The impact of residential demand response on the costs of a fossil-free system reserve

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Abstract

In order to achieve a better understanding of the system value of residential demand response, we study the potential impact of flexible demand on the costs of system reserves in a fossil-free electricity supply. Comparing these costs with traditional means of regulation our analysis aims to contribute to determining the least-cost options for regulation in a fossil-free power system. We extend an existing energy system model with demand response and reserve modelling and analyse the impact for the case of Denmark in 2035 to reflect a system based on renewable resources for electricity and heating.

Keywords: Residential demand response, System reserves, Partial equilibrium model

1. Introduction

The flexibility potential of the demand side has received increased attention in recent years from policy makers in countries developing large amounts of variable renewable electricity generation. TSOs and regulators frequently mention the potential contribution of demand response to reliability in a system with large shares of renewable energies. Technically, load following production, at least to a certain extent, could provide a partial solution to the arising intermittency problem.

Potential contributions of demand response to the efficient operation of power systems have been studied extensively in many different settings. Most essentially, adjusting load at specific points

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in time may lead to savings and potentially avoiding or deferring new investments in generation or grid assets.

Demand response is a resource, most often, restricted to a short duration. An evaluation of its contribution to system operation must therefore be sufficiently detailed on the time scale. Many analyses focus on the hourly scale, and often the economic potential found is limited. Flexibility of the demand side may, however, be better suited for short-term response. For instance, the Danish Energy Agency (2009) argues that new flexibility products are required to utilise demand-side flexibility; pure hourly spot price products would not be sufficient. In order to grasp the full potential one should include contributions within the hour. Such flexibility will then be available as a reserve to the power system.

A few studies investigate the impact of demand response on the reserve requirement. Ali et al. (2015) provide a model framework to optimise residential heat storages in the spot and balancing markets. Douglass et al. (2011) argue that as power from renewable sources displaces conventional generation, new providers of ancillary services are needed. Agent-based models have been used to analyse benefits for consumers of providing system reserves (Lakić et al., 2015, Huang et al., 2015).

We want to contribute to these findings with a study of residential demand response in Denmark using *Balmorel*, an equilibrium model of the electricity and district heating systems (see Ravn et al., 2001).

In this paper, we (1) implement a residential demand response model in *Balmorel*; (2) implement a reserve requirement in the model based on statistical characteristics of forecasting errors and contingencies; (3) estimate the cost of reserves without demand response; (4) estimate the potential savings in costs of reserves with hourly demand response; (5) estimate the potential savings in costs of reserves with demand response contributing to reserves.

2. Method

2.1. Demand response modelling

As a first step, we extend the existing system model *Balmorel* by incorporating responsive electricity demand from households. Implementations of demand-side flexibility in *Balmorel* and similar models have been done in previous works. Some of these have focussed on single applications like electric vehicles (Kiviluoma and Meibom, 2010, Juul, 2012, Hedegaard et al., 2012) or residential heat pumps (Hedegaard and Balyk, 2013, Hedegaard and Münster, 2013). Early versions of the model already included the possibility of adding demand response in the form of elastic demand curves (see Grohnheit and Klavs, 2000). Certainly good arguments exist to represent residential electricity consumers' ability to be flexible using price elasticities. On the other hand, due to the limited manual response of recent real-time pricing trials in Denmark, automation of response could become a crucial factor (cp. Lund et al., 2015). The automation algorithms may be better represented by generic storage-like models instead of elasticities (as implemeted by e.g. Göransson et al., 2014, Biegel et al., 2014, Zerrahn and Schill, 2015, Tveten, 2015). Moreover, the technical potential can be more directly assessed looking at the usage of different appliances, as opposed to assessing the more abstract concept of price elasticity.

We implement a generic demand response model that is based on the assumption that a certain percentage of consumption in any hour would be flexible. Our model extensions are described below with a list of symbols at the end of the paper. For every hour h and geographic area a we define a flexibility potential as a portion of conventional residential demand:

$$D_{a,h}^{flex\text{-}pot} = D_{a,h}^{conv} \cdot k^{flex} \quad \forall\ h, a \tag{1}$$

Moreover, we define a time horizon S for the response such that:

$$\sum_{h}^{h+S} D_{a,h}^{flex} \geq 0 \tag{2}$$

where $D_{a,h}^{flex}$ is used in the overall system balance equation of the model to adjust demand. It thus represents the hourly load-shift delta in MW relative to the baseline demand of the hour $D_{a,h}^{conv}$.

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As the system model we use is defined with an hourly resolution, this representation reflects participation of flexible demand in the hourly spot market. We could as well reserve the flexibility for activation within the hour reflecting participation of demand flexibility in the system reserve. We will therefore include unused flexibility in our reserve modelling in section 2.3, equations (15) and (16).

With such a rolling constraint on flexible volumes we reflect the interdependence of decisions to shift loads at one point in time to other points in time. We use a load-shift horizon of 4 hours. A setup like this may, however, lead to a coupling of flexibility actions at points in time that should in reality be independent. We therefore restrict the rolling constraints to sensible time windows. The length of such larger time windows may be subject to discussion. We find it appropriate to define daily windows such that the effect of a load-shift action will not affect the options to shift loads on another day. The index h in equation (2) therefore is not valid for all hours. Rather, if we define a longer strict load shift horizon as L, then we apply the constraint only for time steps such that the short time window S does not roll over to the next day: $\{\, h \in T \mid h \mod L < L - S \,\}$. Defining $L = 24$ thus will ensure that there will be no rolling over of the constraint at midnight.

At the same time we add a strict constraint on the load shift within the larger time horizon L:

$$\sum_{h}^{h+L} D_{a,h}^{flex} = 0 \quad \forall \, \{\, h \in T \mid (h-1) \mod L = 0 \,\} \tag{3}$$

This ensures that, on the large time horizon, demand flexibility actions do not add or remove demand, but just shift it across time.

To always cover inflexible conventional demand, flexibility is restricted in the following way:

$$D_{a,h}^{flex} \geq -D_{a,h}^{flex\text{-}pot} \quad \forall \, h, a \tag{4}$$

Although we allow $D_{a,h}^{flex}$ to reduce demand (i.e. the variable may become negative), it is always limited by the potential. We do not include an upward limit so that the model is free to choose the optimal time of consumption within the rolling horizon S.

2.2. Reserve dimensioning

In order to determine the required system reserves it is important to keep in mind the different types of reserves and their characteristics. Milligan et al. (2010) provide a detailed overview of the different types of reserves and make for a good point of departure for further analysis. A similarly comprehensive overview of reserves is given in Söder (1993). It takes the perspective and categories used in the Nordel system covering Norway, Sweden, Finland as well as Eastern Denmark, and explains systematically how to dimension the different types of reserves based on forecast errors and outages.

There is no absolute set of rules for the calculation of the requirement for reserves, and different types of methodologies are available (Ibanez et al., 2014). Traditionally more static methods have been used, whereas recently methods relying more on the probabilistic characteristics of variability and contingencies have been developed and applied (Ela et al., 2010, Jost et al., 2015b).

Dimensioning reserves in practice is based on grid codes. For continental Europe rules are provided by the organisation of European transmission system operators ENTSO-E (2004). A harmonised grid code on load-frequency control and reserves is under development (ENTSO-E, 2013). The basic Nordic rules are defined by Nordel (2006). All of these agreements, however, leave some degree of freedom to the individual system operators. More detailed procedures applied in Germany may be found in Haubrich and CONSENTEC (2008). Based on a similar procedure Jost et al. (2015b) make long-term projections for the reserve requirement in Germany. A detailed procedure for Swedish reserves is presented by Söder (1993).

For Denmark criteria for measuring security of supply have been set forth by Danish Energy Agency (2015b). Danish Energy Agency uses a probabilistic model (*SISYFOS*) to determine the level of security of supply in Denmark (Danish Energy Agency, 2015a). A procedure to explicitly determine a reserve requirement, however, is not included.

For the future Danish system the impact of fluctuations and forecast errors in relation to renewable energies on the demand for reserves will be a central issue. The influence of wind power on the reserve requirement is analysed in a long range of studies (for reviews see Holttinen et al., 2012, Hamon and Söder, 2011, Milligan et al., 2010, Ela et al., 2011, 2010).

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A general finding is that wind power only influences the operating reserve requirement and not the contingency reserves (Holttinen et al., 2012). This would mostly affect slower types of reserves. With higher levels of penetration and the development of large offshore wind farms, however, fast frequency response may also be affected (Das et al., 2015).

We choose a more traditional, conservative approach to determine the reserve margin based on static probabilistic criteria. This may overestimate the actual costs of reserves. While dynamic methods to determine reserve have been proposed and applied (e.g. Jost et al., 2015b), due to the focus of this paper on the change of costs from demand response contributions, we opt for the simpler static approach.

Following the findings by Holttinen et al. (2012) as well as Gül and Stenzel (2005), forecasting errors reflect the most important balancing issue introduced by wind power, which will make up a large share of the system we analyse. Holttinen et al. (2009) use the standard deviation to characterise the increase in operational reserve requirements from wind. Although this is a simplified view, their findings confirm that such an approach could be used as a valid approximation. Hodge et al. (2012b), however, find that normal distributions are not good at approximating the distribution of wind forecast errors due to their narrow tails and a low peak. They propose to use the hyperbolic or the Cauchy distributions instead (see also Hodge and Milligan, 2011). Similar findings are presented by Bludszuweit et al. (2008) proposing the beta distribution for a better fit, their main argument being pronounced kurtosis of the error distribution. Hodge et al. (2012a) estimate distributions based on historical day-ahead forecast errors for load and wind for two US systems. Hodge et al. (2012b) compare distributions of wind forecast errors across different countries. For Denmark the distribution is found to be fairly symmetric and its skewness not very distinct.

Danish day-ahead forecast errors on an hourly basis are available from for the years 2013 to 2015 from Nordpool Spot[1]. We use these data to determine a probability distribution of wind forecast errors (figure 1). The day-ahead errors will to some extent be corrected in the intraday market by balance responsible traders. For the dimensioning of reserves capacities a more critical dimension is the hour-ahead error (Das et al., 2015). As ENTSO-E (2010) states, dragging from Danish

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[1]Downloaded from http://www.nordpoolspot.com/historical-market-data/
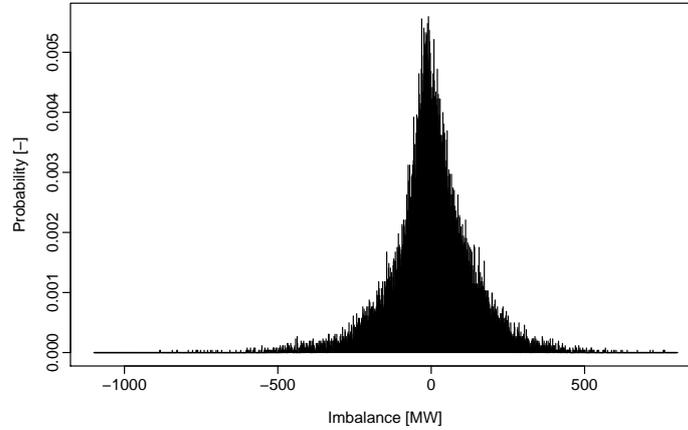
Figure 1: Adjusted distribution of hourly net wind forecast error for the two Danish price zones 2013-15

experience, the normalised wind forecast error is reduced from 5.2% at day-ahead to 3.0% at hour-ahead. It is likely that forecasts can be improved further in the future, and we therefore find it appropriate to use only 50% of the observed day-ahead forecast errors as an approximation for the hour-ahead forecast.

Gül and Stenzel (2005) underline that the role of the demand side as a driver for reserve capacity is limited due to low forecasting errors of 1%-5%. In the future operational reserve capacity may be dispatched mainly for reasons related to the supply side (cp. Gül and Stenzel, 2005, p. 44). Load forecasting errors will, however, still have a role to play in reserve dimensioning. We therefore construct a similar distribution of load forecast errors also using data from Nordpool Spot (figure 2). As with the wind data we adjust the day-ahead errors to approximate hour-ahead deviations assuming load forecasts are improved during the day as well.

In addition to operating reserves to cover forecast errors in load and wind we also take into account capacity to cover for contingencies, as critical outages may occur on power stations or transmission capacity. For the Danish system we take into account capacities in table 1. To be more accurate one should consider partial outages (as in Jost et al., 2015b, Haubrich and CONSENTEC, 2008). As at this point there is quite some uncertainty with regard to the risk for full outages we do not consider partial outages in this analysis.

To calculate probability distributions for outages we use 4000 full load hours for power plant
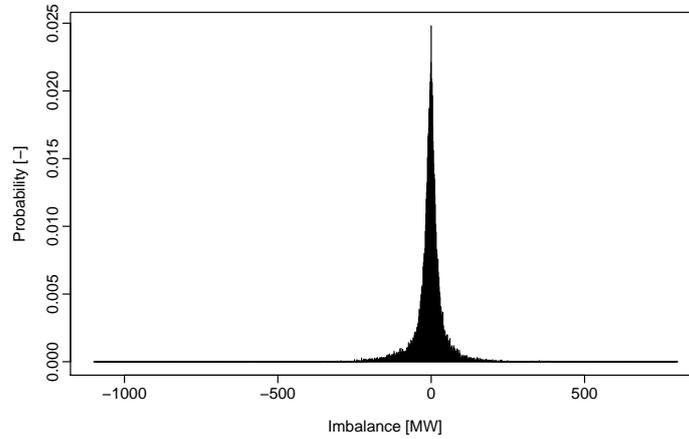
Figure 2: Adjusted distribution of hourly net load forecast error for the two Danish price zones 2013-15

Table 1: Capacities included for contingency estimation

	Capacity [MW]
Power plants	
Fynsværket Block 7	380
Fynsværket Block 8	35
Nordjyllandsværket Block 3	380
Skærbækværket Block 3	390
Studstrupværket Block 3	360
Esbjergværket Block 3	370
Herningværket	90
Amagerværket Block 1	70
Amagerværket Block 3	250
Asnæsværket Block 2	140
Avedøreværket Block 1	250
Avedøreværket Block 2	545
HC Ørstedværket Block 7	75
HC Ørstedværket Block 8	25
Transmission lines	
Sweden – Eastern Denmark	1300
Germany – Eastern Denmark	600
Norway – Western Denmark	1700
Sweden – Western Denmark	680
Germany – Western Denmark	1500
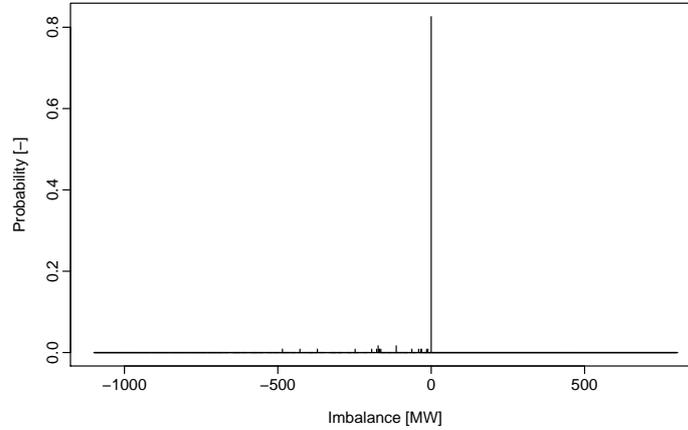
Figure 3: Distribution of plant and line failures

blocks, which corresponds to the number used by Danish Energy Agency (2014a). For transmission lines we use 2500 full load hours corresponding to an average of data on imports over the different lines in 2015.[2] We use a common outage risk on all lines of 1% in any given hour. This number is close to the outage risks considered in a comprehensive German study (Jansen et al., 2005). Although it is lower than the 8% assumed for failures by Danish Energy Agency (2015a,b) it is higher than risks assumed for imports from surrounding countries. Figure 3 shows our resulting probability distribution for outages, obtained by convolution of the individual outage risk probabilities. The probability of no failures occurring at all is thus around 80%.

With these 3 major sources of imbalance risk, wind forecast errors, load forecast errors and outages, we estimate a joint distribution of imbalances for the whole system by convolution (as commonly applied in e.g. Jansen et al., 2005, Molly et al., 2010, Jost et al., 2015a,b). In order to do so, we have to assume that the events are independent. For plant and line failures versus forecasting errors this should be the case. A correlation of wind and load forecasting errors should not be ruled out in general. For the sake of this analysis, however, we ignore any potential correlations. Figure 4 shows the resulting distribution.

In order to determine reserve capacity we need to define the level of deviations required to be covered. The exact criteria used in practice is not publicly available. A security margin of 99.9%

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[2]Data has been retrieved from the Danish TSO on `http://www.energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx`
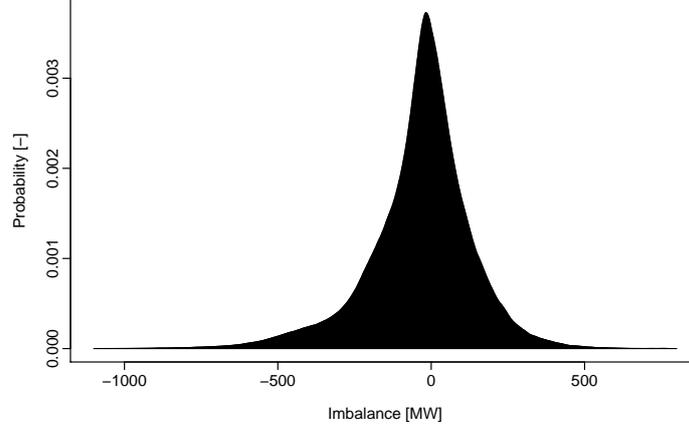
Figure 4: Probability distribution of system imbalances

corresponding to a loss of load probability (LOLP) of 0.1% or 8.76 hours per year is sometimes used (ENTSO-E, 2009). In the light of numbers for actual outages this seems high in a Danish context. We calculate a reserve according to a requirement of a LOLP of 1 hour per year.

We use the cumulative probabilities to find the positive and negative reserve requirements $R^{pos/neg}$ based on the distribution of the system error e^{sys}:

$$P(e^{sys} \leq R^{pos}) = LOLP \qquad \Rightarrow \qquad R^{pos} = 1062\,\text{MW} \qquad (5)$$

$$P(e^{sys} \geq R^{neg}) = LOLP \qquad \Rightarrow \qquad R^{neg} = 763\,\text{MW} \qquad (6)$$

For the reserve modeling we only use the positive reserve assuming that negative capacity would always be available by means of reducing production. We equally divide the reserve requirement into two qualities, fast and slow, representing two categories of response time.

2.3. Reserve modelling

In order to determine the cost of a reserve capacity margin in a fossil-free scenario for Denmark in 2035, we need to define (1) the reserve requirement of the system, and (2) the capacity available to cover for the reserves.

We require total capacity to be able to fulfil demand in any given hour. The hourly flexible demand variable as introduced in equations (1) to (4) enables peak shaving in order to save costs

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of installing peak capacity.

Moreover, we want to ensure that in any given hour we are able to cover for an additional reserve requirement as determined in the previous section 2.2. In order to take into account the capability of different types of generation technologies in regard to ramping we define subsets of technologies that are able to provide the system with fast (FR) and with slow reserves (SR). Fast reserves include frequency response, regulating and ramping reserves (Milligan et al., 2010). Slow reserves include load-following reserve and supplemental reserves. Depending on the technology used a share of capacity may be required to be spinning. This way we make sure that a technology with long start-up times or slow ramping capability is actually available in the required hour. Technology types used for reserves are shown in table 2.

Table 2: Generation technologies providing reserve

	Slow	**Fast**
spinning required	Steam turbines	Steam turbines
	CCGT	CCGT
		Gas turbines
no spinning required	Gas turbines	
	Combustion engines	

Technologies capable of providing fast reserve capacity should reserve a share of capacity in any given hour such that after planned generation the sum of available capacity covers the reserve requirement. We define a variable for such reserved capacity per technology g, area a and time step h for both slow and fast reserves respectively ($K_{a,g,h}^{FR/SR}$). To fulfil the reserve requirement in every country c we define:

$$\sum_{a \in A_c} \sum_{g \in FR} K_{a,g,h}^{FR} \geq R_c^{FR} \quad \forall \, h, c \tag{7}$$

Similarly for the slow reserve capacity:

$$\sum_{a \in A_c} \sum_{g \in SR} K_{a,g,h}^{SR} \geq R_c^{SR} \quad \forall \, h, c \tag{8}$$

The installed capacity of any individual technology capable of providing reserves constrains hourly reserve provision such that:

$$K_{a,g} - G_{a,g,h} \geq K_{a,g,h}^{FR} + K_{a,g,h}^{SR} \quad \forall \, h, a, g \tag{9}$$

For the technologies providing fast reserve capacity we also want to ensure that sufficient capacity is spinning:

$$G_{a,g,h} \geq k^{spin} \cdot K^{FR}_{a,g,h} \quad \forall\, h, a, g \tag{10}$$

where k^{spin} defines the proportion of capacity available for reserves. A similar constraint is added for the slow reserve technologies required to be spinning.

This ensures that no reserves may be provided if a technology is not running. At the same time the constraint forces capacities to be running at higher levels to be able to provide sufficient capacity. This formulation is only an approximation in order to avoid unit commitment. We do ensure on a technology basis that capacity will be spinning. We do not, however, exactly ensure in this way that a particular unit considered for up regulation will be spinning. What we do know is that some capacity of a technology that would be capable of fast up-regulation is spinning. As usually several units of the same technology type would be present in the system, we may risk that all spinning units are fully utilised and we rely on a different non-spinnning unit for the fast reserve. We do consider this inaccuracy to be acceptable in the context of our analysis.

The constraint we use to force spinning capacities in equation (10) allows for increasing levels of reserve provision as generation of a technology increases. To reflect the ramping capability of generation technologies more realistically we introduce an addtional constraint to limit the reserve provision of a technology to a certain percentage of installed capacity.

$$K_{a,g} \cdot k^{ramp} \geq K^{FR}_{a,g,h} \quad \forall\, h, a, g \tag{11}$$

We use approximate ramp rates; moreover, we define the spinning factor k^{spin} such that it stays active only until a minimum load level of 20% is reached.[3] Therefore, as far as reserve provision is concerned, the full ramping capability is only utilised at levels above the minimum load. Again we avoid unit commitment modelling and do not model minimum load requirements explicitly. We do, however, substantially restrict reserve provision at generation levels below the technical minimum using this kind of non-integer linear approximation. Table 3 shows the technology characteristics used (based on Papaefthymiou et al., 2014).

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[3]This will be the case for $k^{spin} = \frac{load^{min}}{k^{ramp}}$

Table 3: Technology characteristics used in reserve constraints

Technology	Min. load [%]	Ramp rate [%/5 min.]	k_{spin} [-]
Steam turbines	20%	20%	1
CCGT	20%	20%	1
Gas turbines	20%	40%	0.5
Combustion engines	0%	100%	1

To determine the overall required capacity we implicitly apply an approach incorporating demand flexibility in a way similar to that of Hedegaard and Balyk (2013):

$$\sum_{a \in A_c} \sum_{g \in G} K_{a,g} \geq \sum_{a \in A_c} \left(D_{a,h}^{conv} + D_{a,h}^{flex} \right) \cdot \frac{1}{1 - k^{loss}} \quad \forall\, h, c \tag{12}$$

While Hedegaard and Balyk (2013) use technology specific capacity credits to ensure that sufficient reserve capacity is available to the system, we have defined a system reserve requirement by equations (7) and (8). This far, demand flexibility only explicitly affects the hourly energy balance of the system, and demand flexibility is able to reduce required peak capacity to serve hourly load. We would like to extend this approach, though, to also allow for provision of reserves from demand flexibility. To analyse this case we extend the reserve capacity equations (7) and (8) with variables reflecting reserve contribution from demand response $R^{Dflex,SR/FR}$:

$$\sum_{a \in A_c} \sum_{g \in FR} K_{a,g,h}^{FR} \geq R_c^{FR} - \sum_{a \in A_c} R_{a,h}^{Dflex,FR} \cdot \frac{1}{1 - k^{loss}} \quad \forall\, h, c \tag{13}$$

$$\sum_{a \in A_c} \sum_{g \in SR} K_{a,g,h}^{SR} \geq R_c^{SR} - \sum_{a \in A_c} R_{a,h}^{Dflex,SR} \cdot \frac{1}{1 - k^{loss}} \quad \forall\, h, c \tag{14}$$

The flexibility potential of the demand side may only contribute to reserves if it is not utilised in the spot market. As we only consider positive reserves, we have to be able to reduce consumption in order to contribute:

$$D_{a,h}^{flex\text{-}pot} + D_{a,h}^{flex} \geq R_{a,h}^{Dflex,FR} + R_{a,h}^{Dflex,SR} \quad \forall\, h, a \tag{15}$$

We want to avoid, however, that a planned increase in consumption due to postponed demand in earlier hours will be postponed even further as this would violate the assumptions used in the demand response modelling of a limited time window for any response. Therefore additional

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demand due to activated flexibility is not allowed to be curtailed and used for reserves. Consequently, any contribution of demand flexibility to reserves is restricted to the original flexibility potential:

$$D_{a,h}^{flex\text{-}pot} \geq R_{a,h}^{Dflex,FR} + R_{a,h}^{Dflex,SR} \quad \forall\, h, a \tag{16}$$

2.4. Scenario set-up

Denmark pursues a strategy of decarbonising its energy system. Although not undisputed the long-term target of a fossil-free energy system in 2050 is widely supported. An important contribution is supposed to come from the electricity and heating sectors, both of which should become fully renewable by 2035 according to a strategy set forth by the Danish Government in 2011. We reflect this strategy in our model using framework conditions in line with the Danish Energy Agency (2014b) "wind scenario" (see Salvucci and Münster, 2015, for further details regarding the scenario implementation).

Although the model formulations in sections 2.1 and 2.3 are applicable to cover any country that is part of the model, we focus on Denmark only for this case study. Both the reserve requirements and the demand response model are therefore only applied in the two Danish regions East and West in order to isolate the effects.

Assumptions about demand response is based on values found in the literature (e.g. Ea Energianalyse, 2011, Heinen et al., 2011). We assume a share of 10% of conventional demand to be flexible. The demand profile used, however, is aggregated across sectors and we do not isolate residential response explicitly. Thus if we assume the residential sector alone to be responsible for the modelled response this is equivalent to a higher share of flexible demand relative to residential consumption, which accounts for about 30% of Danish electricity consumption (Kitzing et al., 2016).

We set up the following model runs for the year 2035 in order to evaluate the system contribution of demand response with high shares of renewable energies:

1. Reference: Neither reserve requirement nor flexible demand

2. Reference flex: Including flexible demand, but without reserve requirement
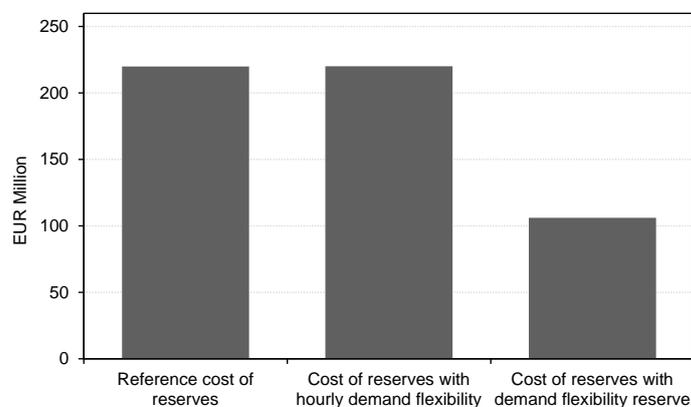
Figure 5: Total costs of fast and slow reserves

3. Base case: Including reserve requirement, without flexible demand

4. Spot: Including reserve requirement, with flexible demand included in the energy balance equation

5. Reserve: Including reserve requirement, with flexible demand included in the energy and capacity balance equations

The difference in costs between the reference and the base case reflects the costs of the reserve requirement if no flexible demand is available. We want to determine the potential contribution of flexible demand to a reduction of these costs. Therefore we need to isolate the effect on reserves from general savings in the spot market.

We can calculate the benefit that demand flexibility generates in the spot market as the difference between the total system costs of cases 1 and 2, the reference cases without and with demand flexibility. But to determine the impact on reserves only, we first find the difference between cases 2 and 4 and compare it to the reference costs of reserve (case 1 minus case 3). We can do the same to find the net effect of a direct contribution of demand flexibility to reserves.

3. Results

3.1. Cost of reserves

The reference case results provide us with a benchmark to compare results derived in the demand response case. We derive total costs of maintaining a certain capacity in excess of demand to provide balancing services covering the imbalances introduced by wind power and load forecasting errors as well as potential plant and line outages.

We arrive at annual benchmark costs of €220 million to provide sufficient reserve capacity to the Danish system in the year 2035. We use the full flexibility of the supply side of the power system, including flexibility in the district heating sector. It should be mentioned that this cost only covers the availability of capacity and not the potential activations due to actual deviations.

Including demand response as a resource that may be used just as any supply-side resource to provide flexibility in order to minimise total system costs, will in the first instance be equivalent to optimising available capacity in the hourly spot market. As we run the model on an hourly basis, any contribution can only be on an hourly level. Moreover, the deterministic nature of the model within a year means that we do not deal with any uncertainties in the first place.

The participation in the spot market does, however, yield a positive effect on the total system. As should be expected from the formulation of the demand response model, within the given assumptions on the flexibility of consumers, load may be served in a cheaper way. The resulting demand profile for one of the modelled weeks is shown in comparison to the original profile in figure 6.

The effect we would like to observe, however, is whether and to what extent the optimisation in the spot market relieves capacity and makes it available for the use as system reserve capacity. In particular, if investments in new capacity that should stay available as peak and reserve capacity could be avoided or reduced, this could be expected to generate significant benefits attributable to the utilisation of demand response – although only participating in the spot market. As it can be seen in figure 5 the cost of reserves is hardly affected by hourly demand flexibility, though.

It has been noted that demand response may be able to contribute actively to system reserves. Due to the limited time horizon of many demand-side measures it would be obvious to exploit
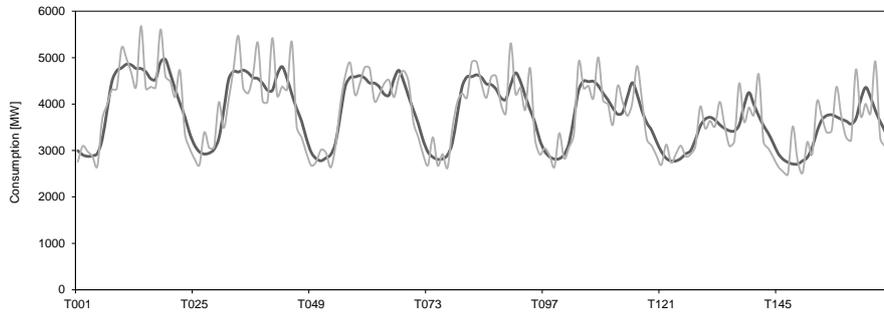
Figure 6: Original (dark) and optimised (light) demand profile assuming hourly demand flexibility for one week

this potential. As noted in the model description we assume idle demand response capacity to be available as reserve. Therefore, although the hourly level is fixed, it also implicitly contains a potential for curtailment or load increase.

The results show that, based on the model structure above, demand flexibility is more valuable as a system reserve than in the spot market. It is therefore fully utilised as reserve. The ability of the demand side to leave idle capacity for system reserves results in a reduction of costs for providing reserves. Comparing the reference case with the demand response case (rightmost bar in figure 5) we find that contributions from the demand side could more than half the costs of reserves provided by generating units.

3.2. Composition of reserves

The composition of capacities available for reserves change under the different scenarios. In figure 7 we show the composition in the modelled 2035 cases as well as a result for the year 2012. Two things are worth noting: First, the fuel shift of the system from fossil fuels to biomass is also reflected in the plants providing reserves; and second, in 2012 we have an overcapacity in the system reflected in the capacity available for slow reserves being much higher than the requirement. Comparing capacities in the 2035 cases, we can see that demand response is going to be used to substitute the expensive fast reserve avoiding costs for spinning capacities.
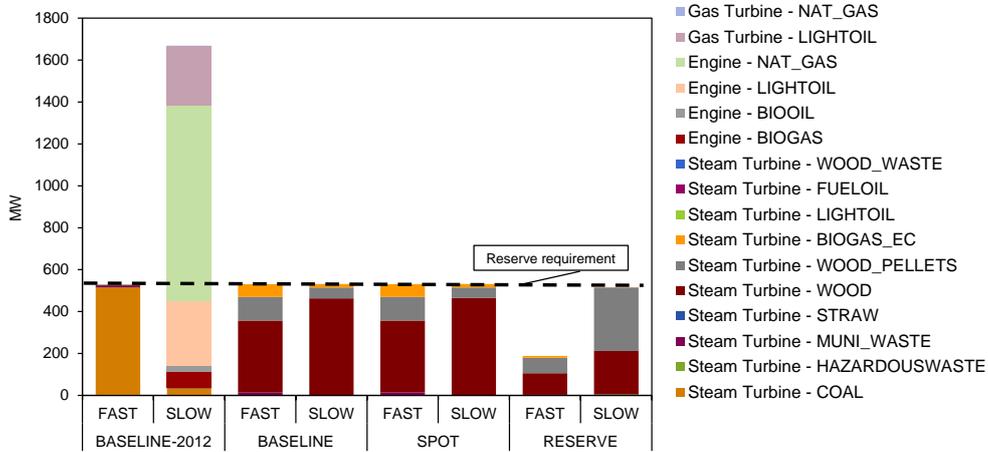
Figure 7: Generation technologies available for reserves

3.3. Price impact of demand flexibility

As we use a linear optimisation model we interpret the marginal values of the electricity balance equation in the model as the electricity production cost that provide us with the spot prices. As the costs of the system changes with the different demand flexibility scenarios we apply, so do the electricity prices. Results are presented in table 4.

Table 4: Electricity prices in reserve scenarios

	Eastern Denmark [€/MWh]			**Western Denmark [€/MWh]**		
	Min.	*Max.*	*Avg.*	*Min.*	*Max.*	*Avg.*
No demand flexibility	39.37	1,231.00	60.54	42.27	1,229.77	60.59
Hourly demand flexibility	39.36	1,217.93	60.42	42.26	1,217.88	60.46
Demand flexibility reserve	39.44	1,229.70	61.15	42.35	1,228.47	61.32

We allow the model to invest in new generation capacity. Therefore the hours triggering investments due to capacity bottlenecks will have significantly higher marginal values. Such spikes may be interpreted as scarcity prices required in order to finance new investments. We find that the utilisation of demand response reduces these scarcity prices due to a lower demand for new capacity. However, if demand flexibility is utilised in the reserve instead of the spot markets the reduction in the price peak is much lower.

4. Discussion

While the overall results point into the expected direction, a couple of issues remain to be resolved regarding the details of both the demand response and the reserve modelling. The full utilisation of demand flexibility for reserves, for instance, seems to be a too extreme solution. One would expect that in time slices that determine the maximum requirement for reserve capacity, there may be a trade-off between utilising the response potential fully in the spot market, or leaving it to stay available for intra-hour demand response. Utilising the full demand flexibility as reserve does not exactly reflect reality. It should therefore be analysed how less restrictive modelling could relieve that situation.

Regarding the determined costs, ideally, they should be comparable with costs that we actually see in the Danish market. As we include investment costs, however, we cannot directly compare to the total costs in the marginal pricing market of Danish, or better Nordic, regulating power. Moreover, we do not reflect in our reserve dimensioning and modeling the Nordic cooperation that enables crossborder provision of reserves subject to available transmission capacities.

An important precondition for using demand response as a reserve capacity in general would be automatic control. This could happen in a centralised way or even in a more autonomous decentralised manner. Our analysis relies on studies that identified certain potentials, some of which may not be fully automated. Moreover automation will come at a cost that we have not considered in our model runs.

Another issue that may have an influence on the value of demand flexibility in general is the timing of its introduction. Early availability of demand flexibility will reduce or delay the investment needs in new flexible capacities.[4]

At this stage we have not performed a sensitivity analysis.[5] Potential sensitivity analyses should include the following dimensions:

- The share of flexible consumption k^{flex} reflecting different levels of adoption or technical

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[4]We intend to investigate scenarios with early adoption and late adoption in another study. Presumably the difference in costs may have important policy implications with regard to smart grid regulatory initiatives.

[5]We plan to do that for a later version of this paper

barriers with regards to full automation. Different cost levels may also be associated with the share of flexibility available.

- The load-shift time horizons S and L that will be different for different appliances and somewhat uncertain due to behavioural aspects.

- The required security of supply as reflected by *LOLP*.

- The distribution of wind and load forecast errors.

- The parameters characterising the risk of outages on power plants and transmission lines.

5. Conclusion

Keeping in mind the limitations discussed above we were able to determine a first estimate of the system value that demand flexibility may contribute with by participating in hourly spot and reserve markets. While attractiveness of the price differences in hourly spot markets may be limited also in future systems, participation in reserve markets may provide an interesting additional source of income to providers of flexibility on the demand side. Any evaluation of the feasibility of such measures must take into account competition in all of the markets for providing flexibility. Therefore it is necessary to have a wide focus in any analysis of flexibility options.

Further analysis will focus on refining the modelling of reserves and demand flexibility. Moreover, a more detailed assessment of the input parameters would be required in order to draw valid conclusions. Finally, addressing the mentioned element of competitions, contributions of the demand side should be compared to other possible flexibility measures both within and outside of Denmark.

Acknowledgement

Nomenclature

h: index for hours

c: index for countries

g: index for generation technology

a: index for areas

A_c: set of areas belonging to country c

FR: set of generation technologies capable of providing fast reserves

SR: set of generation technologies capable of providing slow reserves

$D_{a,h}^{flex\text{-}pot}$: hourly demand flexibility potential in area a [MWh]

$D_{a,h}^{conv}$: hourly conventional residential demand in area a [MWh]

k^{flex}: consumption share assumed flexible [-]

$D_{a,h}^{flex}$: shift from flexible demand in area a [MWh]

S: short-term load shift horizon [h]

L: long-term load shift horizon [h]

e^{sys}: system balancing error [MW]

R^{pos}: positive reserve requirement [MW]

LOLP: loss of load probability [-]

$K_{a,g,h}^{FR}$: hourly capacity of technology g in area a reserved for fast reserves [MW]

$K_{a,g,h}^{SR}$: hourly capacity of technology g in area a reserved for slow reserves [MW]

$G_{a,g,h}$: hourly generation by technology g in area a [MWh]

R_c^{FR}: fast reserve requirement in country c [MW]

R_c^{SR}: slow reserve requirement in country c [MW]

$R_{a,h}^{Dflex,FR}$: hourly demand flexibility reserved for fast reserves in area a [MW]

$R_{a,h}^{Dflex,SR}$: hourly demand flexibility reserved for slow reserves in area a [MW]

$K_{a,g}$: installed capacities of generation technology g in area a [MW]

k^{spin}: factor for spinning requirement [-]

k^{loss}: factor for distribution losses [-]

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