

# THE ROLE AND VALUE OF DEMAND-SIDE MANAGEMENT IN MANITOBA HYDRO'S RESOURCE PLANNING PROCESS

## **TESTIMONY OF PHILIPPE DUNSKY**

assisted by Martin Poirier, Brent Langille, Marina Malkova, and Bruno Gobeil

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## INTRODUCTION AND QUALIFICATIONS

### RELEVANT QUALIFICATIONS

Philippe Dunsky is President of Dunsky Energy Consulting, a Canadian firm comprised of 10 full-time specialists in demand-side energy management, including energy efficiency, demand response, customer-sited renewable energy and related areas.

Philippe has been involved in the design and evaluation of energy efficiency and related programs, policies and strategies for over two decades. In his current consulting practice, he advises a wide range of clients – primarily utilities, government agencies and others responsible for setting and achieving DSM goals – on strategic and resource planning, program design, technical support, potential studies, and performance evaluation. In Canada, his *government* clients have included the relevant agencies and departments in B.C., Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, as well as the federal government; his *utility* clients in Canada have included the likes of BC Hydro, Fortis BC (gas and electric), Manitoba Hydro, Enbridge Gas, Hydro-Quebec, Gaz Metropolitain, Nova Scotia Power, NB Power, Newfoundland Power, and Newfoundland and Labrador Hydro. His clientele in the U.S. is comprised of similar organizations, including the California Public Utilities Commission, the New York State Energy and Research Development Agency (NYSERDA), Efficiency Maine Trust, Efficiency Vermont, the New Jersey Board of Public Utilities, Northeast Utilities, National Grid, and Northeast Energy Efficiency Partnerships.

Philippe has been an expert witness in utility proceedings on over a dozen occasions. He is also the author of numerous published papers on the topic of DSM, including peer-reviewed papers, and is a frequent speaker at leading industry conferences.

Prior to founding his firm in 2004, Philippe was Executive Director of the Helios Centre for Sustainable Energy Strategies, an energy think-tank, from 1996 to 2004. Prior to that, he worked for five years in a variety of consulting and analytical capacities related to energy policy, including as a member of the Quebec government commission tasked with developing the province's energy policy.

In addition to his consulting practice, Philippe served for 10 years as a governor of the Canadian Green Municipal Fund (approx. \$700M in loans and other instruments for municipally-led projects). He has also served on a large variety of boards and committees, including in the for-profit, not-for-profit, and government sectors (including the Quebec Energy Efficiency Agency, the Ontario Power Authority, and Enbridge Gas Distribution, among others).

His most recent projects include several that are specifically relevant to this project, including: DSM potential studies (both energy and capacity); development of long-range DSM plans; design of a broad range of programs (including efficiency, fuel switching, and solar PV) across all market sectors; providing technical support to leading DSM program administrators; advising on

proper treatment of DSM in broader resource planning; and conducting large-scale program evaluation projects.

Mr. Dunsky's experience in Manitoba includes four prior engagements: expert testimony in two hearings, at the request of stakeholder groups; a strategic evaluation of Manitoba Hydro's Power Smart plans, programs and activities, on behalf of the Crown corporation; and assistance to the government of Manitoba on energy policy related issues.

## **PURPOSE OF EVIDENCE**

I was retained to examine the role that DSM could play in Manitoba Hydro's resource planning process. To this end, I was tasked with reviewing the evidence – including Manitoba Hydro's recent potential study and its planned DSM savings – in order to determine whether the utility's characterization of the DSM resource is adequate for purposes of long-run resource planning. I was also asked to recommend a level of savings – both energy and capacity – that would be appropriate for this purpose.

# THE ROLE OF DSM IN OPTIMIZED ENERGY PLANNING

## INTRODUCTION

In the 1960s and 1970s, utility planning focused primarily on assessing supply options to meet demand forecasts. Over time, this approach was discredited because it took demand as a given. To the contrary, utilities and regulators realized that demand could be “shaped”, through DSM efforts, in much the same way that supply could be built.

As a result, planning evolved away from “which combination of supply resources is the cheapest way to meet forecast demand?”, and toward “which combination of supply or demand resources is the least costly and least risky way to achieve equilibrium?”, i.e. to keep the lights on. This came to be known as Least-Cost Integrated Resource Planning, or IRP for short.

Unfortunately, the planning framework Manitoba Hydro has used for this hearing harkens to a pre-IRP era and, in that respect, is not conducive to solving for the least-cost strategy. Instead, the utility seems to take demand forecasts as given – an exogenous event that cannot be modified beyond the current DSM plan –, and then proceeds, on that basis, to assess supply options to meet that given demand. Risk is addressed by sensitivity analyses around demand forecasts, as well as by a very similar DSM stress test.

Below I present a brief history of Integrated Resource Planning, its current practice, as well as its implications for the case at hand. I will point to the fact that as a result of the current planning framework, Manitoba Hydro’s approach can lead to sub-optimal investments in Demand Side Management and, inversely, to over-investment in new supply.

## INTEGRATED RESOURCE PLANNING (IRP): HISTORY AND CURRENT PRACTICE

Least-Cost Integrated Resource Planning stems from as far back as the 1960s, when arguments were brought up in favor of competitive provision of power generation. The first energy crisis of the 1970s accelerated thinking about resource planning and risk, as utilities faced massive cost overruns and, just as critically, lower-than-projected demand, costing billions of dollars of ratepayers’ money.

The next decades saw the development of new supply-side technologies and options, as well as increasing efforts (and associated budgets) directed at demand-side management (DSM), adding further complexity to both the planning and energy procurement processes.

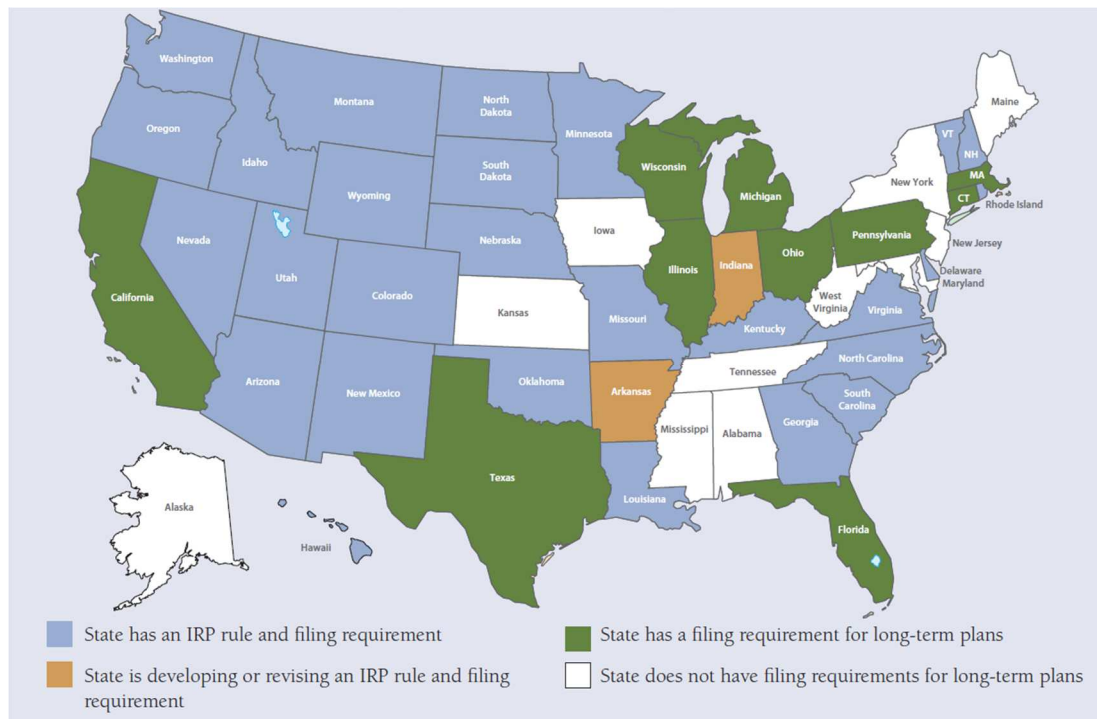
IRP is a response to these multiple challenges. Its goal is to minimise the total societal cost of energy generation – and use – over the long term. It does so by seeking to evaluate *all* potential resources – both supply- and demand-side –, on an equal footing and in a timely manner. Resources can include:

- **On the demand side:** Energy efficiency programs, demand response initiatives, direct load control, interruptible power, rate structure changes, demand-side renewables (e.g. solar PV), industrial cogeneration, behavioural encouragement programs, fuel switching and fuel retention programs, conservation voltage regulation, T&D efficiency improvements, and others as well; and
- **On the supply side:** A variety of technologies (intermittent renewables; baseload renewables, nuclear, or fossil-fired plants; and “peaker” plants), and strategies (e.g. utility-owned, PPAs with independent power producers, PPAs with other utilities, purchases from short-term energy and capacity markets, and increased transmission capacity (to increase imports and load balancing)).

Proper IRP planning is the process of fairly accounting for all of these options, rather than only the group of generation options. Among other things, it means viewing demand not as an exogenous event that can only be *forecasted*, but as a partially-controllable factor that can be shaped. Recognizing the ability to shape demand opens utilities (and their regulators and ratepayers) to a vast array of opportunities that, in many instances, are far less expensive than their supply alternatives.

Today, the vast majority of states in the U.S. that do long-term resource planning, use IRP to plan for resource needs (figure 1). And while the map unfortunately is limited to our neighbours to the south, IRP is increasingly the planning tool of choice in Canada: for example, both B.C. and Nova Scotia are currently in the throes of their own IRP processes.

**FIGURE 1 – U.S. States with Integrated Resource Planning or Similar Processes<sup>1</sup>**



## WHY IS IRP SO IMPORTANT FOR ENERGY EFFICIENCY?

To be able to minimize costs, energy efficiency and other DSM options must be assessed essentially at the same time, and in the same manner, as investments in new supply or T&D. For this to happen, the DSM resource must be characterized at a relatively high level, much the same way generation options are characterized. For example, a “potential study” may define different DSM scenarios based on cost-effectiveness or other criteria; those scenarios can then be fed into the IRP mix, the same way different supply options are included in the analysis (figure 2).

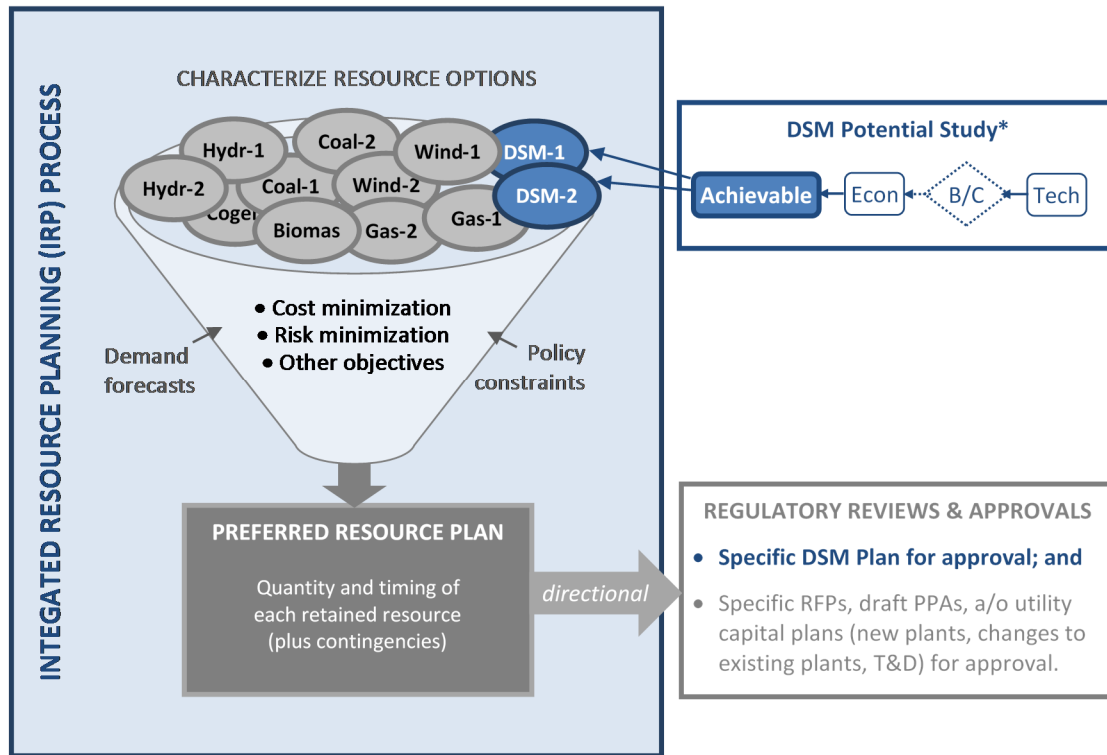
This integrated process helps to ensure that least cost options are fully considered, bringing economic and environmental benefits to the planning process. **DSM cannot be addressed only with uncertainty analysis, once the die is cast and supply options have been chosen;** rather, they must be an integral part of the options considered at the outset. Failure to do so will result in an exaggerated focus on supply solutions. And while sensitivity analyses might help choose

<sup>1</sup> Wilson, Rachel and Bruce Biewald. 2013. "Best Practices in Electric Utility Integrated Resource Planning – Example of State Regulations and Recent Utility Plans", Synapse Energy Economics Inc.



the “least bad” option – or the least cost among a limited pool of options – the optimal solution will remain elusive, likely resulting in higher costs and risks for consumers.

**FIGURE 2 – Illustration of the Resource Planning Process and Related DSM Steps<sup>2</sup>**



## THE ROLE OF DSM IN MEETING FUTURE NEEDS

As noted previously, DSM can help to meet energy as well as capacity needs (figure 3). Depending on the targeted end-uses and technologies, DSM and its various components can meet baseload, peak or “needle peak” needs, much the same way traditional supply does. For example, a broad range of measures targeting electric heating (e.g. improving building thermal envelope, advanced thermostats, geothermal heating, fuel switching to natural gas, etc.) will generate most energy savings during winter’s peak consumption periods, thereby contributing to both energy *and peak capacity* needs. Demand response, interruptible rates, and direct load control initiatives can be even more focused on peak savings, and akin to dispatchable “peaker” plants, designed to operate only a few hours or a few days a year. Other DSM resources, for

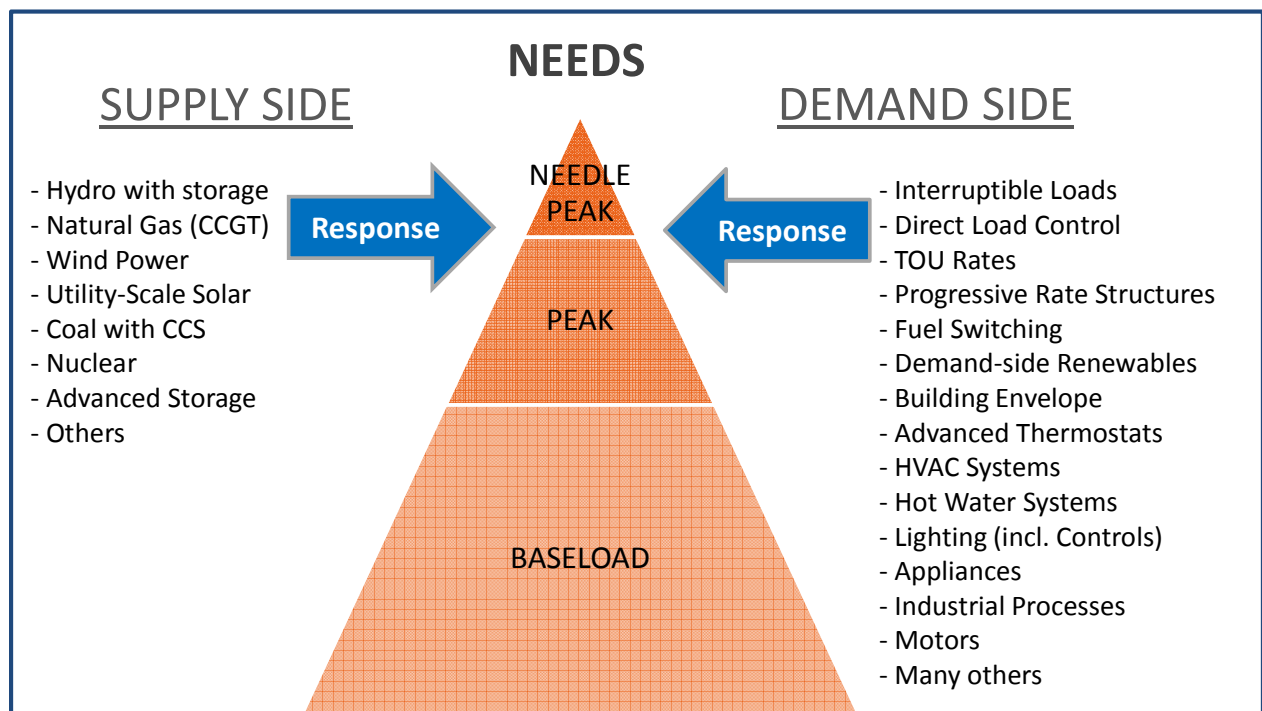
<sup>2</sup> Dunskey, Philippe and François Boulanger, *Appropriate Treatment of DSM in Integrated Resource Planning (IRP)*, for Efficiency Nova Scotia Corporation, January 17, 2014.

example programs aimed at improved lighting efficiency, will produce savings year-round, meeting baseload energy requirements much like a baseload plant would.

In other words, DSM is a very versatile resource. An appropriately designed DSM portfolio can include any mix of baseload, peak, or needle peak resources, providing the very same operational flexibility that a large storage hydro plant can offer. Moreover, by bringing changes to the portfolio's deployment (putting more money into one stream, less into another), the load shape of the DSM Power Plant can evolve over time to meet evolving needs, a function that supply resources are not as able to accommodate.

Figure 3 below illustrates the different options to meet different components of demand.

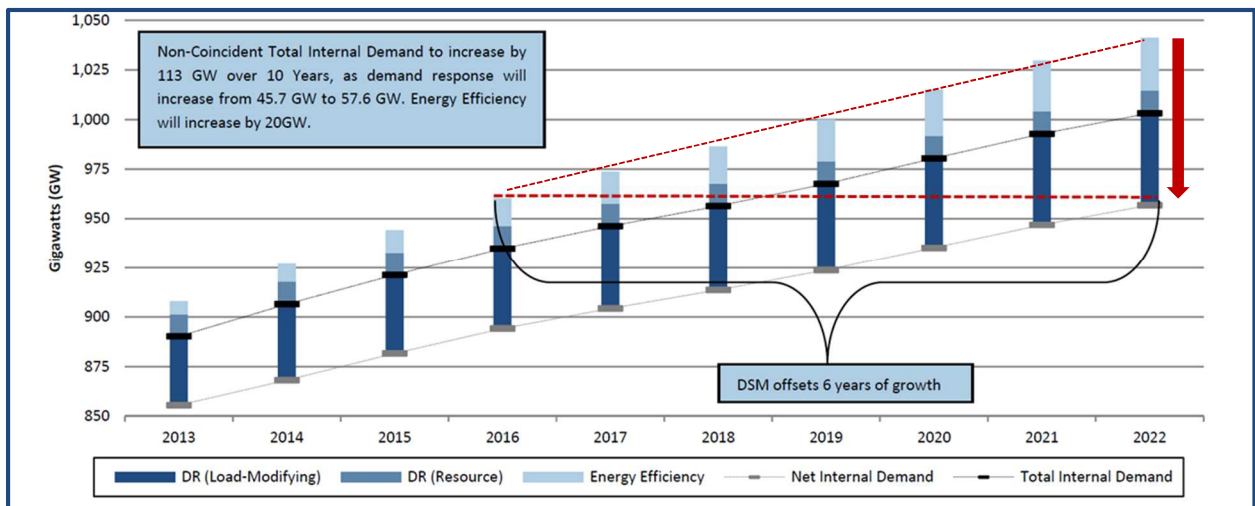
**FIGURE 3 – Energy and Capacity Needs Met with DSM**



From a planning perspective, the DSM resource can therefore be used to either offset or delay the need for supply-side investments. This is not merely a theoretical argument: indeed, as experience with DSM performance has improved, organizations focused on “keeping the lights on” are increasingly *relying* on DSM to meet future needs.

One example is the North American Electric Reliability Corporation. NERC recently determined that DSM will eliminate 6 years of growth in the need for peak capacity across the U.S. (despite uneven DSM efforts nationwide). This is illustrated in the chart below.

**FIGURE 4 - NERC DSM Peak Demand Offset Forecast<sup>3</sup>**



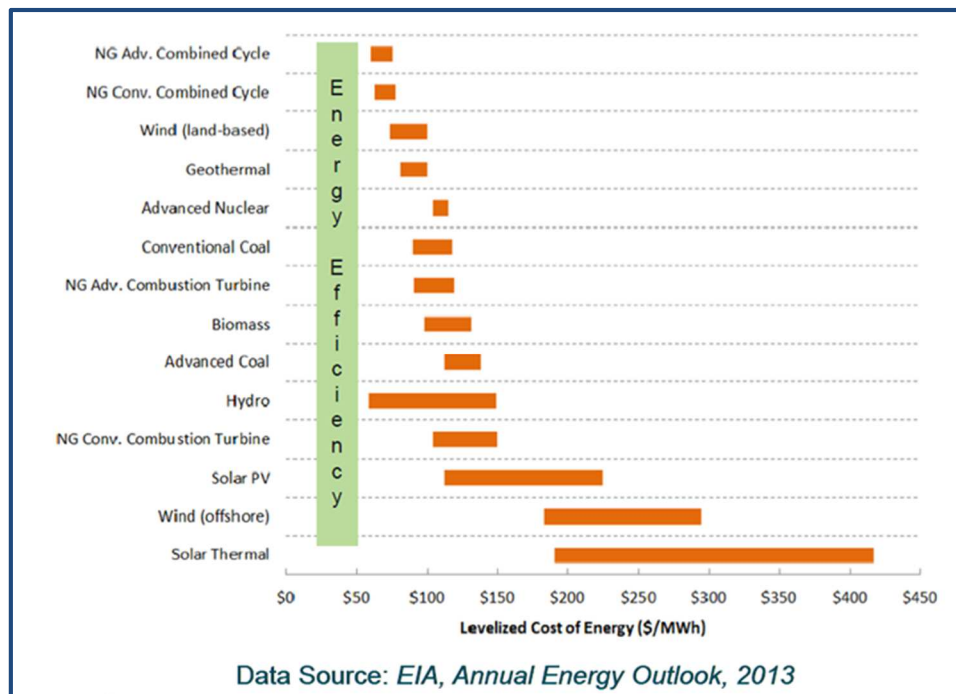
Similarly, the ISO-NE – the independent system operator of the New England forward capacity market – now accepts DSM programs as a “biddable” resource that planners account for and rely upon. And in California, still traumatized by the blackouts and brownouts that hit the state’s economy at the beginning of the millennium (as a result of a botched effort at market deregulation at the time), the state’s system planners – including the utilities regulator (CPUC), the policy and planning agency (CEC) and the Independent System Operator (ISO) – this year announced that DSM will henceforth be relied upon to offset essentially *all* load growth in that state.

## DSM’S RISK PROFILE

In addition to its flexibility to match load profile needs, DSM is broadly recognized as a low cost / low risk resource. Indeed, DSM is very cheap, generally costing between 2 and 4 cents/kWh on average, which is significantly less expensive than any supply side option (including hydro). Figure 5 overlays the typical cost of EE against the range of supply option costs according to the U.S. Energy Information Administration. As can be seen, DSM is far less expensive than even the least expensive hydroelectric option.

<sup>3</sup> North American Energy Reliability Corporation (NERC). *2012 Long-Term Reliability Assessment*, November 2012.

**FIGURE 5 - Compared Levelized Costs of DSM and Supply Side Options<sup>4</sup>**



Just as importantly, DSM is also generally viewed as a lower risk option. As we have mentioned before, DSM's lower risk profile is a function of key advantages that apply across the four pillars of resource planning risk:

- Performance Risk:** If it were treated as a static resource, DSM performance might be considered less certain than many supply options, since a given program may attract fewer (or more) participants than anticipated. However, that performance risk is diluted over hundreds of measures, dozens of market segments, dozens of end-uses, and a multiplicity of programs and program tools (incentives, financing, education, etc.). **These multiple "levers" allow DSM program managers to actively manage performance by shifting resources across the portfolio and across tools, in turn ramping up or ramping down "production" to meet goals.** Supply resources, meanwhile, may be subject to occasional "all-or-nothing" emergency repairs and supply disruptions (in the case of fossil plants), in-service-date delays, or to the vagaries of Mother Nature (in the case of renewables that rely on rainfall and wind).<sup>5</sup>
- Cost Risk:** DSM cost risk is similarly diluted, as program managers can adjust incentives as needed and/or shift resources across the portfolio. On the supply side, fossil plants

<sup>4</sup> SEE Action – State & Local Energy Efficiency Action Network. "SEE Action Webinar: Using Integrated Resource Planning (IRP) to Encourage Investment in Cost-Effective Energy Efficiency Measures", September 26<sup>th</sup>, 2013.

<sup>5</sup> Unfortunately, the advent of climate change has increased the risk associated with renewables, as rainfall patterns deviate from historic averages (and risks of prolonged droughts increase), and wind gusts and storms increase in frequency and intensity.

are uniquely susceptible to wild fuel price swings in the short term, and to large deviations from initial price forecasts over the long-term. Meanwhile, both fossil plants and, to a larger extent, utility-built large-scale hydro, are susceptible to construction cost overruns.<sup>6</sup>

- **Demand Forecast Risk:** A critical but oft-neglected resource planning risk is the risk inherent in demand forecasting, i.e. the risk that we invest to meet a need that fails to materialize (or inversely, that we fail to invest on time to meet a real need). DSM addresses this risk in two important ways: first, investment in DSM can be ramped up or down as needed to match needs as they evolve<sup>7</sup>, and second, DSM potential itself is strongly correlated with demand, such that as demand grows, DSM “auto-adjusts” by increasing production (and inversely, as demand shrinks or grows more slowly, so too do DSM savings).<sup>8</sup> On the opposite side of the scale, the capital sunk into large hydro plants provides no opportunity to adjust to slower demand<sup>9</sup>, while gas plants, with a mix of initial capital and variable fuel costs, fall somewhere in between.
- **Regulatory risk:** Finally, every generation resource faces the longer-term risk of changes to the regulatory regime. This is especially the case for fossil plants, which face the strong probability of future carbon-related regulations and associated costs. Hydro plants may face future operating restrictions aimed at addressing environmental concerns or water usage rights. In the case of DSM, the only real regulatory “risk” is in fact a benefit: the risk that new codes and standards are adopted, thus replacing program savings with larger regulatory-driven savings. In this case, the risk is a benefit, as savings would be strengthened while utility program costs are reduced.

One recent report – authored by the former chairman of the Colorado Public Utilities Commission (and recent nominee to preside over the Federal Energy Regulatory Commission) – sought to assess the relative risk (and cost) of a variety of resources, including DSM.

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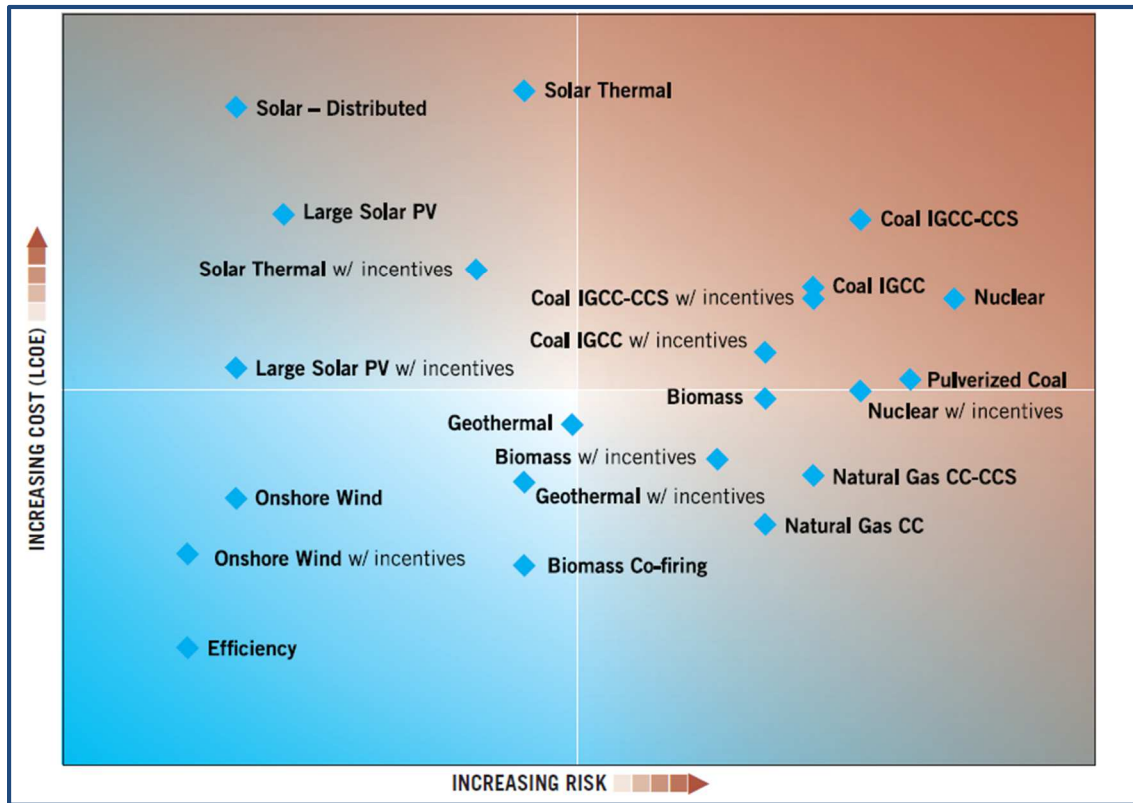
<sup>6</sup> Power purchase agreements from IPPs commonly shield utilities from such construction cost overruns.

<sup>7</sup> While DSM *can* be adjusted when needed, regular cycling should be minimized to the extent possible to maintain the resource’s long-term performance.

<sup>8</sup> For example, stronger-than-anticipated demand typically arises as a result of a stronger economy, which implies more residential housing starts, renovations, and appliance replacements, and more commercial building construction, changes in existing commercial space to accommodate expansions or new entrants, and/or changes in industrial processes to increase output. All of this activity increases stock turnover, providing more opportunity for improving the efficiency of homes, buildings, lighting, appliances, motors and other end-uses.

<sup>9</sup> Transmission capacity may reduce this risk *in part* by increasing export opportunities. However, Manitoba is not an island, and as such, there is a strong risk that slower economic growth in the province is mirrored in neighbouring provinces and states, meaning a strong likelihood that Manitoba’s unplanned surplus exports will meet with lower than anticipated export prices. Hydro-Quebec’s current situation – the utility is exporting its surplus power at a fraction of what it cost to build the new supply – should serve as a warning (see footnote 12).

FIGURE 6 - Projected 2015 Resource Costs and Risks (Binz et al.)



As the reader will see, energy efficiency is deemed to be the lowest combined cost *and* risk resource available. Unfortunately, this chart does not address large-scale hydropower.

## THE RISK OF NOT PLANNING FOR DSM

### DSM RESOURCE VS. DSM STRESS TEST

The last time Manitoba Hydro conducted a resource planning study was in 2001<sup>10</sup>. In the current case, Manitoba Hydro asserts that it intended to use the DSM potential study to perform an evaluation with different levels of DSM and generation, but that the potential study took longer than expected to complete, depriving the planning process of the needed information.<sup>11</sup> Whatever the reason, by not treating DSM as a resource option, MH has *de facto* excluded the single lowest cost and lowest-risk resource available.

<sup>10</sup> CAC\_GAC/MH I-018a

<sup>11</sup> CAC\_GAC/MH I-018b

Including DSM as a “stress test” in no way diminishes this concern, as the stress test only allows for a comparison of which *generation* options are least risky should demand not materialize, not *how much cost and risk could be avoided* by a deliberate, *planned* effort at more aggressive DSM. Worse, by treating demand as a purely exogenous event – rather than a resource option to consider upfront on an equal footing with supply – one is naturally led toward planning for new generation, no matter the additional cost and risk.

### **GETTING LOCKED IN TO CAPITAL PLANS**

In theory, a plan is only a plan – it does not in and of itself lock in capital commitments beyond those immediately required. My concern, however, is that once a utility commits to new capital plans (as opposed to future DSM, PPAs, or other resources) , reversing those plans becomes exceedingly difficult, as momentum, expectations and interests align to push those plants forward, no matter what the alternatives. From our experience, the resulting fate is too often repeated, resembling a four-part act:

1. **the utility commits to building** (because it fails to fully account for alternatives and risk);
2. **the utility proceeds to build** *in spite of* new “facts on the ground” or alternative options (no matter how glaringly obvious they may become);
3. **the utility finds itself awash in** (needlessly expensive) **surplus energy**; and
4. **the utility scrambles to find demand for its new supply** – by selling at a loss (whether to similarly depressed export markets or to new loads through generous rate subsidies), and/or by reducing or eliminating its lower-cost DSM programs.

I have watched this play out in my own province, where we are currently inundated with surplus power and selling it at a fraction of what it cost us to build (at tremendous cost to the economy).<sup>12</sup>

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<sup>12</sup> Québec’s most recent forecast involves over 50 TWh of surplus power for the next decade, as a direct result of overcommitting on new supply and failing to pull back from those commitments when evidence abounded that anticipated load growth would fail to materialize. Those 50 billion kWh cost Quebecers approximately 10 cents/kWh to build, and we are currently selling them at approximately 3.5 cents on the export market (we are also attempting to attract new industry with offers of subsidized power in the 3 to 3.5 cent range). Meanwhile, our DSM programs, which we are actively abandoning as a result of these surpluses, cost us on average 3 cents/kWh saved.

## **IMPACT ON CONSUMERS**

This is not a theoretical debate, of course. The inability to benefit from low-cost DSM savings opportunities, because one is already committed to large capital expansions, can set into motion a process wherein not only society, but the most marginalized in society, lose:

1. Ratepayers as a whole are asked to bear the rate increases needed to fund new large-scale capital projects;
2. Consumers are provided with less assistance to help offset those increases by more efficient consumption, as DSM programs take on a more minimalist function; and
3. The urge to minimize DSM program costs – one of the remaining *fungible* costs during a period of rapid capital expansion – leads to a growing focus on the efficiency of DSM plans, at the expense of costly programs aimed specifically at low-income customers.

Meeting growing demand for energy services, whether through capital expansions or heightened DSM investments, will likely lead to higher revenue requirements on the whole. However, forfeiting the lower-cost DSM option not only adds undue cost to the system, but diminishes consumers' ability to *offset* higher prices with more efficient demand.

## **DEFERRAL VALUE VS. ADDITIONAL EXPORT REVENUE**

Finally, I note that Manitoba Hydro argues that, unlike most other jurisdictions,

“in the Manitoba Hydro situation the main economic benefit from increasing DSM arises not from increased DSM deferring generation but from increased DSM increasing the level of exports. In Manitoba Hydro’s situation, there *typically* are economic benefits from advancing generation and economic losses from deferring generation.”<sup>13</sup>  
[our emphasis]

Thus, according to Manitoba Hydro, “evaluating DSM by studying it as competing with new hydro generation and deferring that generation would have the perverse outcome of negatively affecting the economics of the DSM.” Manitoba Hydro proposes to assess the value of DSM based on the benefits of increased exports<sup>14</sup>.

In practice, both answers may be correct: DSM may generate maximum value by increasing exports, or it may generate maximum value by deferring generation, all depending on the relative revenue (exports) or avoided costs (deferred generation) of each. To be more specific, if the risk-adjusted value of export revenue is greater than the cost of generation, then DSM’s value will indeed, as MH argues, be best realized as an export-augmentation strategy. Inversely,

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<sup>13</sup> CAC\_GAC/MH I-018b

<sup>14</sup> Using Manitoba Hydro’s words: “to determine the increase in generation system operation benefits associated with increasing the exports resulting from the higher levels of DSM.”



if the cost of new generation (whether Keeyask or Conawapa) exceeds the anticipated, risk-adjusted export revenue, then DSM should be addressed as a capital deferral opportunity, because it will generate greater returns than the generation alternative.

One other possibility is that both occur simultaneously, i.e. that the export market – and associated interconnection capacities – are large enough to accommodate both the additional planned generation *and* the additional DSM. If this were the case, then we would concur with Manitoba Hydro as well. That said, while I have not studied Manitoba Hydro's interconnection capacities, I assume that export opportunities are not boundless; that is, there is a limit – either physical or price-related – at which additional power can or should no longer be exported.

Ultimately, Manitoba Hydro's assertion that there are "typically" benefits from advancing generation and losses from deferring generation is an oversimplification. The more valid question is: will additional generation-driven exports "crowd out" the potential for additional, higher-return DSM-driven exports? If this is the case, then DSM must be understood to be "competing" against new generation.

Take for example the following situation: a new hydro project can be built at a levelized cost of 7¢/kWh, and the production exported at an anticipated price of 8¢/kWh. Setting aside the issue of risk, this would seem to be cost-effective insofar as it generates a 14% margin. Yet what if increased DSM is available at a cost of 4¢/kWh? The increased DSM could free up power from the system for export at 8¢, thus generating a 100% margin. While the hydro option viewed alone may seem beneficial, when viewed alongside the alternative, it suggests a significant lost opportunity, with Manitobans forfeiting 3¢/kWh in net returns or, put differently, paying 3¢/kWh more than otherwise necessary for the same revenue.

One counter-argument to this is that the generation would have been needed anyhow; as such, the strategy benefits Manitobans by having export customers effectively finance the early costs of a long-term resource for Manitobans. One problem with this logic is that it rests on a large and untested assumption: that Manitobans will indeed need the additional power in the longer term. Aggressive DSM programs have proven time and again their ability to effectively decouple economic growth and energy demand. As a result, a growing number of provinces (e.g. Nova Scotia, Ontario) and states (e.g. Massachusetts, Vermont, California, Minnesota) now forecast essentially flat demand for electricity, despite continued growth in economic and other indicators. These regions are planning on *no new generation resources* (beyond internal replacements).

Later in this report, I will propose scenarios of what I believe the province can achieve in terms of demand-side management. These scenarios would seem to suggest little if any need for additional resources, at least for the time being, through a DSM portfolio far less expensive than the cost of the new generation plants. I will also suggest that in the longer term, there is a reasonable likelihood that new technologies, including demand-side solar photovoltaic, may ramp up so quickly as to permanently suppress growth in demand for utility-supplied power.

These are not certainties by any means. But by ignoring their very real possibility, Manitoba Hydro risks locking itself into a path of new supply that, as a result, will lock *out* the much less expensive option of more efficient demand.

## SUMMARY

If the least-cost path for Manitoba Hydro and its ratepayers is to be chosen, DSM must be included in the analytical process at the outset, and on an equal footing with supply options. Neglecting to do so risks committing Manitoba Hydro to needlessly expensive (and difficult-to-reverse) capital plans for years to come. Considering DSM in sensitivity analysis treats it as an exogenous event – something that *happens* – rather than as a resource that is *chosen* and invested in. This distinction is not one of semantics, but more fundamental: DSM will not *happen* if it is not planned for and committed to, and as a result, ratepayers will be locked into more expensive resource options.

DSM is typically the least expensive, lowest risk, and most versatile resource available, and can be used to offset demand and defer more expensive capital investments indefinitely, as we will see in the following section. Ambiguity regarding the best way to value DSM – as an export resource or to defer generation – by no means changes the fundamental economics at play: to neglect the lowest-cost option means to commit to a higher-cost path.

## THE DEMAND-SIDE RESOURCE IN MANITOBA

### INTRODUCTION

During my testimony at Manitoba Hydro's 2013/14 GRA last year, I presented three scenarios of increased demand-side management activity:

1. a "strict minimum" scenario that would see MH ramp up its incremental annual DSM program savings to a level equal to 1% of demand per year;
2. a second that would see them ramp up to 1.5% per year using DSM programs only; and
3. a third – which fell in between the previous scenarios – in which the utility would ramp up to 1.5% using a combination of programs *and* other strategies such as changes to rate structures, or a push for tighter codes and standards.

At the hearing, recognizing the absence of an independent study of the achievable potential, I recommended the PUB set a conservative "floor" equal to the first scenario, at least for the 2013-15 period, to be followed by a hearing to determine whether and to what extent the target should be higher. Since that time, Manitoba Hydro has released its long-delayed potential study, as well as a new Power Smart plan.

In this section, I will discuss the potential study, and specifically the results of my firm's review of it. With this review in mind, I will present an updated assessment of Manitoba Hydro's latest Power Smart plan as it pertains to the current NFAT. I will then present an update of the level of DSM that I believe Manitoba Hydro can achieve, taking into account the full range of DSM resources at its disposal, and conclude with my recommendations to the Board.

### THE DSM POTENTIAL STUDY

My firm reviewed the EnerNOC potential study completed for Manitoba Hydro. To do so, we examined some of the key assumptions and parameters used to define the study, and compared them against best practices in the industry. We also ran a benchmarking exercise to compare the study results with the results of similar studies in North America. **Based on our review, it is my opinion that the study has likely materially understated the achievable cost-effective potential in the province.**

#### ***BENCHMARK: A LOW-ISH SAVINGS POTENTIAL ESTIMATE***

We conducted a benchmarking exercise of Manitoba Hydro's study with similar potential study results across North America. To ensure comparability, we focused on the most common savings timeframe, i.e. a 10-year horizon, and specifically excluded horizons of less than 5 years or more than 15. We furthermore limited our set to recent potential studies (2009+), as well as to only

those studies that assessed the maximum achievable potential.<sup>15</sup> Of course no two regions are entirely alike, which is why we also attempted to include a broad enough cross-section, including regions in both cold and warm climates, and regions with both a long and short history of aggressive savings efforts.

While different studies may use different methodologies, potential studies generally produce three sets of results:<sup>16</sup>

- *Technical Potential*: A theoretical maximum meant to reflect what would occur if all end-uses, irrespective of cost, magically upgraded to the most efficient, technically-feasible solution.<sup>17</sup>
- *Economic Potential*: A subset of the technical, this accounts only for those measures that are deemed cost effective. Note that different regions define and compute cost-effectiveness in different ways – a point we will return to later.
- *Achievable Potential*: A subset of economic, this accounts for market uptake, given consumer preferences, stock turnover rates, and market barriers. Most studies assess the “maximum achievable” cost-effective savings potential, while others also prepare a subset limited by self-imposed constraints (e.g. by a pre-established DSM budget).

The chart below illustrates the results of our benchmarking study using each of the three “potential” results.<sup>18</sup>

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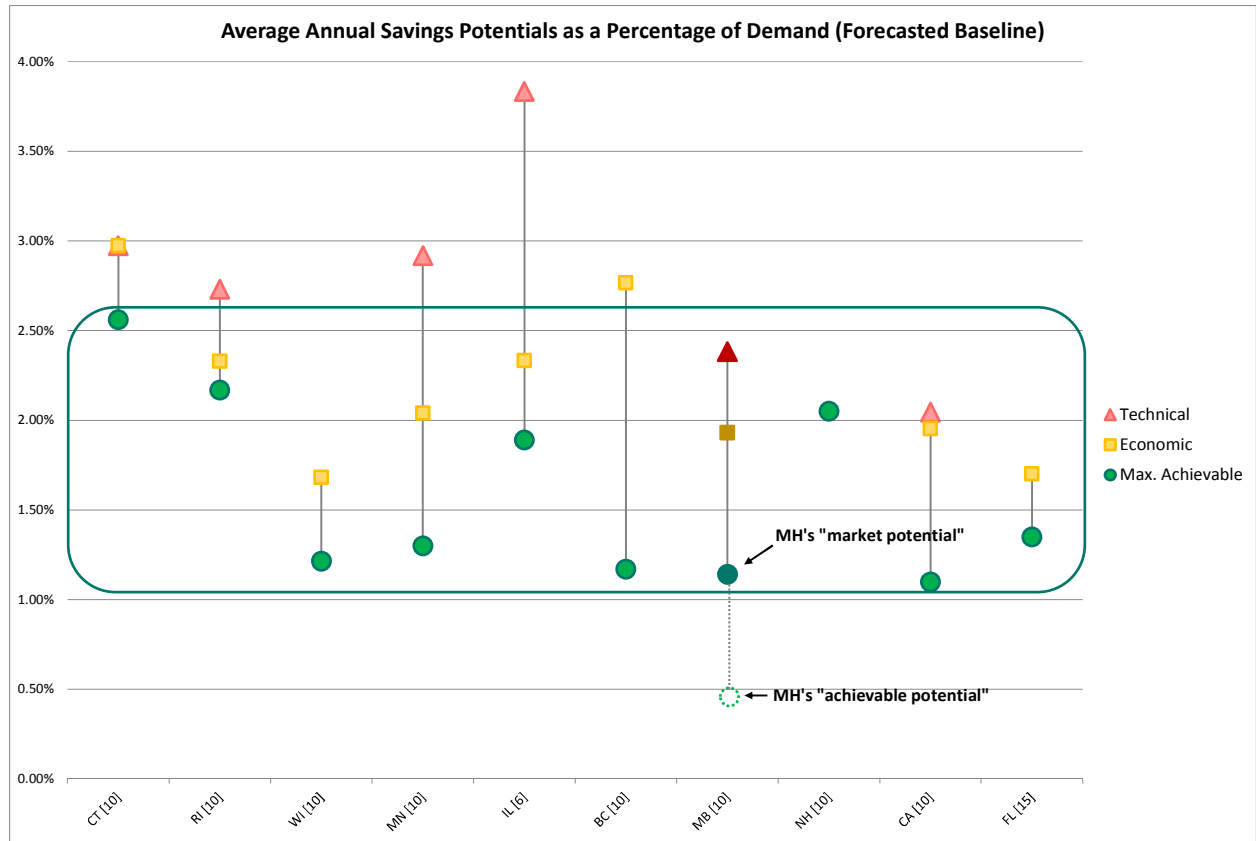
<sup>15</sup> For example, we excluded studies that examine only what is economic (which would overstate the achievable), as well as studies that place artificial constraints unrelated to cost-effectiveness (eg. Incentive limitations or others), which would understate the achievable.

<sup>16</sup> Note that in all cases, savings ought to be “incremental”, meaning they are above and beyond efficiency improvements that are expected to take hold naturally, i.e. in the absence of DSM programs.

<sup>17</sup> Some studies limit the technical potential to measures that provide a similar service. For example, the technical savings potential for lighting in a retail store may not include replacement of all halogen bulbs by more efficient compact fluorescent (CFL) bulbs, insofar as the lighting quality of CFLs – of great importance to the retail clothing sector for example – is inferior to that of halogen lamps.

<sup>18</sup> Note that in the case of Achievable Potential, we focus here on the maximum achievable values. For Manitoba, the study’s “market potential” is understood to be akin to the maximum achievable potential, though we also indicate the study’s constrained subset, which it calls simply “achievable”.

**FIGURE 7 – Comparison of Potential Study Results**



We observe several take-aways:

1. What Manitoba Hydro calls the **“achievable” potential** (<0.5%/yr over 10 years) lies far outside of the range of “maximum achievable” potentials from other studies. This does not make it wrong per se, but suggests that it does not likely attempt to reflect the full extent of achievable, cost-effective savings; it may reflect self-imposed constraints.
2. What Manitoba Hydro calls the **“market” potential** lies at the extreme low end of the range of maximum achievable results from other studies. While the study chooses a different terminology, we view this as the closest indicator of what can be achieved, cost-effectively, in the province, *for those measures and end-uses that it addresses*, and *within the methodological constraints of the screening process that it uses*. We return to this later in this section.
3. Manitoba Hydro’s **technical and economic potential** estimates similarly fall on the lower end of the range of values.
4. Potential studies commonly apply different scopes (e.g. inclusion or exclusion of fuel switching, customer-sited generation, etc.) and/or methodologies (e.g. economic screening and achievable estimates). It is reasonable to assume that several of these

studies applied a limited (as opposed to comprehensive DSM) scope, and/or screening methodologies that fall short of best practices.

**While it is not possible to conclude from a mere comparison of results, I retain from this analysis that the market potential is worth considering as a starting point estimate of the maximum achievable savings in Manitoba,** although what the study terms the “achievable” potential – a far outlier – is not.<sup>19</sup> I also note that the other potential studies examined here may suffer from some important limitations in terms of the types of DSM included and not included in the analysis.

### **MARKET POTENTIAL: METHODOLOGICAL CONCERNS LEAD TO UNDERSTATED SAVINGS**

In addition to the benchmarking analysis, we conducted a closer examination of the EnerNOC potential study parameters. Our assessment focused on each key parameter of a potential study, in order to understand the extent to which Manitoba Hydro’s relatively low potential may be the result of unique characteristics, or rather of the parameters of the study itself.

In the course of our examination, we identified 14 aspects of the study that unduly limit the estimated savings potential. These can be grouped into three broad categories:

- 1. EXCLUSIONS: A broad array of opportunities were simply not considered as part of this study.** These include individual measures (e.g. air-source heat pumps in the residential sector), entire end-uses (e.g. site-specific industrial processes; large “miscellaneous” loads), fuel switching opportunities (all sectors), early replacement opportunities (e.g. lighting), demand-side renewables (e.g. rooftop solar), and non-program strategies (e.g. rate structures or beyond-baseline codes & standards). Whatever the reason for these exclusions (study scope, budget limitations, others?), they amount to a material understatement of available electric load reduction opportunities.
- 2. SCREENING LIMITATIONS:** The economic screening process follows some common practices, but is conducted in a highly restrictive manner (e.g. high screening thresholds, zero non-utility benefits, zero ability to bundle measures,); it is further hampered by an unduly high discount rate that is inconsistent with the treatment of supply options and, as a result, unfairly discounts DSM’s benefits.

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<sup>19</sup> This does not mean that the “achievable” value is incorrect; in fact, it is common practice in this industry to examine “constrained” achievable scenarios, for example to assess what an *existing* level of effort might produce into the future, or what could be done within a pre-defined budget. While this value may be useful for some purposes, it is irrelevant for a long-term resource planning exercise that seeks to define what *can be*, rather than what *currently is* or could *easily be*.

3. **OTHERS:** An important discrepancy with the load forecast – consistency with which is paramount to the accuracy of a potential study – is disconcerting. Because the total forecast load used by the study is significantly *lower* than the load forecast used by Hydro for its overall energy planning, this can only result in a significant understatement of savings opportunities across the board. In addition, achievable market adoption rates often appear far lower than is found in many other regions, including those that served as the basis for the study itself.

The following table summarizes these limitations and their applicability to the various “potential” categories. The symbols indicate the direction of change that would likely be brought to each type of potential under more comprehensive and/or appropriate study parameters. A more detailed version of this table, with comments and references, is presented in appendix A.

**FIGURE 8 – Likely Changes to MH’s DSM Potential Study Results under Adjusted Parameters**

ISSUE	TECHNICAL potential	ECONOMIC potential	MARKET potential
<b>1. EXCLUSIONS</b>			
Measures	↑	↑	↑
Industrial Loads	↑	↑	↑
Misc. Loads	↑	↑	↑
Fuel Switching	↑	↑	↑
Demand-Side Renewables	↑	↑	↑
Early Retirement Opportunities	↑	↑	↑
More stringent regulations (C&S)	↔	↔	↑
Rate Structure	↔	↔	↑
Future Technologies	↑	↑	↑
<b>2. SCREENING METHODOLOGY</b>			
Discount Rate	↔	↑	↑

ISSUE	TECHNICAL potential	ECONOMIC potential	MARKET potential
Benefit-Cost Threshold	↔	↑	↑
Measure Bundling	↔	↑	↑
Non-Energy Benefits (NEBs)	↔	↑	↑
3. OTHERS			
Discrepancy with load forecast	↑	↑	↑
Low adoption rates	↔	↔	↑

Depending on the scope of the study request, these limitations do not necessarily suggest errors per se. Indeed, numerous potential studies self-impose certain limitations – in particular regarding the types of savings opportunities to be included – for reasons of context (assessment of some opportunities may not be relevant in some situations), study budget, or both. **Whatever the reason, however, the study clearly reflects only a part of the province’s full cost-effective opportunity for electricity savings.**

**A full reassessment of the study’s results – adjusting for each of these factors – is outside of the scope of our engagement in this project. However, I am left with little doubt that the maximum achievable potential in Manitoba is higher than the “market” potential of approximately 1.15% annual incremental savings (as a percent of load) indicated in this study.**



## MH'S DSM TARGETS COMPARED WITH OTHER JURISDICTIONS

### CONTEXT

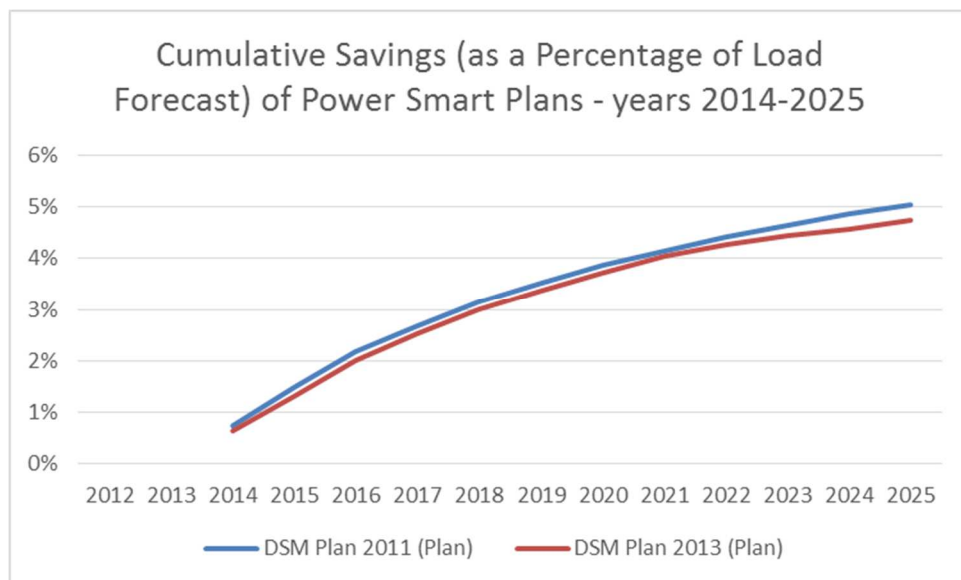
In last year's GRA, we examined Manitoba Hydro's DSM savings objectives, and conducted a benchmarking exercise for this purpose. At the time, we found that the Corporation's DSM goals amounted to approximately 0.4% of savings on electric sales per year, and were furthermore declining. This was in stark contrast to the savings goals – more often than not regulatory or statutory requirements – of other DSM leaders throughout North America (1.5% to 2.6% of annual savings).

In its decision last year, the Public Utilities Board asked Manitoba Hydro to increase the energy savings from its DSM Plan:

"The Board believes that it is fundamental that Manitoba Hydro enhances Demand-Side Management efforts from those reflected in the 2011 Power Smart Plan. (...) The Board does not agree with Manitoba Hydro's decision to cut Demand-Side Management spending and targeted savings. (...) The Board urges Manitoba Hydro to incorporate Demand-Side Management programs into its plan that target higher level of energy efficiency, as was recommended by Mr. Dunsky and endorsed by the Consumers' Association of Canada (Manitoba) Inc. and the Green Action Centre." (Order 43-13, p. 42)

I was therefore surprised to learn that the 2013 Power Smart Plan not only fails to substantially increase savings, but in fact plans for a slight (though not material) decrease in savings over time.

**FIGURE 9 – Comparison of Cumulative Savings – Power Smart Plans**



As a result, Manitoba Hydro's savings targets relative to its peers remains largely unchanged.

In the current proceeding, we sought to understand to what extent Manitoba Hydro intends to correct this trajectory. In so doing, I learned that the Corporation is assessing strategies for existing programs, and recently launched a new “Community Geothermal” program as well. I also understand that the next plan update may correct this to some extent, though the update is not expected to be made public before the middle or end of March, 2014.<sup>20</sup>

### ***BENCHMARKING UPDATE***

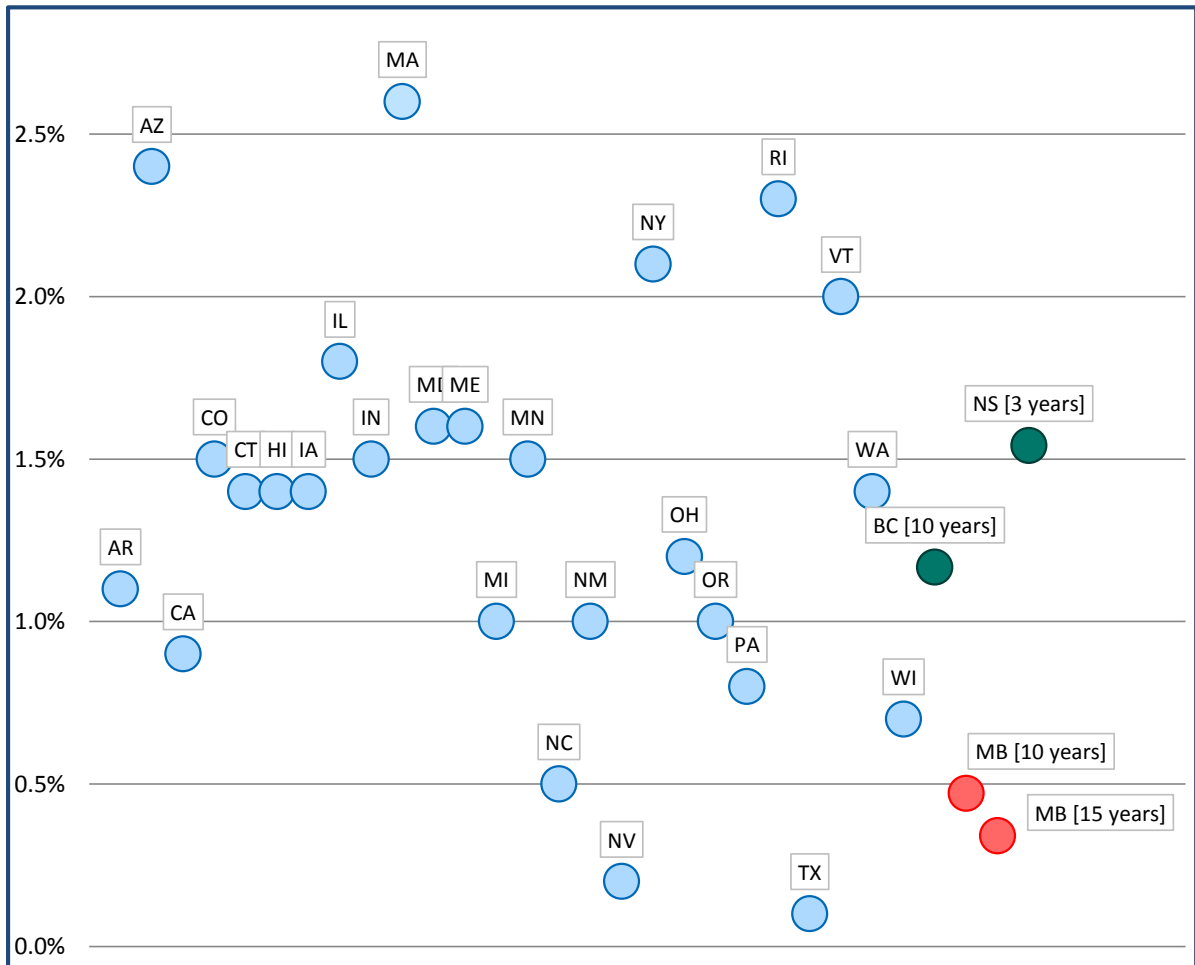
In the absence of the new plan numbers, we sought to update our original benchmarking analysis. To do so, we adjusted Manitoba Hydro’s savings to reflect its 2013 Plan, and similarly adjusted the savings of all our benchmark regions to reflect the most recent information available. Benchmarked regions include the full slate of U.S. states (for which data is more easily available), as well as the two Canadian provinces included in our more detailed benchmark analysis (Nova Scotia and B.C.).<sup>21</sup>

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<sup>20</sup> CAC\_GAC/MH I-001a and CAC\_GAC/MH I-001b.

<sup>21</sup> Please refer to our evidence in last year’s GRA for an explanation of the choice of cohort regions.

**FIGURE 10 – Electricity Targets (Average Annual Electric Savings as % of Sales)**



Not surprisingly, we find that Manitoba Hydro's targets remain far lower than what leaders are aiming at. Even California, with its decades-long commitment to aggressive DSM, continues to target substantially more *additional* savings in coming years, on top of what has been achieved over a strong, three-decade long investment. In fact, California is now joining numerous other regions in relying on DSM to meet *all load growth*, effectively flattening demand despite continued population and economic growth.

Another interesting case is the state of Minnesota, given its proximity to Manitoba (see "Case Study – Minnesota" for details). There, strong state and regulatory support are combining with utility leadership to target and achieve high levels of DSM savings. The Next Generation Act of 2007 sets the minimum annual energy savings at 1.5%, of which 1% must come from utility programs (energy efficiency and self-generation). Xcel Energy Minnesota, the largest electric utility in the State, has achieved an average of 1% savings on energy sales from 2005-2011, and going forward is now relying on 1.4% annually from DSM programs alone. These savings are *in addition to* savings from codes, standards, and other non-program efforts.

## CASE STUDY – MINNESOTA<sup>22</sup>

Manitoba does not have to look far away to find a good example of DSM leadership and innovation. Just south of the border, Minnesota is recognized as a leader with strong commitment to aggressive DSM targets, innovative approaches to common DSM challenges, and strong state and regulatory support of utility efforts. Customer energy efficiency programs have been in place in Minnesota since the 1980s, and savings as well as spending have only increased over time.

**Aggressive Targets, Achievements and Budgets:** The Next Generation Act of 2007 sets DSM targets at a minimum of 1.5% of electric sales annually. A minimum of 1% per year must be met with customers' energy efficiency and self-generation. Up to 0.5% can be achieved by investments in utilities' infrastructures. In addition, the law establishes the goals of reducing per capita use of fossil fuel by 15% by 2015, and to supply 25% of total energy used in the state with renewable sources by 2025.

Xcel Energy (MN) achieved an average of 1% savings on energy sales from 2005-2011, with program spending equal to 1.7% of revenues from retail sales. In the 2013-2015 Triennial Plan, Xcel Energy establishes savings goals of 1.38% annually.

**Energy Efficiency as a Resource:** Minnesota's regulated utilities are required to file integrated resource plans, identifying resources to meet consumer needs in future years, including significant energy efficiency and conservation savings. The law explicitly declare energy efficiency a "resource", and cost-effective conservation a "preferred choice".

**State leadership:** The State of Minnesota has been in the Top 10 States (ACEEE Scorecard) during six of the last seven years. The State of Minnesota has set aggressive standards for state buildings, with the long-term goal of having a zero-carbon building stock by 2030. The State also supports building benchmarking and retrofit implementation.

**Incentives:** Minnesota's regulator instituted a shared benefit incentive in 1999. Under this mechanism, utilities receive important financial incentives for achieving DSM savings targets.

### **Cost-Effectiveness Criteria**

Programs must be cost-effective on average (i.e. on a bundled-measures, *not individual measure* basis). Furthermore, cost-effectiveness is assessed using the Societal Cost Test – which explicitly accounts for environmental and other benefits of DSM – as its primary test for decision making. Cost-effectiveness is required with the exception of low-income programs, pilots, and new technologies.

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<sup>22</sup> Sources: Downs, Annie et al., 2013. The 2013 State Energy Efficiency Scorecard, American Council for an Energy-Efficient Economy: Washington (DC). York, Dan et al. 2013. Making the Business Case for Energy Efficiency: Case Studies of Supportive Utility Regulation, American Council for an Energy-Efficient Economy: Washington (DC). ACEEE State Policy Database, <http://aceee.org/sector/state-policy/minnesota>. Energy - New Laws 2007, <http://www.house.leg.state.mn.us/hinfo/newlawsart2007-0.asp?storyid=608>. Decoupling: A better utility business model, <http://fresh-energy.org/2013/11/a-better-utility-business-model/>.

## WHY ARE MH'S DSM TARGETS SO LOW?

Last year, we examined in detail the exogenous factors that might explain Manitoba Hydro's low DSM targets, including:

- Climate (Manitoba is uniquely cold)
- Sectors (Manitoba has large industrial loads)
- Size (Manitoba is smaller than some other regions)
- Rates (Manitoba's rates are lower than many others')
- Other savings (Manitoba has a reasonably strong history of codes and standards)

In that examination, none of these factors were found to explain the deltas of Manitoba Hydro's planned savings compared to the cohorts (DSM leaders sharing similar characteristics with Manitoba Hydro).

As we noted then, one explanation might be that cost-effectiveness screening is too restrictive. Although Manitoba Hydro often reiterates it uses several tests for decision-making, the precise DSM screening policy remains ambiguous. It seems, however, that the non-participant test (RIM) and the Levelized Utility Cost (LUC) play dominant roles.<sup>23</sup>

If the RIM continues to play a role in MH's DSM screening, this would lead to excluding otherwise cost-effective DSM opportunities. For example, the RIM may suggest that a DSM opportunity is not economic even if the total cost to customers (rate x consumption) decreases. This test is so restrictive that nearly every jurisdiction in North America has long abandoned it as a primary screen.

The LUC, meanwhile, is useful to compare DSM to supply side options, but is dangerous if used instead to compare DSM options *among themselves*. Indeed, doing so can only lead to cream skimming, i.e. to choosing the least amount of DSM possible in an effort to minimize *average* unit costs. By rejecting cost-effective opportunities, this approach – which is not used, to my knowledge, anywhere else in North America – necessarily leads to higher utility costs.

Cost-effectiveness screening practices at Manitoba Hydro *may* be needlessly hampering its overall DSM effort. More important, however, is the corporation's strategic focus, which is clearly set on new generation and only partially interested in DSM. As I have stated previously, from what I have seen so far, I believe that Manitoba Hydro's Power Smart team is very capable of meeting significantly larger targets, on the order of those being achieved in leading regions elsewhere on the continent. However, a stronger target – and of course the resources to achieve it – cannot come from the Power Smart team alone; it must be part of a clear, strategic orientation.

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<sup>23</sup> CAC\_GAC/MH I-018a

## SUMMARY

Manitoba Hydro's potential study identifies a maximum achievable energy savings opportunity of 1.1%/yr on average. Yet our assessment of the study points to entire swaths of savings opportunities that were not considered, including (a) large opportunities left outside the study's scope (e.g. fuel switching, customer-sited renewables), (b) important measures left out of the analysis altogether (e.g. air-source heat pumps in the residential sector), and (c) *entire loads* for which no savings opportunities are included (site-specific industrial processes, or the very large "miscellaneous" loads category). Furthermore, the study adopts a restrictive approach to cost-effectiveness screening, and one that is not consistent with MH's own internal process. Finally, the study is based on a load forecast that is not calibrated with MH's own forecast, and as such necessarily understates stock turnover and construction activity, resulting in missed savings opportunities.

It is equally clear that Manitoba Hydro's current DSM effort falls far short of leading efforts elsewhere on the continent. Indeed, our update of last year's benchmarking exercise finds no material change in the overall portrait, with leaders continuing to commit to cost-effective savings in the range of 1% to 2.5% per year from energy efficiency programs alone. Manitoba Hydro can and should be doing far more to help ratepayers reduce utility bills in the short-term, while helping defer unnecessary capital investments (or generate additional export revenue) in the mid and longer terms.

## HOW MUCH DSM CAN MANITOBA PLAN FOR?

### REASONABLE YET AGGRESSIVE DSM TARGETS FOR MANITOBA

We assessed, during the 2012/13 & 2013/14 General Rate Application, what DSM savings could be achieved if Manitoba Hydro was to ramp-up its DSM efforts. At that time, we suggested that Manitoba Hydro could *at a minimum* ramp-up its DSM savings to 1.0% by 2015, and sustain this level of savings in the long run. We also presented two more aggressive scenarios, and concluded that while we believed they would be achievable, it was more prudent to wait for the results of a potential study before committing.

As we saw previously, the potential study has since been released. This study points to a “market potential” of approximately 1.1% per year on average, which is on the low end of results from similar studies elsewhere. More importantly, the study suffers significant limitations, both in scope and methodology, which systematically understate the cost-effective, achievable potential.

Given these considerations, I am now more comfortable in suggesting that, under certain conditions, Manitoba Hydro could commit to somewhat more aggressive scenarios, assuming:

- a reasonable ramp-up period,
- extra time to allow for time lost in the past year, and
- a strong commitment by both the PUB and Manitoba Hydro to tracking, evaluating, and reporting on performance.

The two revised scenarios are as follows:

**Scenario A: The more aggressive scenario would achieve an average of 1.3% savings/year** from utility programs alone (1.5% including C&S). This includes a 6-year ramp-up period.

**Scenario B: The more cautious scenario would achieve 1.1% savings/year on average** from utility programs alone (1.3% including C&S). This includes a 5-year ramp-up period.

The table below provides the DSM program-driven savings associated with each scenario, both as a % of forecast sales, and in GWh/yr. We also provide the average annual savings over an initial 10-year period (2014-2023). While these savings can be produced from Power Smart programs alone, we add a second totals column at the end that *includes* non-program savings, specifically the savings that Manitoba Hydro currently anticipates from codes and standards.

**FIGURE 11 – Dunsky’s DSM Scenarios (excluding codes and standards)**

		2014	2015	2016	2017	2018	2019	2020 ++	10 YEAR AVG 2014-2023 (programs only)	10-yr Avg. 2014-2023 (prog’s + C&S)
<b>Scen. A (1.3%)</b>	%/yr:	0.6%	0.8%	1.0%	1.2%	1.4%	1.5%	1.5%	<b>1.3%</b>	<b>1.5%</b>
	GWh/yr:	135	182	231	280	331	360	365	3,013 GWh/yr (cumulative)	3,534 GWh/yr (cumulative)
<b>Scen. B (1.1%)</b>	%/yr:	0.5%	0.7%	0.8%	1.1%	1.3%	1.3%	1.3%	<b>1.1%</b>	<b>1.3%</b>
	GWh/yr:	122	149	181	267	305	312	317+	2,634 GWh/yr (cumulative)	3,220 GWh/yr (cumulative)

**The more aggressive scenario (Scenario A)** would exceed the “market” potential identified by Manitoba Hydro. This reflects the numerous additional savings opportunities not accounted for by that study, as well as the other limitations I noted previously (see Figure 8). It would require strong commitment and innovative approaches from Manitoba Hydro, but is achievable, and still far lower than what some other leaders are targeting and achieving. **I note that this scenario effectively means that Manitoba would achieve neighbouring Minnesota’s current performance in 5 years’ time.**<sup>24</sup>

**The less aggressive scenario (Scenario B)** would include a somewhat longer ramp-up time and top off at a somewhat lower rate than Scenario A. From a programs perspective, **after the 5-year ramp-up, Manitoba Hydro’s savings would still fall short of Nova Scotia’s latest annual performance results.**<sup>25</sup> When accounting for *all* savings opportunities, **this scenario is similar to BC Hydro’s latest 10-year target.**<sup>26</sup>

<sup>24</sup> Minnesota utilities currently achieve 1.4% from programs alone, and at least 1.5% when including codes and standards.

<sup>25</sup> In its most recent, fully-evaluated year (2012), Efficiency Nova Scotia achieved 1.4% savings/load from energy efficiency programs, and 1.5% when including the codes and standards it could have influenced.

<sup>26</sup> BC Hydro’s recently adopted Integrated Resource Plan includes DSM targets of 1.5%/yr, on average, over the 2014-23 timeframe. This includes programs, codes and standards, and customer-sited generation (the latter being 0.2% of the total).

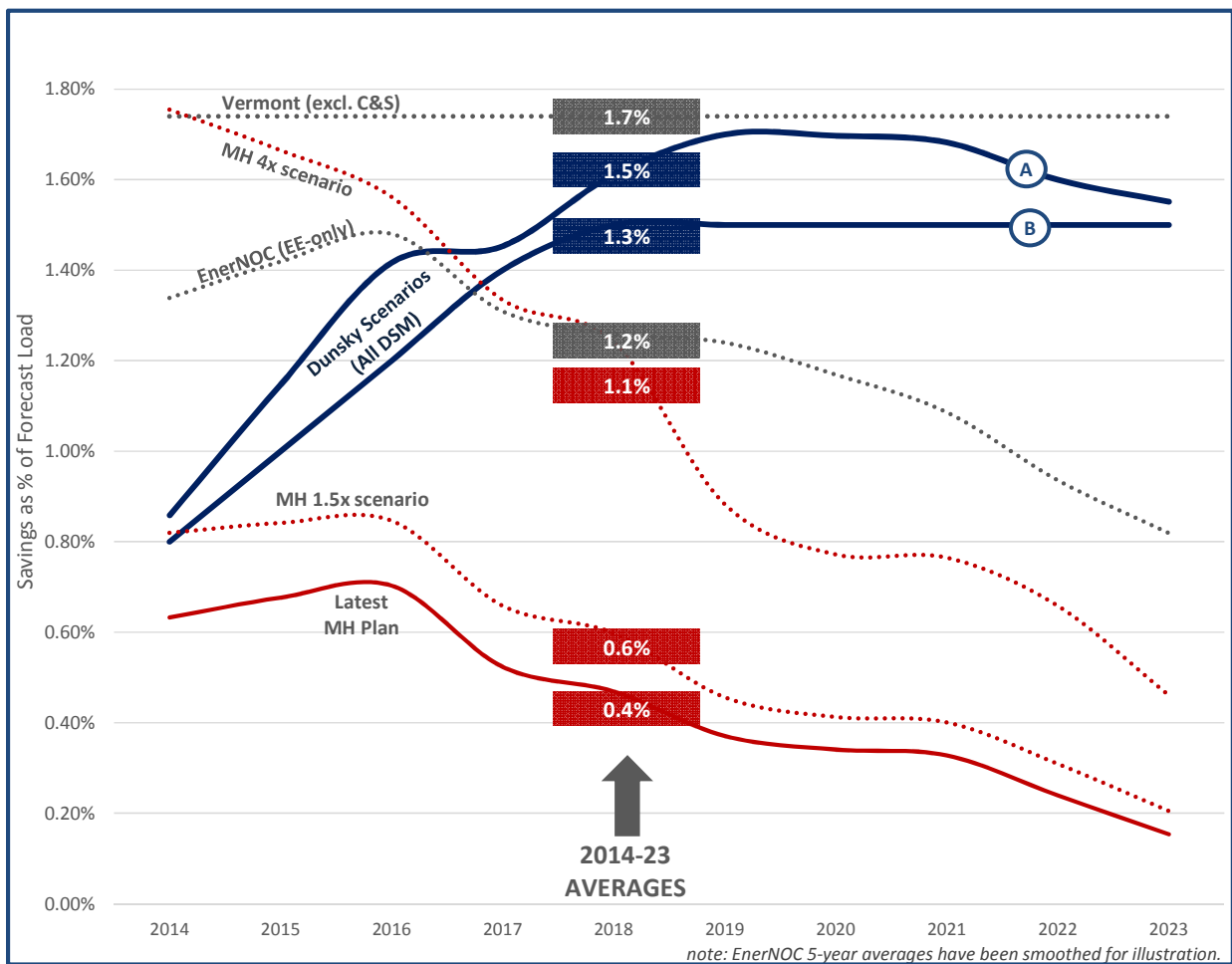


## COMPARING SCENARIOS

The following graph illustrates the cumulative savings (as a percentage of load reduction) that would result from a number of options to consider:

- MH's current 2013 Plan
- MH's current "scenarios" that involve 1.5x or 4x savings above its current plan
- Our 2 scenarios, as described above, and
- For illustrative purposes, Vermont's average savings targets for the period

**FIGURE 12 – Compared 10-Year Scenarios** (incl. anticipated C&S except where otherwise noted)



*Note: To ensure an equivalent comparison, each scenario and plan accounts for DSM programs as well as non-program savings, i.e. Manitoba Hydro's currently-anticipated savings from codes and standards. Note that the multiples in MH's "1.5x" and "4x" scenarios apply only to the program portion of the total.*

As the reader can see, Manitoba Hydro's 1.5x scenario only slightly increases the savings achieved by the Power Smart Plans, achieving an average savings of 0.6% over the period – *including savings from codes and standards* – due in part to the current plan's rapid decline. The 4x scenario is more aggressive, especially during the first years, but the current plan's decline once again leads to a dramatic drop over time, producing *average* annual savings of only 1.1%/yr (again, *including savings from C&S*).

EnerNOC's market potential presents a similar average value (1.2%/yr) over the period. Keeping in mind that this includes codes and standards, it represents *program* savings of just over 1.0%. I also note that because of the study's scope limitations, it *does not* account for several large savings opportunities, including fuel switching/retention – as such, it is labeled as "EE-only" (energy efficiency only), whereas *our higher savings scenarios* can be achieved by a broader set of DSM opportunities.

More importantly, the steep decline of the EnerNOC line is a function of the static nature of the potential study: because it does not account for the unknown (future innovations), the study assumes a diminishing basin of opportunity. As I discuss later (see discussion starting on page 35), this is an understandable but absolutely unrealistic assumption. The empirical evidence from the past thirty years is clear: continued technological improvements – whether through introduction of new technologies, efficiency improvements to existing technologies, or declining costs – have and are constantly replenishing the reservoir of savings opportunities. Dramatic advances in solid-state lighting technology, and similarly dramatic reductions in the cost of producing solar panels, are but two recent examples of this.

Finally, our two scenarios begin at current Power Smart Plan levels, proceed to ramp up over 5-6 years to levels currently achieved in such places as Minnesota or Nova Scotia, and hold constant thereafter. I believe this is a more realistic path for Manitoba Hydro than its current "4x" scenario, both in allowing for initial ramp-up, and in accounting for future opportunities.

While our scenario is new, I did note that Manitoba Hydro does not seem to question the fact that its 4x scenario can be achieved:

"If Manitoba Hydro were directed to achieve the 4x scenario and notwithstanding any consideration for cost effectiveness, no significant organizational changes would be envisioned. Manitoba Hydro is well positioned to pursue energy savings through demand side management (DSM) based upon its extensive history and experience with DSM, its position as an integrated energy service provider (electricity and natural gas), its existing relationships with customers as an energy services provider through its customer care activities and account managers, its ability to leverage billing systems and customer account information, and the significant recognition and value of the Power Smart Brand. The best approach to achieving the 4x scenario would need to be assessed and decisions on internal resource requirements and

contracting to third parties would be made after undertaking an assessment of varying program design options.”<sup>27</sup>

We concur with this assessment. While growth of any operation is always challenging, Manitoba Hydro has a core expertise in DSM, a significant history with DSM, enviable market presence, and access to valuable DSM tools that many of its peers, with larger targets still, must do without.

## CAN THIS BE DONE AT REASONABLE COST?

As I stated last year, the cost of achieving DSM savings has remained fairly constant over the past couple of decades, and evidence strongly suggests that while achieving additional savings may require higher incentives and efforts, added costs are commonly offset, at least in part, by economies of scale.

In my testimony last year, I examined the actual savings (energy saved/energy sold ratio) and costs (\$/first-year kWh) from a broad range of states and provinces. My conclusion was that there is only a very weak relationship between unit costs and depth of savings, and that relationship was negative, meaning that, if anything, increasing savings may lead to a *decrease* in the unit cost of savings. This is largely consistent with my experience across a broad array of program administrators: average costs needn’t materially increase to achieve greater savings, because the move to some higher-cost opportunities can be offset by increased efficiencies and market intelligence.

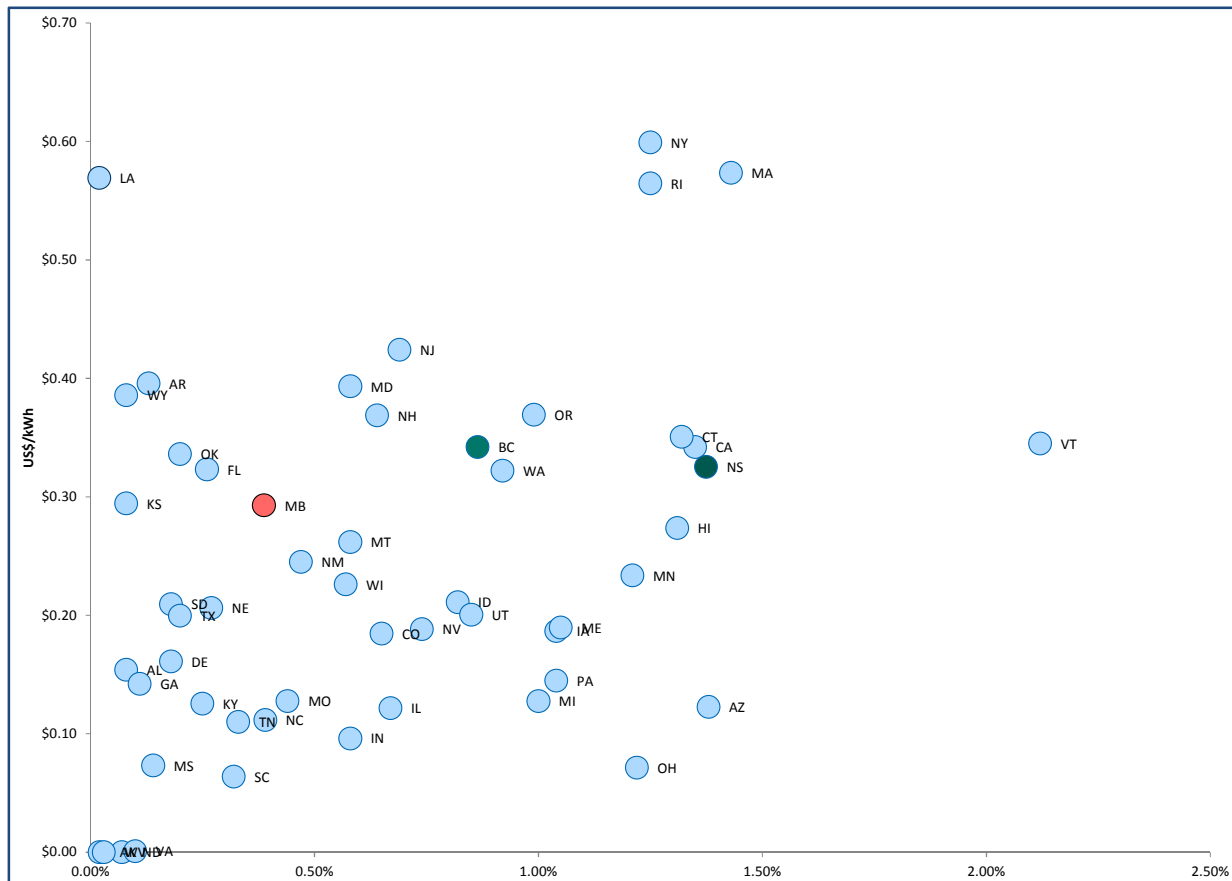
I have now updated that analysis, using the latest results from DSM programs across the continent. This new analysis largely confirms the previous findings: there is essentially no relationship between depth of savings and unit costs (although the negligible relation that *is* observed is positive this time). Manitoba Hydro’s most recent costs are slightly above average; this is not surprising in that Canadian regions commonly face somewhat higher costs.

The chart below presents the results of this updated analysis. The horizontal axis represents the extent of savings achieved in each region’s most recently reported year, expressed as a % of total demand. For example, the savings generated by Manitoba Hydro’s Power Smart in 2012 amounted to 0.39% of the utility’s demand. The vertical axis meanwhile, represents the average unit cost of those savings, expressed on a *first-year basis*. For example, in its most recent year, Hydro’s Power Smart plan cost approximately 29 cents for each kWh produced *in that year*. The reader should note that since the savings from energy efficiency typically last some 15 years, Hydro’s *equivalent annualized* cost – i.e. the same metric used to compare all electricity resource options – is approximately 2.9¢/kWh (29 cents divided by the present value of one kWh/yr over 15 years).

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<sup>27</sup> CAC\_GAC/MH II-010d

**FIGURE 13 – DSM Program Costs (first-year unit cost) and Savings**



Once again, the relationship between costs and targets is weak to negligible (an R-squared of 0.1). The plot suggests that most aggressive DSM savings, including the two Canadian cohorts, are being secured at costs in the range of 30 to 40 cents/first-year kWh. Assuming a real discount rate of 5.05% and an average useful life of 15 years, this implies unit costs in the range of **3¢/kWh to 4¢/kWh**.

This finding would also appear to be consistent with the EnerNOC potential study. While that study did not identify the utility cost of savings, analysis of its TRC ratios suggests utility costs for achieving the “market potential” scenario of approximately 3¢/kWh.<sup>28</sup> This is also consistent with MH’s current Power Smart plan costs, which are now coming in at a costs of approx. 3¢/kWh). **For planning purposes, I suggest using a unit cost of 3.5¢/kWh**, i.e. midway in the 3-4 cent range.

<sup>28</sup> In its response to CAC-GAC/MH I-011a, EnerNOC provided the benefit/cost ratios using the TRC – i.e. including both utility costs *and participant contributions* – of its “market potential”, which average out at just under 2:1 over time. Assuming a benefit (avoided cost) of approximately 8.5¢, this would suggest a total resource cost of savings of approximately 4.5¢/kWh. Assuming again that Manitoba Hydro pays for 2/3 of this cost (participants pay for the other third), we arrive at a levelized cost of savings for Manitoba Hydro of 3.0¢/kWh.

### *INNOVATIONS CONTINUOUSLY REPLENISH THE DSM RESERVOIR*

Improvements in energy efficiency are fundamentally about innovation. Innovations in technology, first and foremost, that lead to more efficient options, or that drive down the cost of those options (the move from incandescent light bulbs to CFLs and now to LEDs – a fourfold improvement in efficiency – is but one among hundreds of examples). Innovations too in computing power that allow us to collect and mine reams of consumption data in order to more efficiently identify savings opportunities (the advent of “touchless” building audits is an excellent example of this). And innovations in communications technologies and associated infrastructure, that allow us to collect that data more efficiently, and to communicate opportunities more effectively to customers (emerging “smart” thermostats are but one example).

While supply resources also benefit from technological innovations – wind and solar power are cases in point, as are fracking and horizontal drilling – their resource is in large part a function of nature: the size and slope of rivers, the amount of rainfall, the reserves of coal or gas in the ground, etc. In other words, innovation drives all energy options to some extent, but drives DSM far more.

The challenge of DSM for planning purposes, then, becomes the challenge of predicting innovations: we know they will happen, but we don’t know exactly how or how much. Yet the reverse is true too: we know that a static view – one in which future DSM savings are limited to the savings opportunities available today – is wholly inappropriate for a long-term planning horizon, much less one covering the coming 20 years.

**Yet this static view, which implicitly assumes zero innovations over the coming two decades, lies at the root of two important documents in the current proceeding: Manitoba Hydro’s Power Smart plan, which anticipates a significant reduction in new savings over the longer term, and EnerNOC’s potential study, which similarly assumes significant reductions in DSM potential over time. In both cases, a very real methodological challenge has led to a very unrealistic prognosis for the future of DSM.**

### *THE CASE OF SOLAR PV*

Solar photovoltaic power, or solar PV, was once a wildly expensive option, unthinkable from a resource planning perspective outside of niche markets like calculators, off-grid hunting camps, and far-away telecommunications towers. Yet a combination of technological advances and innovations, economies of scale, and international trade have dramatically altered the outlook for solar PV.

Solar PV costs have been declining sharply (10%/yr. on average since 2006), and are expected to continue to do so in the near future. The decline is such that solar will be deployed at unit costs unforeseen before.

Because of these declines, solar PV has begun to achieve “grid parity” – meaning that the cost to produce electricity from solar panels, on a ¢/kWh basis, is the same or cheaper than the cost of purchasing power from the grid (electricity rates) – in a handful of U.S. states. More importantly, various forecasts now expect grid parity to hit a large share of worldwide electricity demand as early as 2020.<sup>29</sup> This sudden competitiveness has caught many utilities and regulators by surprise, a feeling well summarized by Jon Wellinghoff, the recently-retired (2013) chairman of the U.S. Federal Energy Regulatory Commission (FERC):

“Solar is growing so fast it is going to overtake everything”<sup>30</sup>

In its evidence on the topic, Manitoba Hydro provided a chart – reproduced below as Figure 14<sup>31</sup> – that forecasts solar PV system costs through 2020 for two types of projects:<sup>32</sup>

- “Residential systems” refers to solar panels installed on residential rooftops, and includes the full cost of installations,
- “Utility systems” refers to what is commonly termed “utility-scale solar”, or “solar farms” that involve hundreds or thousands of panels; their scale makes them akin to a power plant, and

This chart anticipates residential system costs declining to \$1.12/watt by 2020. Given Manitoba’s annual sunshine (global solar radiation in Winnipeg based on Natural Resources Canada data), this translates into residential rooftop solar PV costing approximately 8¢/kWh by 2020.<sup>33</sup>

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<sup>29</sup> For example, a recent study from Navigant Research concluded: “By the end of 2020, solar PV is expected to be cost-competitive with retail electricity prices, without subsidies, in a significant portion of the world”. The same report anticipates 436,000 MW of new solar PV installations worldwide in the 2013-2020 timeframe.

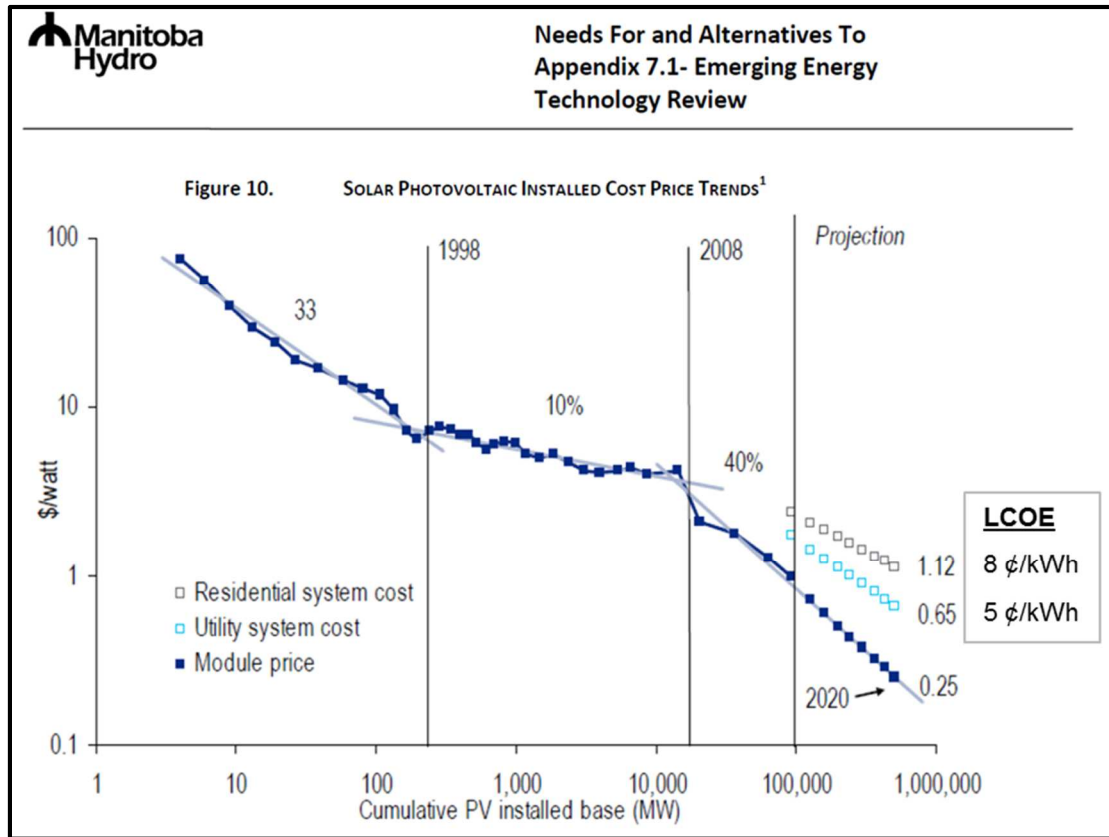
<sup>30</sup> See <http://www.greentechmedia.com/articles/read/ferc-chair-wellinghoff-sees-a-solar-future-and-a-utility-of-the-future>

<sup>31</sup> I note that the chart is actually taken from a 2013 report on the topic by Citigroup.

<sup>32</sup> The third point on the chart refers to the price of solar modules alone. Because power from solar PV involves more costs than just the modules (e.g. inverters), we do not discuss this further here.

<sup>33</sup> This is effectively the cost consumers would pay if they financed the cost of the panels over their lifetime, at a rate equivalent to Manitoba Hydro’s current weighted average cost of capital. In today’s interest rate environment, some customers have access to cheaper capital still (e.g. HELOC or mortgage rates).

FIGURE 14 – Projected Costs of Solar PV Systems



I note that if this cost forecast is correct, and given the utility's own projected rate increases, **residential Grid Parity would be reached in Manitoba well before the end of the current planning period.** Moreover, the graph's projections for utility-scale PV costs are even more dramatic (forecast cost of \$0.65/w by 2020). If this is accurate, **the cost of utility-scale solar in Manitoba would drop to approximately 5¢/kWh in Manitoba**, well below the projected levelized cost of Conawapa, by 2020.<sup>34</sup>

These are obviously significant developments, from three perspectives:

- **Internal demand:** adoption of cost-competitive solar by Manitobans could deplete demand, effectively growing the DSM reservoir by the addition of a new and powerful demand-side resource;
- **External demand:** adoption of solar in neighbouring states and provinces, whether by homes and businesses or at the utility scale, could suppress export prices; and

<sup>34</sup> Based on GSR in Winnipeg. Since utility-scale projects could be located further south, actual production may be somewhat higher (and ¢/kWh cost somewhat lower) as a result.

- **Manitoba Hydro's supply options:** solar could become the least-expensive generation option, if generation is still needed, for Manitoba Hydro to pursue.

I have some concerns about the aggressive PV price reductions forecast in Manitoba Hydro's evidence, which I would characterize as the upper bound of possibilities. As a result, we set out to assess "Grid Parity" – the most likely date at which residential rooftop solar PV becomes cheaper than power rates – using two cost reduction scenarios: the aggressive reduction scenario included in MH's evidence, which amounts to annual cost reductions of 18%, and a more conservative estimate based on a moderate 5%/yr. reduction (half the rate of annual improvements since 2006). Using these high/low cost scenarios, and accounting for both solar radiation data and incentives available in neighbouring provinces and states, our model assesses Grid Parity for Manitoba and its immediate neighbours: Ontario, Saskatchewan, Minnesota, and North Dakota.<sup>35</sup>

#### Case Study: Colorado's Xcel Energy Chooses Solar PV On Price Alone

For the first time, Xcel Energy says it is buying wind and solar power in Colorado not because of a mandate to use more renewables, but purely because the power will be competitive with natural gas.

Xcel has asked regulators to approve deals to buy 170 megawatts of solar power and 450 megawatts of wind power from projects under development by third parties. The utility would use its natural gas generation to balance the intermittent nature of the wind and solar resources.

Colorado has a renewable portfolio standard that requires investor-owned utilities to get 30% of their power from renewables by 2020. Xcel is on pace to meet the standard.

"This is the first time that we've seen, purely on a price basis, that the solar projects made the cut—without considering carbon costs or the need to comply with a renewable energy standard—strictly on an economic basis," said David Eves, CEO of Public Service of Colorado. It's likely that more utility CEOs will be telling the same story if the cost of solar photovoltaic panels continues to fall and federal and state tax incentives remain in place.

From <http://www.utilitydive.com/news/for-first-time-price-the-only-reason-xcel-is-buying-renewables/177906/> (Oct. 3, 2013)

As can be seen on the chart below, two of the five regions (Ontario and Minnesota) recently hit grid parity (though in the case of Ontario, through a very deliberate and aggressive policy strategy). Saskatchewan, meanwhile, will hit parity within the coming 4 years, depending on which cost reduction scenario is correct, and North Dakota sometime in the 2015-22 timeframe. In Manitoba, using the same assumptions, **rooftop solar should be at parity with residential power rates as early as 2018 (using Manitoba Hydro's projected costs), or as late as 2026 (using our more conservative cost reduction estimates)**, the latter being, coincidentally, the year of Conawapa's anticipated in-service date. Of course,

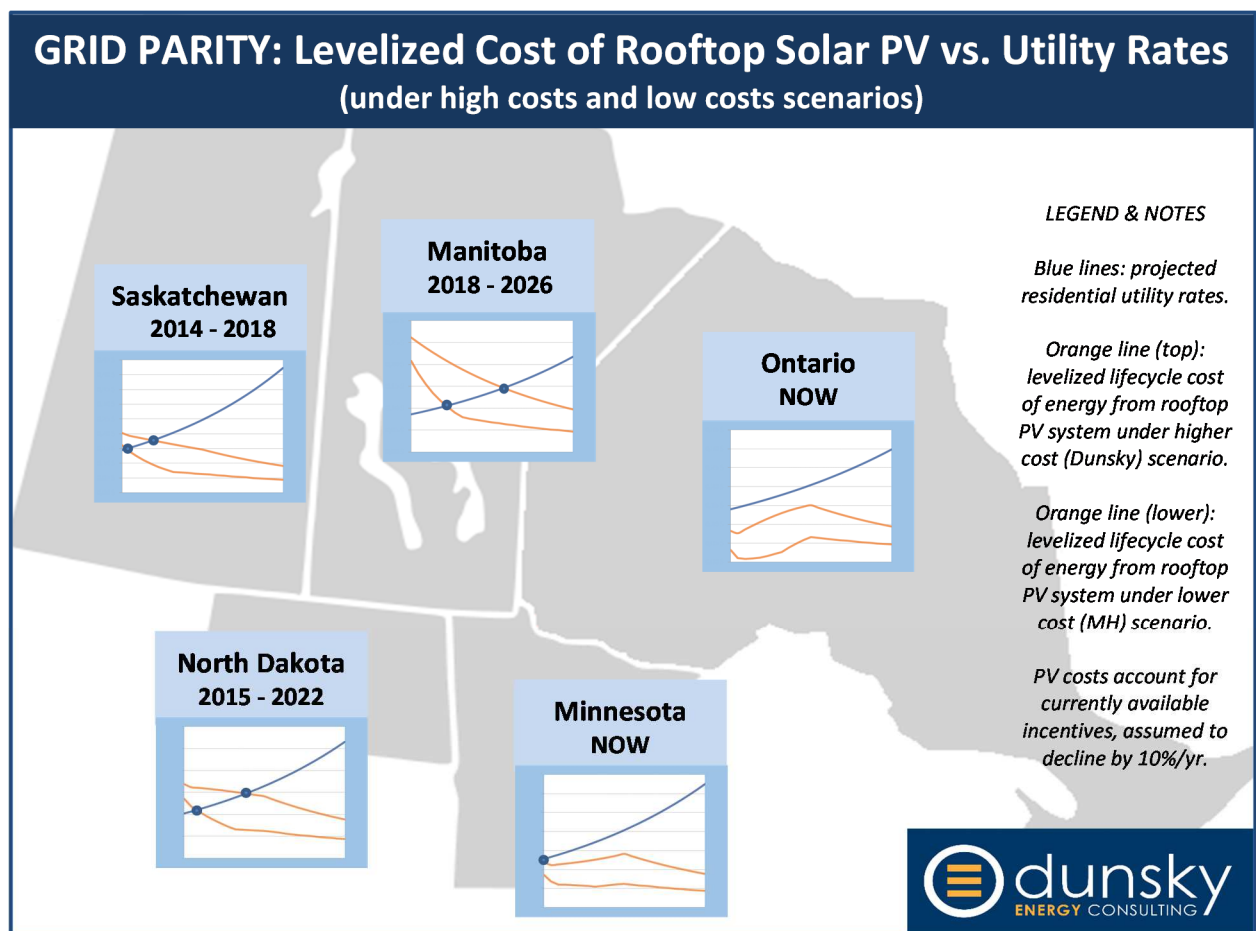
<sup>35</sup> Two methodological notes: (1) To acknowledge the fact that solar PV can produce when the grid is off-peak or when the customer is drawing power at the first tier rate, we use *average* residential prices, rather than (commonly-higher) marginal rates; and (2) to acknowledge the fact that some existing incentives could be reduced or replaced in the near future, and/or that solar integration charges could be considered, we reduced current solar PV incentives linearly by 10% starting in 2015.



incentives (rebates, tax credits, feed-in-tariffs, etc.) and faster-than-expected system cost decreases can further speed up the process.<sup>36</sup>

The chart below illustrates these findings.

**FIGURE 15 – Residential Solar PV System Grid Parity**



The implications of grid parity are of course significant. I do not anticipate a sudden “solar outbreak” – capital barriers and lack of interest will invariably create an adoption lag. Yet over

<sup>36</sup> It is important to note that contrary to common belief, cold climates like Manitoba’s can offer strong solar PV potential. In fact, Manitoba’s potential is amongst the highest in Canada (after Alberta and Saskatchewan). The province’s production suffers in winter months due to the shorter days, but this is offset by higher production during the summer because of longer days; furthermore, PV power conversion efficiencies actually improve in cold weather (or mild summer weather). Another issue – the angle at which the sun hits land in the winter (an acute angle reduces solar radiation per m<sup>2</sup> of land) – can be corrected by adjusting the tilt of solar panels (there is still a loss of production due to the inclination of the sun but much less severe than what the outside temperature would suggest). Snow accumulation can be addressed in part by appropriate solar PV installation designs; however occasional manual labour to remove snow may be required.

time, and barring a sudden reversal of the solar cost trajectory, there is little doubt that solar PV will contribute significantly to the pool of future demand-side management opportunities, both in Manitoba *and* in the province's export regions. These opportunities will not be unlike other energy saving opportunities for residential customers: adoption will take time, and can be influenced by voluntary programs that provide some combination of information, incentives, financing, and other tools.

This is just one example – though a clearly historic one – of the continuous innovation and technological progress that has – and will into the future – continue to replenish the DSM potential.

## WHAT ABOUT CAPACITY (MW) NEEDS? THE ROLE OF DEMAND RESPONSE

Manitoba Hydro has stated repeatedly that capacity issues are not the primary driver for its proposed capital plans. According to Hydro, the need for additional generation is based on future dependable energy supply, not system peak demand, so there is no strong driver to invest in programs (or generation) for capacity or load shifting<sup>37</sup>. Given this, the utility has neglected to even assess demand response (DR) options, and has no plans for capacity reduction efforts beyond its currently Curtailable Rates Program for Industrial Customers.<sup>38</sup>

This lack of interest might be understandable, yet the question remains: what if the context were to change and Manitoba Hydro *were* in need of new capacity resources?

## CAPACITY SAVINGS FROM ENERGY EFFICIENCY PROGRAMS

But addressing additional demand response opportunities, it is important to point out that “traditional” DSM activities focused primarily on energy savings also produce capacity savings. Measures such as efficient lighting, building insulation or fuel switching all reduce the amount of energy used at peak, to varying degrees, and as such produce varying levels of capacity savings. These MWs can be relied upon, even if they are “passive” in nature: once a home is insulated, a geothermal heating system is installed or lighting is retrofitted, for example, the peak consumption for these end uses will be reduced for the lifetime of the measures (and beyond, assuming replacement by similarly efficient systems).

Based on our two scenarios for more aggressive DSM in Manitoba, and using Manitoba Hydro's current Power Smart ratio of capacity to energy savings, I estimate the peak load reduction of

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<sup>37</sup> CAC\_GAC/MH I-030b

<sup>38</sup> CAC\_GAC/MH I-303b, CAC\_GAC/MH I-031a

our scenarios at approximately 1,000 MW by 2025 (specifically 1,045 MW for scenario A, and 957 MW for scenario B).

**FIGURE 16 – Estimated DSM Peak Load Savings from Aggressive Scenarios - 2025**

	Energy Savings (at meter)	MW/GWh Ratio <sup>39</sup> (of current PS Plan)	Capacity Savings (at generator)
<b>Dunsky Scen. A</b>	4,364 GWh	0.239	<b>1,045 MW</b>
<b>Dunsky Scen. B</b>	3,999 GWh		<b>957 MW</b>

#### **ADDITIONAL OPPORTUNITIES FROM DEMAND RESPONSE**

At this point in time, we understand that the Manitoba Hydro system does not need additional capacity beyond the 1,000 MW our two DSM scenarios would produce. Yet should needs change, it is worth noting the large untapped potential for demand response. Indeed, complementary demand response resources can provide additional capacity savings, including dependable and dispatchable capacity, and are increasingly the focus of attention in other regions.

In its most recent Power Smart plan, Manitoba Hydro estimates that it will have 161 MW of demand response (DR) assets available in each of the 3 years covered by the plan, increasing to 162 MW in 2027 for planning purposes.<sup>40</sup> This corresponds to a peak load reduction of roughly 3.5%. In this proceeding, Manitoba Hydro confirmed that its demand response effort is currently limited to a curtailable load program for qualifying industrial customers<sup>41</sup>, which is used for reliability, contingency reserves and firm energy requirements.<sup>42</sup> Thus, in addition to the 1,000 MW from DSM, Manitoba Hydro would have an additional 160 MW at its disposal based on current and projected curtailable loads.

Yet curtailable loads are only one of a number of demand response opportunities. Indeed, the area of DR has garnered significant attention in the past several years as a combination of needs and technological progress has opened new opportunities for utilities throughout the continent.

To provide an initial estimate of the resource available to Manitoba Hydro, I leveraged two demand response potential studies that my firm led or was involved with in the past two years. It is worth noting that these studies were conducted for *Canadian* utility clients – specifically for two provinces that share many common characteristics with Manitoba, including climate, prevalence of electric space heating, and large industrial loads.

<sup>39</sup> Excluding MW savings from the curtailable rate program, to avoid double-counting.

<sup>40</sup> All energy savings (GWh) are at meter and all capacity savings (MW) are at generator.

<sup>41</sup> CAC\_GAC/MH I-031b

<sup>42</sup> CAC\_GAC/MH I-031g

Based on these studies, I estimated the achievable DR potential in Manitoba at between 6.2% and 12.7% by 2025. I note that these estimates fall within the range of results from two important U.S.-based potential studies (they found savings opportunities to range between 4.6% and 15.1%).<sup>43</sup>

Using this range as a reasonable proxy of achievable DR in Manitoba by 2025, I calculated the capacity savings potential after adjusting for our DSM-driven load reduction scenarios, as well as the existing curtailable rates.

**FIGURE 17 – Estimated Total Peak Load Savings Opportunity by 2025**

	Lower Scenario	Higher Scenario
<b>Peak Savings from Energy-focused DSM</b>	<b>957</b>	<b>1,045</b>
MH's Existing Curtailable Rate	162	162
<b>Additional DR Activities</b>	<b>122</b>	<b>413</b>
<b>TOTAL</b> <i>% of 2025 peak load</i>	<b>1,241 MW</b> 23%	<b>1,619 MW</b> 30%

In other words, for planning purposes, a robust demand-side management effort could generate approximately 1,200 MW to 1,600 MW of capacity savings, in addition to the energy savings discussed previously.

#### **WHAT KIND OF PROGRAMS COULD BE DEPLOYED TO ACHIEVE THESE SAVINGS?**

As stated earlier, Manitoba Hydro already has curtailable rates in place for industrial customers. While large industrial loads do represent an important part of the potential, Direct Load Control (DLC) and Time of Use rates (TOU), combined with enabling technologies like “smart” thermostats (see sidebar on next page) or connected water heaters, represent other opportunity areas which also offer significant potential.

End uses with particularly high potentials vary by sector. For the residential sector, water heating and space heating offer strong potential for savings in the province. Lighting, ventilation and cooling end uses can provide additional savings in the commercial sector. Another strategy to capture capacity savings is through partial fuel switching to reduce peak demand. An

<sup>43</sup> Federal Energy Regulatory Commission (FERC), June 2009. “A National Assessment of Demand Response Potential”, The Brattle Group / Freeman, Sullivan & CO / Global Energy Partners, LCC; and Electric Power Research Institute (EPRI), *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. 2010-2030*, January 2009. Note that Manitoba Hydro might have higher DR potentials due to its industrial structure, which lends itself to curtailment rates.

electrically heated building can be outfitted with a fossil fuel heating system to take part or all of the heating load on hours where peak capacity is an issue. This approach has been used extensively by Hydro Quebec in the residential and commercial sectors.

## SUMMARY

**Clearly the savings opportunity in Manitoba is significantly greater than either Manitoba Hydro's current Power Smart plan, or the market potential identified in the potential study. Based on our review of the EnerNOC study, on our own experience with DSM portfolios across the continent, on our updated benchmarking exercise, and on our knowledge of Manitoba in particular, I conclude that Manitoba Hydro could ramp its total DSM savings plan, including currently-projected codes and standards – to an average of 1.3 to 1.5% per year over the coming decade. While it would still lag behind regions like Vermont or Massachusetts, this level of savings would put the utility on par with other leading regions that resemble it more closely, such as Minnesota, B.C. or Nova Scotia. This level of savings will produce cumulative annual energy savings upward of 3,200 to 3,500 GWh by 2023/24, with more to come. Furthermore, this should be achievable at costs – in the range of 3-4¢/kWh – far below new generation costs as well as projected export prices.**

**I also note that the combination of continuous improvements in technology, combined with the “game-changing” advent of cost-competitive, customer-sited solar PV in Manitoba, should provide confidence, at least for planning purposes, that this level of incremental savings can be sustained throughout the planning horizon.<sup>44</sup> As such, I urge the PUB to plan for sustained incremental annual savings, following the initial 10-year period, at the level of the tenth year. Finally, while Manitoba Hydro does not anticipate peak capacity constraints, I note that the combination of the aforementioned, energy-focused DSM savings, as well as**

## CASE STUDY: SMART THERMOSTATS

Communications-enabled, or “smart” thermostats, encompass a broad array of technologies and service options, including “Basic” WiFi communications platforms, advanced programming platforms, “Smart” functionalities, and feedback functions. DR-enabled functions can further provide utilities with direct load control options.

The current market for programmable communicating thermostats is mostly driven by utility programs, focusing mainly on peak demand reduction programs. The market is evolving rapidly, with new partnerships and players increasing their presence and services for consumers.

The ability to receive control signals from a remote server translates into a built-in Demand Response Capability. Various strategies are used by thermostat manufacturers to deliver peak reduction during a demand response event. Those include primarily changing the temperature set points, cycling the HVAC mode, and pre-conditioning the home prior to the demand response event.

The manufacturer or service provider can provide up-to-date, accurate curtailment potential and near real-time feedback on participation, thus increasing achieved peak reduction results reliability while reducing the measurement and verification requirements.

<sup>44</sup> The only caveat to this remark is that depending on the evolution of solar PV, it is not clear at this stage whether the resulting “savings” – or reduced demand for grid-supplied power – will be attributable to utility programs per se. This changes nothing to the supply-demand picture for planning purposes, but may represent a cost-saving opportunity for the utility.

**additional opportunities related to demand response, could provide the utility with capacity savings in the range of 1,200 to 1,600 MW by 2025. These savings estimates, derived from what I consider to be a high level assessment, would need to be firmed up by a more detailed assessment, but can be used for planning purposes in the current proceeding.**

## CONCLUSIONS AND RECOMMENDATIONS

I have assessed the evidence in this proceeding, and have concluded that Manitoba Hydro could make far greater use of demand-side management opportunities – including energy efficiency, fuel switching, customer-sited renewables and, if needed, demand response – than is currently anticipated, and at much lower cost than the alternatives.

Specifically, I believe that the utility should, for planning purposes, plan on savings on the order of 3.2 to 3.5 TWh/year by 2023/24, increasing by at least 0.3-0.4 TWh per year thereafter. These savings should be assumed to cost approximately 3.5¢/kWh to procure. Similarly, while peak needs do not appear to be a driver for current planning, I note that approximately 1,200 to 1,600 MW of peak capacity savings can be made available for planning purposes by 2025, the vast majority attributable to the same DSM initiatives that would provide the energy savings noted previously.

While the scope of my work did not include an assessment of the impact such savings would have on the need for (or value of) specific capital projects, I encourage the Board to ensure that the implications of this resource are fully considered prior to authorizing capital commitments. Without full consideration of the demand-side resource, there is a very real risk that the opportunity for resource planning to effectively minimize costs and risks to ratepayers, as to society as a whole, may not be realized.

## APPENDIX A : SUMMARY REVIEW OF THE POTENTIAL STUDY PARAMETERS

The table below summarizes the findings of our review of the EnerNOC potential study. Note that we have focused below on key parameters of the study insofar as they may impact overall savings results. Specifically, we have identified a number of savings opportunity areas that were left out of the study (in many cases because they were excluded from the study's scope), as well as a number of methodological limitations to the economic screening process that may have impacted the number of measures considered cost-effective.

In the table below, the symbols (↓, ↔ and ↑) indicate the direction in which each potential – technical, economic, or maximum achievable (“Market”) – would likely change using more appropriate or comprehensive study parameters.

ISSUE	Technical potential	Economic potential	Market potential
<b>Exclusions: Measures</b>	↑	↑	↑
<p>A significant number of measures were screened out at the technical level<sup>45</sup>. Of them, a surprising number were excluded because they were “not included in the initial market profile”<sup>46</sup>. This includes air source heat pumps for the residential sector (ASHP), for example, despite extraordinary progress in ASHP efficiencies (much higher), noise (much lower), and ability to operate in cold climates (new models designed specifically for cold climates). Others were excluded because they were thought to be not cost-effective or to have low savings (solar water heater, heat traps, etc.), although these are reasons to exclude the measures at the economic, not the technical, potential level.</p>			

<sup>45</sup> CAC\_GAC/MH I-005a

<sup>46</sup> CAC\_GAC/MH II-002



ISSUE	Technical potential	Economic potential	Market potential
<b>Exclusions: Industrial Loads</b>	↑	↑	↑
<p>Industrial processes, which represent more than half of MH's industrial load, account for only 14% of the industrial economic potential. A large share of industrial processes is considered saturated and has been excluded from the potential study<sup>47</sup>. No new technology advances related to industrial processes seem to have been included to account for future technology development.</p>			
<b>Exclusions: Misc. Loads</b>	↑	↑	↑
<p>Large loads are attributed to “miscellaneous” line items in the residential and commercial sectors to account for unknown future end-uses. This may be entirely reasonable: it may reflect the growth in plug loads, for example, and is accounting for it is analogous to our argument of the need to account for anticipated but unknown technology improvements over time (see “Future Technologies” issue below). However, the study assumes zero efficiency savings from these loads, a wholly unrealistic assumption that understates the savings potential.</p>			

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<sup>47</sup> CAC\_GAC/MH I-025a to CAC\_GAC/MH I-025c.

ISSUE	Technical potential	Economic potential	Market potential
<b>Exclusions: Fuel Switching</b>	↑	↑	↑
<p>We understand that a part of MH’s anticipated load growth stems from a growing shift toward electric space and, more importantly, water heating (market shares of the latter are forecast to climb from 49% to 63%). We also understand that the potential study was limited strictly to energy efficiency measures – as opposed to the broader suite of demand-side management opportunities – and as such, programs designed to discourage adoption of electric heat, or to encourage switching to certain non-electric heat sources, were not included in the study.</p>			
<b>Exclusions: Demand-Side Renewables</b>	↑	↑	↑
<p>Once considered very niche opportunities, demand-side renewable energy generation – and in particular rooftop solar photovoltaic – represents a significant growth area for demand-side electricity opportunities. And while somewhat different that efficient end-use equipment, their end result – reductions in the need for grid-supplied power – is the same. Not accounting for potential gains from solar or other demand-side renewables, while still too common for potential studies, nonetheless leaves considerable additional opportunities off the table.</p>			

ISSUE	Technical potential	Economic potential	Market potential
<b>Exclusions: Early Retirement Opportunities</b>	↑	↑	↑
<p>While many DSM programs encourage adoption of high-efficiency measures <i>within</i> the natural investment cycle (e.g. at burnout, or for new construction), it is also common for programs to encourage the <i>early replacement</i> of existing but inefficient equipment. Unfortunately, the potential study ignored the potential for early replacement measures, which generate greater savings (savings during the remaining life of the existing equipment should be calculated using the old unit's energy consumption, not a new unit's consumption, as the baseline).<sup>48</sup></p>			
<b>Exclusions: More stringent regulations (C&amp;S)</b>	↔	↔	↑
<p>Market adoption could be increased significantly by adoption of more aggressive codes &amp; standards in the province, as well as by other regulations (eg. mandating building performance labelling). In fact, Manitoba has a history of adopting strong codes and standards, yet further improvements were not considered in the achievable potential.<sup>49</sup> Adoption of more stringent codes and standards can drive market adoption rates to near-100%, rather than the much lower rates considered “achievable” in their absence.</p>			

<sup>48</sup> CAC\_GAC/MH II-003

<sup>49</sup> CAC\_GAC/MH I-024c, CAC\_GAC/MH I-024e

ISSUE	Technical potential	Economic potential	Market potential
<b>Exclusions: Rate Structure</b>	↔	↔	↑
<p>Increased adoption of energy efficiency options – including of DSM program offerings – would be encouraged if Manitoba Hydro’s rate structure were modified (without changing the <i>average</i> rate) to provide a clearer price signal to consumers. This was done recently in British Columbia, where consumers are now able to benefit more from their conservation efforts. However, it is not clear if the impact of such strategies was considered in the market achievable potential.<sup>50</sup></p>			
<b>Exclusions: Future Technologies</b>	↑	↑	↑
<p>Technological innovations are constantly bringing new opportunities to the efficiency table, whether through more efficient products, or cost reductions in existing high-efficiency products. Accounting for such progress in a potential study is difficult, but equally daunting is ignoring the likely improvements altogether. Some of the more recent potential studies have begun accounting for anticipated improvements, but this study did not. We note that this likely explains why the potential appears to taper off over the longer term.</p>			

<sup>50</sup> CAC\_GAC/MH I-024c, CAC\_GAC/MH I-024e

ISSUE	Technical potential	Economic potential	Market potential
<b>Discrepancy: Missing Loads</b>	↑	↑	↑
<p>Alignment of a potential study with the load forecast is critical, as the savings potential itself is driven in large part by the combination of stock turnover (of equipment, buildings, etc.) and stock growth (eg. new construction and associated load increases). Yet the load forecast used by the potential study (renamed “Projections” in the revised version) is significantly <i>lower</i> than Manitoba Hydro’s forecast. In this case, the discrepancy necessarily implies a significant understatement of the energy savings potential.</p>			
<b>Discount Rate</b>	↔	↑	↑
<p>The real discount rate used for the potential study (5.95%) is considerably higher than the rate used for MH’s supply options (5.05%)<sup>51</sup>. While likely a result of the study’s timing, this is clearly inconsistent and detrimental to DSM as it understates the benefits of DSM. Furthermore, leading jurisdictions increasingly opt for a much lower discount rate – a societal rate designed to better reflect the DSM resource’s lower risk and/or actual cost structure – in the range of 3%, or half of Manitoba Hydro’s value. The arguments used for a societal rate apply to a very large degree to MH’s context.</p>			

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<sup>51</sup> CAC\_GAC/MH I-012

ISSUE	Technical potential	Economic potential	Market potential
<b>Benefit-Cost Threshold</b>	↔	↑	↑
	<p>The potential study uses a threshold of 1 at the measure level (a measure with benefits equal or greater than costs “passes” and is included in the economic potential). This is overly restrictive, as it excludes measures that may be anticipated to become cost-effective in the near- or mid-term, or that ought to be pursued for other reasons, such as equity in the case of low-income customers. Given this, potential studies commonly apply a B/C threshold below 1, for example at 0.7 or 0.5, to ensure that the study is more reflective of the real-world of DSM programs.</p>		
<b>Measure Bundling</b>	↔	↑	↑
	<p>Measures are screened on an individual basis. In practice, both markets and DSM programs often promote <i>bundles</i> of measures, just as DSM plans are more commonly screened at the program or even portfolio level. Screening at the lowest common denominator results in excluded measures that may be cost-effective when bundled with similar measures; as a result, real-world DSM measures may be excluded entirely from the potential analysis.</p>		

ISSUE	Technical potential	Economic potential	Market potential
Non-Energy Benefits (NEBs)	↔	↑	↑
<p>The potential study uses the Total Resource Cost (TRC) test, which is the most common approach for this type of study. However, since the TRC accounts for <i>all costs</i>, including those borne by participants directly rather than by Manitoba Hydro and its ratepayers, proper application of the TRC requires accounting for the non-energy benefits that similarly accrue to participants. These NEBs can be significant.</p> <p>In this case, NEBs are excluded from the analysis, with the sole exception of water savings. It is worth noting that accounting for NEBs is by no means common practice for potential studies, given the difficulty in monetizing them; however, recognition of their presence is one of the reasons that studies commonly set the B/C threshold at far below 1 (see “Benefit-Cost Threshold” above).</p>			



50 Ste-Catherine St. West, suite 420, Montreal, Québec, Canada H2X 3V4 | T. 514.504.9030 | F. 514.289.2665 | [info@dunsky.ca](mailto:info@dunsky.ca)

[www.dunsky.ca](http://www.dunsky.ca)