Regulated Pricing Plan Working Group

MEETING NOTES - Meeting #7

Ontario Energy Board
2300 Yonge Street, North Hearing Room

Monday, November 8, 2004
9:00 a.m. - 4:45 p.m.

Barrie Hydro (John Olthuis)
BOMA, FRPO, CIPPREC (Mike McGee)[1]
Consumers Council of Canada (Julie Girvan)
Cdn. Federation of Ind. Business (Bruce Fraser)
Coalition of Large LDCs (Paula Conboy)
Direct Energy (Ian Mondrow)
Electricity Distributors Association (W. Taggart)
EPCOR Utilities Inc (Leigh-Anne Palter)
IMO - Settlements (Joseph Freire)
Kinetiq (Jim Steele)
Ontario Energy Savings Corp. (Gord Potter)
Ontario Federation of Agriculture (Ted Cowan)
The SPi Group Inc. (Gay Cook)
Vulnerable Energy Consumers Coalition (B. Harper)
Navigant Consulting (Mitch Rothman)
Navigant Consulting (Todd Williams)
Ontario Energy Board (Chris Cincar)
Ontario Energy Board (Russell Chute)

NOTES OF MEETING

Review of #4 and #5 Meeting Notes

Draft meeting notes for the 4th and 5th WG meetings had earlier been circulated by Board staff for final comments. A note had been included in the #4 meeting notes about RPP consumers switching to the spot price pass through. A WG member noted that it should be left to state that such circumstances had not been addressed by the WG and, therefore, the additional commentary should be removed.

In terms of the #5 meeting notes, it was also suggested that the meeting notes implied that proration of tiers would be simple, from an implementation perspective, for all LDCs and that this was not the case. It was agreed that this could be problematic for some LDCs and that this should be reflected. An LDC WG member also requested an opportunity to forward to the WG via e-mail some concerns associated with the notice periods agreed upon, primarily for price structure changes. *[Note: The concerns of the Coalition of Large LDCs were subsequently forwarded to Board staff and is attached].*

Decision Strawman - Conventional Meters

Navigant clarified that the contents of the Decision Strawman for “conventional” meters reflected majority WG support on each of the elements and not necessarily a full consensus.

[1] Building Owners & Managers Association (BOMA), Federation of Rental-housing Providers of Ontario (FRPO), Canadian Institute of Public & Private Real Estate Companies (CIPPREC).

Navigant further explained that the focus of this part of the meeting was intended to address the three unresolved elements: *the frequency of price adjustments, tiered price structure and customer mobility.*

In addition, once these three issues were resolved, the WG will have a final Decision Strawman which will form the WG recommendations to Board staff for RPP consumers with "conventional" meters.

<u>Price Adjustment</u>

Navigant explained that there had been substantial consensus on all of the aspects of the price adjustment except the adjustment frequency. The 3 options for frequency that remained were 3, 6 and 12 months.

There were some questions around what "unexpected" variances referred to. Navigant noted that some variations in price will be expected such as those due to seasonal changes in price and demand and these "expected" variances will be accounted for in the price forecast. However, some variances will result from unexpected events, such as a long nuclear plant outage, which cannot be forseen and taken into account, and it is these "'unexpected" variations in price that will necessitate the need for true-ups and price adjustments.

There were questions around how true-ups would get shown on the RPP consumer's bill. Board staff responded that the Board would likely prefer maximizing transparency via a separate line item, but the Board may be constrained, beyond its control, by decisions made by the Ministry in a separate process on the standard/simplified bill.

It was explained that 3, 6 and 12 months appeared multiple times in the strawman to reflect the WG decision on an "integrated" process. It was noted that this integrated price adjustment process was similar to the Union Gas model currently in effect.

As noted in previous meetings, the primary reason for many members not supporting a quarterly adjustment, as is done in natural gas, was the implications associated with the fact that many electricity LDCs used bi-monthly billing. Hence, most RPP consumers would see a price change on every bill that they received. It was clarified that about 75% of LDCs have bi-monthly billing. As a result, it was noted that this would not likely be acceptable given that one of the primary objectives was price stability. It was then suggested that, at minimum, the price adjustment frequency should be at least every 6 months to balance the competing objectives of price stability and cost reflectivity.

A substantial WG consensus then began to form around "semi-annual" adjustments with a trigger. The rationale for the trigger was to ensure variance account balances did not become excessive and unmanageable. At the same time, there was also a substantial

WG consensus that "quarterly" adjustments would be preferred if all LDCs moved to monthly billing and this may be the case with the penetration of smart meters in the market. The discussion ended on this matter with only 2 WG members not supporting semi-annual adjustments. One supported quarterly adjustments, if there is a move to monthly billing, and the other supported annual adjustments. ***[Action: These 2 WG members to provide a rationale for these preferences].***

There was also consensus that there should be no maximum price increase (i.e., cap) associated with each price adjustment. Instead, the WG was of the view that such decisions should be left to the Board's discretion within the context of other potential future bill impacts such as distribution rate changes.

Tiered Pricing

The discussion then moved on to the issue of tiered pricing. In order to focus WG discussion, Navigant noted that, if tiers were supported, the principles that the WG had agreed on included designing those tiers to minimize cross-subsidies between customer classes via different tiers for the residential and small business classes. Navigant went on to identify what the WG had already rejected in terms of tiers. This included "seasonal" tiers and having more than 2 tiers.

One WG member noted that they were of the view that eliminating tiered pricing was not an option as it would likely be viewed as recommending a step backwards in terms of creating the conservation culture desired by the Minister. Accordingly, the WG should move forward on tiers and focus their discussion on options to best address these cross-subsidy concerns.

Navigant added that consumer response to tiered pricing would likely increase as consumers became better educated and more accustomed to it over time.

Given the above, Navigant presented two models for consideration which both had 2 tiers, as per the current approach. The primary difference from the status quo in the **first model** was to set the threshold so that, on average, each customer class obtained the same fraction of supply from the lower tier. The **second proposal** would raise the commercial class threshold for the first tier from 750 kWh to 1500 kWh. Data provided by one LDC showed that, under the current approach, about 25% of residential supply was priced at the upper tier while just under 75% of small business customer supply was priced at the upper tier. As a result, changing to the 1500 kWh threshold would lower the amount of commercial supply from 75% to 45% subject to the upper tier. However, Navigant added that it was important to take into account that 62% of electric heat residential supply was at the higher tier. One WG member added that this was important to take into account since a large portion of electric heat customers are low income.

Given the above, Navigant noted that there are essentially 2 classes for residential.

Board staff asked if LDCs had the data to differentiate between electric and non-electric heat consumers. An LDC WG member noted that not all LDCs continued to track such information since market opening and that it would also be difficult, if not impossible, to know when a customer changed from electric to natural gas heat.

Navigant added that the second proposal would represent the simplest approach and should meet the concerns of the small business customers, but it would result in about a 1% price increase for residential RPP consumers. Model 1 would result in a larger price increase for residential consumers.

A WG member suggested a relatively straight-forward approach to help address low income electric heat residential consumers would be to raise the 750 kWh threshold in the winter months and offset that by lowering the 750 kWh threshold in the summer. As a result, it could be designed to be revenue neutral and it would positively impact residential consumers with electric heating (i.e., a necessity) and negatively impact residential consumers with air-conditioning which is more of a luxury. It was further added that many electric heat consumers do not have an option to switch to natural gas because, for example, it is simply not available to them.

It was added that if the MUSH sector (primarily > 50 kW) is ultimately included in the RPP, along with small business (< 50 kW), it would distort all of this analysis undertaken by Navigant.

Navigant noted that cross-subsidization should not be associated solely with tiered pricing. A single flat price also results in cross-subsidization because residential and small business consumers have different load profiles. Therefore, there are cross-subsidies associated with any approach other than the spot price pass through.

A LDC WG member noted that Model 1 was likely too complex to implement and was based on data most LDCs likely do not have.

It was also suggested that the Ministry likely set the tiers for both classes at the same level, based on residential consumption, because there may have been an expectation that business consumers would move off of default supply to a retailer.

One WG member cautioned that, if residential and small business tier prices are set the same but if the tier volume level for small businesses is higher than residential, a certain amount of gaming may result. The higher small business tier may encourage residential customers to claim to run businesses out of their home and request the small business tier to maximize their usage at the lower tier price. The WG member suggested that the first tier price for small businesses could be set slightly higher than the first residential tier price to take away this incentive. Board staff asked if the customer designation was included on the bill and a LDC WG member responded positively.

It was also suggested that tiers should not be based on the average consumption within any class, as was being suggested, because this would remove the conservation incentive.

An LDC WG member cautioned that the changes to the tiers that were discussed, such as new thresholds for small business consumers, would result in structural changes and therefore would have cost implications for LDCs which would need to be recovered from all consumers.

One approach suggested was to look at the load profile for each of the customer classes and have the tiers apply to the % of volume associated with the off-peak and on-peak consumption for each class. The lower priced tier would apply to off-peak and the higher priced tier would be applied to on-peak % volume. It was suggested that this approach would be more consistent with the move to smart meters as cross-subsidization is not only associated with the total volume of energy consumed, but also the time it is consumed. It was added that residential customers consume throughout the day while many small businesses tend to consume more during the on-peak periods when power costs more to produce. Navigant noted that it is about a 45% (off-peak) - 55% (on-peak) split. However, there may be data contraints.

The appropriate **price differential** between tiers was then discussed. It was noted that it should likely be about 2-3 cents/kWh and, if the goal is to increase conservation, the differential should be increased.

Two WG members stated that their preferred approach remained to be a single price (i.e., no tiers). Navigant responded that tiered pricing would better achieve the objectives of cost reflectivity and encouraging conservation, while both approaches resulted in some degree of cross-subsidization.

Lowering the threshold to 500 kWh for the first tier was also mentioned as an option to increase the conservation incentive. However, a WG member responded that there was no point in setting a level that no consumer could achieve. Another a WG member noted that it is likely not the consumers between 500 kWh and 750 kWh that we need to worry about, as these are likely the consumers running the necessities of life (e.g., stove, refrigerator, heat). In other words, there is little if any discretionary energy use at such levels of consumption.

Another WG member suggested that the WG should focus on price differentials as opposed to levels of consumption and noted that the current price differential is about 16%.

Those WG members that supported a single price, relative to tiers, stated that they were willing to support tiers assuming that it would be unacceptable to have no conservation incentive included in the RPP.

The discussion closed on this issue with a WG member noting that the price differential ultimately needed to be based on empirical evidence and the WG would not have access to such evidence to decide on the specifics at this time.

Customer Mobility

Navigant began the discussion on customer mobility by explaining two alternative approaches: requiring RPP consumers to pay the accumulated variance that they owe when they exit RPP vs no clearing of the variance upon exit. Navigant added that it essentially came down to a trade-off between equity in requiring all consumers to be responsible for their own costs vs the additional LDC administrative and systems costs of going this route. Navigant explained that the majority of WG members had supported not requiring a true-up upon exiting at the last meeting.

Navigant also added that the WG concluded in the previous meeting that customer moves were not a significant concern, in terms of cost-shifting, as this primarily only arises when customers move to a smaller dwelling and those that move outside of the province which only represents 3% of all customers.

Navigant went on to discuss some potential cost-shifting impacts assuming no clearing of the variance upon consumers exiting RPP. The impacts were based on an assumption of an accumulated variance of $200 million over the year which would result in about $50 being added to each RPP consumer bill if none exited. In terms of moves, if 3% left the province and did not pay their share of the variance, it would add only about $1.50/year to the bill of each remaining RPP consumer. In terms of switching, if 20% switched to a competitive retailer, it would increase the amount each remaining RPP consumer must pay by $12.50 to $62.50/year in total.

One WG member felt that a 20% switching rate was too high. Navigant clarified that the 20% did not represent the number of customers. Instead, it represented the total volume of energy consumption that moved to retailer supply.

Navigant added that the $200 million likely represented a worst case scenario and that it was also a two-way street as there should also be times when there are positive variance balances.

A WG member could not understand why it would be so difficult for LDCs to determine the variance amount owing since the price will be available from the OPA and their past consumption shows up on each bill they received from their LDC. It was added that STRs would indicate which customers switched to a retailer so it should be relatively simple to identify such consumers.

A LDC WG member responded that the data for billing and the data for each customer's previous consumption was maintained in two separate databases and it would be a separate run to determine these amounts owing.

Navigant suggested that, if it would be costly to determine precise amounts owing, another option may be to simply approximate the variance owing. There was no response to this suggestion.

Board staff advised the WG that the Board would be unable to justify such cross-subsidization based solely on qualitative claims of significant systems costs. As a result, further information in the form of real quantitative cost estimates would be required for the Board to even consider this as a real option.

A WG member noted that, if the MUSH sector is ultimately included in the RPP, such customers could be walking away from a substantial amount without a final true-up.

Another WG member was of the view that the quality of LDC billing was quite poor as the result of estimated bills and confusing billing references and thus we have bigger fish to fry than addressing this issue.

It was also noted that the materiality of these amounts would likely decline as smart meters are deployed.

While the majority of the WG supported no true-up on RPP consumers switching to a retailer, the two WG members representing residential consumers supported requiring RPP consumers to pay what they owe upon a switch.

Board staff reiterated their advice to the WG that, if the WG wanted the Board to seriously consider this as an option, quantitative systems cost estimates would need to be provided. ***[Action: Navigant to prepare a clear question detailing the information required for the LDC WG members to respond to].***

Smart Meters Strawman Discussion

Navigant began this segment of the meeting explaining the results of some research they had undertaken on other jurisdictions that had implemented time-of-use (TOU) pricing. The intention was to assist the WG in making more informed decisions on a smart meter strawman.

The focus for “smart” meters was primarily on pricing given the WG’s decision that the other elements would be transferable from the “conventional” meter strawman.

Number of Time of Use Periods/Seasonality

Navigant noted that they had looked at 20-25 jurisdictions and chose 3 to show the WG which all had 3 levels of TOU prices; one of which had about a 1:2:3 ratio in terms of the price differential (e.g., 6, 12, 18 cents/kWh). All 3 topped out at about 18 cents/kWh. These jurisdictions used different nomenclature for their price levels. Two had peak, mid-peak, and off-peak periods, and one used peak, intermediate, and off-peak.

Navigant also showed an illustrative chart for Ontario which was also based on 3 levels of TOU prices and a similar 1:2:3 ratio in the price differential (e.g., 4, 8, 11 cents/kWh).

A LDC WG member advised that when TOU prices are set, regardless of the form, there will be a need for it to be made clear whether it is based on standard time, as most LDC settlement systems are based on standard time.

A WG member noted that 3 price levels which varied by season plus possibly the addition of critical peak pricing (CPP) may be too much for consumers to understand during the initial transition since, to date, they have only been exposed to a single constant price. Navigant noted that there is a need to maximize the benefit of the planned smart meter investment.

It was suggested that regardless of the degree of increased complexity, it will be much more complex than residential consumers are accustomed to and, therefore, there will be a need for a good consumer education program to maximize that benefit.

A WG member suggested that one way to simplify it would be to have only two seasons (i.e., cut out the shoulder seasons). Board staff added that it may not be worth the added complexity of also having shoulder seasons since information previously provided by the IMO showed there was essentially no difference in the prices in the fall relative to summer and winter. Another WG member questioned the need for more than 2 seasons given the billing lag implications (i.e., billed for winter consumption in the spring).

There was general agreement on 3 price levels during the day. However, in terms of seasonality, the WG differed on whether these price levels should vary based on 2 or 3 seasons (i.e., exclude or retain the shoulder season).

Period-specific application of Global Adjustment

This had been discussed at the previous meeting and there was no support for adjusting the Global Adjustment (GA) between peak and off-peak periods (i.e., apply to off-peak prices if negative and to peak prices if positive). Accordingly, there was consensus on a uniform GA application across all periods.

Critical peak pricing (CPP)

CPP was then discussed. A WG member questioned whether CPP had been implemented anywhere across an entire jurisdiction and/or if it was made mandatory anywhere. Navigant responded that, including California, CPP had been implemented only on a niche or pilot project basis and, to their knowledge, it had been implemented only on a voluntary basis (i.e., there was no experience anywhere with application to entire customer classes). It was noted that those who volunteer for such programs tend to be the "keeners" or those most likely to respond to prices and, therefore, it would be unlikely that the same pilot program results would be achieved if CPP was made mandatory for all consumers. There was also some confusion between the terminology of "super" peak prices vs "critical" peak prices among WG members, with "critical" peak pricing that only applied on certain days along with "super" peak pricing that applied in certain seasons.

Another WG member expressed concern that Ontario was considering implementing CPP across the province based on no analysis at all, while California had now invested a couple of years and millions of dollars in conducting and analyzing pilots and they were still not yet ready for a full roll-out of CPP.

Board staff suggested a potential option for WG consideration may be to similarly implement CPP at the outset based on a voluntary basis in Ontario. However, it was noted that this approach would become very complex since those that did volunteer for CPP would need to have all of their other TOU prices adjusted downward (relative to those who did not volunteer) to compensate them. Therefore, each LDC would need to have 3 different TOU price levels that differed for each of the two groups of consumers and varied by season.

In terms of a mechanism to potentially ease the transition, it was suggested that if and when CPP is implemented, one approach may be to provide a 1 year grace period, whereby no RPP consumer's bill (on CPP + TOU) is higher than it would have been if they had remained solely on TOU pricing.

The WG concluded that, given no other jurisdiction had implemented CPP on a jurisdiction-wide basis and that the limited results the WG had seen were all based on voluntary pilot/niche programs, the WG did not feel comfortable recommending mandatory CPP application for Ontario at this time. Instead, the WG decided that it would be prudent for the OEB to first undertake further research into CPP and reconsider mandatory implementation in 2007 when there are more than a handful of smart meters in Ontario. This research could include voluntary pilots to determine the optimal structure, communications strategy and likely impact (i.e., how do the results compare to the California SPP research?). *[Note: According to the OEB's Draft Implementation Plan for Smart Meters, a smart meter requirement for new installations will not apply until some time in 2006].*

<u>Variance Recovery</u>

There was consensus on a single variance "pool" for both conventional meter and smart meter RPP consumers with uniform recovery across both, as this is only transitional and separate pools could become quite complex given the expected continuous level of migration from the conventional meter RPP to the smart meter RPP over a 4 year period.

Next Steps

This concluded the RPP WG meetings to develop recommendations. A report will now be drafted by Navigant for circulation to the full WG. It was agreed that WG members would receive at least 4 days to review the draft.

Future Meetings

The WG will meet one more time for a partial day to finalize the WG Report which consolidates all of the RPP recommendations for smart and conventional meters.

Date Finalized: *November 25, 2004*

Prepared by: *Chris Cincar, Ontario Energy Board, 416.440.7696*

ATTACHMENT

Coalition of Large LDCs - Timing implications of rate changes

Most LDCs would typically allow 6 to 8 weeks to implement a simple pricing change. This is the elapsed time from when the "final rates" are made available, to when the changes are promoted to the live production system for billing.

The following are considerations in implementing pricing changes in a utility billing system:

a) Updating Rate/Tariff Tables: In many utility billing systems, conventional rates are table driven, with a table for each tariff type. Updating commodity prices (eg, to change 4.7/5.5 to some other rate(s) in a LDC's system can require updates to approximately 40 tariff tables (for PowerStream and Hamilton Hydro for example). Many LDC's have both a complex billing engine to calculate bills for interval meters and a separate interfaced CIS billing engine for calculating standard cumulative meter bills. Once the tariff table code changes are made they must be unit tested to ensure that they have not corrupted the application unit functionality. Subsequently, integration and product testing is carried out in parallel to ensure that the billing application continues to operate as expected through the entire billing process and that all interfaces with other applications are able to handle the changes and an accurate and understandable bill can be created. This often requires changes to a separate bill formatting application which receives the calculated billing data and formats it for presentment on the bill paper stock. With many different rates/tariffs and numerous situations that need to be tested (e.g., cancel/rebill, rate reclassification, meter changes, etc.) there are numerous test scripts executed to ensure that the bills are all calculated correctly and the presentment is accurate/appropriate.

b) Who does the price change apply to? Changing the eligibility criteria from status quo for who does and who does not get the price change will increase the time required to implement. Changing the definition of RPP eligible from the currently defined Price Protected customers will impact the timing required to process even a simple price change.

c) Nature of Price Change: Is it simply a change from one price to another, or does it also involve a rate structure change? Rate structure changes are typically more complex and require longer times to implement and test. Some billing systems may consider a change from 2 tier (eg, the current 4.7/5.5 pricing) to 1 tier (a flat rate) to be a structure change that may require special processing such as prorating. Rate structure changes also affect cancel/rebill capability. Bill presentment over rate structure changes can be very challenging and result in confusion for customers.

d) Collision with other CIS system changes being implemented in the same timeline can lengthen coding, testing and therefore implementation times. For example, there may be overlapping activities resulting from rolling out new Distribution rates for March, new commodity rates for May 1 and EBT process changes that create conflicting needs for scarce resources, whether they be people (designers, programmers, testers), or availability of code to be changed, test systems, etc.

It is cautioned that rate changes cannot be thoroughly tested and implemented in two weeks. These changes have significant consequences if done incorrectly, and sufficient advance time must be provided to implement, test and push changes into production. Having said this we believe that a minimum 30 day implementation would be more appropriate for conventional simple rate changes and 90 where more extensive system changes, including bill print changes are required.