Seams Issues Matrix

Description of Seam Issue	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Comments
Non Standard Time Zone	All	All	All	Market Rule / Business Practice	No	John Doe, Company 1	No	The lack of a standard Time Zone causes Market Inefficiencies
MaxGen/MaxLoad 345Kv	Other	ECAR	ECAR	Physical	No	John Doe, Company 1	Yes	Undersized Transmission Line
Compensation for Unscheduled Flows of Electricity	All	All	All	Market Rule / Business Practice and Physical	Yes/IIPTF	Mark Lively	Yes	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.
Compensation for Inadvertent Interchange	All	All	All	Market Rule / Business Practice and Physical	Yes/IIPTF	Mark Lively	Yes	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.
Compensation for Loop Flow	All	All	All	Market Rule / Business Practice and Physical	Yes/IIPTF	Mark Lively	Yes	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.
Compensation for Reactive Power	All	All	All	Market Rule / Business Practice and Physical	Yes/IIPTF	Mark Lively	Yes	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.

#	Reference Paper or Supporting Document Provided
2	Reference Work Paper on Undersized Transmission Lines
3	“Profit-Enhancing Seam Management: A White Paper on Pricing The Unscheduled Flows of Electricity Across the Seams Between Utilities Using A Geographically Differentiated Auction of Inadvertent Interchange”, released 2001 March 25.
3	"WOLF: Wide Open Load Following," A presentation to the NERC Market Interface Committee, 2002 September 4-5, Houston, Texas
3	E-Mail by Mark Lively to NAESB WEQ Seams Subcommittee of 9/4/2003 8:28:10 PM Eastern Standard Time

WOLF
Wide Open Load Following

Mark B. Lively
Utility Economic Engineer
Gaithersburg, Maryland
301-428-3618
MbeLively@aol.com
www.LivelyUtility.com

NERC Market Interface Committee
2002 September 4-5
Houston, Texas

Mark B. Lively

- Utility Economic Engineers (1992 to date)
- Ernst & Ernst (1976-1991)
- AEP (1971-1976)
- Kentucky Power (1969)
- MIT
  - S.B. EE 1969
  - S.M. Mgt 1971
- Sigma Xi
- IEEE
  - Power Engineering Society
  - Reliability Society
  - USA Energy Policy Committee
- Professional Engineer

WOLF

Wide Open Load Following

A Location Marginal Pricing Mechanism for Unscheduled Flows of Electricity

- Inadvertent interchange
- Loop flow
- Reactive power
- Unified basis

WOLF

- Sets universal price
- Geographical differentiates
- Prices reactive power

WOLF

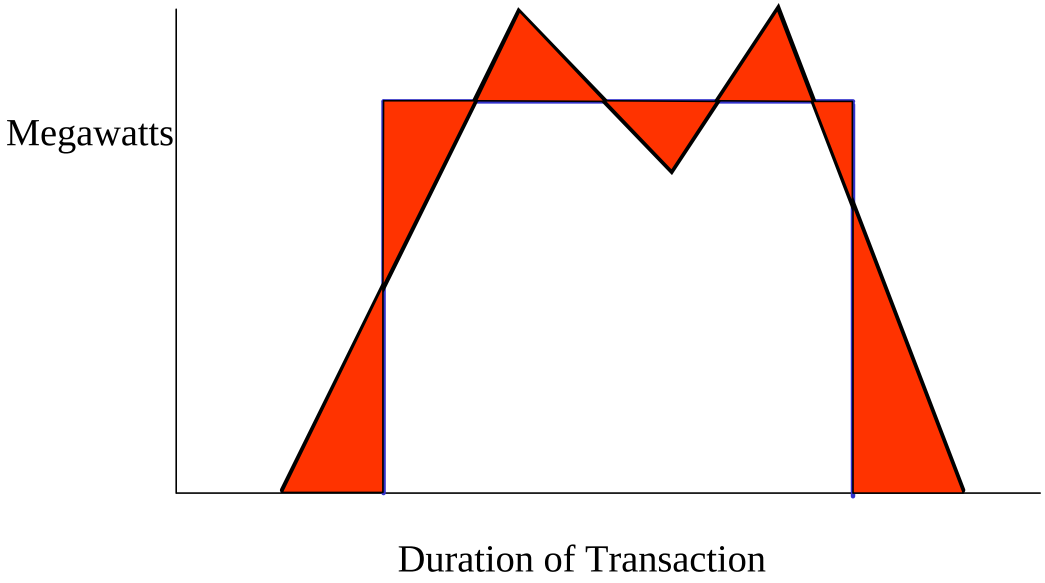
- Sets universal price
  - Frequency (ACE), time error, cumulative time error
- Geographical Differentiates
  - Marginal line losses, constraints
- Prices reactive power
  - Voltage, active power price

System Dispatch

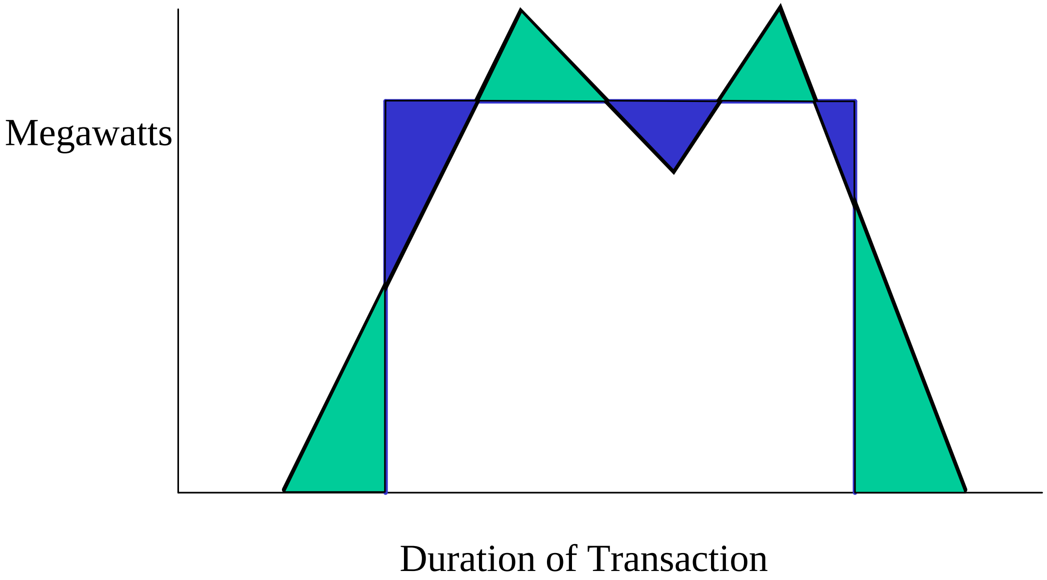
Command and Control With INCs and DECs

- Generation reliability
  - All INCs or All DECs
- Transmission reliability
  - Mix of INCs and DECs
  - Reactive power
- Economics
  - Mix of INCs and DECs
  - Reactive Power

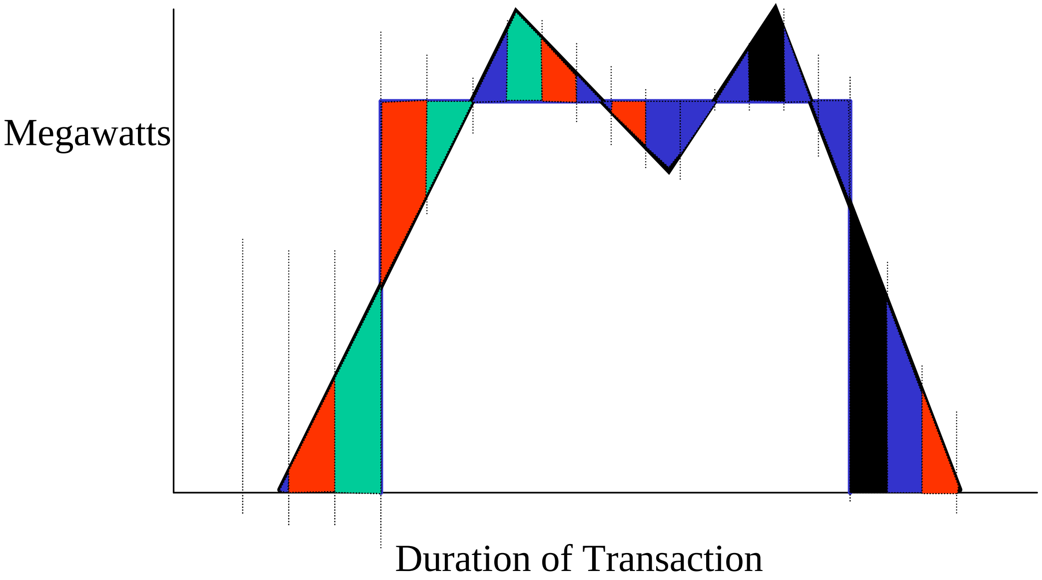
Delivering Active Power



Delivering Active Power

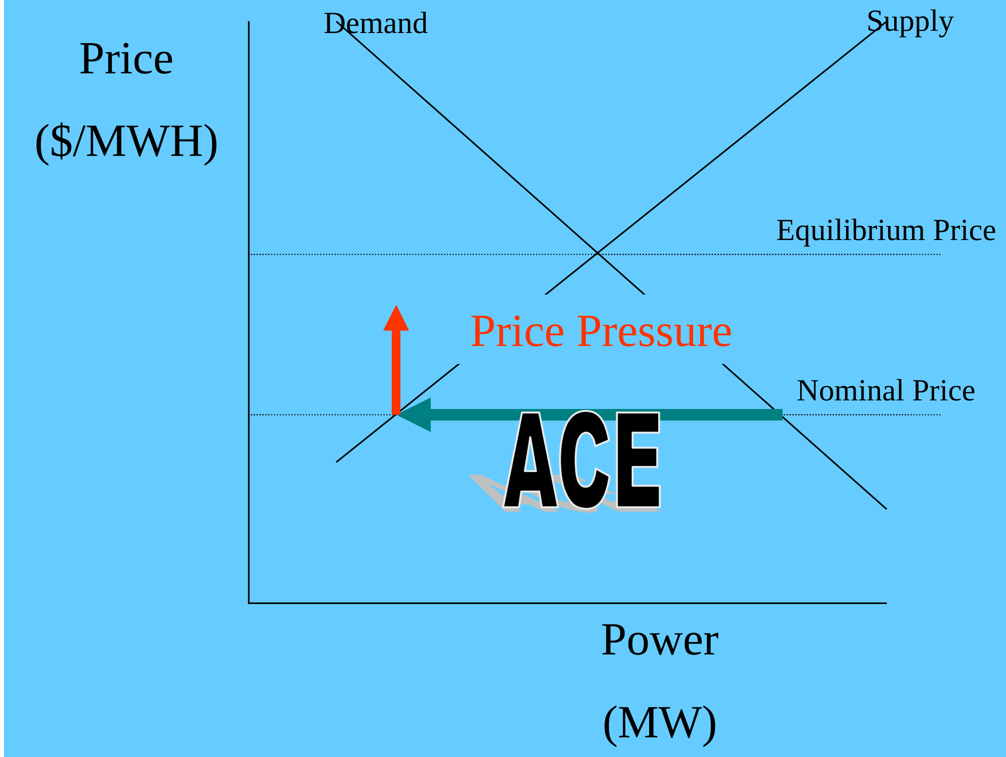


Delivering Active Power



Economic Theory

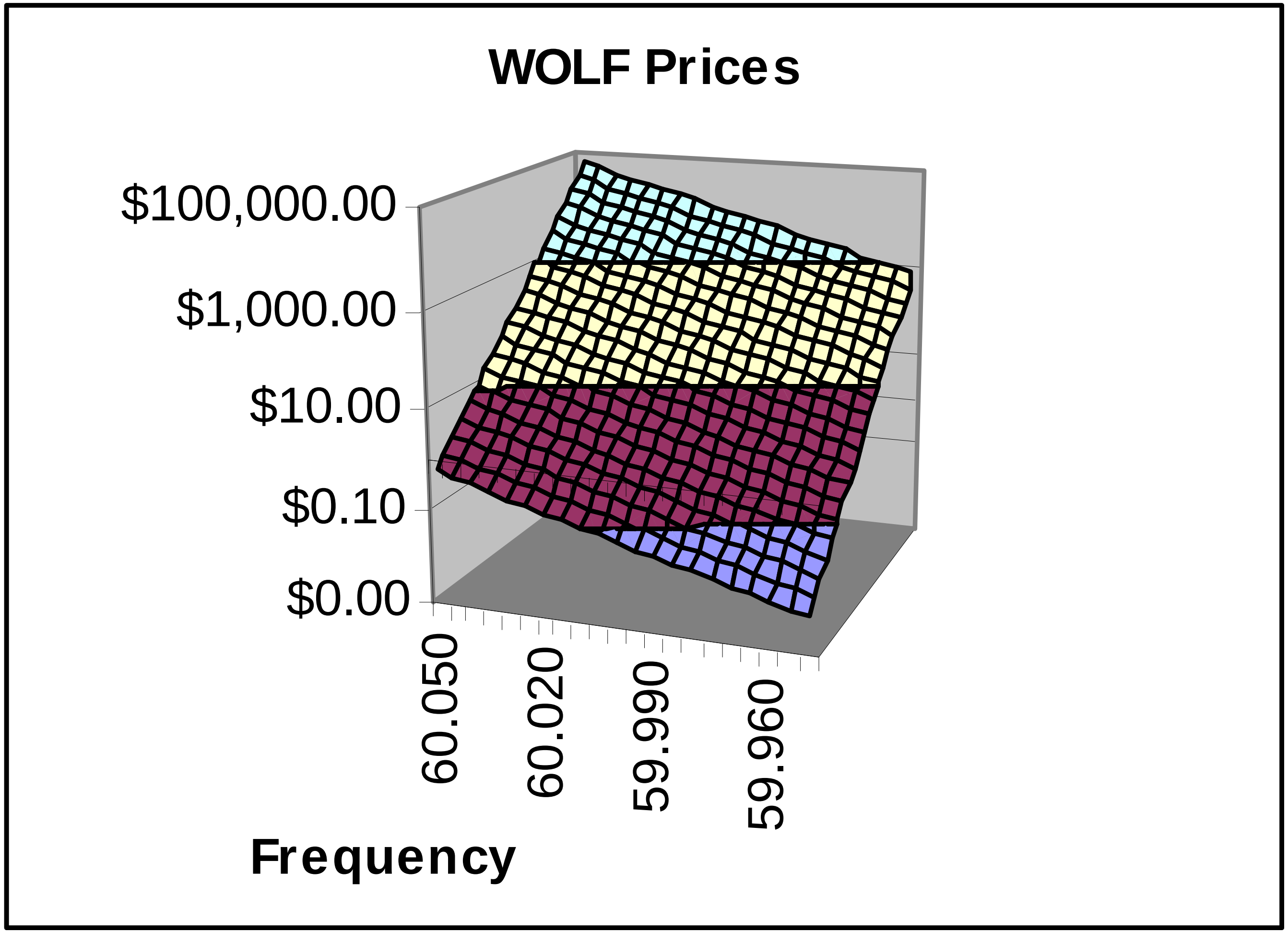
Dynamic Pricing



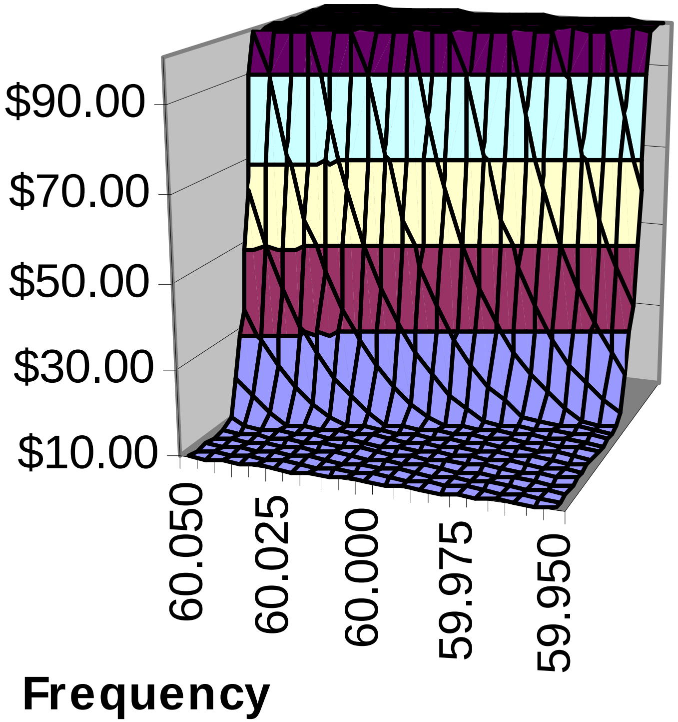
WOLF Pricing

Inadvertent Interchange

- Base Price
  - Initial Seed
- Frequency Response
  - $10^{-(\text{Frequency Error})/(\text{Frequency Factor})}$
- Time Response
  - $10^{-(\text{Time Error})/(\text{Time Factor})}$
- Cumulative Time Error
  - Adjusts Seed

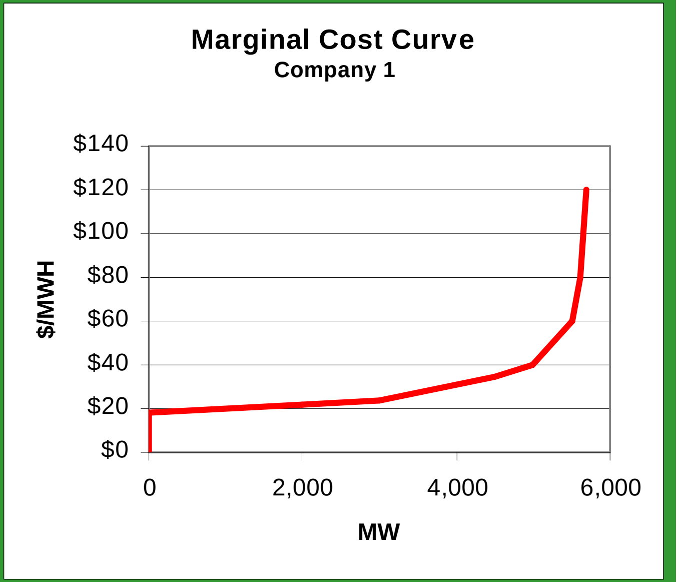

WOLF Prices
$100,000.00
$1,000.00
$10.00
$0.10
$0.00
60.050
60.020
59.990
59.960
Frequency

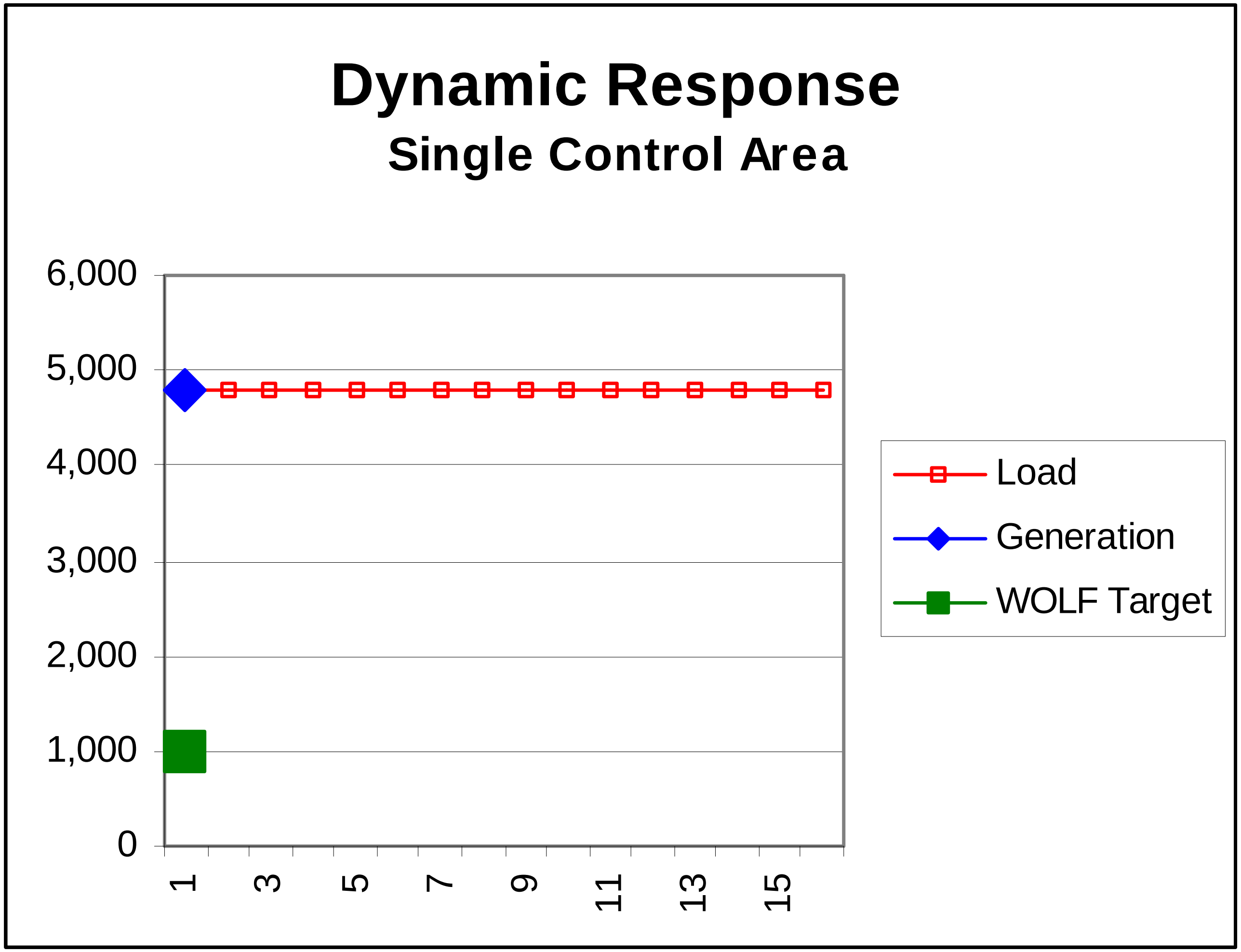
WOLF Prices


$90.00
$70.00
$50.00
$30.00
$10.00
60.050
60.025
60.000
59.975
59.950
Frequency

Single Control Area

- Marginal Cost Graph
- 4800 MW Load
- 50 MW/.001 Hertz
- WOLF Parameter
  - $20/MWH Seed
  - 0.02 Hertz/Decade
  - Time Error
  - Cumulative Time Error



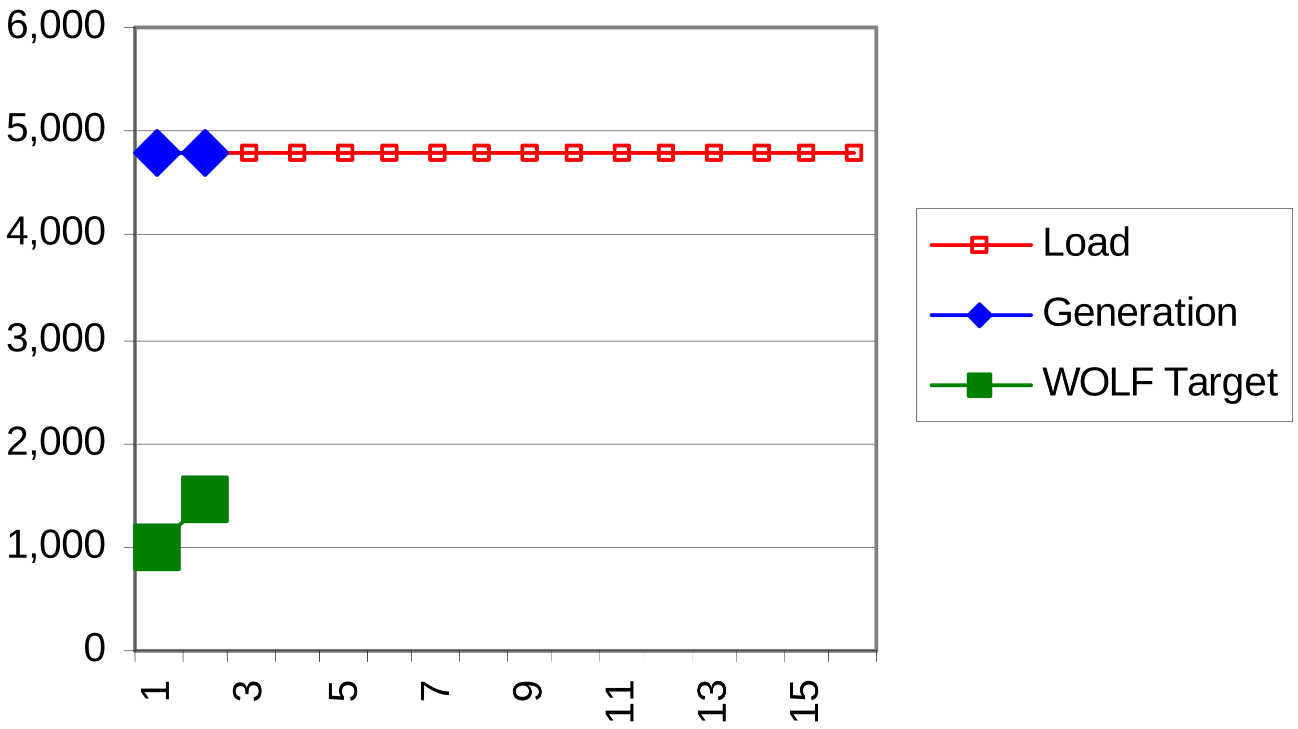


Dynamic Response

Single Control Area

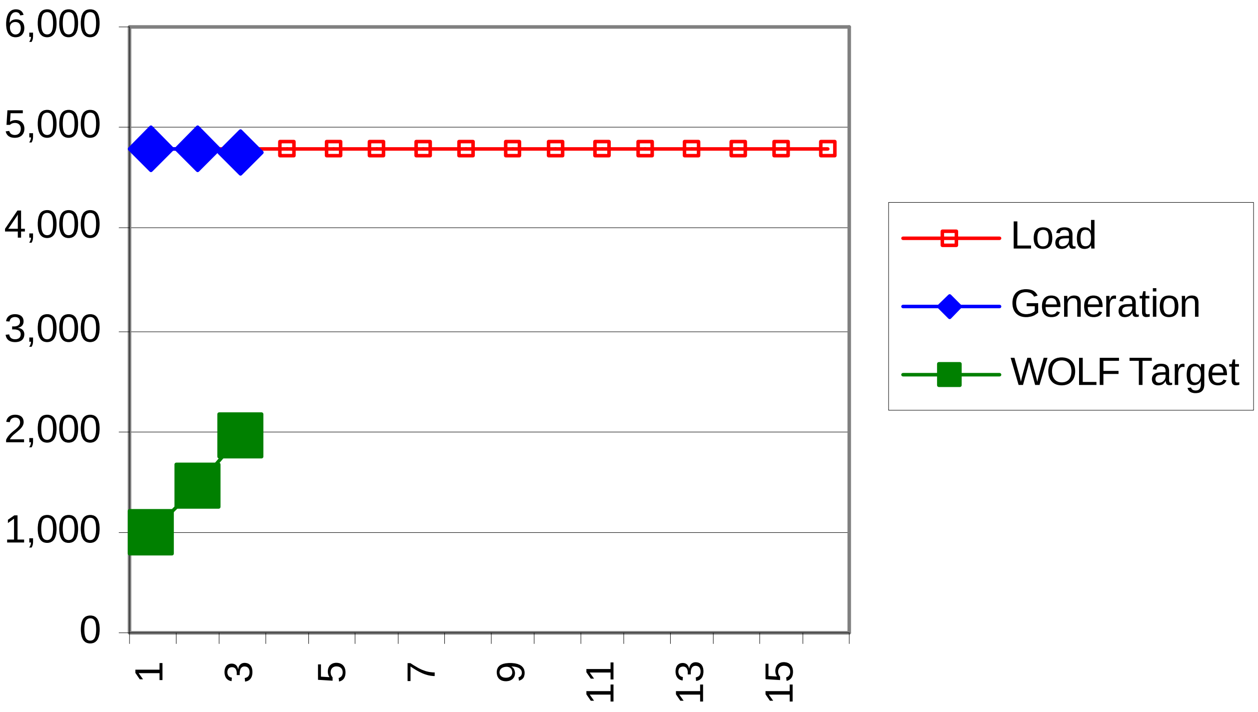
Dynamic Response

Single Control Area



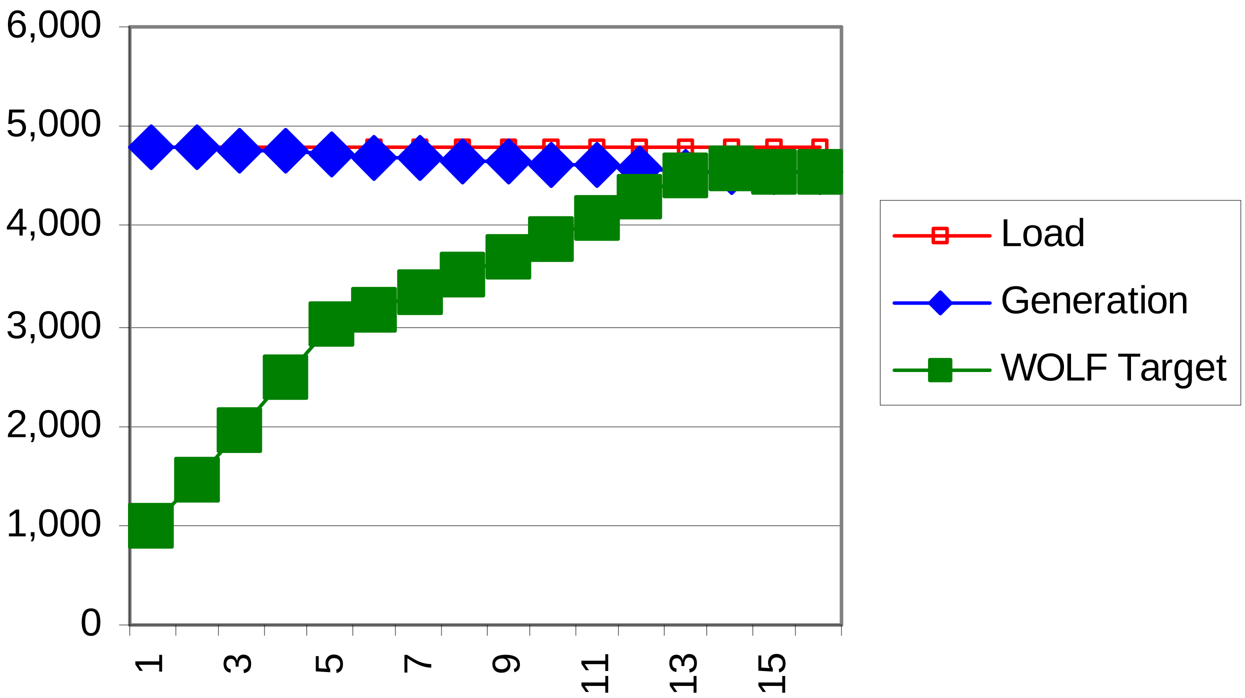
Dynamic Response

Single Control Area



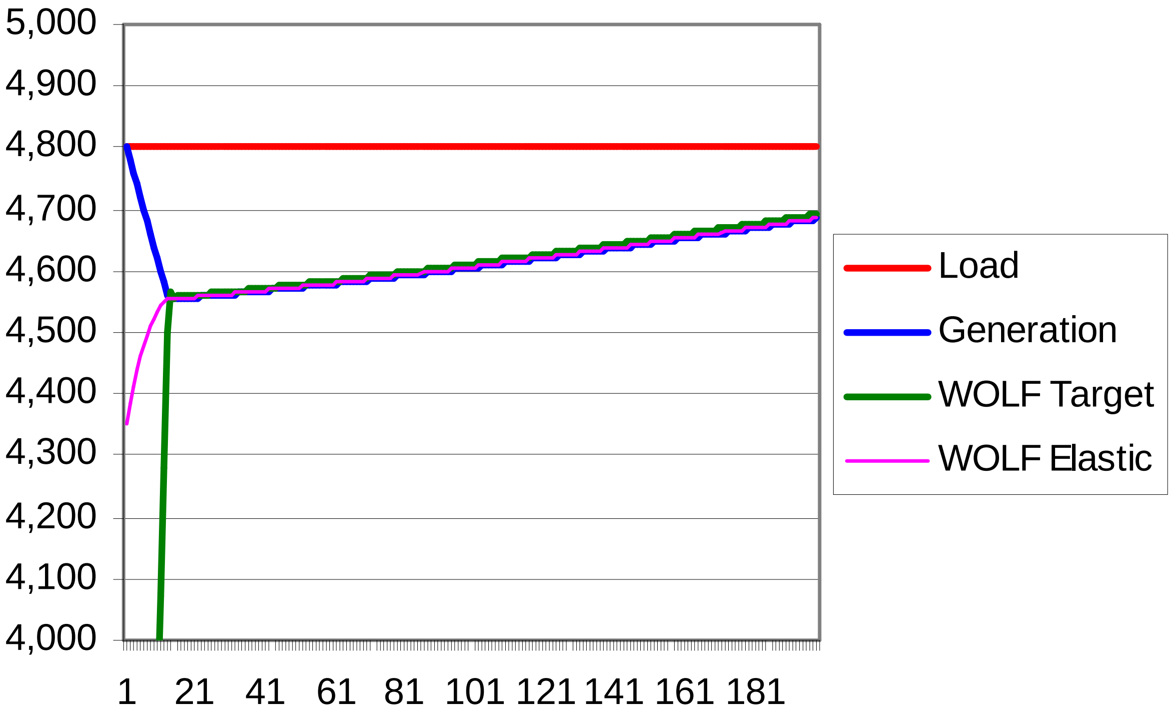
Dynamic Response

Single Control Area



Dynamic Response

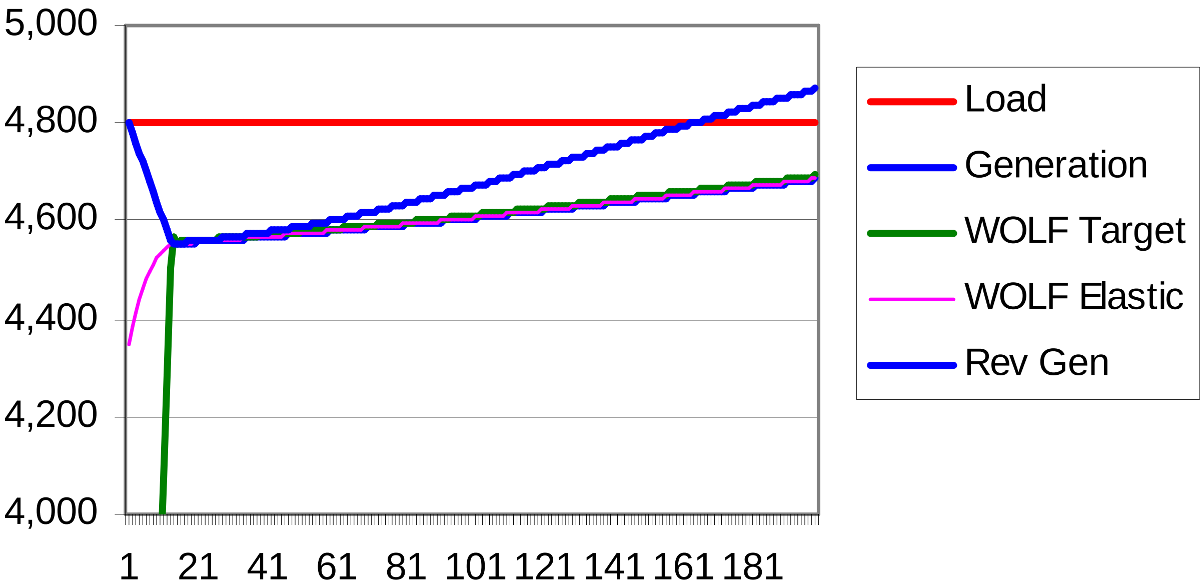
Single Control Area



Dynamic Response

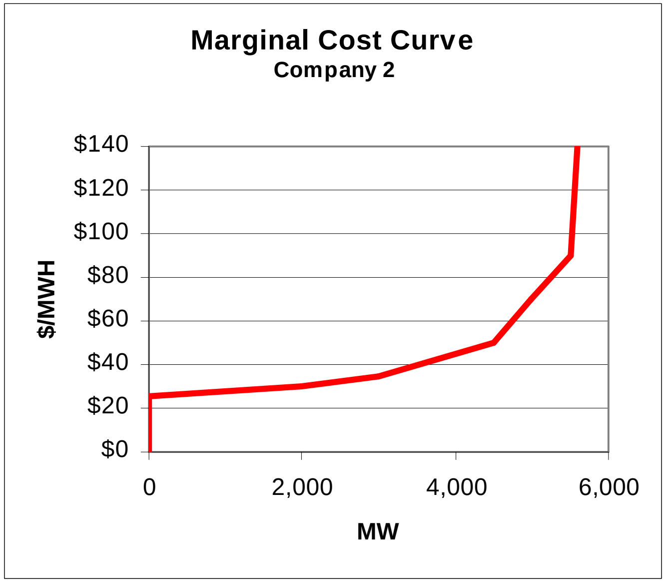
Single Control Area

With Cumulative Time Error Factor Divided by 5



Second Control Area

- Marginal Cost Graph
- 4800 MW Load
- 100 MW/.001 Hertz
- WOLF Parameter
  - $20/MWH Seed
  - 0.02 Hertz/Decade
  - Time Error
  - Cumulative Time Error



Transmission Company

Electrical Losses

- 5 MW Losses at 100 MW Flow
- Price Differential
  - 1% at 10 MW
  - 5% at 50 MW
  - 10% at 100 MW
  - 15% at 150 MW

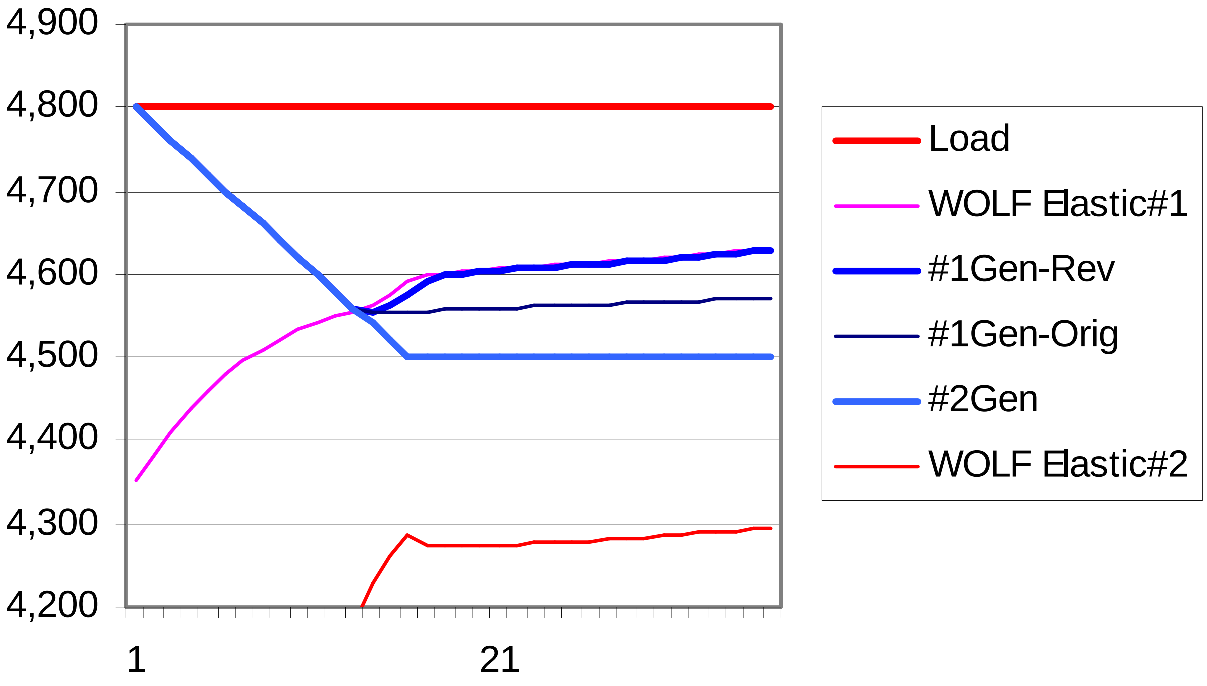
Transmission Company

Constraints

- 100 MW Contingency Limit
- Price Multiplier
  - No price effect under 100 MW (i.e. x 1.0000)
  - 50 MW per price decade
    - 1.0000 at 100 MW
    - 10.0000 at 150 MW
    - 100.0000 at 200 MW

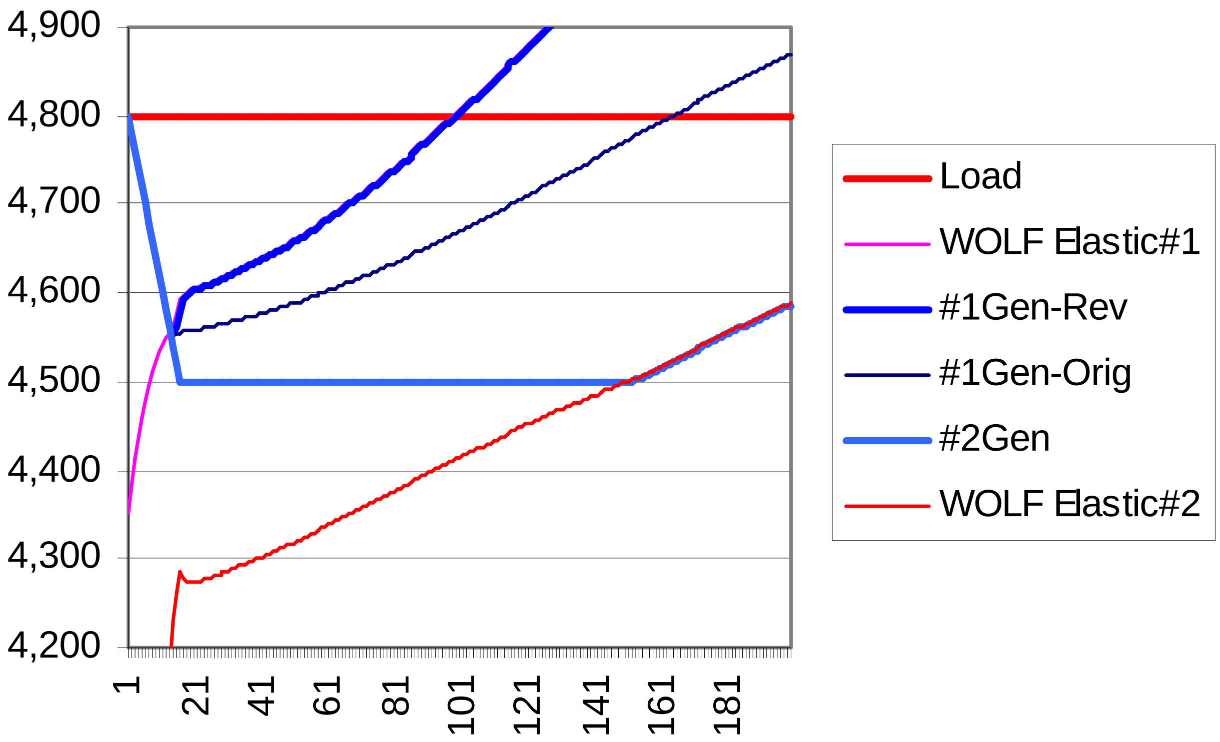
Dynamic Response

Both Control Areas



Dynamic Response

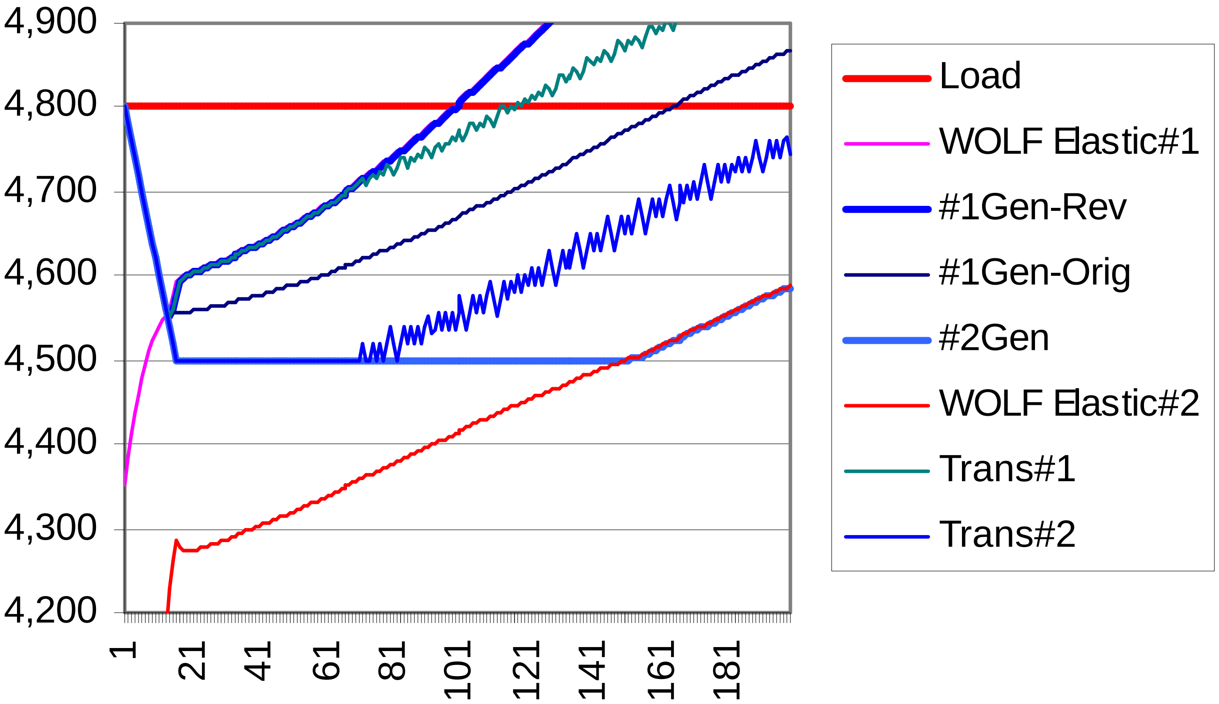
Both Control Areas



Dynamic Response

Both Control Areas

With Transmission Limits



WOLF Pricing

Summary

- Cash Out Unscheduled Flows of Electricity
  - Loop Flow
  - Inadvertent Interchange
  - Reactive Power
- Get Finances to Mesh with Physics
  - INC prices when INCing generation
  - DEC prices when DECing generation

Mark B. Lively
19012 High Point Dr.
Gaithersburg, Md. 20879
301-428-3618
MbeLively@aol.com

2003 June 19

Congestion Management Working Group
Midwest ISO
Via Exploder

I participated in today's conference via the telephone call-in. I mainly commented and asked questions about inadvertent and uninstructed deviations. I consider them to be parts of the same issue, how to price unscheduled flows of electricity, at least that is the terminology I have used for the issue since 1989.

GOOD VERSUS BAD

At least one person used the phrases "good inadvertent" and "bad inadvertent" without explaining what those phrases mean. As I have heard those phrases, "good inadvertent" is the delivery of inadvertent when the network frequency is low or the receipt of inadvertent when network frequency is high. Conversely, "bad inadvertent" is the delivery of inadvertent when the network frequency is high or the receipt of inadvertent when network frequency is low. This is summarized in Table 1.

Inadvertent Interchange
Defining Good Versus Bad
Table 1

Frequency / Inadvertent	Low	High
Delivery	Good	Bad
Receipt	Bad	Good

The concept of good versus bad is best explained when the frequency is low. The delivery of inadvertent when frequency is low helps the system by keeping the frequency from going even lower. Those who receive inadvertent when the frequency is low are short of power and are a drag on the rest of the network. This is considered to be bad inadvertent. Conversely, when frequency is high, any delivery of inadvertent just contributes to the frequency deviation and is thus considered to be bad. Those who receive inadvertent when the frequency is high keep the frequency from going even higher. This is considered to be good inadvertent.

Similarly there should be "good uninstructed deviation" and "bad uninstructed deviation" with good and bad depending upon the health of the network. Good uninstructed deviation would include surpluses when the MISO is short and deficits when MISO is long. Bad uninstructed deviation would include surpluses when MISO has a surplus and shortages when

MISO has a shortage. Instead, all uninstructed deviations are nominally treated as bad. Shortages are to be penalized at 140% of LMP[1] under the current plan and surpluses are to be penalized at 40% of LMP.

Uninstructed Deviation
Defining Good Versus Bad
Table 2

MISO Balance Uninstructed	Shortage	Surplus
Delivery	Good	Bad
Receipt	Bad	Good

USING TWO SETS OF LOCATIONAL MARGINAL PRICES (LMP)

One way around this issue is to acknowledge that there can be two different sets of locational marginal costs. Considering the discussion today, let's call the traditional locational marginal cost LMP-SCD, for security-constrained dispatch. Let's call the new locational marginal cost LMP-UD, for uninstructed deviation. MISO would use LMP-SCD for amount of generation or load that was bid into the dispatch program. MISO would use LMP-UD for uninstructed deviation including inadvertent.

An advantage to having the two different LMPs is the elimination of the special exceptions discussed today for intermittent generators, non-conforming loads, generation in the process of starting up, and generation in the process of shutting down. These generators and loads could choose to participate in the security-constrained dispatch and settle at the LMP-SCD for the amount determined by the security-constrained dispatch. However, the LMP-UD would be applicable to any uninstructed deviations, whether above or below the dispatch level. The generators and loads could similarly choose not to participate in the security-constrained dispatch and settle at the LMP-UD for their output or load. The LMP-UD would also be used to settle inadvertent by the control areas.

SETTING LMP-UD

Since LMP-UD would be used for both uninstructed deviation and inadvertent, MISO would need a way to set LMP-UD to reward good uninstructed deviation and good inadvertent and to punish bad uninstructed deviation and bad inadvertent. High prices reward inadvertent

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[1]

	Billed at 100% of LMP		Billed at 60% of LMP		Total	
MW	MW	LMP-MW	MW	LMP-MW	LMP-MW	Change
90	90	90	0	0.0	90.0	N/A
89	88	88	1	0.6	88.6	1.4
88	86	86	2	1.2	87.2	1.4
87	84	84	3	1.8	85.8	1.4

surpluses and uninstructed deviation surpluses and punish inadvertent shortages and uninstructed deviation shortages. Low prices reward inadvertent shortages and uninstructed deviation shortages and punish inadvertent surpluses and uninstructed deviations surpluses.

From Table 1 for defining good versus bad inadvertent, a high price on the left column of the table when frequency is low will reward good inadvertent and punish bad inadvertent. Similarly, a low price on the right column of Table 1 when the frequency is high will again reward good inadvertent and punish bad inadvertent. The same analysis is true for the two columns of Table 2 for defining good versus bad uninstructed deviation.

System operators already combine the two tables for defining good versus bad in their development of area control error (ACE). Under the above analysis, we should have high LMP-UD prices when ACE is negative and low LMP-UD prices when ACE is positive. I have in various papers proposed that the LMP-UD prices can be a continuous function of ACE, a concept I have called WOLF for Wide Open Load Following.

IMPORTANCE OF MAINTAINING SMALL INTERVAL PRICING

During the conference, I argued against using hourly average LMP-UD to cash out inadvertent and uninstructed deviation, saying that we should use the five-minute data. I gave the example of a system emergency during the first half of an hour and a surplus during the second half. I present a numeric example in Table 3.

Inadvertent Interchange
Importance of Retaining Small Time Intervals
Table 3

	Inadvertent	Price	Payment
1st ½ Hour	-50 MWH	$100/MWH	-$5,000
2nd ½ Hour	60 MWH	$20/MWH	$1,200
Total	10 MWH	N/A	-$3,800
Average Basis	10 MWH	$60/MWH	$600

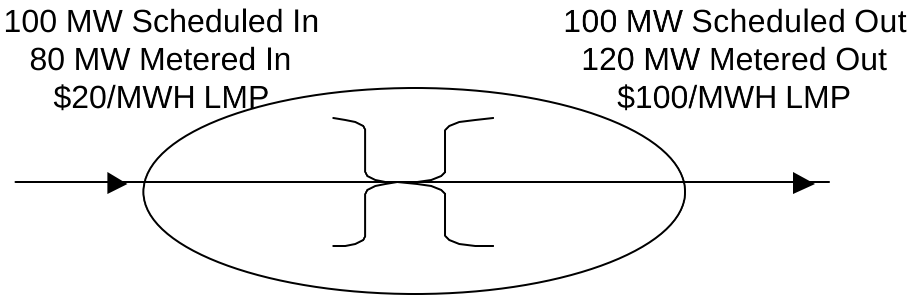
CASHING OUT INADVERTENT INTERCHANGE BY PARTS

During the conference, the current proposal to cash out inadvertent was based on the average LMP for all of the generator nodes. Someone suggested that the average LMP also include all of the load nodes. I argued that the LMP should be applied against the unscheduled flows across each of the interconnections that the control area has with other control areas.

In Figure 1, I present a control area that has 100 MW scheduled through it from left to right. However, the flow out on the right is 120 MW while the flow in on the right is only 80 MW. Thus, there is inadvertent out of 40 MW. Because of the constrained flow gate in the control area, the LMP at the right interface is $100/MWH and is much higher than the LMP at the left interface of $20/MWH. If the generation is all to the left of the constrained flow gate, the inadvertent would be priced at $20/MWH or $800/Hour. If the generation is all to the right of the constrained flow gate, the inadvertent would be priced at $100/MWH or $4,000/Hour. The alternative that I suggested would price 20 MW unscheduled out on the right at $100/MWH or $2,000/Hour and 20 MW unscheduled out on the left at $20/MWH or $400/Hour, for a total of $2,400/Hour.

An advantage of this geographically differentiated cash out of inadvertent is that it produces a zero sum for MISO as a whole. Note that the payment of $2,000/Hour to this control area on its right would be matched by a payment from the neighboring control area of the same $2,000/Hour. In the same way, the payment of $400/Hour to this control area on its left would be matched by a payment from the neighboring control area of the same $200/Hour. This would be true for any number of control areas.

Inadvertent Interchange Example
With Constrained Flow Gate
Figure 1



CLOSING

I appreciated being able to participate in the conference today by telephone. Listening to the discussion provided me with new insights into how to explain the issues presented in this letter. I look forward to talking with you again, either individually or collectively.

Yours truly,

Mark B. Lively
Utility Economic Engineer

North American Energy Standards Board
Inadvertent Interchange Payback Task Force

Pricing Comparison between WOLF and Schedule 4

By Mark Lively
Utility Economic Engineers
Gaithersburg, Maryland
301-428-3618
MbeLively@aol.com

On August 6 I made a presentation to the NAESB IIPTF in Philadelphia covering Wide Open Load Following (WOLF), my method to price inadvertent interchange on a geographically differentiated basis. On August 20, I was a minor participant in a teleconference to discuss the merits of using Schedule 4 of the Open Access Transmission Tariff (OATT) that jurisdictional utilities have on file with FERC. I believe that the use of Schedule 4 (or the mentioned modifications of Schedule 4) is ill advised in that the procedure is open to inappropriate manipulation, will lead to financial imbalances, and does not include non-jurisdictional utilities.

SCHEDULE 4

Schedule 4 is the part of the OATT covering cashing out imbalances that FERC jurisdiction transmission providers have with their customers. Non-jurisdictional transmission providers do not necessarily have a Schedule 4, since they are not required to file an OATT with FERC.

Generally a Schedule 4 will state that the transmission provider will calculate an out of pocket cost (OOP) as the basis for any cash-out. The OOP is then incremented or decremented depending on whether the transmission customer is short or long respectively. Further, some Schedule 4's have minimums for shortages, such as $100/MWH.

Schedule 4 versus OOP

The discussion of using Schedule 4 was bifurcated during the teleconference. Some of the discussion was to use Schedule 4 in its fullest detail. The rest of the discussion was to use only the OOP portion of Schedule 4, thus eliminating the increments and decrements mentioned above as well as the minimums.

The use of Schedule 4 provides the advantage that FERC has approved each Schedule 4 on file for use as a pricing mechanism. Indirectly that approves the use of OOP to determine the Schedule 4 prices, but not the use of a pure OOP as a price. A disadvantage is that non-jurisdictional utilities do not have a Schedule 4.

Auditing

There is now no specific method used by each utility in calculating OOP. Indicative of this is the paucity of data on the results of the implementation of Schedule 4 as well as a sensitivity of the transmission providers about the competitive nature of the data that go into OOP.

Zero Sum Game

Howard Ilian discussed the net economic impact of using OOP. He believes that generally the value of OOP for receivers of inadvertent interchange will be greater than the value of OOP for providers of inadvertent interchange. Under that premise, paying each provider its OOP and charging each user its OOP will result in a positive cash flow to the bank, a term I will use for the operator of the balancing fund. Note that Howard's analysis is for OOP, not for Schedule 4. Schedule 4 would reduce the payments by those who are short and increase the payments to those who are long relative to OOP.

OOP When System Is Constrained

Howard's premise breaks down when a user of inadvertent interchange has no alternative way to obtain inadvertent interchange, such as CG&E during the summer of 1999. Under such a situation OOP is undefined mathematically for the receiver of inadvertent interchange and can be set at any level that the user desires. The potential for the user to define the OOP at an advantageous level is obvious. This will tend to change the balance for the bank from the net income Howard suggests to a net loss.

I note that this reversal of the cash balance under Schedule 4 is related to the California debacle. Economic theory used in California suggested that providers were financially advantaged by bidding their short run marginal costs, which is closely related to OOP. But this theory failed when providers anticipated running their generators at maximum power. At maximum power, marginal cost is mathematically undefined.

OOP is similarly undefined when a receiver of inadvertent interchange has no surplus capacity. The providers in California were able to set their bids at exorbitant levels while still being consistent with the economic theory that nominally supported bids based on marginal cost. However, the theory did not address the concept of short run marginal costs being undefined. Similarly a reliance on OOP breaks down when a utility runs out of capacity.

Distrust Among Participants

I have no experience that suggests that utilities will indeed manipulate their OOP to get out of paying high prices during a shortage. However, my experience working for investor owned utilities, municipal utilities, and cooperatives suggests that there is enough distrust among these entities to prevent them from accepting the OOP claims of each other. There is growing similar mistrust within each of these groups, though historically the mistrust within each group was less than the mistrust between the groups. OOP is very subjective, and is not an objective enough way to set the price for inadvertent interchange.

WIDE OPEN LOAD FOLLOWING (WOLF)

WOLF removes most of the subjectivity from the calculation of a price for inadvertent interchange. WOLF sets the price based on system frequency including its calcula, such as cumulative time error. In the example I presented on August 6, WOLF started with a nominal price of $20/MWH. That price increased by a factor of 10 for every 20 millihertz that the system frequency decreased, or about 12.2% per millihertz compounded. These coefficients produce a set of prices shown in Table 1.

Basic WOLF Pricing
No Time Error Correction
No Geographic Differentiation

$20/MWH Nominal Price
10 X for 20 millihertz
Table 1

Frequency (Hertz)	Price ($/MWH)
60.020	$2.00
60.015	$3.56
60.010	$6.32
60.005	$11.25
60.000	$20.00
59.995	$35.57
59.990	$63.25
59.985	$112.47
59.980	$200.00

Absent geographic differentiation, WOLF sets a uniform, objective price across the entire network. With geographic differentiation, WOLF sets internally consistent prices at each interconnection point on the network.

Data Inadequacy and Bilateralism

On August 4, NAESB IIPTF met with NERC to discuss the data necessary for cashing out inadvertent interchange. NERC is not now able to reconcile hourly inadvertent interchange data, at least not quickly. I subsequently commented to IIPTF that part of the reconciliation problem is that there is not an incentive for the numbers to be accurate, i.e., there is no cash effect of reporting bad data, whether too high or too low.

One way to provide incentives to get the data correct is to bilateralize inadvertent interchange, having each control area be responsible for a cash-out with each of its neighbors instead of having the potential cash-out be with a central bank. If the cash-out is with a neighbor, I believe that the two neighbors would quickly find ways to reconcile inadvertent interchange data. Further, no central bank would have to be created for the process and NERC would not have to increase its workload. Bilateralization works for WOLF but would not work for OOP or Schedule 4.

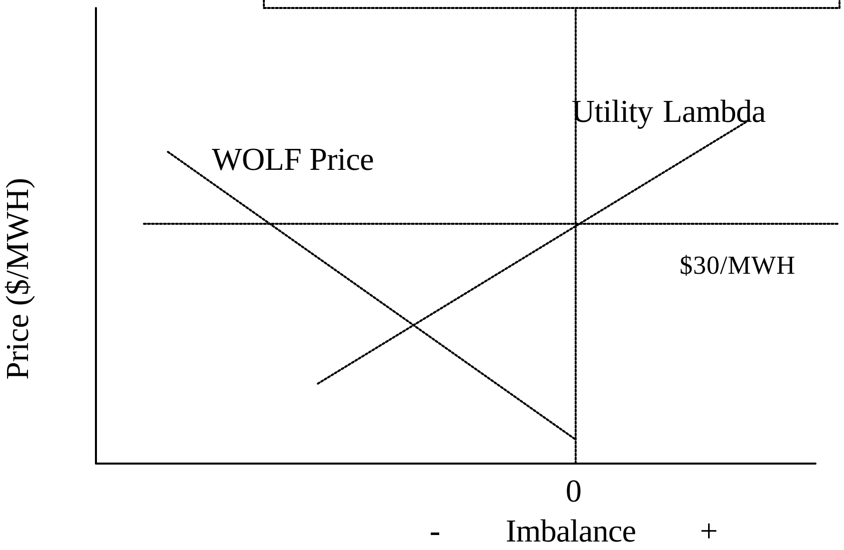
Locational Pricing and Compensation For Loop Flow, Including Parallel Path Flow

The NERC Joint Inadvertent Interchange Task Force concluded that the value of inadvertent was affected by location and frequency. Table 1 shows how WOLF addresses the frequency issue. My excruciatingly detailed presentation of August 6 included how WOLF handles the location issue. I will not address in this letter the process for geographic differentiation except to say that geographic differentiation addresses losses and transmission constraints. In handling the location issue, WOLF also provides payments for parallel path flow and other forms of loop flow. Using Schedule 4 or OPP to cash-out inadvertent interchange does not provide such a benefit.

Gaming Helps The Network

The name inadvertent interchange seems to suggest that inadvertent interchange is entirely unintentional, that utilities try to keep the number close to zero. In practice, the old control paradigm was to keep ACE close to zero by biasing generation for frequency error. WOLF incorporates the frequency bias as shown in Table 1. Thus, WOLF actually provides an incentive for utilities to have some inadvertent interchange. Because of the negative feedback associated with setting the price based on frequency, gaming of the system is limited and redounds more to the benefit of the network than to the benefit of an individual utility.

Consider a utility with a short run marginal cost of $30/MWH. Table 1 provides that utility with an incentive to bias its generation to have negative inadvertent interchange, i.e., from the grid into its control area. The bias ceases when system frequency drops to 59.9964 Hertz. At 59.9964 Hertz the WOLF price would be $30.27/MWH. When the frequency was less than 59.9964 Hertz, the utility would have an incentive to bias its generation to have positive inadvertent interchange.



Game Playing Helps System Frequency
Figure 1

In practice, the breakpoint for the utility would be closer to 60 Hertz, as is shown in Figure 1. At zero imports, the utility marginal cost is $30/MWH. The importation of power will lower the utility's generation and thus its marginal cost. For instance, in extreme cases, importing power will allow the utility to shut down its most expensive generation, reducing its marginal costs below $30/MWH. Figure 1 shows the utility's marginal cost as decreasing as the utility imports more electricity, as indicated by a negative imbalance. Reliability, cost minimization under uncertainty, and other issues will support this decision for the utility to operate around a breakpoint closer to 60 Hertz.

Figure 1 also shows that the WOLF price would be lower than $30/MWH at 60 Hertz, or zero imbalance. As the imbalance becomes negative and frequency drops, the WOLF price rises. The utility will have an incentive to limit its negative inadvertent interchange to some amount that is less than the amount that would have been predicted on a static marginal cost estimate of $30/MWH.

WOLF Permits Joint Dispatch With No Sharing Of Internal Data

As demonstrated for the utility with a marginal cost of $30/MWH, when a utility biases its generation to achieve an economic level of inadvertent interchange, the result will be an internal system lambda equal to the WOLF price. The inadvertent interchange will also change the system frequency and thus the WOLF price.

When a second utility biases its generation to achieve an economic level of inadvertent interchange, its internal system lambda will similarly equal the WOLF price and will also equal the internal system lambda of the first utility. The two utilities will effectively jointly dispatch their generation without directly revealing any internal information to each other.

Similarly, when a third utility biases its generation to achieve an economic level of inadvertent interchange, its internal system lambda will equal the WOLF price and also the internal system lambdas of the first two utilities. Thus, WOLF pricing of inadvertent interchange achieves a joint cost minimization without any utility revealing competitive information about its internal cost structure.

CONCLUSIONS

By providing an objective way to cash-out inadvertent interchange WOLF addresses some of the distrust that would be inherent in the use of OOP and Schedule 4. WOLF also eliminates the issue of auditing internal cost structures associated with the use of OOP, even achieving joint dispatch without any direct revelation of internal cost functions. WOLF meets the NERC JIITF finding that the value of inadvertent interchange is frequency dependent, while the use of OOP and Schedule 4 does not achieve such a result. WOLF can be used in a bilateralized market, one that minimizes the need for a central banker while maximizing the incentive for data accuracy. Finally, WOLF provides the added benefit of compensating for parallel path flow and other forms of loop flow.

Mark Lively
Utility Economic Engineers
Gaithersburg, Maryland
301-428-3618
MbeLively@aol.com

Profit-Enhancing Seam Management

A White Paper on Pricing The Unscheduled Flows of Electricity Across the Seams Between Utilities Using A Geographically Differentiated Auction of Inadvertent Interchange

By
Mark B. Lively
Utility Economic Engineer
19012 High Point Dr.
Gaithersburg, Md. 20879
301-428-3618
MLively@LivelyUtility.Com
WWW.LivelyUtility.Com

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Mark B. Lively

Mark Lively began working in the utility industry in 1969, with a summer job for his hometown utility, Kentucky Power Company. Mr. Lively earned a masters of science from the MIT Sloan School of Management in 1971. He also has a bachelors of science from MIT in electrical engineering. After attending MIT, Mr. Lively joined American Electric Power Service Corporation in New York City, the management and engineering arm of the AEP system, of which Kentucky Power Company was a member. In 1976, Mr. Lively joined the Ernst & Ernst Washington Utility Group. He also worked for its successors, Ernst & Whinney and Ernst & Young.

Mr. Lively has focused his efforts on financial issues relating to electric and gas utilities, initially in the controllers office and rate department at AEP, then as a consultant with Ernst & Ernst and its successors, and now as an independent consultant. Mr. Lively uses his MIT education in engineering and management to develop specialized models for his clients. His modeling efforts have previously been recognized by

- The United States Postal Service in his development of the Revenue Requirements Rollforward model for projecting budget costs by mail class and subclass, which is still in use after 20 years.

- The Texas Public Utilities Commission in its 1984 adoption of the Committed Unit Basis as a method to evaluate long-term contracts between regulated utilities and Qualifying Facilities.

- The D.C. Public Service Commission in its 1998 adoption of his testimony about computing the new average wage rate for two utilities that were seeking merger approval.

The concept of Profit-Enhancing Seam Management is based on Mr. Lively's modeling of the way a true spot market for electricity should operate when physical laws are reflected in economic applications.

Profit-Enhancing Seam Management

By Mark B. Lively
Utility Economic Engineer

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Retrospective

Since the first two electric systems were interconnected or tied together, their owners have had the problem of tie-riding freeloaders. Freeloaders ride the ties in two ways – first by taking electricity without making adequate monetary compensation and second by using multiple interties to make a cost-free change in the geographic availability of their electricity. Wheeling contracts will dramatically increase the number of parties with access to a utility's transmission grid and increase the perceived number of tie-riding freeloaders. A pricing mechanism that charges for the unscheduled use of a utility's system may reduce the utility's fear of unconstrained raids on its ability to generate revenue. "Tie-riding Freeloaders – The True Impediment to Transmission Access," Mark B. Lively, *Public Utilities Fortnightly*, **1989 December 21**.

Summary

Twelve years ago I proposed a pricing mechanism to address two seam-management issues, inadvertent interchange and loop flow. Because of the physics of our free flowing AC network, a utility cannot prevent other utilities from borrowing its electricity or from using its transmission wires. A utility's only control option is the drastic measure of opening the switches at transmission stations.

I see a need to charge for inadvertent interchange and loop flow services on a competitive basis, sometimes with the prices being very low to reflect surpluses, sometimes with the prices being very high to reflect shortages. I developed such a pricing concept to replace the existing practice of a return in kind, a practice that ignored how the value of electricity varies with time and with location. The concept is called Wide Open Load Following (WOLF) and develops prices that increase and decrease with the balance between supply and demand. The examples I presented twelve years ago had prices that varied between $20/MWH and $800/MWH, a factor of forty.

Of course, twelve years ago the industry hadn't invented the term "seam management". Indeed the electric industry was barely aware that the seams between utilities created an issue that needed to be managed. Utility personnel kept track of inadvertent interchange, because it had to be paid back. Utility personnel also talked about loop flow. However, the consensus was that the net cost of inadvertent interchange and loop flow was too small for a utility to worry about. After all, utilities helped each other. Paybacks in kind kept everyone even, with everyone earning similar regulated rates of return.

In the last twelve years the industry has changed. The price of scheduled electricity now varies greatly, spiking both with time and with geography, much as I predicted twelve years ago. Price spikes of a factor of forty are not uncommon. Because of such price spikes for scheduled electricity, access to free unscheduled electricity may allow a company to make a multi-million dollar profit. But the utilities providing the unscheduled electricity only get some energy back at a later time, or in another location, not the huge profit created by their delivery of energy.

These price spikes for scheduled electricity are happening with increasing frequency. The lack of seam management pricing allows opportunists in the electricity market to profit from these price spikes for scheduled electricity at the expense of most utilities and their customers. Seam management pricing requires

- A dynamic mechanism to change prices for unscheduled flows of electricity
- A way to change prices geographically
- A way to price reactive power

These three pricing processes need to reflect the physics of electricity and economic theory of supply and demand. The answer seems to be a formulary auction of unscheduled flows of electricity, with the auction formula having a time component and a geographic component.

A formulary auction is consistent with the economic concepts of supply and demand applied on a repetitive, dynamic basis. The WOLF formulary auction results in self-correcting prices. Participants reacting to high or low prices will see that their reactions change the price toward the level desired by the participants. The prices provide incentives for all participants to act in ways that improve the reliability of the entire network, including an automation of the market re-dispatch concept implemented by NERC to reduce the need for transmission line loading relief.

Seam management pricing can be internalized to provide incentives to retail consumers and transmission dependent utilities. California can use the concept of a formulary auction to produce spot prices for retail consumers. Such a pricing plan could have prevented the rotating blackouts that plagued California during the last half of 2000 and the beginning of 2001 and may have reduced the prices charged by bulk power suppliers during that time. Certainly such spot pricing of retail loads would have been more equitable than blackouts. Internalization of a spot market can still help California avoid blackouts during the summer of 2001.

"Good Old Boys' Club" Atmosphere

As has been stated in various published articles,[1] utilities treat each other as fellow members of a "good old boys' club". Utilities often help each other without trying to obtain compensation, at least **compensation at a fair market price**. The title "good old boys' club" is also appropriate in that "girls" were not permitted in. The term "girls" as used here refers to hard-nosed competitors who wanted to make money by generating electricity. Though the hard-nosed competitors might have been satisfied for a regulated rate of return, these hard-nosed competitors were not utilities, did not have a franchised service area, and were prohibited from selling electricity at retail.

The atmosphere in the electric industry has changed. Independent power producers abound, making money by selling electricity, some at retail and some at wholesale. And at least in California during the latter half of 2000 and the beginning of 2001, the independent power producers have earned very high returns on their investments. These returns have been much greater than those that the utility members of the "good old boys' club" were allowed to earn. Still looking at the independent power producers, some are arms of regulated utilities. So the "good old boys' club" has changed considerably. The "good old boys' club" is no longer limited to regulated utilities and some members are making large rates of return. Despite these changes, the interaction among utilities maintains a club-like atmosphere.

The club-like atmosphere of the electric network remains in the perpetuation of tie-riding freeloaders. Seam management issues allow some club members to profit from the sale of services actually provided by other members of the club. These seam management issues seem likely to be perpetuated and exacerbated by the actions being taken by the clubhouse proctors, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Council (NERC.)

FERC's approach to seam management seems to be to define the issue away. FERC encourages mergers and the creation of Independent System Operators (ISOs) and Regional Transmission Operators (RTOs). These larger entities attempt to bury the seams within their larger organizational structure, as discussed below. NERC's approach seems to perpetuate the ability of tie-riders to freeload off their neighbors through a perpetuation of a return in kind. Only in extreme situations does NERC or its regional councils seem to advocate a cash payment. Even in the case of egregious behavior, the payment mechanisms advocated are penalties or fines. Penalties and fines are associated with the clubhouse atmosphere mentioned above and are antithetical to a competitive market.

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[1] See "Inadvertent Interchanges -- A New Way to Price Unscheduled Electricity," *Electrical World*, December 1991; "Competition Versus the Good Old Boys' Club," Forum, *IEEE Computer Applications In Power*, January 1997; and, "Real-Time Reliability Based Electricity Pricing," *1998 Proceedings*, Annual Reliability and Maintainability Symposium, Anaheim, California, 1998 January 19-22.

ISOs and RTOs are multi-utility organizations that operate large sections of the power grid. By their amalgamation of several utilities into a single operating structure, ISOs and RTOs internalize the seams that had existed between the individual utilities. Since the seams between utilities are now internal to the new organization, they can almost be ignored for financial purposes. Payment for the use of these internal seams is to be covered in some comprehensive program to allocate revenue among the members or to allocate costs among all users of the system. These methods are especially inappropriate when a user is interested in only part of the network.

The administrative elimination of seams is inconsistent with the physical needs of the system and will cause problems for the network. For instance, the revenue allocation procedures proposed by some ISOs and RTOs provide little or no incentive for distributed generation to be located near load centers. Many load centers are in areas where it is costly to build a new power plant. Why should an independent producer locate a generator near a load center? There's no reason to when such locations are more expensive and there is no reduction in the payment for use of the transmission system.

As written twelve years ago, an important part, perhaps the most important part, of seam management is to price the unscheduled flows across these seams. Traditional embedded cost based regulation does not work for seam management. Traditional regulation does not produce prices that vary with time and the vagaries of the market. Traditional prices will not go low enough during off-peak periods of constraint. Nor will traditional prices go high enough during on-peak periods of constraint. Further, for loop-flows, the provider of the service is situational, and may not be easily determined. Thus, there needs to be a way to set these prices during periods of constraint. A good way to set these prices is a true competitive spot market for the unscheduled flows of electricity. The method discussed in this paper is a geographically differentiated Walrasian auction of inadvertent interchange. The concept is known as WOLF, for Wide Open Load Following.

The Central Market

Most electric utilities are parts of large networks. These large networks are physically tied together with transmission lines. The physics of these transmission line ties is such that all the components of the network work closely together. The components work together so closely that they are sometimes considered to be parts of a single machine. As a part of a single machine, each generator will respond to any shortage of electricity on the network. Likewise, each generator will respond to any surplus of electricity on the network.

Each utility operates its own central market for electricity. The various generators under the utility's control compete against each other, just as producers of other goods compete against each other in a traditional central market. The competition among generators produces the lowest total cost of operating all of the generators while meeting the load requirements of the utility's customers.

Unlike most central markets, a utility does not need to set prices for the electricity traded in its central market. The utility already owns the electricity, except in cases where a generator is under contract to the utility. However, the utility does have the equivalent of a transfer price in the form of System Lambda, the short run marginal cost of operating the network. The application of Equalized Lambda has reduced utility operating costs significantly since its introduction decades ago.

Utilities reap even bigger savings by interconnecting with other utilities. Some of the savings are achieved by competition among fuel supplies. The competition among fuel supplies is an extension of the Equalized Lambda concept to more generators. But most of the savings relates to the cost of providing electricity reliably.

Electric reliability improves as the number of generators increases. Reliability also improves with the size of the surplus. Having surplus generation is expensive. So, utilities prefer to improve reliability by taking advantage of economies of scale. Economies of scale, of course, require large generators. Achieving a great number of large generators requires the interconnection of several utilities. As part of these interconnections, utilities may participate in bilateral transactions or form power pools. But a large part of the value of the interconnection among utilities is simply being part of a larger machine.

Interconnecting to be part of a larger machine becomes beneficial only if electricity is allowed to flow between the utility and the rest of the network. If this flow is not part of a scheduled bilateral deal or a power pool transaction, the flow is called inadvertent interchange. Inadvertent interchange is difficult to treat on a bilateral basis. Electricity delivered by one utility to another utility may pass through the second utility to a third, fourth, or fifth utility, with the latter being the one that used the electricity provided by the first utility. Only an examination of the total unscheduled flow that a utility has with all of its neighbors reveals whether the utility is providing or receiving inadvertent interchange from the network.

The concept of Equalized Lambda can be modified to price inadvertent interchange in a concept called Wide Open Load Following (WOLF). A utility dispatcher's basic job is to maintain a balance between supply and demand by ordering all generators to increase or decrease production. Equalized Lambda is an economic concept that is generally implemented by the utility dispatcher. The dispatcher identifies economic inefficiencies and orders some generators to increase production, while ordering other generators to decrease production.

WOLF decentralizes the dispatch decision. Under WOLF, the dispatcher sends out a price signal to the generators, not orders to increment or decrement production. When there is a global shortage of electricity, the dispatcher raises the price of electricity. When there is a global surplus of electricity, the dispatcher lowers the price of electricity. Each generator then makes its own dispatch decision to increase or decrease production based on the concurrent price of electricity, as the dispatcher provides that price to each generator. The concept is one form of a Walrasian auction.

A centralized auction of unscheduled generation provides independent generators an incentive to help the network. This assistance to the network is achieved without the formalities of negotiated contracts, just through the pricing mechanism. A dynamic auction prevents the problems associated with long-term contracts, such as of having too much capacity at inflated prices followed by a dearth of capacity because of unanticipated growth of demand.

Physics of Electricity Generation

Inadvertent interchange is the difference between a utility's scheduled deliveries to other utilities and its metered deliveries to other utilities. Utilities have sophisticated meters on the power lines that interconnect them. These meters are read several times a minute, generally about every two or three seconds. The deliveries and receipts are summed and netted to determine the utility's net interchange with all of the other utilities on the network. The utility compares this net interchange with its net schedule of deliveries and receipts with other utilities. The difference between the metered interchange and the scheduled interchange is inadvertent interchange. Inadvertent interchange is calculated as part of the determination of Area Control Error (ACE). Utility dispatchers use ACE to determine the need to increase or decrease generation.

Some people look at electricity as a service. Electricity can also be viewed as a fungible commodity, for an erg is an erg is an erg. At least there is no way to distinguish between ergs at a particular place and time. In that regard, electricity is a truly fungible commodity. There are few limits on the interchangeability of electricity at a particular place and time. Two exceptions can be identified. If the generating plant was not on line at the time, the generating plant did not contribute to an erg used at that time. Similarly if the generating plant did not have an electrical path to the location, the generating plant did not contribute to an erg used at that time. Treating electricity as a fungible commodity allows the use of economic language that is more generic than the language of electricity.

A raw material goes through several stages in the manufacture of a finished product. For electricity, the raw material is generally some form of stored energy, perhaps the chemical energy of a fossil fuel, the atomic energy of nuclear power, or the potential energy of water stored behind a dam. A basic law of physics is that energy can't be created or destroyed, just that its form can be changed. Electric generators change the form of energy into electricity.

Most electric generation plants involve changing the stored energy mentioned previously into the kinetic energy of a moving fluid, such as steam or water.[2] The moving fluid hits a turbine-generator. A turbine is essentially a fan being allowed to operate in reverse, with the fluid moving the turbine instead of the fan moving the fluid. This transfers the kinetic energy of the fluid to the turbine, increasing its kinetic energy. Similarly, a generator is essentially a motor being allowed to operate in reverse. The generator changes mechanical energy into electrical energy instead of the motor converting electrical energy into mechanical energy.

Why this droll lesson in the generation of electricity? There is no inventory of electricity. There is a near inventory of electricity in the form of the kinetic energy of the rotating turbine-generator, what previously had been referred to as mechanical energy. Accountants would call the kinetic energy of the rotating turbine-generator a nearly finished good. The finished good would be the electricity delivered into the grid and to the customers. The conversion process, from the kinetic energy of the rotating turbine-generator to the finished good of electricity, is nearly immediate. Thus, the kinetic energy of the rotating turbine-generator can be treated almost as if it were an inventory of electricity.

With many manufacturing processes, the speed at which a raw material is being processed will slowly change the inventory of finished goods available for sale. Similarly, the speed at which the finished good is delivered can change the inventory of the finished good. Indeed, the inventory of finished goods is dependent on the balance between the raw materials going into the manufacturing process and the deliveries of the finished good. So it is with electricity. For electricity, the rate at which fuel is burned or water is delivered through the dam can lead to a change in the kinetic energy of the rotating turbine-generator. The kinetic energy of the rotating turbine-generator is also affected by the rate at which consumers use electricity.

Economics of Electricity Generation

An inventory of electricity, or a near inventory of electricity, is an important economic concept. With a high inventory, economists predict low prices. With a low inventory, economists predict high prices. The relation between inventory and prices is experienced in the retail market every

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[2] The change in form is, of course, not necessary for wind energy. Mechanical engineers and similar professions will say that wind already is a moving fluid, even though most laymen don't think of wind and other gasses as fluids.

day through clearance sales at department stores and car lots. The United States famously experienced the concept in the 1970's when the Soviets had massive failures in their wheat harvests. The Soviets then secretly bought massive amounts of American wheat inventories. Almost overnight, available wheat inventories in the United States were depleted and spot wheat prices shot up. OPEC is similarly learning that it can control the price of oil indirectly by changing production levels. This indirect price control by OPEC is more effective than OPEC just trying to demand higher prices directly.

The kinetic energy of the rotating turbine-generator, as a near equivalent of the inventory of electricity, can be used as a predictor of the price of electricity. In terms of seam management, the kinetic energy of the rotating turbine-generator can also be used to set prices.

The kinetic energy of the rotating turbine-generator would nominally be calculated in terms of ergs, KWH, BTUs, or any other measurement used for energy. But because the rotating turbine-generator is indeed rotating, part of the calculation includes the speed with which the rotating turbine-generator is rotating, normally measured in rotations per minute (RPM). The rotational speed can be converted to cycles per second, or Hertz. In the United States and many other parts of the world, system operators try to keep the frequency of the network at 60 Hertz by controlling the speed of the rotating turbine-generator.[3]

The calculation of the inventory of the kinetic energy of the rotating turbine-generators connected to the grid is nominally an insurmountable task, considering the thousands of turbine-generators that connect to each grid. The inventory determination is simplified by the physics of the electric network. The rotating turbine-generators evenly share inventory with each other. As stated previously, there is no way to determine which power plant delivered which erg to a consumer. These ergs are fungible at each geographic point at each moment in time. So, when two or more sets of generators and their loads are joined together, the power flows freely among all the generators and all the loads. The free flow of electricity equalizes the frequency applicable to the power produced by each of the generators.

The equalization of the frequency allows a utility operator to determine how well generation is being matched with load. Figure 1 is a typical representation of supply and demand. The horizontal line represents an imbalance between supply and demand. This is the Area Control Error (ACE) previously mentioned. Utilities raise and lower generation levels to drive ACE to zero. Utility operators are so concerned about the balance between supply and demand that cost is almost not a consideration.

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[3] Not all parts of the world operate on 60 Hertz. European networks have their systems designed to operate at 50 Hertz. Some utilities in Japan operate at 50 Hertz and some at 60 Hertz.

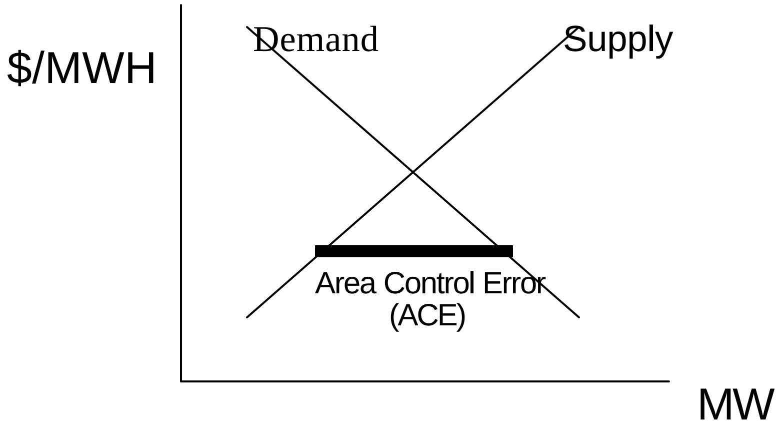

Figure 1: Utility Dispatch Considerations

The utility club has a rule about the free flow of electricity. Any energy borrowed due to the free-flowing nature of the grid must be paid back. NERC is in the process of formalizing the rule in its setting of the criteria for control areas. The most recent version of the NERC rules proposed by its Control Area Criteria Task Force (CACTF) continues the concept of a return in kind, keeping the industry in a club-like environment. CACTF has ignored suggestions that the rule should be a payment of cash for inadvertent interchange, not the return of the energy in the form of an erg for an erg. True competition will include cash payments representing the true value of the electricity being delivered.

Pricing Electricity Generation

Since the value of a commodity changes with the available inventory of the commodity, the inventory level of electricity can be used to set the price for inadvertent interchange and other unscheduled flows of electricity. Frequency is a measure of one near inventory of electricity. A second near inventory of electricity can be inadvertent interchange itself.[4]

Consider the situation where a small part of the electric network has decided to cash-out inadvertent interchange. The small part of the network seeking to cash-out inadvertent interchange internal to that part of the network has inadvertent interchange with the rest of the

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[4] Frequency and inadvertent interchange are merely two of many possible measurements for near equivalents of an inventory of electricity. Cumulative time error is another. Cumulative time error is the result of frequency deviations over an extended period of time. Mathematically, cumulative time error is the time integral of the frequency deviation. To a lesser extent, hydroelectric dams provide another near inventory for electricity. Operators can decide to produce electricity or to store water for the future production of electricity. A similar situation exists for other generation technologies that have limited fuel supplies, that have limited environmental authority to release pollutants, or that have prescribed maintenance cycles.

network. Such inadvertent interchange is electricity that has been produced by a utility, but not yet delivered to the customer of the utility, a true inventory of finished goods.

The electric industry has long recognized a commonality between system frequency and inadvertent interchange, creating Area Control Error (ACE) as a combination of the two items. ACE is defined to be inadvertent interchange as biased by the frequency deviation. A simple mathematical change of variables allows ACE to be the frequency deviation as biased by inadvertent interchange with the rest of the grid. The two definitions are almost equivalent and will be treated as such in this paper.

Formula 1 presents a pricing formula for inadvertent interchange based on ACE. The change of variables mentioned above allows the use of a frequency tolerance factor measured in Hertz/decade. This frequency tolerance factor can be used on any network without having to be adjusted for the size of the network. As the word "tolerance" implies, the factor may have to reflect local conditions relating to the toleration of the electric network for frequency excursions. For instance, India typically has frequency excursions close to 100 times that allowed in the United States. Thus, the tolerance factor for Formula 1 as applied in India might initially be close to 100 times the tolerance factor for Formula 1 that would be applied in the United States.

Basic WOLF Pricing Formula

$$\text{Price (\$/MWH)} = C1 * 10^{(-ACE)/C2} \qquad \text{Formula 1}$$

Where:

ACE = Area Control Error, a combination of frequency deviation and inadvertent interchange, measured in Hertz.

C1 = Nominal Price of electricity (e.g., $20/MWH)

C2 = Frequency Tolerance Factor (e.g., 0.020 Hertz/decade)

When the pricing formula is applicable to the entire grid, there is no inadvertent interchange with the rest of the grid and ACE simplifies to frequency deviation. Various articles have described methods for setting the nominal price of electricity based on cumulative time error, the integral of ACE.[5] Formula 1 will provide appropriate prices for seam management purposes with a wide range of frequency tolerance factors.

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[5] "WOLF Pricing," *Public Utilities Fortnightly*, 1994 October 1; and, "Real-Time Reliability Based Electricity Pricing," *1998 Proceedings*, Annual Reliability and Maintainability Symposium, Anaheim, California, 1998 January 19-22. Also see footnote 4.

Formula 1 is a Walrasian auction. Leon Walras (1834--1910) studied the dynamics of the market, explaining it as an unusual two-step auction, an auction with no bidding. Walras hypothesized the existence of a village that produced and consumed a fungible commodity such as widgets. Each morning, the auctioneer would survey the producers and consumers for a feeling of their supply and demand curves. The auctioneer would announce a nominal price for the widgets to be traded that afternoon. In the afternoon, when the producers brought their widgets to the market and the consumers brought their money, the auctioneer would adjust the nominal price based on the actual imbalance between supply and demand. The adjustment would produce a final transaction price. In the same way, Formula 1 begins with a nominal price and adjusts that nominal price based on the actual imbalance between supply and demand.

The auction achieved through Formula 1 is repetitive, recurring every few seconds. The repetitive nature of Formula 1 allows the nominal price to be adjusted between each auction, as discussed above. One option is to use cumulative time error to modify the base price. The frequency error producing the adjustment will also cause the cumulative time error to change. The change in the cumulative time error would then change C1, the Nominal Price of Electricity, for the next round of the auction. Formula 1 is driven only by the imbalance between supply and demand. Therefore, the change in C1, the Nominal Price of Electricity, will drive the price produced by Formula 1 closer and closer to the optimal price for electricity, the equilibrium price which is the mantra for most economists.

Table 1 presents the result of applying Formula 1 to the frequency profile of the Eastern Interconnection during 2000. Figure 2 is a histogram of the frequencies for the 17,568 half-hour periods during that leap year. The range for each block of the histogram was 0.005 Hertz centered on the indicated frequency.

As shown on the first line of Table 1, during 2000 the Eastern Interconnection had 2 half-hour periods when the average frequency was exceedingly low, between 59.9525 Hertz and 59.9575 Hertz, the range that is centered on the indicated 59.955 Hertz. The frequency error is calculated as the difference between 60 Hertz and the actual frequency. For this line of Table 1, the frequency error was thus between –0.0425 Hertz and –0.0475 Hertz. Formula 1 produces a WOLF price of $3,556.56/MWH when the frequency error is –0.045 Hertz, the mid point of the first block.

The actual average frequencies for the two half-hour periods with the lowest frequency were 59.9560 Hertz and 59.9573 Hertz. The frequency errors were -0.0440 Hertz and –0.0427 Hertz. Formula 1 produces prices of $3,170.14/MWH and $2,718.42/MWH for these frequency errors. Applying the same detail calculation of Formula 1 for each of the 17,568 half-hour periods during 2000 results in an average price of $41.68/MWH. The average cumulative time error in 2000 was positive, i.e., the clocks were ahead of actual time. Unless producers and consumers were allowed to react to these prices, the adjustment to C1, the Nominal Price of Electricity, would have reduced the average price below the stated average of $41.68/MWH.

HYPOTHETICAL FORMULA 1 PRICES FOR 2000 EASTERN INTERCONNECTION USING HALF HOUR AVERAGE FREQUENCY

Table 1

System Frequency (Hertz)	Frequency Error (Hertz)	WOLF Price Range ($/MWH)	Number of Periods
59.955	-0.045	3,556.56	2
59.960	-0.040	2,000.00	2
59.965	-0.035	1,124.68	19
59.970	-0.030	632.46	77
59.975	-0.025	355.66	248
59.980	-0.020	200.00	578
59.985	-0.015	112.47	1,101
59.990	-0.010	63.25	1,685
59.995	-0.005	35.57	2,687
60.000	0.000	20.00	3,776
60.005	0.005	11.25	3,659
60.010	0.010	6.32	2,201
60.015	0.015	3.56	992
60.020	0.020	2.00	345
60.025	0.025	1.12	128
60.030	0.030	0.63	52
60.035	0.035	0.36	13
60.040	0.040	0.20	3

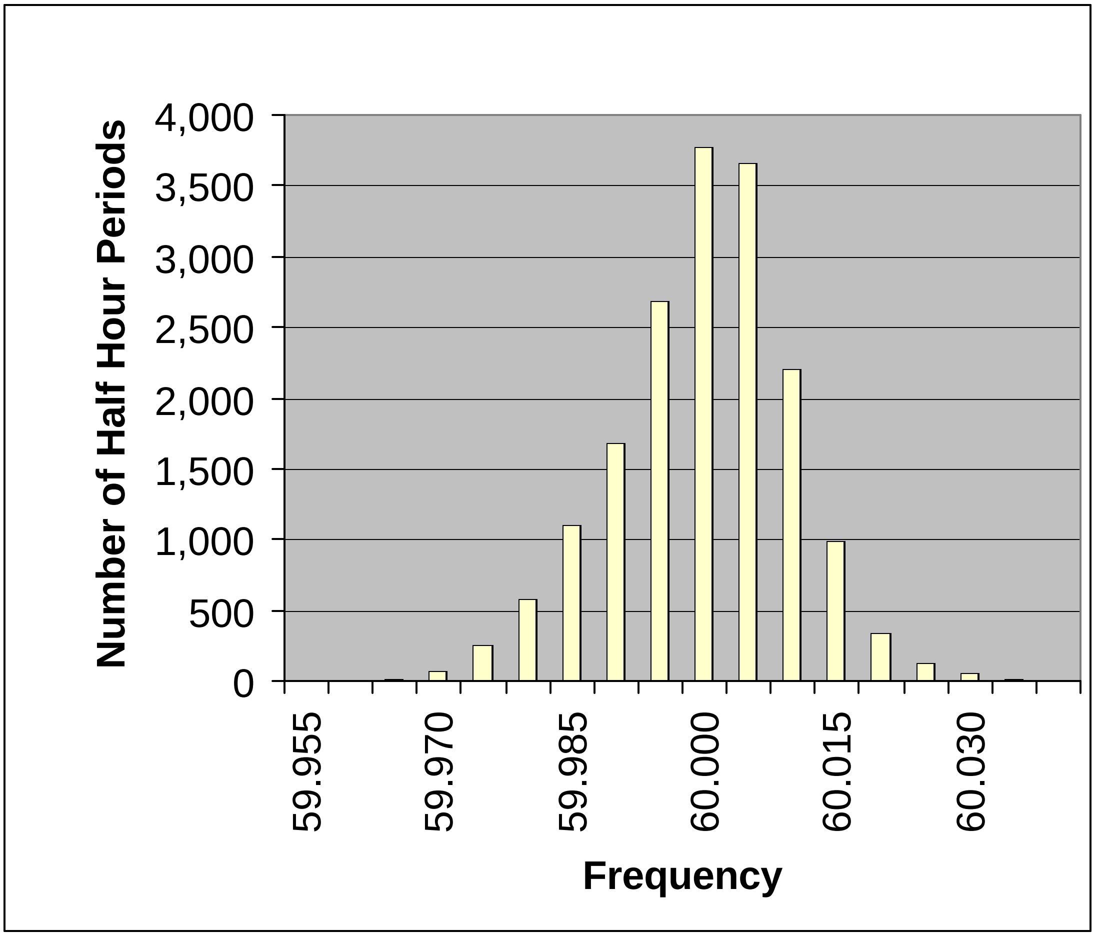

Figure 2: Eastern Interconnection Frequency Excursions - 2000

Decentralizing the Central Market

The transmission system ties electric utilities together into a large unified system. Because of the transmission system, generators in Texas and Florida provide some of the electricity consumed in Maine and Minnesota, and vice versa. The transmission system connecting these diverse locations have certain physical attributes. These physical attributes include electrical line losses and constraints on the amounts of electricity that can move across individual power lines or across groups of power lines that form the interface between utility systems.

The movement of electricity over long distances has led some to question the assumption that loop flow generally results in a net decrease in electrical losses for all utilities. This is especially true when several utilities are moving electricity from and to the same general area. Further, some utilities are now selling the right to move electricity across their lines. The profit earned by such utilities lessens the club-like atmosphere that was once associated with loop flow. That one utility is making money from the movement of electricity from point A to point B leads other utilities providing such a path to want to earn money for the movement of electricity along their own lines. Thus jealousies arise when some utilities are able to sell wheeling services that resulted in loop flow on lines owned by other utilities.

The physical attributes of transmission lines effect the economics of the central market for electricity.

- Electrical line losses affect the relative merit of dispersed generation. Utility dispatch systems recognize the effect of line losses by modifying the concept of Equalized Lambda. The standard Equalized Lambda concept includes an adjustment factor for the marginal line losses between a generator and a central location. Thus, the equalization of the marginal cost of each generator includes both the actual cost of the generator at its plant site and the marginal cost to move the electricity to a central location.

- Transmission constraints can prevent some low cost generation from competing with high cost generation. Utility dispatch systems recognize transmission limitations by operating some units on an “out of merit” basis. In essence, the operation of units “out of merit” sets up a separate dispatch area whose interaction with the rest of the grid is constrained by the amount of electricity permitted to be scheduled in or out of the separate dispatch area.

The auction of inadvertent interchange must be geographically differentiated to reflect the physics of the transmission system. WOLF differentiates the auction geographically to reflect both transmission limitations and the marginal line losses experienced on the network. WOLF prices are for points on the network. The geographic auction of inadvertent interchange results in different prices for a utility’s inadvertent interchange at each interchange point the utility has with other utilities. These differing prices provide an effective way to cash-out parallel path flow and other forms of loop flow.

The Physics of Transmission

A common aphorism is that electricity follows the path of least resistance. In practice, electricity follows all available paths, splitting among the available paths in the way that results in the least electrical loss on the network as currently configured. Thus, when there are several possible paths for electricity to travel between two points, some of the electricity will travel on each path. The unscheduled flow of electricity across electrical lines owned by another company is called loop flow.

The “loop” designation relates to the closed path created by the combination of two paths: the path over which the electricity was supposed to flow, and the path over which the electricity did flow. The amount of the loop flow could be subtracted from each of the lines identified by the two paths to determine the flows of electricity that would have occurred without the interconnection between the two utilities.

Loop flow has an algebraic effect, in that sometimes it results in an increase in the electrical flow along some lines and a decrease in the electrical flow along other lines. An increase in electrical flow will increase the electrical line losses incurred on the lines, with additional heat released into the environment. A decrease in electrical flow will decrease electrical line losses.

Loop flow will almost always reduce the total electrical losses on the network. When only two utilities are considered, there are three likely results.

- The first utility can incur increased electrical losses while the second utility enjoys a net decrease in electrical losses.
- The second utility can incur increased electrical losses while the first utility enjoys a net decrease in electrical losses.
- Both utilities can enjoy a net decrease in electrical losses.

The “good old boys’ club” handled the loop flow issue by ignoring the loop flows, especially since the most common loop flow result was that both utilities enjoyed a net decrease in electrical losses. At least that was the common, though unproven, assumption.

As more utilities are connected together, the number of possible results expands exponentially with the number of interconnection points. There can be almost any combination of utilities incurring increased electrical losses. The rest of the utilities will enjoy a net decrease in electrical losses. The only result that should not occur is for each utility to incur an increase in electrical losses.

The movement of electricity through wires results in electrical line losses. Wires heat up. Electrical losses in a transmission line are roughly proportional to the square of the power flow through the transmission line. When the power flow doubles, the actual line losses will roughly quadruple. If actual line losses are 0.5 MW at 100 MW, actual line losses will be about 2 MW at 200 MW. The relative losses double from 1/2% to 1% while the actual line losses are four times as large.

System operators are very interested in line losses on a marginal basis. Marginal line losses relate the change in actual losses to the change in total load. On a percentage basis, marginal line losses are nominally twice average line lines. Continuing the above example, marginal line losses would be 1% at 100 MW and about 2% at 200 MW. If the line loading were about 100 MW and were increased by 1 KW, we would expect the electrical losses to be increase by 1% of 1 KW, or 0.01 KW. A 1 KW line loading increase at 200 MW would cause line losses to increase by 2%, or 0.02 KW.

Figure 3 illustrates the concept of loop flow and marginal electrical losses. Two utilities are initially connected at a single location, “a”. For Utility X, “a” is a major load center. For Utility Y, “a” is a major generation center. Utility X incurs electrical losses to move electricity from its generator to “a”. If Utility X added generation at “a” to meet an increase in load at “b”, Utility X would experience a decrease in its electrical losses equal to 5% of the generation added at “a”. Similarly, Utility Y incurs electrical losses to move electricity from its generator to “c”. If Utility Y added more generation at “a” to meet an increase in load at “c”, Utility Y would experience an increase in its electrical losses equal to 6% of the generation added at “a”.

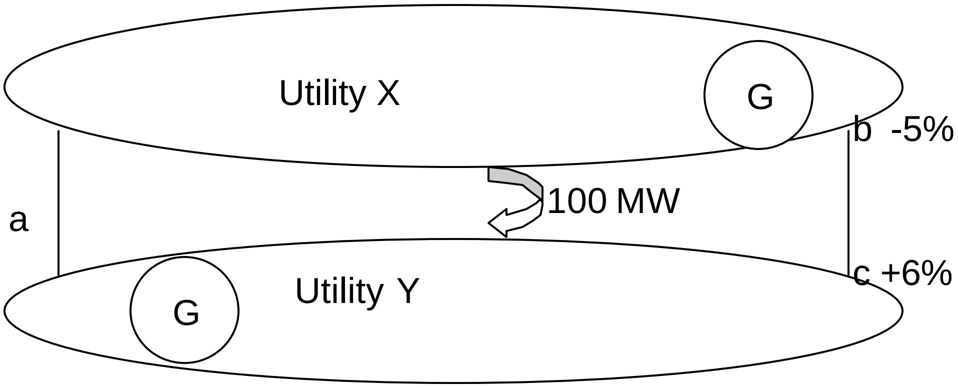

Figure 3: Marginal Loss Example

The line at the right of Figure 3 is a very short transmission line that could be added between “b” and “c”, making the two points electrically equivalent. If the line were to be added, there would be loop flow in a clockwise direction. Electricity would flow at “a” from Utility Y to Utility X. Electricity would also flow from Utility X at “b” to Utility Y at “c”. Both utilities should experience a decline in electrical line losses. The marginal line losses between “a” and “b/c” would be somewhere between the “–5%” that Utility X had been experiencing and the “6%” that Utility Y had been experiencing. The resulting marginal lines losses will depend greatly on the relative sizes of the two utilities and the strength of their transmission systems.

Each transmission line has a limit on the amount of electricity that can be moved. Some of these limits relate to thermal capacity. The electrical losses heat the wires and the wires expand. The longer wires sag more. Sagging wires can come too close to items under the wires, resulting in a flash of electricity from the wires. Other limits relate to the stability of the network. For instance, the sudden loss of one transmission line may cause the cascading loss of other transmission lines. Then, with too many lines suddenly down, parts of the system may go black. When transmission limits are reached, utility dispatchers send “out of merit” signals to generators to limit the overload on the transmission lines.

Figure 4 is a modification of Figure 3. A transmission constraint exists that limits the desired flow of electricity from left to right to 275 MW. The actual flow across the constrained interface is 300 MW. This results in an excessive loading of 25 MW. Utilities will react to the situation in Figure 4 by increasing generation on the right side of the constraint and decreasing generation on the left side of the constraint. If the overload becomes intolerable, utilities will institute rotating blackouts on the right side of the network. Such rotating blackouts are considered to be better than waiting for a disturbance that could cause the entire network to go black.

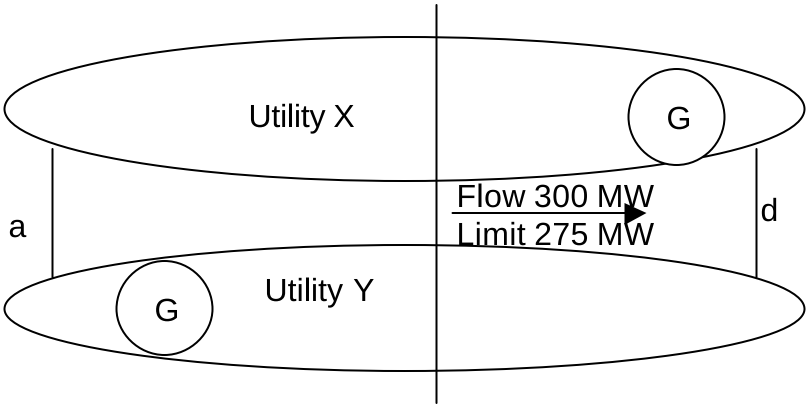

Figure 4: Transmission Constraint Example

Under the current NERC rules, and also under FERC regulations, there would be no payment between Utility X and Utility Y for the loop flow being experienced, unless a specific contract were signed for a wheeling transaction. Neither utility is incurring a cost for which the other utility would be deemed to be responsible. In fact, both utilities are enjoying a decrease in operating costs. But the loop flow is the result of a seam between the two utilities. In a competitive environment, there should be payment for the use of each other's wires.

Transmission Economics

Marginal line losses provide a way to compare the value of two generators miles apart. Consider two power plants at either end of the single transmission line mentioned earlier, the one that has marginal line losses of 1% at 100 MW. Consider the situation when the upstream generator is operated at a marginal cost of $20/MWH and the line is loaded at 100MW. At this load level, the transmission line has postulated marginal losses of 1%. In this situation, the downstream generator should be operated at a marginal cost of $20.2/MWH.

When the same line is loaded at 200 MW, marginal losses would be 2%. The marginal cost at the second power plant should then be $20.4/MWH. Thus, the second power plant should adjust its output until its marginal cost of operation is $20.40/MWH. The mathematics for the economics behind this concept is presented in most power engineering textbooks under the topic of Equalized Lambda.

Marginal electrical losses are independent of the route selected for their calculation. Thus, the marginal electrical losses are the same for both utilities involved in the two utility loop flow example presented in Figures 3 and 4. Therefore, once utilities agree to a price at one location, a consistent network of prices is agreeable to the utilities at all locations.

Transmission Pricing

Loop flow jealousies led to the General Agreement on Parallel Path (GAPP) protocol. A few utilities even implemented GAPP on an experimental basis. Industry practice identifies utilities that contract to provide a path for the scheduled flow of electricity. Electricity scheduled across the contract path will actually flow across all of the lines on the interconnection on an unscheduled basis. The GAPP procedure calculated the portions of scheduled wheeling services that went across the wires of utilities not on the contract path. Under GAPP, the provider of the contract path then shared its revenue with the GAPP participant that owned the parallel paths. The GAPP experiment lasted two years and had mixed results. The GAPP protocol would be ill suited for seam management.

Long before the GAPP experiment, individual utility control room operators dealt with the issue of geographic differentiation of the value of electricity. Utility operators had to decide which power plants to dispatch. They based the decision on different fuel costs and limited transmission capability between the disparate parts of a utility's network. Utility engineers developed two protocols to handle the need for geographic differentiation: recognition of marginal line losses, and a so-called excursion from economic dispatch. The latter practice is referred to as a “so-called” excursion because the practice is merely an extreme version of the recognition of marginal line losses. Generators are still being dispatched as economically as possible. Not as economically as if the transmission capability were greater, but still more economically than if the generators were not connected with any transmission wires.

Recognizing Marginal Line Losses

Electric utilities have long acknowledged that marginal line losses provide the best way to compare the instantaneous value of generation in one location with the value of generation in another location. The application of the concept is shown in Formula 2.

Varying Price With Electrical Losses Between Locations

Price (L1) = Base Price * (1+Marginal Losses (L1)) Formula 2

Where:

Prices are in $/MWH

L1 = An identified remote location

Marginal Losses (L1) = Marginal losses between the remote location L1 and the central station (can be positive or negative)

The prices developed by Formula 2 depends on the marginal loss factor at “b/c” relative to “a”. As postulated above in the discussion of Figure 3, this marginal loss factor will be a weighted average of the “-5%” at “b” and the “+6%” at “c”. Table 2 presents a range of payments under the assumption that the loop flow is 100 MW in a clockwise direction and that the base price at “a” is $20/MWH. Utility X pays for the 100 MW it receives at “a” and is paid for the 100 MW it delivers at “b/c”.

LOOP FLOW PRICING EXAMPLE
FOR 100 MW OF CLOCKWISE FLOW IN FIGURE 4

Table 2

	Analysis at "a"		Analysis at "b/c"		Net
Loss Factor	Price ($/MWH)	Payment X to Y ($/hour)	Price ($/MWH)	Payment Y to X ($/hour)	Payment X to Y ($/hour)
-4%	20.00	2,000	19.20	1,920	80.00
-3%	20.00	2,000	19.40	1,940	60.00
-2%	20.00	2,000	19.60	1,960	40.00
-1%	20.00	2,000	19.80	1,980	20.00
0%	20.00	2,000	20.00	2,000	0.00
1%	20.00	2,000	20.20	2,020	-20.00
2%	20.00	2,000	20.40	2,040	-40.00
3%	20.00	2,000	20.60	2,060	-60.00
4%	20.00	2,000	20.80	2,080	-80.00
5%	20.00	2,000	21.00	2,100	-100.00

The first row in Table 2 is for a loss factor at "b/c" of "–4%" relative to "a". Under the assumption that the loss factor at "b/c" is "-4%" relative to "a", the new line between "b" and "c" had relatively little effect on the electrical losses experienced by Utility X, but a major impact on the losses experienced by Utility Y. The net flow through Utility Y completely reversed direction. This could increase the electrical losses incurred by Utility Y. The net of the payments for the deliveries at "a" and at "b/c" reflects this possibility.

From the perspective of Utility X, the new line has reduced its electrical losses by 4.5% of the 100 MW loop flow, or by 4.5 MW. The marginal loss factor before the connection was 5%. The marginal loss factor after the interconnection is 4%. The marginal loss factor for the 100 MW should be the average of these two values, or the 4.5% used in this calculation. At a value of electricity of $20/MWH, Utility X is reducing its internal costs by $90/hour. Since Utility X is making a net payment of $80/hour to Utility Y, Utility X is enjoying net savings of $10/hour.

From the perspective of Utility Y, the new line first reduced its electrical losses by 5.0% of the 100 MW loop flow, or by 5.0 MW and then increased it to 5.0% of the 100 MW loop flow. The losses are thus nominally the same as before on Utility Y, just in different locations. Since Utility X is making a net payment of $80/hour to Utility Y, Utility Y is nominally enjoying net savings of $80/hour.

Transmission Constraints

The so-called excursions from economic dispatch are merely an extension of the method utility dispatchers use to recognize marginal transmission losses. The difference between the two concepts is a matter of degree. Marginal transmission losses are generally less than 10%, though they can, of course, be higher. Thus, the marginal value of generation at one station is within 10% of the marginal value of generation of other stations. Excursions from economic dispatch are generally much greater than 10%. The marginal value of some stations can be double or hundreds of times the value of other stations. Formulas 3 and 4 present a way to set these relative prices.

Price Varies With Violated Constraints on Transmission System

Price (L1) = Base Price * $10^{A*Excess/C3}$ Formula 3
Price (L2) = Base Price * $10^{-B*Excess/C3}$ Formula 4

Where:

Prices are in $/MWH
L1, L2 = Identified locations
A = Price Allocation Factor for areas downstream of the constraint
B = Price Allocation Factor for areas upstream of the constraint (equal to 1 – A)
C3 = Excess loading tolerance factor (e.g., 50 MW/decade)

Implementation of Formulas 3 and 4 will result in prices similar to those shown in Table 3. As suggested earlier, Formulas 3 and 4 would only be used when there are transmission constraints. Further, the use of Formulas 3 and 4 will generally result in greater price disparities than the 5% and 6% shown in Figure 3, such as demonstrated in Figure 4 and Table 3.

Table 3 presents the calculations specified in Formulas 3 and 4. Absent the constraint, the base price of electricity in the network is $20/MWH. In this case, the downstream portion of the grid is expected to bear the greater effect of the price change, 80% at “d” versus 20% at “a”. The difference between the flow of 300 MW and the limit of 275 MW results in an overload of 25 MW, not shown in Table 3. Since the excess loading tolerance factor is 50 MW, the overload is a factor of 0.50, or half the tolerance. The nominal effect is to change some prices by a factor of 3.16 (the square root of 10.0, as specified in the formula.) The factor change is allocated mostly to “d”. As a result, the price at “d” increases by a factor of 2.51. The factor is also allocated to "a". As a result, the price at "a" decreases by a factor of 0.79. These prices only apply to unscheduled flows of electricity, as is demonstrated in Table 4.

TRANSMISSION CONSTRAINT PRICING EXAMPLE

Table 3

Location	Base Price ($/MWH)	Allocation Factor	Flow (MW)	Limit (MW)	Tolerance Factor (MW)	Price ($/MWH)
a	20	0.2	300	275	50	15.88
d	20	0.8	300	275	50	50.23

As shown in Figure 4, there is a path in the network that is overloaded. The desired maximum flow for left to right is 275 MW, but the actual flow is 300 MW, for a nominal overload of 25 MW.

- Pursuant to Formula 3, the overload results in a price increase in the area downstream of the overload. The price at "d" increases from the nominal price of $20/MWH to $50.23/MWH. The price increase encourages generators in the right in the Figure 4 to increase production. Presumably the price of $50.23/MWH is substantially above the marginal cost of production.

- Pursuant to Formula 4, the overload results in a price decrease in the area upstream of the overload. The price at "a" decreases from the nominal price of $20/MWH to $15.88/MWH. The price decrease encourages generators on the left in the Figure 4 to decrease production. Presumably the price of $15.88/MWH is substantially below the marginal cost of production.

The actual net payment will depend on the unscheduled flows. In Figure 4, the assumption had been that the total flow was 100 MW in a clockwise direction. Table 4 shows the interaction of pricing unscheduled flows of electricity with various contracts the two utilities might have to provide transportation for each other.

Table 4 presents eight combinations showing variations of which utility is providing the transportation service, which way the transportation service was been scheduled, and two possible levels of scheduled service. All of the scheduled services are priced at a rate of $2.00/MWH. The actual flow in each case is the previously hypothesized 100 MW in a clockwise direction.

Based on the Table 4 convention of viewing all transactions from the perspective of Utility X, positive service schedules indicate that Utility X is providing the scheduled service. Accordingly, when Utility X receives the wheeling fee, the wheeling fee is positive, as occurs in the top half of Table 4. The negative service schedule indicates Utility Y is providing the service. The negative wheeling service fees in the bottom half indicates that Utility X is paying that amount.

EFFECT OF WHEELING ON PAYMENT FOR UNSCHEDULED FLOWS
(PAYMENTS ARE STATED FROM THE PERSPECTIVE OF UTILITY X)

Table 4

		Wheeling Service			Loop Flow			
Seller	Direction	Schedule (MW)	Price ($/MWH)	Fee ($/hour)	Flow (MW)	Price ($/MWH)	Fee ($/hour)	Net Revenue ($/hour)
X	Clockwise	75	2.00	150.00	25	34.35	858.78	1,008.78
X	Counter	75	2.00	150.00	175	34.35	6,011.45	6,161.45
X	Clockwise	125	2.00	250.00	-25	34.35	-858.78	-608.78
X	Counter	125	2.00	250.00	225	34.35	7,729.01	7,979.01
Y	Counter	-75	2.00	-150.00	175	34.35	6,011.45	5,861.45
Y	Clockwise	-75	2.00	-150.00	25	34.35	858.78	708.78
Y	Counter	-125	2.00	-250.00	225	34.35	7,729.01	7,479.01
Y	Clockwise	-125	2.00	-250.00	-25	34.35	-858.78	-1,108.78

The loop flow is the difference between the service schedule and the actual flow of 100 MW in the clockwise direction. On the first line, Utility Y was buying clockwise service of only 75 MW. For this Utility Y would pay $2/MWH, or $150/hour. There was 25 MW of unscheduled flow in a clockwise direction. Utility X was delivering electricity at “d” to Utility Y that is worth $50.23/MWH at the same time that Utility Y is delivering electricity at “a” to Utility X that is worth only $15.88/MWH. The price differential is $34.25/MWH. The 25 MW of loop flow thus results in a payment of $858.78/hour from Utility Y to Utility X. The wheeling fee of $150/hour raises the net income to Utility X to $1,008.78/hour.

On the second line of Table 4, Utility Y is buying 75 MW of counter clockwise service from Utility X. This exacerbates the loop flow issue, since the unscheduled flow is the difference between the scheduled flow of 75 MW in the counter clockwise direction and the actual flow of 100 MW in the clockwise direction. Ideally, Utility Y would have eliminated the scheduled flow of 75 MW, since the scheduled flow was in the opposite direction of the actual flow. Not only would Utility Y have saved its wheeling fee, but also Utility Y would not have had to pay so much for loop flow.

Reactive Power

Most electric utilities operate an AC (alternating current) grid. As discussed previously, the frequency of the AC system in the United States is approximately 60 Hertz, meaning that the voltage cycles between being positive and negative approximately 60 times a second. Similarly, the current delivered to a customer will alternate between being positive and negative at the same rate of approximately 60 times a second. Though the frequency and voltage both oscillate at the same frequency, they are often out of phase with each other: sometimes the current will be leading the voltage, sometimes the current will be lagging the voltage.

The phase difference between the voltage and the current is the result of non-resistive or reactive loads on the network. Some reactive loads require the current to lead the voltage. A common reactive load with a leading current requirement is the load associated with fluorescent lights. Some reactive loads, such as motors, require the current to lag behind the voltage. Some items, such as transmission lines, impose a reactive load that varies between being leading and lagging.

Reactive loads can have several deleterious effects on electric grids. First, reactive loads take up some of the capacity of the transmission system. By taking up some of the capacity of the transmission system, reactive loads reduce the amount of real power that can be transferred on a set of lines. Second, reactive loads increase transmission line losses. Line losses increase with the sum of the reactive and resistive power carried on the transmission line. In some respects, the loss of transmission capacity and the increase power losses are related maters. The relation between these two issues is based on the thermal capability of the lines.

Reactive loads can also change the voltage on the lines. Leading reactive loads increase the voltage above nominal. Lagging reactive loads decrease the voltage below nominal. Though utilities can and do adjust the operation of their generators to produce reactive power, this is often inefficient. Instead, utilities try to reduce electrical losses and increase the capability of the wires to carry real power. The efficiency of the transmission system can be improved by producing reactive power closer to the associated loads, such as at distribution substations or at the sites of major customers.

Reactive power can be an important seam management issue, with its importance being determined by the voltage at the delivery point. Formula 5 can be used to set the price for reactive power. Reactive power is seldom scheduled between utilities. Unless a transfer of reactive power is scheduled, the price would be applicable to the entire reactive power flow at an interchange point.

Example of Formulary Auction of Inadvertent Interchange

Reactive Power Price Varies With Local Voltage

Price ($/MVAHR) = C4 * Energy Price * $(10^{Volt/Nom} - 10^{Nom/Volt})$ Formula 5

Where:

Price is credit for lagging reactive power and charge for leading reactive power

Energy Price is in $/MWH

Volt = Voltage at the metering location

Nom = Nominal Voltage at the metering location

C4 = Reactive Power conversion factor (e.g., 10 [$/MVAHR]/[$/MWH])

Supply and Demand Concepts

WOLF pricing for seam management is consistent with the economic concepts of supply and demand. Electricity is produced at the same time that consumers demand it. Imbalances between demand and the primary energy source (such as fuel into the boiler or water moving through a dam) result in inadvertent interchange with neighboring utilities, or a change in the frequency at which the turbine-generators rotate. Utility operators use these phenomena to control their generators. These phenomena can also be used to set the price paid for unscheduled flows of electricity.

Utility operators control their systems by matching the total supply of electricity to the total demand for electricity, including electrical losses. But a utility does not have real-time meters on every load, and certainly does not have meters to indicate the demand associated with electrical losses. Though a utility can measure its total generation, there is thus no load measurement against which the utility should balance the generation level. Utilities learned that they did not need to measure load. They could just as easily measure the difference between load and generation by measuring inadvertent interchange and frequency error.

As previously discussed, an isolated utility will be able to determine whether its generation is in balance with its load by the resulting system frequency. A surplus of generation will push the frequency up. A shortage of generation will push the frequency down. An interconnected utility will be able to determine whether its generation is in balance with its load by the resulting inadvertent interchange. A surplus of generation will cause the utility to export inadvertent interchange, and a shortage will cause the utility to import inadvertent interchange. Global imbalances, totaled across all of the interconnected utilities, will have the same effect on frequency as a local imbalance has on an isolated utility.

Every few seconds, utilities calculate Area Control Error (ACE), a combination of inadvertent interchange and frequency error. When the utility is exporting power and the frequency error is positive, ACE is positive. When the utility is importing power and the frequency error is negative, ACE is negative. The relative sizes of inadvertent interchange and the frequency error will determine whether ACE is positive or negative in the other two situations: exporting power while frequency is low, and importing power when frequency is high.

Based on ACE, a utility operator will tell its generators to increment or decrement generation. At the same time, the utility operator will also analyze the relative merits of the generators under its control. Based on this analysis, the utility operator may tell some generators to increase generation while other generators are told to decrease generation. The marginal electrical losses on the network can be an important issue in this controlled competition among a utility's generators.

Global orders to increment or decrement generation can be translated into global orders to increase or decrease the settlement price for unscheduled flows of electricity, as is demonstrated in Figure 5, a typical supply and demand curve from classical economics. The horizontal axis is measured in Power (MW). The vertical axis is measured in Price of Energy ($/MWH). The intersection of the supply and demand curves defines the equilibrium price, where economic efficiency is optimized.

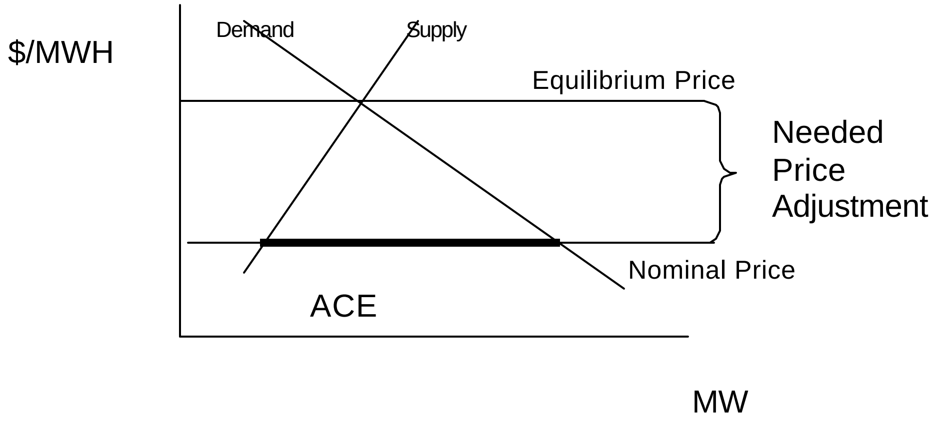

Figure 5: Needed Price Adjustment

Figure 5 introduces a second price, which is labeled as the nominal price. For demonstration purposes, the nominal price has been selected to be lower than the equilibrium price. The nominal price can also be higher than the equilibrium price. From left to right in Figure 5, the nominal price first crosses the supply curve and then the demand curve. This segment of the nominal price line is highlighted. The length of the line segment represents ACE, the area control error mentioned above. At this nominal price, the demand for electricity exceeds the supply and ACE is defined as being negative.

With ACE negative, utility operators will call for generators to increment production. According to Figure 5, the nominal price needs to be adjusted upward toward the equilibrium price. The size of the price adjustment is proportional to the size of ACE. The price should continue to be adjusted upward until the equilibrium price is reached. When the equilibrium price is reached, ACE will be zero. This is consistent with the way utility operators control generators. The operators will continue to send out signals to increment production until ACE is zero.

The delicate balance necessary to achieve a zero ACE is generally elusive. The former NERC operating procedure recognized this delicate balance by specifying that ACE must cross zero within ten minutes after the last time ACE crossed zero. Indeed, since ACE is calculated every few seconds, ACE may never actually equal zero, in that the crossing of zero may happen between the instances when ACE is being calculated from the various metered data. In regard to the histogram of the Eastern Interconnection presented earlier, only 258 of the half hour periods achieved an **average** of zero frequency error, let alone managed to maintain frequency error equal to zero for an extended period of time. This suggests that the nominal price is almost always different from the equilibrium price and needs to be adjusted.

Utility operators repetitively send signals for generators to increment or decrement production. The decisions to send such signals are based on the concurrent measurement of ACE. Some knowledge of the transitions that are occurring is required. For example, it is useful to know if a particular unit is ramping up or down or that load is expected to change in a particular way. The decision to adjust the nominal price is a hunt for the equilibrium price, which should be based on the concurrent measurement of ACE. Research suggests that the adjustment to the nominal price should be independent of any "knowledge" of anticipated transitions in production levels. Despite this, knowledge of those transitions may be an important part in the decision process of individual generators in responding to the price for unscheduled flows.

Benefits of Using WOLF for Seam Management Pricing

WOLF provides a competitive market price for unscheduled flows of electricity across the seams between utilities, ISOs, and/or RTOs. The WOLF pricing mechanism allows the participants to influence the prices that they pay or are paid for unscheduled flows of electricity, including inadvertent interchange, loop flow, and reactive power. WOLF changes prices in a manner consistent with the change sought by participants as they react to the WOLF prices. High WOLF prices encourage additional generation or lower load. Additional generation and lower load will both cause the WOLF prices to drop, automatically. This feature of WOLF also encourages participants to improve the reliability of the network. When reliability of the network is threatened, the WOLF price reacts to encourage participants to ease the conditions threatening the reliability of the network. This is especially true when the problem is transmission line overloads. Not only does the WOLF price increase to discourage load downstream of the constraint but also the WOLF price decreases to discourage generation upstream of the constraint.

Self-Correcting Prices

WOLF changes the seam management price to reflect the value of electricity to the entities delivering and receiving the unscheduled flow of electricity, as is illustrated in Figure 6. Seam management is generally discussed as an issue involving two or more of the following: vertically integrated utilities, generation and transmission cooperatives, independent system operators, regional transmission organizations, or federal agencies. For these entities, each is responsible for the real time balance between the needs of its customers, and the supply coming from generators. The generators are owned by or under contract to the utility.

Figure 6 presents the net imbalance curve for a single utility. The imbalance curve is the difference between the utility's supply and the utility's demand at various pricing levels. The imbalance curve is calculated as the surplus of supply over demand. Thus the imbalance curve has the upward sloping characteristic of a supply curve. The imbalance curve is centered on "0" (zero), since the utility is supposed to maintain its imbalance at zero. The internal equilibrium price is the price level where the imbalance curve crosses zero.

Figure 65also presents a WOLF pricing curve developed pursuant to Formula 1. The WOLF pricing curve is downward sloping, due to the negative number in front of the exponent. In Figure 6, the nominal price used in Formula 1 has been set at a level that is greater than the internal equilibrium price for the utility's imbalance curve. The high nominal price creates a situation where the utility might claim that the WOLF price is unreasonably high, since the WOLF price is higher than the utility's internal equilibrium price.

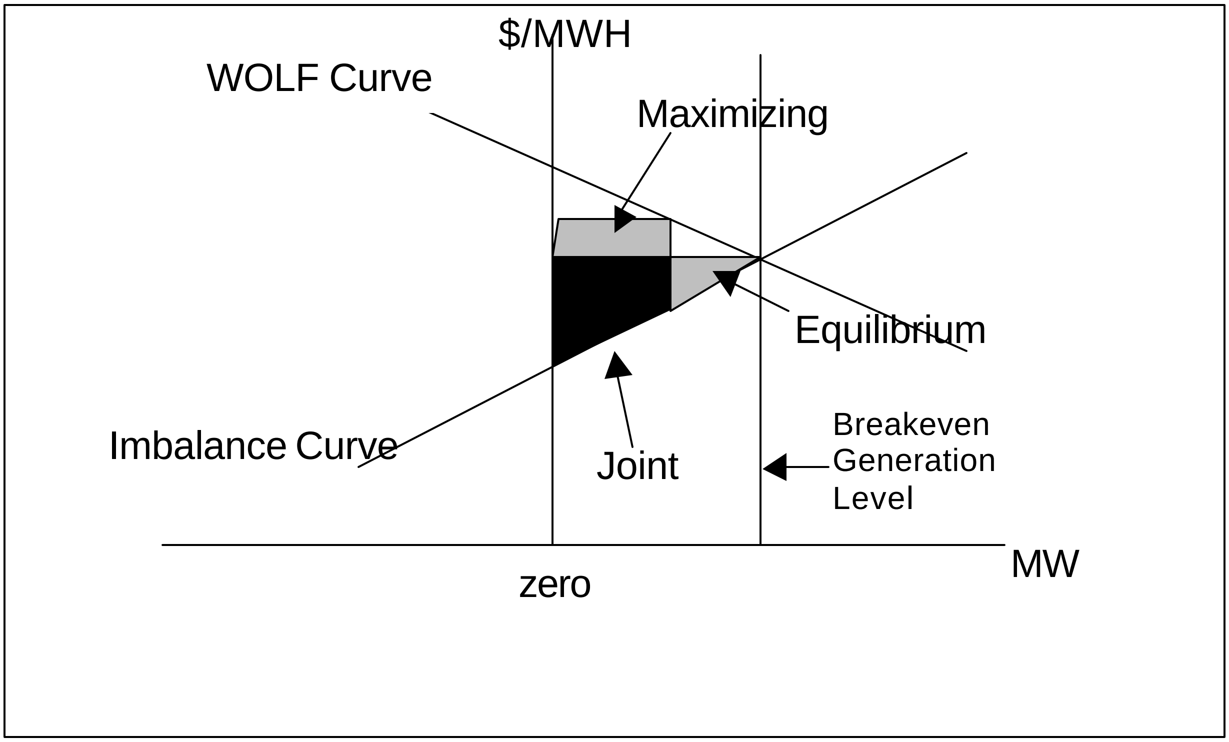

Figure 6: Pricing Curves and Profit Potential

The "good old boys' club" has rules that coax, but do not force, a utility to balance its internal supply and demand. For many years, such coaxing included the publication of an "honor roll" of utilities that had done a good job of balancing their internal supply and demand. But no money changed hands if a utility did a bad job of balancing its internal supply and demand. In a competitive market, such as is envisioned for the electric industry, money would change hands when a utility is out of balance.

In Figure 6, the utility is encouraged by the high prices to be out of balance. The utility earns revenue by generating more electricity than is needed by its customers. The WOLF price is postulated as being too high, at least relative to the utility's internal equilibrium price. The utility has an economic incentive to enhance its profitability by increasing generation and by decreasing load until the value of its marginal supply and marginal load is equal to the WOLF price.

Because of the structure of Formula 1, the increased utility generation lowers the WOLF price while raising the utility's marginal cost. For its actions, the utility earns the profit shown in

Figure 6. Note that the utility has several incentives to withhold generation. These incentives would cause the utility operate at less than the breakeven generation level indicated in Figure 6.

- Utilities have a reliability responsibility to their customers. The importation or exportation of power increases the probability that a transmission outage can lead to a blackout. Thus the utility will seek to obtain some of the indicated profit shown in Figure 6, but could be deemed negligent in protecting its customers from outages produced by sudden imbalances during system emergencies. Even in a competitive market, utilities are still greatly concerned about the reliability of their networks and thus are likely to operate at some level less than the breakeven generation level indicated in Figure 6.
- The WOLF price is constantly changing, as is the utility's net balance curve. Further, the utility's net balance curve is a static concept, applicable if the utility's generation stays at a specific level long enough for various generators to reach dynamic equilibrium. Thus, a short-term or dynamic net balance curve is likely to be much steeper than the utility's nominal net balance curve. These uncertainties would lead the utility to stop short of the breakeven level indicated in Figure 6.
- The utility can increase its profit by withholding generation. The withheld generation will prevent the WOLF pricing curve from being reduced entirely to the utility's imbalance curve. The forgone profit associated with additional generation or reduced load can often be less than the increased profit associated with the higher WOLF price.

Some observers of the California market during 2000 and 2001 have accused independent generators of withholding generation to push up the market price. The evidence of widespread withholding of generation is of uncertain merit.

The effect on the utility's profit of withholding generation is also shown in Figure 6. The shaded areas represent three different contributions to the utility's operating income as a result of over generating in order to sell electricity at the WOLF price. When the utility increases production, the WOLF price declines.

One production level (as indicated on the horizontal axis of Figure 6) that could be chosen by the utility is to increase generation (move to the right on the horizontal axis) until the utility's internal marginal cost and the WOLF price meet. Under this generation plan, the utility's operating profit would be the sum of the two areas labeled **Joint** and **Equilibrium**. This production plan is similar to the concept of Equalized Lambda mentioned previously in regard to evaluating line losses on the transmission system. The Equalized Lambda approach generally produces the minimum operating cost for a network.

A second plan would be to maximize the generator's profit. Generators can sometimes earn additional profit by withholding some generation from the market. The production level (as indicated on the horizontal axis) is not increased as far as under the concept of Equalized Lambda. Under the profit maximization plan with reduced generating levels, the utility's operating profit would be the sum of the two areas labeled **Joint** and **Maximizing**. The utility can operate its generation at a marginal cost level that achieves equilibrium with the WOLF price. The utility can alternatively operate its generation at a level that maximizes its profits. Or the utility can forgo such additional profits by operating its generation to meet is internal load, as utilities have traditionally done.

Under current situations, utilities must make a specific offer of generation before any payment is made. Very short-term profit opportunities, such as those that are suggested in Figure 6, are foregone. Thus, with WOLF pricing for seam management, utilities, ISOs, and RTOs could improve their profit potential without entering into a formal dispatch relation with other entities. Figure 7 shows that the same profit potential exists for those utilities that find the WOLF price is below their imbalance curves. As with utilities that find the WOLF price is above their imbalance curves, these high cost utilities also have the ability to adjust their generation to the equilibrium level. But when they do so, these high cost utilities also find that they are operating sub-optimally, in that they could obtain higher operating profits at a higher marginal cost of generation and a lower WOLF price.

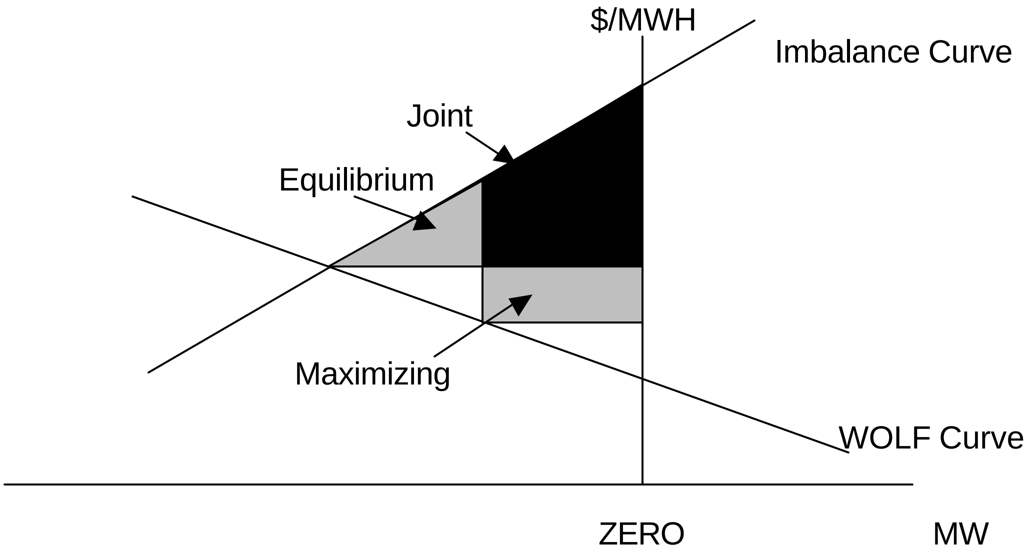

Figure 7: Profit Potential With Low WOLF Prices

Market Redispatch

Figure 4 introduced the concept that there are limits on the capacity of transmission lines to carry electricity. Historically, utility personnel would implicitly recognize these transfer limits when they scheduled purchases and sales with neighboring utilities. Under the new face of competition, the sales transactions are increasingly being made by entities that are unrelated to the operators of the transmission grid. These entities are unaware of the implicit considerations that had been limiting the scheduled flow of electricity between utilities.

FERC's rules require an automated transmission scheduling system. The automated transmission scheduling system allowed an increased number of scheduled transactions. These scheduled transactions were made without knowledge of the implicit limitations on the transmission system. The utilities became increasingly concerned about the violation of scheduled and actual flows across constrained transmission paths, especially across parallel paths. The utilities, through NERC, developed the concept of Transmission Line Loading Relief (TLR). Under the TLR program, engineering considerations would lead to the denial of requested transmission schedules. In extreme cases, scheduled transactions would be terminated.

FERC wanted an economic alternative to these engineering constraints. NERC developed the concept of Market ReDispatch (MRD). Under MRD, power plant operators would commit to adjust their operating levels to reduce the congestion on constrained transmission lines. When congestion occurred, transmission customers could buy a paired MRD service. Under MRD, one generator (or set of generators) would commit to increase generation (or decrease load) on the downstream side of the constraint and another generator (or set of generators) would commit to decrease generation (or increase load) on the upstream side of the constraint. Relatively few sets of generators decided to offer these MRD services, and even fewer transmission customers sought to take advantage of the offers that were made.

With WOLF pricing for seam management, MRD is automatic. Utility X in Figure 4, presented previously, has an incentive to increase its generating level to take advantage of the WOLF price of $50.23/MWH. This high price to Utility X is only applicable to increased flows of electricity at "d". To the extent that Utility X increases generation on the left side of its system, on the upstream side of the constraint, Utility X would only earn $15.88/MWH. At these prices, Utility X would have an incentive to increase generation on the right side of the network and decrease generation on the left side of the network, to the extent that Utility X had the ability to do either of these dispatch options.

The automatic MRD option is also available to Utility Y, to the extent that Utility Y has any available generation in the right side of its system. The value of Utility Y participating in the WOLF MRD is almost independent of its contracts for wheeling services, such as those presented in Table 4.

MRD involves marginal generation. As such, the concepts presented in Figure 6 and 7 are applicable. Generators are concerned about reliable service to their customers. The greater the amount of electricity that is being delivered off system or that is being received from off system, the greater the likelihood that a transmission incident will cause the utility to lose its ability to serve its customers. Some of this reliability concern coincides with utility decisions to limit the amount of redispatch that it is willing to do. However, the WOLF prices can provide some economic incentives for the utility to make a trade off between these reliability incentives when the network is constrained.

WOLF allows all parties to participate in MRD, including transmission dependent utilities and retail consumers. Many customers will commit to purchase fixed levels of power. Any imbalance between the metered flow and the power commitment is an unscheduled flow that can be treated as a Seams Management issue. Such customers can participate in an MRD effort by interrupting their load when prices are very high in the area where the customer has a firm commitment for the delivery of electricity.

Reliability Effects

Customers want their electricity delivered without interruption. Some customers are even willing to pay a premium for highly reliable service. WOLF pricing provides a mechanism to reward those entities that help a utility provide the highly reliable service that some customers desire. At the same time, WOLF pricing also allows a utility customer to interrupt itself to achieve a desired balance between high reliability and the price of electricity.

During the vast majority of the hours of the year, most utilities have enough electricity to supply their entire load. On a standalone basis, utilities would normally be short of power for only a few hours a year. Interconnecting with other utilities provides access to additional supplies of electricity. On an interconnected basis, these networks of utilities will be short of power for even fewer hours a year. Some of this increased reliability is achieved by one utility buying specific amounts of electricity for specific periods from other utilities. But some of the increased reliability is unscheduled, due to the free flowing nature of electricity. Pricing unscheduled flows of electricity across the seams will increase the willingness of participants to allow other entities to use their system, whether in the form of inadvertent interchange or in the form of loop flow.

Increasingly, new generation is being built on speculation that the developer will be able to make enough short-term sales of electricity to justify the investment. With an automated pricing mechanism for unscheduled deliveries of electricity across the seam between the utility and the independent generator, the independent generator does not have to worry about the market power of the utility in terms of negotiating a contract that is biased in favor of the utility. The independent generator would be able to deliver electricity and to collect revenue based on the competitive market, defined by the seam management price. This financial independence provides the independent generator with an incentive to gauge the market for electricity in a different manner than the command and control approach adopted by most utilities.

For instance, a generator that operated only during the two half-hours with the worst frequencies during 2000 on the Eastern Interconnection would have earned $3,170.14/MWH and $2,718.42/MWH, or an average of $2,944.27/MW. Such a payment would cover all variable costs and a substantial portion of the fixed cost of any generating system. Such a payment mechanism would provide small independent operators an incentive to build peaking power plants. These generators would only operate during the few hours that have the highest cost.

Table 5 analyzes the reliability incentives for independent generators under two scenarios. The first scenario assumes that the fuel cost for independent generators is $50/MWH. The second scenario doubles the fuel cost for independent generators to $100/MWH. Though these costs are referred to as fuel cost, the costs could be any variable cost incurred by the utility, including fees associated with pollution issues.

Table 5 accumulates payments for the highest priced periods. The first column is a count of the number of half hour periods included in the analysis. The second column is the revenue that would be associated with these periods. The third column is the fuel costs associated with the low cost scenario. The fourth column is the net income the independent generator would earn under the low cost scenario by operating for the number of hours shown in the first column. The fifth and sixth columns repeat the concepts presented in the third and fourth columns but for the high cost scenarios. Annual net operating income of $132,270.23/MW would allow the amortization of the debt associated with many small generators in a very few years.

RELIABILITY INCENTIVES FOR INDEPENDENT GENERATORS
OPERATING AT HIGHEST PRICED PERIODS ONLY

Table 5

		Low Fuel Cost Scenario (@ $50/MWH)		High Fuel Cost Scenario (@ $100/MWH)	
Half Hour Periods	Payment ($/MW)	Fuel Cost ($/year)	Net Income ($/year)	Fuel Cost ($/year)	Net Income ($/year)
2	2,944.28	50.00	2,894.28	100.00	2,844.28
11	8,861.99	275.00	8,586.99	550.00	8,311.99
47	23,361.56	1,175.00	22,186.56	2,350.00	21,011.56
179	53,722.00	4,475.00	49,247.00	8,950.00	44,772.00
581	106,404.70	14,525.00	91,879.70	29,050.00	77,354.70
1,412	167,570.23	35,300.00	132,270.23	70,600.00	96,970.23

Internalizing Seam Prices

WOLF pricing for seam management is an externalization of centralized dispatch beyond the generators of a single utility. The use of a price signal allows an independently owned generator to make its own decisions about how to optimize its operations. WOLF pricing can also be used to internalize seam management prices to retail consumers and transmission-dependent utilities. The internalization of seam management prices makes better use of customer elasticity of demand with respect to the wholesale market price of electricity. Customer elasticity of demand will reduce consumption and the cost of electricity during periods of peak demand.

Seam management refers to unscheduled flows of electricity across the interface between adjacent utilities. WOLF is meant as a mechanism to price such unscheduled flows of electricity. WOLF prices reflect the spot competitive market for electricity, as determined from physical measurements of the system.

The spot competitive market for electricity is nominally inconsistent with the revenue requirement determination applicable to most requirement customers, such as retail consumers, transmission dependent utilities, or seams internal to an ISO or an RTO. Despite these inconsistencies, the spot competitive market price can be used to price delivery variations from standard contracts derived using traditional cost of service rate making. If the spot competitive market prices can be used for variations from standard contracts, then spot competitive market prices can also be used for the entire delivery. Spot market pricing requires both parties to forego the protection nominally associated with the traditional cost of service ratemaking.

WOLF prices are inconsistent with the cost of service ratemaking normally used to set the price for retail customers, for transmission dependent utilities, or for independent power plants. A competitive market can force prices painfully low and painfully high. The characterization of prices as being painfully low or painfully high depends on the viewpoint of the participant, as a seller or as a buyer. Very few rate design concepts consistent with traditional cost of service ratemaking will produce prices as extreme as the prices produced by WOLF. Despite the inconsistencies between a competitive market and traditional ratemaking, WOLF prices can be applicable to the unscheduled flows associated with such deliveries, including the entire delivery when contractual agreements are not in place.

The internalization of seam management prices brings consumers and independent power producers into the competitive market. Their participation in that competitive market will improve how the market functions, increasing the elasticity of demand and reducing the cost of producing electricity. The cost reduction is especially significant when consumers are allowed to forgo demand during high cost periods, allowing the utility to install less capacity than the utility might otherwise install.

Independent Power Producers

WOLF can be used to pay independent generators for their production. The results of applying the WOLF concept to the half hour averaged frequency errors on the Eastern Interconnection were shown previously. The average of these prices was $41.68/MWH. This price would not have been high enough to support most power plants during 2000. However, for plants that sought to provide only reliability support to the interconnection, the price that would have been paid for the top 1,412 half hours was $167,570.23/MW, or $237.35/MWH.

Some independent power producers may find an annual revenue stream of $167,570.23/MW sufficient to justify building new generators. This justification would be enhanced by the need to generate electricity for only the top 1,412 half hours. Thus, though the WOLF price is meant to apply to unscheduled flows, such as variations from the supply contract for an independent power producer, power producers could decide to sell all of their output without a contract at the seam management price developed by WOLF.

Internalization of seam management prices allows each potential generator to make its own evaluation of whether to build or not to build. It also removes the necessity for each potential generator to negotiate an individualized contract with the utility. California and New York both adopted another approach, fixed priced tariffs, in the late 1980s as standard offers available to any qualifying facility. The results were gold rushes of qualifying facilities trying to get favorable contracts under these standard offers. California and New York utilities are still trying to recover the costs associated with such contracts, including the buyout of contracts deemed to be in excess of the eventual need for power in these two states.

Ancillary Services

FERC has created the concept of ancillary services for utilities to supply over and above normal transmission services. The issue relates to the scheduling of transmission services for hour-long blocks even though the delivery of the service will vary throughout the hour. FERC’s definition of ancillary services needlessly segments the market. Another approach is to internalize the seam management prices for the periods when ancillary services are needed. Thus instead of having several different types of ancillary services, the unscheduled deliveries would be viewed as being packaged many different ways.[6]

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[6] See "Electric Transmission Pricing: Are Long-term Contracts Really Futures Contracts?," *Public Utilities Fortnightly,* 1994 October 15; "Thirty-One Flavors or Two Flavors Packaged Thirty-One Ways: Unbundling Electricity Service," *The National Regulatory Research Institute Quarterly Bulletin*, Summer 1996.

WOLF divides each delivery into several deliveries differentiated by small time segments. Thus, a delivery of electricity for an hour might be viewed as 120 deliveries that occurred over consecutive 30-second intervals. The price for each interval would depend on Formula 1.

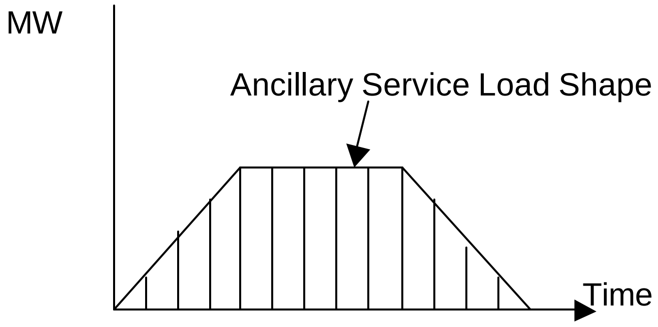

Figure 8: Parsing Ancillary Services

Figure 8 provides an example of how WOLF can be used to price ancillary services. The delivery is divided into small energy blocks by time period. Formula 1 would determine the price for each energy block. The Formula 1 price would be adjusted as necessary for location. The price for each of the energy blocks would be different. The load shape presented in Figure 8 is meant to be generic, but is likely to be the shape of the output required from generators that are committed to provide spinning reserve. They are required to be able to ramp up to full load in a short period of time, hold that level of production for another period of time, and then are allowed to ramp down as other units replace their production.

Transmission Dependent Utilities

Seam management prices can similarly be used for a utility's interaction with transmission dependent utilities (TDUs). In many respects, a TDU creates a seam that is identical to the seam that a utility will have with other transmission entities, whether another utility, an ISO, or an RTO. The TDU will have internal generation or will schedule purchases for the utility to deliver to the TDU. The scheduled purchases may be from other utilities or from the utility on whose transmission grid the TDU is located.

The TDU is expected to manage its portfolio of supplies so that its imbalance on the utility is zero. Any non-zero balance can be cashed out at WOLF prices, just as the utility would be cashing out imbalances across its seams with other utilities. And, just like the traditional seam with other utilities, the seam between a utility and a TDU may involve unscheduled deliveries in either direction. The TDU can over-schedule deliveries into itself over the utility's transmission lines, resulting in electricity that should be sold to the utility at the TDU interface with the utility.

There may be legal differences for a utility in regard to the seam that it has with a TDU versus the seam that it has with other utilities. FERC is very protective of TDUs, requiring utilities to provide a variety of ancillary services to TDUs. As discussed above, it can be shown that each of the ancillary services involving the delivery of energy is a hedge against the spot price of electricity.[7] In the same way, a utility's power contract with independent power producers can be viewed as a hedge against the long-term market price of electricity.

The WOLF seam management price can also be used for the entire delivery made by the utility to the TDU. Such a situation would be applicable when a contract impasse arises between the two entities. In this case, the seam management issue can be viewed as the seam between the effectiveness of consecutive contracts. Sometimes the seam between the effectiveness of two contracts will not involve the utility to whose transmission system the TDU is attached. The TDU may purchase electricity from a multitude of suppliers, none of which is the directly connected utility. The suppliers under these contracts may similarly reach an impasse with the TDU. Seam management pricing can similarly be applicable to seams between such consecutive contracts not involving the local utility.

Retail Consumers

Many retail sales customers have contracts that specify the demand they are allowed to impose on the utility. Consumption in excess of the contract demand can be treated as a seam management issue. The price for such consumption would be the competitive seam management price, varying with the conditions on the utility at the time of the consumption.

Retail power sales contracts can also be viewed as power hedges in a manner similar to the treatment of independent power contracts. In such a context, the contract demand can be viewed as the utilities obligation to deliver power at all times. The customer would also be obligated to take that amount of power at all times. The contract demand charge would then be a strike price for an associated option. The energy associated with the contract demand would be priced pursuant to the contract. The utility would meet any excess power requirements at the seam management price. Similarly, the utility would buy back any surplus that the customer did not use at the seam management price. The demand charges and the energy charges in such a retail contract should be viewed as parts of a hedging financial instrument.

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[7] See "Electric Transmission Pricing: Are Long-term Contracts Really Futures Contracts?," *op. cit.*; "Electric Customer Participation in the Competitive Market: Reliability, Futures Contracts, and Arbitraging," *The National Regulatory Research Institute Quarterly Bulletin*, Winter 1997; and, "The Need For A True Spot Market," the *Blue Ribbon Panel of the California Power Exchange*, delivered 2000 November 21, presented and defended 2000 November 28.

Most retail consumers buy electricity on an as-needed basis, with no contract demand or even a billing demand. A tariff filed with the public service commission determines the price paid for all energy. The prices in such a tariff are typically based on the utility's embedded cost of generation and transmission. This basis for retail prices is different from the competitive market associated with seams management. Many people have alleged that a competitive market will produce prices that are below embedded costs. These allegations have led to the claim for stranded cost recovery when customers depart the system, such as when a state adopts a customer choice program.

Though advocates of competitive markets have alleged that prices will fall, a competitive market can also lead to prices that are much greater than the prices produced by traditional regulation. Perhaps the greatest effect of moving toward a competitive market will be a redistribution of prices, both geographically and chronologically. Prices for short periods of time will increase greatly. Prices for the vast majority of time will be lower.

Under certain conditions, the revenue associated with the price increases will be approximately equal to the revenue associated with the price decreases and the imbalance between the two revenue changes will be small. Some localities will experience a net increase, and some a net decrease. Further, the increases will occur in spikes, such that most years will see a net decrease and only a few hours will see a net increase. The net increase in those few hours may overwhelm the decreases that had occurred during the rest of the time.

Retail consumers can buy electricity at the competitive market, such as the seam management prices identified in this paper. The way that the competitive market prices are expected to spike must be considered when permitting retail consumers to buy at the competitive market. Prodigal customers try to alternate their purchases between the competitive market and the utility's standard supply.[8]

The concept of prodigal customers is based on the Prodigal Son parable in the Christian New Testament. The prodigal customer leaves the utility's standard supply when the competitive market is cheap and returns to the utility's standard supply when the competitive market is expensive. The utility's standard supply of electricity is generally priced on an average cost basis.

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[8] See "Competitive Electricity Prices by Changing Tariffs, Not By Changing Providers," *The Washington, D.C. Customer Choice and Utility Competition Report*, prepared for the District of Columbia Office of the People's Counsel Conference *Utility Competition: What Is It And Why Should I Care?* 1998 May 5; and, "Daily Cashouts of Gas Imbalances Using A Formulary Auction," *National Regulatory Research Institute Quarterly Bulletin*, Fall/Winter 1999. "Daily Cashouts of Gas Imbalances Using A Formulary Auction" is an adaptation of the "Supplemental Comments on Auctioning Gas Pipeline Imbalances on behalf of the Pennsylvania Office of Consumer Advocate and the Ohio Consumers' Counsel" ("Supplemental Comments") in FERC Docket Nos. RM98-10-000 and RM98-12-000, filed 1999 April 22, which the author wrote under contract for the Pennsylvania Office of Consumer Advocate under the supervision of Ms. Denise Goulet, Assistant Consumer Advocate, Commonwealth of Pennsylvania.

Though the average cost of a utility's standard supply is an average across many sources, the more important average is across time. The average across time results in inter-temporal subsidies. Inter-temporal subsides involve low cost periods providing subsidies to high cost periods. Since the prodigal customer was not on the utility's standard supply during the low cost period, the prodigal customer does not contribute to the subsidy necessary to reduce the price during the high cost period.

The lack of contribution by the prodigal customer to the subsidy can result in other retail customers of the utility subsidizing the prodigal customer's return to the standard supply. The prodigal customer issue should be addressed in any public policy decision about allowing retail consumers access to competitive market prices, such as the seam management prices discussed in this paper.

California

California changed the regulatory structure for its electric utilities in 1996 with the passage of legislation that led to the creation of the California Power Exchange (CalPX) and the California Independent System Operator (CaISO). In 1999, CaISO experienced some price spikes in a few products it sold. Beginning in June 2000, CalPX and CaISO experienced high prices for the basic electricity sales. In late 2000 and early 2001, CaISO went through all three stages of power alerts, including imposing rotating blackouts on California consumers. The blackouts could have been avoided by implementing appropriate seam management pricing techniques and extending those seam prices to retail consumers.

Under the 1996 California legislation, the electric utilities were to sell their generating plants and buy all of their power needs through auctions run by the CalPX. Until the generating plants were sold, the utilities also had to sell all of the output of those plants through the CalPX auctions, even the electricity that they were buying for their own needs. This “buy all, sell all” requirement guaranteed CalPX a significant initial revenue stream. That revenue stream would not be jeopardized until retail consumers began buying from independent marketers that were allowed to bypass CalPX.

CaISO was to run the transmission system. As part of its transmission services, CaISO provided ancillary services to meet the difference between the block hourly contracts sold on the CalPX and the real time load profiles experienced by the load serving entities in California. A 10-minute forwards contract eventually became a major CaISO ancillary service when prices started escalating.

The new market structure began in April 1998. During the summer of 1999, there were allegations of market power being exerted in the spot market for some CaISO ancillary services, with temporary spikes in the price for reserves. In May 2000, the price for electricity transactions on the CalPX significantly escalated. The average price in May 2000 was about twice the average price for May 1999. The average price on the CalPX more than doubled again in June 2000. In addition to these high prices, shortages of power led the CalPX to go through all three stages of power alerts, including the order for rotating blackouts. Appropriate seam management practices, including the internalization of prices, would have reduced the demand for electricity sufficiently to prevent these blackouts.

The new regulatory structure for the California utilities includes a price freeze for retail consumers. The prices were frozen at a level that was to allow the California utilities to recover stranded costs. Once the stranded costs were recovered, the retail rates were to move to market levels through purchased power mechanisms.

San Diego Gas & Electric, the smallest of the three California utilities, reported the completion of its recovery of stranded costs early in 2000. When CalPX prices began to soar during the summer of 2000, SDG&E was able to increase its retail rates to recover the high prices it was paying for bulk power purchased on the CalPX. The other two utilities, Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) were nominally still in the stranded cost recovery mode with retail prices frozen. The differential between the high wholesale price of electricity versus the low frozen retail prices has caused SCE and PG&E to incur billions of dollars of debt, just as the previous differential between the same frozen retail prices and an even lower wholesale price of electricity had allowed the three utilities to pay off billions of dollars of debt.

Deregulation

Under the name of deregulation, California had its electric utilities divest themselves of their generating capacity and other long-term supplies of electricity. California created the Power Exchange to auction electricity and the Independent System Operator to control the transmission system. The auctions operated by the CalPX and CaISO were not true spot markets, at least not in the way that true spot commodity markets operate.[9]

Without a true spot commodity market, buyers and sellers were able to manipulate the market price through the bid prices and ask prices posted with the market operators. Analysis with seam management pricing is likely to show that the resulting settlement prices were not efficient, in that they were significantly different from the equilibrium price. At times these settlement prices may have been above the equilibrium price. At other times these settlement prices may have been significantly below the equilibrium price.

California also froze retail rates for an extended period of time, nominally to allow the electric utilities to recover stranded regulatory costs. The price freeze exacerbated the shortage of electricity in California. The price freeze reduced the elasticity of retail demand. Customers thus had no financial incentive to heed the governor’s call for conservation during emergencies. The poor response is likely to have resulted in settlement prices significantly higher than would have been the case if seam management prices had been internalized by the California utilities for payment by retail consumers.

Retail Elasticity

Internalizing the WOLF price to retail consumers will increase the elasticity of demand with respect to the bulk power of electricity. Retail consumers of electricity are price inelastic with

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[9] “The Need For A True Spot Market,” the *Blue Ribbon Panel of the California Power Exchange*, delivered 2000 November 21, presented and defended 2000 November 28.

respect to the price of bulk power. For economists, price inelastic means that the proportional change in consumption in response to a price change will be less than the proportional change in price. Thus, an inelastic consumer will reduce consumption by less than 1% if the price increases by 1%. A major historical contributor to the inelasticity of retail consumers is the design of the retail tariff. The current California retail rate design has further reduced the elasticity of retail consumers.

Retail ratemaking is often described as using average embedded cost. The costs are averaged over many pieces of equipment and over an extended period of time. An increase in the bulk price the utility pays for electricity for a short period of time is often offset by a decrease in the bulk price the utility pays for electricity for a different period of time. Rather than have retail prices go up and down, utilities and commissions have generally decided to set fixed prices for retail consumers. These fixed retail prices are decoupled from the bulk power market for electricity, and retail consumers are insulated from bulk power prices. This insulation from bulk power prices makes retail consumers more inelastic than they would be if the bulk power price were internalized for retail consumers.

The new regulatory regime in California froze retail prices for an extended period of time. During the first part of this freeze, the bulk power component of the retail price was in excess of the cost of bulk power to the California utilities. The freeze initially allowed the California utilities to make a profit on the bulk power component of the retail price. This profit on the bulk power component of the retail price was designed to allow the California utilities to recover stranded cost. The profit on the bulk power component of the retail price also depressed retail consumption, due to elasticity effects. The freeze continues despite a significant increase in the bulk price of electricity. In light of the increase in the bulk price of electricity, the freeze in the retail price of electricity is now inflating retail consumption.[10]

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[10] The concept is covered in greater detail in Good Market Segmentation or Bad: An Analysis of the California Electricity Market, printed January 2001 by the National Regulatory Research Institute in its *Quarterly Bulletin*.

> Consider a call by the Governor to conserve power. At $7.00/KWH, the price electricity has reached in the Midwest, I should have a financial incentive to conserve electricity. But fuel clauses billed on a single Watt-hour reading once a month assume a fungible commodity. Thus, the consumption during the conservation period costs me a mere $0.10/KWH, the average cost to me of electricity during the month. Sure, my supplier may be paying $7.00/KWH, but the $6.90/KWH differential is being paid by all of my supplier's customers, and only to a very, very small extent by me. Why should I conserve when the financial effect on me is so small?
>
> A more galling issue is when my utility institutes rotating blackouts, presumably during periods when costs are very high. The high costs paid by the utility during these time periods are spread across all energy during the fuel clause period. If my service has been blacked out, the average cost of energy while I was consuming energy (the period excluding the blackout) is much less than the average cost of electricity for all energy. The average cost that I am paying is higher than the weighted average that I should be experiencing.

The article also deals with load research techniques that can be used to assign real time bulk power prices to retail consumers whose consumptions are recorded on watt-hour meters that are read once a month.

Figure 9 shows the effect of the California rate freeze on the demand curve for retail consumption. For any given ACE, the rate freeze has rotated the demand curve clockwise, making the demand curve steeper. In Figure 9, the rate freeze has changed the demand curve from the moderately sloping Demand-1 to the steeply sloping Demand-2. The change in the slope of the demand curves has also increased the equilibrium price for the retail load. The increase in the equilibrium price suggests that the California retail rate freeze justifies higher settlement prices than would have been appropriate without the retail rate freeze.

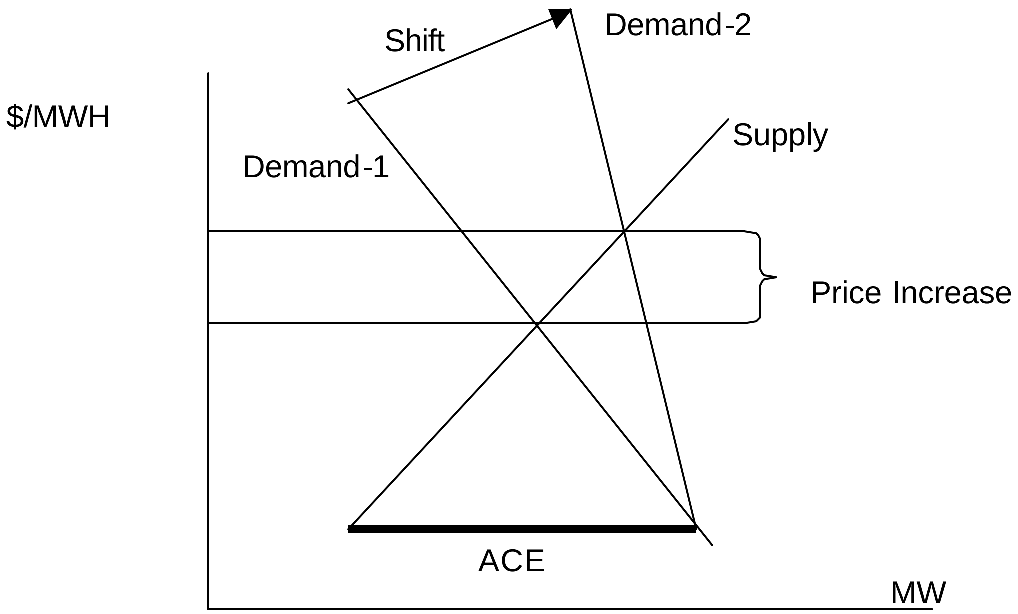

Figure 9: Effect of California Rate Freeze on Elasticity

Avoiding Rotating Blackouts

The inflation of retail consumption is one of the causes of rotating blackouts that California has been experiencing since the middle of Summer 2000. Passing bulk power prices through to the retail consumer will reduce retail consumption. The manner in which the bulk power prices are passed through to retail consumers will determine if the reduction in retail consumption will be great enough to prevent additional blackouts in California during Summer 2001.

The standard way to pass bulk power prices through to retail consumers involves fuel and purchased power adjustments. Such a pass-through is much less effective than allowing the retail consumers to experience the actual bulk power prices. Fuel and purchased power adjustments impose the price change on all consumption, even consumption during low cost periods. This averaging of the price change will undercharge during the high-price periods and overcharge during the low-price periods. The undercharge during the high-price periods will diminish the consumer's response to the bulk power price change. This diminished consumer response may mean that the CaISO will have to continue imposing rotating blackouts during Summer 2001.

Under WOLF, the price will continue to increase until supply balances demand. The continued increase in price will lead consumers to further their conservation in the consumption of electricity. The reduced consumption will eliminate the need for rotating blackouts and improve the equity of the network.

Inequity of Rotating Blackouts

Rotating blackouts under existing pricing mechanisms are inequitable. Some customers are forced to bear the high cost of bulk power purchased when they are not consuming electricity because of the rotating blackout imposed on them. The high cost of power during these periods should be charged to customers who continue to consume during the periods of rotating blackouts, not to customers who were blacked out during the rolling blackouts.

The internalization of seam management prices will reduce the inequity associated with rotating blackouts. Customers who use electricity during high price periods pay high prices for their electricity. Thus, customers who are not affected by rotating blackouts pay the high price for the electricity they consume during the blackout. The customers who are affected by the rotating blackouts do not pay the high prices that are prevailing at that time.

The allocation of energy consumption between high cost periods and low cost periods is generally accomplished with sophisticated meters. Some of the same allocation results can be obtained with sophisticated load research concepts. Historical consumption and historical weather patterns can provide indicators for each customer of the expected pattern of consumption during the current billing period. These indicators can be adjusted for serendipitously placed meters on the distribution network. One of the most important of these serendipitously placed meters will determine when a particular part of the distribution network was affected by a rotating blackout.

Ancillary Services

CaISO has created several types of ancillary services. The plethora of ancillary services has resulted in some that are thinly patronized by providers of electricity. The small number of providers has led to allegations of market power and market manipulation. WOLF broadens the definition of the market supplies beyond just the suppliers who have decided to bid into the market. All unscheduled deliveries are part of the market. The transmission grid brings some of these supplies to market. Some of the supplies are already physically located in the area where an ancillary service is sought, but were bidding their supplies into different markets. By treating unscheduled flows of electricity as an ancillary service, all generators connected to the grid can provide that ancillary service.

SPOT RETAIL PRICING COULD HAVE PREVENTED CALIFORNIA ROTATING BLACKOUTS

Utility Economic Engineer Mark B. Lively has published "Profit-Enhancing Seam Management", a report on pricing the unscheduled flows across the interconnections between utilities, ISOs, and/or RTOs. The report advocates true spot pricing, using a geographically differentiated Walrasian auction of inadvertent interchange. The report concludes by finding that the internalization of such seam management pricing would have reduced California retail consumption enough to have avoided the alerts that have occurred during the last eight months, including the rotating blackouts.

Twelve years ago, Mr. Lively wrote "Tie-riding Freeloaders – The True Impediment to Transmission Access," Mark B. Lively, *Public Utilities Fortnightly*, 1989 December 21. "Tie-riding Freeloaders" proposed changing the method utilities treat each other in regard to the unscheduled flow of electricity between and among the interconnected utilities. The general method then, as now, was for utilities to compensate each other through a return in kind, a KWH for a KWH. "Tie-riding Freeloaders" advocated setting a market price for whenever the metered KWH was different from scheduled KWH. The prices would vary based on (1) changes in system frequency, (2) transmission line loadings, and (3) accumulated clock error. "Profit-Enhancing Seam Management" provides formulas to achieve such prices.

"Tie-riding Freeloaders" presented examples twelve years ago with prices that varied between $20/MWH and $800/MWH. At that time, the implicit price ratio of forty to one seemed absurd. The nation didn't experience such price ratios until some bulk power competition came to the Midwest in 1998 and 1999, as Mr. Lively reported in "Electricity Is Too Chunky: The Midwest power prices were neither too high nor too low. They were too imprecise," *Public Utilities Fortnightly,* 1998 September 1.

"Profit-Enhancing Seam Management" develops the concept of treating electricity as a true spot commodity market. In a true commodity market, a spot transaction is delivered immediately out of inventory, such as with an inventory receipt. In such markets, the inventory level for the commodity has a major impact on the spot market for the commodity. Though there is no inventory of electricity, Mr. Lively describes how system frequency provides a measurement of a near inventory of electricity, the kinetic energy of the rotating equipment. "Profit-Enhancing Seam Management" also describes how prices can be geographically differentiated without regard to the imbedded cost of the transmission system.

"Profit-Enhancing Seam Management" includes a discussion of internalizing the seam prices, using the spot prices for retail consumers, such as the so-called deregulated retail consumers in California. Mr. Lively concludes that the use of such spot prices for retail consumers in California would have eliminated the need for the rotating blackouts that have been implemented by the California ISO and could have lowered the settlement prices in the California market.

Mr. Lively is an independent consulting engineer based in Gaithersburg, Maryland. He can be reached at 301-428-3618, MbeLively@aol.com, or http://www.LivelyUtility.com/