



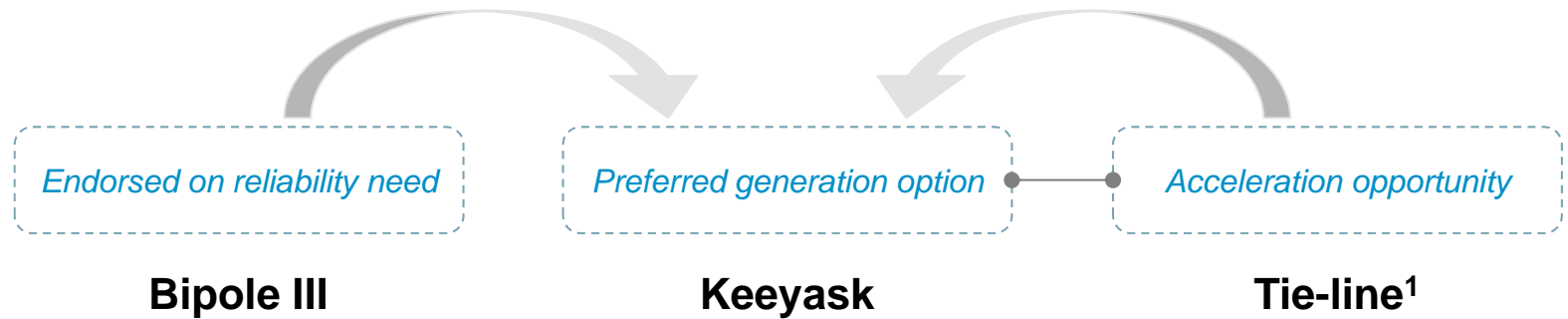
# Bipole III, Keeyask and Tie-Line review

September 19, 2016

THE BOSTON CONSULTING GROUP

# Exhibit 1: Assessment of complex program of three projects

Each with standalone objectives and integrated benefits



## Project objective

### Mitigate longstanding system reliability risk

- Ensure reliability against losing Bipole I & II lines or Dorsey converter station

### Satisfy future Manitoba energy need

- Meet future domestic energy need
- Leverage Manitoba's clean hydro resource

### Secure cost-effective dependable energy

- Reduce future need for domestic generation
- Expand market access in MISO (MN & WI)

## Secondary considerations

### Strengthen physical transmission capability

- Additional peak capacity (enabling new generation)
- Redundancy for maintenance

### Leverage resource attributes to cover part of costs through export

- "New hydro" to satisfy US tie-line requirement
- Leverage increased peak capacity from Bipole III

### Increase value of domestic resources

- Reduce Bipole corridor reliability requirement
- Improve Keeyask value generation potential

1. Tie-line = MMTP plus GNTL  
BCG Report.pptx

## Exhibit 2: Core questions being addressed in this effort

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- 1 Were the original decisions the right ones?**
- 2 Is there further downside risk?**
- 3 Can they be stopped or paused without undue cost or risk?**

# Exhibit 3: Summary of key messages

## 1 Original decision on Bipole III justifiable but Keeyask (in hindsight) a less prudent decision

- Bipole III East was lowest-cost option to address longstanding, untenable reliability risk but the Province directed Hydro not to consider it
  - Of remaining options, Bipole III West lowest cost vs. All gas and Import + gas
- Keeyask (with US Tie-line) long-run economics attractive on paper, but financial and execution risks not fully considered
  - Rationale existed for accelerating Keeyask, e.g.: sustainable energy solution that capitalizes on expiring export opportunity
  - However, several factors suggest decision imprudent, e.g.: lower / delayed capex alternatives (e.g. gas) not fully explored, costly constraints not fully challenged, permits not in place ahead of proceeding, discount rates did not reflect project risk
- Imprudence can be traced to systemic decision governance issues, e.g.: lack of clear objective function and criteria/constraints of Hydro and regulatory body, rates not linked to allowable returns, iterative (vs. upfront) approach to investment decisions

## 2 Based on current outlook, project economics expected to worsen and remain sensitive to key uncertainties

- Capital execution will likely overrun and export price assumptions expected to worsen (outside of carbon constrained scenario)
- Equity ratios dip into single digits - similar to 1970-1995, but Province with 30%+ net debt/GDP vs. ~20% before

## 3 Despite these challenges, cancelling in flight projects to shift to alternatives is not a realistic option

- ~\$5B already sunk on Bipole III and Keeyask with cancellation costs of ~\$1B each, bringing effective total to ~\$7B
- ~\$3.2B cost to complete Bipole III West clearly more favourable vs. ~\$4.5B rerouting costs of Bipole III East
  - Furthermore, decision to reroute Bipole III would strand Keeyask, making it uneconomic and likely trigger cancellation
- ~\$4.7B cost to complete Keeyask yields an NPV \$3-5B more favourable vs. switching to gas option, and avoids strategic risks

# Exhibit 4: Were the original decisions the right ones?

## **Bipole III East was lowest-cost option to address longstanding, untenable reliability risk but was refused**

- Reliability risk associated with Bipole I&II and Dorsey has been untenable for a long time: High concentration (e.g., 70% of energy), high incidence risk (e.g., 1/20 years), high societal impact (~\$4-20B), major political implications
- Bipole III East lowest cost option but Provincial decision not to pursue based on environmental grounds
- Of remaining options, Bipole III West lowest cost vs. All gas and Import + gas

## **Original decision on Keeyask (with Tie-line) an imprudent decision**

- New generation capacity required to meet domestic demand ... but not until 2024+
- Keeyask project represents 2019 acceleration option to leverage US Tie-line import and export opportunity
- On paper, represents most favourable NPV option vs. delayed Keeyask (without Tie-line) or delayed gas
- Hydro generation deemed favourable vs. gas considering fuel price volatility and regulatory (e.g. CO<sub>2</sub>) risk
- But assessment did not fully consider execution risks and sensitivities, e.g., project risk, industrial account risk, export price risk
- Additional downside financial risks of additional leverage (with Bipole III running concurrently) and associated discount rates to account for these risks did not appear to be fully factored into decisions
- Fuller assessment of lower capital and lower risk options would have been more prudent action at the time
  - Gas alternative
  - More aggressive challenging of costly constraints, e.g., regulatory requirement of Tie-line
  - Greater scrutiny of scope and design decisions

## **Imprudence can be traced to systemic decision governance issues**

- Lack of clear objective function and criteria/constraints of Hydro, Government and Regulator, e.g., role of Hydro to drive economic growth vs. service domestic needs; role of regulator to maintain low rates vs. govern responsible stewardship of assets
- Ineffective rate-setting regime, e.g., rates not linked to allowable return, creating disconnect with system investment plan
- Iterative (vs. upfront) approach to investment plan decisions, e.g., ensuring full project scope considered holistically (Bipole III, Keeyask, US Tie-line) to appropriately capture compounded execution and financial risks

# Exhibit 5: Mitigating risk of Bipole I&II, Dorsey a necessity

## Represent unusually large contingencies

### Bipole I&II carry majority of MH electricity

- ~70% of energy (MWh)
- ~50% of generation capacity<sup>1</sup> (MW)

### Unable to meet winter demand without Bipole I&II

- 1500MW short of peak demand in 2017
- Assumes max. imports and running all thermal plants

## Significant and real risk of catastrophic failure

### Fire significant risk to Dorsey

- 1/29yr expected frequency<sup>2</sup>

### Tornado at Dorsey unlikely but catastrophic

- 1/4000yr; Ellie<sup>3</sup> was scare
- Could take years to rebuild

### Freezing rain and wind significant risk to Bipole I&II

- 1/20yr expected frequency

### Ground ice buildup also risk to Bipole I&II

- Near-miss with shifted tower bases

## ~\$4-20B societal impact of prolonged outage

### Outage likely to last weeks to months

- 5-8 weeks for Bipole I&II
- Weeks to year(s) for Dorsey

### Rolling blackouts and/or demand curtailment

- Must force demand down to supply limit

### ~\$4-20B cost depending of type and time of outage

- ~\$10/kWh that fail to supply
- ~\$4B for Jan. line outage
- ~\$20B if full year

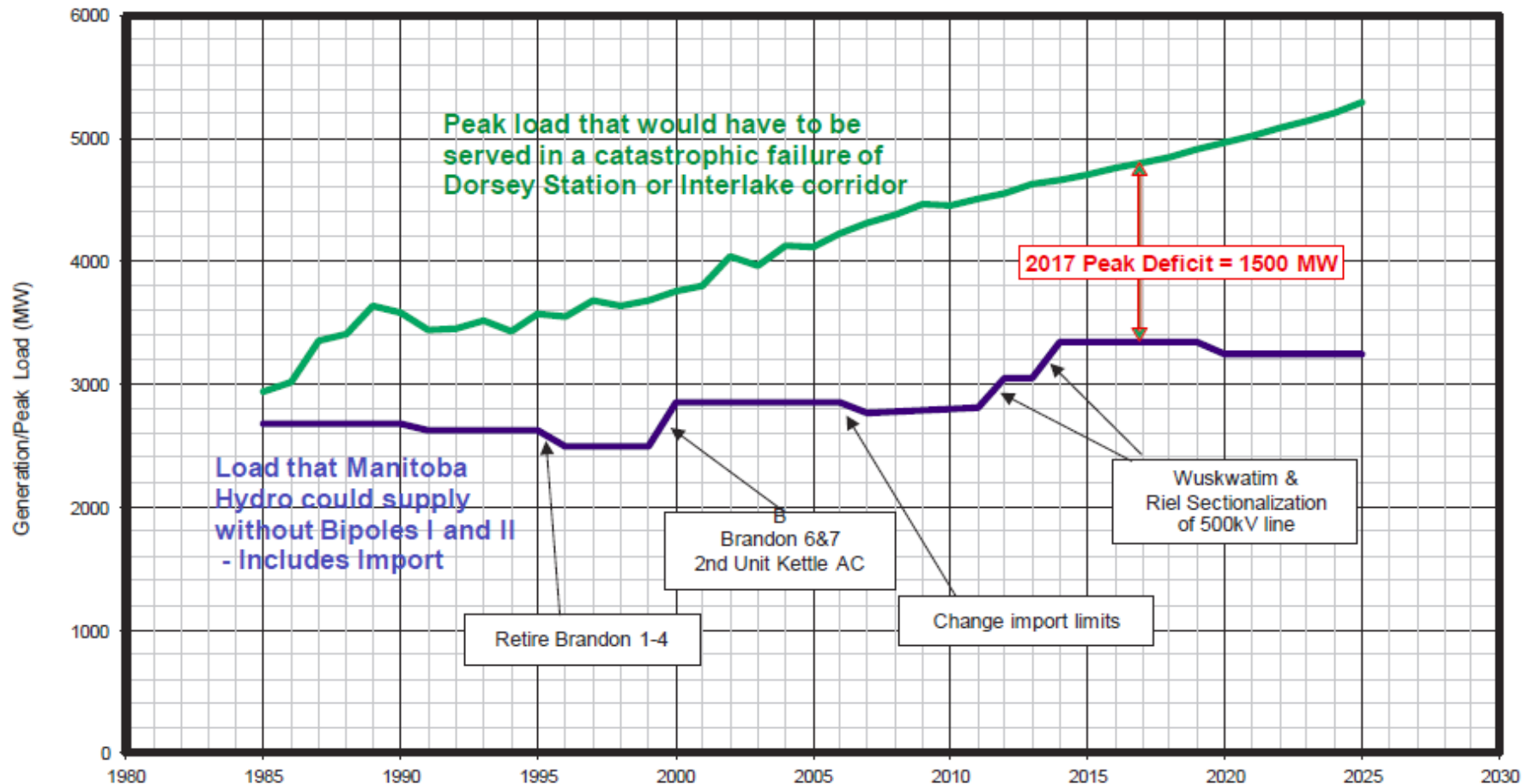
### Popular backlash against MH and government likely

- Failure to honor Hydro Act

1. Total (100%) includes both generation and import line capacity. 2. After hardening of relay building in 2011 risk may be lower than stated in the reports. 3. Strongest tornado in Canadian history, 25km away. Source: Teshmont (2001, 2006, 2012)

# Exhibit 6: Peak load growth making loss of Dorsey or Bipole I & II consequences more severe (1.5 GW peak shortfall in '17)

Manitoba Load Serving Capability



Source: Reliability Alternatives for Mitigating the Risks of a Dorsey or Interlake Corridor Outage (2011)

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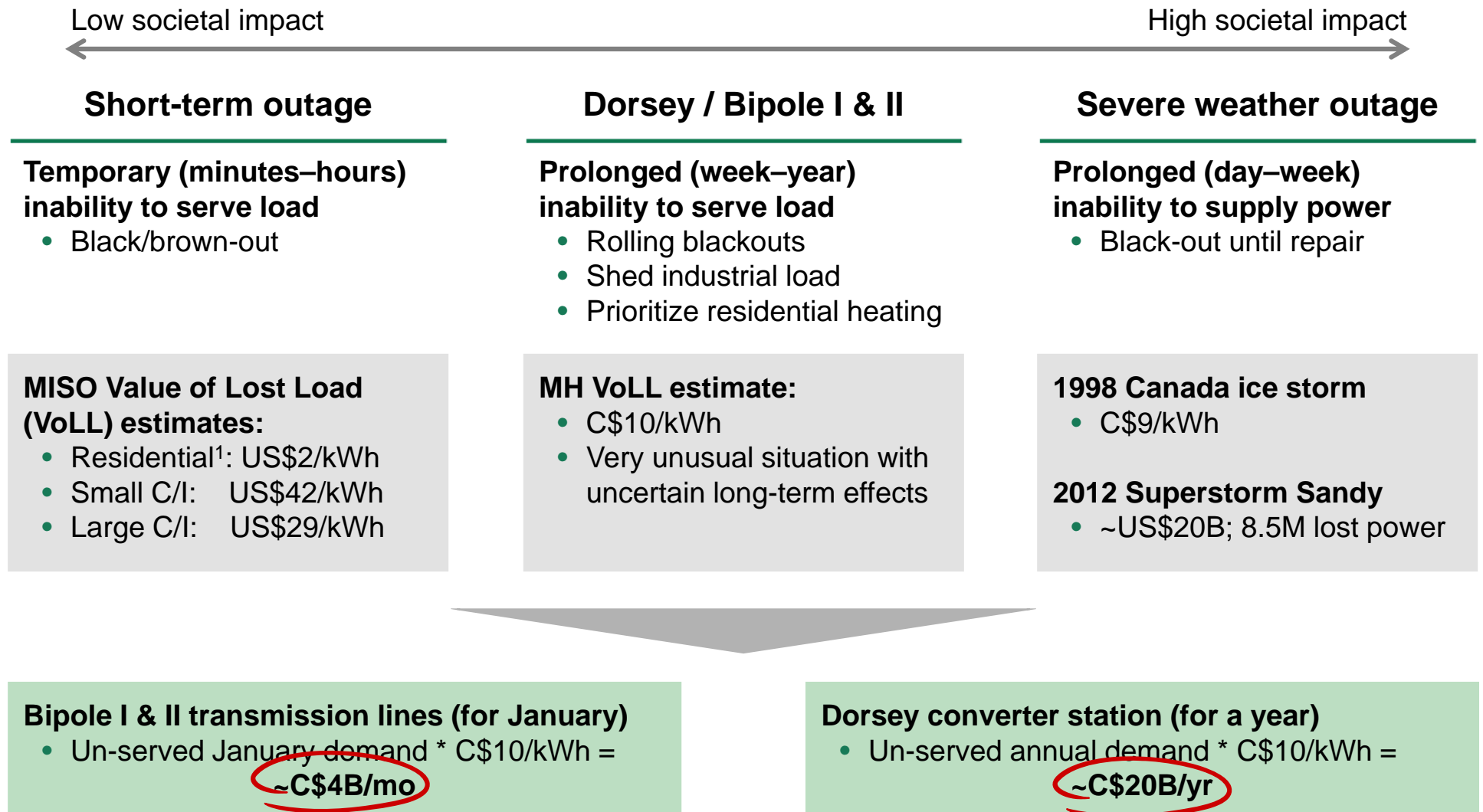
# Exhibit 7: Probabilistic studies show risk to Dorsey and Bipole I & II, and there have been several near misses

Threat	Dorsey <sup>1</sup>	Bipole I & II
Tornado, downburst	<b>1/4000yr</b> (summer) Down <b>month to year(s)</b> <ul style="list-style-type: none"> <li>• 3km away (Sep. '96)</li> <li>• 25km away<sup>2</sup> (Jun. '07)</li> </ul>	<b>1/17yr</b> (summer) Down <b>days to weeks</b> <ul style="list-style-type: none"> <li>• 19 towers destroyed (Sep. '96)</li> </ul>
Fire	<b>1/29yr</b> Down <b>week to months</b> <ul style="list-style-type: none"> <li>• Exploding transformer</li> </ul>	N/A
Wide-front wind	<b>1/200yr</b>	<b>1/90yr</b> Down <b>week to months</b>
Freezing rain & wind	<b>1/50yr</b>	<b>1/20yr</b> Down <b>week to months</b>
Ground ice buildup	N/A	Unknown; <b>likely significant</b> <ul style="list-style-type: none"> <li>• Tower bases shifted from the ground</li> </ul>
Sabotage	Unknown	Unknown

1. After hardening of relay building in 2011 several of the risks to Dorsey are likely lower than stated in the reports. 2. Elie; strongest tornado in Canadian history  
 Source: Teshmont (2001, 2006, 2012)

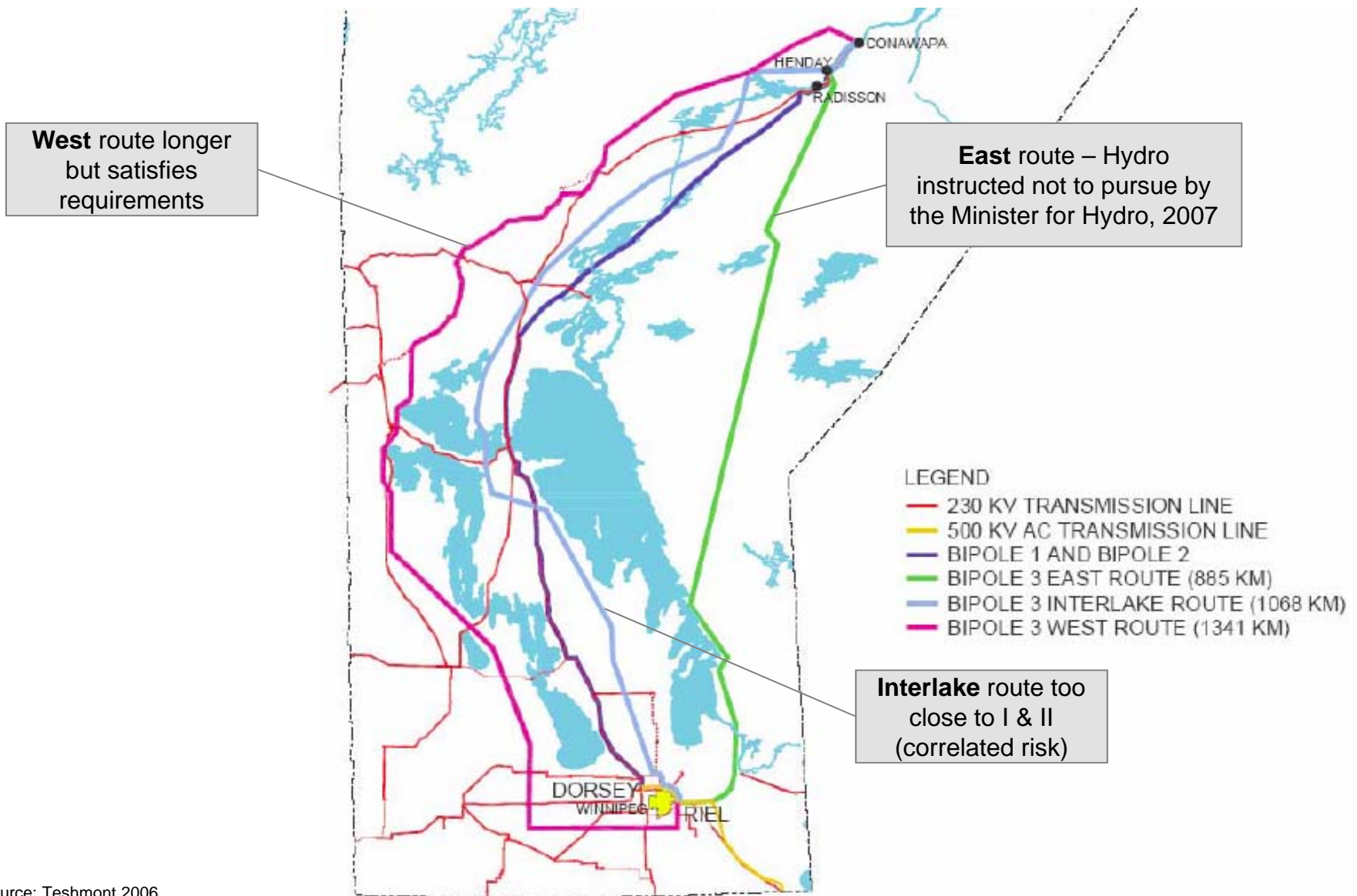


# Exhibit 8: Societal impact of loss of Bipole I & II or Dorsey for month of January ~C\$4B, and ~C\$20B for full year



1. Likely higher for customers reliant on electric heating, and may underestimate modern reliance on electronics  
 Source: "Estimating the Value of Lost Load", London Economics (2013); "Manitoba Customer Interruption Cost Evaluation", R. Billington, PowerComp Associates (2001); "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages", Executive Office of the President (2013)





# Exhibit 9: Bipole III West route chosen to minimize risk correlation with Bipole I & II



Source: Teshmont 2006  
BCG Report.pptx

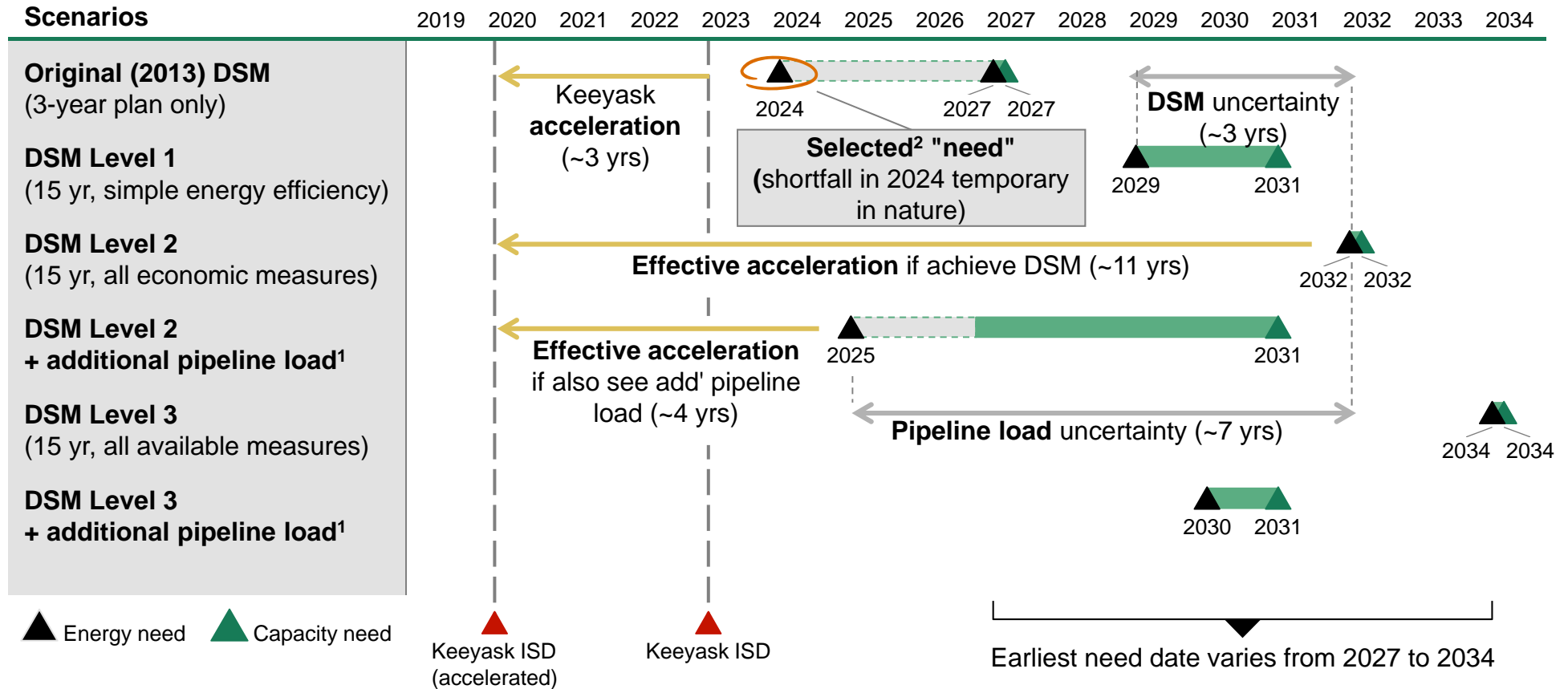
# Exhibit 10: Bipole III East the most favourable option

But directed not to pursue by previous government, hence Bipole III West pursued

	<i>Lowest cost, not selected</i> <b>Bipole III East</b>	<i>Selected option</i> <b>Bipole III West</b>	<b>All-gas</b>	<b>Import + gas</b>
Description	<b>Alternative access to northern hydro</b> <ul style="list-style-type: none"> <li>2000MW line</li> <li>Could stage (line first, conv. stations later<sup>1</sup>)</li> </ul>	<b>Alternative access to northern hydro</b> <ul style="list-style-type: none"> <li>2,300MW line</li> <li>Cannot stage line and converter stations</li> </ul>	<b>Backup generation</b> <ul style="list-style-type: none"> <li>2000MW gas in the South</li> </ul>	<b>Import line + backup generation</b> <ul style="list-style-type: none"> <li>1500MW US line</li> <li>500MW gas</li> </ul>
Cost estimate used in 2011 EIS <sup>4</sup>	Not formally assessed but estimated to be \$900m less expensive <ul style="list-style-type: none"> <li>Staged converter station build</li> <li>700-900km shorter</li> </ul>	<b>~\$3.3B</b> (capital cost in-service dollars)  <b>~\$10M/y</b> annual cost	<b>~0.7B</b> more than BP III on PV <sup>2</sup> basis <b>~\$3B</b> gas turbine <b>~\$181M/y</b> pipeline reservation fee + variable costs	<b>~\$4.5B</b> (capital cost in-service dollars)  Annual costs subject to contract terms and variable costs
Additional benefits	<b>\$28M/yr from reduced losses<sup>3</sup></b>  <b>Additional capacity for new hydro</b>	<b>\$26M/yr from reduced losses<sup>3</sup></b>  <b>Additional capacity for new hydro</b>	<b>More dependable energy</b>	<b>Larger import/ export potential</b>  <b>More dependable energy</b>
Risks	<b>Route through Boreal forest</b>	<b>No specific risk</b>	<b>Environmental risk, pipeline reservation fee</b>	<b>Environmental risk, future price of securing capacity</b>
Verdict	 <b>In 2007 the province directed MH to study Western routes</b>	 <b>Lowest cost of available options</b>	 <b>Higher cost, CO<sub>2</sub>-emitting</b>	 <b>Higher cost, CO<sub>2</sub>-emitting, difficult to secure US partner</b>

1. Line primary concern, given low probability of Dorsey destruction. 2. Present Value. 3. Current Bipole I&II transmission losses 8.6%; Bipole III West 6.4% to 7.0%; Bipole III East 6.0% to 6.4%.  
 4. Environmental Impact Statement (2011)  
 Source: Manitoba Hydro, BCG analysis

# Exhibit 11: Timing of domestic requirements



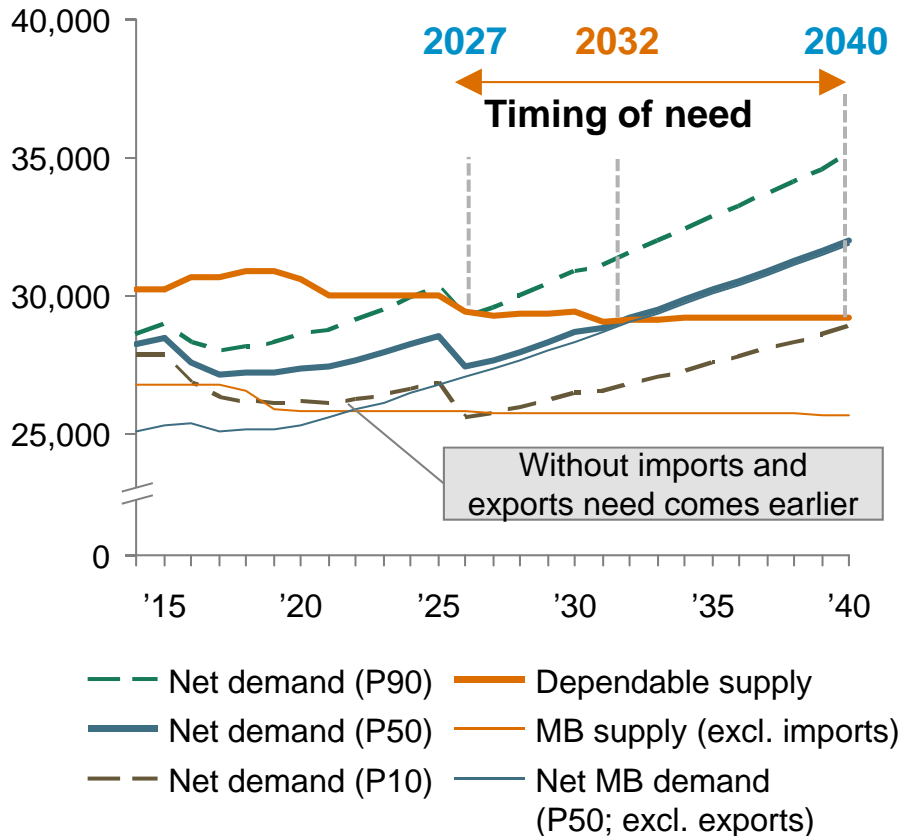
**Realistic DSM pushed need date out, but expected additional pipeline load pulled it back to ~2027**

1. 1700MWh additional load planned by pipeline customers. 2. Put forward by MH, and accepted by NFAT panel (partly because they expected additional pipeline load to materialize). Source: NFAT Final Report

# Exhibit 12: New generation capacity required, although not until 2027 or beyond

## NFAT: Supply vs. net demand<sup>1</sup>

Dependable energy supply vs. net demand (GWh)



1. Gross demand minus DSM, including exports unless noted  
Source: Manitoba Hydro (NFAT)

## Timing subject to forecast uncertainty

**Gross demand** forecasted to grow by 1.5% p.a.

- **Residential segment:** Population growth and increased penetration of electric heating
- **Mass market segment:** GDP growth (2%) and population key drivers
- **Top customers segment :** 17 companies, "Potential Large Industrial Loads" longer term

**Demand Side Mgmt. (DSM)** expected to offset 66% of demand growth over 15 years

- **Conservation rates:** MH proposed higher rates for electricity beyond threshold
- **Fuel switching:** Switch to gas heating
- **Load displacement:** Industrial self-generation

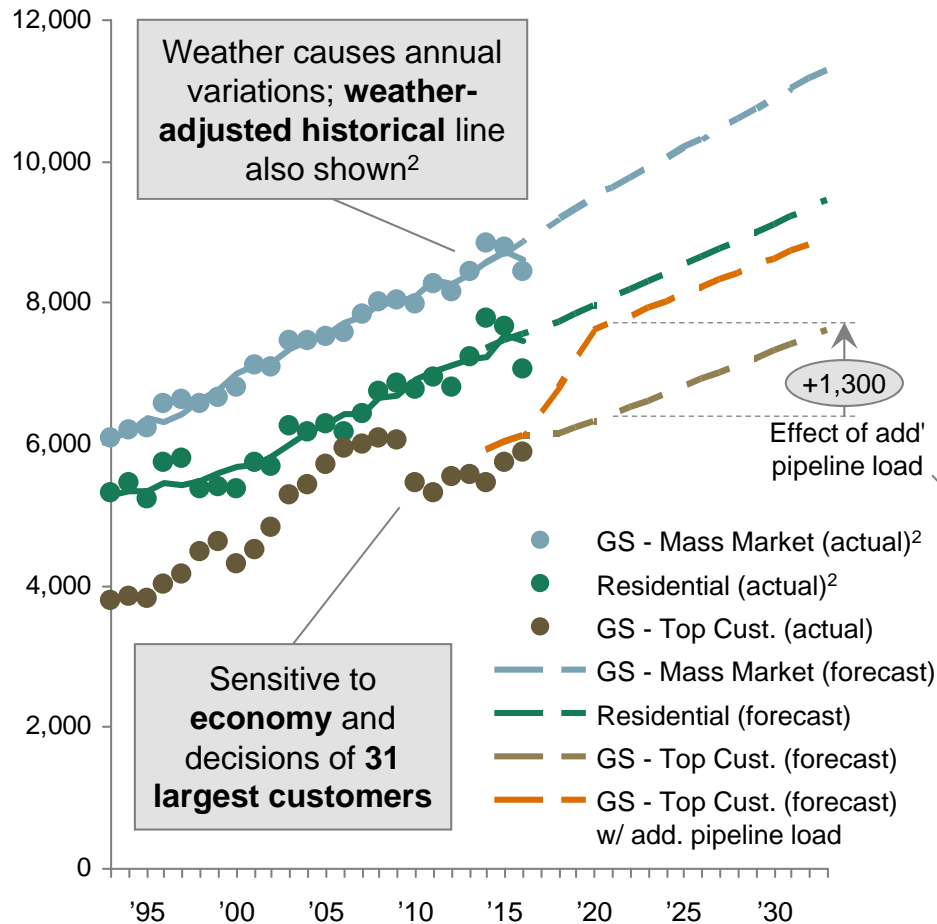
**Uncertainty for both gross demand & DSM**

- Decisions of larger industrial customers (e.g., pipeline load)
- DSM adoption may be lower than in other markets due to low retail rates

# Exhibit 13: Gross demand forecast sensitive to Top Customers

Forecast methodology sound, but inherent risk in lumpy Industrial demand

Customer segment gross demand<sup>1</sup> (GWh)



## Demand forecast by customer segment

### Methodology to forecast demand by segment

- **General Service – Mass market:** GDP and residential customer number drive demand
- **Residential segment:** Population, electric heating penetration, etc. drive demand
- **General Service – Top Customers:** Individual forecasts for top 31 drive near-term demand; annual PLIL<sup>3</sup> increment beyond that

### Historically, demand forecast accurate for General Service and Residential

### Top Customers largest source of uncertainty

- Sensitive to largest customers and economic cycles
- E.g., expected 1700GWh add' pipeline load (+1300GWh over PLIL<sup>3</sup>) but only ~500GWh now expected to materialize

1. Gross MB demand shown; net demand is gross demand minus DSM, plus net exports. 2. Weather-adjusted line also shown (N/A to Top Cust.). 3. Potential Large Industrial Loads  
Source: Manitoba Hydro



# Exhibit 14: NPV & upside favoured Keeyask by 2019 + Tie-line

But at substantially higher capital risk vs. delayed gas option



Criteria	Gas generation 2022+	Keeyask 2025/26	Keeyask '19 + Tie-line
Resource type	<b>Fossil</b> (CO <sub>2</sub> emitting; fully dispatchable)	<b>Renewable</b> ("new hydro"; dispatchable subject to water)	<b>Renewable</b> ("new hydro"; dispatchable subject to water)
Cost structure	<b>Variable cost intensive</b> CAPEX (PV <sup>1</sup> ): ~\$2.8B Variable cost: ~\$40-62/MWh LCOE <sup>3</sup> : ~75-265 \$/MWh <sup>4</sup>	<b>Capital intensive</b> CAPEX (PV <sup>1</sup> ): ~\$4.4B Variable cost <sup>2</sup> : ~\$3-4/MWh LCOE <sup>3</sup> : ~68 \$/MWh	<b>Capital intensive</b> CAPEX (PV <sup>1</sup> ): ~\$6.2B Variable cost <sup>2</sup> : ~\$3-4/MWh LCOE <sup>3</sup> : ~68 \$/MWh <sup>5</sup>
NPV (NFAT)	<b>Reference case</b>	-\$38M benefits to MH and \$591M payments to province compared to gas reference	+\$386M benefits to MH and \$1148M payments to province compared to gas reference
Upside and risk	Higher or lower gas and CO <sub>2</sub> prices than forecast Federal or provincial restrictions on CO <sub>2</sub>	Increased export prices from US Clean Power Plan, etc. Cost and schedule overrun	Increased export prices from US Clean Power Plan, etc. Cost and schedule overrun, and tie-line permitting

1. Present Value of capital expenditure for scenario (including late-time gas generation) 2. Only water rental included here 3. Levelized Cost of Electricity. 4. Varies by utilization. 5. Keeyask only. Source: NFAT, BCG analysis

# Exhibit 15: Tie-line a key source of value for Keeyask project

Greatly improves economics of Keeyask given potential for export to subsidize low domestic rates

## Minnesota Power needed rapid path to reduce CO<sup>2</sup>



### The problem

- MP legally mandated to achieve 26.5% RPS by 2025
- MP had set its own target to produce 1/3rd of current 1900 MW from renewables
- CPP may require MP to reduce 30% CO<sup>2</sup> from coal by ~2030
- Can only import new source of renewable power

MP were looking for a near-term solution

## MP had several options to solve CO<sup>2</sup> challenge



### Several options to solve

- Build out wind
- Wait for utility scale PV to drop in price (as per trend)
- Start build out of gas
- Lock in new source of hydro power to import (Keeyask provided the option)

Keeyask one of several viable options considered

## Building Keeyask and tie line had benefits for MH



### With the tie line, MH gets

- ~3 TWh new cost-effective dependable energy
- Import capacity of ~700MW dependable capacity to offset hydro risk
- 885MW increase in export capacity used to offset construction cost of Keeyask

MH built early to capture benefits in a closing window



# Exhibit 16: Gas carried less uncertainty, but Keeyask with tie-line had higher expected incremental NPV<sup>1</sup>

## Gas generation 2022+

Smaller and staggered capital costs, with future fuel expense

Key sensitivities (discount rate, energy prices, capital costs) can vary NPV by  $-\$1B$  to  $+\$0.7B$

## Keeyask 2025/26

Large capital investment

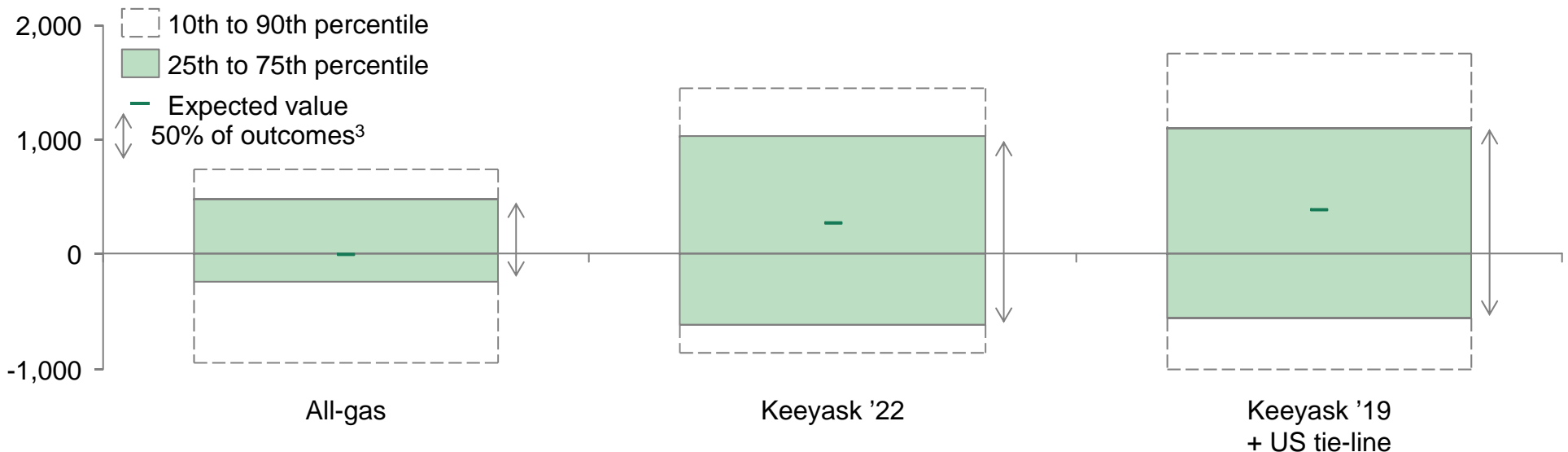
Expected incremental NPV  $\sim\$0.3B$ , but more sensitive (ranges from  $-\$0.8B$  to  $+\$1.4B$ )

## Keeyask '19 + Tie-line

Large capital investment and early additional export rev.

Highest expected incremental NPV ( $\sim\$0.4B$ ), but also most sensitive (largest up/downside)

Incremental NPV<sup>1</sup> over all-gas reference case<sup>2</sup> (\$M)

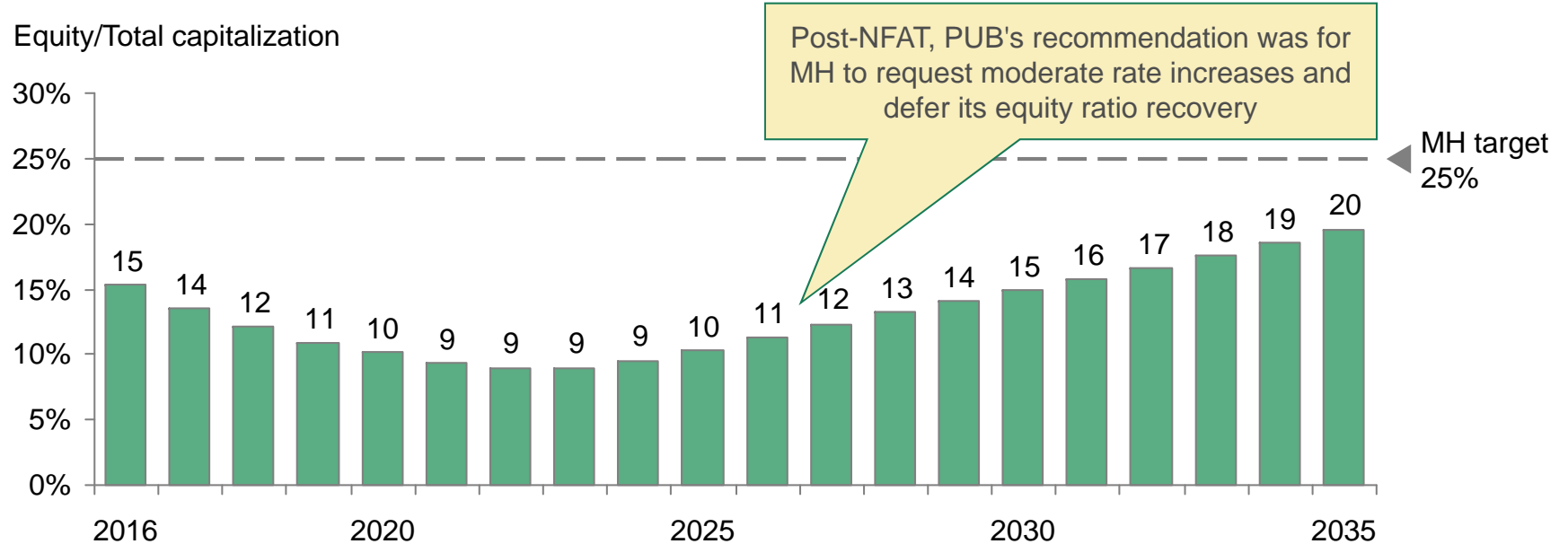


1. Having sunk \$1.2B. NPV benefit to Manitoba Hydro only (excluding water rental and capital tax and guarantee fee payments) 2. All-gas reference case with reference values for discount rate, energy prices, and capital costs. 3. Considering uncertainty in discount rate, capital costs, and energy prices. Note: Manitoba Hydro did not update this analysis to reflect final DSM level 2 demand forecast Source: NFAT final report

# Exhibit 17: Implied equity ratios of NFAT submissions

NFAT and PUB supported equity ratio falling to 9%

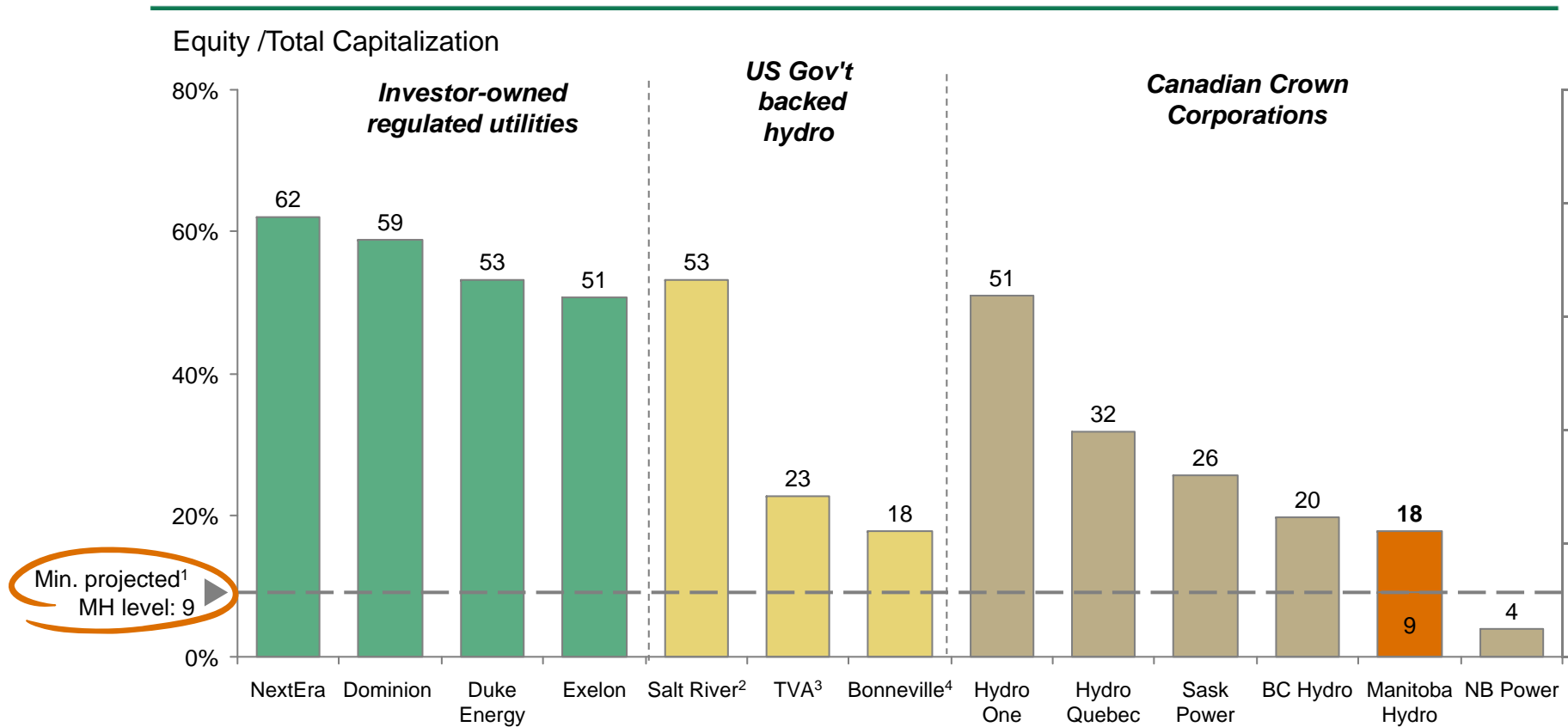
## Equity ratio approved during NFAT assessment



**Single digit equity ratios were not highlighted as a significant risk when projects approved**

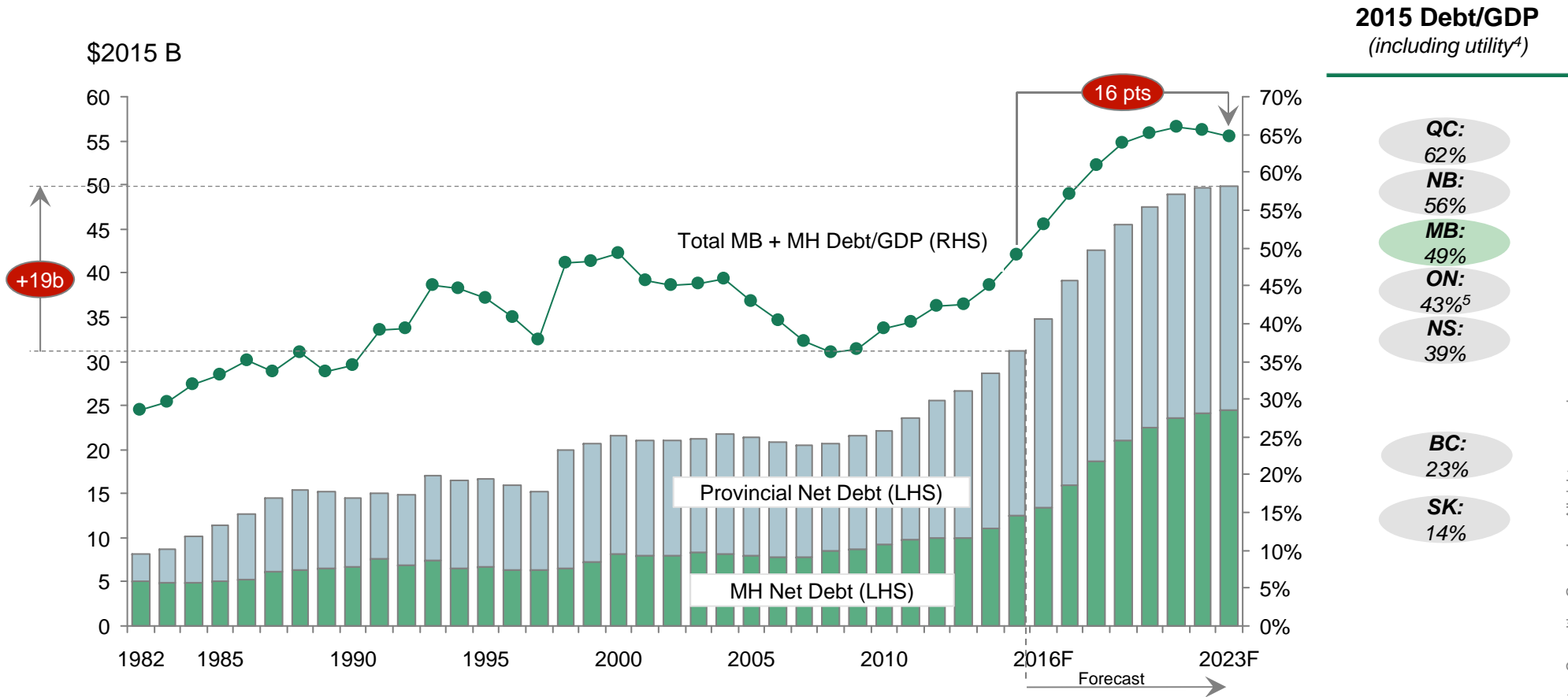
# Exhibit 18: Equity ratios well-below most peers

## Capital structure and credit rating for US and Canadian gov't and investor-owned regulated utilities



1. 2022 Expected Equity Ratio on NFAT Base Case 2. Salt River Project an entity of the State of Arizona 3. Federally owned corporation 4. US Federal administration within Dept. of Energy  
Source: 2015 Audited Financial statements, SNL

# Exhibit 19: Hydro debt included, total debt-to-GDP ratio forecast will increase to 65%



**Limited capacity for the Province to provide debt backstop**

Source: Canadian Department of Finance, Manitoba Hydro Debt Management Strategy Report, RBC, 2015 Utility Annual Reports

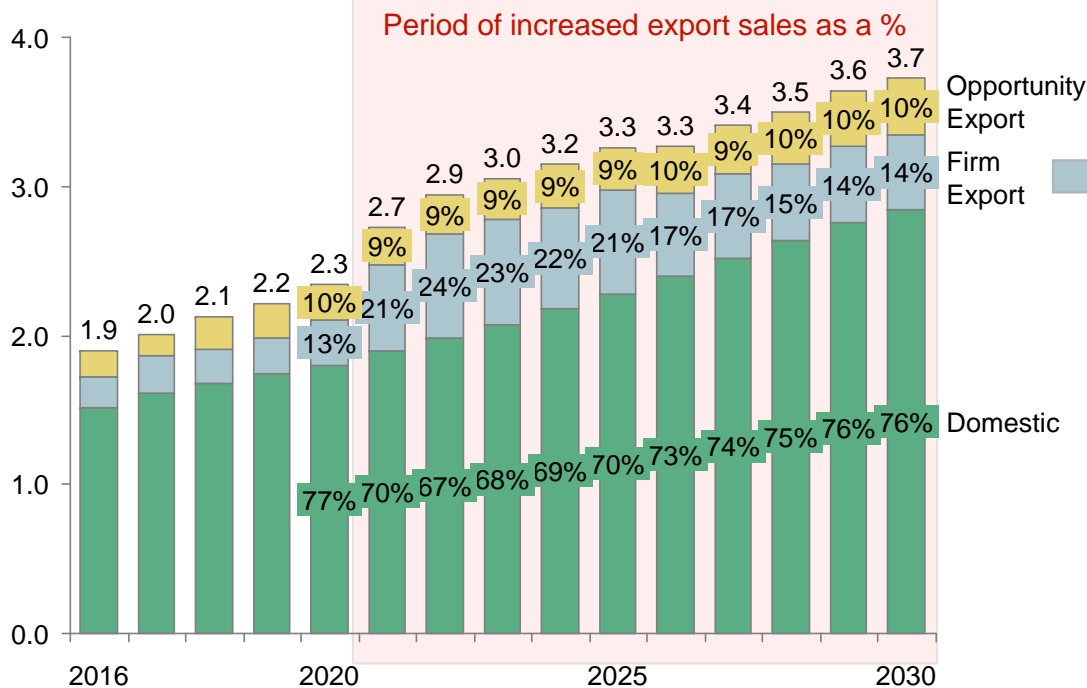
1. Total Debt calculated as Provincial Net Debt + Manitoba Hydro Net Debt in base case. 2. Debt to GDP ratio from RBC report; excludes Manitoba Hydro debt 3. Provincial debt forecasts modeled based on Provincial target to close budget gap within 8 years 4. Provincial net debt with utility crown corporation debt included 5. Ontario Provincial debt plus OPG debt (including asset removal and nuclear waste management liabilities)

# Exhibit 20: Firm export volumes and prices benefit economics

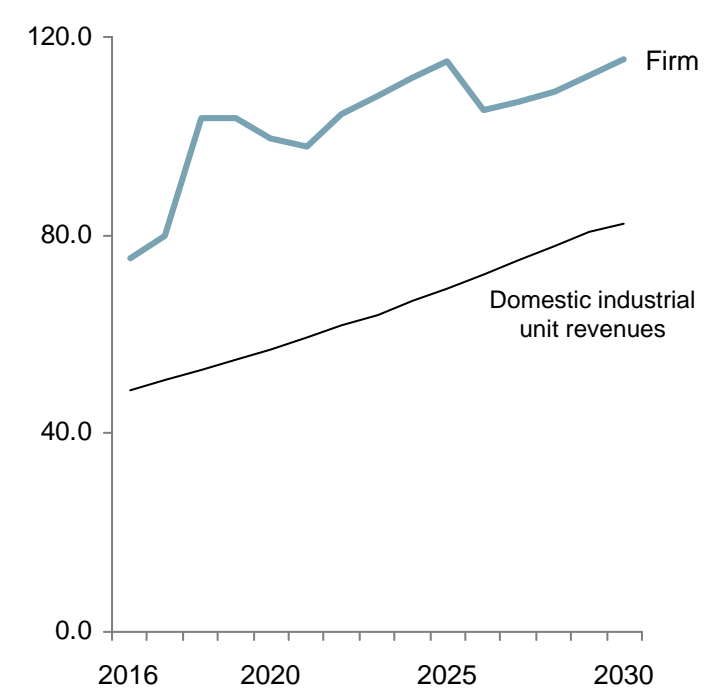
**Revenue mix expectations:  
Firm export expected to grow to 20%+**

**Price expectations:  
Firm export at 15% premium**

Forecasted domestic demand and export revenues IFF '15 (C\$B)



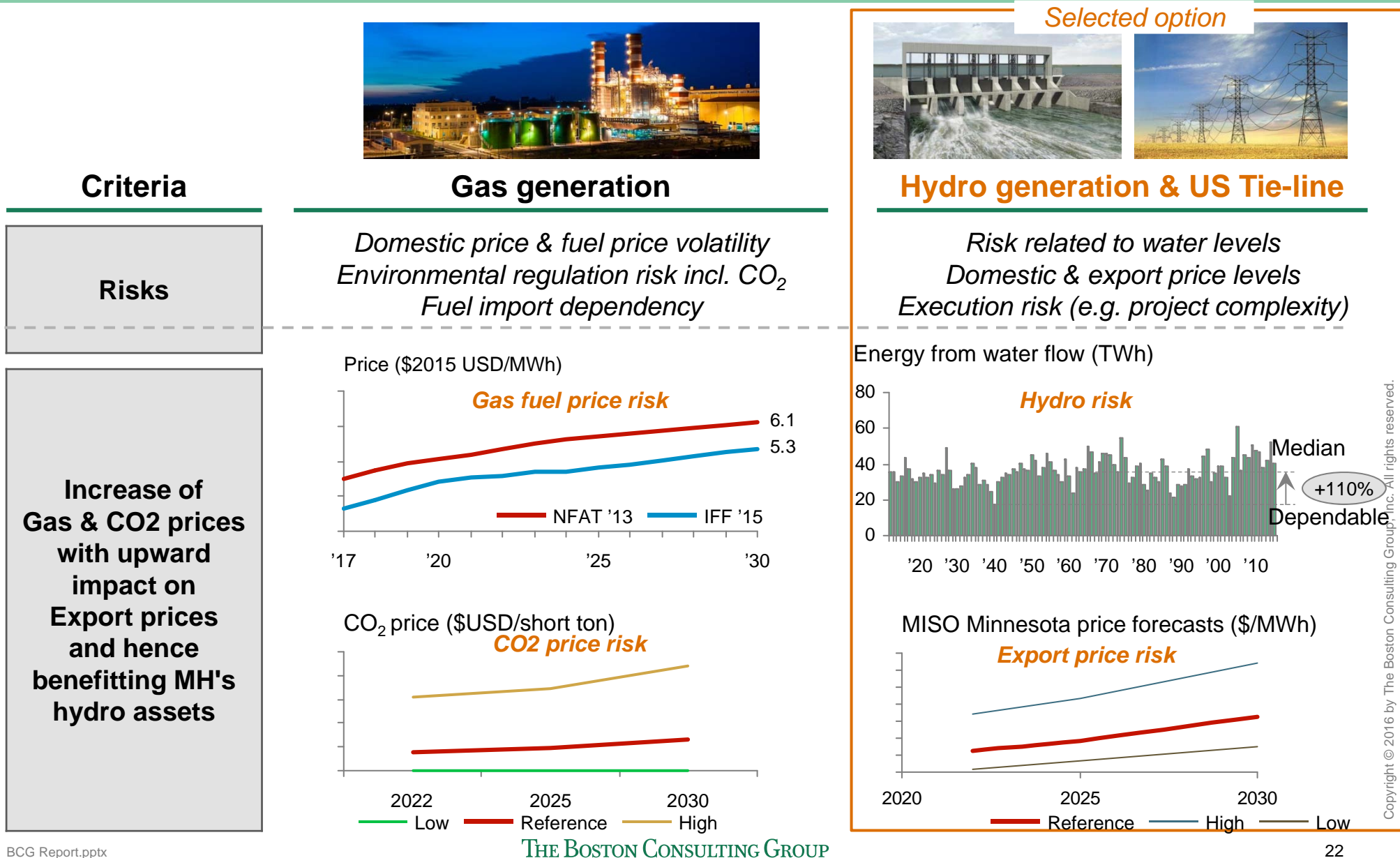
Unit revenues IFF '15 (\$/MWh)



Source: Manitoba Hydro, BCG analysis  
BCG Report.pptx

# Exhibit 21: Gas & CO<sub>2</sub> price risk vs. Hydro & Export price risk

Manitoba's resources and the current regulatory model better fits with the hydro based risk profile



# Exhibit 22: Manitoba Hydro's regulatory framework oriented towards maintaining consistent, low price increases

## Hydro Act

**Outlines Manitoba Hydro's core purpose: to provide sufficient power for Provincial needs and engage in the activities required to provide power economically and efficiently**

- Regulatory framework allows for exports of power

**Directs that prices be set such that MH can recover operating and interest costs and build sufficient reserves to fund replacement of assets and new investment in property or plant**

- Act also outlines MH's ability to borrow under Provincial guarantee

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## PUB

**PUB mandate exclusively to review the price of power; no supervisory authority granted**

**Track record of PUB to prioritize low, stable increases over time rather than implement lumpier price increases timed with capital expenditures**

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## Provincial Cabinet

**Province reviews capital plans, export contracts and interconnect agreements**

- Province may direct PUB to review other elements of MH's operations on its behalf

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## Other legislation

**MH also subject to other legislation that influences PUB and public attitude towards price:**

- Affordable Utility Rate Accountability Act requires Manitoba to have lowest combined price of gas, electricity and auto insurance among provinces
- Clean energy legislation governing development of renewables prioritizes low rates

# Exhibit 23: Manitoba regulatory construct different from traditional utility cost-of service model on several dimensions

## Manitoba PUB "Modified" Cost of Service

## Traditional Cost of Service

### Rate framework

**Price of power** set based on PUB judgment

Revenue requirement = Operating Expenses + (Gross value of the utility's tangible and intangible property – Accrued depreciation) \*  
**Allowed Return on Rate Base**

#### PUB considerations:

- Operating expenses
- Retained earnings reserves
- Proposed capital plans
- Smooth trajectory of rate increases

### Objective function

- Provide sufficient power for Provincial needs and engage in the activities required to provide power economically and efficiently

- Maximize return within regulatory bounds

### Investor

- Government

- Institutions and individuals

### Return on equity

- Outcome of rate setting process
- Varies with revenue increases

- Primary lever of rate setting process
- Set at level to attract private capital

### Capital Plan

PUB informed of plan but no formal approval

Regulatory approval of CapEx required before addition to rate base

### Supervisory Authority

PUB lacks supervisory authority

Regulatory supervisory authority granted

### Allowance/disallowance

No disallowance authority from PUB

Regulatory authority to disallow expenditures from rate base





# Exhibit 25: Is there further downside risk?

Outlook under current assumptions already highly sensitive to performance across 6 key factors:







- 1) **Water flows / Hydro risk: No change to existing range of uncertainty for near term-impact**
  - High variability in range of possibilities
- 2) **Capital execution costs: Both projects likely to exceed P90**
  - Bipole III expected to run over by \$0.3B with 12 month delay and Keeyask expected to run-over by \$0.7B with 21 month delay, including interest
  - For Bipole III, transmission line construction productivity in winter and tower steel availability the main drivers
- 3) **Export prices: Expected to worsen (outside of longer term carbon constrained scenario)**
  - Most recent forecasts represent a ~13-17% decrease in long-term export prices vs. IFF '15
  - Firm energy premium reducing up to 10%
- 4) **Interest rates: Favorable movement since NFAT in long term rate**
  - Assumptions of long term rates fall from 6.3% to 4.4%, reducing debt service levels and discount rate
- 5) **Domestic rates: Potentially lower than forecast initially**
  - PUB granted 3.36% vs 3.95% as requested (partially due to lower interest rate and debt servicing cost)
- 6) **Net domestic demand: No change to expected case**

**Equity ratios expected to dip to single digits, creating a potentially precarious position for the province**

- Falls to <12% in expected scenario
- Under extreme sensitivities (severe capex overrun, sustained drought), feasible for equity to go below 5%
- While single-digit equity ratios observed 1970-1995, Province with 30%+ net debt/GDP vs. ~20% before

# Exhibit 26: Project economics expected to worsen

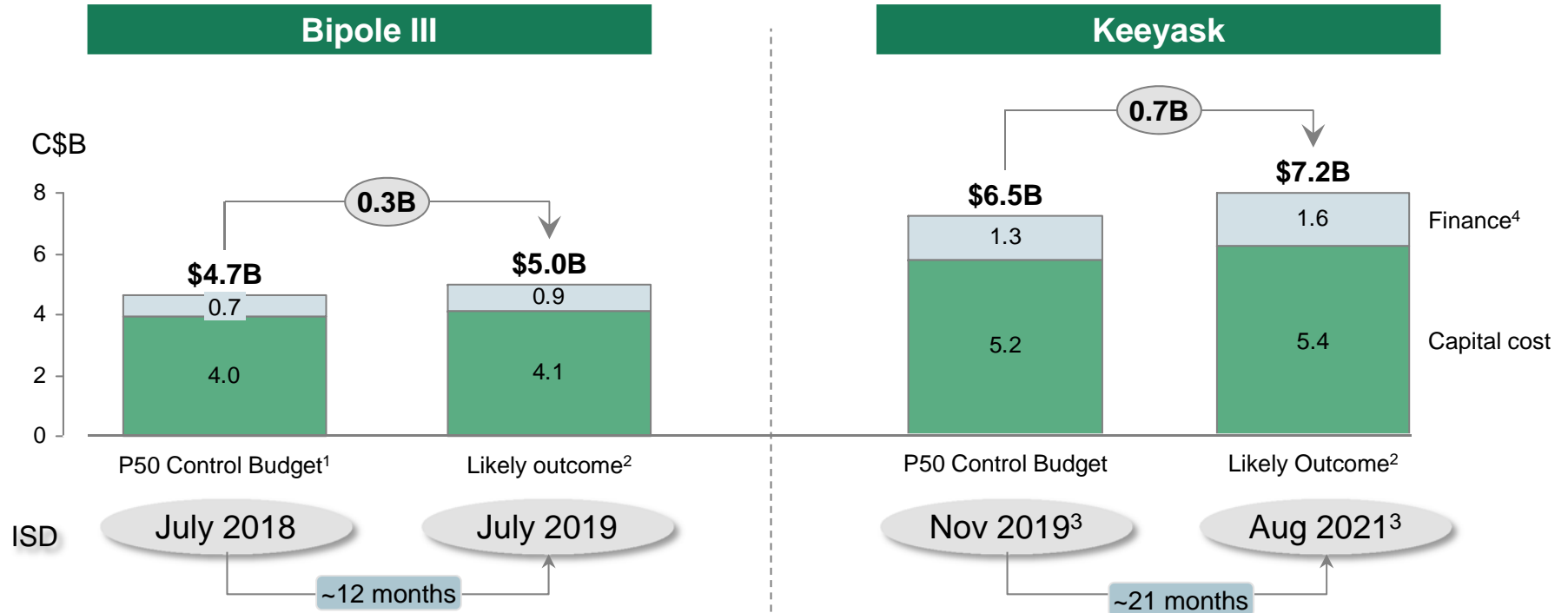
And remain sensitive to key uncertainties

		BCG view on assumptions
<b>Water flows / Hydro risk</b>	<b>Hydro risk influences total supply which drives opportunity sales</b> <ul style="list-style-type: none"> <li>102 scenarios various sequences of drought and flood time periods</li> <li>Climate change not explicitly modeled (impact unclear)</li> </ul>	 <i>Range of uncertainty unchanged</i>
<b>Export prices</b>	<b>Revenues sensitive to fluctuations in export price levels:</b> <ul style="list-style-type: none"> <li>Reference scenario below previous forecasts</li> </ul>	 <i>Adverse movement in MISO</i>
<b>Capital Execution</b>	<b>Cost and schedule overruns at one or both large projects can lead to increased borrowing and deterioration of capital profile:</b> <ul style="list-style-type: none"> <li>Scenarios modeled for cost and schedule overruns at Keeyask and Bipole</li> </ul>	 <i>Adverse movement in both projects</i>
<b>Interest rates</b>	<b>Canadian long-term interest rates influence MH borrowing costs</b> <ul style="list-style-type: none"> <li>+/- 100 bps change</li> </ul>	 <i>Favorable movement from NFAT to today</i>
<b>Domestic Rates</b>	<b>Domestic rates increases influence how quickly MH recoups its capital investments:</b> <ul style="list-style-type: none"> <li>3% vs. 4% vs. 5% annual growth rate</li> </ul>	 <i>Range of uncertainty unchanged</i>
<b>Net domestic demand</b>	<b>Revenue and export quantities sensitive to domestic demand:</b> <ul style="list-style-type: none"> <li>Three levels considered: P50 (base) vs. P90 (high gross demand) vs. P10 (lower gross demand)</li> </ul>	 <i>Range of uncertainty unchanged</i>

Note: Exchange rate sensitivity limited given the company's internal FX net position, therefore there was no specific sensitivity analysis performed  
 Source: Manitoba Hydro

# Exhibit 27: Capital cost & project schedules have deteriorated

~\$1.0B in additional capital, ~12 month delay for BPIII and ~21 month delay for Keeyask



**Transmission line construction productivity in winter main driver of schedule – 17% more than baseline must be completed in two remaining seasons**

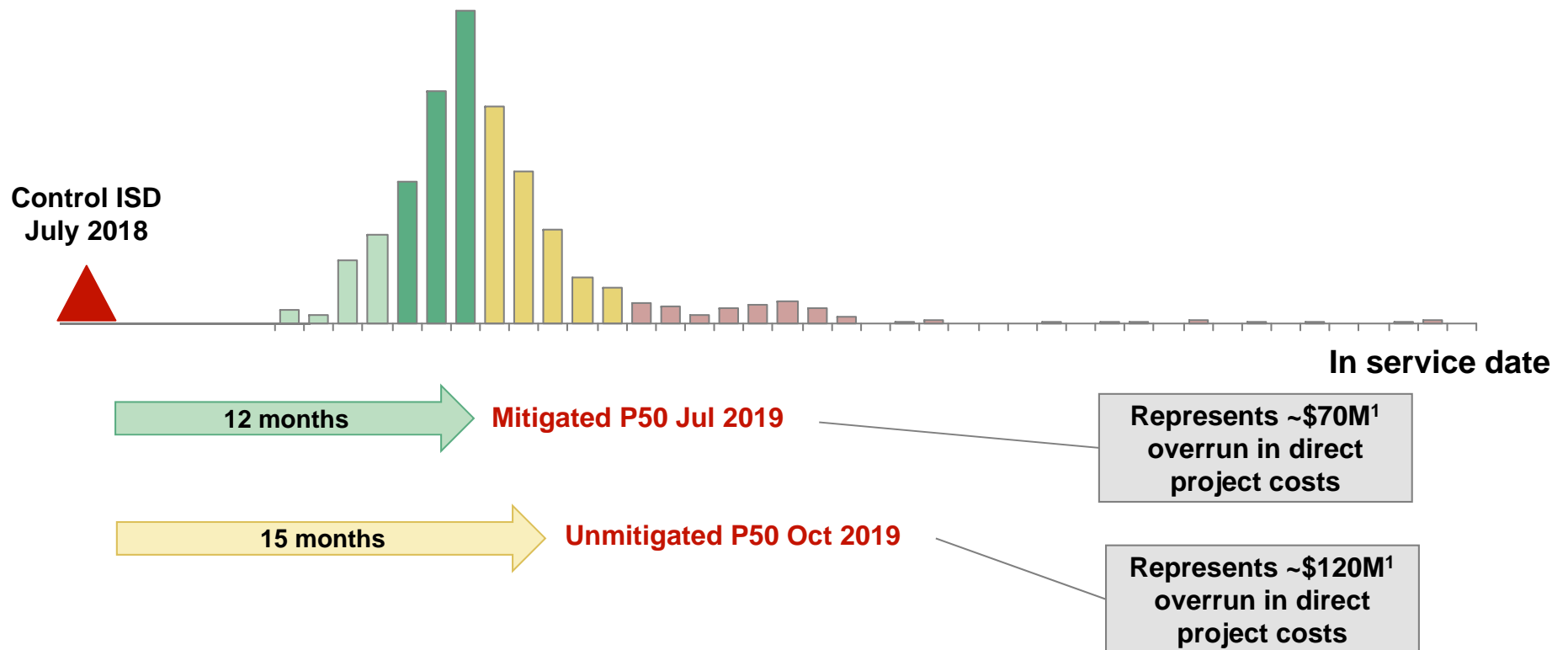
**Loss of 1 complete summer construction season likely due to GCC contract underperformance, especially related to earthworks (at ~70% vs target) and concrete productivity (at ~40% vs target)**

Sources: 1. Manitoba Hydro control budget. 2. BCG Analysis 3. First unit ISD 4. Includes interest & escalation

# Exhibit 28: Bipole III 12 month delay is the most likely outcome

## Bipole III ISD distribution

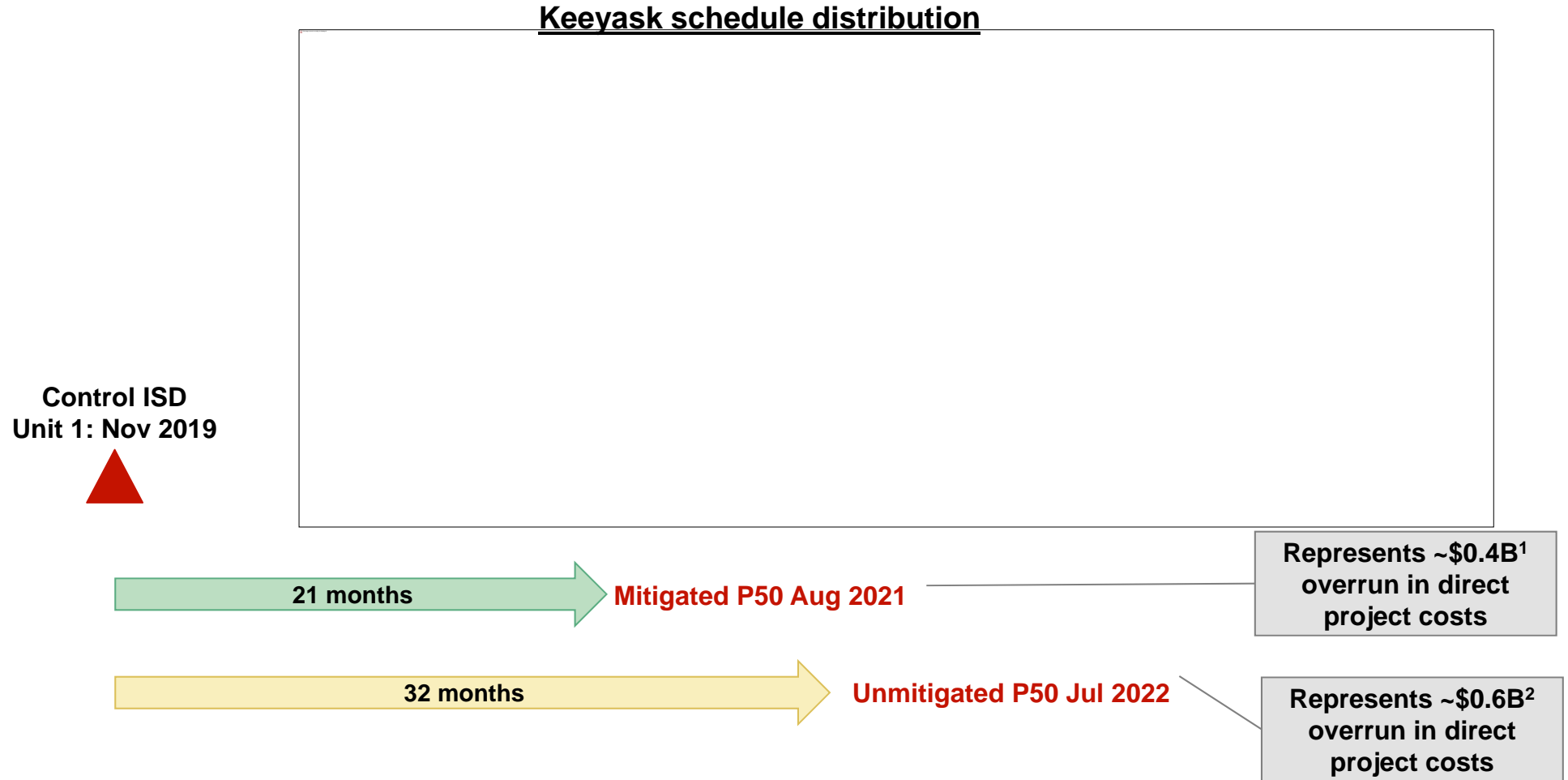
*Based on current performance to date incorporating schedule mitigation activities*



1. Excludes interest (Additional \$0.2B in finance costs)  
 Note: This is based on mitigated estimates (August 15, 2016). Based on 1000 simulation runs  
 Source: MH durations estimates

# Exhibit 29: Mitigated project delay expected to be ~21 months

Estimated in-service cost equal to ~\$7.2B



1. Excludes interest (Additional \$0.3B in finance costs) 2. Excludes interest (Additional \$0.7B in finance costs)

Note: Activity durations and mitigation plans determined in conjunction with Manitoba Hydro. Based on 10000 simulation runs on 12-Aug-2016

Source: MH durations estimates. BCG analysis

BCG Report.pptx

# Exhibit 30: Expected case \$250M over control budget (incl interest), assumes some acceleration of construction

All numbers in nominal C\$ B

	Control Budget P50	Current performance without mitigation (Downside case)	Mitigated schedule (Base case)	
<b>Spend to date</b>	<b>1.8</b>	<b>1.8</b>	<b>1.8</b>	Excludes capitalized interest
Transmission Line	0.6	1.1 <sup>2</sup>	1.0	
Converter Stations	1.1	1.2	1.2	~\$15M/mo burn rate <sup>1</sup> for delay
Collector Lines	0.1	0.1	0.1	
Community Development Initiative	0.0	0.0	0.0	
Contingency	0.35	-	-	
Escalation	0.2	0.1	0.1	Changed escalation rate reduces costs
<b>Total project capex (excl interest)</b>	<b>4.1</b>	<b>4.3</b>	<b>4.2</b>	
Interest on incremental overrun	-	0.2	0.2	
Interest on Control Budget P50 project cost	0.5	0.5	0.5	
<b>Total interest capex</b>				
<b>Total project capex (incl interest)</b>	<b>4.65</b>	<b>5.0</b>	<b>4.9</b>	Potential ~\$50-100M savings through mitigations to manage schedule overrun. Preliminary est. of mitigation cost = \$8M
<b>% of P50 control budget</b>	<b>100%</b>	<b>108%</b>	<b>105%</b>	
Schedule over run (months)	-	15 months	12 months	
<b>Project completion</b>	July 2018	October 2019	July 2019	

1. \$15M/month burn rate applied to 12 months for Downside case and 9 months for mitigated case, with the remaining overrun charges relating to internal costs of the commissioning team and scaled down T-Line and Converter Station teams as needed. Includes \$350M contingency allocation in addition to burn rate 2. Number rounded up to nearest billion  
 Source: MH control budget, CEF 2015, BCG analysis

# Exhibit 31: Fully loaded project cost overrun forecast ~\$700M

~\$250M project capex benefit from schedule mitigation activities

(All numbers in nominal C\$ B)

	Control Budget P50	Current trajectory without mitigation	Mitigated schedule
<b>Spend to date excl interest<sup>1</sup></b>	<b>2.1</b>	<b>2.1</b>	<b>2.1</b>
Generating Station (to-go)	2.4	3.3	3.1
Generating Outlet Transmission (to-go)	0.2	0.2	0.2
Contingency & Reserves (remaining)	0.3 <sup>2</sup>	-	-
Escalation (total)	0.2	0.2	0.2
<b>Total project capex (excl. interest)</b>	<b>5.2</b>	<b>5.8</b>	<b>5.6</b>
Interest on incremental overrun <sup>3</sup>	-	0.7	0.3
Interest on Control Budget P50 project cost	1.3	1.3	1.3
<b>Total capitalized interest</b>	<b>1.3</b>	<b>2.0</b>	<b>1.6</b>
<b>Total project capex (incl interest)</b>	<b>6.5</b>	<b>7.8</b>	<b>7.2</b>
<b>% of P50 control budget</b>	<b>100%</b>	<b>120%</b>	<b>111%</b>
Schedule over run (months)	-	32	21
Unit 1 ISD date	November 2019	July 2022	August 2021

Potential ~\$250M benefit from mitigations and avoided interest

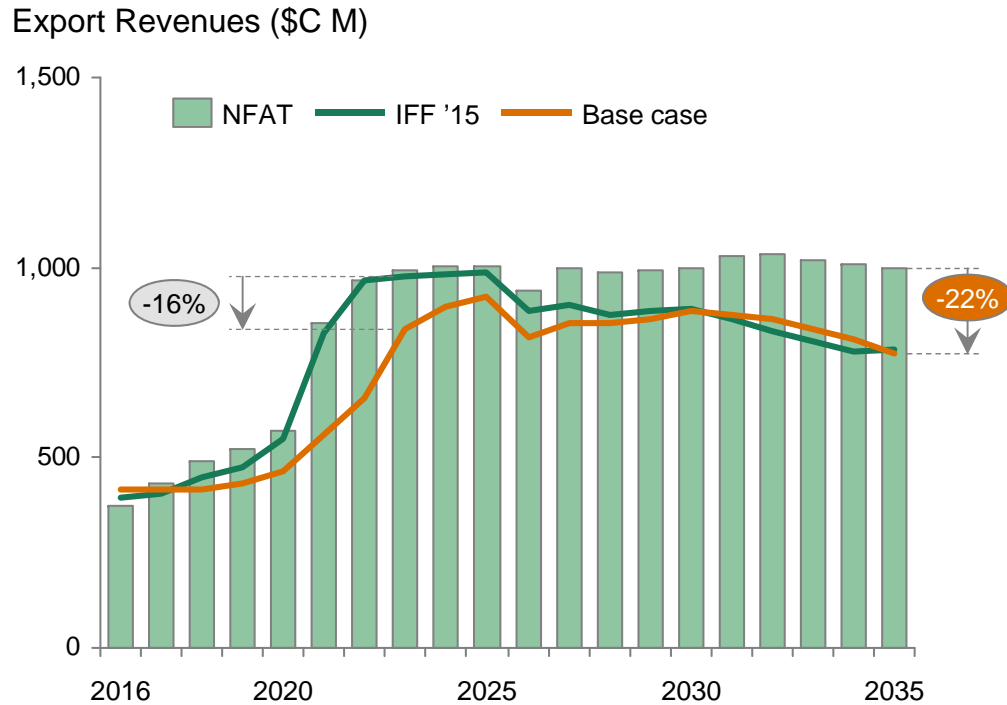
1. As at March 2016. 2. Original cont./reserves of \$0.7B for project costs already partially allocated to contracts – \$0.3B remaining. Assumed will be used up completely for overruns 3. Includes compounding effect due to schedule delay + additional interest on incremental project spend.  
 Note: Cost over run in fixed price, milestone based contracts (mainly equipment supply & install) reduced from previous phase due to greater certainty on risks (e.g. GGH contracts >50% complete, better SPI=0.94 vs 0.7 from previous phase on T&G, etc)  
 Source: MH control budget, CEF 2015, BCG analysis



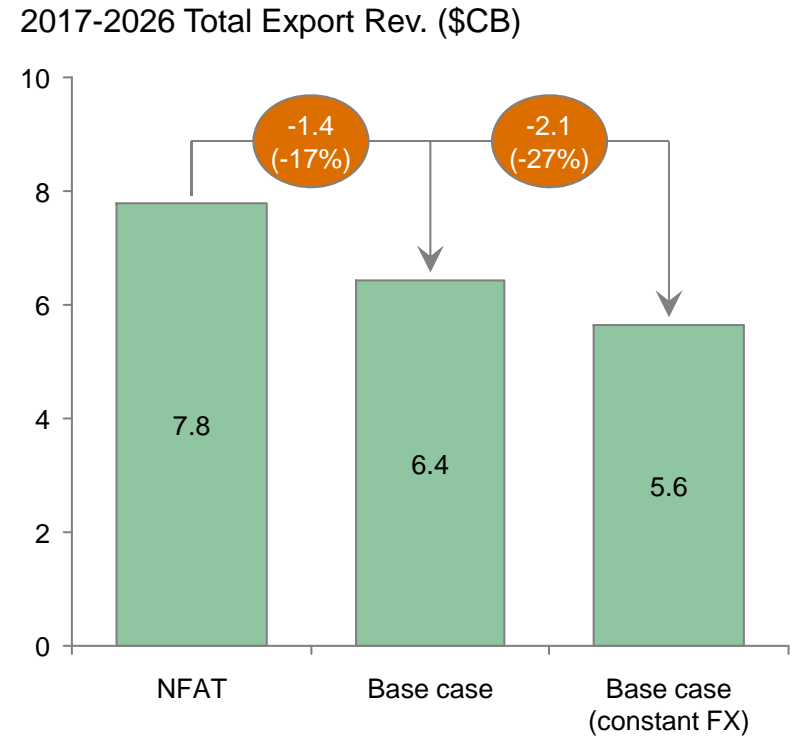
# Exhibit 32: Keeyask delay and low export prices impact revenue

Reducing latest forecast of export revenues by 19-28%

## Export revenue forecasts have been revised downward since NFAT



## Expected export revenues reduced by 19% to 28%



**Secured firm contracts (30% of revenue<sup>1</sup>) reduce further downside; upside expected in case of Clean Power Plan approval**

1. Including current contracts and term sheets, but not available uncommitted firm energy which could be contracted (17% of revenue).

Source: Manitoba Hydro, BCG analysis

# Exhibit 33: Expected case equity ratios sustained at <15% through 2030

## Key assumptions

### NFAT

- Bipole in '19, Keeyask in '21, Tie-line in '20
- Level 2 DSM
- 2013 Interest rates

### IFF '15

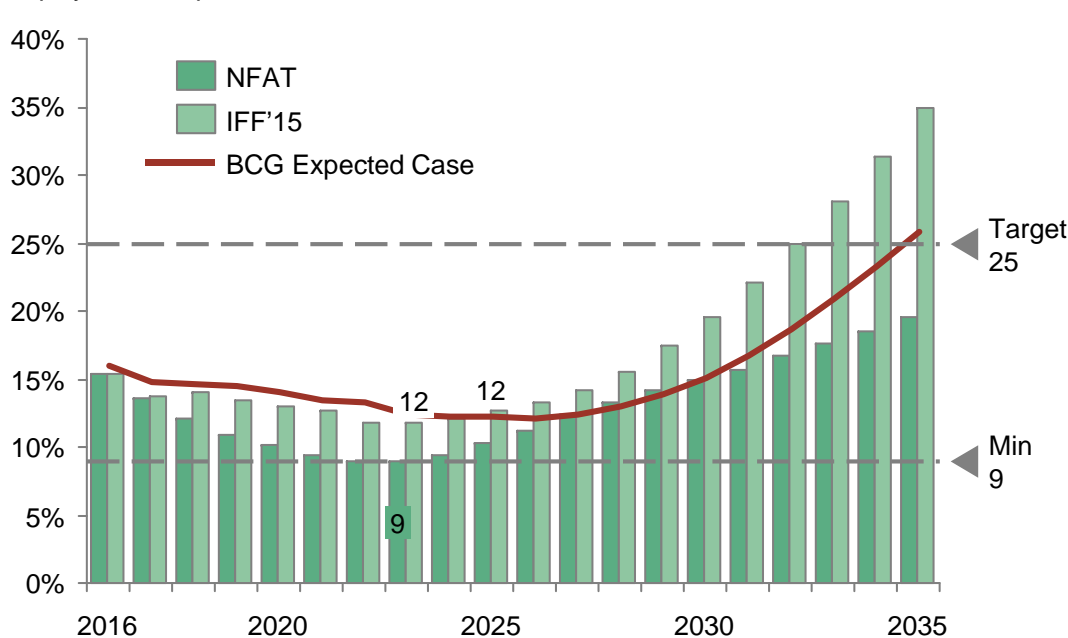
- Unchanged ISDs
- Reduced export price and slightly reduced demand
- Lower, 2015 interest rates

### BCG Expected Case

- 12 mos. Bipole III delay
- 21 mos. Keeyask delay
- \$1B total cost overrun
- Lower, 2016 reference export prices
- Lower, 2016 interest rate forecasts

## Projected ratios have decreased materially under revised capital and price assumptions

Equity/Total Capitalization



## Additional risks

Additional project CapEx overrun

Further export price deterioration

Hydro risk

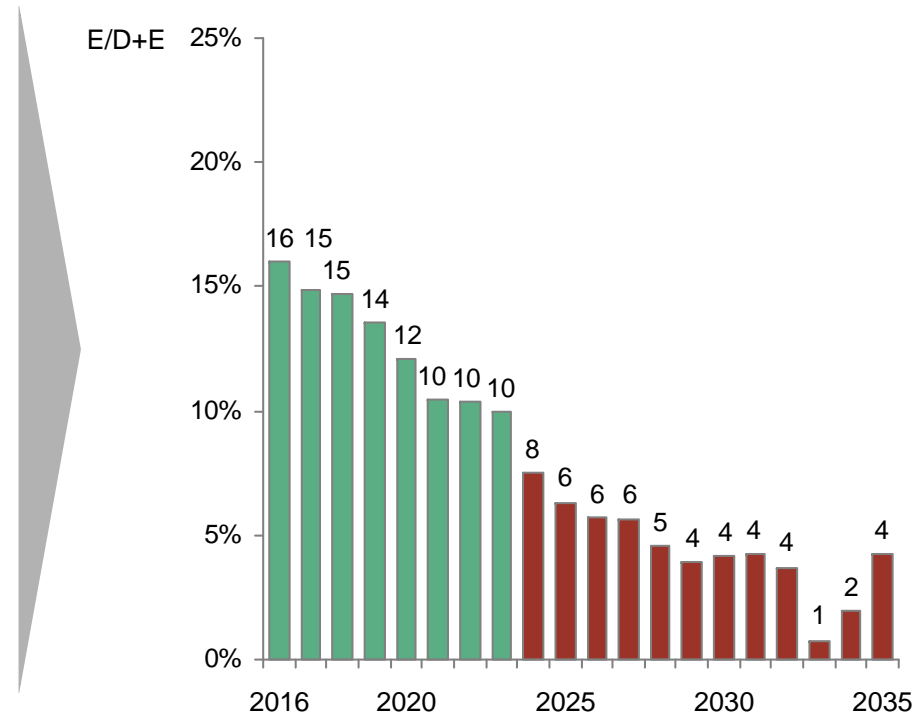
Increasing interest rates

Lower domestic rate increases

# Exhibit 34: Stress test shows significant impact if further downside risk experienced – equity % dips to low single digits

Downside scenario modelled

Water flow	Low flow scenario
Capital project overruns <i>Schedule (months)</i>	Keeyask: 32mth delay BPIII: 15mth delay
Interest rates <i>Long range forecasts</i>	ST~3.85% LT ~5.4%
Export prices	Peak and off peak spot curve as per IFF'16 (no premium and reduced base)
Cost inflation <i>Overall OM&amp;A cost increase</i>	2% in 2016-17 3.5% pa 2018 - 2021



# Exhibit 35: Can the projects be stopped / paused?

## **Bipole III and Keeyask are already well advanced in their construction with \$5B already sunk**

- Bipole III \$2.5B (53%) spent of \$4.7B control budget
- Keeyask with \$2.5B (39%) of \$6.5B control budget spent, including completion of milestones that prevent contractual cancellation

## **Cancelling Bipole III and Keeyask would bring total spend up to ~\$7B**

- In addition to sunk costs, Bipole III and Keeyask would both incur cancellation costs (e.g., breakage, remediation) of ~\$1B each
- Decision to just cancel (or reroute) Bipole III would strand Keeyask, making it uneconomic and likely trigger cancellation
- Implication of cancelling both projects is ~\$7B capital spent without completion of any functioning assets

## **Economics remain in favour of continuing both projects when compared to alternatives**

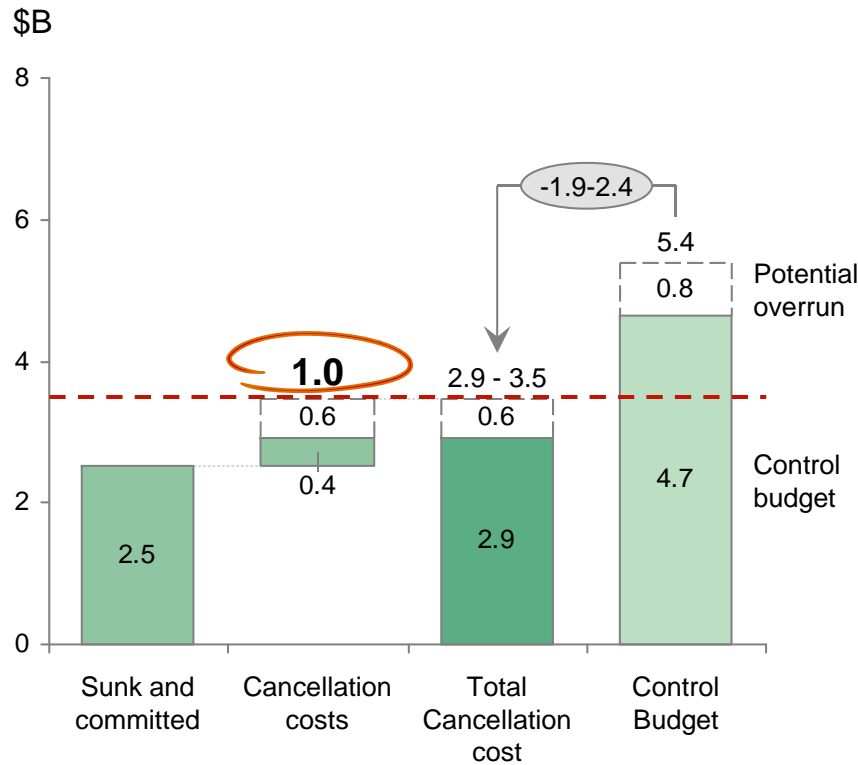
- ~\$3.2B cost to complete Bipole III West clearly more favourable vs. ~\$4.5B rerouting costs of Bipole III East
  - Construction cost of Bipole III East ~\$3.0-3.5B on top of ~\$1B Bipole III West cancellation costs
- \$4.7B cost to complete Keeyask yields an NPV \$3-5B more favourable vs. switching to gas option
  - Gas option with incremental \$11.9B spend (including cancellation and capitalized cost of gas supply)

## **Further, several strategic risks to consider for stopping or pausing Keeyask**

- Considerable trust and relationship damage with four First Nations partners likely to impede any future Hydro project
- Market risk of inability to supply MISO plus requirement to add domestic reserve
- Direct GDP impact of ~0.5%, particularly impacting First Nations communities

# Exhibit 36: Cancellation of either project brings to bear significant further cost

## Bipole III

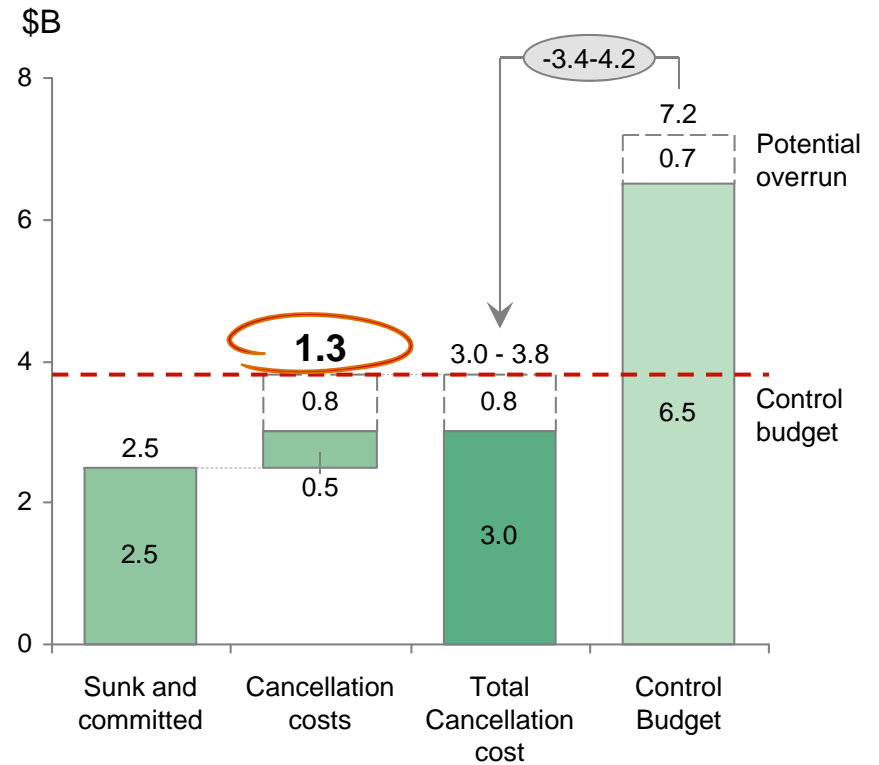


% of control budget

53%

74%

## Keeyask



39%




58%

Source: Manitoba Hydro estimate of cancelation; BCG analysis  
BCG Report.pptx

# Exhibit 37: Strategic impacts of cancellation potentially severe




## Bipole III: Major risks relate to future reliability

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-  Continued system reliability risk: failure at Dorsey C.S. or on Bipole I or II will jeopardize the Province's energy supply
-  Limited capacity and decreasing operational reliability on BP I & II
-  Cancellation or rerouting of Bipole III strands Keeyask and likely implies cancellation due to deterioration of economics

## Keeyask: Significant stakeholder impacts

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-  Considerable trust and relationship damage with four First Nation partners likely to impede any future Hydro project – social license to operate many years in the making
-  Market risk of inability to supply MISO plus requirement to add domestic reserve
-  Direct GDP impact of ~0.5%, particularly impacting First Nations communities

# Exhibit 38: Completing Bipole III is the best go-forward option

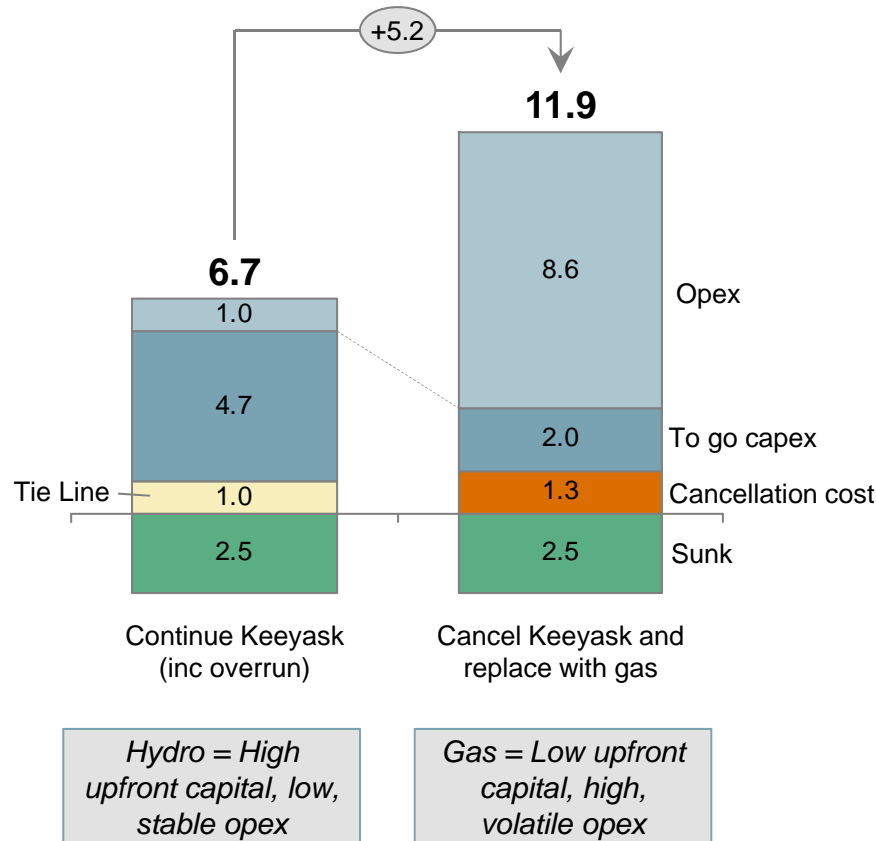
Shifting to the east route would be more costly and require at least 5 years for approvals

Go Forward Option	Verdict	Rationale	Incremental Cost	Likely ISD
Cancel Bipole III West	X	<ul style="list-style-type: none"> <li>System still lacks redundancy and exposed to major outage risk</li> <li>Strains relationship within MISO and risks exports</li> </ul>	<ul style="list-style-type: none"> <li><b>\$400M to \$1B</b> to cancel, wind-down and remediate</li> </ul>	<ul style="list-style-type: none"> <li>N/A – no solution implemented</li> </ul>
<i>Selected option</i> Continue Bipole III West	✓	<ul style="list-style-type: none"> <li>Fastest way to improve reliability</li> <li>Supports Keeyask and future hydro generation</li> </ul>	<ul style="list-style-type: none"> <li><b>\$2.2 – 3.2B</b> to complete</li> </ul>	<ul style="list-style-type: none"> <li>2018 – 2019</li> </ul>
Shift to East Route	X	<ul style="list-style-type: none"> <li>More costly with later in-service date</li> <li>Negative environmental and First Nations impacts along east route</li> </ul>	<ul style="list-style-type: none"> <li><b>~\$3.4 -4.5B+</b>, (~\$2.3 – 3.4B for new East route work)<sup>1</sup></li> </ul>	<ul style="list-style-type: none"> <li>2025 – 2026</li> </ul>
All-Gas	X	<ul style="list-style-type: none"> <li>Future input price volatility (gas, imports)</li> <li>Loss of export revenue through lack of capacity for new Keeyask power</li> </ul>	<ul style="list-style-type: none"> <li><b>\$3.4-4.1B<sup>2</sup></b> (NPC<sup>3</sup> of gas + Bipole III cancellation + add'l O&amp;M)</li> </ul>	<ul style="list-style-type: none"> <li>2021 – 2022</li> </ul>
Import + Gas	X	<ul style="list-style-type: none"> <li>Damage to relationships with US partners and First Nations groups</li> </ul>	<ul style="list-style-type: none"> <li><b>\$4.9-5.5B<sup>4</sup></b> (capital cost + Bipole III cancellation)</li> </ul>	<ul style="list-style-type: none"> <li>2021 – 2022</li> </ul>

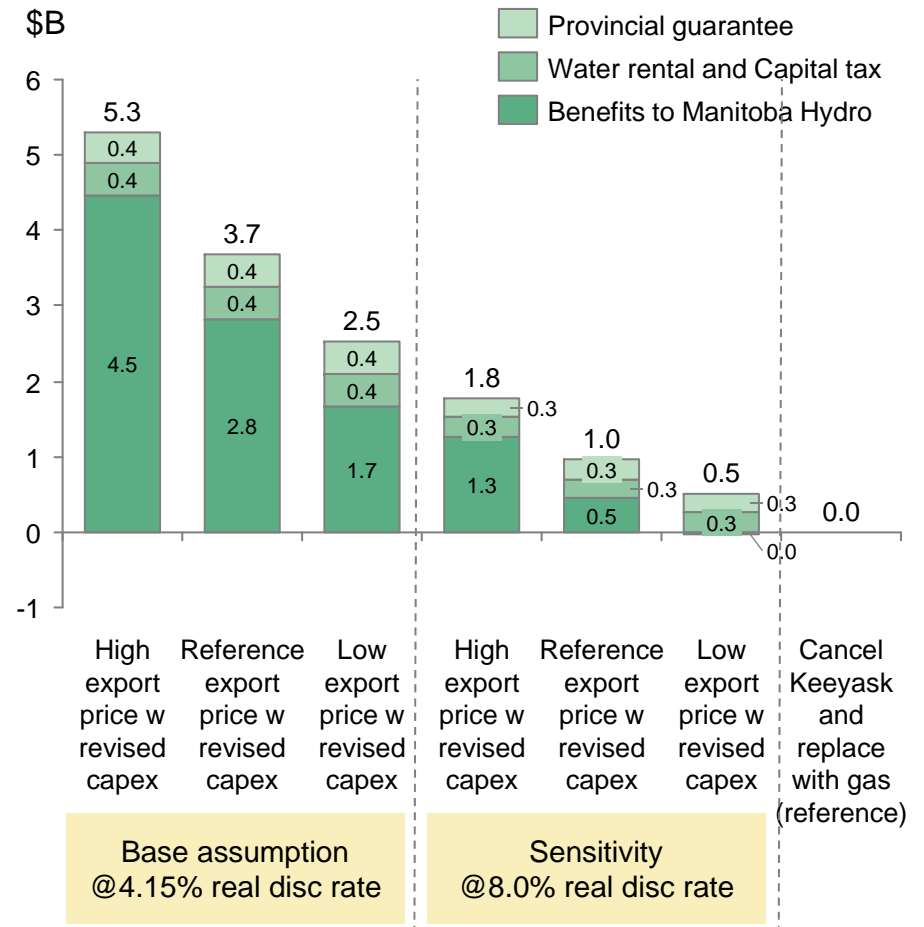
1. Assumes some work on collector lines and convertor stations continues. Estimate is purely factored at low levels of maturity 2. Based on MH and BCG scenario analysis, with contingency and over-run factors applied 3. NPC = net present cost 4. Capital cost from Manitoba Hydro Bipole III EIS + BCG analysis of Bipole III cancellation cost

# Exhibit 39: Economically, continuing Keeyask is most attractive option

**Forward capital and operating cost of gas vs Keeyask is ~\$5B higher**



**Relative NPV of continuing is \$3-5B greater than replacing with gas**



Source: Economic Bar Charts, Manitoba Hydro, BCG analysis  
BCG Report.pptx