BEFORE THE BRITISH COLUMBIA UTILITIES COMMISSION

British Columbia Hydro	**)**	
and Power Authority	**)**	**Project No. 3698573**
Large General Service	**)**	
Rate Application	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

BRITISH COLUMBIA SUSTAINABLE ENERGY ASSOCIATION

AND SIERRA CLUB BRITISH COLUMBIA

Resource Insight, Inc.

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honour society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit 1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 230 times on utility issues before various regulatory, legislative, and judicial bodies, including the utility regulators of twenty-eight states, four Canadian provinces (Ontario, Nova Scotia, Manitoba, and Alberta), New Orleans and the District of Columbia, and two U.S. Federal agencies.

Q: Have you testified previous regarding electric utility rate design?

A: Yes. I have testified on rate design issues in numerous proceedings.

Q: Have you testified previously in British Columbia?

A: Yes. I filed testimony in BCUC Project No. 3698388, regarding BC Hydro's 2005 Resource Expenditure and Acquisition Plan.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the British Columbia Sustainable Energy Association (BCSEA) and Sierra Club of British Columbia (SCBC).

Q: What is the purpose of your direct testimony?

A: I have been asked by my clients to review the proposals of BC Hydro for splitting the current Existing Large General Service (ELGS) rate class into Medium General Service (MGS) and Large General Service (LGS) classes, and the rate designs proposed for those new classes. The principal focus of my review and testimony is the effects of the rate proposals on energy efficiency, in terms of both investments (including participation in the PowerSmart programs) and operations.

Q: What issues do you address?

A: In the five sections below, I discuss the following issues:

- accelerating the flattening of the energy rates in the new MGS class,
- the counter-productive effects of the historical baseline in the new LGS class,
- alternative approaches to the design of the LGS rate,
- the problems with demand charges and the effect of reducing them,
- other rate-design issues: the minimum charge and migration rules.

Q: Please summarize your conclusions.

A: I agree with BC Hydro that the declining-block energy rate in the ELGS class is inappropriate and inefficient. The declining-block rate design should be flattened faster than Hydro proposes in the MGS and should be flattened in the LGS rate as well.

The addition of a Part-2 LRMC energy rate to the LGS rate, set to approximate long-range marginal costs, is an important innovation, but the proposal to charge (or credit) the Part-2 LRMC rate for the difference between the customer's monthly energy usage and its three-year rolling historical baseline (HBL) eliminates most of the potential efficiency incentive and would sometimes goes so far as to reward increased usage. As proposed, the combination of the Part-2 LRMC energy rate and the rolling HBL would create complexity and confusion, but not much conservation. The new rate should be designed so that using more energy does not increase the entitlement of an LGS customer to additional energy at the Part-1 rate.

The proposed demand charges in the MGS and LGS rates would not provide useful incentives for energy conservation or shifting of load to less-expensive times. Those demand charges should be radically reduced, allowing Hydro to increase the MGS and LGS (Part 1) energy rates.

The Commission should also eliminate the minimum charges in the MGS and LGS rates. Finally, the rates should be designed so that customers who conserve are not penalized by being shifted between rate classes in a way that increases their bills.

III. Flattening Energy Rates in the MGS Class

Q: What comments do you have regarding Hydro's proposal to flatten the energy rate in the new MGS class, by gradually reducing the first block and raising the tail block?

A: While Hydro's proposal moves in the right direction, the changes should be faster. Hydro proposes to phase in the rate flattening over six years, as shown below in Table 1. Hydro's proposed six-year rate design phase-in does not always result in *any* customer experiencing the maximum allowed increase. As shown in the "Maximum Expected Total" line of Table 1, the largest rate increase that Hydro expects to observe in F2016 is less than 15.6%, even though Hydro considers a 16.6% increase to be acceptable; similar gaps occur in the projections for F2013 and F2015.[1] In the years in which Hydro proposes relatively large maximum rate-design bill increments (F2014–F2016), very few

[1] I use the term "Total" to indicate that the increase includes both the class average rate charge (CARC) and the rate-design effect. I use the term "Expected" to identify Hydro's projection of the maximum increase that would actually occur, as opposed to the ceiling that Hydro applied in its design process.

of the roughly 15,500 MGS customers would experience increases in the highest interval Hydro reports: 12 in F2014, 1 in F2015, and 6 in F2016.[2] These customers would be the largest energy users with the highest billing load factor, who have traditionally paid the lowest rate.[3] Their rate increases are larger than average because they have been getting a larger discount from marginal cost than other customers.

Table 1: Hydro Proposed Six-Year MGS Rate-Flattening Phase-In

	F2011	F2012	F2013	F2014	F2015	F2016
Assumed CARC[a]	10.63%	3.70%	6.80%	7.00%	5.60%	6.60%
Maximum Allowed Rate-Design Effect[a]	2%	4%	6%	8%	10%	10%
Total[a]	12.63%	7.70%	12.80%	15.00%	15.60%	16.60%
Cumulative Total	12.63%	21.30%	36.83%	57.35%	81.90%	112.10%
Cumulative Design Effect	1.81%	5.73%	11.68%	20.02%	31.39%	43.72%
Maximum Expected Total[b]	12.6%	7.7%	12.6%	15%	15%	15.6%
Customers Near Max.	2,814	23	224	12	1	6
Cum. Expected Total	12.6%	21.3%	36.6%	57.0%	80.6%	108.8%
Cum. Expected Design Effect	1.8%	5.7%	11.4%	19.8%	30.4%	41.5%

[a]*Source: Application, Table 2-1* [b]*Source: Application, Table M-6*

The transition to a flat energy charge for the MGS rate could be accomplished much faster. Table 2 summarizes a phase-in over four years, rather than the six years proposed by Hydro. The maximum increase in each year is constrained by Hydro's proposed 10% limit on bill increases resulting from rate design.

[2]Hydro reports the results in bins of various sizes, ranging from 0.6% to 1.6% (Application Table M-6). The top bins for F2014 and F2015 are one percent wide, while that for F2016 is 1.6 percent wide.

[3]Load factor is the ratio of average usage to peak load. The billing load factor is the ratio of average usage to the billing demand.

Table 2: Accelerated MGS Rate-Flattening Phase-In

	F2011	F2012	F2013	F2014
Assumed CARC	10.63%	3.70%	6.80%	7.00%
Maximum Allowed Rate-Design Effect	10.00%	10.00%	10.00%	10.00%
Total[a]	20.63%	13.70%	16.80%	17.00%
Cumulative Total	20.63%	37.16%	60.20%	87.43%
Cumulative Design Effect	9.04%	19.55%	30.75%	42.97%

[a]CARC plus rate design.

Hydro estimates that the faster flattening of the energy rate would increase the conservation effect. Compared to Hydro's proposal, Hydro estimates that a front-loaded implementation (10% in the first year, followed by 8%, 6%, 4% and 2% maximum bill increases) would save 185 additional GWh (BCUC IR 1.8.3), while immediate flattening would save 510 GWh (Application at Table M-3). The incremental energy savings from a steady 10% annual phase-in limit would fall between these two values.[4]

Q: Could the tailblock energy rate be increased further?

A: Yes. Even were the energy charge flattened immediately, the tailblock energy rate in F2011 would be about 4.529¢/kWh, which is only about a third of Hydro's 12.86¢/kWh estimate of the long-run marginal cost (LRMC) for energy in 2011. The tailblock charge can be further increased by lowering the initial block and by reducing the demand charge. As I explain in Section VI, demand charges do not send very effective price signals.

[4]I have not attempted to interpolate the conservation effect of the steady rate-design phase-in, for two reasons. First, Hydro's estimates of the conservation effects of its own proposal are inconsistent between Table M-3 and BCUC IR 1.8.3. Second, the rate phase-in in BCUC IR 1.8.3 is not complete, and would require another 9% or 10% maximum bill increase to fully flatten rates.

IV. The Historical Baseline in the Large General Service Rate

Q: Please summarize the proposed rate design for the energy component of the LGS rate.

A: The proposed rate design comprises the following four energy rates:

- a high Part-1, Tier-1 rate for the first 14,800 kWh per month;
- a low Part-1, Tier-2 rate for consumption between 14,800 kWh and an historical baseline (HBL), as well as any usage above 120% of the HBL;
- a high Part-2 LRMC rate, based on estimates of LRMC, for the positive or negative difference between actual monthly usage and the HBL, limited to ±20% of the HBL;
- a minimum-energy rate applied to all usage, limiting the extent to which the Part-2 LRMC credit for any usage less than the HBL can reduce the Part-1 average energy price.[5]

The HBL for each month would normally be the rolling average of usage in the same month in the preceding three years. Hydro proposes special rules for setting the HBL for new customers and when usage in one of the preceding three years was less than half the usage in the next-lowest year.[6]

[5]In the revised tariff filing of 22 January and in its response to BCSEA IR 2.1.2, Hydro redefines "Part 2" to be all the various charges and credits that may result from usage varying from the HBL. I use the terminology from the original application tariffs.

[6]Hydro calls the latter situation an "anomaly."

Q: What problems have you identified with Hydro's proposed determination of the historical baseline (HBL)?

A: There are two basic problems with Hydro's proposed baseline: the rolling baseline and the complexity of the computation.[7] Both of these problems would provide incentives to increase consumption and encourage gaming.

A. The Problems with the Rolling Baseline

Q: Why is a rolling HBL a problem?

A: The updating of the HBL undercuts the efficiency incentives that the two-part rate design are intended to create. Using energy above the HBL would cost the customer the LRMC-based Part-2 LRMC rate in the first year, but would increase the HBL in the next three years, giving the customer more energy at the lower Part-1 rate.

For example, for a customer whose usage consistently exceeds the Tier-1 threshold of 14,800 kWh/month, a permanent increase (or decrease) of 1 kWh/month would be priced as follows:

- the Part-2 LRMC rate in first year;
- one-third Tier 2, two-thirds LRMC in the second year;
- two-thirds Tier 2, one-third LRMC in the third year;
- Tier 2 in year 4 and after.

Since the Part-2 LRMC rate is effective for the equivalent of only two years of usage (the first year, plus two thirds in the second year and one third in

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[7] Hydro refers to this monthly baseline as an historical baseline (HBL), to distinguish it from the annual customer baseline (CBL) computed for the transmission rate. In the tariff sheets, Hydro uses the term Billing Baseline (BBL), which is just the HBL adjusted to different billing periods in each month.

the third year), the incentive to implement long-term efficiency measures is very weak.

Q: Can you provide a numerical example of this effect?

A: Yes. For simplicity, this example is for a single month over time and assumes the F2013 energy rates Hydro used for its examples in response to BCSEA IR 1.1.1: 9.26¢/kWh for Tier 1, 4.45¢/kWh for Tier 2 and 9.42¢/kWh for the Part-2 LRMC-based rate.[8] The use of constant prices over time is unrealistic, but is useful in understanding how the HBL affects bills over time, without the added complexity of changing rates. I also use the 30,000 kWh/month that Hydro uses in several of the examples in BCSEA IR 1.1.1. Table 3 compares two cases for a customer with an HBL of 30,000 kWh for the month: Case 1, in which the customer continues to use 30,000 kWh for that month in each of the next six years, and Case 2, in which the customer reduces usage by 2,000 kWh in year 1 and continues using 28,000 kWh for that month in each of the next six years.

Table 3: LGS Monthly Energy Bill, with Permanent Reduction

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Case 1: Flat Usage						
HBL	30,000	30,000	30,000	30,000	30,000	30,000
Usage	30,000	30,000	30,000	30,000	30,000	30,000
Energy Bill	$2,047	$2,047	$2,047	$2,047	$2,047	$2,047
Case 2: 2,000-kWh Reduction						
HBL	30,000	29,333	28,667	28,000	28,000	28,000
Usage	28,000	28,000	28,000	28,000	28,000	28,000
Energy Bill	$1,858	$1,892	$1,925	$1,958	$1,958	$1,958
Savings	$(188)	$(155)	$(122)	$(89)	$(89)	$(89)
$/kWh Saved	0.0942	0.0776	0.0611	0.0445	0.0445	0.0445

[8] These prices are different from the F2013 prices projected in Table L-13 of the Application or the slightly different prices in Appendix O. The Part-2 LRMC-based rate is also lower than the 12¢/kWh that Hydro says it uses for modeling (Application at 1-10).

In Year 1, the customer saves 9.42¢/kWh—the Part-2 LRMC rate for each kWh of load reduction—but that benefit declines, reaching 4.45¢/kWh—the Tier-2 rate—from Year 4 onward.

The same pattern occurs for a permanent increase in load; see Table 4.

Table 4: LGS Energy Bill, with Permanent Increase

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Case 1: Flat Usage						
HBL	30,000	30,000	30,000	30,000	30,000	30,000
Usage	30,000	30,000	30,000	30,000	30,000	30,000
Energy Bill	$2,047	$2,047	$2,047	$2,047	$2,047	$2,047
Case 3: 2,000 kWh Permanent Increase						
HBL	30,000	30,667	31,333	32,000	32,000	32,000
Usage	32,000	32,000	32,000	32,000	32,000	32,000
Energy Bill	$2,235	$2,202	$2,169	$2,136	$2,136	$2,136
Bill Increase from Case 1	$188	$155	$122	$89	$89	$89
$/Incremental kWh	0.0942	0.0776	0.0611	0.0445	0.0445	0.0445

For any long-lived efficiency investment, the additional incentive due to the Part-2 LRMC energy rate would be small. Even though the first-year incremental or decremental rate is more than twice the previous tail-block rate, the present value of the incremental or decremental energy bill over 20 years at a 10% discount rate would increase only about 15% over the Tier-2 rate.[9]

Q: Your examples have addressed the effect of a permanent reduction or increase in load. What about a change that affects just a single year?

A: Hydro's proposed rate design would also provide very limited incentives for the sort of single-year changes that would be typical of decisions related to maintenance of equipment and allocation of work among facilities. Table 5

[9]For this computation, I included Hydro's projection of annual rate increases through 2016, and extrapolated later increases at the 6.7% average increase Hydro expects for 2011–2016.

shows the effect, at the F2013 rates, for a customer increasing usage for one year.

Table 5: LGS Energy Bill, with One-Time Usage Increase

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Case 1: Flat Usage						
HBL	30,000	30,000	30,000	30,000	30,00	30,000
Usage	30,000	30,000	30,000	30,000	30,000	30,000
Energy Bill	$2,047	$2,047	$2,047	$2,047	$2,047	$2,047
Case 4: 2,000-kWh One-Time Increase						
HBL	30,000	30,667	31,333	32,000	32,000	32,000
Usage	32,000	30,000	30,000	30,000	30,000	30,000
Energy Bill	$2,235	$2,104	$2,104	$2,104	$2,047	$2,047
Bill Increase from Case 1	$188	$(33)	$(33)	$(33)	$–	$–
$/Incremental kWh in Year 1	0.0942	(0.0166)	(0.0166)	(0.0166)		
Cumulative Bill Difference from Case 1	$188	$155	$122	$89	$89	$89

The customer pays the Part-2 LRMC rate for the additional 2,000 kWh in Year 1, but gets a discount of 1.66¢/kWh for each of the next three years. Other than the time value of money, the net cost of the additional consumption over four years is the Tier 2 rate of 4.45¢/kWh. The same pattern would occur for a one-year reduction in usage; the customer would save 9.42¢/kWh in Year 1, followed by offsetting surcharges in the following three years, reducing the net benefit to 4.45¢/kWh.

With annual rate increases, the refunds in years 2–4 would be larger, resulting in even lower net costs for the additional usage in Year 1. Table 6 provides an example of this effect, where Year 1 is F2011, and the escalation rates are from Table L-13 of the Application.[10] The sum of the bill changes

[10] Since Table L-13 does not include F2016, I extrapolated the rates from the CARC in Table 2-1 of the Application and the 1.1% Part-2 LRMC inflation rate in Table L-13 for F2012–F2015.

comes to a net cost of $83 over the four years, or 4.14¢/kWh for the 2,000 kWh difference in Year 1.

Table 6: LGS Energy Bill, One-Time Increase, with Rate Increases

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Energy Rates with CARC Inflation						
Tier 1	0.0810	0.0843	0.0906	0.0976	0.1034	0.1102
Tier 2	0.0390	0.0406	0.0436	0.0469	0.0498	0.0531
Part 2	0.1286	0.1295	0.1309	0.1324	0.1338	0.1353
Case 1: no change						
HBL	30,000	30,000	30,000	30,000	30,000	30,000
Energy Bill e	$1,792	$1,865	$2,004	$2,157	$2,287	$2,438
Case 4: 2,000 kWh One-Time Increase						
HBL	30,000	30,667	30,667	30,667	30,000	30,000
Usage	32,000	30,000	30,000	30,000	30,000	30,000
Energy Bill	$2,049	$1,805	$1,945	$2,100	$2,287	$2,438
Bill Increase from Case 1	$257	-$59	-$58	-$57	$0	$0
$/Incremental kWh in Year 1	0.1286	(0.0296)	(0.0291)	(0.0285)		
Cumulative Bill Difference from Case 1						
	$257	198	140	83		

Q: What would the customer have paid for the extra 2,000 kWh of usage in Year 1 under the existing ELGS rate design?

A: The customer would have paid 3.9¢/kWh in Year 1, and received no credits in later years. The conservation incentives for this one-time change in usage would be greater with the existing rate design than with Hydro's proposed rolling-average HBL.

Q: Considering the complexity of the proposed Rate LGS design, might most customers assume that the load reductions will save them the Part-2 LRMC charge, regardless of what would be shown by a detailed financial analysis?

Hydro presents different estimates of future rates in different parts of the Application (e.g., the Application at 3-28 states that a Part-2 LRMC for rate of 13.1¢/kWh was assumed for modeling purposes in F2015).

A: No. It is always best to design rates so that the price signals are most effective when customers fully understand the rate design. Some customers would understand the true implications of the HBL updates and recognize that the effective benefit of reduced consumption is much less than the Part-2 LRMC energy rate. Others may view the HBL update as a long-term punishment for using less energy or a reward for using more energy. Most will probably be approached by consultants or trade organizations, who will explain how the LGS rate actually operates and what kinds of increased usages it rewards.

Q: Aren't managers usually fixated on the quarterly and annual financial performance, and thus unlikely to consider the effects of the HBL on bills in later years?

A: Some managers are undoubtedly focused exclusively on the short term, especially if they are hoping to cash in on a bonus or use good short-term results to land another job quickly. But any manager who will be facing similar incentives in future years is likely to think about the effect of the rolling HBL on meeting goals in those years, as well. Indeed, faced with the prospect of trying to explain that an increase in the electric budget next year was partly due to success in controlling load this year, the building manager (or energy manager, for larger enterprises) may decide that the best career strategy is to maintain stable loads, not reduce energy use.

B. Other Problems Related to the HBL

Q: Are there other features of the proposed LGS rate that interact with the rolling HBL to create confusing incentives for customers?

A: Yes. The proposed anomaly rule and price-limit bands would both allow for gaming by customers, and in some cases even result in Hydro paying customers to increase their energy usage. Good rate design encourages customers to focus on actions that reduce the costs to the utility and the broader society (in this case, the province), and does not distract with opportunities to reduce their bills without reducing costs.

Q: How would the price-limit band encourage gaming and provide perverse price signals?

A: A customer who was near the top of the price-limit band (120% of the HBL) in a month would have an incentive to increase usage and get above the price-limit band, to use the lower-cost Tier-2 energy above the band. The combination of the Tier-2 energy and the increase in the HBL in later years can make that strategy quite lucrative. Table 7 shows the additional cost to the customer of using an additional 7,500 kWh in Year 1, with the F2013 energy rates from BCSEA IR 1.1.1.

Table 7: Effect of the Price Limit Band, Usage Surge over Price Limit Band

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total
Case 1: Flat Usage							
HBL	30,000	30,000	30,000	30,000	30,000	30,000	
Usage	30,000	30,000	30,000	30,000	30,000	30,000	180,000
Energy Bill	$2,047	$2,047	$2,047	$2,047	$2,047	$2,047	$12,281
Case 5: Extra Usage in Year 1							
HBL	30,000	32,500	32,500	32,500	30,000	30,000	
Usage	37,500	30,000	30,000	30,000	30,000	30,000	187,500
Energy Bill	$2,679	$1,923	$1,923	$1,923	$2,047	$2,047	$12,540
Extra Cost	$632	$(124)	$(124)	$(124)	$0	$0	$259

The additional usage (6,000 kWh at the Part-2 LRMC rate, 1,500 kWh at the Tier-2 rate) costs the customer $632 in year 1, but the higher HBLs in Years 2–4 give the customer an annual credit of 2,500 kWh at the difference between Part-2 LRMC rate and the Tier 2 rate, for a total credit of $373. This results in a total bill for the six years that is only $259 more than the base case. Thus this customer would pay only about 3.5¢/kWh for the extra 7,500 extra kWh.

Q: Is this problem exacerbated if the energy rates rise over time?

A: Yes. With annual inflation in the rates, the credits in years 2–4 would be larger, resulting in an even larger net reward for the additional usage in Year 1. Table 8 provides an example of this effect, where Year 1 is 2011. With the expected rate increases, the Case-5 customer's cost from using an extra $7,500 kWh in Year 1 falls from $259 to $176, and the net price for the additional energy is about 2.34¢/kWh.

Table 8: Effect of the Price Limit Band with Rate Increases

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total
Case 1: Flat Usage							
HBL	30,000	30,000	30,000	30,000	30,000	30,000	
Usage	30,000	30,000	30,000	30,000	30,000	30,000	180,000
Energy bill	$1,792	$1,865	$2,004	$2,157	$2,287	$2,438	$12,543
Case 5: Extra Usage in Year 1							
HBL	30,000	32,500	32,500	32,500	30,000	30,000	
Usage	37,500	30,000	30,000	30,000	30,000	30,000	187,500
Energy bill	$2,622	$1, 643	$1,785	$1,944	$2,287	$2,438	$12,719
Extra cost	$830	$(222)	$(218)	$(214)	$0	$0	$176

Q: How might the anomaly rule encourage gaming and provide perverse price signals?

A: The problem is that customers may be able to increase future HBL values by increasing an already high usage until usage is more than twice that in a previous low-usage year, triggering the anomaly rule and excluding the low year from the computation of future HBLs.

In Table 9, I present an example in which a customer averaging 30,000 kWh had one year with low usage (18,500 kWh) in the three years preceding year 1. In Case 6, the customer uses 36,000 kWh in Year 1, not triggering the anomaly rule in Year 2, giving the customer an HBL of just 30,833 kWh in Year 2. In Case 7, the customer uses 37,500 kWh in year one, triggering the anomaly rule in Year 2, giving the customer an HBL of 37,750 kWh in year 2. In either case, usage in Years 2–5 returns to the same 30,000 kWh/month level. This computation uses the F2013 energy rates.

Table 9: Effect of the Anomaly Rule

	Year									
	−2	*−1*	*0*	*1*	*2*	*3*	*4*	*5*	*6*	**Total**
Case 6: Anomaly Rule Not Triggered										
HBL				30,000	30,833	34,667	32,000	30,000	30,000	
Usage	33,500	18,500	38,000	36,000	30,000	30,000	30,000	30,000	30,000	
Energy bill				$2,612	$2,005	$1,815	$1,947	$2,047	$2,047	$12,474
Case 7: Anomaly Rule Triggered										
HBL				30,000	37,750	35,167	32,500	30,000	30,000	
Usage	33,500	18,500	38,000	37,500	30,000	30,000	30,000	30,000	30,000	
Energy Bill				$2,679	$1,681	$1,790	$1,923	$2,047	$2,047	$12,166
Bill Effect of 1,500 extra kWh				$67	$(325)	$(25)	$(25)	–	–	$(308)

In this example, the extra 1,500 kWh in the higher-load case initially costs the customer $67, or 4.45¢/kWh, which is the Tier-2 rate.[11] However, the higher HBL in that case results in lower energy bills in years 2–4, for total savings of $375 and a net savings over the four years of $308. In this situation, the customer is rewarded with net *savings* of about 20.5¢/kWh per extra kWh used in Year 1.

Again, rising energy prices over time would make the problem worse.

Q: How might customers exploit these problems in the proposed LGS rate design?

A: Customers who are able to anticipate and control their usage would be able to reduce their bills over several years by intentionally increasing energy use. Even

[11]The incremental usage is above 120% of HBL, so the price limit band reduces the incremental price to Tier 2.

customers who experienced higher bills might well face only a small increase, providing little incentive for efficiency. Those industrial customers with excess capacity and the ability to shift load between months (perhaps at some loss in efficiency) could shift usage to trigger the price-limit band and the anomaly rule, and take advantage of the shifting HBLs, to save energy at the Part-2 LRMC price in one month, while using additional energy at the Tier-2 price in another month.

Q: Would the proposed LGS rate design provide efficient price signals to a new customer with no billing history?

A: No. Under Hydro's proposal, the new customer would be granted an HBL of 90% of its actual load in the first year of operation, and thus would pay the Part-1 rates for 90% of its load and the Part-2 rate for the remaining 10%. Hence, the cost of higher usage in the first year for most new LGS customers would be just the Tier-2 price times 0.9, plus the Part-2 price times 0.1, or a weighted average of about 4.8¢/kWh in F2011.[12] But each kWh of increased usage in F2011 increases the HBL by one kWh in F2012, one half kWh in F2013, and one third kWh in F2014, giving the customer a credit of about 12.95¢ + ½ × 13.09¢ + ⅓ × 13.24¢ = 21¢ per extra kWh used in F2011. Table 10 shows the effect for a new 30,000 kWh/month customer of consuming at its normal level in the first year, 25% higher first-year usage, and 25% lower first-year usage. Under Hydro's proposed rate design, the more energy a new customer uses in the first year, the lower its total bill over the first few years.

[12] 0.9 × 3.9¢ + 0.1 × 12.9¢ = 4.8¢/kWh

Table 10: Effect of Proposed LGS New-Customer Rule, with Rate Increases

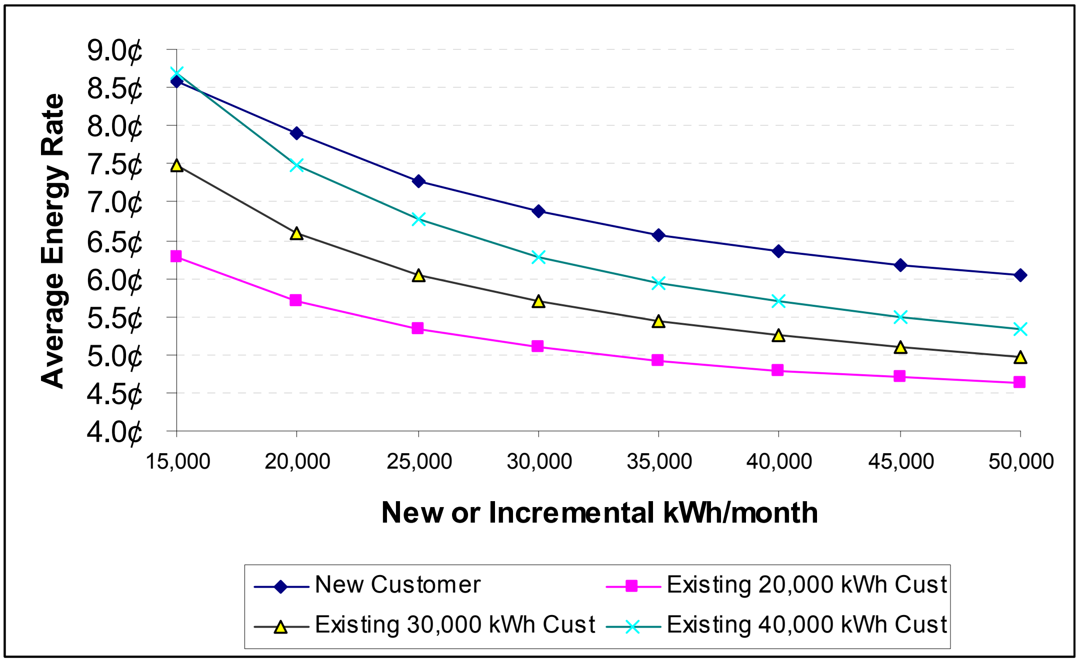
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total
Case 8: New Customer with Flat Usage							
HBL	27,000	30,000	30,000	30,000	30,000	30,000	
Usage	30,000	30,000	30,000	30,000	30,000	30,000	180,000
Energy bill	$2,060	$1,865	$2,004	$2,157	$2,287	$2,438	$12,812
Case 9: Extra Usage in Year 1							
HBL	33,750	37,500	33,750	32,500	30,000	30,000	
Usage	37,500	30,000	30,000	30,000	30,000	30,000	187,500
Energy bill	$2,420	$1,198	$1,676	$1,944	$2,287	$2,438	$11,963
Case 10: Low Usage in Year 1							
HBL	20,250	22,500	26,250	27,500	30,000	30,000	
Usage	22,500	30,000	30,000	30,000	30,000	30,000	172,500
Energy bill	$1,701	$2,265	$2,331	$2,371	$2,287	$2,438	$13,393

Q: How would the bills for new customers compare to equivalent expansions by an existing customer, under Hydro's proposal?

A: Hydro explains (Application at 3-37) that it intended to make Rate LGS neutral between a new customer and an equivalent incremental expansion at an existing customer site. In this regard, Hydro has failed. The existing customer is likely to have a lower bill for large expansions, since any increase in load of more than 20% over the HBL will be priced at the applicable Part 1 rate, which will usually be the low Tier-2 rate. In the first year, an existing customer doubling its load will pay the Tier-2 rate for 80% of the increment and the Part-2 LRMC rate for 20%, which is generally a lower-cost mix than the combination of the Tier-1, Tier-2, and Part-2 rates for the new customer. Figure 1 below compares the average energy rate charged for various size load increments for a new customer and various size existing customers. Except for the very smallest increment and very largest existing customer in this example, the existing customer pays less than the new customer. For any given load increment, the smallest existing customers (for whom the ratio of the expansion to existing load is highest) pay the lowest energy price for the expansion.

Figure 1: Average Energy Price for New and Expanded Customers

(Hydro Proposal, 2011 Prices)



After the phase-in period for the HBL, the expanded customer's incremental load would be priced entirely (or mostly) at the lower Tier-2 rate, while the new customer pays a mix of Tier-1 and Tier-2 rates.

Q: Have you prepared a bill comparison of a load increase by an existing customer to the same load from a new customer, with Hydro's proposed rate design?

A: Yes. I computed the energy bill of a 30,000 kWh/month new customer, for various load levels in the first year; see Table 10 above. Below, in Table 11, Case 11 shows the energy charges for a 30,000 kWh/month customer adding another 30,000 kWh/month. The expanding customer receives two benefits compared to the new customer: not paying for any additional Tier-1 energy, and triggering the anomaly rule in year three. Adding a flat 30,000 kWh/month increases the customer's energy bill $1,708 in the first year and $9,438 over six years, considerably less than the new customer's $2,060 in the first year and $12,812 over six years (Table 10, Case 8).

Table 11 also shows that higher incremental load in the first year (Case 12) reduces the customer's total bill, and lower incremental load (Case 13) increases the total bill. These are additional examples of the perverse effects of the price limit band and the anomaly rule, which helps the customer in Case 11 and Case 12, but not with lower load in Case 13. In addition, the increase in the existing customer's bill is always less than the new customer's bill for the same increment of load (Table 10, Cases 9 and 10).

Table 11: Major Customer Expansion, with Rate Increases

	Year									
	–2	*–1*	*0*	*1*	*2*	*3*	*4*	*5*	*6*	**Total**
Case 1: Flat Usage										
HBL				30,000	30,000	30,000	30,000	30,000	30,000	
Usage	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	180,000
Energy bill				$1,792	$1,865	$2,004	$2,157	$2,287	$2,438	$12,543
Case 11: Doubling Load with Addition										
HBL				30,000	40,000	60,000	60,000	60,000	60,000	
Usage	30,000	30,000	30,000	60,000	60,000	60,000	60,000	60,000	60,000	360,000
Energy Bill				$3,499	$3,794	$3,312	$3,564	$3,781	$4,031	$21,981
Increase from Flat Usage				$1,708	$1,929	$1,308	$1,407	$1,494	$1,593	$9,438
Case 12: Doubling Load, Extra Usage in Year 1										
HBL				30,000	42,500	63,750	62,500	60,000	60,000	
Usage	30,000	30,000	30,000	67,500	60,000	60,000	60,000	60,000	60,000	367,500
Energy Bill				$3,792	$3,838	$2,984	$3,351	$3,781	$4,031	$21,777
Increase from Flat Usage				$2,000	$1,974	$981	$1,193	$1,494	$1,593	$9,234
Case 13: Doubling Load, Lower Usage in Year 1										
HBL				30,000	37,500	47,500	57,500	60,000	60,000	
Usage	30,000	30,000	30,000	52,500	60,000	60,000	60,000	60,000	60,000	352,500
Energy Bill				$3,207	$3,750	$4,141	$3,778	$3,781	$4,031	$22,687
Increase from Flat Usage				$1,415	$1,885	$2,137	$1,621	$1,494	$1,593	$10,145

C. Conservation Effects

Q: Do Hydro's estimates of the conservation effects of its rate design reflect the multi-year effects of the HBL?

A: No. Hydro fails to reflect the multi-year effect of its rate design. The LGS conservation estimates described in the Application (Appendix P at 4) reflect only the following three factors:

- the volume of energy in LGS bills within the Price Limit Bands,
- the difference in the current year's price between the LRMC-based Part-2 marginal rate and the ELGS Tier-2 rate,[13]
- the short-term price elasticity assumed for design changes in the marginal rate.

This analysis does not include two important considerations. First, Hydro estimates the price response in a particular year as if the customers would not know that using additional energy in the current year will reduce bills in future years and that saving energy in the current year will increase bills in future years. Second, Hydro does not reflect any customer response to the change in total bills in future years.

Q: Is Hydro aware of these omissions in its analysis?

A: Yes, at least in some of its responses. Hydro acknowledges that its conservation estimation methodology does not take into account the conservation effect of using a rolling average HBL. Hydro states:

> The methodology BC Hydro uses to provide estimates of conservation is completed for a single year, using price elasticity estimates for a single year, and is therefore *not sensitive to the multi-year effect of the baseline definition*.… (BCSEA IR 2.11.1, emphasis added)

Hydro also acknowledges this limitation of its conservation-estimation methodology in the context of its inability to quantify the conservation effects of various HBL averaging periods. Hydro states:

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[13]Hydro appears to ignore the small fraction of LGS monthly bills that would fall below 14,800 kWh, for which the marginal ELGS rate would be Tier 1, not Tier 2.

> BC Hydro believes that a longer rolling average baseline period could provide a stronger conservation signal than a shorter one. However, BC Hydro has not developed separate conservation estimates for these different baseline definitions, as BC Hydro's rates model for estimating savings does not take this function into account. (BCSEA IR 2.11.1)

Q: Did Hydro estimate the effects of the HBL in reducing the conservation incentive in the LGS rate?

A: Yes. For its example, Hydro computed that the net present value (NPV) of the customer benefit for an example of a one-time reduction in load would be 5.1¢/kWh, much closer to the low Tier-2 rate (3.7¢/kWh) than to the LRMC-based Part-2 rate (12¢/kWh) (BCSEA IR 2.14.2).

Q: Do Hydro's discovery responses consistently indicate an understanding of the incentive problems raised by the variable HBL?

A: Unfortunately not. In at least one response, Hydro seemed confused about the effect of the variable HBL, denying that it undermines efficiency incentives at all.

> The correct way to evaluate the marginal price signal is on a monthly basis, without discounting, per the logic described in Appendix P, which uses an LRMC-based price signal when a customer's consumption is within the Price Limit Band. The expected conservation impact over one year is the sum of the 12-monthly conservation calculations.
>
> Under the proposed design, a customer can conserve up to 20 per cent of its baseline usage and receive credit at LRMC for this conservation. Assuming the customer does so, the NPV per kWh of conservation is equal to LRMC. BCSEA IR 2.14.3

In BCSEA IR 2.11.1 and 2.14.2, Hydro acknowledges that conservation in one year will increase bills in future years, that the HBL will result in an NPV price signal smaller than the first-year price signal, and that its conservation model does not reflect all the effects of its rate design. In BCSEA IR 2.14.3, Hydro gets all of these points backwards, insisting that only the first year's price counts and that discounting of future price effects from the change in HBL is irrelevant.

Q: Does that mean that Hydro has overstated the conservation effect of the LGS rate design?

A: Yes. The effective increases in marginal rates would be smaller than modeled in Hydro's conservation analysis, and in many cases, the marginal rate for incremental energy use would be negative. Without knowing exactly how many customers would be in each of the situations I described above, how many customers will catch on to the gaming opportunities, or how various customers would discount future bill effects, I cannot determine whether the net effect of the LGS rate design would be higher or lower energy consumption than under ELGS. At best, the LGS rate design would be a large amount of effort in customer education (and better customer education probably means less conservation effect), customer service, and administration, for very little conservation.

Hydro also suggests that its estimates of conservation effects of rate design are flawed by their failure to reflect interaction with other initiatives:

> Even if BC Hydro had an estimate of potential conservation savings related to these different baselines, to determine the net impact on BC Hydro's overall DSM plan savings, BC Hydro would need to consider these estimates in the context of other DSM initiatives (e.g., DSM related codes and standards and Power Smart initiatives). (BCSEA IR 2.11.1)

V. Alternative Approaches to Large-General-Service-Rate Design

Q: You have demonstrated that the updating of the HBL to reflect customer usage eliminates most of the conservation incentive of the LGS rate, and that the declining block in Part 1 energy prices, the price limit band, and

the anomaly rule exacerbate that problem. How could these problems be corrected?

A: The obvious solution would be to take the following steps:

- phase out the declining-block energy rate in Part 1,
- not revise the HBL update with usage (which would eliminate the need for the anomaly rule),
- eliminate the price-limit band.

Q: How might a revised LGS rate be structured?

A: One approach would be to use Hydro's proposed structure, with the following changes:

- The Part-1 rate would be a single flat rate, averaging the Tier-1 and Tier-2 rates and including the revenue currently collected through the basic charge, which provides no conservation incentives.
- Each customer's HBL would be set once, and either remain constant thereafter or change only to reflect changes in some non-energy index that the customer must report for other purposes, such as employment, floor-space area, or output.
- New customers would be assigned an HBL based on that index, times a standard-efficiency usage factor, reflecting norms for new construction or remodeling.
- The customer would be charged the Part-1 rate for its HBL, and charged or credited for the Part-2 LRMC rate for the difference between its actual usage and its HBL.[14]

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[14] Unlike Hydro's proposal, this alternative approach would not be subject to gaming by moving load among months, so the HBL could be set monthly or annually.

A simpler alternative approach would dispense with the Parts 1–2 LRMC distinction and more directly tie the rate design to the Heritage Contract concept that Hydro customers are entitled to the benefit of the low embedded cost of heritage energy. The HBL would be replaced with a fixed entitlement for each customer in the heritage resources, stated as an annual kWh quantity. Each customer's Heritage Entitlement would be set in the same manner as I describe for the HBL above. Each customer would pay the LRMC rate for all its usage, and receive a credit equal to a Heritage Rate times its Heritage Entitlement. The Heritage Rate would be set each year to return to the LGS class the difference between the LRMC revenues and the costs allocated to the LGS class by the cost-of-service study.

Q: The treatment of district heating loads on the LGS rate has been raised in this proceeding. Do you have any suggestions as to how the electric usage for district heating systems might be treated on an improved LGS rate?

A: Yes. The HBL or Heritage Entitlement for the district heating system would be set based on the energy that a like amount of heated space would use with new standard heating equipment.[15]

VI. Demand charges

Q: Do demand charges give customers efficient incentives for energy efficiency and cost control?

[15] A conversion factor would be needed to convert avoided natural gas (if that is the standard fuel in the particular location) to electric equivalents. I suggest a value of about 8,000 Btu/kWh, reflecting the amount of gas necessary to generate and deliver a kWh to customer load.

A: No. Demand charges are not intended to provide incentives to conserve energy, which would be accomplished more effectively by recovering the same revenue through energy charges. In some cases, a customer may anticipate that an efficiency measure will also reduce billing demand, so the demand charge improves the economics of the efficiency investment. But demand charges often discourage efficiency, as in the following situations:

- An efficiency measure, such as installing variable speed drives, will tend to increase billing demand, and demand charges will discourage the customer from undertaking the measure.
- Demand charges may also encourage a customer to shift load to reduce its billing demand, while total energy use, such as starting equipment earlier than needed and running it for more hours, to avoid a spike in usage if all equipment is turned on simultaneously.
- With fixed revenue requirements, higher demand charges usually require lower energy charges, encouraging increased electric use.

Also, demand charges divert investment and manager attention from energy conservation to reduction of billing demand.

Demand charges are often assumed to be appropriate means for recovering costs related to generation, transmission, and distribution capacity, but provide relatively ineffective price signals for capacity costs, for the following reasons:

- The demand-charge portion of the electric bill is determined by the customer's individual maximum demand. Capacity costs are driven by coincident loads at the times of coincident peak loads, not by the non-coincident maximum demands of individual customers. The customer's individual peak hour is not likely to coincide with the peak hours of the other customers sharing a piece of distribution equipment, especially since the peaks on the secondary system, line transformer, primary tap, feeder, substations, sub-transmission lines, and transmission lines occur at different times.

- Some customers will naturally have maximum demands at times off the system, transmission, and distribution peaks. An industrial firm may experience its peak demand at 7 AM, when it is starting up all its equipment. A demand charge may just encourage the firm to delay some start-ups to later hours, resulting in higher loads later at the day, when system equipment is more-heavily loaded. An entertainment venue may experience its peak load late in the evening. A demand charge may just encourage the management to run as much equipment as possible (e.g., heating water, making ice) earlier in the evening when generation, transmission, and distribution loads are higher.
- Demand charges provide little or no incentive to control or shift load from those times which are off the customers' peak hours but which are very much on the generation and T&D peak hours. Customers can reduce demand charges merely by redistributing load within high-load system hours. Some of those customers will be shifting loads from their own peak to the peak hour on the local distribution system, on the transmission peak, or on Hydro's peak load hour, thereby causing customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, or the regional generation system.
- Demand charges can be difficult to avoid; even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour.
- In order to respond to demand charges effectively, customers need to install equipment to monitor loads, interrupt discretionary load, and schedule deferrable loads. Rather than promoting conservation at high-cost

times, or shifting of load from system peak periods, demand charges encourage customers to waste resources on the arbitrary tasks of flattening their personal maximum loads, even if those occur at low-cost times.

Q: What pricing signals do demand charges give to customers?

A: For the reasons explained above, demand charges are ineffective in shifting loads off high-cost hours. In addition, they may cause some customers to shift loads in ways that increase costs.

Q: Should demand charges be eliminated entirely from rates?

A: That might be the appropriate outcome, although that change will probably require more than just this rate-design proceeding. Capacity costs for generation, system and regional transmission, substation and feeder costs (as well as any time-of-use variation in generation energy costs) would be more-efficiently recovered through on-peak energy charges. That approach would encourage reduction of usage in high-load periods, when transmission and distribution equipment is heavily loaded.

The only reasonable purpose for demand charges is to recover costs driven by the customer's own peak demand, such as a portion of dedicated line transformers and perhaps a portion of feeder capacity.[16] Since Hydro credits customers only 25¢/kW-month for transformer ownership, it is unlikely that an efficient demand charge would be as much as $1/kW-year.

While the Commission may not wish to reduce demand charges below $1/kW-year in this proceeding, demand charges for the MGS and LGS rates should be reduced substantially to increase the revenues available for energy charges.

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[16]Some of the line-transformer costs are driven by energy usage on the transformers.

Q: Is there any information in Hydro's Application that suggests that demand charges are ineffective in inducing conservation?

A: Customers mentioned the following problems with controlling demand charges in Hydro's Customer Engagement Report:

- Participants suggested that time-of-use rates and changes to the design of the demand charge would be more effective for them in achieving conservation than changes to the energy rate design. (Appendix F at 16)
- Participants noted that the demand charge is an issue for some companies in the forestry industry, who pay a demand charge whether or not they use energy. (Appendix F at 17)

Q: How should the Commission deal with demand charges in this proceeding?

A: The Commission should reduce demand charges to bring energy charges closer to marginal cost. As Hydro Witness Lisa Coltart testifies, Hydro's "main purpose for filing this application is to achieve energy conservation, which in the current cost environment requires marginal rates that better reflect BC Hydro's LRMC of new energy supply" (Coltart Direct at 2-23).

Q: Does Hydro explain why it did not propose to reduce demand charges to pursue its "main purpose for filing this application?"

A: Yes. Ms. Coltart says,

> Any changes to the demand or basic charge provisions of the ELGS rate structure on a cost of service basis would result in higher demand or basic charges, therefore making it more difficult to design a rate structure that is class revenue neutral and provides a more efficient price signal. The apparent 'gain' in fairness would be offset by a 'decrease' in fairness arising from increased subsidization of BC Hydro's marginal costs by customers with little or no load growth or who are conserving. (Coltart Direct at 2-23).

As I read this testimony, Hydro is claiming that rate design should be determined by fairness, rather than efficiency, and that fairness, as somehow determined from something Ms Coltart calls "a cost of service basis," requires higher (and hence less efficient) demand charges.

Q: Is Ms. Coltart's argument correct?

A: No. The primary purpose of the fully allocated cost-of-service study (FACOS) is to allocate embedded costs fairly among rate classes. Hydro allocates a portion of generation costs and most transmission costs on the class contribution to the average of four coincident system peaks, and 65% of distribution costs on class non-coincident peaks. These allocators are intended to roughly approximate the contribution of the classes to requiring the investments and expenses in Hydro's revenue requirements.

The primary purpose of rate design *within a class,* on the other hand, is to provide efficient price signals. Of the billing determinants in Hydro's rate, only the marginal energy rates are likely to provide effective price signals. Since Hydro's energy rates are so much less than its marginal cost of energy, the priority in rate design should be to increase the energy rates.

Q: Are the demand measures used in the FACOS the same as the demand measures used in Hydro's rate design?

A: No. The FACOS allocates costs on the basis of loads at the system coincident monthly peaks and the class annual non-coincident peak, while the rate design charges customers based on their own individual peaks. This will usually not be at either the monthly system peak or the annual class non-coincident peak. Indeed, the coincident peak ignores loads in eight months, and the non-coincident peak ignores loads in twelve months, but customers are charged demand charges for their own maximum demands in every month.

Q: How much could Hydro increase the LGS Part-1 energy rate were it to reduce the demand charge?

A: Just flattening the Tier-1 and Tier-2 energy rates would result in a Part-1 energy rate of about 4.53¢/kWh in F2011.[17] Reducing the Step-3 demand charge to the Step-2 charge ($8.442/kW-month to $4.40/kW-month, before voltage and transformer-ownership discounts) would allow the average Part-1 energy rate to rise to about 5.17¢/kWh, an increase of about 14%. Reducing both the Step-2 and Step-3 demand charges to the $2.44/kW-month used for Step 2 in Table M-7 would raise the energy rate to 5.89¢/kWh, 26% above the proposed rate.

VII. Other Rate-Design Issues

A. Minimum Total Bill

Q: What is the minimum monthly charge under the proposed MGS and LGS rates?

A: The minimum monthly charge is equal to 50 percent of the maximum demand charge billed in the period November 1–March 31 in the previous 11 months. In other words, a customer with summer load far below winter load may pay the same bill in summer months, so long as its usage does not push the monthly bill above half the winter peak. The same would be true for a customer whose operations decline for other reasons after a winter peak.

[17] I used the billing determinants in Appendix O and the projected rates in Appendix L for this computation.

Q: What is the effect of that minimum charge?

A: For the few customers whose bills are set by the minimum charge, it would eliminate all efficiency incentives.

B. Migration

Q: Do you have any comments on the rules for migration of customers among SGS, MGS, and LGS rates?

A: Yes. First, the Commission should attempt to avoid situations in which a customer's bill increases due to shifting from LGS to MGS or MGS to SGS, as a result of conservation. Those perverse effects are illustrated in the graphs in BCUC IRs 1.21.1 and 2.11.1. The Commission may accomplish this goal by coordinating rate designs or by allowing customers to stay on the more-favourable rate even if their usage falls below the usual breakpoint.[18]

Second, I notice that Hydro proposes to use a single SGS demand reading as if it were actually the same reading two months in a row (Application at 1-13). This unreasonable assumption is required by Hydro's failure to read SGS rates monthly. An SGS customer who exceeds the 35 kW threshold three times in a year would be shifted up to the MGS class. Hydro argues that this is equivalent to the rule proposed for migration from MGS to LGS, where six actual meter readings above the threshold are required to move the customer to the higher (and generally less expensive) rate. Hydro's failure to provide even monthly feedback to SGS customers and some residential customers is out of step with the continent-wide move towards more capable remote meter reading,

[18]It would be reasonable to require the customer to make a showing that its reduction in load was due to an improvement in efficiency, rather than reduction in the space occupied or other contractions in business. Such a claim might trigger an on-site audit under Power Smart.

with hourly load data available to the utility and often the customer. This issue is beyond the immediate scope of this proceeding, but the deficiency in Hydro's meter-reading procedures should not be allowed to interfere with efficient design of the MGS rate and should be remedied as soon as practical.

Q: Does this conclude your testimony?

A: Yes.