ELECTRICITY DEMAND IN ONTARIO

Submitted to the Ontario Energy Board regarding RP-2003-0144

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Hydro One Networks & Hydro One Brampton

Context

In Ontario, growth in peak electricity demand has outstripped increases in supply, to the extent that Ontario is experiencing situations when peak demand threatens to exceed the available supply of reliable, reasonably priced capacity. Exacerbating this problem is the need to replace or refurbish a significant fraction of the province's aging generating facilities over the next 5-15 years. While the issue of addressing new supply is urgent, actions that reduce base and peak demands, in an economic manner without adversely affecting the provincial economy, can and should also be initiated.

The Delivery Utilities' Perspective

The purpose of electricity delivery systems (transmission and distribution) is to move electricity from one geographic area to another. This necessarily means that the systems must be designed to balance the supply and demand within and between geographic areas. As such, these electricity delivery systems must be designed and constructed to meet peak electricity demand, plus contingencies, in each geographic area. The cost to construct and maintain electricity delivery systems is directly related to the peak demand that they must meet. The long lead times required to bring additional assets into service and the long service life of these assets make reliable long term peak demand forecasts imperative. For example, there is a risk of overestimating demand side potential, and therefore not embarking on supply initiatives in timely enough manner to avoid severe price spikes and/or blackouts.

Hydro One is the major transmitter and the largest electricity distributor in the province of Ontario. It is committed to helping provide solutions, both supply and demand, that provide net benefits to its customers and its shareholder. Hydro One believes that business cases addressing the costs and benefits of each solution must be prepared to set priorities based on an assessment of net benefits and to help determine how the costs and benefits will be properly apportioned.

For instance, reductions in future demand that alleviate the need for asset rehabilitation, upgrade or construction may help avoid future costs that would otherwise be reflected in transmission and distribution rates. However, because transmission revenues and some distribution revenues are based on peak demand, reductions in current peak demand (or in future peak demand for which assets have already been built) would reduce expected revenue without an accompanying reduction in costs. Distribution revenues would similarly be negatively impacted by reductions in overall energy demand. Transmission and distribution rates and/or structures would need to be adjusted to compensate for these lost revenues, or the financial viability of the province's electric utilities could be compromised.

Demand Side Management and Demand Response

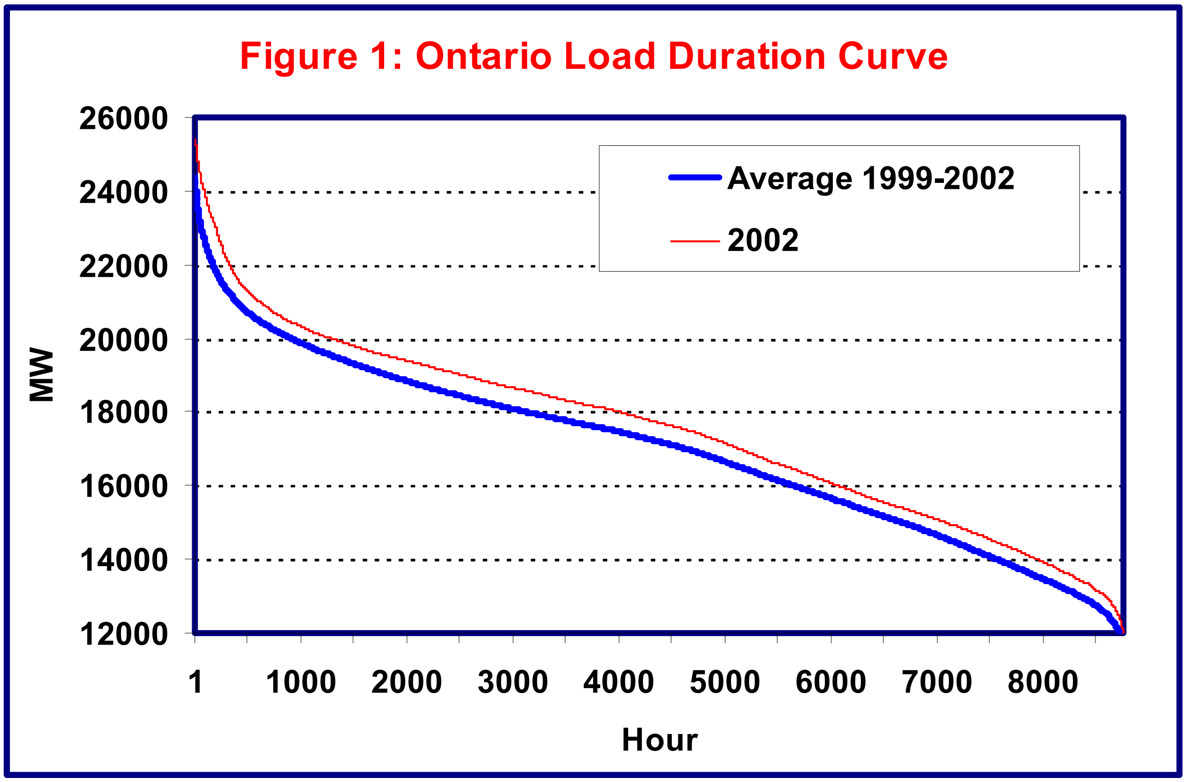
Demand Side Management (DSM) refers to actions which result in sustained reductions in the amount of energy required, such as efficiency and conservation. Such actions result in long term decreases in peak demand. Demand Response (DR) refers to actions which result in temporary reductions in the amount of energy required. Such actions do not generally result in long term decreases in peak demand. While Hydro One supports DSM activities for which an adequate business case can be made, DR has the greatest potential to make the short-term contributions required to ensure near term adequacy of supply. Therefore, in this submission, Hydro One has concentrated on peak demand and DR data that it believes will be most useful to the Board and the Advisory Group in their deliberations.

Hydro One has initiated a number of investigations to better define electricity demand in Ontario, as the first step in understanding what elements of demand are contributing to the adequacy of supply shortfall and where focussed DSM and DR initiatives might be beneficial. These investigations are intended to answer the following questions:

- What is the peak demand problem in Ontario?
  - How often do the peaks occur and how large are they?
  - What comprises peak demand?
- What is the demand side management potential in Ontario?
- What is the potential for demand response from customers?

What is the Peak Demand Problem in Ontario?

It is important to understand the exact nature and extent of the peak demand in Ontario because until the composition and duration of the peak is understood a proper response cannot be determined. Figure 1 shows the peak duration curves for 2002 and the average of 1999-2002. A duration curve shows the number of hours for which demand exceeds various levels; it is a good way to show whether the Ontario electricity demand is peaky. The average of 1999-2002 is used in order to adjust for the impact of the extreme weather experienced in 2002. However, it must be recognized that delivery systems must be capable of coping with such extreme weather factors as well as other demand shocks.



As can be seen in the above load duration curves, high demand situations occur for relatively short periods of time. Demand response programs could be particularly effective in these situations. Table 1 presents this data in more detail for the period 1999-2002.

Table 1

Ontario Hourly Load Characteristics for the 1999-2002 Average: Number of Hours in which Load Falls within Selected Intervals

	11:00 pm-6:59 am	7:00 am-12:59 pm	1:00 pm-5:59 pm	6:00 pm-10:59 pm	All Hours
>24,000 MW					
Winter	0	0	0	0	0
Spring	0	0	0	0	0
Summer	0	5	17	3	25
Fall	0	0	2	1	3
Year	0	5	19	4	28
23,001-24,000 MW					
Winter	0	0	0	4	4
Spring	0	0	0	0	0
Summer	0	8	18	9	35
Fall	0	1	2	1	4
Year	0	9	20	14	43
22,001-23,000 MW					
Winter	0	2	0	29	31
Spring	0	0	0	0	0
Summer	0	14	30	14	59
Fall	0	2	3	2	6
Year	0	18	34	45	96
21,001-22,000 MW					
Winter	0	12	9	77	98
Spring	0	0	0	3	3
Summer	1	23	44	29	97
Fall	0	3	6	13	21
Year	1	37	59	121	218
20,001-21,000 MW					
Winter	4	89	66	130	288
Spring	0	6	4	18	28
Summer	2	44	71	45	161
Fall	0	9	23	36	67
Year	6	148	163	228	544

Based on the average for 1999-2002, the table indicates how many hours in an average year that demand could be expected to exceed certain levels. The breakdown by time of year, clearly indicates that the highest demand situations occur in the summer and are of relatively short duration. For instance, demand would only be expected to exceed 24,000 MW, in an average year, for approximately 28 hours, all of which would be expected to occur in the summer. Similarly, demand would be expected to exceed 23,000 MW for approximately 71 hours, of which only 4 hours would be expected to occur in the winter. Applying the same analysis to 2002 (which must be noted was a year of extreme weather), demand exceeded 24,000 MW and 23,000 MW for 88 and 199 hours respectively.

As expected, peak commodity prices tend to coincide with these peak demand periods. Table 2 provides the price paid for commodity, both excluding and including uplift[1], for periods when demand exceeded 20,000 MW.

Table 2

Estimated Commodity Cost Excluding and Including Uplift in the Year 2002

		Excluding Uplift		Including Uplift		Average
Load (MW)	Energy (GW.h)	Cost (million $)	Average Price (¢/kW.h)	Cost (million $)	Average Price (¢/kW.h)	Import Price (¢/kW.h)
>25,000	479	76	15.8	126	26.3	62.5
24,001-25,000	1,686	270	16.0	384	22.8	55.4
23,001-24,000	2,604	386	14.8	469	18.0	35.1
22,001-23,000	2,851	341	12.0	406	14.3	27.9
21,001-22,000	5,891	529	9.0	602	10.2	17.7
20,001-21,000	13,974	1,025	7.3	1,089	7.8	8.4

Note. For the period prior to market opening, "spot" prices were estimated using average price associated with similar load levels after market opening.

Substantial incremental costs are incurred due to the price increases associated with peaks in demand.

Using in-house end-use models, Hydro One has analyzed the summer and winter peak day profiles by sector and end-use. The analysis is useful to show which customer groups and what end-uses are major contributors to the summer and winter peaks in Ontario (see Figures 2 and 3). The summer peak demand is dominated by a few large end uses, especially residential air conditioning with almost 22% of the peak demand. The winter peak demand is spread more equally across a number of end uses, the largest demand being less than 13%.

[1] Uplift includes energy charges related to congestion, losses, operating reserve and Intertie Offer Guarantees (IOGs). IOGs pertain to payments made for imported power which may be in excess of the market clearing price.

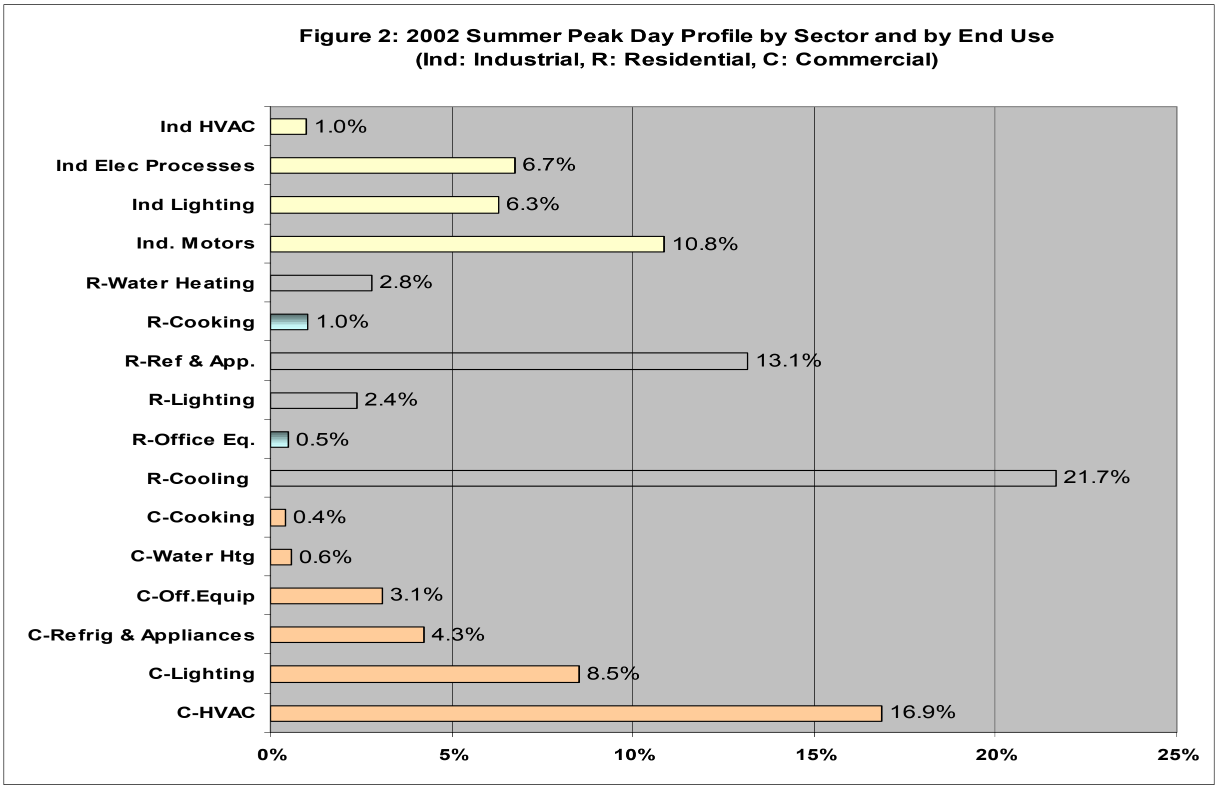


Figure 2: 2002 Summer Peak Day Profile by Sector and by End Use
(Ind: Industrial, R: Residential, C: Commercial)
Ind HVAC
1.0%
Ind Elec Processes
6.7%
Ind Lighting
6.3%
Ind. Motors
10.8%
R-Water Heating
2.8%
R-Cooking
1.0%
R-Ref & App.
13.1%
R-Lighting
2.4%
R-Office Eq.
0.5%
R-Cooling
21.7%
C-Cooking
0.4%
C-Water Htg
0.6%
C-Off.Equip
3.1%
C-Refrig & Appliances
4.3%
C-Lighting
8.5%
C-HVAC
16.9%
0%
5%
10%
15%
20%
25%

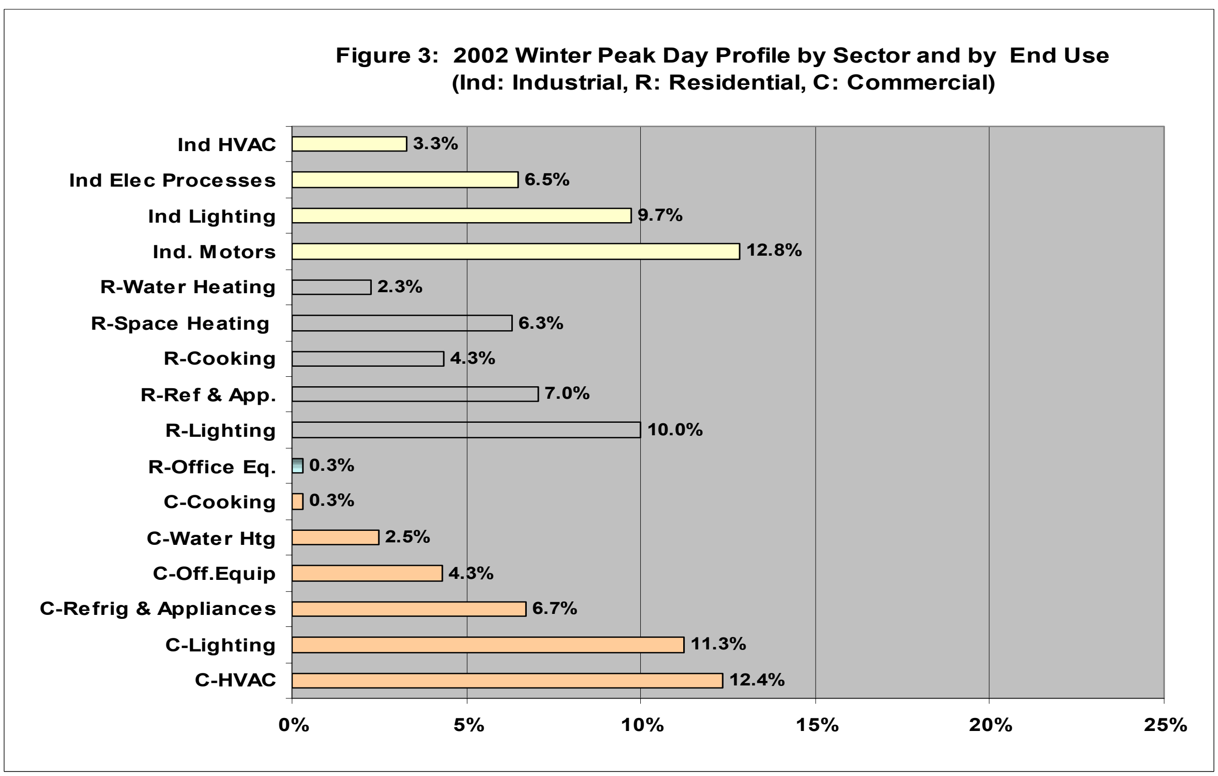


Figure 3: 2002 Winter Peak Day Profile by Sector and by End Use
(Ind: Industrial, R: Residential, C: Commercial)
Ind HVAC
3.3%
Ind Elec Processes
6.5%
Ind Lighting
9.7%
Ind. Motors
12.8%
R-Water Heating
2.3%
R-Space Heating
6.3%
R-Cooking
4.3%
R-Ref & App.
7.0%
R-Lighting
10.0%
R-Office Eq.
0.3%
C-Cooking
0.3%
C-Water Htg
2.5%
C-Off.Equip
4.3%
C-Refrig & Appliances
6.7%
C-Lighting
11.3%
C-HVAC
12.4%
0%
5%
10%
15%
20%
25%

What is the Demand Side Management Potential in Ontario?

Hydro One has engaged a consultant to update the technical potential of DSM programs in Ontario. This update is important because the last DSM analysis done in the late 1980s and mid 1990s is out of date and because the focus at that time was winter peak savings rather than summer peak savings. At the time of preparing this submission, the DSM potential study has not been completed. The potential savings presented here are therefore preliminary estimates only and are limited to efficiency improvement (see Table 3).

Table 3
Preliminary Estimates of
Technical Potential from Efficiency Improvement Savings
(MW by 2012)

	Life Cycle Cost of Savings					
	5 ¢/kW.h		10 ¢/kW.h		30 ¢/kW.h	
	Summer	Winter	Summer	Winter	Summer	Winter
Residential	180	480	530	830	1420	2490
Commercial	1000	1090	2130	1840	2220	1930
Industrial (1)	860	730	860	730	860	730
Total (1)	2040	2300	3520	3400	4500	5150
% of Peak Demand	7.8	9.0	13.4	13.3	17.1	20.1

Note 1: Industrial estimates are not yet screened with respect to life cycle cost due to lack of cost information

Hydro One has screened technical potential estimates provided by the consultant on a life cycle cost basis. The proper way to screen this data would have been on the basis of total customer cost, which includes equipment savings and avoided cost of generation, but Hydro One does not have access to that information at this time. From a provincial perspective, this evaluation is best done by a centralized agency that has access to all pertinent information.

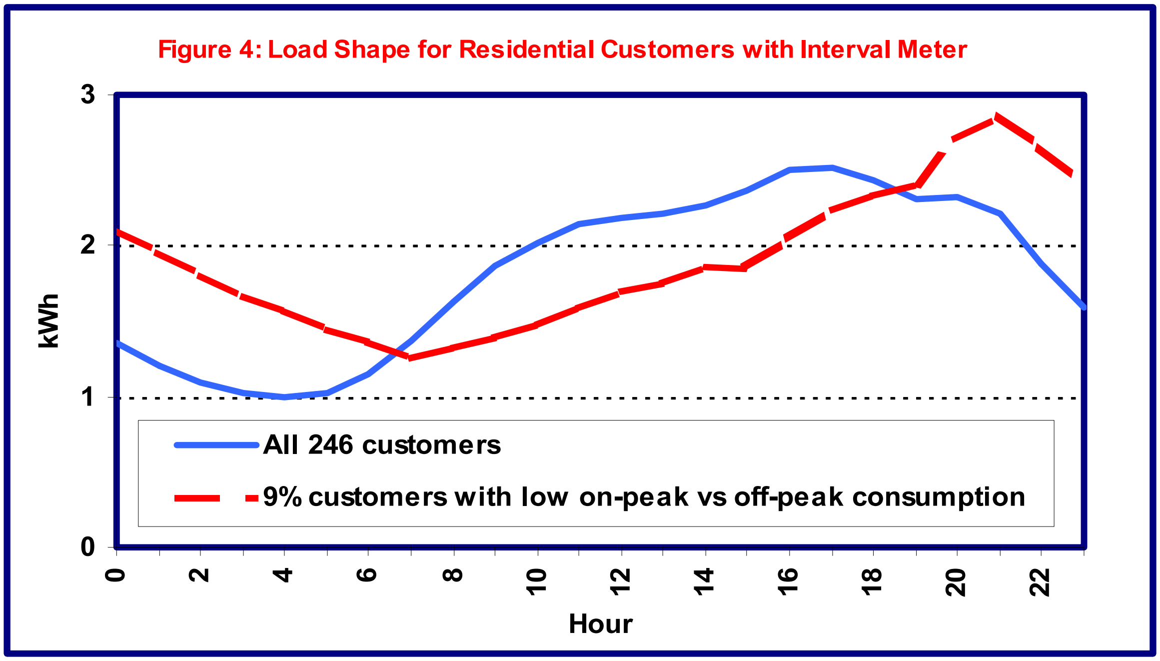
While significant efficiency improvement savings potential exists for lighting, motor and air conditioning initiatives, assuming sufficient money is available to finance the programs, it has historically taken significant periods of time to achieve only a small portion of identified savings through equipment upgrade or replacement programs. Programs that target behavioural change are faster to implement, but measurement of results is extremely difficult. DR programs targeted at those few periods of very high demand are likely to provide significantly more relief from supply constraints and associated economic consequences over the short term.

What is the Potential for Demand Response from Customers?

It is useful to analyze the actual DR behaviour of residential and general service customers, to determine where best to concentrate. Some interval metering studies utilizing voluntary customer membership have concluded that expected reductions in demand, both for individual customers and in aggregate, from the universal application of residential interval meters would be substantial. Interpretation of such studies must be done very carefully, conclusions regarding the behaviour of the overall customer population should not be drawn from analysis of a study with voluntary participation. Customers who have existing load profiles resembling the "target" profile may volunteer in far greater numbers than those with differing load profiles since they stand to benefit financially without having to substantially adjust their energy usage. It is difficult to gauge the response of the balance of customers to interval meter data and real time price signals based on the apparent response of these free riders. Unless the price signals received by those customers with existing demand profiles that differ from the target profile are sufficient to overcome their price inelasticity, implementation of an interval meter structure will not result in substantial demand reduction.

For example, Hydro One Brampton (HOB) has over 2,000 residential interval meters installed, which were part of a joint gas-water-electric meter program a number of years ago. This was not a voluntary program, and customers are not billed on an hourly price basis. Hence, the demand curve for these customers is considered to be fairly representative of residential customers in Brampton. An analysis of the data from a random sample of 246 interval meters concluded that there was hardly any correlation between the hourly electricity spot price and the demand from these customers. This was expected, since they did not receive the hourly price signals. The analysis also indicated that these customers had very little response to daily variations in price, for which they would have received some price signals from general media coverage. This is consistent with the expectation that residential demand is relatively inelastic with respect to price.

Within the residential sample under study, it was found that about 9% of the customers had lower demand during the day than they did in the evening and at night (see Figure 4). These customers, who could benefit significantly from an hourly rate structure, are likely to be disproportionately represented in any interval meter pilot for which customers were enrolled on a voluntary basis. However, since these customers usage pattern already matches the target demand curve, they would be considered free riders.



Similar analysis done using data for Hydro One Networks' general service customers, generated counterintuitive results. Although these customers were exposed to spot prices for electricity, their response to higher or lower hourly price signals was minimal and statistically insignificant (i.e. their demand was also inelastic). Possible explanations for this apparently irrational response from such a price sensitive customer segment are that they could not adjust their demand on an hourly basis and/or they had entered into a fixed price arrangement and therefore did not actually experience any hourly variation in price. More predictable price signals (eg. time of use rates) and/or more advance notice of price variations may be required to access the DR potentials of these customers.

Conclusions

There is significant potential for reductions, over time, in both base and peak demands. However, it is not clear how best to achieve these reductions given the apparent inability of customers to adjust their behaviour under existing market structures and prices. It is imperative that detailed business case analyses be performed on all DSM and DR initiatives, prior to their implementation, to ensure that the DSM/DR goal(s) of each initiative will be achieved as a result of that initiative, while at the same time respecting the environmental, health and economic constraints that were deemed desirable/acceptable in the business case.