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Comparing Optional Rates

Many cooperatives offer rate options designed to allow a customer to lower energy bills by changing their usage patterns.

Time-of-use (TOU), curtailable, interruptible, load management and unbundled rates are popular examples of methods used to lower a customer's contribution to a distribution cooperative's wholesale power cost. When these optional rates are properly designed, everyone wins: the customer lowers his or her bill, the cooperative maintains existing margins, and the power supplier reduces peak demand. But, if not well designed, optional rates can become problems.

The preferred approach to rate design is to "unbundle" each cost component required to serve each rate class through a cost of service study. Rates are then designed so the customer is billed for the cooperative's wires cost (including margins) plus wholesale power cost, which should be billed in a way that reflects wholesale demand and energy rates. The published rate may be "bundled," but the rate tracks cost. If this procedure is followed, TOU rates work automatically, because any change in the customer's usage which changes wholesale power cost is automatically passed through to the customer. (Revenue goes down but wholesale power cost goes down a corresponding amount.)

Not every utility has rates designed to be "transparent" to wholesale charges. If a customer is given a choice between a standard rate and an optional rate with a dramatically different relationship between demand and energy charges, some very high or very low load factor customers might receive savings by moving to the optional TOU rate without changing usage.

Another rate design problem can occur when developing a new TOU rate for customers currently served on an existing rate which produces excess margins. It is not uncommon for large power rate classes to show higher rates of return than other classes. When designing the new TOU rate it is important to consider the level of margin recovered in the standard rate. If the correct level of margin is not recovered in the new TOU rate, an improper price signal will be provided, allowing existing customers to simply change rate classes and reduce cooperative revenues without any off-setting reduction in power cost.

A final issue concerns diversity. Diversity is a reflection of the amount of demand a given rate class actually contributes to the power supplier's billing demand. The cooperative should attempt to design a new TOU rate attractive enough to cause customers to CHANGE usage patterns to move load off-peak, not just attractive enough to reduce billing for customers whose standard usage is such they would not have contributed to the peak in any case.

If properly designed, optional load management or time-of-use rates should be higher than standard rates UNLESS the customer actually manages his or her load.

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GUERNSEY Energy FOCUS
for the energy industries
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206 Investigations Indicative of Market Power Concerns

Editor's note: Generations of children have gathered around a dining room table to play Monopoly. In doing so, children quickly learn the key to the game. It is not important to own all the assets around the board; to win, one only needs to control major assets in a given market. In the real world, monopoly power can have real consequences for individuals and companies, including electric cooperatives and their members.

"Monopoly power," or more generally, "market power," is the ability to raise and sustain prices at levels significantly above cost. Within the electric utility industry, the concept of market power was historically irrelevant, as companies were guaranteed their vertically integrated monopoly positions in return for agreements to submit to regulated rates. However, the deregulation of the wholesale market encouraged by the Federal Energy Regulatory Commission (FERC) Order 888 and its progeny has resulted in the emergence of true energy markets, within which large generation companies are allowed to "compete" based on "market-based rates." Such sales potentially benefit all market participants by allowing buyers to "shop" from alternative generation sources to obtain power at relatively low prices, by allowing generators to profit from sales into markets outside their service territories, and by reducing the need to expand generation capacity within otherwise isolated control areas.

Of clear concern is the possibility that firms with market power will use market-based rate authority to the detriment of consumers participating in wholesale power markets. Such concerns are exacerbated during peak periods, wherein (as proven during the California experience) sellers into the market can take advantage of tight supply to raise prices to levels well in excess of the true cost of service.

The FERC has the authority to address these issues by initiating a "Section 206" investigation under the Federal Power Act. However, before initiating a 206 proceeding, the FERC first screens whether an applicant seeking market-based rate authority has the potential to wield market power. In search of a suitable screen, the FERC has issued a variety of rulemakings designating different tests to be used to detect the presence of market power in the wholesale market.

Historical Market Power Tests Used by FERC

The test used by FERC prior to 2001 was based upon a **"hub and spoke"** principle, whereby market power was measured not only in the control area under scrutiny (the "hub"), but also in the adjacent control areas tied by transmission paths (the "spokes"). This methodology was broadly criticized for being too lenient a yardstick for accurately assessing the dangers of market power, especially in load pockets or other transmission-constrained areas.

Analytical inconsistencies were another complaint concerning the hub and spoke analysis. The methodology relied upon computation of the

See Market Power on page 2.

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VRA/ERP Deadline Nears

The July 12 deadline for RUS borrowers to complete their vulnerability and risk assessment (VRA) is fast approaching. This first step in the required emergency restoration plan update identifies assets critical to the reliable and efficient performance of the cooperative. The VRA will also help identify security upgrades to reduce the vulnerability of the Cooperative's critical assets. The risk assessment combines the likelihood of an event with the projected consequences of that event to develop an overall indicator of risk. This risk indicator is useful for prioritizing security upgrades as well as prompting development of mitigation measures to reduce the consequences of critical asset damage or loss. If you feel behind schedule, give us a call. We can help.

For more information call Randy Nason, Vice President, Security at 405.416.8285 or visit www.chguernsey.com> Announcements>RUS/ERP Final Rule

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Herfindhal-Hirschman Index (HHI), which is found by summing the squares of the market shares of all firms in the market. Given that the "market" could be defined by a variety of combinations of control areas and that "market shares" would vary significantly between peak and off-peak periods, reliance upon the hub and spoke test produced dubious results wherein almost no firms were denied market-based ratemaking authority.

In November of 2001, the FERC attempted to resolve this confusion through the adoption of a new market power test for electric generation. Known as the **"Supply Margin Assessment"** (SMA), this test shifted the focus of the screen for market power from analyzing market share to examining whether firms applying for market-based rate authority have sufficient capacity to serve the entire wholesale market peak demand. The assumption followed that if a firm cannot serve the entire wholesale market on-peak with its generation portfolio, the firm must face competition and therefore cannot have market power.

The logic of the SMA was heavily criticized by wholesale market participants on both the buying and selling sides. Owners of generation argued that the SMA test would produce false positives in detecting market power, as the bulk of their generation capacities were dedicated to serving native load commitments and therefore unavailable for sale into the wholesale power market. Conversely, buyers voiced concerns that the SMA test provided no sensitivity to the amount of generation owned by a firm. A change in the capacity owned by an applicant would change the supply margin by an equivalent amount, making a firm no more or less likely to pass or fail the test.

The New FERC Tests of Market Power

On April 14, 2004, the FERC issued an order modifying its generation market power analysis and mitigation policy for firms applying for market-based rate authority. The order replaced the SMA analysis with two "indicative screens" designed to detect the presence of market power. Failure to pass either of these screens would create the presumption that the applicant has market power, thereby triggering a 206 proceeding. This would require the applicant to either proceed to mitigation or to provide a "delivered price test" to disprove the results of the indicative screens.

The first of the two screens required by the FERC is referred to as the **"pivotal supplier"** test. Similar conceptually to the SMA, this test requires the applicant to compare its net capacity available *after serving native load commitments* to the net uncommitted supply available in the wholesale market at the time of the market peak. Put another way, the test seeks to determine whether the uncommitted capacity in the market can meet the peak demand without the applicant's resources. If the applicant's net capacity exceeds the net uncommitted supply, the test is failed and the firm must either devise measures to offset market power issues or disprove all market power concerns using a delivered price test.

The second screen required by the FERC is the **"uncommitted market share analysis."** This test measures the applicant's uncommitted resources on peak as a percentage of the total uncommitted resources available on peak during the four seasons. An applicant will fail this test if its uncommitted capacity exceeds 20% of the total uncommitted capacity in the market in any of the four seasons. Conversely, if an applicant passes both this screen and the pivotal supplier test, it will automatically be eligible for market-based rates.

If an applicant fails either the pivotal supplier screen or the uncommitted market share analysis, a 206 proceeding is initiated and the applicant is presumed to wield market power. In such event, the applying firm can perform a **"delivered price"** test to refute the presumption. This test is performed in a manner similar to the "hub and spoke" analysis used in years past, but with specific parameters given to define the size and scope of the market designed to derive a much more consistent outcome. If the HHIs calculated from this exercise are all less than 2,500 (corresponding to four equally-sized firms), the assumption of market power is refuted and the applicant is eligible for market-based rates. Otherwise, the applicant must submit to cost-based rates or face alternative mitigation measures as approved by the Commission.

Currently, the FERC has yet to determine whether the capacities used

for the delivered price test should be calculated net of native load commitments. Since current procedure calls for the computation of ten HHIs (for the "off-peak," "peak" and "super-peaks" of the summer, winter and shoulder months, as well as one summer "extreme peak"), the wary applicant must file twenty HHI examinations to disprove market power. Moreover, the applicant is expected to submit revised pivotal supplier and market share screens with each of these tests, implying that up to *sixty* screens may be required of an applicant seeking to qualify for market-based rates. This presents a hefty burden upon applicants but an equally daunting burden upon those wishing to intervene in such cases.

FERC Investigation under Section 206 of the Federal Power Act

As of March 2005, forty-five generating companies, with average generation capacity of 1,616 MW, have passed the pivotal supplier and market share tests, allowing these firms to qualify for continued market-based rate authority. By comparison, thirteen companies, averaging 8,335 MW of generation within

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the control areas under scrutiny, have received deficiency notices from the FERC warning them of impending investigations under Section 206 of the Federal Power Act concerning perceived market power. These firms are now required to perform delivered price tests to rebut presumptions of market power and/or submit proposed mitigation measures to the Commission. As firms continue to file market power updates with the FERC, new 206 investigations will surely follow as other companies fail to comply with the new requirements.

Market Power Concerns for Electric Cooperatives

1. Pros and cons of the FERC's new Market Power Test

The FERC's new market power screens represent an improvement in the protections afforded consumers within wholesale power markets. By focusing upon uncommitted capacity within specific control areas, the methodological consistency of the pivotal supplier and market share tests is likely to reduce the number of false negatives and false positives found for firms possessing market power. However, concerns remain that these screens may fail to detect utilities with large capacities and large contractual loads; under certain circumstances, such firms may be able to avoid serving their native commitments, leaving them with a significant market share of uncommitted capacity and the ability to charge market-based rates into the wholesale market. Moreover, by focusing the scope of its analyses upon specific control areas, the screens may ignore intra-system transmission constraints that may create market power within portions of control areas. Although the FERC is promoting RTOs as the ultimate answer for all such issues, the movement to RTOs provides no guarantee that system dispatch will fully address these concerns.

> *"…market power issues are of great importance for any electric cooperative…"*

2. Importance of impending investigations

The outcomes of impending 206 investigations are of great interest to all wholesale power buyers within the affected markets. In the absence of market power concerns, buyers within a region benefit from sellers' market-based rate authority, as competition tends to drive wholesale prices toward cost. Capacity surpluses during off-peak periods guarantee that almost every region can benefit from market-based rates without concern of market power issues at such times. However, as regional resources become constrained during on-peak periods, sellers within a region become increasingly likely to wield monopoly power over uncommitted capacity, allowing for abuse of market-based ratemaking authority. As many companies have yet to submit market power studies to the FERC in conformance with the new tests, cooperatives must be wary of the price risks that purchases from wholesale markets may hold in the near future.

3. Potential affect on 2005 wholesale prices

As the 2005 summer approaches, market power concerns will become a significant issue in many parts of the country. In a market with already escalating wholesale power costs, market power issues are of great importance for any electric cooperative that may rely upon the wholesale market for meeting future peak demand. Higher loads from a growing economy coupled with normal summer weather will strain an essentially unchanged stock of generation capacity and limited transmission import availability. As a result, 2005 may pose far greater market power concerns than were experienced in 2004.

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FERC Market Power Screens Status

Firms Subject to 206 Proceedings with Potential Generation Output to Control Area (MW)	
Alliant Energy	6,160
AEP Power Marketing	8,927
Aquila	2,086
Duke Power	28,642
Entergy	28,879
Empire District	1,222
Kansas City Power & Light	4,375
Pinnacle West	9,680
Public Service Co. of New Mexico	2,077
Puget Sound Energy	1,101
Southern Company	4,582
Tampa Electric	3,487
Westar Energy	6,203

Firms Passing Both Screens including Installed Generation (MW)	
AES Companies	12,485
American Ref-fuel Co. of Niagara	50
Avista Corp.	1,519
Bear Swamp Power Co.	599
Bellows Falls Power Co.	49
CMS Generation Michigan Power	8,424
Colton Power	40
Consolidated Water Power Co.	33
Dartmouth Power Associates	1,238
Dayton Power and Light Co.	4,490
Delta Energy Center	880
Dow Pipeline Co.	873
Eastern Desert Power	51
Edison Mission Energy	7,583
El Paso Electric	799

Firms Passing Both Screens including Installed Generation (MW)	
EPCOR	263
First Energy	1,155
FPL Energy Cowboy Wind	107
Georgia Energy Cooperative	0
GWF Energy	363
Goldman Sach Group	3,673
Great Lakes Hydro America	1,794
Idaho Power Co.	1,694
Madison Gas & Electric Co.	997
Mandota Hills	50
Mead Westvaco Energy Services	145
Merrill Lynch Capital Services	0
Millennium Partners	360
Minnesota Power	2,037
Mitchell EMCooperative	0

Firms Passing Both Screens including Installed Generation (MW)	
Northeast Utilities Service Co.	3,349
NIPSCO	3,600
Pastoria Energy Center	750
PEI Power Corp.	42
Pittsfield Generating Co.	163
Puget Sound Energy	1,101
Rainbow Energy Marketing	0
Saracen Energy	0
Sempra Energy Resources	3,185
Telemagine	0
Trimont Wind I	101
Westbank Energy Capital	0
Wisconsin Electric Power Co.	6,141
Wisconsin Public Service	2,485
Wisconsin River Power Co.	51