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USAID SPONSORED FORUM ON ANCILLARY SERVICES FOR THE CENTREL UTILITIES

Warsaw, Poland

February 22-24, 2000

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USAID SPONSORED FORUM ON ANCILLARY SERVICES (AS)

Warsaw, Poland

February 22-24, 2000

DRAFT AGENDA

Day 1-Tuesday, February 22, 2000, Definitions, Requirements, and Characteristics

Time	Subject	Notes and Remarks
08:30 - 09:00	Welcome and Introductions	
09:00 - 10:15	Definition and Scope of Ancillary Services (AS) ***Singh, Kirby***	This is a critical session. It will establish a common understanding and will highlight those AS that are of primary interest in this forum.
10:15 - 10:45	*Break*	
10:45 - 12:30	Fifteen to twenty minute presentations on AS by four CENTREL members and 2-3 Visiting Experts ***Markel, Chicharro***	To describe the approach to AS being taken or planned or being implemented in their country or region. Each speaker should also highlight specific issues and problems of importance to them.
12:30 -14:00	*Lunch at the Marriott Hotel*	
14:00 -15:30	Planning and Scheduling of Ancillary Services ***Singh***	How much of each AS is needed. Effect of Reliability and other operating criteria, load levels and pattern of load variation
15:30 - 16:00	*Break*	
16:00 - 17:30	Technical Requirements for Ancillary Services and their Verification ***Kirby***	Characteristics and properties that AS must meet. How to determine whether the services are/will be available.
19:00	*Dinner* *Hosted by USAID / Electrotek*	Mazurek Restaurant

Proposed structure of technical sessions: In every technical session, it is planned to have a 10-15 minute presentation (or longer if appropriate) by a moderator highlighting the major issues for that session. This will be followed by a round table discussion for the remaining time (about one hour) in which the key issues will be discussed and specific CENTREL problems addressed.

Day 2 - February 23, 2000, Costs, Trading, Competitive Markets

Time	Subject	Notes and Remarks
08:30 - 09:45	Costs incurred in providing Ancillary Services ***Kirby, Singh***	Both actual and opportunity costs will be discussed.
09:45 - 10:15	*Break*	
10:15 - 11:30	Long term and short term policy for Ancillary Service development ***Kirby***	The use of long-term contracts for AS. What time horizons are to be covered? Who should contract for the AS – ISO for e.g.
11:30 - 12:45	Exchange and trade of AS among independent systems ***Alonso***	How independent (separate TSO/ISO/MO) systems trade AS.
12:45 - 14:00	*Lunch at the Marriott Hotel*	
14:00 - 16:00	Setting up a competitive market for AS ***Singh***	Factors influencing design. Capacity and energy bids. Sequential and simultaneous auctions. "Smart" and "Rational" Buyer
16:00 - 16:30	*Break*	
16:30 -17:30	Paying for Ancillary Services and cost recovery ***Kirby, Markel***	Who will pay for the AS and how much. How will AS costs be recovered by the market operator

Day 3 - February 24, 2000, Infrastructure

Time	Subject	Notes and Remarks
09:00 -10:00	Infrastructure for Ancillary Services Management ***Singh, Markel, Kirby***	Software, hardware and communication systems needed.
10:00 -11:00	Open - for review, discussions and future plans	
11:00 -11:45	*Free time /Checkout*	
11:45	*Lunch at the Marriott*	

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Saiz Chicharro
Brendan Kirby
Larry Markel
Harry Singh

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PG&E Energy Services is an unregulated subsidiary of PG&E Corporation. (see back)

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CENTREL FORUM ON ANCILLARY SERVICES

(Organised by Electrotek, CENTREL Members and sponsored by US AID)

CENTREL ISSUES AND PROCEDURES

(Prepared by Karol Holan - CENTREL Secretariat Head)

Warsaw, 22 - 24 February 2000

CENTREL

6

Interconnected Power Systems in Europe

CENTREL - associated member ships of UCTE
UCTE (previously UCPTE)
SUDEL
NORDEL
UPS/IPS
GB
BG/RO

CENTREL

Main Tasks and Objectives of CENTREL are as follows

- the optimal generation and transmission capacity utilisation
- reliable parallel operation of the CENTREL Members interconected systems with the UCTE systems
- promotion of cooperation of CENTREL with the UCTE and other organisations operating power systems
- general improvement of technical facilities through the exchange among all the Members
- improvement of operational conditions of the CENTREL member power systems
- operating the Energy Accounting and Control Centre (EACC)
- carrying out the energy accounting tasks and the load - - frequency control according to the requirements of parallel operation with UCTE
- monitoring of EU legislation - concerning the internal market in electricity and the harmonisation of electricity legislation in the countries of CENTREL Members

CENTREL

Importants Steps in the Process of CENTREL Development

11 October 1992	Foundation of CENTREL
12 October 1993	Signing the Catalogue of Measures for CENTREL
18 October 1995	The CENTREL - UCTE trial parallel operation through VEAG system
1 October 1996	Commissioning of the CENTREL - EACC in Warsaw The second one - year CENTREL - UCTE trial parallel operation
1 October 1997	Submission of ČEZ, a.s., MVM Rt., PSE SA and SE, a.s. Applications for UCTE Membership
16 April 1998	UCTE decision on CENTREL - UCTE permanent parallel operation
29 October 1998	Accession of CENTREL Members as associated members to the UCTE
1 January 1999	Associated membership of CENTREL Members in the UCTE came into effect
19 November 1999	ČEZ, a.s. replaced by ČEPS, a.s. in CENTREL membership
1 July 1999	Collective membership of UCTE in ETSO

CENTREL

Further Steps of CENTREL

(Present State)

adopted by the Council of CENTREL at Mošovce *(Slovakia)* on 19 November 1999

- CENTREL Members will mutually coordinate their preparation of individual applications to UCTE full membership
- OIWG will be responsible fo the coordination of this process
- CENTREL Members make effort to be accepted as ETSO idividual members since July 2001
- Mr. Aleš Tomec *(CENTREL Steering Committee Chairman)* was appointed by the Council of CENTREL to be counterpart for CENTREL to the ETSO representative Mr. Jürgen Schwarz of DVG *(Germany)*
- The next CENTREL Steering Committee Meeting will be held in Podebrady *(Czech Republic)* on 4 - 5 May 2000
- The next CENTREL Council Meeting will be held in Poland on 1 - 2 June 2000
- SE, a.s., will host and organise UCTE Steering Committee and General Assembly Meeting on 25 April 2002

CENTREL

Internal European Market for Electricity

(Present State)

- Creation of the Association of Transmission Systems Operators in two steps :
  - first step - 1 July 1999, creation of the Association of Associations
  - second step - since 1 January or 1 July 2001 - Association of TSO's of the EU Members or states will have signed agreement with EU
- The principles of the TSO's Association to be applied to all non - EU states strongly interconnected with Internal Electricity Market electrical networks *(CENTREL,Switzerland, Norway)*
- Development of the Economic and Technical Rules for Cross - Border Transsmision as well as Network Regulation
- UCTE - internal undbundling in accordance with the Chapter IV of the Directive EU 96/92/EC
- To elaborate the position of the Industry access to the Grids and Tariffs

CENTREL

Conclusions towards the CENTREL Development

(Present State)

- Reliable paralell operation of the CENTREL Members interconnected systems with the UCTE sytems
- To perform continuously the implementation process of the legislation changes in the power industry
- To follow the European Electricity Market Development and to realise its impact to the CENTREL Members
- To finish a privatisation process in all CENTREL member companies
- To support the controlled opening of electricity market in the CENTREL countries
- To reach full competitive ability of the CENTREL Members
- To co-operate on the synchronous zone extention process development
- To coordinate its policy in the area of ancillary services
- To co-operate with all regional electric power groups

CENTREL

Development of Ancillary Services in CENTREL

(Present State)

- Council of CENTREL meeting held at Mošovce *(in Slovakia)* on 19 November 1999 decided to establish Task Force Ancillary Services wthin SOWG
- The tasks to be oriented mainly towards power echange, power reserves and regulation capacities
- Nomination of the CENTREL member companies representatives for the Task Force Ancillary Services
- Mr Grzegorz Blajszczak (PSE SA) appointed by the Task Force Ancillary Services Chairman
- The first meeting held at Krasna-Visalaje *(Czech Republic)* on 15 - 17 December 1999
  - Discussed the further three ancillary services
    - — ability of black start
    - — ability of island operation
    - — voltage supply
  - Technical and trade regulations for the ancillary services trade *(primary, secondary and terciary regulations)*
- Relations between market players and ancillary services may have two forms:
  - Direct contact betweenTSO and generator
  - Contract between saler and buyer
- CENTREL Forum on Ancillary Services in Warsaw on 22 - 24 February 2000 *(participation of the CENTRELMembers and Electrotek - USA - experts)*

CENTREL

CENTREL FORUM ON ANCILLARY SERVICE

(Organised by Electrotek, CENTREL Members and sponsored by US AID)

PRESENT STATE OF THE ANCILLARY SERVICE DEVELOPMENT IN SE, a. s.

WARSAW, 22 - 24 FEBRUARY 2000

14

Ancillary services in the environment of the SE, a.s.

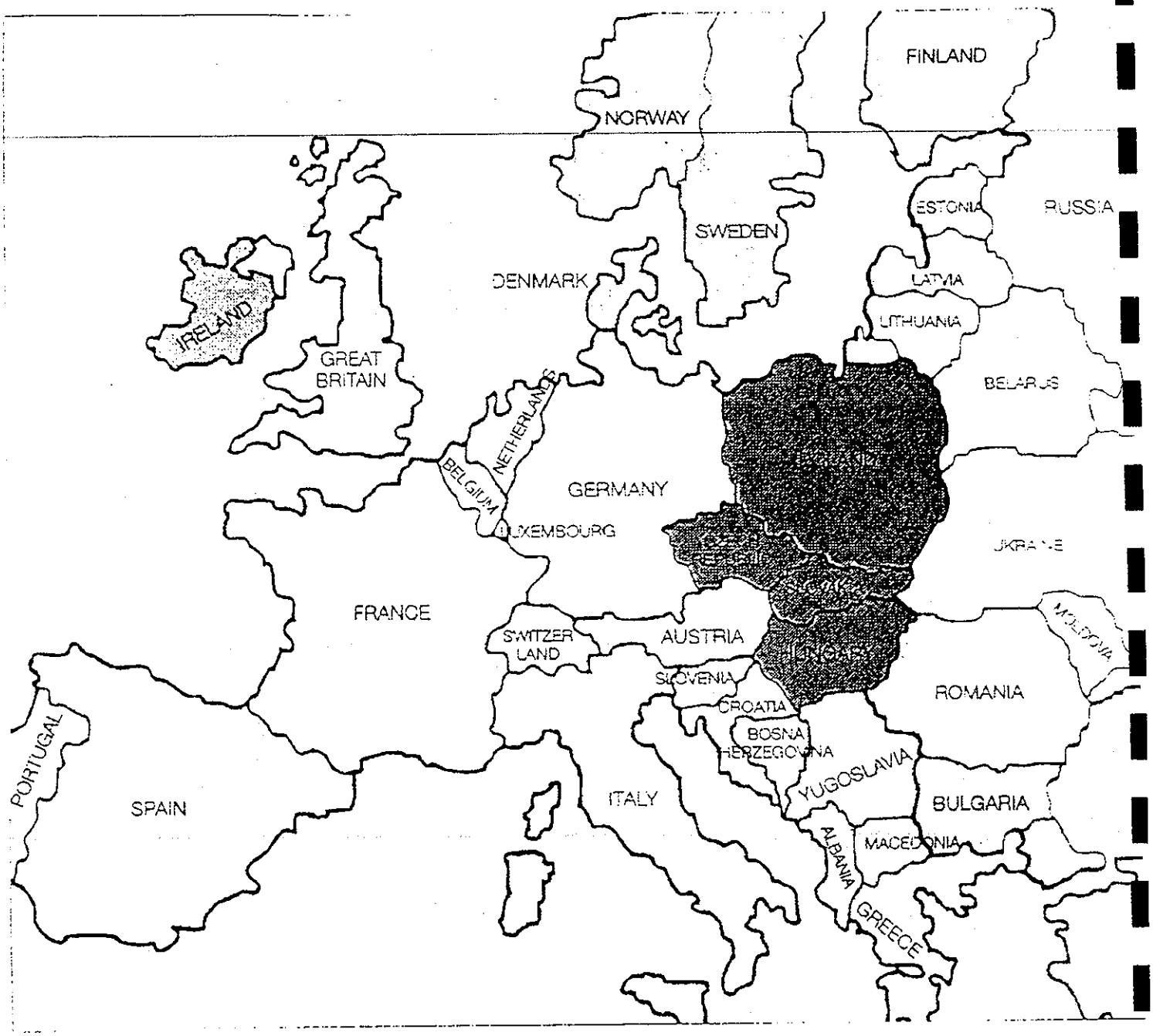
Ancillary services in the environment of the Slovak Republic power system are provided in accordance with CENTREL, respectively UCTE procedure. Currently they are being worked out and procured by the SE, a.s. From technical point of view it can be said that power system operation in Slovakia has been improved. Recently a technical device, developed in cooperation with Slovak companies, specialised at terciary regulation has been implemented. By means of voltage values monitoring in the selected „pilot" nodes the reactive power flows are automatically controlled by means of dispatch control system LS 3200, respectively by means of a dispatcher. Losses in the system are optimised this way. This device technologically moves the qualitative side of ancillary system services forward in the framework of transmission system.

As it was explained in the introduction, the SE, a.s. work as a vertically structured joint-stock company, comprising electricity generation, transmission and trading.

The transmission system operates as an economically dependant subsidiary and the national dispatch centre is subordinated to the SE, a.s. headquarters. Only electricity distribution is performed outside the SE, a.s. Ancillary services, provided by individual organisational units of the SE, a.s. are clearly specified and assigned to individual technical entities. They are not financially evaluated and individual entities are not feed for providing these services. The costs divided into separate activities of ancillary services are not traced. Economy and accountancy are traced individually at each organisation unit (e.g. Transmission System, National Dispatch Centre, individual power plants), however, on the level of a different structure as is that of the ancillary services. Economy of all the entities is closed at the level of the SE, a.s. in the framework of a common economy. This situation is a result of organisational structure of power industry in Slovakia. At present transformation process of power industry is being discussed. There exist numerous variants of a possible proceeding, the decision is estimated to be made in the half of 2000. Now it would be premature to speak of a dominant variant of transformation, as so far no specific variant is prevailing.

The only unavoidable decision is the one on providing transparent separation of economy and accountancy of the Transmission system together with the National Dispatch Centre, from the SE, a.s., in accordance with the EU Directive 96/92. The situation in Slovakia is strongly influenced by the so far the National Regulatory Body for electric power industry has not been established and the function of a regulator is being carried out by three bodies of state administration: Ministry of Economy, Ministry of Finance and Antimonopoly Office. Another important factor of the Slovak power system is a continuous deformation of electricity prices. Next, the absolute extent of the Slovak power system should

also be taken into consideration. All the neighbouring power systems are at least two times larger. It is very difficult to intend to open market, respectively transform power industry in the conditions of such a small power system. Similarly, in the conditions of a long time unchanged and undervaluated electricity tariffs it is not easy to solve evaluation of ancillary system services without a fundamental price reconstruction and electricity prices rise. Even the last electricity tariffs rise since February 1st, 2000 (30% for retail trade and 5% for wholesale trade) has not solved this problem as electricity price in Slovakia was held-down and currently it is included in the production costs of the SE, a.s. and distribution utilities. Therefore in Slovakia the issue of electricity tariffs is being closely viewed, with the objective to eliminate the cross-subsidies partly, to transform electric power industry and to prepare establishment of an independent regulatory body. At present, the issue of defining and evaluation of ancillary services is being viewed and internal proposals for proceedings are being elaborated. They will be published after a general view of this issue has been settled.



CENTREL/ UCPTE ass. memb.

UCPTE SUDEL

NORDEL

UPS/IPS

GB

BG/RO

VLÁDA SLOVENSKEJ REPUBLIKY
Government of Slovak Republic

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- Ministerstvo pôdohospodárstva
  Ministry of agriculture
- Ministerstvo kultúry
  Ministry of culture
- Ministerstvo školstva
  Ministry of education
- Ministerstvo privatizácie
  Ministry of privatisation
- Ministerstvo hospodárstva
  Ministry of economy
- Ministerstvo financií
  Ministry of finance
- Ministerstvo živ. prostredia
  Ministry of environment
- Ministerstvo zdravotníctva
  Ministry of health service
- Ministerstvo vnútra
  Ministry of interior
- Ministerstvo spravodlivosti
  Ministry of justice
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  Ministry of defence
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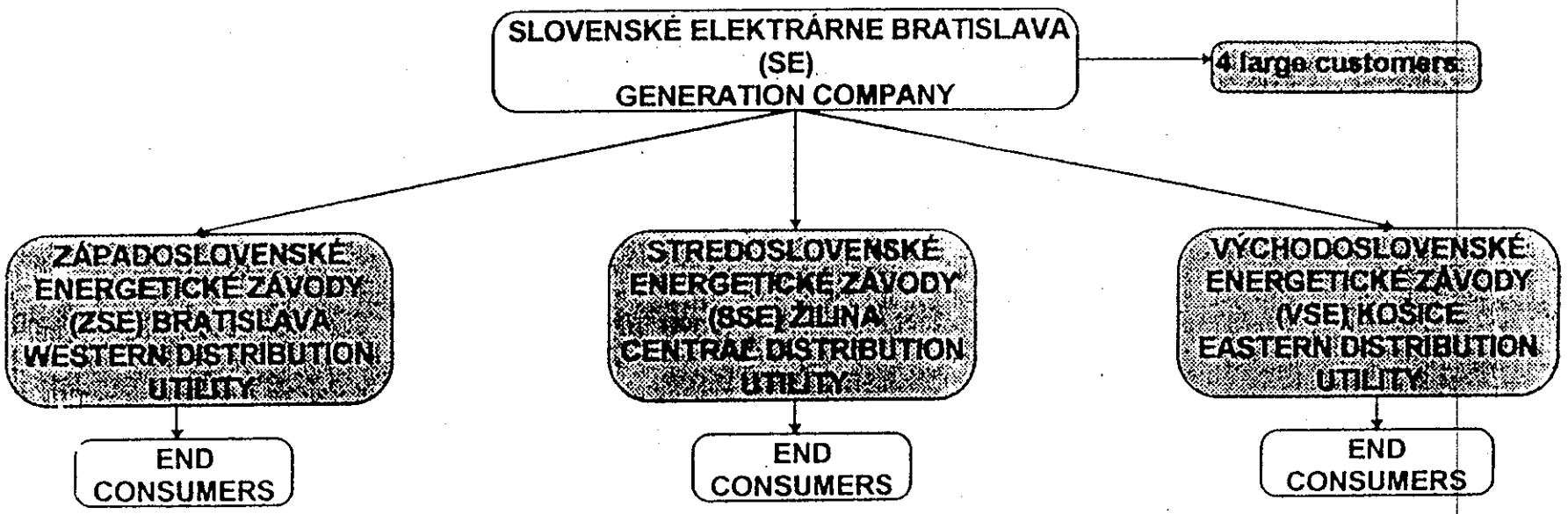
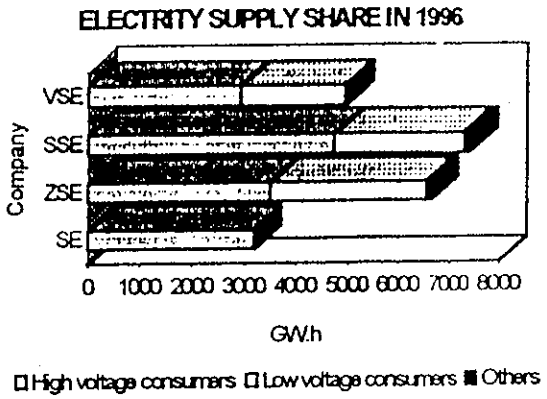
  Ministry of architecture
- Ministerstvo práce
  Ministry of employment
- Ministerstvo dopravy
  Ministry of transportation

SLOVENSKÉ ELEKTRÁRNE ®

SLOVAK ENERGY SECTOR





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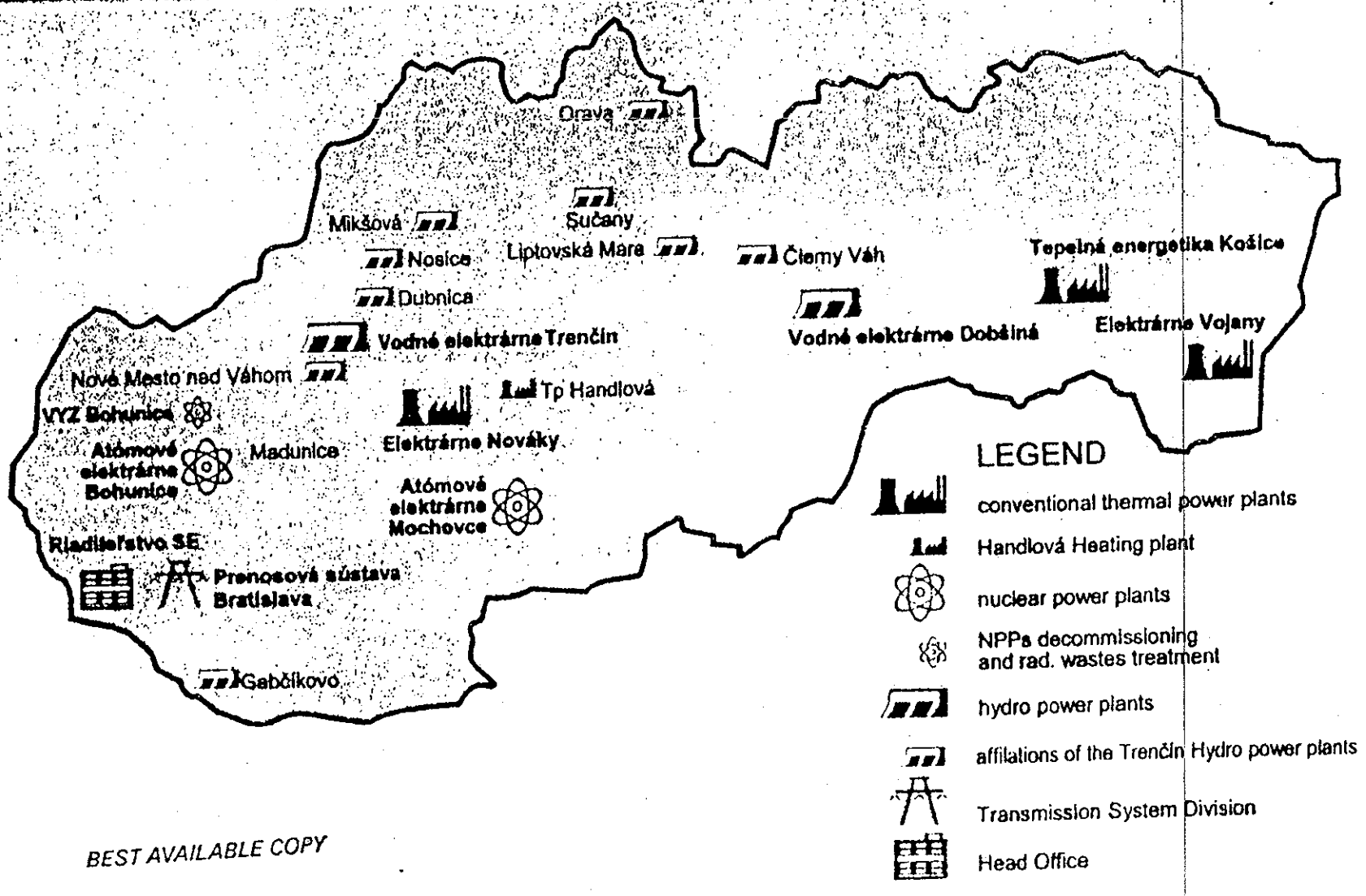

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SLOVENSKÉ ELEKTRÁRNE, a.s.

Main goals

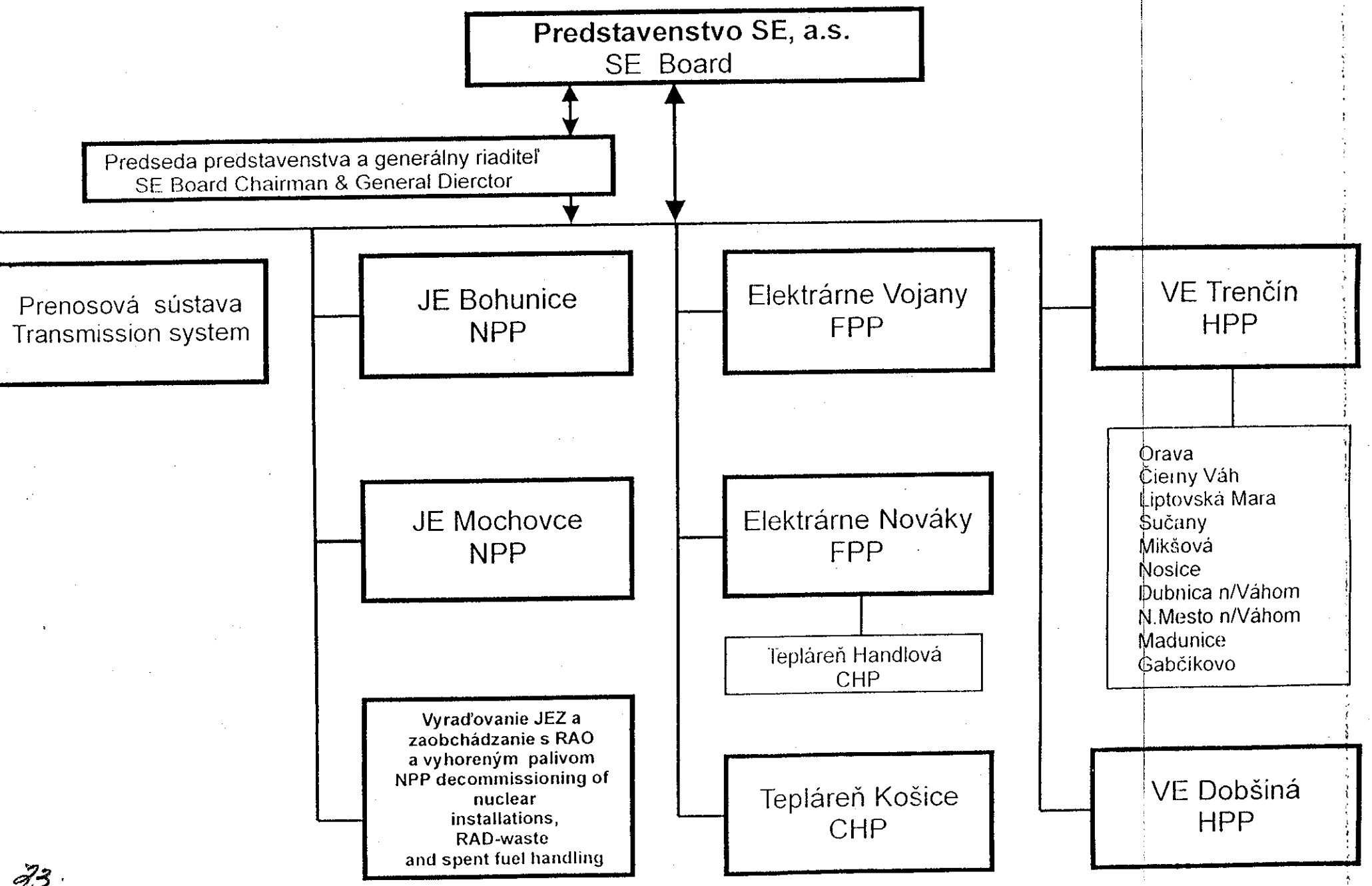
- ***safe, ecological, reliable and economical*** operation of electric and heat energy sources and power system
- ensure - in accordance with governmental program of economy development - ***balanced*** consumption and production of energy (do not exceed 15 % share of electricity import)
- preserve ***significant position of company*** on energy market by implementation of investment projects
- ***increase nuclear safety*** of sources and keep them on international acceptable level of nuclear safety
- decrease long term ***ecological impact*** in according with international commitments of SR
- apply ***Least Cost Planning*** methods in development plans
- design energy sources with **reasonable costs** for future

SLOVENSKÉ ELEKTRÁRNE, a.s.

Main goals

- permanent intention of ***alternative*** energy sources and ***hydro-potential*** optimum use
- secure ***financing*** for optimal development projects
- implement mechanism of ***energy price modification*** to ensure company development
- **diversify** import of primary energy sources, import and transit possibilities of electricity
- apply ***Demand Site Management*** - DSM and ***DSM-in house*** projects to decrease power demand
- intensify co-operation ***UCPTE and CENTREL*** countries and gradually integrate power system of EU and SR

Organizačná štruktúra SE, a.s.
Organisational chart of the SE, a.s.



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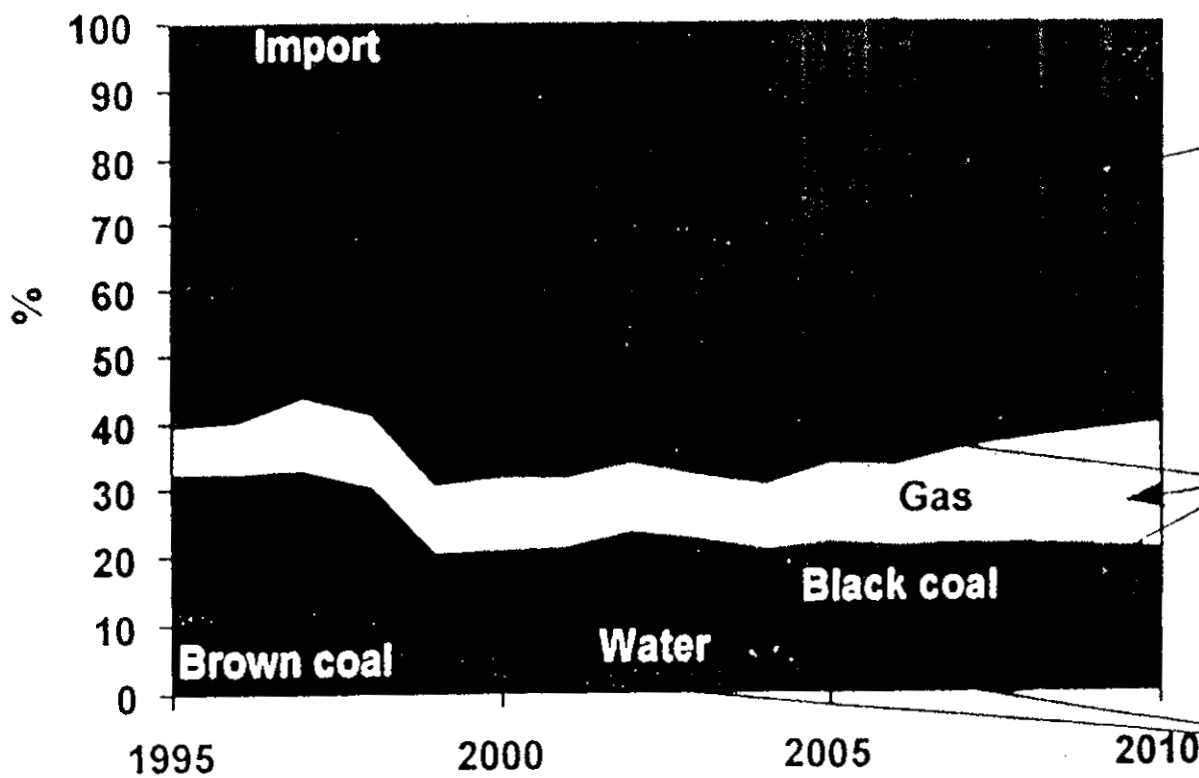
Primary energy share at SE, a.s.



Potential suppliers
- Russia
- Germany
- USA
- France
- Great Britain

Potential suppliers
- Russia
- Ukraine
- Poland - coal

Other suppliers
- high transport costs

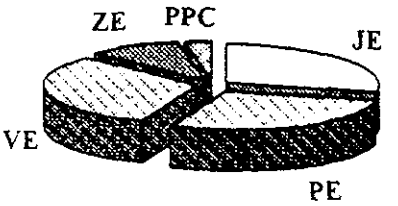
Domestic sources

24

INŠTALOVANÝ VÝKON ELEKTRÁRNÍ ES SR

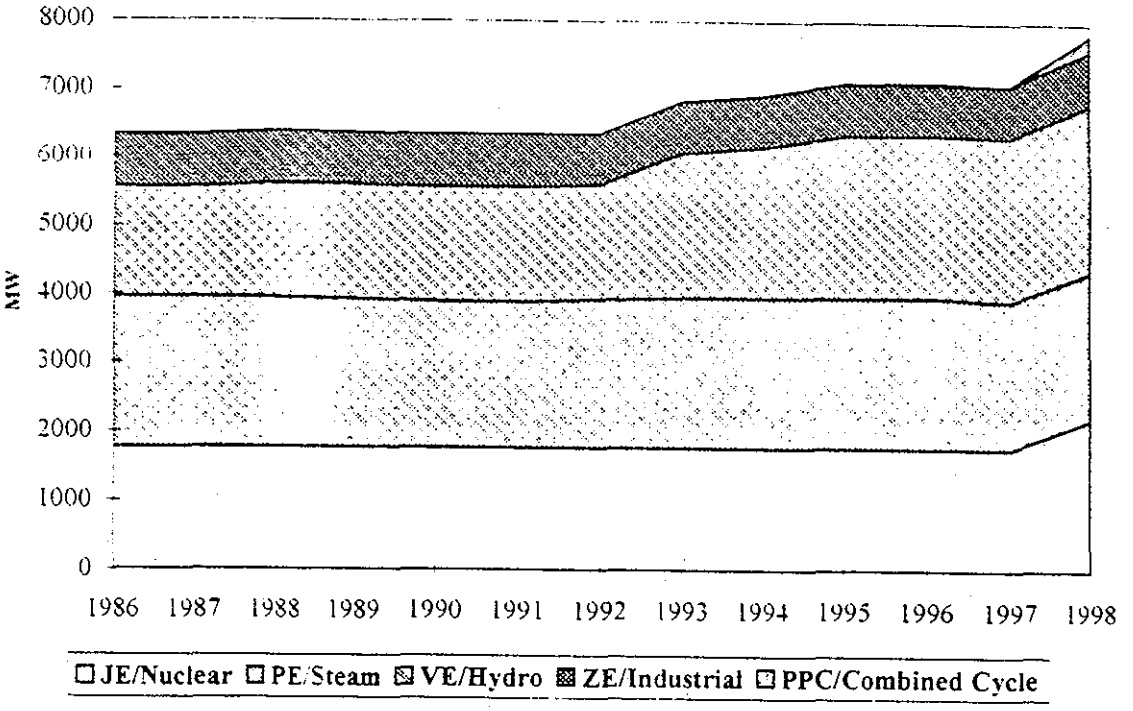
Installed capacity of the power plants in SR

Elektráreň	MW	%	Power plant
JE	2 200	28,1	Nuclear
PE	2 166	27,7	Steam
VE	2 470	31.5	Hydro
ZE	777	9,9	Industrial
PPC	218	2,8	Combined Cycle
Suma	**7 831**	**100,0**	**Total**



VÝVOJ INŠTALOVANÉHO VÝKONU V R. 1986-1998

Development of installed capacity in the years 1986-1998



ŠTRUKTÚRA BLOKOV (nad 90 MW) ELEKTRÁRNÍ ES SR

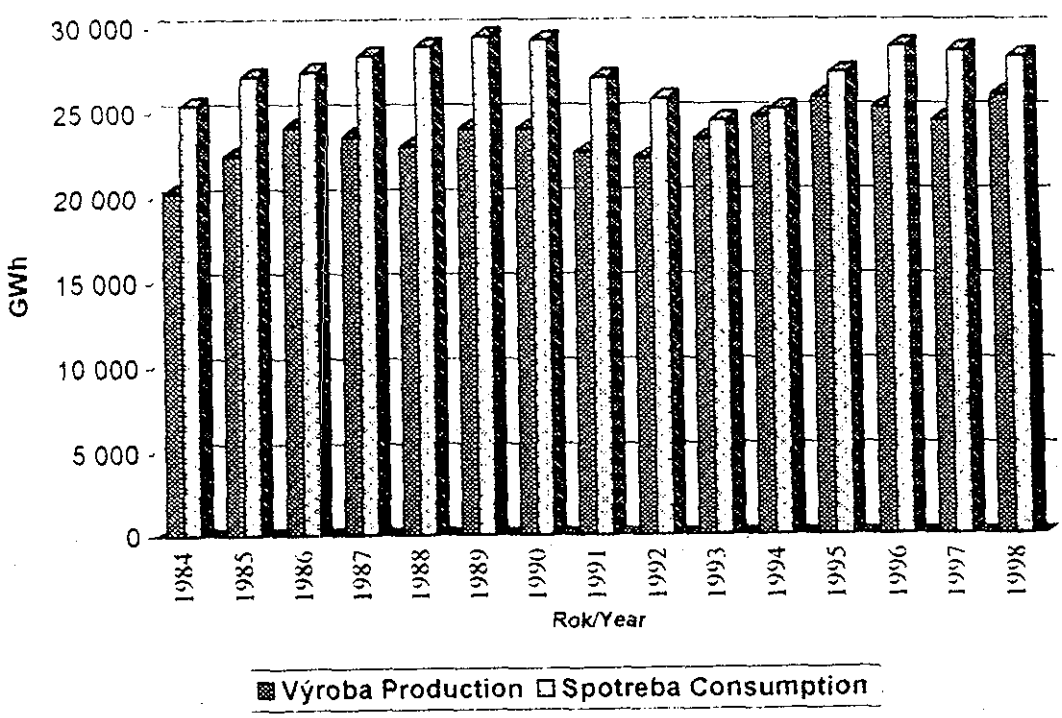
Structure of the units (over 90 MW) of power plants of SR

Blok (MW) Unit (MW)	Počet blokov Number of units	Druh Type	Elektráreň Power plant
220	8	JE	Jaslovské Bohunice
220	2	JE	Mochovce
110	6	PE	Vojany 1
110	6	PE	Vojany 2
110	4	PE	Nováky
218	1	PPC	Bratislava
122.4	6	PVE	Čierny Váh
90	8	VE	Gabčíkovo

VÝROBA A SPOTREBA EL. ENERGIE ES SR V ROKOCH 1984-1998 (GWh)

Production and consumption of the el. energy of SR in years 1984 - 1998 (GWh)

Rok Year	Výroba Production	Spotreba Consumption	Index-výr. Index-prod.	Index-spotr. Index-cons.
1984	20 360	25 442	103,9	103,0
1985	22 494	27 125	110,5	106,6
1986	24 170	27 415	107,5	101,1
1987	23 630	28 362	97,8	103,5
1988	23 074	28 913	97,6	101,9
1989	24 081	29 504	104,4	102,0
1990	24 062	29 297	99,9	99,3
1991	22 709	27 038	94,4	92,3
1992	22 340	25 781	98,4	95,4
1993	23 417	24 497	104,8	95,0
1994	24 740	25 162	105,6	102,7
1995	25 905	27 324	104,7	108,6
1996	25 290	28 875	97,6	105,7
1997	24 547	28 629	97,1	99,1
1998	26 017	28 268	106,0	98,7



PRENOSOVÁ SÚSTAVA SLOVENSKEJ REPUBLIKY

Transmission system of Slovak Republic

Transformačný výkon	8 410 MVA	Transformation capacity
Vedenia 400 kV	1 677 km	Lines 400 kV
Vedenia 220 kV	964 km	Lines 220 kV
Rozvodne 400 kV	16	Substations 400 kV
Rozvodne 220 kV	8	Substations 220 kV
Transformátory 400/220 kV	1 400 MVA	Transformers 400/220 kV
Transformátory 400/110 kV	4 410 MVA	Transformers 400/110 kV
Transformátory 220/110 kV	2 600 MVA	Transformers 220/110 kV

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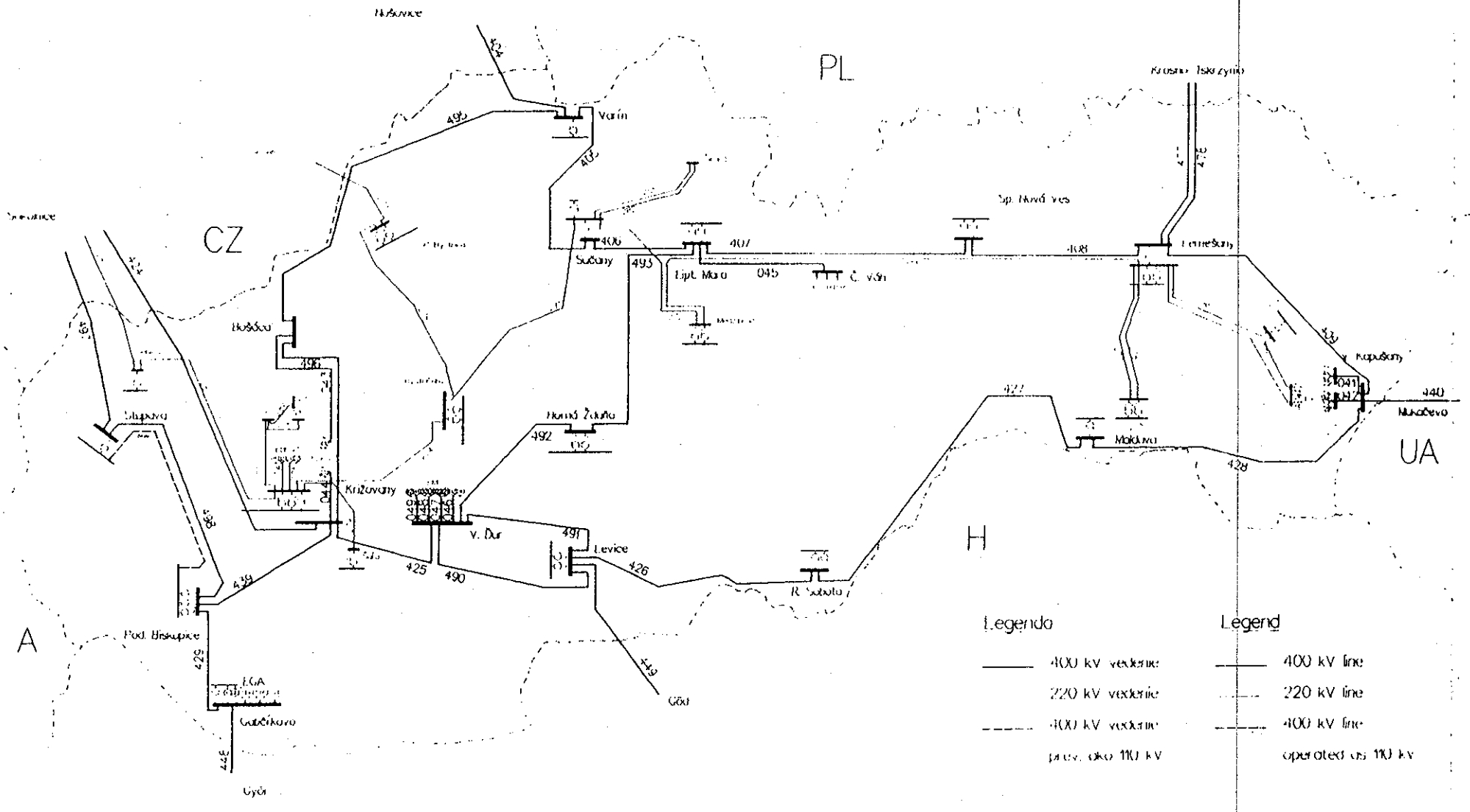
Prenosová sústava Slovenskej republiky



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SLOVENSKÉ ELEKTRÁRNE

27.

DIAGRAM TÝŽDENNÝCH MAXÍM

Diagram of the week maximums

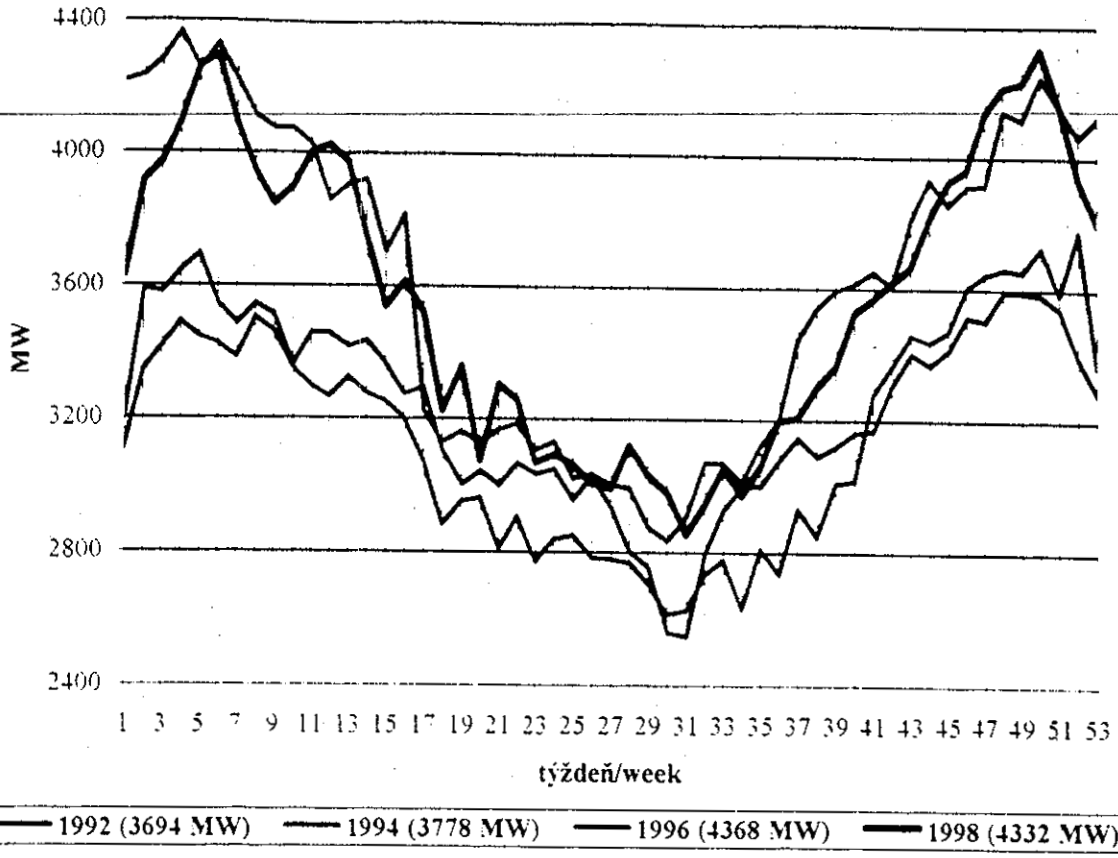
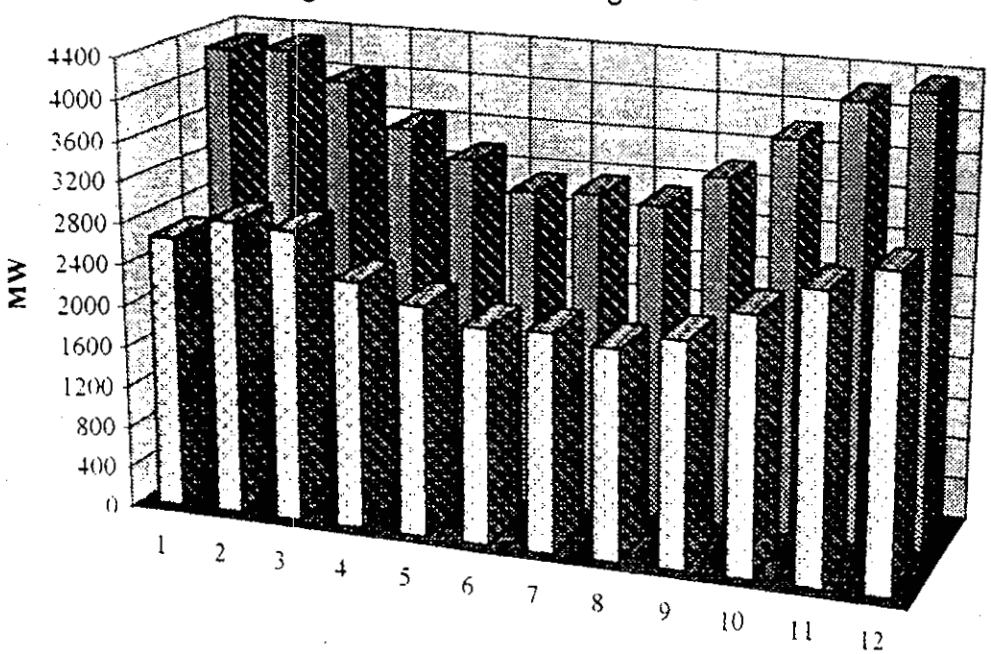


DIAGRAM MESAČNÝCH ZAŤAŽENÍ ES SR

Diagram of month loadings in SR



max. (bez čerp.) / (without pumping)

min. (absolútne) / (absolute)

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System services supplied by CEZ/CEPS in the Czech republic and ancillary services procurement

1) Present situation

~~All ancillary services (AS) is provided by CEZ (about 15% of it comes from IPPś units~~ contracted by CEZ)

Standard simplified mechanisms (calculations) are utilized to set system requirements. Under weekly planing procedures, calculations for sufficient spinning reserve and non-spinning reserve is provided. Detailed allocation of primary regulation and secondary/tertiary regulation is processed mainly on a day ahead basis by dispatchers.
Replacement („cold") reserve is planned on an annual/monthly planning basis.
Other ancillary services such as Black start ability, island operation ability and voltage support is planned by CEZ on an annual/monthly basis.

Wholesale price of the electricity (for distributors) is regulated by ministry decrees in a form of price caps, applicable for supply from utility (CEZ). Till the 31.1.2000 this price included payment for system services.

No price caps are given to the electricity from IPPś , and no obligation of IPPś to supply also ancillary services exists. It means that IPPś compete with CEZ supplying electricity for distributors for prices just below the price cap, but do not supply any of the ASś.

Effective from 1.2.2000 there is a separate rate for system services which is paid by distributors and is associated to each MWh supplied to the distributors from the transmission grid. Based on this regulation, CEPS in now in the process of preparing the contract with CEZ for supplying ancillary services. Each of the ancillary services would have assigned price valid for the year 2000 for each capacity, actually suplied as a ancillary services. The requirement for the amount of AS have been published by CEPS for each week of the year 2000 break down into weekdays and weekends requirements. This requirements are precized on a monthly basis. This means, that as an ancillary service is paid only the required capacity. For any other excess capacity, there is no payment.

2) Proposal for the year 2001

There is the new energy law proposal which have been approved by government and is postponed to the parliament. It is expected to be enacted by parliament this year and effective from (possibly) Jan. 2001 will open the first stage of the electricity market in 2002. In order to keep CEPS as the future TSO one step ahead, we proposed new regulation formula for the second half of the year 2000, which is at present under the discussion with regulator. This proposal suggests:

- system services rate will be paid by distributors to CEPS for each kWh procured by distributors to the final consumers
- this rate have been calculated from fixed and variable costs, associated with the ancillary services provision
- every generator, who is able to meet technical standards of the published Grid code
  1) is eligible to be conected to the transmission grid
  2) is entitled to supply at minimum the share of each AS, which is appropriate to it's share of the electricity market. It will be covered by contract between CEPS and

generator including verification mechanism of suplying service with appropriate quality, payment conditions etc.

- the rest of each AS, which will not be primarily covered by qualified generators (this share is equal to the total market share of the generators technically non-qualified for ancillary services supply) will be traded in an open bidding process.
- all system services will be ordered in bilateral contracts for a remaining part of the year 2000
- till the end of the year , CEPS will develop its ability to procure all the ancillary services via standard market mechanisms (i.e. bidding process for part of services, procured by bilateral annual/monthly contracts, and day ahead market for the rest of it)
- CEPS will also develop sophisticated mechanisms/methodologies to calculate hourly system requirements for each ancillary services including their evaluation

The day ahead market will be organized using internet aplication. This aplication we will start to test as a "market game" with all potential participants from the early autumn in order to get some know-how and information before starting the real market.

We expect to be prepared to fully open the market for ancillary services from 1/1/2001.

For procurement and handling we have defined nowadays the 5 main categories and 3 supplemental categories.

Main categories are:

- primary regulation
- secondary regulation – 10 minute spinning reserve with direct on line communication with central regulation system
- tertiary regulation – 30 minute spinning reserve with direct on line communication with central regulation system
- quick start regulation – 10 minute non spinning reserve
- replacement reserve – „cold start" units

Supplemental categories are:

- U/Q control at the level of transmission grid
- black start ability
- island operations ability

While supplemental categories are typically regional „in-system" services, we have identified potentially 4 of 5 main categories to be able to trade within CENTREL systems (except for secondary regulation at present which means automated secondary regulation).

What we expect of that is:

- allow each TSO to procure sufficient system reserves even with poorer (temporary) domestic ability
- keep domestic market players off the strong market games in the domestic markets
- support efficient allocation of as much reserves as is possible at the CENTREL level
- gain benefits from open market with AS

3) Ancillary services prices at the domestic market

We expect it should set by the market mechanism. One of the possible bid price structure is:

- primary regulation – price in CZK/MW for each hour supplying service
- secondary regulation - price in CZK/MW for each hour supplying service (variable costs is included)
- tertiary regulation – fix price for reserve capacity CZK/MW in each hour + variable price for electricity supply
- quick start reserve - fix price for reserve capacity CZK/MW in each hour + variable price for electricity supply and price for startup when called
- replacement reserve - fix price for reserve capacity CZK/MW in each hour + variable price for electricity supply and price for startup when called

For the very early stage of the open market, we have developed simulation model (based on opportunity cost simulation, including a market strategy "parameters"), which allows us to evaluate possible range of bid prices and consequently market clearing prices, and predict potential market failures. This model will be utilized also to prepare rate case for the system services rates for the year 2001, which hopefully includes also some know-how from the pre-market stage in 2000.

If we will reach some agreement within the CENTREL group about rules for AS market, we will open the bidding procedure also for offers from abroad basicly on the principle of the reciprocity.

Start AS [illegible] full [illegible] of [illegible] market 1/1/2001.

There are 4 IPPs [illegible] run by non-[illegible] IPPs.

Ancillary Services Market in Hungary

22-24. February, 2000
Warsaw, Poland

Antal Balázs, Péter Simig, Zoltán Tihanyi - MVM Rt.

Ancillary Services Market in Hungary

Current Situation

- System operation is based on contracts
- Operational Code is obligatory for each player connecting to the system
- Tariff system is regulated

Antal Balázs, Péter Simig, Zoltán Tihanyi - MVM Rt.

Ancillary Services Market in Hungary

Current Situation

Ancillary services are:

- Primary reserves
- Secondary reserves - spinning or quick-start
- Tertiary reserves - spinning or cold
- Reactive power regulation
- Start-up/shut-down of generating units
- Black-start ability
- Emergency response rate
- Other special services

Antal Balázs, Péter Simig, Zoltán Tihanyi - MVM Rt.

Ancillary Services Market in Hungary

Current Situation

Other special services are e.g.:

- Surplus capacity/energy in peak
- Decreased minimum regulating limit/energy generation during light load period
- Rescheduled/shortened planned maintenance program

<u>On demand of the System Operator!</u>

Antal Balázs, Péter Simig, Zoltán Tihanyi - MVM Rt.

Ancillary Services Market in Hungary

Current Situation

Payments for providing ancillary services

- Reserves: in percentage of energy fee, based on availability or utilisation (primary), according to PPAs
- Reactive power, black-start: fixed charge, based on availability, according to PPAs

Ancillary Services Market in Hungary

Current Situation

Payments for providing ancillary services

- Emergency response rate: based on actual utilisation, calculation method is in PPAs
- Other special services: according to method announced in decree of minister of Economic Affairs

Antal Balázs, Péter Simig, Zoltán Tihanyi - MVM Rt.

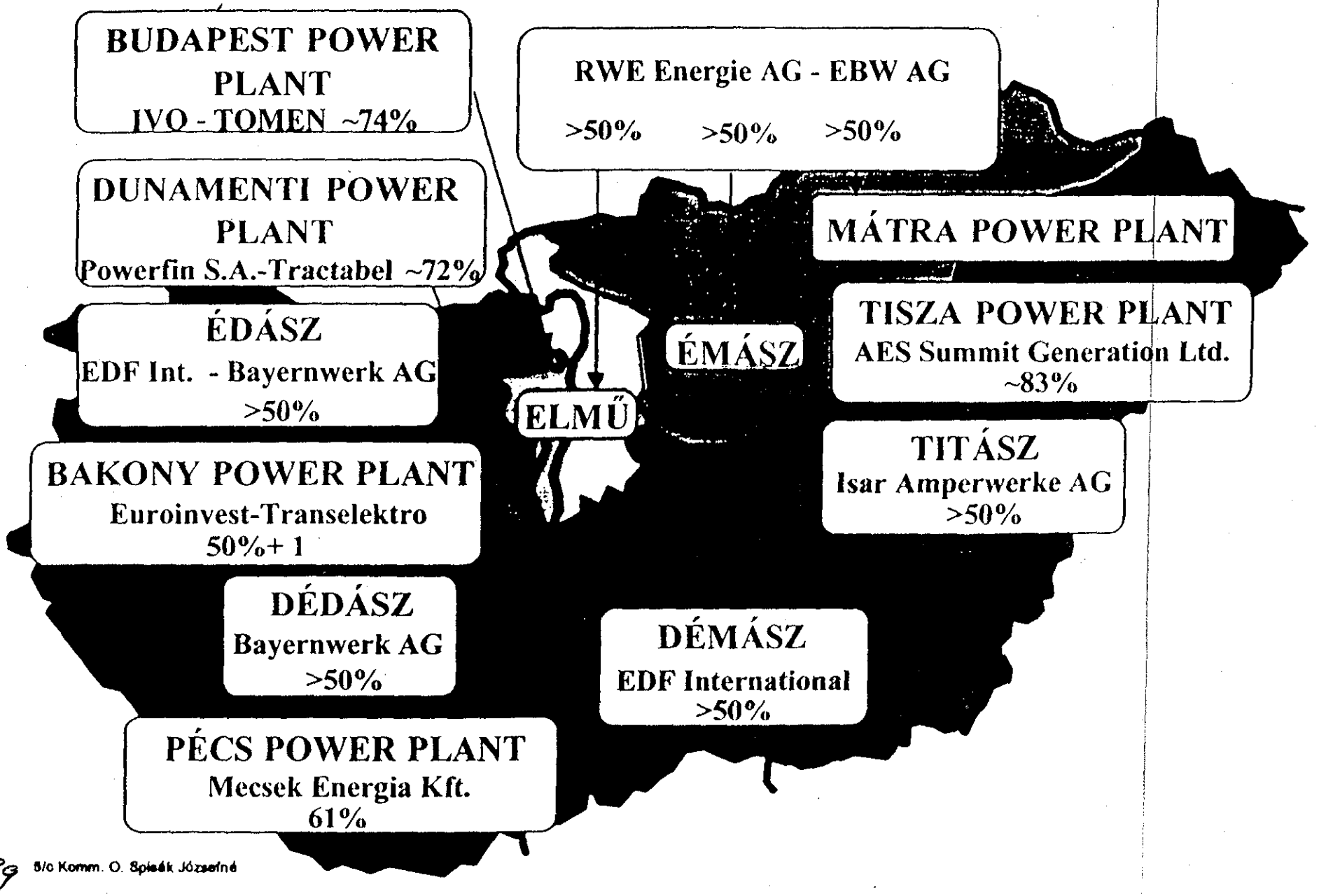
Ancillary Services Market in Hungary

Possible Future Solutions

- Bilateral contracts between ISO and generators, suppliers, customers
- Internal market for ASs run by ISO
- Common market for some ASs within CENTREL or even on a wider scale

PRIVATISED POWER COMPANIES OF THE FORMER MVM-GROUP

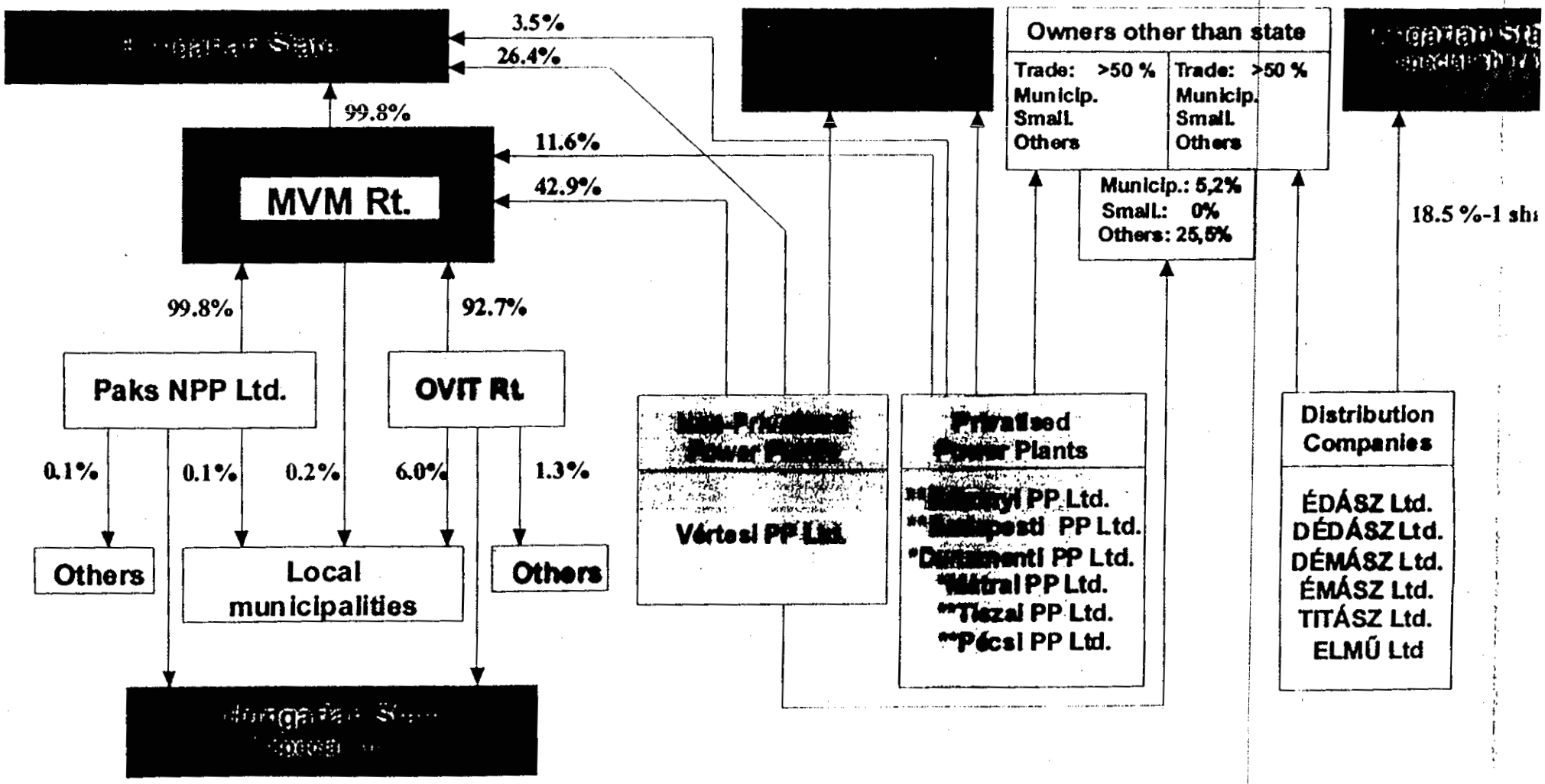
(January 1999)



39 S/o Komm. O. Spiesák Józsefné

Ownership Structure of the Former MVM-Group

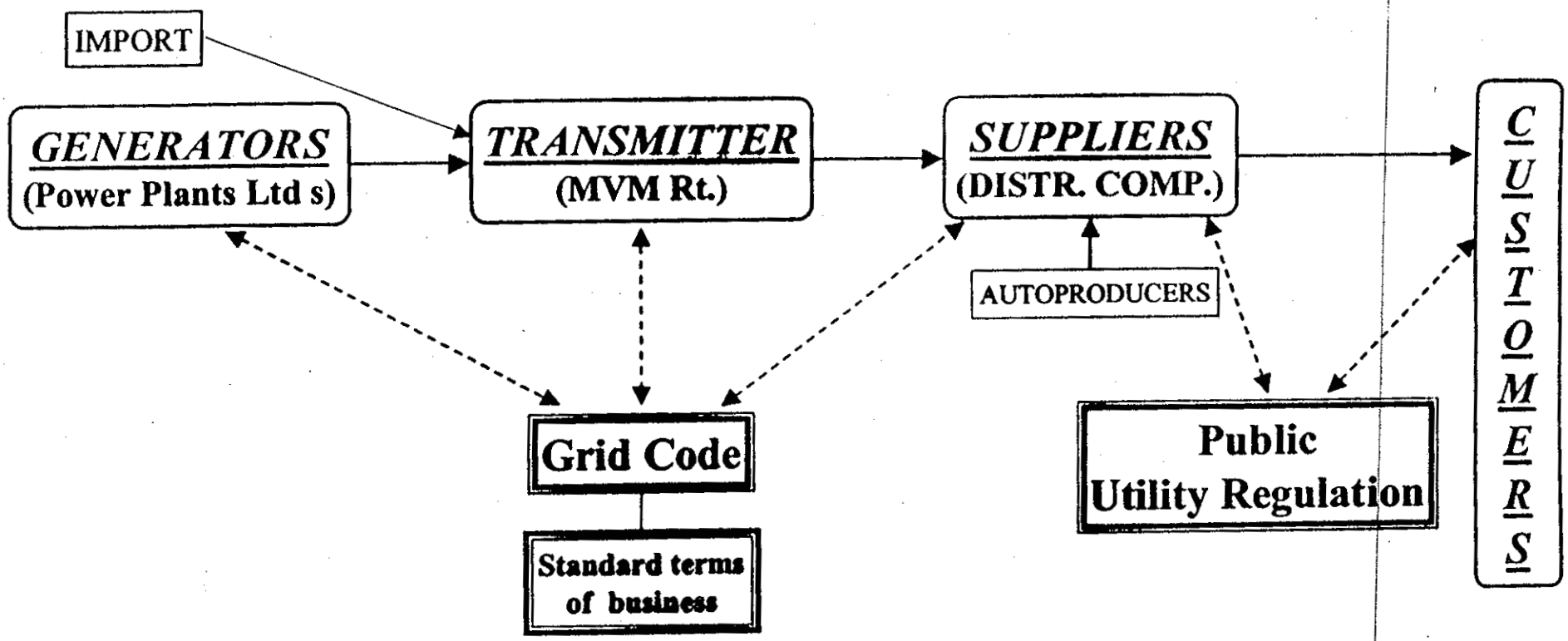
January 1999



** MVM Rt. stake: 0 %
* MVM Rt. stake: 25 % + 1 share

40 Komm. O. Spisák Józsefné

MODEL OF OPERATION END REGULATION



Long term and annual PPA

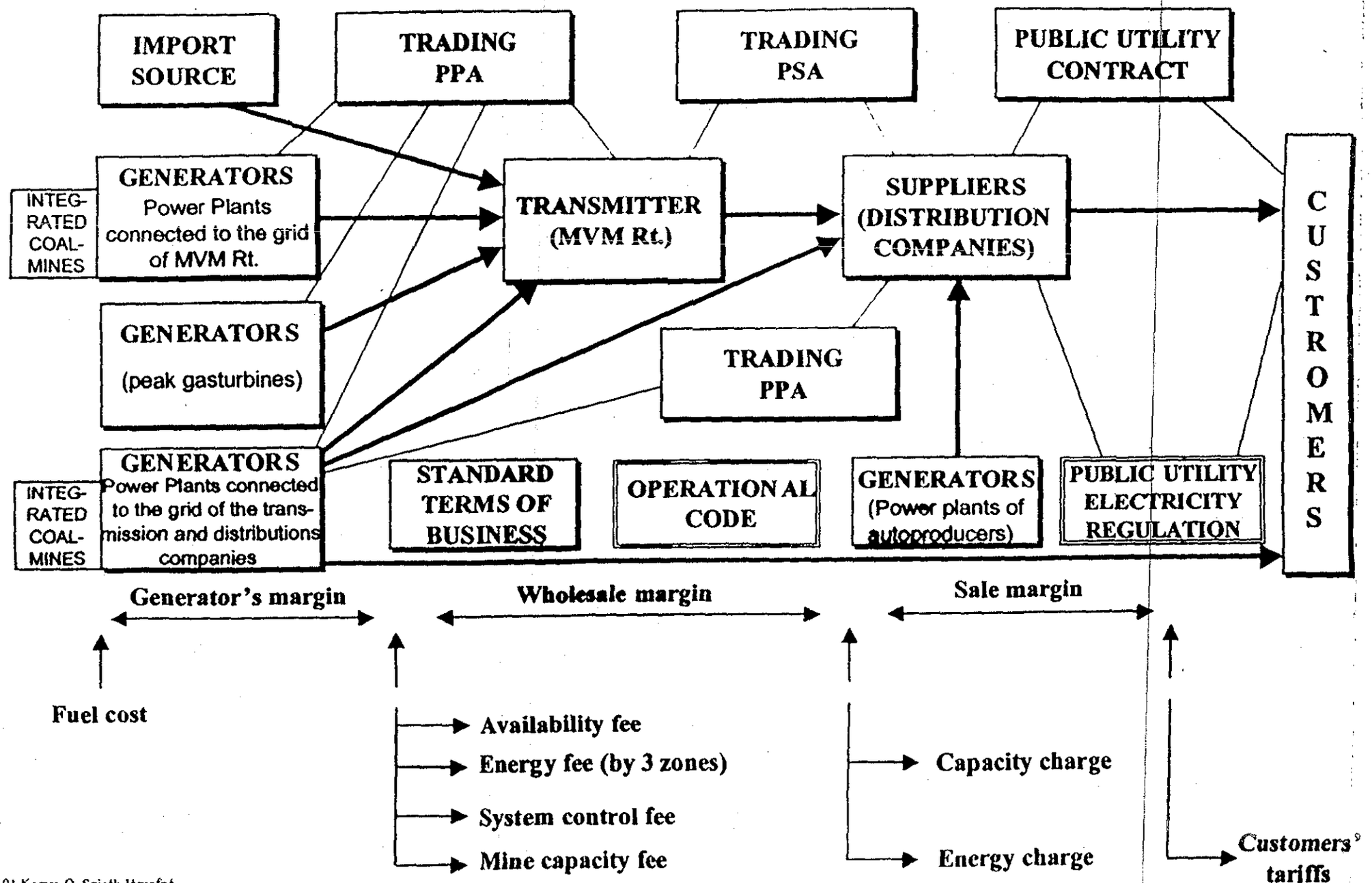
Long term and annual PPA

Public utility contract

Generator s margin | *Wholesale margin* | *Sale s margin* | *Customers tariffs*

Komm. O. Spisák Józsefné

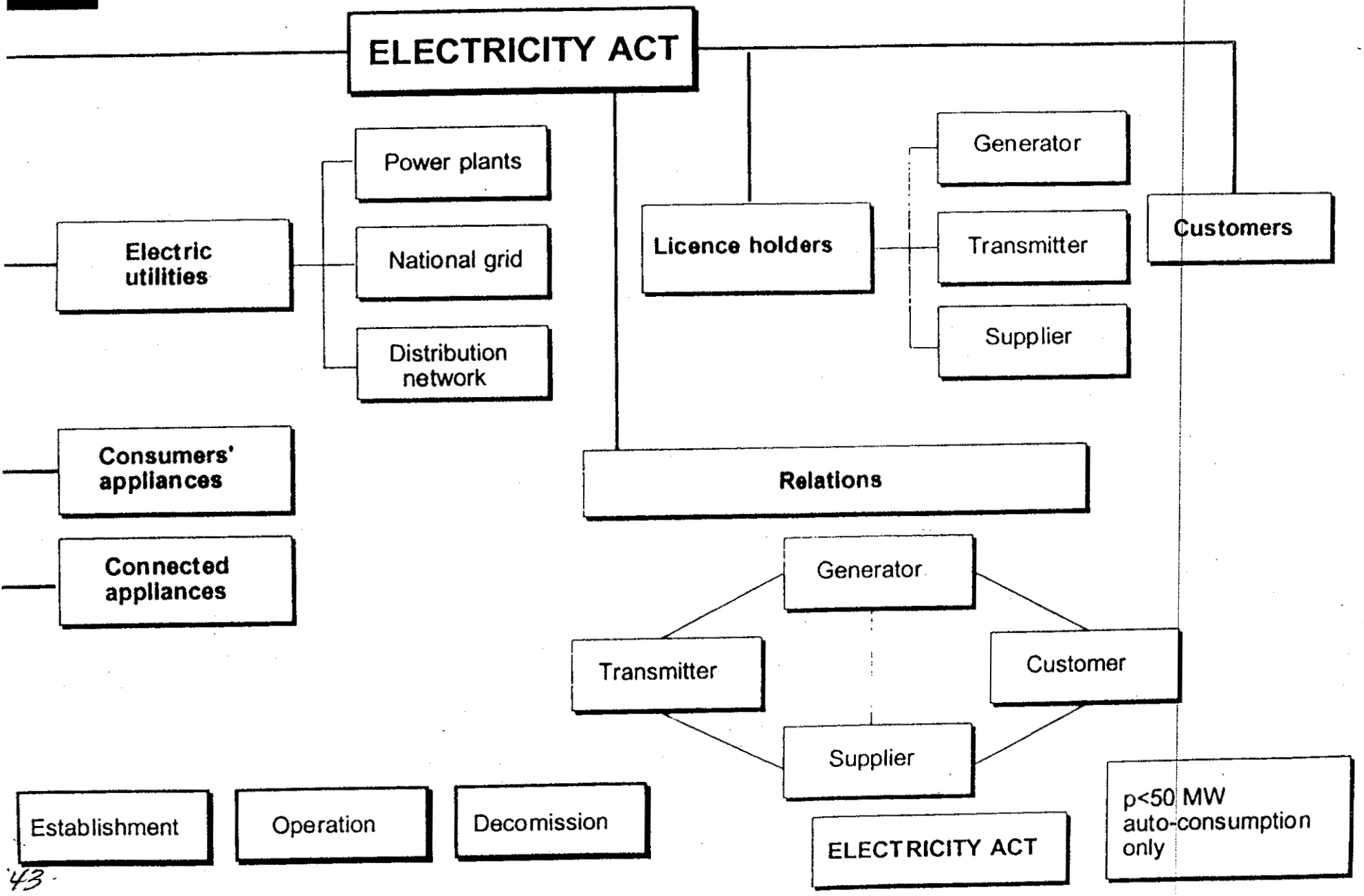
MODEL OF OPERATION



101 Komm.O. Spisák Józsefné

42

EFFECT OF THE ELECTRICITY ACT



43

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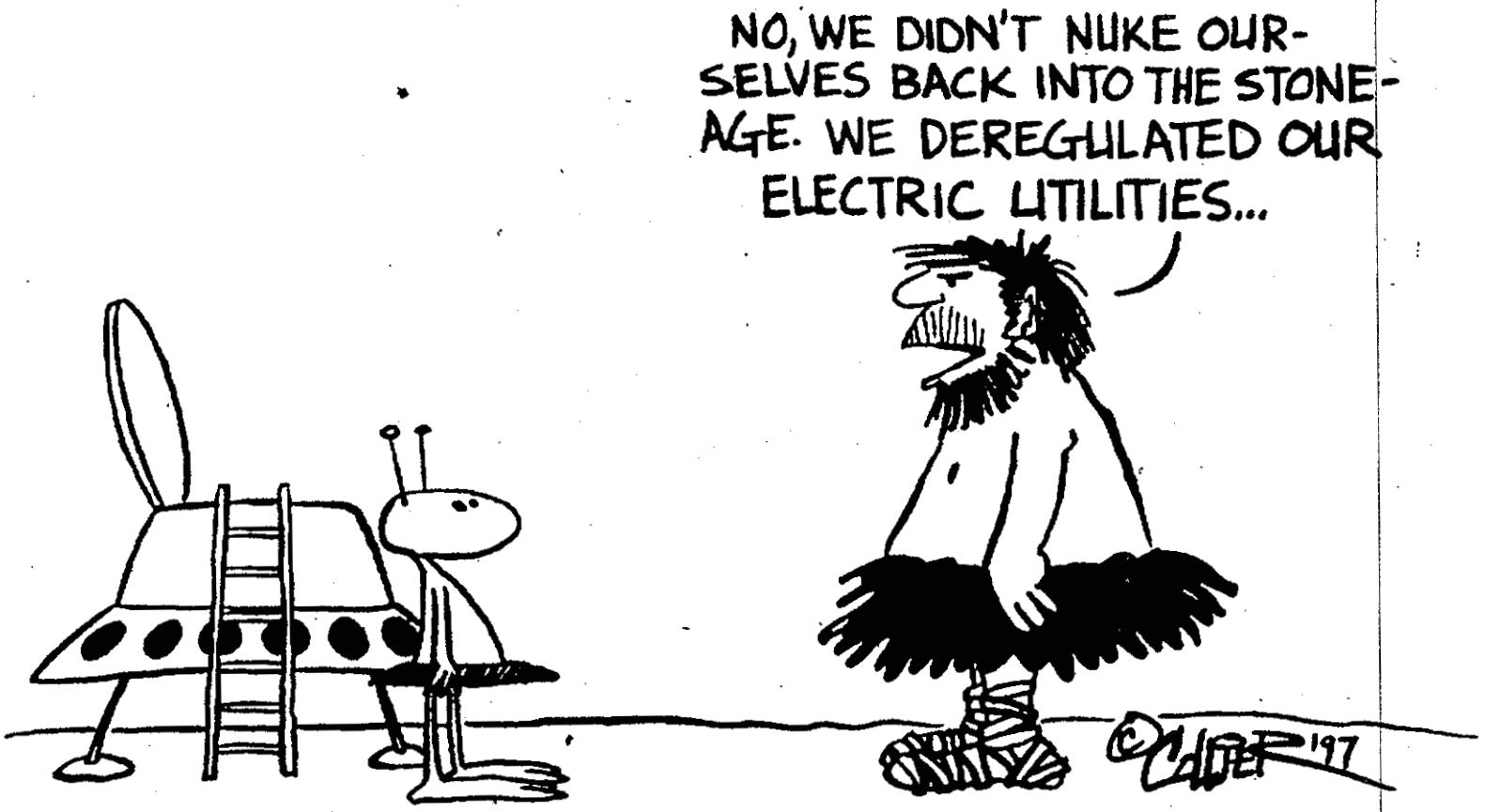
Ancillary Services

Brendan Kirby
Oak Ridge National Laboratory
Consultant
kirbybj@ornl.gov 865-576-1768
www.ornl.gov/psr

Ancillary Service:
What are They and Why Have Them


NO, WE DIDN'T NUKE OUR-
SELVES BACK INTO THE STONE-
AGE. WE DEREGULATED OUR
ELECTRIC UTILITIES...
©CALDER '97

System Operator's Risk/Reward Calculation

- RISK: Public humiliation with thousands of innocent people siting in the dark.
- REWARD: A certificate of appreciation in a handsome plastic frame.

Ancillary Services ...

- Support basic electrical services:
  - Generating capacity
  - Energy supply
  - Power delivery
- Essential for reliability and for commercial transactions
- Amount to ~10% of wholesale costs ($12 billion/year @ 4.1 mills/kWh)

What Is Technically Required?

- Balance generation & load
  - normal operations
  - contingencies
- Maintain voltages
  - normal operations
  - contingencies
- Restart the system

Objective

Identify functions and services provided by generating units and the transmission system that are today buried within vertically integrated utilities and bundled into one price

- Exhaustive (covers all the services provided)
- Mutually exclusive (no overlap among identified services)

This is Not New Technology

Utilities have been performing these functions for decades, but as vertically integrated regulated monopoly organizations.

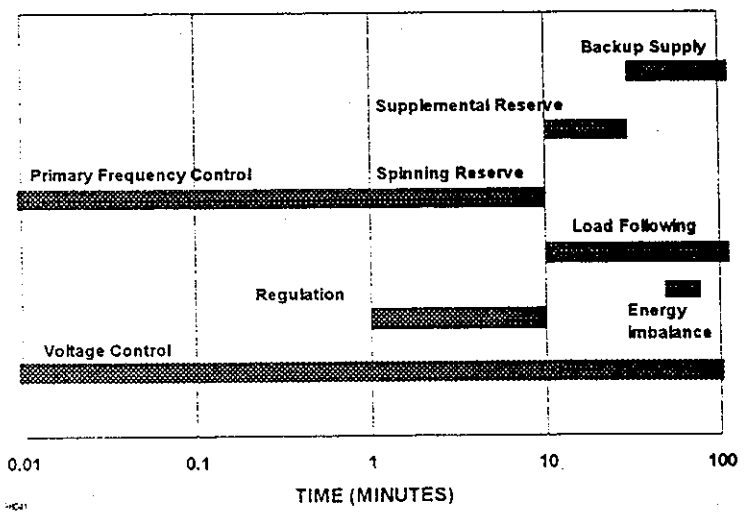
A structure with multiple competitive parties require clearer definitions, measurements, requirements rules, and operating policies

We need to think about the power system in new ways

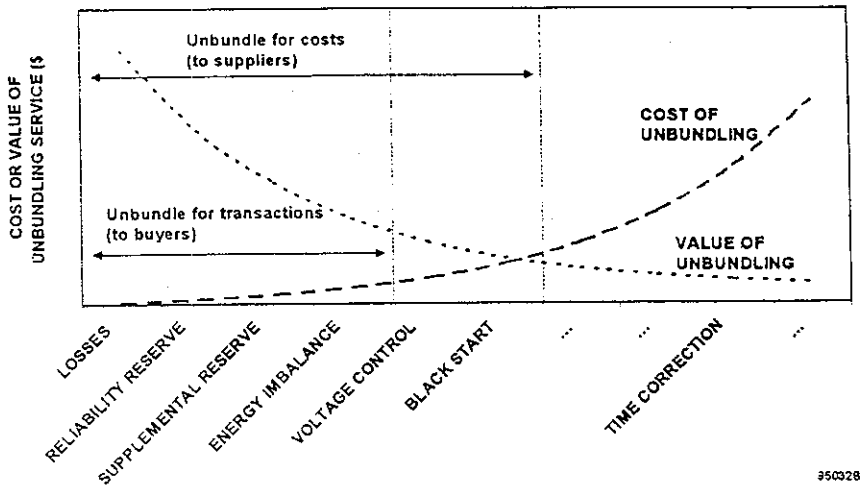
Nine Common Ancillary Services

- System control
- Regulation
- Load Following
- Operating reserves
  - Frequency responsive
  - Supplemental
- Backup supply
- Voltage control
- Black start
- Network stability

Ancillary Services Have Different Time Scales



Degree of Unbundling Should Depend on Cost and Value



Basics Assumptions

Market decisions better than command and control

- **Let markets supply what they can**
  - **energy**
  - **reliability**
- **Supplier competition reduces costs**
- **System operator must be independent of financial interest in transactions**

You can not buy or sell what you can not measure

Why Create Competitive Markets for Ancillary Services?

- The cost of some ancillary services are not trivial
- Loads differ in their ancillary service requirements
- Generators differ in their capabilities and requirements
- Markets allow diverse individuals to balance value
  - this may increase load participation in supplying services

Who Cares About Ancillary Services and Why

- Generator owners: profitable sales, understand costs
- Power marketers: profitable sales and purchases
- Control-area operators, ISOs, Security coordinators: sufficient reliability resources are available and perform as expected
- Government regulators: sufficient ancillary services to maintain reliability and support competitive markets at reasonable cost
- Customers: high reliability and low prices

Several Perspectives

Control Area - Resource - Consumer

- System operator / planner
- Generator
- Load

- Transmission / distribution provider
- Aggregator
- Marketer

Technical Requirements

Services Well Defined but...

No agreement yet on

- quantifying provision or consumption
- measurement
- pricing

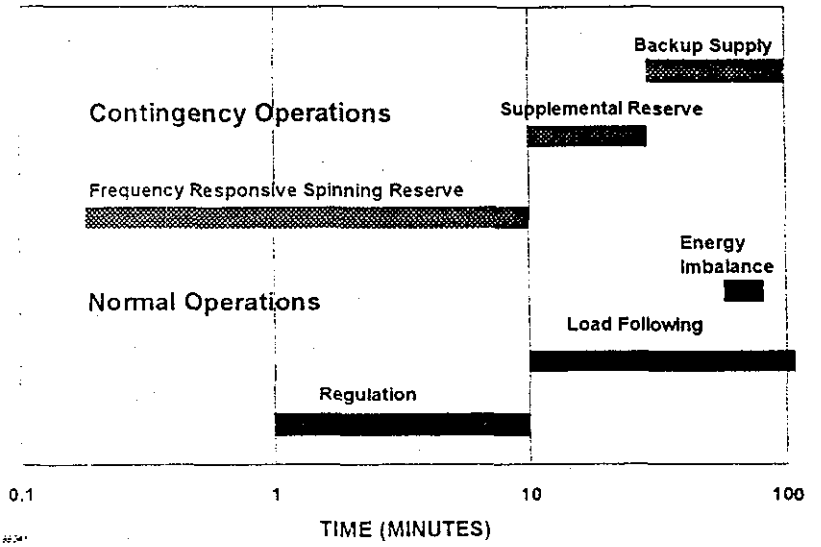
NERC draft Policy 10 offers limited clarification

- "details" left to the Operating Authority

Response Time Dictate Some Characteristics

- Fast (less than 1 minute) it is automatic, local response
- Intermediate can have coordinated response from a fleet of resources under central control
- Commercial markets can respond in ~1 hr

Time Scale for Real Power Services



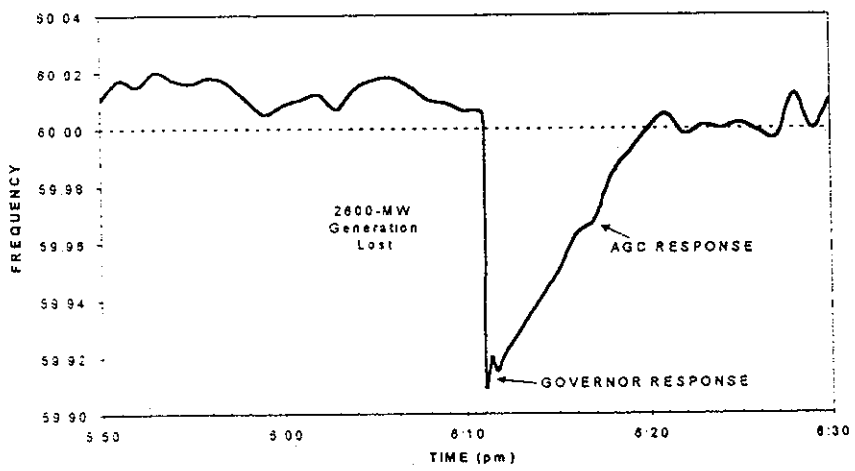
Contingency Reserves

- Sudden, unplanned failures of generation and transmission are unavoidable
  - N-1 criteria
- Physical requirement
  - restore generation/load balance
  - arrest frequency decay (obligation to system)
- Insufficient time for market response
- Problem addressed on a control area basis

Contingency Reserves Characteristics

- Frequency responsive
  - fast, autonomies response
  - coordinated droop & deadband
- Supplemental
  - fully available in 10 minutes
- Backup supply
  - return to commercial operation
  - restore reserves

Response to a Major Generation Failure



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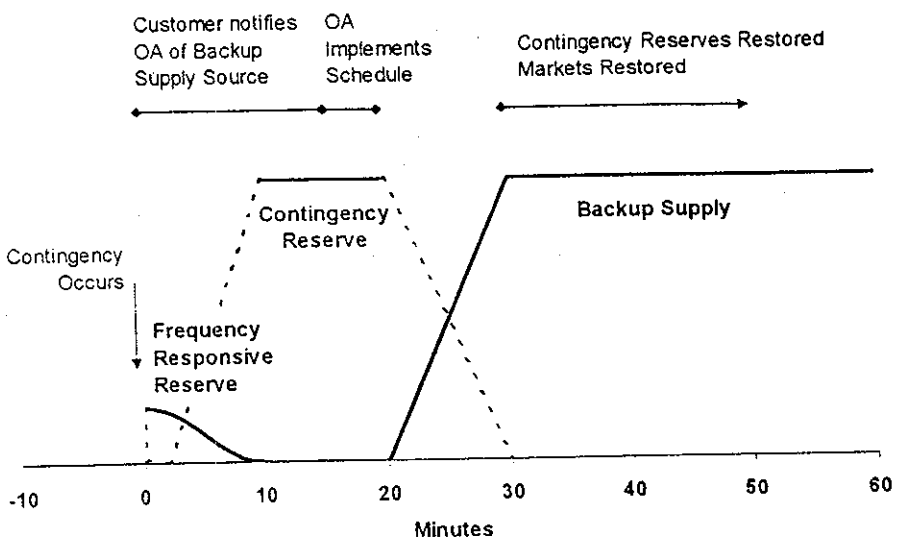
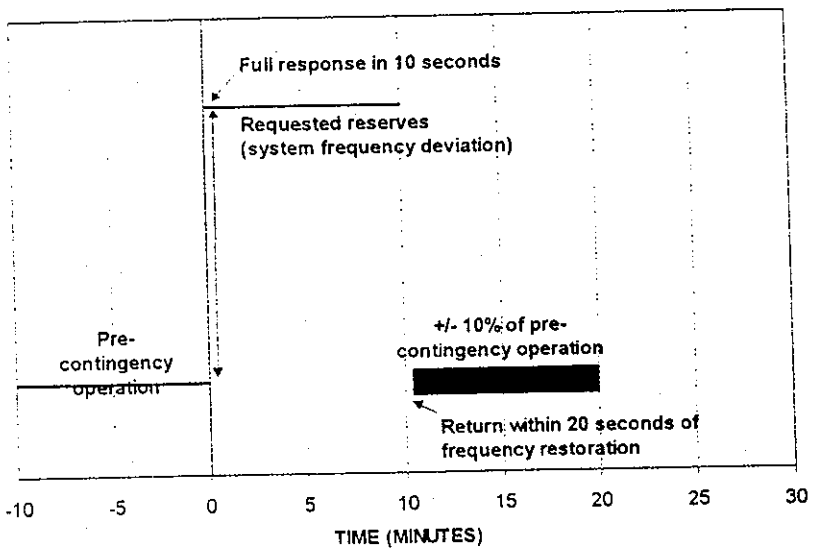
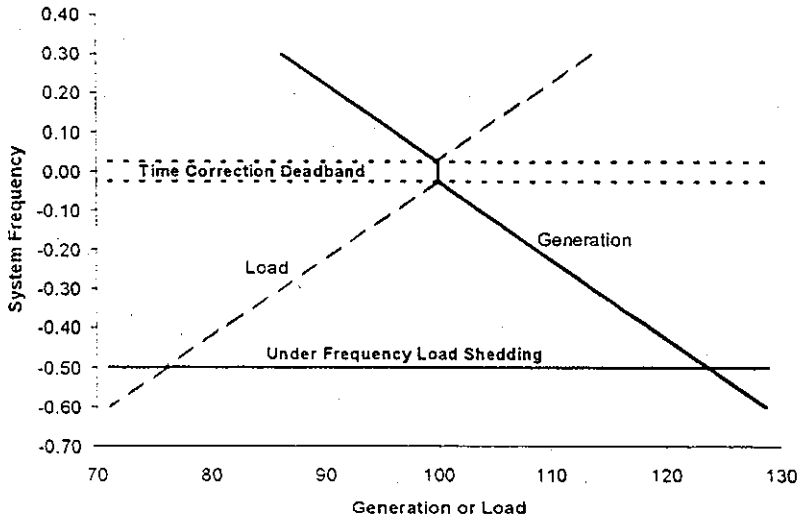
Ancillary Service Coordinated Contingency Response



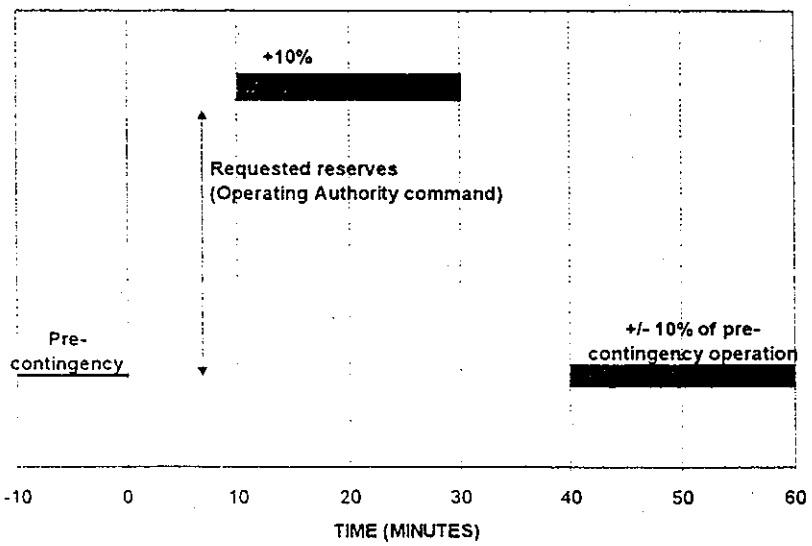
Frequency Responsive Reserve Required Performance



Load or Generation Could Provide Frequency Response



Supplemental Reserve Required Performance



Underfrequency Load Shedding and Frequency Responsive Reserve Differ

- Underfrequency load shedding is not optional (you were going to be cut off anyway)
- Moves into the governor control frequency band - So it deploys more often
- SILOS - Shed In Lieu Of Spin

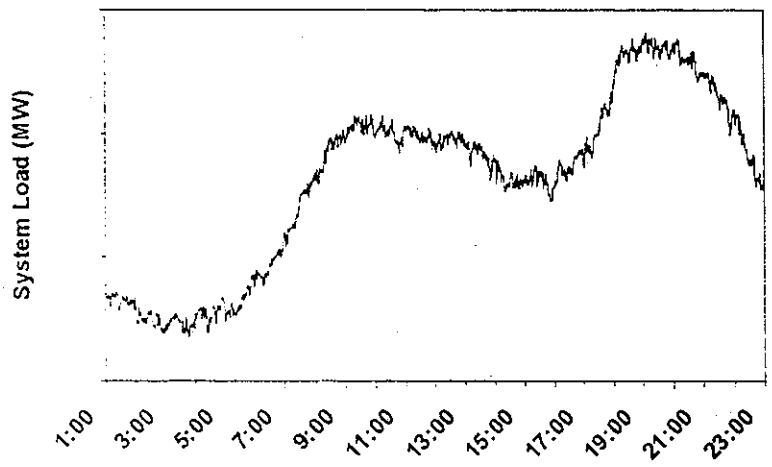
Contingency Reserve Resources

- Load or generation
- Post event concerns
  - restoring reserves
  - returning to pre-event schedule
- "Fleet" response
- With or without real-time metering
  - post-event metering
  - statistical metering
  - testing

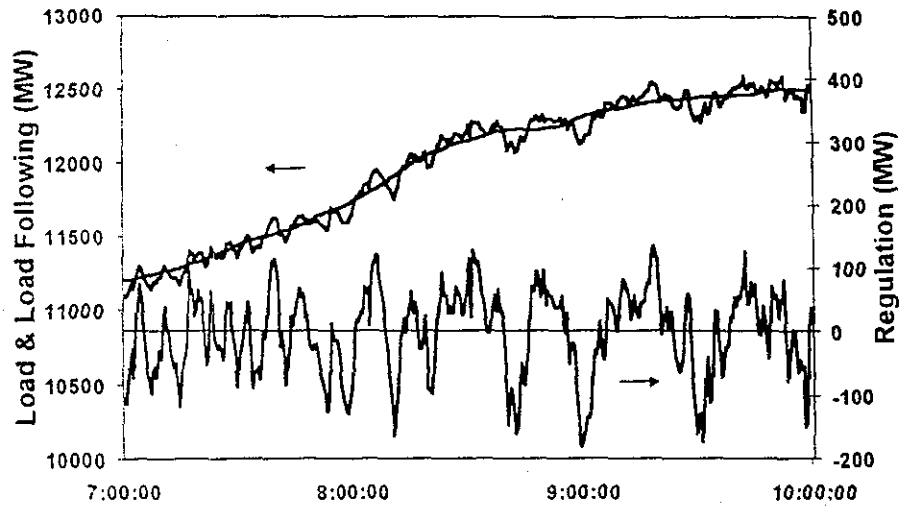
Backup Supply

- After the system deals with a contingency:
  - operating reserves must be restored to cover the next contingency
  - the commercial generation / load balance must be restored
- Timing must be coordinated with operating reserve duration & commercial markets
  - timing is related to the risk the *system* takes of not being able to respond to the next contingency

Typical System Load Data



Regulation and Load Following Balance the System Under Normal Conditions



Regulation & Load Following

- Both address the time varying characteristic of balancing generation and load under normal operations
- The "system" only has to compensate for the aggregation
- The aggregation is composed of individual loads and generators with *diverse* characteristics

Load Following Is Longer-term Analogue To Regulation

- Use of generation to meet hour-to-hour and daily variations in load
- Occurs over 10 minutes to hours
- FERC did not require in Order 888 tariffs
- Competitive provision and pricing feasible and desirable

Regulation And Load Following Differ

	REGULATION	LOAD FOLLOWING
Patterns	Random, uncorrelated	Largely correlated
Generator control	Requires AGC	Manual
Maximum swing (MW)	Small	10 – 20 times more
Ramp rate (MW/minute)	5 – 10 times more	Slow
Sign changes	20 – 50 times more	Few

Regulation Unresolved Issues

- Generator costs:
  - Heat-rate penalty, O&M costs, unit commitment
- Performance measurement
  - Time interval (e.g., 1 minute), interpretation of AGC signals, performance limits (ramp and jerk rates)
- Disaggregation to individual customers

Voltage Control and Reactive Supply

- Voltages throughout the power system must be maintained within a narrow range
- Reactive power consumption and production must balance in real time
- Reactive power can not be moved as far as real power

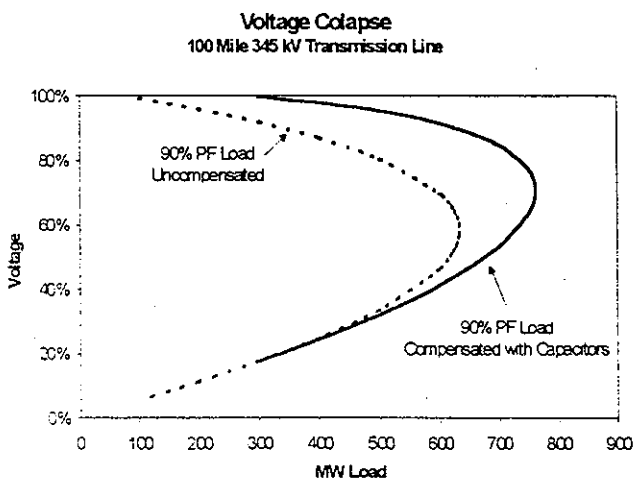
System Reactive Power Requirements

The power system itself is a consumer and producer of reactive power

- Dynamic
- Change with contingencies
- Depend on:
  - transmission system configuration
  - generation dispatch
  - load magnitude and pattern

Supply resources under system operator control

Voltage Collapse



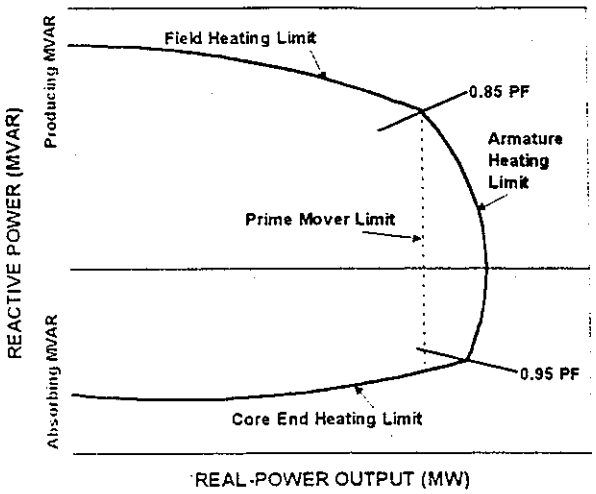
Voltage Control

- Required for normal operations, outage prevention, and system restoration
- Fernando Alverado suggested mirrored real & reactive services

Reactive Support
Generation & Transmission

- Generator
  - fast response, output rises with V drop
- Capacitor
  - switched response, output drops with V^2
- Reactor
  - switched response, output drops with V^2
- SVC
  - fast response, output drops with V^2
- STATCOM
  - fast response, output drops slowly with V

Generator Reactive Limits



Voltage Control Requirements

- Maintain acceptable voltages throughout the system
- Dispatch transmission and generation resources
- Manage reserves to handle contingencies

- Difficult to allocate voltage control burden among customers

System Black Start

Unique Characteristics

- No system power for: unit start, auxiliaries, communications, or control
- System condition unknown
- Rapidly changing configuration

More Than a Generator Service

- System black start requires
  - Generators that can start themselves
  - Transmission-system people, controls, and communications
  - System-control people and communications
  - Other resources returning to service
- Everything needed to run the system under normal conditions
  - Economic constraints relaxed

System Requirements

- A Plan & *Flexibility*
- People
- Communications
- Control
- Information
  - current conditions
  - capabilities & requirements
- Generation resources

Black Start Units

- Location
  - topography
  - technical capability
- Capacity
  - real & reactive
  - min & max
- Stability
  - unloaded, loading & loaded
- Control
  - real & reactive
  - frequency & voltage
  - accuracy & speed
  - local & remote
- Black start capability
  - within required time

Next Start Units

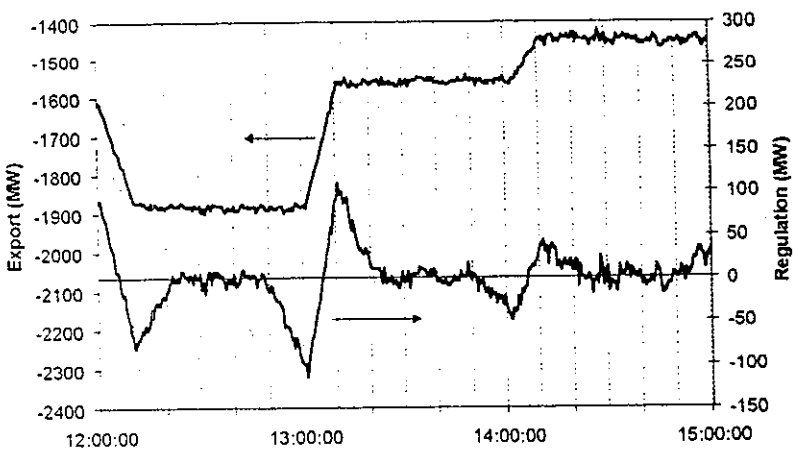
Restoration requires generators return to service

- each unit goes from being a load to requiring load

Terry Volkmann, NSP, suggests:

	# hours it takes to Synchronize		
# of hours it takes for the T. Provider to provide power to the generating unit	Unit 1	Unit 2	Unit 3-N
1 Hour	4	5	6
2 Hours	6	8	10
3 Hours	10	14	18

Block Schedules *Create* "Regulation" Burden

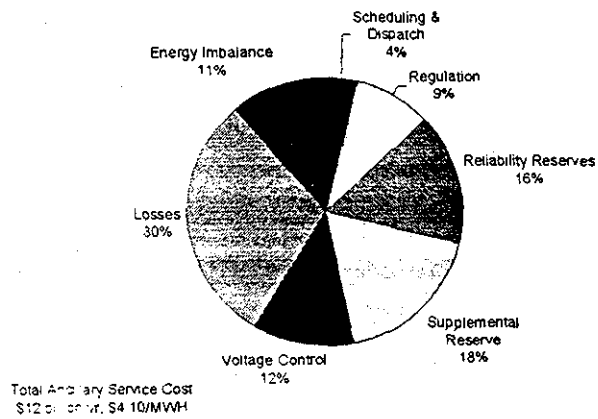


Network Stability

Location specific application of fast control over real or reactive power to maintain system stability, increase transfer capability, and reduce required reserves

Ancillary Service Costs

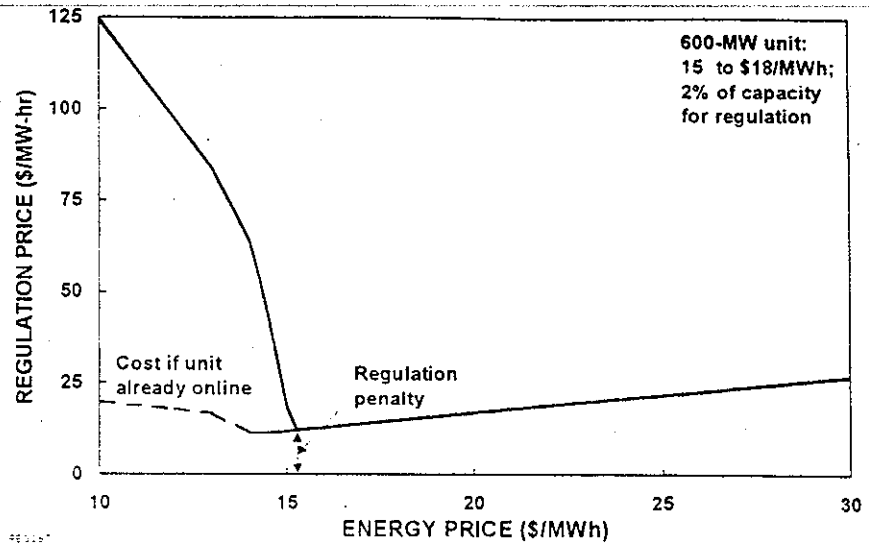
Imbedded Cost Based Averages Provide an Estimate of the Size of the Ancillary Services Market



Regulation Cost Components

- Heat-rate penalty
- Unit commitment
- Opportunity cost
- Increased O&M
- Shortened lifetime

With Competition, Regulation Price Depends on Spot Energy Market



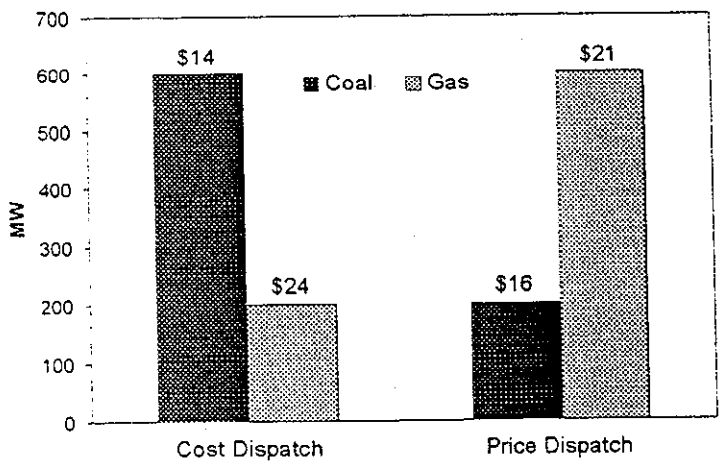
Modeling Ancillary Service Markets has Provided Interesting Insights

- Cost dispatch and price dispatch yield different results and different incentives
- Ancillary service markets and the energy market strongly interact
- Several market structures are possible, impacts of market rule choices are not always obvious

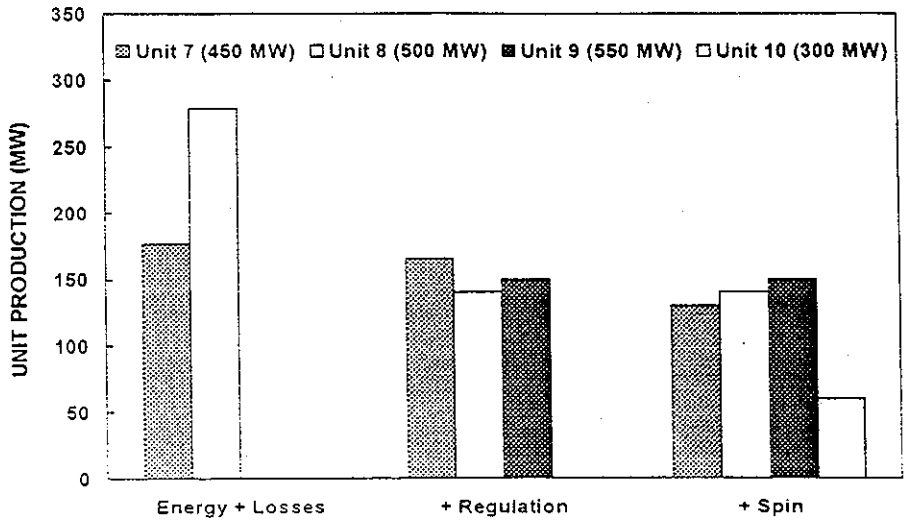
Least-Cost & Least-Price Dispatch Yield Different Results

- Should ISO minimize price or system cost?
  - To minimize price, run price-setting unit at maximum output
  - To minimize cost, run price-setting unit at minimum output
- Results may differ only slightly for system ...
- But differ greatly for individual generators
- Decision affects ancillary-services markets as well

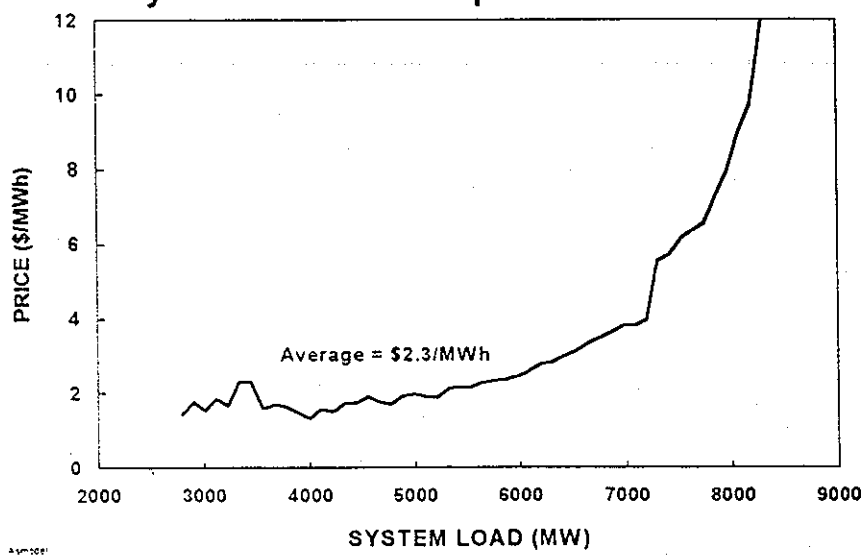
Cost and Price Dispatches Quite Different



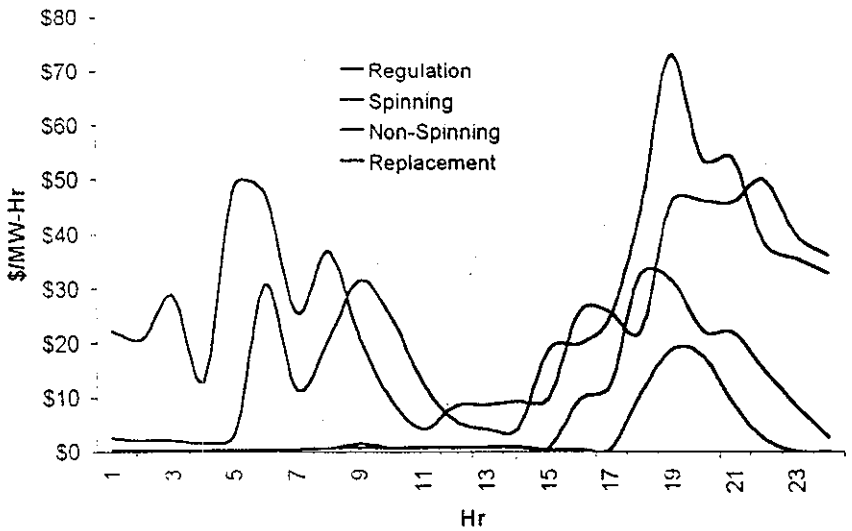
Ancillary Services May Require Generator Redispatch



Ancillary-Service Price Varies With System Load and Spot Price



Average Ancillary Service Prices
California December Weekday



Key Issues to Consider

- Who makes unit-commitment (and other) decisions?
  - ISO or individual generators
- Who bears risks of these decisions?
- What information is shared with whom?
- Should ISO minimize price or cost? For energy, ancillary services, or all?
- Should markets clear sequentially or simultaneously?
- How to define services without gaps or overlaps?
- How to encourage load participation in markets?
- Role of installed capacity markets?

How Long Should the Contract Be?

Contract Length Tied to:

- Provision of other services
- Market power / local requirements
- System planning
- Capital investment

Provision of Other Services

- Some services require the generator to be in service and partly loaded (i.e. regulation)
- Generator must be viable in the energy market
- "Contract" length should be tied to energy market commitments (hourly)

Market Power / Local Requirements

- Generators providing some services (voltage) have local market power
- Longer term contracts are needed (years)

Capital Investment or System Planning Requirements May Lengthen Contracts

- Black start requires an integrated system plan
- Black start requires generator capital investment
- Longer contracts are needed (years)

Individual Service Contract Lengths

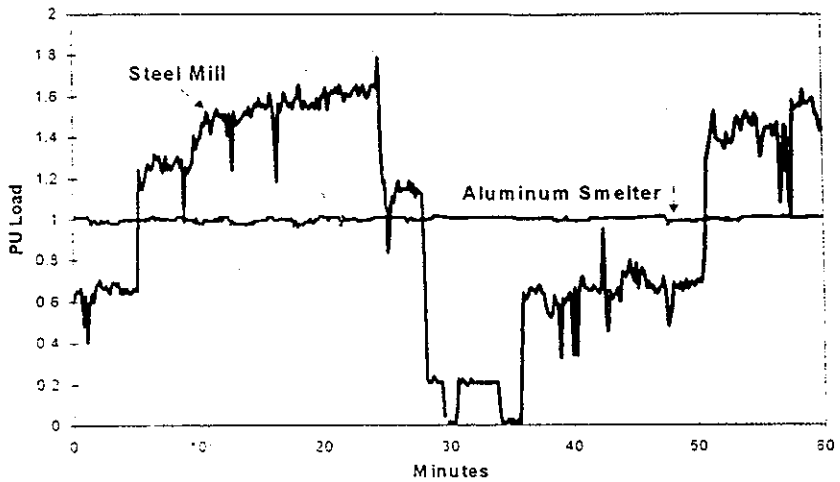
- Hourly contracts:
  - Regulation
  - Load following
  - Frequency responsive reserve
  - Supplemental operating reserve
  - Backup supply (?)
- Multi year contracts
  - Voltage support (?)
  - Black start
  - Stability

Who Should Contract For Each Service?

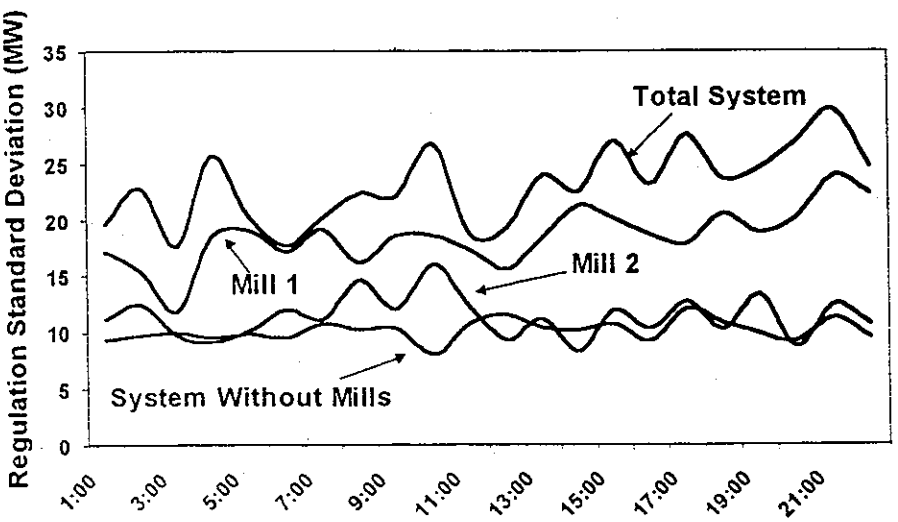
- Some services are clearly to the system:
  - voltage support
  - black start
  - stability
- Others result from individual performance, and could be self provided:
  - regulation
  - load following
  - backup supply
- Some have both characteristics:
  - frequency responsive reserve
  - supplemental operating reserve

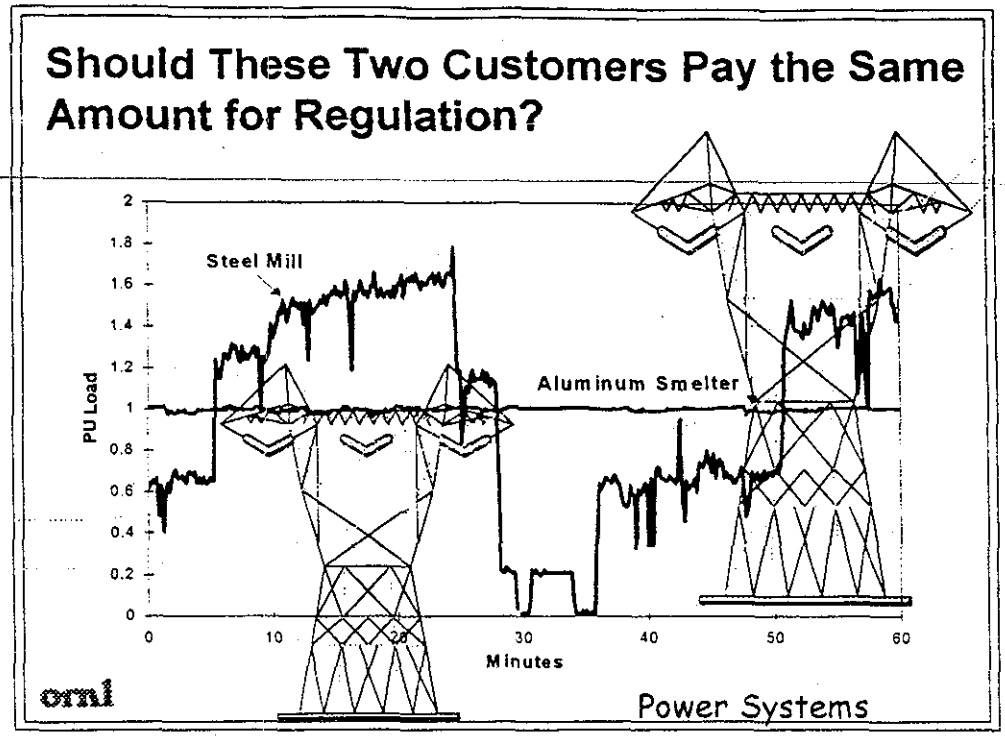
Who Should Pay ?

Should These Two Customers Pay the Same Amount for Regulation?



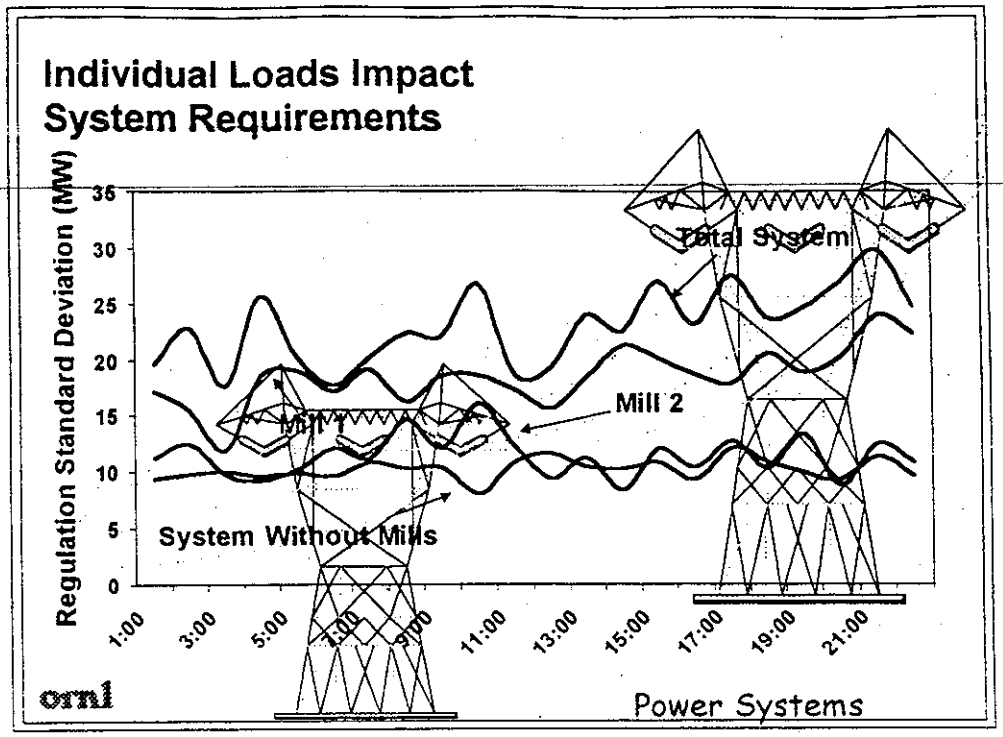
Individual Loads Impact System Requirements





In a competitive market differentiation among the burdens individuals place on the system will eventually lead to a demand for differentiation in the market.

This is just one example. The steel mill is clearly imposing a much greater regulation burden on the system. But current tariffs charge both the same. Eventually the aluminum plant will tire of subsidizing the steel mill.



Here we see the impact of 2 mills on the regulation requirements of a single control area.

Note that either mill individually often imposes a greater burden than all the other loads combined

Some Individual Loads Impose Large Ancillary-Service Costs

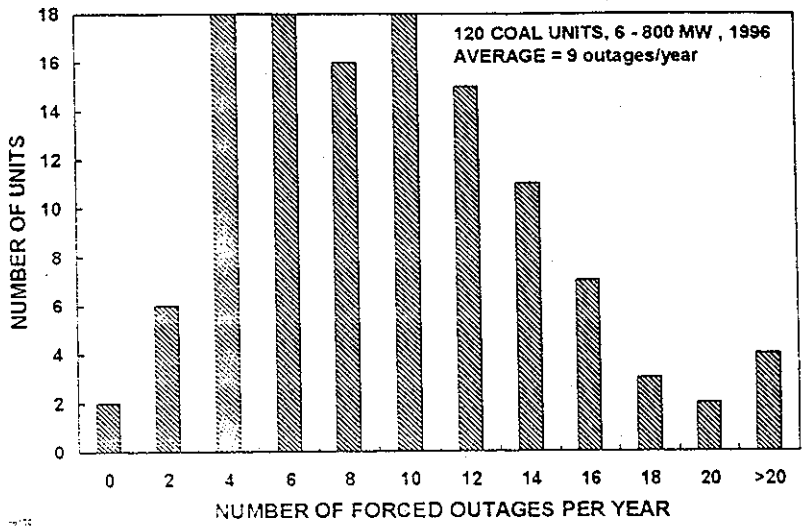
	Percentage of total		
	Mill 1	Mill 2	Rest of load
Energy & Demand	1	2	97
Load following			
Sunday	21	8	71
Wednesday	7	3	90
Regulation			
Sunday	59	23	18
Wednesday	17	27	56

Industrial Customers Can Dominate Ancillary Services

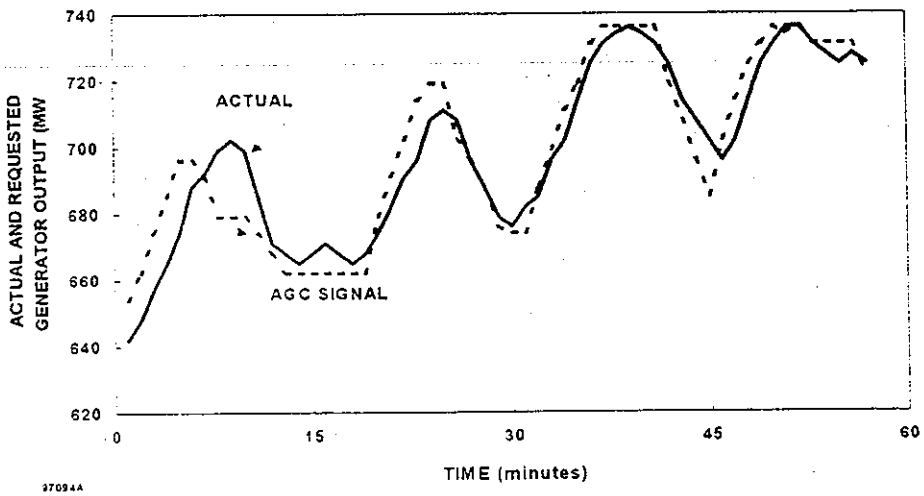
- Load
  Industrial share = 34%
- Regulation
  Industrial share = 93%
- Load following
  Industrial share = 58%*

* Time of use likely important

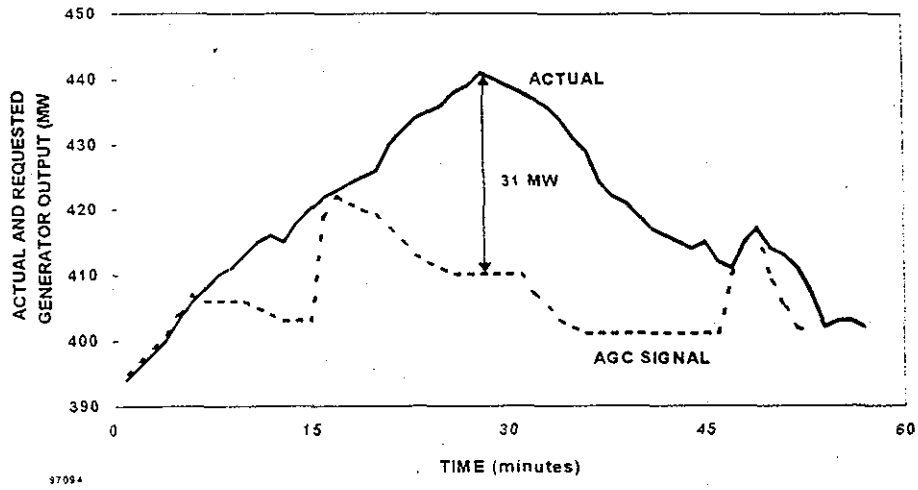
Outage Frequency Differs Substantially Among Generators



This Unit Regulates Well



Poor Regulation Increased ACE by 31 MW During Hour



How Price Signals Are Given Is Important

Interruptible rates continuously compensate customers who then hope to never reduce load

Real-time-prices allow customers to choose when it is more economic for them to continue to consume and when it is economic to curtail

Future Developments

- Demand side elasticity
  - energy
  - reliability services
- Differentiation among consumers

Infrastructure Requirements

Communications

- Speed may be important in only one direction
  - system operator deploying fast resources (regulation and contingency reserves)
  - response confirmation can be much slower
- Fast signals likely can be broadcast
  - blocks of resources deployed for a contingency
- Market participation communications
  - prices
  - bids
  - awards

Certification & Performance Measurement

- Formal certification procedures may be required for infrequent services (black start, frequency response)
- Defined measurements (and associated metering) are required to monitor performance

Markets

- Markets and market rules
- Bidding

North American Electric Reliability Council (NERC) Calls Ancillary Services *Interconnected Operations Services* (IOS)

http://www.nerc.com/

- Operating & Planning Standards
- Status of NERC Operating Standards Under Development
  - Policy 10 - Interconnected Operations Services
  - Draft 3 (Word 97 Acrobat)
  - Reference Document - Interconnected Operations Services Draft 1
  - White Paper - Certification and Performance Measures for Interconnected Operations Services Draft 1
  - Policy 10 Comments

88

MAINTAINING SYSTEM BLACKSTART IN COMPETITIVE BULK-POWER MARKETS

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Consulting in Electric-Industry Restructuring
Oak Ridge, Tennessee

Restructuring the electric-power industry may provide substantial benefits in customer choice and economic efficiency, but it presents new challenges for bulk-power reliability. The incentives to maintain and properly deploy system blackstart services that worked for vertically integrated utilities may not work when the system operator, the transmission system, and individual generators are in separate commercial organizations.

To understand how the power system could be restored after a major blackout in a restructured industry, we reviewed existing and proposed North American Electric Reliability Council (NERC) rules and interviewed experts from 25 utilities located in each of the regional reliability councils (Hirst and Kirby 1998); the Edison Electric Institute sponsored this work. Utilities differ greatly in their attention to blackstart planning, preparation, training, and testing. These differences are not justified by differences in technical requirements among utility systems.

While the conditions that require system blackstart, a complete collapse of a major portion of the interconnection, are fortunately rare, the societal and economic consequences are so great that a reasonable effort is justified in preparing to meet such a contingency. Meaningful (i.e., detailed) standards for system blackstart planning, training, testing, and performance do not exist. Adequate performance is currently assured by holding the vertically integrated utility responsible for the final result. In general, the utility empowers its system operator to compel heroic action from its generation and transmission resources and people when this service is required. The system operator evaluates the risk of damage to generators and other equipment versus the system's need for restoration and the utility's risk of incurring the wrath of regulators and customers.

The current system for assuring adequate system restoration will likely not work under restructuring. System blackstart requires the coordinated efforts of the system operator, the transmission system, blackstart generators, and the remaining generators. Where it was previously only necessary to determine if the overall restoration performance was acceptable (not always an easy task) now it is necessary to determine if the performance of each party is acceptable and to assign responsibility (i.e., blame) if the restoration does not occur smoothly and promptly. Separate generation, transmission and system-control entities will have to be compensated for the risks they take and the damages and costs they incur because of blackstart activities. Clear standards for required performance along with contractual relationships to specify each party's responsibilities and compensation will be required to maintain system reliability.

PHYSICAL REQUIREMENTS

Unlike many other engineered systems, the four North American power system interconnections are designed to be in continuous *synchronized* operation. Individual pieces of equipment are taken out of service for maintenance, but each interconnection as a whole is designed to run without interruption.

Nevertheless, the power system must be prepared for the rare occasions when all or a major portion of the system is forced out of service. This might be the result of a particularly severe disturbance resulting in the loss of stability and the need for many generators to shut down. If this occurs, the system must be able to be restored to normal operations as quickly as possible. This is called system-blackstart capability.

The principal function of system blackstart is to restore the power system; restoring service to customers is secondary. The importance of this distinction is that system blackstart does not start with a prioritized list of customers that are restored in order. (For safety reasons, restoration of power to nuclear plants is an exception.) Instead, restoration is designed to return generation and transmission to service as quickly as possible. Load is used, especially in the early stages, to maintain the stability of generation; it is the loads' locations and magnitudes that determine which loads are restored when.

System restoration requires four sets of resources:

- Blackstart-generating units (often hydro and combustion-turbine units) that can start themselves without an external electricity source and can then energize transmission lines, restart other generating units, and ultimately restore service to customers;
- Nonblack start generating units that can quickly return to service after offsite power has been restored to the station and can then participate in further restoration efforts;
- Transmission-system equipment, controls, and communications (including ones that can operate without grid power), and field personnel to monitor and rebuild the electrical system after a widespread blackout; and

- System-control equipment and communications (including ones that can operate without grid power), and people to plan for and direct the restoration operations after such a blackout.

For system restoration to be effective there must be a well thought out restoration plan, training exercises, and verification testing. Because the exact condition of the system at the time of failure will not be known ahead of time, the plan must be flexible. A great deal of additional information (charging current for each transmission line, loads on each substation feeder, etc.) must be assembled and available to the system operator to support flexibility in blackstart operations.

Blackstart proceeds as follows: (1) the system operator determines the nature, cause, and extent of the outage and whether the blackstart plan should be implemented; (2) the system operator communicates with appropriate utility departments, neighboring utilities, and the regional reliability council; (3) loads are disconnected and the transmission system is sectionalized, either directly from the control center or by the system operator directing field personnel to perform the operations; (4) the system operator directs one (or multiple) blackstart generators to begin operation; (5) once such a unit has started itself, the system operator begins the complex process of re-energizing a portion of the transmission system and providing power to other generating units; (6) generators without blackstart capability return to service as soon as possible after offsite power has been restored to them to allow restoration of the overall system to continue; (7) the system operator directs the reconnection of loads to the system as additional generation is returned to service, initially to help stabilize the generation and later to restore normal operations; (8) as individual islands of balanced generation and load grow, the system operator coordinates their resynchronization into the interconnection; and (9) service is restored to the remaining customer loads. All these steps must protect equipment and personnel, and maintain voltages and frequency near their reference values.

The coordination problem of re-energizing the grid is complicated. Generators have minimum and maximum load limits (MW) and maximum ramp rates (MW/minute). As the first generators come back online, the system operator must provide sufficient load to keep the units above the minimum load limits but not exceed their generating capabilities, ramping limits, or voltage-control capabilities. It is difficult to balance generation and load when both, along with the system configuration, are changing rapidly. Real power load is obtained by re-energizing groups of customers. Timing is critical because of the overall need to restore the system rapidly but also because the nonblackstart generators are each coming online first as loads because of their auxiliary equipment, then increasing that load as they prepare to restart generation, and finally requiring load themselves when they synchronize to the grid and begin delivering power. The longer it takes to restore offsite power to nonblackstart generators, the longer it can take for these units to return to service. Such delays can occur because conditions at the nonblackstart generators deteriorate the longer they are without power to operate their auxiliaries.

The transmission system itself presents a dynamic reactive load. Transmission lines are highly capacitive when not loaded and voltages can easily become excessive. Generators and reactors are used to hold voltages down. Unfortunately, generators are less stable when they are absorbing large amounts of reactive power than when they are producing reactive power. The system operator must be aware of each unit's reactive capabilities and the loads that will be imposed as each transmission segment is energized.

Restoration usually involves restarting the system in several locations at once. As the restoration progresses, each island contains a growing generation and load balance. These islands must be synchronized to re-establish the interconnection. This process involves matching the frequency and phase angle of adjacent systems before closing the breaker to connect the systems. Normal operations are resumed when the entire system is reconnected and all load is restored. Depending on the extent of the blackout, damage to the system, and other load and generation conditions, restoration will take hours to days.

Selecting the blackstart generators is somewhat location dependent. Blackstart generators must be electrically close enough to the other units they are to help restart to be able to energize the transmission lines connecting the two plants and control voltages at both ends. The blackstart units must also have sufficient capacity and ramping capability to be able to provide the restart power required by the other units. The system operator determines how many units within the control area must have blackstart capability, where they are to be located, and how to use them in the event of a blackout.

Unit and system testing and exercises are performed for three reasons. First, they assure that the equipment is properly maintained and capable of performing the required task. Second, they train personnel (this is especially important because of the rare need for the service and the resulting inability to get useful on-the-job experience). Third, they test the plan itself. Posttesting and postsimulation analysis is performed to determine what improvements are required in facilities, equipment, communications, personnel training, or to the plan itself.

Three types of blackstart units are in common use. Hydro units are generally used, when available. They are usually

quick starting, can often be started remotely, and generally exhibit stable and fast control. Hydro units are so well suited for blackstart that NERC procedures recommend that all hydro units be equipped for blackstart capability. Frequently, a small (1 MW) turbine is included in the installation to power auxiliary loads, allowing the start of the main turbine(s).

Combustion turbines and internal-combustion-engine-driven plants (e.g., diesel units) are often equipped with blackstart capability. These units can usually start rapidly, often under remote control, and can be precisely controlled.

Some thermal plants, while not capable of blackstarting themselves, can be equipped for load rejection. This technique relies on identification of the imminent collapse of the system, isolating the generator to its own auxiliary load (and possibly to some local load), reducing the generator's output from the pre-event operating level to match the isolated load, and maintaining that output until the system calls on the unit to connect to the grid, re-energize a part of the system, increase output, and help restart other units.

CURRENT PROVISION OF SERVICE

To identify how system blackstart is currently provided, we interviewed experts from 25 utilities located throughout the country. We also obtained documents from these utilities, and from a variety of other sources, including other utilities and NERC.

Testing of system restoration is generally accomplished by simulation or with a table-top exercise. Some utilities do no testing or simulation, while others (Union Electric, American Electric Power, and Southern) actually use blackstart units to energize portions of the grid (generally a single transmission line) and provide restoration power to a fossil unit. In England, the National Grid Company periodically tests the ability of blackstart units to restore service to nonblackstart generating units and for these nonblackstart units to then return to service quickly.

Utilities vary greatly in their treatment of blackstart. This range does not appear to be based on actual differences in system vulnerability or requirements. Geographically adjacent utilities often take very different approaches, suggesting that the key factor in designing a blackstart plan is the judgment and experience of those involved rather than probabilistic analyses of system failures.

COST COMPONENTS

We identified four types of costs associated with the provision of blackstart:

- Costs associated with blackstart units themselves. These include capital costs, testing costs, training costs, equipment damage costs, and fuel plus labor costs during actual blackstart operations.
- Transmission-system costs, including capital costs (telecommunications, synchronization capability, controls, emergency power for circuit breakers and facilities, etc.), planning and engineering costs, training costs, and personnel costs during an actual event.
- System-control costs, including capital costs (e.g., telecommunications, computers, and emergency-power systems) and operating costs for planning, testing, and training.
- Costs at nonblackstart power plants to enable them to restart quickly once offsite power is restored as well as equipment-damage costs (e.g., damage to the turbine because of operation at frequencies too far from 60 Hz) incurred during an actual event that results from returning to service too quickly.

Obtaining estimates for these costs was difficult. Utilities have not accounted for these costs in an easily accessible fashion. It is also difficult to unambiguously assign system-operator and transmission-system costs to system blackstart. The utilities felt that system-blackstart requirements do not influence personnel requirements at the control center. While many people are required in the field to verify conditions and perform operations, these people are already employed by the utility. It is also hard to pin down control-center or transmission-system capital costs that can be attributed to blackstart requirements. Emergency power for the control center, for example, is required in case the control center's primary power supply is disabled. This could happen (and is most likely to happen) even if the rest of the power system is viable. The same is true for backup power supply for the rest of the system. Communications and control systems must be redundant and survive even if their primary power supply is disabled. Transmission circuit breakers must be capable of a limited number of operating cycles (typically open-closed-open) without external power support. None of these costs is incurred exclusively for system blackstart. Only a few costs, such as providing synchronizing capabilities at selected locations on the transmission system, can be attributed solely to system blackstart.

Costs associated with providing blackstart capability to generators are conceptually easier to identify and associate with the blackstart requirement. Still, we were not able to obtain many cost figures because generally utilities do not track these costs. Costs associated with nonblackstart generators returning to service are even more elusive, although no less real.

Houston Lighting and Power estimated that provision for blackstart capability might add $1 million to a $100 million fossil plant. Annual increased labor cost is modest as well, perhaps $0.1 million. It blackstarts one unit a year using 30 to 40 people to gain experience. Southern estimated the cost of adding blackstart capability to a $25 million, 80-MW combustion turbine at $0.1 million.

CURRENT STANDARDS

NERC (1997b) delineates required actions in various policies. System restoration from a blackout condition is addressed in Policy 5E: Emergency Operations - System Restoration and in Policy 6D: Operations Planning - System Restoration. Policy 5E specifies the following:

> After a system collapse, restoration shall begin when it can proceed in an orderly and secure manner. Systems and control areas shall coordinate their restoration actions. Restoration priority shall be given to the station supply of power plants and the transmission system. Even though the restoration is to be expeditious, system operators shall avoid premature action to prevent a re-collapse of the system. Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must remain in balance at normal frequency as the system is restored.

Policy 6D requires "each system [to] develop and periodically update a logical plan to reestablish its electric system ... . A reliable and adequate source of startup power for generating units shall be provided. ... Generation restoration steps shall be verified by actual testing whenever possible. ... System restoration procedures shall be verified by actual testing or by simulation."

NERC's (1997a) Planning Standards also address system blackstart (Section IVA) by, again, requiring "a coordinated system blackstart capability plan" and requiring that blackstart generators demonstrate their capability once every five years "through simulation or testing."

NERC's (1998) proposed Policy 10 improves upon the existing NERC guidance by including requirements for certifying and testing blackstart units themselves. Unfortunately, the policy does not address any system control, transmission system, or nonblackstart unit requirements. Nor does it address training, simulation, or exercises.

While the guidance currently offered by NERC is helpful, it may not be enough for a restructured industry where competitive entities must be organized and act cooperatively to address a system emergency. NERC offers little detail concerning either the required response that the service is supposed to deliver or the resources that should be dedicated to service provision. NERC provides no specifics on the number of generating units that should be blackstart equipped, how to determine this, or how quickly blackstart units should respond. It says nothing about how often the system restoration plan should be tested or what should be included in such tests.

STANDARDS UNDER RESTRUCTURING

In a restructured electricity industry, it may be appropriate to have separate standards for each of the four components of system blackstart. Such standards could include the following elements.

System Operator: The system operator will, at least once a year, simulate system restoration using information on blackstart generation, transmission, nonblackstart generation, load, and the restoration plan. The regional security coordinator will certify the restoration plan only if the simulation demonstrates a high probability that restoration will be successful. Simulations and training exercises will include operating personnel from system operations, transmission operations, blackstart generators, and nonblackstart generators. The exercise will be conducted in the facilities the personnel will be working in during a restoration using the communications equipment that will be available during such a restoration. The entire restoration plan will be simulated with each party reporting on actions they would take in a restoration. A computer simulator will be used to determine the expected response from the power system to each action taken.

Transmission System: The system operator will certify the transmission provider's capability (personnel and equipment) to support the blackstart plan. The transmission provider will supply the control-area operator with detailed information concerning the transmission blackstart capabilities and requirements of all equipment on the transmission system. This information shall include: charging current, control capability without support from the grid under manual and automatic control, communications capability with and without grid support, personnel available for emergency response to restore the system, and availability of synchronization and other special equipment to restore the system. Communications, metering, and control systems must be capable of operating without support from the power system with sufficient capability to support the system blackstart restoration plan.

Blackstart Generators: In addition to metering and communications requirements, each blackstart generator will undergo separate starting tests, line-energizing tests, and load-carrying tests. The blackstart test, which will be conducted at least twice a year, involves isolating the generator from the power system, having the unit start itself within the agreed upon time of being directed to do so by the system operator, and then remaining stable (both voltage and frequency) for at least 30 minutes. The line-energizing test, which will be conducted at least every three years, will demonstrate the ability of the generator to energize a previously de-energized transmission line and to remain stable for at least 30 minutes. The load-carrying test, which will be conducted at least every six years, will demonstrate the ability of the generator to pick up sufficient load at the remote end of the isolated transmission system to demonstrate its capability to supply this load for at least 30 minutes.

Nonblackstart Generators: Each nonblackstart generating unit must prepare and submit to the system operator its restoration plan. The restoration plan will assume that the system failure was not the result of physical damage to or failure of this generator. The plan must specify the amount of time the generator requires, after the restoration of off-site power, before it is capable of synchronizing and picking up load. The plan must specify the amount of off-site real and reactive power required by each unit during the time it is preparing to return to service. The plan must specify the capabilities and requirements of the nonblackstart generator once it synchronizes to the grid including minimum load, maximum load, ramp rate, and reactive capability range at minimum and maximum load.

RESTRUCTURING

The lack of specificity in blackstart requirements presents a fundamental problem under restructuring. This lack of specificity, coupled with the need for multiple independent parties (generators, transmission owners, and the system operator) to work cooperatively makes it difficult to assign responsibility for failure of the final result (rapid system restoration). Hence, the current system of indirect regulatory pressure is likely to be ineffective.

In April 1996, the U.S. Federal Energy Regulatory Commission (FERC) issued its landmark Order No. 888 initiating restructuring of the electric power industry on a national level. As part of its program to unbundle generation from transmission, FERC required transmission providers to offer six ancillary services to transmission customers. FERC did not impose any requirements with respect to blackstart, perhaps assuming that the cost to provide this service would be incorporated in the basic transmission tariff. So little help is provided here.

Gaining the cooperation of all parties in preparing for and executing the activities required to restore the power system after a large-scale blackout is difficult because of the expense involved. On a systemwide basis, system-blackstart costs are surely quite low compared to total generation costs, but they can be quite high for an individual generator. A combination of technical requirements and economic incentives will be needed to assure successful provision of the service.

The system operator could likely procure blackstart capability competitively from generators. Technical restrictions concerning unit capabilities (speed of response, control capability, voltage control, etc.) may limit the number of suitable generators. Locational restrictions may further reduce the number of units that can provide this service (e.g., such units must be electrically close enough to other units to be useful in restarting them). But the predominant response from the utilities we surveyed was that often enough units meet (or could meet) the technical requirements to allow formation of a competitive market. Within reason, restoration plans could be adjusted to accommodate changes in the location of blackstart units.

To facilitate competitive procurement of blackstart services from generators, system operators would have to be explicit about the services such units are required to provide. This requirement would include the speed of response, minimum and maximum real and reactive capabilities, and ability to control frequency and voltage. It would also require that the system operator know what resources will be required at each location. The competitive assessment would evaluate technical feasibility, capital costs, testing costs, and costs during actual use of the service.

System-operator and transmission-system costs related to system blackstart, on the other hand, should be dealt with as are other system-operator and transmission-system costs. They will likely require FERC review to assure that they are prudent and can be recovered in regulated rates.

Individual nonblackstart generators may affect the cost of blackstart in two ways. First, the amount of offsite power required to restart units and the speed with which that power must be restored may differ. Second, generators may differ in the time it takes to return to service and begin supporting the power system once offsite power is restored. These differences can be a result of the generating technology employed as well as commercial considerations. Larger units, for example, require more power to restart. Consequently, blackstart units have to be larger. Other generating units may impose additional system-blackstart requirements. The location and controllability of nonblackstart units affect their value when restoring the system. How quickly off-site power has to be restored to other generators to avoid damaging the unit and

greatly delaying the unit's ability to return to service may also differ. Compensating nonblackstart units for their costs associated with supporting system restoration could be difficult. Alternatively, provision of blackstart capability could be a requirement for connecting to the grid. We found little evidence that this cost differentiation has been recognized or is being addressed.

Nonblackstart generators could be required to return to service within a specified time after the system restores offsite power to them. This amount of time would depend on how long it takes the system to restore offsite power, recognizing that a generator will be in progressively worse condition the longer it remains without offsite power to operate auxiliaries and/or as the unit cools. Additional time may be required to restart each subsequent unit at a generating plant.

This type of specificity, which recognizes unit capabilities and system needs, is required in moving to a competitive environment. Since restoration events are very rare, economic incentives might not be sufficient in motivating response from the nonblackstart units. Simple requirements with strong penalties for failure to comply might be better. The incentives or penalties should recognize the benefit that the system receives from units that are inherently capable of fast and flexible response. This recognition could be accomplished through a combination of charges for system restoration at rates that reflect the burden or benefit the individual generator places on the system during restoration coupled with response requirements when the service is required.

CONCLUSIONS

While system blackstart is conceptually well understood and universally acknowledged to be important, its detailed requirements are difficult to pin down. For the system to require blackstart, something went badly wrong. It is difficult to quantify expected results from the blackstart service without prior knowledge of what will go wrong. Still, this does not explain the diversity among utility blackstart plans. The current system of indirect regulatory pressure on vertically integrated utilities will not work in a restructured environment. NERC's technical guidelines fall short as well.

Competitive markets could develop for blackstart capability. Reliability requirements restrict the locations and capability requirements for individual blackstart generators. However, if there are enough generators located so that they can provide the blackstart service, the competition among them may be enough to allow markets to determine the prices of this service. The control-area operator is the only buyer because it is responsible for determining how much of the resources to acquire and how to deploy them. The system-control and transmission portions of system blackstart cannot be provided competitively. These services, by definition, can be provided only by the monopoly entities that manage and operate control areas.

FERC views system blackstart narrowly, focusing on the ability of some generating units to self start. FERC apparently did not consider the transmission-system and system-control activities associated with this service. More important, FERC imposed no requirement on transmission providers to offer the service or on transmission customers to pay for it. And NERC's standards for this service lack specificity; they do not address the need for nonblackstart generators to aggressively support system restoration.

Possible ways to ensure continued provision of this essential service in a restructured electricity industry include (1) NERC developing more specific planning, testing, and operating standards for this service; (2) FERC recognizing system-blackstart as distinct from generator-blackstart capability; (3) FERC requiring transmission providers to offer and transmission customers to purchase this service; and (4) Providing the system operator with the authority to ensure that blackstart and nonblackstart generators, transmission owners, and the system operator itself provide and coordinate this service, which will require both technical requirements and economic incentives for generators and transmission providers.

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LOAD AS A RESOURCE IN PROVIDING ANCILLARY SERVICES

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Most of the commercially important ancillary services involve maintaining or restoring the generation and load real-power balance over varying time frames. Traditionally utilities have addressed this problem almost exclusively by controlling generation. It does not have to be this way, however. The important concept is to balance load and generation, which can be done using either side of the equation. Controlling load may be the single largest untapped resource currently available to the electricity industry. Restructuring is beginning to provide the framework within which this resource could be exploited. Several obstacles exist (primarily related to aggregation, communications, and economic incentives) but technical and commercial solutions to these problems exist.

WHICH SERVICES MIGHT LOADS SELL?

Table 1 presents the 12 ancillary services commonly discussed (Hirst and Kirby 1998). Clearly loads will not sell System Control, System Black Start, or Dynamic Scheduling. Energy Imbalance and Real-Power-Losses are primarily accounting services with the required physical energy and capacity coming from other services. Reactive Supply and Voltage Control from Generation and Network Stability are also services that loads are not likely to have the resources to supply (though if they do they should be encouraged to participate).

The five remaining services (Regulation, Load Following, Frequency Responsive Spinning Reserve, Supplemental Reserve, and Backup Supply Plan) deal with maintaining or restoring the real-energy balance between generators and loads. These services are characterized by the required response time, the response duration, and the communications and control required to facilitate the service. Figure 1 shows the required response for the five energy balancing functions. Because regulation requires continuous adjustment of real power transfers between the resource and the system it is unlikely that many loads will be capable of delivering that service at this time. (Water-pumping load, such as municipal-water and irrigation systems, may be a possible exception if they use variable-speed drives for their pumps.) The contingency reserves are especially amenable to being provided by loads. Load following could be provided by loads directly or through the use of a spot market price response on a shorter time frame than 1 hour.

Table 1. Key Ancillary Services and their definitions

System Control: Control-area operator reliability and commercial functions

Reactive Supply and Voltage Control from Generation: Injection and absorption of reactive power from generators to control transmission voltages

Regulation: Maintenance of the minute-to-minute generation/load balance to meet CPS 1 and 2

Load Following: Maintenance of the hour-to-hour generation/load balance

Frequency Responsive Spinning Reserve: Immediate (10-second) response to contingencies and frequency deviations

Supplemental Reserve: response to restore generation/load balance within 10 minutes of a generation or transmission contingency

Backup Supply Plan: Customer plan to restore system contingency reserves within 30 minutes if the customer's primary supply is disabled

Real-Power-Loss Replacement: Compensation for transmission-system losses

Energy Imbalance: Accounting for the hourly discrepance between scheduled and actual transactions

Dynamic Scheduling: Real-time metering, telemetering, and computer software and hardware to electronically transfer some or all of a generator's output or a customer's load from one control area to another

Network Stability: Use of fast-response equipment to maintain a secure transmission system

System Black Start: The capability to start generation and restore all or a major portion of the power system to service without support from the outside after a total collapse

The same types of restrictions apply to loads supplying ancillary services that apply to generators supplying the same services. For a generator to supply contingency reserves it must have capacity available to respond to the contingency. The generator cannot be operating at full load. Similarly, a customer selling contingency reserves must have capacity it

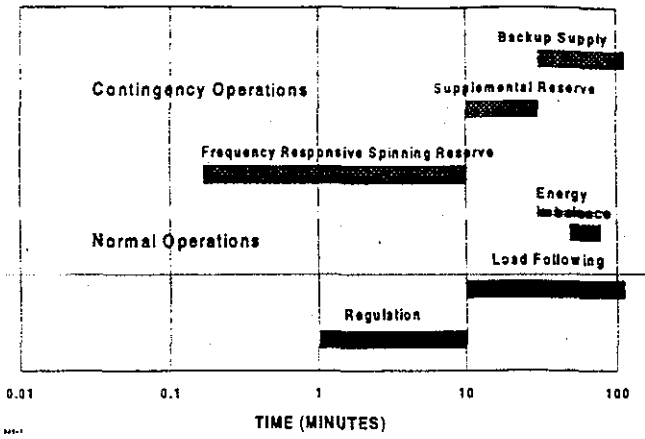

Fig. 1. Ancillary service dynamics.

can unload when the contingency occurs. The customer cannot already be at minimum load.

WHY UTILIZE LOAD AS A RESOURCE?

There are several reasons that loads should be encouraged to sell ancillary services. FERC is encouraging open competitive markets for generation. FERC ordered the unbundling of ancillary services to promote competitive markets, which should improve economic efficiency and lower electricity prices. These markets should be open to any technology capable of providing the service, not just to generators, which will expand supplies and reduce horizontal-market-power problems.

Beyond the argument of fairness, having loads participate as suppliers, as well as consumers, of electricity services improves resource utilization. Ancillary services consume generating capacity. When loads provide these reserves, generating capacity is freed up to do what it was designed for, i.e., generate electricity.

Loads will probably respond more quickly to control-center requests than large generators because the load response is composed of many small resources. This will likely more than overcome the communications and control delays associated with their greater numbers.

Loads should also be a more reliable supplier of ancillary services than conventional generators. Because each load will generally be supplying a smaller fraction of the total system requirement for each service, the failure of a single resource is less important. Just as a system with ten 100-MW power plants requires less contingency reserves than one with a single 1000-MW plant so too a system that utilizes a large aggregation of loads as a resource to supply reserves will require less redundancy in the basic resource than one that carries all of its reserves on a few large generators. There can still be common-mode failures in the facilities of the aggregator but it is easier and cheaper to install redundancy in this portion of the system than with an entire 1000-MW plant.

PROVISION OF INDIVIDUAL SERVICES

In all cases the owner of a load, in cooperation with an aggregator and the system operator, would determine the portion of the load which could provide the service. Metering, communications, and control requirements would then be established.

Looking first at the services required to restore the generation/load balance after a contingency *Supplemental Reserve* is a likely candidate for many loads. The resource must fully respond within 10 minutes of the contingency.* Response must be maintained for an additional 20 minutes, i.e., until 30 minutes after the contingency. This is a short interruption that many customers may find acceptable. Candidates include water pumping, building temperature control, water heaters, and air compressors. Anything that inherently has some storage in the process, or any process for which storage can be readily added is a good candidate.

The system operator takes some of the 10 minutes to recognize the contingency and to call for response. The aggregator's communications process will also consume some time. This leaves a few minutes for the load itself to respond.

Obviously, the load itself must be consuming power for it to curtail consumption during the contingency. Many candidate loads cycle as they provide service (e.g., hot water heaters). Since individual loads do not cycle together, the aggregation will always have some load available for curtailment. The aggregation has to be accurately characterized to know how much operating reserve is available at any time. Individual loads also have to be controlled after the reserve is released to prevent them from all returning to service simultaneously.

Frequency Responsive Spinning Reserve is both easier and more difficult for loads to provide. Because the service responds to system frequency, each load has the triggering signal available at all times. The service only has to be provided until it is replaced by Supplemental Reserve, 10 minutes, creating a shorter interruption. Full response is required within 10 seconds, however, which may make it harder for some loads to provide. A typical generator droop characteristic could be created by having each load in an aggregation respond at slightly different frequencies.

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*Specific timing requirements for each service vary from region to region. The requirements referenced here are from NERC (1998) Draft Policy 10.

Frequency Responsive and Supplemental Reserves restore the system's generation/load balance and maintain it for 30 minutes. Thirty minutes after a contingency occurs the customer that was receiving the lost generation is responsible for making other arrangements or curtailing its load. The *Backup Supply Plan* is a pre-arrangement that tells the system operator how to proceed for each load's loss of primary supply. Some loads may find it attractive to provide Backup Supply for other loads. The 30-minute warning provides time for communications and for the curtailing load to take actions to reduce its own costs.

Loads may also wish to participate in maintaining the generation and load balance during normal operations, though this seems less likely. A load or aggregation of loads could provide *Load Following* by cycling their daily operations in response to direct MW commands from the system operator or by responding to short-term price signals (Hirst and Kirby 1997).

Regulation is the least likely of the generation/load balancing services to be provided by load. It is possible, however, that loads with variable speed drives (e.g., water pumping) could accept automatic-generation control signals from the system operator. Municipal water pumping accounts for approximately 1% of electricity consumption nationally, providing a potentially significant source of load-based regulation or other ancillary services.

PAST USE OF LOAD CONTROL

Load control has been and is currently used in a number of locations [NERC (1997b) *Operating Manual*]. Some implementations have been successful but the idea has not been universally adopted. This is at least partly because of traditional rate structures, which provide little flexibility to customers. The customer must agree up front to be subject to utility control, usually for a year or more. There is no ability to enter and leave the market as the customer's economic conditions change. The customer often gets paid a flat fee independent of how or if the resource is actually used. This provides little flexibility for the load and little incentive to actually perform.

Similarly, the cost of peaking generation or peak reserves are typically spread over an entire season or year. Charges (both operating and capital) are not assigned exclusively to the hours when the generation or reserves are required. Assigning the costs to the hours when they are needed would result in much higher prices for those services during specific hours (and lower prices at other times). Under either good economic regulation or a truly competitive market, the result would be the same total revenue collection (that required to pay for the resource). Providing a price signal that accurately reflects the real-time cost to provide the service will encourage all suppliers, loads and generators, to offer supply when it is needed most.

SUPPLIER CONTROL OF ITS FACILITY

While automatic deployment is necessary when selling some reserves, it is often important to allow the load to decide when it will participate and when it will not. Just as the price of hourly energy and each of the ancillary services vary, so do customer economics. For many customers there are times when less flexibility exists and the load cannot be interrupted without high costs being incurred. These times are often independent of anything happening on the power system and are therefore unrelated to the price of the service. For the right price, a residential customer might be willing to automatically curtail air-conditioning use for 30 minutes to supply contingency reserves, for example. This same customer would probably be unwilling to curtail use at any price on the evening when he was holding a dinner party, however. Similar restrictions might apply for an industrial customer such as a continuous chemical processing plant while it is taking a monthly inventory and needs a stable process. In both cases the customer choice not to participate is unrelated to the utility economics; neither load is trying to avoid providing the service when it is highest in value. In fact, the chemical plant may intentionally select times for its inventory when the power system is not stressed, such as at night or on weekends. It would do this not because of a concern for the power system but because that may be a time when the chemical process is stable as well due to reduced activity at the chemical plant.

The utility needs information about which loads will be supplying services ahead of time. The load must declare that it is available before it enters or leaves the market. Perhaps this declaration would be one day in advance for the following 24 hours. Both the utility and the load will need the ability to change the availability on shorter notice, perhaps with economic consequences. A load that experiences technical difficulties and is suddenly incapable of supplying the service must be able to leave the market. Conversely, if the power system finds itself unexpectedly short of reserves it will need to be able to call for additional reserves quickly, perhaps by rasing the current price. Indeed, this is how the day-ahead, hour-ahead and real-time markets are intended to operate in California's competitive bulk-power system.

It is critical to avoid providing an incentive for a resource (either load or generation) to declare itself available when it is not (as is done in the United Kingdom). Equipment failures are inevitable but service providers should have an incentive to maintain the reliability of their resources. They should never find it profitable to sell a service that they know they cannot deliver.

TRADING CERTIFICATION FOR METERING

Most of the generators on a typical power system are relatively large and expensive. It is reasonable for the system operator to monitor unit output and bus voltage every 2 to 8 seconds. The amount of data and the expense per MW are both reasonable. When the operator calls for response the response can be monitored in real time.

Providing the same information from hundreds or thousands of individual resources would be prohibitively expensive and would provide an overwhelming amount of data that could not be managed in real time. An alternative to real-time monitoring of each individual resource exists. Loads could be certified, either individually or in aggregation, for the provision of each ancillary service. Certification would consist of exercising the resource under controlled conditions to determine the reliable response (NERC 1998). Testing of the contingency reserves, for example, would not be announced to the resource. The response would be measured on control-area metering. Periodic testing would monitor continued capability. Recording meters at each resource could also be audited to verify performance for both actual events and tests.

AGGREGATION AND COMMUNICATION

The major objection often voiced to customer supply of ancillary services is that the system operator cannot deal with the large number of individual resources and that the communications requirements would be overwhelming. These are valid concerns but ones that can be addressed. Aggregators can provide a genuinely valuable function here. By handling the communications with a large number of loads they can present the system operator with a single point of contact for a reasonable amount of capacity, similar to the system operator's interface with generating resources. They can also be an interpreter between the electrical system and customers. The system operator is not interested in learning the details and concerns of each customer. Similarly, customers are in businesses of their own and have neither the time nor the interest in learning all about the power system. The aggregator can bridge this gap, creating a valuable resource in the process.

Communications are inherently different with an aggregation of resources than with a single entity. As mentioned above, it is not currently practical to collect data from thousands of individual loads every 2 to 8 seconds. It is practical, however, to send instructions to those loads as fast as necessary. That is because it is the same signal going to large groups of the loads. That signal could be "deploy now" or it could be "the current price for response is SX".

CUSTOMER ECONOMICS

In competitive bulk-power markets, customers will have many choices with respect to their use of electricity and their payment for electricity services. In the context of this discussion, they can choose to participate in hourly markets and face spot prices that can vary widely in response to supply/demand relationships. Alternatively, they can sell reserve services (options) as discussed above. Decisions on whether to participate in spot markets or sell reserves will be based on the customer's flexibility in modifying its electricity use (in particular, its fixed and variable costs to modify its electricity use in real time), the prices of energy and reserve services, and the frequency with which outages occur.

For example, higher reserve prices and less frequent outages will lead customers to sell reserve services, forgoing opportunities to reduce consumption at times of high spot electricity prices. On the other hand, increasing flexibility (i.e., declining cost) in modifying electricity use will lead to more decisions to participate in spot energy markets.

CONCLUSIONS

Loads can provide several of the energy-balancing ancillary services. They should be encouraged to do so because of the reliability and commercial benefits provided by expanded supplies of these resources. Artificial barriers to the entry of customers into these markets should be removed. The customers themselves will have to determine their economic costs and benefits to see if and when they will participate. Loads must be given the flexibility to respond to their own economic constraints.

Technical problems associated with the need to aggregate many individual loads to achieve a resource of sufficient size to be useful can be overcome. This may be one of the areas where load aggregators can play a genuinely useful role. An aggregator can relieve the system operator of the burden of dealing with an excessive number of individual resources while still providing the required response. Similarly, the high communications burden associated with a large number of resources can be alleviated by broadcasting control signals to the resources. Rigorous certification, coupled with post-event meter audits, can substitute for real-time monitoring of each resource.

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ENERGY DIVISION

CUSTOMER-SPECIFIC METRICS FOR THE REGULATION AND LOAD-FOLLOWING ANCILLARY SERVICES

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180

CONTENTS

Page

SUMMARY v

LIST OF ACRONYMS vii

1. INTRODUCTION 1

2. DATA 5
   - DATA QUALITY 5
   - TEMPORAL AGGREGATION FOR REGULATION 6
   - TIME-AVERAGING PERIOD 10

3. REGULATION 13
   - SYSTEM-LEVEL METRICS 13
   - CUSTOMER-SPECIFIC METRICS 14
   - RESULTS 21

4. LOAD FOLLOWING 23
   - SYSTEM-LEVEL METRICS 23
   - CUSTOMER-SPECIFIC METRICS 25
   - RESULTS 27

5. CONCLUSIONS 31

ACKNOWLEDGMENTS 33

REFERENCES 35

REGULATION VECTOR-ALLOCATION METHOD 37

101

SUMMARY

In competitive electricity markets, the costs for each ancillary service should be charged to those who cause the costs to be incurred with charges based on the factors that contribute to these costs. For example, the amount of generating capacity assigned to the regulation service is a function of the short-term volatility of system load. Therefore, the charges for regulation should be related to the volatility of each load, not to its average demand.

This report discusses the economic efficiency and equity benefits of assessing charges on the basis of customer-specific costs (rather than the traditional billing determinants, MWh or MW), focusing on two key real-power ancillary services, regulation and load following. We determine the extent to which individual customers and groups of customers contribute to the system's generation requirements for these two services. In particular, we analyze load data to determine whether some customers account for shares of these two services that differ substantially from their shares of total electricity consumption.

We defined and applied metrics for regulation and load following. For regulation, we chose the standard deviation (MW) of the thirty 2-minute values in each hour. For load following (MW), we chose the difference between the maximum and minimum values of the 30-minute rolling-average load during each hour.

We also developed and applied methods to allocate these system-level metrics to individual customers and to groups of customers. The regulation allocation method uses a trigonometric relationship to correlate an individual customer's regulation burden with the total burden. The load-following allocation method calculates each customer's share of the total requirement on the basis of its coincident load-following requirement.

Application of these allocation methods shows that charging customers for these ancillary services on the basis of average loads can be inequitable. For one control area, a few large industrial customers account for 34% of system load, compared with 93% of the regulation and 58% of the load-following requirements (Fig. S-1). These customers disproportionately use these services but, in general, are not paying their fair share under typical utility tariffs. The subsidies inherent in today's ancillary-service pricing methods cannot, and should not, be sustained. Indeed, industrial customers with near-time-invariant loads, such as aluminum smelters and paper mills, will justifiably claim they require none of these services and, therefore, should not have to pay for them.

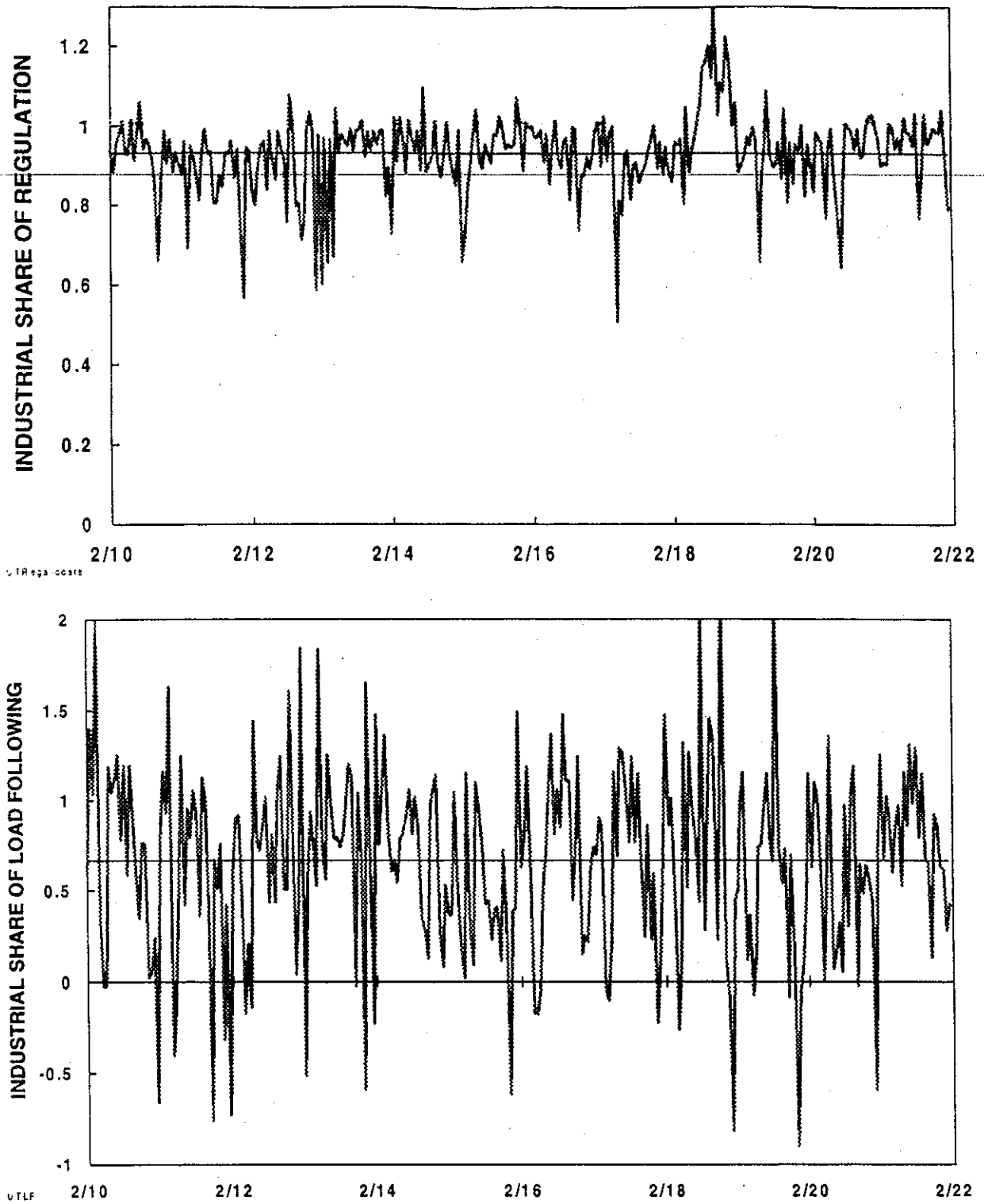


Fig. S-1. The shares of system regulation (top) and load following (bottom) calculated for several large industrial customers for 12 days in February 1999. Note that these customers sometimes account for more than 100% of the total, implying that the nonindustrial customers were reducing the requirements for these services.

103

LIST OF ACRONYMS

ACE	Area control error
AGC	Automatic generation control
CPS	Control performance standard
FERC	U.S. Federal Energy Regulatory Commission
ISO	Independent system operator
NERC	North American Electric Reliability Council
RTO	Regional transmission organization

INTRODUCTION

In its recent Notice of Proposed Rulemaking, the Federal Energy Regulatory Commission (FERC 1999) wrote, "The Commission believes that, whenever it is economically feasible, it is important for the RTO [regional transmission organization] to provide accurate price signals that reflect the costs of supplying ancillary services to particular customers." Earlier, FERC (1996) wrote in its Order 888. "Because customers that take similar amounts of transmission service may require different amounts of some ancillary services, bundling these services with basic transmission service would result in some customers having to take and pay for more or less of an ancillary service than they use. For these reasons, the Commission concludes that the six required ancillary services should not be bundled with transmission service."

Recognizing the economic efficiency and equity benefits of assessing charges on the basis of customer-specific costs, we investigated the requirements for two key ancillary services, regulation and load following. We determined the extent to which individual customers and subgroups of customers contribute to the system's generation requirements for these two services, in particular whether some customers account for shares of these two services that differ substantially from their shares of total electricity consumption.

The remainder of this section defines these two ancillary services and explains how they differ from each other. Chapter 2 describes the data we obtained, the quality-control checks we applied to the data, and our data conversions to separate system-level regulation from load-following requirements. Chapters 3 and 4 present (1) the methods we developed to create system and customer-specific metrics for regulation (Chapter 3) and load following (Chapter 4) and (2) the results obtained with these methods. Chapter 5 presents our conclusions.

Because electricity is a real-time product, control-area operators must adjust generation to meet load on a minute-to-minute basis. As the electricity industry becomes deintegrated, with competitive generation separated from regulated transmission and system control, defining the requirements and responsibilities to meet time-varying customer loads is increasingly important. Regulation and load following are the two key ancillary services required to perform this function. (Energy imbalance is, depending on one's definition, either the service or the accounting function that corrects for hourly errors in the provision of energy and the other two services.)

Loads can be decomposed into three elements (Fig. 1). The first element is the average load (base) during the scheduling period, 85 MW over the one hour shown in this case. The second element is the trend (ramp) during the hour and from hour to hour (the morning pickup

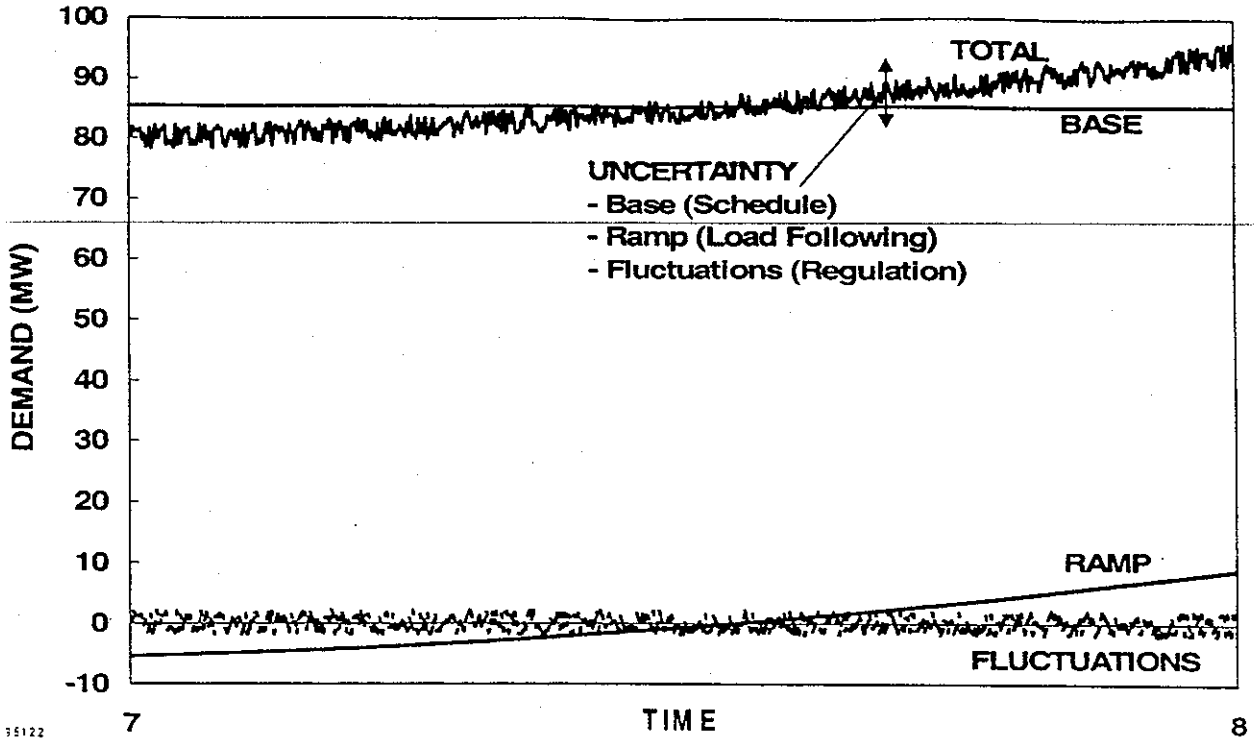


Fig. 1. Components of a hypothetical load on a weekday morning.

in this case); here that element increases from −5 MW at 7 a.m. to +9 MW at 8 a.m. The third element is the rapid fluctuations in load around the underlying trend; here the fluctuations range over ±2 MW. Combined, the three elements yield a load that ranges from 78 to 96 MW during this hour.

The system responses to the second and third components are called load following and regulation. These two services (plus, perhaps, energy imbalance) ensure that, under normal operating conditions, a control area is able to balance generation to load. The two services are briefly defined below [see also FERC (1996), Hirst and Kirby (1998), and Interconnected Operations Services Working Group (1997)]:

- Regulation is the use of online generating units that are equipped with automatic generation control (AGC) and that can change output quickly (MW/minute) to track the moment-to-moment fluctuations in customer loads and to correct for the unintended fluctuations in generation. In so doing, regulation helps to maintain interconnection frequency, manage differences between actual and scheduled power flows between control areas, and match generation to load within the control area. This service can be provided by any appropriately equipped generator that is connected to the grid and electrically close enough to the local control area that physical and economic transmission limitations do not prevent the importation of this power.

106

- Load following is the use of online generation equipment to track the intra- and inter-hour changes in customer loads. Load following differs from regulation in three important respects. First, it occurs over longer time intervals than does regulation, 10 minutes or more rather than minute to minute. Second, the load-following patterns of individual customers are highly correlated with each other, whereas the regulation patterns are largely uncorrelated. Third, load-following changes are often predictable (e.g., because of the weather dependence of many loads) and have similar day-to-day patterns. Even when not predictable by the control-area operator, the customer can inform the control center of impending changes in its electricity use.

FERC (1996), in its Order 888, which defined six ancillary services, did not discuss load following. Perhaps because of this omission, most utilities and independent system operators (ISOs) do not include load following in their tariffs.* The absence of this service requires the California ISO to acquire much more regulation (as well as other services, such as replacement reserves and supplemental energy) than it otherwise would (Wolak, Nordhaus, and Shapiro 1998). Specifically, the California ISO buys regulation in amounts equivalent to about 5% of daily load, compared with about 1% for most utilities. Thus, the ISO is substituting an expensive service (regulation) for an inexpensive one (load following). Perhaps because of these problems, FERC (1999), in its notice on RTOs, proposed to require RTOs to operate real-time balancing markets. The primary resource for these markets is generators that can change output every five or ten minutes (i.e., to follow load).

*The Mountain West Independent Scheduling Administrator in Nevada is the only U.S. entity we know of that has proposed to create an explicit load-following service (FERC Docket No. ER99-3719-000, July 23, 1999). Most utilities provide load following through the 5- or 10-minute economic dispatch of their generating units.

107

DATA

We obtained 30-second data from a control-area operator on generation and load for a 12-day period in February 1999, a total of 34,560 observations.* For each 30-second interval, the data included total generation, net imports, total load, and the loads for several individual industrial customers. These large industrial customers include, among others, steel mills, oil refineries, and air-separation facilities. For confidentiality reasons, we scaled all the data shown here.

We summed the industrial loads to create a subgroup that we called *industrial load*. We called the difference between total load and industrial load *nonindustrial load*. Figure 2 shows the hourly loads for five days (Wednesday through Sunday). The total and nonindustrial loads show the expected winter patterns with morning and evening peaks, and with lower loads (by about 10%) on the weekends. The industrial load, on the other hand, is relatively constant from hour to hour. Its coefficient of variation (ratio of standard deviation to mean) is about half that of the nonindustrial load.

DATA QUALITY

This data set includes almost 3 million elements. Given its large size, it is not surprising that we found several anomalies in the raw data. Overall, one record is missing every three hours. The analysis software we developed for this project does not require all the data for a particular period to be present. We used linear interpolation to impute the missing data.

Another type of data anomaly was harder to recognize. We found 12 cases where one or more industrial loads rise for a single reading without a corresponding rise in the total load. For these load changes to be real, a simultaneous drop would have to occur in nonindustrial load for that single time step. We deleted five data points as being clearly impossible. We dropped three points because the control-area operator data-collection system identified problems at those times. We deleted one record because multiple industrial loads spiked simultaneously with no corresponding spike in the total load.

Failure to eliminate bad data results in errors in the analysis. Spikes in the data show up as abnormally high regulation requirements (high hourly standard deviation of the short-term

*We obtained and analyzed comparable data for a 12-day period in August and September 1999. We do not report these late-summer results because they are so close to those reported here for February.

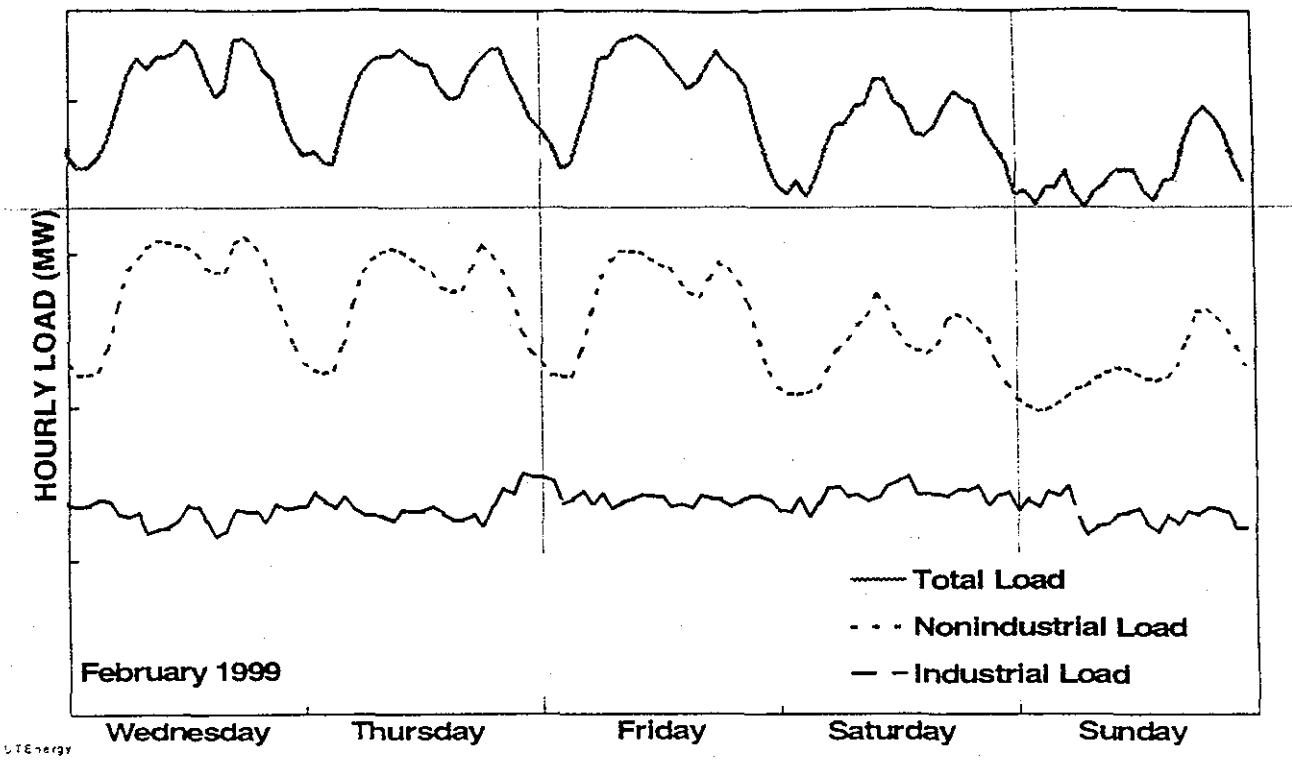


Fig. 2. **Hourly system load, nonindustrial load, and industrial load (the sum of several large industrial loads) for five days.**

fluctuations) for one or more of the loads. To facilitate analysis, the software performs several data checks. Total generation is compared with the sum of the individual generator outputs and the difference is reported if the imbalance exceeds 10 MW. Reported and calculated area control error (ACE) is reported if the difference exceeds 10 MW. Spikes in industrial load not reflected in total load are reported if they exceed 100 MW. These anomalies are recorded by the software so that the specific data points can be examined for possible elimination. Dropping too many data points runs the risk of eliminating interesting and important events. We identified questionable data in fewer than 0.1% of the 34,560 records.

TEMPORAL AGGREGATION FOR REGULATION

Assessing the individual customer contribution to the overall regulation requirement necessarily involves generation performance. A control area is not expected to perfectly match generation and load instantaneously. Rather, generation matches load with some time lag, and, therefore, generation matches load only approximately. The North American Electric Reliability Council (NERC 1999) Control Performance Standards (CPS) 1 and 2 set statistical limits on the allowable differences between one-minute averages of the control area's difference between aggregated generation and interchange schedules relative to load (i.e., ACE). The cost of regulation is a function of the opportunity and operating costs of the generation capacity used to provide regulation. The control-area operator studied here is

109

satisfied with its CPS performance. It meets NERC requirements without wasting money by overcompliance.

Although the AGC systems at most utility control centers send raise and lower pulses to individual generators as frequently as every two or four seconds, generators do not follow such short-term load fluctuations. Our prior work (Hirst and Kirby 1996) suggests that generation follows load at the one- to two-minute interval.

We began this portion of the analysis with the 30-second data on generation and load regulation for the full 12 days. Regulation is here quantified as the difference between total load (generation) and the 30-minute rolling average of load (generation). We aggregated these 30-second data to create three additional datasets with 60-, 120-, and 240-second averages of the original data.

Figures 3 and 4 show, for one hour, the relationship between the regulation components of load and generation. The first graph shows that load fluctuates rapidly and substantially around its rolling average, whereas generation moves much more slowly and with a much smaller amplitude. In going from 30- to 60- to 120- to 240-second averages, the generation patterns are largely unchanged, but the load patterns become much smoother, smaller in amplitude, and slower moving. The ratios of the standard deviation of generation to the standard deviation of load increase from 0.45 for 30-second averages to 0.5, 0.6, and 0.7 with 60-, 120-, and 240-second averages. Note that even with 4-minute averages, load volatility remains 40% higher than generation volatility. A close look at the graphs showing 2- and 4-minute averages suggests that generation lags load by at least two minutes (Fig. 4).

These visual observations are confirmed by statistical analysis. We calculated correlation coefficients between generation and load for each of the four datasets for each of the 12 days. We then repeated these analyses by lagging generation 1, 2, ... , 12 time periods from load (Fig. 5). The correlation between generation and load increases in going from 30-second averages to 4-minute averages. The correlation between lagged generation and load is highest for a lag of 3 to 4 minutes.

Finally, we ran regression models of generation as a function of current and prior-period loads with 30-, 60-, and 120-second data. The models all have high explanatory power (the R^2 values are all about 0.7). The models all show that current load is a poor predictor of current generation. (Remember, we are discussing here only the fluctuations in generation and load about their 30-minute rolling averages, not the totals.) Load has a statistically significant effect on generation between 1 and 9 minutes.

We found these results surprising. We had expected to find that 30 seconds was too short a time-averaging period and that the appropriate period would fall between 1 and 2 minutes because CPS, the performance metric for the control area, is based on 1-minute averages. These results suggest that 4 minutes may be more appropriate. Although the data and

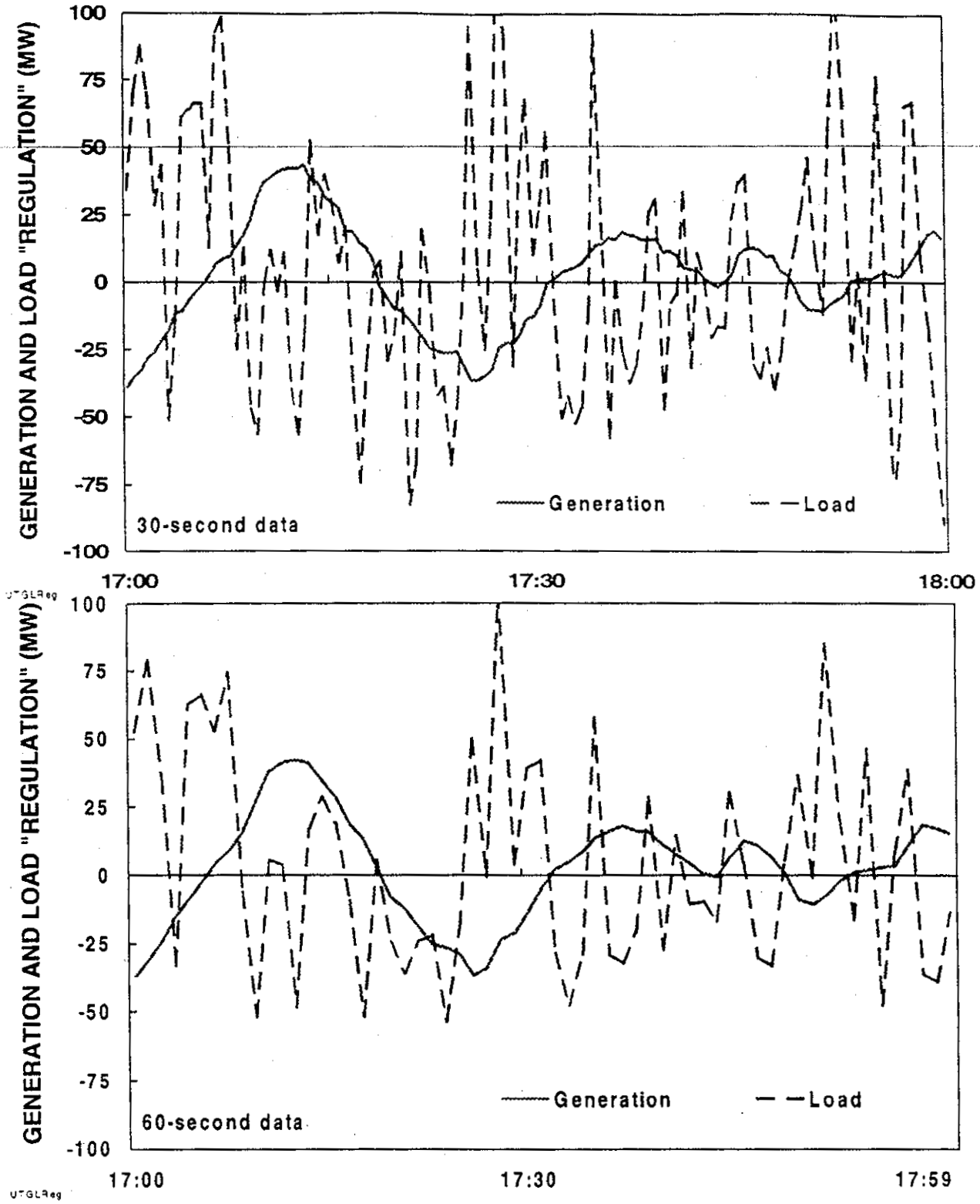


Fig. 3. Relationship between the regulation components of utility generation (solid line) and load (dashed line) with 30-second averages (top) and 60-second averages (bottom).

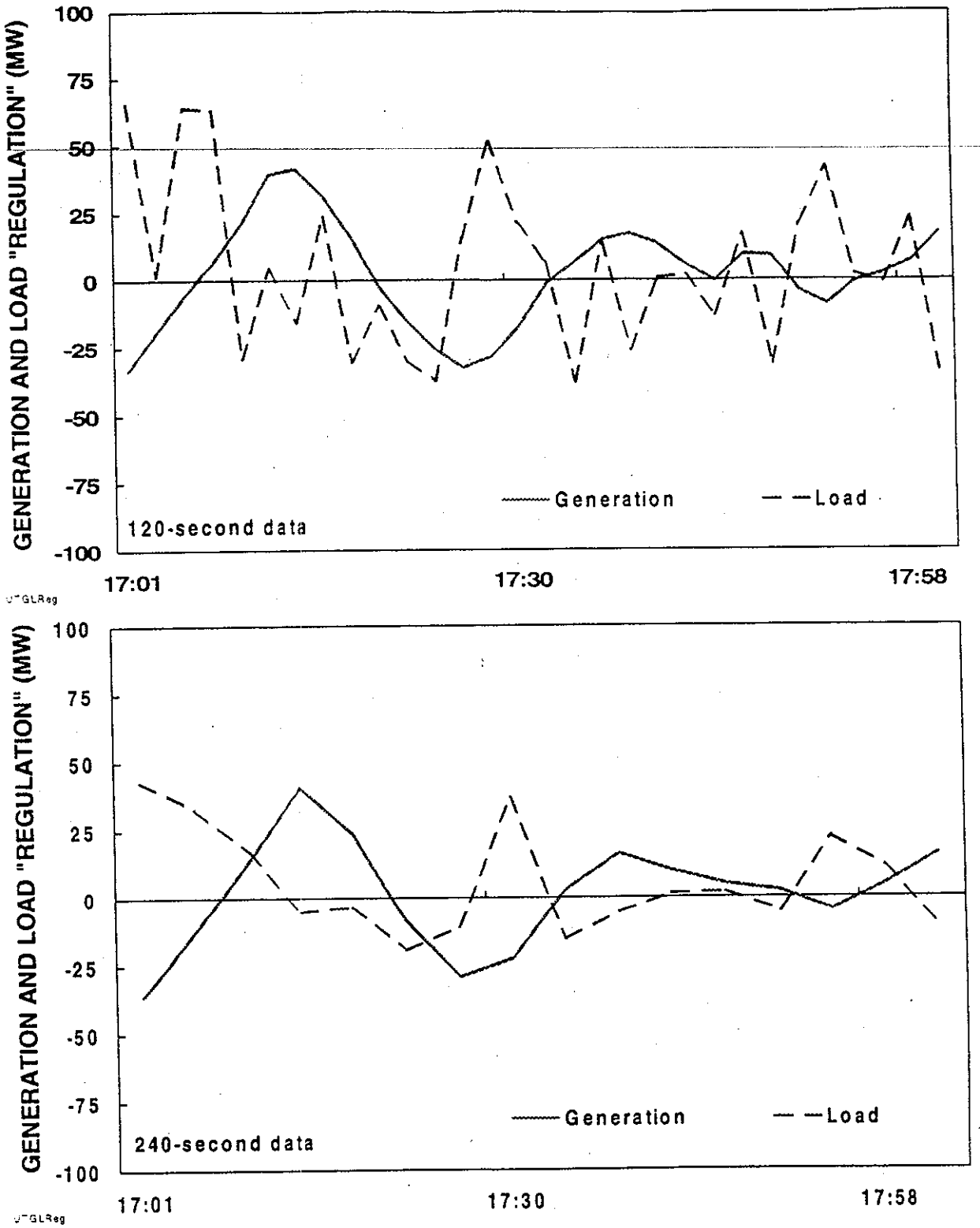


Fig. 4. Relationship between the regulation components of utility generation (solid line) and load (dashed line) with 120-second averages (top) and 240-second averages (bottom).

112

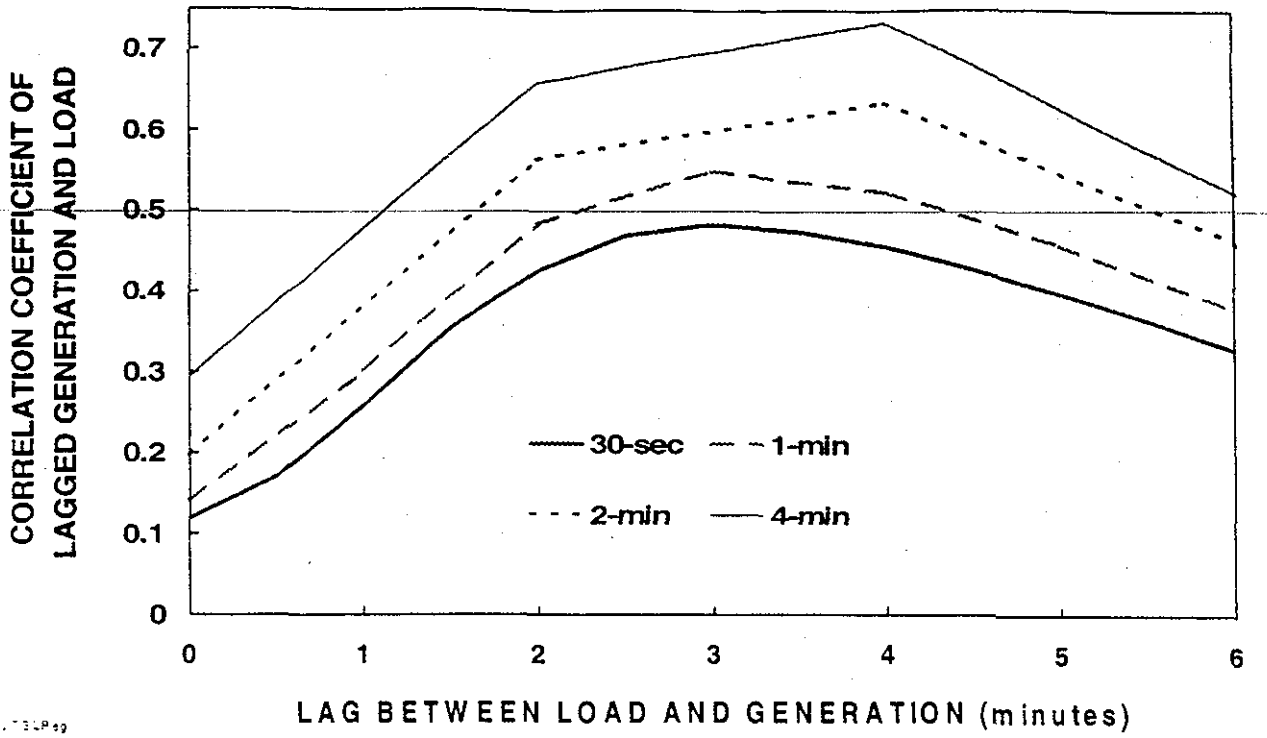


Fig. 5. **Correlation coefficient between generation and load regulation as a function of the time-averaging period (30 seconds to four minutes) and the lag between load and generation.**

analysis suggest a 4-minute time-averaging period, we chose a 2-minute period because this is a conservative approach (i.e., it preserves more information) and it is consistent with the results of our analysis of regulation data for two other utilities.

TIME-AVERAGING PERIOD

There is no hard-and-fast rule to define the temporal boundary between regulation and load following. If the time chosen for the split is too short (e.g., five minutes), too much of the fluctuations will appear as load following and not enough as regulation. If the boundary is too long (e.g., 60 minutes), too much of the fluctuations will show up as regulation and not enough as load following. But in each case, the total is unchanged and is captured by one or the other of these two services.

We used rolling averages to define the boundary between the two services.* We tested 20-, 30-, 40-, 50-, and 60-minute rolling averages with 2-minute data. For the 30-minute rolling

*The use of a rolling average to separate regulation from load following is an analytical convenience, not possible in real time. System operators instead use sophisticated analytical methods to forecast loads for the next few hours, based on current and expected weather conditions, prior loads, and other factors.

113

average, as an example, we calculated the rolling average for each 2-minute interval as the mean value of the seven earlier values of the variable, the current value, and the subsequent seven values:

$$\text{Load following}_t = \text{Load}_{\text{estimated-}t} = \text{Mean}\ (L_{t-7} + L_{t-6} + \ldots + L_t + L_{t+1} + \ldots + L_{t+7}),$$

$$\text{Regulation}_t = \text{Load}_t - \text{Load}_{\text{estimated-}t}.$$

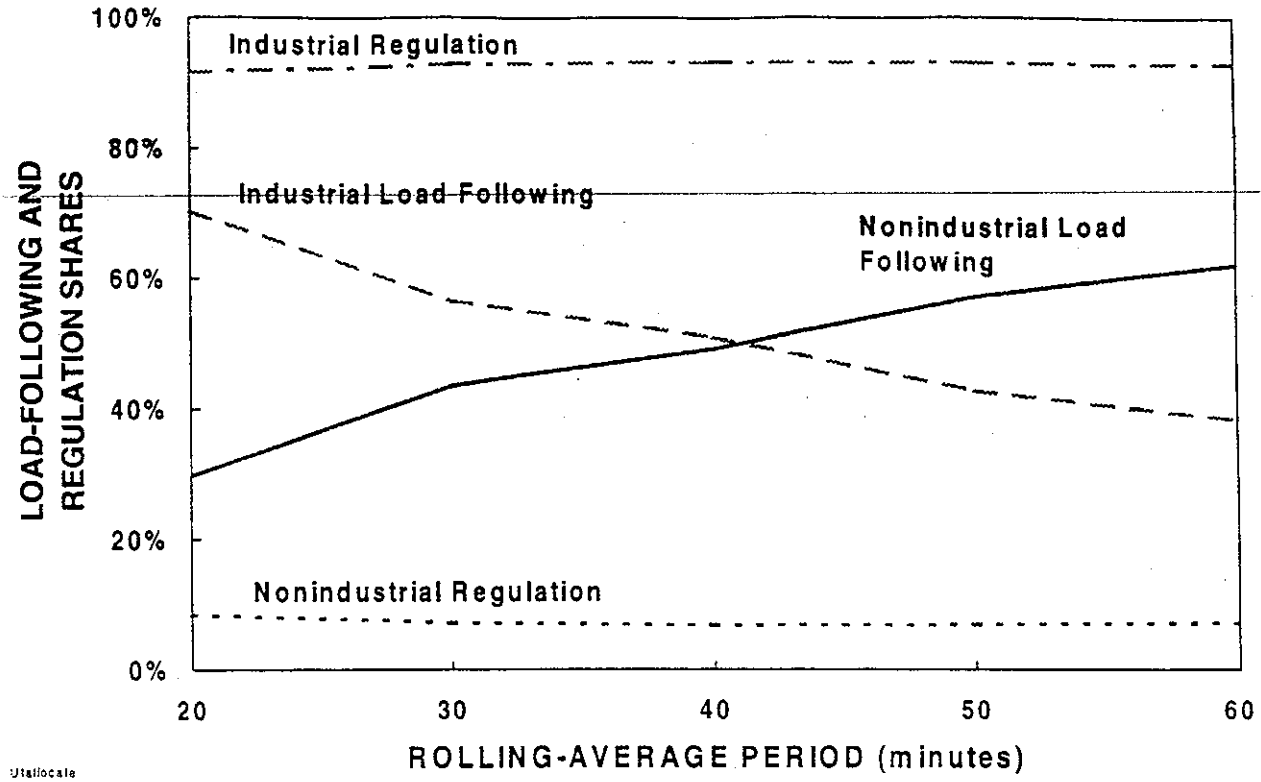
Selecting the appropriate rolling-average period to analyze load following depends on the factors that affect generation costs, which are specific to the generators providing load following. Several questions must be answered to determine the appropriate rolling-average period. Does the predictability of load following reduce costs by enabling economic dispatch for the units that provide load following? Are costs reduced for all slower movements or only for predictable movements? What is the lead time required to enable load following?

We analyzed the impact of changing the rolling-average period. The top part of Fig. 6 shows a shift in load-following responsibility (but no similar shift in the regulation responsibility) between the industrial and nonindustrial customers as the rolling-average period changes from 20 to 60 minutes. As discussed in Chapter 3, we use the standard deviation of regulation as the key metric for this service. For purposes of this comparison with load following, we multiply the regulation standard deviation by 3, which captures 99% of its variation.

We also compared the regulation and load-following magnitudes. The bottom part of Fig. 6 shows that the sum of total load-following and regulation requirements remain relatively constant, varying from 161 MW at 20 minutes to 156 MW at 60 minutes. Nonindustrial regulation requirements remain constant, as well, at 7 MW. Nonindustrial load following rises as the time-averaging period is extended, from 23 MW at 20 minutes to 31 MW at 60 minutes. Lengthening the rolling-average period from 20 to 60 minutes shifts 22 MW of the industrial variability from load following to regulation.

Changing the rolling-average duration has two major impacts. Shortening the period shifts the industrial variability from regulation to load following and shifts load following from the nonindustrial to the industrial customers. Selecting the correct rolling-average duration should be based on a break point in the generation cost drivers to provide each service, probably based on the costs of economic dispatch and the time required to implement it. For this analysis we used a 30-minute rolling average.

Because this control-area operator is satisfied with its CPS performance, we do not deal with the *amount* of each service that should be provided. This project deals only with the *allocation* among customers of the existing services and their costs.



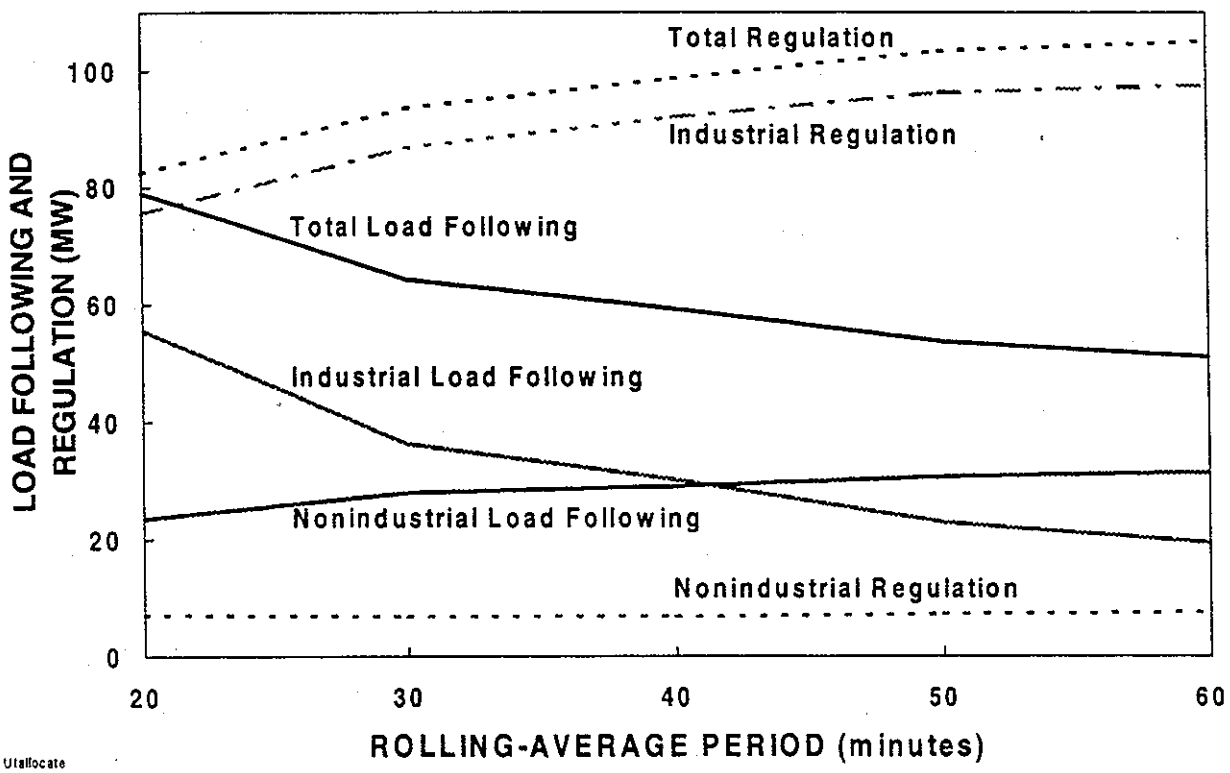


Fig. 6. The effects of changes in the rolling-average period on the allocation of load variation between regulation and load following by type of load.

115

REGULATION

SYSTEM-LEVEL METRICS

Selection of an appropriate metric for regulation should be based on the underlying cost drivers to provide the service (i.e., the units that are on AGC). For example, if the costs are dominated by ramp-rate (MW/minute) considerations, then the speed of regulation units might be a better metric than the amount of regulation capacity. In addition, the chosen metric should be amenable to mathematical manipulation that permits definition of the relationships between individual loads and the total load. In this project, we analyzed load data only; we did not consider the types and costs of generating units used to provide the service. (We did, as explained in Chapter 2, examine the dynamics of generation vs loads.)

We examined four possible metrics for regulation, using the 2-minute regulation values defined above:

- Standard deviation (MW) of the 30 values in each hour;
- Average of the absolute values (MW) of the 30 values in each hour;
- Average regulation rate (MW/minute), calculated as one-half the average of the absolute values of the 29 differences between adjacent regulation values;* and
- Maximum regulation rate (MW/minute), calculated as one-half the maximum value of the absolute values of the 29 differences between adjacent regulation values.

Table 1 summarizes the average, maximum, and minimum values of these four metrics for total system load. Overall, regulation (as measured by the standard deviation) is 1.3% of total load. The two magnitude metrics (standard deviation and average of the absolute values) are highly correlated with each other. These correlation coefficients are all above 0.95 for total load, nonindustrial load, and industrial load. These very high correlations suggest that we need use only one of these two magnitude factors; we chose the standard deviation.

*We multiply the average by one half to convert from the 2-minute differences to 1-minute differences. This metric can also be calculated as the total path length (the sum of the absolute values of all the MW movements) during an hour divided by 60.

Table 1. Regulation metrics for system load for 12 days in February 1999 (288 hourly observations)

	Standard deviation (MW)	Average of absolute values (MW)	Average rate (MW/minute)	Maximum rate (MW/minute)
Average	31	25	14	41
Maximum	50	46	21	84
Minimum	16	13	8	18

On the other hand, the correlations between either of these two magnitude variables and the average regulation speed variable are lower (0.7 for nonindustrial load and 0.6 for industrial load). These lower correlation coefficients suggest that we may need two variables to accurately capture regulation, a magnitude (MW) factor and a ramprate (MW/minute) factor. Without information on the costs of regulation ramprate, we did not pursue this second metric.

Finally, the correlation coefficients between load itself and regulation are very low, suggesting that load is a poor predictor of regulation requirements.

Figure 7 shows the hour-to-hour patterns in regulation magnitude for weekdays and weekends. Figure 8 shows the variations from day to day in average regulation burden. These graphs show that the industrial loads have much greater volatility than do the nonindustrial loads. Indeed, as a share of total load, the industrial loads require about six times as much regulation as do the nonindustrial loads.

CUSTOMER-SPECIFIC METRICS

Having established system-level metrics for regulation, we turn our attention to the development of metrics for customer-specific assignment of the total regulation amount. This customer allocation is especially important for utilities that have nonconforming loads (e.g., steel mills).

Because regulation is the short, minute-to-minute fluctuations in load, the regulation component of each customer's load is largely uncorrelated with those of other customers. If each customer's load fluctuations (σ_i) is completely independent of the remainder of the system, the total regulation requirement (σ_T) would equal

$$\sigma_T = \sqrt{\sum \sigma_i^2} \ , \qquad (1)$$

where i refers to an individual customer and T is the system total.

117

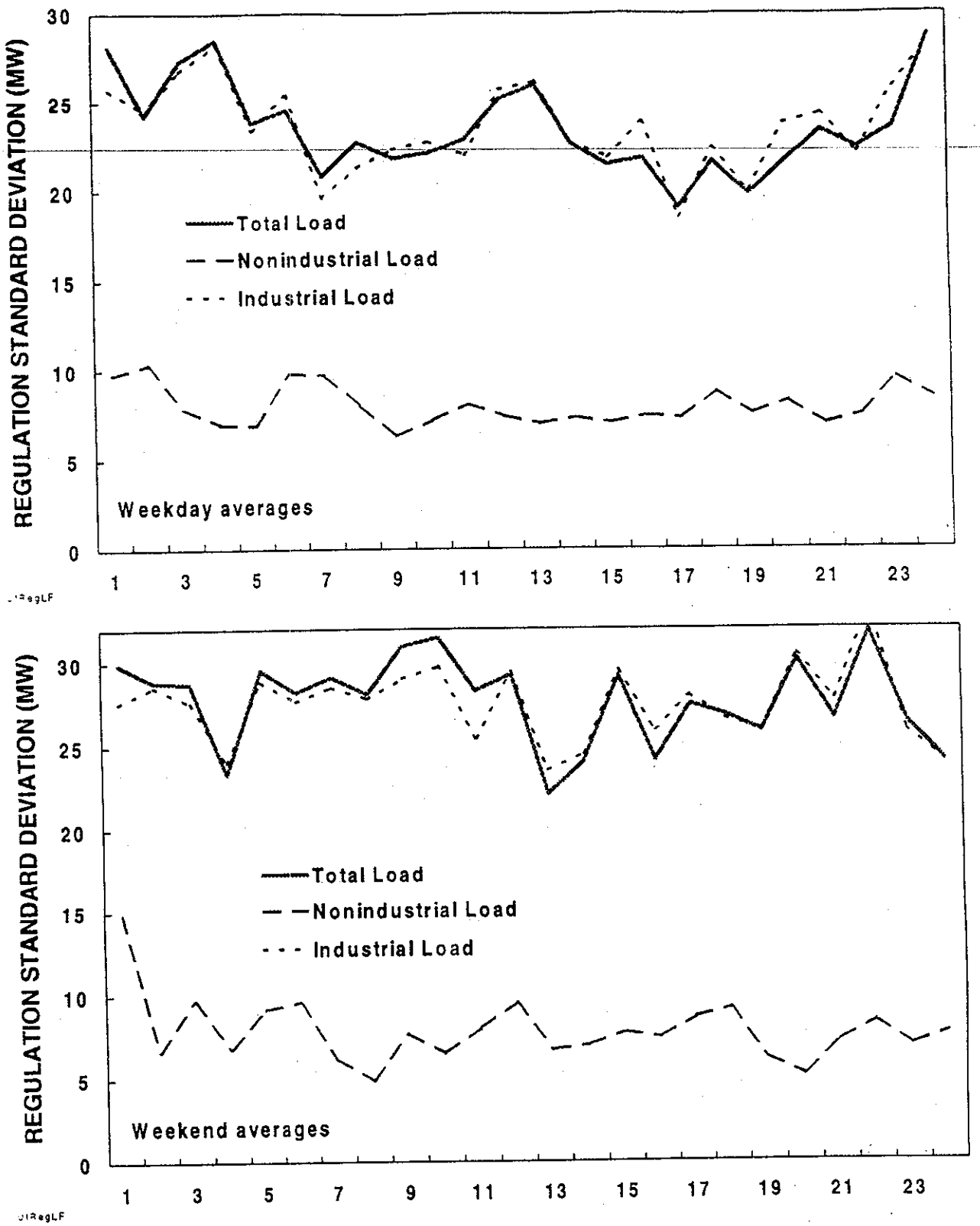


Fig. 7. Average hourly regulation requirement for weekdays (top) and weekends (bottom) for total load, nonindustrial load, and industrial load.

118

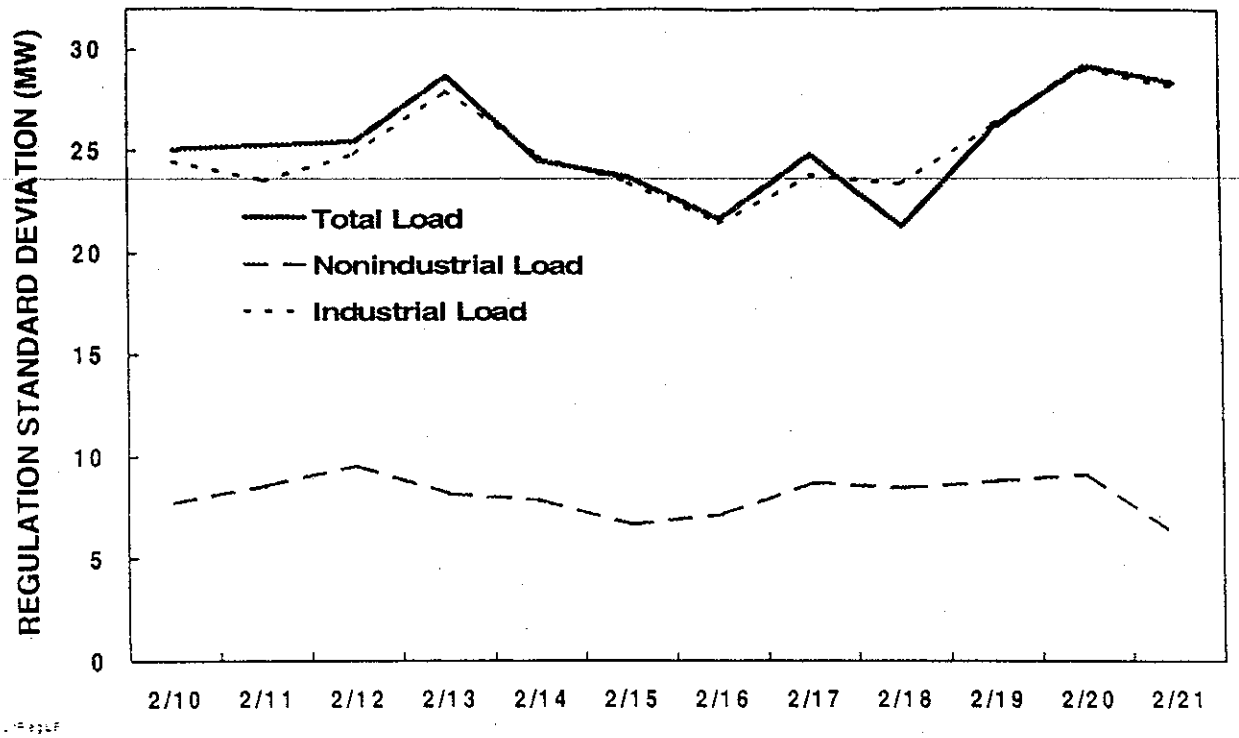


Fig. 8. Average daily regulation requirement.

In this idealized case, the share of regulation assigned to each customer would equal

$$\text{Share}_i = (\sigma_i/\sigma_T)^2 , \tag{2}$$

and there would be no need to analyze interactions among customer loads in calculating the total regulation burden.

If, on the other hand, the loads are completely correlated with each other [i.e., the correlation coefficient (r) between each pair of loads equals 1], the total regulation requirement is the simple sum of the individual requirements:

$$\sigma_T = \sum \sigma_i . \tag{3}$$

In this idealized case, the share of regulation assigned to each customer would equal

$$\text{Share}_i = \sigma_i/\sigma_T . \tag{4}$$

Table 2 shows the total regulation requirement and customer shares for two customers, one with a standard deviation of 3 MW and the second with a standard deviation of 4 MW. If the two loads are independent of each other ($r = 0$), the total regulation requirement is 5 MW.

119

If, however, the two loads are completely and positively correlated with each other ($r = 1$), the total regulation requirement is 7 MW. Finally, if the two loads are completely and negatively correlated with each other ($r = -1$), the total regulation requirement is 1 MW.

Table 2. Total regulation requirement (and % of total) for two loads as a function of the correlation between the two loads

Load	Standard deviation (MW)	Regulation amount (% share)		
		Uncorrelated	Positively correlated	Negatively correlated
1	3	1.8 (36%)	3 (43%)	-3 (-300%)
2	4	3.2 (64%)	4 (57%)	4 (400%)
Total	--	5	7	1

Figure 9 shows results from an analysis of data for 19 large industrial customers from another control area. As expected, the actual value of the total regulation requirement is slightly (9%) higher than the total calculated as if the loads were completely uncorrelated. Also as expected, the actual value is much (63%) less than that calculated as if the loads were completely correlated. In this case, the loads exhibit a slight positive correlation with each other.

Figure 10 shows geometrically the possible relationships between two loads (A and B) and the total regulation requirement. (Each element could be represented by its standard deviation.) In the top panel, the two loads are uncorrelated, and the total regulation requirement is the square root of the sum of the squares of the individual loads (Eq. 1). In the middle panel, the same two loads are negatively correlated with each other, yielding a total regulation requirement less than that shown in the top panel. The bottom panel illustrates a situation opposite to that shown in the middle panel; in this case, the two loads are positively correlated with each other, and the total regulation requirement is more than that shown in the top panel.

The question is how to allocate fairly the total regulation requirement between these two loads (and, by extension, among several loads). The allocation method should yield results that are independent of any subaggregations. In other words, the assignment of regulation to load L should not depend on whether L is billed for regulation independently of other loads or as part of a group of loads. In addition, the allocation method should reward (pay) loads that reduce the total regulation burden.* In the middle panel of Fig. 10, load A offsets some of the

*A third criterion for choosing an allocation method could be independence of the order in which loads are added to the system. This objective overlaps with the first one discussed above.

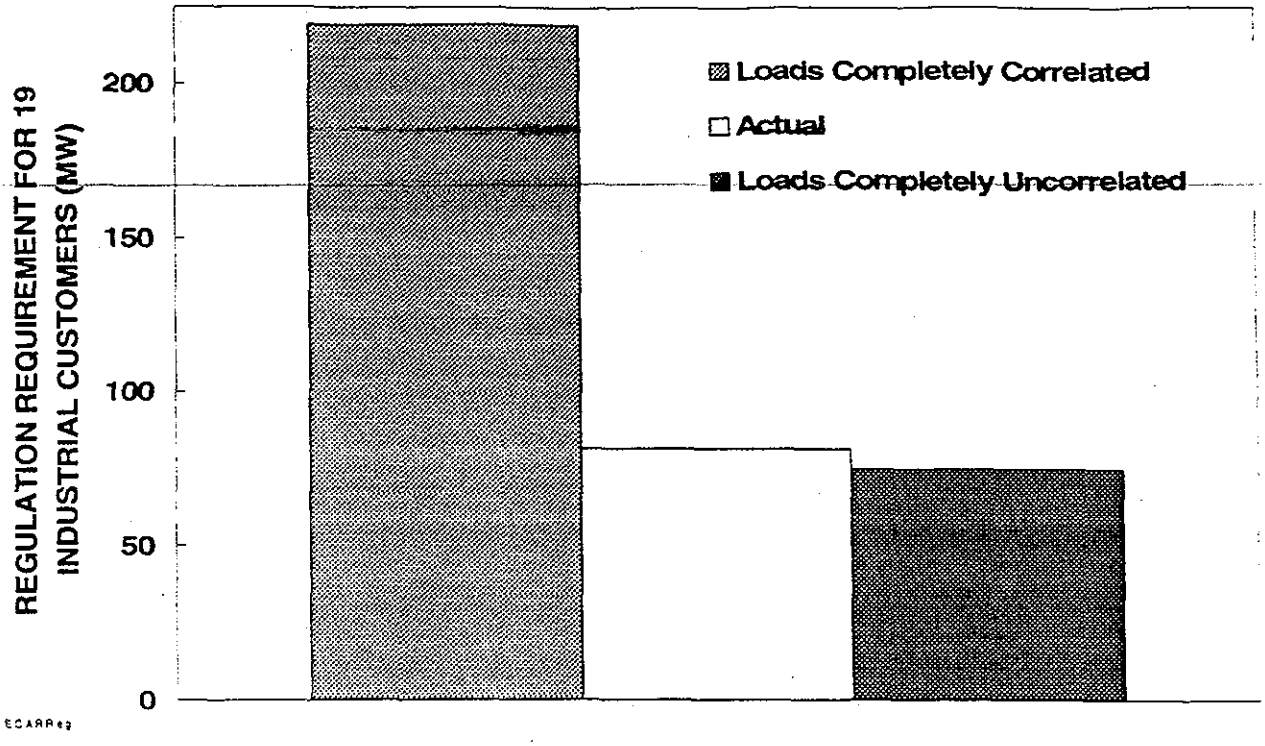


Fig. 9. **Regulation requirement for 19 customers, showing the relationships among the actual value and those requirements that would occur if the loads were completely uncorrelated or were perfectly correlated.**

regulation requirement of B, yielding a total requirement less than that of B alone; A should be paid for its contribution to reducing regulation.

Figure 11 illustrates schematically the method that we developed for such allocations; see the Appendix for details.* This method works for the two extreme situations discussed above, when loads are either completely uncorrelated or perfectly correlated. More important, this method yields reasonable results for the intermediate cases when loads are partially correlated with each other. Consider two loads A and B and the *Total*, with the regulation requirement of each based on the standard deviation of the short-term fluctuations. We propose a geometric approach to calculating the contribution of A to the *Total*, based on the projection of A onto the *Total* (shown as X in Fig. 11):

$$X = (Total^2 + A^2 - B^2)/(2 \times Total) . \qquad (5)$$

*Alternative methods can probably be applied to this problem, but they may not scale appropriately, may not handle loads that are neither completely uncorrelated nor completely correlated with each other, and may be sensitive to subaggregations. The final section of the Appendix describes an alternative approach that we tested but found unsatisfactory.

121

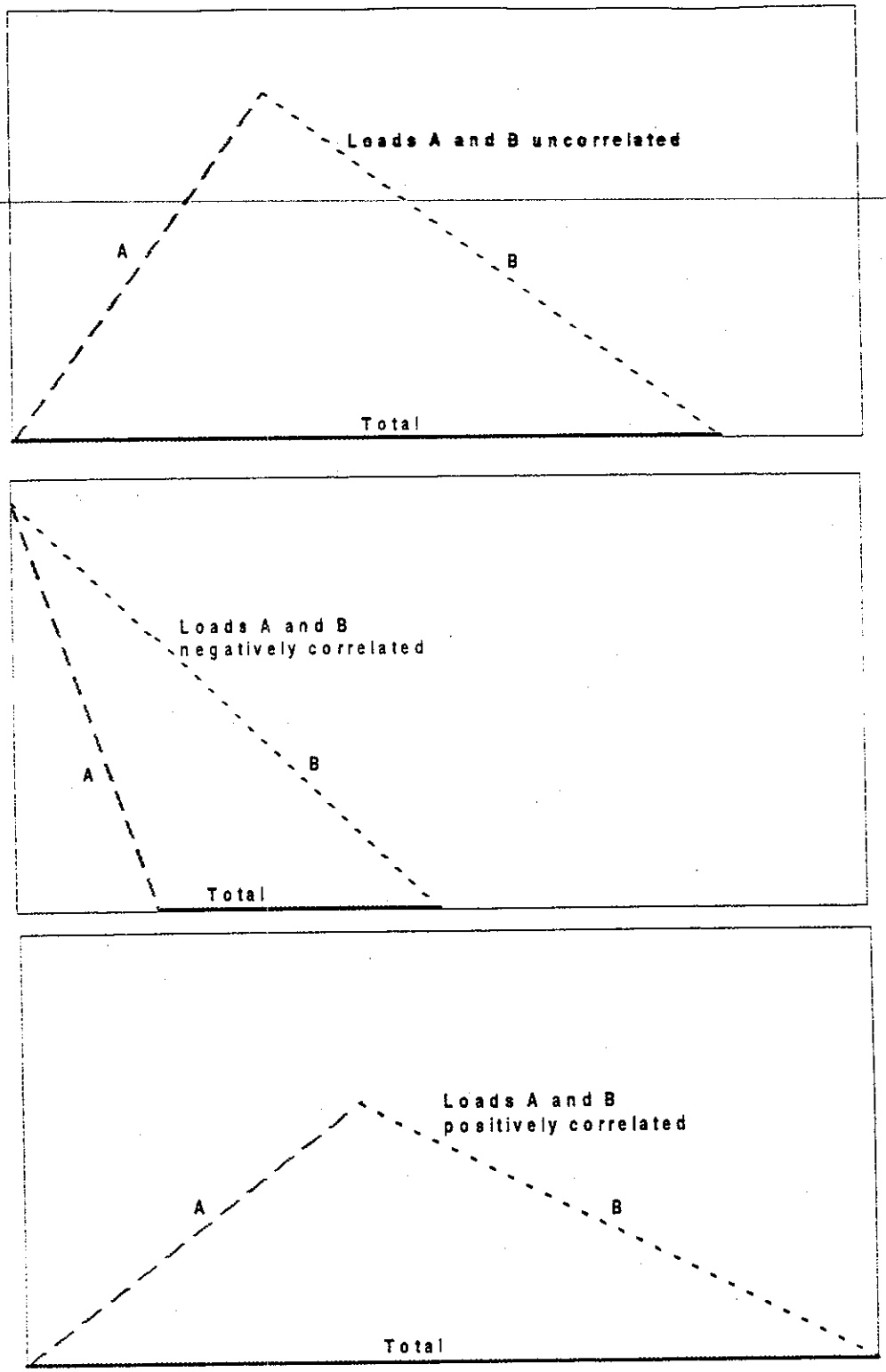


Fig. 10. The relationships between the standard deviations of two loads and the total regulation requirement, assuming the two loads are uncorrelated, negatively correlated, or positively correlated.

122

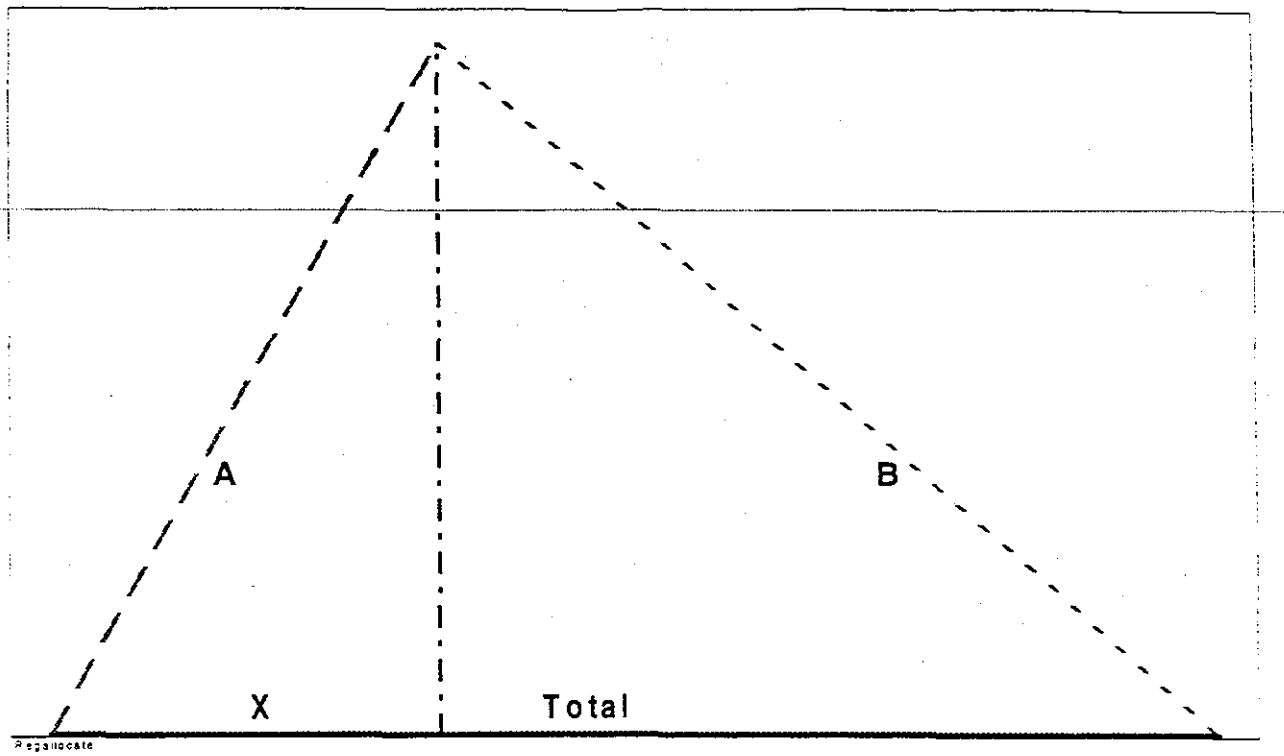


Fig. 11. Geometric allocation of individual loads *A* and *B* to regulation *Total*. *X* is *A*'s share of the total. *B*'s share, by subtraction, is *Total* − *X*.

The contribution of *B* to the *Total* is then equal to *Total* − *X* or

$$Total - X = (Total^2 + B^2 - A^2)/(2 \times Total) . \qquad (6)$$

This method can be extended to three or more loads through disaggregation of the total into various components. The only computational requirement is to calculate the standard deviation of each component and of each subtotal (total minus load *i*). Consider, as an example, a utility that wants to assign regulation charges separately for the residential class, the commercial class, five industrial customers, and the remainder of the industrial class, eight groups in all. The utility would calculate, for each hour, the standard deviation of eight subtotals (total − residential class, total − commercial class, and so on) as well as the standard deviations of each group of customers and the total, 17 values in all.

Table 3 illustrates numerically how the allocation process works with more than two loads. The table shows the standard deviations for four industrial loads and their total. The final column shows the method's allocation of the 26.3-MW regulation total to the four loads. If these four loads were completely uncorrelated, the total regulation requirement would be 30 MW, 14% higher than the actual. (The actual regulation requirement is lower than what would occur if the loads were uncorrelated because the loads are slightly negatively correlated with

123

each other.) If, on the other hand, the loads were completely and positively correlated, the total requirement would be 58 MW, 121% higher than the actual.

The method proposed here can accommodate a mix of individually metered loads and subaggregations, such as several large industrial loads that are metered separately and aggregations of thousands of residential and commercial customers. The subaggregations of the nonmetered residential and commercial loads will have the correct share of regulation assigned to them; any cost shifting will occur within the subaggregations and not between the subaggregations and the individually metered loads. This desirable property greatly reduces the need to meter any but the most nonconforming loads.

Table 3. Application of regulation-allocation method to four industrial loads

Load	Standard deviation (MW)	Standard deviation of total minus load (MW)	Regulation allocation (MW)
A	20.0	21.2	12.2
B	12.5	25.7	3.6
C	10.1	26.0	2.2
D	15.5	22.3	8.3
Total	26.3		26.3

RESULTS

During the 12 days studied, the hourly regulation standard deviation for the system as a whole ranged between 16 and 50 MW, with a mean of 31 MW (see Figs. 7 and 8). The nonindustrial and industrial standard deviations averaged 10 and 31 MW. (For comparison, the average nonindustrial load was 1280 MW, and the average industrial load was 670 MW, yielding a total system load of 1950 MW during these 12 days.)

The allocation method assigned the industrial customers 93% of the regulation total, almost triple their 34% share of system load. As shown in Fig. 12, there were several hours when the industrial customers were assigned more than 100% of the regulation requirement (reaching 132% one afternoon). During the hours that the industrial share exceeded 100%, the nonindustrial customers would have received a credit for regulation, offsetting their regulation costs during the other hours.

We applied the same method to allocate the industrial load among its components. Interestingly, two of the loads are negatively correlated with the others, yielding small negative regulation requirements.

124

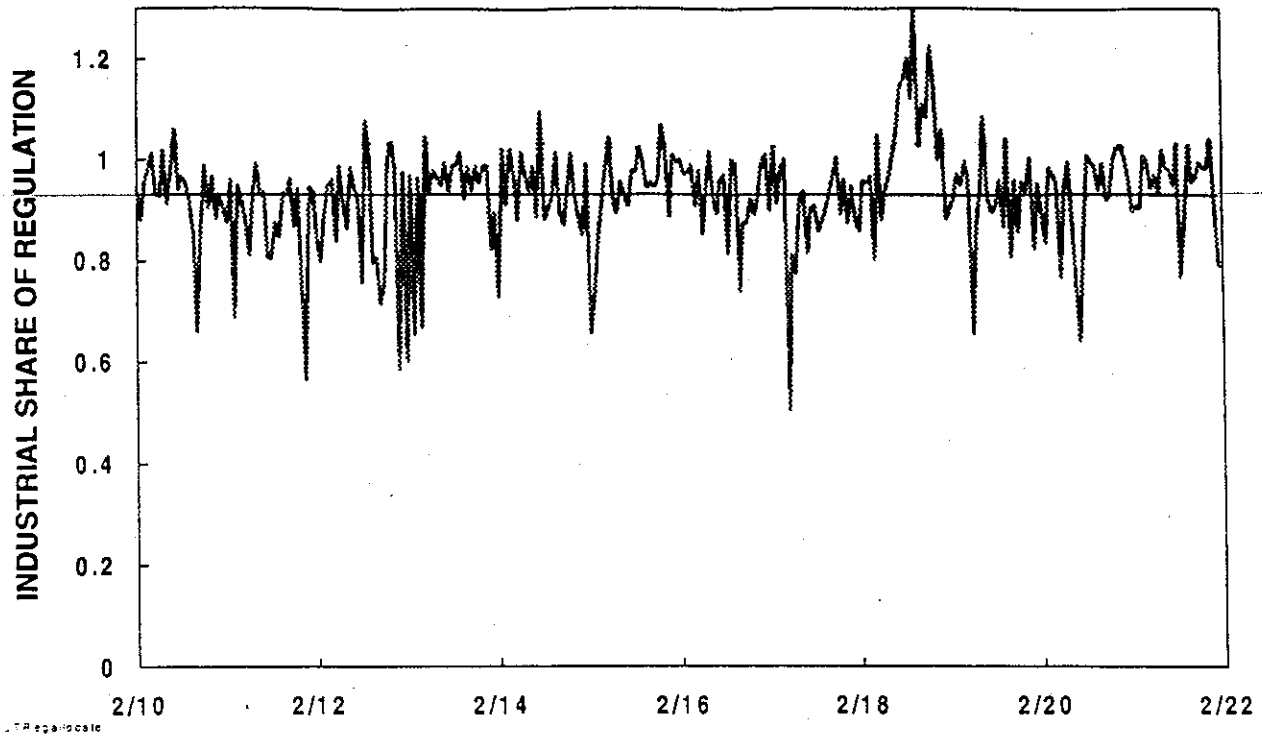


Fig. 12. The share of hourly system regulation requirement assigned to several large industrial customers, which averaged 93% over these 12 days.

125

LOAD FOLLOWING

SYSTEM-LEVEL METRICS

We examined two possible metrics for load following:

- Load-following magnitude (MW) measured as the difference between the maximum and minimum values of 30-minute rolling-average load during each hour and
- Load-following rate (MW/minute) measured as the ratio of the first metric divided by the number of minutes between the highest and lowest load values.

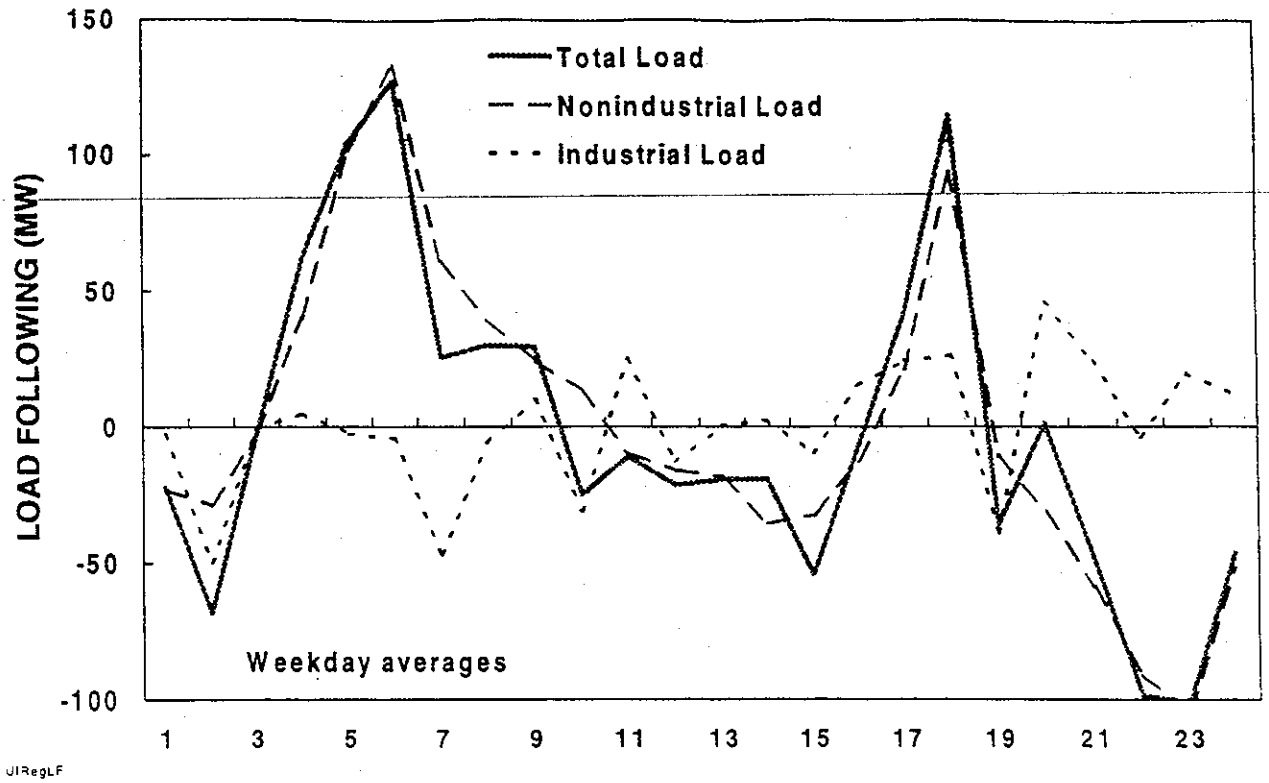
Unlike regulation, load following is a signed quantity, positive if it is rising during the hour and negative if it is falling. Table 4 summarizes the average, maximum, and minimum values of these two load-following metrics for total system load. Figure 13 shows the hour-to-hour pattern in load following for weekdays and weekends. Unlike regulation, there is a clear diurnal pattern, reflecting the morning and early-evening peaks and the late-evening dropoff shown in Fig. 2. The nonindustrial loads track this diurnal pattern closely, while the industrial load is much more erratic in its load following. Figure 14 shows the variations in average load-following requirement from day to day. Overall, load following is 3.3% of total load.

Table 4. Absolute values of load-following metrics for system load for 12 days in February 1999 (288 hourly observations)

	Magnitude (MW)	Ramp rate (MW/minute)
Average	64	1.7
Maximum	181	6.3
Minimum	11	0.2

The load-following magnitude and ramprate metrics are highly correlated. The correlation coefficients between the magnitude and ramp rate are above 0.95 for total load, nonindustrial load, and industrial load (Fig. 15). These high correlation coefficients suggest that load-following requirements are adequately captured by only one factor. Physically, the high correlation coefficients mean that the load-following ramping requirements are greatest during the morning and early-evening pickups and late-evening dropoff.

126



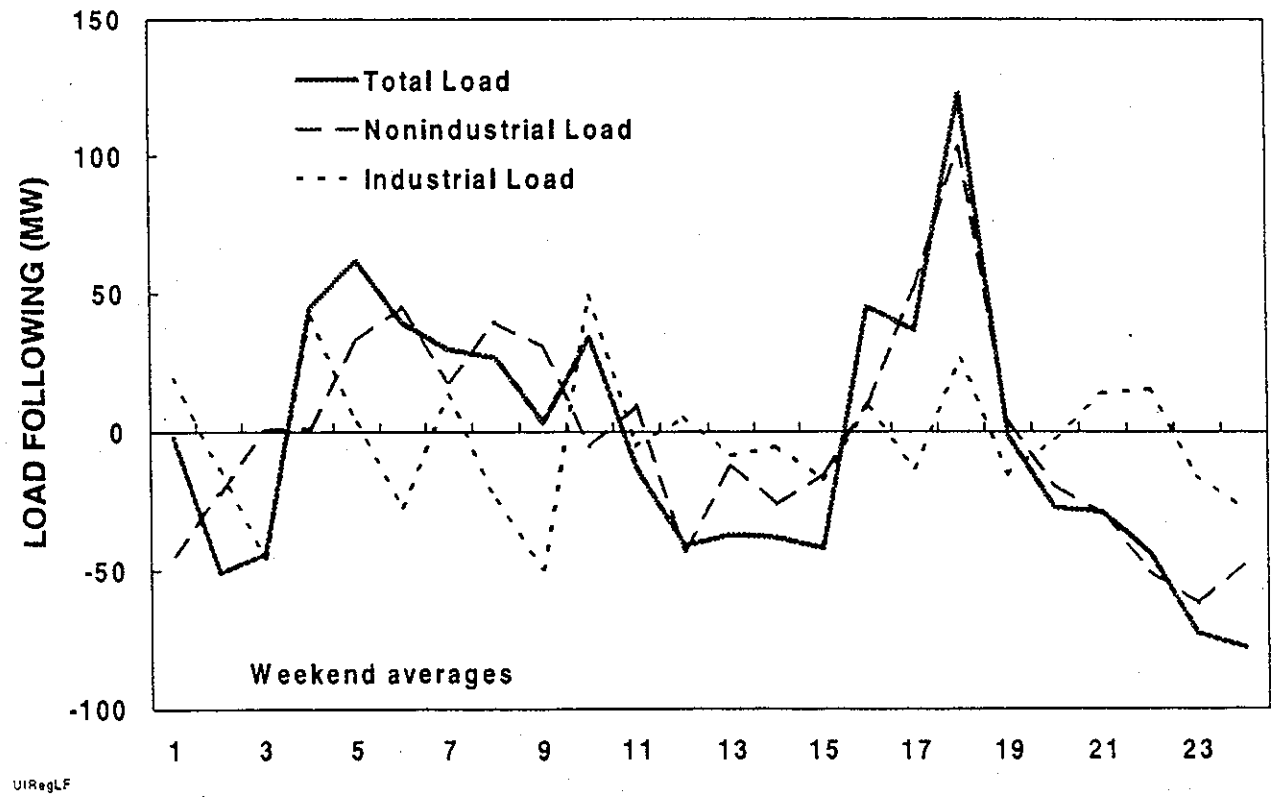


Fig. 13. Average hourly load-following requirement for weekdays (top) and weekends (bottom).

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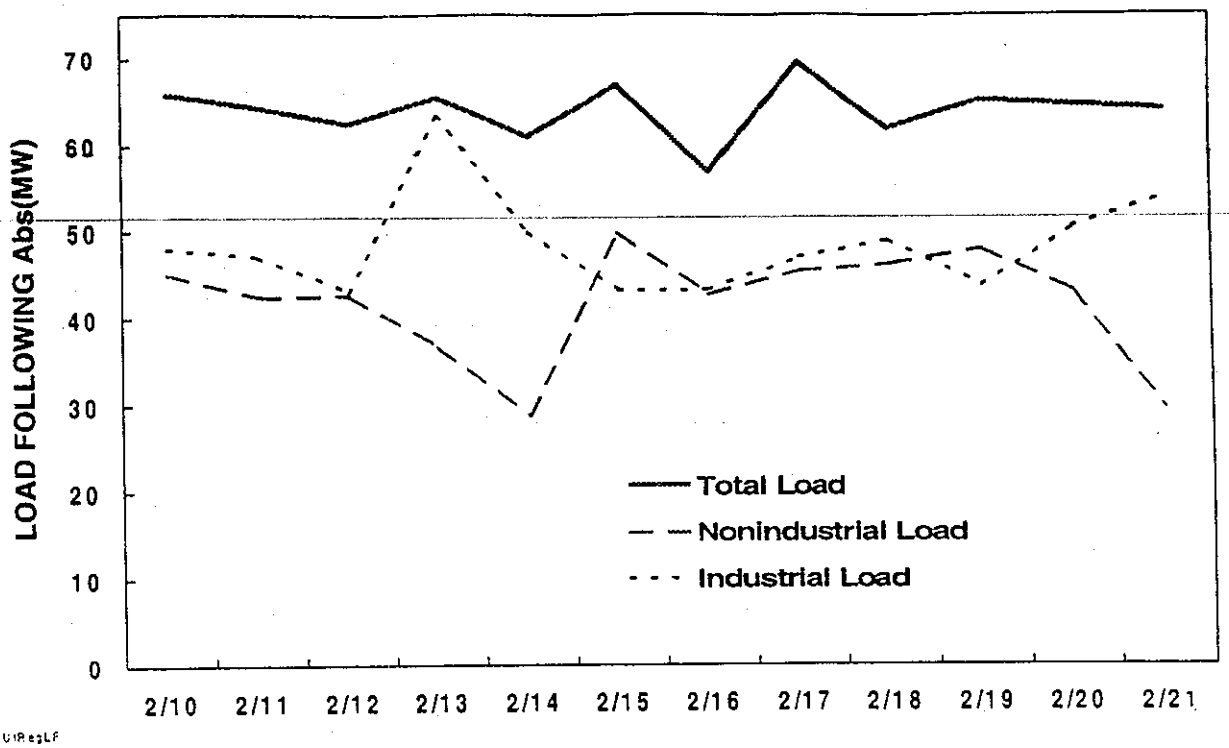

Fig. 14. Average daily load-following requirement.

As with regulation, the correlation coefficients between load and load-following magnitude are very small, suggesting that load itself is a poor predictor of load-following requirements.

CUSTOMER-SPECIFIC METRICS

We calculate each customer's share of load following (or that of each group of customers) as the ratio of the customer's *coincident* load-following amount to the total load-following amount:

$$\text{Share}_i = (\text{Load}_{i,\,Tmax} - \text{Load}_{i,\,Tmin})/(\text{Load}_{Tmax} - \text{Load}_{Tmin}) ,$$

where i refers to a customer or group of customers, T_{max} is the time within the hour that the system reaches its maximum load, and T_{min} is the time within the hour that the system reaches its minimum load. Note that T_{max} and T_{min} refer to the times of the maximum and minimum *system* loads, not those for the individual components.

Figure 16 illustrates how this method works. The graph shows the rolling averages for one hour for a hypothetical system, with residential, commercial, and industrial loads. The residential load in this example increases monotonically throughout the hour, from its minimum

128

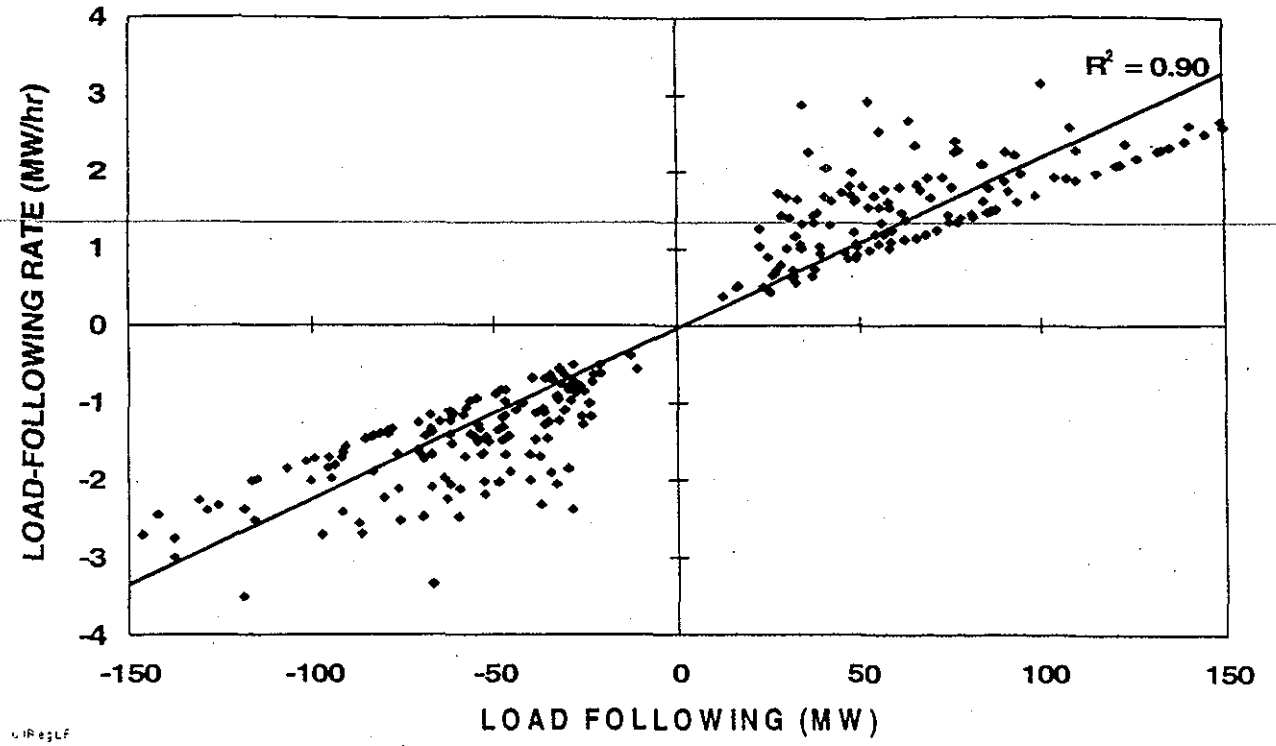

Fig. 15. Load-following ramprate as a function of load-following magnitude for total load.

value of 120 MW at 0:00 to its maximum value of 203 MW at 1:00. The commercial load also increases during the hour, from 310 MW at 0:00 to 402 MW at 0:46, followed by a slight decline to 399 MW at 1:00. The industrial load, unlike the residential and commercial loads, decreases during the hour, from 250 MW at 0:00 to 220 MW at 1:00. The sum of these changes yields the system load, which increases from 680 MW at 0:00 to 821 MW at 1:00; this difference implies a total load-following requirement of 141 MW with a ramp rate of 2.35 MW/minute [= (821 - 680)/60].

A simple sum of the load-following requirements for each component alone yields a total of 205 MW (= 83 + 92 + 30), far higher than the 141 MW actual. This discrepancy is a function of the signs of the different components as well as the noncoincidence of these changes with the movement of the system as a whole. Allocating the total load-following burden on the basis of the noncoincident movements of each component would unfairly penalize loads that are noncoincident. Even worse, such an allocation scheme would charge customers for load following even if their load moved counter to the system load (as the industrial load does in this example).

In this example, allocating the total load-following requirement according to coincident loads assigns 59% of the total to the residential class and 63% to the commercial class and gives a 21% credit to the industrial class. Allocating the requirement on the basis of

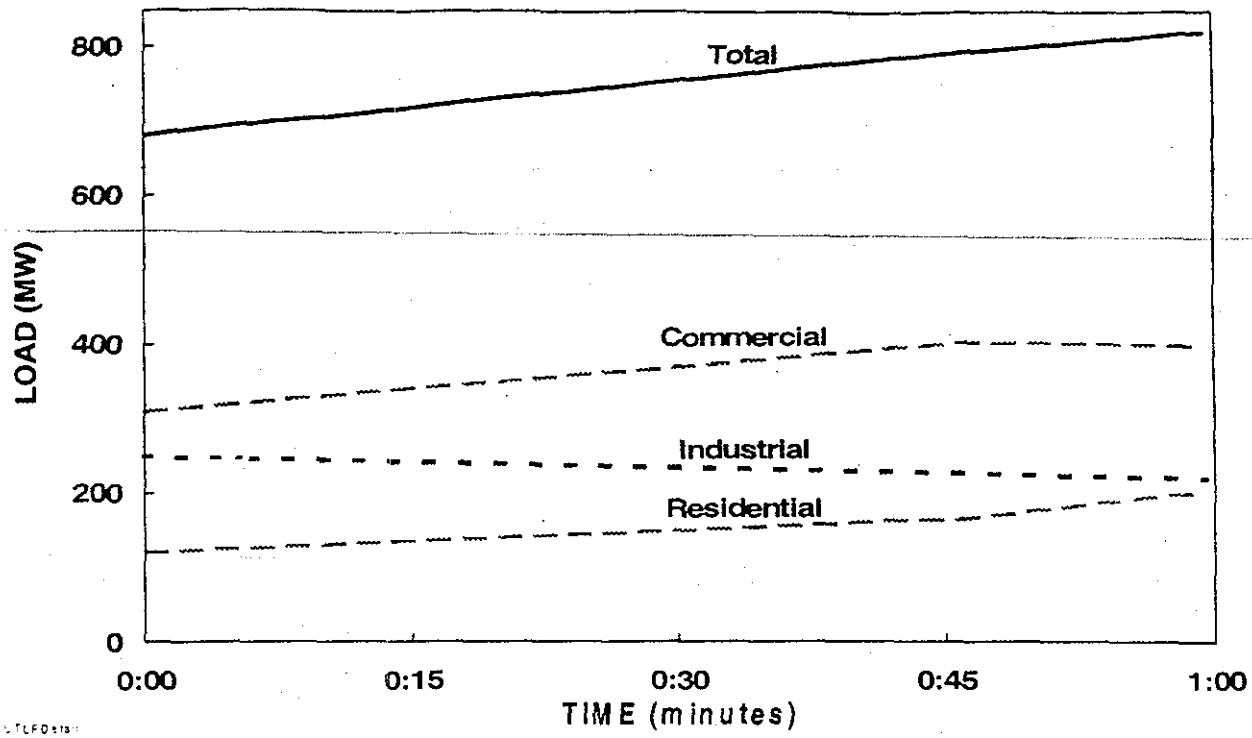

Fig. 16. **Hypothetical system load and its components for one hour. Although the system load-following requirement is 141 MW, the sum of the components is 205 MW, primarily because the industrial load decreases during the hour while the residential and commercial loads increase.**

noncoincident loads would charge the industrial customers for 15% of the total even though their loads were moving counter to the system load during this hour.

RESULTS

The top part of Fig. 17 shows load-following requirements for one of the 12 days studied in this project. The dramatic hour-to-hour variations are quite different from the pattern we had expected to see. The data show large positive load-following requirements at 4 and 5 a.m. and again at 5 p.m., with smaller peaks at 6, 8, 10 a.m., and noon. The data also show large negative values at 7 and 11 a.m. as well as at 1, 3, and 10 p.m.

We had anticipated an early-morning peak, an early-evening peak, and a late-evening dropoff (Figs. 2 and 13). The hourly averages across all the days show just such a pattern (bottom of Fig. 17). Averaged across all 12 days, load-following requirements peak at 4 and 5 a.m. and again at 5 p.m. Requirements then drop sharply at 9 and 10 p.m.

The averaged data show that the nonindustrial load contributes most to the total load-following requirement during the morning and early-evening ramp up and again during the late-evening ramp down. However, during the other hours of the day, the industrial load dominates. Whereas the nonindustrial load-following pattern is consistent from day to day, the industrial

130

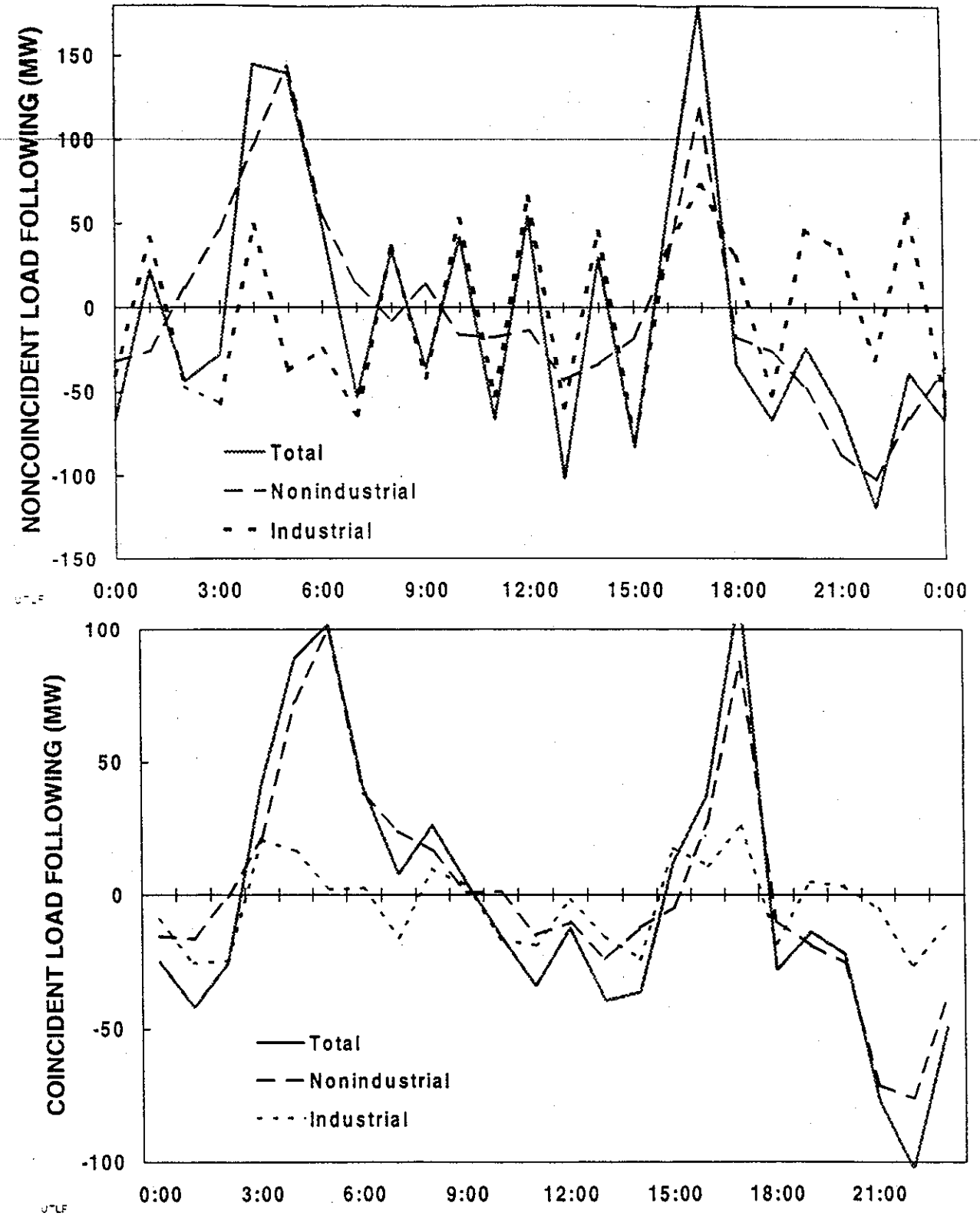

Fig. 17. Load-following requirement for one weekday (top) and averaged over 12 days in February 1999 (bottom).

131

pattern is not. Indeed, the top part of Fig. 17 shows the industrial load-following requirement changing substantially from hour to hour, often swinging from positive to negative and back again. The nonindustrial load, on the other hand, shows the expected winter diurnal pattern.

Figure 18 shows the absolute value of system load following and the coincident contributions from the two components. It shows clearly the importance of the industrial load during the hours of mild load-following changes. In particular, during hours 0 through 4, 7 through 17, 19, 20, and 24, the industrial load accounts for more of the total load-following requirement than does the nonindustrial load. Unlike the nonindustrial load, the industrial load's load-following pattern is not predictable from day to day. (When averaged over several days, the industrial load-following requirement appears to be much smaller than it actually is.)

Because of the patterns shown in Figs. 17 and 18, the industrial loads account for much more of the load-following requirement than we had anticipated: 58%, far above their 34% share of total load (Fig. 19). Because the *cost* of load following is likely to vary from hour to hour and be more expensive during peak-demand periods, the industrial share of load-following costs is likely to be lower than 56%. Correspondingly, the nonindustrial shares of load following and energy are 42% and 66%. Given this substantial difference between shares of load and load following, customer-specific assignment of load following is probably warranted for these large industrial customers.

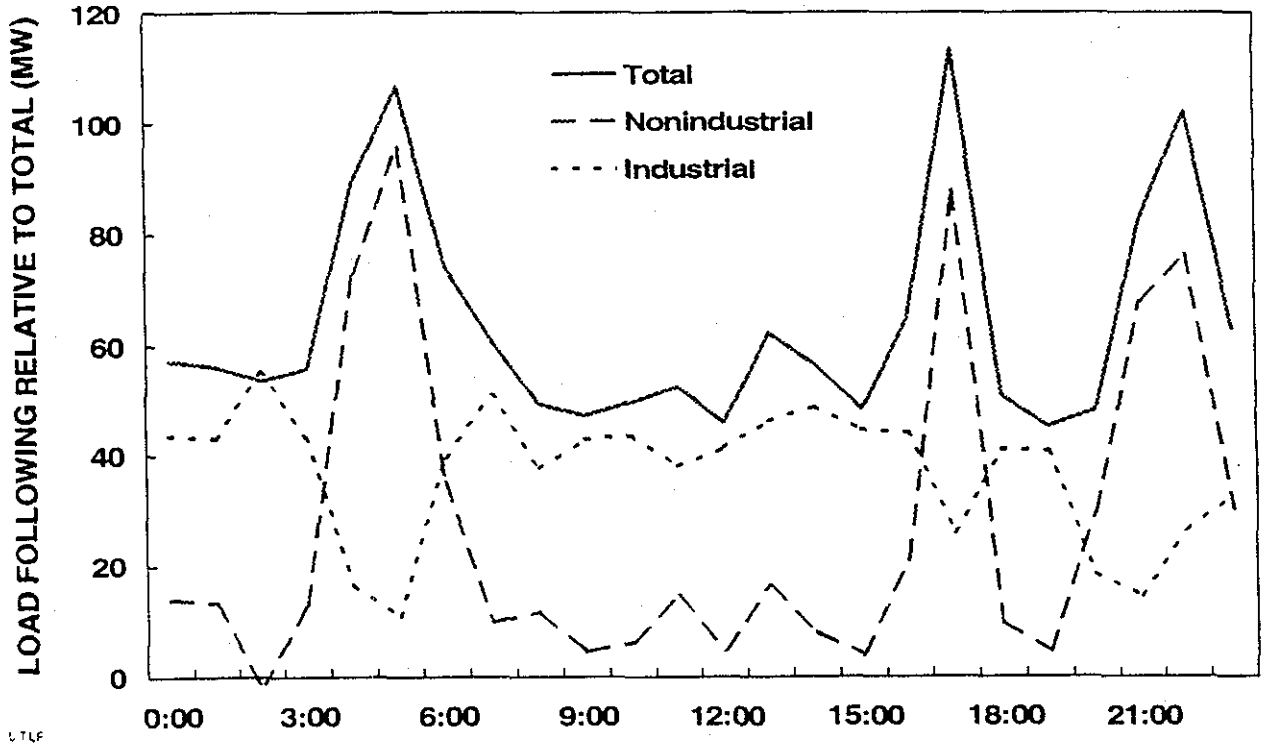

Fig. 18. **System load-following magnitude by hour for 12 days in February 1999 and the contribution to these totals by nonindustrial and industrial customers.**

132

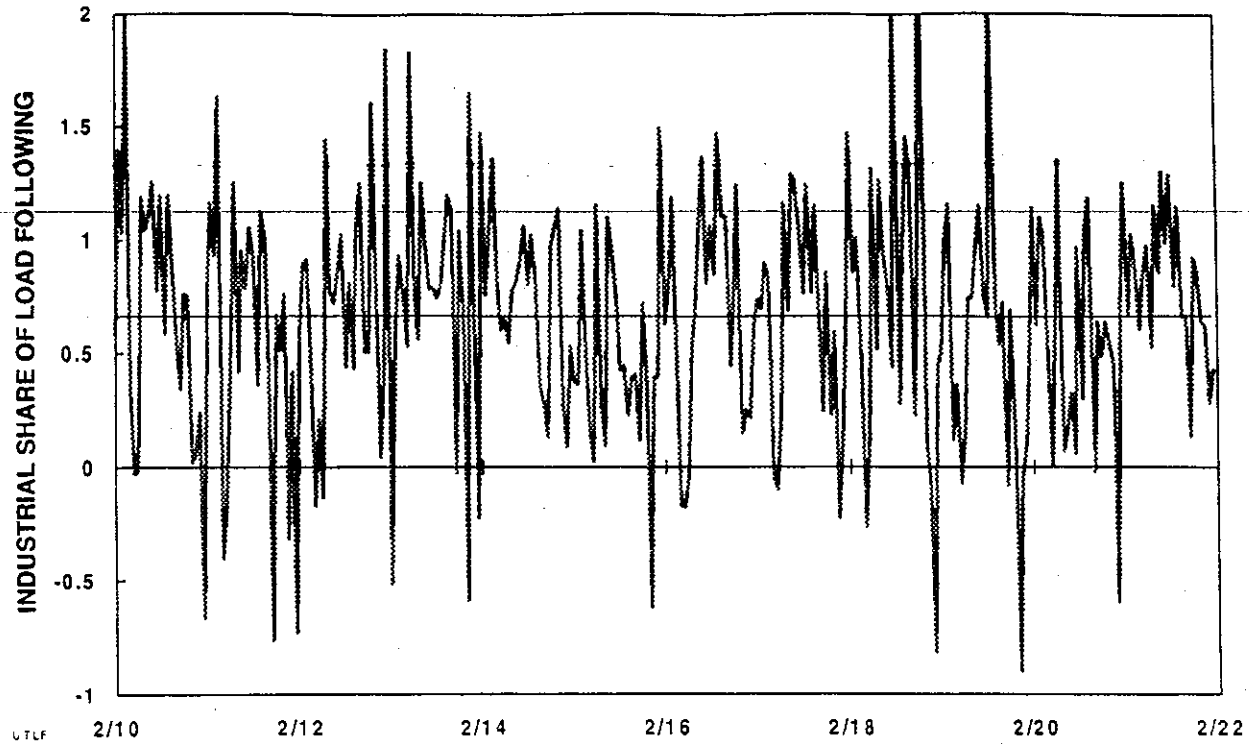

Fig. 19. **The share of hourly load-following requirement assigned to several large industrial customers for 12 days in February 1999, which averaged 58% over these 12 days.**

The share of load following assigned to these industrial customers varies substantially from hour to hour, as shown in Fig. 19. The industrial share exceeds 100% for 26% of the hours and is less than zero for 10% of the hours.

We also examined the individual industrial loads and their relationship to the total industrial load. Here, too, the shares of load-following requirement vary considerably, both in absolute terms and relative to the energy shares. For example, one customer accounted for 22% of the industrial energy use but 40% of the industrial load-following requirement. On the other hand, another accounted for 33% of the energy share but none of the load-following requirement.

CONCLUSIONS

Utilities typically have several large industrial customers with unusual time signatures (called nonconforming loads). Because these loads may contribute disproportionately to a company's load-following and regulation requirements, we developed and applied methods to quantify system-level and customer-specific requirements for these two ancillary services.

Regulation and load following (along with, perhaps, energy imbalance) are the real-power ancillary services that a control area uses to maintain the necessary real-time balance between generation and load. The NERC Control Performance Standards 1 and 2, both measures of area control error, determine whether the amounts and use of the generation resources devoted to regulation and load following are adequate. Because this control-area operator's CPS performance meets NERC criteria, this project focused on the allocation of existing requirements rather than on a determination of the appropriate amounts of each service to provide.

Electricity consumption varies with time. If the consumption data are examined at the 4-second level, they will show considerable random movement. If, on the other hand, they are examined at the hourly level, they will show only smooth and consistent day-to-day patterns. The data themselves do not determine how best to disaggregate the total into the energy, load-following, and regulation components. This disaggregation requires judgment as well as analysis of the control area's mix of generation and loads. Because this control-area operator's generation follows load at only the 2- to 4-minute level, we aggregated the 30-second data to 2-minute averages. We used a 30-minute rolling average to characterize load following; regulation is then the difference between actual load and the rolling average. A longer rolling-average period would shift some load following from industrial to nonindustrial customers and would shift some industrial load following to industrial regulation.

We defined and applied two metrics for regulation and two for load following:

- Standard deviation (MW) of the thirty 2-minute values in each hour;
- Average regulation rate (MW/minute), calculated as one-half the average of the absolute values of the 29 differences between adjacent regulation values;
- Load-following magnitude (MW), equal to the difference between the maximum and minimum values of 30-minute rolling-average load during each hour; and

- Load-following rate (MW/minute), equal to the ratio of the load-following-magnitude metric divided by the number of minutes between these two (highest and lowest) load values.

The amount of generating capacity provided for regulation is a multiple of the regulation standard deviation to ensure sufficient probability of meeting these temporal variations in load. Multiplying the standard deviation by two provides 95% coverage, and multiplying by three provides 99% coverage.

The two load-following metrics (magnitude and ramprate) are very highly correlated; as a consequence, we think it is sufficient to consider only the magnitude metric for this service. The two regulation metrics are also positively correlated, but not to the extent that occurs for load following; therefore, it may be useful to consider both regulation metrics.

We also developed and applied methods to allocate these system-level metrics to individual customers and to groups of customers. The regulation allocation method uses a trigonometric relationship to determine the amount of each customer's regulation requirement that is correlated with the total requirement. The load-following allocation method calculates each customer's share of the total requirement on the basis of its coincident load-following requirement.

Table 5 summarizes results on system and customer-specific assignments. Although the industrial customers as a group account for 34% of the total energy, they account for 93% of the regulation requirement and 58% of the load-following requirement. Within this group of large customers, the allocations are also disproportionate. For example, one customer accounts for 8% of total energy but 38% and 22% of regulation and load following, respectively. On the other hand, another customer accounts for much smaller shares of regulation and load following than of energy.

Current U.S. utility practice (i.e., the tariffs filed with FERC as required by Order 888) typically charges customers for these ancillary services on the basis of average load (i.e., energy). Assume, for purposes of an example, that the hourly costs of regulation and load following are $10/MW and $5/MW, respectively, and that the amounts of generating capacity to provide these services average 93 MW (three times the 31 MW in Table 5) and 64 MW, respectively. Given these assumptions, the average cost to provide these two services would be $1220/hour over this 12-day period. The traditional method of assigning customer-specific charges for these services would bill nonindustrial customers $800/hour and industrial customers $420/hour. Using the allocation methods developed here, $600/hour would be shifted from the nonindustrial bill (a 75% cut) to the industrial bill (a 140% increase) for these two ancillary services. Similar shifts would occur among the individual industrial customers.

Table 5. Characteristics of total load and its components for 12 days in February 1999

	Energy		Regulation		Load following	
	(MW)	Share (%)	(MW)	Share (%)	(MW)	Share (%)
Total load	1954	—	31.2	—	63.9	—
Nonindustrial load	1284	65.7	2.2	7.2	27.0	42.3
Industrial load	670	34.3	29.0	92.8	36.9	57.7
1	264	13.5	16.4	52.6	20.9	32.7
2	33	1.7	2.8	9.0	4.2	6.6
3	77	3.9	6.4	20.5	5.9	9.2
4	10	0.5	0.5	1.7	0.4	0.6
5	10	0.5	2.9	9.2	5.4	8.5
6	275	14.1	-0.1	-0.2	0.0	0.0

The kinds of subsidies identified here among customers and customer classes likely exist for other electricity products, including installed-capacity requirements. For installed capacity, industrial customers (with high load factors) are probably subsidizing other customers with lower load factors.

The results presented here are consistent with anecdotal evidence from other control areas. The regulation requirements for one utility are 50% higher when a single metal-fabrication customer operates than when that customer is offline. Another utility has two steel mills that account for 3% of total load, but over 50% of regulation and load-following requirements. A steel mill in a third utility's service area accounts for 1% of load and 22% of regulation requirements; a paper mill in the same service area accounts for 5% of load but only 1% of regulation. Finally, these results for February 1999 are very similar to those obtained with analysis of late-summer 1999 data from the same control area.

ACKNOWLEDGMENTS

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REGULATION VECTOR-ALLOCATION METHOD

We can think of regulation as a vector and not just a magnitude. For example, start with load *A*. It might be a single house or an entire control area with a regulation burden of 8. Consider another load *B* with a regulation burden of 6 that we want to combine with *A*. If loads *A* and *B* are perfectly correlated positively, they add linearly, as shown in the top of Fig. 20. If the two loads are perfectly correlated negatively, their regulation burdens would add as shown in the middle of Fig. 20. Typically, loads are completely uncorrelated and the regulation requirement for the total is the square root of the sum of the squares, or 10 in this case (bottom of Fig. 20).

Multiple uncorrelated loads are always at 90 degrees to every other load. They are also at 90 degrees to the sum of all the other loads. This characteristic requires adding another dimension each time another load is added, which is difficult to visualize beyond three loads. Fortunately, the math is not any more complex. The fact that each new uncorrelated load is at 90 degrees to every other load and to the total of all the other loads is quite useful. The analysis of any number of multiple loads can always be broken down into a two-element problem, the single load and the rest of the system.

Return to the two-load example but consider the more general case where loads *A* and *B* are neither perfectly correlated nor perfectly uncorrelated. We may know the magnitude of *A* and the magnitude of *B*, but we do not know the magnitude of the total without measuring it directly (i.e., we do not know the *direction* of each vector). We can, however, measure the total regulation requirement and use this vector method to *allocate* the total requirement among the individual contributors.

We know the total regulation requirement because we meter it directly as the aggregated regulation requirement of the control area. We can know the regulation requirement of any load by metering it also. We can know the regulation requirement of the entire system less the single load we are interested in by calculating the difference between the system load and the single load at every time step, separating regulation from load following, and taking the standard deviation of the difference signal. Knowing the magnitudes of the three regulation requirements, we can draw a vector diagram showing how they relate to each other (Fig. 21).

How much of the total regulation requirement is the responsibility of load *A*? We can calculate the amount of A that is aligned with the total and the amount of *B* that is aligned with the total. We can do this geometrically (as shown below) or with a correlation analysis.

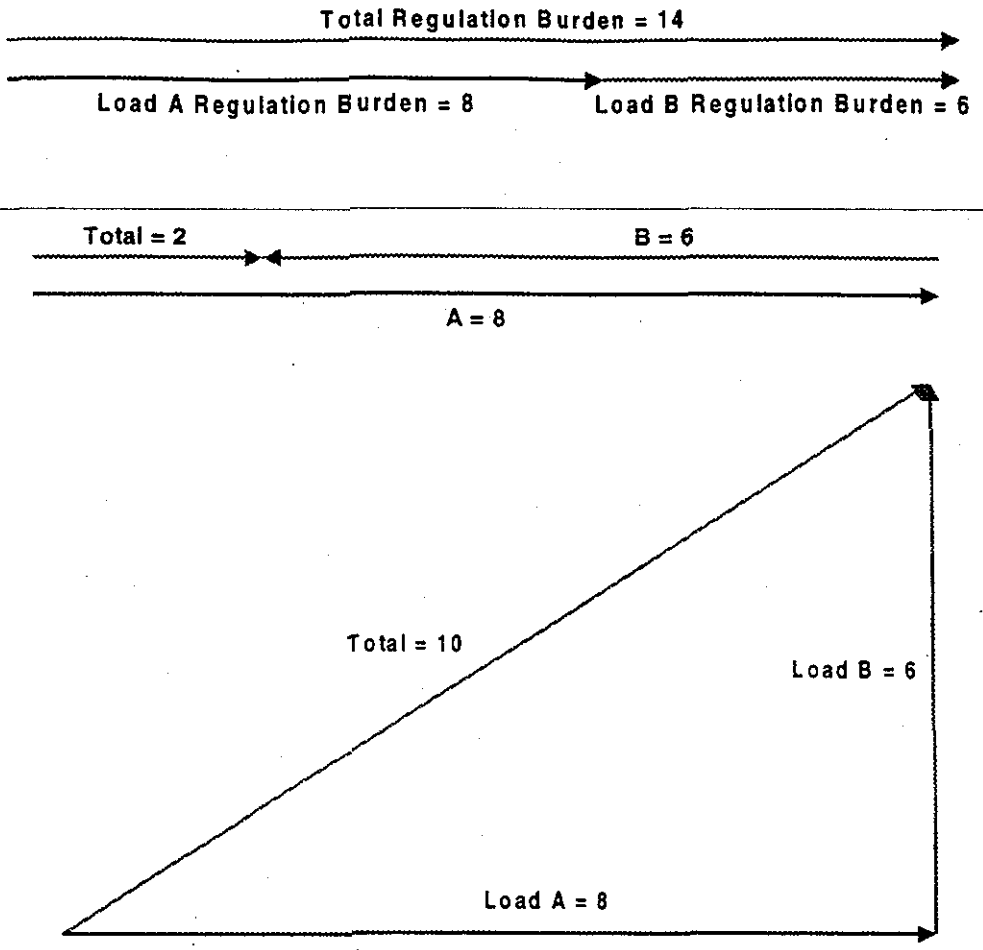

Fig. 20. The relationships among the regulation components (*A* and *B*) and the total if *A* and *B* are positively correlated (top), negatively correlated (middle), or uncorrelated (bottom).

Y is perpendicular to the total regulation *T* (uncorrelated). *X* is aligned with *T* (correlated). *A*'s contribution to *T* is *X*. Knowing *A*, *B*, and *T*, we can calculate *X*. (We could also calculate *Y*, but there is no need to do so.) We can write two equations relating the lengths of the various elements:

$$A^2 = X^2 + Y^2 \tag{A-1}$$

$$B^2 = (T - X)^2 + Y^2 \ . \tag{A-2}$$

Subtract Eq. A-2 from Eq. A-1 to get

$$A^2 - B^2 = X^2 - (T - X)^2 + Y^2 - Y^2 \ ;$$

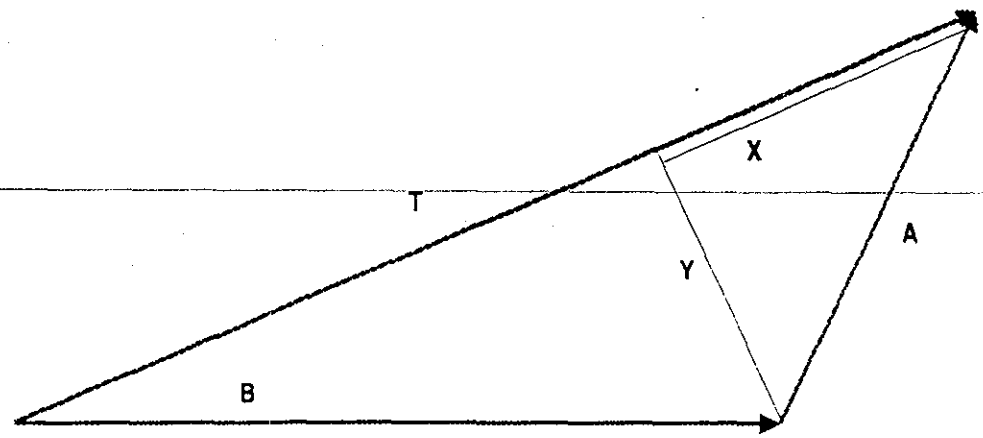

Fig. 21. The relationship among the regulation burdens of loads *A* and *B* and the total (*T*) when *A* and *B* are neither perfectly correlated nor perfectly uncorrelated.

$$A^2 - B^2 = X^2 - (T^2 - T \times X - T \times X + X^2) = -T^2 + 2T \times X .$$

Solving for X (load A's contribution to the total T) yields

$$X = (A^2 - B^2 + T^2)/2T . \qquad \text{(A-3)}$$

Recall that we can decompose a collection of any number of loads into a two-load problem consisting of the load we are interested in and the rest of the system without that load (Fig. 22). We can solve Eq. A-3 for as many individual loads as we wish. Variable T remains the total regulation requirement, variable A becomes each individual load's regulation requirement, and variable B becomes the regulation requirement of the total system *less* the specific load of interest.

This allocation method works well with any combination of individually metered loads and load profiling for the remaining loads. The load profiling can be as simple as making the usual assumption that the other loads' regulation requirements are proportional to their energy requirements. Or measurements of a sample set can be taken to determine the magnitude of their regulation burdens. This vector-allocation method is used to determine the regulation burden of each of the metered loads. The residual regulation burden is then allocated among the remaining loads, assuming they are perfectly uncorrelated.

ALTERNATIVE APPROACH

We initially tested an alternative approach. That approach calculated the *incremental* regulation requirement for each load by calculating the system regulation requirement without that load and then defining the allocation for the individual load as the difference between the total regulation requirement and the regulation requirement without that single load.

140

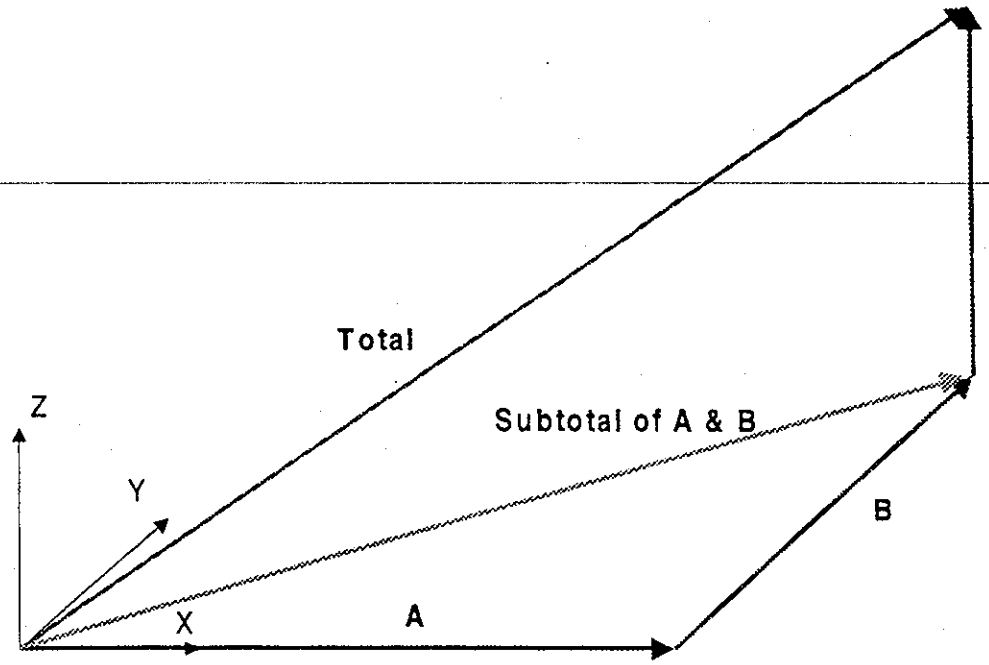

Fig. 22. Application of vector-allocation method to the case with more than two loads.

$$\sigma_{Incremental-j} = \sqrt{\sum \sigma^2} - \sqrt{\sum \sigma^2 - \sigma_j^{\,2}}$$

$$\sigma_{Incremental-j} \,/\, \sum \sigma_{Incremental} = \frac{\sqrt{\sum \sigma^2} - \sqrt{\sum \sigma^2 - \sigma_j^{\,2}}}{\sum_k \left[\sqrt{\sum \sigma^2} - \sqrt{\sum \sigma^2 - \sigma_k^{\,2}}\right]}$$

This method works well in many cases. However, when a load *reduces* the overall regulation requirement, this method blows up. Consider an example in which load *A* has a regulation requirement of 40, load *B* has a requirement of 22, and the total is 30. The incremental burden for *A* is +10, and for *B* it is −8. The total incremental burden is +2, which means that *A* is charged for 150 (= 30 × 10/2) and *B* receives a credit for 120 (= 30 × −8/2). These results are unappealing because they are so sensitive to small changes in the incremental contributions of any single load. In this case, load *A* would get charged for 150 MW, even though its total was only 40 MW, a completely unrealistic result. (Even if loads are 100% correlated, no load should get charged for more regulation than it would require if it was the only load in the control area.) The method developed in the body of the report, and which we recommend, assigns a regulation requirement of 33.6 to *A* and -3.6 to *B*, yielding results that are much more reasonable.

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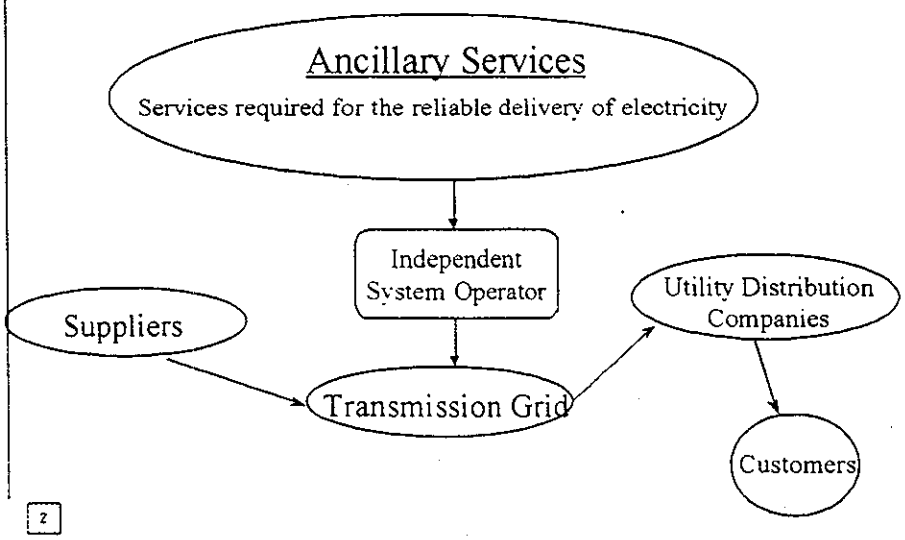
141

Ancillary Services
Definition and Scope

FORUM on Ancillary Services
Feb 22-24, 2000
Warsaw, Poland

Harry Singh

Role of Ancillary Services



2

Ancillary Services Evolution

- FERC Order 888 (1996)
- Development of Independent System Operators ISOs
- FERC Order 2000 (Dec, 1999)

3

Ancillary Services (FERC Order 888)

- Scheduling, Control and Dispatch
- Reactive Supply and Voltage Control from Generation Sources
- Regulation and Frequency Response
- Energy Imbalance
- Operating Reserve (Spinning)
- Operating Reserve (Supplemental)

4

Order 888

- Energy Imbalance
  - Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour.
- Regulation and Frequency Response
  - Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered(predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load.

5

Order 888

- Operating Reserve (Spinning)
  - Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output
- Operating Reserve (Supplemental)
  - Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load.

6

FERC Order 2000/ RTO NOPR

- RTO (Regional Transmission Organization) must serve as provider of last resort for all Ancillary Services as defined in Order 888 and subsequent orders
- RTO can fulfill its obligations through contracts, direct or indirect control of generation and market mechanisms
- Market participants must have the option of self-providing Ancillary Services
- RTO must have authority to establish minimum levels of Ancillary Services and locations. The RTO should consider stakeholder input as well as established industry standards in determining these requirements.
- All generators or other facilities that provide ancillary services must be subject to direct or indirect operational control by the RTO
- The RTO must promote the development of competitive markets for ancillary services whenever feasible

7

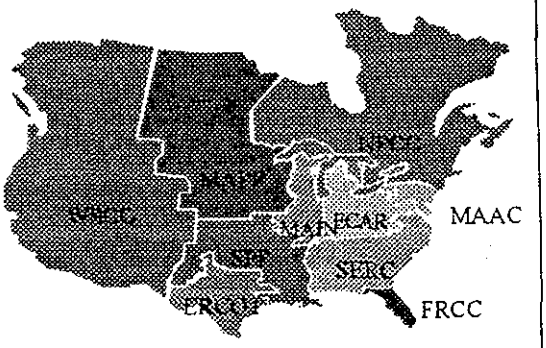
FERC Order 2000

- An RTO must ensure that its transmission customers have access to a real-time balancing market that is developed and operated by either the RTO itself or another entity that is not affiliated with any market participant.
- For the purpose of determining cost responsibility for imbalances, no distinction needs to be made between generators and loads. .For purposes of assessing penalties for inaccurate schedules, we conclude that a penalty mechanism that treats loads and generators differently may be appropriate.

8

NERC Regions

	July 1998 MW	Percent
ECAR	90,330	14.73%
ERCOT	**46,268**	**7.55%**
FRCC (Florida)	**32,440**	**5.29%**
MAAC	**46,524**	**7.59%**
MAIN	**44,991**	**7.34%**
MAPP	**27,895**	**4.55%**
NPCC	**51,000**	**8.32%**
NY	28,900	4.71%
ISO-NE	22,100	3.60%
SERC	**134,561**	**21.94%**
Entergy	21,972	3.58%
Southern	37,440	6.11%
TVA	25,155	4.10%
VACAR	49,994	8.15%
SPP	**35,592**	**5.80%**
WSCC	**103,614**	**16.90%**
NWPP	32,472	5.30%
Rocky Mtn	7594	1.24%
AZ, NM, Southern NV	18,967	3.09%
California	44,581	7.27%
	613,215	100.00%



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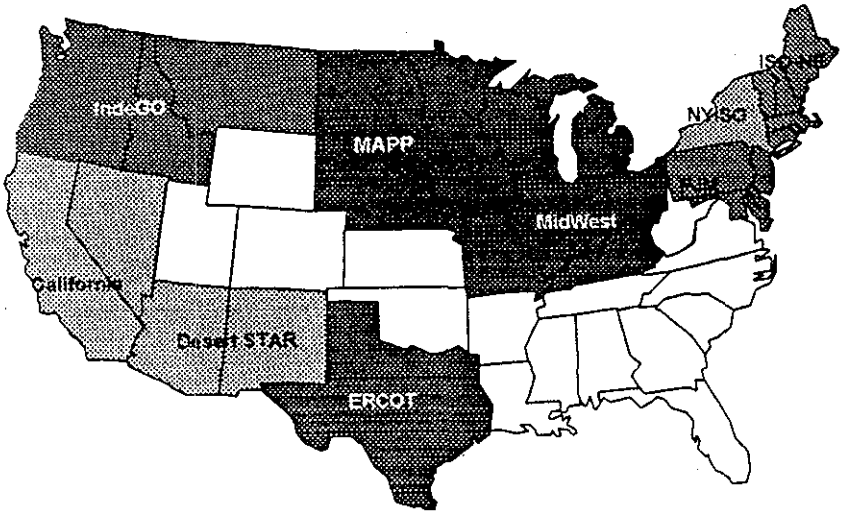
ISO Initiatives in the United States



10

California ISO Ancillary Services

- AGC/Regulation (Reg-up and Reg-down are separate services)
- Spinning Reserve (SR)
- Non-Spinning Reserve (NS)
- Replacement Reserve (RR)
- Voltage and Reactive Power (VAR) Support
- Black Start

11

Definition of Reserves

- Operating Reserve (Capacity that can be delivered as Energy within 10 minutes)
  - AGC/Regulation
  - Contingency Reserve
    - Spinning Reserve (must be on-line and synchronized)
    - Non-Spinning Reserve
- Replacement Reserve (Capacity that can be delivered as Energy within 60 minutes)

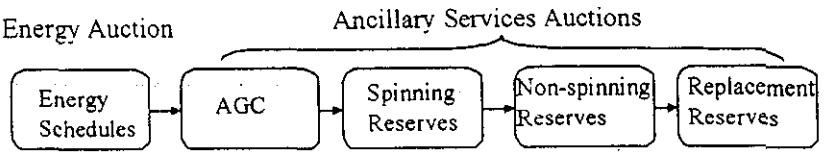
12

AGC/Regulation

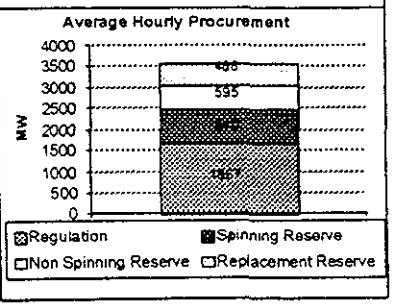
- Definition
  - Service provided by generating units with AGC equipment which automatically adjusts their output in response to Area Control Center (ACC) signals for
    - load following
    - frequency control
    - tie-line control
    - time correction
    - economic operation

13

Ancillary Services (AS)



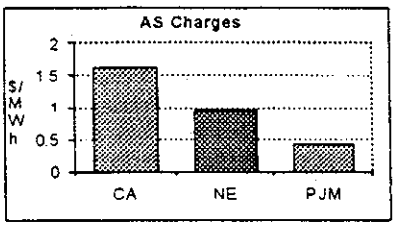
- A unit on reserve supplies an option to generate
- As the buyer of all reserves ISO can pursue a single objective (cost minimization)
- Bidders submit separate bids for capacity and energy



14

Ancillary Services Costs

- Ancillary Services charges in California have been higher than those in other ISOs



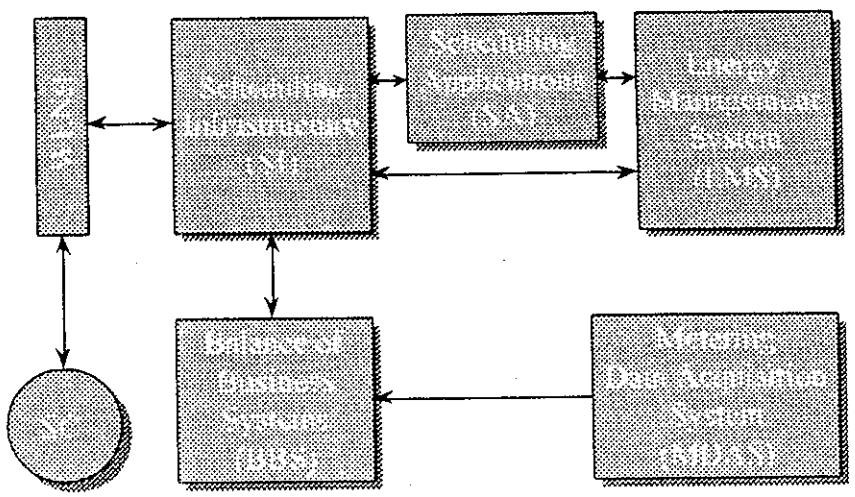
15

Ancillary Services

Systems and Infrastructure

1

ISO System Structure



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Scheduling Applications (SA)

- **ASM**
  - Ancillary Services Management
- **CONG**
  - Inter-zonal Congestion Management
- **BEEP**
  - Balancing Energy and Ex Post Price Determination

3

AS and Congestion Management

- No coordination
  - ASM and CONG run in parallel
- AS are procured regionally
  - regions are unions of congestion zones specified as input in ASM by the user
- No transmission capacity reservation
  - except for existing AS contracts
- No Usage Charges

4

Ancillary Services Requirements

5

AS Requirement Calculation

- AS requirements are calculated for each SC by region
- AGC/Regulation
  - (2–5)% × scheduled load
- Replacement Reserve
  - 7% × max{0, load forecast – scheduled load}
- Spinning and Non-Spinning Reserve
  - 50% × Contingency Reserve

6

AS Requirement Calculation

- Contingency Reserve is based on
  - Scheduled load
  - Scheduled hydro generation
  - Import/Export Energy schedules
  - Worst contingency
    - the maximum of
      - manually entered amount
      - loss of generation
      - loss of inter-tie

7

AS Requirement Calculation

- Contingency Reserve requirement
  - max{worst contingency,
    max{0, 7% × (equivalent load) –
    2% × hydro generation}}
    + non-firm imports
  - equivalent load =
    scheduled load – firm imports + firm exports
  - no Contingency Reserve for wheeling-through transactions and non-firm energy exports

8

Day-Ahead and Hour-Ahead Ancillary Services Bidding, Self-provision, and Settlements

9

Day-Ahead AS Bids/Schedules

- A Resource may submit for each AS
  - 24-hr bid
    - energy bid (may vary by hour)
    - capacity reservation bid (may vary by hour)
  - 24-hr self-provision schedule
    - energy bid (may vary by hour)
- Capacity reservation bids are used in ASM
- Energy bids are used in BEEP

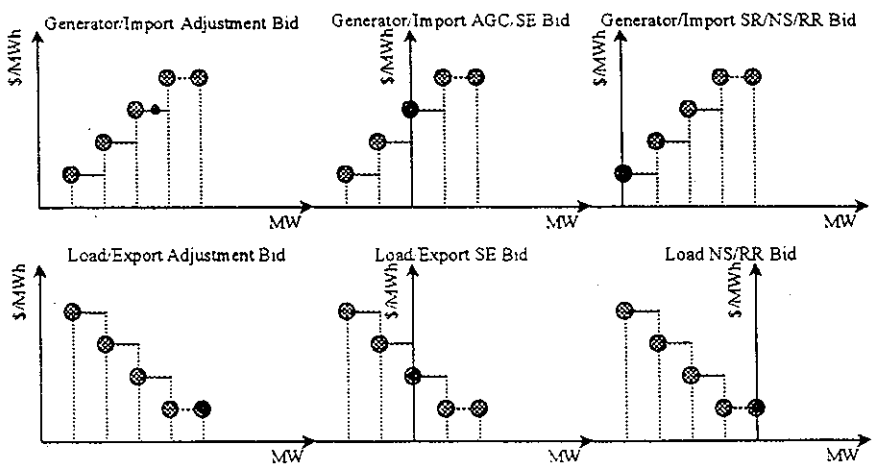
10

Ancillary Services Energy Bids

- AS Energy bid format
  - price vs. quantity staircase curve
    - up to 10 segments
    - positive and monotonically increasing for generation/import
    - negative and monotonically decreasing for load/export
  - relative to the capacity bid/scheduled
  - the first matching portion is used by BEEP
  - extends to negative quantities for AGC

11

Energy Bid Format Examples



12

155

Ancillary Service Self-provision

- Valid self-provision is always accepted
- *Self-provision reduces SC obligation*
  - SC obligation = max{0, SC requirement – SC self-provision}
- Self-provision in excess of requirement
  - is not transferable among regions
  - it does not reduce other SC obligations
  - it is not paid for

13

Day-Ahead AS Bid Evaluation

- AS regional auction
  - inelastic demand = Σ (SC obligation)
  - *cascade AS bid evaluation*
    - capacity accepted in previous auctions is subtracted from capacity bid into following auctions
    - AGC/Regulation
    - Spinning Reserve
    - Non-Spinning Reserve
    - Replacement Reserve

14

156

AS Schedule Example

- Generator with
  - 500 MW maximum capacity
  - 200 MW submitted Energy schedule
  - 6 MW/min ramping capability

	AGC	SR	NS	RR
Bid Flag	No	No	No	No
Submitted	20	20	20	240
Evaluated				
Accepted	20	20	20	240

15

AS Bid Example

- Generator with
  - 500 MW maximum capacity
  - 200 MW submitted Energy schedule
  - 6 MW/min ramping capability

	AGC	SR	NS	RR
Bid Flag	Yes	Yes	Yes	Yes
Submitted	60	60	60	300
Evaluated	60	40	20	250
Accepted	20	20	10	100

16

AS Bid/Schedule Example

- Generator with
  - 500 MW maximum capacity
  - 200 MW submitted Energy schedule
  - 6 MW/min ramping capability

	AGC	SR	NS	RR
Bid Flag	Yes	No	Yes	Yes
Submitted	40	20	40	280
Evaluated	40		20	250
Accepted	20	20	10	100

17

Day-Ahead AS Settlement

- Resource settlement (due SC)
  - ISO pays non-FERC-jurisdictional resources the zonal MCP for the AS capacity they sell
  - ISO does not pay self-providers

18

Day-Ahead AS Settlement

- SC Settlement (due ISO) (AGC, SR, NS)
  - ISO charges SCs for their AS obligation at the regional AS price
  - regional AS price =
    Σ (resource AS payments) / AS demand
  - Replacement Reserve settlement is done ex post since the allocation depends on the dispatched amount and the contributing imbalance deviations

19

Hour-Ahead AS Bids/Schedules

- A Resource may submit for each AS
  - 24-hr bids/schedules (13:00–24:00)
  - 1-hr bids/schedules (13:00–2 hr ahead)
  - bid/schedule capacity may be higher/lower than the final day-ahead schedule
    - if higher, additional capacity is bid/scheduled
    - if lower
      - ★ any capacity reservation bid is ignored
      - ★ DA accepted capacity is bought back at the HA price
      - ★ self-provision is reduced

20

HA Bid/Schedule Interpretation

	Final DA		HA		Final HA		Interpretation
Bid Flag	Yes	No	Yes	No	Yes	No	
Case 1		60		100		100	self-provision increase
Case 2		100		60		60	self-provision decrease
Case 3	60		100		60–100		additional capacity bid
Case 4	100		60		60		capacity buy-back
Case 5		60	100		60–100		additional capacity bid
Case 6		100	60			60	self-provision decrease
Case 7	60			100		100	self-provision increase
Case 8	100			60	60		capacity buy-back

21

Hour-Ahead AS Requirements

- SC HA AS requirements may be different than their DA AS requirements due to
  - different HA Energy schedules
  - different load forecast (affects Replacement Reserve requirements)
  - different final DA Energy schedules from preferred/revised DA Energy schedules due to DA Congestion Management

22

Hour-Ahead AS Obligations

- Self-provision reduces SC obligation
  - SC obligation = max{0, SC requirement – SC self-provision}
- SC obligation may be reduced in HA by
  - reducing AS requirement
  - increasing self-provision

23

Hour-Ahead AS Bid Evaluation

- *AS Regional Auction*
  - inelastic demand = max{0, Σ (HA SC obligation – DA SC obligation) + Σ (HA AS capacity buy-back)}
  - cascade AS bid evaluation
    - capacity accepted in previous auctions is subtracted from capacity bid into following auctions
    - AGC/Regulation
    - Spinning Reserve
    - Non-Spinning Reserve
    - Replacement Reserve

24

161

Hour-Ahead AS Settlement

- Resource settlement (due SC) payments
  - ISO pays non-FERC-jurisdictional resources the HA zonal MCP for the HA AS capacity they sell
  - ISO pays FERC-jurisdictional resources their price for the HA AS capacity they sell
  - ISO does not pay or charge self-providers

25

Hour-Ahead AS Settlement

- SC Settlement (due ISO) (AGC, SR, NS)
  - ISO charges/pays SCs for their AS obligation deviation at the HA regional AS price
  - HA regional AS price =
    Σ (HA resource AS payments) / AS demand
- Resource settlement charges (except RR)
  - ISO charges all resources the HA regional AS price for the AS capacity they buy back in HA

26

162

Hour-Ahead AS Settlement

- Caveats
  - Settlement system currently does not support negative billable quantities
    - no resources will be charged for buying back AS capacity
    - no SCs will be credited for reducing their AS obligation in HA
    - ISO is still revenue neutral
  - Replacement Reserve settlement implications
  - gaming possibilities have not been examined

27

Ancillary Services Dispatch in Real Time

28

163

Ancillary Services Dispatch

- Imbalance Energy is procured competitively to balance generation and demand in real time
- Sources of Imbalance Energy
  - AGC (every 4 sec)
  - Spinning, Non-Spinning, and Replacement Reserve (every 10 min)
  - Supplemental Energy Bids (every 10 min)

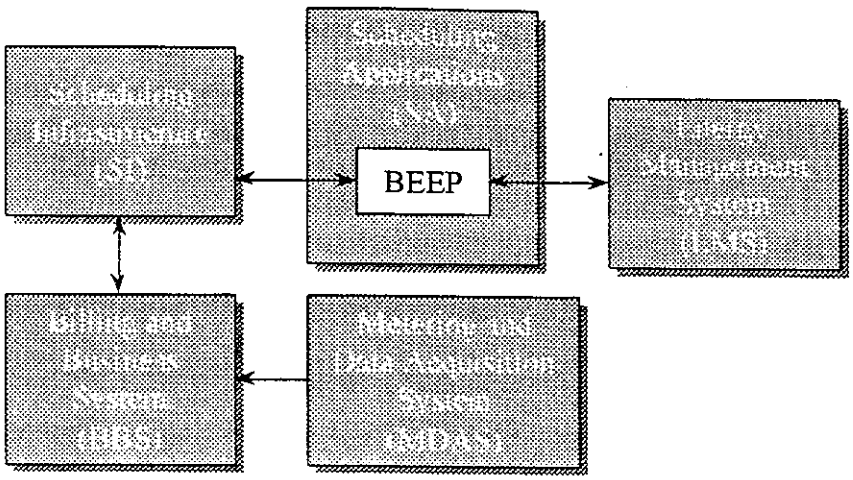
29

BEEP Responsibilities

- Imbalance Energy procurement
  - Real-time inter-zonal congestion management
- Imbalance Energy provision recording for settlement purposes
- AGC unit base point calculation
- Ex post Imbalance Energy price determination

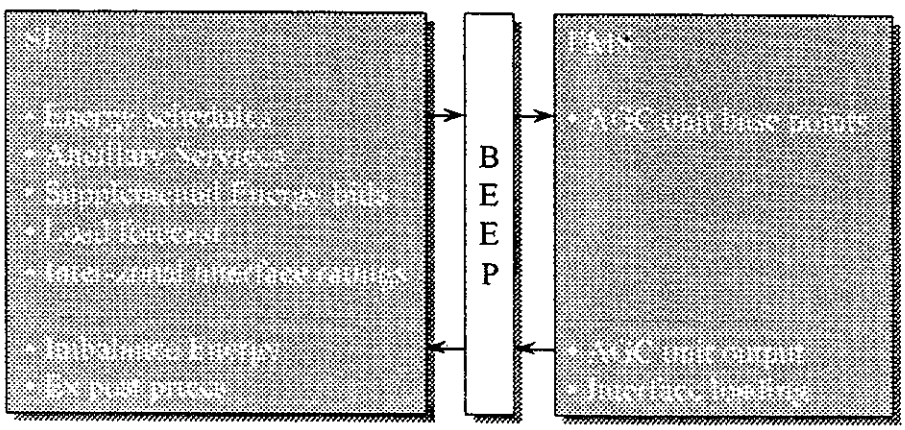
30

BEEP Communication



31

BEEP Input/Output Data



32

165

Imbalance Energy Requirements

- Long-term requirements
  - Mismatch between:
    - load forecast for the next hour
    - energy schedules for the next hour
- Short-term requirements
  - Mismatch between:
    - AGC unit outputs
    - AGC unit base points

33

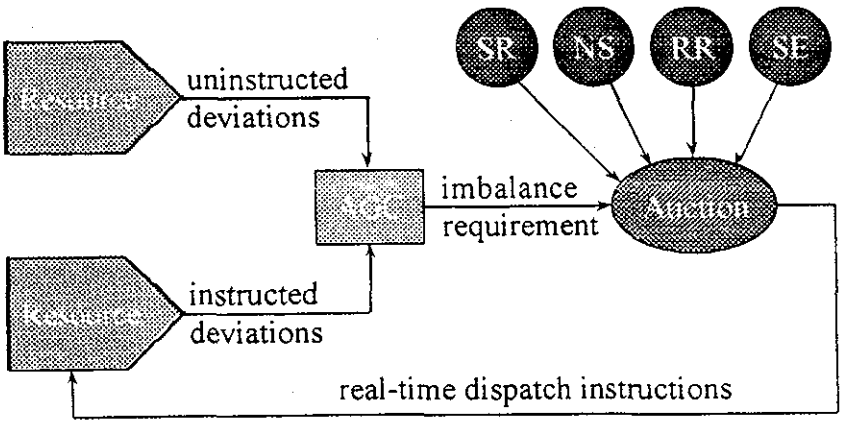
Imbalance Energy Procurement

- Imbalance Energy requirements are met by dispatching in merit order:
  - Spinning Reserves
  - Non-Spinning Reserves
  - Replacement Reserves
  - Supplemental Energy bids

  subject to ramping and network constraints.

34

Real-Time Energy Balancing



35

Imbalance Energy Dispatch

- Long-term dispatch
  - At the beginning of the hour, for all intervals
  - Meet long-term requirements
  - All sources compete
- Short-term dispatch
  - At every execution, for the next interval
  - *Meet short-term requirements*
  - Only fast sources compete

36

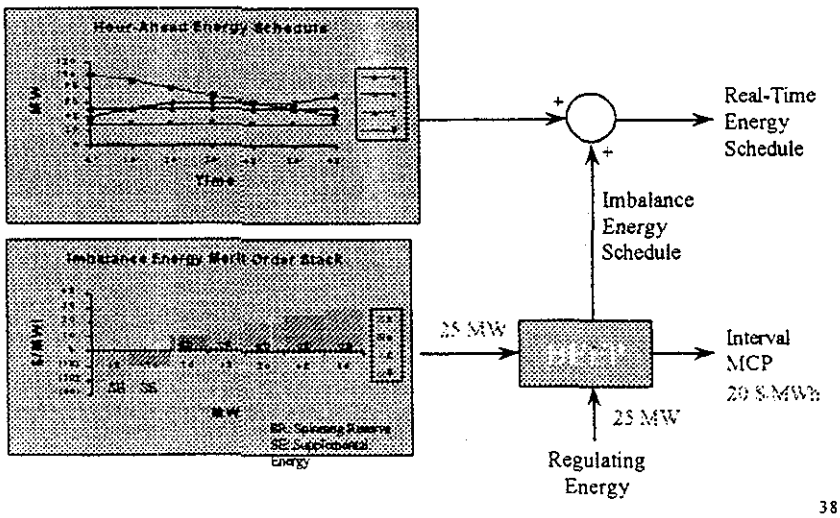
167

BEEP Long-Term Dispatch

Resource ID	Available Capacity [MW]	Energy Price [$/MWh]	Service ID	Time Delay [min]	Ramping Rate [MW/min]	0–10	10–20	20–30	30–40	40–50	50–60
I	40	20	RR	40	2						
C	10	19	SE	0	2						
H	100	18	SE	0	2			10			
G	40	17	RR	20	1			10	20	20	20
C	10	16	SE	0	2			10	10	10	10
F	50	15	SE	0	1			10	20	30	40
E	90	14	RR	30	3				30	60	90
D	20	13	SR	0	2		20	20	20	20	20
C	10	12	SE	0	2		10	10	10	10	10
B	20	11	NS	5	4	10	20	20	20	20	20
A	30	10	SR	0	3	30	30	30	30	30	30
Total						40	80	120	160	200	240

37

BEEP Short-Term Dispatch



38

168

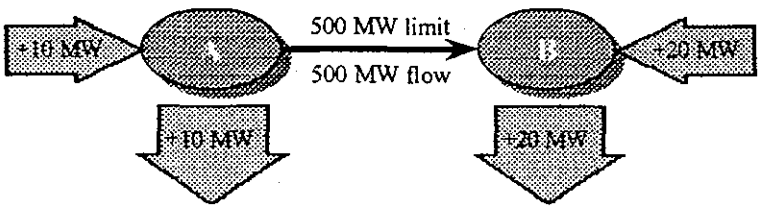
BEEP Final Dispatch

Resource ID	Available Capacity (MW)	Energy Price ($/MWh)	Service ID	Time Delay (min)	Ramping Rate (MW/min)	0–10	10–20	20–30	30–40	40–50	50–60
I	40	20	RR	40	2						
C	10	19	SE	0	2						
H	100	18	SE	0	2			5			
G	40	17	RR	20	1			10	20	20	30
C	10	16	SE	0	2			10	10	10	10
E	50	15	SE	0	1			10	20	30	40
E	90	14	RR	30	3				30	60	90
D	20	13	SR	0	2		20	20	20	20	20
C	10	12	SE	0	2		10	10	10	10	10
B	20	11	NS	5	4	15	20	20	20	20	20
A	30	10	SR	0	3	30	30	30	30	30	30
Total						45	80	115	160	200	250

39

BEEP Congestion Management

- Imbalance Energy requirement and procurement on a zonal basis



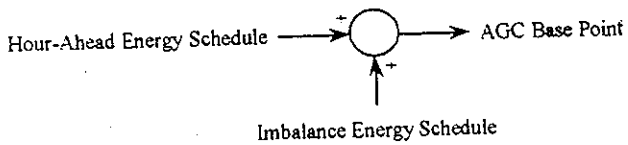
- Manual modification of zonal Imbalance Energy requirements to eliminate violations due to AGC

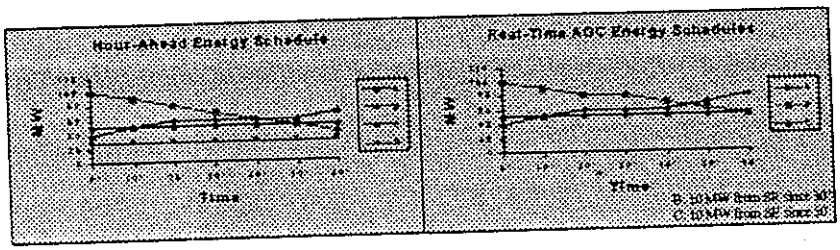
40

169

AGC Base Point Calculation

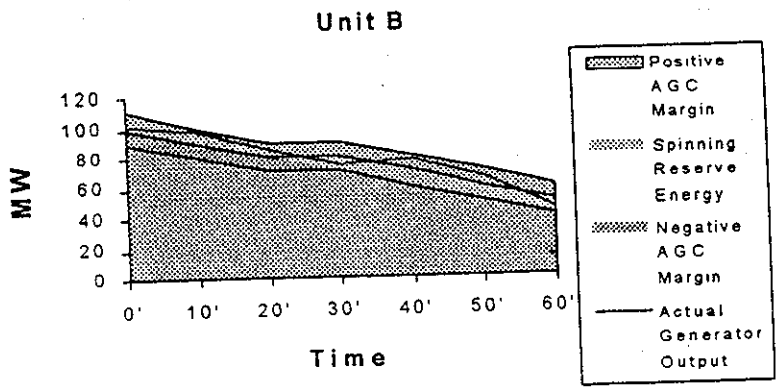
- AGC base point = Real-Time Energy Schedule





41

Multiple AS Provision



42

170

Ex Post Price Determination

Resource ID	Available Capacity (MW)	Energy Price ($/MWh)	Service ID	Time Delay (min)	Ramping Rate (MW/min)	0–10	10–20	20–30	30–40	40–50	50–60
I	40	20	RR	40	2						
C	10	19	SE	0	2						
H	100	18	SE	0	2			5			
G	40	17	RR	20	1			10	20	20	30
C	10	16	SE	0	2			10	10	10	10
F	50	15	SE	0	1			10	20	30	40
E	90	14	RR	30	3				30	30	90
D	20	13	SR	0	2		20	20	20	20	20
C	10	12	SE	0	2		10	10	10	10	10
B	20	11	NS	5	4	15	20	20	20	20	20
A	30	10	SR	0	3	30	30	30	30	30	30
Total						45	80	115	160	200	250
MCP						11	13	18	17	17	17

$$\text{HourlyPrice} = \frac{45 \times 11 + 80 \times 13 + 115 \times 18 + 160 \times 17 + 200 \times 17 + 250 \times 17}{45 + 80 + 115 + 160 + 200 + 250} = \frac{13975}{850} = 16.44$$

43

171

Planning and Scheduling of Ancillary Services

FORUM on Ancillary Services
Feb 22-24, 2000
Warsaw, Poland

Harry Singh

Issues

- How much?
  - Quantity of AS procured
- From where?
  - Level of imports allowed, recognizing transmission congestion
- When?
  - How should the ISO decide between long term procurement, day-ahead procurement and hour-ahead procurement?

2

Operating Reserve Quantities

- The ISO shall maintain minimum contingency Operating Reserve made up of Spinning Reserve and Non-Spinning Reserve in accordance with WSCC MORC criteria equal to:

  (a) 5% of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from hydroelectric resources plus 7% of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from other resources,

  or (b) the single largest Contingency, if this is greater

  or (c) by reference to such more stringent criteria as the ISO may determine from time to time.

3

Replacement Reserve Quantities

- The ISO shall make its determination of the required quantity of Replacement Reserve based on:
  - historical analysis of the deviation between actual and Day-Ahead forecast Demand,
  - historical patterns of unplanned Generating Unit Outages,
  - historical patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand,
  - historical patterns of unexpected transmission Outages, and
  - such other factors affecting ability of the ISO to maintain System Reliability as the ISO may from time to time determine.

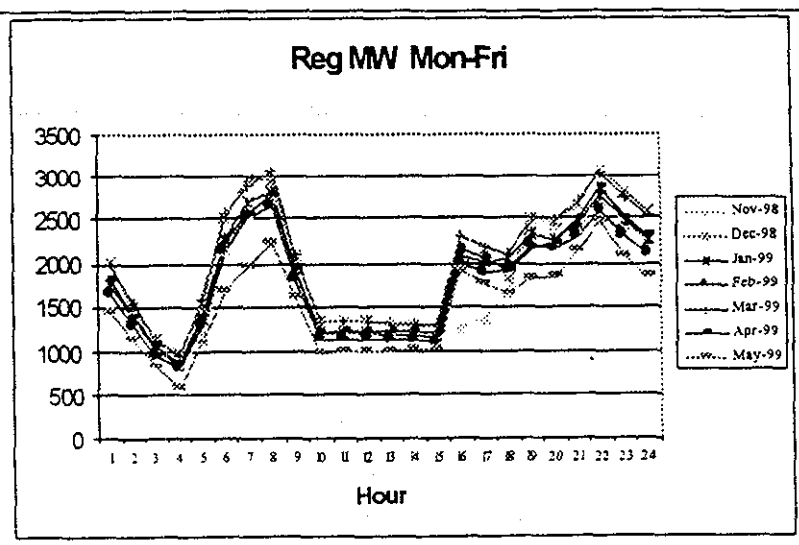
4

Locational Requirements

- The actual location of Ancillary Services on a daily and hourly basis shall depend on the locational spread of Demand within the ISO Control Area, the available transmission capacity, the locational mix of Generation, and historical patterns of transmission and Generation availability.

5

Market Data



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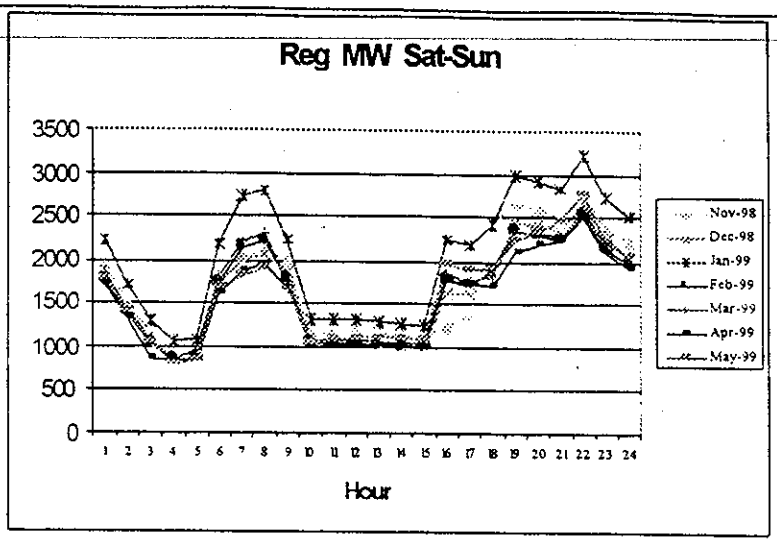
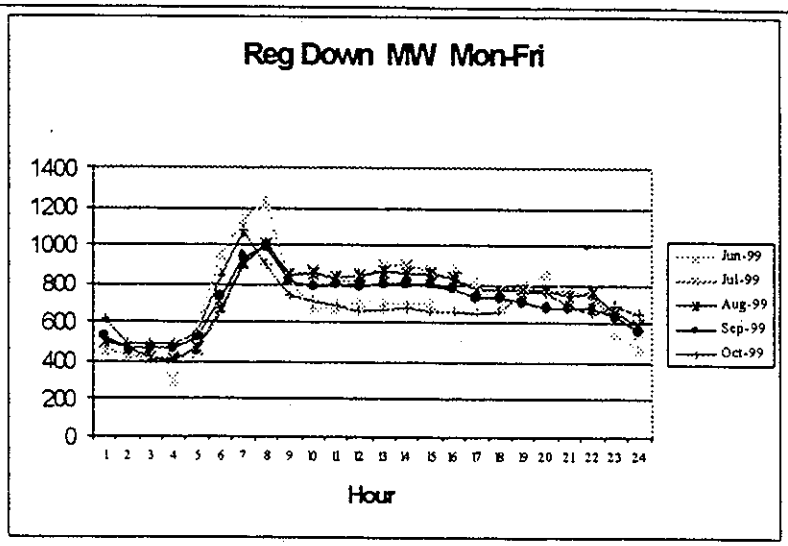
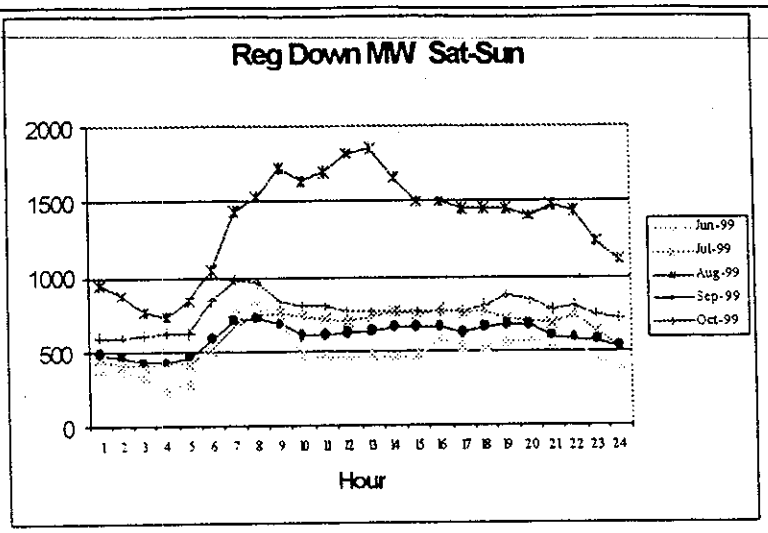

Reg MW Sat-Sun
3500
3000
2500
2000
1500
1000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Nov-98
Dec-98
Jan-99
Feb-99
Mar-99
Apr-99
May-99

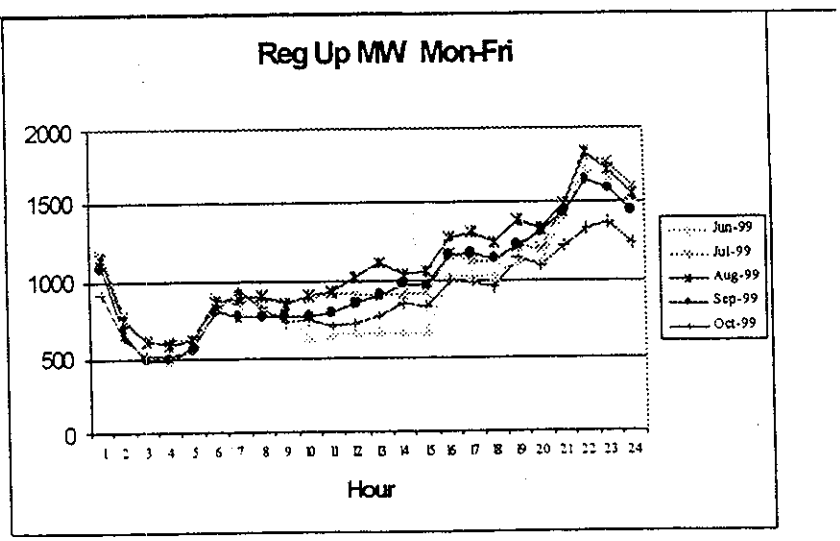
7


Reg Down MW Mon-Fri
1400
1200
1000
800
600
400
200
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Jun-99
Jul-99
Aug-99
Sep-99
Oct-99

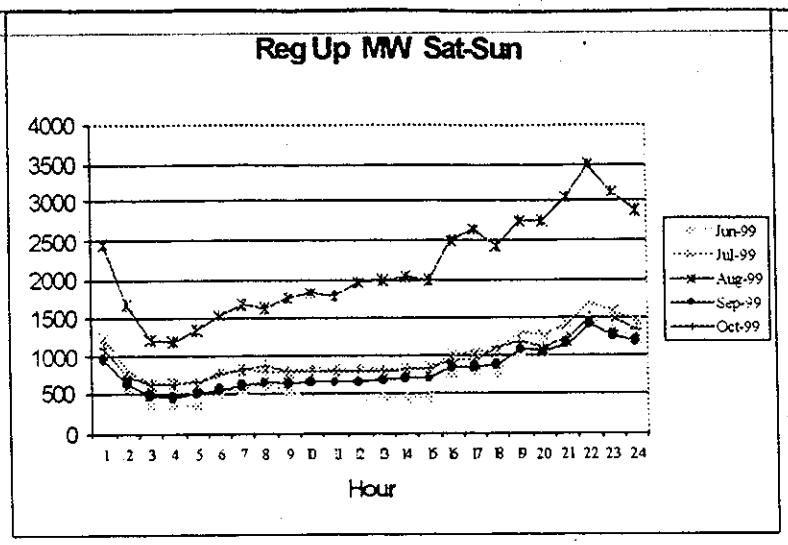
8


Reg Down MW Sat-Sun
2000
1500
1000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Jun-99
Jul-99
Aug-99
Sep-99
Oct-99

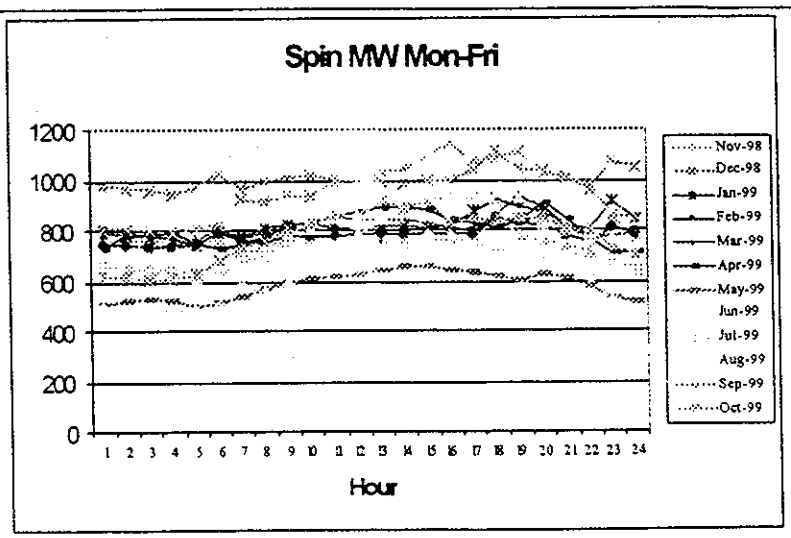
9


Reg Up MW Mon-Fri
2000
1500
1000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Jun-99
Jul-99
Aug-99
Sep-99
Oct-99

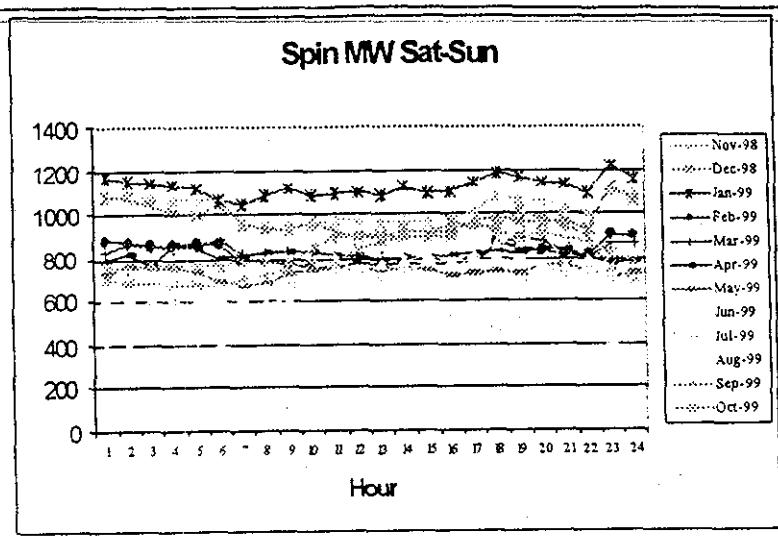
10


Reg Up MW Sat-Sun
4000
3500
3000
2500
2000
1500
1000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Jun-99
Jul-99
Aug-99
Sep-99
Oct-99

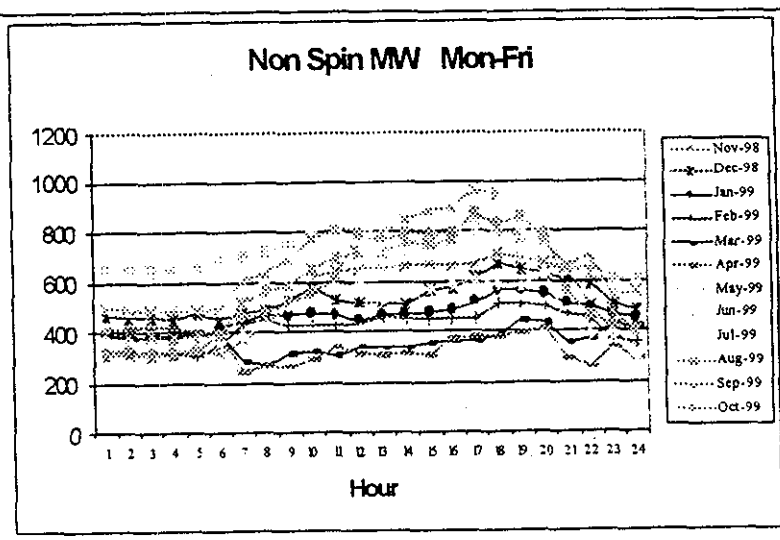
11


Spin MW Mon-Fri
1200
1000
800
600
400
200
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Nov-98
Dec-98
Jan-99
Feb-99
Mar-99
Apr-99
May-99
Jun-99
Jul-99
Aug-99
Sep-99
Oct-99

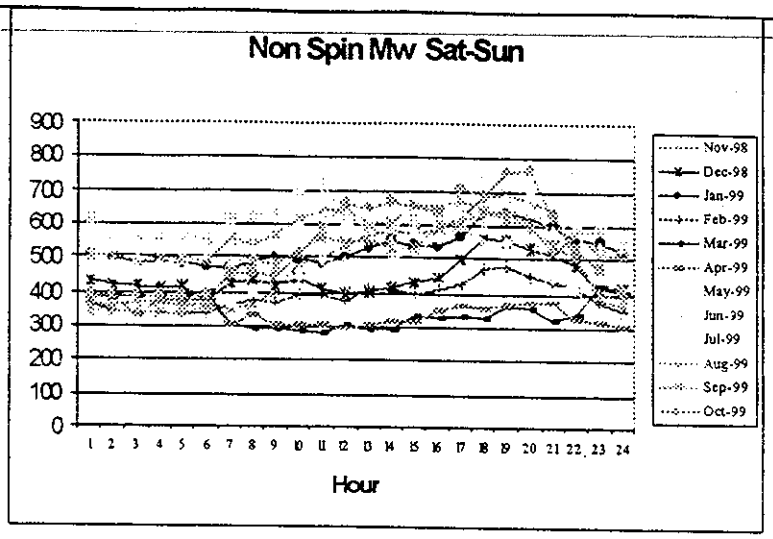
12


Spin MW Sat-Sun
1400
1200
1000
800
600
400
200
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Nov-98
Dec-98
Jan-99
Feb-99
Mar-99
Apr-99
May-99
Jun-99
Jul-99
Aug-99
Sep-99
Oct-99

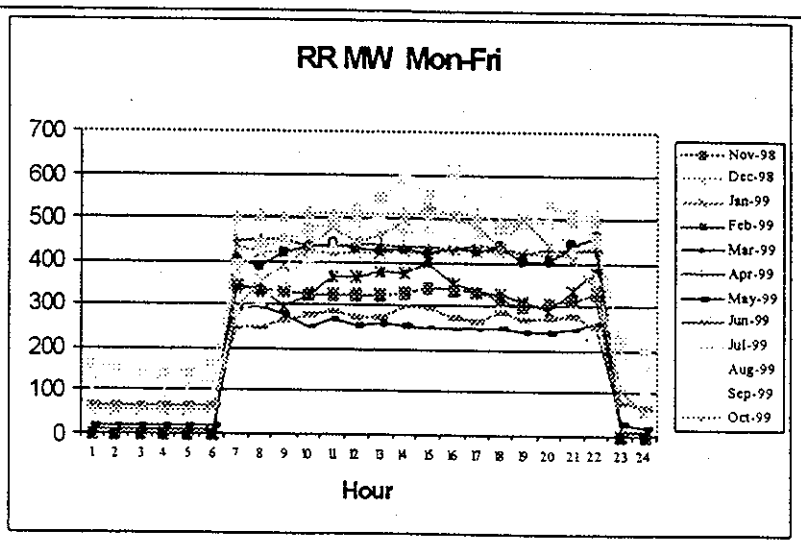
13


Non Spin MW Mon-Fri
1200
1000
800
600
400
200
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Nov-98
Dec-98
Jan-99
Feb-99
Mar-99
Apr-99
May-99
Jun-99
Jul-99
Aug-99
Sep-99
Oct-99

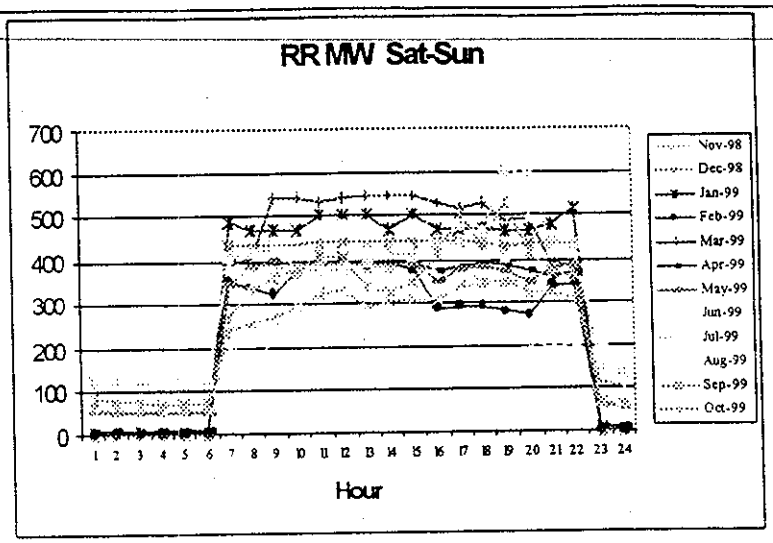
14


Non Spin Mw Sat-Sun
900
800
700
600
500
400
300
200
100
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Nov-98
Dec-98
Jan-99
Feb-99
Mar-99
Apr-99
May-99
Jun-99
Jul-99
Aug-99
Sep-99
Oct-99

15


RR MW Mon-Fri
700
600
500
400
300
200
100
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Nov-98
Dec-98
Jan-99
Feb-99
Mar-99
Apr-99
May-99
Jun-99
Jul-99
Aug-99
Sep-99
Oct-99

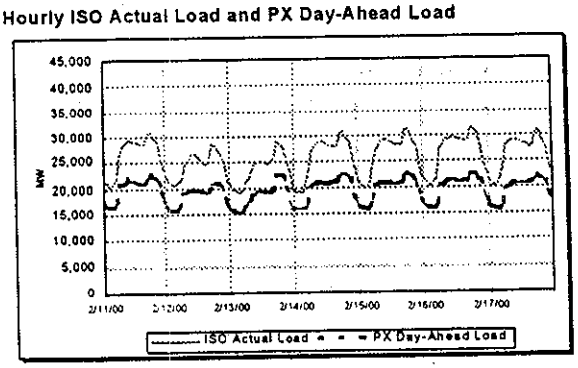
16



17

Last Week (2/11/00 - 2/17/00)

Hourly ISO Actual Load and PX Day-Ahead Load

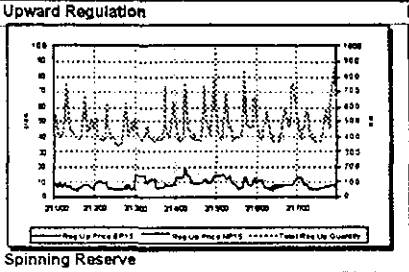


System Peak Load (MW)	31,702

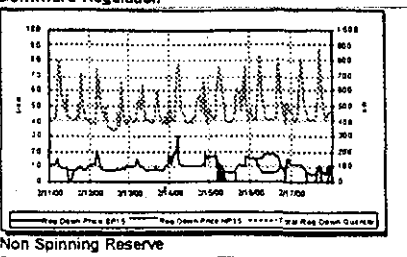
18

Last Week (2/11/00 - 2/17/00)

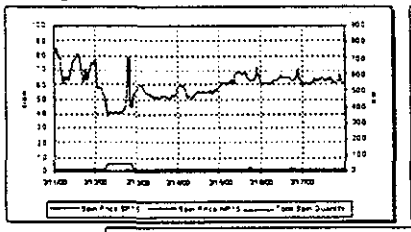
Upward Regulation



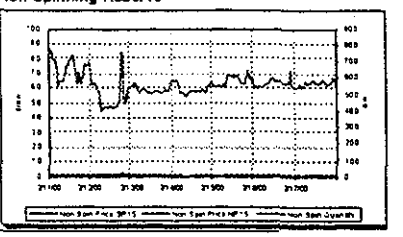
Downward Regulation



Spinning Reserve



Non Spinning Reserve



A/S Price Summary		Reg Up		Reg Down		Spin		Non Spin		Replacement	
		NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Prices ($/MW)	Max	20	20	30	32	3	5	1.55	3.39	1.08	1.08
	Avg	9.21	9.14	9.85	10.05	1.23	1.36	0.20	0.17	0.11	0.11
	Min	3.54	3.54	2	4.5	0.01	2	0	2	0	0

A/S Zonal Procurement	Reg Up	Reg Down	Spin	Non Spin	Repl
# of Hours	9	37	32	24	17

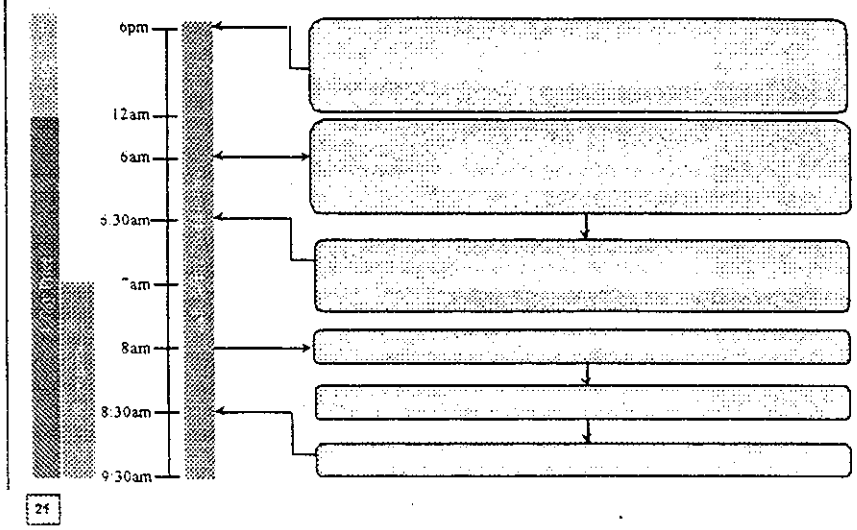
19

Events affecting AS Quantities

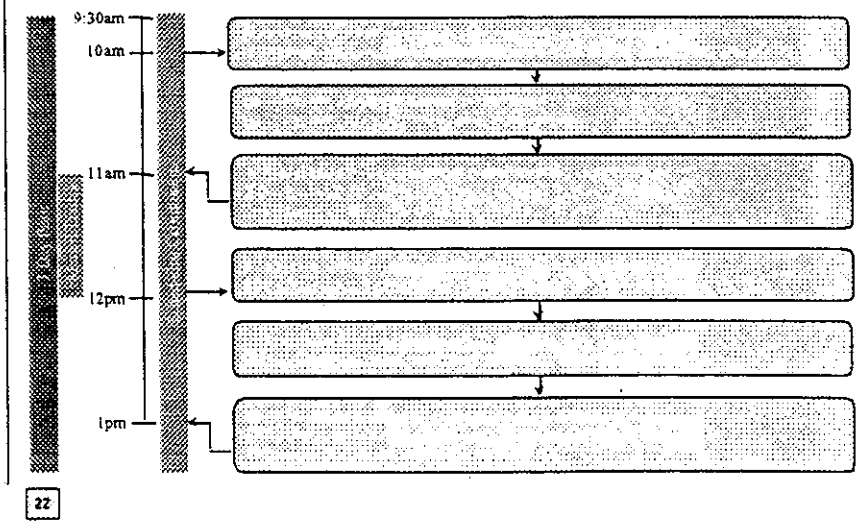
- April 1, 1998: AS Markets commence
- Aug 6, 1998: Max Imports upto 25 % for spinning and non-spinning reserve
- April 6, 1999: Increased procurement of AS in Hour-ahead market
- June 1, 1999: Max Imports upto 50 % allowed
- August 18, 1999: "Rational Buyer" protocol (substitution of lower quality AS by higher quality AS)

20

CA ISO Day-Ahead Scheduling



CA ISO Day-Ahead Scheduling (cont.)



Setting up a Competitive Market for Ancillary Services

FORUM on Ancillary Services
Feb 22-24, 2000
Warsaw, Poland

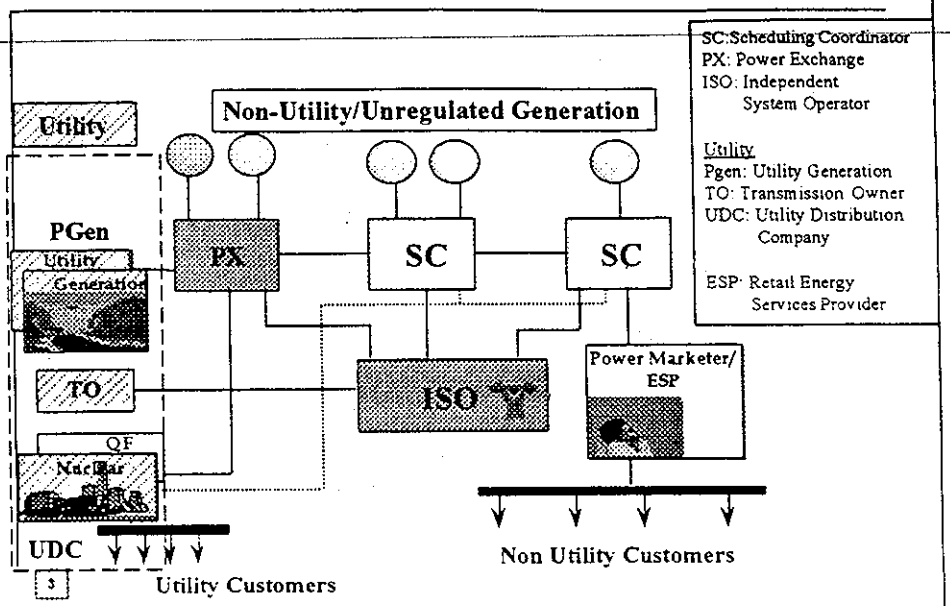
Harry Singh

Competitive Market Structures

- UK , PJM
  - Day-ahead pricing based on multi-part bids, centralized commitment
- Australia
  - Units self-commit; "ex post" pricing by a centralized pool
- California
  - Power Exchange (day-ahead pricing using single-part bids, decentralized commitment)
  - Independent System Operator (responsibility for reliability, real-time operation.congestion management and ancillary services)

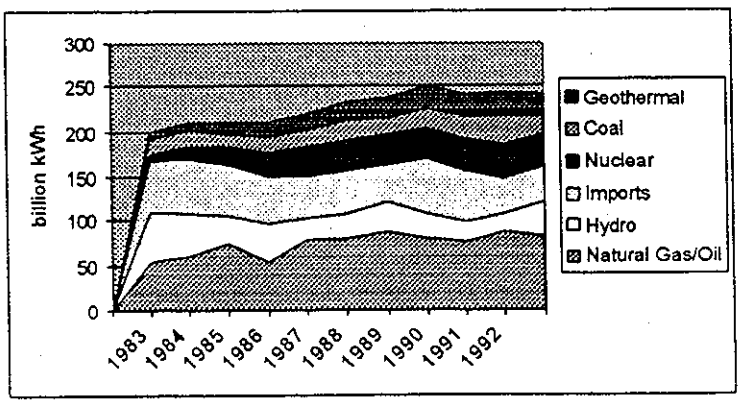
2

The New Market Structure



3

California Resource Mix



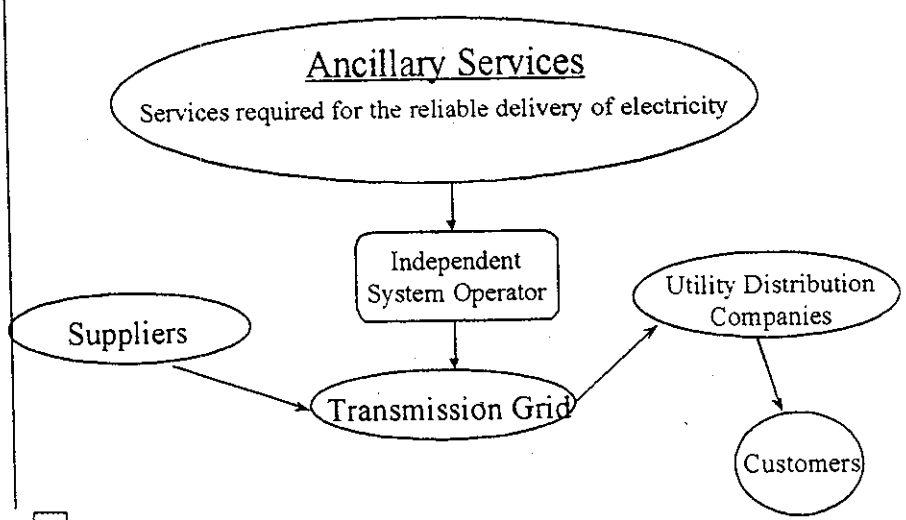
4

Forward, Real-Time and Reserve Markets

- Generation and Load schedules in the forward market cannot be met exactly in real-time due to demand variations, unit outages etc.
- Real-time balancing is the responsibility of the ISO
- Power system reliability and security requires a sufficient quantity of ancillary services
  - Implicit assumption: price does not always call forth supply in real time

5

Role of Ancillary Services



6

Ancillary Services procured by the ISO

- AGC/Regulation (Reg-up and Reg-down are separate services)
- Spinning Reserve (SR)
- Non-Spinning Reserve (NS)
- Replacement Reserve (RR)
- Voltage and Reactive Power (VAR) Support
- Black Start

7

Types of Reserves

- Operating Reserve (Capacity that can be delivered as Energy within 10 minutes)
  - AGC/Regulation
  - Contingency Reserve
    - Spinning Reserve (must be on-line and synchronized)
    - Non-Spinning Reserve
- Replacement Reserve (Capacity that can be delivered as Energy within 60 minutes)

8

AGC/Regulation

- Definition
  - Service provided by *generating units* with AGC equipment which automatically adjusts their output in response to Area Control Center (ACC) signals for
    - load following
    - frequency control
    - tie-line control
    - time correction
    - economic operation

9

Who Buys Reserves?

- Reserve capacity is an externality
  - Energy shippers would prefer to let others supply reserves
  - Reserves must be provided to a level consistent with system reliability, not any participant's utility function
- The purchaser of energy from reserve cannot be identified ahead of time
  - If you could, you would make him schedule capacity
- The ISO is the purchaser, at a level determined by reliability standards (not necessarily economically)

10

Who Provides Reserves?

- Infra-marginal units will choose to leave unloaded capacity for reserves only if they are compensated for opportunity costs
- Markets for energy must be accompanied by markets for ancillary services

11

What are Opportunity Costs?

- Example 1 (without ramping constraints)
  - System Load: 1000 MW
  - Reserve Requirement: 70 MW
  - Generator A: 600 MW @ $18/MWh
  - Generator B: 600 MW @ $20/MWh
  - Optimal Schedule:
    - A: 600 MW Energy
    - B: 400 MW Energy + 70 MW Contingency Reserve
    - Opportunity cost: $0/MWh

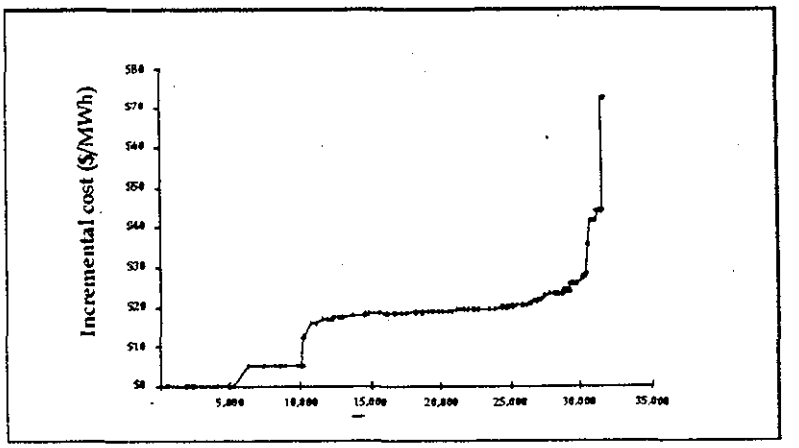
12

What are Opportunity Costs?

- Example 2 (with ramping constraints)
  - System Load: 1000 MW
  - Reserve Requirement: 70 MW
  - A (4 MW/min): 600 MW @ $18/MWh
  - B (4 MW/min) : 600 MW @ $20/MWh
  - Optimal Schedule:
    - A: 570 MW Energy + 30 MW Contingency Reserve
    - B: 430 MW Energy + 40 MW Contingency Reserve
    - Opportunity cost for generator A: $2/MWh

13

Thermal 'supply curve' in California



14

Ancillary Services Procurement

- Reserves and AGC
  - day-ahead and hour-ahead auctions
  - self-provision by Scheduling Coordinators (minimal thus far)
- Voltage Support
  - normal operation
  - long-term contracts (Reliability Must Run)
  - real-time instructions
- Black Start
  - long-term contracts or annual auctions

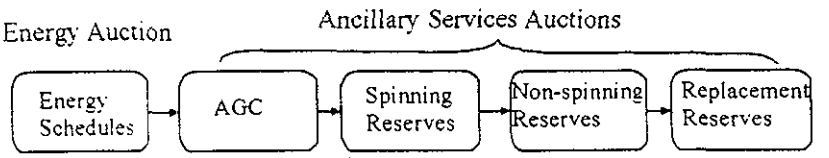
15

Must Reserves be Procured Simultaneously With Energy?

- Short-term efficiency goals met by simultaneous procurement
  - Provision of spinning reserve is compensated at imputed opportunity cost
- Simultaneous procurement is not always possible under all market structures
  - An ISO separate from a PX does not procure any energy in forward markets
- Simultaneous procurement may be possible for consumers that "self-provide" their share of reserves
  - What portion is optimally self-provided?

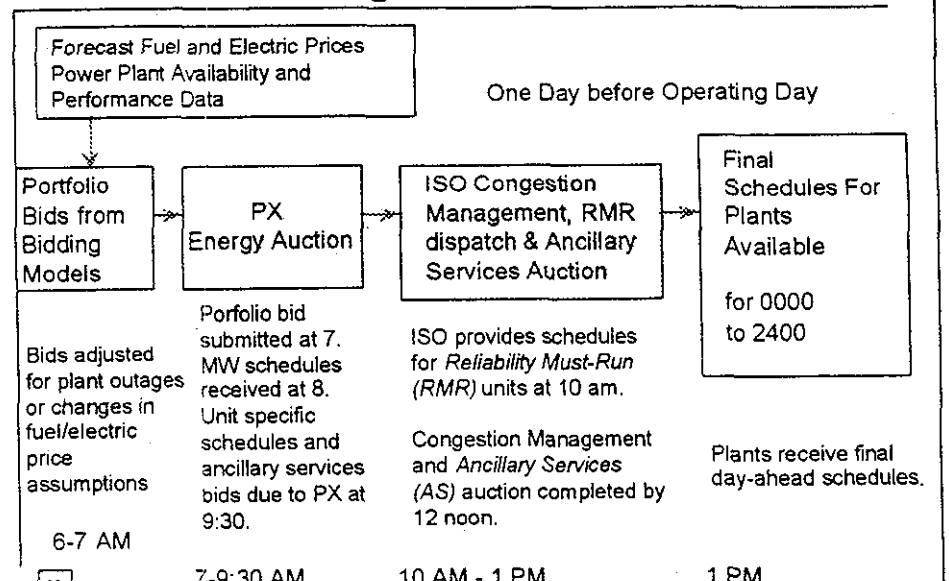
16

Auction Sequence



17

Generation Bidding in ISO and PX Markets



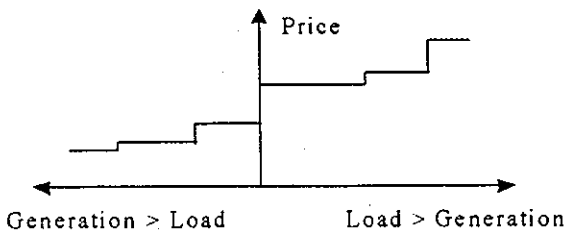
18

Should Reserves be Procured Sequentially or Simultaneously?

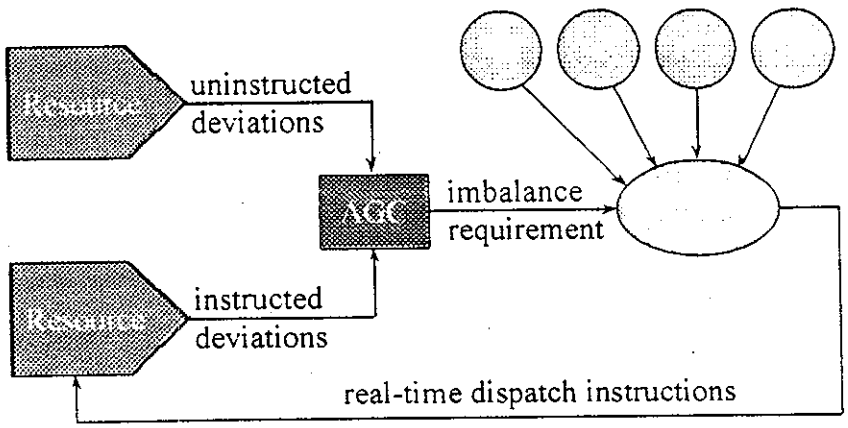
- California started out with the sequential approach
- Problems with the sequential approach
  - May not result in lowest overall cost
  - May result in lower quality products being priced higher than higher quality products
- Alternatives
  - Simultaneous bid evaluation
  - "Rational Buyer" protocol
    - substitute lower quality AS by higher quality AS if it is less expensive

The ISO's Balancing Market

- Centrally dispatched by the ISO
- Used to physically balance demand and supply
- Not used for centralized optimization
- Merit order determined based on energy price bids



Real-Time Energy Balancing



21

Price Calculation

Table 1: Numerical example

Resource	Quantity	Price	Dispatch Instructions 1	2	3	4	5	6	Total
A	36 MW	$20/MWh					6 MW 1 MWh	12 MW 2 MWh	12 MW 3 MWh
B	12 MW	$15/MWh			6 MW 1 MWh	12 MW 2 MWh	12 MW 2 MWh	12 MW 2 MWh	12 MW 7 MWh
C	18 MW	$12/MWh		6 MW 1 MWh	18 MW 3 MWh	18 MW 3 MWh	18 MW 3 MWh	18 MW 3 MWh	18 MW 13 MWh
D	24 MW	$10/MWh	12 MW 2 MWh	24 MW 4 MWh	24 MW 4 MWh	24 MW 4 MWh	24 MW 4 MWh	24 MW 4 MWh	24 MW 22 MWh
MCP *Total MW* *Total MWh*			$10/MWh 12 MW 2 MWh	$12/MWh 30 MW 5 MWh	$15/MWh 48 MW 8 MWh	$15/MWh 54 MW 9 MWh	$20/MWh 60 MW 10 MWh	$20/MWh 66 MW 11 MWh	66 MW 45 MWh

Hourly average ex-post price =

$$\frac{2\times10+5\times12+8\times15+9\times15+10\times20+11\times20}{45}=$$

$$=\frac{755}{45}=\$16.78\ \text{MWh}$$

22

Option-Based Reserves Auction

- A unit on reserve supplies an option to generate
  - Purchasing reserves should involve capping generating costs in the balancing market
- As the buyer of all reserves ISO can pursue a single objective (cost minimization)
- Reserves are not like other options
  - Purchase quantities based on engineering judgment/reliability criteria, not hedging strategies
  - Distinctions between reserve types based on operational considerations
  - Operated for physical need, not based on price

23

Design of the Option-Based Reserves Auction

- 3 separate markets for reserves
- Unit i bids capacity prices R_i and energy strike price E_i
  - Evaluation "score" is $R_i + xE_i$; x is expected production from this reserve type ($0 < x \leq 1$)
  - Paid max(score) - xR_i as a reservation; paid for balancing energy at predetermined price E_i
- Requires unbiased estimation of x for each type of reserve to avoid gaming
- Predetermines reserve units' energy payments

24

Design of the Simplified Reserves Auction

- 3 separate capacity-only markets
- Unit i bids capacity prices R_i and energy strike price E_i
  - Bids selected on the basis of R_i only, (i.e., x = 0)
  - Energy bids E_i are used to determine merit order for real-time dispatch

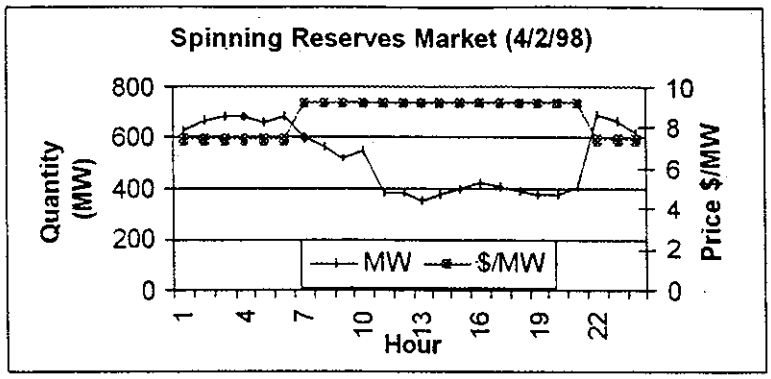
25

Regulatory Issues

- "Cost-based" reserve pricing
  - Generation owners need to get approval from the FERC to sell Ancillary Services at market based rates
  - Utilities can only receive cost-based prices for reserve capacity
  - Arbitrarily selected "cost-based" price caps have little chance of reflecting actual opportunity costs

26

Market Operation (4/2/98): Insufficient supply due to price caps



27

Market Operation (7/9/98): Market power in the absence of price caps

AGC			
NP15		SP15	
MW	$/MW	MW	$/MW
907.5	7.7	1320.7	244.60001
498	7.7	997.08	0
458.08	7.7	722.93	0
377.64	7.7	592.9	0
389.16	7.7	599.36	0
568	7.7	1320.7	244.60001
668	7.7	1320.7	244.60001
542.5	7.7	1320.7	244.60001
630	7.7	1259.57	0
832.19	7.7	1179.96	0
810	7.7	1249.73	0
810	7.7	1296.3	0
810	7.7	1319.07	0
665	7.7	1351.22	0
765	7.7	1372.71	0
765	7.7	1383.66	0
665	7.7	1377.77	0
686	7.7	1341.42	0
631	7.7	1279.14	0
631	7.7	1224.5	0
631	7.7	1233.66	0
624	7.7	1333.7	244.60001
624	7.7	1333.66	244.60001
627	7.7	1320.7	244.60001
629.79	7.7	1210.4525	71.34167

Spinning Reserve			
NP15		SP15	
MW	$/MW	MW	$/MW
291.99	7.37	313.76	190
308.49	7.37	383.41	190
338.49	7.37	383.41	190
339.99	7.36	384.41	190
338.63	7.35	384.41	190
324.99	7.37	314.76	240
247.68	7.37	313.76	240
276.28	7.37	312.66	240
302.94	7.37	379.31	190
328.23	7.37	368.41	190
341.81	7.38	175.13	190
337.9	7.38	204.63	9.22
319.6	7.38	156.63	9.22
277	7.37	156.63	186.36001
292	7.4	156.63	186.36001
294	7.4	156.63	186.36001
286	7.37	156.63	186.36001
286	7.37	156.63	223.58
311	7.37	327.7	223.58
336.13	7.38	274.42	223.58
337.34	7.38	274.42	199.96
302.08	7.38	269.76	199.96
293.49	7.38	281.66	199.96
234.15	7.37	312.66	199.96
305.93	7.37422	274.69	186.432502

Replacement Reserve			
NP15		SP15	
MW	$/MW	MW	$/MW
482.97	7.87	500.49	1
482.97	7.87	500.49	1
482.97	7.87	500.49	1
482.97	7.87	500.48	1
482.97	7.87	500.48	1
482.97	7.87	500.49	1
482.97	7.87	500.49	1
482.97	7.87	500.49	1
482.97	7.87	500.49	1
437.3	7.9	500.5	1
433.8	7.88	500.5	3.95
384	7.87	500.5	3.95
384	7.87	500.5	3.95
235	7.87	500.5	2500
75	7.87	500.5	5000
75	7.87	484.84	5000
235	7.87	500.51	5000
235	7.87	500.5	750
384	7.87	500.5	1
384	7.87	500.5	1
384	7.87	500.5	1
407	7.88	500.5	1
482.97	7.88	500.5	1
482.97	7.87	500.5	1

28

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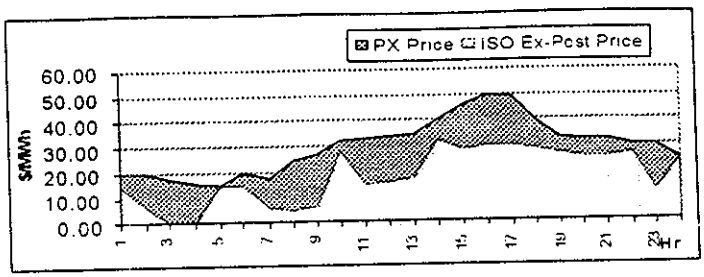
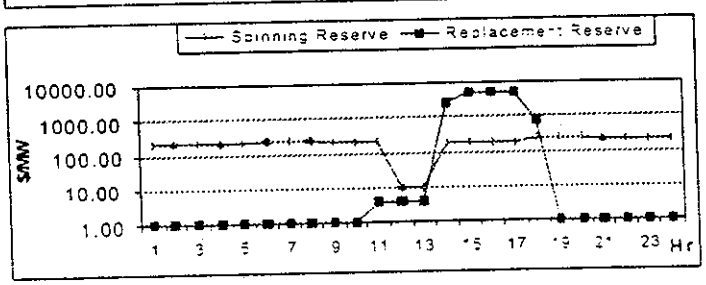
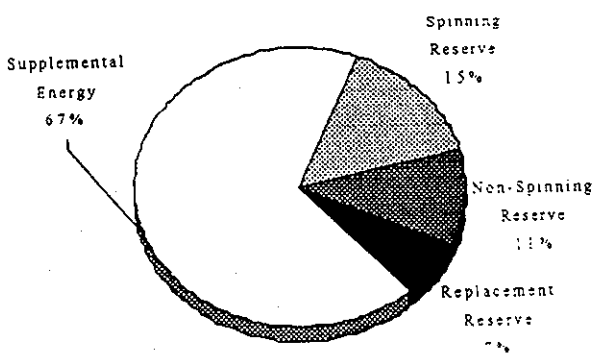
Market Operation (7/9/98) continued





29

Resources used for Real-Time Balancing



30

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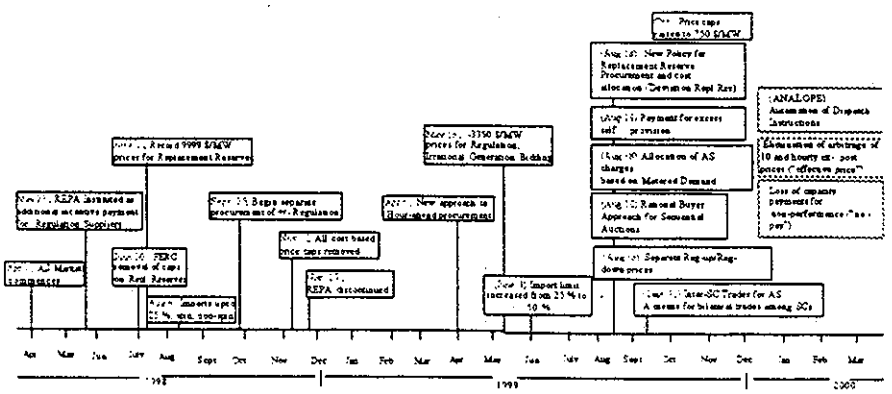
AS Market Performance

- Insufficient Bids for Ancillary Services (AS) Markets
- Decentralized market structure can impose a greater need for AS
- Problems with sequential markets
  - Generator bidding is complex
  - Counterintuitive prices for AS (non-spinning reserve can be more expensive than spinning reserve)
- Regulatory errors
  - some generators subject to price caps while others were not
- Exercise of market power by generators
  - 9999 $/MW prices for Replacement Reserves on July 13, 1998
- Irrational bidding behavior
  - -3350 $/MW for Regulation/AGC on May 16, 1999
- Absence of bilateral market for AS
- Some problems in ISO protocols and software

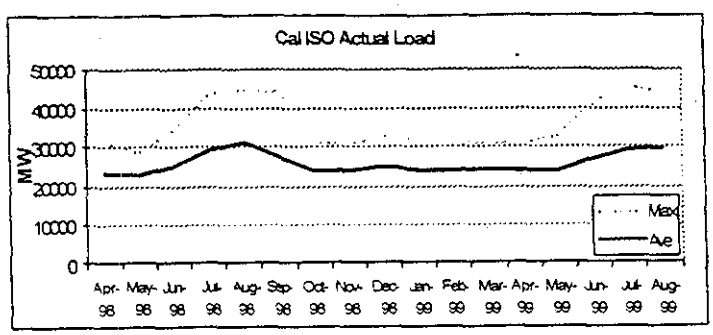
31

AS Redesign



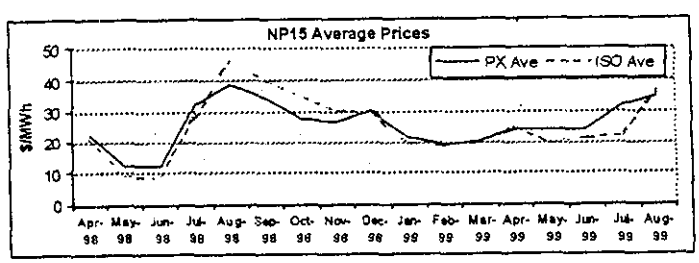
32

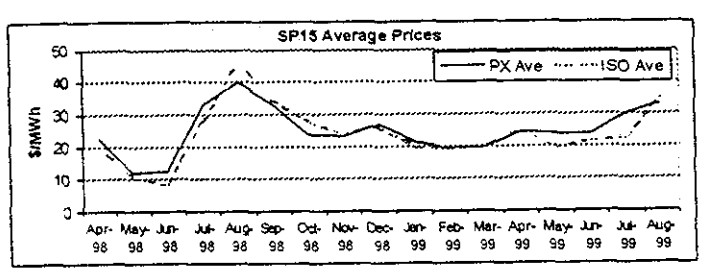
System Load



33

Average Energy Prices





34

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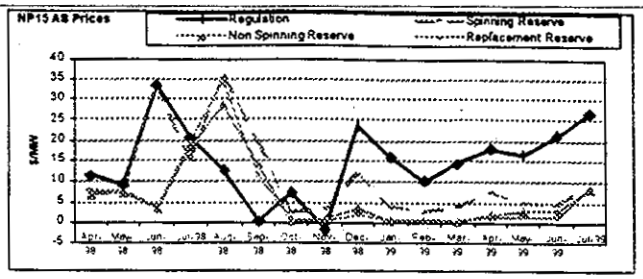
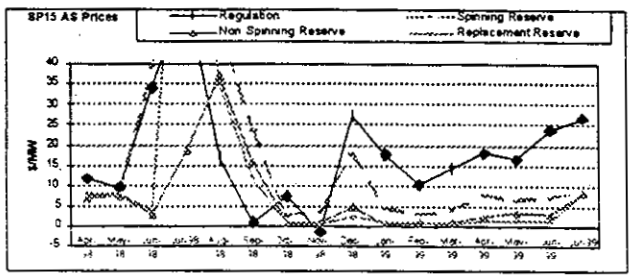
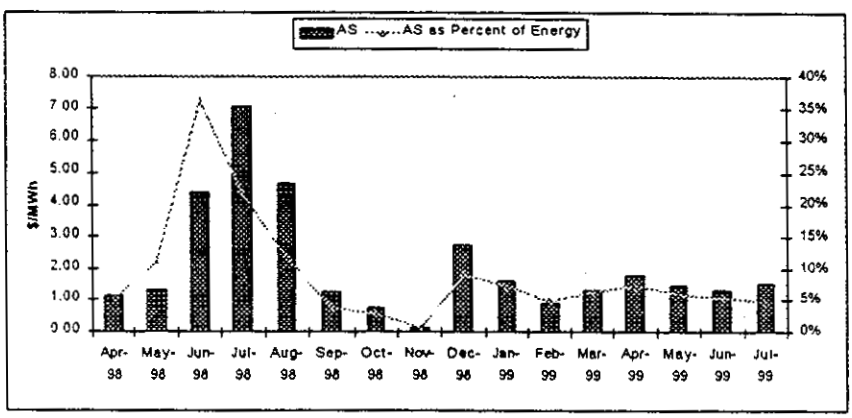
AS Prices





35

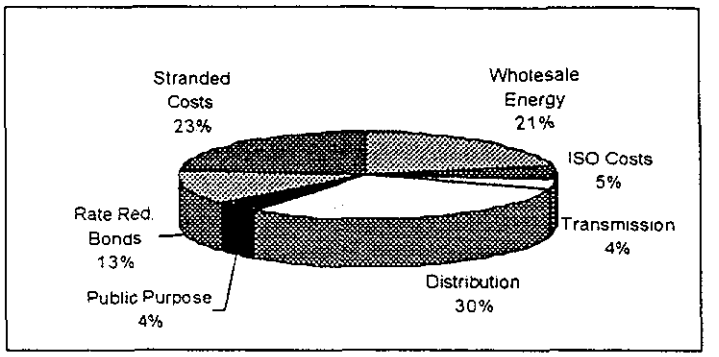
AS Costs/Charges



36

Composition of Retail Energy Costs

Total Market = $ 28 billion

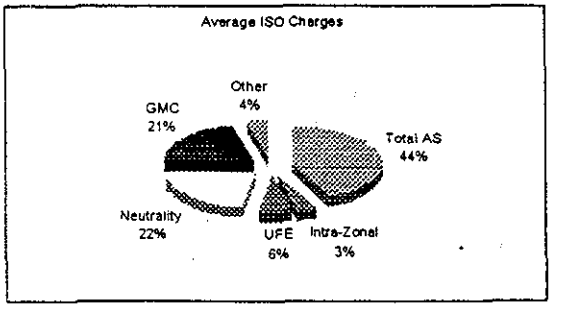


Based on Cal ISO estimate

37

A Study of Cal ISO Charges

- Study period: Apr 98 - July 99
- Average ISO charge: 5.20 $/MWh
  - Ancillary Services (1.59), GMC (0.78), Neutrality (0.82), UFE (0.23), Other (0.15)
- Standard Deviation: 2.17
- Charges are allocated by zone. Averages are shown here.



38

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Lessons Learnt

- Market based pricing for energy must be accompanied by market based pricing for reserves
- Reg-up and Reg-down should be separate services
- Regulation and Load following should be separate services
- AS cost allocation should be done based on metered consumption instead of scheduled load
- Automated communication and dispatch is crucial
- Sequential AS auctions may not always be the most efficient
- Decentralized markets may impose a greater demand for Ancillary Services on the ISO

Competitive Procurement of Ancillary Services by an Independent System Operator

Harry Singh
Member

Alex Papalexopoulos
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Pacific Gas and Electric Company
San Francisco, California

Abstract

This paper discusses the competitive procurement of Ancillary Services by an Independent System Operator (ISO). The paper assumes the existence of an underlying market for energy and explains why this energy market must be accompanied by a market for Ancillary Services. These services include operating reserves and Automatic Generation Control (AGC) both of which may require generators that are infra-marginal in the energy market to choose between supplying energy or Ancillary Services. The paper discusses the design of an auction for these services that has formed the basis for the California ISO's Ancillary Services market. The paper also discusses the real-time dispatch of Ancillary Services.

Keywords: Electric Power Deregulation, Auctions, Operating Reserves.

1. Introduction

Competitive energy markets are being instituted in many jurisdictions as electricity supply industries are restructured in steps towards deregulation. In general, these arrangements require some form of a central auction for electricity to be delivered over short time periods. There are two distinct forms of market structure that have already been implemented around the world; a real-time market, such as the one that has been instituted in the Australian state of Victoria, and day-ahead (forward) markets such as those that have been instituted in England and Wales, Norway, and California [1,2,3].

Since electricity is delivered instantaneously, it is obvious that a day-ahead market requires a balancing service with an associated real-time market. In England and Wales, the balancing function is provided at the day-ahead price. In California, the balancing function is priced separately at an ex-post price that is determined in the real time market based on an auction for imbalance energy and the associated dispatch instructions issued by the Independent System Operator (ISO).

The operation of the real time market is a fundamental responsibility of the ISO. Since the ISO does not own any generation, it must ensure that there is sufficient unloaded capacity among on-line generators to participate in the balancing market and secure the required amount of reserves needed for maintaining the reliability of the system. The ISO must also ensure that there is a sufficient quantity of Automatic Generation Control (AGC) capability and quick-start generation capacity, and conform to mandated reliability criteria [7]. One way the ISO can meet these requirements is to create a competitive market for Ancillary Services.

A premise of this paper is that competitive markets for energy require competitive markets for Ancillary Services. This is particularly true for those services that bear a complementarity to energy markets. Two particular examples are spinning reserves and AGC. Both these services require generating units to maintain on-line unloaded capacity that can respond within 10 minutes. These services are used in real-time by the ISO, either for balancing purposes or for replacing energy that had been scheduled to be provided by a unit that malfunctions.

The main characteristic of the ancillary services discussed in this paper is that capacity is reserved and procured in advance and then incremental energy is dispatched in response to real-time imbalances. This means that there are two relevant prices to be paid to generators. One is the price paid for reserved capacity and the other is the price paid for energy that is dispatched under certain defined conditions. Since the generator cannot anticipate or control the amount of energy it will be called on to produce, it is entitled to a variable energy payment. Since balancing markets are likely to be much smaller than day-ahead markets, it is essential that market designers and regulators ensure that reserve generators do not achieve market power in these real-time energy markets.

Efficient dispatch may require some generating units that are infra-marginal in the energy market to contribute towards the

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reserve requirements in a control area. These infra-marginal units may incur an opportunity cost for setting aside a part of their capacity to provide reserves instead of selling energy in the competitive market. One approach to pricing the reserve services is to simultaneously procure reserves and energy in a single combined auction and compensate the units providing reserves at their opportunity costs derived from the energy auction. This approach can work in a market structure where the entity responsible for procuring Ancillary Services is also responsible for operating the energy market.

Another approach is to set up a separate auction for procuring reserves. A separate reserve auction is better suited for market structures where the Independent System Operator (ISO) is separate from the Power Exchange (PX), the entity that operates the forward energy market. This paper discusses the competitive procurement of Ancillary Services by an ISO under such a market structure. Section 2 of the paper describes the operation of the day-ahead energy market. Section 3 discusses the California model for procuring Ancillary Services while Section 4 presents the role and the financial responsibilities of the purchasers of the ancillary services. Section 5 describes how opportunity costs are incurred in providing reserves while Section 6 presents the structure of the reserves auction. Section 7 presents the interactions between the various energy and ancillary services markets. Section 8 describes how ancillary services are dispatched in real-time and Section 9 addresses practical limitations of the proposed ancillary services auction model arising from market power concerns.

2. The Day Ahead Energy Market

Given the close relationship between the energy and the ancillary services markets it is desirable to start by briefly describing the structure of the day-ahead energy markets. The market structure assumed in this paper consists of a separate grid operator or ISO and market operator or Power Exchange (PX). This model has been adopted in California. It is useful to begin with a conceptual description of the PX energy auction. The PX auction is actually a series of 24 auctions, one for each hour, conducted simultaneously. Generators submit price curves that describe their energy offers as a function of price; the quantity of energy offered must be a monotonically increasing function of price. Loads submit similar curves which must be decreasing. The bid curves may be different for different hours.

The PX aggregates the curves into aggregate supply and demand curves for each hour. It determines the point at which each hour's supply and demand curves intersect. This point sets the PX Market Clearing Price (MCP) for that hour. The bid structure forces generators to bid as if their total cost curves are convex (that is, the bid curves are convex and if one assumes generators bid their costs then they would be claiming to have convex total cost curves). Furthermore, the PX auction model adopted in California and discussed here recognizes no operational or inter-temporal constraints. There may be iterations in the energy auction to help bidders satisfy their operational requirements, but they are not significant in describing the ancillary services procurement model [2,3].

This means that the PX prices and associated dispatch patterns are not likely to lead to the conventional cost-minimizing dispatch for each hour. Units need not bid pure variable costs and are encouraged to internalize all physical constraints. This helps reduce the opportunities for arbitrage between the PX and the ISO's balancing market and makes the pricing process more transparent.

The goal of the PX auction is not necessarily to minimize production costs but to facilitate trade. The PX auction is intended to discover the prices at which parties are willing to transact.

3. Procurement of Ancillary Services

The Ancillary Services which the California ISO is responsible for procuring include spinning reserves, non-spinning reserves, AGC, replacement reserves, voltage support and black start[1]. The Western Systems Coordinating Council (WSCC) definition refers to the first two as operating reserves and the first three are as contingency reserves [7]. Spinning reserves refer to unloaded generating capacity that is on-line and synchronized to the system and all of which can be made available within 10 minutes. Non-spinning reserves refer to unloaded generating capacity that can be made available within 10 minutes but is not necessarily on-line or synchronized to the system. The reserves and AGC services are usually provided by generators by setting aside unloaded capacity in the energy auction for possible use in real time by the ISO. The first four services can be procured by the ISO by means of daily competitive auctions. These auctions occur after the PX energy auction is completed. The sequence of the auctions is AGC, followed by spinning reserves, non-spinning reserves, and replacement reserves. This sequence allows capacity bids that are not selected in one auction (e.g. AGC) to be considered in a subsequent auction (e.g. spinning reserves). The last two ancillary services, i.e., black start capability and VAR support, are more suitable for purchasing based on long-term contracts from among those units physically capable of providing them. Spinning and

[1] The definitions of the various Ancillary Services used in this paper are based on those used by the California ISO and are consistent with standards set by the WSCC.

non-spinning reserve requirements for the ISO are defined by traditional reliability criteria [7][2]. In addition, the ISO needs to make sure it has enough capacity online for a well-functioning balancing market. For this, the ISO may arrange for replacement reserves which are defined as unloaded generation capacity (not necessarily on-line) that can be made available within 60 minutes.

One can interpret operating reserves as a call option[3]. The "strike price" associated with the call option could be the energy price that is agreed to at the time of purchasing the reserves. The exercise value of the option is the price that would otherwise be paid for balancing energy. However, an important characteristic of reserves, as distinct from financial options, is that they are procured not based on any dynamic hedging strategy but based on preset reliability standards defined by NERC and WSCC that relate the reserve requirement to overall generation.

4. Ancillary Services Settlements

The costs incurred by the ISO for purchasing reserves can be classified into two categories, (a) those that are mandated by reliability protocols, and (b) those that can be assigned to the ISO's customers as a function of their observed performance and behavior. For our purposes it is sufficient to assume that the ISO's customers are represented by Scheduling Coordinators (SCs)[4] consistent with the California energy market model. Since the reliability requirements are proportional to scheduled load, the reserve responsibility can be allocated pro-rata to Scheduling Coordinators in proportion to their submitted schedules.

The one exception is the case of replacement reserves which are procured (at least in part) on the basis of what the ISO expects to be the difference between its own load forecast and the sum of the SC submitted schedules. In case the replacement reserves are actually dispatched, their costs are allocated to the Scheduling Coordinators in proportion to positive imbalances[5].

5. Opportunity Costs

Before proceeding with the design of an auction for reserves, it is important to understand the structure of the costs incurred in providing reserves. There are two types of costs that must be represented. These include the opportunity costs of providing reserves and the costs incurred in case the generator is actually dispatched. To understand how opportunity costs arise, consider the case of a single reserve category, spinning reserves. We use spinning reserves as a prototype to motivate the analysis but the same logic applies to other ancillary services sharing the characteristic that capacity is reserved in advance and then used as dispatched generation in real-time.

Suppose that for a given hour the system load requirement is 6000 MW and that the spinning reserve requirement is 200 MW. Assume that 5600 MW of demand is met by a base load nuclear plant operating at full output. For the remaining 400 MW of demand and the 200 MW of spinning reserves, there are two units A and B with incremental energy bids of 4c/kWh and 5c/kWh respectively and a capacity of 300 MW each. In the absence of any ramping rate limits, the economic solution would be to dispatch unit A at its upper limit of 300 MW and unit B at 100 MW. Unit B would provide the spinning reserve from its unloaded capacity. Since unit B is the marginal unit in the energy dispatch, it does not incur any opportunity cost in providing spinning reserves.

Next assume a more realistic scenario where both units are constrained by ramping rate limitations; each is able to provide a maximum of 100 MW in 10 minutes. In this case, the spinning reserve must be provided by both units and both are dispatched at 200 MW. Unit A is an infra-marginal unit, that incurs an opportunity cost to be able to provide spinning reserves. In current operation, it is common to see infra-marginal units incurring opportunity costs in providing reserves during peak load hours. This suggests that bidders should be allowed to bid in a competitive auction for reserves their assessment of opportunity costs in terms of a capacity reservation bid.

The one case where a capacity bid may reflect actual costs instead of opportunity costs is AGC. AGC requires a generator to operate at a level higher that its minimum output, in order to allow movement of the unit in downward as well as upward directions. For example a unit with costs of 5 c/kWh would not normally operate at levels higher than its minimum output when the price in the energy market falls below 5 c/kWh. In order for it to do so, it is entitled to bid for

[2] The WSCC requires an operating reserve requirement of 7 percent of scheduled demand in addition to any provisions made for interruptible imports and firm exports.

[3] A *call option* is a financial instrument that gives the holder a right to buy the underlying asset at a certain time at a certain price.

[4] A Scheduling Coordinator submits a set of balanced generation and demand schedules to the ISO in the day-ahead market and settles with the ISO for any imbalances in the real-time market. The PX is also a Scheduling Coordinator.

[5] For a given Scheduling Coordinator, an imbalance is defined as the difference between the actual aggregate load and actual aggregate generation. An imbalance is positive when actual load exceeds actual generation.

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a capacity payment to cover the actual costs the unit may incur.

6. The Reserves Auction

This section presents the basic structure of an auction for competitively procuring ancillary services. The proposed market structure assumes that there are separate auctions for each category of reserves (spinning, non-spinning and replacement). Each bidders submits a separate capacity bid R_i (\$/MW), and energy bid E_i (\$/MWh) for each service. Successful bidders are paid a capacity reservation payment that is intended to reflect their opportunity costs. Bidders are also paid for energy if they are called on to provide it in real time. Depending on the specific case (as determined later in this section by the value of a weighting factor x) this energy price can be the real-time market price or a "strike price" as if an option were being exercised in the real-time balancing market.

The auctions for reserves differ from the PX auction in one very important aspect. The goal of the PX auction is to facilitate trade because there will be many participants on both sides, i.e., buyers and sellers[6]. Ancillary services are fully the ISO's responsibility, so the ISO acts as the single purchaser in reserve auctions to meet its reliability obligations. If the purchaser of energy from reserves could be identified in advance it could be forced to schedule capacity. Because the "energy purchase" is a random event, the ISO as the agent for all market participants buys the reserves according to a preset formula. As a single buyer the ISO can seek to minimize its costs; the formula that governs the purchase should prevent strategic withholding of reserve demand.

An important property of opportunity costs is that the more infra-marginal a unit (the deeper in the loading order), the greater its opportunity costs in providing spinning reserves. Thermal units' capacity reservation bids should reflect their opportunity costs, which in turn reflect lost profit (market energy price minus marginal cost). The capacity reservation bids R_i should be inversely related to the energy bids E_i, if energy bids are cost-reflective as they ought to be in a competitive market. Thus, to minimize the expected cost of reserves, the ISO cannot consider only the capacity or only the energy bids, but must estimate the probability that reserves will be utilized in real-time. It must include a probability factor represented by a parameter x in the bid evaluation, i.e., bids are ranked on the basis of R_i+xE_i. In order to keep the auction transparent, x must be set by the ISO prior to bid submission.

[6] The PX energy auction is a double auction while the ISO's ancillary services auctions are single sided auctions.

The ISO's reserve auction can then be expressed as the following cost minimization problem:

$$\{\min \sum_i (R_i + xE_i)Q_i \mid \sum_i Q_i \geq Q_{req}, Q_i \leq Q_i^{max}\}$$

where Q_i is the quantity of reserves offered by resource i, R_i and E_i are the associated capacity reservation and energy bids, and Q_i^{max} is the maximum capacity that the resource can offer based on its ramp-rate. Q_i^{req} is the quantity of reserves that needs to be procured.

Next alternative auction designs are examined corresponding to different values for the parameter x.

The (x = 1) case:

By setting x=1, the ISO can determine the maximum extent of its payments [1]. Under assumptions of cost revealing bids, the x=1 scenario allows a bidder to be indifferent between providing spinning reserve or energy. Successful bidders are paid a capacity payment at a price C_i where

$$C_i = \max_{i \notin \Omega} \{R_i + E_i\} - E_i$$

and Ω is the set of all successful bidders. They are paid their energy "strike price" E_i for any energy they are called upon to generate in real-time.

The ($0 \leq x \leq 1$) case:

In the design described in [2], the ISO proposed an auction loosely based on the notion of purchasing call options on the real-time balancing market. In order to pursue a cost minimizing bid evaluation, the ISO would use an unbiased estimate of the probability x (between 0 and 1). In this case, the bids are ranked according to $R_i + xE_i$. Successful bidders are paid at a price

$$C_i = \max_{i \notin \Omega} \{R_i + xE_i\} - xE_i$$

A reserve generator is paid its energy "strike price" E_i if it is called upon to generate in real-time, irrespective of the balancing market price.

The (x=0) case:

The ($0 \leq x \leq 1$) case may be criticized as being too complex and susceptible to being gamed. It is only an approximation to the true cost minimization, as the probability of calling upon a successful bidder to generate in real-time is likely to vary according to the energy bids. Presumably, intelligent bidders could game this market structure to increase their revenues. One scenario involves bidders lowering their energy bids in order to increase their capacity payments. However, this also increases the probability of the bidder's getting called upon to generate in real-time. Ideally, a bidder would like to lower its energy bid as much as possible without altering its position in the merit order stack. Finally,

the option-based case does not result in a uniform price for reserve capacity payments making it less transparent.
An alternative design, is to rank bids solely on the capacity reservation: i.e., the ISO takes bids in order of reservation bids, and pays each successful bidder the highest reservation bid among those accepted.

Since the energy bids are ignored in the bid evaluation, there is less justification to consider them as fixed strike prices. It might appear reasonable to assume that the reserve units are price-takers in the real-time market, i.e., they cannot set the real-time price which they must accept. Clearly if all reserve units are price takers (and there is no obligation to replace reserves that are used), the ISO could end up dispatching all the reserves without impacting the real-time price.

To solve this problem, reserve units are deemed to bid their (preset) energy prices into the balancing market plus any additional costs the ISO may incur. Reliability Council requirements mandate that the ISO should replace spinning reserves that are used in real-time within the hour (i.e., if energy is taken from a spinning reserve unit, the ISO needs to procure additional spinning reserve within a certain time-frame in order to get its reserves back to the WSCC-mandated level). The ISO must factor the cost of such replacements into dispatch decisions. To do so, the energy bids are increased by additional costs such as capacity replacement.

Under this design, energy bids are predetermined, but not payments. For their generation, bidders will be paid the uniform balancing market price. This might seem counter-intuitive from a cost minimization perspective. However, it emerged as the best alternative in the California electric industry restructuring debate under the assumptions of a competitive real-time market.

The three alternatives for bid evaluation are illustrated by using a simple example. Suppose there are three generating units that submit bids as shown in Table 1 into the spinning reserves auction.

Table 1: Bids for spinning reserves auction

Unit	Ri ($/MW)	Ei ($/MWh)	Ramp-Rate (MW/min)	Unloaded capacity (MW)
1	4	35	10	120
2	5	22	10	100
3	12	20	10	100

Suppose that the ISO needs to procure 180 MW of spinning reserves. Depending on the value chosen for x, the outcome of the auction can be different. The results of the ISO's auction for different values of x are shown in Table 2 and Table 3. Table 2 shows the selected quantities and Table 3 shows the capacity prices that are paid to the selected bidders.

Table 2: Spinning reserve auction results

	Selected MW quantities		
x	Unit 1	Unit 2	Unit 3
0	100	80	0
0.5	80	100	0
1	0	100	80

Table 3: Capacity payments to successful bidders

	Capacity price C_i ($/MW)		
x	Unit 1	Unit 2	Unit 3
0	5	5	0
0.5	4	10.5	0
1	0	10	12

The analysis put forth to support this alternative assumed that reserve bidders would bid their true energy costs, and that their capacity reservation bids would be the corresponding opportunity costs. Those assertions were based in turn on the assumption that the reserve market would be competitive as well as the market for balancing energy. That second assumption may not hold if opportunity costs are large enough that non-reserve units are eliminated from the balancing market. Therefore, the argument against an explicitly cost-minimizing solution is less compelling than in the case of the PX auction.

7. Interactions Between the Various Markets

The ancillary services markets are embedded in a series of energy and capacity markets including the forward energy markets (day-ahead and hour-ahead) and the real-time balancing market. It important to manage the interactions between the two markets.

For example, the ISO is responsible for ensuring reliability. Therefore it needs to make sure there is sufficient generation available to match with demand spikes. It buys that energy from the real-time market but because there is no price set on reliability (and no known cost for failure to serve) it cannot assume that the real-time price will suffice to secure sufficient supply. Therefore, the ISO may have to schedule replacement reserves, in excess of the WSCC requirement for reserves, to ensure liquidity in the real-time market.

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Just like generators, loads can choose between the forward and real-time markets. In other words, a load without prescheduled supply can just choose to appear in the real-time market. In fact, if forward prices exceed incremental costs but real-time prices do not – because they are based on incremental bids from already-operating units, or because fixed costs of operation are covered by reservation payments – we should expect massive desertion of load from the forward markets into the real-time markets. The solution for mitigating against this possibility that has been put forward is to make real-time market load deviations responsible for replacement reserve capacity payments [2,3].

There are also relations between the various reserve markets, and the real-time market. The ISO may not always be able to choose the cheapest source of energy from the real-time market. For example, a unit receiving capacity reservation payments as replacement reserve, while it may have the lowest energy bid among available generators, it may not be able to respond to the ISO's call in a timely manner. The ISO may have to take a spinning reserve unit instead. On the other hand, the ISO will probably try to avoid taking energy from spinning or 10-minute reserve units whenever possible because of the high associated replacement costs.

This means that when the ISO looks for real-time generation it looks only at a subset of the available balancing units. However, one cannot consistently identify the relevant energy market as associated with a particular reserve category. Thus, the size of the "reserve energy market" is small, raising market power concerns; these concerns, albeit serious, are hard to quantify.

8. Dispatch of Ancillary Services

All schedules received by the ISO from the PX and other SCs are balanced. In real-time, deviations from scheduled generation and load levels are inevitable, either as a result of normal load and generation variation or as a result of larger unplanned outages, or as a result of strategic decisions by market participants. Such *uninstructed deviations* from schedules result in an energy imbalance that is manifested in the Area Control Error (ACE). The generators on AGC are the first to respond to the imbalances. This action takes place within a time-frame of seconds. In order to periodically, restore the AGC units to their set-points, the ISO must procure energy by means of *instructed deviations* from resources that have submitted the appropriate energy price/quantity bids to the ISO. This action takes place on a slightly slower time-frame: say every ten minutes. The energy bids (E_i) from the various resources including the three types of reserves can be aggregated to form a supply curve as shown in Figure 1.

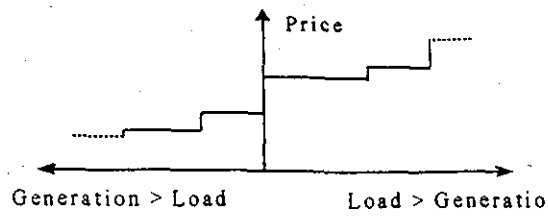

Figure 1: Supply curve for real-time dispatch

Every ten minutes, the ISO conducts a single sided auction[7] for buying or selling energy depending on whether there is excess demand or excess generation in the system. In this sense, the reserves are used along with other available resources in the real-time balancing market. The highest price resource used in the interval sets the price for that ten minute interval. A weighted average of the ten minute prices is calculated at the end of the hour to apply to all uninstructed deviations. A detailed description of the real-time market is beyond the scope of this paper.

9. Market Power and Regulation

In order to secure the regulators' permission to sell energy at market based prices, utilities typically must present a detailed analysis showing the absence of market power. Similarly, they must show that they lack market power in the ancillary services markets in order to be able to sell ancillary services at market based prices. There have been few, if any, attempts to analyze market power in the case of ancillary services. This means that utilities must agree to accept cost-based rates for ancillary services and particularly for reserve capacity. However, determining the cost based rates can be equally arbitrary. Moreover, by choosing a single price to serve as an upper bound or cap for all the hours creates more problems than it solves. For example, in peak hours the opportunity cost of supplying spinning reserves for a generator can be higher than the cost based cap. This would eliminate incentives for infra-marginal generators to make unloaded capacity available for reserves instead of supplying energy. The net consequence would be a shortfall in ancillary services. On the other hand, in off-peak hours, because of the acknowledged possibility of market power, it is quite possible that the prices for reserves could approach the cost-based rates, which can be higher than the competitive prices. This observation seems to be the case in the initial experience in the California market. The prices and quantities for spinning reserves are illustrated in Figure 2 for a given day. The prices throughout the day were at or near the bid caps. During the hours 1-6 and 22-24, the prices were at or near 7.40 $/MW and during the hours 7-21, the prices

[7] At any given instant, the ISO is either buying or selling energy. The ISO does not attempt to optimize the dispatch by simultaneously selling and buying energy.

were at or near 9.50 $/MW[8]. The quantities procured in the hours 7-21 were less than in the lower priced hours, suggesting insufficient supply at the capped prices. In cases of such price-cap induced shortfalls, the ISO may be forced to rely on the increased use of generators on long-term Reliability Must Run (RMR) contracts, at costs that can easily outweigh any savings that result from the price-caps.

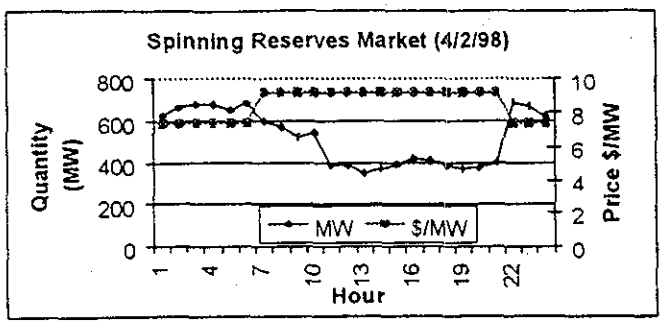

Figure 2: Spinning reserves market results

The reserve capacity markets are only loosely coupled to the other parts of the restructured energy market. The real-time balancing market, on the other hand, is much more closely related to the forward energy markets. Balancing energy is freely substitutable for forward energy. On the other hand, balancing energy is supplied largely from units receiving reserve capacity reservation fees. If the regulators accept that utility market power is mitigated in the forward energy market, but not in the ancillary service market, where does the real-time market fall? A determination that bidders in the real-time market can only receive cost-based rates can have serious repercussions on the prices in the forward energy markets.

10. Conclusion

Competitive markets for electricity require competitive markets for reliability or ancillary services. This paper presents a market structure for the competitive procurement of such services and discusses the role of the opportunity costs incurred in providing these. The design of an auction for ancillary services such as reserves presents an interesting dilemma between strict cost-minimization and efficient incentives for bidders. The proposed design seeks to choose efficient incentives over strict cost-minimization under the assumptions of a well functioning and competitive market.

Disclaimer

This paper does not necessarily reflect the positions of PG&E. Any errors or omissions are the sole responsibility of the authors.

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[8] In the actual implementation of the California ISO's ancillary services auction only those bidders that are not subject to price-caps are eligible to receive the market clearing price. Bidders subject to price-caps are paid according to their bids. This departure from a uniform price auction may also contribute to an increase in prices.

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Design of a Real -Time Electricity Market

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Abstract

This paper describes the design of a market that can be used by an Independent System Operator (ISO) to perform the real-time balancing of demand and supply in the electric power grid. Although, the real-time balancing function is common to all ISOs, there are many different approaches that can be used to price it. The approach described in this paper formed the basis for the design of the California ISO's real-time electricity market.

Introduction

As the electric utility industry restructures, the responsibility for operating the power system is shifting to Independent System Operators (ISOs). One of the primary responsibilities of an ISO is the real-time balancing of demand and supply. This function deals with the management of energy imbalances, which are defined as the difference between aggregate supply and demand in real-time. Management of imbalances requires the use of generation resources whose response may vary as a function of time. Since an ISO does not own any generation resources, it must procure this service in a non-discriminatory manner from resources that belong to multiple owners such as existing utilities, independent power producers and other competitive generation. In some instances, responsive demand may also participate. This service may be procured by organizing a market for Ancillary Services, through long-term contracts or through the introduction of appropriate price incentives in real-time operation [4,5].

This paper focuses on how Ancillary Services and other available resources can be used in real-time for managing energy imbalances. There are two distinct structures that can be used for designing a market to manage energy imbalances. Under either structure, the ISO needs to have at its disposal the appropriate resources which are capable of providing Ancillary Services such as operating reserves and Automatic Generation Control (AGC) along with any Supplemental Energy they may have available from unloaded generating capacity. Under the first structure, the ISO dispatches resources on the basis of their bids and rolls the incurred costs into an uplift that is allocated pro-rata to all customers. This structure, which has been used in the UK, does not explicitly make use of any "real-time" price signals. Instead, it seeks to minimize the uplift costs by imposing penalties on resources that have *uninstructed deviations*[1] from their final schedules established in the short-term forward market[2]. Under the second structure, the ISO seeks to operate a "real-time" market with transparent market clearing prices. These prices are intended to provide appropriate incentives for participating resources to manage their uninstructed deviations in a manner that is consistent with the goal of reducing energy imbalances to zero. The regulating markets in Norway and Sweden and the real-time market in California are examples that fall under this market structure.

Market Structure

The market structure assumed in this paper involves an ISO and a set of independent Scheduling Coordinators (SCs) that represent generators and load [1,2]. The SCs are responsible for submitting schedules to the ISO on a day-ahead basis for each hour of the operating day. The schedules submitted by SCs may involve inter-SC trades. They reflect decisions about generation and demand levels based on the trades that occur in each SC's market. The following rules and observations hold with respect to the market:

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[1] *Uninstructed deviations* are deviations not requested by the ISO. *Instructed deviations* are procured by the ISO in response to the energy imbalances caused by the uninstructed deviations. All schedules in the forward market are assumed balanced.

[2] The short-term forward market is assumed to operate on a day-ahead basis with hourly (or half-hourly) prices.

1. All forward market schedules (including inter-SC trades) submitted to the ISO are balanced on a SC-by-SC basis;

2. In real-time, an imbalance can occur between demand and supply in each SC's portfolio due to deviations from schedules established in the forward markets;[3] such imbalances in the aggregate are reflected in the Area Control Error (ACE);

3. Any aggregate energy imbalance must be restored to zero. The process of restoring the energy imbalances to zero involves the procurement of imbalance energy by the ISO.

The procurement of imbalance energy through competitive auctions is the primary focus of the paper. Additionally, the following observations hold for energy imbalances:

1. At any given instant (or more appropriately, in any given dispatch interval) an energy imbalance is either positive or negative, but not both. Positive imbalances occur when supply exceeds demand, and negative imbalances occur when demand exceeds supply;

2. Individual demand and supply schedule deviations may be instructed or uninstructed. *Instructed deviations* are those requested by the ISO, while *uninstructed deviations* are those not specifically instructed by the ISO. Uninstructed deviations occur due to forecasting errors and normal variations of generation and load from scheduled levels, unplanned outages, strategic behavior by market participants etc.;

3. At any given instant (or more appropriately, in any dispatch interval), the sum of instructed and uninstructed deviations adds up to zero.

In designing a real-time market, two basic issues that must be addressed are, (a) determine the appropriate interval for price calculation and settlements for deviations, and (b) determine the price in each interval.

Design Criteria

The following criteria may be used to evaluate the design of the real-time market:

1. *Revenue adequacy for bidders:* Revenue adequacy for bidders requires that all bids accepted by the ISO in real-time are compensated at prices that are at least equal to their offered prices. This is necessary for creating incentives to respond to the ISO's instructions.

2. *Revenue adequacy for the ISO:* This criterion is relevant if more than one price is used to settle imbalances. It requires that the sum of all payments made and received by the ISO for all real-time deviations (instructed and uninstructed) adds up to zero in a given settlement period (say each hour).

3. *Price stability:* This criterion is essential for every well functioning market. It is related to the relationship between actual imbalances and prices. For example, as demand exceeds supply, the price should increase, and as supply exceeds demand, the price should decrease [3].

4. *Absence of cross-subsidies:* This criterion is important for providing the proper price signals and for reasons of equity. It relates to proper measurement of energy imbalances so that the costs associated with the procurement of imbalance energy can be allocated to those market participants that cause the imbalances.

5. *Susceptibility to gaming:* For operational reasons, it may be undesirable to have speculators in the market that create large uninstructed deviations, particularly if there are obvious opportunities for arbitrage that can be exploited. Large deviations may increase the risk of large imbalances and hence impose a greater operational burden on the ISO.

6. *Simplicity and Transparency:* This criterion is important for facilitating the development of any new market.

Interaction among Resources

The resources that participate in the real-time market are generators and loads that are able to adjust their output in response to ISO's dispatch instructions. These resources may differ in terms of the time frame of their response. They may also be classified by the type of service into two sets: (a) resources whose capacity has been procured ahead of time as Ancillary Services, and (b) resources whose capacity has not been procured ahead of time but is available for use in real-time. The former set includes different categories of reserves: (i.e., spinning, non-spinning, and replacement reserves) and Automatic Generation Control (AGC). The latter category includes resources referred to as Supplemental Energy resources. However, for the purposes of this paper it is more appropriate to classify the resources that participate in the real-time market according to their time

[3] This excludes inadvertent interchange.

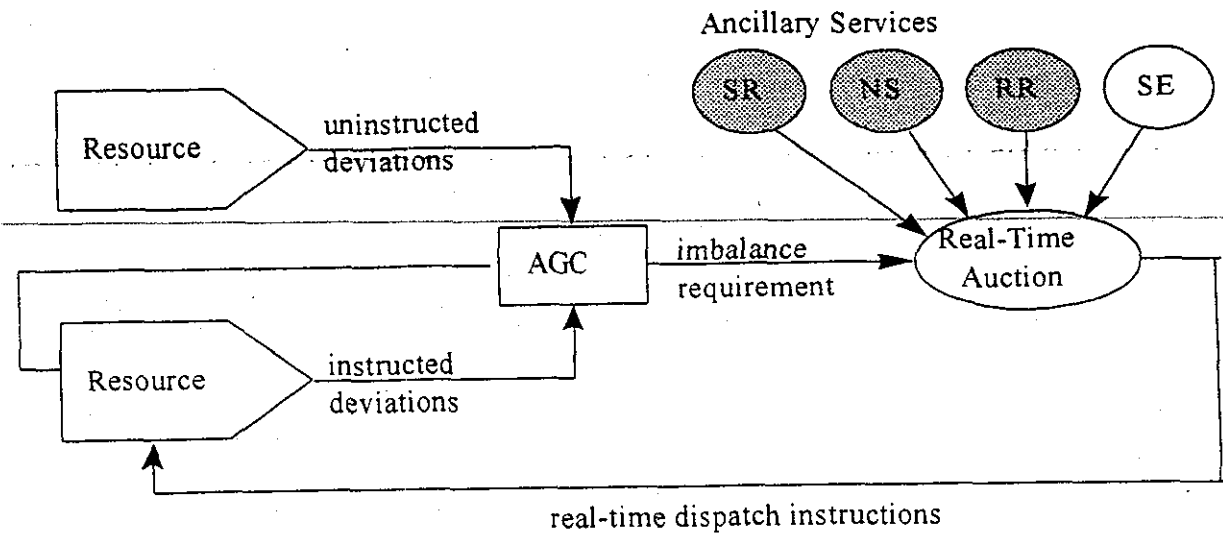

Figure 1: Interaction of different resources in the real-time market

response into (a) AGC resources that respond within seconds, and (b) Reserves and Supplemental Energy that respond within minutes of the ISO's dispatch instruction.

Figure 1 illustrates the interaction between the various categories of resources in the real-time market. Uninstructed deviations from schedules result in an energy imbalance that is manifested in the ISO's Area Control Error (ACE). The generators on AGC are the first to respond to such imbalances. This action takes place within a time-frame of seconds. In order to periodically, return the AGC units to their set-points, the ISO must procure energy by means of instructed deviations from resources that have submitted the appropriate energy price/quantity bids for the imbalance energy auction. This action takes place on a slightly slower time-frame, say every ten minutes. The energy price bids from the various resources, including the three types of reserves, can be aggregated to form a composite supply curve, as shown in Figure 2.

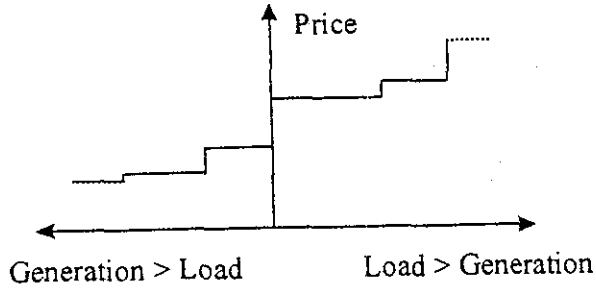

Figure 2: Supply curve for real-time dispatch

In every dispatch interval, say every ten minutes, the ISO conducts a single sided auction[4] for buying or selling energy depending on whether there is excess demand or excess generation in the system. In this market design, the reserves are used along with other available resources in the real-time balancing market. The resource with the highest energy price used in the interval when the ISO buys imbalance energy sets the price for instructed deviations in that ten-minute interval. Similarly, the resource with the lowest energy price used in the interval when the ISO sells imbalance energy sets the price for instructed deviations in that ten-minute interval. A weighted average of the ten-minute prices is calculated at the end of the hour to settle all uninstructed deviations.

Imbalance Energy Procurement: a Series of Auctions

The real-time market can be considered to be a series of *single sided auctions*[5] conducted by the ISO at the beginning of each dispatch interval. Some of these auctions are conducted with buyers, and some with

[4] In any given dispatch interval, the ISO is either buying or selling energy. The ISO does not attempt to optimize the dispatch in a given interval by simultaneously selling and buying energy.

[5] In a single-sided auction there are buyers or sellers, but not both. In a double auction, there are both buyers and sellers. The ISO's role in the real-time market is limited to managing imbalances and restoring them to zero, as opposed to truly operating a market for economic trades.

sellers. Sellers' auctions are conducted during supply deficits, and buyers' auctions are conducted during demand deficits. The quantity being auctioned by the ISO in any given auction is equal to the imbalance energy that the ISO needs to procure based on the net deficit in supply or demand.

It may be impractical to set a clearing price for the purposes of settlements corresponding to every auction. This may result from two factors. First, the large majority of uninstructed deviations are not metered at a frequency that equals the dispatch frequency, e.g., every ten minutes. Second, the sheer volume of doing all settlements at the dispatch frequency may be too cumbersome. Thus settlements may be performed on a somewhat slower time scale (say T).[6] The problem lies in defining a suitable T and in calculating a price for settlements with the winning bidders in all the auctions within a time period T. The possible range of choices for T can vary in multiples of the dispatch interval from 10 minutes to 1 hour.

Price Determination for Instructed Deviations

The section discusses principles for determining the price that applies to instructed deviations. There are three possible cases to consider when defining the price for the settlement period T.

Case 1: All auctions within the time period T are with sellers[7]. In this case, the highest accepted bid among all the auctions within the period T can be used to set the price. Figure 3 illustrates a case where two auctions are cleared at a common price P2, which creates an additional profit or surplus of Q1×(P2–P1) for winners in the first auction. The larger the time interval T, the more auctions clear at a common price and the greater the increase in the sellers' surplus.

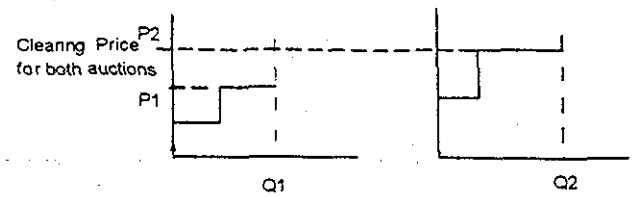

Figure 3: Two auctions with sellers that clear at a uniform price set equal to the highest accepted bid in both auctions.

Case 2: All auctions within the time period T are with buyers[8]. Here, the lowest accepted bid among all the auctions can be used to set the price. Figure 4 shows a case in which two auctions clear at a common price P1, resulting in an additional increase in the consumer surplus of Q1×(P2–P1). Once again, the larger the time interval T, the more auctions clear at a common price and the greater the increase in the winner's surplus.

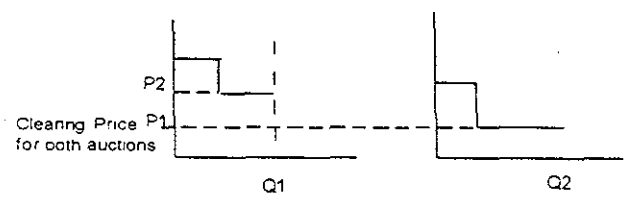

Figure 4: Two auctions that clear at a uniform price set equal to the highest accepted bid among both auctions.

Case 3: Some auctions are with sellers and some with buyers within the time period T. These may be classified into two sets, A and B, of buyers and sellers, respectively. Here, it is difficult to set a single price to settle with all the winning bidders and also satisfy the criterion of revenue adequacy for bidders. The possible choices for price calculation are:

a) *Establish two prices for each time interval T, one for set A (buyers) and one for set B (sellers).*[9] Each price is determined as described in Cases 1 and 2.

---

[6] In the Norwegian and Swedish regulating markets operated by Stattnet and SvK respectively, this time interval is one hour.

[7] This is equivalent to saying that at interval T, the ISO requests the relevant generating units (loads) to increase (decrease) their outputs (consumption).

[8] This is equivalent to saying that in interval T, the ISO requests the relevant generating units (loads) to decrease (increase) their outputs (consumption).

[9] This is similar to the approach followed by SvK, the Swedish grid operator. The imbalances in the system are classified into two categories: active and passive deviations. The active deviations are sales and purchases authorized by the ISO, while the passive deviations are sales and purchases not explicitly authorized by the ISO. Two prices are set for each hour, one for active sellers (and passive buyers) and

b) *Establish a single price based on a pre-determined rule.* The rule may be to use set A, set B, or the larger of the two. Side payments to ensure revenue adequacy for the winning bidders in the set not used to set the price may also be considered.

c) *Choose a time period T that is small enough to avoid Case 3 occurrences.* Clearly, if T is defined to correspond to the dispatch interval, such avoidance is easy. Choosing a shorter time interval also has a significant effect on the surplus. If T is equal to the dispatch interval, the price is the result of one auction only, and therefore, the additional surplus is eliminated.

Case 3a is the basis for the design of the real-time market in Sweden, and appears to satisfy many of the design criteria discussed earlier. It results in revenue adequacy for both the bidders and the ISO, and seeks to limit the role of speculators thereby minimizing gaming. It may be viewed as a design that offers a generous reward for following the ISO's instructions and a penalty for uninstructed deviations from schedules. Since, some degree of uninstructed deviations are inevitable, this system would provide an incentive for introducing de-centralized management of energy imbalances.

In case 3b it might seem reasonable to choose the larger of the sets A and B to set the price for interval T. Thus, during an hour where the ISO increments most of the resources adjusted in real-time, it might make sense to set the price based on the highest bid used. On the other hand, in an hour in which the ISO decrements most of the adjusted resources, the lowest bid selected might be used to set the price. Furthermore, if the ISO makes side payments ("offer shortfall compensation"), it might be acceptable to use an average price instead of the highest or lowest prices.

Case 3c forms the basis of the design of the real time market operated by the California ISO. In this design, instructed deviations are settled at each dispatch interval, which is currently set equal to 10 minutes. This design is further discussed in the remainder of the paper.

Revenue Adequacy for AGC units

The resources that participate in real-time balancing, and consequently in the ISO's real-time auctions include units that provide Ancillary services (e.g., the different reserve categories and AGC), and Supplemental Energy. Ancillary Services are assumed to be procured competitively using a two-part bid format that consists of a capacity reservation price and an energy price [1,2,5]. Supplemental Energy bids use only an energy price and have no reservation payments.

The AGC service differs from the reserve Ancillary Services in at least two significant aspects. First, the AGC service corresponds to a faster time frame than the reserves. Second, AGC allows for bi-directional adjustment of a generating unit's output (up or down). AGC units are continuously responding to the changes in the system load. A given AGC unit's output level may drift with time towards its minimum or maximum limit. If the AGC unit's output reaches a limit, its output level is frozen and the unit becomes ineffective (at least temporarily) for load balancing. The likely course of action taken by the ISO is to restore the AGC unit's output to it nominal set-point (e.g., in the middle of the regulating range) creating a net imbalance to be met by the reserves and supplemental energy units[10]. The net consequence is that no matter how short the interval T is chosen, the inclusion of AGC units in setting the price for that interval would preclude satisfying the assumption in Case 3c. This raises the question of how to ensure revenue adequacy for AGC providers. One possibility is to compensate the AGC units on the basis of their energy price bids instead of the common clearing price for interval T, ensuring that the units are revenue adequate even if the price in interval T is lower than their offered energy price. Another possibility is to let the AGC bidders internalize the risk of revenue inadequacy within their capacity reservation price.[11]

Price Determination for Uninstructed Deviations

In developing the design for calculating the prices that apply to uninstructed deviations, we make two assumptions:

1. It is possible to measure or meter the instructed deviations in each dispatch interval;

2. Uninstructed deviations can only be metered hourly (i.e., they cannot be metered in each dispatch interval).

one for active buyers (and passive sellers).

[10] At times, the ISO may find it useful to introduce a bias to the AGC unit's nominal set-point in order to increase its available AGC capability.

[11] This might be a reasonable approach, particularly if the net energy provided by AGC units is small. The net energy is likely to be smaller if the time interval T is large.

The consequence of these assumptions is to create two frequencies for settlements. The instructed deviations are settled in each dispatch interval, and the uninstructed deviations are settled less frequently every hour. In the California ISO's design, the dispatch interval is ten minutes. For the ISO to be revenue adequate, the hourly price for uninstructed deviations can be set equal to the weighted average of the six 10-minute prices, as follows:

$$\text{Hourly ex-post price} = \sum_{i=1}^{6} \frac{p_i q_i}{q_i}$$

where p_i is the price in interval i, and q_i is the quantity (positive or negative) of imbalance energy procured in interval i. However, this design is far from perfect. For purposes of illustration, consider the case where there are only two time intervals to consider. Further, assume that in the first interval the ISO decrements resources and in the second interval the ISO increments resources. Figure 5 illustrates the case where the quantity of decrement and increment happens to be equal in each interval. The ISO is first selling imbalance energy at the price p1, and then buying the same amount, but at the price p2. Although the net imbalance energy within the hour is zero, the ISO still incurs a net cost of $p2 \times q2 - p1 \times q1$ or $(p2-p1) \times q$, where $q=q1=q2$. Since there is no measured imbalance when both time intervals are taken together, the question of calculating an imbalance energy price becomes moot. The ISO's cost of procuring imbalance energy has to be recovered on a basis other than measured imbalances.

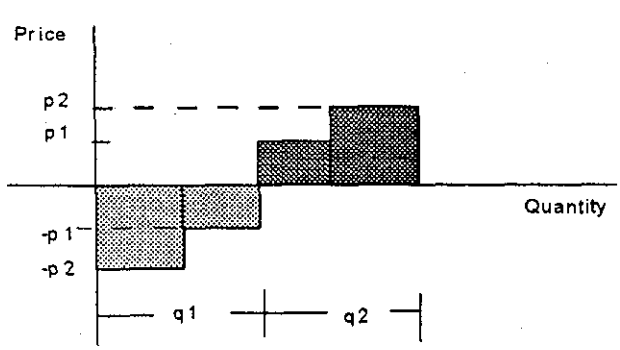

Figure 5: Equal decremental and incremental quantities

A related example illustrates the equity and cross-subsidy problems associated with this approach. Consider a load with unusually large fluctuations (e.g., an arc furnace) that necessitates the ISO's procurement of imbalance energy settled and paid for in each ten minute interval. At the end of the hour, the net uninstructed deviations are measured to be small, and result in an unusually high hourly price for uninstructed deviations. It is unfair to apply this high price to those uninstructed deviations that imposed little burden on the ISO but did not cancel out to zero.

To make the hourly price bear some resemblance to the 10-minute prices, the calculation of the hourly price may be done as follows:

$$\text{Hourly ex-post price} = \sum_{i=1}^{6} \frac{p_i |q_i|}{|q_i|}$$

However under this approach, which has been adopted by the California ISO, the ISO is no longer revenue adequate and may need to recover any revenue shortfall through a separate balancing account.

The use of two different prices for instructed and uninstructed deviations that are based on marginal and average prices sets up arbitrage opportunities that may impose additional burdens on the operations of the ISO.

The Impact of Transmission Congestion

The impact of congestion is to split the ISO's real-time market into separate areas, referred to as congestion regions that are interconnected via congested transmission paths. Imbalance energy is procured by the ISO separately in each region, to meet the uninstructed deviations on a region-by-region basis, without increasing congestion any further. Consequently, separate prices are calculated for each region. The additional complexity that must be addressed relates to price calculation for uninstructed deviations when the occurrence of congestion varies within the hour. For example, congestion may exist on certain transmission interfaces only for a fraction of the hour. Therefore, congestion regions become dynamic as congestion conditions vary within the hour. A detailed discussion of this issue is beyond the scope of this paper.

Numerical Example

Consider the following example where four resources compete for providing imbalance energy, and assume that the scheduled generation is falling behind actual load in real time. Table 1 lists the offered MW quantities and prices, and the dispatch instructions at each of the 10-minute intervals within the hour. The dispatch instructions are relative to the schedules, and they are selected, based on merit order, to meet the ISO imbalance energy requirement at each interval. The

Table 1: Numerical example

Resource	Quantity	Price	Dispatch Instructions						*Total*
			1	2	3	4	5	6	
A	36 MW	$20/MWh					6 MW	12 MW	12 MW
							1 MWh	2 MWh	3 MWh
B	12 MW	$15/MWh			6 MW	12 MW	12 MW	12 MW	12 MW
					1 MWh	2 MWh	2 MWh	2 MWh	7 MWh
C	18 MW	$12/MWh		6 MW	18 MW	18 MW	18 MW	18 MW	18 MW
				1 MWh	3 MWh	3 MWh	3 MWh	3 MWh	13 MWh
D	24 MW	$10/MWh	12 MW	24 MW	24 MW	24 MW	24 MW	24 MW	24 MW
			2 MWh	4 MWh	4 MWh	4 MWh	4 MWh	4 MWh	22 MWh
MCP			$10/MWh	$12/MWh	$15/MWh	$15/MWh	$20/MWh	$20/MWh	
Total MW			12 MW	30 MW	48 MW	54 MW	60 MW	66 MW	66 MW
Total MWh			2 MWh	5 MWh	8 MWh	9 MWh	10 MWh	11 MWh	45 MWh

Market Clearing Price (MCP) is set to the highest accepted price in each interval. These prices are used for instructed deviation settlements, as follows:

A: $1\times20+2\times20=$ $60
B: $1\times15+2\times15+2\times20+2\times20=$ $125
C: $1\times12+3\times15+3\times15+3\times20+3\times20=$ $222
D: $2\times10+4\times12+4\times15+4\times15+4\times20+4\times20=$ $348
Total: $755

The average hourly ex post price used for uninstructed deviation settlements is calculated as follows:

$$\frac{2\times10+5\times12+8\times15+9\times15+10\times20+11\times20}{45}=$$

$$=\frac{755}{45}=\$16.78/\text{MWh}$$

Since the net uninstructed deviation is 45 MWh, the ISO will collect from that settlement:

$45\times16.78=\$755$

In this example, since the ISO was buying imbalance energy in all dispatch intervals, the real time settlements for instructed and uninstructed deviations result in revenue adequacy and there is no need for a balancing account.

Conclusions

The paper describes the design of the real-time market that can be used by an Independent System Operator (ISO) to perform real-time balancing of demand and supply in the electric power grid. The design described in this paper can be interpreted in terms of a sequence of single-sided auctions for imbalance energy. The participation of different categories of resources such as reserves and AGC in the real-time market has been discussed in the paper. Calculation of two different sets of prices to settle for instructed and uninstructed deviations has also been discussed.

Disclaimer

This paper does not necessarily reflect the views of PG&E Energy Services or the Pacific Gas and Electric Company. All errors and omissions are the sole responsibility of the authors.

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ANCILLARY SERVICES IN THE SPANISH SYSTEM

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SPANISH SYSTEM. Overview (1)

Peninsular System (1 999)

Maximum peak load	31 247 MW
Gross electricity demand	184 239 GWh

Generation:	TOTAL SYSTEM	ENDESA
Installed power	43 662 MW	45.4%
Nuclear	7 686 MW	7.4%
Coal	11 238 MW	14.0%
Fuel - gas	8 214 MW	7.4%
Hydro - pumping	16 524 MW	16.6%

Transmission system:	
400 kV circuits	14 538 km
220 kV circuits	15 866 km

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SPANISH SYSTEM. Overview (2)

Peninsular System

Generation	Liberalised activity. Competence
Transmission	Regulated activity
Distribution	Regulated activity
Commercialisation	Eligible clients, V>1 kV(July 2000). Competence

Two Operators:

The **Market Operator (MO)** is responsible for economic settlements:

Day-ahead market	Main market
Intra-daily market	Adjustment markets (6 sessions)

The **System Operator (SO)** is responsible for technical management and system security.

The SO is responsible for Ancillary Services management

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ANCILLARY SERVICES (AS) IN THE SPANISH SYSTEM

- **The AS for active power reserves are fully developed:**

Primary Reserve	Compulsory (automatic, unit governors)
Secondary Reserve	Competitive (automatic, AGC)
Tertiary Reserve	Competitive (under SO requirements)
Deviation Market	Competitive

- **Other Ancillary Services are not developed. They are running by the previous rules to 1998 (co-operative framework):**

  Reactive/Voltage Control
  Black Start

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PRIMARY RESERVE

- All generation units should be equipped with a governor system control
- Adjustment parameters according to UCTE rules
- Service without remuneration
- Generation units without governor should pay a cannon or may contract the service

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SECONDARY RESERVE (1)

- Service structured through Regulation Zones.
- Each Regulation Zone is formed by a set of generation units controlled by an Automatic Generation Control (AGC) system.
- A set of the generation units of the Regulation Zone provide secondary reserve, as a result of a secondary reserve market.
- A master algorithm (belonging to the SO) controls the frequency and France interchange deviation and sends the regulation signals to the different Regulation Zones
- The signals to Regulation Zones are proportional to the reserve assigned in the secondary daily market.

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SECONDARY RESERVE (2)

The service remuneration considers three concepts:

Band: Up/Down reserve capacity, it is paid to each generation unit.

AGC behaviour: The SO monitors in real time the AGC response. Bonus or penalty for the regulation zone.

Secondary energy: Price of the energy according to the tertiary "price staircase". Remuneration to regulation zone.

The band provided by each generation unit and its retribution is the result of a competitive market decided the day ahead (D-1).

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SECONDARY RESERVE (3)

Band Market (Day D - 1)

- The SO publishes the hourly secondary reserve (up/down) needs for day D.
- Each generation unit submit its bids to the SO:
  Up and Down reserve (MW)
  Price (PTA/kW)
- The SO selects the bids until the reserve requirements are completed. The last bid defines the marginal price.
- All the selected bands are paid at marginal price.

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TERTIARY RESERVE (1)

- This Ancillary Service works as an energy market. The band is not paid, only the energy when it is demanded, via phone, by the SO.
- Bids:
  - **Power (MW) that could be deliver before 15 minutes and could be maintained during 2 hours (up/down reserve).**
  - **Price (PTA/kWh).**
- All the generation units have to submit bids for the available reserve.
- The bids could be changed at any time by the agents, there is a dynamic "mailbox" in the information system of the SO.

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TERTIARY RESERVE (2)

- All the bids are sorted by price and they form a "price staircase".
- The SO orders the necessary tertiary reserve according the system necessities. The lower bids one first assigned.
- The energy is paid at marginal price. Price defined by the last bid assigned.
- The tertiary "price staircase" is used to define the secondary energy price.
- Both prices are determined "ex - post"

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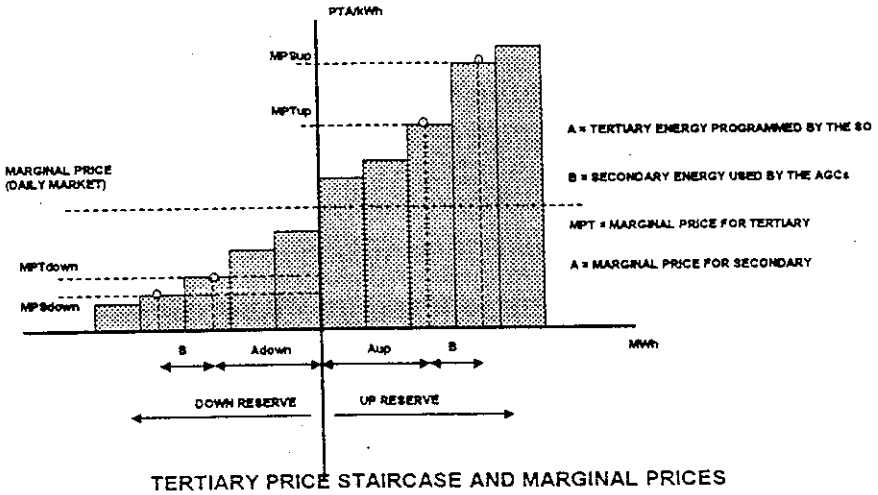
TERTIARY RESERVE (3)



TERTIARY PRICE STAIRCASE AND MARGINAL PRICES

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DEVIATION MARKET

- After an intra - daily market there is not opportunity to renegotiate any change of generation or consumption in an horizon of 4 hours.
- If an important deviation is expected, the SO calls for a Deviation Market Session.
- Only the generation units can submit bids to the SO.
- All the accepted bids are paid at marginal price.

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VOLTAGE CONTROL

- Ancillary Service not developed, there is a draft under discussion.
- The general issues are defined but many details should be clarified.
- Generation:
  - Obligatory reactive band (± MVAr)
  - Additional band could be offered to the SO
- Distribution:
  - Minimum power factor at T-D interface
  - Additional resources could be offered to SO
- *Transmission:*
  - All means of voltage control will be managed according to SO criteria

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BLACK STAR

- Ancillary Service not developed
- There is not draft.

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Market sequence for day D

	Hour	Market	Remarks
DAY D-1	10:00	Daily Market	Bid reception is closed (MO)
	11:00	Daily Market	Results of Daily Market
	12:00	Daily Market	The production plan of Hydro plants are send (SO)
	14.00	Secondary/Tertiary Market	The needs of secondary and tertiary reserves are published (OS)
	14:00	Daily Market	The results of congestion management are published (OS)
	15.30	Secondary Market (Band)	Bid Reception is closed (SO)
	16:00	Secondary Market (Band)	The results of Secondary Market are published (SO)
	17:45	Intra-daily market 1	Bid reception is closed (MO) [Market horizon: 21:00(D-1) to 24:00 (D)]
	18:30	Intra daily market 1	Results of intra-day market 1 are published (MO)
	21:45	Intra-daily market 2	Bid reception is closed. (MO) [Market horizon: 00:00 (D) to 24:00 (D)]
	22:30	Intra-daily market 2	Results of intra-day market 2 are published (MO)
	24:00	Tertiary Market	Tertiary bids are sent to a dynamic "mailbox"
DAY D	01:45	Intra-daily market 3	Bid reception is closed. (MO) [Market horizon: 04:00 (D) to 24:00 (D)]
	02:30	Intra-daily market 3	Results of intra-day market 3 are published (MO)
	04:45	Intra-daily market 4	Bid reception is closed. (MO) [Market horizon: 07:00 (D) to 24:00 (D)]
	05:30	Intra-daily market 4	Results of intra-day market 4 are published (MO)
	08:45	Intra-daily market 5	Bid reception is closed (MO) [Market horizon: 11:00 (D) to 24:00 (D)]
	09:30	Intra-daily market 5	Results of intra-day market 5 are published (MO)
	12:45	Intra-daily market 6	Bid reception is closed. (MO) [Market horizon: 15:00 (D) to 24:00 (D)]
	13:30	Intra-daily market 6	Results of intra-day market 6 are published (MO)

After each intra-daily market a Deviation Market session could be open by OS (if an average deviation higher than 300 MW is expected). In 30 minutes the Agents have to send his bids [Market horizon 4 hours (aprox)]

FORUM ON ANCILLARY SERVICES. WARSAW, February 22-24

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Market sequence for day D (in short)

	Hour	Market	Remarks
DAY D-1	14:00	Secondary/Tertiary Market	The needs of secondary/tertiary reserves are published (OS)
	14:00	**Daily Market**	**The results of congestion management are published (OS)**
	15:30	Secondary Market (Band)	Bid Reception is closed (SO)
	16:00	**Secondary Market (Band)**	**The results of Secondary Market are publishes (SO)**
	18:30	Intra daily market 1	Results of intra-day market 1 are publishes (MO)
	22:30	Intra-daily market 2	Results of intra-day market 2 are publishes (MO)
	24:00	**Tertiary Market**	**Tertiary bids are sent to a dynamic "mailbox" (SO)**
DAY D	02:30	Intra-daily market 3	Results of intra-day market 3 are publishes (MO)
	05:30	Intra-daily market 4	Results of intra-day market 4 are publishes (MO)
	09:30	Intra-daily market 5	Results of intra-day market 5 are publishes (MO)
	13:30	Intra-daily market 6	Results of intra-day market 6 are publishes (MO)

After each intra-daily market a **Deviation Market session** could be open by OS (if an average deviation higher than 300 MW is expected). In 30 minutes the Agents send their bids [Market horizon 4 hours (aprox)]

Endesa

RESULTS AND EXPERIENCES (1)

- The algorithms for:
  - Secondary band market
  - Deviation market

  have been changed in order to improve the market behaviour
- Regulatory mechanisms should act quickly if bad behaviour of algorithms is detected.
- Nowadays, all the developed AS are working well and only minor modifications could be necessary in order to improve them.
- In the beginning only hydro units provided the secondary service. At the end of 1998, as the market was attractive, 24 thermal groups were participating in the market.

Endesa

RESULTS AND EXPERIENCES (2)

Examples of possible improvements

- Price of secondary energy. Sometimes, due to the tertiary reference, the secondary energy prices are very low and could be below to the daily market price.The secondary energy is an energy of high quality and its price should be higher than the daily market.
- The master algorithm that sends signals to the different Regulation Zones is a quick adaptation from the old system rules (cooperative model). There are several proposal under study.
- *Tertiary energy assignment procces:*
  - The consumption of secondary energy should be minimum.
  - The assignment of tertiary programs should be more frequent.
  - The energy programs should consider the unit ramps.

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AVERAGE COST OF THE ANCILLARY SERVICES

Year 1999

1 € = 166,386 PTA

			Impact on final price
• Secondary Reserve (total)		7502 MPTA	0.047 PTA/kWh
Band	4705 MPTA		
Secondary energy	2797 MPTA		
• Tertiary reserve		6559 MPTA	0.025 PTA/kWh
• Deviation market		4218 MPTA	0.016 PTA/kWh
Total AS costs		**18 279 MPTA**	**0.088 PTA/kWh**

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AVERAGE COST OF THE POOL ENERGY

Year 1999

1 € = 166,386 PTA

• Production cost	4.45 PTA/kWh	76 %
• Uplift due to AS	0.09 PTA/kWh	1.5 %
• Uplift due to congestions	0.07 PTA/kWh	1.2 %
• Power guarantee	1.23 PTA/kWh	21 %
TOTAL COST	**5.84 PTA/kWh**	**100%**

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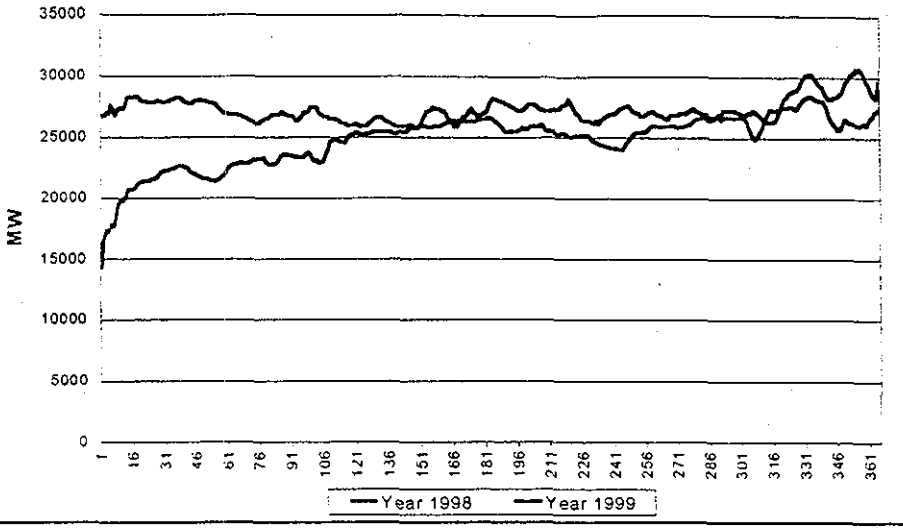
Daily band necessities publishes by the OS



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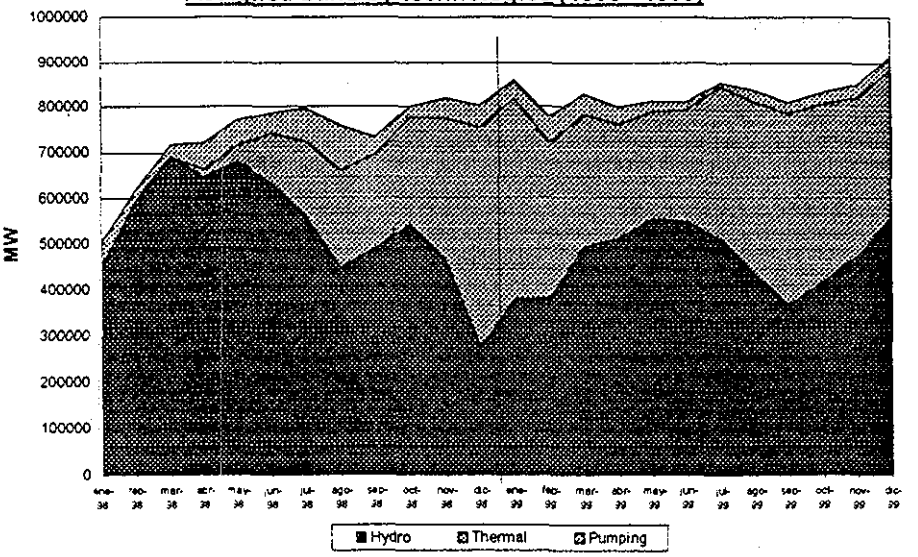
Assigned band by technologies (1998 - 1999)



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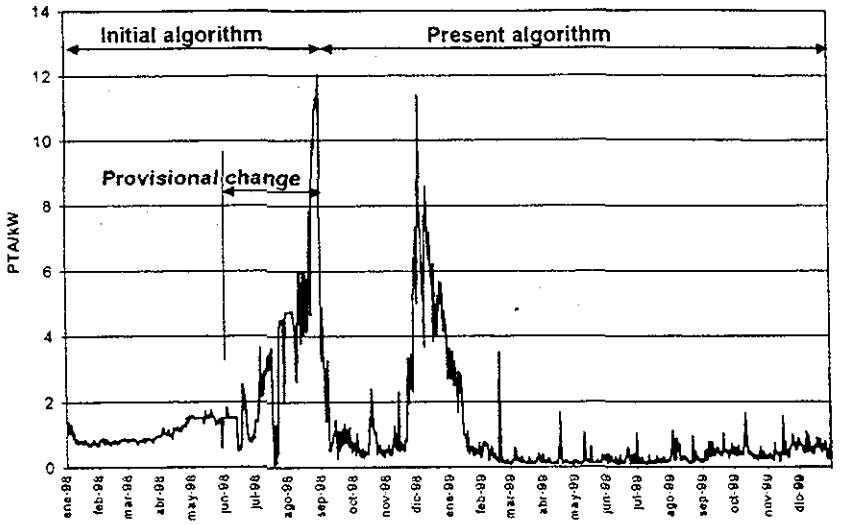

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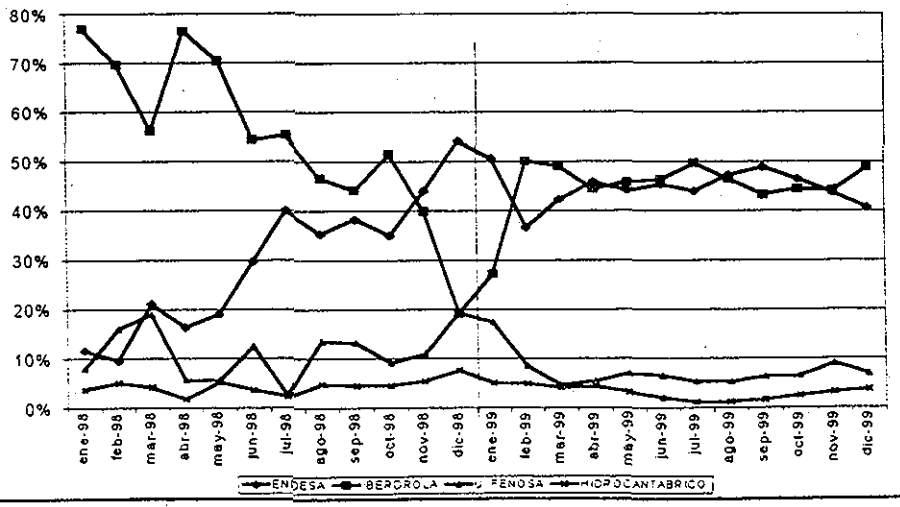
Evolution of the market shares



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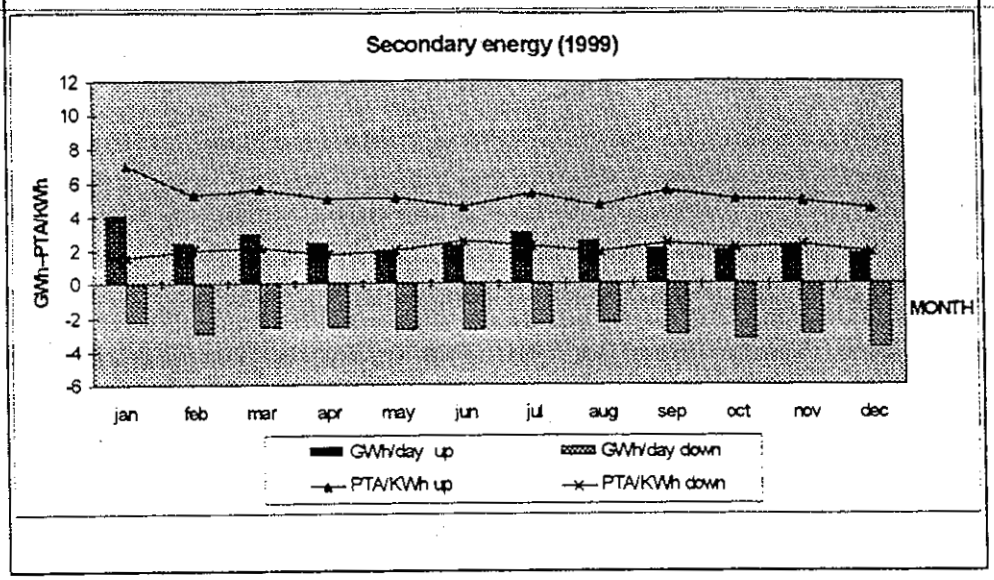

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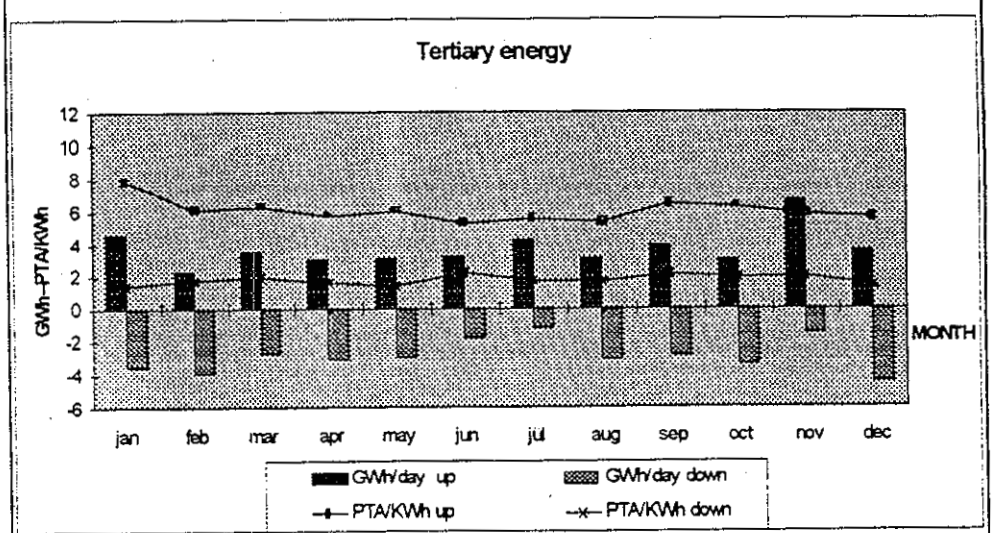

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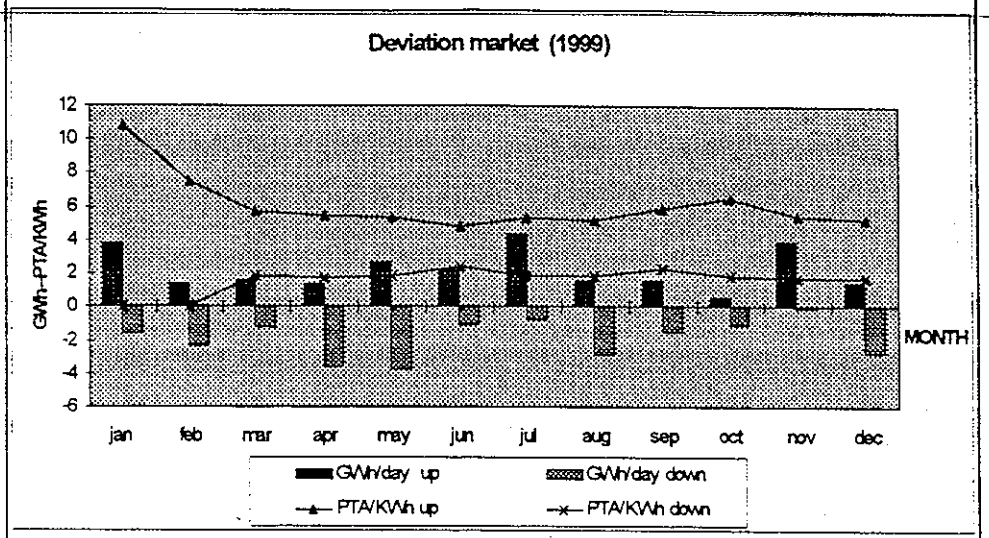

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Webs

- System Operator: www.ree.es
- Market Operator: www.comel.es
- Regulatory Commission: www.csen.es
- Electricity association: www.unesa.es
- Endesa: www.endesa.es

CURRICULUM VITAE

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Qualifications:
- Ingeniero Electromecánico de ICAI (Madrid) in 1976
- Ingeniero Industrial in Electrical Engineering from the Universidad Pontificia Comillas (Madrid) en 1982.
- Doctor Ingeniero Industrial from the Universidad Politécnica de Madrid en 1986.

Professional experience:

From 1976 to 1978 he was with Empresarios Agrupados, an engineering company, working in the Electrical Department for several power plant projects. From 1979 to 1987 he was with the Universidad Pontificia Comillas, working in the Electrical Department as Professor of Electrical Machines and Power Systems, and working on the research staff in R&D projects for Spanish utilities.

From October 1987 to June 1997 he was with Red Eléctrica de España (REE), a public electric utility created in 1985 to unify the operation of the Spanish generation and the EHV transmission system. He was Head of the Network Planning Department, in charge of the development of the Spanish transmission system and he conducted several research projects about network planning subjects.

In July 1987 he joined ENDESA, where he is responsible for Transmission and Ancillary Services at Electrical Markets Direction of ENDESA.

He is author of several papers in the Electric Power Systems fields, and is a member of the IEEE Power Engineering Society. He was member of CIGRE WG 37.12 and UNIPEDE WG 40.05 SYSTMED.

Exchange and trade of AS among independent systems

Warsaw, 23 February 2000

Javier Alonso
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132

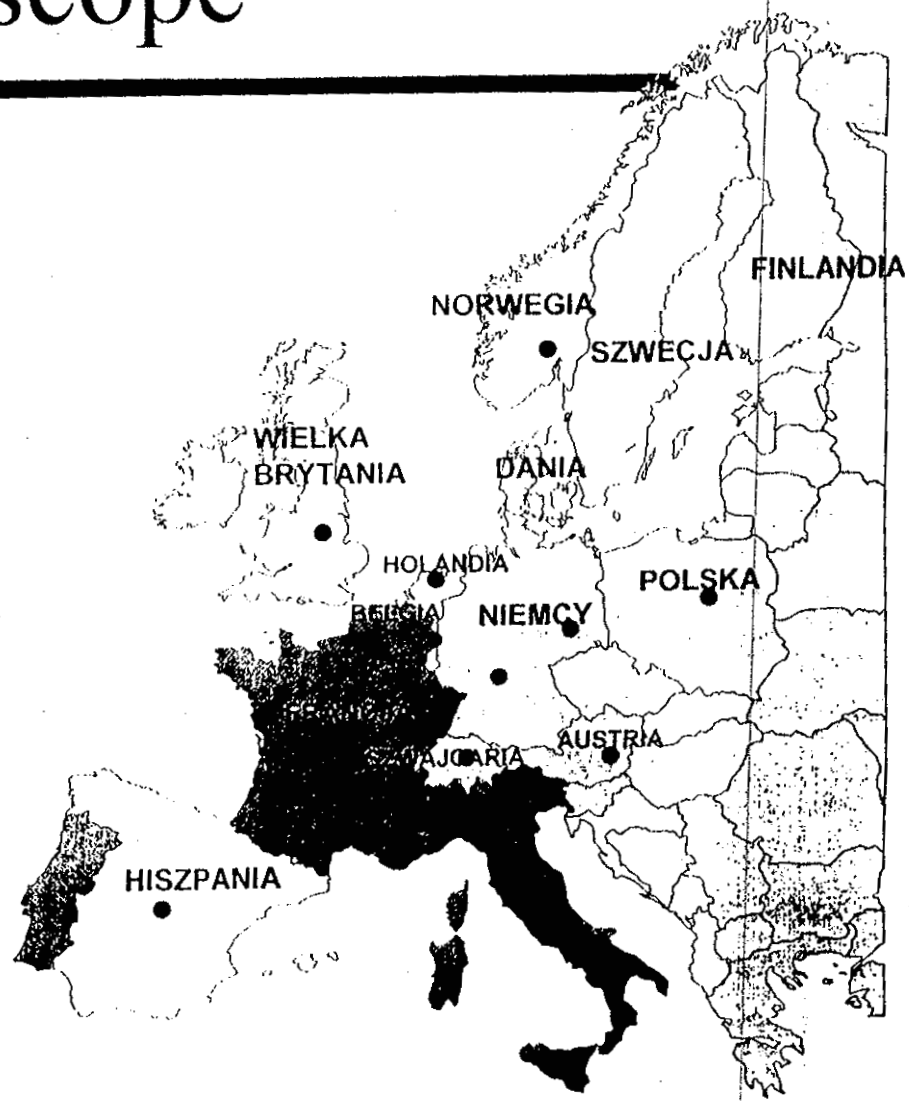
Contents

- AS and energy markets
  - Geographical scope
  - Counterparties and economic flow
- AS "with" and "without" energy
- Trading sequence
- TSO co-operation
- Obstacles to international trade
- Transits

Geographical scope

Energy markets are either national or international (depending on constraints on the borders)

System operation is national or even local.



Counterparties. Economic flow

- Energy markets trade on energy. Distribution companies perform electricity delivery
  - Customers pay the access tariff to the distribution company and the energy to the the market (supplier)
  - Generators sell the energy through the market and supply AS to the TSO (involving energy, sometimes)
- Energy markets are multilateral while System Operation is bilateral (Single Buyer).

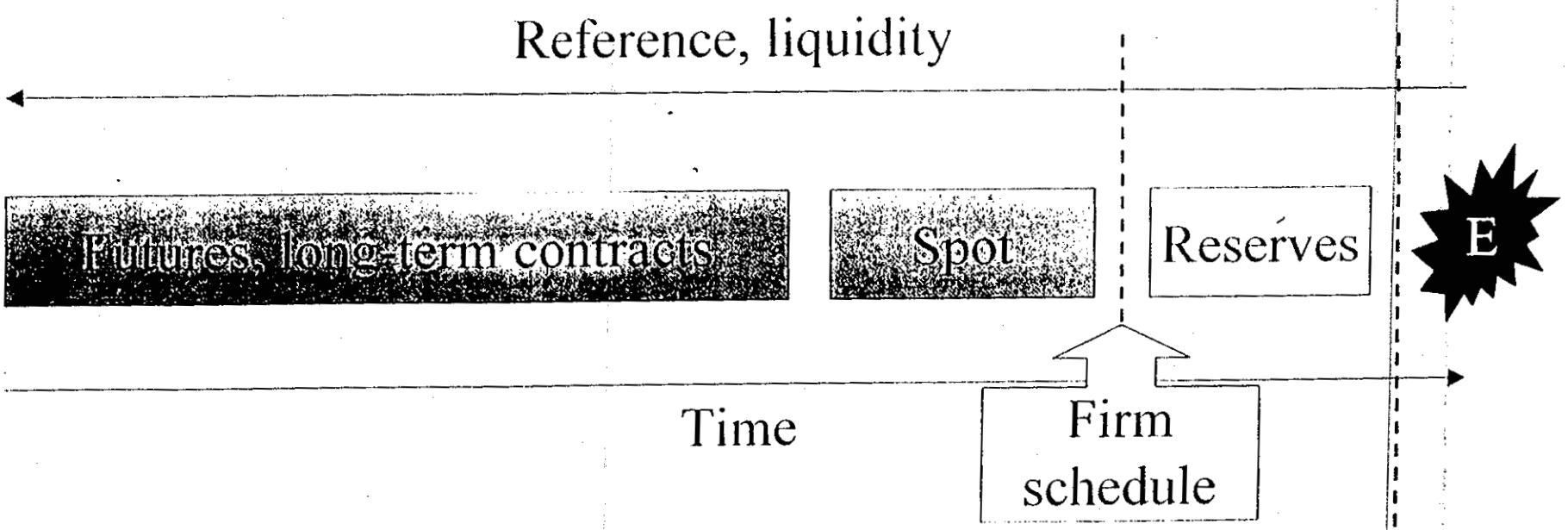
AS should be a transportation cost

AS "with" and "without" energy

- When AS supply involve a change in the schedule:
  - Generators cannot manage its price risk
  - Settlement conflicts
  - Emergency procedures are always needed
- Changing the schedule is not a problem if known in advance (energy renegotiated in liquid markets)

Criteria is "real time" vs "in advance"

Trading sequence



Emergencies should not constitute a reference price:

- **Limited use (even at a fixed price)**
- **Contract for foreseeable problems**

Requirements for domestic trade

- Firmness somewhere before reserve management
  - Constraint management strictly TSO business
- Liquid reserve management market (or arrangements)
  - Known settlement procedure
  - "Universal" access to the imbalance price
  - Imbalances has to be symmetrical
- Known emergency procedures (generators)
- Settlement of AS and losses through the access tariff or charged on imbalances

On the border

- TSOs agree border conditions and firm interconnection capacity
  - Same criteria as for domestic trade
  - Preferably before the spot market (capacity auctions seem to need monthly or even yearly commitments)
- TSO face imbalances at the border
  - Own, market or contracted reserve energy
  - Pass-through to customers or imbalances

239.

TSO co-operation

Scheduling + Settlement of imbalances including a premium (UCTE, CENTREL)

Joint Reserve Management (Single reserve price)

Full integration

Obstacles to trade

- Non-firmness
- Lack of constraints or reserve management procedures (lead to abuse of emergencies)

Sound operation contracts design

Not for trading purposes (use it or loose it)

Not linked to previous commitments

Quantified, scalable

Transits

- Energy markets profit on commercial transits, but not on loop-flows
  - Congestions lead to zonal pricing
- Impact on transmission losses and capacity at the border
  - Losses charged to domestic customers may increase due to international loop-flows
  - If capacity has to be firm, it has to be smaller

Commercial transits should foster investment in transmission assets

Ancillary Services in New York State

USAID Forum on Ancillary Services
Warsaw, Poland
22-24 February 2000

Presented by:
Larry Markel
Electrotek Concepts, Inc.

So Tell Me About ...

- The NYISO
- Ancillary Services
- How About That Market !!
- How Does This Thing Work?
- What Does It All Mean?

Today I will talk about the market for ancillary services in NYS. I'll start with the ISO, describing its structure and operation. Additionally, I'll describe some of the markets operated by the ISO.

Ancillary services are a relatively new commodity available in power markets in the U.S. They include a whole range of services and activities that are used to support the bulk power transmission system. In the United States, each of the fifty states is undergoing change in their power systems: restructuring, competition, new regulatory models. Among the multitude of products and services available in these markets are ancillary services.

Then we'll take a look at the market for ancillary services in NY and see how the prices for these services have behaved.

Next will be some discussion about how the market for ancillary services works in the NYISO.

And I will close with some thoughts on the NY power market

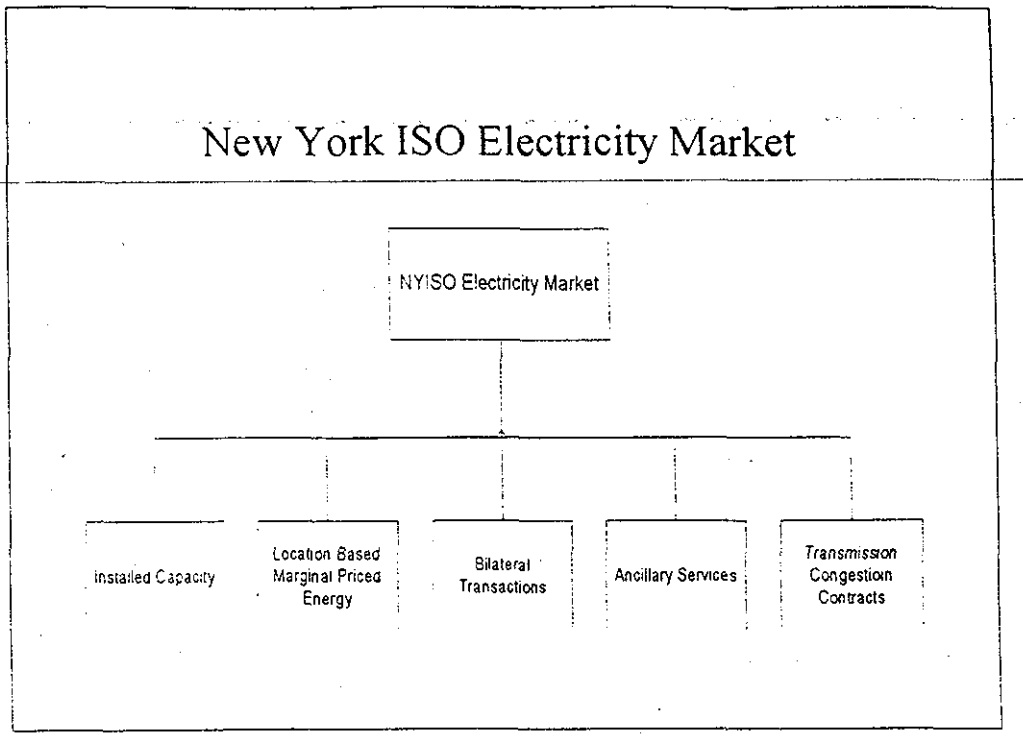
New York ISO

- Began Operation on 18 November 1999
- 131,000 square km
- 1998 Peak Load
  - Winter 1998-1999: 23,879 MW
  - Summer 1998: 28,160 MW
- 1998 Energy Requirements
  - 151.4 TWh

•The market for power in NY is operated by the NYISO. The ISO began formal operation on 18 November 1999. It had been operating in its current mode as the NYPP for some previous months during the testing and trial period for the systems, procedures and protocols. .

•Geographically, the NYISO control area covers over 130 thousand square kilometers. The area is characterized with loads increasing in the eastern and southeastern part of the state and most of the major generating capacity in the western part of the state. He state is transmission constrained, although interconnections with Canada (one 735/765 kV tie, and two 230 kV ties), the New England ISO (one 345 kV tie and one 230 kV tie) and PJM (one 500 kV tie, two 345 kV ties, and two 230 kV ties) offer some support

•The NYISO has a control area that in 1998 had a winter peak of about 23,879 MW and a summer peak of 28,160 MW. The total energy requirement in 1998 was 151.4 TWh.



The products bought and sold in the NYISO include:

•Installed Capacity -- A generator or load that is certified as having met all necessary requirements and is capable of supplying and/or reducing the demand for energy.

•LBMP Energy -- Energy bought and sold in the NYISO that is priced by time and location.

•Bilateral Transactions -- The purchase or sale of capacity, energy, and/or ancillary services between two or more parties.

•Ancillary Services -- Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or "Voltage Support Service"); Regulation and Frequency Response Service (or "Regulation Service"); Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability.

So What Are Ancillary Services?

- Support the Bulk Power System
- Six Types:
  - Scheduling, System Control & Dispatch
  - Reactive Supply & Voltage Support
  - Regulation & Frequency Response
  - Energy Imbalance
  - Operating Reserve
  - Black Start Capability

•Ancillary services support the transmission of energy from resources to loads while maintaining reliability. They are the physical equipment and human resources that provide this support as well as the metered quant8ities.

•Scheduling, System Control & Dispatch -- Two types:

- •System Security Management in real time (e.g. tie line regulation, frequency support, interchange scheduling management, security constrained dispatch, transmission system operation, system emergency management)
- •Capacity Management (e.g. capacity management, operating reserve management and scheduling, outage coordination)

•Voltage Support -- To maintain transmission voltage within limits, generators are operated to produce (or absorb) reactive power.

•Regulation & Frequency Response -- Necessary to balance resources with load and to assist in maintaining frequency. On-line generators are used as necessary (through use of AGC) to follow moment-by-moment changes in load.

•Energy Imbalance -- Internal and external energy balance to control mismatch between scheduled and actual flows.

•Operating Reserve -- Provides back-up generation in the event of a contingency. Operating reserves include spinning reserve (10 minute and 30 minute), operating reserve, and 10 minute non-synchronous reserves.

•Black Start Capability -- Generators that can start without an external power supply and are available for system restoration.

How Does This Thing Work ?

- Two Separate Ancillary Service Markets
  - Day Ahead
  - Hour Ahead
- Products
  - 10 Minute Spinning Reserve
  - 10 Minute Non-Synchronous Reserve
  - 30 Minute Operating Reserve
  - Regulation

•There are two separate markets for AS in NY -- Day-Ahead and Hour-Ahead.

•For each of these markets there are four separate AS products hat are bid and bought in the market (10 Min Spinning Reserve, 10 Min Non-Synch Reserve, 30 Min Operating Reserve and Regulation.

•10 Min Spinning Reserve -- Considered an operating reserve service that provides backup generation in the event of a major generating resource failure. Resources must be already synchronized to the NYS Power System and can respond to instructions to change output level within 10 minutes. Resources must be under NYISO operational control

•10 Min Non-Synchronous Reserve -- Operating reserves that can be started, synchronized and loaded within 10 minutes.

•30 Min Operating Reserve -- Reserves the respond to instructions to change output energy within 30 minutes.

•Regulation -- To maintain transmission voltages within acceptable limits, resources under the control of the ISO are operated to produce or absorb reactive power.

How Does This Thing Work ?

- Market Participants
- Market Mechanisms
  - MIS
  - Bidding
  - Metering
  - Execution
  - Settlement

•Market participants include suppliers, power exchanges, transmission customers, and marketers. To participate in a market one must meet the specific qualifications for that market. There are specific categories of qualification - for 10 Minute Spinning Reserve bidders, for instance, certain technical, contractual, legal and regulatory requirements must be satisfied to be able to participate in the market. The requirements for each participant reflect the specific needs for the service (e.g. metering, testing, interconnection, protection, monitoring, and control).

•Suppliers -- Can include generators, ancillary service providers, and demand-side resources.

•Power Exchanges -- Commercial entities that facilitate the sale/purchase of energy, capacity or ancillary services in the New York Wholesale Market.

•Transmission Customers -- Eligible customer who receives transmission service from pursuant to a service agreement. Can include load-serving entities, energy service customers (ESCo's), municipalities, cooperatives, industrial customers, and commercial customers

•Marketers -- Facilitate the linkage between buyers and sellers

•Market Mechanisms -- The mechanics of the market are the structure and processes that provide an exchange for buyers and sellers. They include the systems, procedures, protocols, and practices of the market in the ISO framework. This includes the bidding process, metering and billing, and the execution and settlement of the transaction -- In some cases the ISO executes the transaction (e.g. through direct control of generating resources), in others the market participant does (interruptible loads, generation).

So What Does It All Mean ?

- Markets Work
  - Buyers and sellers coming together
  - Mechanisms seem to perform required market services

•So we have a function power market in NYS. It has been officially in operation for three months. And the lights are still on!!! Bidders and buyers are coming to the marketplace, and market clearing prices are set. So...**Markets Work!!**

So What Does It All Mean ?

- Or Do Markets Work ?
  - Reliability
  - The Resource Payment Issue

The role of ancillary services in power markets is to promote reliable and efficient use of existing transmission capacity. And based on the experiences in NY, it seems to have done that so far.

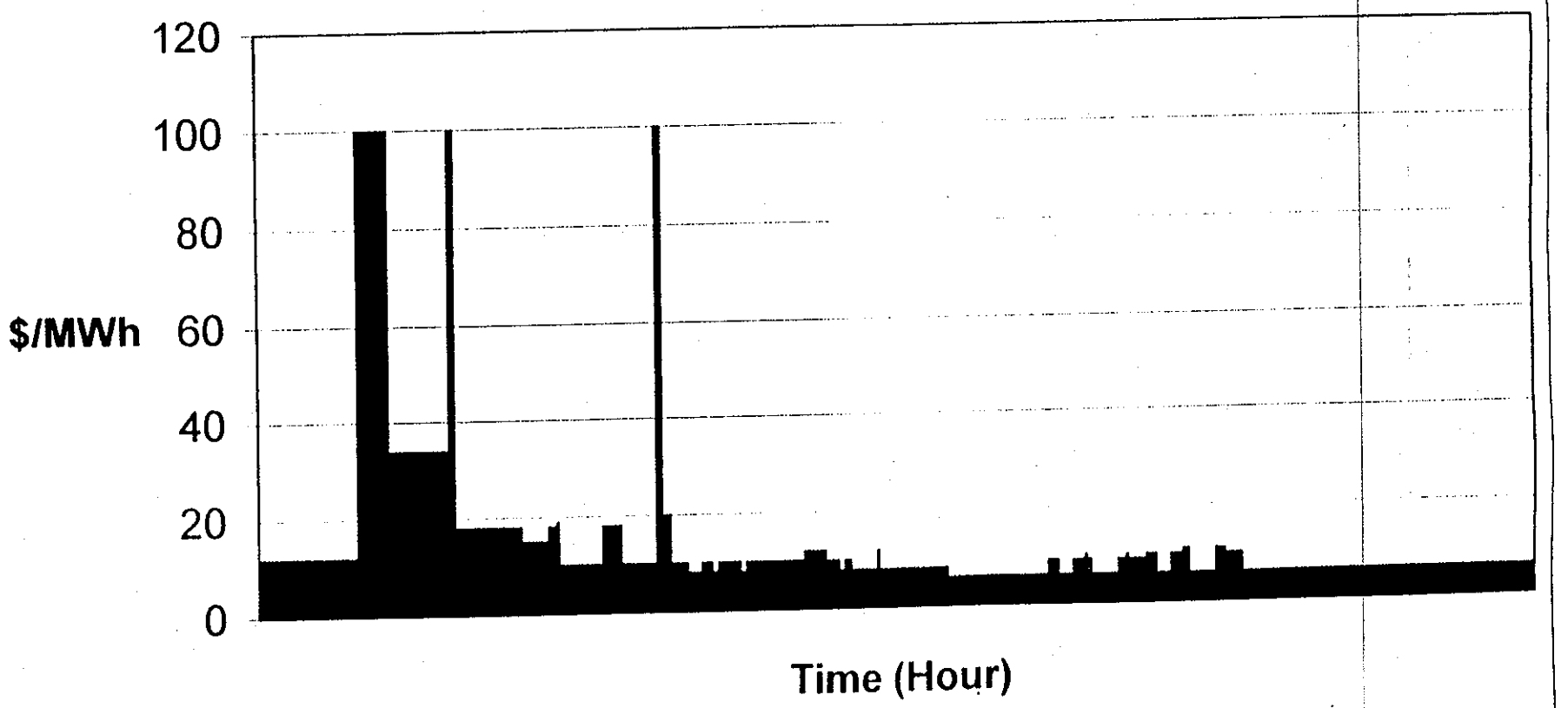
The true test, however, is the test of time. Will the market be able to provide the service that is most expensive to provide in power systems - reliability. And if so, how?

What happens in capacity constrained systems? How will bottlenecks be relieved? When will construction be required? Who pays, and how?

Which of these ways will be the most efficient?

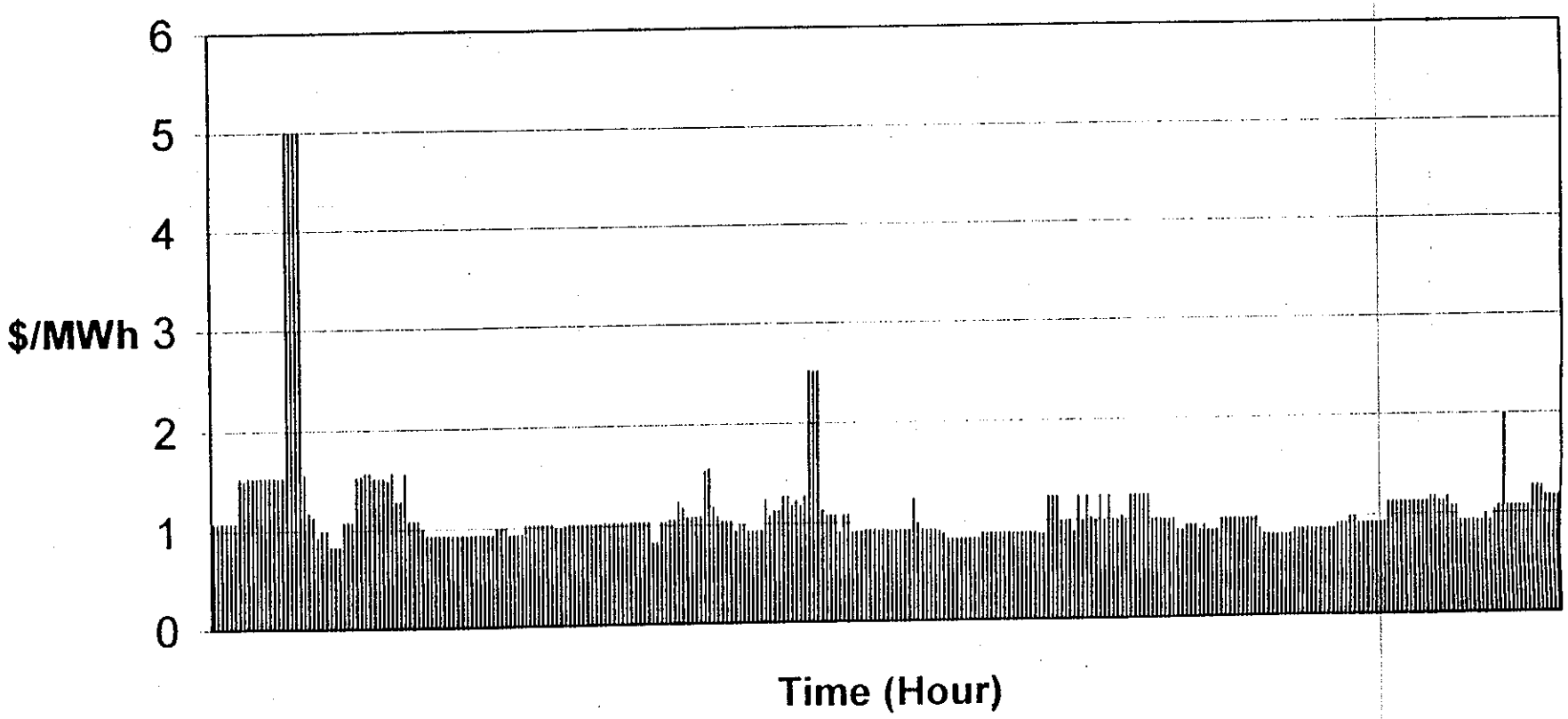
Time will tell.

NYISO Ancillary Services
Day Ahead Market
10 Min Spinning Reserve
18-30 November 1999

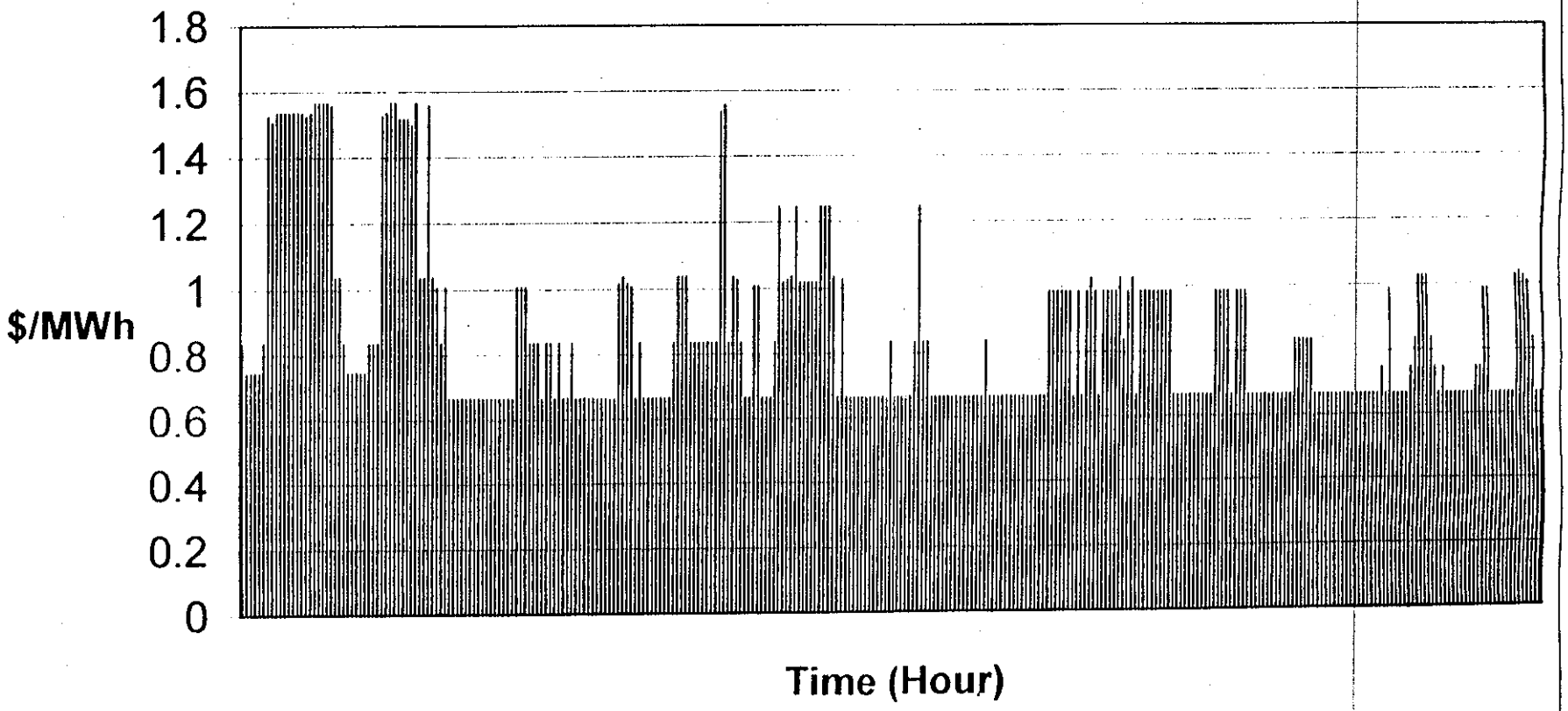


252

NYISO Ancillary Services
Day Ahead Market
10 Min Non-Synchronous Reserve
18-30 November 1999

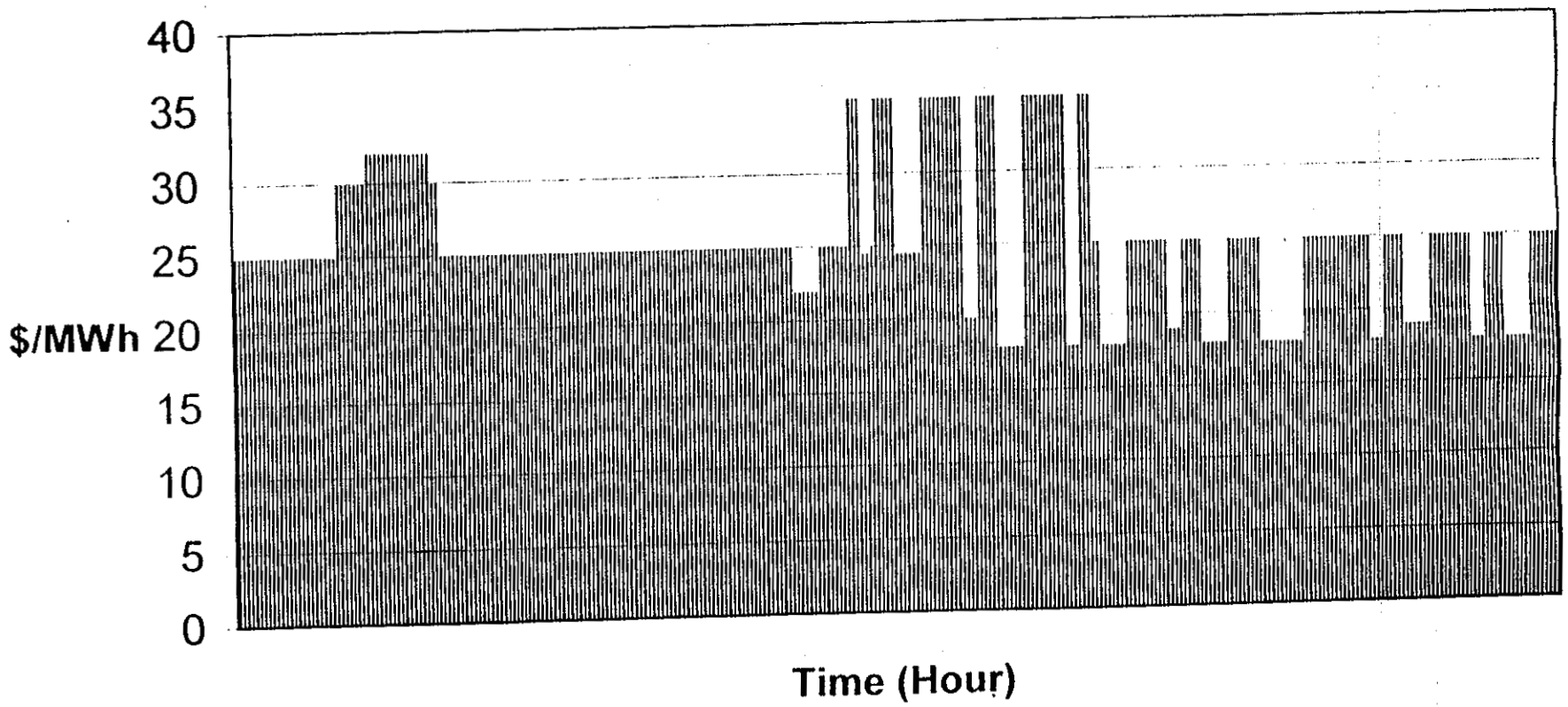


NYISO Ancillary Services
Day Ahead Market
30 Min Operating Reserve
18-30 November 1999



254

NYISO Ancillary Services
Day Ahead Market
Regulation
18-30 November 1999



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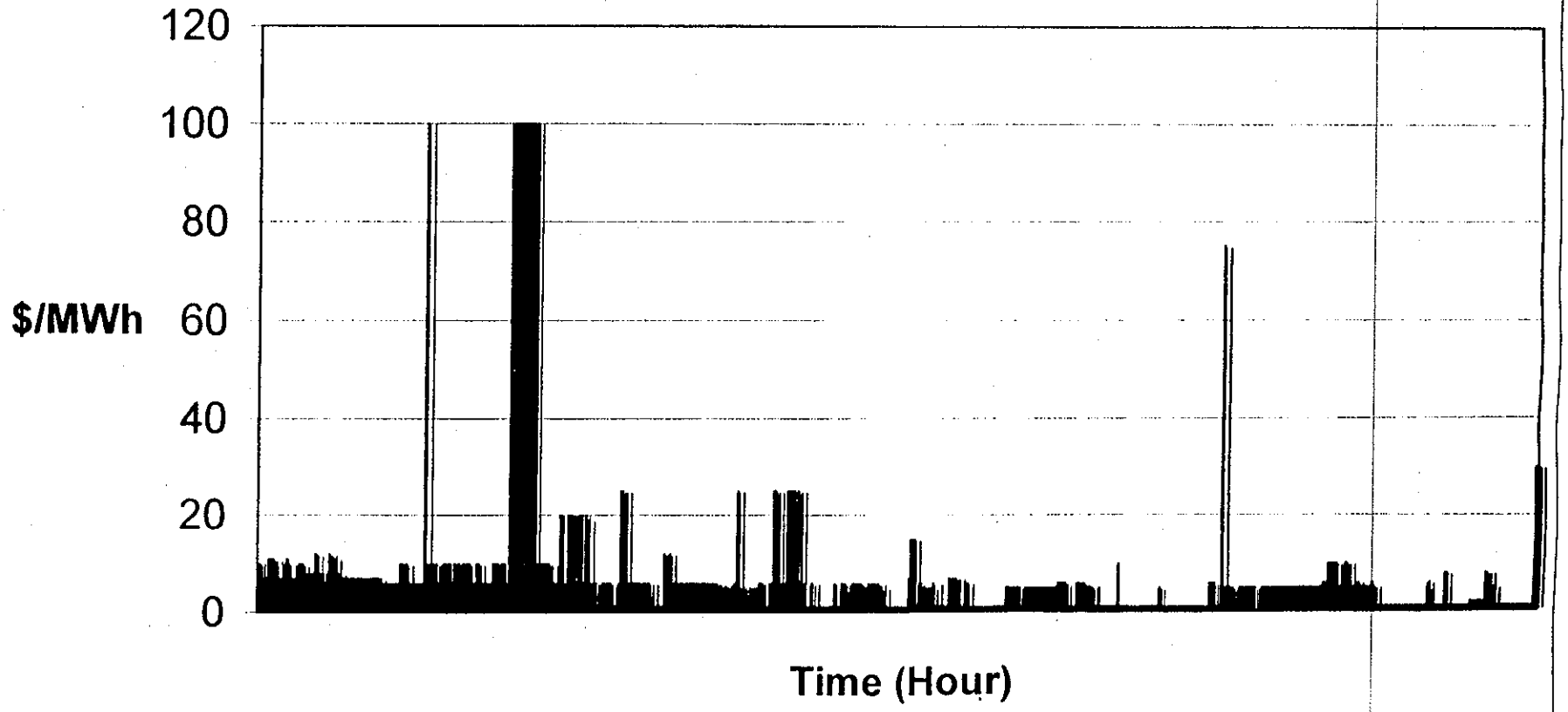
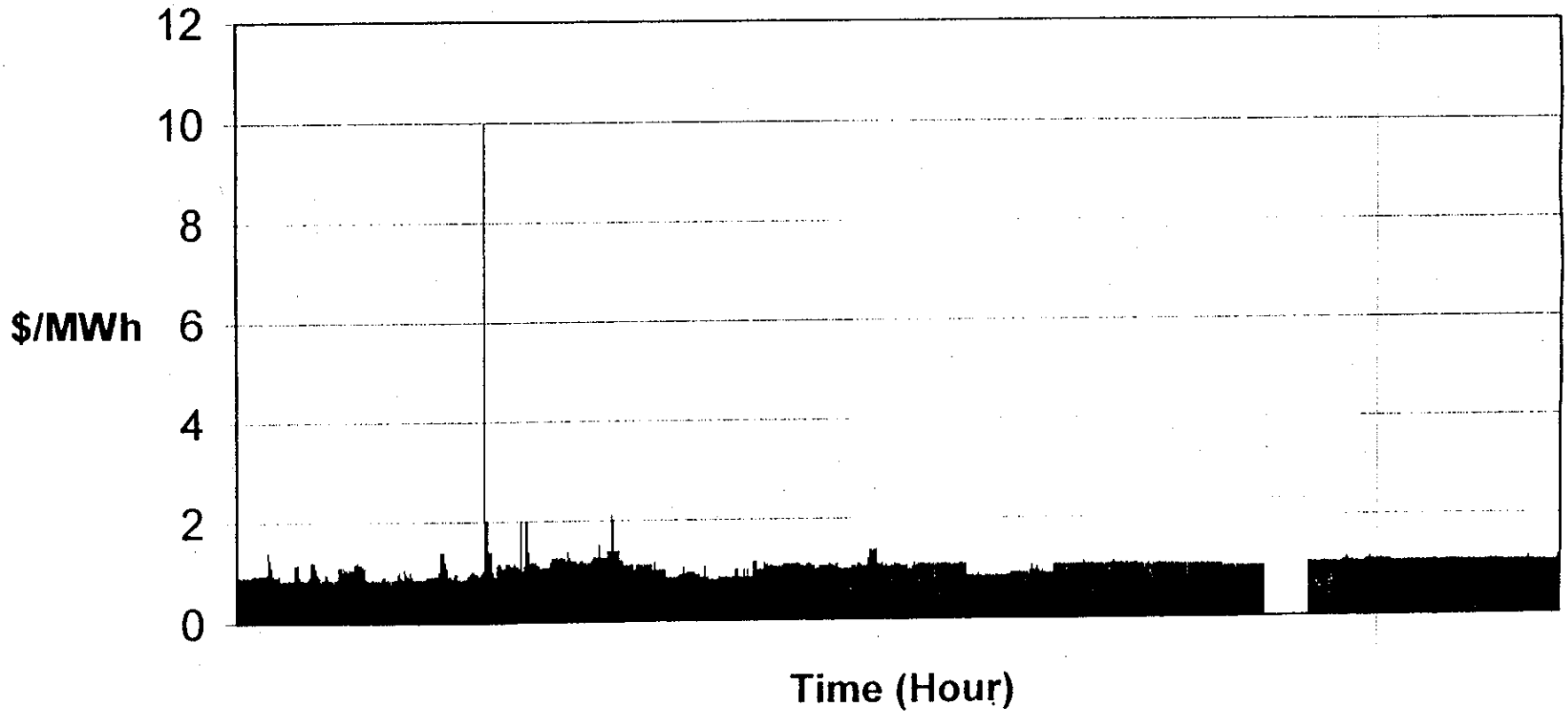
NYISO Ancillary Services
Day Ahead Market
10 Min Spinning Reserve
December 1999



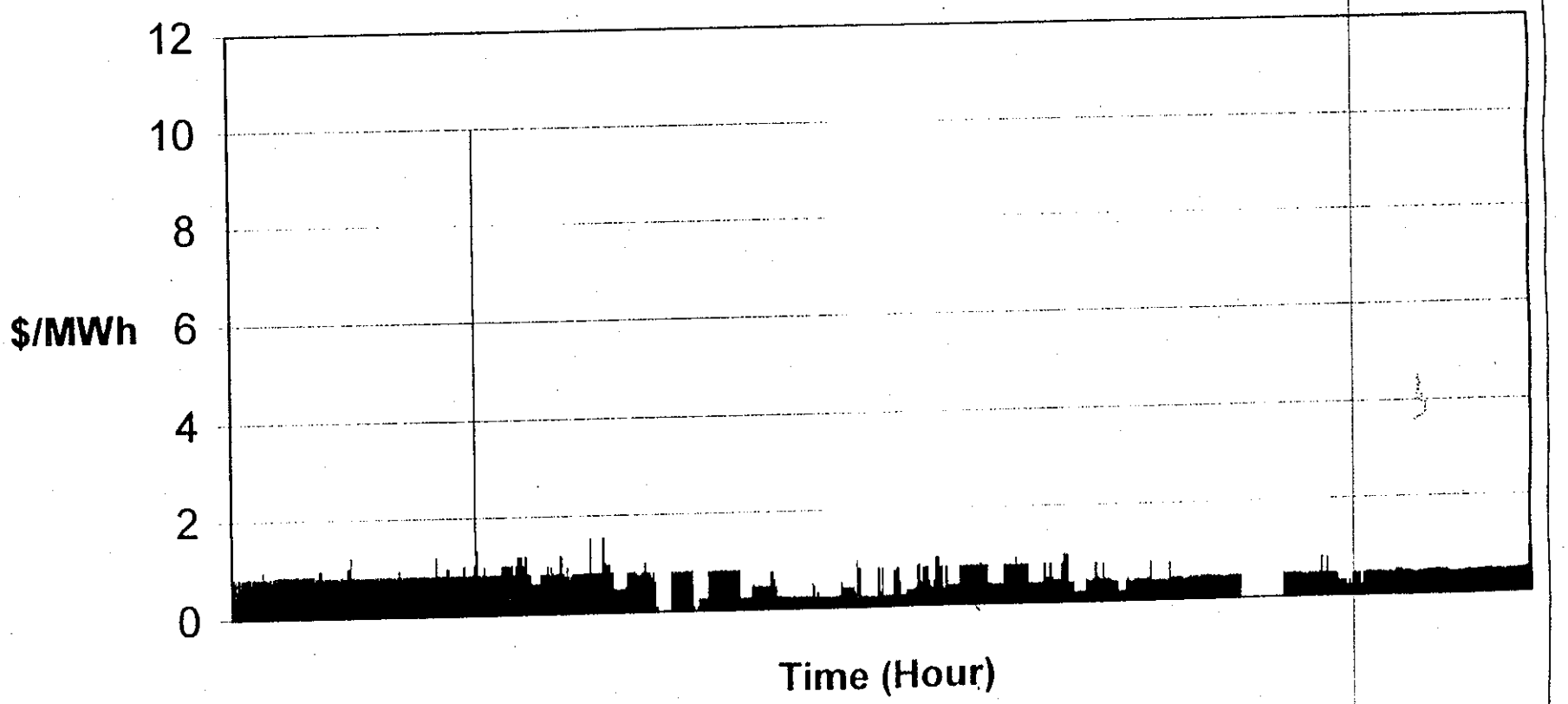
256

NYISO Ancillary Services
Day Ahead Market
10 Min Non-Synchronous Reserve
December 1999



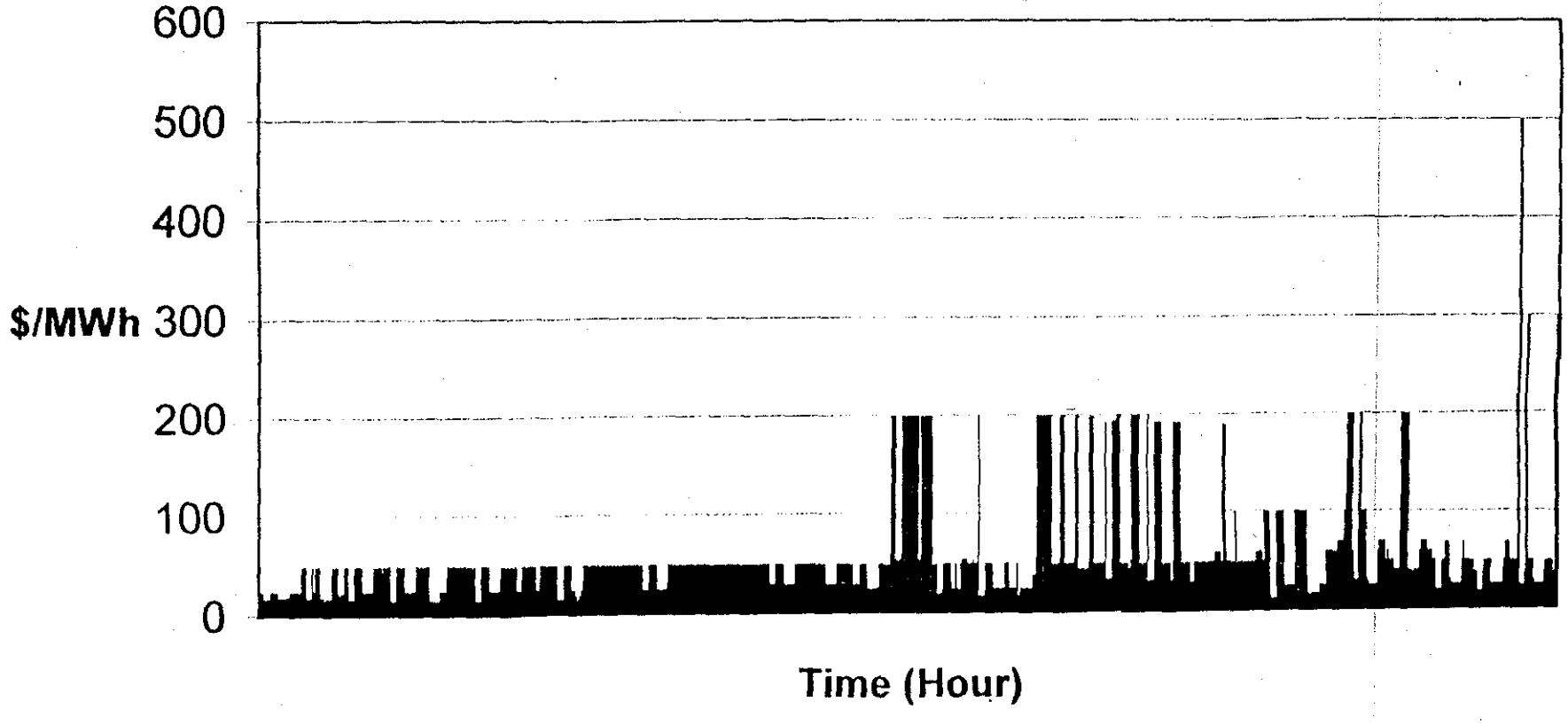
257

NYISO Ancillary Services
Day Ahead Market
30 Min Operating Reserve
December 1999



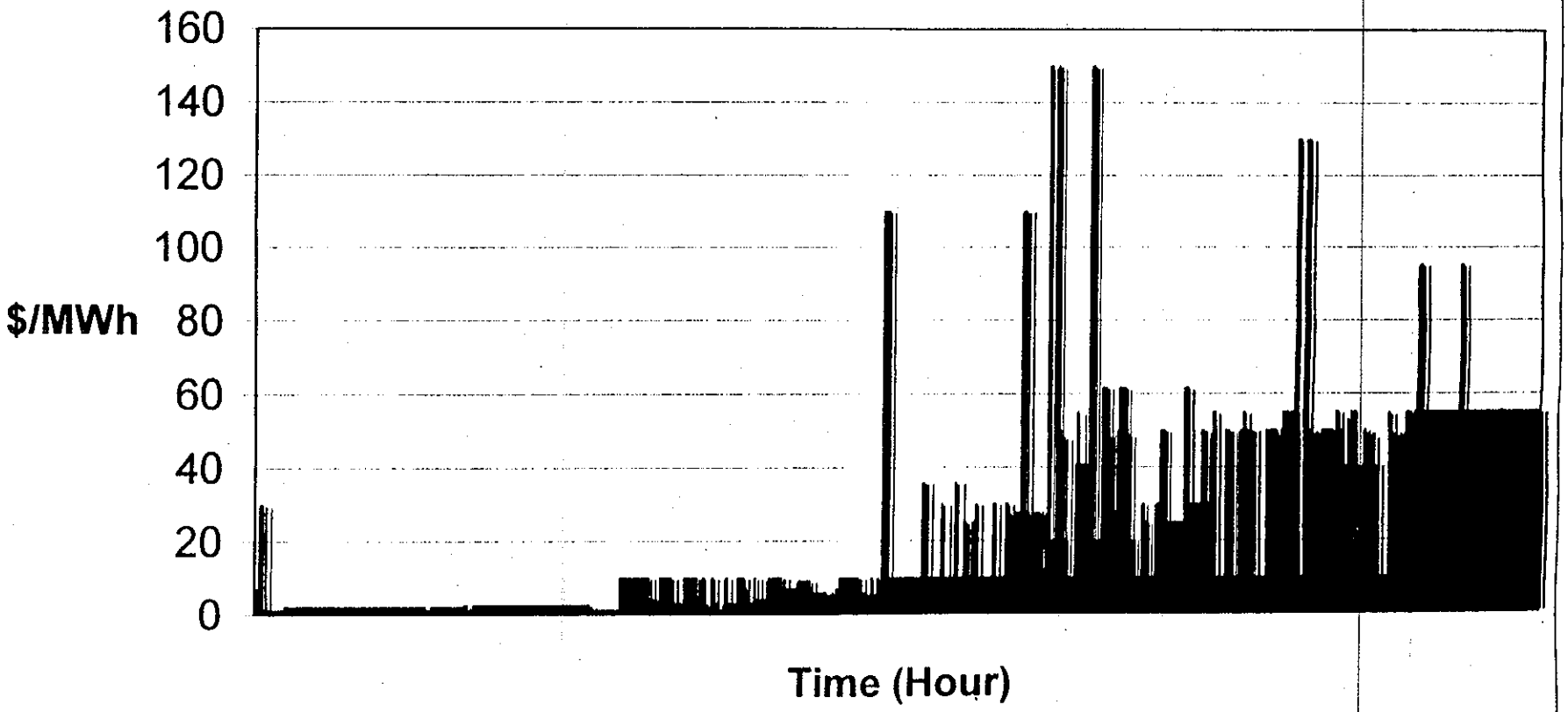
758

NYISO Ancillary Services
Day Ahead Market
Regulation
December 1999



259

NYISO Ancillary Services
Day Ahead Market
10 Min Spinning Reserve
January 2000



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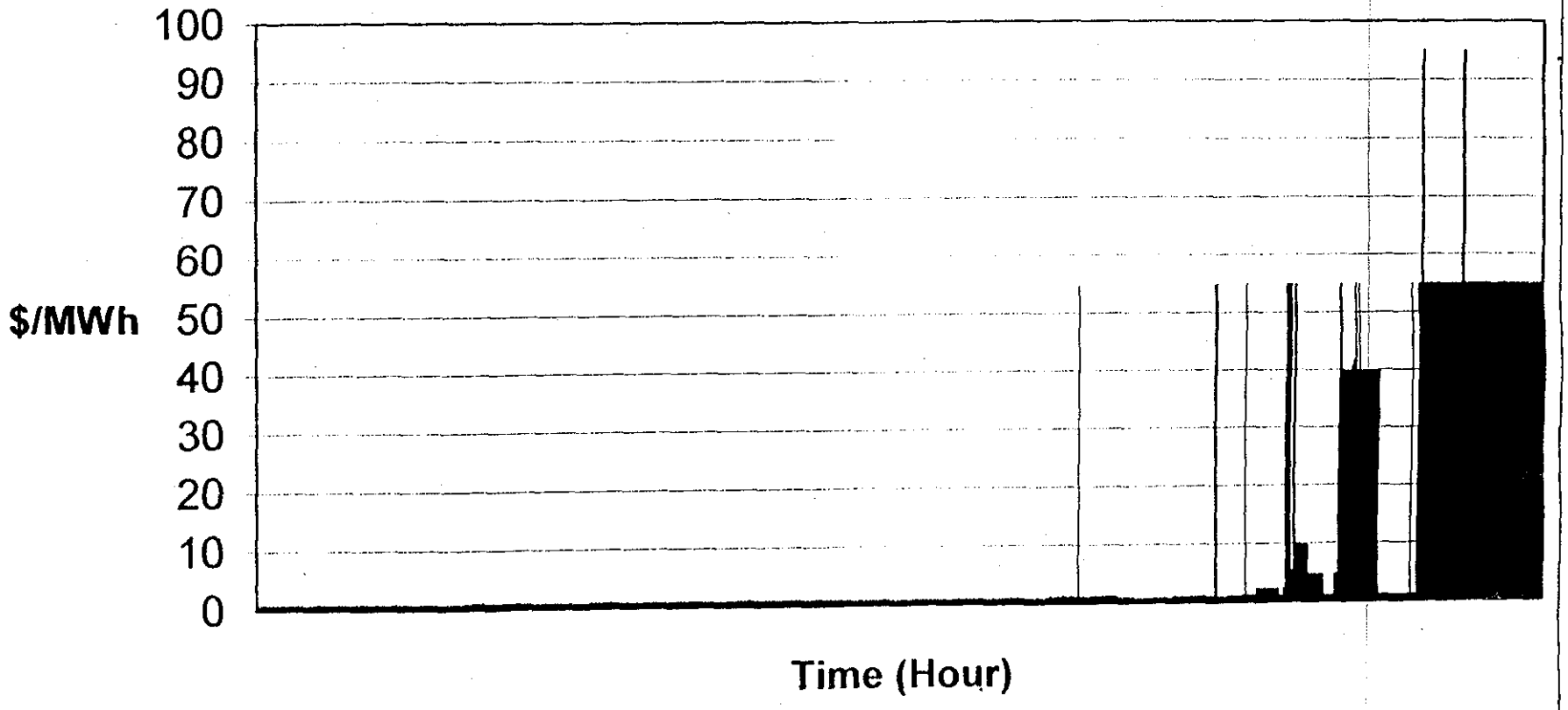
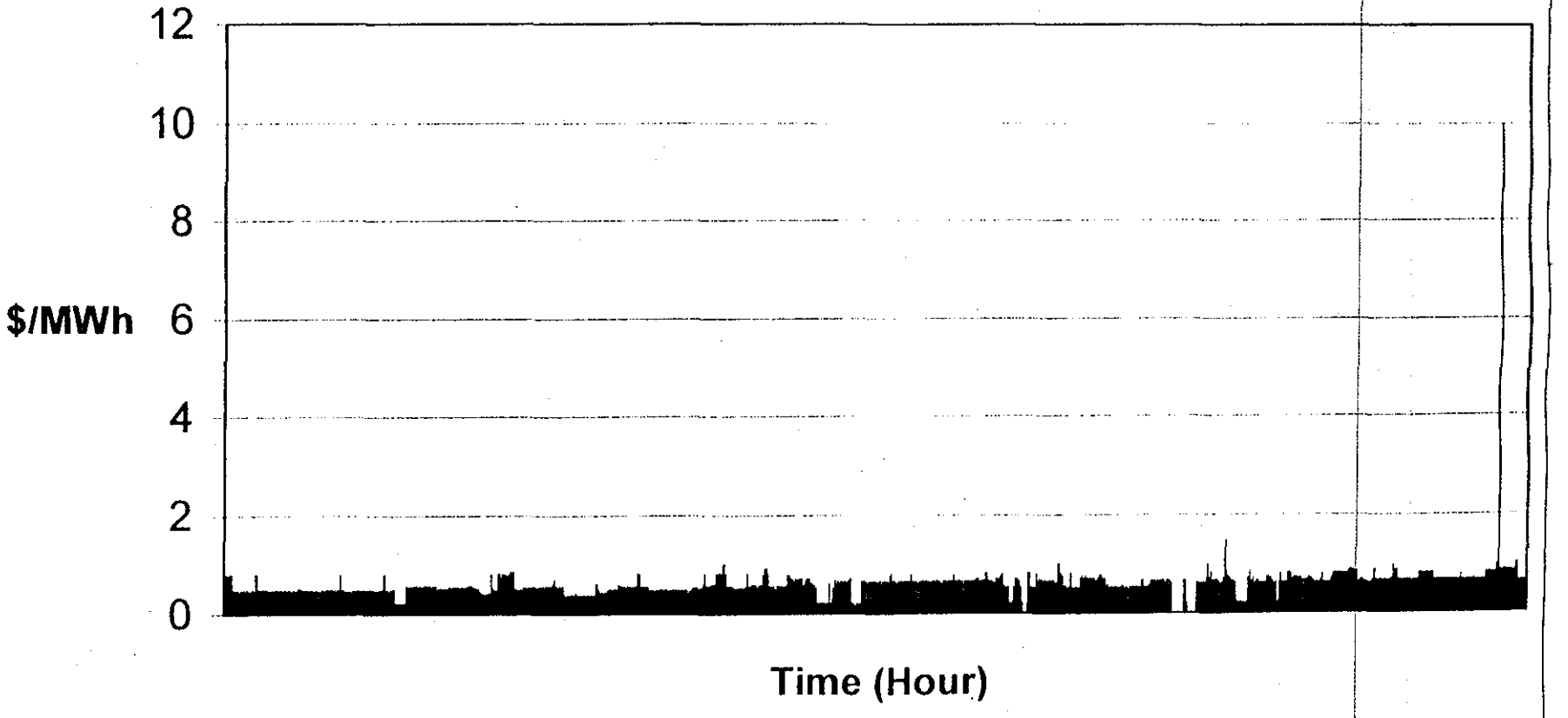
NYISO Ancillary Services
Day Ahead Market
10 Min Non-Synchronous Reserve
January 2000



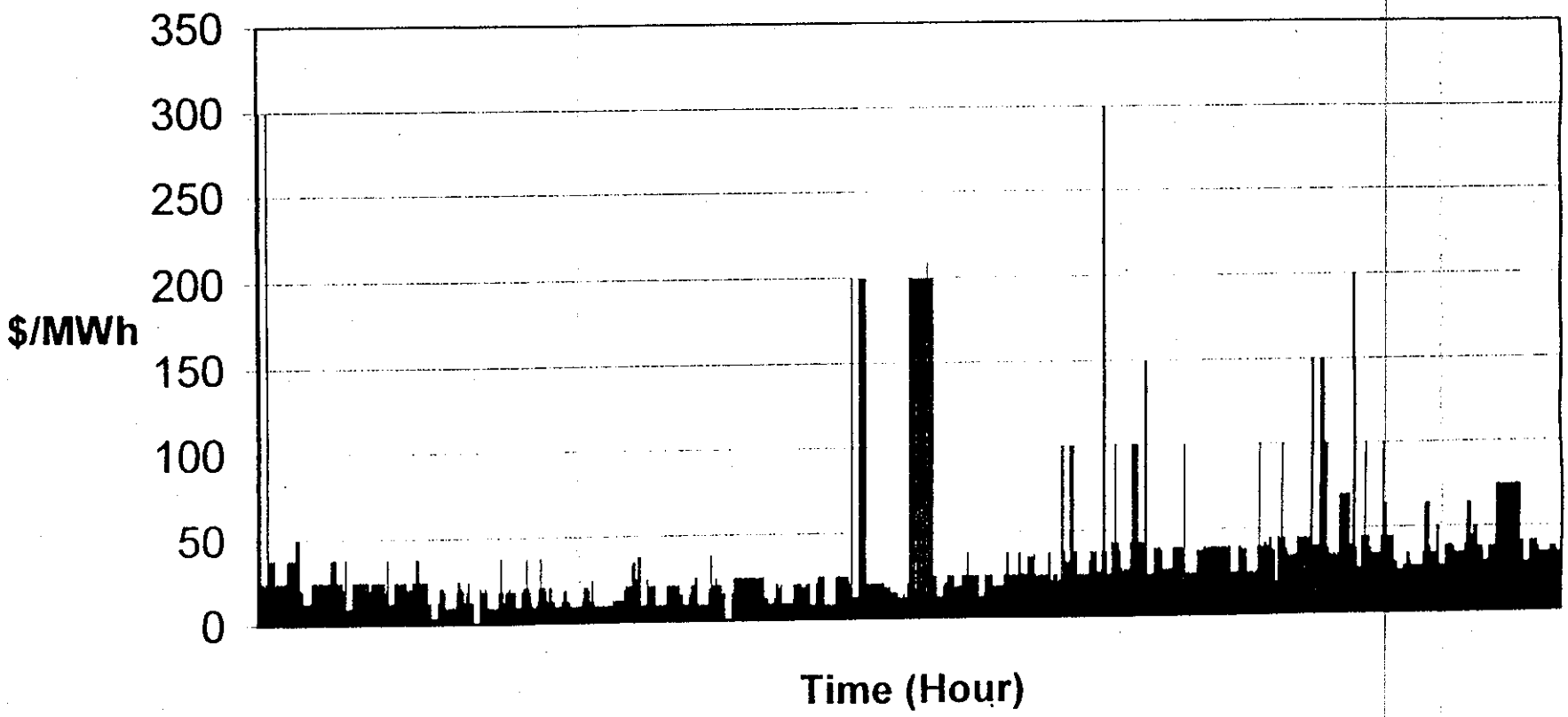
261

NYISO Ancillary Services
Day Ahead Market
30 Min Operating Reserve
January 2000

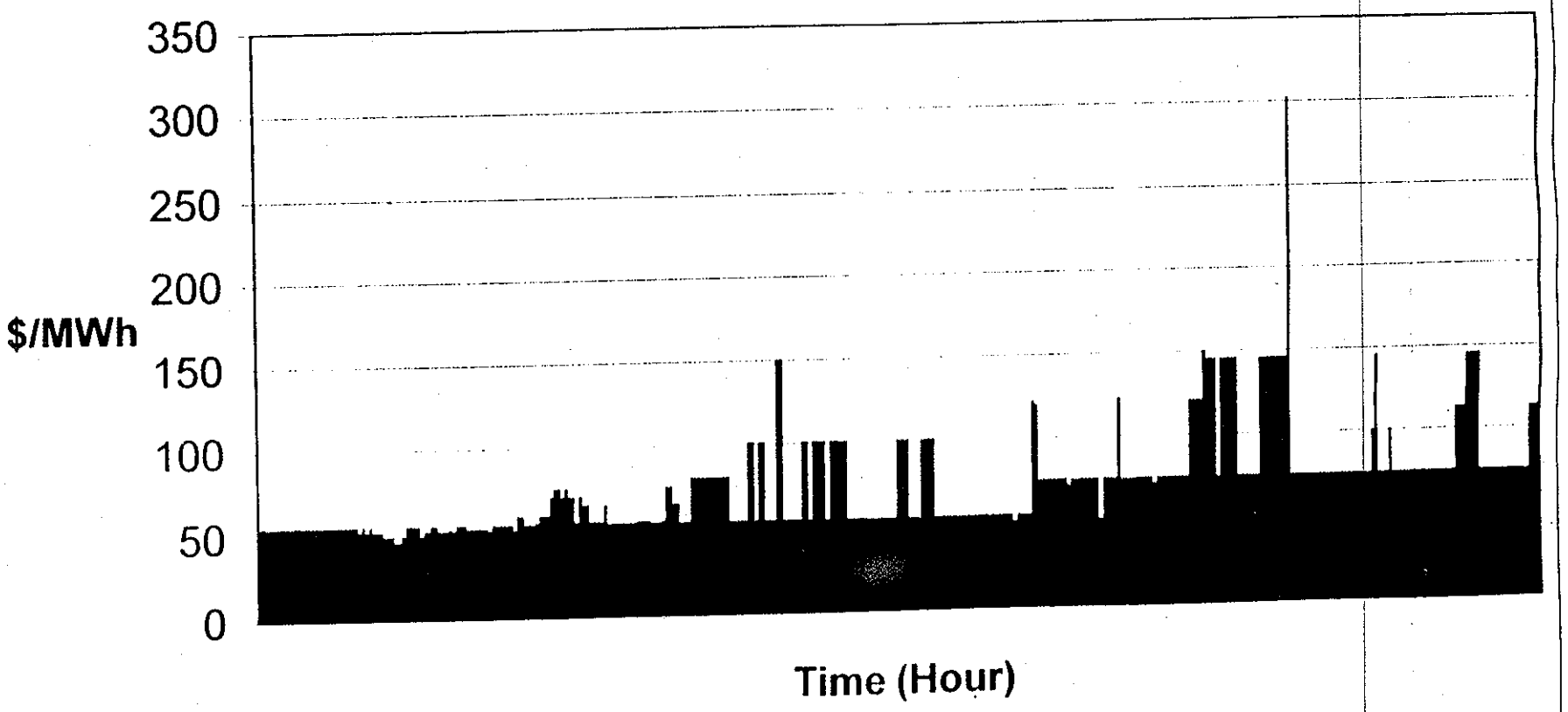


262

NYISO Ancillary Services
Day Ahead Market
Regulation
January 2000



NYISO Ancillary Services
Day Ahead Market
10 Min Spinning Reserve
1-15 February 2000



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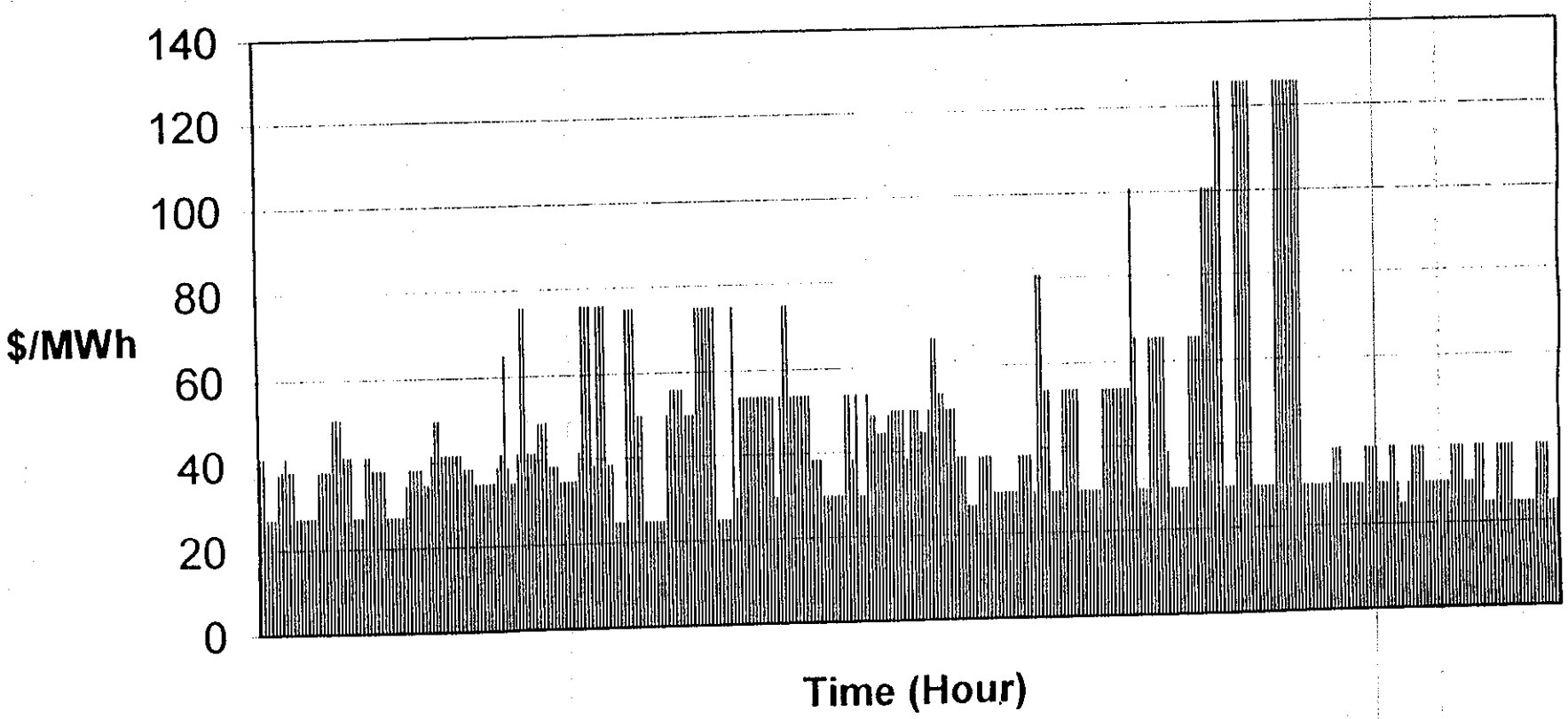
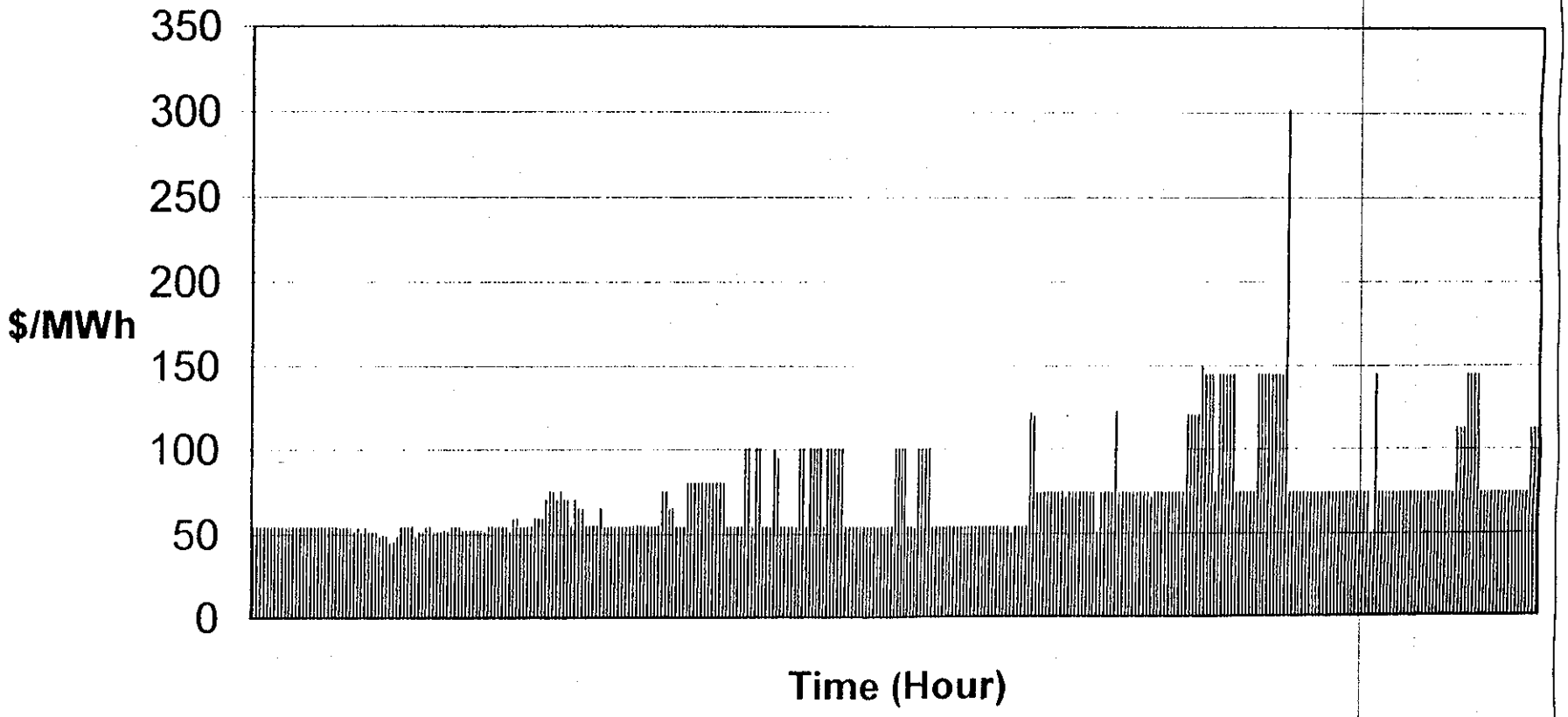
NYISO Ancillary Services
Day Ahead Market
Regulation
1-15 February 2000



265

NYISO Ancillary Services
Day Ahead Market
10 Min Non-Synchronous Reserve
1-15 February 2000



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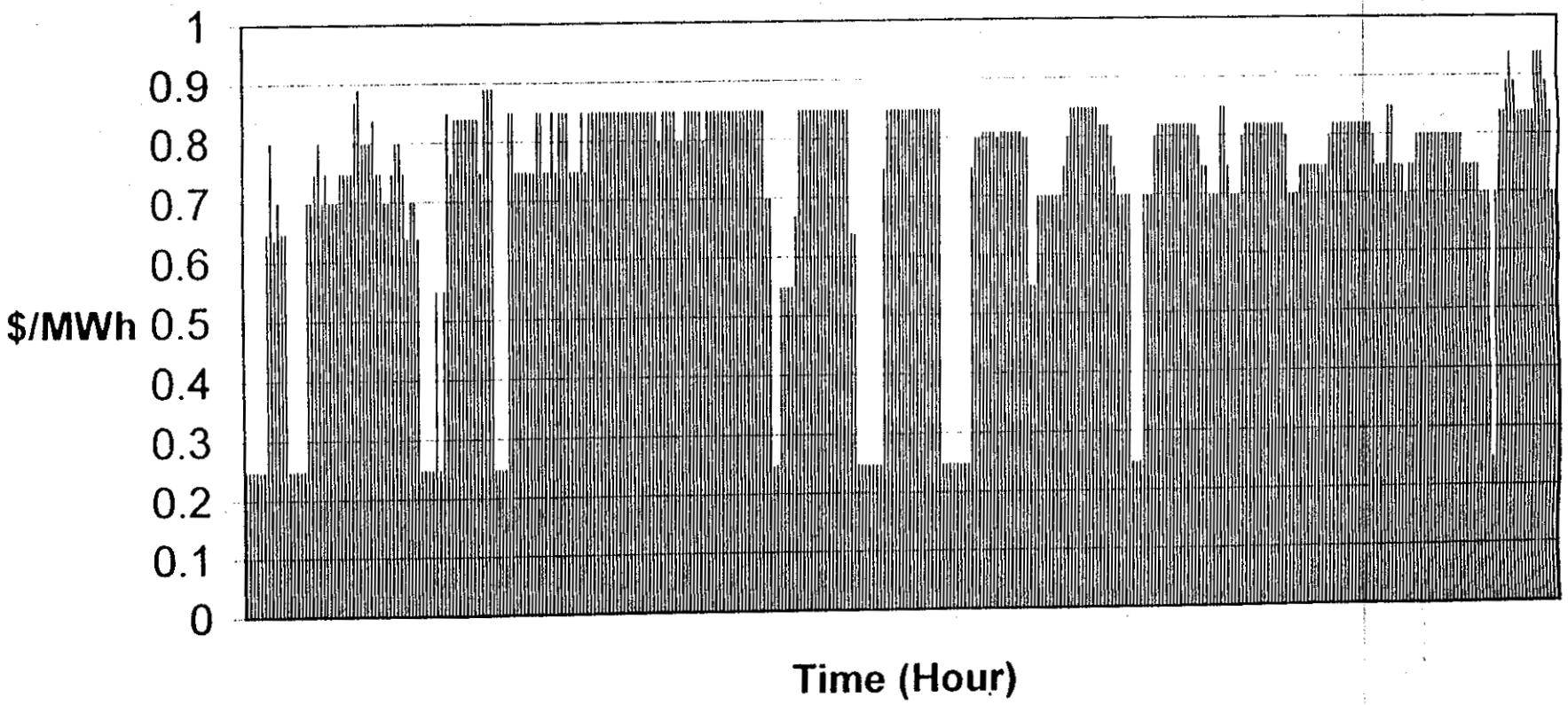
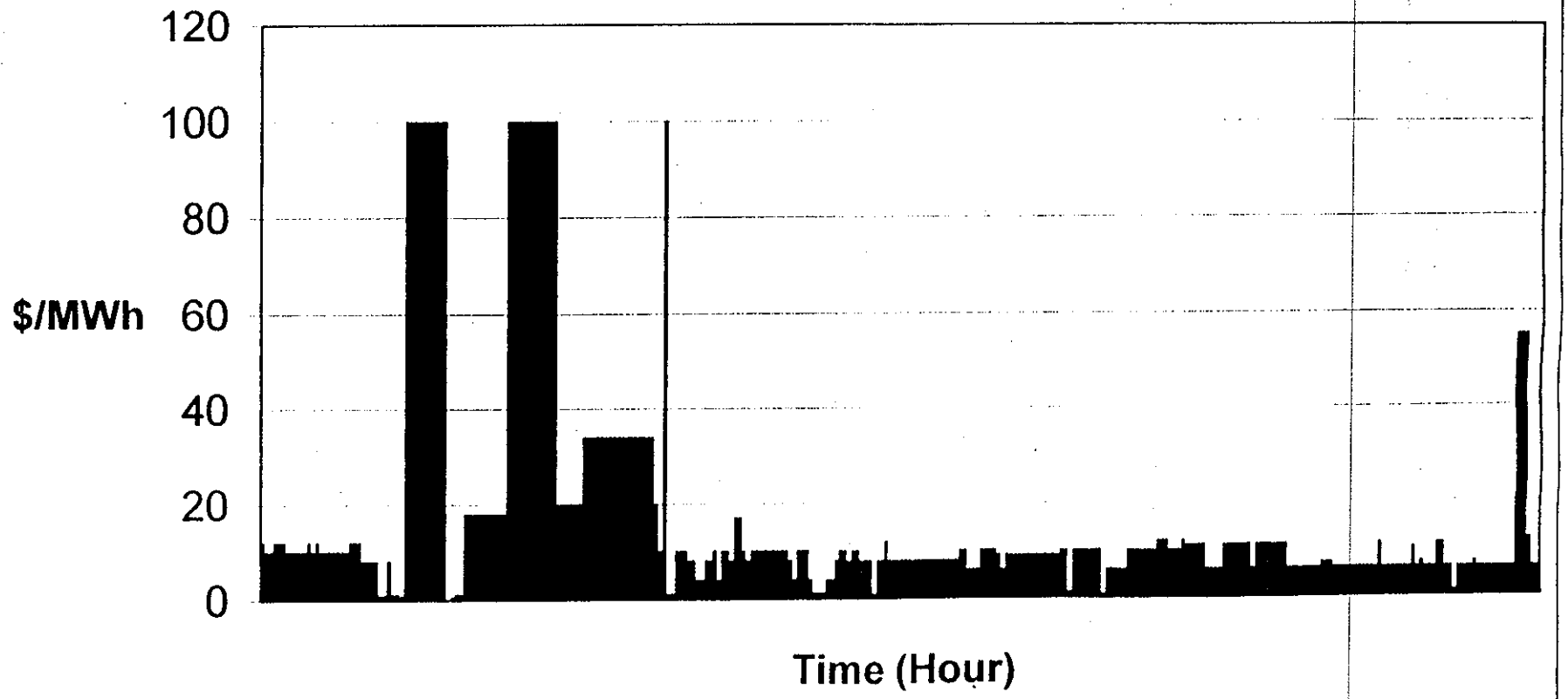
NYISO Ancillary Services
Day Ahead Market
30 Min Operating Reserve
1-15 February 2000



NYISO Ancillary Services
Hour Ahead Market
10 Min Spinning Reserve
18-30 November 1999



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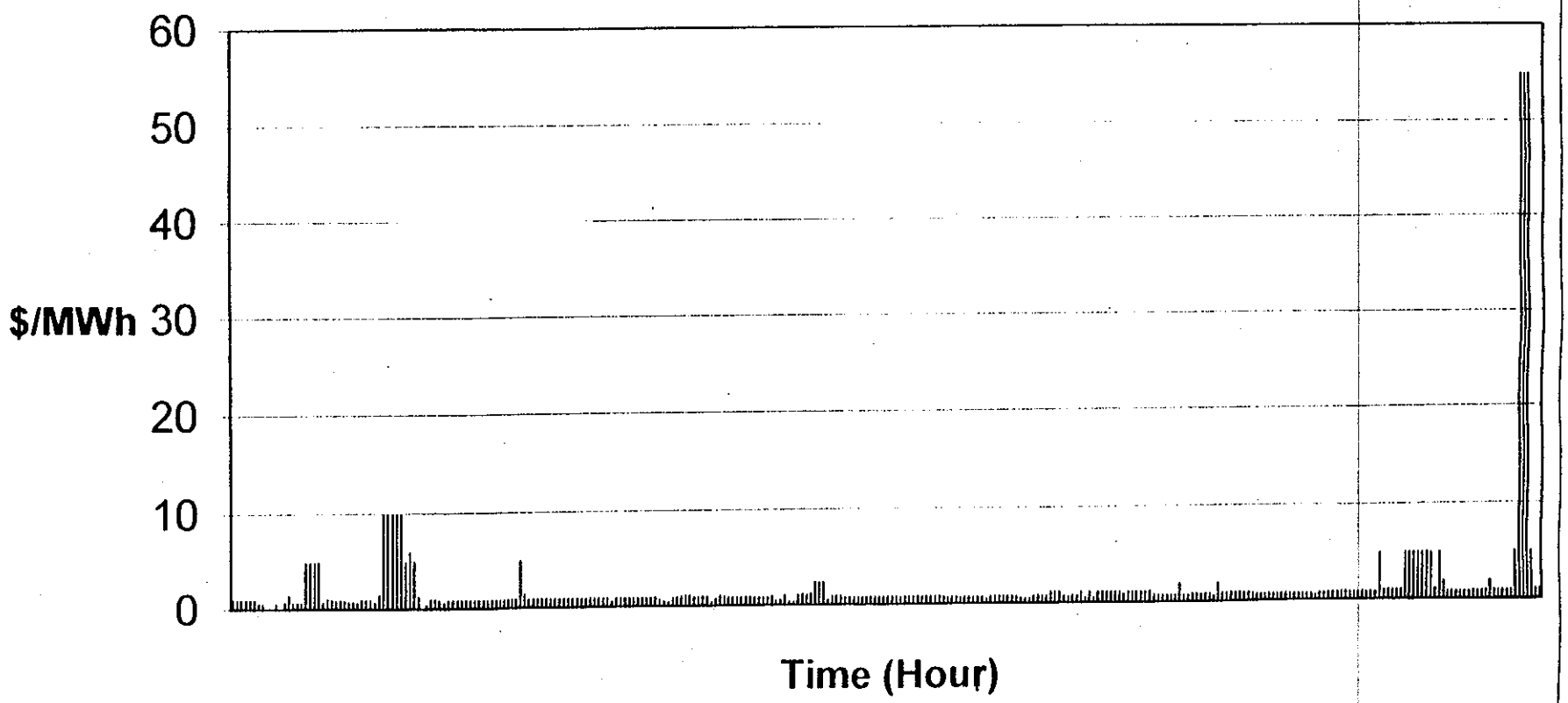
NYISO Ancillary Services
Hour Ahead Market
10 Min Non-Synchronous Reserve
18-30 November 1999



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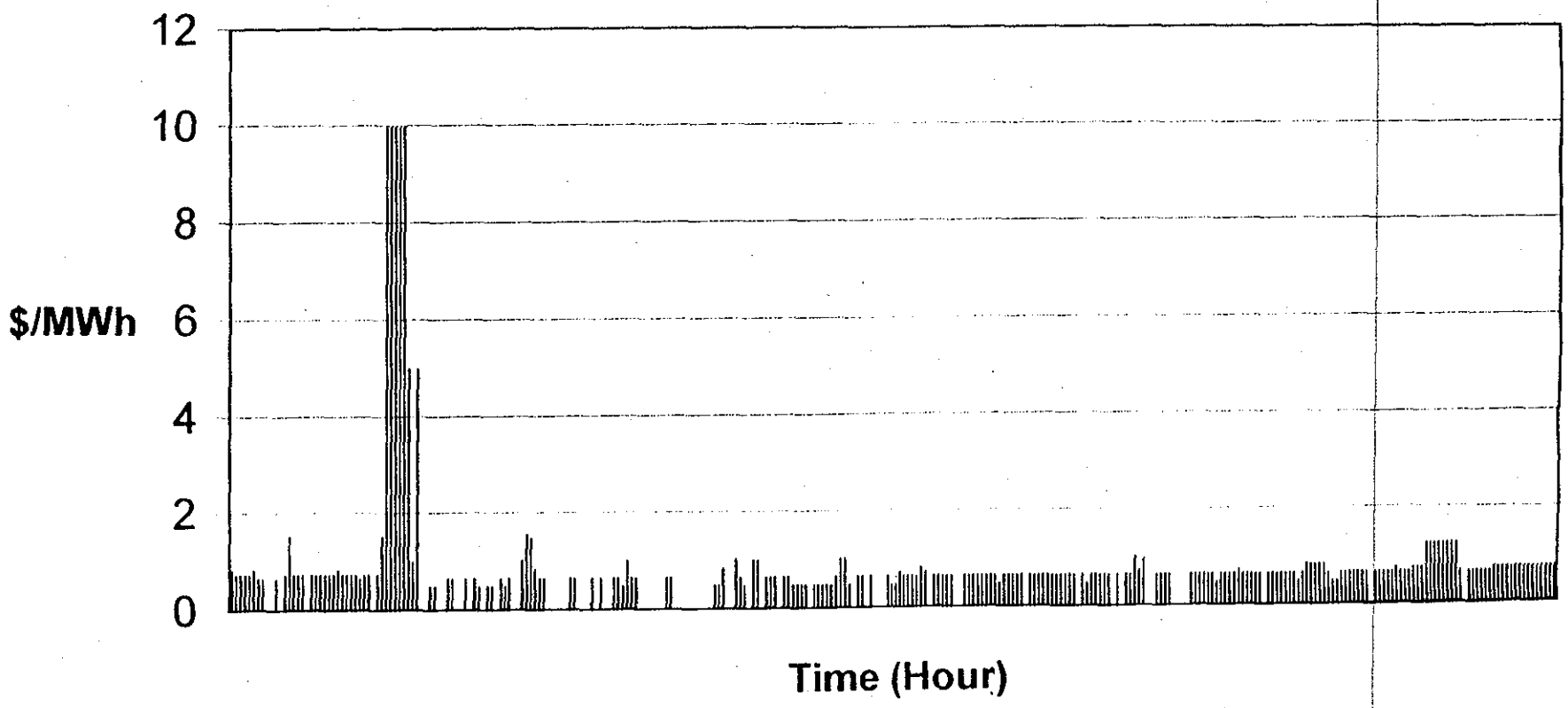
Hour Ahead Market
30 Min Operating Reserve
18-30 November 1999



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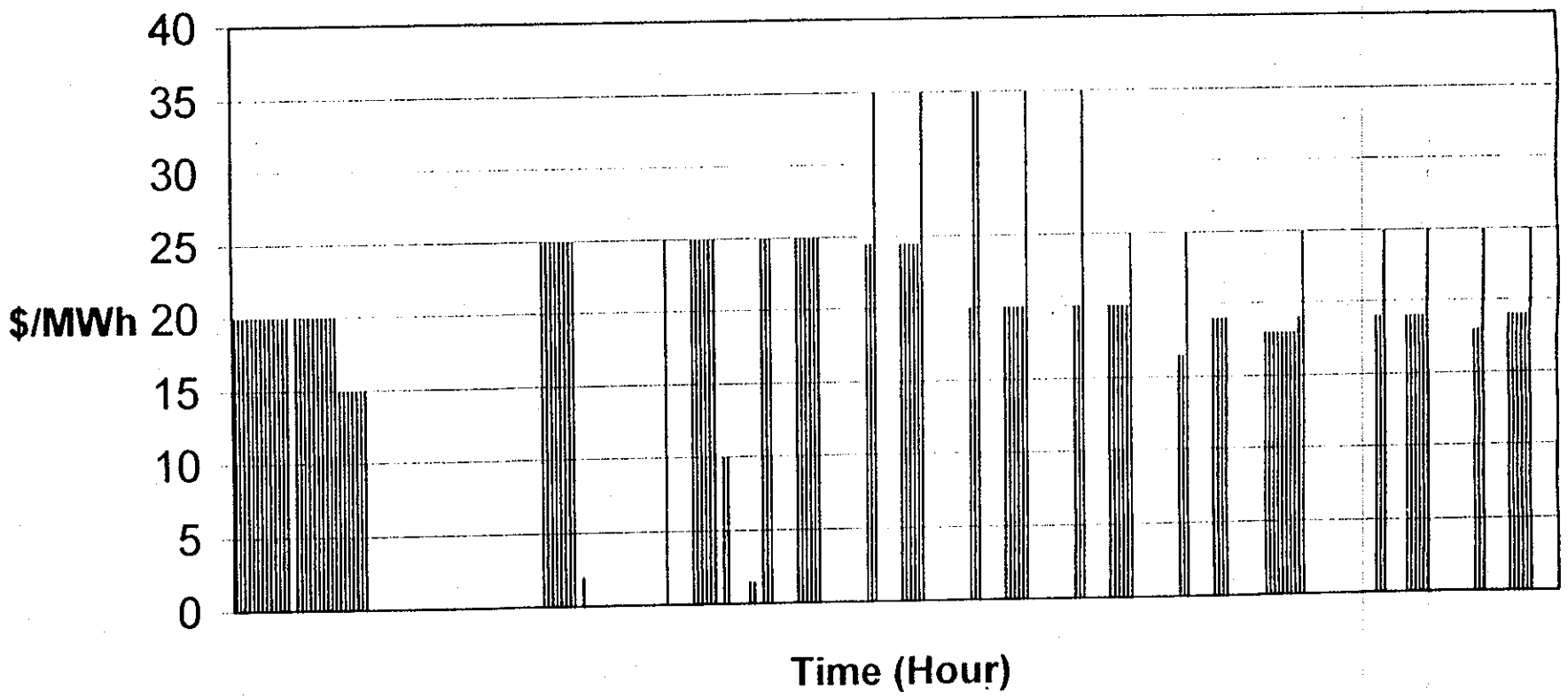
NYISO Ancillary Services
Hour Ahead Market
Regulation
18-30 November 1999



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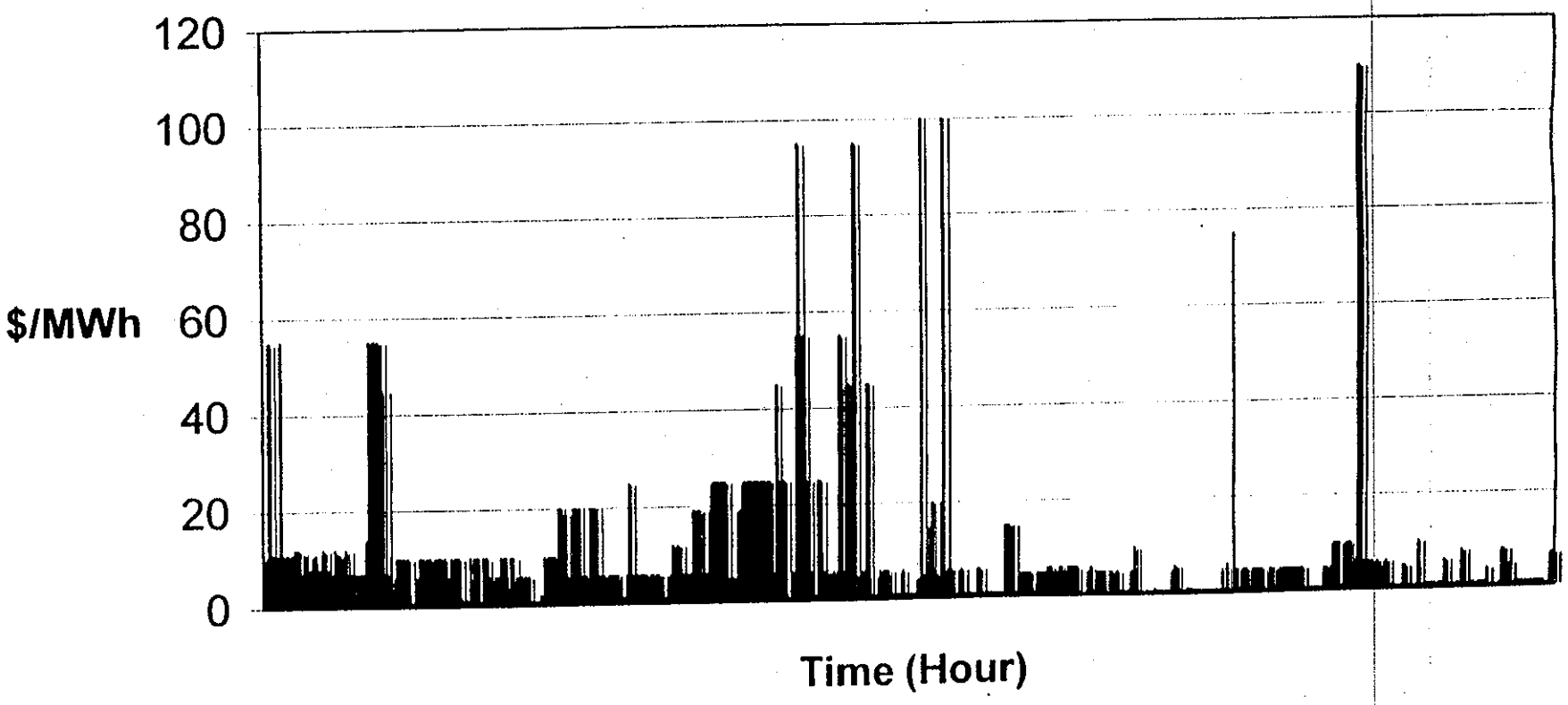
NYISO Ancillary Services
Hour Ahead Market
10 Min Spinning Reserve
December 1999



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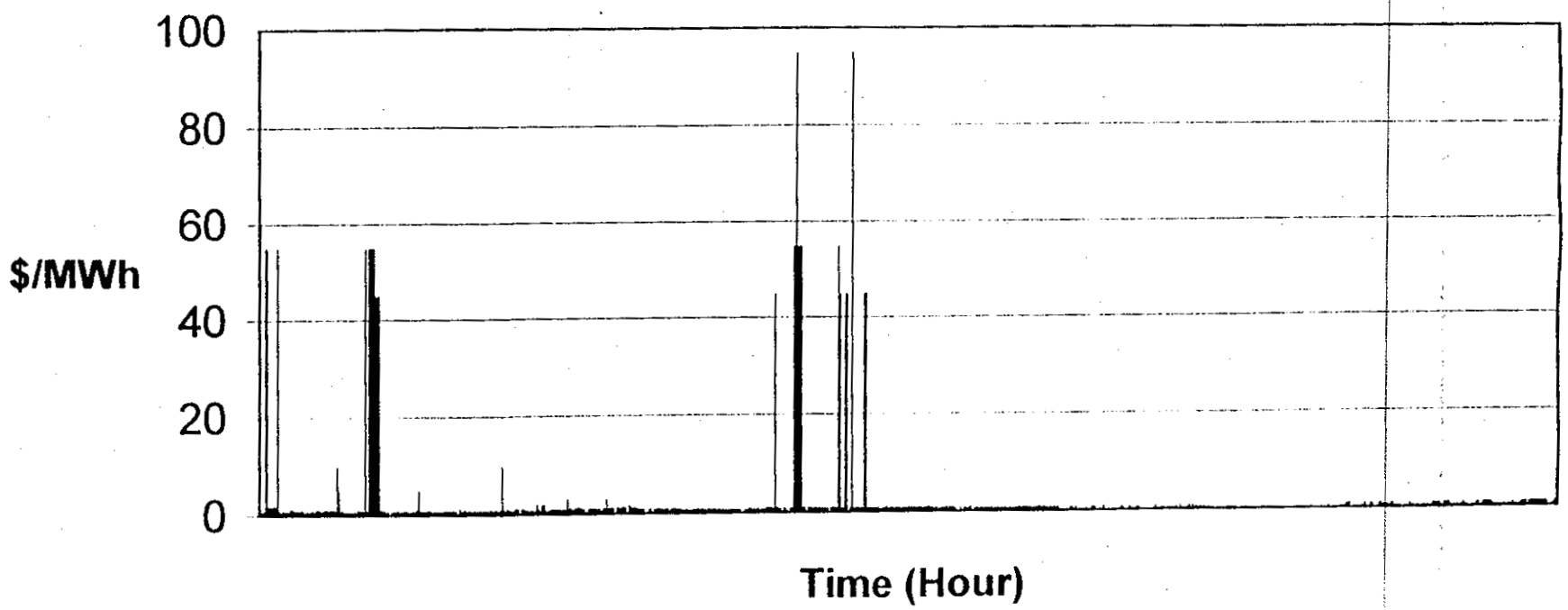
Hour Ahead Market
10 Min Non-Synchronous Reserve
December 1999



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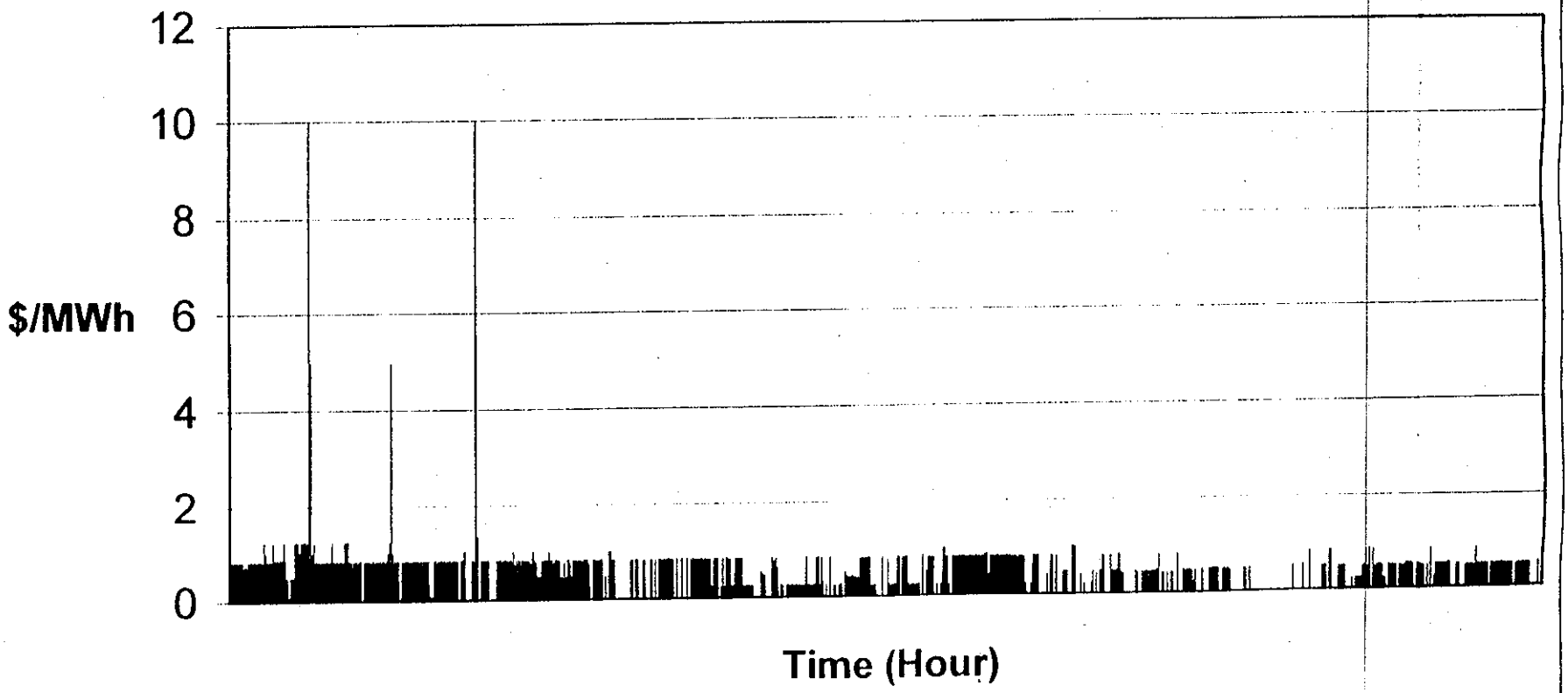
NYISO Ancillary Services
Hour Ahead Market
30 Min Operating Reserve
December 1999



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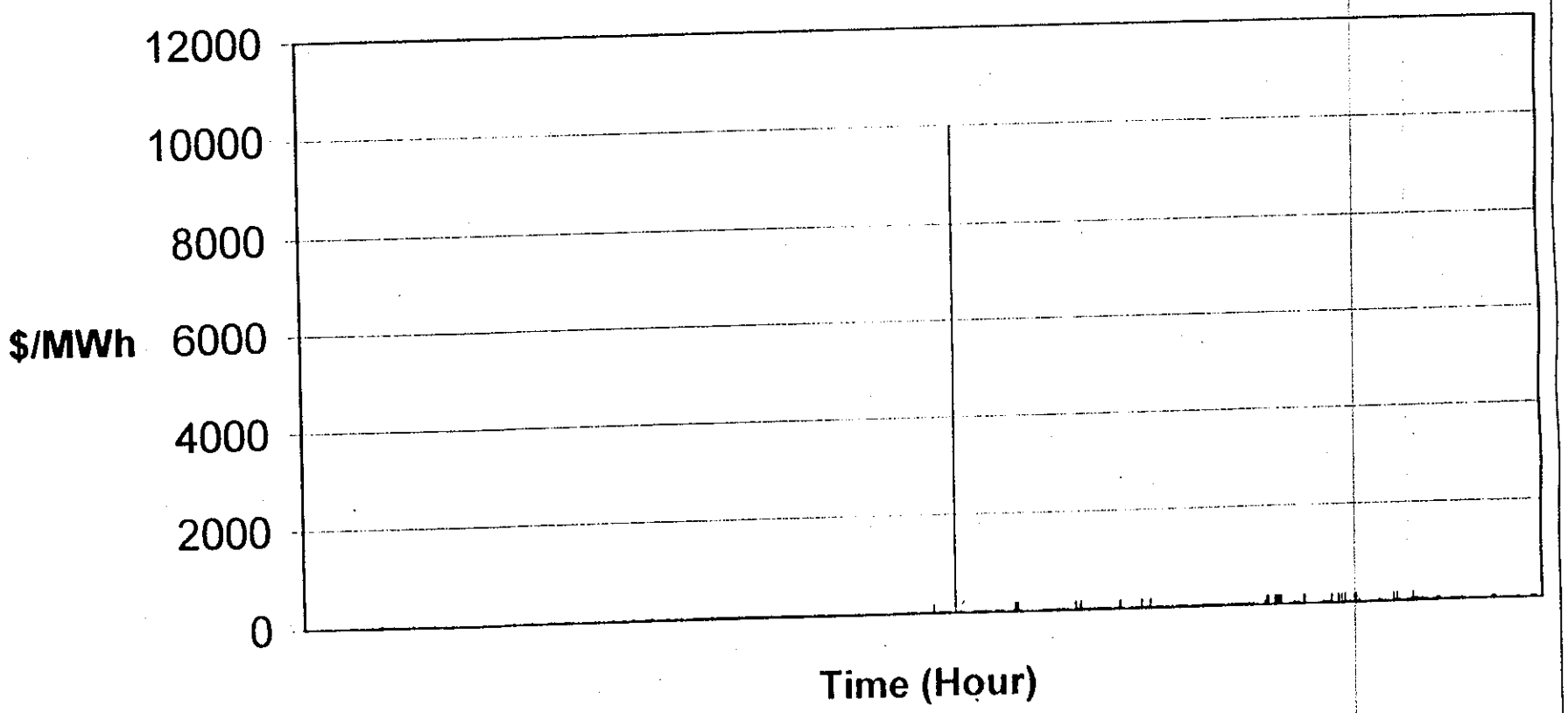
Hour Ahead Market
Regulation
December 1999



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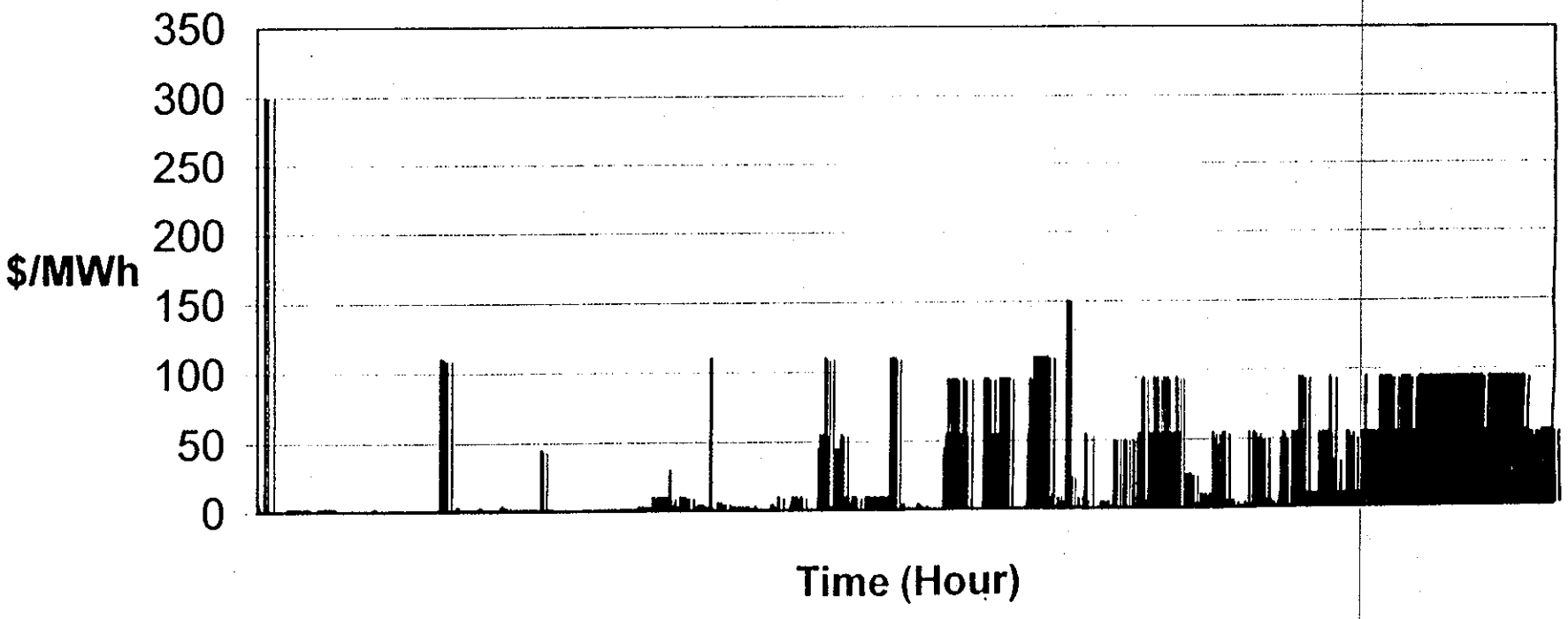
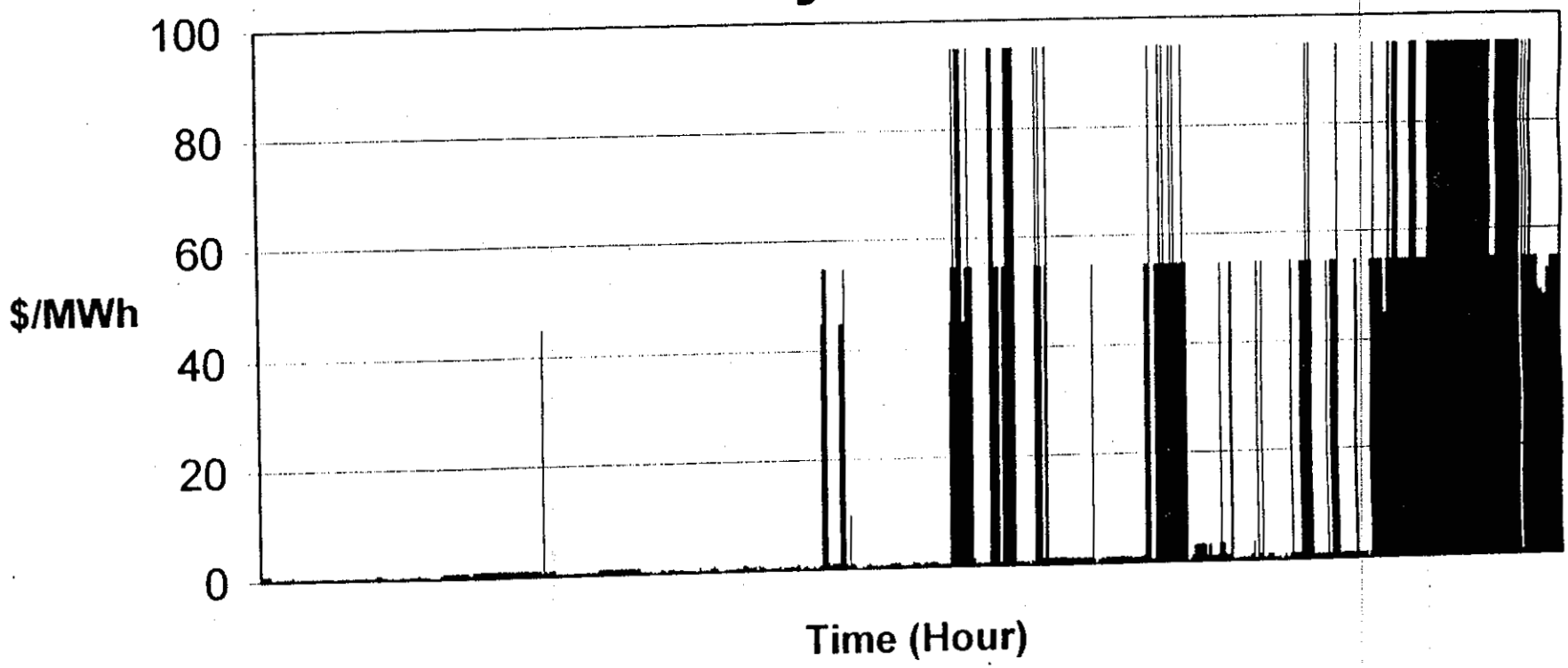
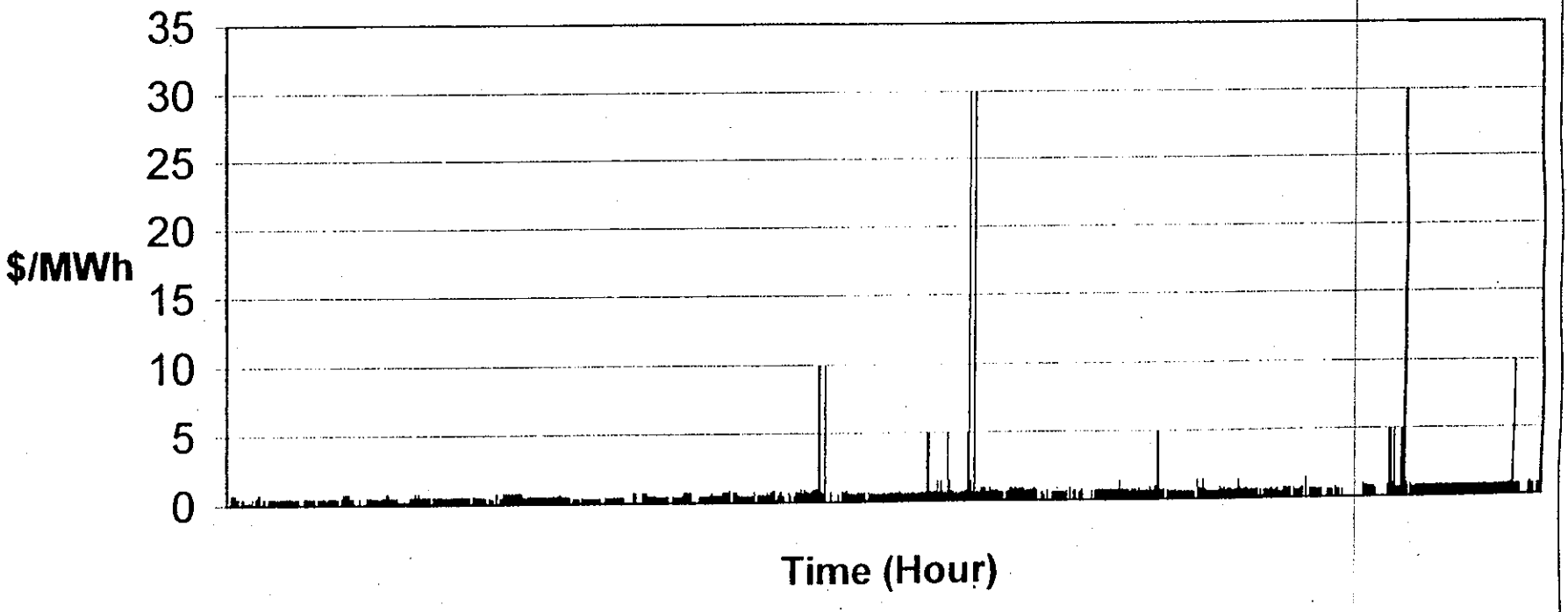
NYISO Ancillary Services
Hour Ahead Market
10 Min Spinning Reserve
January 2000



NYISO Ancillary Services
Hour Ahead Market
10 Min Non-Synchronous Reserve
January 2000



NYISO Ancillary Services
Hour Ahead Market
30 Min Operating Reserve
January 2000



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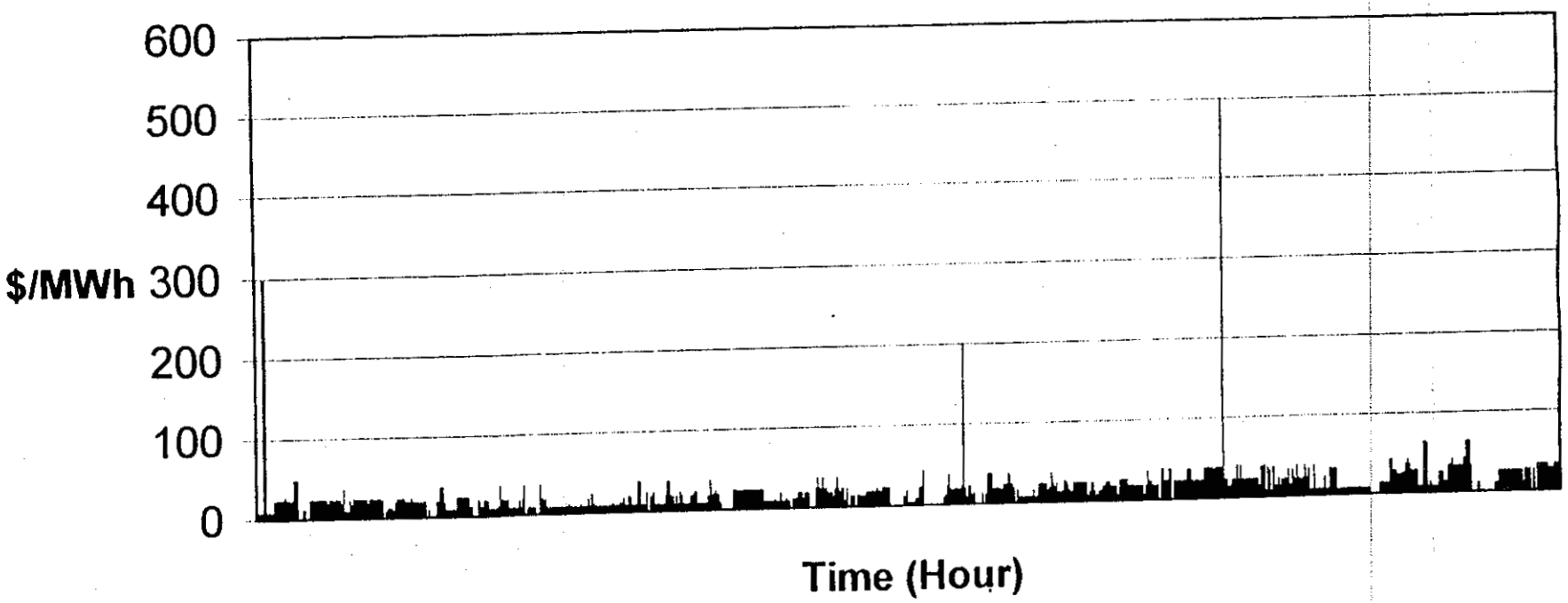
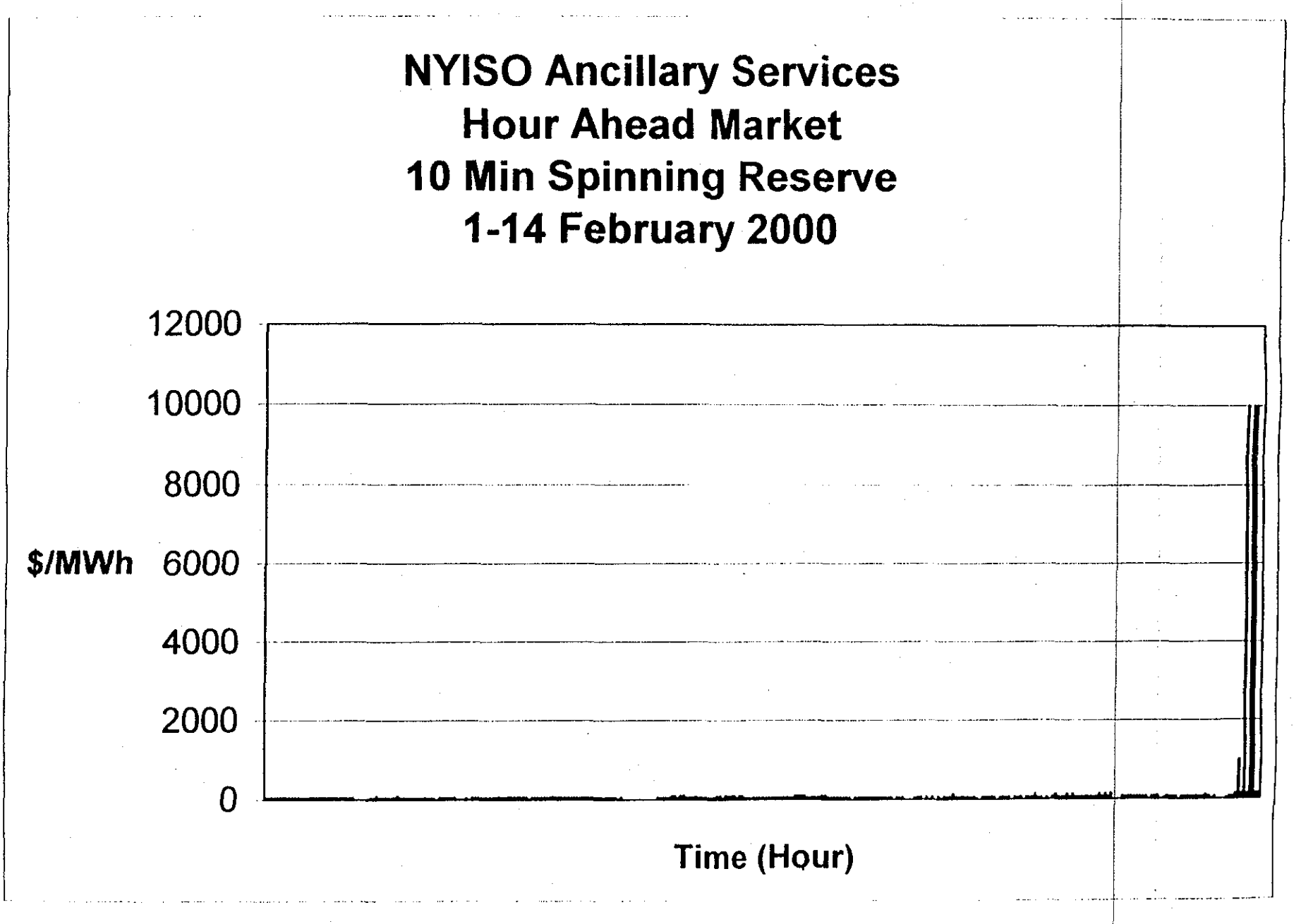
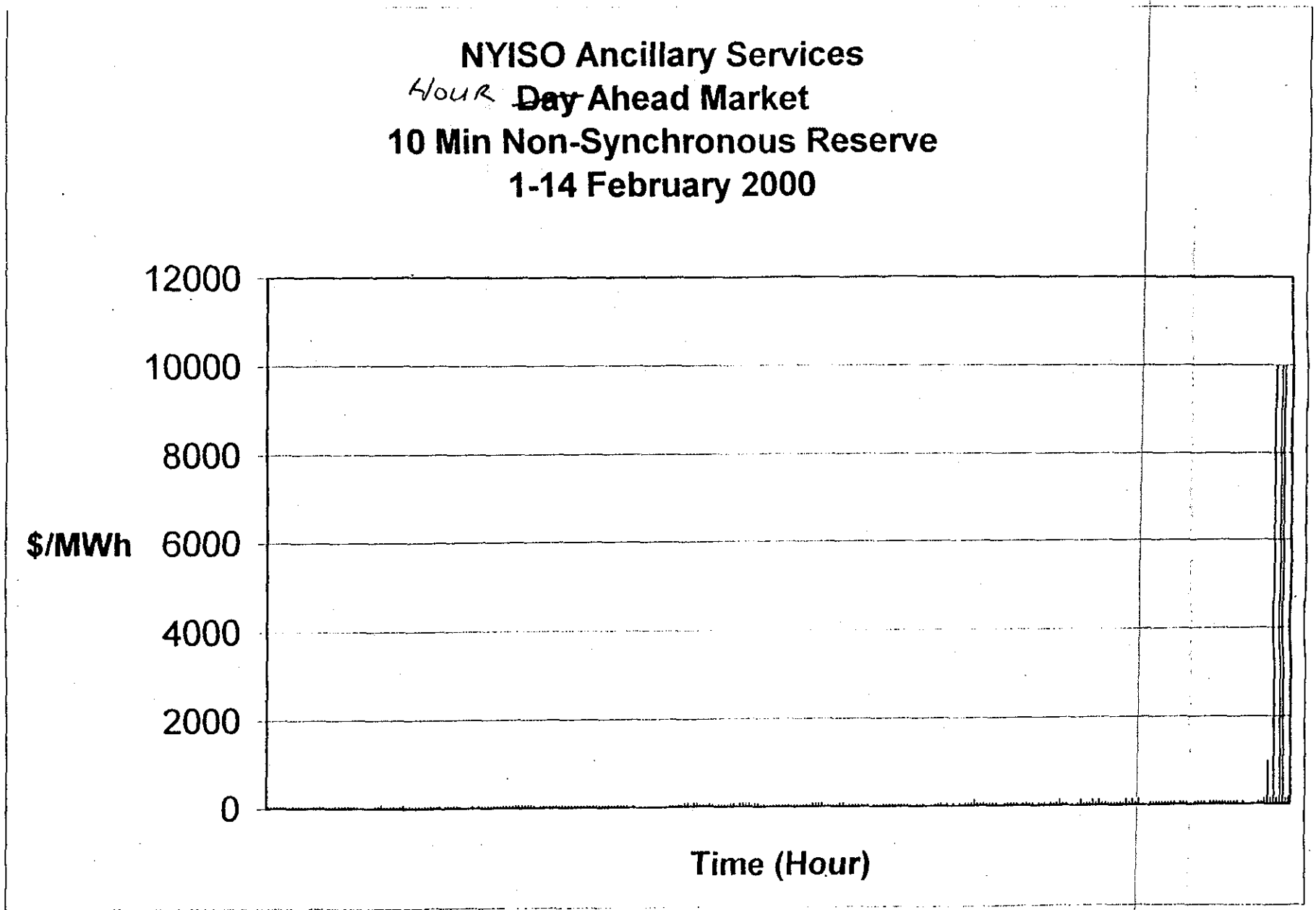
NYISO Ancillary Services
Hour Ahead Market
Regulation
January 2000

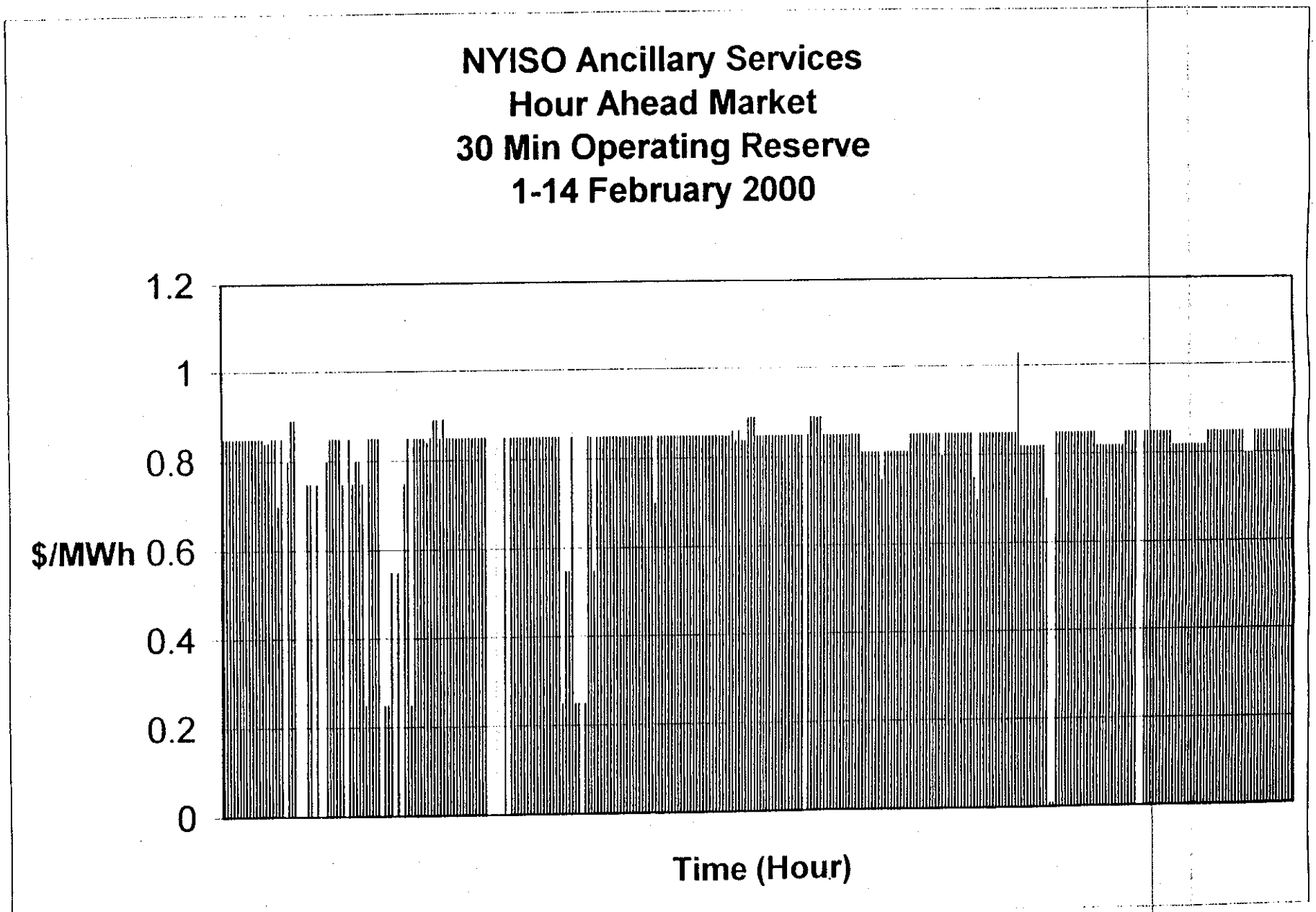



NYISO Ancillary Services
Hour Ahead Market
10 Min Spinning Reserve
1-14 February 2000
12000
10000
8000
$/MWh
6000
4000
2000
0
Time (Hour)

280

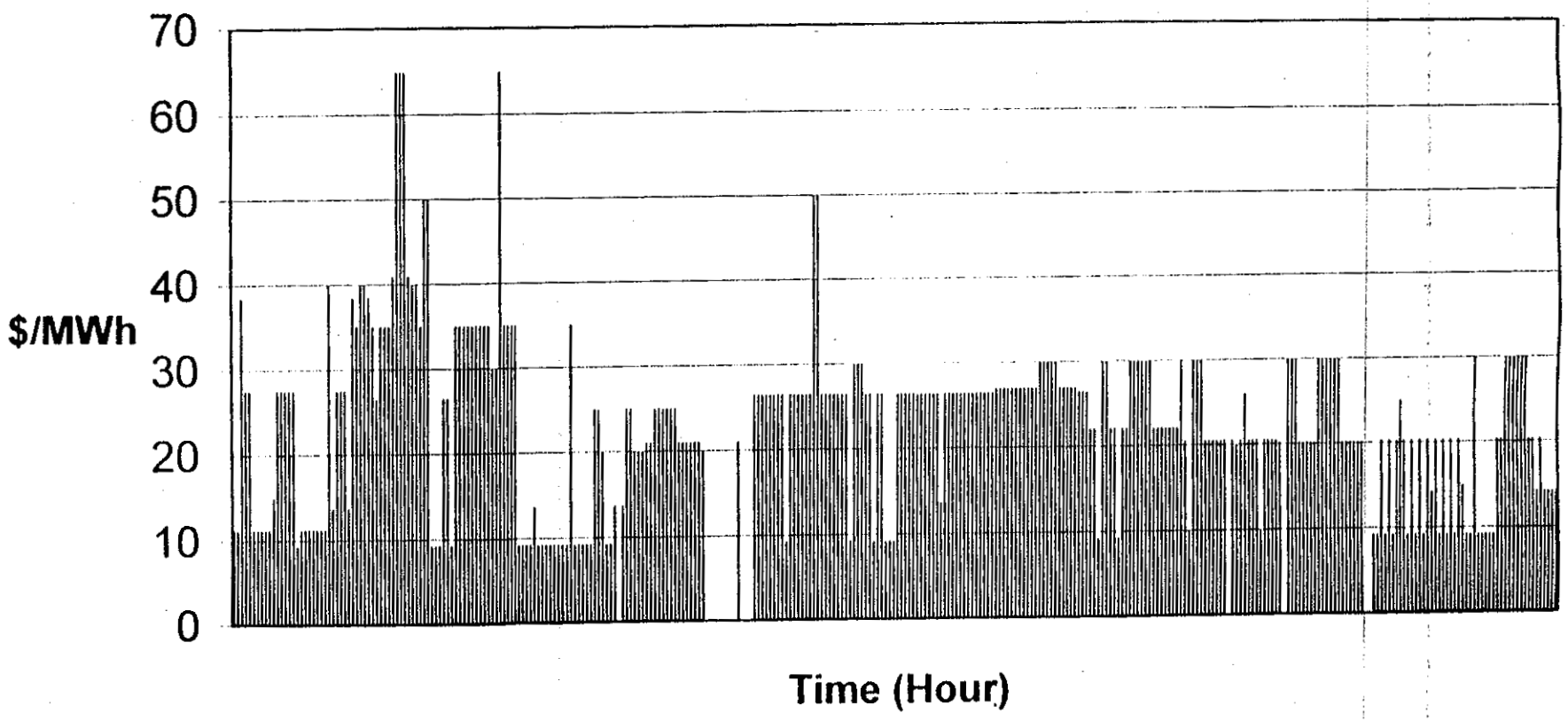

NYISO Ancillary Services
Hour ~~Day~~ Ahead Market
10 Min Non-Synchronous Reserve
1-14 February 2000
12000
10000
8000
$/MWh 6000
4000
2000
0
Time (Hour)

281


NYISO Ancillary Services
Hour Ahead Market
30 Min Operating Reserve
1-14 February 2000
1.2
1
0.8
$/MWh 0.6
0.4
0.2
0
Time (Hour)

282

NYISO Ancillary Services
Hour Ahead Market
Regulation
1-14 February 2000



Ancillary Services in New York State

USAID Forum on Ancillary Services
Warsaw, Poland
22-24 February 2000

Presented by:
Larry Markel
Electrotek Concepts, Inc.

So Tell Me About …

- The NYISO
- Ancillary Services
- How About That Market !!
- How Does This Thing Work?
- What Does It All Mean?

Today I will talk about the market for ancillary services in NYS. I'll start with the ISO, describing its structure and operation. Additionally, I'll describe some of the markets operated by the ISO.

Ancillary services are a relatively new commodity available in power markets in the U.S. They include a whole range of services and activities that are used to support the bulk power transmission system. In the United States, each of the fifty states is undergoing change in their power systems: restructuring, competition, new regulatory models. Among the multitude of products and services available in these markets are ancillary services.

Then we'll take a look at the market for ancillary services in NY and see how the prices for these services have behaved.

Next will be some discussion about how the market for ancillary services works in the NYISO.

And I will close with some thoughts on the NY power market

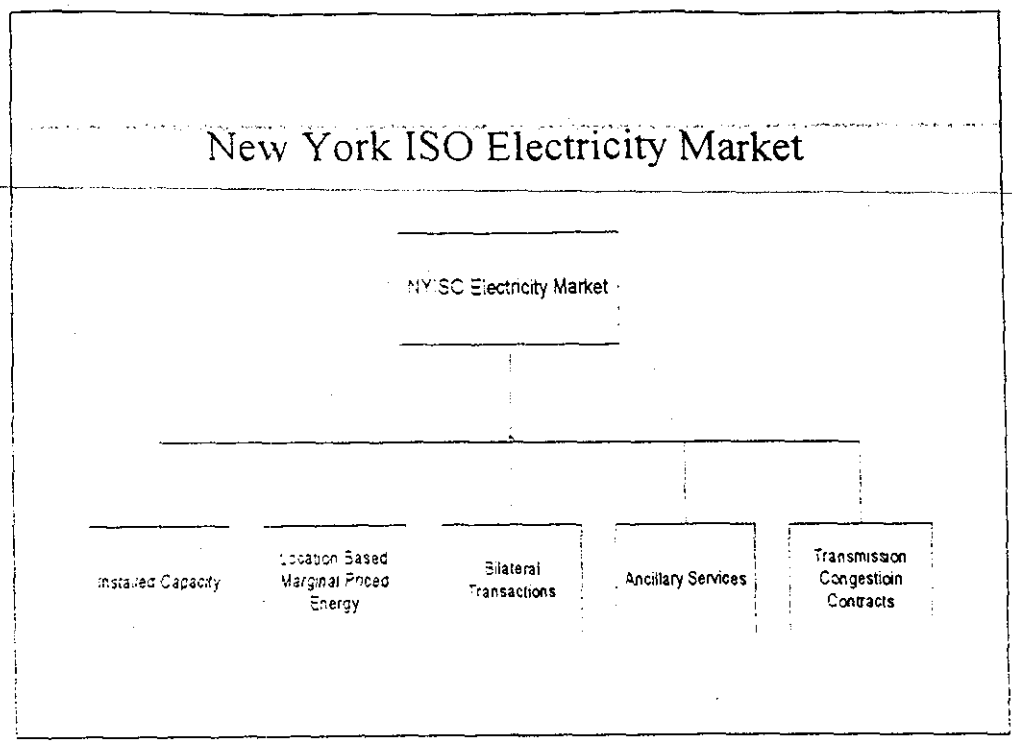
New York ISO

- Began Operation on 18 November 1999
- 131,000 square km
- 1998 Peak Load
  - Winter 1998-1999: 23,879 MW
  - Summer 1998: 28,160 MW
- 1998 Energy Requirements
  - 151.4 TWh

•The market for power in NY is operated by the NYISO. The ISO began formal operation on 18 November 1999. It had been operating in its current mode as the NYPP for some previous months during the testing and trial period for the systems, procedures and protocols. .

•Geographically, the NYISO control area covers over 130 thousand square kilometers. The area is characterized with loads increasing in the eastern and southeastern part of the state and most of the major generating capacity in the western part of the state. He state is transmission constrained, although interconnections with Canada (one 735/765 kV tie, and two 230 kV ties), the New England ISO (one 345 kV tie and one 230 kV tie) and PJM (one 500 kV tie, two 345 kV ties, and two 230 kV ties) offer some support

•The NYISO has a control area that in 1998 had a winter peak of about 23,879 MW and a summer peak of 28,160 MW. The total energy requirement in 1998 was 151.4 TWh.



The products bought and sold in the NYISO include:

- Installed Capacity -- A generator or load that is certified as having met all necessary requirements and is capable of supplying and/or reducing the demand for energy.
- LBMP Energy -- Energy bought and sold in the NYISO that is priced by time and location.
- Bilateral Transactions -- The purchase or sale of capacity, energy, and/or ancillary services between two or more parties.
- Ancillary Services -- Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or "Voltage Support Service"); Regulation and Frequency Response Service (or "Regulation Service"); Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability.

So What Are Ancillary Services?

- Support the Bulk Power System
- Six Types:
  - Scheduling, System Control & Dispatch
  - Reactive Supply & Voltage Support
  - Regulation & Frequency Response
  - Energy Imbalance
  - Operating Reserve
  - Black Start Capability

•Ancillary services support the transmission of energy from resources to loads while maintaining reliability. They are the physical equipment and human resources that provide this support as well as the metered quant8ities.

•Scheduling, System Control & Dispatch -- Two types:

> •System Security Management in real time (e.g. tie line regulation, frequency support, interchange scheduling management, security constrained dispatch, transmission system operation, system emergency management)
>
> •Capacity Management (e.g. capacity management, operating reserve management and scheduling, outage coordination)

•Voltage Support -- To maintain transmission voltage within limits, generators are operated to produce (or absorb) reactive power.

•Regulation & Frequency Response -- Necessary to balance resources with load and to assist in maintaining frequency. On-line generators are used as necessary (through use of AGC) to follow moment-by-moment changes in load.

•Energy Imbalance -- Internal and external energy balance to control mismatch between scheduled and actual flows.

•Operating Reserve -- Provides back-up generation in the event of a contingency. Operating reserves include spinning reserve (10 minute and 30 minute), operating reserve, and 10 minute non-synchronous reserves.

•Black Start Capability -- Generators that can start without an external power supply and are available for system restoration.

How Does This Thing Work ?

- Two Separate Ancillary Service Markets
  - Day Ahead
  - Hour Ahead
- Products
  - 10 Minute Spinning Reserve
  - 10 Minute Non-Synchronous Reserve
  - 30 Minute Operating Reserve
  - Regulation

•There are two separate markets for AS in NY -- Day-Ahead and Hour-Ahead.

•For each of these markets there are four separate AS products hat are bid and bought in the market (10 Min Spinning Reserve, 10 Min Non-Synch Reserve, 30 Min Operating Reserve and Regulation.

•10 Min Spinning Reserve -- Considered an operating reserve service that provides backup generation in the event of a major generating resource failure. Resources must be already synchronized to the NYS Power System and can respond to instructions to change output level within 10 minutes. Resources must be under NYISO operational control

•10 Min Non-Synchronous Reserve -- Operating reserves that can be started, synchronized and loaded within 10 minutes.

•30 Min Operating Reserve -- Reserves the respond to instructions to change output energy within 30 minutes.

•Regulation -- To maintain transmission voltages within acceptable limits, resources under the control of the ISO are operated to produce or absorb reactive power.

How Does This Thing Work ?

- Market Participants
- Market Mechanisms
  - MIS
  - Bidding
  - Metering
  - Execution
  - Settlement

•Market participants include suppliers, power exchanges, transmission customers, and marketers. To participate in a market one must meet the specific qualifications for that market. There are specific categories of qualification - for 10 Minute Spinning Reserve bidders, for instance, certain technical, contractual, legal and regulatory requirements must be satisfied to be able to participate in the market. The requirements for each participant reflect the specific needs for the service (e.g. metering, testing, interconnection, protection, monitoring, and control).

•Suppliers -- Can include generators, ancillary service providers, and demand-side resources.

•Power Exchanges -- Commercial entities that facilitate the sale/purchase of energy, capacity or ancillary services in the New York Wholesale Market.

•Transmission Customers -- Eligible customer who receives transmission service from pursuant to a service agreement. Can include load-serving entities, energy service customers (ESCo's), municipalities, cooperatives, industrial customers, and commercial customers

•Marketers -- Facilitate the linkage between buyers and sellers

•Market Mechanisms -- The mechanics of the market are the structure and processes that provide an exchange for buyers and sellers. They include the systems, procedures, protocols, and practices of the market in the ISO framework. This includes the bidding process, metering and billing, and the execution and settlement of the transaction -- In some cases the ISO executes the transaction (e.g. through direct control of generating resources), in others the market participant does (interruptible loads, generation).

So What Does It All Mean ?

- Markets Work
  - Buyers and sellers coming together
  - Mechanisms seem to perform required market services

•So we have a function power market in NYS. It has been officially in operation for three months. And the lights are still on!!! Bidders and buyers are coming to the marketplace, and market clearing prices are set. So...**Markets Work!!**

So What Does It All Mean ?

- Or Do Markets Work ?
  - Reliability
  - The Resource Payment Issue

The role of ancillary services in power markets is to promote reliable and efficient use of existing transmission capacity. And based on the experiences in NY, it seems to have done that so far.

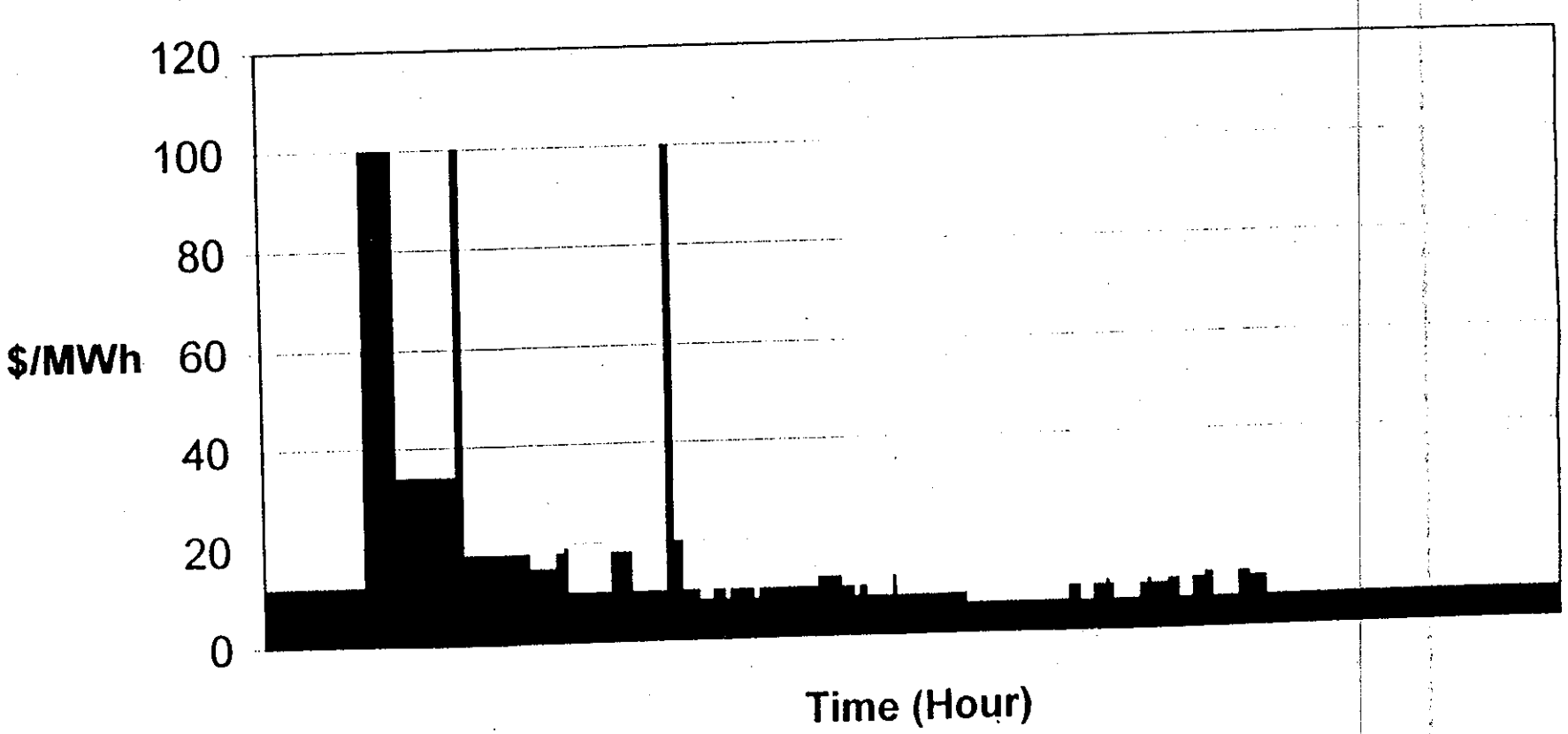
The true test, however, is the test of time. Will the market be able to provide the service that is most expensive to provide in power systems - reliability. And if so, how?

What happens in capacity constrained systems? How will bottlenecks be relieved? When will construction be required? Who pays, and how?

Which of these ways will be the most efficient?

Time will tell.

NYISO Ancillary Services
Day Ahead Market
10 Min Spinning Reserve
18-30 November 1999



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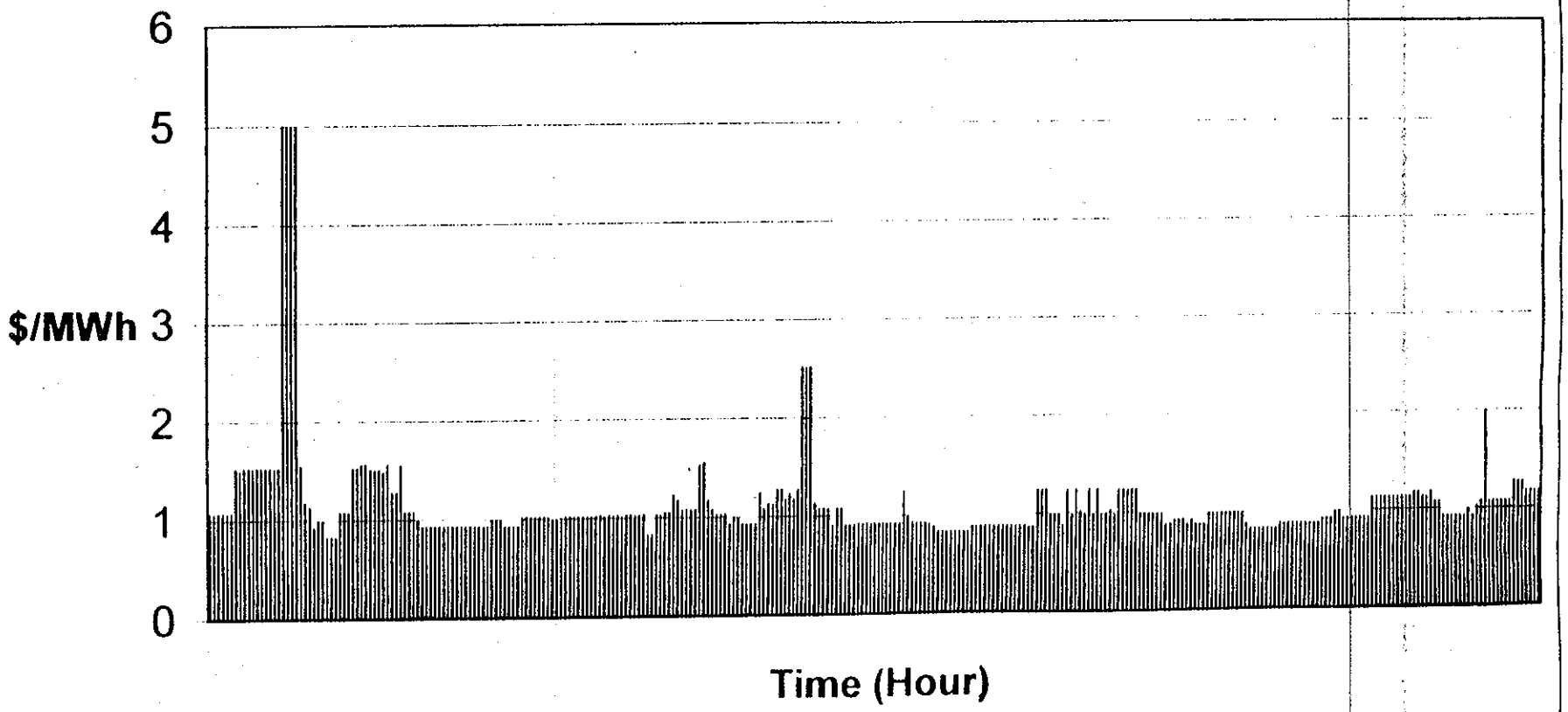
NYISO Ancillary Services
Day Ahead Market
10 Min Non-Synchronous Reserve
18-30 November 1999



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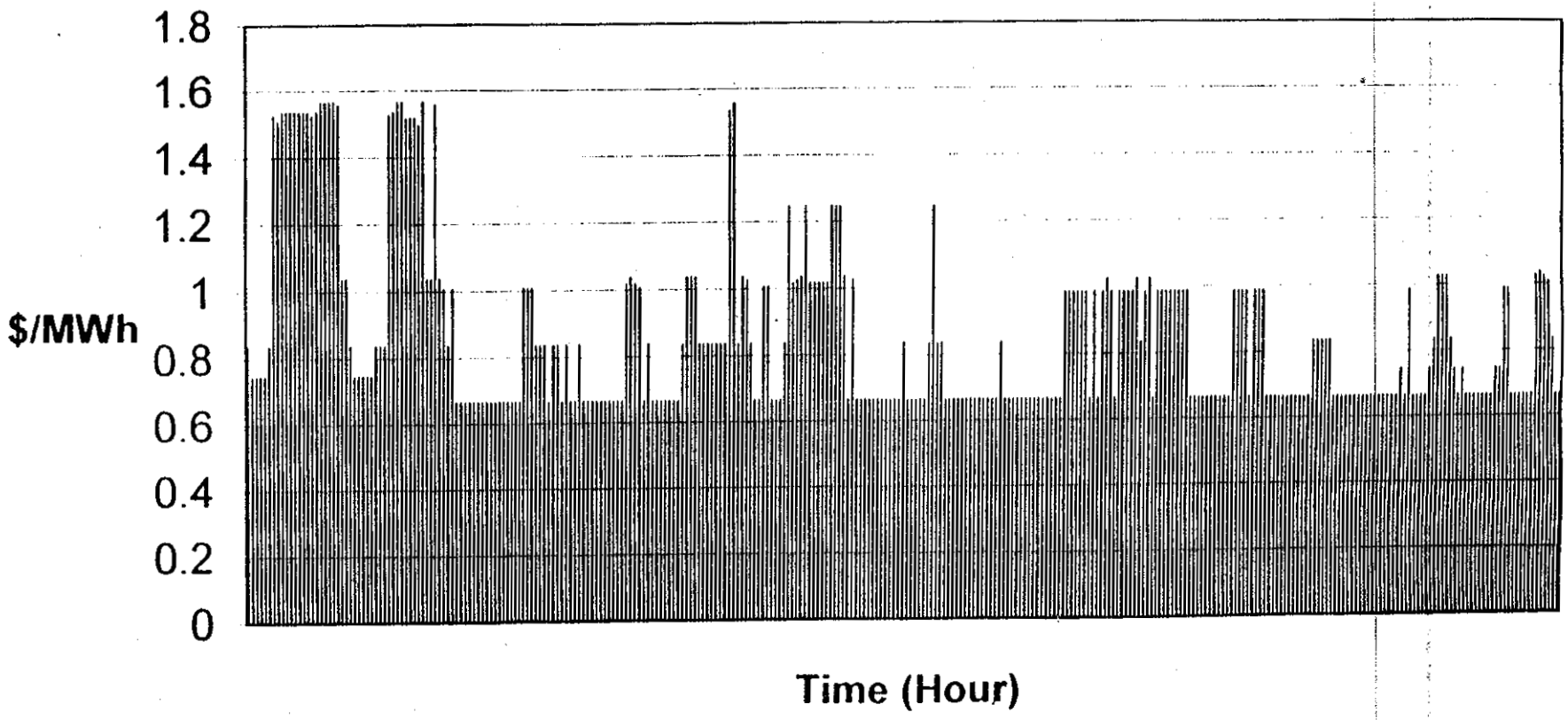
NYISO Ancillary Services
Day Ahead Market
30 Min Operating Reserve
18-30 November 1999



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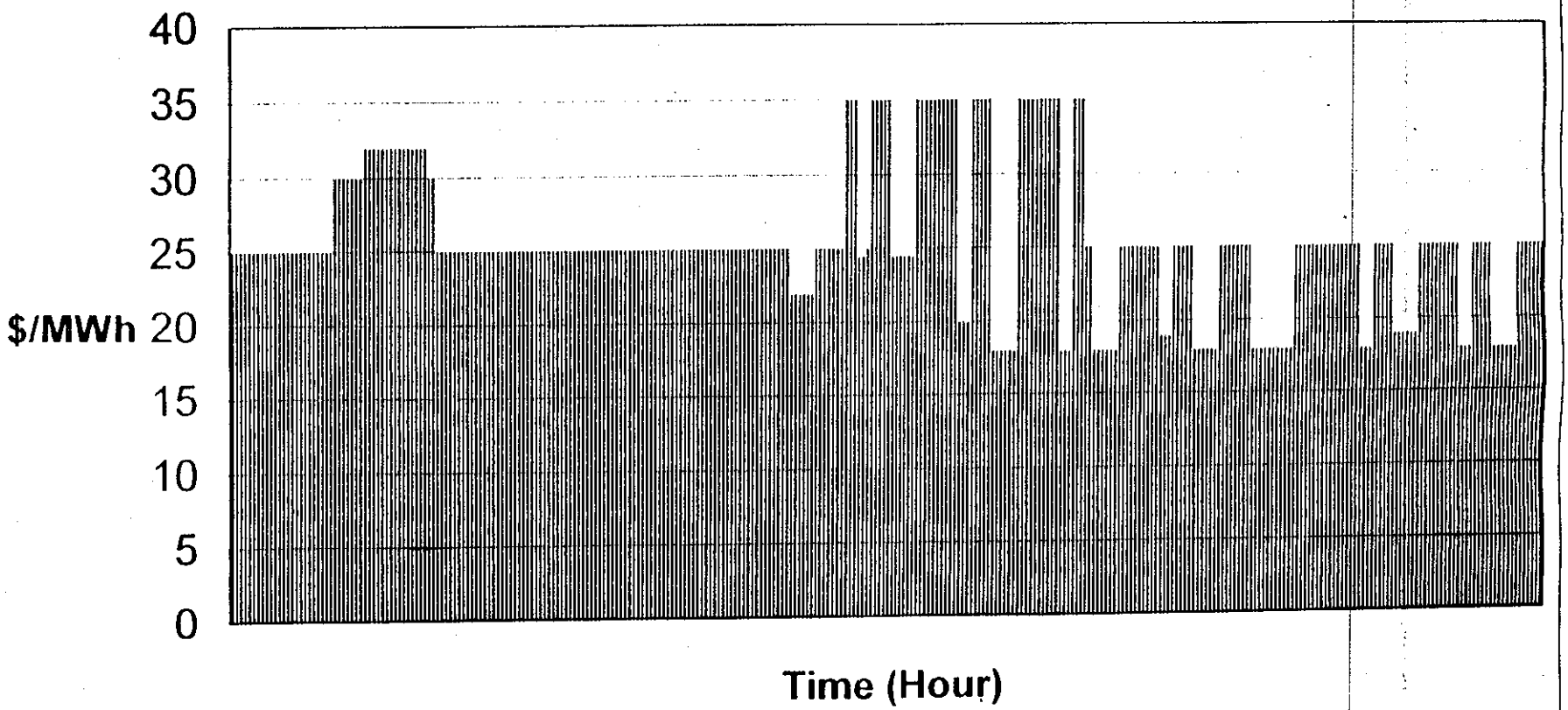
NYISO Ancillary Services
Day Ahead Market
Regulation
18-30 November 1999



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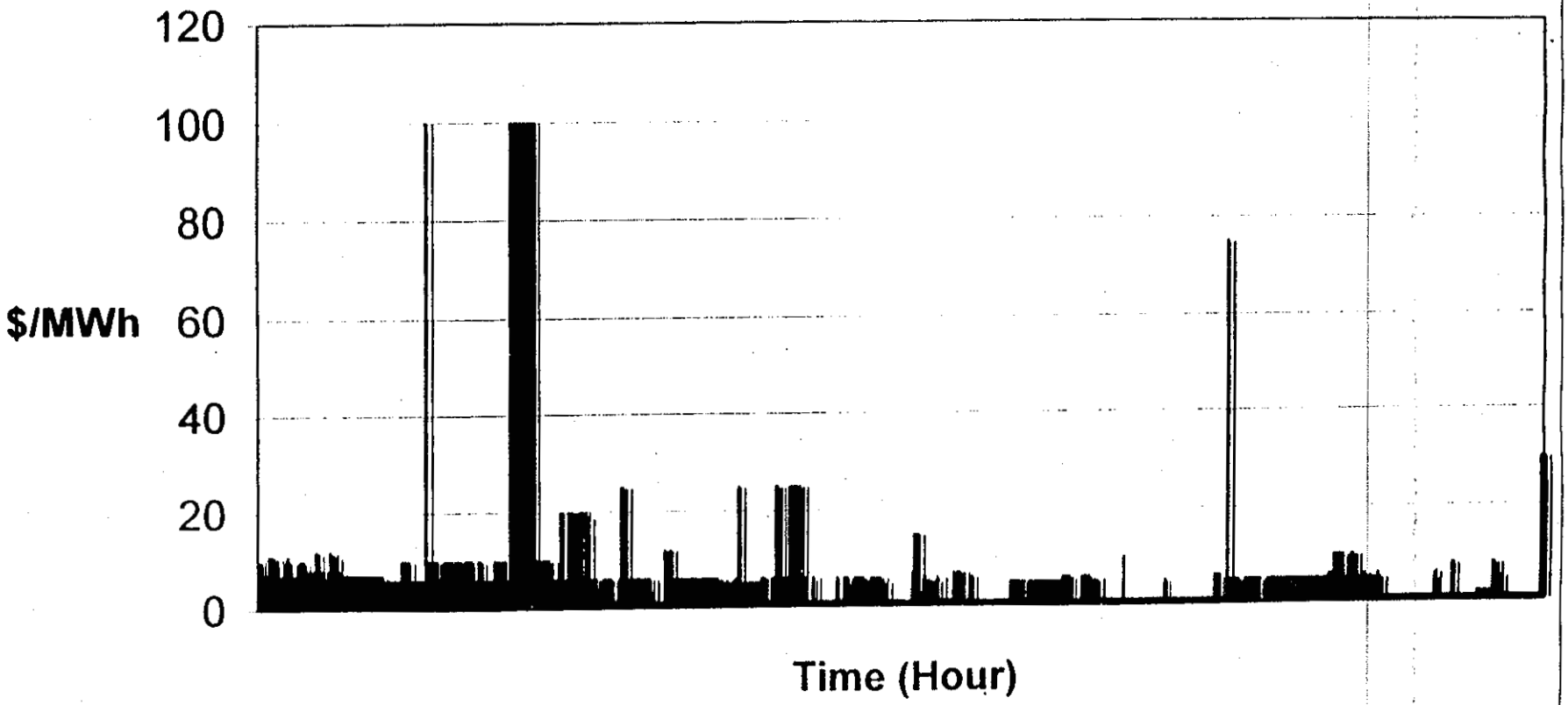
NYISO Ancillary Services
Day Ahead Market
10 Min Spinning Reserve
December 1999



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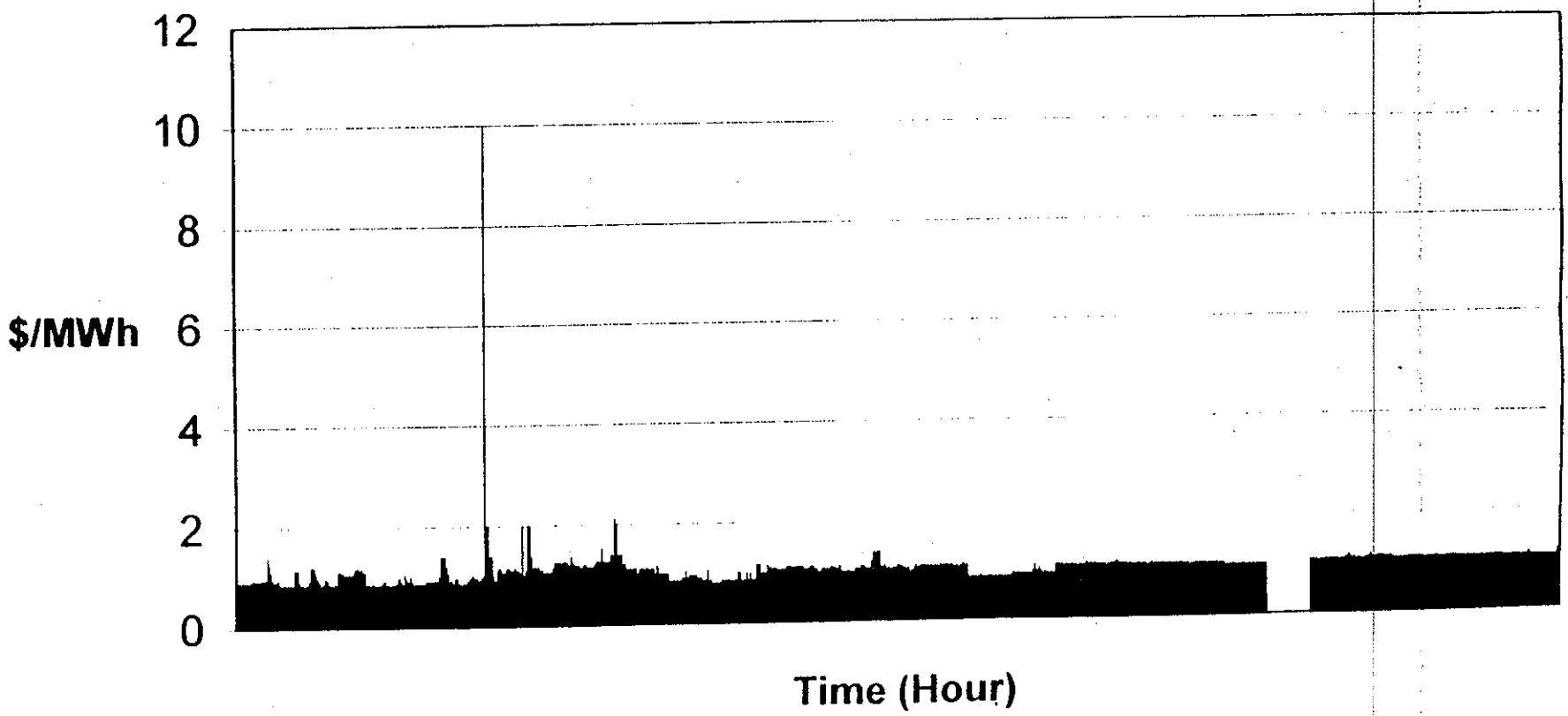
NYISO Ancillary Services
Day Ahead Market
10 Min Non-Synchronous Reserve
December 1999



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Day Ahead Market
30 Min Operating Reserve
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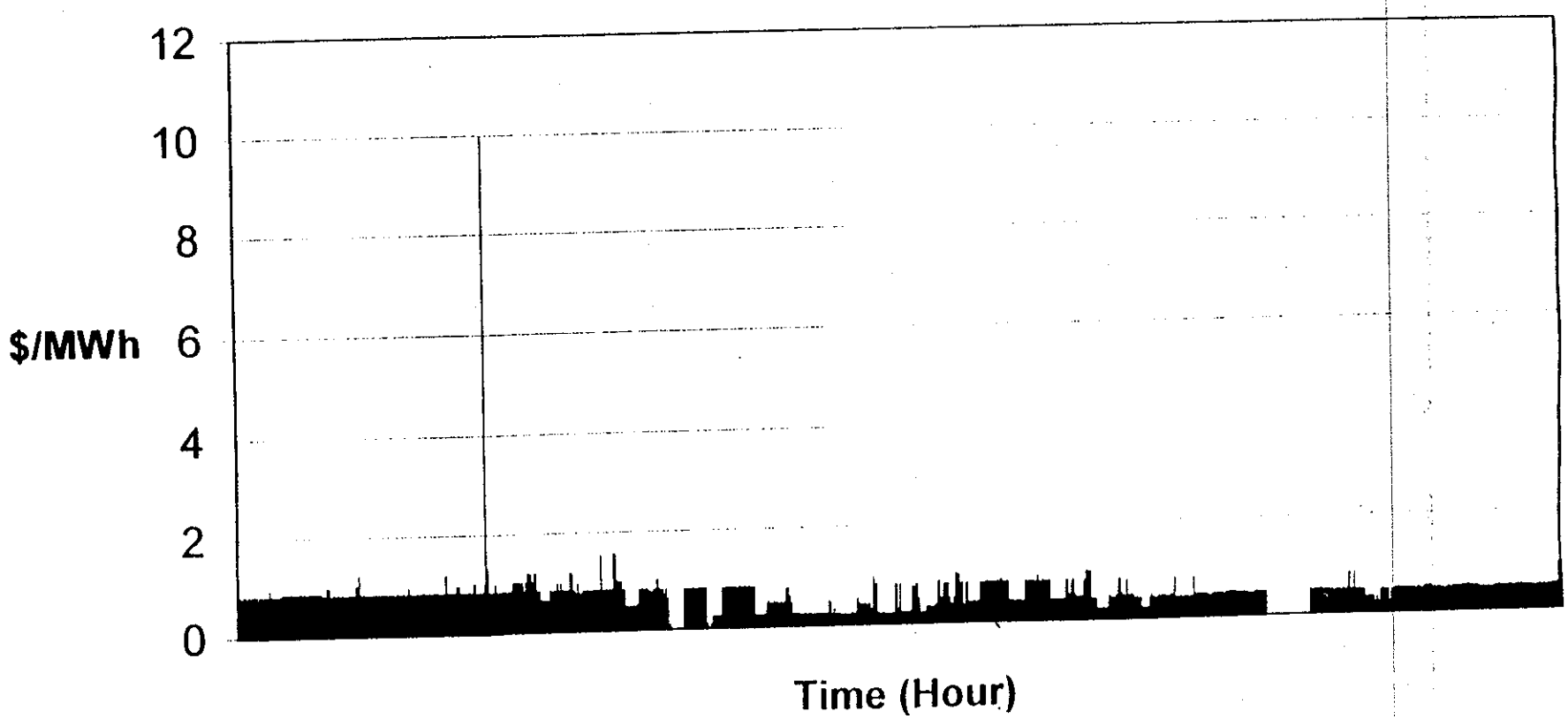
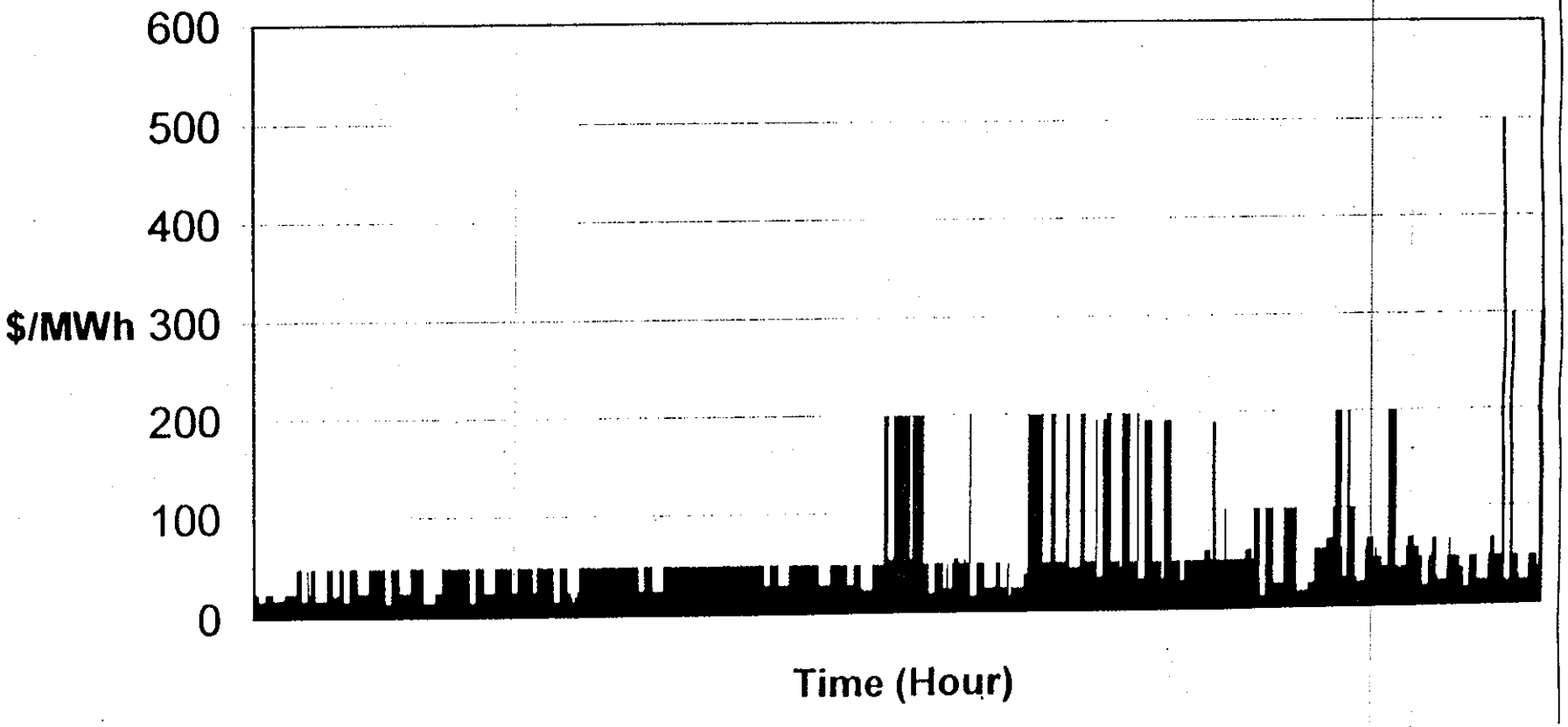


NYISO Ancillary Services
Day Ahead Market
Regulation
December 1999



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NYISO Ancillary Services
Day Ahead Market
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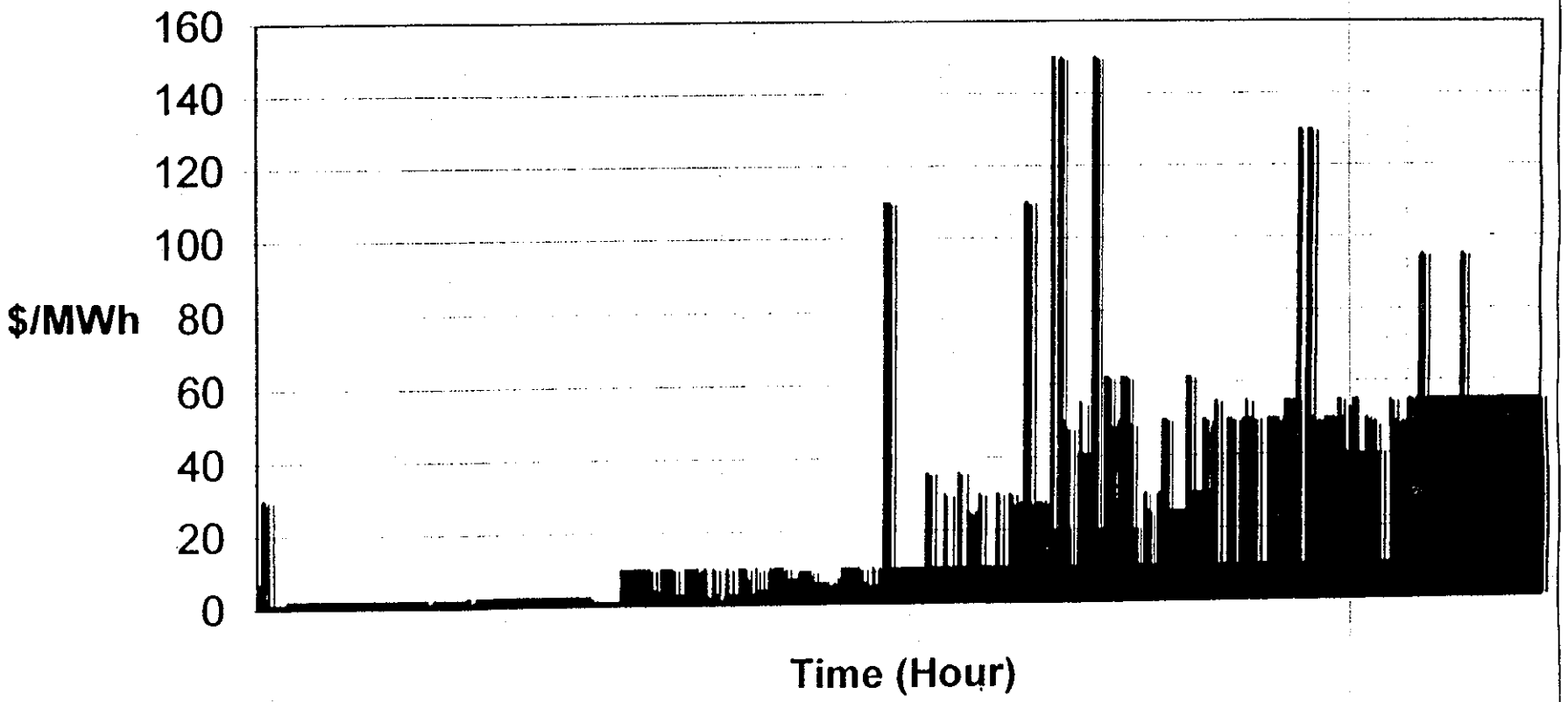
January 2000



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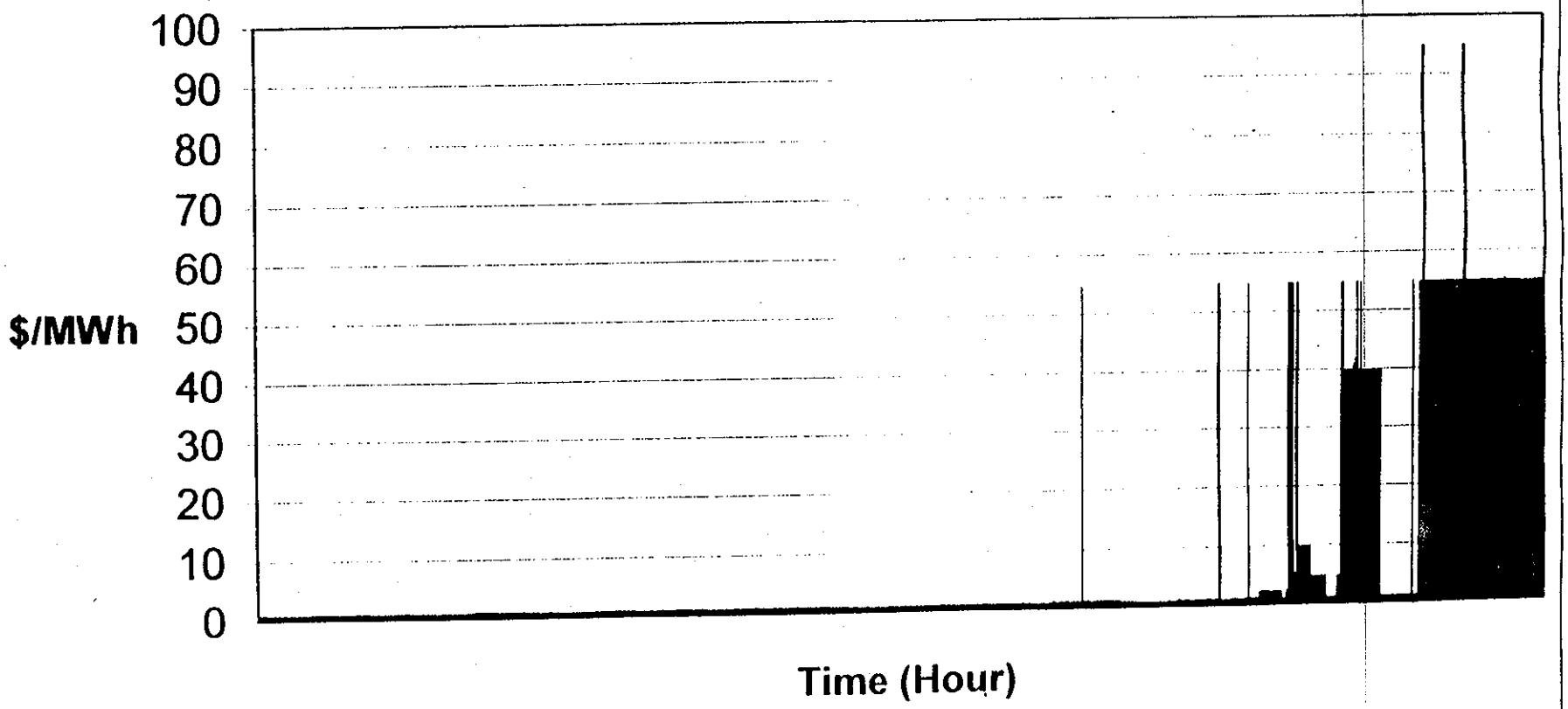
10 Min Non-Synchronous Reserve
January 2000



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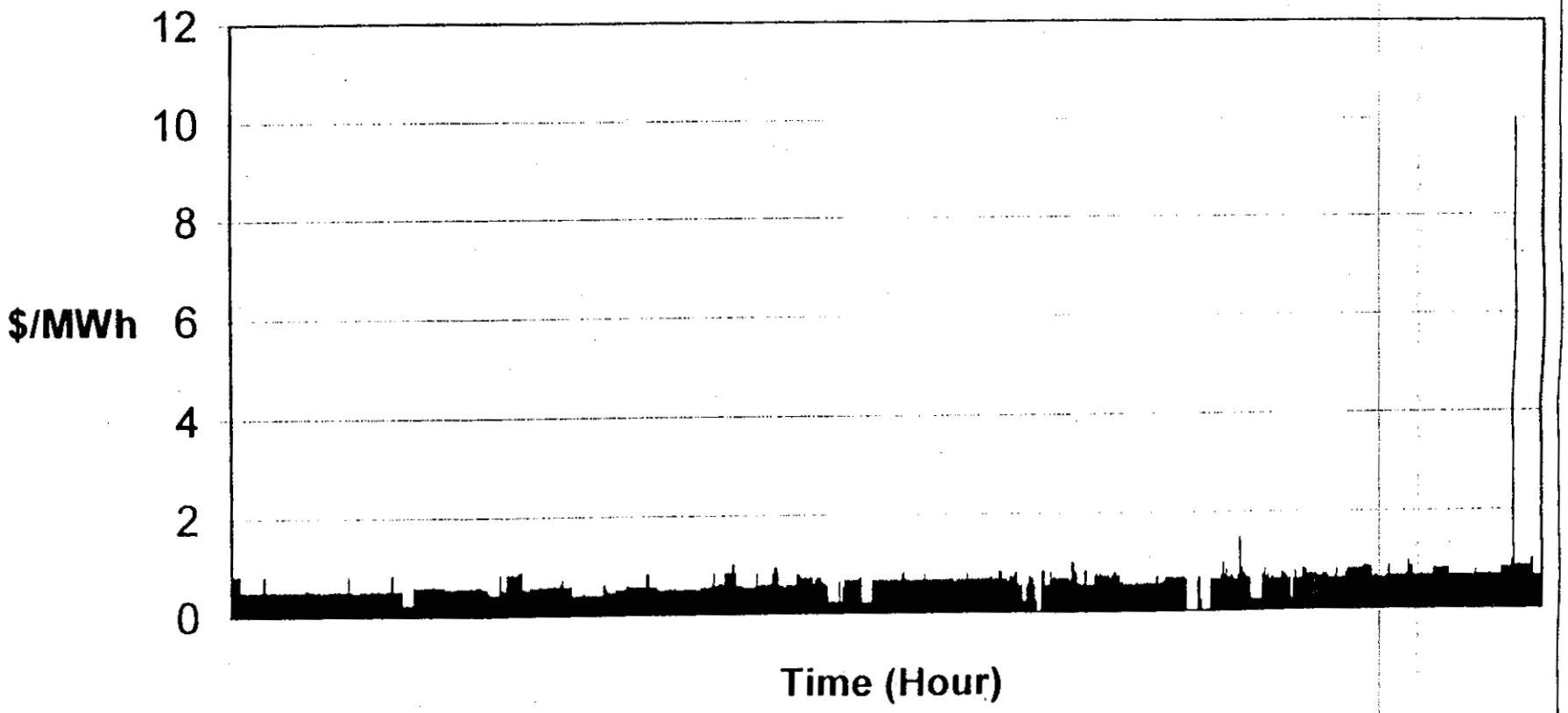
NYISO Ancillary Services
Day Ahead Market
30 Min Operating Reserve
January 2000



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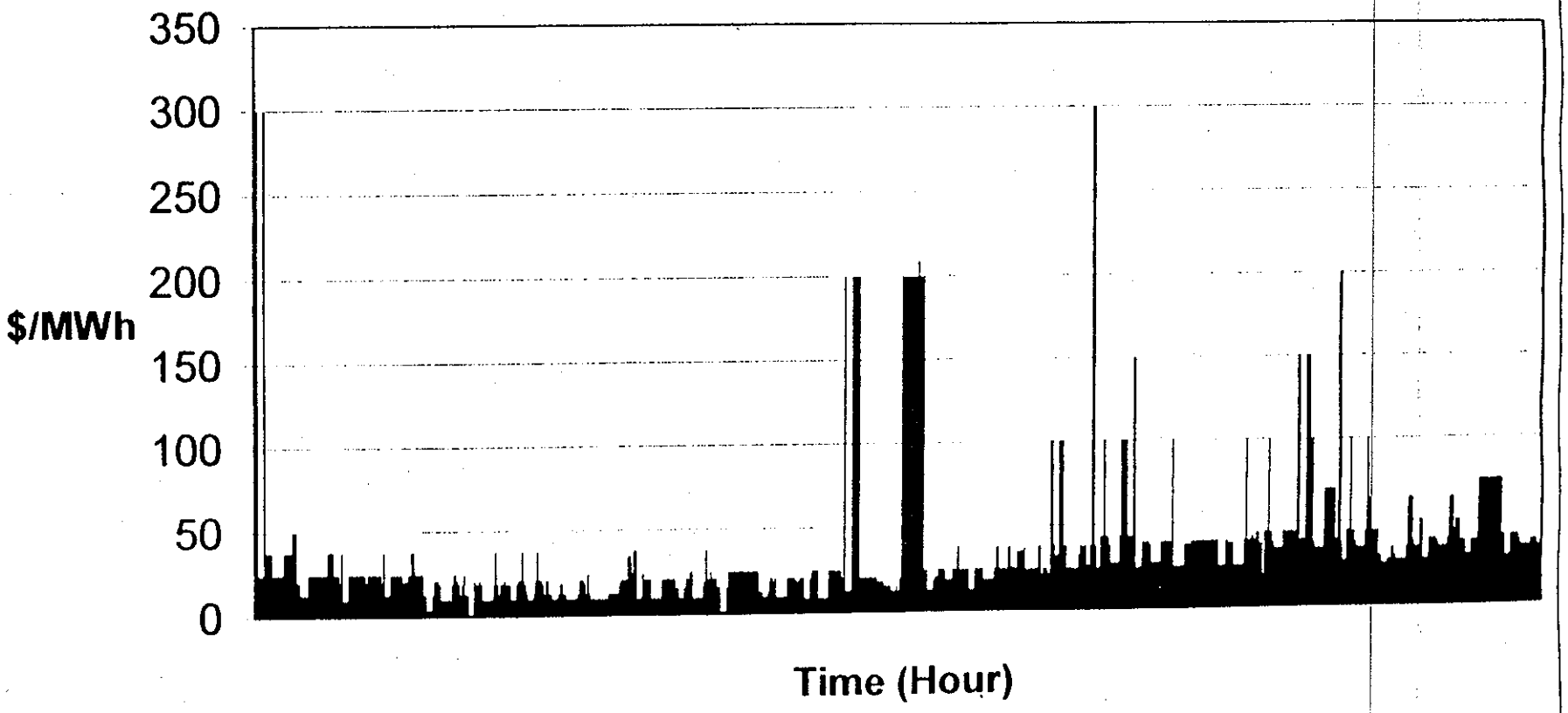
Regulation
January 2000



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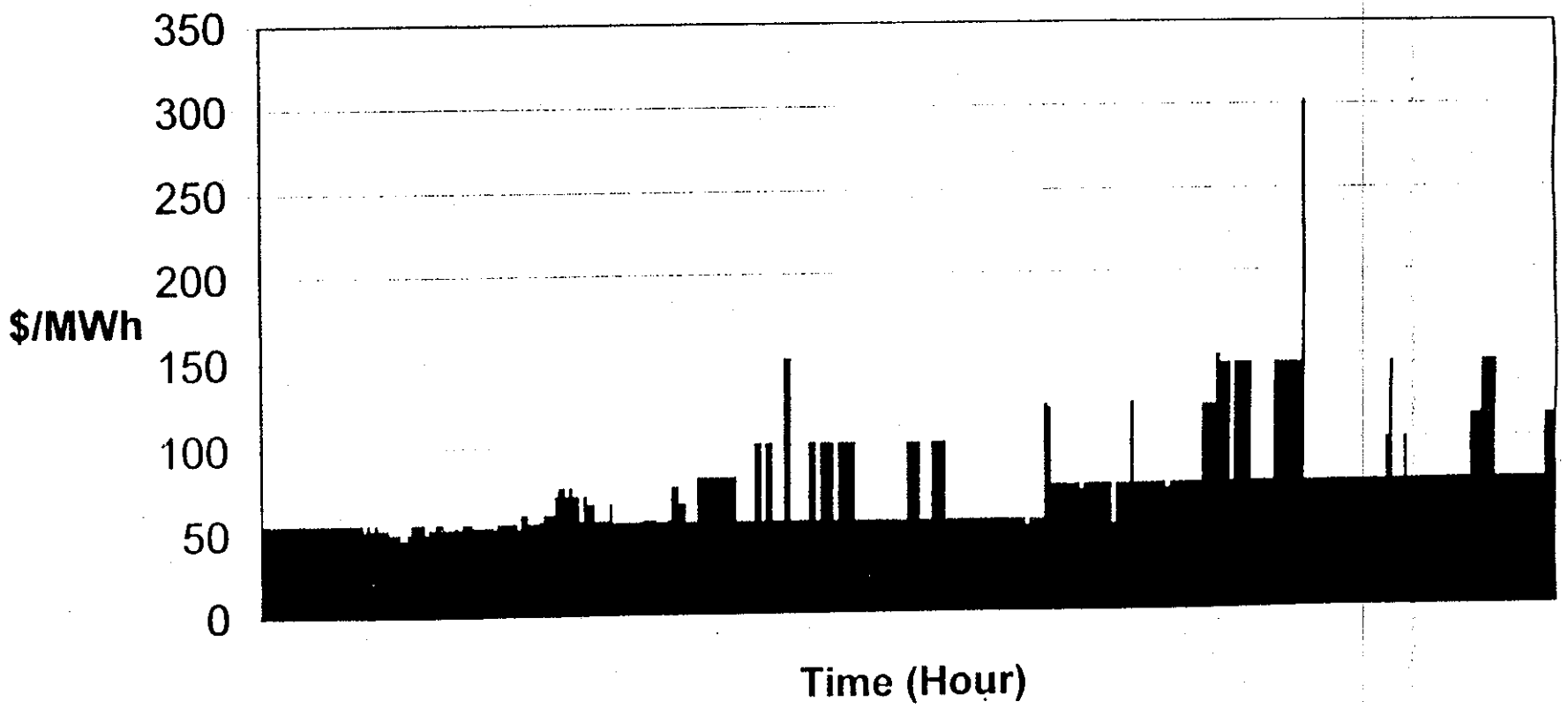
NYISO Ancillary Services
Day Ahead Market
10 Min Spinning Reserve
1-15 February 2000



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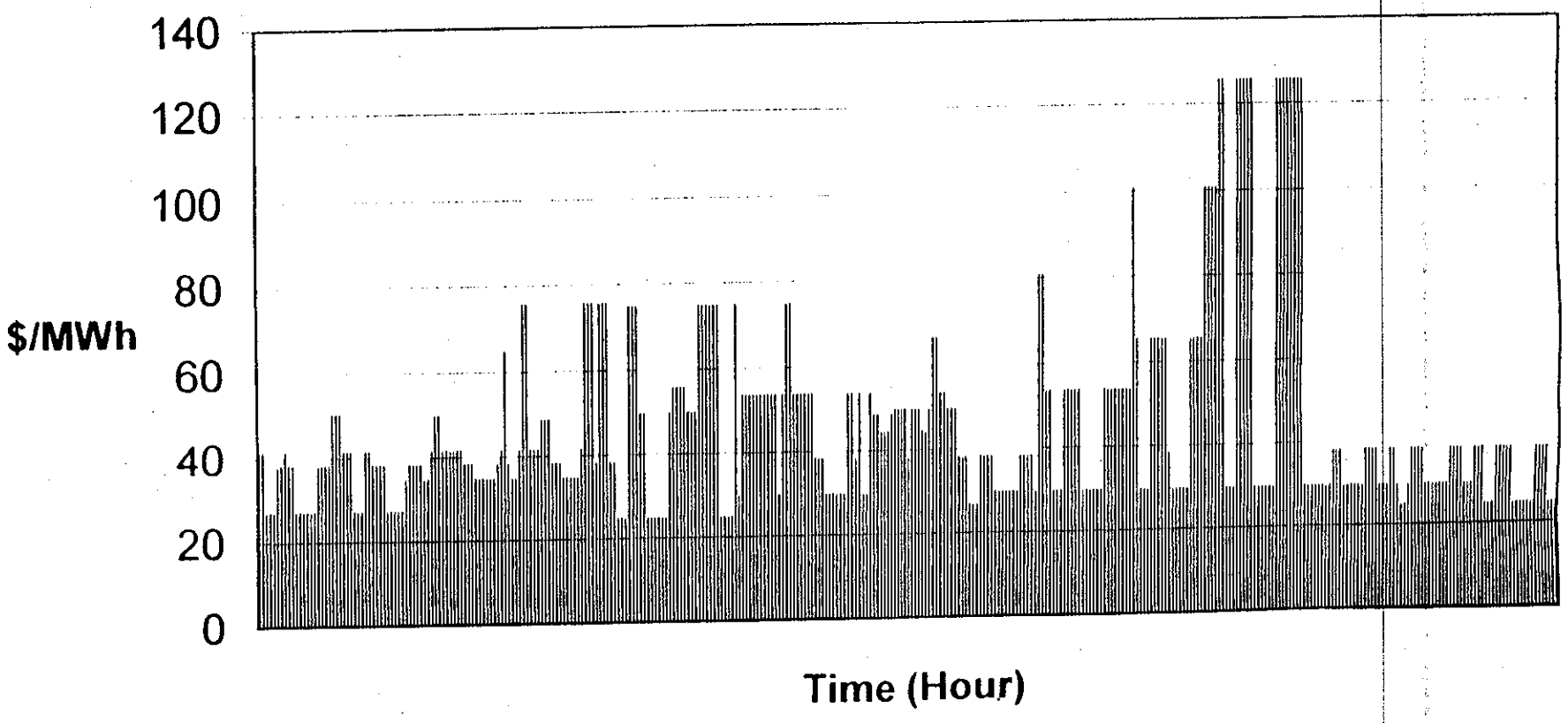
Day Ahead Market
Regulation
1-15 February 2000



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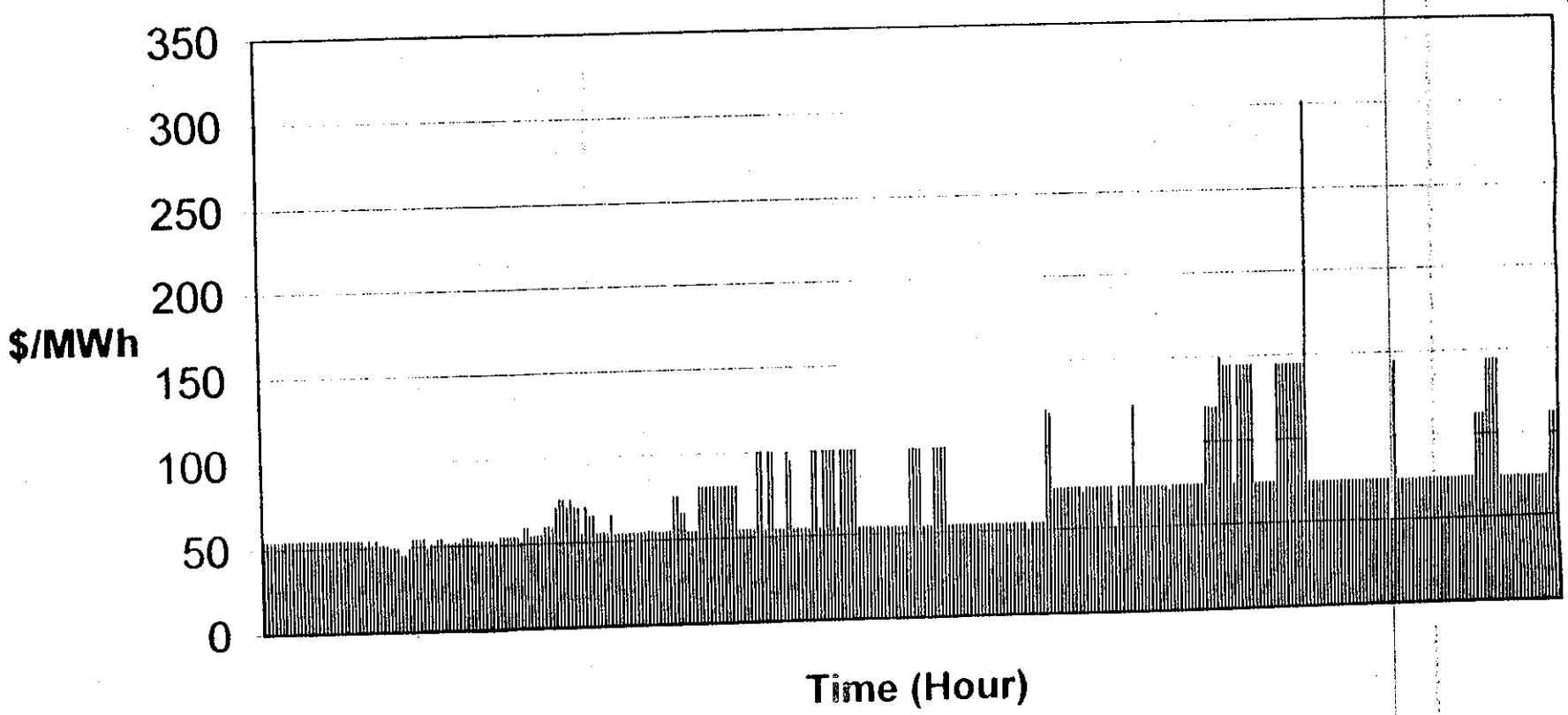
NYISO Ancillary Services
Day Ahead Market
10 Min Non-Synchronous Reserve
1-15 February 2000



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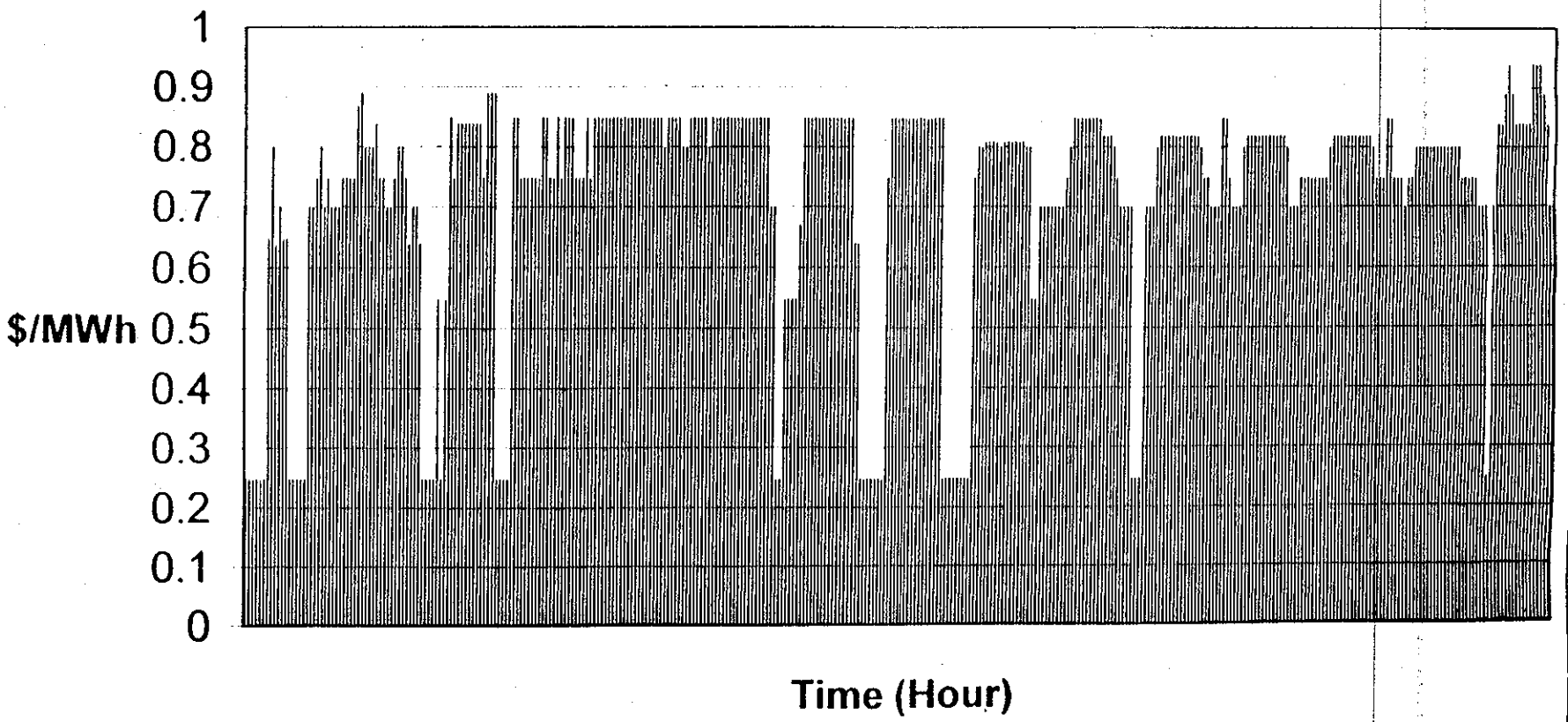
NYISO Ancillary Services
Day Ahead Market
30 Min Operating Reserve
1-15 February 2000



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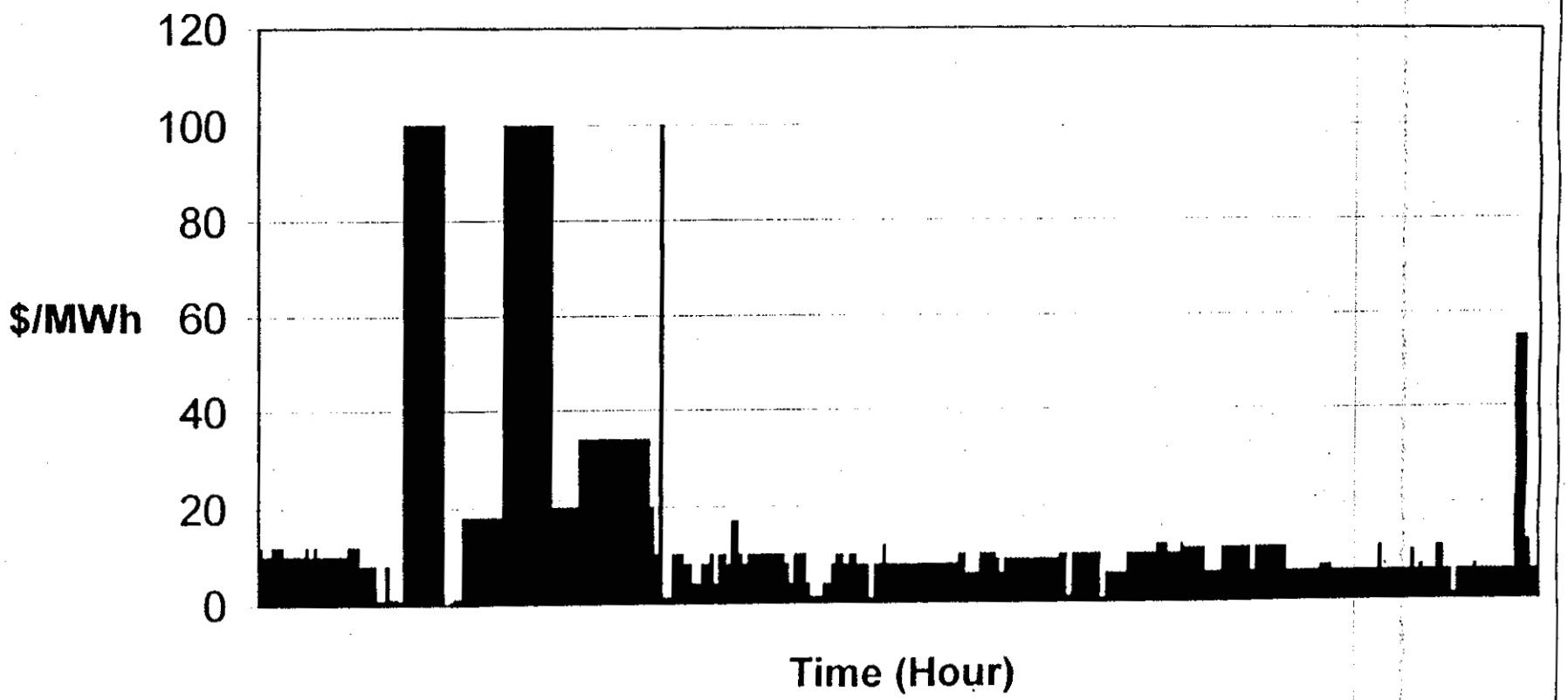
NYISO Ancillary Services
Hour Ahead Market
10 Min Spinning Reserve
18-30 November 1999



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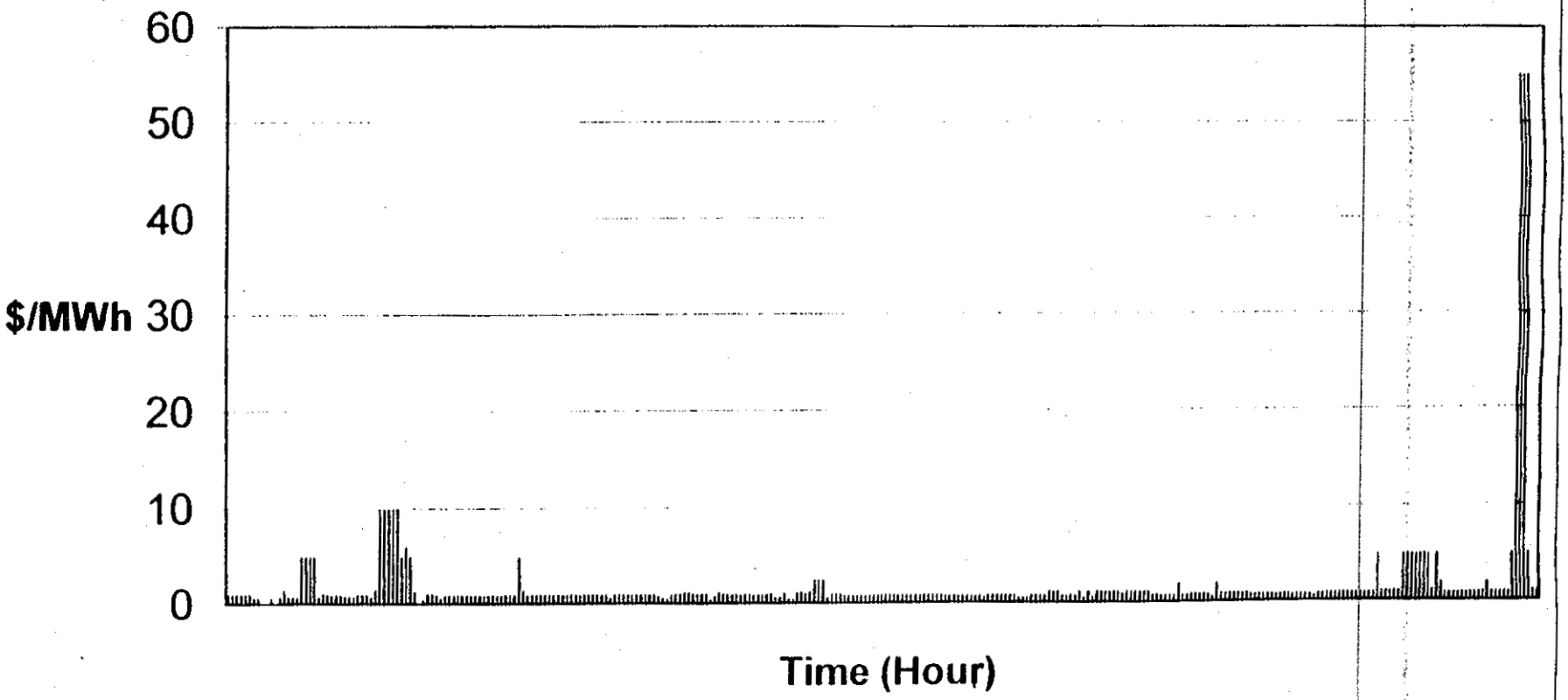
NYISO Ancillary Services
Hour Ahead Market
10 Min Non-Synchronous Reserve
18-30 November 1999



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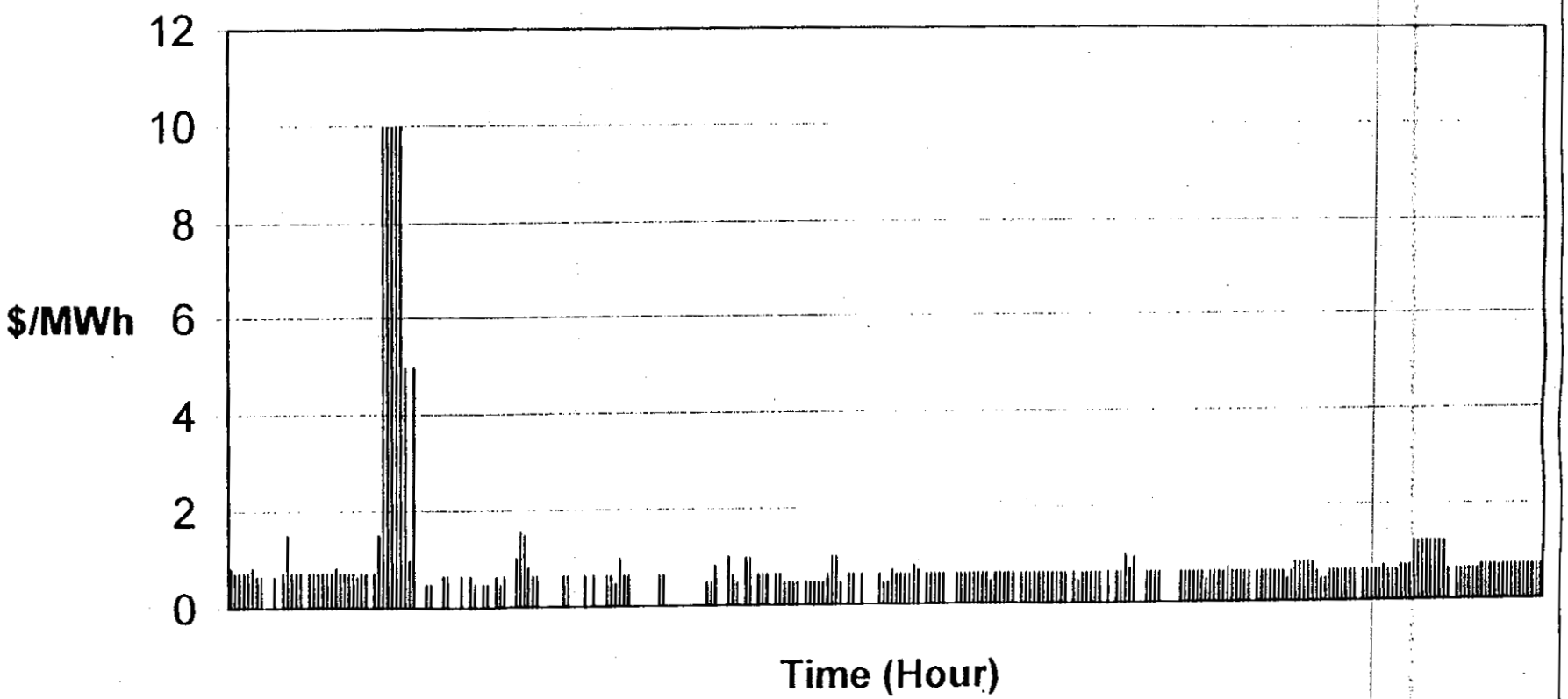
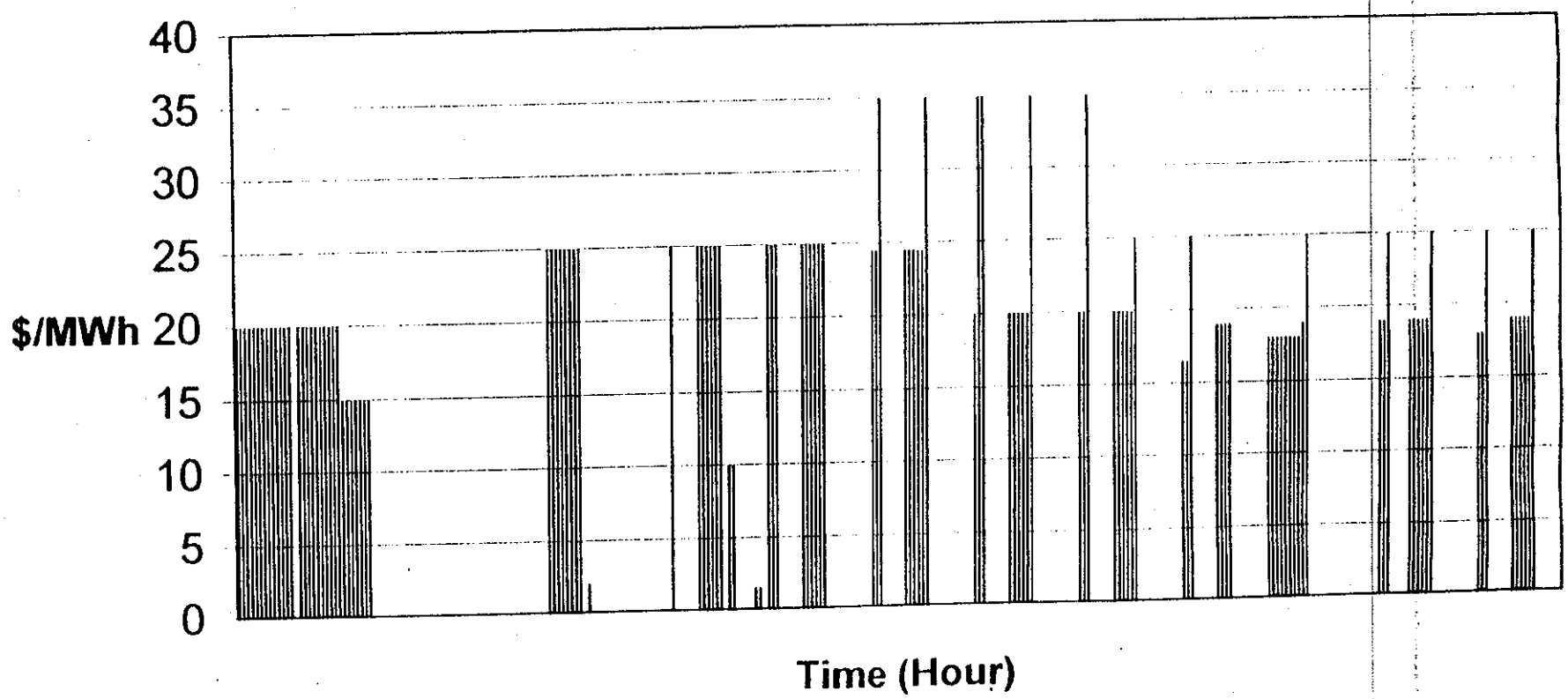
NYISO Ancillary Services
Hour Ahead Market
30 Min Operating Reserve
18-30 November 1999

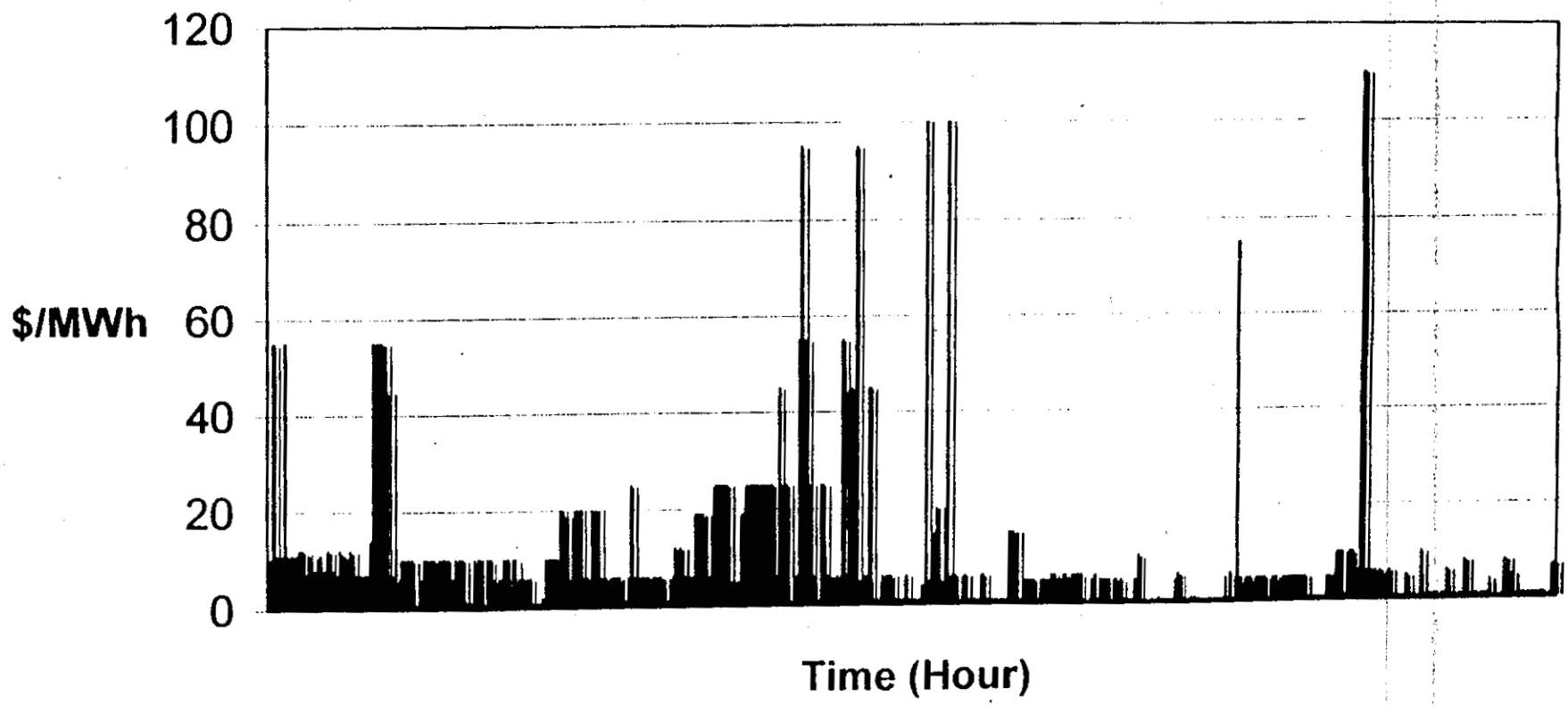


NYISO Ancillary Services
Hour Ahead Market
Regulation
18-30 November 1999

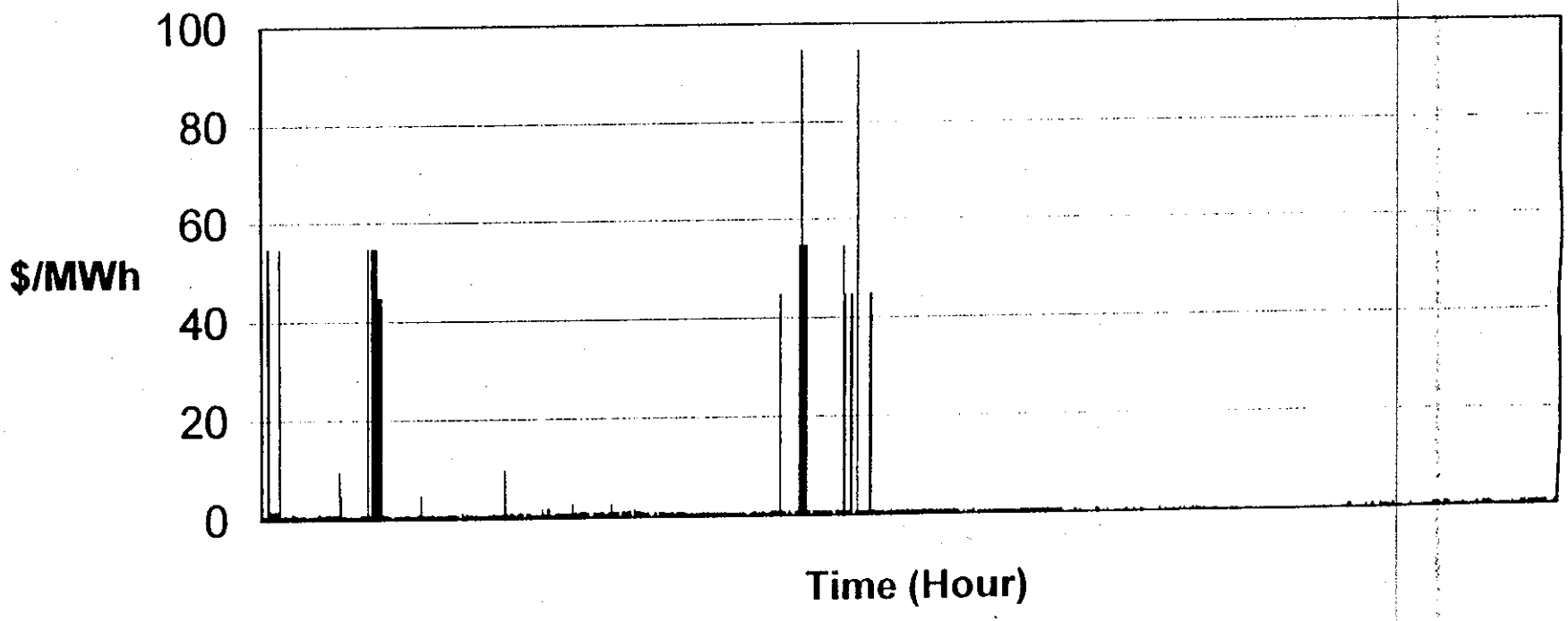


312

NYISO Ancillary Services
Hour Ahead Market
10 Min Spinning Reserve
December 1999

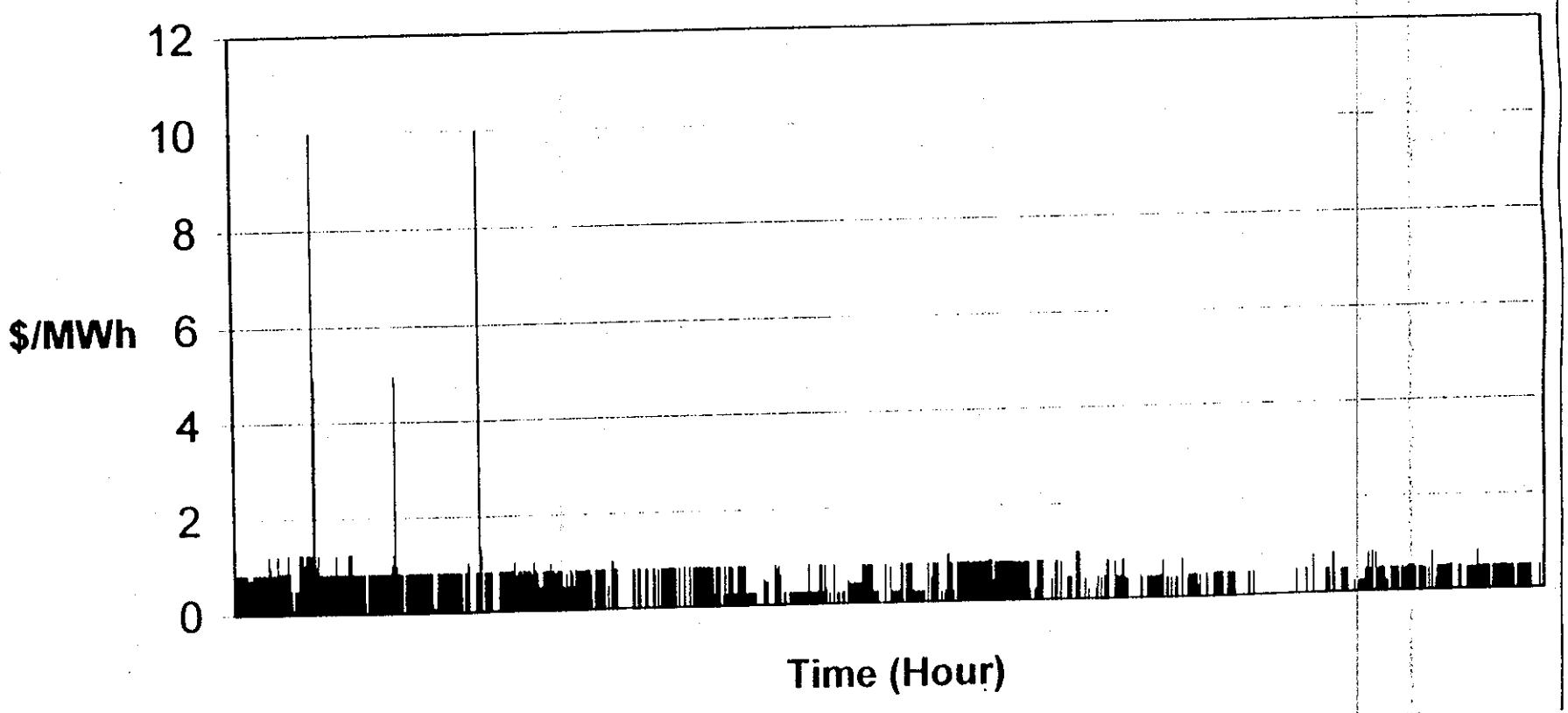


NYISO Ancillary Services
Hour Ahead Market
10 Min Non-Synchronous Reserve
December 1999



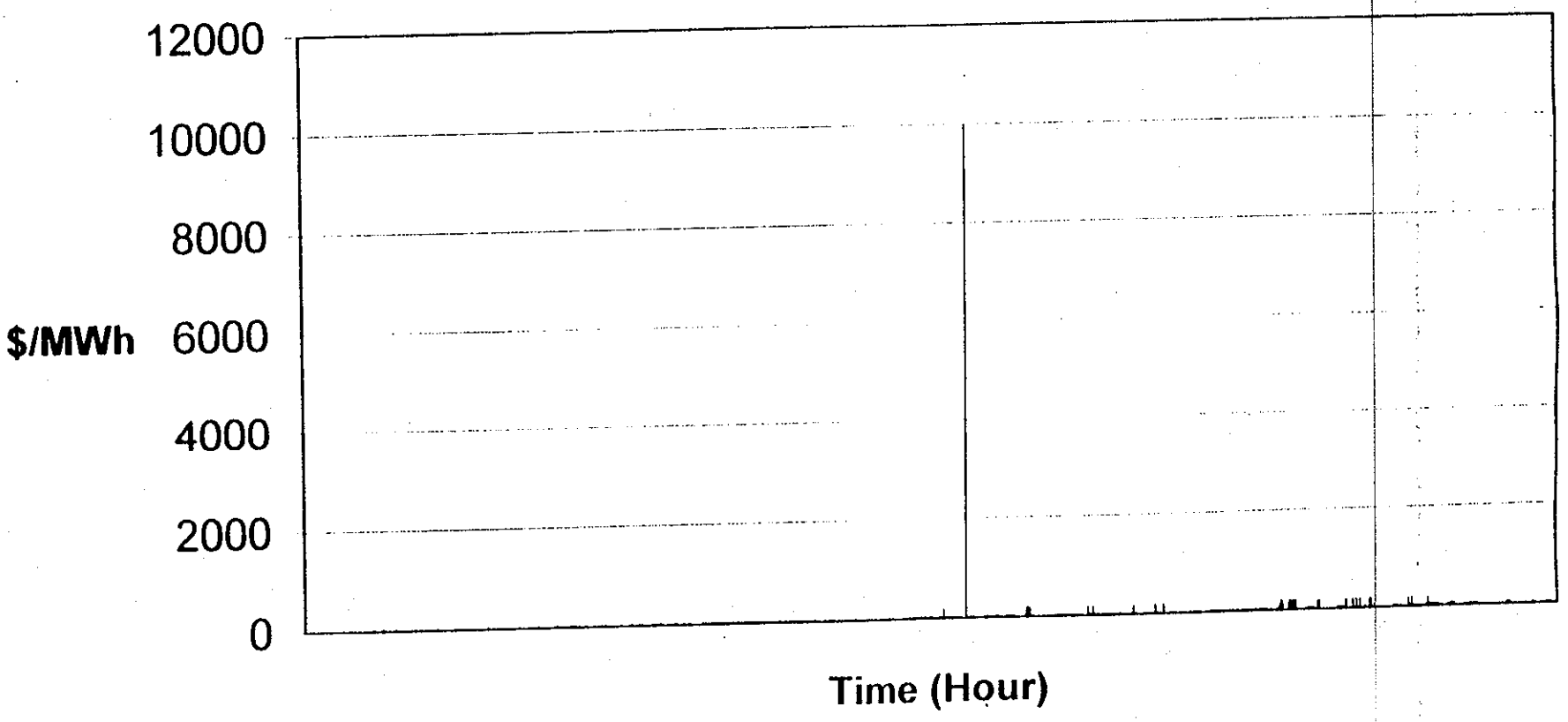
314

NYISO Ancillary Services
Hour Ahead Market
30 Min Operating Reserve
December 1999



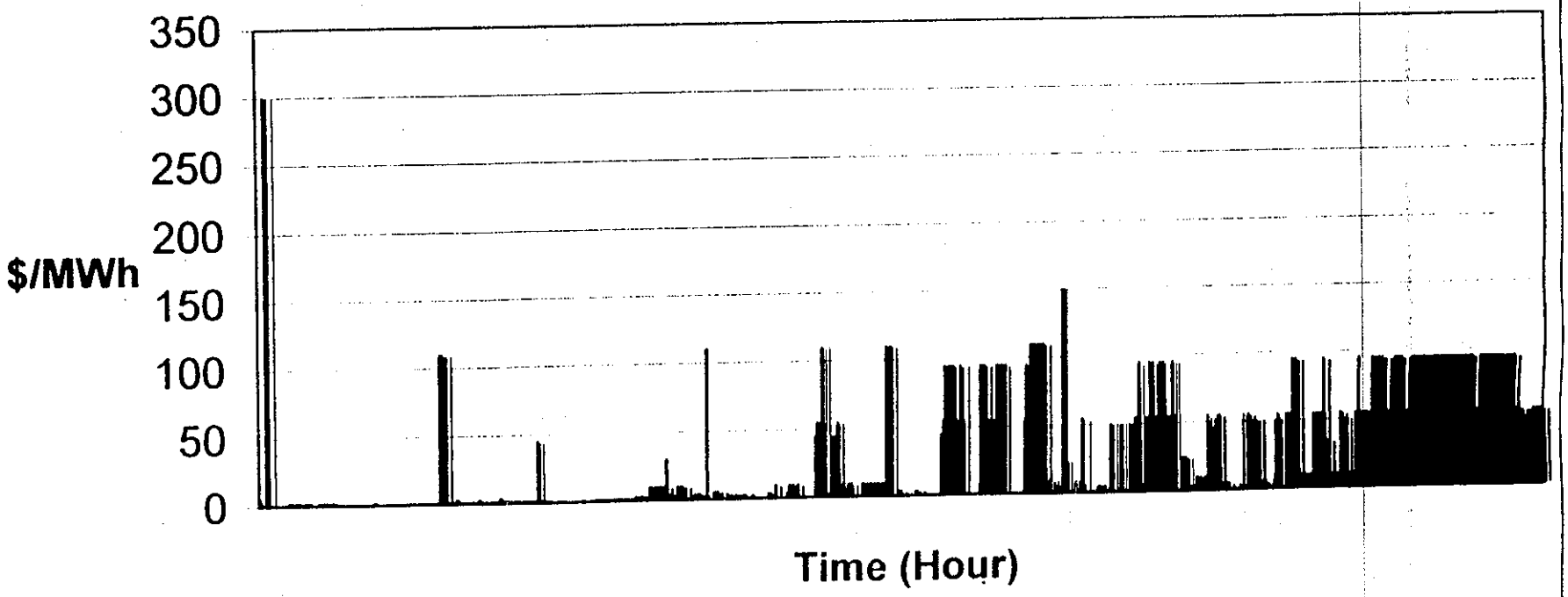
3/5

NYISO Ancillary Services
Hour Ahead Market
Regulation
December 1999



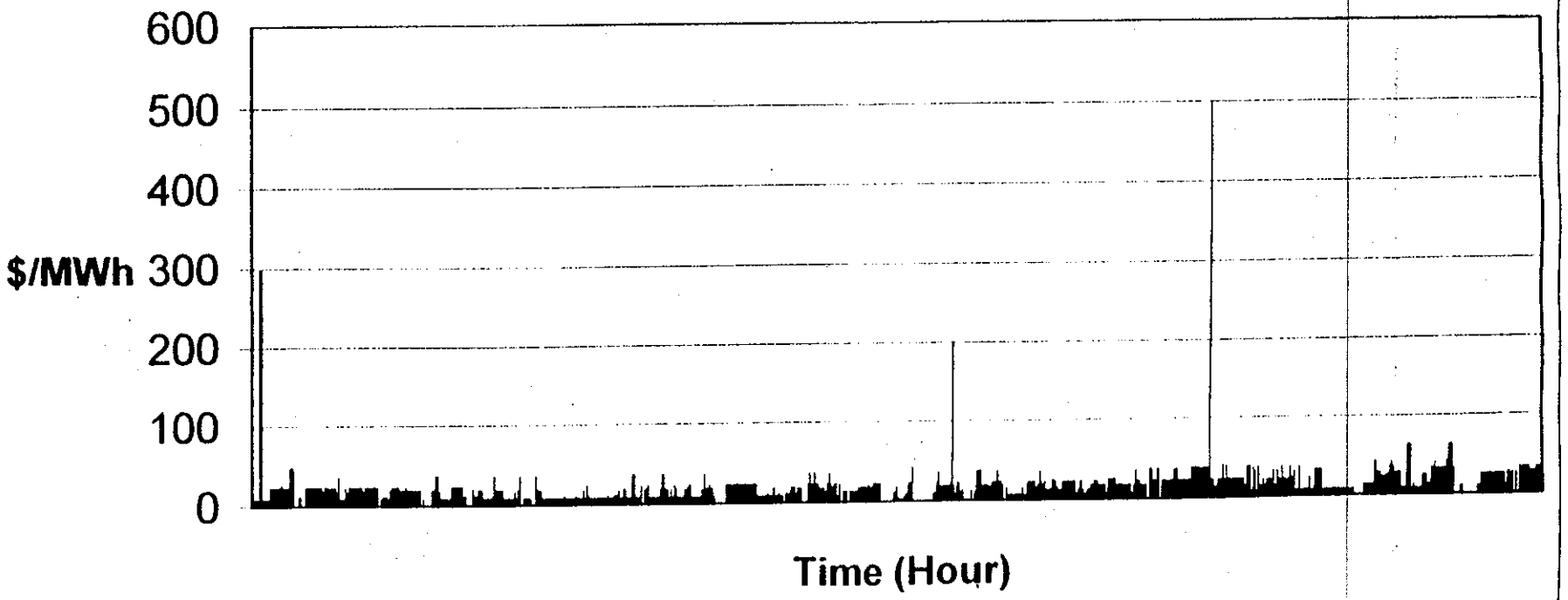
316

NYISO Ancillary Services
Hour Ahead Market
10 Min Spinning Reserve
January 2000



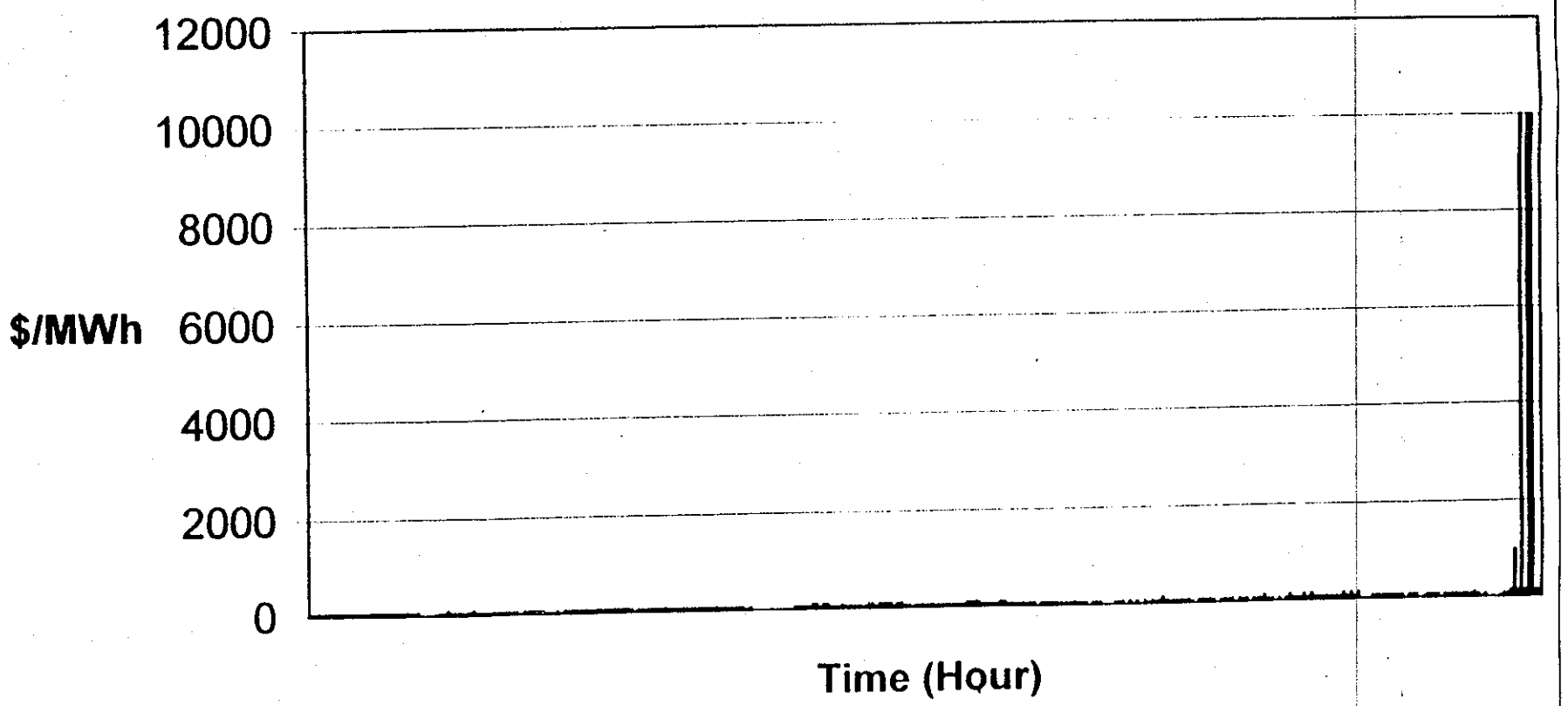
317

NYISO Ancillary Services
Hour Ahead Market
Regulation
January 2000



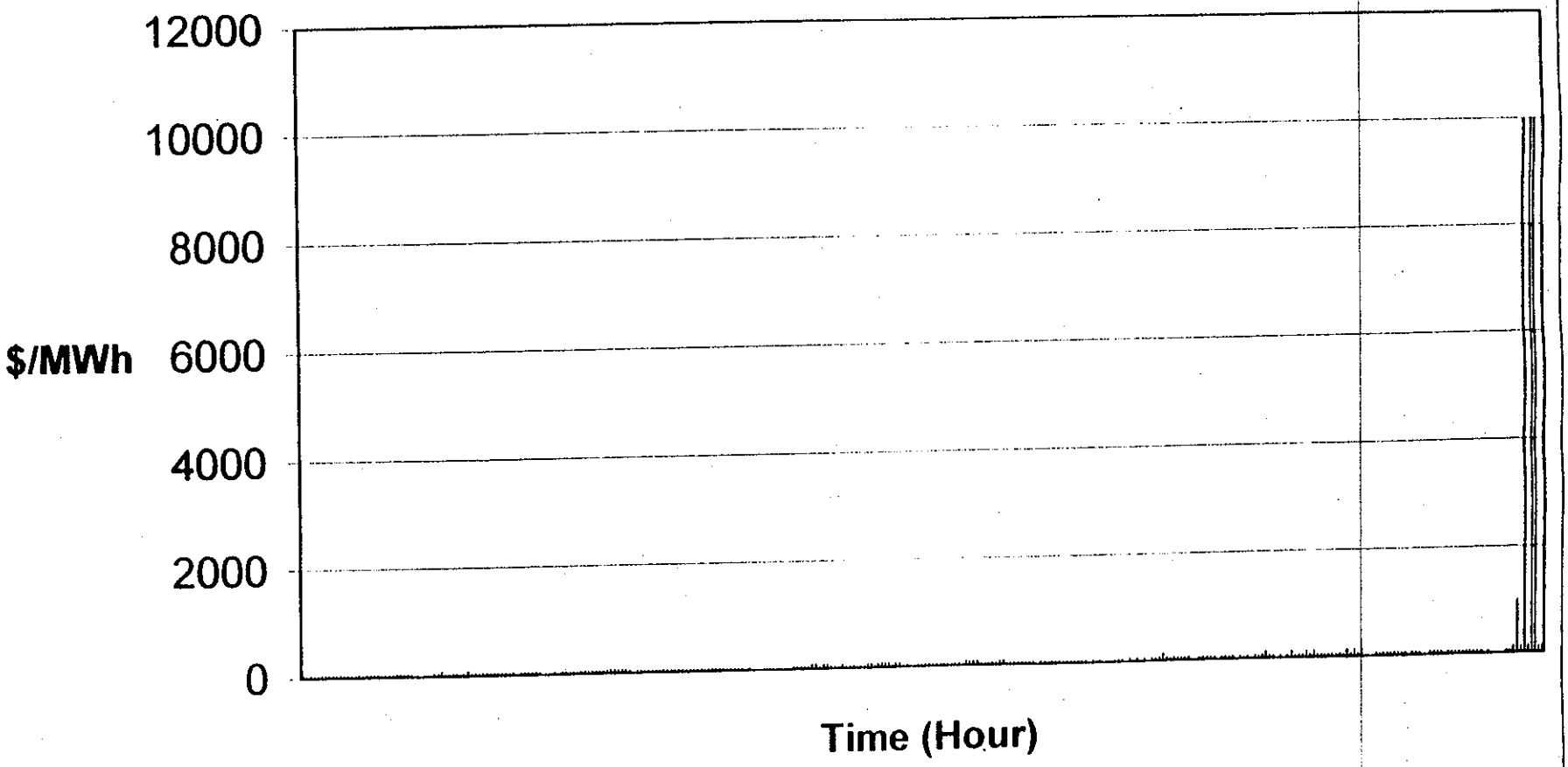
318

NYISO Ancillary Services
Hour Ahead Market
10 Min Spinning Reserve
1-14 February 2000



3/18

NYISO Ancillary Services
Hour ~~Day~~ Ahead Market
10 Min Non-Synchronous Reserve
1-14 February 2000



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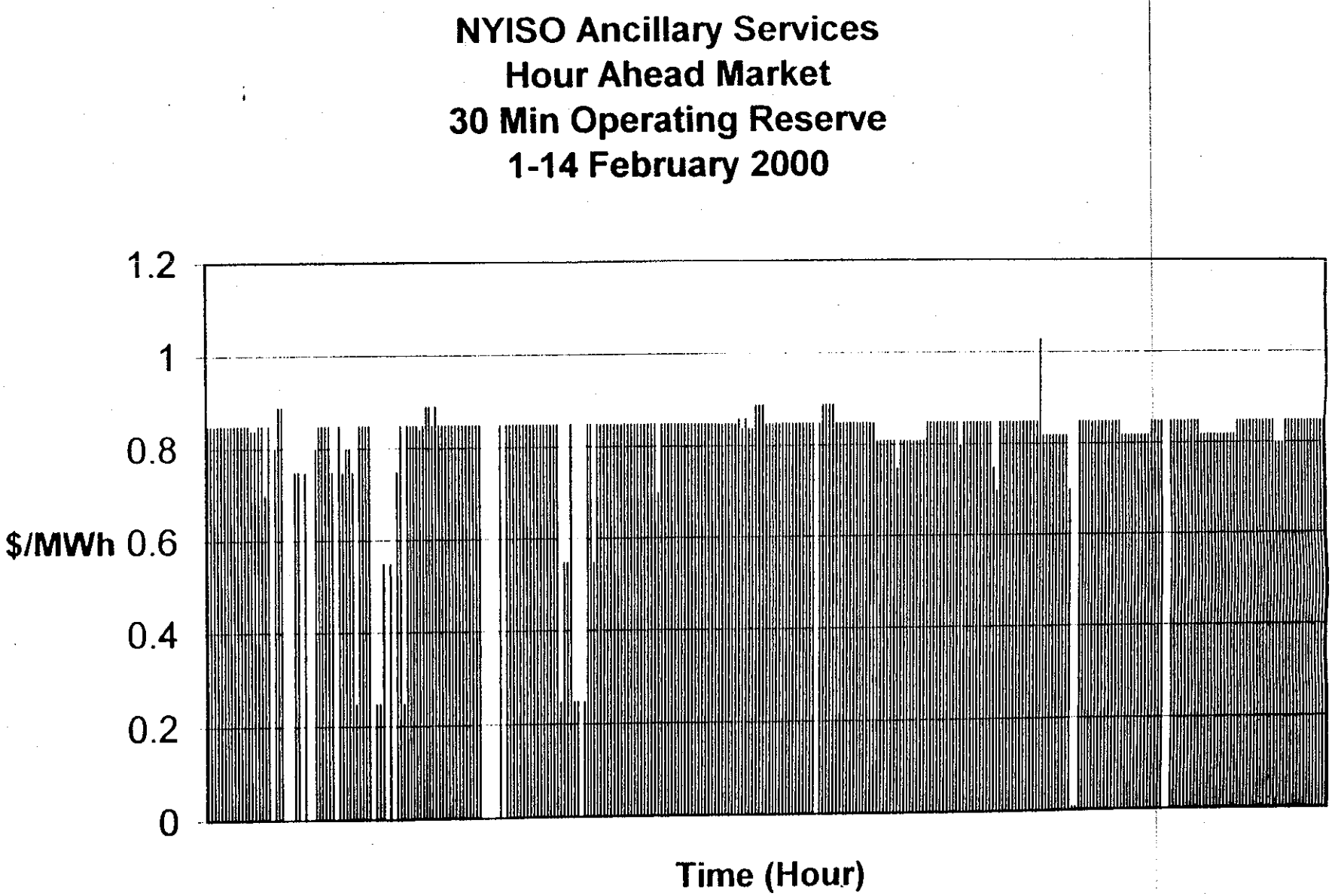
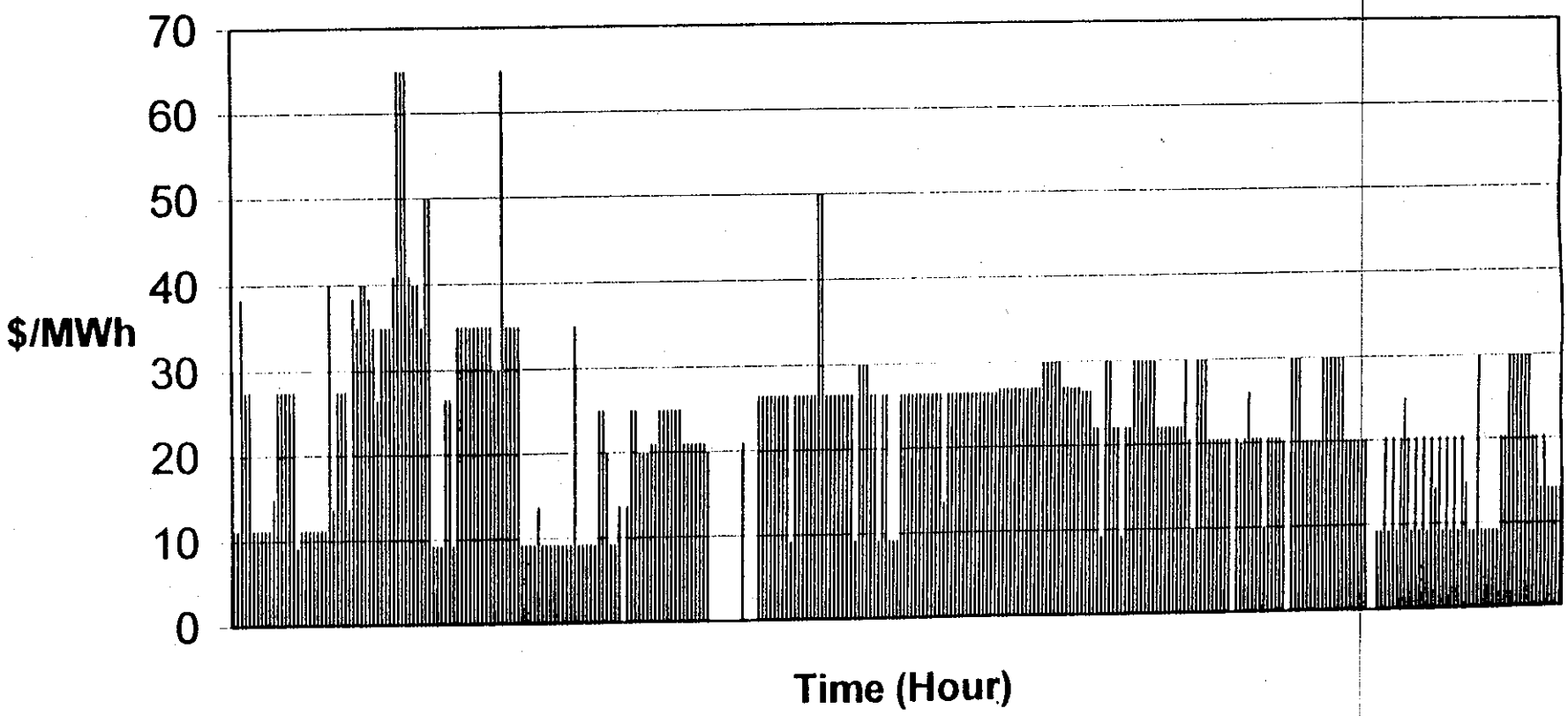

NYISO Ancillary Services
Hour Ahead Market
30 Min Operating Reserve
1-14 February 2000
1.2
1
0.8
$/MWh 0.6
0.4
0.2
0
Time (Hour)

32

NYISO Ancillary Services
Hour Ahead Market
Regulation
1-14 February 2000



322

Ancillary Services in the New England ISO

USAID Forum on Ancillary Services
Warsaw, Poland
22-24 February 2000

Presented by:
Larry Markel
Electrotek Concepts, Inc.

What's It All About ???

- The NEISO
- Ancillary Services in NEISO
- So You Want To Play the Market?
- How Do I Do This?
- And Then ... ?

The subject today is the market for ancillary services in New England ISO. First, I'll describe the ISO, including its structure and operation. Then I'll talk about some of the markets in the ISO.

Ancillary services include a whole range of services and activities that are used to support the bulk power transmission system. These services exist in the realm of real-time operations fo voltage and VAR control, contingency planning for spinning reserve, and unit scheduling and dispatch.

We'll then have a look at the market for ancillary services in New England to see how ancillary service prices have behaved.

Next will be some discussion about how the market for ancillary services works in the New England.

And I will close with some thoughts on the ancillary services markets

New England ISO

- Began Operation on 1 July 1997
- Over 11,200 km of Transmission Line
- 1998 System Hourly Peak Load
  - 21,406 MW (22 July, 17:00)
- 1998 Energy Requirements
  - 116.9 TWh

•The New England ISO power grid covers six-states with 330 generating facilities connected by 7,000 miles of transmission lines. The total system serves more than 6.2 million New England customers.

•Based in Holyoke, Massachusetts, ISO New England was formed on 1 July 1997 by transferring staff and equipment from the New England Power Pool (NEPOOL) to the new organization. Beginning on May 1, 1999, ISO New England, in addition to operating the region's power grid and transmission reservation system, also administers the restructured wholesale electricity marketplace for the region. Seven electricity products are bought and sold by market participants on an Internet-based markets system.

New England ISO Power Market

- Three Markets
  - Energy, AGC and Operating Reserve Market
  - Operable Capability Market
  - Installed Capability Market
- Ancillary Services Market
  - 10 Minute Spinning Reserve
  - 10 Minute Non-Synchronous Reserve
  - 30 Minute Operating Reserve

•There are three markets in the NEISO. These are for all products and services bought and sold in the ISO. The markets have different characteristics and qualifications, depending on the services being provided. Some generating resources must have direct monitoring, control and dispatch from the ISO, with bids due by noon. Others have technically and procedurally less onerous qualification requirements.

•In New England, ancillary services are provided in the first market under Operating Reserve. There are three ancillary services.procured in the market:

- •10 Min SR
- •10 Min NSR
- •30 Min OR

NEISO Ancillary Service Markets

- Three Types:
  - 10 Minute Spinning Reserve
  - 10 Minute Non-Synchronous
  - 30 Minute Operating Reserve

•Ancillary services support the transmission of energy from resources to loads while maintaining reliability. They are the physical equipment and human resources that provide this support as well as the metered quant8ities.

•Scheduling, System Control & Dispatch -- Two types:

•System Security Management in real time (e.g. tie line regulation, frequency support, interchange scheduling management, security constrained dispatch, transmission system operation, system emergency management)

•Capacity Management (e.g. capacity management, operating reserve management and scheduling, outage coordination)

•Voltage Support -- To maintain transmission voltage within limits, generators are operated to produce (or absorb) reactive power.

•Regulation & Frequency Response -- Necessary to balance resources with load and to assist in maintaining frequency. On-line generators are used as necessary (through use of AGC) to follow moment-by-moment changes in load.

•Energy Imbalance -- Internal and external energy balance to control mismatch between scheduled and actual flows.

•Operating Reserve -- Provides back-up generation in the event of a contingency. Operating reserves include spinning reserve (10 minute and 30 minute), operating reserve, and 10 minute non-synchronous reserves.

•Black Start Capability -- Generators that can start without an external power supply and are available for system restoration.

So You Want To Play The Market ?

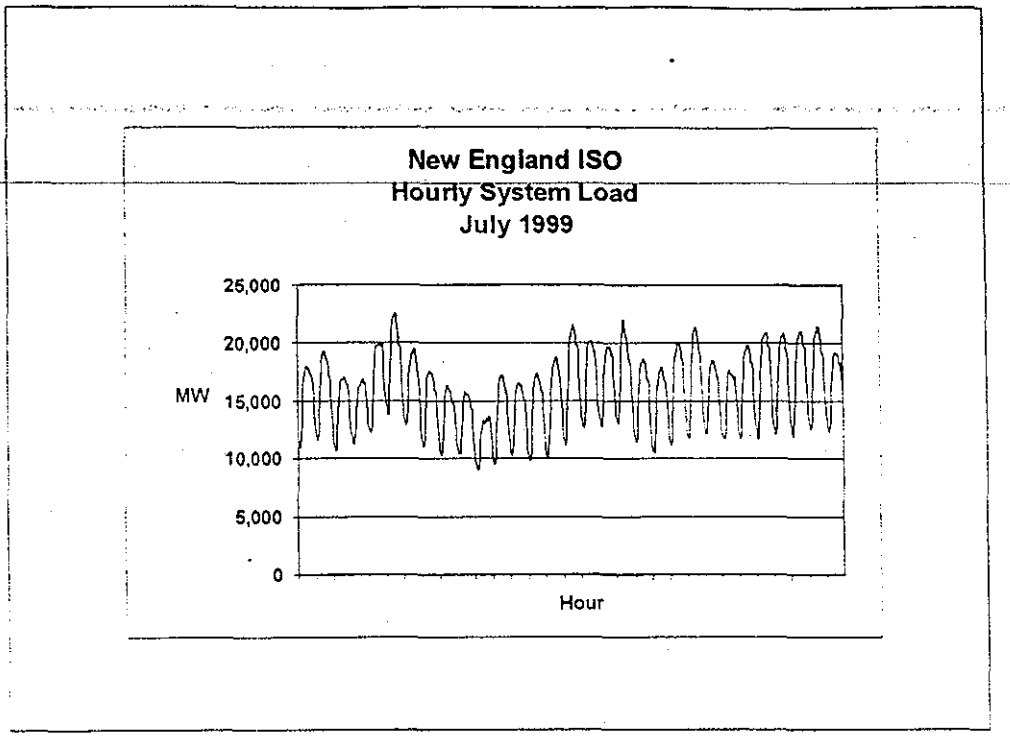
- Operating Reserves
  - 10 Minute Spinning Reserve
  - 10 Minute Non-Synchronous Reserve
  - 30 Minute Operating Reserve

•For the Operating Reserve market there are three separate AS products that are bid and bought: 10 Min Spinning Reserve, 10 Min Non-Synch Reserve, and 30 Min Operating Reserve.

•10 Min Spinning Reserve -- Considered an operating reserve service that provides backup generation in the event of a major generating resource failure. Resources must be already synchronized to the NYS Power System and can respond to instructions to change output level within 10 minutes. Resources must be under NYISO operational control

•10 Min Non-Synchronous Reserve -- Operating reserves that can be started, synchronized and loaded within 10 minutes.

•30 Min Operating Reserve -- Reserves the respond to instructions to change output energy within 30 minutes.



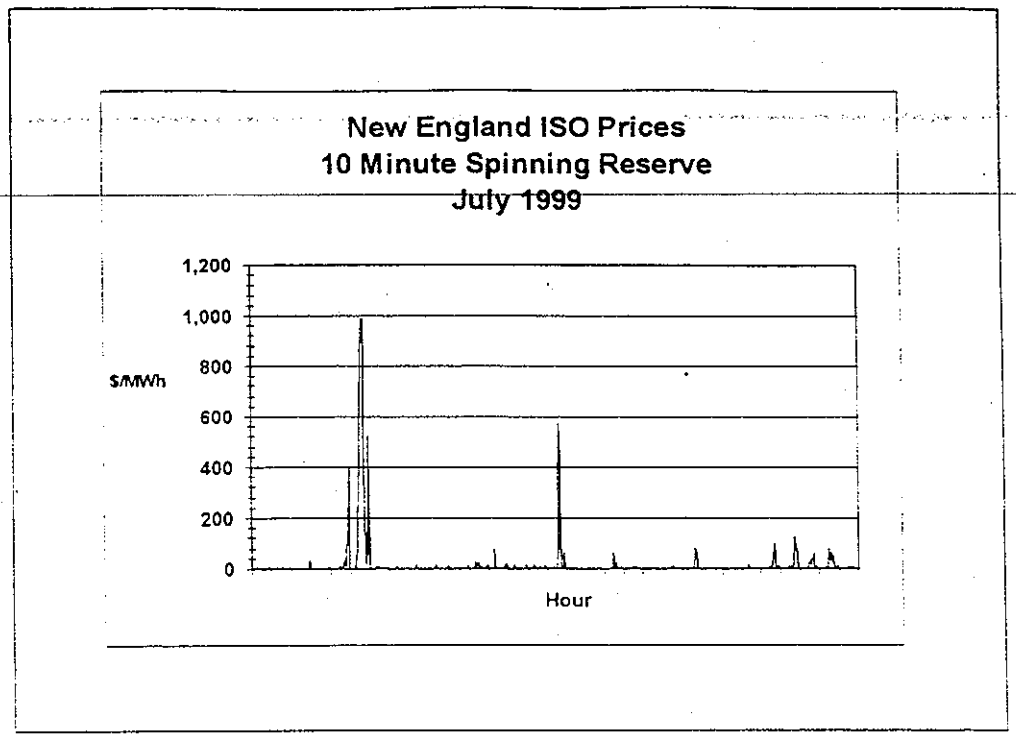
For NEISO, July 1999 was unusually warm. July 5 was the hottest day in 40 years. The all-time NEPOOL peak load was reached on 6 July 1999 at the hour ending 14:00 at 22,544 MW. This is 1100 MW (5%) higher than July 1998 (21,406 MW).

During July there were 5 days which required OP-4 Procedures ("Actions During A Capacity Deficiency"), which resulted in load reductions of up to 600 MW. These OP-4 days were: 5 July, 6 July, 19 July, 29 July, and 30 July). There were 45% more cooling degree days (temperature-humidity indexed) in July than normal.

Typically the values for the three ancillary services are expected to behave as follows:

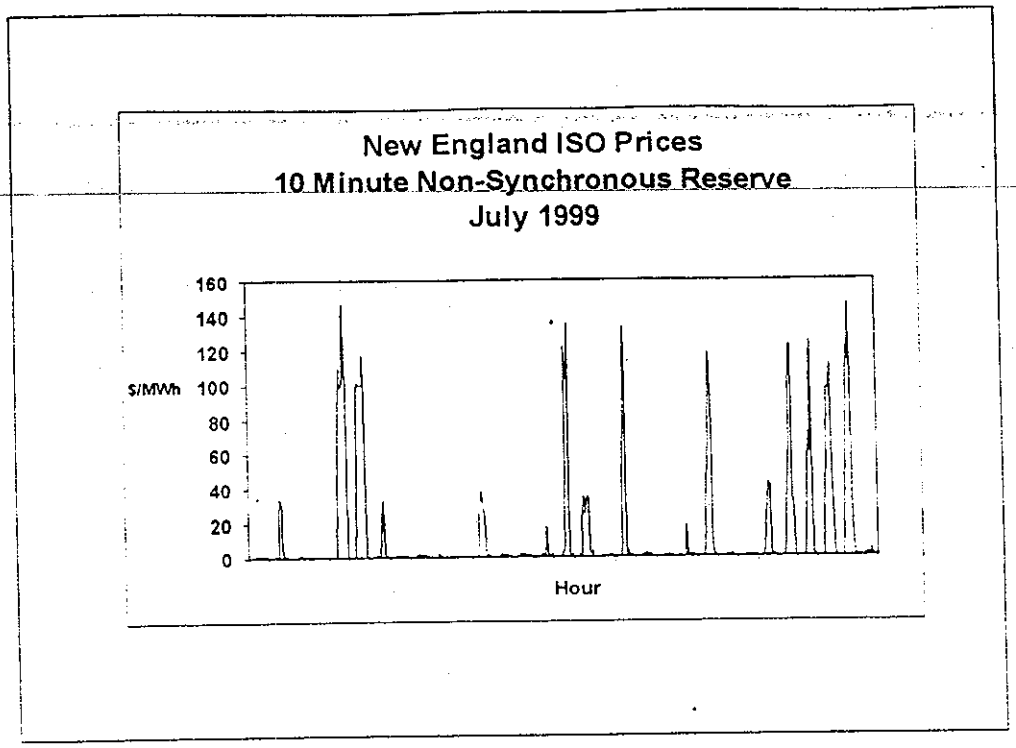
TMSR > TMNSR > TMOR

Let's see how they did.



Prices reached $966/MWh on 6 July at 16:00.

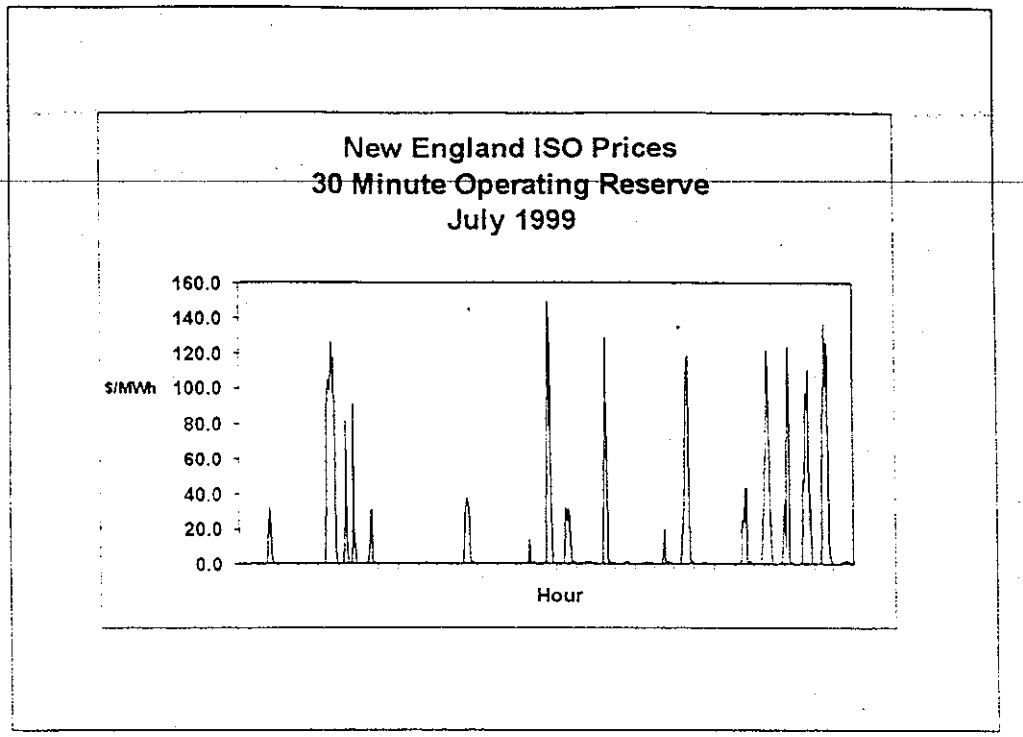
Prices reached $570/MWh on 16 July at 16:00.



10 Min NSR prices were significantly less than TMSR for comparable hours.

•The maximum value for TMNSR was $$145/MWh on 5 July at 19:00.

Generally speaking, the scale of price volatility with NSR does not match that observed with TMSR.



30 Min Operating Reserve prices exhibit behavior like the TMNSR. There is not as much volatility, though prices did increase dramatically during periods of high system loads and low capacity reserves.

How Do I Do This ?

- Market Participants
- Market Mechanisms
  - MIS
  - Bidding
  - Metering
  - Execution
  - Settlement

•A Market Participant for Ancillary Services in New England is a party who purchases Operating Reserves (TMSR, TMNSR, TMOP) from a designated generator, or who sells Operating Reserves from a designated generator.

•Market Mechanisms -- The mechanics of the market are the structure and processes that provide an exchange for buyers and sellers. They include the systems, procedures, protocols, and practices of the market in the ISO framework. This includes the bidding process, metering and billing, and the execution and settlement of the transaction -- In some cases the ISO executes the transaction (e.g. through direct control of generating resources), in others the market participant does (interruptible loads, generation).

How Do I Do This ?

- Ancillary Services - Operating Reserves
  - 10 Minute Spinning Reserve
  - 10 Minute Non-Synchronous Reserve
  - 30 Minute Operating Reserve

•There are three separate AS products hat are bid and bought in the Operating Reserve Market (10 Min Spinning Reserve, 10 Min Non-Synch Reserve, 30 Min Operating Reserve and Regulation.

•10 Min Spinning Reserve -- Considered an operating reserve service that provides backup generation in the event of a major generating resource failure. Resources must be already synchronized to the NYS Power System and can respond to instructions to change output level within 10 minutes. Resources must be under NYISO operational control

•10 Min Non-Synchronous Reserve -- Operating reserves that can be started, synchronized and loaded within 10 minutes.

•30 Min Operating Reserve -- Reserves the respond to instructions to change output energy within 30 minutes.

And Then ... ?

- Are the Markets Working ?
  - Buyers and sellers coming together
  - Mechanisms seem to perform required market services
  - Has been tested under duress and performed well

•The NEISO has been in operation for two and a half years. It has been administering the wholesale power market since May 1999.

•There are well developed mechanisms and procedures based on heuristics that have been adopted for the system operation.

•The system has been tested and has been proven to be dependable. Prices behaved as one would expect, though with significant volatility.

And Then ... ?

- Or Not ?
  - Long Term Capacity
  - Long Term Reliability

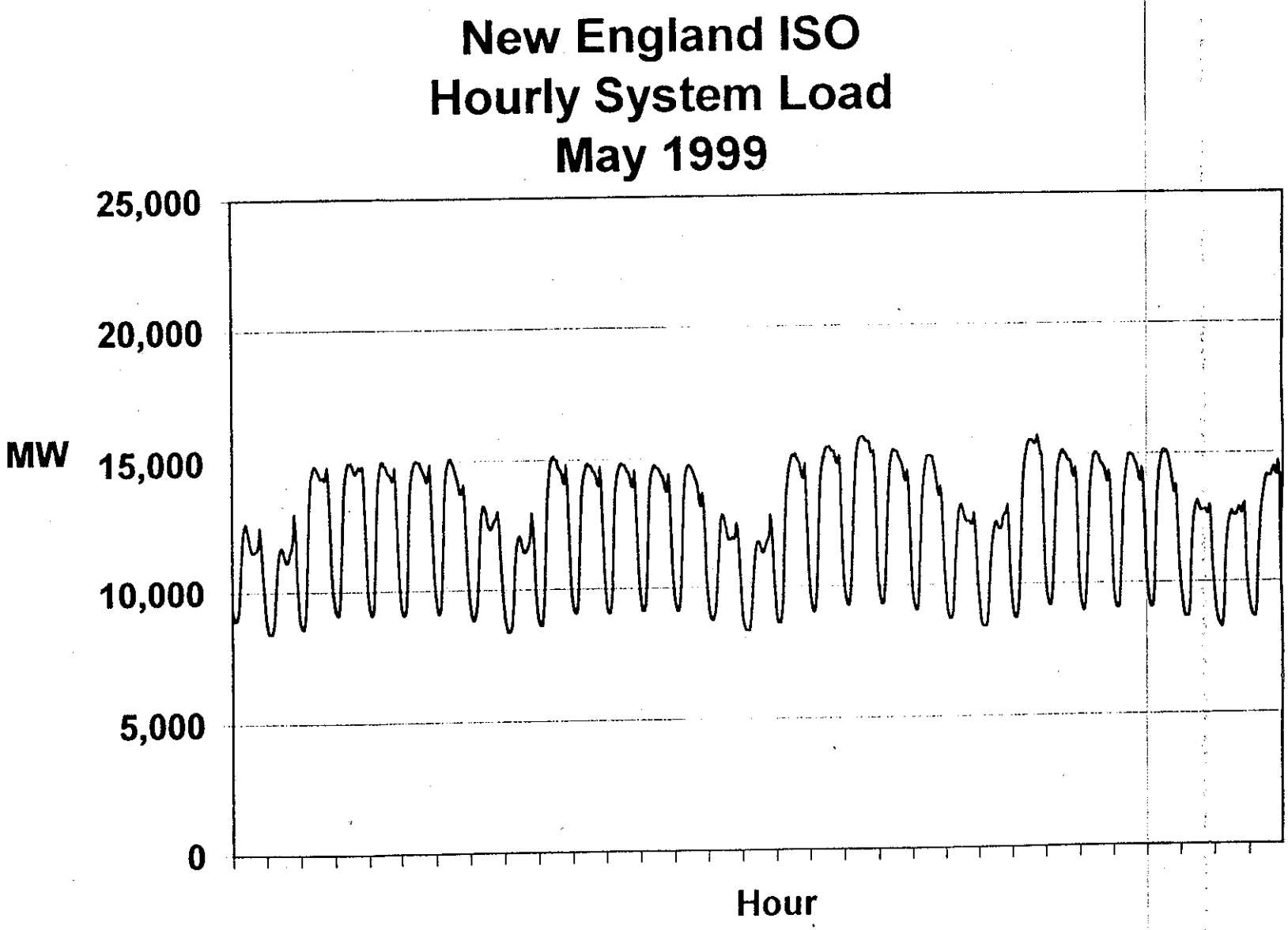
The role of ancillary services in power markets is to promote reliable and efficient use of existing transmission capacity. And based on the experiences in New England, the market seems to have provided these services as needed.

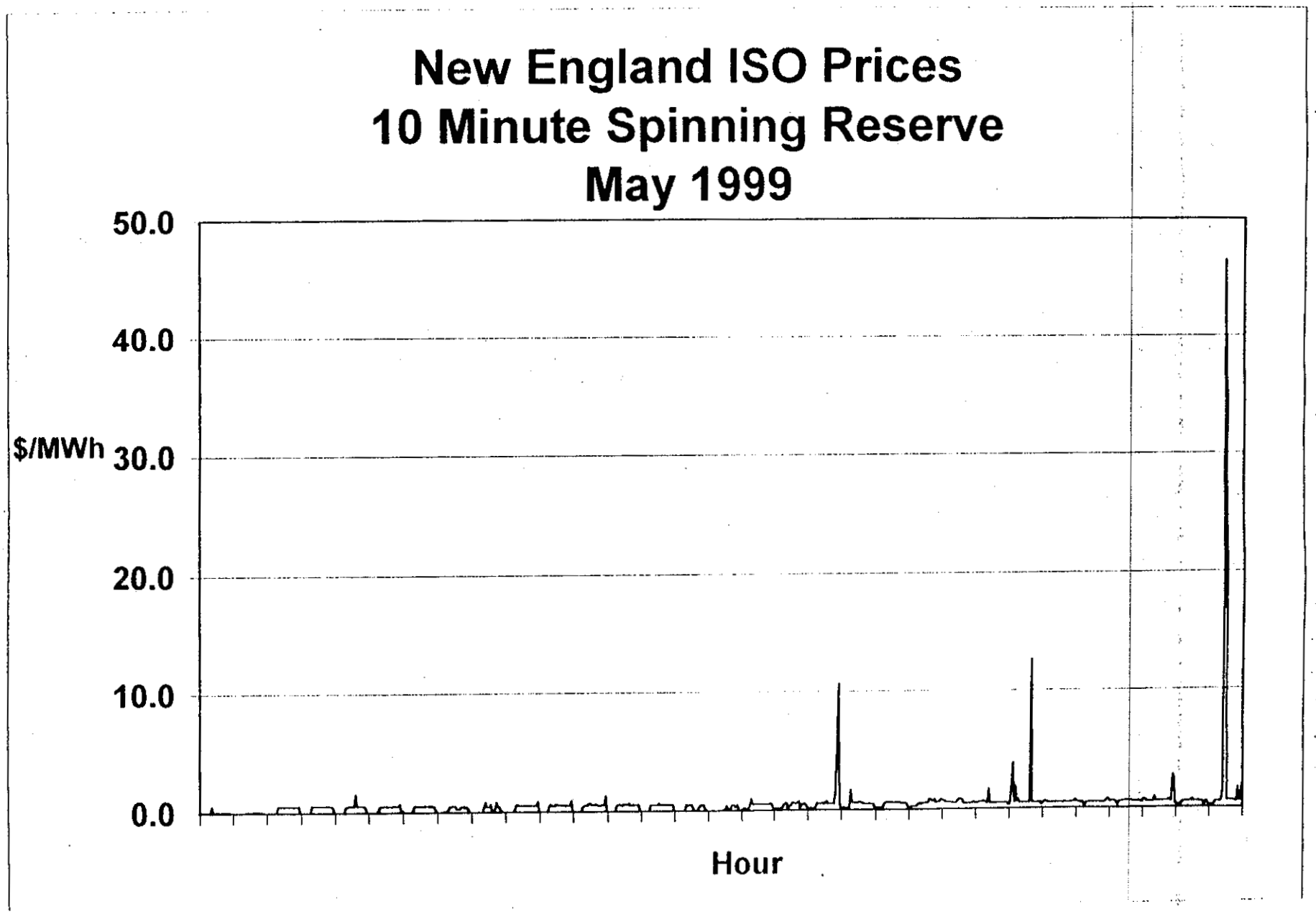
The true test, however, is the test of time. Will the market be able to provide the service that is most expensive to provide in power systems - reliability. And if so, how?

What happens in capacity constrained systems? How will bottlenecks be relieved? When will construction be required? Who pays, and how?

Which of these ways will be the most efficient?

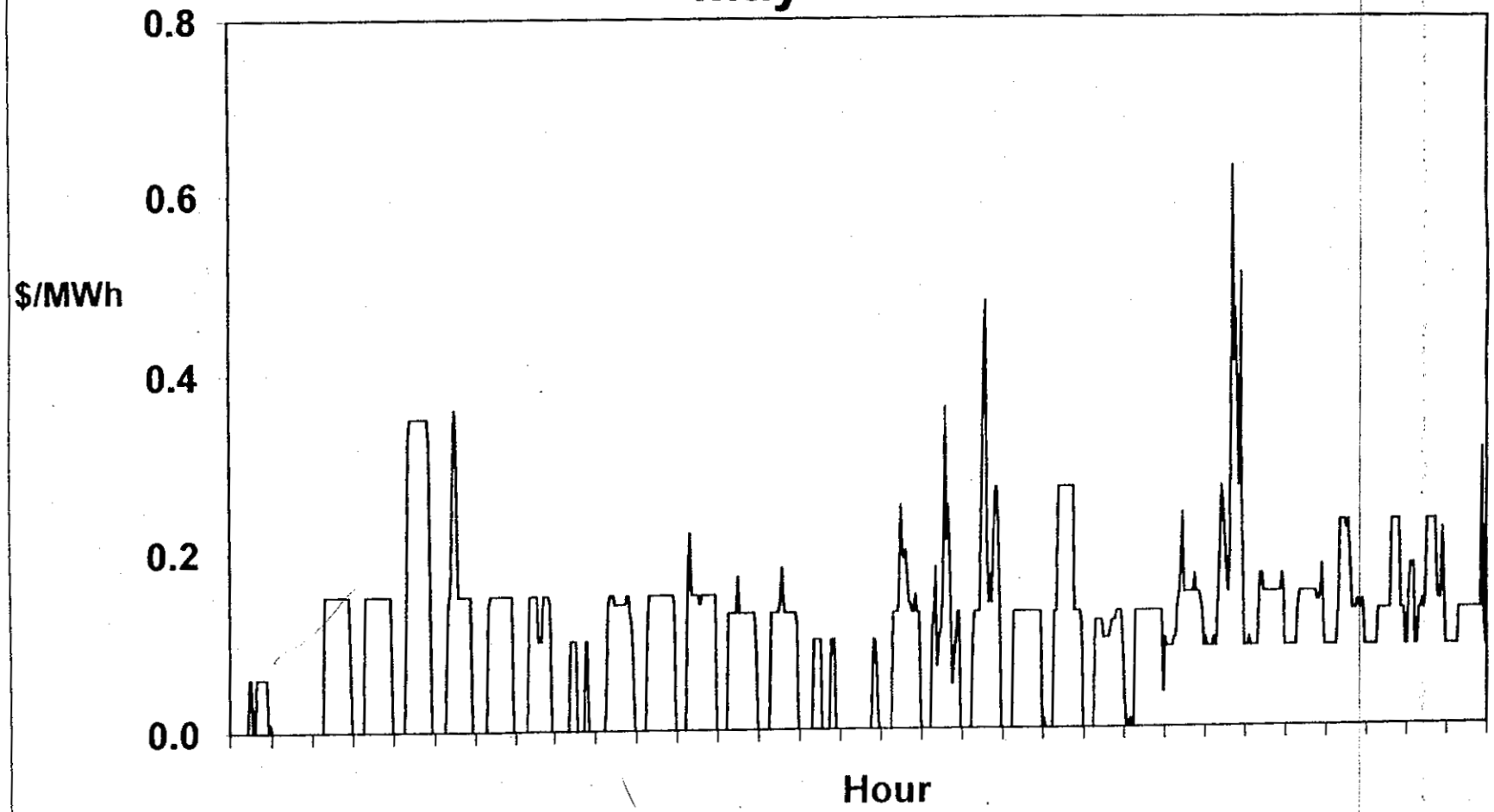
Time will tell.


New England ISO
Hourly System Load
May 1999
25,000
20,000
15,000
10,000
5,000
0
MW
Hour


New England ISO Prices
10 Minute Spinning Reserve
May 1999
50.0
40.0
$/MWh
30.0
20.0
10.0
0.0
Hour

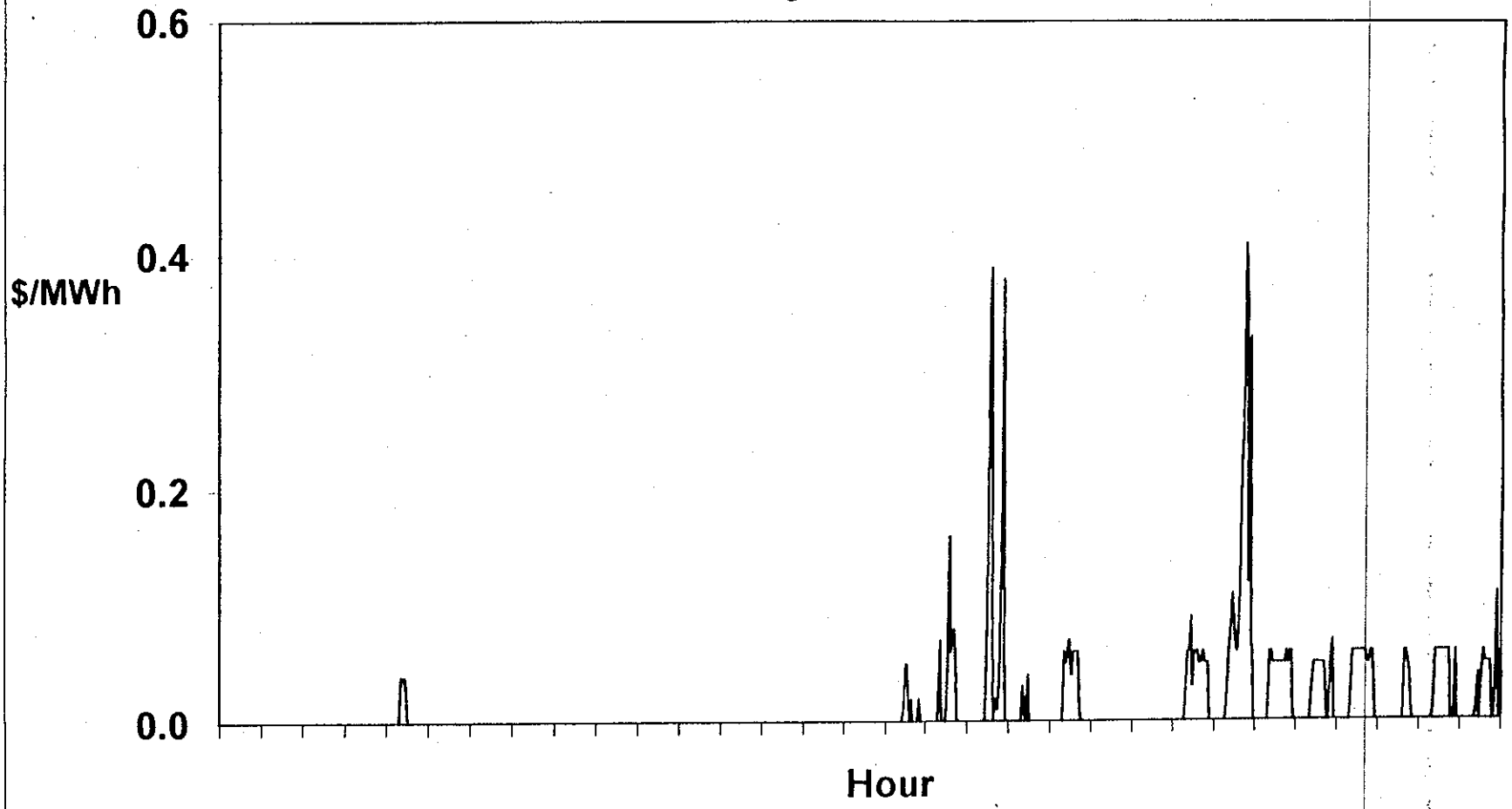
338

New England ISO Prices
10 Minute Non-Synchronous Reserve
May 1999



339

New England ISO Prices
30 Minute Operating Reserve
May 1999



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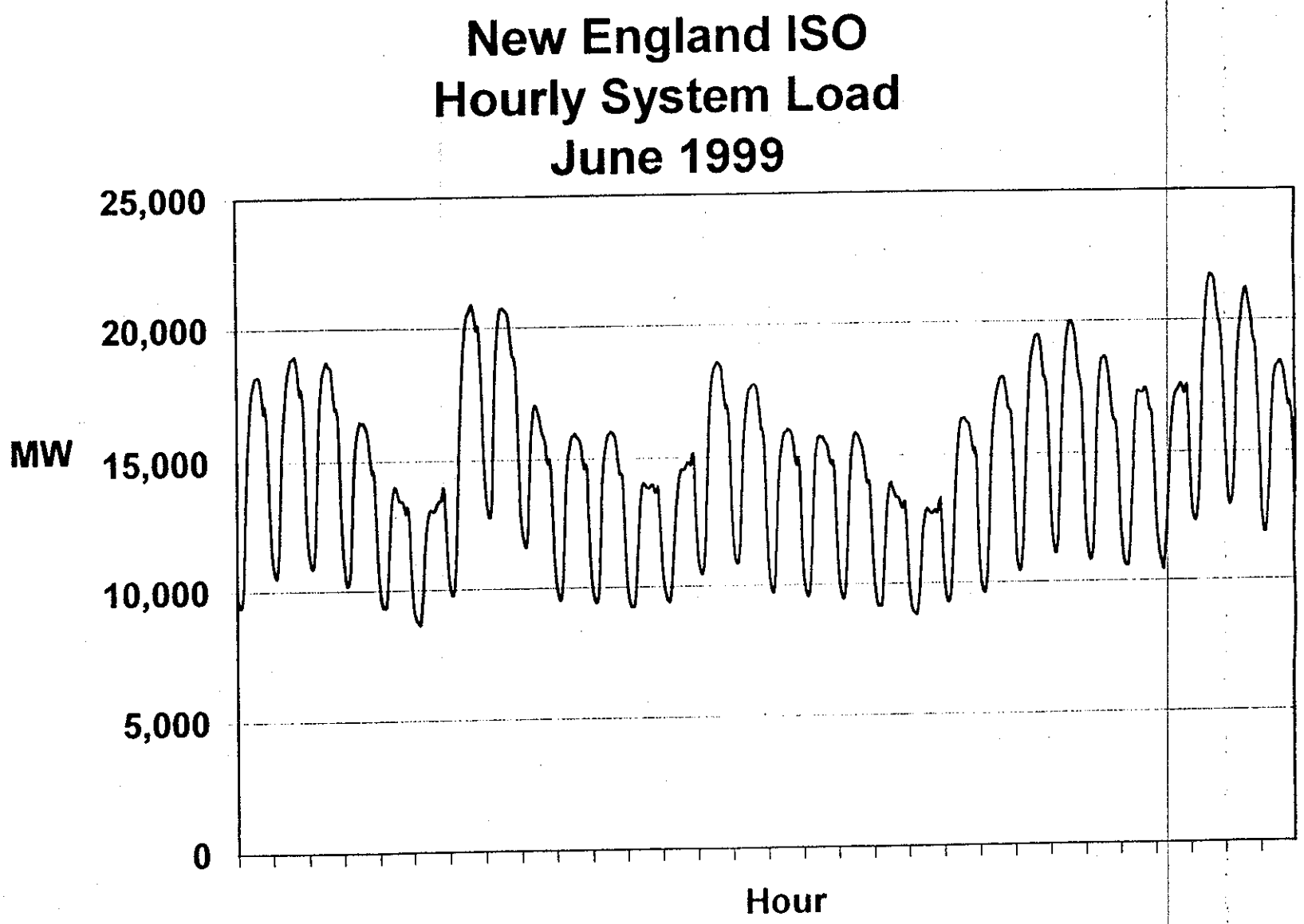
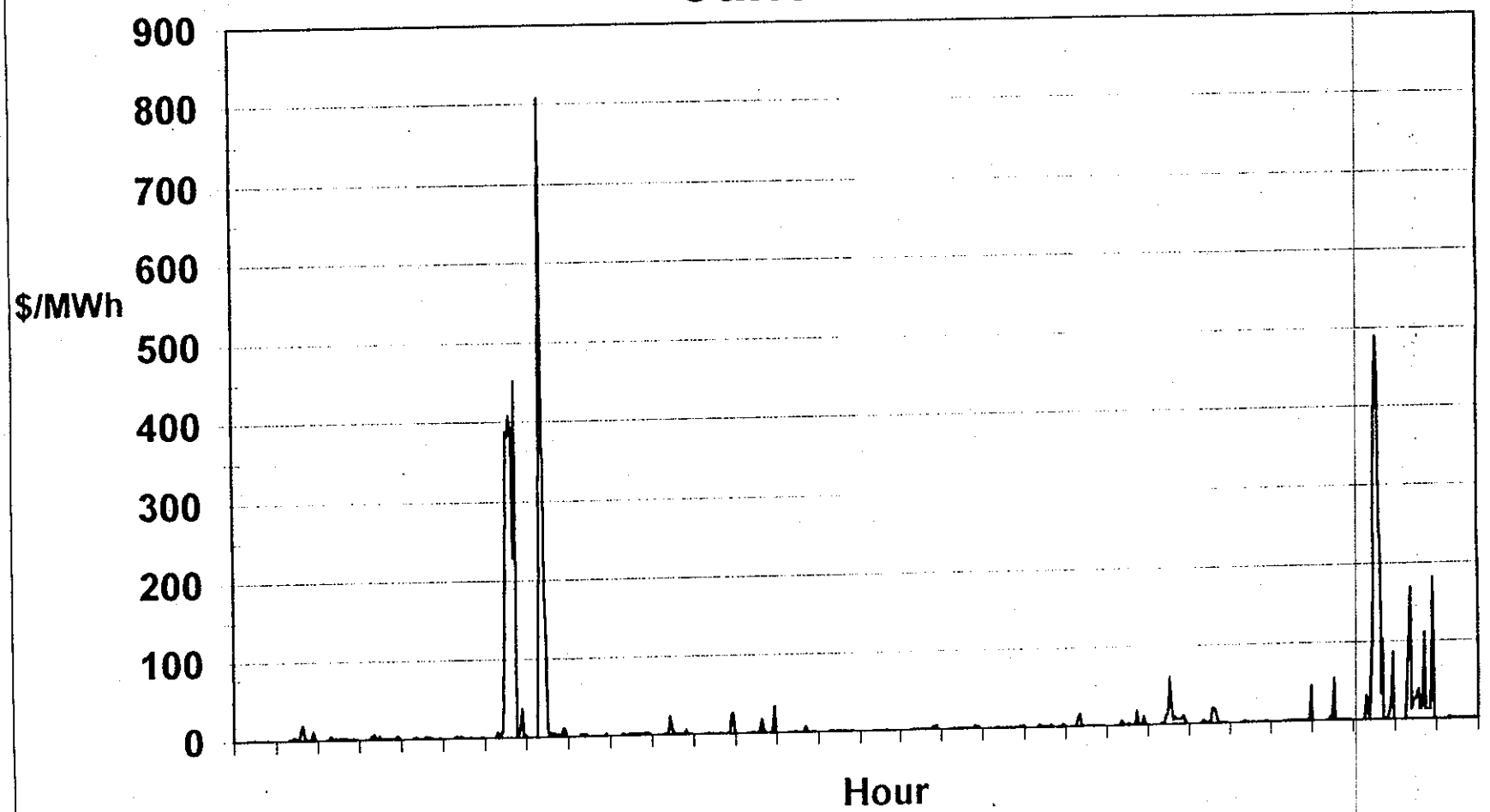

New England ISO
Hourly System Load
June 1999
25,000
20,000
15,000
10,000
5,000
0
MW
Hour

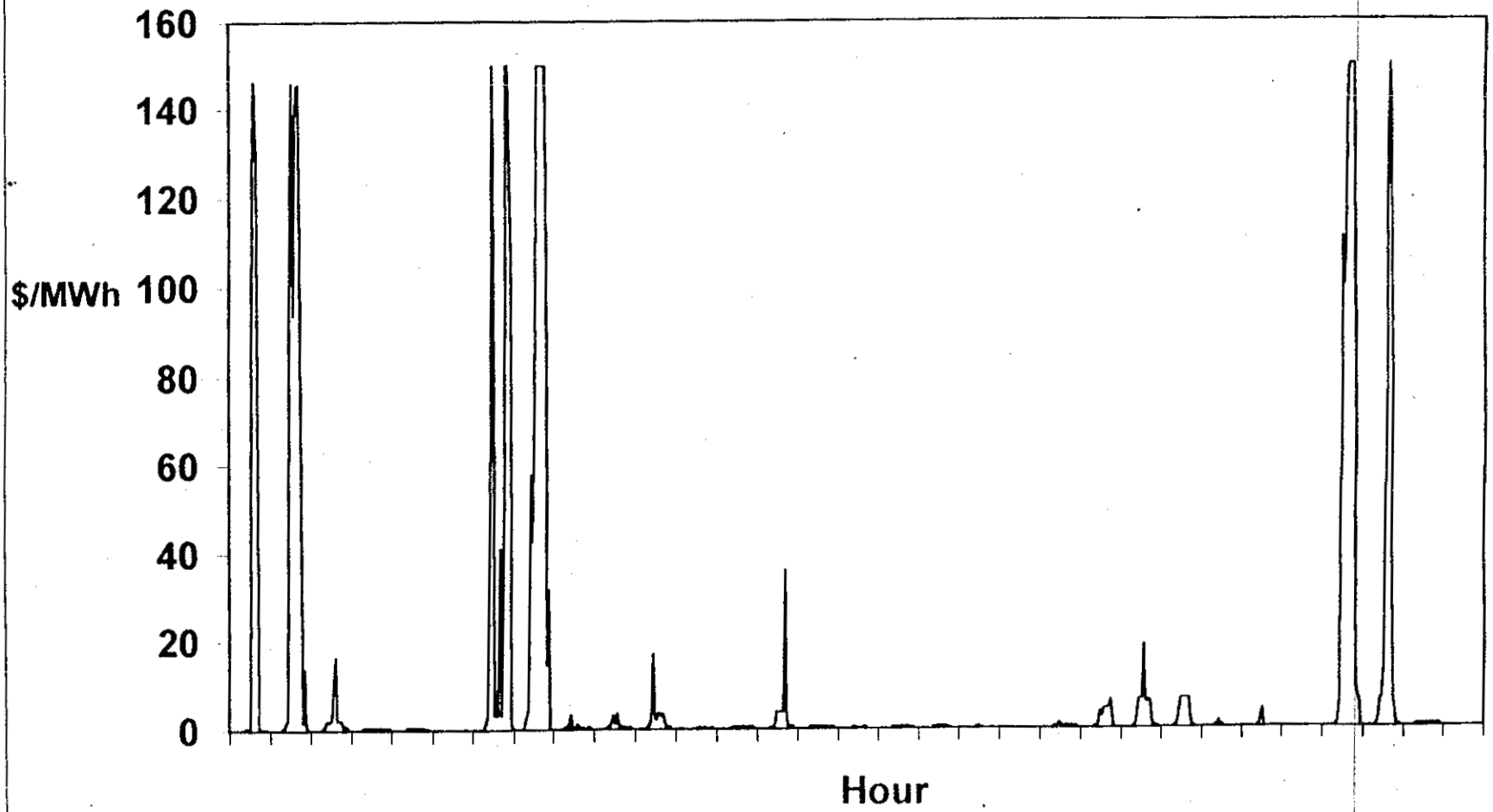
341

New England ISO Prices
10 Minute Spinning Reserve
June 1999



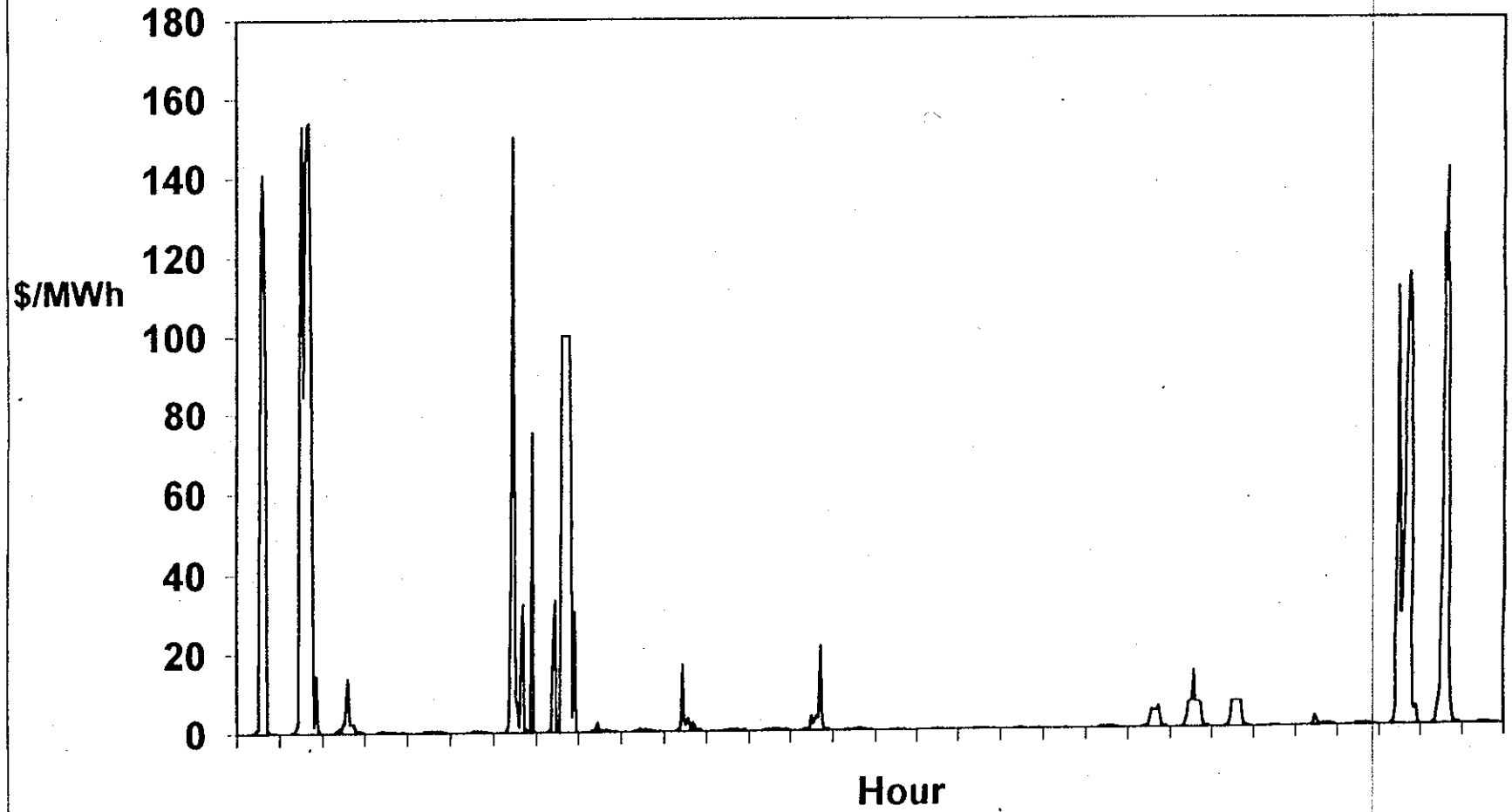
342

New England ISO Prices
10 Minute Non-Synchronous Reserve
June 1999



343

New England ISO Prices
30 Minute Operating Reserve
June 1999



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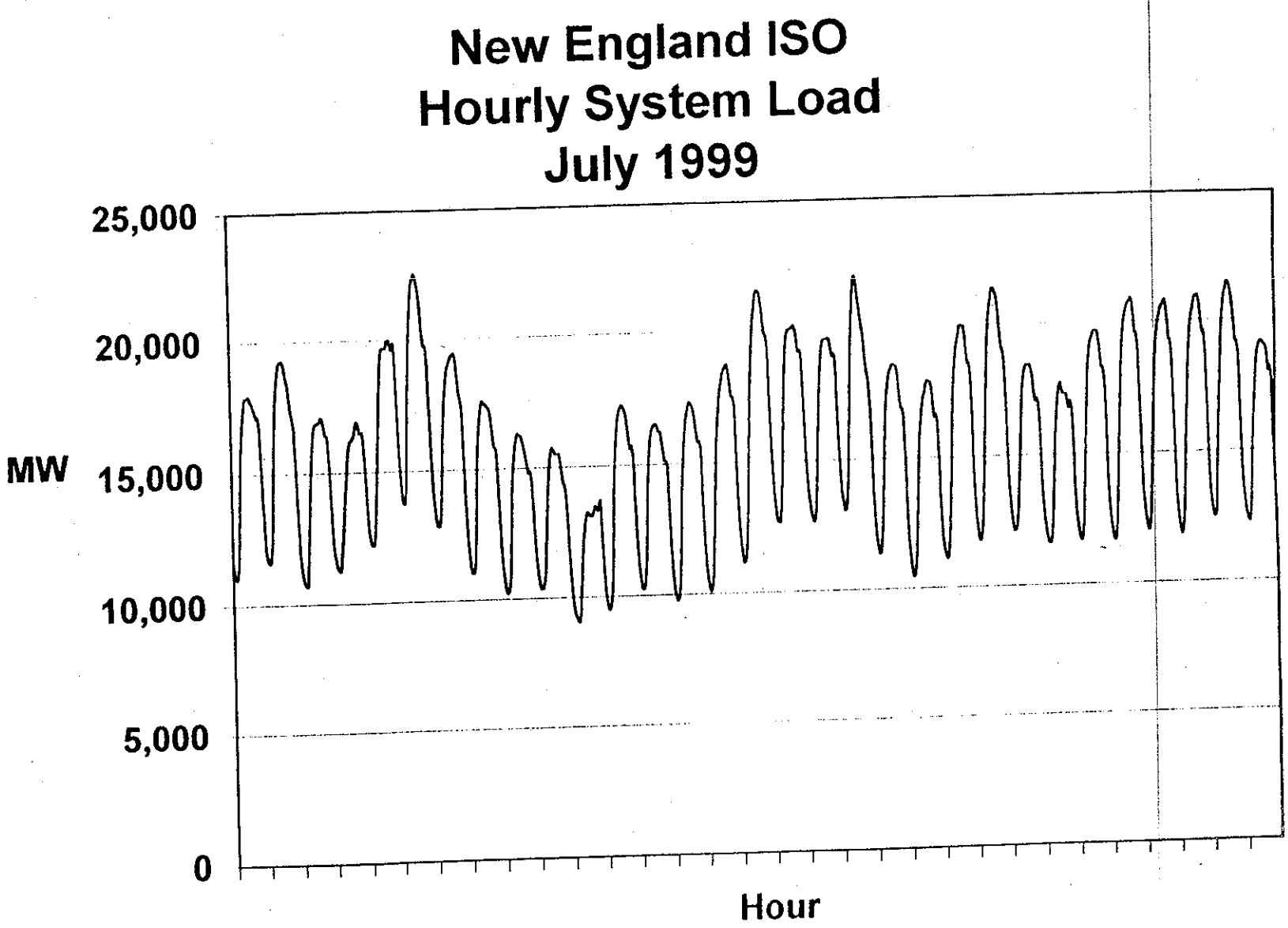
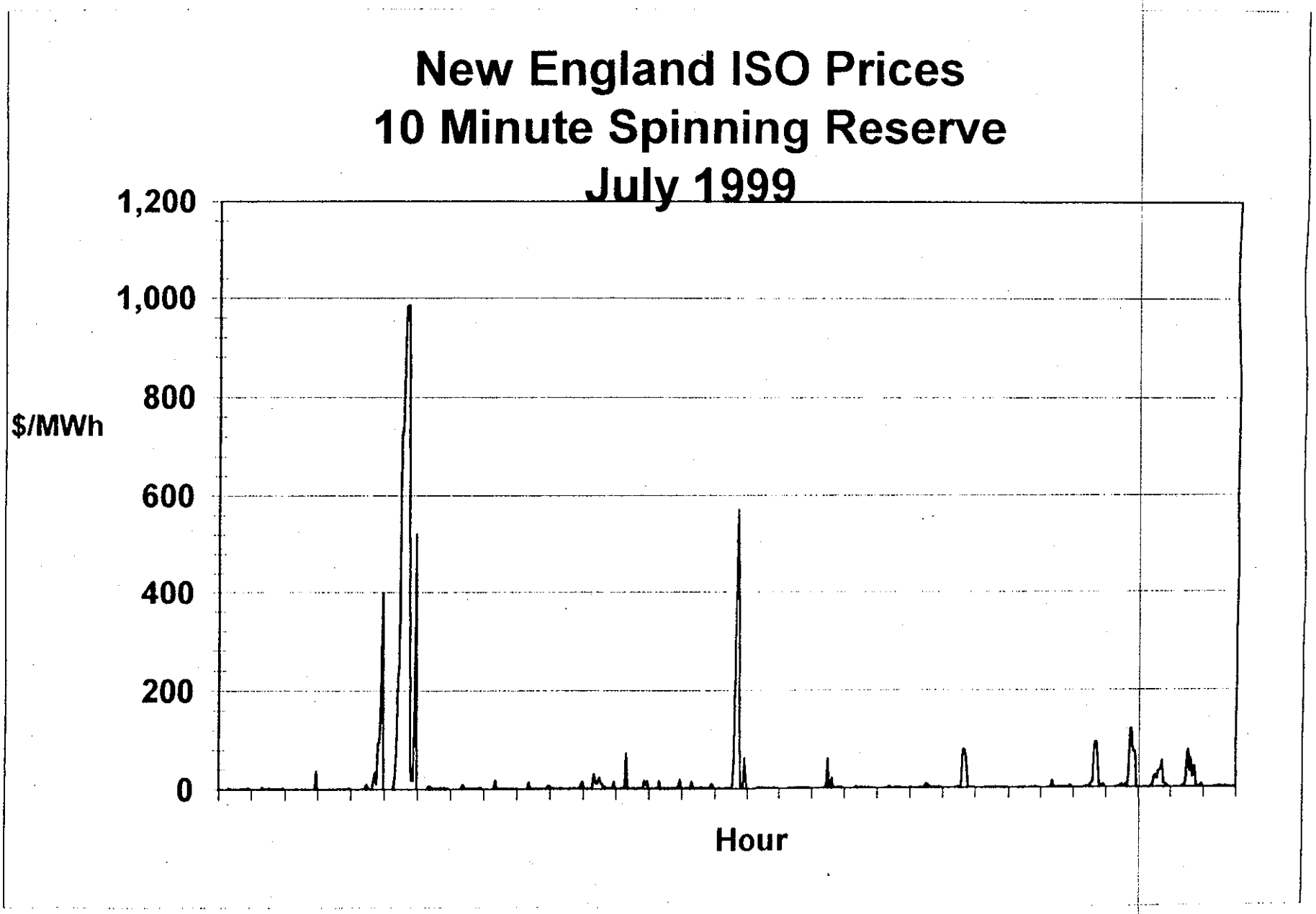
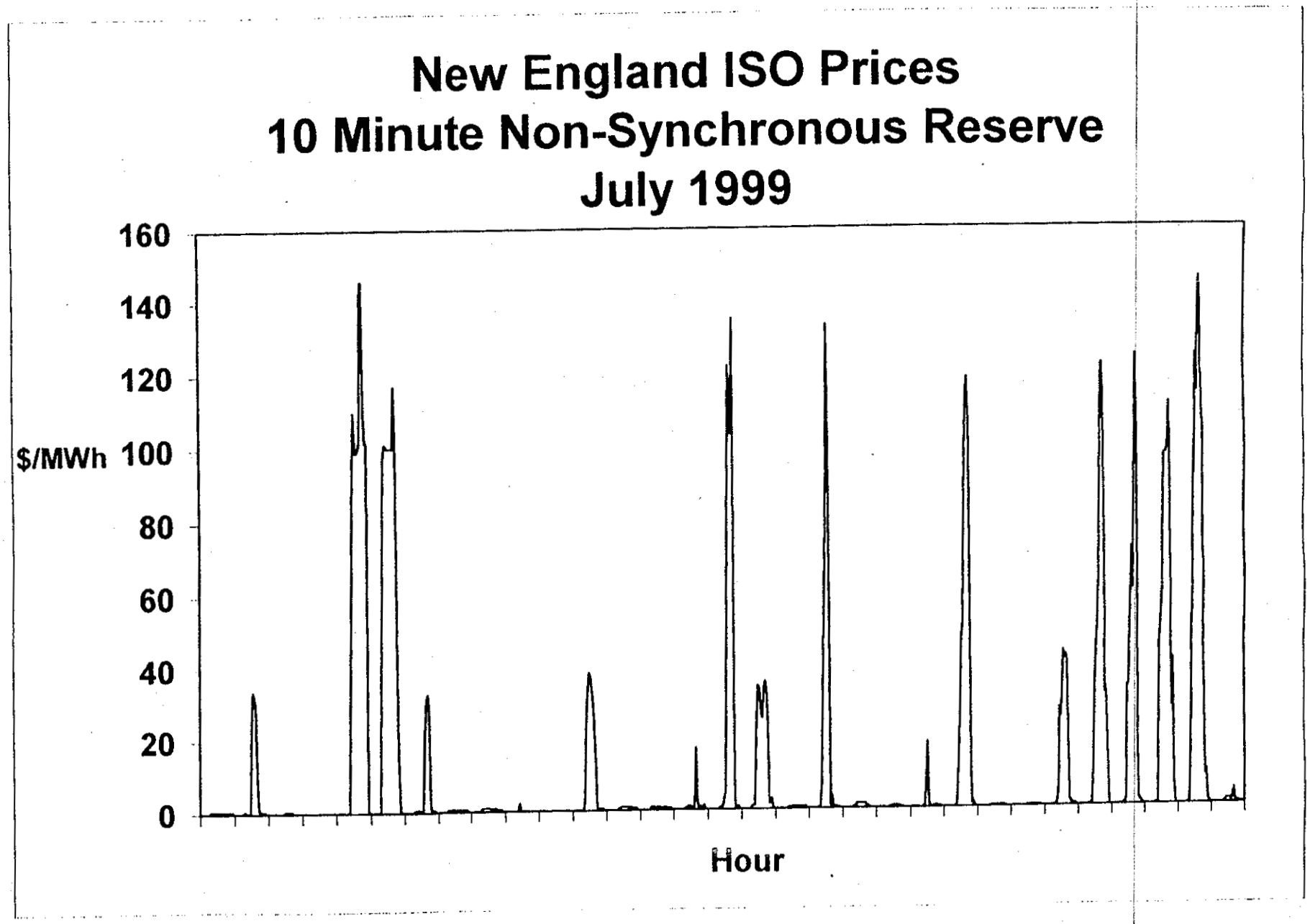

New England ISO
Hourly System Load
July 1999
25,000
20,000
15,000
10,000
5,000
0
MW
Hour

345

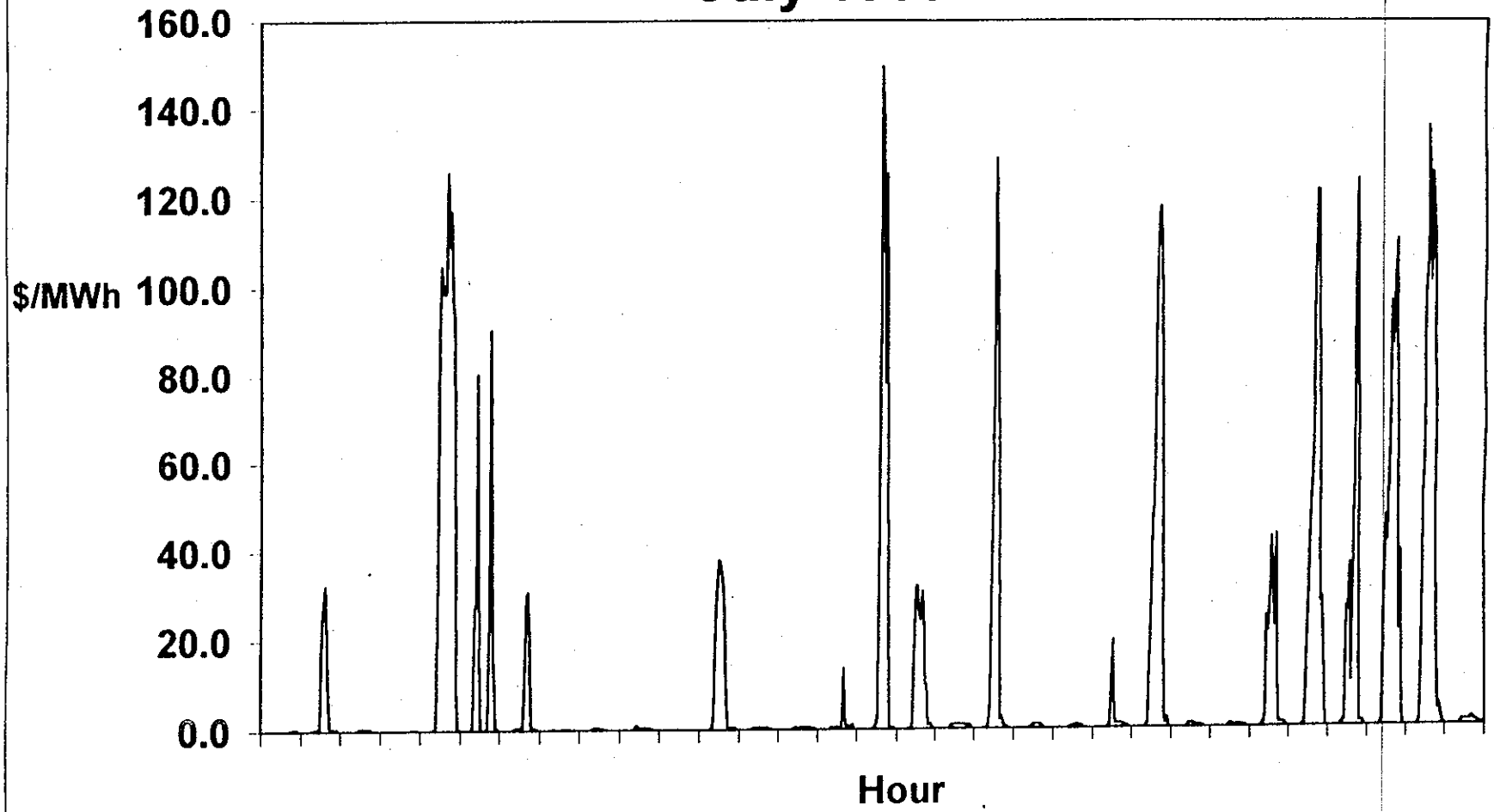

New England ISO Prices
10 Minute Spinning Reserve
July 1999
1,200
1,000
800
600
400
200
0
$/MWh
Hour

346


New England ISO Prices
10 Minute Non-Synchronous Reserve
July 1999
$/MWh
160
140
120
100
80
60
40
20
0
Hour

347

New England ISO Prices
30 Minute Operating Reserve
July 1999



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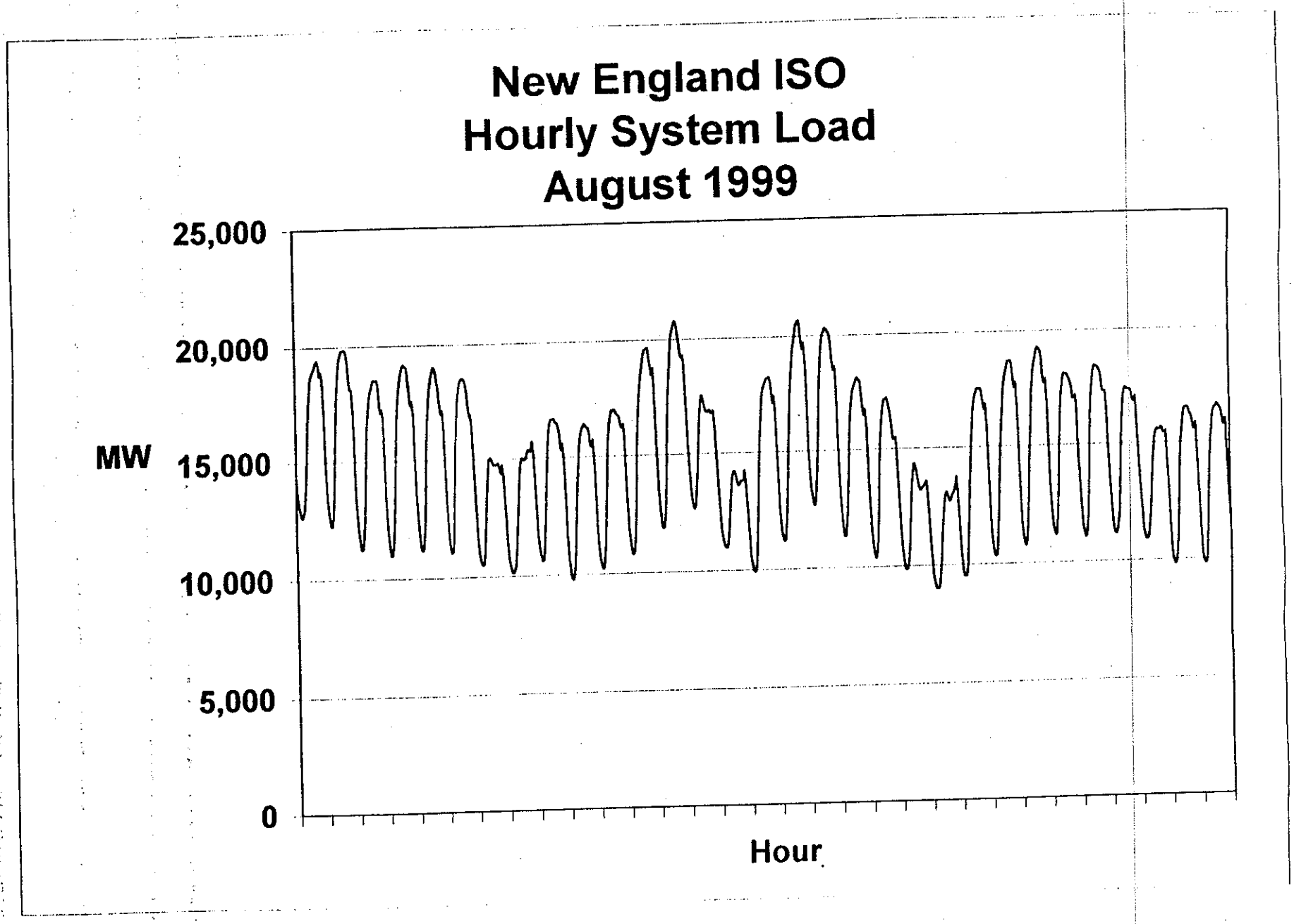
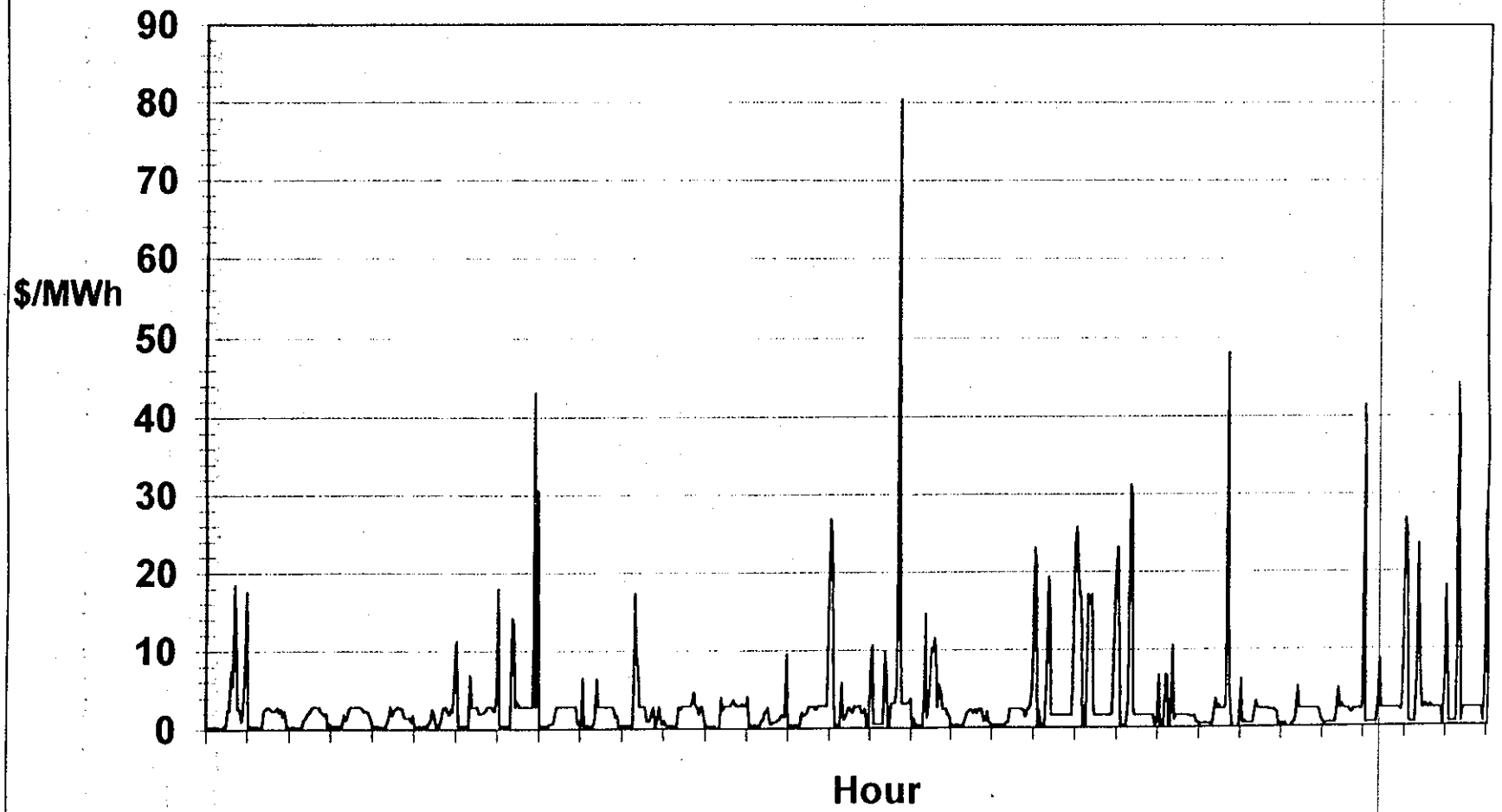

New England ISO
Hourly System Load
August 1999
25,000
20,000
15,000
10,000
5,000
0
MW
Hour

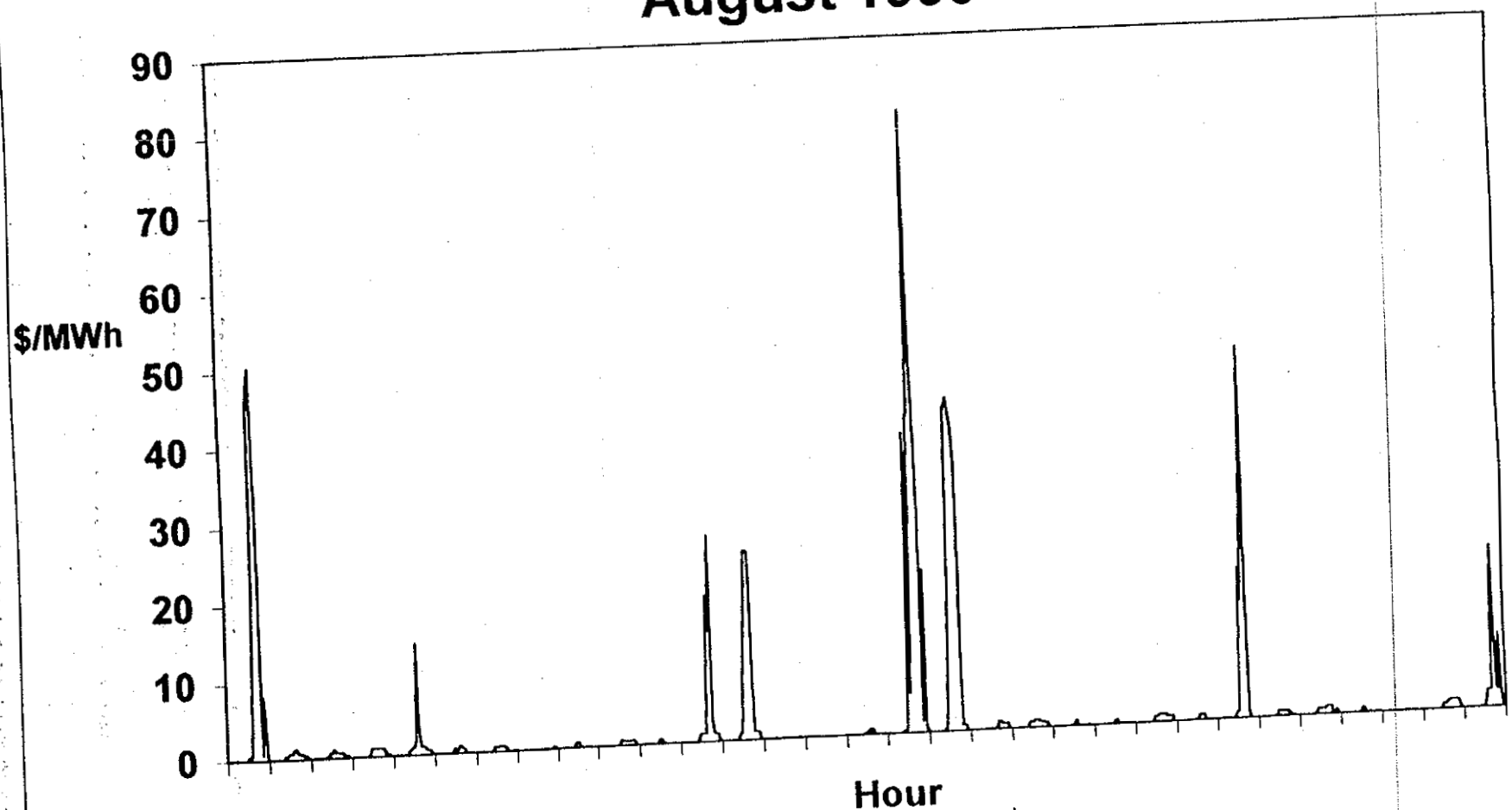
349

New England ISO Prices
10 Minute Spinning Reserve
August 1999

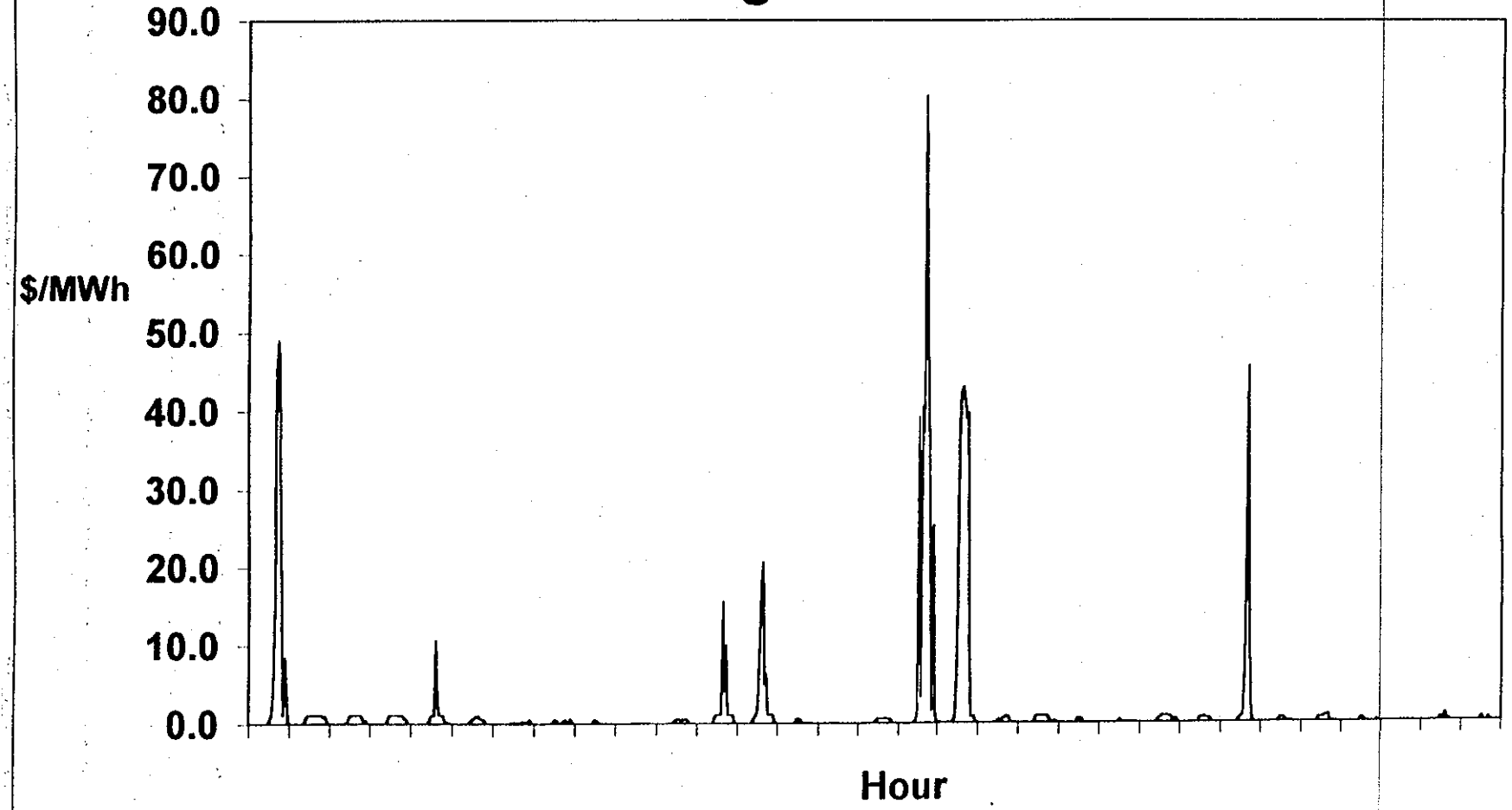


350

New England ISO Prices
10 Minute Non-Synchronous Reserve
August 1999



New England ISO Prices
30 Minute Operating Reserve
August 1999



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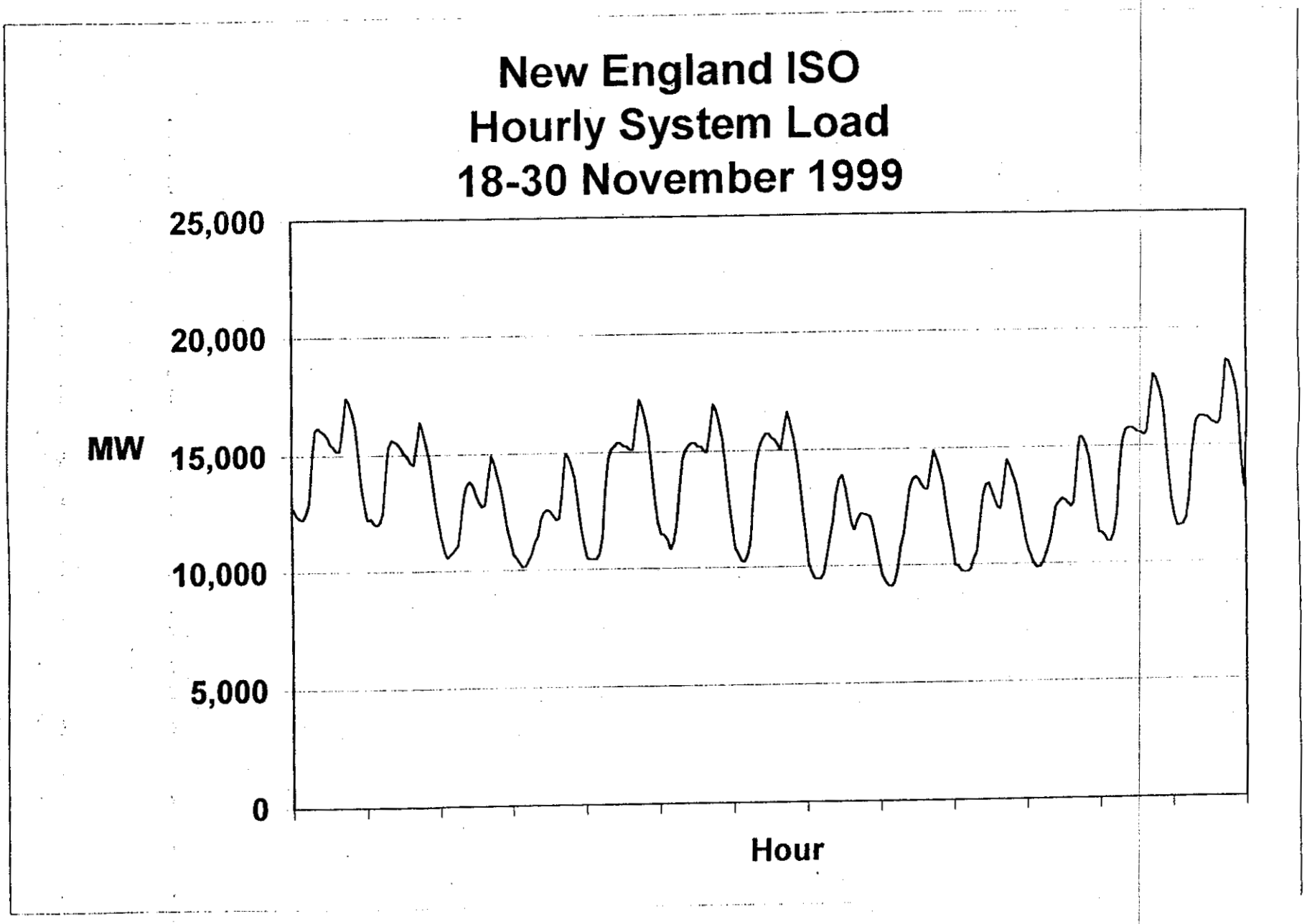
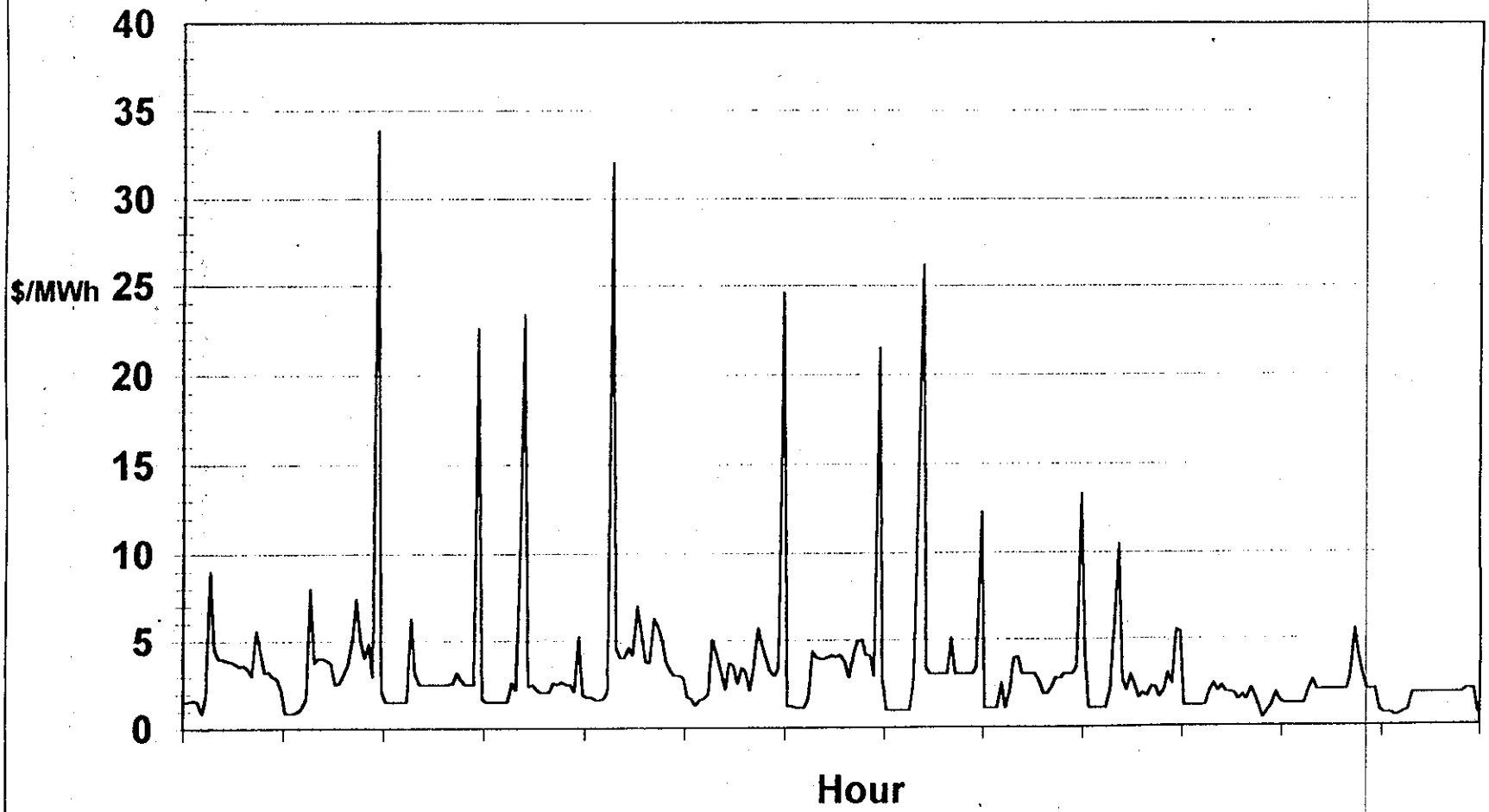
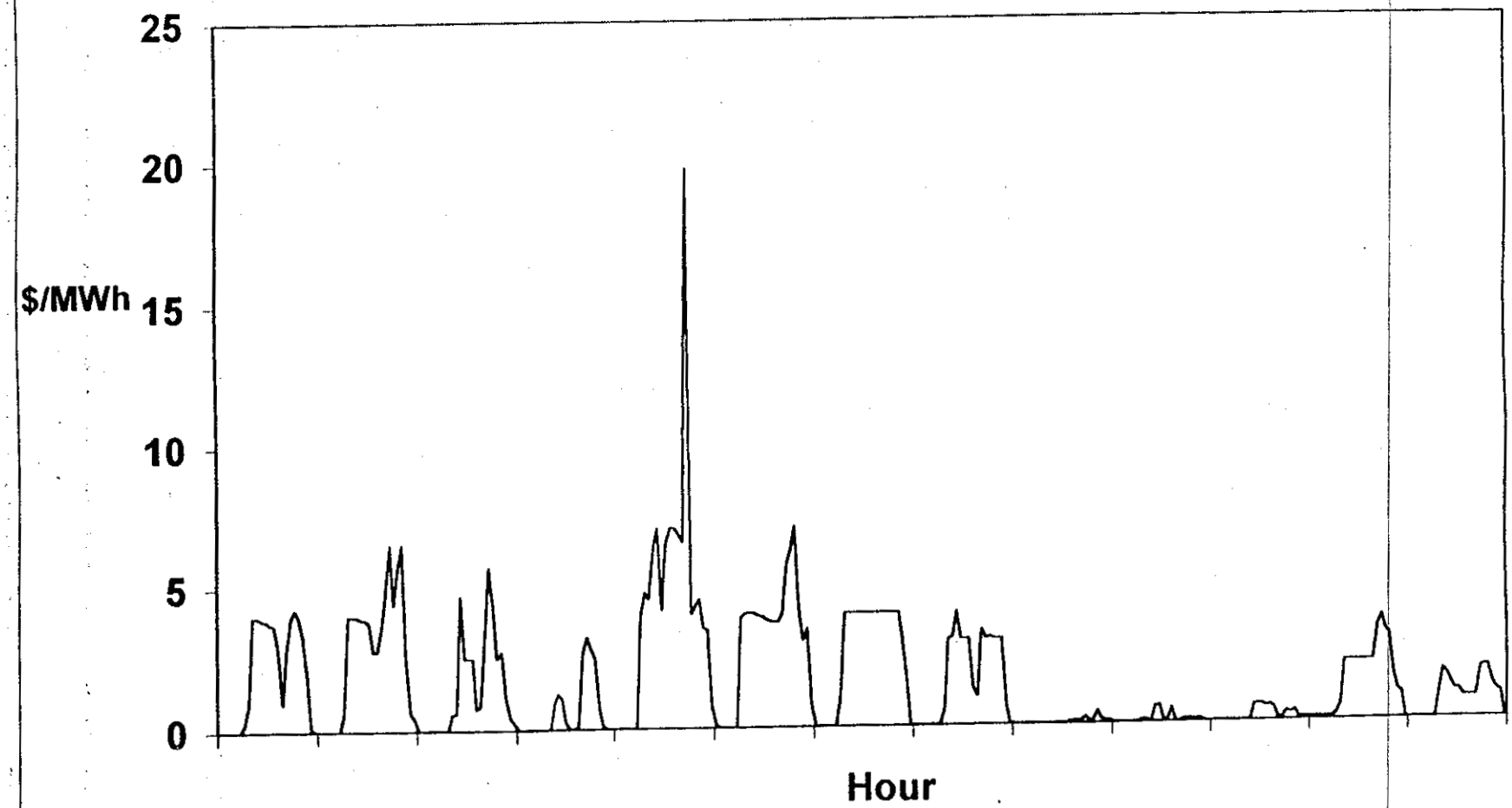

New England ISO
Hourly System Load
18-30 November 1999
25,000
20,000
15,000
10,000
5,000
0
MW
Hour

New England ISO Prices
10 Minute Spinning Reserve
18-30 November 1999



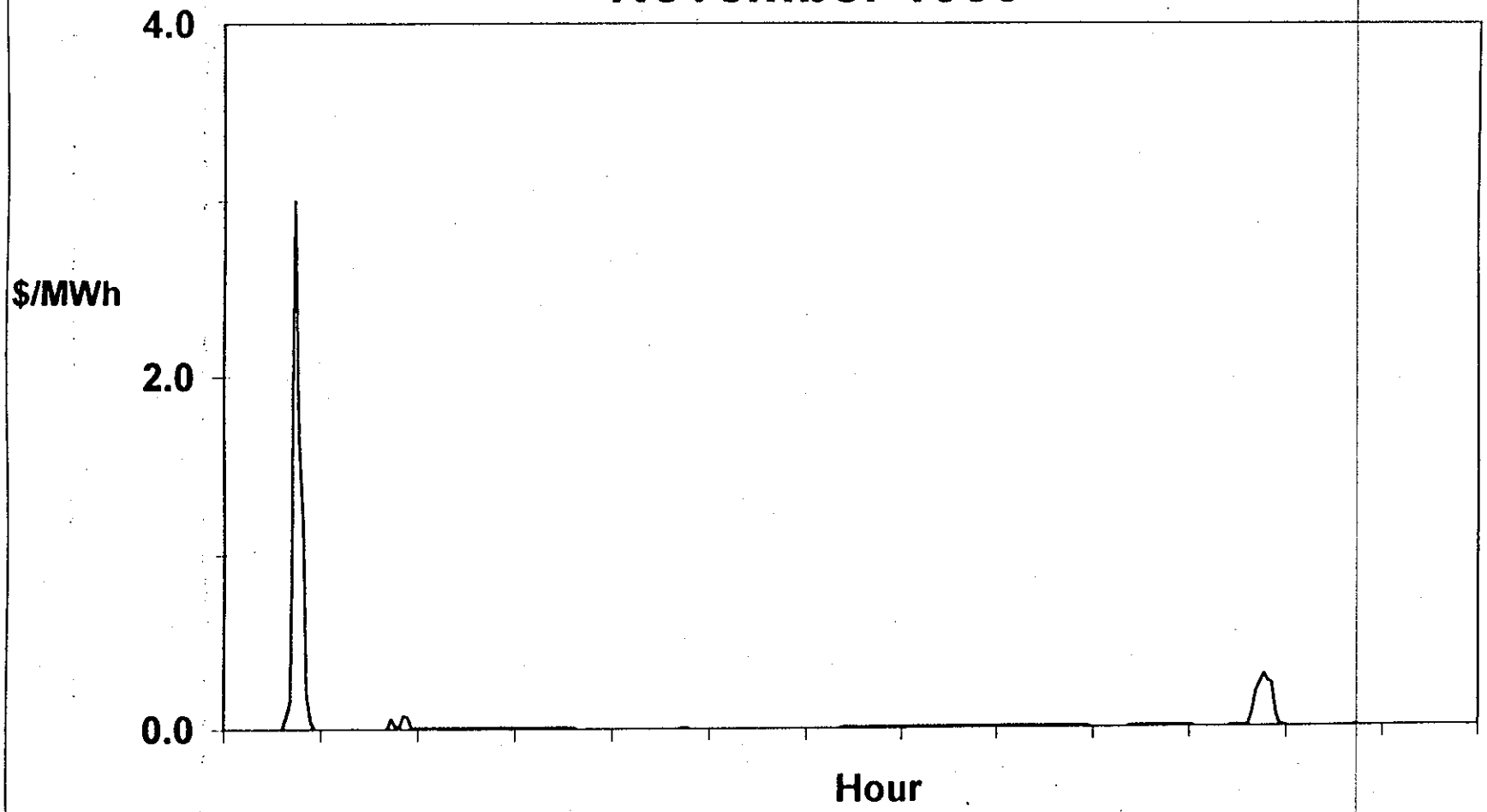
354

New England ISO Prices
10 Minute Non-Synchronous Reserve
November 1999



355

New England ISO Prices
30 Minute Operating Reserve
November 1999



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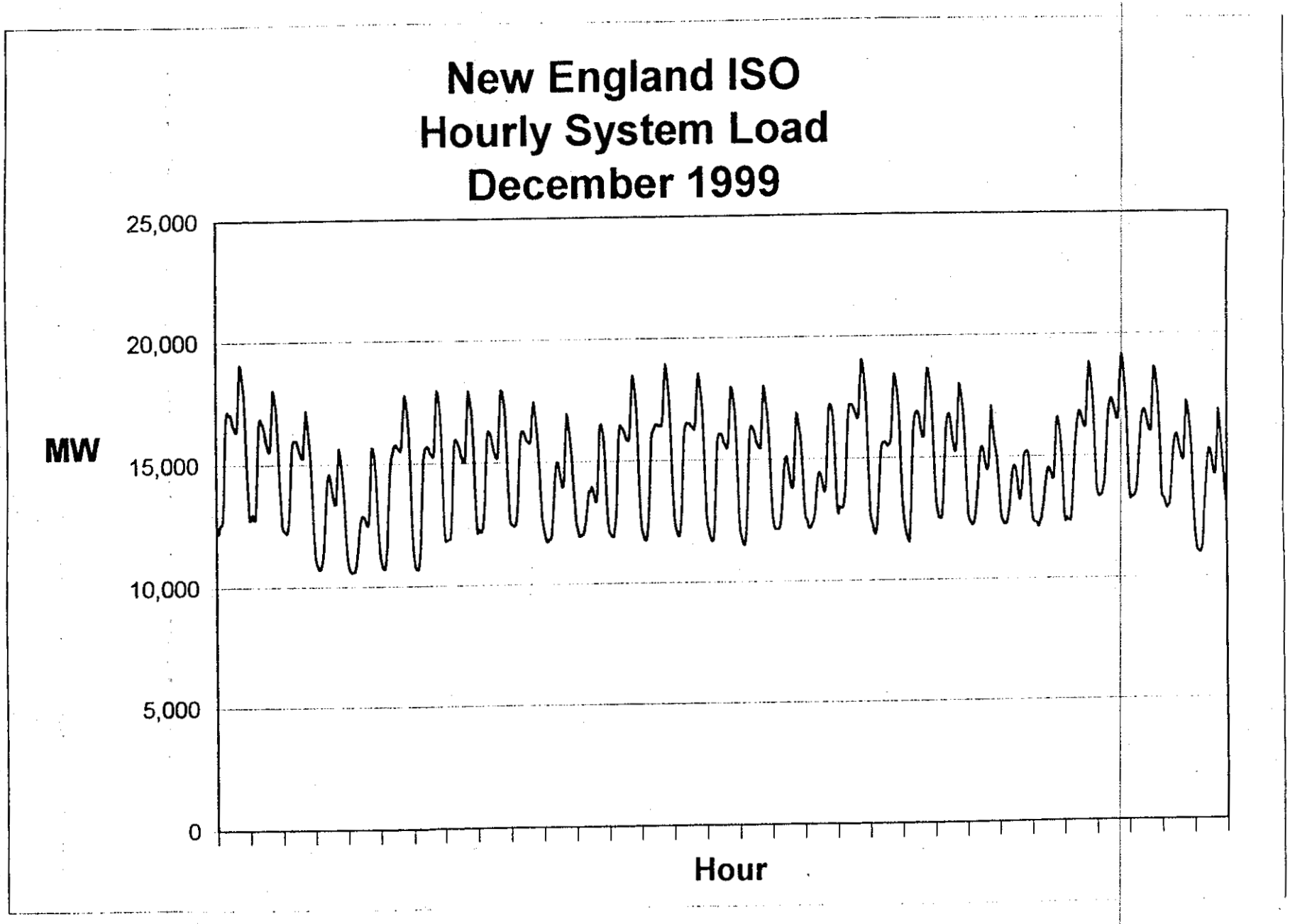
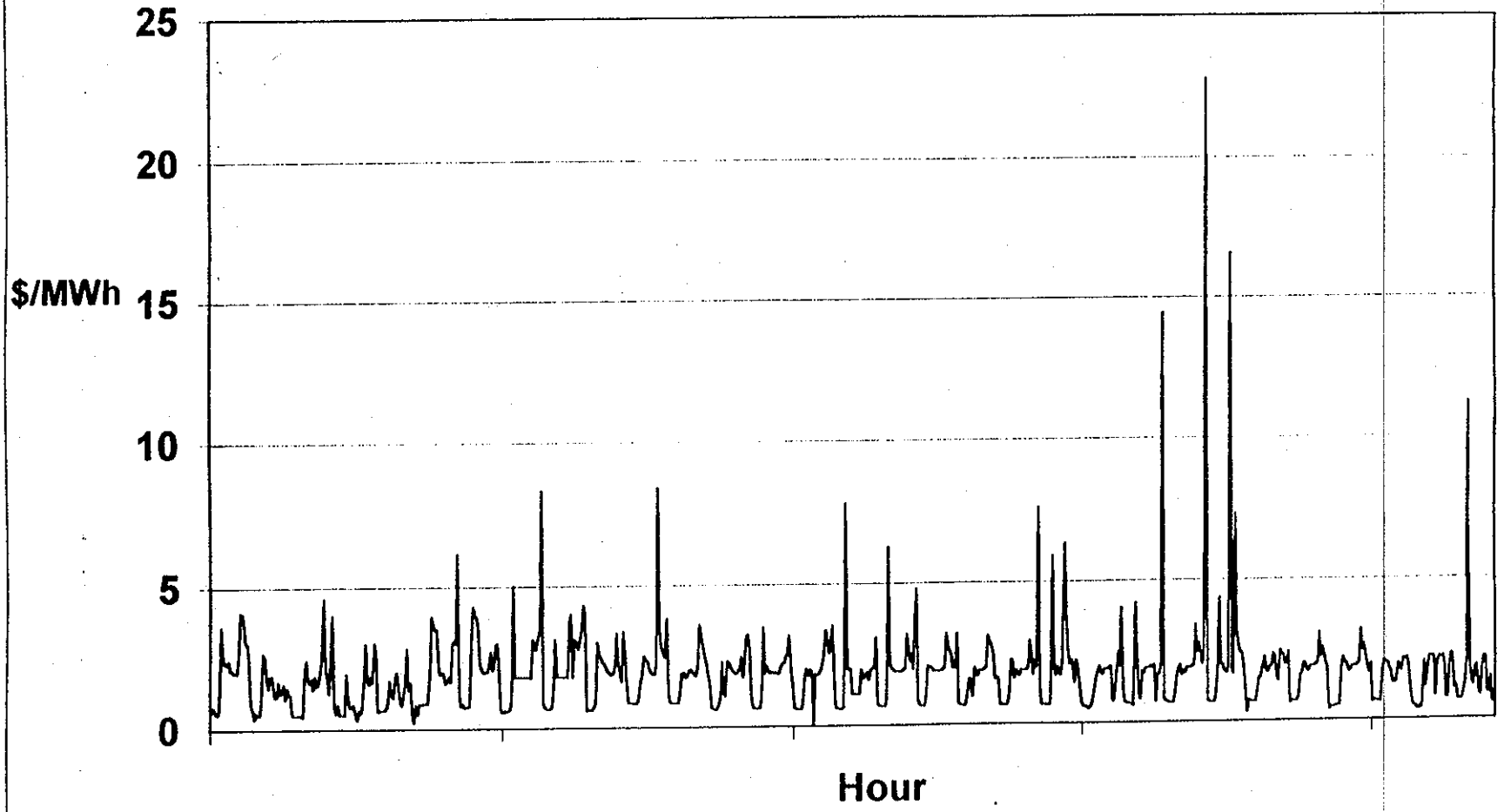
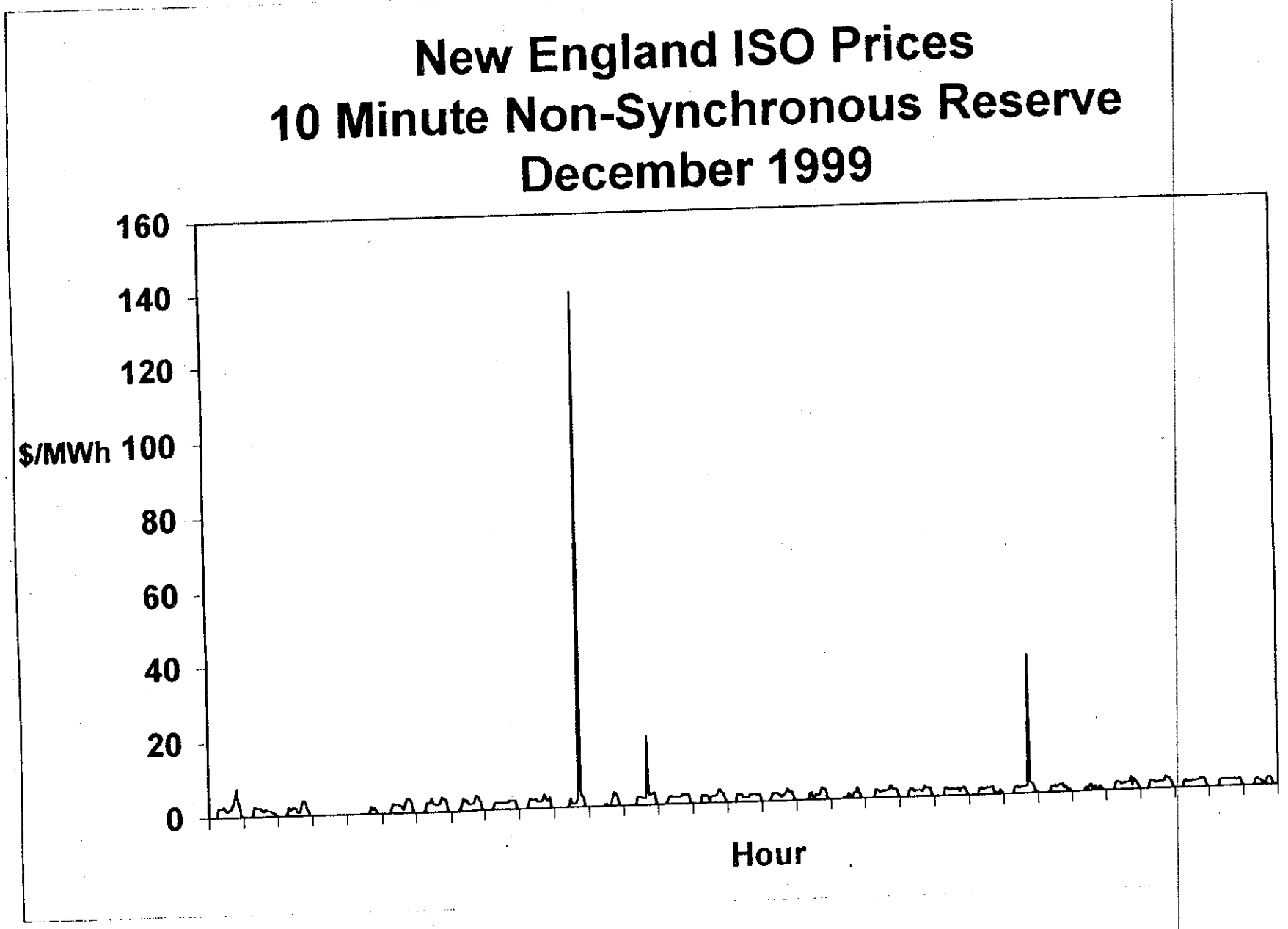

New England ISO
Hourly System Load
December 1999
25,000
20,000
15,000
10,000
5,000
0
MW
Hour

357

New England ISO Prices
10 Minute Spinning Reserve
December 1999

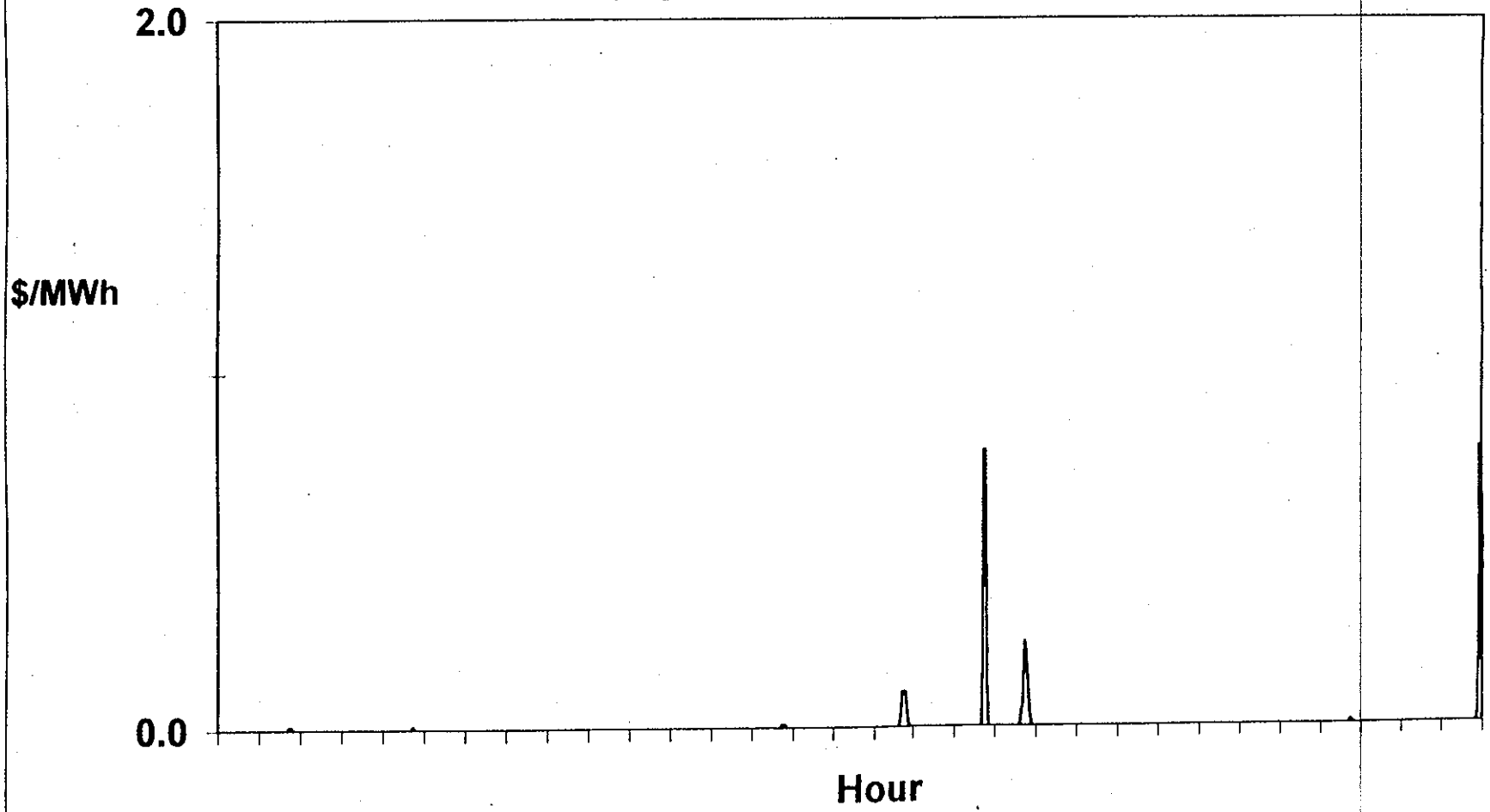


358

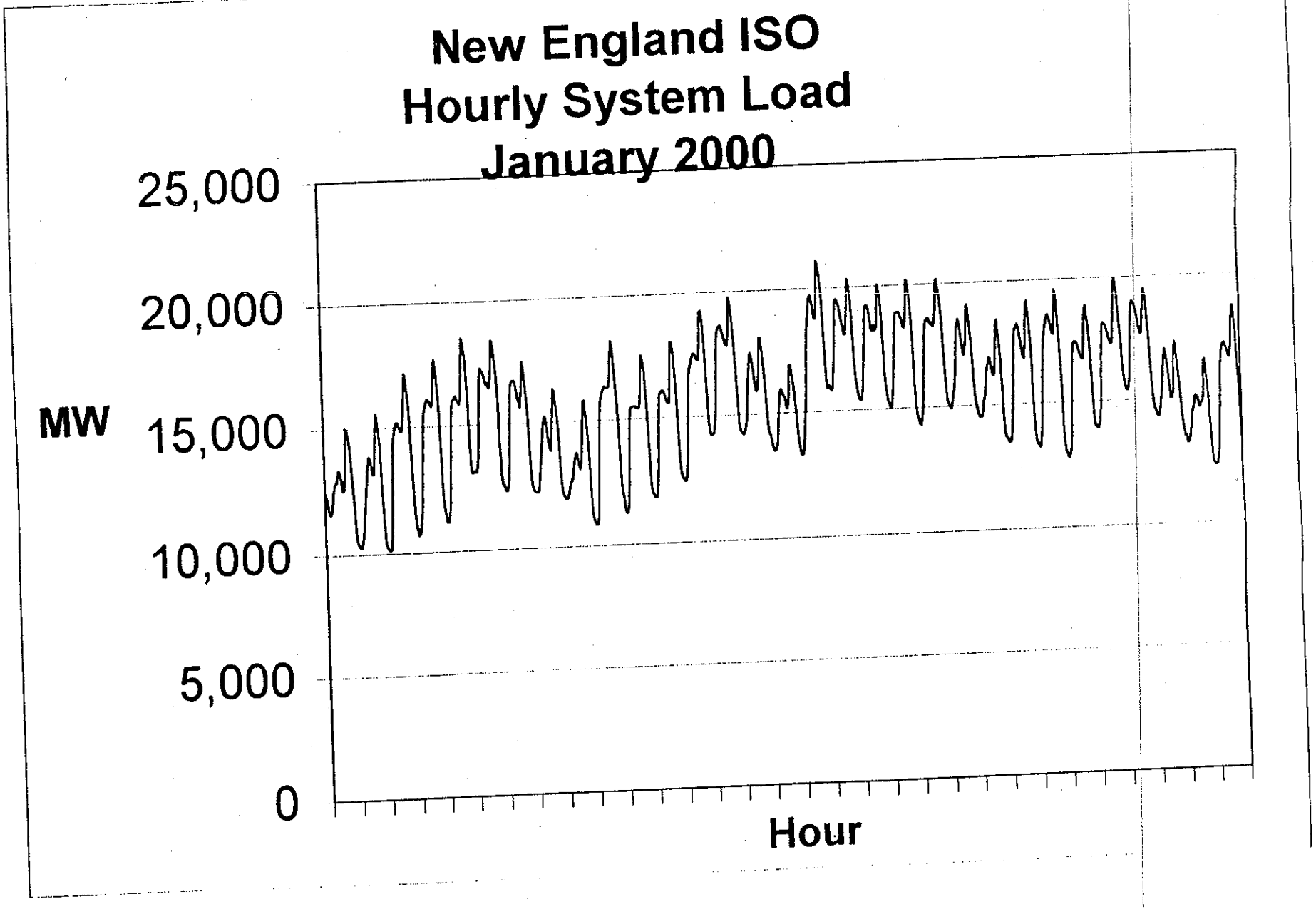

New England ISO Prices
10 Minute Non-Synchronous Reserve
December 1999
160
140
120
$/MWh 100
80
60
40
20
0
Hour

359

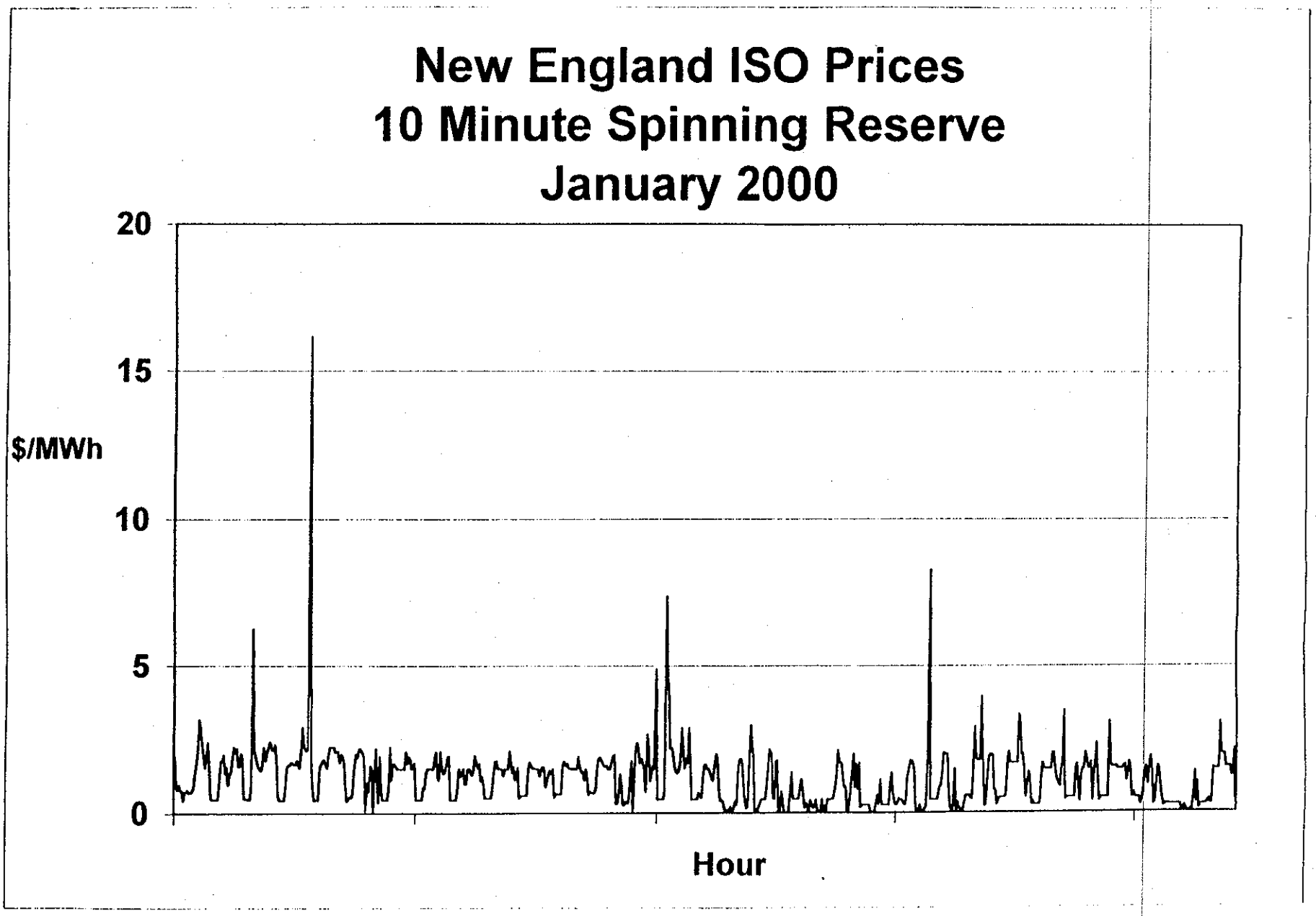
New England ISO Prices
30 Minute Operating Reserve
December 1999



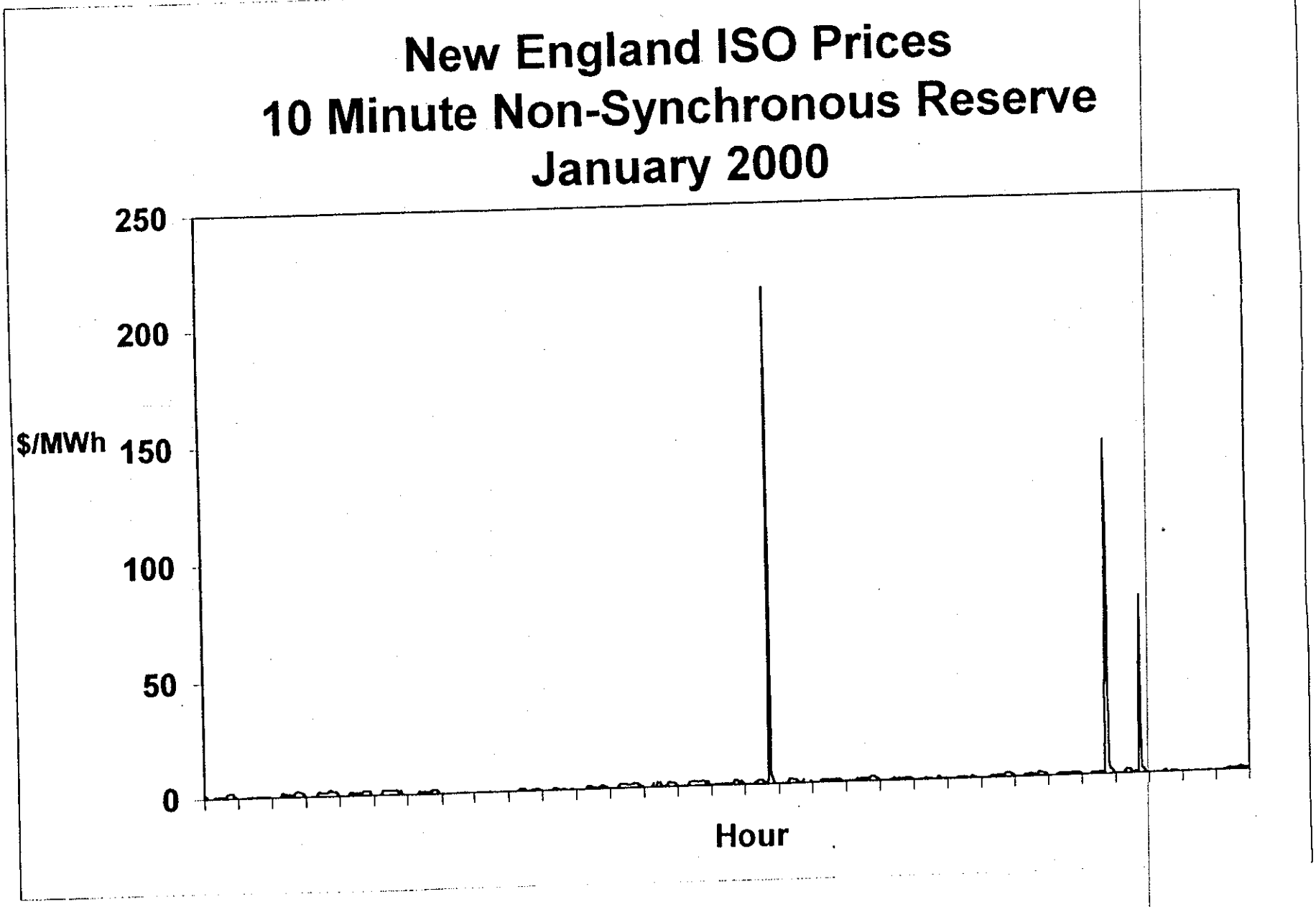
360


New England ISO
Hourly System Load
January 2000
MW
25,000
20,000
15,000
10,000
5,000
0
Hour

361

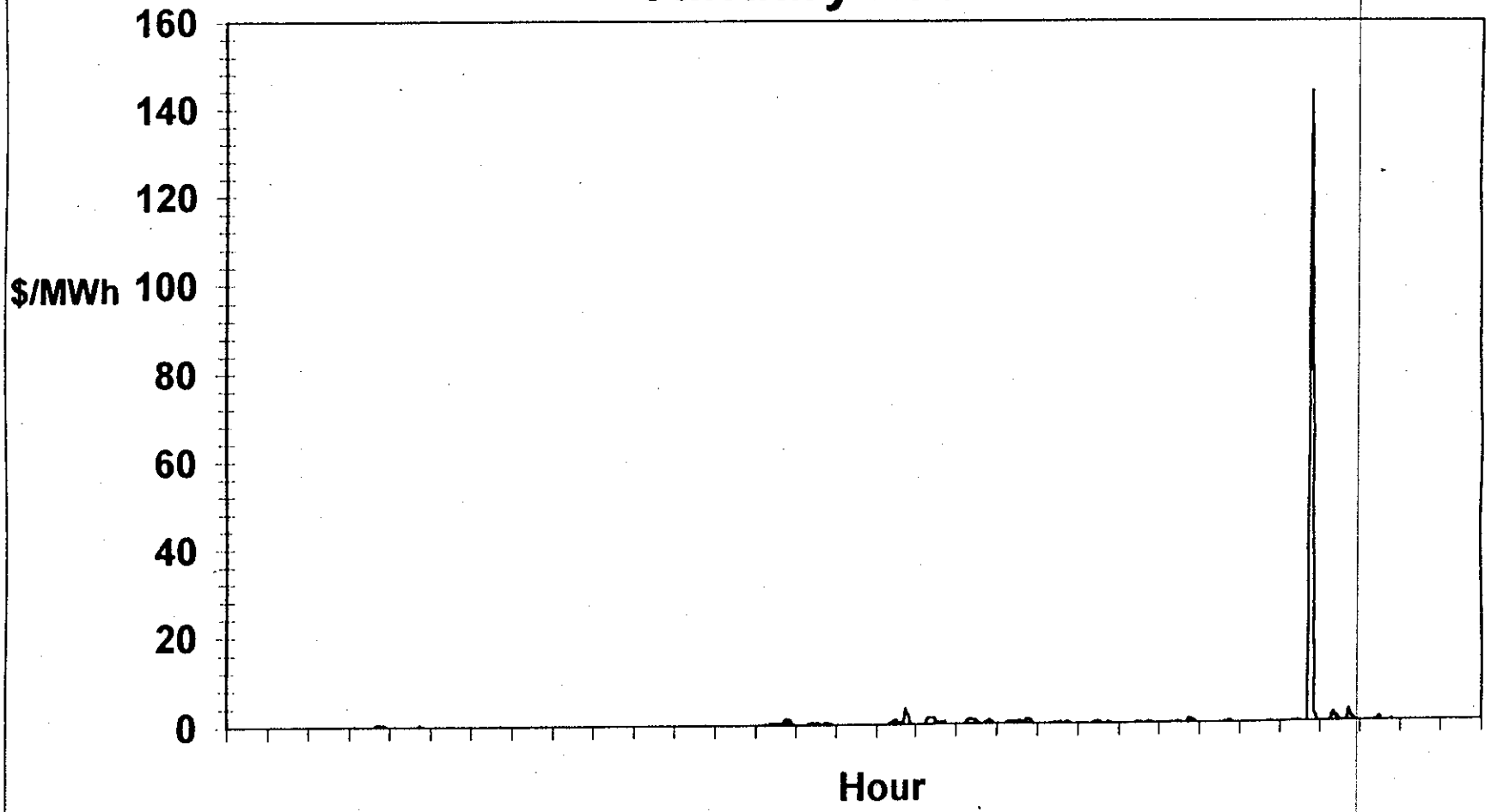

New England ISO Prices
10 Minute Spinning Reserve
January 2000
20
15
10
5
0
$/MWh
Hour

362

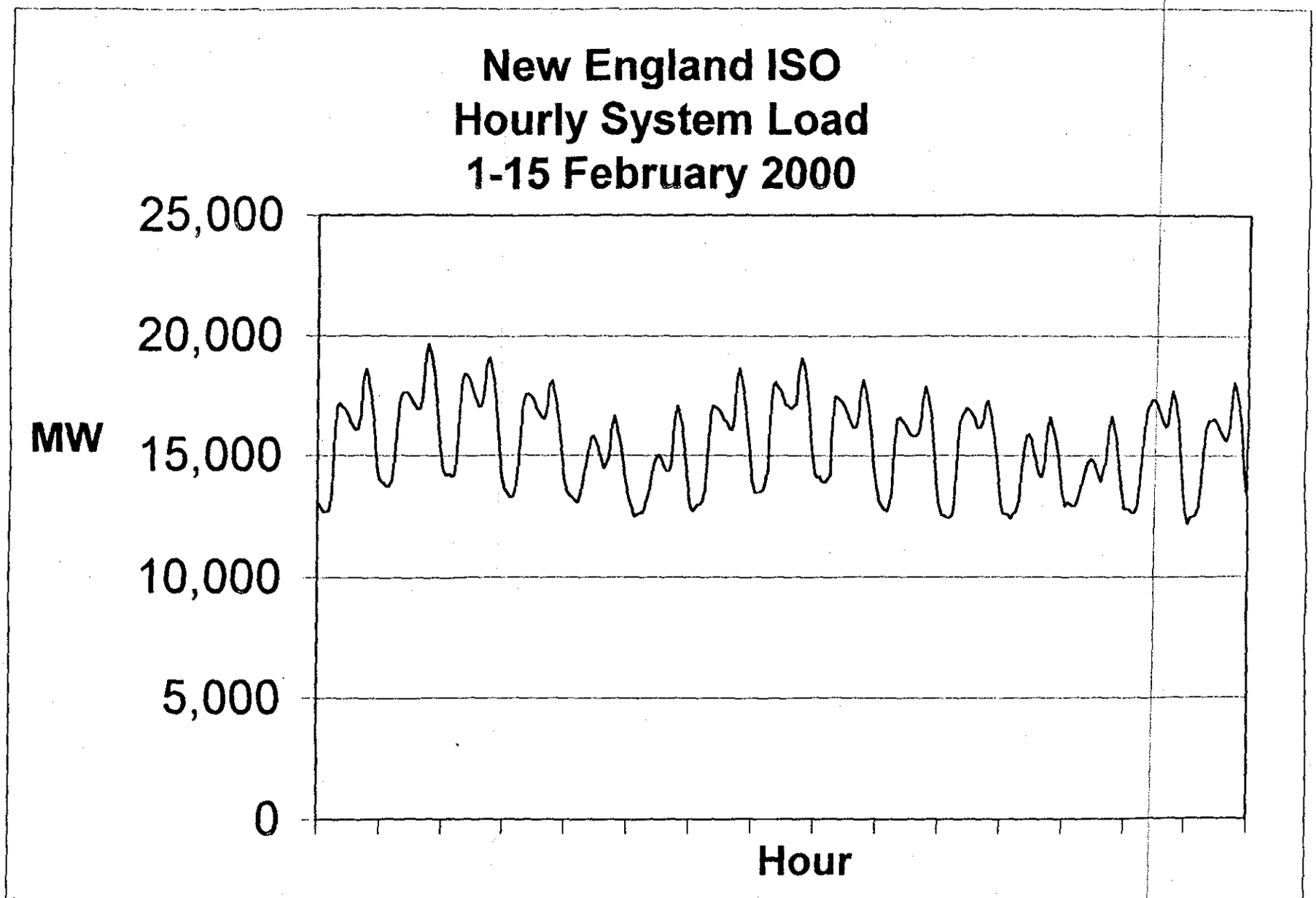

New England ISO Prices
10 Minute Non-Synchronous Reserve
January 2000
250
200
$/MWh
150
100
50
0
Hour

363

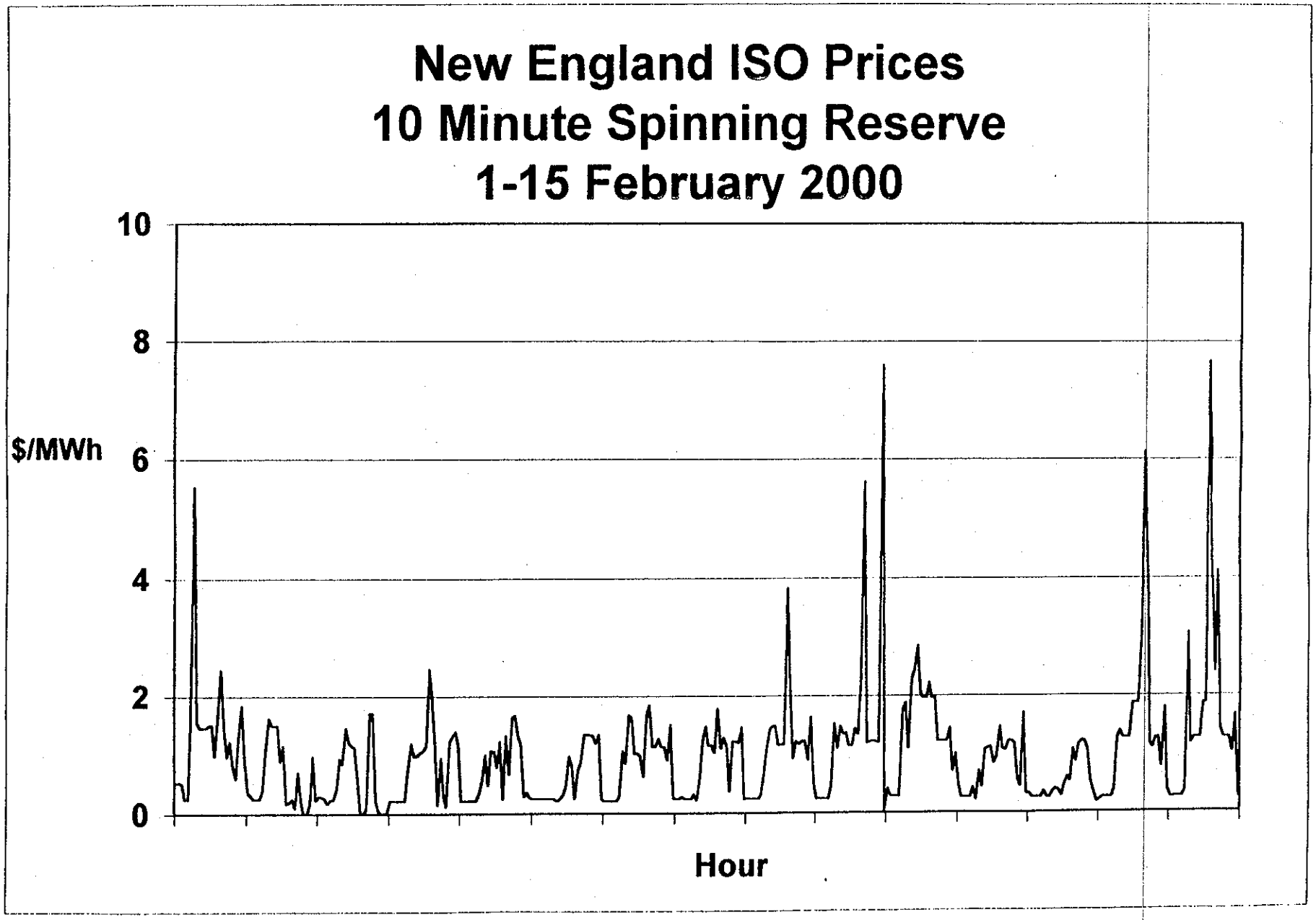
New England ISO Prices
30 Minute Operating Reserve
January 2000



364

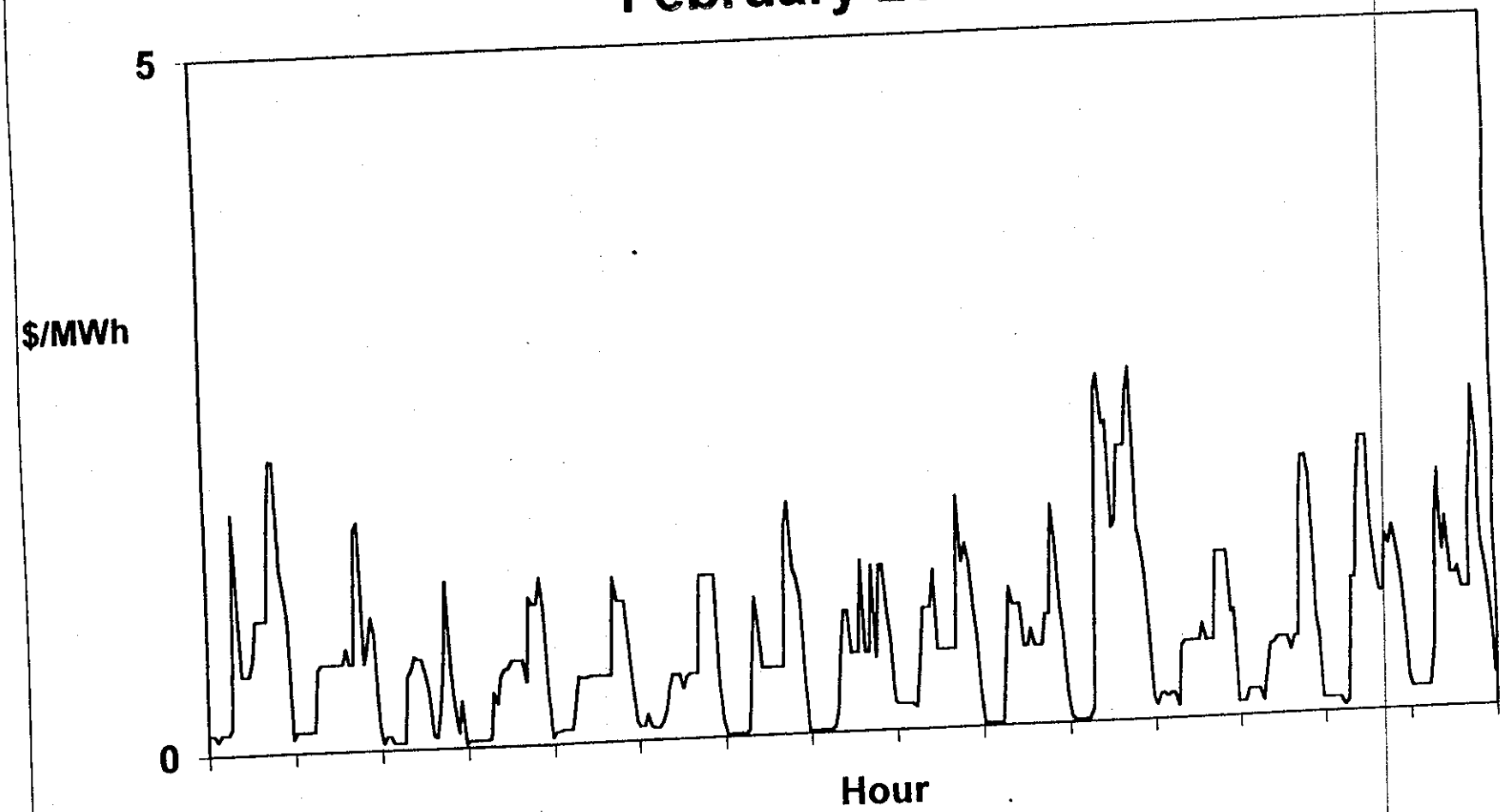

New England ISO
Hourly System Load
1-15 February 2000
25,000
20,000
15,000
10,000
5,000
0
MW
Hour

365

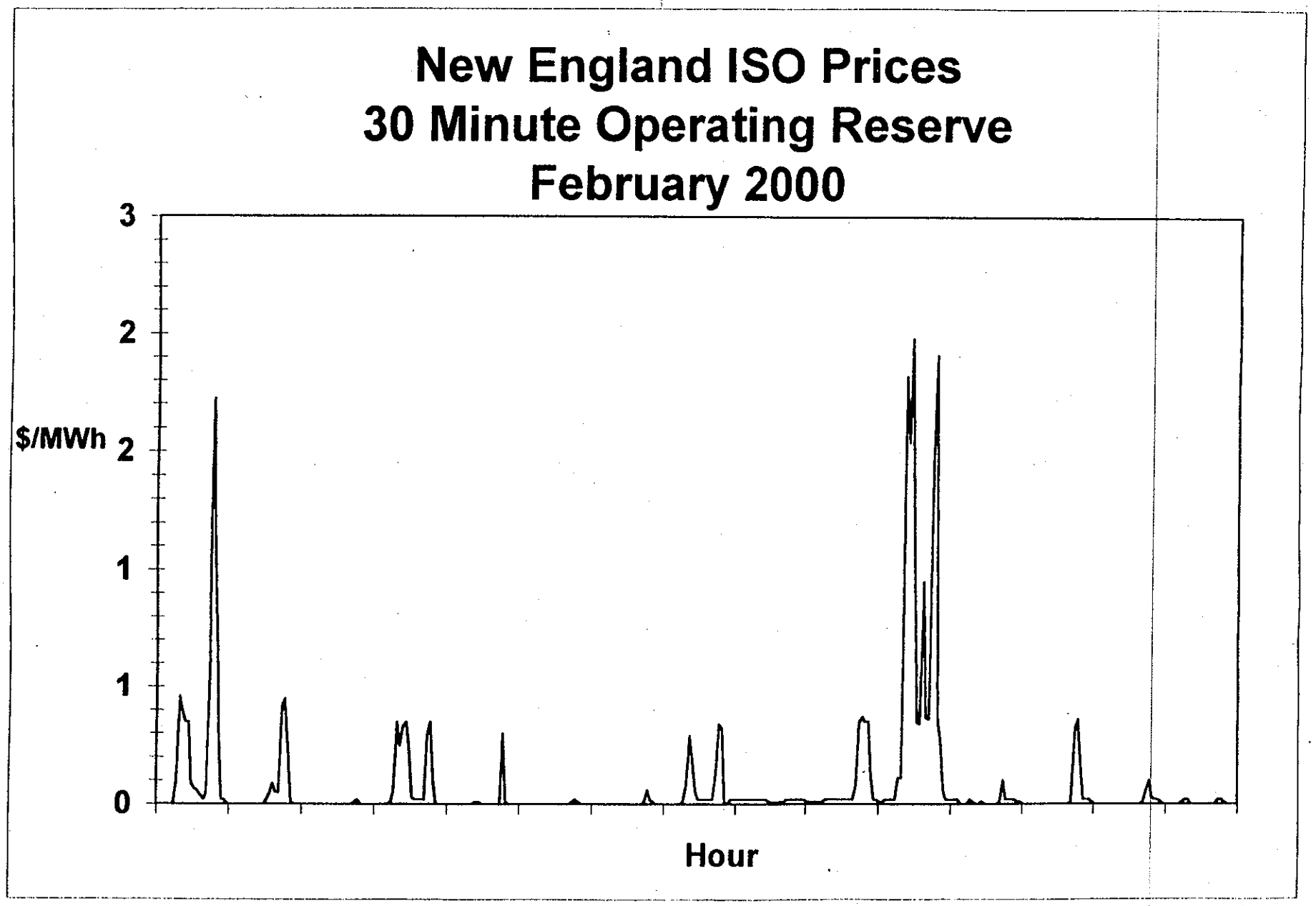

New England ISO Prices
10 Minute Spinning Reserve
1-15 February 2000
10
8
6
4
2
0
$/MWh
Hour

366

New England ISO Prices
10 Minute Non-Synchronous Reserve
February 2000



367


New England ISO Prices
30 Minute Operating Reserve
February 2000
$/MWh
3
2
2
1
1
0
Hour

368