34 King Street East, Suite 600
Toronto, Ontario, M5C 2X8
elenchus.ca

NFAT Review:
A Review of Manitoba Hydro's Demand Side Management Plan

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
The Manitoba Public Utilities Board
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1 EXECUTIVE SUMMARY

Manitoba Hydro (MH) has formulated a Preferred Development Plan which the Manitoba Public Utilities Board (PUB) is reviewing under *The Public Utilities Act*. This plan and alternatives to it are being assessed through a Needs For and Alternatives To (NFAT) review. The PUB panel is required to provide a report with recommendations by June 20, 2014. Elenchus Research Associates ("Elenchus") is one of the team of Independent Expert Consultants (IECs) established by the PUB to assist its review. The detailed Scope of Work (SOW) for Elenchus' work is attached as Appendix 1. This report addresses the Demand-Side Management (DSM) questions and provides guidance to the PUB with regard to the issues raised in the SOW.

Elenchus observes that there is considerable uncertainty regarding how much load reduction from DSM upon which MH may rely at various points in the future. Elenchus concludes that this uncertainty, in isolation from other factors beyond the scope of thus report, is not so great that the proposed Keeyask Generating Station (GS) should be deferred. However, PUB may consider as a precondition to the authorization of Conawapa GS, that MH develop a more rigorous approach to the integration of DSM load reductions with system planning. The return to Integrated Resource Planning (IRP) is advised.

It is anticipated that by adopting a more rigorous IRP approach, MH could realize significantly greater DSM savings that would translate into lower net loads requiring investment in incremental generation capacity. It is noteworthy that DSM is not achieved through a one-time effort (like building a generation station) but rather by continuous DSM program delivery to accumulate savings over years of investment.

In particular, two enhancements to the existing methodologies could be considered:

- A long term statistical study comparing electricity use by participating and non-participating customers of MH with a view to improving estimates of tertiary (end use) consumption of electricity.
- The explicit use of DSM dependability factors for the incorporation of DSM load reductions into Resource Plans.

In addition, Elenchus suggests that PUB consider making it a precondition for the future assessment of the In-Service Date (ISD) for Conawapa that a comprehensive ecological footprint analysis or its equivalent be carried out for all options, including DSM.

2 INTRODUCTION

2.1 ELENCHUS' REMIT

Manitoba Hydro (MH) has formulated a Preferred Development Plan which the Manitoba Public Utilities Board (PUB) is reviewing under The Public Utilities Act. This plan and alternatives to it are being assessed through a Needs For and Alternatives To (NFAT) review. The PUB panel is required to provide a report with recommendations by June 20, 2014. Elenchus Research Associates ("Elenchus") is one of the team of Independent Expert Consultants (IECs) established by the PUB to assist its review.[1] The detailed Scope of Work (SOW) for Elenchus' work is attached as Appendix 1. This report addresses the Demand and Supply Management (DSM) questions and provides guidance to the PUB regarding the issues raised in the SOW.

In Board orders 119/13 and 127/13, the PUB set out its views on the role of IECs and requirements for MH to respond to Information Requests (IRs). Pursuant to these orders, Elenchus staff had a number of informal discussions to obtain answers to IRs that Elenchus had prepared. Throughout this report where there is no citation to the NFAT evidence or other sources of evidence provided by MH reference is made to these discussions. There are other participants in the NFAT review process who are assessing MH's approach to DSM; Elenchus has sought to complement this work, which is overwhelmingly concerned with issues of detail, and consequently this report, while informed by Elenchus' own detailed review of the relevant DSM documents, addresses higher level or more conceptual issues.

2.2 CONTEXT FOR THE REVIEW OF DSM

DSM is the main institutional response[2] to the challenge of using energy efficiency (EE) as an alternative to supply.[3] But DSM differs from generation resources in an important way: like the

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[1] Agreement between PUB and ERA dated August 27, 2013

[2] Throughout this report DSM is taken to be all of MH's EE programs. Any additional EE or conservation is assumed to be provided by other agencies or by consumer responses in the marketplace.

[3] In the late 1970s a radical approach to energy policy based on energy efficiency (EE), small scale renewable energy and a de-emphasis of supply was proposed by Amory Lovins, among others. Lovins referred to such energy policy as a "Soft Path", in contrast with the conventional "Hard path" based on expanding large-scale supply facilities. (The classic paper is "*Energy Policy, the Road not Taken"*, **Foreign Affairs,** November 1978.) The Soft path approach was resisted by policy makers for many

grin of the Cheshire Cat of *Alice in Wonderland*, the estimated savings are visible but the actual level of consumption without DSM (the body of the cat) is unobservable (or only fleetingly so). In practice, the now countless DSM programs that have been put in place employ Estimation and Measurement and Verification (E,M&V) protocols to justify estimates of saving. While estimation and measurement present no conceptual difficulties, verification assumes that there is an actual observed value against which to compare observed consumption; this is not possible.[4] What we actually have are measurement protocols which yield estimated savings, the accuracy of which is unknown. More importantly, the bounds for the possible inaccuracy are not well known.

Figure 1 below presents a conceptual framework for estimating future DSM load savings.

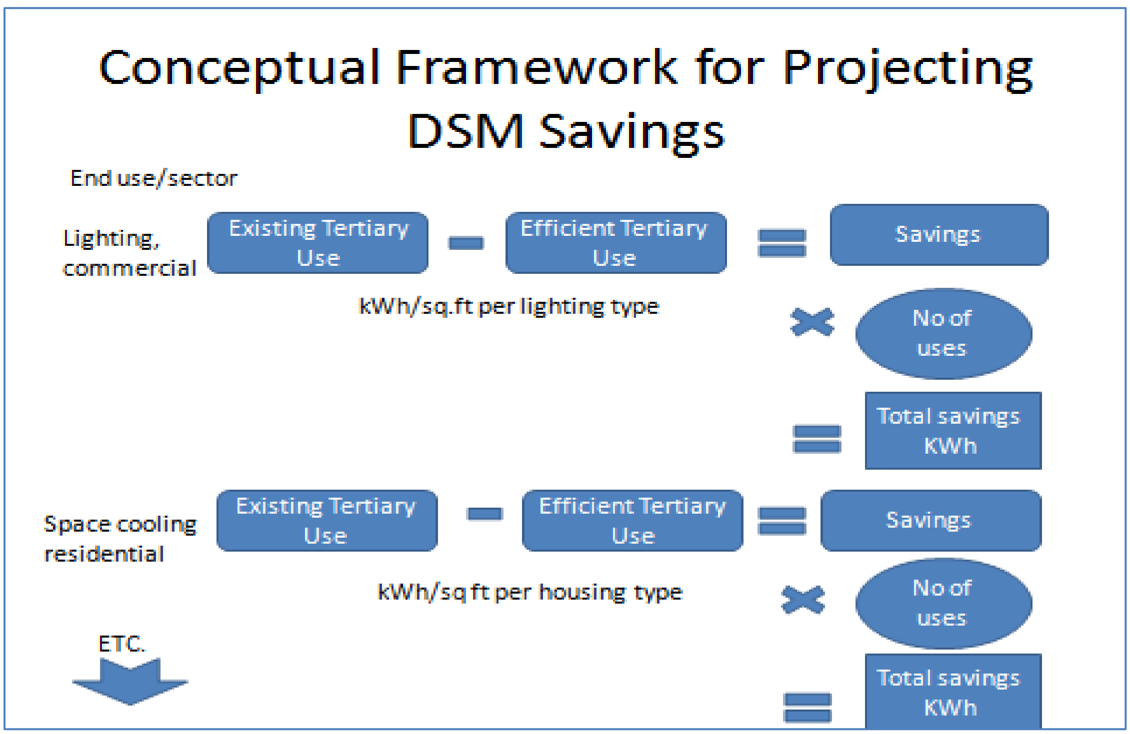

Figure 1

years but then became slowly institutionalized as "Conservation and Demand Management" or "Demand and Supply Management" ("CDM/DSM"). In some jurisdictions, EE was fully integrated into energy utility planning as "Integrated Resource Planning" (IRP) which seeks to evaluate supply and demand reduction options on the same basis to derive the overall "least cost" plan.

4 While this report does not purport to be a thoroughgoing analysis and critique of DSM EM &V reference is made to this literature. However, no protocols or methodological guidelines can change the central theoretical issue, which is that DSM savings estimates are in principle not falsifiable. It is important to understand the logical consequences of this shortcoming and we also provide some empirical heuristics for dealing with the irreducible uncertainties of DSM in the context of system requirements for very high reliability of supply down to a few seconds (i.e. Automated Generation Control (AGC)).

There are two kinds of uncertainties that lie behind the Cheshire Cat grin: the values of the tertiary electricity usages (existing and more efficient); and the number of end uses.[5] The former are determined by both the technology and the specific uses of the technology; the latter by demographics and market factors. For example, the technical output of a type of light bulb, measured in lumens, is the same for individual bulbs within the statistical bounds set by quality control but the amount of light – hence the number of bulbs - varies from user to user (i.e. some users prefer more or less light than others). In the example in **Figure 1** area is taken as a proxy for lumens since demographic data on lumens is scarce. This necessarily introduces uncertainty in projecting the total DSM savings. Demographic and market factors have even greater uncertainties; this is discussed in more detail in 3.3.2.2.

An analogy from the physical sciences is instructive. In Quantum Mechanics the position and momentum of a particle cannot be known exactly. The famous Heisenberg Uncertainty Principle formalizes the relationship as follows: while there is uncertainty regarding the values of position and momentum, there is a precise limit to that uncertainty.[6] By analogy, while the value of energy savings from DSM is not knowable we may be able to put some bounds on the uncertainty. This leads to the central problem that DSM presents for system planners – how much reduced load on which to rely and the corresponding capacity reductions.

A spectrum of responses may be noted:

- Treating any load reduction activities as part of load forecasting ("top down"), an approach which is now rare;
- At the other end of spectrum we have least-cost Integrated Resource Planning (IRP) in which energy efficiency is evaluated the same as supply options (using Levelized Unit Energy Costs (LUEC)) ("bottom up"); and,
- Most utilities have been somewhere in the middle – a combination of bottom up and top down and MH falls into this category.

[5] The definitions of primary, secondary and tertiary energy capture the process of transformation. Primary energy is the energy embodied in primary sources such as, sunlight and fossil fuels; secondary energy is energy made available by transforming primary energy by combustion or photosynthesis, for example. Tertiary energy is the energy used to provide specific services such as heating, cooling and lighting.

[6] More formally, the product of the standard deviations of position and momentum of, say, an electron, is greater than or equal to Planck's constant divided by 2.

This evaluation concentrates on the criterion of **coherence**, while others are addressing the detailed assumptions about DSM in MH's Business Plan. Coherence is not a straightforward criterion but two key metrics may assist in evaluating the coherence of a DSM plan; capacity reserve and load factor. In a more qualitative way, the criterion of coherence is concerned with the marriage of "bottom up" and "top down" approaches to DSM.[7]

Capacity reserve; not an exact concept but provides bounds for the analysis. Capacity reserve is defined as the percent of capacity in excess of projected peak demand. Determining the correct amount of capacity reserve is a matter of judgment.[8] For purposes of this analysis there is no attempt to second-guess the judgments of MH planners, rather the criterion of coherence merely examines the pattern of capacity reserve over the study period to 2028/29. MH's historic and projected capacity reserve is plotted in **Figure 2** along with system load and capacity (CF) factors and the Load Factor for estimated DSM savings.[9]

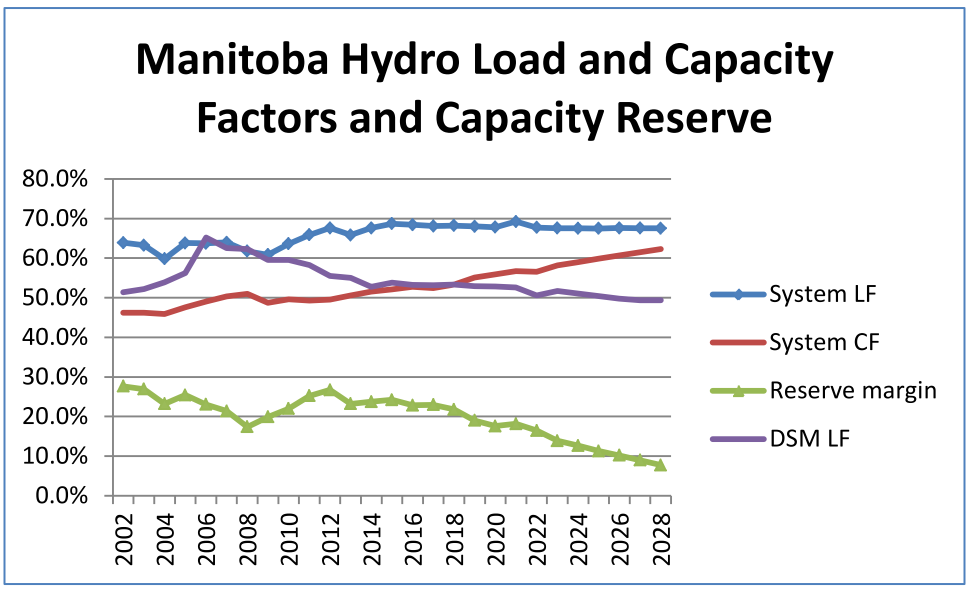

Figure 2

[7] See, for example, **Rivers, N and Jaccard M,** *Combining Top-Down and Bottom-Up Approaches To Energy-Economy Modeling Using Discrete Choice Methods* **The Energy Journal***,* 2005 26(1) at. 83

[8] Larratt Higgins, the doyen of Ontario Hydro forecasters was fond of applying Sir John Macdonald's maxim on whisky to reserve capacity, "A little bit too much is just enough".

[9] Data sources: MH's 2013 load forecast (Appendix D of the NFAT Business Case); MH's Power Resource Plan (Appendix B). As explained in 3.3.2.4, the DSM LF does not include the Curtailable Rate program.

Load factor (LF) is used as a diagnostic tool like a physician's use body temperature; a high-level state variable that is taken to reflect the overall condition of the system. Like body temperature, LFs are very stable and projections that depart from this are suspect.

Recent experiences with decentralized renewable energy have pointed to a promising approach to DSM that builds on IRP. Systems which have added significant amounts of wind power are learning to operate their systems to be able to accommodate the variability and volatility of wind power.[10] As more wind capacity has been brought on system operators are able to build up a progressively more certain estimate of the amount of wind capacity that is stochastically equivalent to dependable generation.

A rigorous approach to IRP, one that treats energy efficiency as exactly equivalent to generation, would recognize a fundamental asymmetry between energy efficiency measures and new capacity. If estimated savings are underestimated (i.e. future load is lower), the central operator merely dispatches less generation. However, capacity not built cannot be dispatched. If energy efficiency estimates prove to be overestimates of savings, supply must still be available. One way to address this asymmetry would be to assess energy efficiency measures rated as dependable capacity akin to wind (there is no dependable energy without dependable capacity). However, as noted there is a big difference: wind output can be measured; DSM estimates largely rely on engineering assumptions or assumptions about "baseline" usage which would have occurred without DSM, not measurements.

Systems planners would never base supply on engineering specifications (i.e. nameplate capacity versus operational experience). While we are not aware of jurisdictions which have yet taken such an approach, California has taken a significant step in this direction.[11] Moreover, the addition of significant amounts of wind capacity to electricity systems is relatively new, even in Europe, and system operators are still developing appropriate tools to manage wind capacity. The natural extension of these tools to DSM may well begin to occur in the next five years or so. While such work does not affect the decision on Keeyask, Elenchus expects that MH will periodically review the appropriate ISD for Conawapa. Elenchus suggests that the adoption of

[10] For a recent discussion see Garg, R., **Wind Integration Cost Calculation Variations And Other Regulatory Challenges** National Regulatory Research Institute Report No. 13-09 , July 2013

[11] Meyers S & Kromer S., *Measurement and verification strategies for energy savings certificates: meeting the challenges of an uncertain world* Energy Efficiency (2008) 1:313–321; California Public Utilities Commission, **California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals** 2006

IRP and the incorporation of a DSM dependability analysis into the IRP should be considered by MH.

3 RESPONSES TO THE SCOPE OF WORK ISSUES

3.1 ORGANIZATION OF THIS SECTION

The fifteen issues identified in the SOW are grouped into themes which correspond to the major section headings: the criteria used by MH to select DSM measures; the potential of MH's DSM programs to defer future capacity; MH's approach to Smart Grid as a potential contributor to DSM; and, the contribution of DSM to the reduction of MH's environmental "footprint". Each section has two main subsections: a brief account of Elenchus' understanding of applicable MH's practices and policies; and, Elenchus' comments on the issue. A summary table is provided in section 5 of the fifteen topics, giving Elenchus' responses in brief and directing the reader to where a fuller discussion of each topic may be found in this section.

3.2 MANITOBA HYDRO'S DSM CRITERIA

3.2.1 UNDERSTANDING

The criteria for selecting DSM measures are laid out in MH's Power Smart Plan. They are:

- Societal Cost (SC);
- Marginal Resource Cost (MRC);
- Total Resource Cost (TRC);
- Rate Impact Measure (RIM);
- Simple Customer Payback (CP) ;
- Levelized Unit Energy Cost (LUEC); and
- Participating Customer Test (PCT).

Appendix 2 provides the full definitions of these tests.

It is Elenchus' understanding that the financial values of energy and capacity, for use in the various tests are provided by MH's system planners. For example, the benefits of a DSM measure in the TRC or MRC are derived from the marginal cost estimates of supply developed by the system planners.[12]

Once an energy efficient measure is identified as a potential opportunity, the first step is to apply Total Resource Cost (TRC) Test, including any measureable non-energy benefits and prior to consideration of any projected program administration or delivery costs (MRC).

If the technology achieves a benefit/cost ratio greater than one or a positive Net Present Value (NPV), then a program is designed to encourage market adoption of the opportunity. If the benefit/cost ratio is less than one, or a negative NPV, and the technology is one which is emerging or supports other qualitative objectives (e.g. solar assisted domestic water heaters), MH may still support the technology. MH may provide such support through such methods as: research, standard development and education, and may utilize financial tools such as on-bill financing to support market development.

The program design may use different market strategies to increase awareness, understanding and adoption of the various technologies. These strategies address market barriers such as first cost, industry knowledge and capacity, and product availability. The benefit/cost ratios and NPVs for the TRC, SCT, PCT and RIM metrics, and the LUC and CP are determined for the proposed design and associated cost and participation projections. As noted, an initiative that fails the TRC may still be pursued if it supports other qualitative objectives such as fairness and equity (e.g. serves the lower income market). In determining incentive levels, MH tries to balance the impacts to all customers by examining the participating customers' benefits and costs, through the simple payback and participating customer metrics, compared to the investment by the utility on behalf of the ratepayer through the RIM and LUC. A program may proceed with a RIM benefit/cost ratio of less than one or a negative NPV, if the program supports other qualitative objectives such as offering a balanced portfolio of programs within or across sectors.

[12] Elenchus thanks MH staff for its assistance in the understanding of MH's approach to DSM program design described in the next few paragraphs.

3.2.1.1 Marginal Costs

MH defines incremental or marginal costs of a DSM measure as the difference between a "standard technology" and the more efficient technology.[13]

3.2.1.2 Curtailable Rates Program

Customers that have enrolled in the program are approached by MH during times of energy constraint, due to low water levels, and asked to curtail consumption, for which they receive a monthly capacity credit from MH. Eligibility criteria for the program require that loads and processes will be configured to allow them to meet the requested curtailments within the notification periods specified in their chosen contract options.[14]

3.2.1.3 Surplus Energy

The Surplus Energy program is a program whereby customers can choose not to take load in exchange for payments at prices that are posted a week ahead. These are non-firm or interruptible contracts. There were 26 customers in 2012. The main use of the program is by customers who have alternate sources of heating. Annual energy sold under this program is about 25 gigawatt-hours (gWh). MH does not include this program in its Power Smart plan.[15]

3.2.2 Elenchus' Comments

Elenchus finds that MH's practices are broadly consistent with other jurisdictions. It is reasonable that MH uses multiple criteria and that it has changed the emphasis among the criteria as circumstances change. However, as in other jurisdictions, the use of multiple criteria adds to the uncertainty of the eventual contribution of DSM to future load reductions. As discussed below, the standard methodology for estimating the potential of DSM to reduce load makes a distinction between technical and market potential. In turn, assessments of market potential have to make assumptions about the "price" of DSM relative to the price of buying energy (in this case electrical energy). Typically, estimates of the marginal cost of electricity are

[13] See Appendix 2

[14] P31 2013 Power Smart Plan – Appendix E

[15] Appendix C Load Forecast p2, 23

used. Some of MH's existing suite of measures was clearly included in the current Smart Plan on the basis of criteria other than the competing marginal cost of electricity. For example, solar-assisted water heating did not meet TRC test but was judged to provide other qualitative benefits. Similarly, some measures that provide benefits to low-income customers but which did not pass the TRC test are included in the Power Smart plan.

Thus, there are two uncertainties: (1) the contribution of such existing measures in the future; and (2) the extent to which future MH measures may also not be based on marginal cost estimates. While it is natural that over time the suite of measures included in the Power Smart plan will change in light of past performance, new information and changing circumstances, there is also a tendency for the recipients of the benefits of particular measures to become 'constituencies' of the program. The most obvious example is that of measures that benefit low-income consumers. It may become difficult for a Crown agency, like MH, to discontinue such programs. If such measures were to be assumed to be replaced by more effective measures in formulating Resource Plans this introduces an uncertainty in the projections of DSM contributions. If some future measures are included on criteria other than marginal cost then evaluations of market potential (such as the Market Potential study, which is discussed below) will not be accurate, thereby introducing uncertainty.

These uncertainties become greater the further into the future we look. Combined with the uncertainties of estimating the amounts of DSM that will be realised at different future dates, discussed below, the uncertainties of DSM savings on which reliance can be placed equivalent to supply ***suggest that a more rigorous approach to assessing the uncertainties would be beneficial. Elenchus does not suggest that MH revise its criteria or its approach to program design, rather that the existence of uncertainties should be explicitly considered in developing Resource Plans.*** This is discussed further in section 3.3.

3.2.2.1 MARGINAL COSTS

MH uses the difference between "standard" technology and a more efficient technology that performs the same function to estimate the marginal resources cost of an EE measure.[16] There is an irreducible arbitrariness to the selection of "standard" technology but MH is following overwhelming industry practice in this. The arbitrariness is reduced in practice by the knowledge

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[16] See Appendix 2.

that DSM professionals have of the available products. Nevertheless, there is room to doubt that the degree of precision that can be assigned to estimates of DSM marginal costs matches that of system marginal costs. Moreover, technologies rarely perform exactly the same functions. For example more energy efficient appliances, such as refrigerators, invariably have other features that may be attractive to consumers, such as, water dispensers or enhanced storage features. This illustrates a larger problem of methodologies that attempt to assess “market” potential – consumers rarely buy actual market products on the basis of potential energy savings alone. This is discussed further in 3.3.2.2.

Again, ***rather than suggest a change in methodology on the part of MH for estimating marginal costs of DSM measures, Elenchus suggests that such methodologies are an additional source of uncertainty that should be explicitly considered in developing Resource Plans***.

3.2.2.2 Curtailable Rates Program

The Curtailable Rates program, although included in the Power Smart plan, is not a true DSM measure. DSM measures, in differing degrees, contribute to both energy and capacity reduction. The central issue in this proceeding, from a DSM perspective, is whether or not DSM measures may obviate the need for additional capacity. The Curtailable Rates program is designed to allow MH to manage better its energy available from the capacity that exists at any point in time. At times in which energy is constrained, due to water levels, customers may elect to reduce consumption thereby allowing MH to sell at export prices the energy made available. This is quite different from DSM resources which result in capacity savings across all periods (daily and seasonal). Elenchus has no comments on the continuance of the program in pursuit of its intended purpose. However, ***Elenchus suggests that it is inappropriate to include capacity savings from this program in the Resource Plan.***

The decisive consideration in this regard is the question as to whether or not Keeyask or Conawapa should be deferred on the basis of assumed capacity reductions from this program. Elenchus’ understanding is that such a deferral would run counter to the intent of the program which is to obtain greater value from the additional capacity represented by Keeyask and Conawapa by making energy available for export during times of low water levels. This value presumes the existence of generating capacity. True DSM presumes the opposite; that deferred capacity adds value to MH (since the resulting total resource cost to MH’s consumers is less).

3.2.2.3 *SURPLUS ENERGY*

Like the Load Curtailment program, this program is not a true DSM measure. The energy not consumed under this program cannot be converted into equivalent dependable capacity. Elenchus makes no comment on the program but ***suggests that inclusion of savings in the DSM contributions to the Resource Plan would be inappropriate***.

3.3 THE POTENTIAL OF MH'S DSM PROGRAMS TO DEFER FUTURE CAPACITY

3.3.1 UNDERSTANDING[17]

MH combines “top-down” with “bottom up” DSM analyses to develop its Resources Plans. MH’s System Planning provides threshold marginal costs, DSM program planners assess DSM measures that meet the applied tests and other considerations and create a forecast of DSM contribution to load reduction. MH’s forecasts of DSM contributions to load reductions are based on a projection of the existing DSM plan which is based on unit energy tertiary (end use) demands (e.g. kWh per light fixture) and demographics of the end use and customer segments. After 2028 no new measures are assumed and the load reductions due to natural decay of the existing measures are used. ***The resulting estimate of the DSM contribution to the Resource plan is taken by MH as 100% dependable.*** The estimated DSM contribution to the Resource Plan is then subjected to a “top down” analysis of heuristic comparisons of the impacts of simply assuming higher levels of DSM, from a 1.5 multiple of the reference case to a multiple of 4 times the reference level.

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. An appropriate approach to evaluate DSM in such a situation is to determine the increase in generation system operation benefits associated with increasing the exports resulting from the higher levels of DSM. Manitoba Hydro has been using this approach for the past number of years in determining the marginal values which then provide a reasonably representative indication of the generation benefits of the DSM. Such marginal values were utilized to develop the DSM Plan utilized in the submission.

[17] Elenchus acknowledges the assistance of discussions with MH staff. Any misunderstandings are the sole responsibility of Elenchus.

It is also worth emphasizing, as already noted, that MH's approach to EE has changed over time. MH previously prepared IRPs with DSM as a supply option. MH is now contemplating a return to IRP. MH's IRPs included the energy savings expected to be achieved through the Corporation's approved Power Smart Plan as part of its base case. The energy savings expected to be achieved through DSM was considered more attractive than alternative supply options and as such, the DSM option was added to the base case which was used for further assessing supplemental supply side options to meet Manitoba's future load.

3.3.1.1 MEASURING ENERGY EFFICIENCY SAVINGS

Comparable to other jurisdictions, MH uses a mixture of engineering assumptions incorporated into electricity end-use models and comparison of measured load against a prior baseline. MH's follows the international standard for EM&V.[18] **Figure 1** describes the basic framework for all estimations of DSM contributions to future load reductions. The key variables are the tertiary energy consumption values – the amount of energy used for the particular end use, e.g. kWh used for space heating in semi-detached houses built in the 1950s. EE seeks to replace end-use technologies with those that are more efficient in their use of energy. The potential for future load reductions simply adds up all of these contributions according to knowledge and projections of the demographics of each end use. In some instances, MH uses engineering data on the tertiary energy use of technology (e.g. incandescent versus compact fluorescent or Light-Emitting Diode (LED) lighting). In others, MH establishes a baseline level of consumption for the customer and compares this to the actual consumption with DSM measures installed. A key factor in determining which approach is taken is the homogeneity of the technology.

3.3.1.2 DISPATCHABILITY AND BACKUP

None of MH's projected DSM measures are treated as dispatchable and no provisions for backup are made.

[18] International Performance Measurement & Verification Protocol; Concepts and Options for Determining Energy and Water Savings, International Performance Measurement & Verification Protocol Committee, 2002.

3.3.2 Elenchus' Comments

Elenchus finds that relative to common practice MH's approach is reasonable, sound, complete and thorough but nevertheless notes that improvements can be made. In particular, the accuracy of DSM savings estimates can be improved by supplementing the existing approaches with a statistical study of the underlying tertiary electricity usages of the various technologies. Like other jurisdictions, MH "verifies" the savings included in the Power Smart reports by comparing participating customers' usages to baseline or calculated energy but does not do retrospective comparisons of participating and non-participating customers to establish the implicit tertiary energy uses.

In terms of the coherence criteria set out in 3.1, there is reasonable coherence between the bottom-up and top-down approaches. **Figure 2** shows the reserve capacity and the load factors for the system as a whole and for the estimated DSM savings for the years 2002/3-2028/9.

After the Curtailable Rates program (see 3.2.1.2 and 3.2.2.2 above) is taken into account the DSM load factor in 2028/9 rises to 54% compared a system load factor of 63%. If estimated DSM savings for the residential, commercial and industrial sectors occurred in exactly the same proportions as load in these sectors it would be reasonable to expect that the load factors for system and estimated DSM savings would be the same unless there were programs specifically aimed at shifting load (which MH does not include in the PSP). With the Curtailable Rates program included the DSM load factor is only 39%. This gives emphasis to the suggestion that the Curtailable Rates program should not be considered as part of the Power Smart Plan since it affects only the industrial sector but biases the total load factor. Since most savings are projected in the commercial and industrial sectors[19] the difference remains puzzling since these sectors normally have higher load factors; this serves to emphasize the uncertainties inherent in DSM projections. Part of the explanation is undoubtedly the imperfect meshing of assumptions regarding market potential with the selection criteria for inclusion in the Power Smart Plan, discussed in 3.2.2 above.

MH's DSM projections are based on its knowledge of the suite of measures in the Power Smart Plan (PSP). The independent expert for the Consumers Association of Canada (CAC) ('Dunsky') argues that MH has under-forecast DSM contributions. As discussed in 3.3.2.3

[19] 2013 Power Smart Plan.

below, Elenchus accepts Dunsky's technical analysis but notes that uncertainties remain that arise out of the inherent nature of DSM.

The top-down sensitivity analysis that complements the bottom-up approach represented by Dunsky's analysis, has the advantage that it assumes a statistical set of savings (i.e. under-estimates for one measure may be cancelled by over-estimates for another, which over a large number of measures increases the confidence in the overall estimate).

However, in Elenchus' view, ***the overall coherence and robustness of MH's Resource Plan may be improved by a return to IRP. Elenchus further suggests that an IRP approach to which is added an explicit recognition of the statistical nature of expected DSM contributions would be an optimal way of addressing the uncertainties of DSM. The main way in which this recognition may be incorporated into planning is by the treatment of DSM as akin to dispatchable intermittent generation.***

3.3.2.1 MANITOBA HYDRO'S APPROACH TO MEASURING ACTUAL DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY SAVINGS

As discussed in the 3.1., above, there are intrinsic limitations to the approaches used by MH to estimate actual DSM savings, which are then used as the basis for projections. Within these limitations, Elenchus accepts that MH's methods conform to industry standards. The fundamental limitation is that the savings from DSM can never be verified because it is impossible to know with certainty what would have happened to consumption in the absence of DSM. The challenge, then, is to establish a range of uncertainty; is it 1% or 20%? The benchmark EM&V protocols skirt this issue.[20]

One way to do this is to conduct a study of past consumer consumption, which would compare statistically the observed consumption of consumers who have participated in DSM and those who have not. For example, residences with the same design and vintage in similar neighbourhoods could be compared. This is different from the regression analyses that are part of the International Protocol (which, to Elenchus' knowledge has not been part of the MH approach estimation). Whereas the protocol seeks to establish a baseline against which to compare actual consumption after the DSM measures are implemented, the purpose of the

[20] The International Protocol refers to confidence levels but this is not the issue – confidence levels relate to a known distribution, precisely what is not known about uncertainty.

study suggested by Elenchus would be to develop estimates of the tertiary end-use consumptions for different categories of load, i.e. space heating, water heating, air conditioning, lighting, and appliances. A key difference is the length of the study. The protocol advises that one or two years are sufficient; the type of study suggested would use at least five years' data. In addition, other statistical techniques (such as ANOVA) may be more appropriate for data analysis. MH has an ideal situation to carry out such studies. MH has, presumably, extensive customer data and also delivers natural gas DSM. Where the relevant data is kept by a government department or agency (e.g. housing stock characteristics) MH would not likely confront data confidentiality issues that may apply to private companies.

3.3.2.2 DSM Potential

Elenchus has reviewed the DSM Potential Study and regards the study as "state-of-the art"; i.e. the findings of the study are thorough, complete and reasonable. However, the drawbacks inherent to all DSM also apply to this study. These shortcomings are:

- Fundamentally untestable DSM savings estimates; and,
- There is no market test for the cost of measures and, therefore, no way to know what are the limits of market and achievable potential estimates.

The first shortcoming has already been discussed at length. The second shortcoming arises from a particular view of markets that has dominated EE policy. That view is that there are chronic and persistent market failures that result in an under-investment in EE. There is a sharp divide in the literature going back thirty years on this as a matter of fundamental presupposition. Advocates of EE point to market failures that cause barriers to EE whereas economists are generally sceptical.[21] This is not a debate unique to EE; there are many markets in which market failures are alleged to occur and the remedy for which is some form of government intervention.[22] Economists generally argue that long run market failures do not exist; markets adjust to changing tastes and technology. Turning to the specific market barriers addressed by

[21] See, for example, Joffe, AB and Stavins RN, *Energy-Efficiency Investments and Public Policy*, **The Energy Journal**, Vol. 15, No. 2 (1994), 43-65

[22] See Hillman, A L., **Public Finance and Public Policy** Cambridge U Press, 2009.

DSM programs, such as those listed in Appendix 3 of Dunsky[23], in terms of economic theory all are different instances of imperfect information. All markets have degrees of information imperfection, e.g. choosing a computer is complex, requiring much specialized knowledge that most people do not possess and assumptions about other products (telecommunications, peripherals). Markets are regarded by economists as superior to other forms of economic co-ordination because they use information more efficiently.[24]

There is, in fact, a market for DSM – the energy services market, in which private Energy Service Companies (ESCOs) offer services that reduce the energy bills of customers. A study by the Lawrence Berkeley Laboratories has estimated that the US market for ESCOs was $4B in revenues, 75% of which were derived from acting as delivery agents for government or utility sponsored DSM/CDM programs.[25] Thus the private market for energy services in the US is about $1B, which is close to 0.1% of energy revenues. In contrast, claimed savings by utilities are about 4% of energy revenues or about 40 times more than the energy services for which customers are willing to pay.[26]

Similarly, the gap between estimates of energy efficiency savings due to government or utility programs and econometric studies of energy efficiency at the macroeconomic level has long been noted.[27] In Elenchus' view there is no definitive answer available to resolve the empirical differences between advocates of EE and economic sceptics. Economic theory recognizes categories of explanation for this: price effects (own and cross price elasticities); income

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[23] Written Testimony of Philippe U. Dunsky re. Manitoba Hydro's Demand-Side Management Plan *in the context of Manitoba Hydro's 2012/13 and 2013/14 General Rate Application on behalf of Consumers Association of Canada (Manitoba) and Green Action Centre November 15th, 2012.*

[24] For example, in Von Hayek, F, "The Use of Knowledge in Society." **American Economic Review** 35 (September): 519–530.

[25] Satchwell A, Goldman C, Larsen P, Gilligan D, Singer T, **A Survey of the U.S. ESCO Industry: Market Growth and Development from 2008 to 2011** Lawrence Berkeley National Laboratory, 2012.

[26] Energy and economic growth: Grounding our understanding in physical reality DavidG.Ockwell **Energy Policy** 36 (2008) 4600–4604

[27] See for example, Auffhammer, M Blumstein, C and Fowlie M, *Demand-Side Management and Energy Efficiency Revisited* **The Energy Journal** 2008 29(3) at 91.

effects[28]; changes in consumer preferences: and changes in technology. Both sides tend to "cherry pick" evidence in relation to these factors.

Nevertheless, there are practical conclusions which may be drawn from the literature that are directly relevant to the current proceeding. Consistent with our other suggestions, it would be prudent to consider the estimates of potential energy and capacity savings arising from the DSM Potential study as indicative. For Resource Plan purposes, the actual savings from DSM in any given year should be taken to be some fraction of the "realisable market potential" savings identified in the study or subsequently by MH on the basis of the study. Elenchus stresses that the estimates of potential are sound in terms of the methods used; the PUB is urged to consider the estimates as the best available estimates of inherently uncertain values. The essential difference between the MH current approach and the approach suggested by Elenchus is one of making assumptions about uncertainty explicit rather than buried in the distinctions between "technical", "market", and "achievable" potentials for DSM and the estimated that flow therefrom.

As an illustration of this economic controversy, consider Canada. Between 1999 and 2012 the average annual decline in the real electricity intensity (kWh per $GDP) of the Canadian economy was 1.4%.[29] The average increase in energy efficiency savings, in terms of avoided capacity, for DSM participants for the period 2002 to 2012 estimated by MH is 9.8%. If Manitoba DSM capacity reductions had occurred at the average Canadian rate of decrease in electricity use intensity the contribution of DSM would be about 30MW by 2012 (not including the Curtailable Rates program). If this amount increased at the annual average DSM savings rate of 1.8% projected by MH to 2028 (from 2012) there would be a 300MW less DSM capacity reduction (i.e. 300MW would have to be made up by supply) in 2028.

3.3.2.3 Expert Evidence for the Consumers' Association of Canada ("Dunsky")

Elenchus has reviewed Dunsky's evidence and is in agreement with the conclusion that, within the scope of the methodologies used by MH to estimate DSM contributions to the Resource

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[28] One aspect of income effects has received considerable interest in the literature – the "rebound" effect, whereby consumers who save money from energy efficiency adjust by consuming more than they would have at their former income (e.g. Ockwell, D, Energy and economic growth: Grounding our understanding in physical reality **Energy Policy** 36 2008 4600-4).

[29] Statistics Canada, **Energy Statistics Handbook 2013** Catalogue no. 57-601-X

Plan, MH's reference case is conservative relative to other North American jurisdictions. However, for the reasons just given in the previous section Elenchus finds this conservatism reasonable even though Elenchus would prefer an explicit consideration of the uncertainties of DSM rather than the assumption of a conservative 100% dependable amount of DSM.

Elenchus disagrees with one of the specific arguments made by Dunsky regarding the issue of why MH's assumptions for DSM are more conservative than other jurisdictions. Dunsky argues that because MH rates have been much cheaper than other jurisdictions, as MH rates rise, due to the proposed NFAT investments, there is more scope for savings (while acknowledging that lower rates lower the economic incentive for consumers to invest in EE). This theoretical argument is plausible but contradicted by Dunsky's own empirical evidence. Dunsky does acknowledge that there is no relationship between DSM savings ratio and rates[30] but continues to maintain that the lower historic rates will mean more incentive for DSM in the future. **Figure 3** provides a scatter plot of the DSM Savings ratio and average electricity rates for the US states in Dunsky's **Figure 1**. The DSM Savings ratios are from Dunsky, the electricity rates from US EIA.[31] The relationship is essentially a "random walk" with a very small positive relationship with a non-significant correlation of 0.15. On the basis of this evidence it is not reasonable to conclude that opportunities for DSM will increase as the cost of MH's electricity rises.

While Dunsky's observations about the conservative nature of MH's assumptions remain valid, the import of the above analysis of the possible impacts of the level of rates on DSM savings again relates to the uncertainty of how much DSM may be treated as equally dependable as increases in generating capacity. Relative to other jurisdictions, MH's proposed DSM program is less aggressive but such conservatism may be prudent given the uncertainties about how consumers will react to the increase in rates projected by MH as a result of its Preferred Development Plan. Such uncertainties are not fully captured by even the best-available techniques for assessing "technical", "market" and "achievable" potentials of DSM. Instead, Elenchus suggests that the incorporation of explicit sensitivity analysis of how much ***dependable*** DSM may be assumed is of value.

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30 P24

31 http://www.eia.gov/state/seds/seds-data-fuel.cfm?sid=US

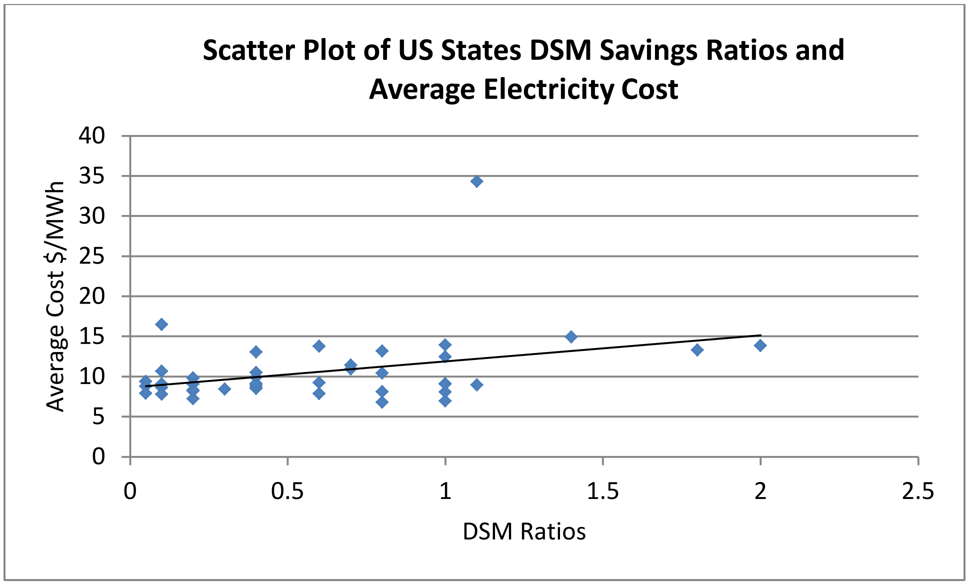

Figure 3

3.3.2.4 STRESS TESTING AND DEFERRALS

MH carried out a top-down "stress test" on the impacts of DSM on the various pathways that it analyzed. The impacts of assuming multiples of 1.5X, 2X and 4X the reference DSM forecast on the calculated surplus capacity was analyzed. Elenchus notes that that the statistical nature of the top-down approach runs counter to the assumption of 100% dependability. Indeed, there is no logical guarantee that the levels will be consistent with the bottom-up assumptions. Higher levels of DSM assume either that: costs of DSM are lower than in the reference case, leading to greater achievable levels of DSM; or, actual savings for the various measures are higher than in reference case; or a combination. There also implicit secondary and tertiary assumptions (and beyond) regarding income elasticities, cross-elasticities of substitutes and changes in consumer preferences. Yet, as argued above, there are good reasons to be skeptical about these assumptions.

In order to attempt to bound these uncertainties Elenchus carried out its own stress test of the interrelations of DSM and dependable capacity. Appendix 3 provides the detailed tabulations. These analyses all end at 2028 because MH does not project new DSM measures beyond this point. The projected ISD for Conawapa is 2026.

The variables analyzed were:

- System Load Factor;
- System Capacity Factor;
- System Capacity Reserve
- DSM Load Factor.

To derive these variables, the following time series data were used:

- System Capacity;
- System Peak Load
- System Load.

The data sources were:

- Load Forecast (Appendix D);
- Power Smart Plan (Appendix E);
- Annual report (Appendix I)
- Supply and Demand tables (Appendix 4.2).

The System Capacity excludes imports.

The following sensitivity cases were examined:

- Base DSM;
- Keeyask ISD of 2020;
- Keeyask pus DSM
- Four levels of DSM (1.5X to 4X).

Base DSM does not include the Curtailable Rates program.

Finally, the sensitivity of the capacity results to the uncertainty inherent in the difference between system LF and DSM LF was explored and a heuristic treatment of uncertainties due to the measured savings and market potential explored.

Figure 4 shows the key variables for the projected period 20013/14-2028/29 (the first year is shown in the figures throughout) without any generating capacity additions; i.e. System LF, CF and CR, DSM LF. The DSM numbers for energy and capacity are both as at the generator in all of the figures below.

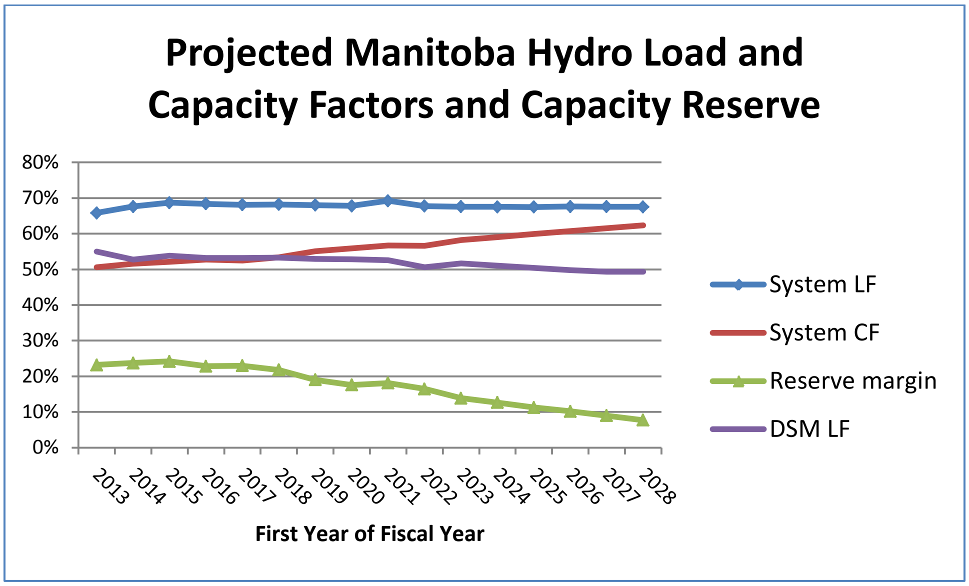

Figure 4

In the forecast period (from 2013) the DSM LF is less than the system LF by an average of 16%. This is an indication that DSM estimates are not fully consistent with projected load. It is not possible to identify the sources of this inconsistency. This is a reflection of the inherent uncertainty of DSM savings projections. In the absence of DSM or new generation the capacity reserve declines below the 12% minimum target by 2023.

Figure 5 shows the reserve capacity from 2013-2028 for the base case (no DSM) and for the five levels of DSM, under the assumption that Keeyask comes into service in 2021. This is an "unsmoothed" projection of the DSM savings levels; hence, all lines show a sudden "jump".

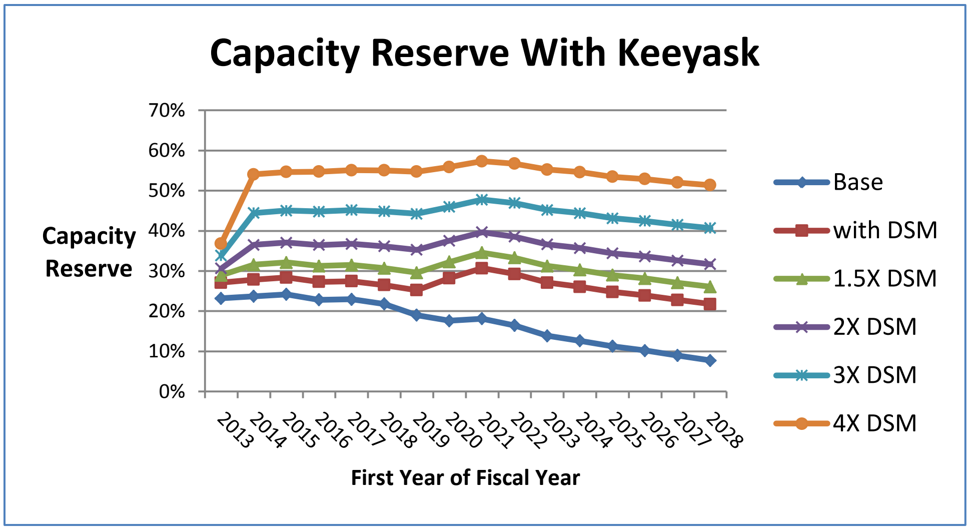

Figure 5

Under these assumptions, the 3X and 4X DSM levels produce Capacity Reserves in excess of 40%, arguably representing too much capacity. **Figure 6** (page 24) shows the same scenarios with the DSM smoothed over the whole period (i.e. the level, 1.5X, 2X etc. is achieved by 2028, not immediately, and the level is reached by linear interpolation). In addition, these projections take account of the inherent uncertainty of the DSM projections with respect to capacity. The figure also shows the target reserve (12%) and the 2002-2012 average (23%). The difference between system and DSM load factors leads to an ambiguity; we may either assume that the capacity reduction is accurate or that the energy reduction is accurate. The implication of a lower DSM load factor is that non-participating consumers must have a higher LF than the system average. If this is not true and the DSM estimates are inaccurate, there are two polar cases: the energy estimate is correct but the capacity is wrong (too high to be consistent with the higher load factor); or, capacity estimate is correct but the energy estimate is not. **Table 1** illustrates the difference between assuming that the participating customers' difference is all on the capacity side versus all on the energy side (at meter).

	2002	2012	2020	2025	2028
Power Smart Plan					
DSM tWh	0.459	1.26	1.61	1.55	1.5
DSM GW	0.102	0.259	0.348	0.351	0.347
System Load Factor	63.9%	67.6%	67.8%	67.5%	67.5%
DSM load factor	51.4%	55.5%	52.8%	50.4%	49.3%
DSM with known capacity					
DSM tWh	0.57	1.53	2.07	2.08	2.05
DSM GW	0.102	0.259	0.348	0.351	0.347
Load Factor	63.9%	67.6%	67.8%	67.5%	67.5%
DSM load factor	63.9%	67.6%	67.8%	67.5%	67.5%
DSM with known energy					
DSM tWh	0.459	1.26	1.61	1.55	1.5
DSM GW	0.082	0.213	0.271	0.262	0.254
Load Factor	63.9%	67.6%	67.8%	67.5%	67.5%
DSM load factor	63.9%	67.6%	67.8%	67.5%	67.5%

Table 1

Figure 6 depicts the impact on the scenarios if the DSM uncertainty is all reflected in less DSM capacity than planned. Since this proceeding focuses on the need for additional capacity, only the polar case in which estimated DSM capacity is too low is modelled. This capacity has to be compensated by supply capacity and lowers the capacity reserve margin.

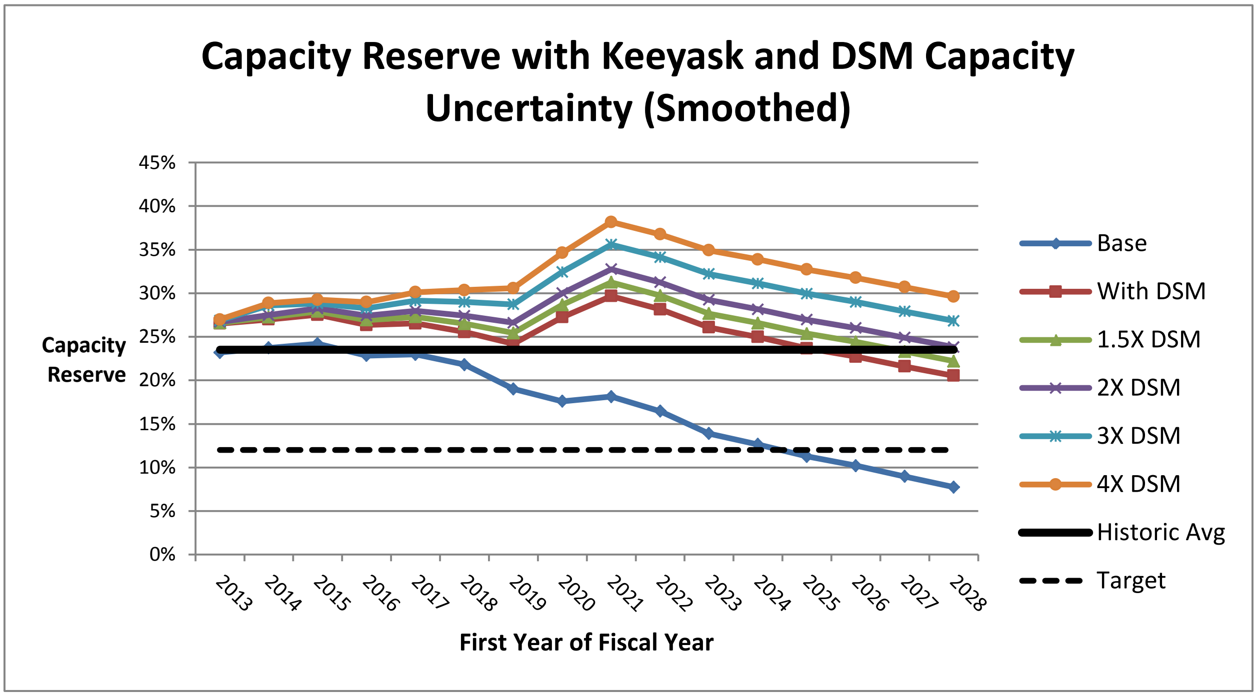

Figure 6

Under these assumptions the Capacity Reserve for the 3X and 4X DSM Savings falls but is still relatively high.

Figure 7 examines the impacts of uncertainties due to measurement and realizable potential issues. All of the scenarios assume that achievable DSM savings are 5% less than assumed by MH's reference projection. For the 1.5X case, the achievable market potential is assumed to decrease by 2% per annum from 2013 to 2028. For the 2X case, this factor is 2.5 % and for the 3X and 4X scenarios it is 3% and 3.5%. These are purely heuristic assumptions for illustration but they all assume that the further into the future projections are made, the greater the uncertainty and that uncertainty rises as a function of the arbitrary assumed multiples of the base DSM.

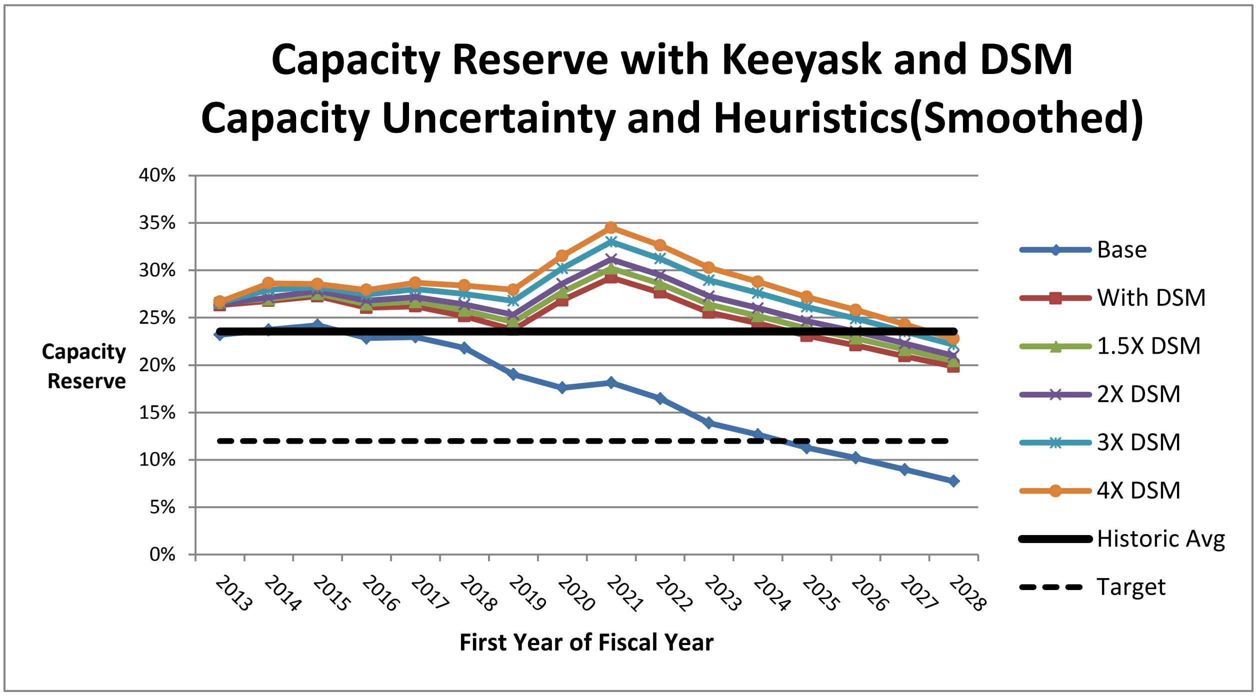

Figure 7

Under the heuristic assumptions, even with 4X DSM Savings the projected Capacity Reserve without Conawapa falls to close to historical levels and is on a downward trajectory. Elenchus' stress-testing exercise reinforces the suggestions already made. While the higher levels of assumed DSM contribution could be taken to suggest that the Keeyask and Conawapa ISDs could be deferred, a more realistic appraisal of the uncertainties associated with DSM does not support such a conclusion. Elenchus emphasizes that the assumptions made for **Figure 7** are arbitrary and were chosen to illustrate how explicitly modelling dependabilities for DSM savings may be used to make decisions about future ISDs for new generating capacity.

3.3.2.5 DISPATCHABILITY AND BACKUP

Dispatchability refers to the ability of the system operator to determine when particular resources will be used. The system operator also ensures that there is sufficient operating reserve at all times to meet North American reliability standards. Since these requirements govern the loss of the largest generating unit, there is no need for "backup" *per se* of DSM resources, just as there is no need to back up any other generator beyond the largest unit. In dispatching the generators to be available for use at particular hours of the day the system operator takes into account, *inter alia*, the dependability of the generating resources. There is no attempt by MH to put its DSM estimates on an equivalent basis. Similarly, to Elenchus' knowledge there is no provision for additional operating reserve in the event that expected levels of DSM load reductions are not achieved.

In systems that have significant levels of intermittent generating capacity (which is not the case for MH), operators may make provision for backing up such generation. In Elenchus' view this would be a prudent practice with regard to DSM resources.

3.3.2.6 Lost Opportunity Revenues

MH uses the opportunity for exports as part of its evaluation of DSM.[32] Strictly, from economic theory, lost opportunity revenues are the value of energy efficiency (i.e. the next best use of MH resources, after DSM, is to sell the electricity). If the DSM program's measures were determined strictly on the marginal cost of each measure up to the point that the last DSM measure equals system marginal cost, then this would be in accordance with economic theory. However, as we have seen, the MRC and TRC as used by MH are not decisive in determining the composition of the MH DSM program. This leads to one type of uncertainty in the actual realization of DSM potential load reductions as already discussed. Where MH uses the value of exports as the determinant of the TRC or MRC, this creates an additional uncertainty. While the value of exports is not part of Elenchus' remit, it is possible to observe that future export prices are likely to be more uncertain that MH's projections of its system marginal costs.

3.3.2.7 Location of DSM

It is possible that in applying qualitative criteria to prospective DSM measures, MH may have the latitude to use location as a criterion but Elenchus is not aware of any evidence of this. Elenchus has not undertaken a detailed analysis of the location of DSM projects since location is not relevant to assessing the DSM contribution to the Resources Plan.

[32] See Appendix 2

3.4 SMART GRID TECHNOLOGIES FOR DEMAND-SIDE MANAGEMENT

3.4.1.1 UNDERSTANDING

Unlike many jurisdictions or utilities, neither the government of Manitoba nor MH has an overarching smart grid plan, "road map" or strategy.[33] MH has studied the various individual technologies that are usually captured under the "smart grid" umbrella.

For "grid modernization" technologies (e.g. more intelligent switchgear or relays), including the greater use of Information Technology (IT), MH considers the latest equipment when conducting upgrades as part of its asset management and is also working with a major equipment supplier on the use of its proprietary approach to assessing such technologies.

MH has conducted a study on the use of 'smart meters' and Advanced Metering Infrastructure (for natural gas and electricity) and concluded that investments in these areas are not currently cost-effective[34]. Similarly MH has studied the use of Time-of-Use (TOU) rates and does not support their introduction, nor Demand Reduction programs or associated concepts ("behind-the-meter" services). (MH does not offer TOU rates to even large consumers, a reflection of the exceptionally low cost of electricity in Manitoba.)

MH is engaged in a number of pilot studies, such as, *inter alia*, on the use of electric vehicles, both private and public (the latter a Mass Transit pilot in conjunction with the City of Winnipeg, the government of Manitoba and a major manufacturing company). MH is also engaged in studies of battery storage, mainly in conjunction with the above Mass Transit pilot, with the additional participation of Red River College.

The Manitoba Hydro Task Smart Grid Strategy Task Force summarizes the recommended approach as follows:

> *"Considering the business context, drivers and priorities, the proposed Manitoba Hydro Smart Grid Strategy can be summarized as:*

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[33] For a Canadian example see, Standards Council of Canada, **The Canadian Smart Grid Standards Roadmap**, October 2012.http://www.scc.ca/en/about-scc/publications/roadmaps/canadian-smart-grid-standards-roadmap **Smart Grid Strategy Task Force Report on Manitoba Hydro's Smart Grid Strategy** (IR Response ERA/MH I-034b)

[34] Centra Gas Manitoba Inc. **Advanced Metering Infrastructure Status Report** February 2, 2010.

- *Manitoba Hydro will continue to build a smarter grid by investing strategically in cost effective initiatives that improve safety, efficiency and reliability, and with consideration for evolving customers' expectations.*
- *The primary area of focus in the coming years will be:*
- *Extension of the communication and information technology infrastructures*
- *Modernization of the distribution system including customer metering*
- *Separate funding will not be set aside for Smart Grid initiatives, but will remain part of our normal financial processes and will require the same level of scrutiny and approval as other projects and activities. Overall capital allocations are not expected to increase due to the development of a smarter energy system.*
- *Manitoba Hydro will participate in the development of Smart Grid standards and use established approval and R&D processes to develop and test new technologies. Smart Grid principles can also be applied to Manitoba's natural gas distribution system.*

3.4.2 ELENCHUS' COMMENTS

In Elenchus' view, MH's approach to smart grid is appropriate. The term "smart grid" is an umbrella concept; most jurisdictions' smart grid plans, strategies or road-maps include the following broad categories of technology:

- Power equipment with more intelligence (ability to receive and act on data and/or ability to communicate with other devices or systems) built-in, such as conductors, switches, relays, reclosers, etc.
- Enhanced IT systems, including greater use of the Internet Protocol, to co-ordinate data from more intelligent equipment, including enhanced SCADA, auxiliary services and handling of customer meter data
- Interval meters (usually called "smart" meters) and associated Automated Meter Reading (AMR) and Advanced Metering Infrastructure (AMI) which make greater use of telecommunications
- Behind-the-meter services such as Demand Response;
- Electric vehicles
- Storage

MH has taken a sensible approach to smart grid, smart meters and AMI, given MH's very low cost of electricity. After a period of heightened interest, the term "smart grid" is becoming devalued.[35] Many in the electric power industry have come to prefer the term "grid modernization".[36] In the public's mind the term "smart grid" is largely synonymous with smart meters which are slow to gain customer acceptance.

Not all "smart grid" technologies have implications for DSM while some are of theoretical interest but of no practical consequence in the current proceeding. An example of the former kind is replacement of existing relays with more intelligent relays while an example of the latter would be battery storage. The most important smart grid technology for DSM is that related to smart meters, including the use of TOU pricing. Elenchus has reviewed MH's study of smart metering, AMR and AMI and agrees with the study's conclusions.

3.5 Carbon Dioxide Footprint

3.5.1.1 Understanding

MH does not estimate a CO_2 footprint *per se* but effectively addresses the same issue through a lifecycle analysis of Keeyask and Conawapa.[37] This analysis indicates a very small lifecycle impact of the two plants. MH does not provide any similar analysis of the environmental impacts of DSM activities.

3.5.1.2 Elenchus' Comments

In the environmental literature of the past twenty years or so there has been considerable discussion and use of the "ecological footprint" concept.[38] An ecological footprint analysis seeks to convert an activity into an equivalent area on the Earth's surface. For example, the construction and operation of a hydroelectric generating plant not only occupies an area of land due to the damming of a river but the materials that go into its construction all represent

[35] Canadian Electrical Association, **The Smart Grid: A Pragmatic Approach: A "State-of-Play" Discussion Paper**, September 2008
http://www.electricity.ca/media/SmartGrid/SmartGridpaperEN.pdf

[36] See for example, Ontario Energy Board, **Report on the Renewed Regulatory Framework for Electricity**, October 2012.

[37] NFAT Appendix 7.3

[38] Wackernagel, M. and W. Rees, **Our Ecological Footprint: Reducing Human Impact on the Earth** New Society Publishers, 2005.

additional uses of the Earth's resources. For fossil fuelled generators, the associated emissions of carbon dioxide may be converted into an equivalent area by using assumptions about the area of forest needed to absorb those emissions.

One of the non-financial and non-economic advantages of the proposed Keeywah and Conawapa projects, both for Manitoba and in a larger North American and even Global context, are the avoided CO_2 emissions relative to fossil-fired generation. ***Elenchus accepts the MH lifecycle analysis as a sound basis for including this advantage in broader evaluation of system options.***

MH has not reported any analysis of the environmental impacts of DSM activities. The manufacture of compact fluorescent light bulbs, for example, involves different materials than incandescent bulbs. There would be a change in ecological footprint due to the replacement of incandescent by fluorescent bulbs. While Elenchus would expect that these (and other DSM) impacts would be small it is not necessarily the case that equivalent capacity reductions from DSM would have a smaller ecological footprint than the expansion of hydro-electric capacity. Empirical analysis would also be needed to estimate whether the CO_2 emissions component of the footprint would be favourable to DSM.

MH's approach to the assessment of the various identified pathways involves a multiple "accounts" analysis including an environmental account. The supporting analysis does not include any analysis of the environmental impacts of DSM. While not likely, it is possible that an a revised evaluative framework which gives weight to the environmental account that includes an analysis of the environmental impacts of DSM activities could suggest that less DSM is desirable. In turn, this may suggest that the ISD of Conawapa could be moved forward. (The ISD for Keeyask cannot be moved forward).[39] ***Elenchus suggests that PUB consider making it a precondition for the future assessment of the ISD for Conawapa that a comprehensive ecological footprint analysis be carried out for all options.***

[39] Subject to Order in Council 128/13

4 SUGGESTIONS FOR IMPROVING THE ANALYSIS OF DSM CONTRIBUTIONS TO THE RESOURCES PLAN

Elenchus finds that MH's approach to DSM and its incorporation into system planning to be reasonable and consistent with the standard industry practices across different jurisdictions. However, in Elenchus' view, standard industry practices should be improved. Significant progress is required before best practices will become commonplace.

Current industry practices tend to minimize the explicit treatment of inherent uncertainties in all DSM programs. There are two major categories of uncertainties: uncertainties in the actual tertiary electricity usages versus assumed tertiary usages; and, the uptake by consumers of the assumed more efficient technologies. The former may be improved by conducting long-term studies of actual consumption by participating and non-participating customers. MH is ideally placed to carry out such studies. The latter uncertainties are more difficult to evaluate. Ultimately, the translation of the "technical potential" of DSM into "market potential" involves a great deal of judgment. The root of this difficulty is that there is no market for "energy"; consumers buy a vast range of products only one characteristic of which is their consumption of electrical energy. Economic theory recognizes five broad factors that determine the demand for any good; the price of the good, the prices of substitutes, incomes, consumer preferences and technology. Studies of market potential simplify this complex situation by assuming that consumers do, in fact, buy "energy savings"; it is assumed that market potential is a straightforward function of the estimated marginal cost of EE versus the electricity price.

A tool that is worth considering in this context is the explicit treatment of DSM as equivalent to intermittent sources of generated electricity (e.g., wind and solar). In the specific circumstances of MH and in the context of the current proceeding, these considerations regarding uncertainty lead to the suggestions presented below.

It is unlikely that any DSM factors on their own will change the case for Keeyask. On the other hand, it would be prudent for MH, as it assesses the ISD for Conawapa in the light of new information, to consider the following preconditions and that the PUB consider making such recommendations.

MH should be encouraged to adopt a more rigorous approach to assessing the uncertainties associated with DSM. Elenchus does not suggest that MH revise its criteria

or its approach to program design, rather that the existence of uncertainties should be explicitly considered in developing Resource Plans.

The overall coherence and robustness of MH's Resource Plan may be improved by a return to IRP. Elenchus further suggests that an IRP approach to which is added an explicit recognition of the statistical nature of expected DSM contributions would be an optimal way of addressing the uncertainties of DSM. The main way in which this recognition may be incorporated into planning is by the treatment of DSM as akin to dispatchable intermittent generation.

Elenchus suggests that it is inappropriate to include capacity savings from the Curtailable Rates program in the Resource Plan and that MH should continue to not include savings from Surplus Energy program in the DSM contributions to the Resource Plan.

In order to help to narrow the range of uncertainty associated with the underlying tertiary consumption values for various end-uses of electricity, MH should consider conducting a study of past consumer consumption, which would compare statistically the observed consumption of consumers who have participated in DSM and those who have not.

Elenchus suggests that MH consider making it a precondition for the future assessment of the ISD for Conawapa that a comprehensive ecological footprint analysis be carried out for all options.

1 # 5 SUMMARY OF SCOPE OF WORK (SOW) RESPONSES

SOW item	Summary Response	Where discussed
• Review MH's DSM factors and comment on whether they are complete, reasonable and accurate.	While MH does not itself refer to 'DSM factors', MH's approach to DSM is complete, reasonable and accurate.	3.2.2
• Review MH's assessment of technical, economic and real DSM and energy efficiency opportunities relative to other jurisdictions.	MH's review of DSM[40] opportunities is comparable to other North American jurisdictions.	3.2.2 , 3.3.2.2 and 3.3.2.3
• Review the extent to which MH has designed and implemented large utility DSM and energy efficiency programs at the residential, commercial and industrial levels in a manner consistent with other North American jurisdictions where such programs have been implemented.	MH's DSM programs for the major customer segments (residential, commercial and industrial) are consistent with utility practices in North America.	3.2.1 and 3.2.2
• Comment on the proper use of TRC and RIM evaluation tools as well as a TSC and benefit analysis from DSM and energy efficiency opportunities.	MH uses TRC, RIM and TSC in manner consistent with North American utility practices in relation to DSM and its consideration of other benefits is reasonable.	3.2.1 and 3.2.2

[40] See footnote 2

SOW item	Summary Response	Where discussed
• Comment on MH’s approach to measuring actual DSM and energy efficiency savings.	MH follows accepted industry protocols but these could be improved.	3.3.1.1 and 3.3.2.1
• Comment on the appropriateness of MH’s adoption of smart grid technologies for DSM.	MH’s adoption of smart grid technologies for DSM is appropriate.	3.4
• Comment on MH’s approach to determining marginal costs for measuring DSM.	MH follows accepted industry practice in basing its estimates of DSM marginal costs on reference standard technologies. However, this approach adds to the uncertainty of estimates of actual DSM potential.	3.2.1.1 and 3.2.2.1
• Comment on MH’s approach to managing DSM and energy efficiency lost opportunity revenues.	MH includes estimated export revenues in its evaluation of DSM opportunities as part of its multiple metrics approach, discussed in 4, above. While reasonable, this also adds to uncertainty.	3.3.2.6
• Comment on the reasonableness, thoroughness and soundness of MH’s DSM and conservation forecasts.	MH’s DSM forecasts are reasonable, thorough and sound but their uncertainty could be made more explicit and addressed in an improved way.	3.3.1 and 3.3.2
• Comment on whether the preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound.	The preferred and alternative resource and conservation evaluations are largely complete, accurate, thorough, reasonable and sound. There is uncertainty over the accuracy of DSM savings and the evaluation would be more complete if the environmental impacts of DSM programs were evaluated.	3.3.1, 3.3.2 and 4
• Critically assess Manitoba Hydro's DSM Potential Study.	The DSM Potential Study is a state-of-the-art study but its approach glosses over key uncertainties.	3.3.2.2

SOW item	Summary Response	Where discussed
• Perform independent stress testing of Demand-Side Management levels and an assessment of the reasonableness of Manitoba Hydro's stress testing of 1.5 and 4 times Demand-Side Management spending.	Elenchus' stress testing of DSM levels supports MH's conclusion that DSM programs are not sufficient to justify the deferral of new hydro-electric capacity.	3.3.2.4
• Examine Manitoba Hydro's current and potential use of Demand-Side Management in terms of: • • System capacity dispatchability	MH treats DSM capacity as non-dispatchable and 100% dependable. Elenchus suggests that DSM should be treated as a non-dispatchable resource subject to **explicit** dependability factors.	3.3.1.2 and 3.3.2.5
13. b. Dependable energy dispatchability	MH treats DSM energy as non-dispatchable and 100% dependable. Elenchus suggests that DSM should be treated as a non-dispatchable resource subject to **explicit** dependability factors.	3.3.1.2, 3.3.2.5 and 3.3.2
13. c. Backup Resources Required	MH makes no provision for backup. For operating reserve this is appropriate but for capacity reserve DSM should treat DSM as a non-dispatchable resource subject to **explicit** dependability factors.	3.3.1.2 and 3.3.2.5
13. d. Cost effectiveness	MH considers the cost effectiveness of DSM in terms of TRC, TSC, MRC, LUC. These are appropriate tests.	3.2.1, 3.2.1.1, 3.2.2 and 3.2.2.1
13. e. Carbon Dioxide Footprint	While MH has made a thorough assessment of the CO2 impacts of new generation it has not looked at the lifecycle impacts of DSM.	3.5
13. f. The role of the Load Curtailment (LC) Program	The LC program's purpose is to optimize **energy** use for exports; it is not an appropriate DSM **capacity** measure.	3.2.1.2 and 3.2.2.2

SOW item	Summary Response	Where discussed
13. g. The role of the Surplus Energy (SE) Program	The SE program allows customers to make energy available (mainly for export). MH should continue not to include it in the Power Smart plan.	3.2.1.3 and 3.2.2.3
13. h. Location of DSM	MH uses qualitative factors as well as metrics in designing its MSM programs. Location could be a factor but Elenchus is not aware of this.	3.3.2.7
• Identify the potential of Demand-Side Management or energy efficiency to defer new generation in Manitoba, including Keeysak G.S. and or Conawapa G.S. alone or in conjunction with other non-hydraulic resources.	As in 12. above, DSM is not likely to defer Keeysak or Conawapa, alone or in conjuction with other non-hydraulic resources	3.3.2.4
• Review and comment on the evidence with respect to Demand-Side Management arising from the last Manitoba Hydro General Rate Application, including the role of Demand-Side Management in deferral of Generation Investments put forth by the Consumer Association of Canada (Manitoba) Inc.'s expert witness. (Dunsky)	Elenchus agrees with Dunsky's benchmarking of MH's DSM programs but disagrees that Manitoba's lower electricity costs will create greater future DSM opportunities.	3.3.2.3

SOW item	Summary Response	Where discussed
• Consult with other specialists as directed by the Board regarding the use of Demand-Side Management as a resource option.	Not Applicable	Not Applicable
• Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.	Not Applicable	Not Applicable

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APPENDIX A: Statement of Work

- Review Manitoba Hydro's Demand-Side Management factors and comment on whether they are complete, reasonable and accurate.
- Review Manitoba Hydro's assessment of technical, economic and real Demand-Side Management and energy efficiency opportunities relative to other jurisdictions.
- Review the extent to which Manitoba Hydro has designed and implemented large utility Demand-Side Management and energy efficiency programs at the residential, commercial and industrial levels in a manner consistent with other North American jurisdictions where such programs have been implemented.
- Comment on the proper use of Total Resource Cost (TRC) and Rate Impact Measure (RIM) evaluation tools as well as a Total Societal Costs and benefit analysis from Demand-Side Management and energy efficiency opportunities.
- Comment on Manitoba Hydro's approach to measuring actual Demand-Side Management and energy efficiency savings.
- Comment on the appropriateness of Manitoba Hydro's adoption of smart grid technologies for Demand-Side Management.
- Comment on Manitoba Hydro's approach to determining marginal costs for measuring Demand-Side Management.
- Comment on Manitoba Hydro's approach to managing Demand-Side Management and energy efficiency lost opportunity revenues.
- Comment on the reasonableness, thoroughness and soundness of Manitoba Hydro's Demand-Side Management and conservation forecasts.
- Comment on whether the preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound.
- Critically assess Manitoba Hydro's DSM Potential Study.
- Perform independent stress testing of Demand-Side Management levels and an assessment of the reasonableness of Manitoba Hydro's stress testing of 1.5 and 4 times Demand-Side Management spending.
- Examine Manitoba Hydro's current and potential use of Demand-Side Management in terms of:
- System capacity dispatchability;
- Dependable energy dispatchability;
- Backup resources required;

- Cost effectiveness;
- CO_2 Footprint;
- The role of the Load Curtailment (LC) Program;
- The role of the Surplus Energy (SE) Program; and
- Location of Demand-Side Management investments.
- Identify the potential of Demand-Side Management or energy efficiency to defer new generation in Manitoba, including Keeysak G.S. and or Conawapa G.S. alone or in conjunction with other non-hydraulic resources.
- Review and comment on the evidence with respect to Demand-Side Management arising from the last Manitoba Hydro General Rate Application, including the role of Demand-Side Management in deferral of Generation Investments put forth by the Consumer Association of Canada (Manitoba) Inc.'s expert witness.
- Consult with other specialists as directed by the Board regarding the use of Demand-Side Management as a resource option.
- Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro’s evidence or are requested by the NFAT Panel.

APPENDIX B: Definitions of Metrics

(Extracts from MH Power Smart Plan)

Societal Cost (SC)

The Societal Cost (SC) metric measures the net economic benefit as measured by the TRC, plus additional indirect benefits such the avoided environmental or societal externalities (e.g. reduced health care costs, increase productivity, employment) and “non-priced” bene enjoyed by participants (improved comfort, improved heath).

(PV (Marginal Benefits) x 1.10) + PV (Measurable Non-Energy benefits)SC =

PV (Total Program Admin Costs + Incremental Product Costs)

Where:

- For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities).
- Measurable non-energy benefits (e.g. water savings).
- For natural gas, the Marginal Benefits includes Manitoba Hydro’s avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings).
- Total Program Admin Costs includes the administrative costs involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs.
- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

Total Resource Cost (TRC)

The Total Resource Cost (TRC) metric assesses whether the benefits that are associated with an energy efficiency program are greater than the costs. This assessment is undertaken irrespective of who realizes the benefits and who pays the costs with any economic transfers between the Corporation and the participating customer being excluded.

In general, if program offers greater benefits relative to costs, then a program for pursuing the opportunity should be considered, however Manitoba Hydro will also consider supporting certain programs where the benefits are less than the costs. In the latter case, the rationale driving the support will be driven by other qualitative factors such as supporting emerging technologies (e.g. solar panels) or targeting low participation market sectors (e.g. lower income).

The Total Resource Cost metric is defined as follows:

PV (Marginal Benefits) + PV (Measurable Non-Energy Beneftits) TRC =

PV (Total Program Admin Costs + Incremental Product Costs)

Where:

- For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities).
- Measurable non-energy benefits (e.g. water savings).
- For natural gas, the Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings).
- Total Program Admin Costs includes the administrative costs involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs.
- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

Total Resource Cost Net Present Value (TRC NPV)

The Total Resource Cost Net Present Value (TRC NPV) calculation reveals if the economic value of the benefits that are associated with an energy efficiency program are greater than the costs.

TRC NPV = PV (Marginal Benefits) - PV (Total Program Admin Costs + Incremental Product Costs)

Where:

- For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities) and measurable non-energy benefits (e.g. water savings).
- For natural gas, the Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings).
- Total Program Admin Costs includes the administrative costs involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs.
- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

Levelized Resource Cost (LRC)

The Levelized Resource Cost (LRC) is used to determine the overall economic resource cost of energy saved through an energy efficiency program. The LRC provides a levelized cost of energy saved per unit over a fixed time period. The Levelized Resource Cost is defined as follows:

PV (Incremental Product Costs + Total Program Admin Costs) LRC = PV (Energy)

Where:

- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.
- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs.
- Energy includes the annual energy savings.

Rate Impact Measure Cost (RIM)

The Rate Impact Measure (RIM) metric is used to provide an indication of the long term impact of an energy efficient program on energy rates. The metric is a benefit/cost ratio that represents the economic impact of a program from the ratepayer's perspective. All program related savings and costs incurred by the utility, including revenue loss and incentive payments, are taken into account in this assessment. The Rate Impact Measure metric is defined as follows:

PV (Utility Marginal Benefits) RIM = PV (Revenue Loss + Utility Program Admin Costs + Incentives)

Where:

- For electricity, the Utility Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market and the avoided cost of new infrastructure (e.g. electric transmission facilities).
- For natural gas, the Utility Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas and avoided transportation costs.
- Revenue Loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption (i.e. customer energy bill reductions).
- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs.
- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.

Levelized Utility Cost (LUC)

The Levelized Utility Cost (LUC) is used to provide an economic cost value for the energy saved through an energy efficiency program. The LUC provides the total cost of the conserved energy based upon the utility's investment on behalf of the ratepayer on a per unit basis levelized over a fixed time period. The cost value allows for a comparison to other supply options and other DSM programs occurring over different timeframes. The Levelized Utility Cost is defined as follows:

PV (Utility Program Admin Costs + Incentives) LUC = PV (Energy)

Where:

- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs.
- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.
- Energy includes the annual energy savings.

Simple Customer Payback Calculation (Payback)

The Simple Customer Payback calculation provides the simple payback of implementing an energy efficient opportunity for customers. This value outlines the amount of time required before the customer recovers the incremental product cost. The value is useful in projecting customer participation rates for energy efficient opportunities. The Customer Payback is defined as follows:

Participant Costs - Incentives CP = Annual Bill Reductions

Where:

- Participant Costs includes the participant's total incremental cost associated with implementing the energy efficient opportunity, which is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.
- Incentives includes funds provided by Manitoba Hydro and external parties to the participant associated with implementing the energy efficient opportunity.
- Annual Bill Reductions include the first year dollar reductions in the customer's electricity, natural gas, and water bills.

Participating Customer Cost (PC)

The Participating Customer Cost (PC) metric evaluates from a customer perspective if the benefits that are associated with an energy efficiency program are greater than the costs over the life of the measure. The Participating Customer Cost is defined as follows:

PV (Incentives + Revenue Loss) PC = PV (Incremental Product Costs)

Where:

- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.

- Revenue Loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption (i.e. customer energy and measurable non-energy (i.e. water) bill reductions).
- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

APPENDIX C: Stress Test Tables

Table 1 Historical and Projected with Base DSM

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total Capacity GW	5.46	5.46	5.47	5.47	5.47	5.47	5.46	5.48	5.5	5.47	5.69
With Keeyask											
Peak GW	3.95	3.99	4.2	4.08	4.21	4.3	4.51	4.39	4.29	4.09	4.17
Load tWh	22.1	22.1	22	22.8	23.5	24.1	24.4	23.4	23.9	23.6	24.7
DSM tWh	0.51	0.55	0.63	0.74	0.95	1.01	1.12	1.22	1.34	1.39	1.41
DSM GW	0.11	0.12	0.13	0.15	0.17	0.18	0.21	0.23	0.26	0.27	0.29
Load Factor	63.9%	63.2%	59.8%	63.8%	63.7%	64.0%	61.8%	60.8%	63.6%	65.9%	67.6%
Capacity Factor	46.2%	46.2%	45.9%	47.6%	49.0%	50.3%	51.0%	48.7%	49.6%	49.3%	49.6%
Capacity Reserve	27.7%	26.9%	23.2%	25.4%	23.0%	21.4%	17.4%	19.9%	22.0%	25.2%	26.7%
Average Capacity Factor	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%
DSM load factor	51.4%	52.2%	53.9%	56.3%	65.2%	62.5%	62.3%	59.5%	59.6%	58.3%	55.5%
Capacity with DSM GW	5.57	5.58	5.60	5.62	5.64	5.65	5.67	5.71	5.76	5.74	5.98
Capacity Reserve with DSM	29.1%	28.5%	25.0%	27.4%	25.3%	23.9%	20.4%	23.2%	25.5%	28.8%	30.3%
Capacity Reserve with DSM and Keeyask											

Table 1 continued

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity GW	5.69	5.69	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	1.48	1.51	1.57	1.62	1.68	1.74	1.77	1.80	1.84	1.83	1.83	1.80	1.74	1.71	1.68	1.68
DSM GW	0.31	0.33	0.33	0.35	0.36	0.37	0.38	0.39	0.40	0.41	0.40	0.40	0.39	0.39	0.39	0.39
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.6%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	23.7%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
Average Capacity Factor	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%	23.5%
DSM load factor	55.0%	52.8%	53.8%	53.2%	53.2%	53.3%	52.9%	52.8%	52.6%	50.6%	51.7%	51.1%	50.4%	49.8%	49.3%	49.3%
Capacity with DSM GW	6.00	6.02	6.03	6.04	6.15	6.15	6.06	6.07	6.08	6.18	6.09	6.09	6.07	6.07	6.07	6.07
Capacity Reserve with DSM	27.1%	27.9%	28.4%	27.3%	27.5%	26.5%	24.1%	22.9%	23.5%	22.0%	19.6%	18.4%	17.0%	16.0%	14.8%	13.7%
Capacity Reserve with DSM and Keeyask	27.1%	27.9%	28.4%	27.3%	27.5%	26.5%	25.2%	28.2%	30.7%	29.2%	27.1%	26.1%	24.8%	23.9%	22.8%	21.8%

Table 2 Projected with 1.5X DSM unsmoothed

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.69	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	2.22	2.27	2.35	2.44	2.52	2.60	2.65	2.70	2.76	2.74	2.74	2.70	2.60	2.57	2.52	2.52
DSM GW	0.46	0.49	0.50	0.52	0.54	0.56	0.57	0.58	0.60	0.62	0.60	0.60	0.59	0.59	0.58	0.58
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.6%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	23.7%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	55.0%	52.8%	53.8%	53.2%	53.2%	53.3%	52.9%	52.8%	52.6%	50.6%	51.7%	51.1%	50.4%	49.8%	49.3%	49.3%
Capacity with DSM	6.2	6.2	6.2	6.2	6.3	6.3	6.3	6.3	6.3	6.4	6.3	6.3	6.3	6.3	6.3	6.3
Capacity Reserve with DSM	28.9%	29.8%	30.3%	29.3%	29.6%	28.7%	26.4%	25.3%	25.9%	24.5%	22.2%	21.0%	19.6%	18.7%	17.5%	16.3%
Capacity Reserve with DSM and Keeyask	28.9%	29.8%	30.3%	29.3%	29.6%	28.7%	27.5%	30.3%	32.7%	31.3%	29.2%	28.2%	27.0%	26.1%	25.0%	24.0%

Table 3 Projected with 2X DSM unsmoothed

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.69	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.20	25.70	26.00	26.30	26.60	27.00	27.40	27.80	28.20	28.60	29.00	29.40	29.80	30.20	30.60	31.00
DSM tWh	2.96	3.02	3.14	3.25	3.36	3.47	3.54	3.61	3.67	3.65	3.65	3.61	3.47	3.43	3.36	3.36
DSM GW	0.61	0.65	0.67	0.70	0.72	0.74	0.76	0.78	0.80	0.82	0.81	0.81	0.79	0.79	0.78	0.78
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.6%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	23.7%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	55.0%	52.8%	53.8%	53.2%	53.2%	53.3%	52.9%	52.8%	52.6%	50.6%	51.7%	51.1%	50.4%	49.8%	49.3%	49.3%
Capacity with DSM	6.30	6.34	6.37	6.39	6.51	6.52	6.44	6.46	6.48	6.59	6.50	6.50	6.47	6.47	6.46	6.46
Capacity Reserve with DSM	30.7%	31.6%	32.1%	31.3%	31.5%	30.7%	28.6%	27.5%	28.2%	26.9%	24.6%	23.5%	22.1%	21.1%	19.9%	18.9%
Capacity Reserve with DSM and Keeyask	30.7%	31.6%	32.1%	31.3%	31.5%	30.7%	29.6%	32.3%	34.6%	33.3%	31.2%	30.3%	29.0%	28.1%	27.1%	26.1%

Table 4 Projected with 3X DSM unsmoothed

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity GW	5.69	6.83	6.86	6.91	7.05	7.08	7.02	7.04	7.08	7.21	7.10	7.10	7.06	7.06	7.04	7.04
With Keeyask							7.11	7.49	7.71	7.84	7.73	7.73	7.69	7.69	7.67	7.67
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.60	4.68	4.65	4.82	4.90	4.97	5.04	5.10	5.17	5.24
Load tWh	25.20	25.70	26.00	26.30	26.60	27.00	27.40	27.80	28.20	28.60	29.00	29.40	29.80	30.20	30.60	31.00
DSM tWh	4.44	4.54	4.70	4.87	5.04	5.21	5.31	5.41	5.51	5.48	5.48	5.41	5.21	5.14	5.04	5.04
DSM GW	0.92	0.98	1.00	1.04	1.08	1.12	1.15	1.17	1.20	1.24	1.21	1.21	1.18	1.18	1.17	1.17
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	42.9%	43.2%	43.5%	43.1%	43.5%	44.6%	45.1%	45.5%	45.3%	46.6%	47.3%	48.2%	48.9%	49.6%	50.3%
Capacity Reserve	23.2%	36.5%	37.1%	36.5%	36.8%	36.2%	34.4%	33.6%	34.3%	33.2%	31.0%	30.0%	28.6%	27.7%	26.6%	25.6%
DSM load factor	55.0%	52.8%	53.8%	53.2%	53.2%	53.3%	52.9%	52.8%	52.6%	50.6%	51.7%	51.1%	50.4%	49.8%	49.3%	49.3%
Capacity with DSM GW	6.61	7.82	7.86	7.95	8.13	8.20	8.16	8.21	8.27	8.45	8.31	8.31	8.24	8.24	8.21	8.21
Capacity Reserve with DSM	33.9%	44.5%	45.1%	44.8%	45.2%	44.9%	43.6%	43.0%	43.8%	43.0%	41.0%	40.2%	38.8%	38.1%	37.0%	36.1%
Capacity Reserve with DSM and Keeyask	33.9%	44.5%	45.1%	44.8%	45.2%	44.9%	44.3%	46.0%	47.8%	46.9%	45.2%	44.4%	43.1%	42.5%	41.5%	40.7%

Table 5 Projected with 4X DSM unsmoothed

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.69	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	5.91	6.05	6.27	6.50	6.72	6.94	7.08	7.21	7.35	7.30	7.30	7.21	6.94	6.85	6.72	6.72
DSM GW	1.23	1.31	1.33	1.39	1.44	1.49	1.53	1.56	1.59	1.65	1.61	1.61	1.57	1.57	1.55	1.55
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.6%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	23.7%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	55.0%	52.8%	53.8%	53.2%	53.2%	53.3%	52.9%	52.8%	52.6%	50.6%	51.7%	51.1%	50.4%	49.8%	49.3%	49.3%
Capacity with DSM	6.92	7.00	7.03	7.08	7.23	7.27	7.21	7.24	7.27	7.42	7.30	7.30	7.25	7.25	7.23	7.23
Capacity Reserve with DSM	36.8%	38.0%	38.6%	38.0%	38.3%	37.8%	36.2%	35.4%	36.1%	35.0%	32.9%	31.9%	30.5%	29.7%	28.5%	27.6%
Capacity Reserve with DSM and Keeyask	36.8%	38.0%	38.6%	38.0%	38.3%	37.8%	37.0%	39.1%	41.2%	40.1%	38.2%	37.3%	36.1%	35.3%	34.3%	33.4%

Table 6 Projected with Base DSM smoothed with DSM Capacity adjusted to System Load Factor

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity GW	5.69	5.69	5.70	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.40	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.60	4.68	4.65	4.82	4.90	4.97	5.04	5.10	5.17	5.24
Load tWh	25.20	25.70	26.00	26.30	26.60	27.00	27.40	27.80	28.20	28.60	29.00	29.40	29.80	30.20	30.60	31.00
DSM tWh	1.48	1.51	1.57	1.62	1.68	1.74	1.77	1.80	1.84	1.83	1.83	1.80	1.74	1.71	1.68	1.68
DSM GW	0.26	0.26	0.26	0.27	0.28	0.29	0.30	0.30	0.30	0.31	0.31	0.30	0.29	0.29	0.28	0.28
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.6%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	23.7%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity with DSM GW	5.95	5.95	5.96	5.96	6.07	6.07	5.98	5.98	5.98	6.08	6.00	5.99	5.97	5.97	5.96	5.96
Capacity Reserve with DSM	26.5%	27.0%	27.5%	26.4%	26.5%	25.5%	23.0%	21.8%	22.3%	20.7%	18.3%	17.1%	15.6%	14.6%	13.3%	12.1%
Capacity Reserve with DSM and Keeyask	26.5%	27.0%	27.5%	26.4%	26.5%	25.5%	24.2%	27.3%	29.7%	28.1%	26.1%	25.0%	23.7%	22.7%	21.6%	20.5%

Table 7 Projected with 1.5X DSM smoothed with DSM Capacity adjusted to System Load Factor

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.69	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	1.52	1.64	1.76	1.90	2.05	2.20	2.37	2.56	2.76	2.72	2.69	2.65	2.62	2.59	2.55	2.52
DSM GW	0.26	0.28	0.29	0.32	0.34	0.37	0.40	0.43	0.45	0.46	0.45	0.45	0.44	0.44	0.43	0.43
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.6%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	23.7%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity with DSM	5.95	5.97	5.99	6.01	6.13	6.15	6.08	6.11	6.13	6.23	6.14	6.14	6.12	6.12	6.11	6.11
Capacity Reserve with DSM	26.6%	27.3%	27.9%	26.9%	27.3%	26.5%	24.3%	23.4%	24.2%	22.6%	20.2%	19.0%	17.7%	16.6%	15.4%	14.2%
Capacity Reserve with DSM and Keeyask	26.6%	27.3%	27.9%	26.9%	27.3%	26.5%	25.4%	28.7%	31.3%	29.7%	27.7%	26.6%	25.4%	24.4%	23.3%	22.2%

Table 8 Projected with 2X DSM smoothed with DSM Capacity adjusted to System Load Factor

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.69	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	1.57	1.75	1.94	2.16	2.40	2.67	2.97	3.30	3.67	3.63	3.58	3.54	3.49	3.45	3.40	3.36
DSM GW	0.27	0.29	0.32	0.36	0.40	0.45	0.50	0.56	0.61	0.61	0.61	0.60	0.59	0.58	0.57	0.57
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.6%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	23.7%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity with DSM	5.96	5.98	6.02	6.05	6.19	6.23	6.18	6.24	6.29	6.38	6.30	6.29	6.27	6.26	6.25	6.25
Capacity Reserve with DSM	26.7%	27.5%	28.3%	27.4%	28.0%	27.4%	25.5%	25.0%	26.0%	24.5%	22.2%	21.0%	19.6%	18.6%	17.3%	16.1%
Capacity Reserve with DSM and Keeyask	26.7%	27.5%	28.3%	27.4%	28.0%	27.4%	26.6%	30.0%	32.8%	31.3%	29.2%	28.2%	27.0%	26.0%	24.9%	23.8%

Table 9 Projected with 3X DSM smoothed with DSM Capacity adjusted to System Load Factor

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.7572	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	1.64	1.91	2.22	2.59	3.01	3.50	4.07	4.74	5.51	5.44	5.37	5.30	5.24	5.17	5.10	5.04
DSM GW	0.28	0.32	0.37	0.43	0.50	0.59	0.68	0.80	0.91	0.92	0.91	0.90	0.89	0.87	0.86	0.85
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.0%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	24.6%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity with DSM	5.97	6.08	6.07	6.12	6.29	6.37	6.36	6.48	6.59	6.69	6.60	6.59	6.57	6.55	6.54	6.53
Capacity Reserve with DSM	26.9%	28.6%	28.8%	28.3%	29.1%	29.0%	27.7%	27.7%	29.4%	27.9%	25.7%	24.5%	23.2%	22.2%	21.0%	19.8%
Capacity Reserve with DSM and Keeyask	26.9%	28.6%	28.8%	28.3%	29.1%	29.0%	28.7%	32.4%	35.6%	34.1%	32.2%	31.1%	30.0%	29.0%	27.9%	26.8%

Table 10 Projected with 4X DSM smoothed with DSM Capacity adjusted to System Load Factor

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.7572	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	1.70	2.04	2.45	2.94	3.53	4.24	5.09	6.12	7.35	7.25	7.16	7.07	6.98	6.89	6.81	6.72
DSM GW	0.29	0.34	0.41	0.49	0.59	0.71	0.85	1.03	1.21	1.22	1.21	1.20	1.18	1.16	1.15	1.14
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.0%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	24.6%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity with DSM	5.98	6.10	6.11	6.18	6.38	6.49	6.53	6.71	6.89	6.99	6.90	6.89	6.86	6.84	6.83	6.82
Capacity Reserve with DSM	27.0%	28.9%	29.3%	29.0%	30.1%	30.4%	29.6%	30.3%	32.5%	31.1%	29.0%	27.8%	26.5%	25.5%	24.3%	23.1%
Capacity Reserve with DSM and Keeyask	27.0%	28.9%	29.3%	29.0%	30.1%	30.4%	30.6%	34.6%	38.2%	36.8%	34.9%	33.9%	32.7%	31.8%	30.7%	29.6%

Table 11 Projected with 1.5X DSM smoothed with DSM Capacity adjusted to System Load Factor and heuristic adjustments

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.69	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	1.42	1.49	1.58	1.66	1.75	1.84	1.94	2.04	2.15	2.07	1.99	1.91	1.84	1.77	1.70	1.63
DSM GW	0.26	0.25	0.26	0.28	0.29	0.31	0.33	0.34	0.35	0.35	0.34	0.32	0.31	0.30	0.29	0.28
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.6%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	23.7%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	61.3%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity with DSM	5.95	5.94	5.96	5.97	6.08	6.09	6.01	6.02	6.03	6.12	6.03	6.01	5.99	5.98	5.97	5.96
Capacity Reserve with DSM	26.6%	27.0%	27.5%	26.4%	26.7%	25.8%	23.4%	22.3%	22.9%	21.2%	18.7%	17.4%	15.9%	14.7%	13.4%	12.0%
Capacity Reserve with DSM and Keeyask	26.6%	27.0%	27.5%	26.4%	26.7%	25.8%	24.5%	27.7%	30.2%	28.6%	26.4%	25.2%	23.9%	22.8%	21.6%	20.4%

Table 12 Projected with 2X DSM smoothed with DSM Capacity adjusted to System Load Factor and heuristic adjustments

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.69	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	1.45	1.58	1.71	1.85	2.00	2.16	2.33	2.51	2.70	2.58	2.47	2.35	2.24	2.13	2.02	1.92
DSM GW	0.25	0.27	0.28	0.31	0.33	0.36	0.39	0.42	0.45	0.44	0.42	0.40	0.38	0.36	0.34	0.32
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.6%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	23.7%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity with DSM	5.94	5.96	5.98	6.00	6.12	6.14	6.07	6.10	6.13	6.21	6.11	6.09	6.06	6.04	6.02	6.00
Capacity Reserve with DSM	26.5%	27.1%	27.8%	26.8%	27.2%	26.4%	24.2%	23.3%	24.1%	22.3%	19.8%	18.4%	16.8%	15.6%	14.1%	12.7%
Capacity Reserve with DSM and Keeyask	26.5%	27.1%	27.8%	26.8%	27.2%	26.4%	25.3%	28.6%	31.2%	29.5%	27.3%	26.0%	24.6%	23.5%	22.3%	21.0%

Table 13 Projected with 3X DSM smoothed with DSM Capacity adjusted to System Load Factor and heuristic adjustments

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.74	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	1.51	1.71	1.92	2.16	2.43	2.73	3.06	3.42	3.82	3.62	3.42	3.22	3.03	2.85	2.67	2.49
DSM GW	0.26	0.28	0.32	0.36	0.41	0.46	0.51	0.58	0.63	0.61	0.58	0.55	0.51	0.48	0.45	0.42
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.1%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	24.4%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	65.8%	68.3%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity with DSM	5.95	6.02	6.02	6.05	6.20	6.24	6.19	6.26	6.31	6.38	6.27	6.24	6.19	6.16	6.13	6.10
Capacity Reserve with DSM	26.6%	27.9%	28.2%	27.4%	28.0%	27.5%	25.7%	25.2%	26.3%	24.4%	21.8%	20.3%	18.6%	17.2%	15.7%	14.1%
Capacity Reserve with DSM and Keeyask	26.6%	27.9%	28.2%	27.4%	28.0%	27.5%	26.8%	30.2%	33.0%	31.2%	29.0%	27.6%	26.1%	24.9%	23.5%	22.1%

Table 14 Projected with 4X DSM smoothed with DSM Capacity adjusted to System Load Factor and heuristic adjustments

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Capacity	5.69	5.74	5.7	5.69	5.79	5.78	5.68	5.68	5.68	5.77	5.69	5.69	5.68	5.68	5.68	5.68
With Keeyask							5.77	6.13	6.31	6.4	6.32	6.32	6.31	6.31	6.31	6.31
Peak GW	4.37	4.34	4.32	4.39	4.46	4.52	4.6	4.68	4.65	4.82	4.9	4.97	5.04	5.1	5.17	5.24
Load tWh	25.2	25.7	26	26.3	26.6	27	27.4	27.8	28.2	28.6	29	29.4	29.8	30.2	30.6	31
DSM tWh	1.55	1.80	2.08	2.40	2.77	3.18	3.65	4.18	4.78	4.48	4.18	3.90	3.61	3.34	3.07	2.81
DSM GW	0.27	0.34	0.35	0.40	0.46	0.53	0.61	0.70	0.79	0.75	0.71	0.66	0.61	0.56	0.52	0.47
Load Factor	65.8%	67.6%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity Factor	50.6%	51.1%	52.1%	52.8%	52.4%	53.3%	55.1%	55.9%	56.7%	56.6%	58.2%	59.0%	59.9%	60.7%	61.5%	62.3%
Capacity Reserve	23.2%	24.4%	24.2%	22.8%	23.0%	21.8%	19.0%	17.6%	18.1%	16.5%	13.9%	12.7%	11.3%	10.2%	9.0%	7.7%
DSM load factor	65.8%	59.7%	68.7%	68.4%	68.1%	68.2%	68.0%	67.8%	69.2%	67.7%	67.6%	67.5%	67.5%	67.6%	67.6%	67.5%
Capacity with DSM	5.96	6.08	6.05	6.09	6.25	6.31	6.29	6.38	6.47	6.52	6.40	6.35	6.29	6.24	6.20	6.15
Capacity Reserve with DSM	26.7%	28.6%	28.5%	27.9%	28.7%	28.4%	26.9%	26.7%	28.1%	26.1%	23.4%	21.7%	19.9%	18.3%	16.6%	14.9%
Capacity Reserve with DSM and Keeyask	26.7%	28.6%	28.5%	27.9%	28.7%	28.4%	27.9%	31.5%	34.5%	32.6%	30.3%	28.8%	27.2%	25.8%	24.3%	22.8%