Oral Direct Evidence of Paul Chernick

Manitoba Hydro General Rate Application for 2017/18 and 2018/19

On Behalf of the Green Action Centre

January 9, 2018

Major Topics

Residential Rate Design

Affordable Rates

Conservation Rates

Marginal Costs and Rate Design

Ineffectiveness of Demand Charges

Affordable Rates History

Longstanding Topic of Discussion and Board Interest

MH Workshop July 19, 2017

- I presented an initial proposal for low-income and space-heating rates
  - Discounts in customer charge and first block for low-income
  - Discount in first block for space-heating, varying with heating use
- I explained how to minimize revenue risk to MH
- Received with interest by several parties
- Suggested that MH refine my design using more detailed and current data

MH Proposed No Affordability Rates in Filing

- Provided no updates or improvements to my proposals
- Proposed only more study

Affordable Rates Rationale

Low-Income

- Many customers experience high financial stress
- Important social issue
- Many potential means to assist; rate design is one available to the PUB
- Many jurisdictions have lower rates for low-income customers
- Eliminating the monthly customer charge should have no effect on conservation incentive
- Reducing the rate for the first 500 kWh has only minor effect on conservation incentive
- Vast majority of kWh would be in bills >500 kWh, maintaining conservation incentive
- First choice should always be to reduce load with DSM; rate design mitigates remaining burden

Electric Space Heating

- Electric heat is more expensive than gas heat
- As rates rise, the burden on heating customers grows
- Many heating customers, especially in North, have no good alternative
- PUB once rejected a conservation rate out of concern for heating customers
- Many jurisdictions have lower rates for space heating, in part to protect customers with limited alternatives or legacy systems
- Reducing the rate for a small fraction of monthly heating use has only minor effect on conservation incentive

Conservation Rates

Residential

- Encourage participation in Power Smart, care in energy use
- Discourage wasteful usage
- Increase the marginal rate for most kWh

Non-residential

- Shift revenue from demand charges to energy charges

Rate Design Example Proposals

With filed rate request (my Table 6)

		MH Interim	LICO-125 All	Non-LICO ESH	LICO-125 ESH	Non-LICO IBR
Basic Charge		$8.44	$0	$8.08	$0	$7.82
First Block	¢/kWh	8.556	4.556	4.556	4.556	7.930
Remainder	¢/kWh	8.556	8.556	8.556	8.556	8.925
First Block kWh						
Summer		—	500	—	500	500
Spring		—	500	150	650	500
Fall		—	500	250	750	500
Winter		—	500	500	1,000	500
Recovery rate from:						
Non-LICO residential (NLR)			$0.00966			
All non-LICO, non-SEP			$0.00246			
Non-discounted NLR kWh				$0.00407		
Non-discounted non-LICO				$0.00096		

Based on interim rates (PUB-GAC 1-4a)

		MH Interim	LICO-125 All	Non-LICO ESH	LICO-125 ESH	Non-LICO IBR
Basic Charge		$8.08	$0	$8.08	$0	$7.82
First Block	¢/kWh	8.196	4.196	4.196	4.196	7.930
Remainder	¢/kWh	8.196	8.196	8.196	8.196	8.352
First Block kWh						
Summer		—	500	—	500	500
Spring		—	500	150	650	500
Fall		—	500	250	750	500
Winter		—	500	500	1,000	500
Recovery rate from:						
Non-LICO residential (NLR)			$0.00966			
All non-LICO, non-SEP			$0.00246			
Non-discounted NLR kWh				$0.00407		
Non-discounted non-LICO				$0.00096		

These designs may not be optimal, but they are improvements over status quo.

No reason to ease into these rates, since negative effects will be small.

PUB can tweak rates in subsequent GRAs.

PUB should order MH to implement these rates (or some variant the Board prefers), and entertain motion to vary if MH has concerns with details.

Marginal Costs and Rate Design

The tail-block energy price is the conservation signal

- If the energy price is less than marginal cost, customers are not charged the full cost of additional usage.
- Energy rates should be brought as close to marginal cost as feasible, for as much usage as feasible.
- Improve payback for efficiency investments.
- Signal that public policy rewards conservation.

MH Underestimates Marginal Costs

- T&D costs
- Generation costs
- Omits all environmental costs

MH Underestimates Marginal T&D Costs

MH understates load-related costs

- Treats load-growth-related removals as not load-related
- Ignores past costs of projects to meet future load growth
- Uses incomplete cost projections

Overstates distribution load

- Understates $/kW

Ignores O&M on new facilities

Assumes 100% load factor

Realistic estimates for residential T&D cost would be:

- Roughly double MH estimate for transmission
- Roughly triple MH estimate for distribution

MH Rebuttal on Marginal T&D Costs

Critiques miss the point

Underestimates marginal costs per kW by mismatching load growth and investment

Overstates distribution load growth

O&M

MH T&D Rebuttal: missing the point

Suggests I did not understand the One Year Deferral (OYD) formula

- I understood it, and used it.
  - My issues with MH's T&D estimate involve the inputs to that computation.

Suggests I misunderstood T&D planning, in critiquing MH's 100% load-factor assumption

> Mr. Chernick may not understand..that transmission and distribution load-growth related capacity projects are planned, by necessity, to accommodate peak load, not a percentage of peak load. (Rebuttal at 75)

- In reality, MH made the mistake it describes, and I corrected it.
- MH says that its DSM screening corrects this error (Rebuttal at 75).
- The rate design comparison should use the same realistic load factors that MH says it used for DSM.

Mismatched Growth and Investment Understates Marginal Cost

Purpose of marginal T&D study is to match:

Load growth over a representative period with…

Investments to meet that growth

Growth and investment can be from:

Consistent historical periods

Consistent forecast periods

Consistent combinations

MH excludes sunk costs of meeting growth

Results in mismatch of load growth and investment

Sunk costs aren't avoidable, but neither were many 2016+ costs of projects already underway in 2015

Even more so now, since the 2016 and 2017 costs are sunk

But that's irrelevant to estimating a representative or typical investment/growth ratio

MH has detailed cost projections for only a few years

Partially corrects for this on transmission, setting years 8–10 at average of 5 years with detailed cost data and 2 years with limited projections. Still understated compared to detailed years.

Fails to do even that for distribution

MH Trims Marginal T&D Costs

Full-Cost

Spending	Cost of projects needed to meet load in this year										
In ↓	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Sum
2012	20										*20*
2013	40	20									*60*
2014	60	40	20								*120*
2015	80	60	40	20							*200*
2016	60	80	60	40	20						260
2017		60	80	60	40	20					260
2018			60	80	60	40	20				260
2019				60	80	60	40	20			260
2020					60	80	60	40	20		260
2021						60	80	60	40	20	260
2022							60	80	60	40	240
2023								60	80	60	200
2024									60	80	140
2025										60	60
Sum	260	260	260	260	260	260	260	260	260	260	2,600

Only spending for 2016+ shown. Spending in 2012–2015 incomplete.

MH Subset of Costs

Spending In ↓	Cost of projects needed to meet load in this year										
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Sum
	% of costs included in plan					25%	25%	15%	15%	15%	
2012	20										
2013	40	20									
2014	60	40	20								
2015	80	60	40	20							
2016	60	80	60	40	20						260
2017		60	80	60	40	5					245
2018			60	80	60	10	5				215
2019				60	80	15	10	3			168
2020					60	20	15	6	3		104
2021						15	20	9	6	3	53
2022							15	12	9	6	42
2023								9	12	9	30
2024									9	12	21
2025										9	9
Counted Sum	60	140	200	240	260	65	65	39	39	39	1,147

MH would count 44% of total, in this example

MH Partial Correction for Transmission

Spending In ↓	Cost of projects needed to meet load in this year										Dist	Trans
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Sum	Sum
	% of costs included in plan					25%	25%	15%	15%	15%		
2012	20											
2013	40	20										
2014	60	40	20									
2015	80	60	40	20								
2016	60	80	60	40	20						260	260
2017		60	80	60	40	5					245	245
2018			60	80	60	10	5				215	215
2019				60	80	15	10	3			168	168
2020					60	20	15	6	3		104	104
2021						15	20	9	6	3	53	53
2022							15	12	9	6	42	42
2023								9	12	9	30	155
2024									9	12	21	155
2025										9	9	155
Sum	60	140	200	240	260	65	65	39	39	39	1,147	1,553

MH would count 50% of total transmission, in this example

MH Rebuttal: Overstating Distribution Load Growth

MH treats all load growth as if it were at distribution

- Divides distribution investment and transmission investment by same growth: 718 MW, 2015/16–2025/26
- That is wrong, as long as GSL>30kV load is growing
- I didn't correct it, for lack of data on load growth by GSL sub-classes

MH serves four voltage groups, each using the higher voltages as well

- Secondary: residential, GSS, GSM (MH ignores marginal secondary distribution costs)
- Primary: GSL <30 kV
- Subtransmission: GSL 30kV–100kV (33 kV and 66 kV)
- Transmission: GSL > 100 kV

MH Rebuttal claims that GSL 30kV–100kV is distribution load

This would not explain inclusion of GSL>100kV

- Sales are 12%–20% of total; share of 2015 forecast load growth unclear

In any case, it's not true

- The PCOSS does not allocate any distribution costs to GSL 30kV–70kV
- MH's estimates of GSL 30kV–70kV marginal cost have zero distribution costs
- In the CEFs, 66 kV projects are included in transmission, unless they are running solely to a distribution substation
- GSL 30kV–70kV is 7% of sales

MH has not addressed this error

- MH should reveal breakdown of load growth by voltage level
- Transmission $/kW = (transmission investment) ÷ (all load growth)
- Subtransmission $/kW = (subtransmission investment) ÷ (distribution + subtrans load)
- Distribution $/kW = (distribution investment) ÷ (distribution load)

MH Rebuttal: T&D O&M

Incremental O&M costs amount to “only” 1% to 2% of incremental capital costs. (Rebuttal at 76)

- That’s a 25%–50% adder on marginal T&D; carrying charge is about 4%
- Hardly inconsequential

MH Estimates of Marginal Generation Costs

Filing estimate

- No documentation provided, including detail vital to comparing to rate design, DSM cost:
  - no info on energy cost estimate by time period
  - no info on generation energy/capacity split
- Marginal cost method was separate from the confidential long-term export price
  - MH *voluntarily* asserted that the result was similar to the export price, extending export-price confidentiality shield
- Marginal cost was not reviewed by Daymark, so no external review
- Assumes 100% load factor:
  - understates capacity cost/kWh by up to 50%
  - understates energy cost by averaging in too much off-peak energy
- Not clear which of the Daymark critiques of the export price forecast affect marginal costs
  - No capacity value
  - No firmness premium
  - No long-term premium
  - Reference price, not average of futures

MH Estimates of Marginal Generation Costs

Update (PUB-MH II-57R)

- Explicitly assumes no firmness premium
- Sets marginal capacity cost estimate = cost of new MH combustion turbine in 2030
- No capacity value for exports, ever.
  - Daymark estimates MISO capacity need ~2023
  - Capacity price when capacity needed in other ISOs:
    - ~$125/kW-year CDN in ISO-NE (2.8¢/kWh at 50% load factor)
    - ~$90 /kW-year CDN in PJM (2¢/kWh at 50% load factor)
- MH still assumes unrealistic flat load

Summary of Marginal Costs and Marginal Rates

Filing marginal costs

All non-residential tariffs have proposed energy rates < MH marginal costs

Corrected marginal costs

All energy rates < marginal costs

Revised MH marginal costs

All non-residential energy rates < MH marginal costs

Corrected revised marginal costs

All energy rates < marginal costs

	Filing	Filing Corrected	MH Revised	Corrected Revised	Proposed 2018 Energy Rate
Residential	7.67	12.66	5.75	11.01	9.23
GSS ND	7.67	12.11	5.75	10.41	4.44
GSS D	7.67	11.96	5.75	10.25	4.44
GSM	7.67	11.75	5.75	10.01	4.44
GSL 0-30	7.67	11.56	5.75	9.80	4.18
GSL 30-100	6.64	9.88	4.79	8.02	3.88
GSL >100	6.64	9.88	4.79	8.02	3.76

Ineffectiveness of Demand Charges

My evidence explains that demand charges:

- Encourage the wrong kinds of customer actions
  - Shift off customer's monthly peak, not off distribution, transmission or generation peaks, or high-load hours
- Hard to avoid
- Reduce energy charges that would encourage efficiency
- Alternatives are available: TOU, CPP, real-time pricing

MH rebuttal adds nothing to record

- Fails to respond to any of my points
- Incorrectly describes demand charges as though they charge for contribution to demand costs

Customer maximum demands do not drive costs

- PCOSS allocates demand costs on CP, high-load hours, or class NCP, not sum of customer demands
- Marginal cost analysis estimates T&D cost per kW of CP load
- MH "does not plan [transmission] capacity based on customer maximum demand, but on provincial coincident peak load." (GAC/MH II-14)
- "All (100%) of subtransmission and distribution plant capacity is driven by the coincident peak demand of all customers in the study area." (GAC/MH II-14)