REFERENCE:

Application Page 16, PUB-MFR-8.

PREAMBLE TO IR (IF ANY):

The application indicates the purpose is to "address the significant financial impacts due to the current drought conditions" (page 3) and further extends the discussion of drought as justification for the exigent circumstances in Section 1.3

QUESTION:

a) Please explain how Figure 2, Energy from Inflow, and Figure 3, Energy in Storage, at page 12 of 51 of the Application take into account the addition of Keeyask (and, where relevant, pre-versus-post Limestone). Is the energy in storage from past years adjusted to reflect a consistent larger installed generation plant on the Nelson River? (i.e., what would the same quantity of water produce given the current plant installed?) Or is the data at each point in time reflective of the plant that was installed at that respective point in time?

RESPONSE:

Both Figure 2 (Potential Hydraulic Energy from Inflows) and Figure 3 (Total Potential energy in Storage) on page 12 of 51 of the Application were prepared assuming all hydraulic stations in the Manitoba Hydro system are in service, including Keeyask generating station, for all historic years shown.

Note that these charts reflect aggregate *potential energy*. The actual amount of hydraulic generation in any given flow year may be much less than these charts suggest because the ability of the Manitoba Hydro system to use all inflows and storage in the system is limited. Aggregate values, as opposed to specific inflow locations or reservoir storage levels, can mask details about how conditions can vary across the system.

The contrast of water conditions across the system has been very significant in the 2020-2021 period, where inflows on the Churchill River basin were well above average to near record high leading up to and during this period while southern portions of the system experienced drought conditions. Manitoba Hydro has been maximizing the Churchill River Diversion flows through this entire period, however a lot of water had to be spilled down the lower Churchill River and therefore not used for hydroelectric generation. For the period of April to early November 2021, over 4 Terrawatt-hours (TWh) of potential energy has been spilled. This amounts to about 15% of the projected total hydraulic generation for 2021/22 (26.4 TWh, reference Figure 10 of the Application).

Figure 1 below illustrates the potential energy from inflows for the Churchill River basin. This data forms part of the aggregate which is provided in Figure 2 of the Application. Figure 2 below illustrates the potential energy from inflows for the Winnipeg River basin which has experienced below average to record low inflows since early 2020.

Figure 1. Potential Hydraulic Energy from Inflows – Churchill River Basin

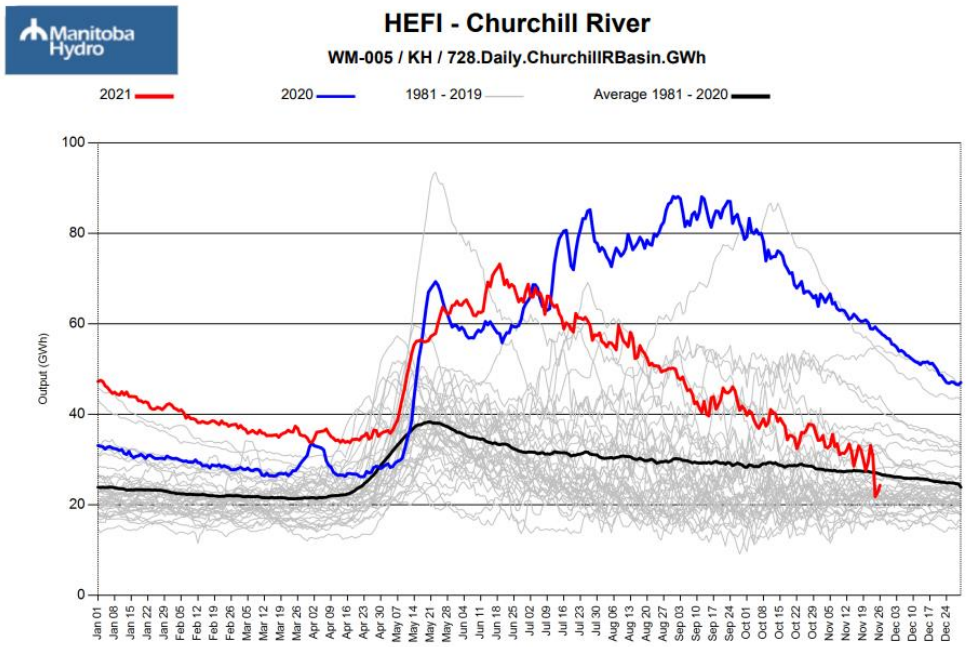
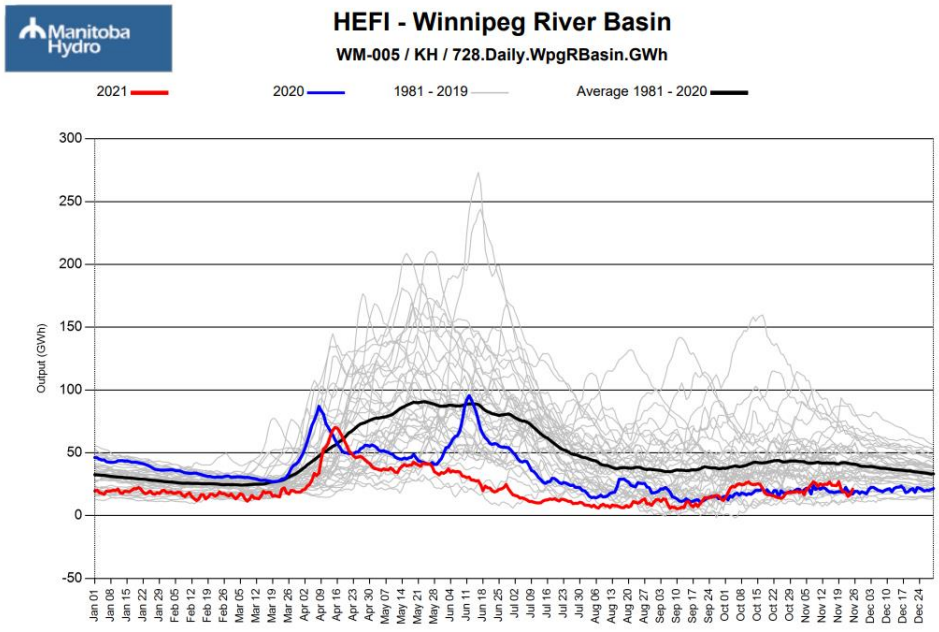


Figure 2. Potential Hydraulic Energy from Inflows – Winnipeg River Basin



REFERENCE:

Application Page 16, PUB-MFR-8.

PREAMBLE TO IR (IF ANY):

The application indicates the purpose is to "address the significant financial impacts due to the current drought conditions" (page 3) and further extends the discussion of drought as justification for the exigent circumstances in Section 1.3

QUESTION:

b) Please confirm the following estimates of the "cost" of a 5-year drought from past Manitoba Hydro filings – if not accurately recorded, please provide the correct value;
   i. IFF07-1 - $2.825 billion (page 17) (2007)
   ii. IFF15- $1.857 billion (page 27) (2015)
   iii. Current estimate - $1.3 billion (PUB MFR-8)

c) Please confirm that as of the 2003/04 drought, Hydro estimated the cost of a 5-year drought at $2.2 billion, while the Corporation had $1.135 billion in retained earnings (March 31, 2003), as reported by the PUB at Order 143/04 page 14. If Hydro does not agree with these values recorded by the PUB, please provide any needed corrections with explanation.

RESPONSE:

b)

i. Not confirmed. Including financing, the cost of a 5-year (2009/10 to 2013/14) in IFF07- 1 (page 20) was $2.131 billion. The $2.825 billion number quoted is the impact of the 5-year drought (2009/10 to 2013/14) by 2017/18 due to the continued impact of the additional financing costs.

ii. Confirmed.

iii. Manitoba Hydro confirms that the current estimate of the reduction in net extraprovincial revenue from a 5-year drought is $1.3 billion. However, as noted in the response to PUB MFR 8, this estimate does not include financing

costs, and as such are not directly comparable to the figure corrected in part i. or the figure confirmed in part ii.

c) In IFF03-1, the cost of a 5-year drought was estimated at $1.1 billion. This estimate excluded financing costs and the details were provided in the response to PUB/MH I-63a from the 2004 General Rate Application. The $2.2 billion drought cost reported by the PUB at Order 143/04 page 14 was explained at pages 107 and 108 of the transcript. This cost estimate was not based on a quantitative analysis but rather based on a set of judgements on the coincidence of a number of factors to give a sense of how high the drought cost could be under a set of adverse circumstances. The factors included: higher natural gas prices, higher market prices for energy, the possibility of adverse weather conditions and adverse exchange rates, and a proxy for the cost of financing. It is confirmed that the retained earnings for the electric segment at March 31, 2003 was $1.135 billion.

REFERENCE:

Figure 21 – Annual Customer Class Differentiation [PDF p.43] Figure 22 – Proposed Increase and Annualized Revenues by Class [PDF p.44]

PREAMBLE TO IR (IF ANY):

Using PCOSS21 as the basis for determining differentiated annual rate increases, Manitoba Hydro specifies one-time and annual seven-year adjustments in Figure 21 [PDF p.43] needed to bring the Revenue Cost Coverage (RCC) for all customer rate classes within the Zone of Reasonableness (ZOR) ranging from 95% to 105%.

Figure 22 [PDF p.44) outlines the proposed rate increases for each customer rate class sought by Manitoba Hydro in its 2021/22 Interim Rate Application when considering the adjustments specified in Figure 21.

QUESTION:

a) Please provide Figure 21 – Annual Customer Class Differentiation [PDF p.43] updated to reflect the one-time adjustment necessary to immediately bring all customer class RCCs to 100%.
b) Please provide Figure 21 – Annual Customer Class Differentiation [PDF p.43] updated to reflect the annual adjustment over seven years necessary to immediately bring all customer class RCCs to 100%.
c) Please provide Figure 22 updated to reflect the adjustments identified in b) and c) above.
d) Please provide Figure 21 – Annual Customer Class Differentiation [PDF p.43] updated to reflect the one-time adjustment needed to bring customer rate classes with RRC greater than 105% to the upper limit of the ZOR (105%) with the resulting shortfall recovered exclusively from customer rate classes with RCC below 100%.
e) Please provide Figure 21 – Annual Customer Class Differentiation [PDF p.43] updated to reflect the annual adjustment over seven years needed to bring customer rate classes with RRC greater than 105% to the upper limit of the ZOR (105%) with the resulting shortfall recovered exclusively from customer rate classes with RCC below 100%.

f) Please provide Figure 22 updated to reflect the adjustments identified in e) and f) above.

RESPONSE:

Response to a) and b):

The following figure identifies the rate adjustment required immediately and over a seven-year timeframe to bring all customer class RCCs to 100%.

Customer Class	PCOSS21 RCC	One-time Adjustment Required to bring RCC to Unity a)	Annual Differentiation Required to bring RCC to Unity over 7 years b)	RCC
Residential	96.2%	3.9%	0.5%	100.0%
GSS ND	113.8%	-12.1%	-1.8%	100.0%
GSS D	104.0%	-3.8%	-0.6%	100.0%
GSM	99.3%	0.7%	0.1%	100.0%
GSL 0-30	95.6%	4.7%	0.7%	100.0%
GSL 30-100	103.7%	-3.6%	-0.5%	100.0%
GSL >100	101.2%	-1.2%	-0.2%	100.0%
Area & Roadway Lighting	123.3%	-18.9%	-2.9%	100.0%

c) The following figure identifies the average rate increase or decrease, and resulting additional revenue required to implement an average increase of 5.0% and bring all customer class RCCs to 100%. The rate changes have not been adjusted to maintain rate harmonization between the GSS and GSM classes.

Customer Class	Rate change required to bring RCC to Unity a)	Annualized Additional Revenue (millions) a)	Rate change required to bring RCC to Unity over 7 years b)	Annualized Additional Revenue (millions) b)
Residential	9.1%	$70.9	5.6%	$43.5
GSS ND	-7.7%	($12.6)	3.1%	$5.1
GSS D	1.0%	$1.9	4.4%	$8.2
GSM	5.8%	$12.4	5.1%	$11.0
GSL 0-30	9.9%	$11.5	5.7%	$6.6
GSL 30-100	1.3%	$1.3	4.5%	$4.3
GSL >100	3.8%	$6.5	4.9%	$8.3
Area & Roadway Lighting	-14.8%	($4.1)	1.9%	$0.5

Response to d) and e):

The following figure identifies the rate adjustment required immediately and over a seven year time-frame to bring the RCC of the GSSND and AR&L classes to the upper limit of the ZOR (105%), with the resulting shortfall recovered exclusively from the Residential, GSM and GSL 0-30 kV classes.

Customer Class	PCOSS21 RCC	One-time Adjustment required to bring GSSND and ARL into ZOR d)	Annual Differentiation required to bring GSSND and ARL into ZOR over 7 years e)	RCC
Residential	96.2%	1.5%	0.2%	97.7%
GSS ND	113.8%	-7.7%	-1.1%	105.0%
GSS D	104.0%	0.0%	-0.0%	104.0%
GSM	99.3%	1.5%	0.2%	100.8%
GSL 0-30	95.6%	1.5%	0.2%	97.0%
GSL 30-100	103.7%	0.0%	-0.0%	103.7%
GSL >100	101.2%	0.0%	-0.0%	101.2%
Area & Roadway Lighting	123.3%	-14.8%	-2.3%	105.0%

f) The following figure identifies the average rate increase or decrease, and resulting additional revenue required to implement an average increase of 5.0% and to bring the RCC of the GSSND and AR&L classes to the upper limit of the ZOR (105%) with the resulting shortfall recovered from the Residential, GSM and GSL 0-30 kV classes. The rate changes have not been adjusted to maintain rate harmonization between the GSS and GSM classes.

Customer Class	Rate change required to bring GSSND and ARL into ZOR d)	Annualized Additional Revenue (millions) d)	Rate change required to bring GSSND and ARL into ZOR over 7 years e)	Annualized Additional Revenue (millions) e)
Residential	6.6%	$51.6	5.3%	$40.9
GSS ND	-3.1%	($5.0)	3.8%	$6.3
GSS D	5.0%	$9.3	5.0%	$9.3
GSM	6.6%	$14.2	5.3%	$11.3
GSL 0-30	6.6%	$7.7	5.3%	$6.1
GSL 30-100	5.0%	$4.9	5.0%	$4.9
GSL >100	5.0%	$8.5	5.0%	$8.5
Area & Roadway Lighting	-10.6%	($2.9)	2.6%	$0.7