Valuation of Demand Response in the Nordic Power Market*

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Abstract: This paper presents an analysis of the value of adding different kinds of demand response to the Nordic power market. It is based on an analysis modelling one week at one hourly time resolution. 100 simulations have been carried out for each of the varying inputs such as inflows and demand. It shows that demand response has a value, and that most of this value often is obtained from very few instances. Also, it is shown that the value of demand response depends on location and the type.

Keywords: Power market, demand response, valuation.

1 Introduction

The 1990s was the decade of power market liberalisation in Western Europe. Many academic papers were written concerning efficient market design. Most made the point that to achieve a well-functioning power market the focus should be on the unbundling of utilities, limiting concentration of the industry players and the creation of liquid spot and financial markets. Ensuring demand side participation was however seldom a major point – neither was it mentioned in the EU directive, EC (1996), which forced the electricity markets to be deregulated in all member countries.

Over recent years, concerns have been growing with regard to the efficient operation of these markets. Evidence of abuse of market power, and a general fear that the markets will not attract the necessary investments in new capacity are some of the reasons. For many, it has become clear that consumer response plays a key role here; see e.g. Borenstein and Bushnell (2000), Nordel (2002) and IEA (2003).

Consumer response to high prices is thus now seen as a necessity for any deregulated power market model (including the Nordic) to function efficiently as it would make prices more predicable and less volatile, thus lowering the risks for market participants. This should bring forward investments which would otherwise be delayed due to high risk premiums. Similarly, it will reduce the possibilities of abusing market power.

The ideal case is to have a perfect match between consumers' willingness-to-pay and the marginal cost of supplying the electricity. If consumers are not prepared to or enabled to voluntarily respond to price variations, a welfare loss will occur.

Demand response (DR) can be described as consumers' reactions to prices in the short term and this will be the focus of this paper. In the Nordic power market, Nord Pool, prices on the day-ahead market (Elspot) are set for each hour and these are here considered to be driving the demand response actions. Using a model of the Nordic power system (Balmorel), the economical consequences of adding two different DR resources (peak clipping and load shifting) is compared with a reference case in which there is no additional activity, or a generation case, where open cycle gas turbines are added instead.

The next section gives an introduction to the Nordic power market. This is followed in Section 3 by a description of the valuation approach. The following sections present the Balmorel model and the parameter variability. Section 6 presents the results followed by a summary of conclusions in Section 7.

2 The Nordic power market

This analysis covers the four Nordic countries; Denmark, Finland, Norway and Sweden. A power exchange exists, Nord Pool, covering all four countries. In the Nord Pool price area, zonal pricing is used with 2-4 price areas being defined in Norway, 2 in Denmark, while Sweden and Finland each are treated as one price area. This regime gives locational signals, as prices will differ if transmission bottlenecks hinder least cost dispatch of power to match the local consumption. Marginal transmission losses are however not part of the locational signal in the Nordic market.

* This paper is based on output from a research project funded by the Danish Energy Agency. See Møller Andersen, F., S. Grenaa Jensen, H.V. Larsen, P. Meibom, H. Ravn, K. Skytte and M. Togeby (2006) for further information

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Table 1 - Demand in the Nordic countries in 2003

	Denmark	Finland	Norway	Sweden	TOTAL
Total demand, 2003, GWh	35210	84702	115008	145476	380396
Growth, 1994-2003, p.a.	0.6%	2.4%	0.1%	0.6%	0.8%
Demand per capita, 2003, kWh/yr	6574	16143	26645	16497	16240
Demand by sector, 2003					
• Interruptible boilers	0.0%	0.1%	2.3%	0.4%	0.9%
• Households	29.3%	25.0%	33.4%	31.1%	30.2%
• Industry	29.2%	55.2%	41.4%	44.0%	44.5%
• Service	33.0%	18.7%	21.2%	19.3%	21.0%
• Agriculture and other	8.5%	1.0%	1.6%	5.2%	3.5%
Maximum system load, 2003, MW	6,435	14,040	19,984	26,400	66,859

Source: Nordel (2004)

The Nordic region has an electricity demand of approximately 380 TWh and a population of around 25 million. Large differences between the countries exist as indicated in Table 1. Historically, low electricity prices in Norway and Sweden have led to a large power intensive industry sector and, for Norway in particular, a tradition for using electricity for space heating.

Peak demand normally varies between 37 GW (summer, 5-6 am) and 58 GW (winter, 5-6 pm) with all four national systems peaking during winter.

A total of 90,000 MW of generation capacity is found in the region along with 4,800 MW of transmission capacity to Russia, Poland, and Germany. Hydro power makes up roughly half the generation in the region, with the remaining half being equally split between nuclear and other thermal power. However, the capacity mix varies significantly between countries: Norway being 99% hydro and Denmark 75% thermal fossil and 25% renewables (wind and biomass).

All Nordic countries deregulated their power markets during the 1990's. The competition that followed led to decommissioning of much of the surplus capacity that existed prior to deregulation. As a consequence, the Nordic countries will soon need new means of supplying the peak demand, either through building new generation capacity or reducing the demand during peak load periods.

3 Approach

The analytical set up is the meta-modelling approach presented in Violette et al. (2006). This is a methodology where existing power market models are combined with a Monte Carlo analysis to evaluate different DR products. The approach can be described as:

- identifying main uncertain parameters,
- establishing their probability distributions
- drawing random samples of outcomes from the combined probability space,
- for each sample, simulating the power market, and
- analysing results.

In order to compare the impacts of implementing DR with those of doing nothing or building generation capacity instead, five scenarios have been designed which cover a base case scenario, three DR scenarios and a scenario with additional generation capacity.

The two types of demand response considered are peak clipping and load shifting. The former reduces demand at a given price level. The latter also reduces peak demand, but here the demand (return energy) appears again later on. In this analysis it has been assumed that foregone demand appears within the next 6 hours with a flat profile. The two types of demand response are illustrated in Figure 1.

The 5 scenarios are:

1) Reference: Load disconnected at value of lost load (here assumed to be 5000 NOK/MWh[1])
2) DR1 (PC): Peak clipping of 1,000 MW in South Norway disconnecting at 1000 NOK/MWh
3) DR2 (LS-DK): Load shifting of 1000 MW in Western Denmark
4) DR3 (LS-NO): Load shifting of 1,000 MW in Southern Norway
5) GT: Additional 1,000 MW of gas turbines.

[1] 1 US$ ~ 6.5 NOK (as of October 2006)

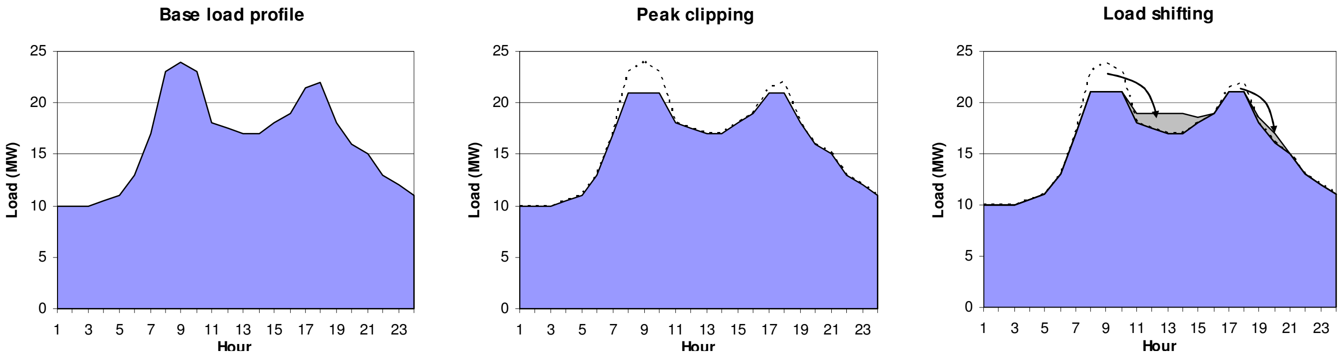

Figure 1 – Types of demand response: Peak clipping vs. load shifting

4 The model

The Balmorel model has been used for the analysis. It is a partial equilibrium model of the power and combined heat and power (CHP) sectors in Northern Europe. It is deterministic and is based on linear programming. It can handle multiple transmission constrained regions and various subdivisions of time. A description of the model can be found in Ravn (2004). A few changes were made in order to model the demand response products.

The year 2010 was used as base year in the analysis. The development of installed capacity in the period 2005-2010 has been constructed based on current industry plans.

The purpose of the analysis is to estimate the value of demand response taking extreme situations into account as it is assumed that these will be a major contributor to the total value. To capture these extremes, the model was set up to an hourly time resolution. Given the high level of resolution, the analysis was restricted to one winter week only. Hydro constraints for that week were based on annual simulations.

Looking at merely one week is not optimal, but was necessary due to the computation time when doing that many simulations (five times 100) with hourly time resolution. The implications for the results will be discussed later.

5 Parameter variability

In the analysis, the following parameters were varied:

- Hydro power
- Wind power
- Temperature (affecting demand)

Their distributions were assessed based on statistical Nordic data from a relatively long time series.

Figure 2 shows the actual variation in yearly hydro power production per country from 1950 to 2000. Denmark has no hydro power.

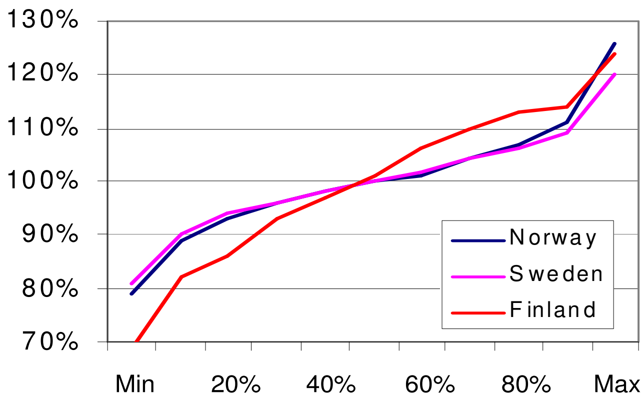

Figure 2 – Annual hydro variability

The weekly wind variability is based on Danish wind production measurements in the period 2000-2005. The distribution is shown in Figure 3.

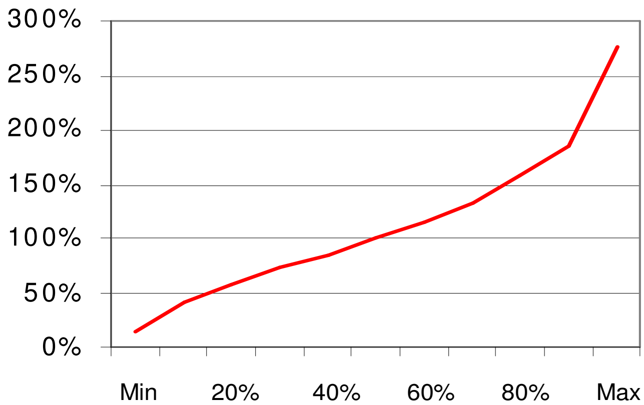

Figure 3 – Weekly wind variability

Similarly, the temperature variability during winter in the Nordic countries has been assessed based on data for January and February 1965-2005. The results are shown in Table 2.

Table 2 - Distribution of the daily winter temperatures in the four Nordic countries.

	Denmark (°C)	Norway (°C)	Sweden (°C)	Finland (°C)
Min	-14,1	-17,0	-19,5	-30,6
10%	-4,3	-9,6	-7,8	-14,8
20%	-2,8	-7,3	-5,9	-11,4
30%	-1,6	-5,8	-4,5	-9,5
40%	-0,6	-4,5	-3,0	-7,7
50%	0,4	-3,3	-1,9	-6,0
60%	1,2	-2,1	-0,9	-4,6
70%	2,0	-1,0	0,1	-3,5
80%	3,2	0,1	1,2	-2,2
90%	4,3	1,3	2,1	-0,8
Max	8,6	5,6	6,9	2,4

Table 3 shows the impact on electricity load per 1°C decrease in temperature based on a regression model on hourly Nordic data for 2000-2005.

Table 3 - Temperature impact on electricity demand in MW and percent of average national demand

	Denmark	Finland	Norway	Sweden
MW %	22 MW 0,5%	86 MW 0,9%	220 MW 1,7%	269 MW 1,6%

The programme Crystal Ball was used draw the 100 simulations of varied input. A Latin Hypercube sampling was used. It is a stratified sampling technique, where the random variable distributions are divided into equal probability intervals. A probability is randomly selected from within each interval for each basic event.

The advantage of this approach is that the random samples are generated from all the ranges of possible values, thus giving insight into the tails of the probability distributions. Furthermore, the method leads to output values that all represents equal probabilities.

6 Model results

The results for each alternative scenario 2-5 have been compared to those of the reference scenario with respect to electricity prices and total costs.

Electricity prices are of interest for evaluating the impacts on power prices from the different scenarios. Also, it is an indicator of how strained the power system is. Figure 4 shows an example of prices as the result of the different scenarios.

The reference case and DR peak clipping scenario results are equal as prices are not high enough to trigger load curtailment. The gas turbine case lowers prices to the point at which it will have its short run marginal costs covered by the power price. The load shifting option (only the Danish scenario has been shown) lowers prices during peak hours and increases them during off-peak hours as expected.

The total system costs have been evaluated to assess at the potential benefits of demand response. The total costs in this analysis consist of:

- Production costs
- Costs of power exchange
- Cost of disconnecting consumers

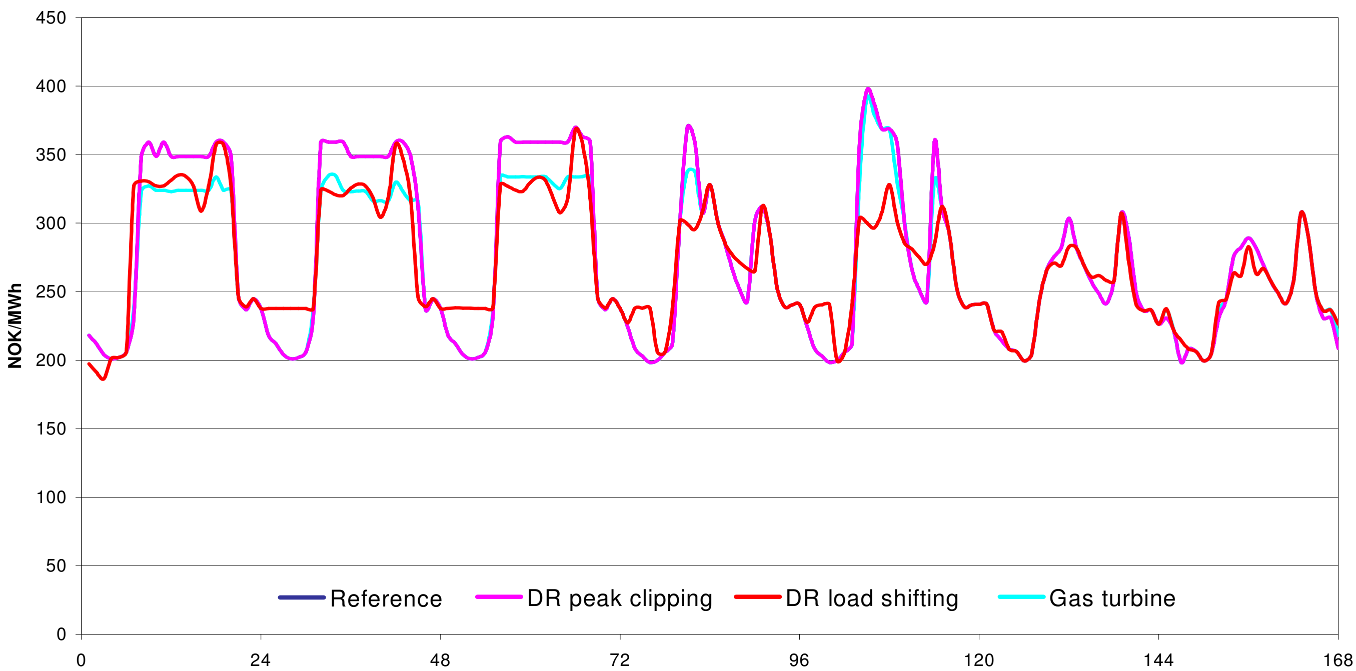

Figure 4 – Examples of changes in prices for different scenarios

The production costs include fuel costs, variable O&M costs and CO_2-emission costs. Capital costs and fixed O&M costs are not included as they only differ from one scenario to another with respect to the costs of implementing DR or commissioning the gas turbine. Therefore, the estimated benefit of each scenario should be compared to the expected additional costs of investing.

The costs of power exchange cover the costs or benefits of importing or exporting to countries outside the Nordic region. Costs of disconnecting consumers arise when consumers are disconnected at the value of lost load.

Table 4: Total costs deviations (in %) compared to the reference case (in million NOK)

Scenario	Percentile				
	10%	50%	90%	95%	Avrg
Reference	953	1,050	1,213	1,302	1,084
DR1 (PC)	-0.0	-0.0	-0.0	-0.6	-4.1
DR2 (LS-NO)	-0.3	-0.5	-1.9	-3.6	-2.9
DR3 (LS-DK)	-1.0	-1.8	-2.6	-2.8	-1.8
GT	-0.0	-0.1	-4.4	-10.6	-5.7

Table 4 summarizes the benefits which arise from the different scenarios. The average benefit from each alternative scenario without taken the necessary investment costs into consideration is 4.1 million NOK in the DR1 (PC) scenario, 2.9 million NOK in the DR2 (LS-NO) scenario, 1.8 million NOK in the DR3 (LS-DK) scenario, and 5.7 million NOK in the GT scenario. The reason why the benefit from DR with load shifting is relatively low may be that it can be interpreted as a kind of electricity storage with quite heavy restrictions on the use, and that the value of such an additional storage in a system with significant amounts of controllable hydro power is limited. The peak clipping option gets the majority of the value from preventing load continuously during dry year periods but whether a 1000 MW potential for this exists in not known. Some options will not be able to be called over a longer time horizon.

The results also show that in most of the analysed cases the benefit from the peak load technologies is zero, but in a few cases the benefit is very high. For instance, in the scenario with DR1 (PC) the 95% percentile is only a benefit of 0.6 million NOK, even though, the average benefit is 4.1 million NOK.

This can be seen in Figure 5 which graphs the cost differences between the scenarios. The *disconnecting costs* decrease by up to 230 million NOK compared to the reference scenario and with the most of the value being achieved in a very few case. The changes in *production costs* are between -7 and 10 million NOK. Changes in *exchange costs* are limited to between -2 and 5 million NOK.

Comparing the result of the two load shifting scenarios, it can be seen that DR3 (LS-DK) gains most value from changed power exchange with countries outside the Nordic region while the DR2 (LS-NO) scenario get most value from the reduction in disconnections.

It was earlier stated that the benefits of each scenario should be compared with the investments needed for expanding the demand response or building the gas turbines. Regarding the latter, the annual capital costs of 1,000 MW are approximately 300 million NOK corresponding to 5.7 million NOK per week. The benefit in week 5 has been estimated 5.7 million NOK, but being a winter week, it is also one of the weeks that are expected to show the highest benefits. It is unlikely that a weekly benefit of 5.7 million NOK can be obtained all weeks of the year.

The costs of implementing DR (peak clipping and load shifting) have not been estimated. The average benefits achieved in week 5 in the scenarios were 4,000 NOK/MW/week for the DR1 (PC) scenario while the DR2 (LS-NO) and DR3 (LS-DK) scenarios gave 2,900 and 1,800 NOK/MW/week respectively.

7 Comparison with other studies

DOE (2006) presents results from several other valuation studies. They are all conducted in the context of the US and vary in multiple ways, e.g. by methodology, system size and market penetration.

Figure 6 shows normalised gross benefit estimates from this report. The ten studies from there have been supplemented by the benefits (i.e. cost savings) from the three DR scenarios in this analysis using the same normalisation. As costs in the figure are annual figures, the benefit from week 5 has been scaled up. The bars show the cases where the week 5 benefits would arise only for one month per year (and none in the remaining part), for three months or for 6 months.

It can be seen that cost estimates from this analysis are lower than the IRP studies, which uses a similar methodology. An explanation could be the large amount of hydro power in the Nordic countries (over the IEA/DRR study) and the fact that only year 2010 was analysed. In addition, the value of DR is expected to grow as capacity margins erode.

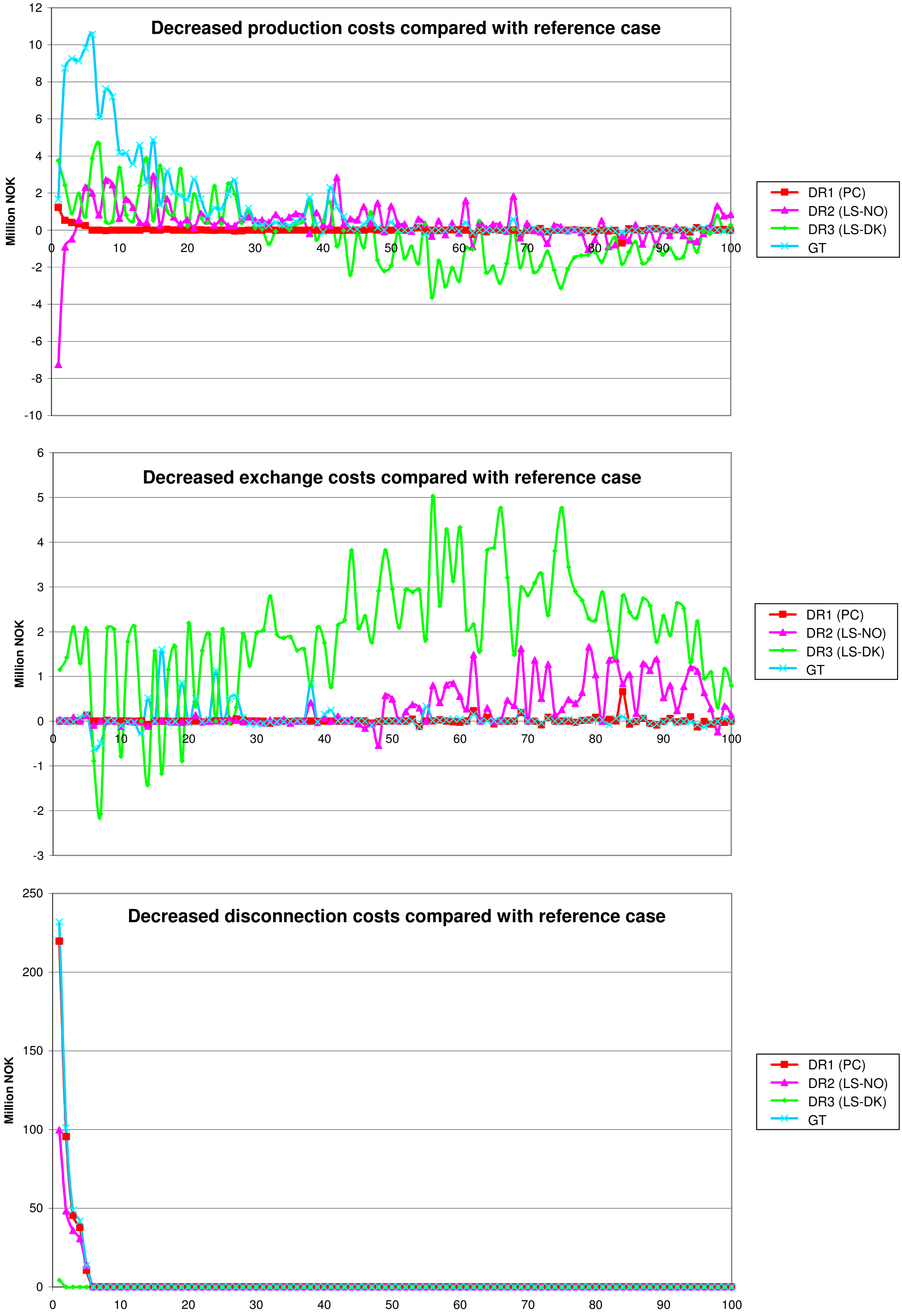

Figure 5 - Scenario costs vs. reference case costs - week 5, 2010. Cases ordered after decreasing total costs of reference case.

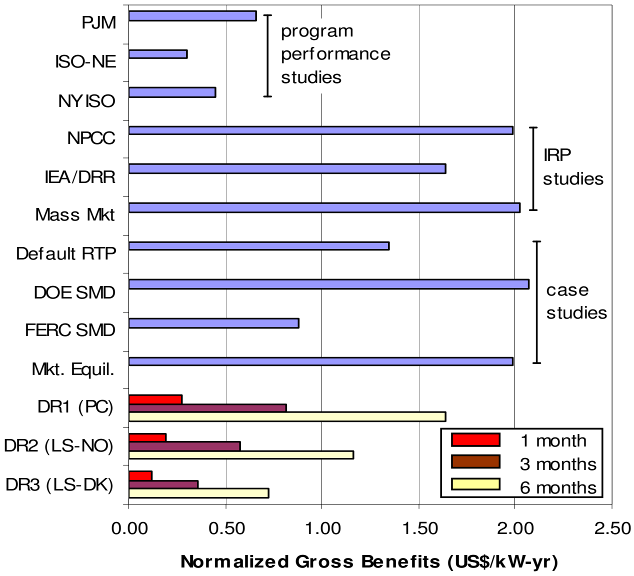

Figure 6 – Comparison of valuation studies

Whether the week 5 benefits from the analysis should be scaled to 1, 3 or 6 months requires further investigation, but the lower benefit in this study is in line with Doorman and Wolfgang (2006), which found no value of 600 MW of load shifting in Norway.

8 Conclusions

This paper has presented the results of a Nordic case study in which some of the benefits of implementing DR have been estimated by use of a Monte Carlo analysis approach.

The results show the system will benefit in all scenarios. As no estimates of implementation costs were available, no ranking between scenarios can be obtained. As an option, the peak clipping scenario looks superior as the value of load shifting in a system with large amounts of hydro power is limited.

It was also shown that a large proportion of the total benefit was obtained in from only a few cases. Since the benefit is low in the majority of the cases, some industry players might not see the importance of demand response. Similarly, it can be hard to set up a business, which is solely based on demand response, as the revenue stream will be unreliable.

In general, the value of demand response as assessed in this study is expected to have a lower value than would be the case in reality. Some reasons for this are:

- The potential value of demand response as reserve capacity is not included.
- Full information is assumed with 'optimal' use of the hydro power within the week and no demand and wind forecast errors.
- The potential value of deterring abuse of market power has not been assessed.
- Only some uncertain parameters are included in the Monte Carlo analysis. Relevant parameters excluded from this analysis are transmission line outages and changes in prices outside the Nordic area.

Apart from refining the analysis by addressing the above issues some further work is required. In order to compare annual benefits of DR with the annual costs including capital costs, it would be relevant to estimate the benefit of a whole calendar year. Also, additional years beyond 2010 should be analysed. Finally, in order to accurately compare options, the costs of implementing DR should be estimated.

9 Acknowledgments

We would like to thank the Danish Energy Agency for funding the project and Rasmus Bøg, DONG Energy, Jesper Werling, EA Energy Analyses, Hans Ravn, RAM-løse EDB and Dan Violette and Rachel Freeman, Summit Blue Consulting for valuable input.

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