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PROCEEDINGS OF A SEMINAR ON ELECTRIC TRANSMISSION PRICING, TIME OF USE RATES, AND CAPACITY PAYMENTS

Riga, Latvia
December 9-10, 1992

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Prepared by:

RCG/HAGLER, BAILLY, INC.
1530 Wilson Boulevard
Suite 900
Arlington, VA 22209 USA
(703) 351-0300

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AGENDA

LIST OF PARTICIPANTS

PAPERS PRESENTED:

- Mark B. Lively, "Determining the Appropriate Charge for Transmission Services in the Baltic Countries"
- Mark B. Lively, "Potential Benefits and Methods for Implementing Time of Use Rates for Wholesale Power Transactions in the Baltic Countries"
- Mark B. Lively, "Dynamic Pricing for Wholesale Power Transactions in the Baltic Countries"
- Charles F. Zimmermann, "Alternative Types of Capacity Obligations and Methods of Computing Capacity Payments"

B

Seminar on Electric Transmission Pricing,
Time of Use Rates, and Capacity Payments

Agenda

Location: Dispatch Center Baltija, 1 Shmerla Street, Riga, Latvia

Date: December 9 and 10, 1992

Countries involved: Estonia, Latvia, Lithuania

Agenda for Wednesday, December 9, 1992

9:30	Introductory remarks and discussion of the agenda by Vilnis Kreslinsh, director of DC Baltija
9:45	Presentation by Metcheslav Vonsovich (DC Baltija) on existing arrangements to provide wheeling service and existing methods of payment for wheeling service
10:15	Presentation by Mark Lively on the determination of the appropriate percentage charge to be used to pay for transmission services in the Baltic countries
11:45	Discussion led by Metcheslav Vonsovich (DC Baltija) on proposals regarding the percentage charge to be used to pay for transmission services
13:00	Lunch
14:00	Presentation by Metcheslav Vonsovich (DC Baltija) on existing proposals to establish time of use rates, day/night rate differentials, and seasonal rate differentials in wholesale power transactions among the Baltic countries
14:30	Presentation by Mark Lively on the potential benefits and methods of implementing time of use rates, day/night rate differentials, and seasonal rate differentials in wholesale power transactions among the Baltic countries
16:30	Discussion led by Metcheslav Vonsovich (DC Baltija) of proposals to establish time of use rates, day/night rate differentials, and seasonal rate differentials in wholesale power transactions

Agenda for Thursday, December 10, 1992

9:30	Presentation by Charles Zimmermann (RCG/Hagler, Bailly) on alternative types of capacity obligations and alternative methods of computing the level of capacity payments
11:30	Discussion led by Metcheslav Vonsovich (DC Baltija) on capacity obligations and methods of computing capacity payments
13:00	Lunch
14:00	Presentation by Charles Zimmermann (RCG/Hagler, Bailly, Inc.) on the basic principles of contract law and the basic structure of power sales contracts
15:00	Discussion led by Metcheslav Vonsovich (DC Baltija) on power sales contracts
16:00	Closing remarks by Vilnis Kreslinsh (DC Baltija), Charles Zimmermann (RCG/Hagler, Bailly), and Mark Lively

ELECTRIC POWER CONTRACTING AND PRICING PROGRAM

DETERMINING THE APPROPRIATE CHARGE FOR TRANSMISSION SERVICES IN THE BALTIC COUNTRIES

by

MARK B. LIVELY

UTILITY ECONOMIC ENGINEER
19012 High Point Drive
Gaithersburg, Maryland 20879
U.S.A.

9/10 December 1992
Riga, Latvia

Funded by USAID
Under contract with RCG/Hagler, Bailly, Inc.

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As parts of the former Northwest Integrated Power System of the former Soviet Union, Latvia, Lithuania, and Estonia find that their electrical networks are the result of the central planning characteristic of the former Soviet Union.

> One result of that central planning is Latvia, Lithuania, and Estonia being in the middle of the network and separating different parts of Russia. Accordingly, the three republics wheel electricity from one part of Russia to other parts of Russia, notably from St. Petersburg to Pskov and Kaliningrad, also from Byelorussia.
>
> Further, the different currencies used by the various countries and other financial issues has led to a decision for the wheeling charge to be expressed as a fraction of the electricity delivered for wheeling by the intermediate party.

Under current conditions, 8.3% of the electricity delivered by St. Petersburg is retained by Estonia as its payment for delivering the remaining 91.7% on to Pskov or to Latvia. Similarly, Latvia retains 8.3% of the electricity delivered to it as payment for delivering the remaining 91.7% to Lithuania. Finally, Lithuania retains 8.3% of the electricity delivered to it by Byelorussia or Latvia as payment for delivering the remaining 91.7% to Kaliningrad. The Baltic republics are interested in methods for justifying the retention rates they charge for wheeling electricity.

In most of the world, the conventional wisdom is that the cost of providing electric service is constantly changing, including the cost of providing wheeling services. At night, additional wheeling services can be accomplished with little additional electrical losses, and it even improves the reactive power situation. During the day, additional wheeling services may cause line overloads forcing the interruption of service to sales customers.

Just as the cost providing wheeling services change throughout the day, the value to the wheeling customer changes throughout the day. At some times, Pskov may have enough generation to meet its own load, and the value Russia of transmission is slight. During the day, Pskov must rely on power from St. Petersburg

or Byelorussia, and the value of transmission is high. Prices can change dynamically throughout the day and the year to reflect these variations in cost and value.

Two dynamic pricing models for wheeling have been advocated in leading journals and symposiums, and are the subjects of another paper at this program. Though methods exist to determine a dynamic, time-varying retention rate for wheeling services, most people are more comfortable with having a static, unvarying rate for electric services. Fortunately, static rates can be applied under contract to one portion of an electric service while dynamic rates are charged for other portions of an electric service. Thus, static and dynamic rates can co-exist when appropriate decision rules are in place to differentiate between which services are priced at which rates.

The two most common methods for determining utility prices in the U.S. are accounting costs and economic costs. Accounting cost pricing has been known under several variants including average cost pricing and rate base pricing. It is the traditional method used for most utility pricing cases in the U.S. Economic cost pricing is also know as marginal cost pricing, and is sometimes used an a adjunct to average cost pricing.

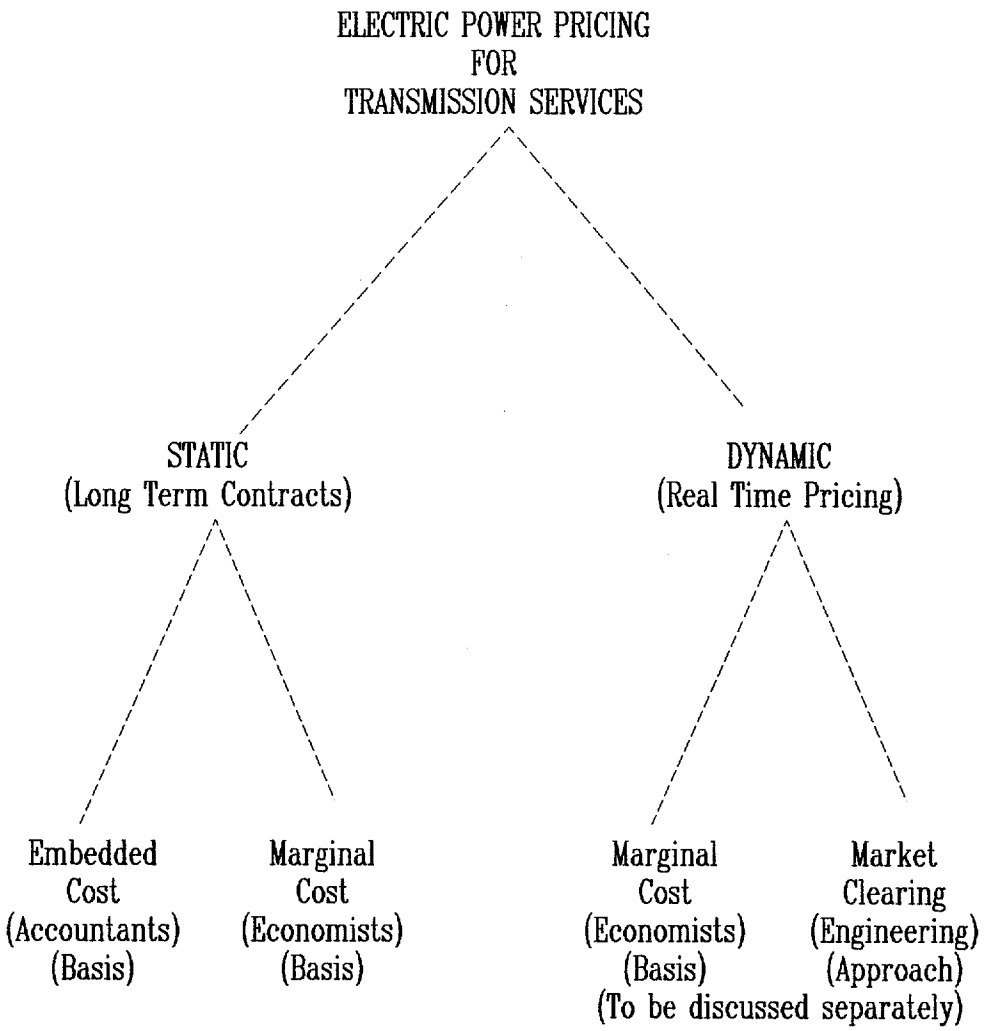
An embedded cost allocation example is provided. The example begins with the development of the power requirements of the various services offered by the utility, including sales to traditional customers and a wheeling service. The requirements at the customer meter are increased by the electrical losses that the utility is expected to experience at the various voltage levels. The wheeling service uses only the transmission system and only is charged for losses on the transmission system. An energy requirement is similarly developed. The power and energy requirements are then transformed into allocation factors, which represent the fraction of the utility's equipment used by each service. The normalizing factors will be discussed later.

The wheeling service uses identified fractions of the utility's production and transmission plant. The allocation of costs to the Wheeling Service is a simple multiplication of component cost and the allocation factors. Under conventional monetary arrangements, the wheeling customer would pay $17,844,000. But since the rate is to be a retention rates, the payment must be normalized relative to the value of the delivered electricity. The normalized costs are calculated by the simple multiplication of component cost and the normalizing allocation factors. If the utility had delivered electricity that it had produced, the cost of the electricity would be $204,646,000. Thus the retention rate should be 8.72%.

A marginal cost assignment example is also provided. Marginal cost studies look different from embedded cost studies. Where embedded cost studies allocate a portion of each cost category to a service, marginal cost studies use the unit cost of

each cost category to price the amount of the related determinant used by the service. Marginal cost studies should use similar or identical assumptions for transmission losses and load factors.

The similarity in assumptions for transmission losses and load factors should keep the marginal cost retention rate close to the embedded cost retention rate. However, the great variation among the various component ratios of marginal cost to embedded cost results in marginal cost based retention rate being higher than the embedded cost retention rate.


ELECTRIC POWER PRICING
FOR
TRANSMISSION SERVICES
STATIC
(Long Term Contracts)
DYNAMIC
(Real Time Pricing)
Embedded
Cost
(Accountants)
(Basis)
Marginal
Cost
(Economists)
(Basis)
Marginal
Cost
(Economists)
(Basis)
Market
Clearing
(Engineering)
(Approach)
(To be discussed separately)

ELECTRIC POWER PRICING FOR TRANSMISSION SERVICES

FIXED PRICE/EMBEDDED COST BASIS

POWER REQUIREMENTS
(MW)

	TOTAL	RESIDENTIAL SALES	COMMERCIAL SALES	INDUSTRIAL SALES	WHEELING SERVICE
DELIVERIES	4000	1000	1000	1000	1000
DELIVERIES AT SECONDARY DISTRIBUTION VOLTAGE					
	1500	1000	500	0	0
SECONDARY DISTRIBUTION VOLTAGE LOSSES - 3%					
	45	30	15	0	0
DELIVERIES AT PRIMARY DISTRIBUTION VOLTAGE					
TO SECONDARY	1545	1030	515	0	0
TO CUSTOMERS	500	0	500	0	0
TOTAL	2045	1030	1015	0	0
PRIMARY DISTRIBUTION VOLTAGE LOSSES - 2%					
	41	21	20	0	0
DELIVERIES AT SUBTRANSMISSION VOLTAGE					
TO DISTRIBUTION	2086	1051	1035	0	0
TO CUSTOMERS	500	0	0	500	0
TOTAL	2586	1051	1035	500	0
SUBTRANSMISSION VOLTAGE LOSSES - 3%					
	78	32	31	15	0
DELIVERIES AT TRANSMISSION VOLTAGE					
TO SUBTRANSMISSION	2664	1083	1066	515	0
TO CUSTOMERS	1500	0	0	500	1000
TOTAL	4164	1083	1066	1015	1000
TRANSMISSION VOLTAGE LOSSES - 4%					
	167	43	43	41	40
INPUT TO POWER SUPPLY					
	4331	1126	1109	1056	1040

ELECTRIC POWER PRICING FOR TRANSMISSION SERVICES

FIXED PRICE/EMBEDDED COST BASIS

ENERGY REQUIREMENTS
(GWH)

	TOTAL	RESIDENTIAL SALES	COMMERCIAL SALES	INDUSTRIAL SALES	WHEELING SERVICE
DELIVERIES	21,500	4,000	4,500	7,000	6,000
DELIVERIES AT SECONDARY DISTRIBUTION VOLTAGE					
	6,250	4,000	2,250	0	0
SECONDARY DISTRIBUTION VOLTAGE LOSSES - 2%					
	125	80	45	0	0
DELIVERIES AT PRIMARY DISTRIBUTION VOLTAGE					
TO SECONDARY	6,375	4,080	2,295	0	0
TO CUSTOMERS	2,250	0	2,250	0	0
TOTAL	8,625	4,080	4,545	0	0
PRIMARY DISTRIBUTION VOLTAGE LOSSES - 1.6%					
	138	65	73	0	0
DELIVERIES AT SUBTRANSMISSION VOLTAGE					
TO DISTRIBUTION	8,763	4,145	4,618	0	0
TO CUSTOMERS	3,500	0	0	3,500	0
TOTAL	12,263	4,145	4,618	3,500	0
SUBTRANSMISSION VOLTAGE LOSSES - 2.1%					
	258	87	97	74	0
DELIVERIES AT TRANSMISSION VOLTAGE					
TO SUBTRANSMISSION	12,521	4,232	4,715	3,574	0
TO CUSTOMERS	9,500	0	0	3,500	6,000
TOTAL	22,021	4,232	4,715	7,074	6,000
TRANSMISSION VOLTAGE LOSSES - 2.4%					
	529	102	113	170	144
INPUT TO POWER SUPPLY					
	22,550	4,334	4,828	7,244	6,144

ELECTRIC POWER PRICING FOR TRANSMISSION SERVICES

FIXED PRICE/EMBEDDED COST BASIS

ALLOCATION FACTORS

	TOTAL	RESIDENTIAL SALES	COMMERCIAL SALES	INDUSTRIAL SALES	WHEELING SERVICE
SALES DELIVERIES PLUS LOSSES (MW)					
DETERMINANT	3,331	1,126	1,109	1,056	40
FACTOR	100.00%	33.81%	33.29%	31.70%	1.20%
SALES DELIVERIES PLUS LOSSES (GWH)					
DETERMINANT	16,550	4,334	4,828	7,244	144
FACTOR	100.00%	26.19%	29.17%	43.77%	0.87%
TOTAL DELIVERIES AT TRANSMISSION VOLTAGE (MW)					
DETERMINANT	4,331	1,126	1,109	1,056	1040
FACTOR	100.00%	26.00%	25.61%	24.38%	24.01%
TOTAL DELIVERIES AT TRANSMISSION VOLTAGE (GWH)					
DETERMINANT	22,550	4,334	4,828	7,244	6,144
FACTOR	100.00%	19.22%	21.41%	32.12%	27.25%
NORMALIZING SALES DELIVERIES PLUS LOSSES (MW)					
DETERMINANT	3,331				1,040
FACTOR	100.00%				31.22%
NORMALIZING SALES DELIVERIES PLUS LOSSES (GWH)					
DETERMINANT	16,550				6,144
FACTOR	100.00%				37.12%

ELECTRIC POWER PRICING FOR TRANSMISSION SERVICES

FIXED PRICE/EMBEDDED COST BASIS

COST ALLOCATION

Description	Annual Cost	Wheeling Service Allocation Factor	Wheeling Service Allocated Cost
Production			
Energy	$300,000,000	0.87%	$ 2,610,000
Demand	260,000,000	1.20%	3,120,000
Transmission			
Energy	400,000	27.25%	109,000
Demand	50,000,000	24.01%	12,005,000
Total	$610,400,000		$17,844,000

NORMALIZATION ALLOCATION

Description	Annual Cost	Normalized Wheeling Service Allocation Factor	Normalized Wheeling Service Allocated Cost
Production			
Energy	$300,000,000	37.12%	$111,360,000
Demand	260,000,000	31.22%	81,172,000
Transmission			
Energy	400,000	27.25%	109,000
Demand	50,000,000	24.01%	12,005,000
Total	$610,400,000		$204,646,000

Transmission Cost Normalized 8.72%

ELECTRIC POWER PRICING FOR TRANSMISSION SERVICES

FIXED PRICE/MARGINAL COST BASIS

COST ACCUMULATION

Description	Marginal Cost	Wheeling Service: Wheeling Usage	Wheeling Service: Allocated Cost
Production			
Energy	$25.00/MWH	144 GWH	$ 3,600,000
Demand	$35.00/KW-YR	40 MW	1,400,000
Transmission			
Energy	$ 0.01/MWH	6,144 GWH	61,440
Demand	$18.00/KW-YR	1,040 MW	18,720,000
Total			$23,781,440

COST NORMALIZATION

Description	Marginal Cost	Wheeling Service: Wheeling Usage	Wheeling Service: Allocated Cost
Production			
Energy	$25.00/MWH	6,144 GWH	$153,600,000
Demand	$35.00/KW-YR	1,040 MW	36,400,000
Transmission			
Energy	$ 0.01/MWH	6,144 GWH	61,440
Demand	$18.00/KW-YR	1,040 MW	18,720,000
Total			$208,781,440

Transmission Cost Normalized 11.39%

ELECTRIC POWER CONTRACTING AND PRICING PROGRAM

POTENTIAL BENEFITS/ METHODS FOR IMPLEMENTING TIME OF USE RATES FOR WHOLESALE POWER TRANSACTIONS IN THE BALTIC COUNTRIES

by

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In most parts of the world, the conventional wisdom is that the cost of providing electric service is constantly changing. Most electric utilities reflect this time variation in cost in the prices that they charge other utilities for short term transactions. Indeed, many transactions in the U.S. have prices that change every hour. In England, and in some other parts of the world, the accounting for bulk transactions is done every 30 minutes.

Changing the price of bulk electricity throughout the day produces many benefits, the most important of which is the increased economic efficiency with which all participants in the bulk market are able to operate their generators. A utility with excess coal capacity can increase generation and sell the excess at a profit during some period, or can reduce generation and buy excess nuclear generation or hydro energy that would otherwise be dumped. Further, it lessens the ability of a utility to impose additional costs on its neighbors by riding the interties, of being a tie-riding freeloader. I generally define a tie-riding freeloader as a utility that takes advantage of interchange practices in ways that decrease the freeloader's cost while increasing the costs of other utilities in the network.

I present an example of how a utility can decide to optimize its own economics by taking advantage of a single interchange price. Though my example uses a price of $20/MWH, any price used for all time periods will allow a utility to freeload. I then show the effect of this freeloading on the neighboring utilities, showing how the cost for the rest of the system increases because of the freeloader.. Various pricing options are available to encourage a joint optimization, including what I call a high option and a low option. These options give all of the dispatching benefit to only one party, either the buyer or the seller. Many bulk power pricing provisions results in these benefits being shared.

The methods for time-of-use pricing can be broadly grouped as static and dynamic. Static prices for a time period are set prior to the beginning of the time period. Some people include situational pricing within the concept of static prices. Situational pricing would have different price schedules with each price schedule being

applicable to specific events, such as the outage of a major power plant. There are two basic approaches to determining static prices: embedded cost and marginal cost. Dynamic pricing could be considered the ultimate in situational pricing. Under the various forms of dynamic pricing, generation loading, line loading, and reactive power flows all influence the price to be charged for bulk electricity. Dynamic pricing is discussed in a separate paper.

For static pricing, I have constructed an example with two types of generating plants with different cost structures. For simplicity purposes, I have assumed that the relevant decision period is one 24 hour day. The low operating costs of Type 1 generation makes it optimal for loads lasting at least 15 hours, otherwise Type 2 generation is cheaper, as shown in the screening curve. The two types of generation are dispatched to meet a daily load curve in the cheapest possible manner.

For this optimal dispatch, I present four embedded cost allocation methods, resulting in a range of allocations of costs to the five groups of hours.

METHOD A - Each hour shares equally in the fixed costs of generation that operates during that hour, independent of the amount of generation during each hour.

METHOD B - Each generation type is subdivided prior to allocation to time period. Each hour share equally in the fixed cost of each subdivision operated during that hour.

METHOD C - Each hour shares equally in the fixed costs of generation that is fully loaded during that hour. As a result, hours with partially loaded generation are charged only variable cost.

METHOD D - Each hour shares equally in the fixed costs of generation that is fully loaded if lower merit generation is also operating.

The total average cost would be appropriate for determining time-of-use rates for bulk power transactions, or for retail sales. The summary presents the total costs allocated to each time period, as well as the average price that would be charged during the time period based on the allocation methods.

I then present four marginal cost allocation methods based on two assumptions of the calculation of marginal cost and two assumptions on adjusting the rates to achieve the total revenue requirement of the system.

LOW ASYMPTOTE - Marginal cost is the cost of the most expensive unit that is currently operating.

HIGH ASYMPTOTE - Marginal cost is the cost of the least expensive unit that would be available to meet additional load. For Period 5, additional load would require more fixed costs in addition to more variable cost.

ADJUST ALL - Change all rates proportionately to achieve the revenue requirement of the system.

ADJUST CONSTRAINT - Change the rate of the constrained time period (Period 5) as necessary to achieve the revenue requirement of the system-Ramsey pricing.

Each of the 8 cost allocation methods have advantages and disadvantages, with different people supporting each of the concepts.

BENEFITS OF
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

1. Producers receive revenue commensurate with cost (i.e., reduce or eliminate losses on sales transactions)

2. Buyers pay less for purchased power than the cost they can avoid (i.e., reduce or eliminate uneconomic purchases)

3. Prevent competitors from reducing their costs at your expense (i.e., stop tie-riding freeloaders)

4. Provide better basis for prices to large industrial consumers

5. Provide cost incentive for load management programs

BENEFITS OF
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

TIE-RIDING FREELOADER EXAMPLE

AVAILABLE RESOURCES

Description	Size	Cost
Self Generation Type 1	500 MW	$10/MWH
Self Generation Type 2	50 MW	$50/MWH
Interconnection Ties	200 MW	$20/MWH

TYPICAL OPERATING PATTERNS

Self Sufficiency

		Resources Used			Resource Cost			
Hour	Load	Type 1	Type 2	Ties	Type 1	Type 2	Ties	Total
1	400	400	0	0	4,000	0	0	4,000
2	550	500	50	0	5,000	2,500	0	7,500
Total	950-	900	50	0	9,000	2,500	0	11,500

Tie-Riding

		Resources Used			Resource Cost			
Hour	Load	Type 1	Type 2	Ties	Type 1	Type 2	Ties	Total
1	400	450	0	-50	4,500	0	-1,000	3,500
2	550	500	0	50	5,000	0	1,000	6,000
Total	950-	900	0	0	9,500	0	0	9,500

Profit from tie-riding 2,000

Double Tie-Riding

		Resources Used			Resource Cost			
Hour	Load	Type 1	Type 2	Ties	Type 1	Type 2	Ties	Total
1	400	500	0	-100	5,000	0	-2,000	3,000
2	550	500	0	50	5,000	0	1,000	6,000
Total	950-	1,000	0	-50	10,000	0	-1,000	9,000

Profit from tie-riding 2,500

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BENEFITS OF
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

TIE-RIDING FREELOADER EXAMPLE

RESOURCES of REMAINDER OF NET

Description	Size	Cost
Self Generation Type 1	2500 MW	$11/MWH
Self Generation Type 2	350 MW	$60/MWH
Interconnection Ties	200 MW	$20/MWH

TYPICAL OPERATING PATTERNS

Self Sufficiency

		Resources Used			Resource Cost			
Hour	Load	Type 1	Type 2	Ties	Type 1	Type 2	Ties	Total
1	2,000	2,000	0	0	22,000	0	0	22,000
2	2,600	2,500	100	0	27,500	6,000	0	33,500
Total	4,600-	4,500	100	0	49,500	6,000	0	55,500

Tie-Riding

		Resources Used			Resource Cost			
Hour	Load	Type 1	Type 2	Ties	Type 1	Type 2	Ties	Total
1	2,000	1,950	0	50	21,450	0	1,000	22,450
2	2,600	2,500	150	-50	27,500	9,000	-1,000	35,500
Total	4,600-	4,450	150	0	48,950	9,000	0	57,950

Loss due to allowing tie-riding 2,450

Double Tie-Riding

		Resources Used			Resource Cost			
Hour	Load	Type 1	Type 2	Ties	Type 1	Type 2	Ties	Total
1	2,000	1,900	0	100	20,900	0	2,000	22,900
2	2,600	2,500	150	-50	27,500	9,000	-1,000	35,500
Total	4,600-	4,400	150	50	48,400	9,000	1,000	58,400

Loss due to allowing tie-riding 2,900

BENEFITS OF
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

TIE-RIDING FREELOADER EXAMPLE

JOINT ECONOMIC DISPATCH -- LOW PRICE OPTION

Former Tie-Riding Freeloader

		Resources Used			Resource Cost			
Hour	Load	Type 1	Type 2	Ties	Type 1	Type 2	Ties	Total
1	400	500	0	-100	5,000	0	-1,000	4,000
2	550	500	50	0	5,000	2,500	0	7,500
Total	950-	1,000	50	-100	10,000	2,500	-1,000	11,500
Gain Due to Joint Economic Dispatch								0

Remainder of Net

		Resources Used			Resource Cost			
Hour	Load	Type 1	Type 2	Ties	Type 1	Type 2	Ties	Total
1	2,000	1,900	0	100	20,900	0	1,000	21,900
2	2,600	2,500	100	0	27,500	6,000	0	33,500
Total	4,600-	4,400	100	100	48,400	6,000	1,000	55,400
Gain Due to Joint Economic Dispatch								100

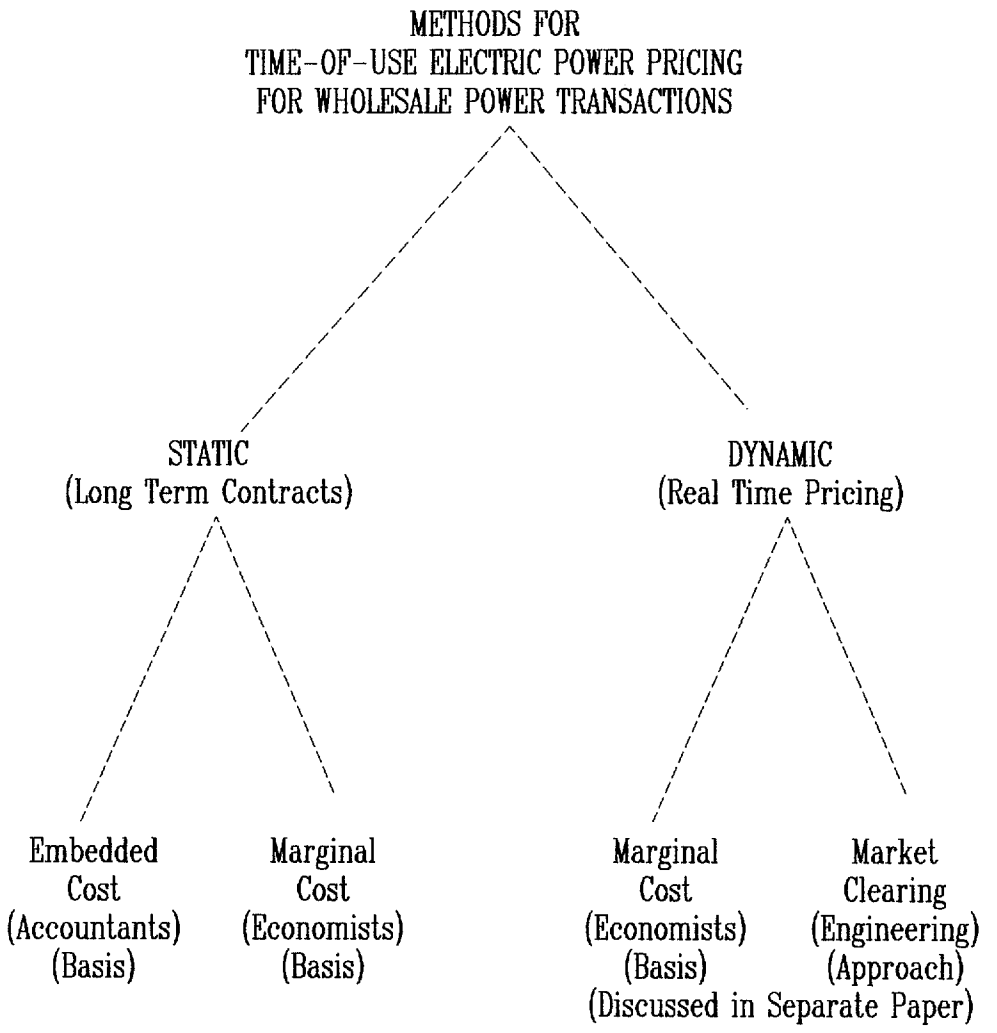
JOINT ECONOMIC DISPATCH -- HIGH PRICE OPTION

Former Tie-Riding Freeloader

		Resources Used			Resource Cost			
Hour	Load	Type 1	Type 2	Ties	Type 1	Type 2	Ties	Total
1	400	500	0	-100	5,000	0	-1,100	3,900
2	550	500	50	0	5,000	2,500	0	7,500
Total	950-	1,000	50	-100	10,000	2,500	-1,100	11,400
Gain Due to Joint Economic Dispatch								100

Remainder of Net

		Resources Used			Resource Cost			
Hour	Load	Type 1	Type 2	Ties	Type 1	Type 2	Ties	Total
1	2,000	1,900	0	100	20,900	0	1,100	22,000
2	2,600	2,500	100	0	27,500	6,000	0	33,500
Total	4,600-	4,400	100	100	48,400	6,000	1,100	55,500
Gain Due to Joint Economic Dispatch								0


METHODS FOR
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS
STATIC
(Long Term Contracts)
DYNAMIC
(Real Time Pricing)
Embedded
Cost
(Accountants)
(Basis)
Marginal
Cost
(Economists)
(Basis)
Marginal
Cost
(Economists)
(Basis)
Market
Clearing
(Engineering)
(Approach)
(Discussed in Separate Paper)

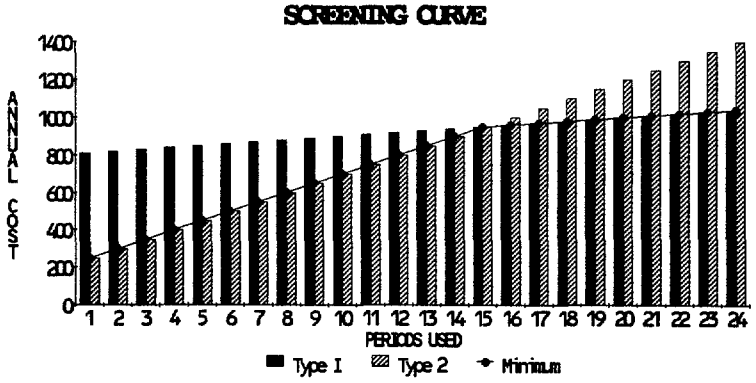
METHODS FOR
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

TECHNOLOGICAL COST ASSUMPTIONS

GENERATING OPTIONS	I	II
FIXED COST ($/MW-DAY)	800	200
VARIABLE COST ($/MWH)	10	50

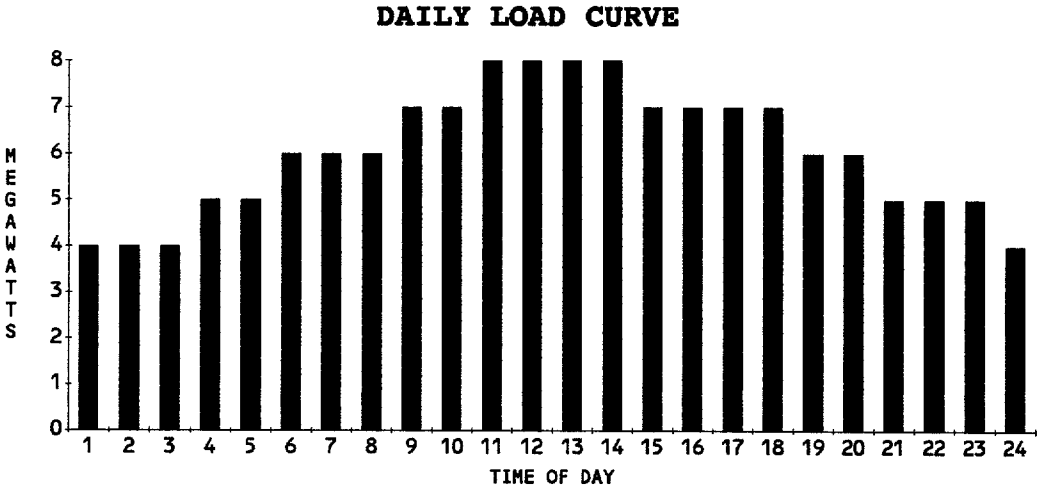
SCREENING CURVE

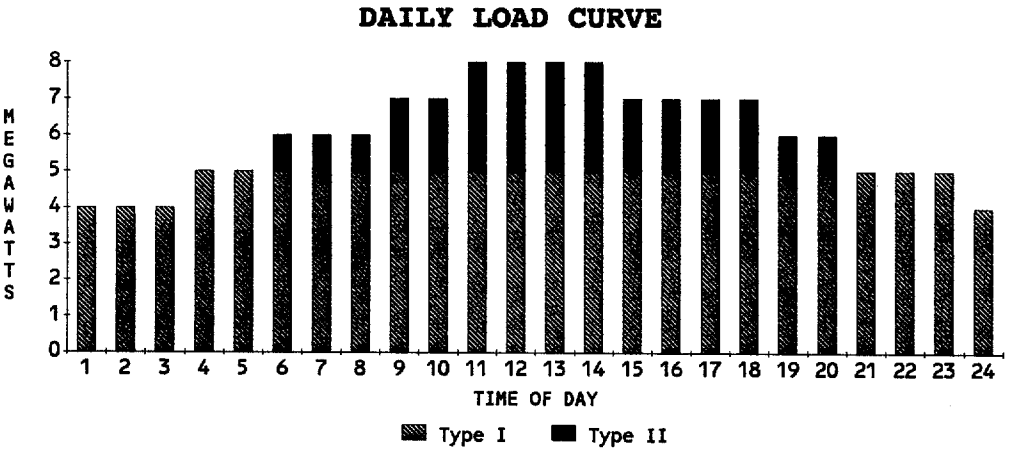
Hours Operated	Type 1 Cost	Type 2 Cost	Minimum Cost
1	810	250	250
2	820	300	300
3	830	350	350
4	840	400	400
5	850	450	450
6	860	500	500
7	870	550	550
8	880	600	600
9	890	650	650
10	900	700	700
11	910	750	750
12	920	800	800
13	930	850	850
14	940	900	900
15	950	950	950
16	960	1000	960
17	970	1050	970
18	980	1100	980
19	990	1150	990
20	1000	1200	1000
21	1010	1250	1010
22	1020	1300	1020
23	1030	1350	1030
24	1040	1400	1040



METHODS FOR
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

EMBEDDED COST ALLOCATION





METHODS FOR
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

EMBEDDED COST ALLOCATION

Type I Generation

		Generation		Method A Hours	Method B Blocked Hours Approach			Method C Fully	Method D Constrained
Period	MW	MWH	Cost	Run	Load 4	Load 5	Total	Loaded	Shadow
1	4	16	160	666.67	533.33	0.00	533.33	0.00	0.00
2	5	25	250	833.33	666.67	200.00	866.67	1000.00	0.00
3	5	25	250	833.33	666.67	200.00	866.67	1000.00	689.66
4	5	30	300	1000.00	800.00	240.00	1040.00	1200.00	1655.17
5	5	20	200	666.67	533.33	160.00	693.33	800.00	1655.17
		116	1160	4000.00	3200.00	800.00	4000.00	4000.00	4000.00

Type II Generation

		Generation		Method A Hours	Method B Blocked Hours Approach				Method C Fully	Method D Constrained
Period	MW	MWH	Cost	Run	Load 6	Load 7	Load 8	Total	Loaded	Shadow
1	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	1	5	250	50.00	16.67	0.00	0.00	16.67	0.00	0.00
4	2	12	600	60.00	20.00	30.00	0.00	50.00	0.00	0.00
5	3	12	600	40.00	13.33	20.00	50.00	83.33	150.00	150.00
		29	1450	150.00	50.00	50.00	50.00	150.00	150.00	150.00

Summary

				TOTAL ALLOCATED COSTS				AVERAGE ALLOCATED COSTS			
Period	MW	Hours	MWH	Method A	Method B	Method C	Method D	Method A	Method B	Method C	Method D
1	4	4	16	826.67	693.33	160.00	160.00	51.667	43.333	10.000	10.000
2	5	5	25	1083.33	1116.67	1250.00	250.00	43.333	44.667	50.000	10.000
3	6	5	30	1383.33	1383.33	1500.00	1189.66	46.111	46.111	50.000	39.655
4	7	6	42	1960.00	1990.00	2100.00	2555.17	46.667	47.381	50.000	60.837
5	8	4	32	1506.67	1576.67	1750.00	2605.17	47.083	49.271	54.688	81.412
		24	145	6760.00	6760.00	6760.00	6760.00	46.621	46.621	46.621	46.621

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METHODS FOR
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

MARGINAL COST ALLOCATION

Low Asymptote

Load Data				SRMC		Adjust All		Adjust Constraint	
Period	MW	Hours	MWH	Rate	Total	Rate	Total	Rate	Total
1	4	4	16	10	160.00	12.050	192.80	10.000	160.00
2	5	5	25	10	250.00	12.050	301.25	10.000	250.00
3	6	5	30	50	1500.00	60.250	1807.49	50.000	1500.00
4	7	6	42	50	2100.00	60.250	2530.48	50.000	2100.00
5	8	4	32	50	1600.00	60.250	1927.99	85.938	2750.00
					5610.00		6760.00		6760.00

High Asymptote

Load Data				SRMC		Adjust All		Adjust Constraint	
Period	MW	Hours	MWH	Rate	Total	Rate	Total	Rate	Total
1	4	4	16	10	160.00	8.930	142.88	10.000	160.00
2	5	5	25	50	1250.00	44.650	1116.25	50.000	1250.00
3	6	5	30	50	1500.00	44.650	1339.50	50.000	1500.00
4	7	6	42	50	2100.00	44.650	1875.30	50.000	2100.00
5	8	4	32	80	2560.00	71.440	2286.08	54.688	1750.00
					7570.00		6760.00		6760.00

ELECTRIC POWER CONTRACTING AND PRICING PROGRAM

DYNAMIC PRICING FOR WHOLESALE POWER TRANSACTIONS IN THE BALTIC COUNTRIES

by

MARK B. LIVELY

UTILITY ECONOMIC ENGINEER
19012 High Point Drive
Gaithersburg, Maryland 20879
U.S.A.

9/10 December 1992
Riga, Latvia

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Under contract with RCG/Hagler, Bailly, Inc.

ELECTRIC POWER CONTRACTING AND PRICING PROGRAM

DYNAMIC PRICING FOR WHOLESALE POWER TRANSACTIONS IN THE BALTIC COUNTRIES

by

MARK B. LIVELY

In most parts of the world the conventional wisdom is that the cost of electricity is constantly changing. Utilities have long reacted to this varying cost of electricity in the way each utility dispatches its generators, continually adjusting the output of one versus another to improve the utility's economics. Further improvements in economics can be achieved by dispatching one utility's generators against the generators of another utility, reducing high cost generation and increasing low cost generation. But for a utility to agree to this joint dispatch, the utility must be able to receive a benefit, either compensation for operating its units or a price less than the cost of its alternative generation. All of the possible combinations of could be combined to produce a time schedule of prices for various combinations of load and generation availability. But that is an exhausting task. A better approach is dynamic pricing.

The best known of the dynamic pricing methods is "Schweppe" pricing. Schweppe pricing involves the short run marginal cost of the optimal method of meeting each load period, nominally each hour. After the fact, the output of each generation is re-optimized based on known conditions. Short run marginal cost is then calculated based on these re-optimized generator loadings. When appropriate, additional charges, in the form of shadow prices, are assigned to those periods when generation is constrained. Finally, in some situations, all prices during the analysis period are increased or decreased to meet the revenue target for the system.

I have been advocating another dynamic pricing method known as WOLF pricing. I claim that system conditions reveal the extent of the imbalance between supply and demand. High frequency and early time clocks both reveal that supply exceeds demand. Economic theory suggests lower prices to encourage more demand and to discourage generation. The opposite occurs when frequency is low and time clocks are late. The concept can be applied instantaneously using sample prices shown in the example.

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Both pricing models use the incremental fraction of delivered power for the geographic dispersion of prices. For a given reference price anywhere on an unconstrained electric network, the price at any other place on the electric network can be calculated by the incremental fraction of delivered power. Given a reference price on the St. Petersburg border with Estonia of ABC and marginal losses of 2%, the price at the Estonia border with Latvia would be 102% of ABC, and the transmission retention rate would be 2%. Since transmission losses increase quadratically with line loading, Estonia would be paid 2% when its losses were only 1%. This retention rate would change throughout the day, all year long. Further since the incremental fraction of delivered power can be calculated as a complex value, the concept also determines a time-varying charge for reactive power.

Both dynamic pricing models recognize that transmissions lines are sometimes constrained, requiring load shedding or the "uneconomic" dispatch of some generators. Each pricing model provides a method to disconnect the prices in the disjoint regions, providing additional benefits to the owners of the transmission lines connecting the disjointed regions.

METHODS FOR
DYNAMIC PRICING
FOR WHOLESALE POWER TRANSACTIONS

1. Determine Dynamic Price

   A. Short Run Marginal Cost - "Schweppe" Pricing
      (See Caramanis, M.C, R.E. Bohn, and F.C. Schweppe, "Optimal Spot Pricing: Practice and Theory,", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-101, No. 9, (1982), pp3234-3245; and, Caramanis, M.C, R.E. Bohn, and F.C. Schweppe, "The Costs of Wheeling and Optimal Wheeling Rates", IEEE Transactions on Power Systems, Vol. PWRS-1, No. 1, February 1986, pp63-73.)

   or

   B. Market Clearing Pricing - WOLF
      (See Lively, M.B., "Tie Riding Freeloaders--The True Impediment to Transmission Access", Public Utilities Fortnightly, December 21, 1989; and, Lively, M.B., "Inadvertent Interchanges -- A New Way to Price Unscheduled Electricity", Electrical World, December 1991.

2. Determine Geographic Price Dispersion
   Use incremental fraction of delivered power (See Cohn, N., "Control of Generation and Power Flow", Standard Handbook for Electrical Engineers, Eleventh Edition, pp16-2 through 16-47, McGraw-Hill Book Company, New York; and Keith, D.A., "Marginal Cost of Electricity Supply As a Basis for Price Negotiations in Power Contracting", Proceedings of a Seminar on International Power Pricing, June 1992)

3. Dynamic Transmission Price is Differential in Geographic Prices

4. Normalized Transmission Price is Ratio of Geographic Prices

METHODS FOR
DYNAMIC PRICING
FOR WHOLESALE POWER TRANSACTIONS

SCHWEPPE PRICING

1. Utilities minimize their costs using equalized lambdas, creating global optimums.

2. Optimal re-dispatch lessens price manipulation by major players.

3. True-up to system revenue requirement keeps network whole.

METHODS FOR
DYNAMIC PRICING
FOR WHOLESALE POWER TRANSACTIONS

MARKET CLEARING PRICING

1. ENGINEERING CONTROL THEORY

2. ECONOMIC SUPPLY AND DEMAND THEORY

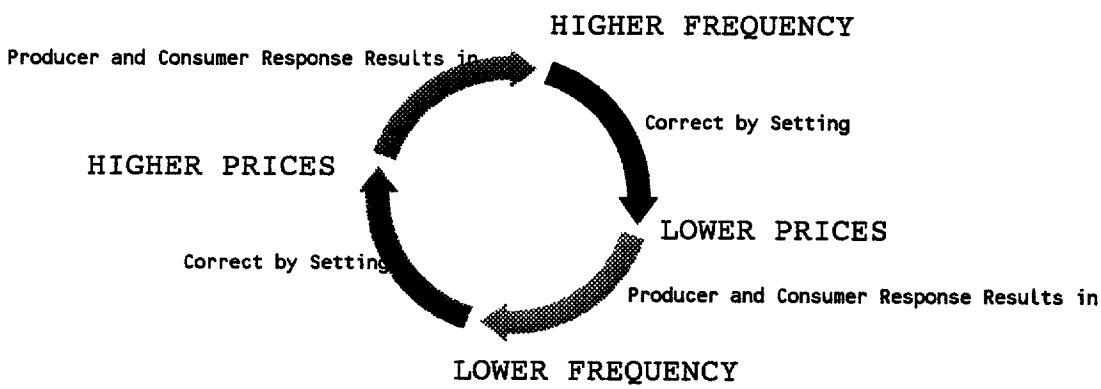
3. PRICE INCREASE - ECONOMIC THEORY PREDICTS
   A. GENERATORS INCREASE PRODUCTION
   B. USERS DECREASE DEMAND

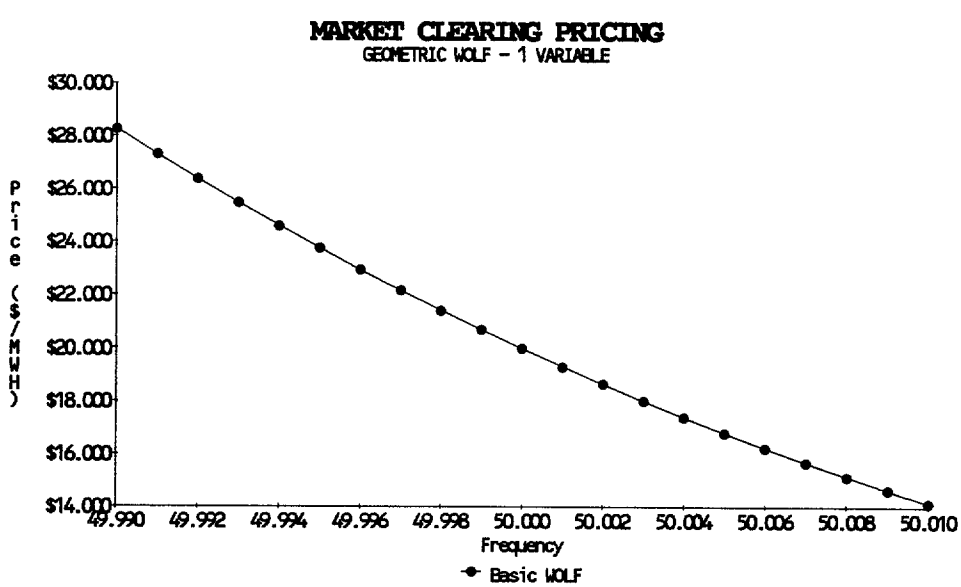
4. ELECTRICAL SYSTEM RESPONSE - MECHANICAL ENGINEERING FREQUENCY INCREASES

5. INTEGRATE ENGINEERING WITH ECONOMICS
   A. LOW FREQUENCY - INCREASE PRICES TO ENCOURAGE MORE PRODUCTION, LESS DEMAND
   B. HIGH FREQUENCY - DECREASE PRICES TO ENCOURAGE MORE DEMAND, LESS PRODUCTION
   C. LATE CLOCK - INCREASE PRICES A LITTLE TO ENCOURAGE MORE PRODUCTION AND LESS DEMAND
   D. EARLY CLOCK - DECREASE PRICES A LITTLE TO ENCOURAGE MORE DEMAND AND LESS PRODUCTION

METHODS FOR
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

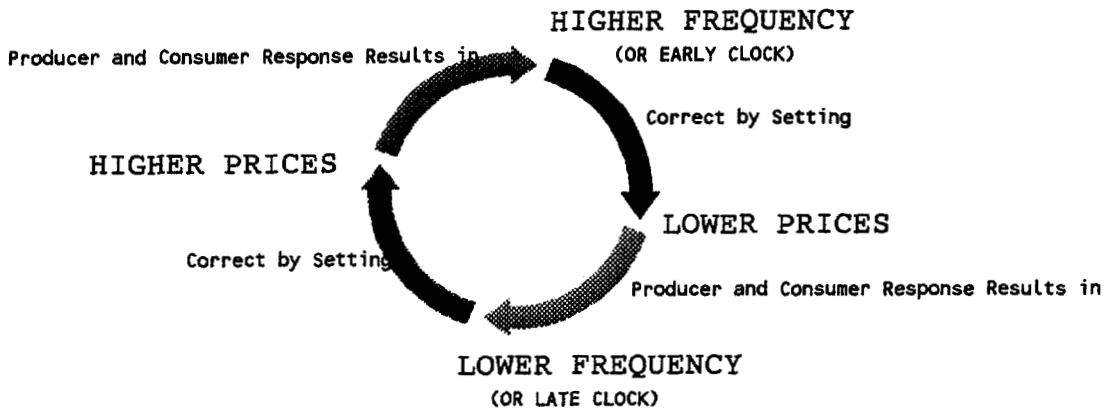
MARKET CLEARING PRICING

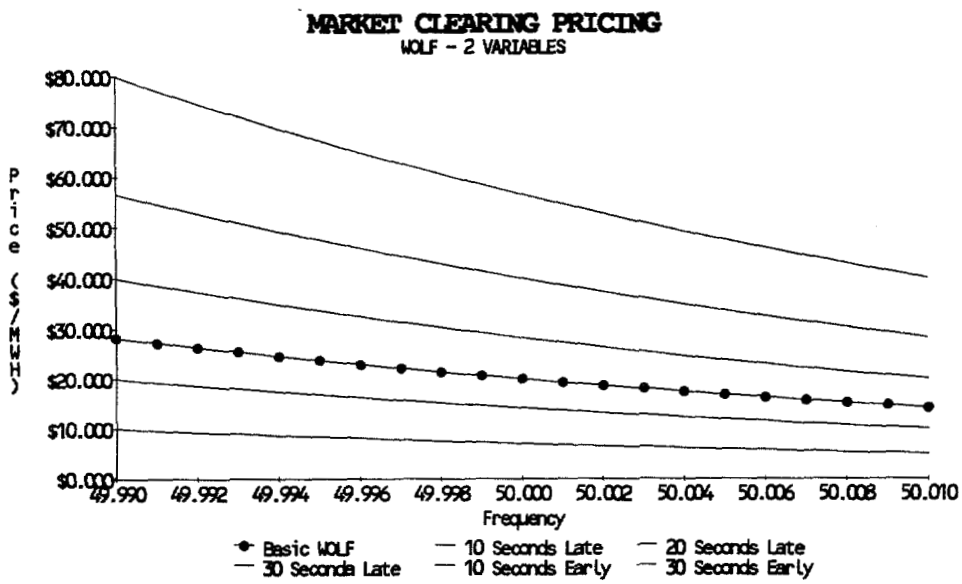




METHODS FOR
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

MARKET CLEARING PRICING





METHODS FOR
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

MARKET CLEARING PRICING

SAMPLE WOLF PRICES FOR FREQUENCY AND CUMULATIVE TIME DELAY

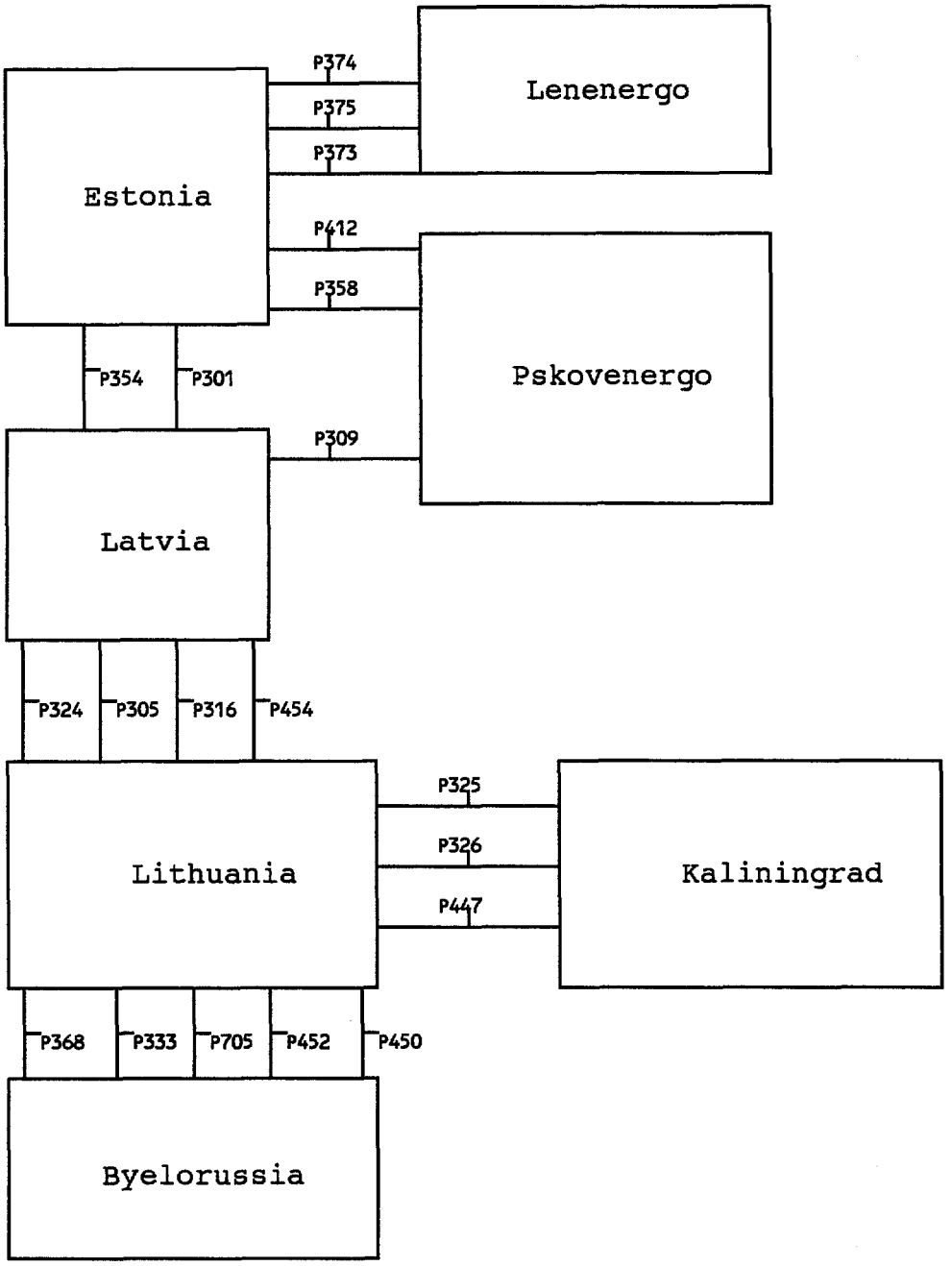
	Cumulative Time Delay in Seconds, i.e., How Late (or Early if Negative) A Synchronous Clock Is								
Frequency	0	10	20	30	40	-10	-20	-30	-40
49.990	$28.284	$40.000	$56.569	$80.000	$113.137	$20.000	$14.142	$10.000	$7.071
49.991	$27.321	$38.637	$54.642	$77.275	$109.283	$19.319	$13.660	$9.659	$6.830
49.992	$26.390	$37.321	$52.780	$74.643	$105.561	$18.661	$13.195	$9.330	$6.598
49.993	$25.491	$36.050	$50.982	$72.100	$101.965	$18.025	$12.746	$9.013	$6.373
49.994	$24.623	$34.822	$49.246	$69.644	$98.492	$17.411	$12.311	$8.706	$6.156
49.995	$23.784	$33.636	$47.568	$67.272	$95.137	$16.818	$11.892	$8.409	$5.946
49.996	$22.974	$32.490	$45.948	$64.980	$91.896	$16.245	$11.487	$8.123	$5.743
49.997	$22.191	$31.383	$44.383	$62.767	$88.766	$15.692	$11.096	$7.846	$5.548
49.998	$21.435	$30.314	$42.871	$60.629	$85.742	$15.157	$10.718	$7.579	$5.359
49.999	$20.705	$29.282	$41.411	$58.563	$82.821	$14.641	$10.353	$7.320	$5.176
50.000	$20.000	$28.284	$40.000	$56.569	$80.000	$14.142	$10.000	$7.071	$5.000
50.001	$19.319	$27.321	$38.637	$54.642	$77.275	$13.660	$9.659	$6.830	$4.830
50.002	$18.661	$26.390	$37.321	$52.780	$74.643	$13.195	$9.330	$6.598	$4.665
50.003	$18.025	$25.491	$36.050	$50.982	$72.100	$12.746	$9.013	$6.373	$4.506
50.004	$17.411	$24.623	$34.822	$49.246	$69.644	$12.311	$8.706	$6.156	$4.353
50.005	$16.818	$23.784	$33.636	$47.568	$67.272	$11.892	$8.409	$5.946	$4.204
50.006	$16.245	$22.974	$32.490	$45.948	$64.980	$11.487	$8.123	$5.743	$4.061
50.007	$15.692	$22.191	$31.383	$44.383	$62.767	$11.096	$7.846	$5.548	$3.923
50.008	$15.157	$21.435	$30.314	$42.871	$60.629	$10.718	$7.579	$5.359	$3.789
50.009	$14.641	$20.705	$29.282	$41.411	$58.563	$10.353	$7.320	$5.176	$3.660
50.010	$14.142	$20.000	$28.284	$40.000	$56.569	$10.000	$7.071	$5.000	$3.536

WOLF Half Lifes

Frequency	0.02 Hertz
Clock Error	20 Seconds

METHODS FOR
TIME-OF-USE ELECTRIC POWER PRICING
FOR WHOLESALE POWER TRANSACTIONS

Different Price for Each Time Period (5 minutes; 10 minutes; or 1 hour)
Different Price for Each Interconnection Point (p374,p375,p373, ...)



ALTERNATIVE TYPES OF CAPACITY OBLIGATIONS AND METHODS OF COMPUTING CAPACITY CHARGES

Prepared for:

Seminar on Electric Transmission Pricing,
Time of Use Rates, and Capacity Payments
December 9-10, 1992

Control Center of the Baltic Power Systems Ltd.
1 Shmerla Street
Riga 226006 Latvia

Prepared by:

Charles F. Zimmermann
RCG/Hagler, Bailly, Inc.
1530 Wilson Boulevard, Suite 900
Arlington, VA 22209-2406

Supported by:

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U.S. Agency for International Development
Washington, D.C. 20523

December 1992

OUTLINE

- The relationship between electricity prices and development planning

- Alternative types of capacity obligations among power systems in the United States

- Alternative types of capacity obligations that could be developed in the Baltics

- Alternative methods of computing capacity charges

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DEVELOPMENT PLANNING FOR U.S. POWER SYSTEMS

In the United States, development planning in the electric power sector is usually subject to the following objectives:

- The future development of the generation, transmission, and distribution system must provide the level of capacity needed to meet projected peak loads and energy requirements while achieving and maintaining standards of reliability.

- Investments designed to reduce the customers' peak load or energy requirement must be compared with investments designed to increase the capacity of the generation, transmission, and distribution system. An optimal mix of demand-side and supply-side investments should be identified.

- The expected cost of providing electric power to the consumer must be minimized, while maintaining standards of reliability.

Alternative development plans are compared, to select the best plan:

- The "least cost" plan is the one that minimizes the expected net present value of revenue requirements over the time period encompassed by the planning process (for example, over a 20-year period), while maintaining standards of reliability.

- The "best" plan may be the one that achieves a reasonably low cost (measured by the expected net present value of revenue requirements) under a variety of scenarios - for example, scenarios reflecting a variety of assumptions about oil prices and economic growth rates. The best plan may be the one under which the power system is prepared to cope with a variety of future conditions, including unfavorable conditions.

- The selection of the "best" plan may also involve a consideration of the environmental effects of power generation, transmission, distribution, and use.

THE RELATIONSHIP BETWEEN ELECTRICITY PRICES AND DEVELOPMENT PLANNING IN THE UNITED STATES

In any development plan for a U.S. power system, the projection of electricity demand must be consistent with the projection of the present value of revenue requirements. Electricity prices provide a link between these two projections.

- Electricity demand will be influenced by the level of prices (for example, the average tariff) and by the form of consumer tariffs (for example, the use of day/night tariffs or declining block rates).

- The tariffs and the demand projection may be used to project the level of customer revenue in each future year.

- Projected revenue must be equal to, or reasonably close to, projected revenue requirements in each future year. These revenue requirements will be influenced by the amount of new investment needed to meet the peak load and energy requirements specified in the electricity demand projection.

Prices achieve a balance between supply and demand.

- If the electricity price projection is too low, projected revenue will not be large enough to meet projected revenue requirements. There will not be enough money to pay for the capital investments in the development plan, so the development plan will be impossible to achieve. The reliability targets will not be met and shortages of electricity may be projected for peak periods.

- If the electricity price projection is too high, the present value of revenue requirements will not be minimized. The high level of prices will reduce electricity demand, and there will be excess generation and transmission capacity. When excess capacity exists, the average cost per kWh increases. Therefore there is a danger that high prices will lead to higher costs.

CAPACITY CHARGES AND DEVELOPMENT PLANNING

In the United States, a development plan is feasible only if the power system can obtain the necessary capital from lenders and from shareholders. To accomplish this, the power system must be able to persuade potential investors that tariffs will be high enough to pay operating expenses, interest and principal on long-term debt, and dividends to shareholders. The power system must show that it can provide a level of profit sufficient to attract capital from shareholders - that is, a level of profit sufficient to make the average shareholder want to buy more shares of stock in the company, rather than selling his stock in the company.

Regulatory approval for proposed tariffs will depend, in part, on an assessment by regulatory authorities of the effect of these tariffs on the ability of the power system to finance new capacity additions.

Capacity charges are used to recover the fixed costs of power generation and transmission, including the annual capital cost. An allowance for profit (that is, a return on equity) is part of the annual capital cost. If capacity charges are too low, there is a likelihood that profits will be too low, and therefore there is a danger that the development plan will not be feasible.

Perhaps the simplest example of the relationship between capacity charges and development planning is a project developer's attempt to obtain financing for an independent power plant. Under "project financing," the individual project - the generating unit - must have enough projected revenues to cover all expenses including a reasonable return on capital. If the developer cannot show that the capacity and energy charges will be sufficient to cover the cost of building and operating the proposed generating unit, the developer will not be able to obtain the necessary capital and the generating unit will not be built. In many instances the developer will try to negotiate capacity payments that ensure the recovery of fixed costs.

For a large power system it is desirable to negotiate capacity payments when a new capital project is developed to provide generating capacity or transmission capacity to another power system.

THE RELATIONSHIP BETWEEN ELECTRICITY PRICES AND DEVELOPMENT PLANNING IN THE BALTICS

Under the former Soviet system of planning there was almost no relationship between electricity prices and development planning.

- It was not necessary to project electricity prices before projecting peak loads and energy requirements.

- It was not necessary to calculate the level of prices needed to obtain financing for the capital projects contained in the development plan.

In the future there must be a linkage between electricity prices and development planning, but the precise form of this linkage is unclear.

- At present there is very little capital available to invest in generating stations and transmission system improvements.

- There is no regional authority coordinating the development plans of Eesti Energia, Latvenergo, and the Lithuanian State Power System.

- Equipment suppliers in Russia and other countries to the east may be less reliable than western suppliers, and may not be able to meet western standards. Western capital may be needed to finance the use of western equipment for maintenance and refurbishment.

- Foreign capital is expected but the sources of foreign capital have not all been identified. It is difficult to project the proportion of total capital from different sources (for example, private sector debt versus EBRD and IBRD loans) and therefore the overall cost of capital for power systems is not known.

ARE CAPACITY CHARGES NEEDED IN THE BALTICS TO RECOVER THE COST OF HISTORICAL INVESTMENT?

In the development of a method for calculating capacity charges for international power transactions, there are at least three alternative approaches to the issue of historical investment:

1) Exclude historical investment from the fixed costs used to compute capacity charges. Assume that the "return" on past investments in the power sector has no relationship to the ability of power systems to obtain financing for future investment. Assume that it would be fruitless to try to allocate the costs of historical investment among the three power systems.

2) Include historical investment in capital costs used to compute capacity charges, but use a methodology that ensures that the charges associated with historical investment are much lower than the charges associated with new investment. For example, include only a charge for depreciation and amortization on the basis of historical cost, without adjustment for inflation.

3) Develop a methodology to compute capacity charges on the basis of the costs that would have been incurred if the generating stations and transmission lines in the Baltics had been built in a western market economy.

Because there was almost no relationship between electricity prices and development planning in the Northwest Interconnected Power System, the first approach appears to be the most reasonable.

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ALTERNATIVE TYPES OF CAPACITY OBLIGATIONS AMONG POWER SYSTEMS IN THE UNITED STATES

Although a wide variety of capacity obligations exists, there are four basic types of obligations among power systems:

1. Sale of capacity and energy from generating units that were built to provide wholesale power to companies other than the owner(s) of the units

2. Participation in a joint venture, in which a generating unit is built to provide capacity and energy to two or more owners

3. Sale of capacity and energy from power systems with unplanned excess capacity or ability to displace higher-cost generation

4. Participation in a power pool, in which each member must meet its own capacity needs and reserve requirements

For simplicity these four categories may be called "planned sales," "joint ventures," "unplanned sales," and "power pools."

ALTERNATIVE TYPES OF CAPACITY OBLIGATIONS AMONG POWER SYSTEMS IN THE UNITED STATES

Planned sales

Sale of capacity and energy from a generating unit or units that were built to provide wholesale power to companies other than the owner(s) of the units

- Capacity charges must cover either the seller's actual annual capital costs per kW, or the level of annual capital costs per kW that was projected by the seller before the generating unit was built.

Alternative ownership arrangements:

1. The generating unit may be owned by an independent power producer (IPP) - a generation company that is in the business of building and operating power plants for the sale of wholesale power in competitive markets. The profits of IPPs are not regulated by government authorities.

2. The generating unit may be owned by a power system which routinely constructs, or plans to construct, more generating capacity than the amount required to meet the needs of retail customers. This additional capacity is planned to provide power to wholesale customers.

3. The generating unit may be owned by a government-owned power system that was created to provide hydroelectric power to other power systems. The purchasers typically include municipal systems that own distribution lines but have no generation or transmission investment. There are two large hydroelectric authorities owned by the U.S. government - Bonneville Power Authority and the Tennessee Valley Authority - and several hydroelectric authorities owned by state governments.

4. The generating unit may be owned by an industrial or commercial company which uses a portion of the steam for purposes other than power generation. This type of generating unit is called a cogeneration plant, and is roughly comparable to a combined heat and power (CHP) plant. Most cogeneration facilities in the United States are not owned by power systems and do not provide district heating.

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ALTERNATIVE TYPES OF CAPACITY OBLIGATIONS AMONG POWER SYSTEMS IN THE UNITED STATES

Joint ventures

Participation in a joint venture, in which a generating unit is built to provide capacity and energy to two or more owners

- In most cases there are no capacity charges for capacity used to serve the retail customers of the joint venture partners. Each owner pays a share of capital expenditures and fixed costs.

- If a portion of the capacity is used to sell power in wholesale markets, capacity charges will be used to recover the capital costs and other fixed costs associated with wholesale power sales.

Alternative ownership arrangements:

1. The joint venture may be created by two or more power systems, each of which will use the new generating capacity to serve retail customers. The partners choose to share the cost of a large power plant, rather than building smaller power plants independently, so that the partners can reduce generation costs per kW and costs per kWh. For example, the partners may share the cost of a nuclear power station with two or more nuclear reactors at a single site.

2. The joint venture may include power systems with a variety of needs for generating capacity. A partner may use some of all of its share of joint venture capacity to sell wholesale power to other power systems, rather than serve retail customers.

- If the joint venture includes only partners who use their joint venture capacity to sell wholesale power, the joint venture falls in the "planned sales" category. In this situation the generating unit is built to provide wholesale power to customers other than the owner of the unit, and capacity charges are used to recover capital costs.

ALTERNATIVE TYPES OF CAPACITY OBLIGATIONS AMONG POWER SYSTEMS IN THE UNITED STATES

Unplanned sales

Sale of capacity and energy from power systems with unplanned excess capacity or ability to displace higher-cost generation

- Capacity charges should equal or exceed the seller's incremental cost of providing capacity. If the seller has excess capacity, this incremental cost will be very low.

- If the seller has excess capacity, the capacity charges may be large enough to make a contribution to the seller's fixed costs, but are unlikely to cover the seller's fixed costs on a fully distributed cost basis.

- If the energy is used to displace higher-cost generation, capacity charges will be negotiated between buyer and seller. The buyer may be willing to pay a capacity charge that is higher than the seller's fully distributed cost.

Ownership arrangements

- The seller is a power system, in most cases. Independent power producers and cogenerators typically do not build capacity in excess of the amount they are contractually obligated to provide.

Situations in which unplanned sales are made:

1. If the seller's long-term projection of retail customer demand was an overestimate, the seller typically will have constructed more generating capacity than the amount required to meet the needs of its retail customers.
2. If the price of heavy fuel oil increases sharply, and the buyer has power plants designed to rely on heavy fuel oil for baseload generation, the buyer may purchase capacity and energy from power systems that have coal-fired or nuclear capacity available for additional wholesale power sales. In theory a gas price increase could have the same effect.
3. The most favorable condition for unplanned sales is one in which the seller has excess capacity, the buyer has oil-fired capacity, and the price of oil has increased sharply.

ALTERNATIVE TYPES OF CAPACITY OBLIGATIONS AMONG POWER SYSTEMS IN THE UNITED STATES

Power pools

Participation in a power pool, in which each member must meet its own capacity needs and reserve obligations

- There are no capacity charges associated with membership in the power pool, because a member is not required to use long-term contracts to meet its own capacity needs and reserve obligations. If a member chooses to purchase capacity or to participate in a joint venture to build capacity, the decision is not attributable to membership in the power pool.

- The power pool agreement should specify the prices to be paid for energy purchased to cover scheduled outages, unscheduled outages, and capacity deficiencies. These types of power purchases will involve only energy charges, because the seller does not assume a long-term obligation to provide capacity.

- In the simplest case, a power pool is formed by power systems which have the ability to operate independently but choose to join the pool to reduce their costs or increase the reliability of service to their customers.

- In a spot pricing pool there are no capacity payments, but hedging contracts may be used by sellers to stabilize their revenues.

INNOVATIVE TYPES OF CAPACITY OBLIGATIONS THAT COULD BE CREATED IN THE BALTICS

For Estonia, Latvia, and Lithuania it is possible to create new types of capacity obligations that are suited to the transition to a market economy. In international transactions among the Baltic countries the treatment of historical costs may be very different from the way historical costs are treated in the United States and other western countries.

Innovative types of capacity obligations may involve either jont ventures or power sales contracts.

Joint ventures to maintain and refurbish generating units. For a particular generating unit, the three power systems may become equity owners of a joint venture in which the generating unit is maintained and refurbished to provide capacity and energy to the owners.

- There are no capacity charges. Each owner agrees to pay a share of future capital expenditures, but historical capital expenditures are not allocated among owners.

- Each owner should agree to pay energy charges based upon variable costs, which should be easy to measure. Fuel costs will be the largest component of variable cost. To make the agreement simple it would be possible to compute the monthly energy charge as the average monthly cost of fuel per kWh, multiplied by a factor (for example, 1.04) reflecting an allowance for transmission losses.

- The owners must reach agreement on the method of dispatch of the unit and the decision-making structure for day-to-day operation. For example, day-to-day operation may be the responsibility of (1) the power system in the country where the unit is located, (2) the Baltija Dispatch Center, or (3) a committee with one representative from each equity owner.

- Historical capital expenditures may be reflected in tariffs for domestic (retail) customers of the power system in the country where the unit is located. The joint venture would not be responsible for recovering these costs.

INNOVATIVE TYPES OF CAPACITY OBLIGATIONS THAT COULD BE CREATED IN THE BALTICS

Power sales contracts without recovery of historical costs. Power systems may continue the present pattern of ownership while using contracts to establish pricing principles for power sales. In a bilateral agreement, the buyer and seller may negotiate an agreement for the sale of capacity and energy, in which historical capital expenditures are excluded from capacity payments.

- Capacity charges must cover future capital expenditures and future fixed costs, but not historical capital expenditures. Historical capital expenditures may be defined as expenditures that precede the effect date of the contract.

- Alternative ownership arrangements:

  1) Each power system continues to own 100 percent of each generating unit within its territory. Costs and revenues may be measured for the power system as a whole. The power system may raise capital by issuing long-term debt or by receiving government funds obtained by government borrowing from the IBRD or EBRD.

  2) A generating unit may be reorganized as an operating company with its own accounting records. The operating company may raise capital by issuing long-term debt or by receiving funds obtained by government borrowing. There may be an agreement that the purchasers of wholesale power have the right to audit the accounting records of the operating company.

  3) A generating unit may be reorganized as a joint venture involving the power system and one or more foreign companies providing foreign equity capital to maintain and refurbish the generating unit. (This approach is being implemented in Poland.)

  4) An entire power system may be privatized or reorganized as a joint venture with foreign equity owners. Some of the foreign capital obtained through restructuring may be used to maintain and refurbish the generating units(s) used to export power. (This approach is being implemented in the eastern provinces of Germany.)

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ISSUES INVOLVED IN INNOVATIVE CAPACITY OBLIGATIONS

To create innovative capacity obligations for the Baltics, it will be necessary for the power systems to resolve issues that are not addressed in market economies. Some of these issues are listed below.

Should maintenance costs be capitalized, if maintenance has been deferred?

> In market economies, maintenance is normally treated as a set of fixed and variable operating costs that are recovered through energy charges and are not capitalized. This approach is reasonable when generating units and transmission lines are kept in good condition through normal maintenance. In the Baltics, however, it may be necessary to make up for the lack of adequate maintenance in the past.

If maintenance costs are capitalized, over how many years should deferred maintenance be amortized?

> For any category of capital assets (equipment, buildings, transmission lines, etc.) the number of years of depreciation or amortization must not exceed the useful operating life of the capital assets. The true cost of generation and transmission should not be disguised by using 3-year or 40-year amortization periods for equipment with a shorter lifetime.

What date or guideline should be used to distinguish "historical" capital expenditures from "new" capital expenditures?

> It should not be difficult to argue that capital expenditures made prior to a country's independence should be considered "historical." If a new joint venture or a new sales contract is negotiated, some agreement must be reached regarding capital expenditures made after independence and before the effective date of the agreement. The simplest solution is to consider such expenditures "historical."

ALTERNATIVE METHODS OF COMPUTING CAPACITY CHARGES

Because a capacity charge is a payment to cover the cost of providing capacity, it is necessary for the buyer and the seller to agree upon a definition of capacity costs. The following discussion consists of two parts:

Alternative definitions of capacity costs

A: the cost of a particular type of generating capacity

B: the cost of the cheapest method of ensuring that the annual peak load can be met

C: the cost of a combustion turbine designed for peaking

Alternative methods of computing capacity charges

1) Seller's cost at specific generating stations

2) Seller's distributed cost of capacity, based upon LRMC

3) Seller's incremental capacity cost

4) LRMC (based on the cost of peaking capacity)

5) LRMC (based on the cost of the next unit)

6) Buyer's avoided capacity cost

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ALTERNATIVE DEFINITIONS OF CAPACITY COSTS

In most power systems there is a mix of generating units designed for base load, cycling, and peaking, and there is a range of investment alternatives including construction of new generating units, "life extension" of older units, and investment in demand-side management measures (to enable customers to reduce load or shift load from peak to off-peak periods). Capacity may also be purchased from other power systems. Different power systems, regulatory agencies, and experts involved in ratemaking may use different definitions of capacity cost. For example, the following alternatives exist:

A: There are different categories of capacity (at least three categories: baseload, cycling, peaking), and capacity cost can only be defined for a specific category. In a power contract the capacity charge cannot be determined until the load profile is specified or the units needed to provide the power are identified. The capital cost of peaking capacity (in $/kW/year) is usually lower than the price of baseload capacity, because it is cheaper to install a kW of combustion turbine capacity than a kW of baseload power plant capacity. The energy cost of peaking capacity (other than hydro) is usually higher than the baseload energy cost.

B: The cost of a generating unit may be divided into two components: a capacity cost and an investment designed to reduce operating costs. The capacity cost is the cost of the cheapest method of ensuring that the annual peak load can be met - either a new combustion turbine designed for peaking, an increase in hydroelectric peaking capacity, a life extension of an older thermal unit, or a voluntary demand management program. The rest of the capital cost of the generating unit is an investment designed to reduce operating costs.

An investment in generating capacity other than peaking capacity may be justified by projected savings in fuel costs per kWh. For example, it is possible to add a heat recovery steam generator to a combustion turbine to lower fuel costs.

C: The cost of a generating unit may be divided into a capacity cost and an investment designed to reduce operating costs. To simplify the calculation of capacity cost, the capacity cost may be defined as the cost per kW per year of a combustion turbine designed for peaking.

ALTERNATIVE METHODS OF COMPUTING CAPACITY CHARGES

There are many different ways to compute capacity charges. The following methods are described below:

1) Seller's cost at specific generating stations

2) Seller's distributed cost of capacity, based upon LRMC

3) Seller's incremental capacity cost

4) LRMC (based on the cost of peaking capacity)

5) LRMC (based on the cost of the next unit)

6) Buyer's avoided capacity cost

None of these methods is related to the buyer's ability to pay. In a market economy, electric tariffs are rarely raised to a level at which the customer's ability to pay is an important criterion in selecting a method of computing capacity charges.

In the United States, the buyer's avoided capacity cost is often the basis for capacity charges paid to independent generation companies.

ALTERNATIVE METHODS OF COMPUTING CAPACITY CHARGES

Seller's cost at specific generating stations

It is possible for both capacity and energy charges to be calculated on the basis of the seller's cost at specific generating stations.

Under this approach the seller identifies specific generating stations that can be used to provide firm capacity to the buyer. For each of these stations the seller calculates annual capacity costs per kW on the basis of standard operating assumptions consistent with the design of the plant. For example, the capacity charge could be based upon:

- the stations' annual capital cost per kW, assuming full load
- the station's annual capital cost per kW, based on planned capacity utilization.

If this approach is used in the Baltics, the buyer and seller may agree to exclude historical capital expenditures from the calculation of capacity charges.

This method of computing capacity charges may be preferred to the LRMC-based approaches because it is based upon actual costs incurred by the seller rather than a projection of costs that might be incurred to build generating units in the future. This method is simpler than the distributed cost method because it does not depend on information about the seller's entire power system and projected sales. If a capacity contract does not exist, this method may also be preferred to the seller's incremental cost and buyer's avoided cost approaches, which require a clear definition of the seller's obligation to provide firm capacity to the buyer.

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ALTERNATIVE METHODS OF COMPUTING CAPACITY CHARGES

Seller's distributed cost of capacity, based upon LRMC

Another method of computing capacity charges is to consider wholesale customers to be a class of customers for which prices should be based on the seller's distributed cost. Under this approach the wholesale customer's rates are calculated on the same principles as the household and industrial rates. The capacity charge for wholesale customers is computed on the same principle as the demand charge for large industrial customers.

Among the various methods of allocating capacity costs to customer classes, one alternative is to allocate capacity costs in proportion to the revenue that would be required if capacity were priced at LRMC. This approach involves four steps:

1. The seller computes a total capital carrying charge based on seller's actual cost of plant and equipment. The capital carrying charge includes costs for generation and transmission investment.

2. The seller estimates incremental capacity required to serve each customer class. Incremental capacity is the capacity that would not be needed if the customer class did not have a firm capacity requirement.

3. For each customer class, the cost of incremental capacity is computed on the basis of the LRMC of the incremental capacity required to serve that customer class. An LRMC-based revenue requirement is computed by adding up these costs.

4. The capital carrying charge in step 1 is allocated among customer classes in proportion to their shares of the LRMC-based revenue requirement computed in step 3.

ALTERNATIVE METHODS OF COMPUTING CAPACITY CHARGES

Seller's incremental capacity cost

The annual capital cost used to compute capacity charges may be defined as the incremental cost associated with the seller's obligation to provide firm capacity to the buyer. The concept of incremental and decremental cost is routinely applied to variable costs and may also be applied to fixed costs. It is more difficult to apply the concept to fixed costs, however, because it is less clear what the buyer and seller would have done in the absence of the capacity transaction.

The generating capacity that now exists in the Baltic countries was not built for the purpose of implementing contracts to sell capacity. The cost of existing capacity may be considered a "sunk cost" - a capital expenditure that has already been made. The obligation of an importer to pay for this capacity is unclear.

There are two ways to define the seller's incremental capacity cost:

1) The seller's incremental capacity cost is the annual cost per kW that the seller would have avoided if the seller had not had the obligation to provide capacity to the buyer. The seller's obligation may be to provide firm baseload, cycling, or peaking capacity, or some combination of these.

2) The seller's incremental capacity cost is the annual cost that the seller will incur as a result of signing a new contract and making a new commitment to the buyer.

ALTERNATIVE METHODS OF COMPUTING CAPACITY CHARGES

The LRMC of capacity is the projected cost per kW per year of supplying an additional kW of capacity in a particular portion of the year (for example, the peak hours during the winter season) over a period of many years, using both new and existing plant and equipment and using fuel from the sources of supply that are planned for the future.

This definition may be interpreted in different ways, depending on the approach used to measure capacity cost. The LRMC of capacity may be calculated on the basis of the cost of peaking capacity or the cost of the next generating unit to be built.

LRMC (based on the cost of peaking capacity)

Under Approach C (described above), capacity cost may be defined as the cost per kW per year of a combustion turbine designed for peaking. If this definition of capacity cost is accepted, LRMC must be calculated on the basis of the cost of peaking capacity. This is called the "peaker method" and it is the method that is most commonly used for LRMC analysis. The LRMC (in dollars per kW per year) can be estimated as the projected annual capital cost of a new combustion turbine designed for peaking operation, divided by the capacity of the unit.

Many combustion turbines in the United States are designed to use natural gas during peak periods. The cost of natural gas is typically classified as a "variable cost" although natural gas exploration, production, and transmission are capital-intensive activities with a high proportion of fixed cost. There are two possible approaches to the peaker method:

A: The annual capacity cost associated with a new peaking unit may be defined as the annual cost of the generating unit alone.

B: The annual capacity cost associated with a new peaking unit may be defined as the annual cost of the total capital investment that is (a) necessary to build and operate the unit, and (b) recovered through demand charges or other types of fixed monthly or annual payments. This total capital investment may include investment in gas pipelines, gas storage fields, petroleum product pipelines, and storage tanks for light fuel oil.

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ALTERNATIVE METHODS OF COMPUTING CAPACITY CHARGES

LRMC (based on the cost of the next unit)

One way to implement Approach A - the viewpoint that a particular kind of capacity must be identified before a capacity cost can be measured - is to estimate LRMC based on the cost of the next unit. Under this approach (the "next unit" approach) a least-cost plan is developed for either (a) the power pool or region in which the buyer and seller are located, or (b) the seller's power system alone. To achieve economic efficiency the regional approach is preferred. The capacity cost associated with the next generating unit to be constructed is used to compute the capacity charges in a wholesale power contract.

One reason for considering the "next unit" approach is that the "peaker" approach does not guarantee the seller enough revenue from capacity charges to assure repayment of the cost of a generating unit that has a higher cost per kW than the peaking unit. The "peaker" approach tends to encourage construction of combustion turbines that are expensive to operate and use fuel inefficiently. The "next unit" approach may provide the seller with enough revenue from capacity charges to assure repayment of the capital investment in the next unit or in a comparable type of unit. The "next unit" approach should make it easier for the seller to raise capital.

In a region where none of the power systems are able to build a new generating unit, or the drop in electricity demand has eliminated the need for a new generating unit, the "next unit" approach may not be practical. If the power systems are planning major investments in life extension or demand-side management, the annual capacity cost per kW associated with these investments may be used in place of the annual capacity cost per kW of a generating unit.

Other approaches to LRMC

There are other approaches to LRMC that are more difficult to implement, and are not included in the list of alternatives in this presentation. For example, the "differential revenue requirements" method involves a comparison between two long-term development plans involving two different projections of electricity demand. It is not always clear how much of the difference in revenue requirements should be allocated to capacity cost; one option is to use the cost of peaking capacity.

ALTERNATIVE METHODS OF COMPUTING CAPACITY CHARGES

Buyer's avoided capacity cost

In the United States the term "avoided cost" is commonly used in negotiations of the price of capacity and energy sold by independent power producers and cogeneration facilities. The concept of avoided cost is very similar to the concept of decremental cost. Avoided costs are projected over the economic life of a new power plant or cogeneration facility.

There are two ways to define the buyer's avoided capacity cost:

1) The buyer's avoided capacity cost is the annual cost per kW that the buyer would have incurred if the buyer had not had the obligation to purchase capacity from the seller.

2) The buyer's avoided capacity cost is the annual cost that the buyer will avoid as a result of signing a new contract and making a new commitment to purchase capacity from the seller.

The buyer's potential savings associated with a contract to purchase capacity and energy involve energy costs as well as capacity costs. However, it would be normal to expect the buyer's avoided capacity cost to be equal to or higher than the seller's incremental capacity cost. If new capacity is involved, the buyer may prefer to determine capacity and energy payments through competitive bidding, rather than basing these payments on the buyer's avoided costs.

AMERICAN ELECTRIC POWER *Service Corporation*

AEP

180 East Broad Street *(614) 223-1000*
P.O. Box 16631
Columbus, Ohio 43216-6631

October 22, 1982

The Honorable Kenneth Plumb, Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426

Dear Secretary Plumb:

Submitted for filing on behalf of Appalachian Power Company (APCO) is Modification No. 19, dated October 1, 1982, to the Interconnection Agreement, dated February 1, 1948, between APCO and Virginia Electric and Power Company (VEPCO) designated APCO Rate Schedule FERC No. 16.

Modification No. 19, captioned Service Schedule I - Oil-Displacement Capacity and Energy, provides for the sale by APCO to VEPCO of capacity and energy in the amount of 600,000 kilowatts for the period January 1, 1983, through December 31, 1984, inclusive.

Presently VEPCO is purchasing 600,000 kW of System Unit Power from APCO which will expire on December 31, 1982. Service Schedule I is intended to replace that service and will permit VEPCO greater flexibility in purchasing capacity and energy than provided for in Service Schedule H.

The energy deliveries contemplated by this Agreement are to be made in two parts designated Parts 1 and 2. Part 1 energy is a fixed-energy take, on a take-or-pay basis, of 150 MWh per hour during on-peak periods and of 75 MWh per hour during off-peak periods. The price of Part 1 energy will be based on the fuel costs, adjusted for losses, of the AEP System's Tanners Creek Units 1, 2 and 3. Part 2 energy is an additional optional energy-take from 0 to 450 MWh per hour. Its price will be based on the fuel costs, adjusted for losses, of the AEP System's Gavin Units 1 and 2 and Amos Unit 3.

As negotiated by the parties, the proposed demand charge for capacity will be at a rate of $2,812,500 per month for the years of 1983 and 1984. A statement of the cost computations which underlie this level of demand charge is attached as Exhibits I and II.

An estimate of the revenue to the AEP parties for capacity and energy delivered to VEPCO during the 12 months immediately following the month in which this sale will commence is included in Exhibit III.

This Agreement is beneficial to all parties and their customers and is in the public interest. Therefore, the parties respectfully request the Commission to waive any requirements not already complied with under its Rules and Regulations in connection with this filing and permit this Agreement to become effective January 1, 1983.

There is enclosed a check payable to the order of the Federal Energy Regulatory Commission in the amount of $500 representing the filing fee pursuant to Section 36.2(f) of the Commission's Regulations. Also attached is a proposed form of Notice suitable for publication in the Federal Register.

No facilities will be installed or modified in order to supply this service and no similar service is provided to any other customer.

Correspondence relating to this filing should be addressed to:

M. B. McNulty - Assistant Vice President
American Electric Power Service Corporation
180 East Broad Street
Columbus, Ohio 43215

Edward J. Brady, Esquire
American Electric Power Service Corporation
180 East Broad Street
Columbus, Ohio 43215

J. W. Vaughan - President and Chief Operating Officer
Appalachian Power Company
40 Franklin Road
Roanoke, VA 24009

Mr. J. I. Oatts - Vice President
Virginia Electric and Power Company
P. O. Box 1194
Richmond, VA 23209

A copy of this filing has been sent to:

Mr. S. G. Smith - Secretary
Public Service Commission of West Virginia
State Capitol Building - East Wing
Charleston, W. VA 25305

Mr. W. Young - Chief Clerk
Virginia State Corporation Commission
Box 1197
Richmond, VA 23209

Very truly yours,

M. B. McNulty
Assistant Vice President
Interconnection Agreement Division

VEPCO2pc:5

Attachments

cc: J. G. Howard (American Electric Power Service Corp.)
Senior Vice President - Rate Department

C. F. DeSieno (Amercian Electric Power Service Corp.)
Vice President - Interconnections and Special Contracts

6C

Proposed Monthly Capacity Demand Charge to VEPCO
For Oil-Displacement Capacity and Energy

Energy	Part 1	Part 2	Total
Amount	150,000kW	450,000KW	600,000kW
Demand Cost ($/kw-month)	-0-	6.25[1]	N/A
Charge	-0-	$2,812,500	$2,812,500

[1] From Exhibit I page 2 of 2

CAPACITY DEMAND COSTS
BASED ON 1981 FPC-1

		GAVIN 1 & 2	AMOS3[a]	AMOS3[b]	SOURCE/ 1981 FPC-1
1.	Plant Rating (MW)	2600	867	433	p403 L9
2.	Generating Plant ($)	614,570,763	197,827,635	94,448,297	p403 L17
3.	Generation Plant ($/kW)	236.37	228.17	218.13	(2)/(1)
4.	Carrying Charge (%) - 15% ROE	18.37	18.37	18.92	Exhibit II
5.	Monthly Invest. ($/KW-month)	3.62	3.49	3.44	(3)x(4)/12
6.	Production Cost ($)	248,749,471	73,618,789	48,735,688	p403 L34
7.	Maintenance Cost ($)	11,735,703	4,051,554	2,025,777	p403 L(29-33)
8.	1/2 Maintenance Cost ($)	5,867,851	2,025,777	1,012,888	(7)/2
9.	Fuel Cost ($)	230,516,810	67,541,692	45,696,478	p432 L21
10.	Fixed Production ($)	12,364,810	4,051,320	2,026,322	(6)-(8)-(9)
11.	Fixed Production ($/KW-month)	.40	.39	.39	(10)/(1)/12
12.	Avg. Fuel Inventory ($) 75 days burn	47,366,468	13,878,430	9,389,687	(9)x75/365
13.	Carrying Charge (%)	15.06	15.06	15.62	Exhibit II
14.	Plant Rating (MW)	2600	867	433	P403 L9
15.	Fuel Inventory Cost ($/KW-month)	.23	.20	.28	(12)x(13)/(14)x12
16.	Transmission Plant ($)	655,556,374	655,557,374	612,688,173	P203 L53
17.	MLR Demand (MW)	4942	4942	4740	p328
18.	Transmission Plant ($/KW-month)	2.03	2.03	2.04	(16)x(4)/(17)x12
19.	Transmission O&M ($)	18,472,811	18,472,811	13,235,184	p321 L99
20.	Transmission O&M ($/KW-month)	.31	.31	.23	(19)/(17)x12
21.	Demand Cost	6.59	6.42	6.38	(5)+(11)+(15)+(18) +(20)
22.	Weighted Average Demand Cost		$6.53/kW-month		
23.	Proposed Demand Charge		$6.25/kW-month		

a. Ohio Power's Share
b. Appalachian Power's Share - Supplementary Source: Internal Accounting for lines 1,2,6,7,9,12, and 1
MUNIS1pc.2

APPROPRIATE ANNUAL CARRYING CHARGES BASED UPON TWELVE MONTHS ENDING DECEMBER 31, 1981

	COMPONENT	A	O	For Materials & Supplies A	For Materials & Supplies O
1)	COST OF MONEY	11.377	11.189	11.377	11.189
2)	DEPRECIATION	1.301	1.308	--	--
3)	FEDERAL INCOME TAX	4.242	3.871	4.242	3.871
4)	OTHER	2.000	2.000	--	--
	TOTAL	18.920	18.368	15.619	15.060

1) See page 2, 3.

2) Sinking fund factor with provision for R_1 dispersion 33-year life ($i^{B}d$)

3) $T\% = T/1-t\ (i + i^{B}d - o^{d})\ (1 - Bb/i)\ (.9)$

Where t = corporate tax rate (46%) B = Capitalization ratio debt
i_d = cost of money b = Debt rate
o^d = straight line depreciation, 33-year life
.9 = provision for accelerated depreciation

4) Includes Insurance, General Administration and taxes other than Federal, gross receipts, sales or use taxes

The components listed above are of necessity approximations and it is not intended to indicate that some components will or should be fixed at all times or at any given figure, i.e., particular components may vary from time to time. Rates for Service are negotiated at arms-length and the carrying charges as specified herein and the cost of money utilized is acceptable only as to these transactions.

A - Appalachian Power Company O - Ohio Power Company

MAWpc.4

CARRYING CHARGE DEVELOPMENT*

I. Appalachian Power Company (A)
Calculation of Capitalization Ratio

	$000's
Debt	1,203,859
Preferred Stock	211,820
Common Equity	832,179
Total	2,247,858

a) Debt Ratio $\frac{1,203,859}{2,247,858} = 53.56$

b) Preferred Ratio $\frac{211,820}{2,247,858} = 9.42$

c) Common Equity $\frac{832,179}{2,247,858} = 37.02$

Cost of Money

	13.5% R.O.E. Embedded				15% R.O.E. Embedded			
Equity	37.02%	@ 13.50%	=	5.00%	37.02%	@ 15.00%	=	5.55%
Preferred	9.42%	@ 10.31%[1]	=	.97%	7.42%	@ 10.31%[1]	=	.97%
Debt	53.56%	@ 9.06%[2]	=	4.85%	53.56%	@ 9.06%[2]	=	4.85%
Total	100.00%			10.82%	100.00			11.37%

1) Preferred Rate = $\frac{\text{Annualized Dividends}}{\text{Preferred Outstanding}} = \frac{21,842}{211,820} = 10.31\%$

2) Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}} = \frac{109,054}{1,203,859} = 9.06\%$

*Based upon capitalization data in financial reporting for twelve months ending 12/31/81.

M.A.W.
APC01pc.6
8-24-82

CARRYING CHARGE DEVELOPMENT*

I. Ohio Power Company (O)
Calculation of Capitalization Ratio

	$000's
Debt	1,544,708
Preferred Stock	305,240
Common Equity	930,924
Total	2,780,872

a) Debt Ratio $\frac{1,544,708}{2,780,872}$ = 55.55

b) Preferred Ratio $\frac{305,240}{2,780,872}$ = 10.98

c) Common Equity $\frac{930,924}{2,780,872}$ = 33.48

Cost of Money

	13.5% R.O.E. Embedded			15% R.O.E. Embedded		
Equity	33.48%	@ 13.50%	= 4.52%	33.48%	@ 15.00%	= 5.02%
Preferred	10.98	@ 8.62%[1]	= 0.95%	10.98%	@ 8.62%[1]	= 0.95%
Debt	55.55%	@ 9.40%[2]	= 5.22%	55.55%	@ 9.40%[2]	= 5.22%
Total	100.00%		10.69%	100.00%		11.19%

1) Preferred Rate = $\frac{\text{Annualized Dividends}}{\text{Preferred Outstanding}} = \frac{26,301}{305,240}$ = 8.62%

2) Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}} = \frac{145,278}{1,544,708}$ = 9.40%

*Based upon capitalization data in financial reporting for twelve months ending 12/31/81.

M.A.W.
OPC01pc.1
8-24-82

Exhibit III

Oil-Displacement Capacity and Energy
Estimated Monthly Revenues
For 12 Months Ended December 31, 1983

MONTH	ESTIMATED MWH (1)	DEMAND CHARGE (2)	ENERGY CHARGE (3)	TOTAL ESTIMATED REVENUE (4)
January 1983	332,800	$ 2,812,500	$ 8,878,500	$ 11,691,000
February "	345,000	2,812,500	9,182,500	11,995,000
March "	341,500	2,812,500	9,140,500	11,953,000
April "	273,300	2,812,500	7,389,500	10,202,000
May "	301,300	2,812,500	8,109,500	10,922,000
June "	336,400	2,812,500	9,000,500	11,813,000
July "	363,100	2,812,500	9,696,500	12,509,000
August "	342,800	2,812,500	9,142,500	11,955,000
September "	319,300	2,812,500	8,496,500	11,309,000
October "	327,000	2,812,500	8,697,500	11,510,000
November "	336,200	2,812,500	8,940,500	11,753,000
December "	363,900	2,812,500	9,630,500	12,443,000
TOTAL	3,982,600	$33,750,000	$106,305,000	$140,055,000

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company) Docket No.

NOTICE OF FILING

The filing Company submits the following:

Take notice that American Electric Power Service Corporation (AEP) on behalf of its affiliate, Appalachian Power Company (APCO) tendered for filing on
Modification No. 19 to the Interconnection Agreement between APCO and Virginia Electric and Power Company (VEPCO). This Modification provides for the sale by APCO to VEPCO of 600 MW of Oil-Displacement Capacity and Energy from January 1, 1983 to December 31, 1984.

The demand charge for said service will be $2,812,500 per month.

Applicant has requested the Commission to accept the Modification for filing on or before January 1, 1983 as it intends to begin the sale of Oil-Displacement Capacity and Energy to VEPCO as of that date.

Any person desiring to be heard or to protest said application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 N. Capitol Street, Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's Rules and Practice and Procedure on or before
Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,
Secretary

Modification No. 19

to

Interconnection Agreement

Dated February 1, 1948

between

APPALACHIAN POWER COMPANY

and

VIRGINIA ELECTRIC AND POWER COMPANY

Dated: October 1, 1982

THIS AGREEMENT, made and entered into as of the 1st day of October, 1982, between Appalachian Power Company (APCO) a Virginia corporation, and Virginia Electric and Power Company (VEPCO) also a Virginia corporation.

W I T N E S S E T H:

WHEREAS, APCO and VEPCO entered into an Interconnection Agreement, dated February 1, 1948 and several Modifications thereto (said Interconnection Agreement, as so modified, being herein called the 1948 Agreement); and

WHEREAS, APCO has evaluated its forecasted load, capacity requirements and fuel costs and has determined that electric power will be available in the near future from its coal-fired generating plants; and

WHEREAS, VEPCO wishes to displace higher cost electric energy which includes energy from oil-fired generating plants; and

WHEREAS, the parties desire to promote economical electric power supply and efficient utilization of their production capacity; and

WHEREAS, VEPCO's present purchase of capacity and energy under Service Schedule H - System Unit Power terminates December 31, 1982; and

WHEREAS, the parties, having evaluated their future load and capacity requirements, have determined that the purchase of capacity and associated energy by VEPCO from APCO is beneficial to both parties; and

WHEREAS, the parties desire to further modify the 1948 Agreement, as hereinafter set forth;

NOW, THEREFORE, THE PARTIES AGREE AS FOLLOWS:

Section 1. Section 4.3 of Article 4 of the 1948 Agreement is hereby modified to read:

"4.3 The following Service Schedules are agreed to and hereby made parts of this Agreement:

Service Schedule A - Energy Transfer
Service Schedule B - Emergency Service
Service Schedule C - Short Term Power
Service Schedule D - Interchange Power
Service Schedule E - Unit Power to Virginia Company
Service Schedule F - Limited Term Power
Service Schedule G - Fuel Conservation
Service Schedule H - System Unit Power

Service Schedule I - Oil-Displacement
Capacity and Energy"

Service Schedule I is attached hereto as Appendix I and is made a part of the 1948 Agreement and shall be effective as of January 1, 1983.

Section 2. Except as hereinabove modified and amended, all the terms and conditions of the 1948 Agreement shall remain in full force and effect.

Section 3. This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their duly authorized officers.

APPALACHIAN POWER COMPANY

By _____

VIRGINIA ELECTRIC AND POWER COMPANY

By _____

Vepco

VIRGINIA ELECTRIC AND POWER COMPANY RICHMOND, VIRGINIA 23261

October 12, 1982

Mr. M. B. McNulty
Assistant Vice President
Interconnection Agreements Division
American Electric Power Service Corporation
180 East Broad Street
Columbus, OH 43215

Dear Brian:

Enclosed are four (4) executed copies of Modification No. 19 as discussed during our telephone conversation on October 12. As indicated during our discussion, we have signed the Modification with the understanding that Section 2.21 of Service Schedule I will be changed to read "...beginning at 11 PM on Monday and ending 7 AM on Saturday..." Also as discussed with you and Dave Wright, the references to weekly scheduling of Part 2 energy will be changed to daily scheduling. We also understand that the present flexibility of scheduling permitted in the unit power transactions will be retained under the application of Service Schedule I.

If you have any questions, please call.

Very truly yours,

Larry W. Ellis

Larry W. Ellis
Manager - Power Supply

/Pat

Attachments

APPENDIX I

SERVICE SCHEDULE I
OIL-DISPLACEMENT CAPACITY AND ENERGY

Under Agreement dated February 1, 1948

between

Appalachian Power Company

and

Virginia Electric and Power Company

SECTION 1 - DURATION

1.1 This Service Schedule, a part of and under the Interconnection Agreement dated as of the 1st day of February, 1948 between Appalachian Power Company (APCO), a member of the American Electric Power System (AEP System), and Virginia Electric and Power Company (VEPCO), shall become effective on January 1, 1983 and shall continue in effect until December 31, 1984 unless extended by written mutual agreement.

SECTION 2 - SERVICES TO BE RENDERED

2.1 Throughout the duration of this Service Schedule, APCO shall stand ready, subject to the provisions contained herein, to deliver to VEPCO oil-displacement capacity (Capacity) and associated energy (Energy) in any amount as described in subsection 2.2.

2.2 The deliveries of Energy shall be designated as Part 1 Energy and Part 2 Energy, each part subject to the terms set forth below.

2.21 Part 1 Energy is a fixed-energy take, for each week during the term of this Service Schedule, on a take-or-pay basis, of 150 MWH per hour during the 5 weekly 16-hour periods, from 7 AM to 11 PM Monday through Friday with the exception of national holidays which occur on Monday or Friday, and 75 MWH per hour during the 5 weekly 8-hour periods, from 11 PM to 7 AM, beginning at 11 PM on Monday and ending 7 AM on Saturday, plus all hours of national holidays which occur on Monday or Friday.

2.22 Part 2 Energy is an optional energy take, from 0 to 450 MWH per hour anytime, that shall be scheduled daily by VEPCO.

2.3 If uncontrollable forces such as civil or labor disturbances, strike, restraint by court or public authority or

other similar forces or events cause the coal supply on the AEP System as determined by AEP to fall below 50 days anticipated burn then APCO reserves the right to reduce the amount of Capacity and Energy being made available under this Service Schedule by one-half until the coal supply reaches 50 or more days, and if such coal supply falls as determined by AEP below 40 days anticipated burn, APCO reserves the right to make no power available under this Service Schedule until the coal supply again reaches 40 or more days. In the event of such reductions in availability of power, the charges in subsections 3.11 and 3.21 of this Service Schedule shall be prorated accordingly.

2.4 APCO shall cause its units to be operated and maintained in a manner consistent with safe, prudent and efficient operating practice.

2.5 The number of kilowatt-hours of Energy to be delivered to VEPCO and the time of delivery thereof, subject to the conditions of delivery provided for in this Service Schedule, shall be scheduled in advance for each hour, on a daily basis by VEPCO. The number of kilowatt-hours of such Energy so scheduled during each clock hour shall be recorded as provided for in Article 7 of the 1948 Agreement. The aggregate number of kilowatt-hours of Energy so recorded for any month shall be used for the purpose of effecting billings and payments under this Service Schedule for such month. Each of the parties shall exercise due diligence and reasonable care and foresight in arranging for and in operating their respective power sources so that amounts of Energy shall be delivered and taken in accordance with such delivery schedules.

SECTION 3 - COMPENSATION

3.1 Payments for the supply of Capacity under this Service Schedule shall be made each month by VEPCO to APCO and shall be at the following rate:

3.11 A monthly demand charge of $2,812,500.

3.2 Payments for Energy supplied under this Service Schedule shall be made each month by VEPCO to APCO and shall be according to the following rates:

3.21 For Part 1 Energy the rate per kilowatthour shall be 1 mill, plus the average monthly unit cost of fuel, expressed in mills per kWH, consumed at the AEP System's Tanners Creek Units 1, 2, and 3 during the billing month, adjusted for transmission losses.

3.22 For Part 2 Energy the rate per kilowatthour shall be 1 mill, plus the

average monthly unit cost of fuel, expressed in mills per kWH, consumed at AEP System's Amos Unit No. 3 and Gavin Units Nos. 1 and 2, during the billing month, adjusted for transmission losses.

3.3 The amount of Part 2 Energy to be priced at the rate specified in subsection 3.22 shall be limited to a pro rata portion of 450 MWH per hour, pro-rated in proportion to the aggregate actual capacity available in any such hour from the units specified compared to the aggregate initial rated capacity of such units, which is 3900 MW. During any period when all or portions of the units specified in subsection 3.22 are unavailable, any Energy scheduled in excess of the energy furnished on the pro rata basis above described shall be supplied from other sources, and the rate for such energy per kilowatthour shall be 1 mill plus the greater of: (a) the average monthly unit cost of fuel consumed at the specified units during the billing month, adjusted for transmission losses; or (b) the actual out-of-pocket cost of the energy supplied from such other sources.

3.4 The average monthly unit cost of fuel consumed by the units upon which energy charges are predicated, adjusted for transmission losses, referred to above, is defined as the product of (1) the total cost of fuel consumed at those units during the month, divided by the corresponding net kilowatthours generated at such units during the month and (2) 1.02 to adjust for transmission losses.

3.5 Costs associated with this Service Schedule shall be determined according to generally accepted accounting principles in the industry. Any fees, taxes or surcharges imposed by any regulatory or governmental agencies on any Capacity and Energy supplied by APCO to VEPCO shall be added to the charges for service under this Service Schedule.

SECTION 4 - BILLINGS AND PAYMENTS

4.1 Billing and payments for the purposes of effecting settlements under this Service Schedule shall be made in accordance with and subject to the terms and conditions of Article 8 of the 1948 Agreement.