Part 2 of a 3-Part Series—
Deregulated Retail Power Pricing:
What Will It Mean to You?

Seven Energy Efficiency Options: How Different Power Pricing Structures Can Affect Them

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ABSTRACT

Part 1 of Lindsay Audin's 3-Part Series on "Interactions Between Retail Power Pricing and Energy Efficiency Options" reviewed the new types of pricing which have recently evolved, following the deregulation of electricity. These electricity pricing programs can impact the payback periods of both energy efficiency and distributed generation plans. Professionals will want to minimize costs risks. To do this, they need to pay close attention to how they integrate power procurement with equipment-based efforts to cut their energy costs.

Part 2 of Mr. Audin's report, presented here, analyzes seven major energy efficiency systems, and reviews how each is influenced by different power pricing options.

In the Commercial/Industrial sectors, there are hundreds of technical measures that can improve energy efficiencies. (Walt Smith's article in *Strategic Planning for Energy and the Environment*, Summer 2000, Vol. 20, No. 1, lists 302 of them) Not all warrant analyzing the way to best match them to various energy pricing options. But this sampling of seven of the more important ones could be extended to other energy system upgrades and new installations.

To examine how the pricing structures described in Part 1 could interact with the costs effectiveness of energy equipment, the following energy-efficiency options are examined:

1. *off-peak consumption reduction* due to an energy management system, load reductions/shutdowns, occupancy sensors, or manual efforts

2. *peak demand shaving* due to an energy management system, on-peak load reductions/shutdowns/fuel switching, or manual efforts

3. *thermal storage* that creates ice at night to avoid running chillers during the day. Actual energy *use* doesn't change much (relative to a standard electric chiller system) and may, under some circumstances, be slightly higher.

4. *variable speed drives* (VSD) that reduce kWh consumption of fans/pumps (note: if fans or pumps are not oversized, they are still likely to run at 100% at peak times)

5. *automated dimming* of electric lighting (by either daylighting or temporary illuminance reductions)

6. *gas/steam absorption cooling or hybrid gas/electric cooling* that reduces peak demand (relative to cooling using only electricity)

7. on-site *distributed generation or cogeneration*.

PRICING OPTIONS 1

Fixed Rate Structures

A. *Simple Flat Price*—This is the simplest form of pricing and applies only to the commodity portion of the bill. Delivery charges, stranded costs, etc. continue to be collected by a separate bill from the LDC. The same price is charged for all power received during the term of the contract, regardless of season or time of day.

B. *Fixed Bundled Total Price*—Where a defined utility rate reduction schedule is part of the early years of deregulation, the power supplier sells power below the utility price for several years, in effect bringing future guaranteed rate reductions into the present to provide those "savings in advance," but in later years maintains rates higher than would have been charged at that point by the utility.

C. *Fixed/Floating Summer Pricing*—The price is fixed for 8-9 months, but floats for 3-4 months (typically during summer), typically based on wholesale PX/ISO pricing. The floating price may be for 100% of the power during the floating period, or may include a negotiated mix of floating and fixed pricing, possibly with a floor and/or cap.

Potential interactions between these rate options and the seven efficiency upgrades:

1. *Off-peak consumption reduction*—Look at a daily load shape. When off-peak demand is reduced, peak demand is unaffected, so demand charges (now seen only in the customer's delivery bill) are unaffected. In both his regulated delivery bill and in his unregulated commodity bill, the customer sees savings due to the reduced number of kilowatt-hours. Since unregulated flat priced commodity power (in this case) includes peak demand costs in all kWh whether used day or night, any consumption reduction under this contract is worth more than under a tariff that separates out demand to be separately charged. Payback periods for upgrades that reduce consumption are therefore shortened.

   In one case, an off-peak power price of $.05/kWh was being used by an HVAC contractor trying to pitch improved control of fan operating hours. When the unregulated commodity power rate was used instead, the total was over $.10/kWh, cutting the payback period in half. If the original payback was 4 years, that period now dropped to 2 years, which was the same as the term of the power contract. In essence, the extra savings came out of the power supplier's pocket.

2. *Peak demand shaving*—Once demand charges are folded into all consumption charges, the value of reducing peak demand drops.

Only the demand charges included in the still-regulated delivery tariff will be saved. As a result, payback periods for such options as load shedding programs and backup generation are stretched out.

3. *Thermal storage*—An existing system will no longer generate the same savings because its dependence on the differential pricing between on- and off-peak power will disappear under annual flat pricing. A fixed/floating option may still provide savings, possibly at an even higher rate if wholesale pricing spikes during the cooling season. Since wholesale markets do not guarantee any pricing, however, it is also possible that its pricing could remain low most of the time, resulting in a loss of value for the thermal storage system.

   In one case, this problem resulted in the customer choosing to remain under a regulated tariff. Otherwise, his total operating costs might have risen. Where a thermal storage system did not exist and was proposed in a Northeastern city with high demand charges (over $25/kW for summer months), shifting to a fixed price regime tripled the payback period. The rate-of-return on the system was then too low to meet the Purchasing Department's minimum specs for investment, and the upgrade proposal was dropped.

4. *Variable speed drives*—VSDs are an excellent way to reduce kWh consumption and could (depending on when they are used during the day) have a shorter payback under a fixed price regime. In many cases, VSDs will not significantly reduce peak demand because properly sized motors may still need to run at full speed during cooling peaks. When peak demand charges are, however, folded into consumption charges, each kWh avoided by a VSD is worth more, increasing the savings from this option. This advantage should remain under a fixed/floating price regime because the VSD was unlikely to be utilized very much during peak cooling periods (i.e., fans would need to run close to full speed anyway).

5. *Automated dimming*—A similar situation may occur with automated dimming that takes advantage of daylight entering a space. Since much of the benefit of that option is achieved during the

peak demand period, a fixed price regime will eliminate the demand portion of savings normally seen under a standard utility tariff. While a high fixed price could yield acceptable savings because kWh consumption is reduced, the impact would be muted because a sizable chunk of the cost of peak demand has now been merged with the base cost of energy for all other hours, including at night. In effect, much of the savings that would have been concentrated in a few daylit hours are now also spread to night and weekend hours because kWh cost is the same for all hours. The high cost of daylight dimming (especially as a retrofit) is a hard sell, even with high demand charges. Losing much of those savings due to a fixed price could make the rate-of-return too low to be funded.

6. *Gas/steam absorption cooling*—The promotion of a two-stage absorption machine to replace an inefficient electric chiller may also run aground, again due to the disappearance of the peak demand charge for generation. Since the kWh charge becomes a constant (for this customer) during the entire year, and the only visible demand charge was for power delivery, the previously large jump in seasonal power cost to run an electric chiller was greatly reduced.

   In one case, when it came to a rate-of-return analysis, keeping the old electric chiller for a few more years won hands down.

7. *Distributed generation*—As previously mentioned, a fixed price regime (regardless of its form) reduces the impact of peak demand charges because such costs are now spread among all kWh instead of acting as a penalty for excessive usage for a short period of time. Unless a facility uses a great deal of heat year round (e.g., a heated pool, or water process load), cogeneration's main benefit is the avoidance of the most costly power consumption during peak demand.

   A fixed/floating price regime may move some costs (normally spread by utility tariffs across all months) into the cooling season, thereby reducing its winter rates. Since most facilities in the US must deal with summer (not winter) power peaks, the value (in reduced power costing) of the cogen system could thereby be significantly diminished in winter, possibly making it a losing proposition for 6 or more months (relative to a standard utility tariff). Such a major change in power pricing could result in a cogen system looking more like a stranded asset than a way to cut overall energy costs.

PRICING OPTION 2

INDEXED RATE STRUCTURES

A. *Discount Off of a Regulated Price*—A defined (or negotiated) discount (either $/kWh or %) off of a known pricing structure is provided, such as: the utility's tariff on a defined date, or (if its generation has been sold) its monthly published price, for a given rate class; or the published standard offer (i.e., the "price to beat") or shopping credit

B. *Index to Bilateral Wholesale Market Pricing*—An index is a formula and/or discount relative to a published futures market price (e.g., New York Mercantile Exchange [NYMEX]) or a spot market price listed in an independent third party publication (e.g., Megawatt Daily). Pricing is typically done for daily on- and off-peak blocks of power.

C. *Direct ISO Hourly Pricing*—The supplier charges whatever hourly price is seen at either the Day Ahead Market (hourly pricing seen 24 hours in advance) or Real Time (also known as Hour Ahead) pricing, possibly plus a $/kWh (or %) service charge.

D. *Hedged Wholesale Pricing Pass Through*—Pricing is based on a combination of wholesale market rates and the use of hedging instruments (e.g., futures, options) that cap and floor the end user's price. The final retail rate paid by the end user typically includes charges to cover the cost of those instruments, and possibly a $/kWh (or %) service charge.

E. *Load Factor Indexing*—Pricing is based on an end user's monthly (or annual) load factor (i.e., average demand divided by peak demand) and may change as that factor changes.

Potential interactions between these rate options and efficiency upgrades:

1. *Off-peak consumption reduction*—If most of the reduction is off peak, the average demand will drop while the peak demand remains unchanged, thereby lowering load factor and potentially raising monthly (or annual) pricing. Even fixed price contracts are typically based on load factor over the prior 1- or 2-year period, so a consistent change in load factor could change the cost of future unregulated power once it is time to renew the contract. A major reduction in consumption (for any reason) may not please the supplier because he based his flat $/kWh contract rate on a load profile in which that typical off-peak energy usage was seen, and he projected revenue based on it.

2. *Peak demand shaving*—This option is very sensitive to how the indexing is done. If the price is indexed to a wholesale block price (such as flat 16-hour forward or monthly future), reducing peak demand will have only a limited effect because the price is flat for the 6 AM to 10 PM period. If the indexing is to an hourly spot market price, however, the peak shaving system may be able to offer much greater value when a facility's peak demand time coincides with that of the wholesale market. Unfortunately, wholesale prices often jump when a transmission or generation problem occurs at times that have no relation to weather or the customer's operation. To maximize the value of a peak shaving system, it must be automated to take advantage of such grid-wide price fluctuations through real-time communication with PX/ISO pricing and controls that respond to it without the need for human intervention. If indexed to a defined load factor, an automated peak shaving system can help greatly to maintain or improve that factor, thereby reducing costs.

3. *Thermal storage*—As indicated under "peak demand shaving," some loss of value may occur if hourly spot market pricing is used because such pricing may vary independently of the peak time of the facility. On the other hand, block pricing that is flat between 6 AM and 10 PM (the wholesale market peak period) and then drops during all other hours should allow a thermal storage system to

continue to provide some savings. Under a load factor index, one would assume that the price provided by the supplier was based on the historical operation of the existing thermal storage system, so continued successful operation of that system becomes essential just to maintain that price. Installing such a system where it did not previously exist could greatly improve load factor, resulting in a price reduction for all kWh used at the facility, depending to some degree on how the load factor is calculated (e.g., monthly or annually).

4. *Variable speed drives*—Under the inverse square law for such devices, cutting flow by 30% results in reducing motor demand by about 50%, so a relatively small speed adjustment yields a big drop in power consumption. On the other hand, a properly sized motor will likely need to run at nearly full speed when peak capacity is needed for cooling, so peak demand may not be reduced. The net result is a lowered load factor and a potentially higher average price.

5. *Automated dimming*—While daylight dimming is based on specific hours of the day and occurs without regard to wholesale markets, reduced demand due to acceptable reductions in illuminance levels has the potential to track wholesale pricing variations if automatically keyed to such pricing information. As a result, an automated dimming system could take advantage of hourly pricing variations. It could also help limit or raise load factor, thereby reducing pricing indexed to LF. A price indexed against daily or monthly block pricing, however, could limit the value of a dimming system since the same price may be applied across the 6 AM to 10 PM period, minimizing differences during peak times.

6. *Gas/steam absorption/hybrid cooling*—A price indexed to a block rate would not provide the same savings as a tariff in which peak demand was separately charged (and thus could be avoided). If the chilled water system was sized such that it could use gas cooling primarily during the day and electric cooling at night (or mainly as base load), a hybrid system holds the potential for minimizing the impact of price spikes or sustained high block rates. Such a system would also help raise load factor, thereby potentially reducing the cost of power under an LF indexed regime.

7. *Distributed generation*—If existing on-site generation is used simply to shave peaks, see "peak shaving" above for potential interactions. If it is to be used more extensively (e.g., to broadly flatten a load profile by running routinely during the summer), then one must consider the inherent risk in investing in what could become an on-site stranded asset. A price indexed to a block rate could, for example, result in a power price below the amortized cost of a gas-fired generator for most hours of the day and most months of the year, thereby making the investment in generation a losing proposition. Unless the generator's capacity could also be optioned to a supplier for use during times of capacity shortage (when hourly prices spike), a block rate covering the 6 AM to 10 PM period would likely deny much profit to the generator's owner. If the index is to a defined load factor, however, an existing generator could help contain pricing. The potential profitability for a new generator could become meaningless unless tied to a probability curve of market pricing to better understand with any certainty how often it could be used to defer high pricing.

PRICING OPTION 3

USAGE COMMITMENT CLAUSES

A. *Balance/Swing Penalty*—Most pricing regimes involve a commitment to purchase defined amounts of power and energy over a monthly billing period, based on past usage patterns. A defined variation (e.g., ± 10-20%) from that assumed pattern is allowed, with anything over it (and possibly under it) being charged at a different (and possibly volatile spot market) rate. Where interval metering (which provides usage in 15-minute periods) and real time usage is involved, however, it is possible that allowable variations would be measured over much time periods much shorter than one month. In Chicago, when their hourly demand varied beyond their contract allowance, some power customers ended up paying more under an interval metered rate that charged hourly wholesale pricing than they would have paid under a fixed annual rate.

B. *Contracted Total Volume*—A long contract term with an assumed minimum could result in a penalty for insufficient use as a result of an aggressive energy conservation or efficiency program, or switching from a large electric chiller to a gas-fired unit, thus losing some (or all) of the savings such an upgrade was assumed to provide. A clause allowing variations with a minimum number of month's notice of a usage change could avoid this problem.

Potential interactions between these rate options and efficiency upgrades:

1. *On- or off-peak consumption reduction*—While most volume commitments provide a relatively wide band of usage before being triggered, some efficiency options hold the potential for exceeding them. A conversion from electric heat to gas or oil heat, for example, could easily cut winter monthly (and annual) power usage by more than 20%. If the contract is written to define variations by account instead of by the aggregation of all of a customer's accounts, it is possible that even a conversion of central plant electric drives (e.g., for forced draft boiler fans) to steam drives could make that much difference during winter months for an account covering only the customer's central boiler plant.

2. *Peak demand shaving*—Merely shaving peaks (without significantly reducing consumption) should have little or no impact on a volume commitment, unless that contract also involves maintenance of a defined peak demand level.

3. *Thermal storage*—An existing thermal storage system, if operating properly, should not impact a volume commitment because that commitment would have been made based on historical power usage with the thermal storage system in operation. Under most circumstances, a new thermal storage system would use about the same number of kWh as a standard electric chiller system, but it would shift the chiller demand to night hours, thus impacting a facility's peak demand commitment.

4. *Variable speed drives*—Use of existing VSDs that have been installed for several years should not impact a volume commitment based

on past usage history, but installation of new units would cut consumption. Unless the VSDs controlled a very large process load, however, adding them to, say, only fans is unlikely to yield a 10% overall power reduction.

5. *Automated dimming*—Since lighting rarely accounts for much more than about 30% of total building kWh consumption or peak demand, occasional dimming is unlikely to impact most volume commitments. A major lighting upgrade could, however, result in a 10% reduction in kWh and kW.

6. *Gas/steam absorption or hybrid cooling*—A switch from electric to gas or steam driven cooling could have a significant impact (i.e., over 10%) on consumption and peak demand during summer months but is unlikely to impact annual usage to the same degree, unless used in process (as versus only building) loads.

7. *Distributed generation*—If used simply to shave peaks, only a peak demand commitment is likely to be impacted. If routinely used to minimize grid-based power, however, a serious impact on a kWh commitment is possible.

In all cases, one should assume that failure to meet an annual volume commitment will likely result in a higher power price from the same supplier when it comes time to renew the contract. No supplier wishes to incur the risk and extra effort inherent in dealing with a customer who does not know how to keep its contractual commitments.

PRICING OPTION 4

CAPACITY MARKETING

A. *Demand Cooperatives*—When several customers pool their demand and then work together to minimize it when profitable, the arrangement is often called a "demand cooperative." Such entities have existed prior to deregulation and provided savings.

B. *Capacity Trading*—In some tight generating markets (e.g., the northeast and west coast), customers can option to a supplier their installed generating capacity (e.g., a backup or emergency generator) and/or their ability to shave demand through an energy management system. To comply with calls from utilities and/or ISOs for load reductions, many customers had to install or upgrade their EMS, metering, communications, and other systems, potentially incurring significant costs. Any major drop in peak demand or consumption from participation in such programs could result in a balancing penalty, thereby cutting the savings and lengthening the payback for such new equipment.

Potential interactions between these rate options and efficiency upgrades:

1. *Consumption reduction*—Since capacity trading is insensitive to changes in consumption (as long as they have only a minimal effect on daytime demand), there are no interactions between them.

2. *Peak demand shaving*—The ability to shave peaks actually frees up capacity. As a result, that option enhances any form of capacity marketing.

3. *Thermal storage*—A typical storage system would run every day that cooling is needed. It would therefore be already working when a call for capacity was received, and would therefore not be able to enhance capacity marketing. On the other hand, failure of a thermal storage system could negatively impact any arrangement in which the customer pledges load reduction and fails to deliver it. It is possible, however, that having a capacity trading agreement could allow a customer whose thermal storage system failed to purchase capacity at a price below the utility tariff's demand charge, thereby reducing the financial hit that might otherwise be felt.

4. *Variable speed drives*—If a facility can accept occasional speed reductions and/or cycle various drives sequentially to result in an overall accountwide reduction in demand at any one time, this option could enhance capacity marketing capabilities.

5. *Automated dimming*—While automated reductions based on daylighting would not necessarily be coincident with the grid-

wide need for capacity, a dimming system that was automatically triggered by capacity market pricing would enhance capacity marketing capabilities.

6. *Gas/steam absorption/hybrid cooling*—The ability to switch from electric to gas or steam-based cooling (assuming there is sufficient total capacity to still meet the building load) could also be used to enhance capacity marketing capabilities.

7. *Distributed generation*—The ability to reduce one's demand by feeding some loads from a gas-fired generator could also be used to enhance capacity marketing capabilities. While some have tried to claim that renewable power generation (e.g., photovoltaics) sources could also be helpful in this regard, the high installation cost of most alternative power generating systems would call for their continued use to generate revenue whether or not an ISO, supplier, or utility was willing to pay for needed extra capacity. Some suppliers and utilities may, however, offer a higher price for such power if continuously offered into the grid so that it may be sold as "green" power at a premium to others (see further discussion in Part 3, Winter 02-03, *SPEE.*

PART 3

In the final section of this major 3-part series, planned for the Winter 2002-2003 issue of SPEE, Mr. Audin discusses other power purchasing options and how they also can impact your plans. He concludes by recommending ways that proper coordination can lead to the most efficient energy usage and energy purchasing.

Mr. Audin's series of articles on "What Deregulated Retail Power Pricing Can Mean To You" has been abstracted from a report he gave at the Association of Energy Engineers "World Energy Engineering Congress," October 26, 2001. Each of these articles will appear on AEE's on-line journal Accesswww.aeecenter.org/joumalsonline (see box, next page.)

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Audin has been named Energy Manager of the Year by three different national or regional organizations, most recently by the Association of Professional Energy Managers in 1995. In 1993, the Association of Energy Engineers (AEE) named him their International Energy Manager of the Year, and in 1996 inducted him into its Energy Manager's Hall of Fame, the highest recognition in that field.

He served on the board of the New York Designer's Lighting Forum, the *Energy User News* Technical Advisory Board, and an ASHRAE 90.1 technical committee. His column on lighting and energy issues has appeared quarterly in *Architectural Record* magazine since 1991.

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