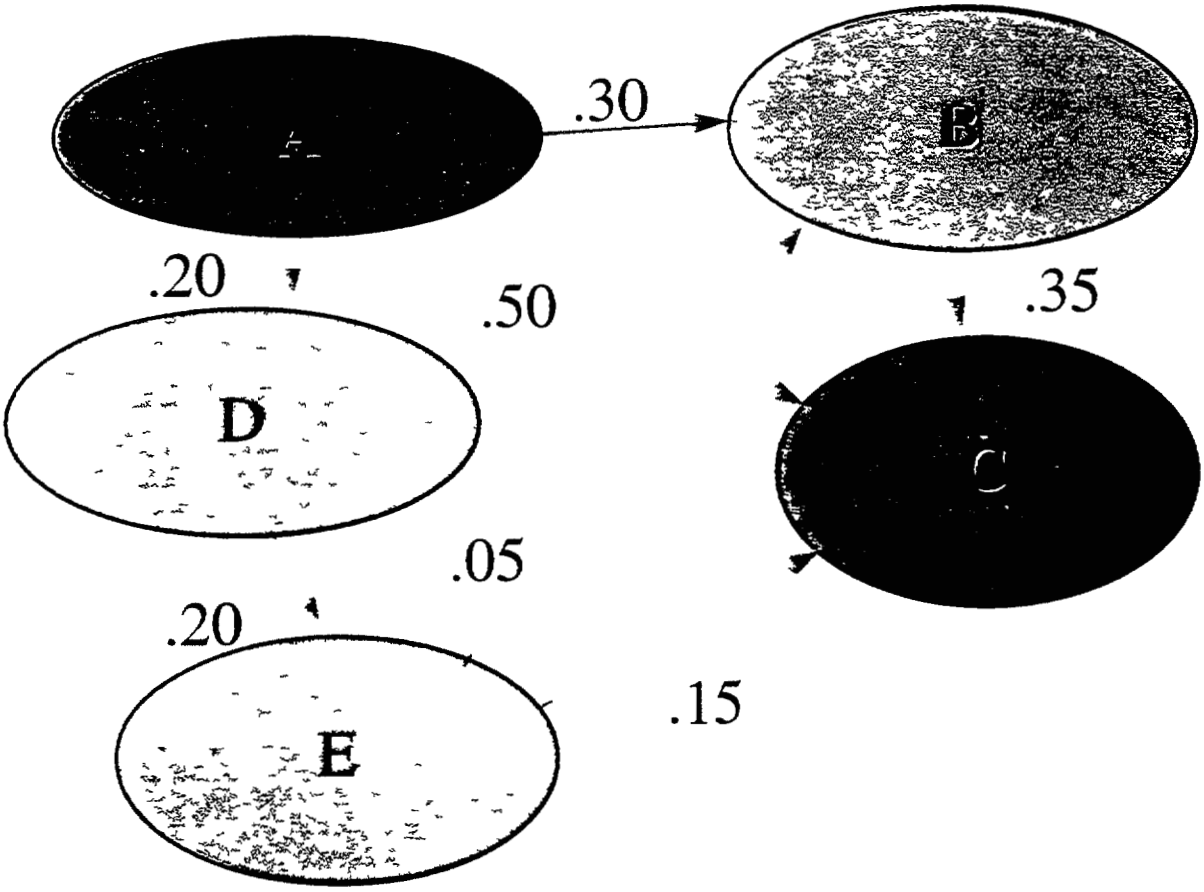


ITR=Interchange Transaction Request

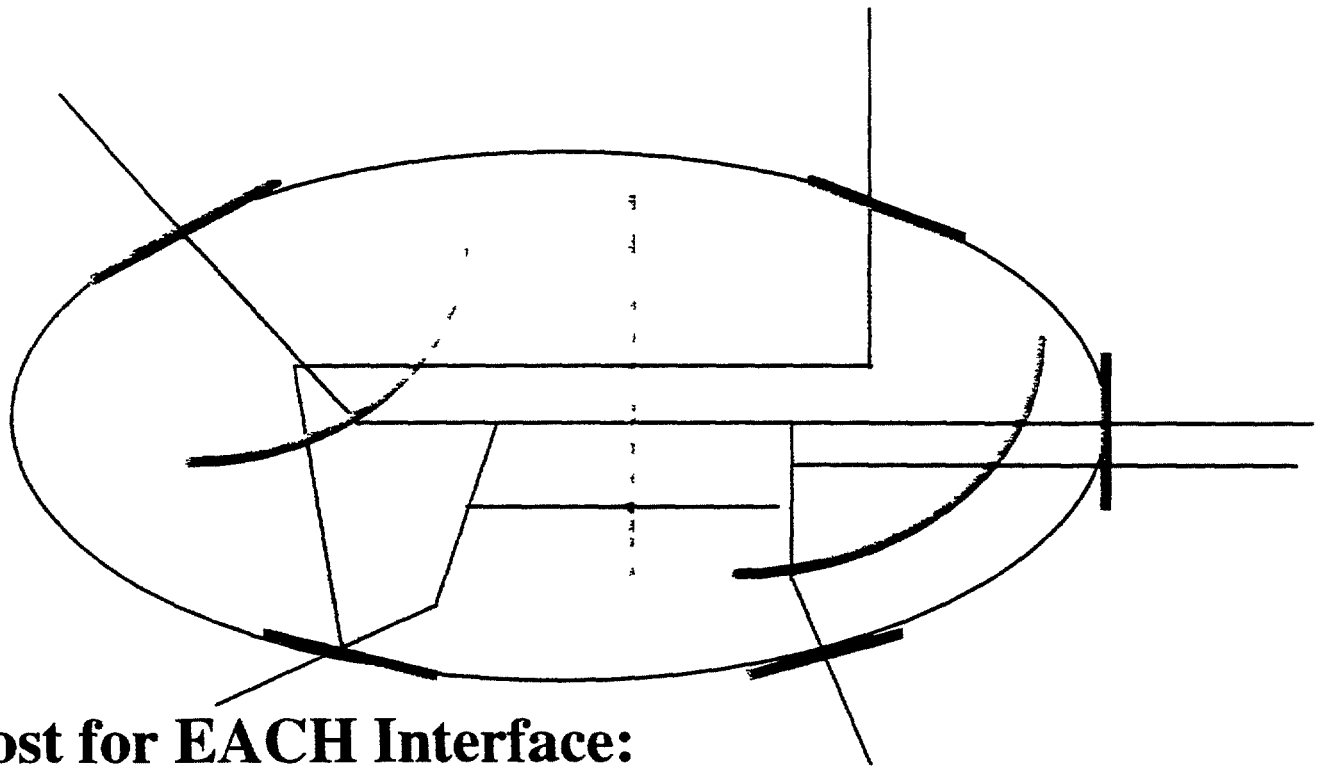
NERC
Transaction Reservation and Scheduling



NERC
Transaction Reservation and Scheduling



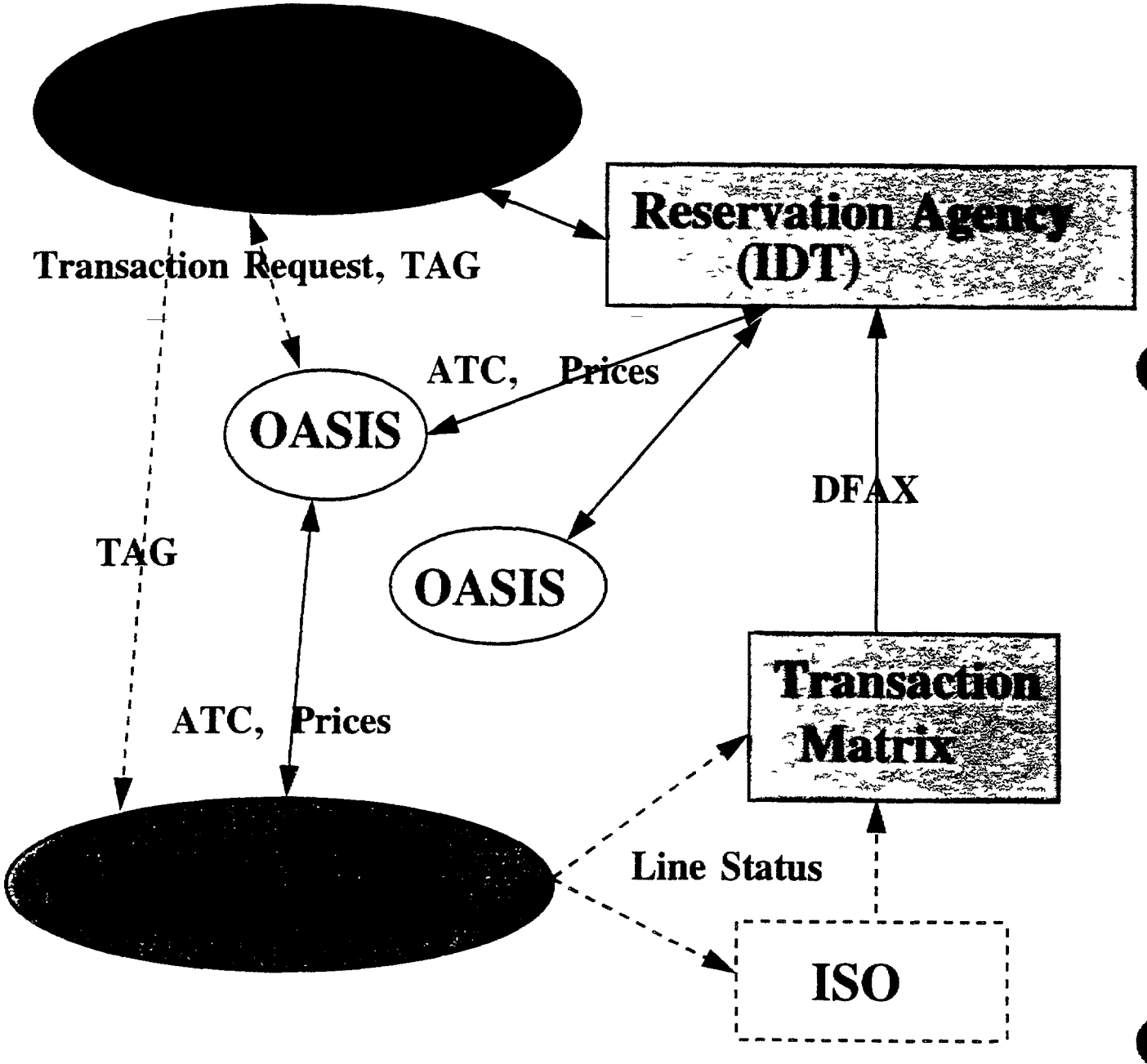
OASIS and ATC



Post for EACH Interface:

1. **Capacity available for Reservation (H,D,W,M,Y)**
2. **Price for Reservation and Services**
3. **Price to make additional capacity available**

TRS PROCESS OVERVIEW



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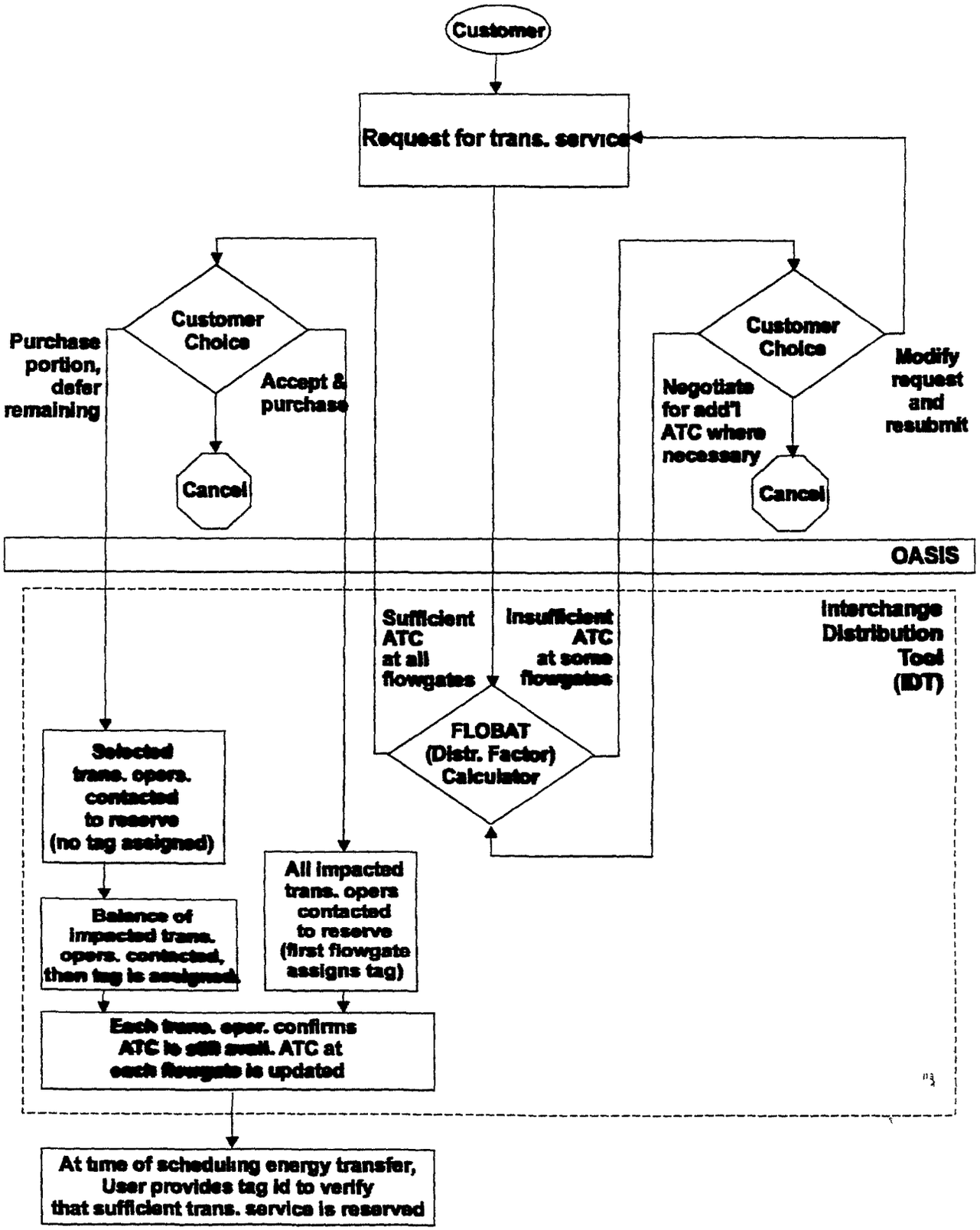
The Process


Customer
Request for trans. service
Customer Choice
Purchase portion, defer remaining
Accept & purchase
Cancel
Customer Choice
Negotiate for add'l ATC where necessary
Modify request and resubmit
Cancel
OASIS
Interchange Distribution Tool (IDT)
Sufficient ATC at all flowgates
Insufficient ATC at some flowgates
FLOBAT (Distr. Factor) Calculator
Selected trans. opers. contacted to reserve (no tag assigned)
Balance of impacted trans. opers. contacted, then tag is assigned
All impacted trans. opers contacted to reserve (first flowgate assigns tag)
Each trans. oper. confirms ATC is still avail. ATC at each flowgate is updated
At time of scheduling energy transfer, User provides tag id to verify that sufficient trans. service is reserved