Industrial Time of Use (TOU) Rates

In many electricity markets, the marginal cost of producing or purchasing electricity varies hour-to-hour (or even minute to minute). Even where the cost of producing or purchasing electricity is relatively stable, transmission networks are designed to accommodate the times when demand is highest, increasing overall costs on the system. At the same time, most cost-based retail prices do not vary by time. This creates economic inefficiencies.

The most economically efficient way to deal with this issue would be to employ so-called "dynamic pricing" that sees retail prices change in real-time to reflect the wholesale and other costs of electricity. However, this approach raises a number of issues (technological, political, and practical) that most jurisdictions have not been prepared to confront.

Instead, some jurisdictions have adopted TOU rates which vary depending on the time of day or week that electricity is consumed. These rates are, in effect, a simpler and less contentious approach to having retail rates based directly on cost of production. TOU rates are implemented on the assumption that they send a price signal that, while not perfectly efficient, is at least adequate to induce consumers to reduce their on-peak consumption – either by shifting to off-peak hours, or reducing demand overall.

An industrial TOU rate could shift demand from peaks, in order to avoid the need for new generation capacity additions (as distinct from BC Hydro's stepped rate, which is intended to drive down energy consumption overall rather than to shave peaks).

TOU rates can fit uncomfortably in a regulated market, where prices are generally set on an embedded-cost basis rather than on some derivative of producers' marginal costs. This is especially problematic when the actual cost of producing electricity, as from hydroelectric dams, does not vary by hour or season. When TOU rates are intended to address transmission congestion, or to provide appropriate price signals to delay or prevent marginal costs in the future, these rates may have even less of a relationship with embedded costs.

A TOU rate that provided a price signal for the cost of new capacity would over-recover BC Hydro's costs during peak periods. In order to keep overall rates from over-recovering costs, some electricity would have to be sold at a discount. This structure creates its own distortions, such as below-cost prices at off-peak times, and a TOU rate would need to be carefully designed to provide the desired incentives with minimal unintended consequences.

In fact, BC Hydro has – since 2006 – an optional industrial Time of Use Rate designed to balance overall bill impacts and provide an incentive for industrial customers to consume power during low load hours (LLH) rather than high load hours (HLH). Customers using it would have customer baselines, similar to those under the existing Transmission Service Rate, for each of four time periods (LLH and HLH during the winter; spring; and other). No customers have opted to use this tariff, which is seen to add excessive complexity; offer low margins; and create production timing risks.

Industrial TOU pricing is mandatory in California. Pacific Gas and Electric, ("PG&E) differentiates with "part-peak" and "off-peak" rates in the winter, and with "max peak", "part peak" and "off-peak" from May to October, when the overall system peaks. There are also additional charges and credits related to "peak day pricing" events. Most of the cost differentiation in the PG&E rate occurs in the demand (capacity) charge portion of the rate, with less effect in the energy portion.

Under the PG&E rate for firm service at transmission voltage, the summer max-peak demand charge is $14.03 per kilowatt (kW), compared with just $3.04 in part-peak, and no charge off-peak. Incremental demand charges on peak days are $1.20 per kilowatt, but the credit for peak-day demand is nearly $6.00. The off-peak energy charge is about 6.4 cents per kW.h, while the max-peak price is about 9.4 cents. The part-peak summer price is about 7.8 cents. There are no winter demand charges, and winter energy prices are little different from those in the summer.

Clearly, PG&E has imposed a relatively strong price signal on the max-peak, and has designed its program around capacity conservation. This suggests that a very high value is being placed on avoiding the incremental unit of new generation. It may also suggest a relatively inelastic industrial sector that requires large price signals to prompt a demand response (although this can only be inferred from the rate).

California imports a significant fraction of its electricity from its neighbours, and is known to suffer from a congested transmission network. These factors may explain PG&E's emphasis on capacity, rather than energy charges to limit demand at peak times. A focus on capacity might make sense in BC if the objective was to avoid or defer the need for investment in capacity projects such as pumped storage.

In contrast to the PG&E approach, industrial rates in Ontario use dynamic pricing for large customers, compared with simpler TOU pricing for the vast majority of other customers. That is, customers with suitable metering are charged a "market" energy price for every hour, in addition to basic and demand charges. This fits with the power pool structure of Ontario's electricity market, where generators bid to sell electricity into the pool.

This approach might be applicable in BC in periods where BC Hydro sells surplus power into the markets. When BC Hydro is in surplus, the marginal cost of selling power to an industrial customer is closely related to the market price. Even when BC Hydro is in slight surplus or load-resource balance, Powerex imports significant energy during light load hours for sale during heavy load hours. Often domestic load is the limit on these imports, and an incentive for using electricity during light load hours would produce an overall benefit. However, when BC Hydro is not in surplus it is bound by self-sufficiency objectives and the market prices are not the appropriate margin. Another complication could occur if BC Hydro were in a prolonged surplus and market prices were lower than embedded costs – in this case, costs could leak from industrial to other customer classes.

As a derivative of TOU, some jurisdictions, such as Manitoba, also employ surplus rates and curtailable programs (or rates). Manitoba offers commercial customers whose load exceeds 200 kW a rate based on spot market conditions, but these customers may be subject to lengthy interruptions and are typically required to have a working alternate backup system. Customers with a minimum of 5 MW of connected load can opt in to a curtailable service program, in which they must drop a minimum of 5 MW of load within a specified time-frame when requested to do so by Manitoba Hydro. In return, they receive a monthly credit on their Hydro bill which depends on the amount of curtailable load they make available and the exact curtailment option they select. These programs allow the utility to respond to specific periods of surplus, shortage, or lucrative market opportunity.

Curtailment programs have been tried in BC. Some have been successful, such as the use of grinder loads for emergency system stability, and curtailment in general was also quite successful during the California energy crisis. However, curtailment programs have usually not been successful in BC. In general, this reflects the fact that most industrial processes are relatively inflexible and rely on enormous capital investment. As such, they are relatively unresponsive to the modest short-term price signals that these programs tend to offer. That is because even large changes in electricity prices tend to be overwhelmed by other considerations unless these price effects apply consistently over a large period of time, so that they can be accommodated into the industrial processes cost effectively.

Questions to Consider:

1. What should any TOU rate in British Columbia target?
2. What kind of price spreads would be needed?
3. What benefits are companies hoping to realize?
4. What is the best way to manage the potential conflict between recovery of embedded costs and an effective marginal cost signal?
5. How would customers who do not pursue a TOU be impacted?
6. Would alternate instruments meet objectives better?
7. Should BC Hydro continue to offer incentives for curtailable load needed for reliability?