International Journal of Sustainable Energy Planning and Management Vol. 11 2016 33-50

International Journal of
Sustainable Energy Planning and Management

Increased demand-side flexibility: market effects and impacts on variable renewable energy integration

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ABSTRACT

This paper investigates the effect of increased demand-side flexibility (DSF) on integration and market value of variable renewable energy sources (VRE). Using assumed potentials, system-optimal within-day shifts in demand are investigated for the Northern European power markets in 2030, applying a comprehensive partial equilibrium model with high temporal and spatial resolution. Increased DSF is found to cause only a minor (less than 3%) reduction in consumers' cost of electricity. VRE revenues are found to increase (up to 5% and 2% for wind and solar power, respectively), and total VRE curtailment decreases by up to 7.2 TWh. Increased DSF causes only limited reductions in GHG emissions. The emission reduction is, however, sensitive to underlying assumptions. The study shows that increased DSF has the potential of improving intergration of VRE. However, low consumers' savings imply that policies stimulating DSF will be needed to fully use the potential benefits of DSF for VRE integration.

Keywords:

electricity markets
Demand-side flexibility
Renewable energy integration
URL:
dx.doi.org/10.5278/ijsepm.2016.11.4

1. Introduction

The Northern European power system is experiencing an extensive growth in electricity generation from variable renewable energy sources (VRE) like solar, wind and run-of-river (ROR) hydropower, a growth that is expected to continue in the coming decades [1, 2]. In previous work, [3, 4] point out that VRE technologies have three main characteristics that influence the value of produced electricity: the supply is uncertain (i.e. subject to forecast errors), they are location specific (plants must be located where the primary energy carrier is available), and the supply is variable (determined by weather conditions). These characteristics cause challenges and costs related to integrating VRE into the power system.

Based on thorough literature reviews, [4–6] quantify the contribution from the uncertain, location-specific and variable supply of renewable energy, and find that about two thirds of the VRE integration costs are caused by the variability in supply of VRE. The variability in supply causes challenges related to excess VRE supply, curtailment and security of supply [5, 7, 8], as well as a downward effect on electricity prices through the merit-order effect [9–12]. The merit order effect not only influences consumers' costs and revenues of conventional production technologies, it also reduces the market value, or profitability, for existing and future VRE producers [3, 4, 13, 14]. As the VRE market shares increase, the market value of VRE is reduced considerably through the merit order effect. Market modeling studies report that at a

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List of symbols

Symbol	Definition
s, S	*Week of the year,* $s = \{s_1, s_2, ..., s_s\}$, S = 52 (*total weeks of the year*)
n, N	*Day of the year,* $d = \{d_1, d_2, ..., d_D\}$, D = 364 (*total days of the year modeled*)
t, T	*Hour of the week,* $t = \{t_1, t_2, ..., t_T\}$, T = 168 *(total hours of the week)*
h, H	*Hour of the day,* h = $\{h_1, h_2, ..., h_H\}$, H = 24 *(total hours of the day)*
c, C	*Country, c = {DK, FI, GE, NE, NO, SE, UK}, C = All model regions.*
(r, R), (a,A)	*Region, r =* {Denmark1, Denmark2..., *UK}, R = All model regions. (a,A) is alias for (r,R)*
D	*Consumer's utility function*
d	*Electricity demand (MWh)*
g	*Electricity generation (MWh)*
$\overline{g}$, $\underline{g}$	Maximum and minimum power generation level for groups of generation units (MW)
$X^{(a,r)}$	Electricity transmission from region a to region r (MWh)
$\overline{X}$	*Transmission capacity limits between regions (MW)*
d^{pump}	*Energy used for pumped storage (MWh)*
ω^{pump}	*Water amount pumped back to the hydro reservoirs by pumped storage (MWh)*
η^{pump}	*Pumped storage energy efficiency (fraction)*
i,I	*Power generation technology type,* $i = \{i_{HY}, i_{RE}, i_{TH}, i_{NUC}, i_{CHP}\}$
i_{VRE}	*Subset of i, variable renewable energy sources* $i_{RE} = \{i_{ROR}, i_{WIN}, i_{SOL}\}$
i_{TH}	*Subset of i, thermal (gas, coal and oil) power generation groups* $i_{TH} = \{i_{ngas1}, i_{ngas2}, ..., i_{oil4}\}$
j,J	*Thermal power operating mode based on cycling condition j = {low, medium,* high}
$\underline{ramp}$, $\overline{ramp}$	*Maximum capability of hourly up- or down power ramping (fraction of total installed capacity)*
K^P, K^T, K^D	*Electricity production, transmission and distribution cost (€/MWh)*
k^d_{TH}, k^c_{TH}	*Direct production costs and cycling costs of thermal power technologies (€/MWh)*
v	*Water amount in reservoir at end of time period s (MWh)*
ω	*Water inflow in time period s (MWh)*
$\underline{v}$, $\overline{v}$	*Maximum and minimum level of hydro reservoir (MWh)*
$\underline{v_o}$, $\overline{v_o}$	Maximum and minimum initial levels for the hydro reservoirs (MWh)
Δd	Up- or downward shift in demand triggered by demand-side management (MW)
d^{max}	Maximum and average diurnal electricity demand
γ	Potential for demand shifting (percentage)

25–35% wind market share, the revenue per produced unit wind power (i.e. the "received price") corresponds to about 70–80% of the average electricity price. For solar power, the reduction in market value is even more distinct: At a 30% market share, the price "received" by the solar producers corresponds to 40–70% of the average price [4, 14, 15]. Reduced VRE market value caused by the merit order effect is hence expected to become an increasingly important VRE integration cost factor, and a possible obstacle for achieving further increases in VRE market shares.

A flexible power system that could adjust to changes in availability of supply is advantageous for cost-effective integration of high VRE market shares. A variety of measures could be adopted to increase the flexibility of the power system, and hence improve VRE integration (see, e.g. [16] for an overview). One way of obtaining increased flexibility in the supply-demand balance, is to increase the demand-side flexibility (DSF), also known as demand-side management (DSF) [17]. The possible benefits of DSF for improved VRE integration are investigated in several previous studies. Most of these studies focus on potentials, residential loads, microgrids and single households, changes in peak load, balancing costs, and grid-related costs [16]. No previous studies are found to quantify the impacts of DSF on the VRE market value. Furthermore, the effect of DSF on producers' revenues and consumers' costs is sparsely studied. Studies investigating flexibility measures in relation to the VRE market value focus mainly on supply-side flexibility, through storage [4, 14] or grid extension [13, 15, 18]. The effect of short-term demand-side flexibility (i.e. within-day) on the VRE market value has, to our knowledge, not previously been quantified. From a methodological viewpoint, few existing studies investigate the dynamics between regional DSF and VRE supply for power regions constrained by transmission capacities.

This study aims at filling some of the methodological and knowledge gaps identified above, by quantifying the effects of short-term DSF, in the form of within-day demand-shifting, on the VRE market value, on VRE curtailment, and on consumers' costs and producers' revenues. A high-resolution model is applied to simulate the Northern European power markets in the year 2030 under different scenarios for demand-side flexibility. Northern Europe is chosen as the study region, since this region is expected to eventually have one of the world's largest shares of VRE.

The rest of the article is organized as follows; Section 2 discusses DSF in relation to VRE integration. Section 3 presents the Balmorel modeling framework and the scenarios investigated. Section 4 summarizes the key results from the analysis, and a sensitivity analysis is presented in Section 5. Section 6 discusses the study's findings and closes with a conclusion.

2. Demand-side flexibility for improved VRE market value

2.1. A considerable, but unexploited potential

Different measures and methods can be used for describing flexible electricity consumption. One common measure is price elasticity, and the price elasticity of electricity consumers in real time has been quantified in several previous studies [20–23]. For the future energy system, however, the price elasticity is generally hard to predict since estimates based on historical data will exclude the impacts of new smart appliances and systems. A common approach for estimating future DSF potentials is therefore in the form of a GW load increase or reduction. Considerable GW potentials for demand-side flexibility from European consumers are reported in previous studies. Ref. [24] finds a 61 and 68 GW potential for load reduction and increase, respectively, from demand-side management in Europe. Ref. [25] finds a 8.8 and 35.8 GW potential for load reduction and increase for German households and industry, respectively. By also including trade and service sectors and municipal utilities, the potential increases to 11.3 and 46.7 GW, respectively. Ref. [26] finds that the German peak consumption could be completely shifted to off-peak hours only by utilizing intrinsic thermal storage capacities in electricity devices. Ref. [16] summarizes the demand shifting potentials found in previous studies for residential, service sector and industry loads for Germany between 2010 and 2012. They report potentials for load reduction and increase corresponding to 3–4 times the maximum wind power production in 2010 (29 GW). Ref. [27] and [28] present estimates for the percentage of peak load in the Nordic region that can be moved from one period of the day to another. They find that about 18% of the peak load in the Nordic region, on average, may be moved from peak to off-peak hours. The estimates from [27] and [28] are used as case study scenarios in this study, which are described in more detail in Section 3.2.

2.2. Demand-side flexibility for VRE integration

Several previous studies investigate DSF as flexibility measure for VRE integration. Ref. [29] identifies demand-side management as the power system flexibility option with the highest benefit to cost ratio for VRE integration. This is supported by [30], who find that DSF is more promising than both storage and interconnection for reducing total system costs at high VRE market shares. Ref. [31] and [32] find that more wind power enters the market when the consumer flexibility increases. Ref. [33] studies DSF in a small autonomous power system and finds that a higher share of VRE in the power mix could be handled by deploying demand-side integration in the form of load-shifting. These findings are supported by several previous studies on small-scale implementation of DSF, reporting a 20% reduction in VRE integration costs and a 10–20% increased VRE generation [16]. Ref. [34] considers a small stand-alone renewable energy system for a single residential home, and finds that DSF, in the form of demand shifting, limits the need for balancing and back-up power, improves the overall system efficiency and the utilization of the resources.

Although DSF is identified as a valuable flexibility source for VRE integration in previous work, few studies investigate DSF in relation to the VRE market value. Figure 1 gives a simplified illustration of a

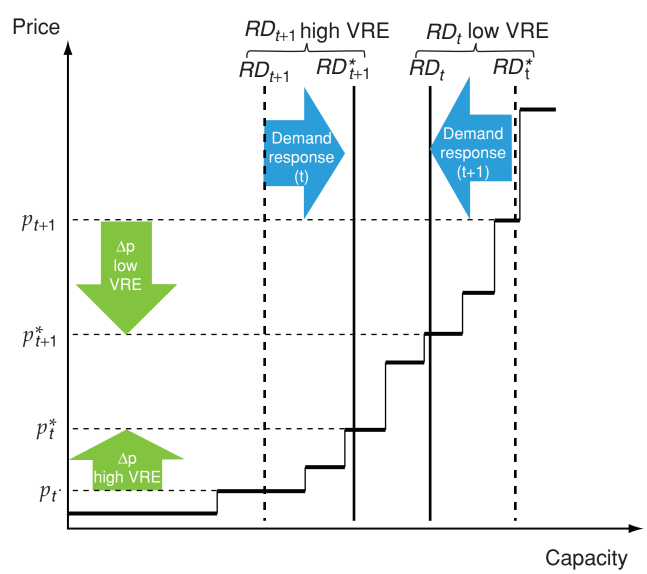

Figure 1: The effect of price responsive demand on market clearing prices in two subsequent time-periods; 1) a situation with low VRE supply and high demand, causing a high residual demand level and a high price, 2) a situation with excess VRE supply causing a low residual demand level and low price.

merit-order curve and market clearing between supply and the short-term (assumed to be inelastic) electricity demand. The effect of demand-side flexibility on the market-clearing price is illustrated for two situations: 1) High demand, low VRE supply and a high price level: Reduced consumption from flexible consumers in this situation causes a leftward shift in the residual demand curve and a price reduction. 2) Low demand, high VRE supply and a low price level: Increased electricity consumption from flexible consumers in this situation causes a rightward shift in the residual demand curve and a price increase. In this way, demand is shifted according to VRE supply and VRE producers benefit from increased received prices in hours with high VRE supply. The VRE producers will be less affected by the reduced prices, since the demand decrease occurs in hours with low VRE supply. Demand-side flexibility hence causes increased received price for VRE producers (p^{-VRE}), and thus improves VRE integration through reduced merit order effect and increased VRE market value[†].

3. Methodology and scenario description

3.1. The equilibrium model Balmorel

The Balmorel model is a comprehensive partial equilibrium model simulating generation, transmission and consumption of electricity under the assumption of competitive markets (see, e.g. [35, 36]). Ref. [37–40] are examples of previous scientific contributions applying earlier versions of the Balmorel model included. The current model version covers the power markets of Germany, the Netherlands, the United Kingdom, and the Nordic countries, with a specifically detailed representation of the Nordic countries (15 regions for Norway, 4 regions for Sweden and 2 for Denmark). As a benchmark, regionalized data for the year 2012 for installed capacity, demand, VRE production, hydro inflow, transmission capacities, export balance, and fuel and carbon prices are applied for calibrating the model. Using observed hourly spot prices and other market data, the model is calibrated for the calendar year 2012. The updated model offers a number of important features that enable detailed analysis of a power system with high shares of VRE. It includes a more detailed modeling of reservoir hydropower and pumped storage, limitations in thermal flexibility, and a high degree of detail in technologies, time and space. To study the future energy system a "most likely" *baseline* 2030 scenario is defined, where the future annual consumption levels and investments in new generation and transmission capacity are determined exogenously based on energy market forecasts, transmission grid development plans and planned energy market investments.

The model calculates the electricity generation per technology, time unit and region, maximizing a consumer's utility function minus the cost of electricity generation, transmission and distribution. Mathematically, this can be expressed by an objective function subject to a number of linear constraints:

$$\max\left[\sum_{s\in S}\sum_{t\in T}\sum_{r\in R}\left\{D_{r,s,t}(d_{r,s,t})-\left(\sum_{i\in I}K_i^P(g_{r,i,s,t})+\sum_{A\in R,A\neq r}K_{a,r}^T(X_{s,t}^{(a,r)})+K^D\sum_{i\in I}g_{r,i,s,t}\right)\right\}\right]_{(\forall r,a,i,s,t)} \quad (1)$$

In the *baseline* scenario, the total power demand is determined exogenously for each region. The hourly variation in power demand is set equal to the observed hourly consumption profiles in 2012, scaled according to the total annual power demand of the year to be studied. An energy balance constraint ensures that power supply must equal demand in every time step:

$$\sum_{i\in I}g_{r,i,s,t}+\sum_{a\in R,a\neq r}\left(X_{s,t}^{(a,r)}-X_{s,t}^{(r,a)}\right)=d_{r,s,t}\ (\forall r,a,i,s,t) \quad (2)$$

The model includes costs and losses of electricity distribution within each region, with the assumption of no constraints on the electricity flow within a region. Hourly trade with third countries is determined exogenously, while the power exchange between regions is determined endogenously, with restrictions on transmission capacities between regions:

$$X_{s,t}^{(a,r)}\le\overline{X}^{(a,r)}(r\neq a)\,(\forall r,a,i,s,t) \quad (3)$$

The supply side consists of various generation technologies, with a specified fuel type, fuel efficiency, variable and fixed costs, heat/power combination factor (CHP units) as well as environmental characteristics for each technology. The maximum capacity level constraint for a specific generation technology is defined by

$$g_{r,i,s,t}\le\overline{g}_{r,i}\ (\forall r,i,s,t) \quad (4)$$

Each thermal technology type is divided into four groups, with different fuel efficiency levels and variable production costs, representing the cost of old, average,

[†] In situations with (i) high demand and high VRE supply or (ii) low demand and low VRE supply, the effects illustrated in figure 1 will be less pronounced.

new and future power plants. Plant-specific costs related to thermal power plant cycling (i.e. power plant start up, shut down, or operating at sub-optimal levels) are not modeled directly since all thermal power technologies are represented on an aggregated level. Instead, a novel approach is applied, where average cycling costs are included on an aggregated level. The marginal costs of thermal power technologies (K_{TH}^{P}) are divided into direct costs (k_{TH}^{d}) (fuel, CO_2 and other variable costs) and cycling costs (k_{TH}^{c}) . When the power ramping of a technology group is high from one hour to the next, power plant cycling is more likely to occur and will increase the marginal costs of the technology group. The cycling costs are modeled piecewise linearly by letting each technology group be able to operate in J=3 different operating modes $g^{j}_{r,iTH,}t$ (j={low, medium, high}) based on the cycling condition.

$$g_{r,i_{TH},s,t} = \begin{cases} g^{low}_{r,i_{TH1},t} \\ g^{medium}_{r,i_{TH2},t} \\ g^{high}_{r,i_{TH3},t} \end{cases} \quad where \sum_{j \in J} g^{j}_{r,i_{TH},t} = g_{r,i_{TH}} \quad (\forall r, i_{TH}, s, t, j) \quad (5)$$

In each operating mode the technology group will have different capability of ramping power up or down from one hour to the next, with increasing cycling cost for increasing ramping capability.

$$\underline{ramp}^{j}_{i_{TH}} \cdot \bar{g}_{r,i_{TH}} \leq g^{j}_{r,i_{TH},s,t} - g^{j}_{r,i_{TH},s,t-1} \leq \overline{ramp}^{j}_{i_{TH}} \cdot \bar{g}_{r,i_{TH}} \ (\forall r, i_{TH}, s, t, j) \quad (6)$$

An increased need for ramping up or down from one hour to the next will then force the model to select a more expensive operating mode of the technology, and hence induce increasing cycling costs for increasing levels of ramping. The cycling costs (K_{TH}^{P}) for each technology group are determined partly on the basis of cycling costs reported in the literature [41] and partly through a thorough model calibration for the base year 2012 against observed historical market data for prices and hourly changes in production levels. The resulting average cycling costs give a conservative approximation compared with numbers found in the literature, which could be explained by the omission of cycling costs for units modeled as must-run technologies (i.e., nuclear power, CHP and other thermal must-run technologies), for which seasonal minimum and maximum production levels are defined as

$$\underline{g}_{r,i,s} \leq g_{r,i,s,t} \leq \bar{g}_{r,i,s} \ (\forall r, i = \{i_{NUC}, i_{CHP}\}, s, t) \quad (7)$$

VRE sources (i_{VRE}) (wind, solar power and run-of-the-river hydropower) have exogenously given production profiles varying on an hourly level according to variations in wind speed, sun light intensity and water flow:

$$g_{r,i_{VRE},s,t} \leq \bar{g}_{r,i_{VRE},s,t} \ (\forall r, i_{VRE}, s, t) \quad (8)$$

In situations of congestion, the model allows for solar and wind curtailment instead of generating negative prices. This is rationalized by the assumption that the stringency of the current renewable energy priority dispatch rules is gradually reduced across Europe as the share of VRE increases. (Note that in the presence of feed-in tariffs or other premium systems, there will only be solar and wind curtailment once the negative power price exceeds the tariff level. Due to high uncertainty about future tariff levels such premiums are not considered in this study, which may cause a moderate overestimation of the price, and an underestimation of VRE production, in situations with VRE curtailment).

For reservoir hydro, the power generation is also limited by a reservoir equation (Equation 9), stating that the hydro storage level in the end of time period s is equal to the hydro resource in the end of the previous time period plus the inflow minus the total hydropower production during time period s. In addition, there are minimum and maximum restrictions on the hydro reservoir storage level (Equation 10), the starting levels for the hydro reservoirs (Equation 11) and the seasonal restrictions on the water flow through the hydro turbines (Equation 12):

$$v_{r,s} \leq v_{r,s-1} + \omega_{r,s} - \sum_{t \in T} gr, i_{HY}, s, t \quad (\forall r, i_{HY}, s, t) \quad (9)$$

$$\underline{v_r} \leq v_{r,s} \leq \overline{v_r} \quad (\forall r, s) \quad (10)$$

$$\underline{v_{or}} \leq v_{r,1} \leq \overline{v_{or}} \quad (\forall r) \quad (11)$$

$$\underline{g}_{r,i_{HY},s} \leq g_{r,i_{HY},s,t} \leq \bar{g}_{r,i_{HY},s} \quad (\forall r, i_{HY}, s, t) \quad (12)$$

Pumped storage is included in the model by adding the following sections to Equations 2 and 9:

$$\sum_{i \in I} gr,i,s,t + \sum_{A \in R, A \neq r} \left(X_{s,t}^{(A,r)} - X_{s,t}^{(r,A)} \right) = d_{r,s,t} + d_{r,s,t}^{pump} = d_{r,s,t}^{total} \quad (2.2)$$

$$v_{r,s} \leq v_{r,s-1} + \left(\omega r,s + w_{r,s}^{pump} \right) - \sum_{t \in T} gr,i_{HY},s,t = v_{r,s-1} + w_{r,s}^{total} - \sum_{t \in T} gr,i_{HY},s,t \quad (9.2)$$

where $\omega_{r,s}^{pump}$ is the water amount (measured in energy units) pumped back to the hydro reservoirs and $d_{r,t}^{pump}$ is the energy used for pumping in hour t, such that

$$\omega_{r,s}^{pump} = n^{pump} \cdot \sum_{t \in T} d_{r,s,t}^{pump} \ (\forall r,s,t) \quad (13)$$

η^{pump} is the assumed pumped storage energy efficiency, which is set to 75% in this study.

Finally, we have the non-negativity restrictions:

$$X_{s,t}^{(a,r)}, g_{r,i,s,t}, g_{r,i_{TH},t}^{j}, d_{r,s,t}, d_{r,s,t}^{pump}, v_{r,s}, \omega_{r,s}, \omega_{r,s}^{pump} \geq 0 \ (\forall r,a,i,s,t,i) \quad (14)$$

Market clearing-conditions are analyzed by applying two different modes of the model: i) a long-term (one year) optimization horizon where the total regulated hydro generation is allocated to specific weeks, and ii) a short-term (weekly) optimization horizon with an hourly time resolution where the weekly hydropower supply is allocated on an hourly basis.

A detailed presentation of the mathematical model and the data sources is provided in [42].

3.2. Endogenous modeling of demand shifting

In this study, DSF is analyzed in the form of within-day load shifting, by assuming that a certain share of the demand may be shifted from one hour to another on a diurnal basis. Ref. [16] discusses DSF in relation to VRE integration, and argues that load shifting is the most beneficial type of DSF, since it enables the same quality and continuity of the energy service offered. Furthermore, as opposed to energy storage, which is subject to losses, no energy conversion is needed for demand shifting, and a 100% efficiency could hence be achieved [43]. DSF is modeled by adding a variable representing an hourly shift in demand ($\Delta d_{1(r,s,t)}$) to the energy balance, where $\Delta d_{r,s,t}$ could have either positive or negative value, depending on whether there is an upwards or downwards shift in demand. Limitations on the maximum allowed shift in demand, as a share of the maximum demand (specified by γ for each region), are included as a model constraint:

$$\left| \Delta d_{r,n,h} \right| \leq d_{r,n}^{\max} \cdot \gamma_r (\forall r,n,h) \quad (15)$$

where $d_{r,n,h}$ is the *baseline* demand in region r, day n and hour h, $d_{r,n}^{max}$ is the diurnal peak (or maximum) electricity demand for region r in day n and γ is the assumed potential for demand shifting in region r, in percentage. Since this study focuses only on short-term shifts in demand, keeping the total daily demand constant, a constraint is added, stating that the sum of all shifted power within a day equals zero:

$$\sum_{H} \Delta d_{r,n,h} = 0 \quad \text{or, analogously:} \sum_{H} \Delta d_{r,n,h}^{up} = -\sum_{H} \Delta d_{r,n,h}^{down} \ (\forall r,n,h) \quad (16)$$

The system optimal DSF is determined endogenously based on the potential reported by [27] and [28]. As discussed in Section 2.1, future DSF potentials are associated with a high degree of uncertainty. To account for this uncertainty, a *baseline* scenario, where no DSF is assumed, is compared with two DSF scenarios: 1) a *moderate* DSF scenario, where a 50% realization of the maximum potential reported by [27] and [28] is assumed, and 2) a Full DSF scenario, where the total potential is assumed implemented. Table 1 reports the scenario assumptions that have been investigated (i.e., the DSF potentials (γ) for all modeled countries) and the corresponding possible average GW

Table 1: Overview of the DSF potential (γ) for each scenario, and the corresponding possible average shift in demand in GW. The potential is given in proportion (percentage) of the peak demand (defined as the daily maximum demand level) that can be shifted on a diurnal basis.

Scenario	DK	FI	NO	SE	GE	UK	NE
baseline (no flexbility)	0	0	0	0	0	0	0
Moderate flexibility (50% of potential realized)							
share of peak demand (%)	4.0%	10%	12%	7.5%	6.0%	6.0%	6.0%
average possible shift in load (GW)	0.2	1.0	1.9	1.4	4.5	2.8	1.0
Full flexibility (all potential realized)							
share of peak demand (%)	8.0%	19%	24%	15%	12%	12%	12%
average possible shift in demand (GW)	0.4	2.0	3.8	2.7	8.9	5.7	2.0

shift in demand. The potential percentages are interpreted as the share of peak consumption that may be moved on a diurnal basis.

4 Results and discussion

4.1. Production mix and consumption

Figures 3.1-3 show the change in modeled average diurnal consumption profiles when assuming increased DSF, for Germany and Norway, all year (Figure 3.1), five winter weeks (weeks 2-6) (Figure 3.2) and five summer weeks (weeks 34-38) (Figure 3.3). For Norway, a considerable smoothening of the consumption profile is found, and a complete shift towards a slightly higher consumption in low-demand nighttime hours, both for the summer and winter seasons. For Germany, the impacts are found to be different for different seasons. During winter weeks, the pattern is similar to the Norwegian one, with shifts in demand from peak hours to low-demand nighttime hours (Figure 3.2). During summer weeks, on the other hand, DSF causes increased consumption in high-demand daytime hours between 1 and 6 p.m. (Figure 3.3). This is explained by the peaking supply of solar power during mid-day hours, causing low prices.

There is a general trend of reduced production from mid-merit/peak technologies (natural gas, reservoir hydro and pumped hydropower), while production from baseload/mid-merit coal and lignite technologies is increased (Figure 3 and Table 2). During peak hours, power generation from natural gas and coal is substantially reduced, but the total coal power generation increases with increasing DSF, due to increased production in off-peak periods. Production from mid-merit/peak technologies, providing supply side flexibility (reservoir hydro, pumped hydro and natural gas), declines during daytime and increases at nighttime. DSF reduces the curtailment (i.e. increases production) of VRE technologies by 7.2 TWh (Full flexibility scenario). The increased VRE production is caused by two main effects: 1) increased wind (5.8 TWh/year) and ROR (0.6 TWh/year) power generation in off-peak hours, due to fewer hours with excess power supply, and 2) increased solar power

Table 2: Average production levels in the *baseline* scenario and change in production for the different DSF scenarios, total for all modeled countries and for Germany and Norway.

		***baseline* scenario (total production in TWh)**	**DR scenarios (change in GWh) Moderate**	**Full**
Total	CHP, biomass and nuclear	391	+323	+386
	Coal and lignite	313	+3219	+5033
	Natural gas	91	–8234	–13513
	Fuel oil	0.1	–125	–140
	Reservoir hydro and pumped storage	145	–1997	–2929
	VRE	554	+4213	+7151
	of which ROR hydro	106	+424	+566
	of which wind	383	+3330	+5847
	of which solar	64	+459	+738
Germany	CHP, biomass and nuclear	113	0	0
	Coal and lignite	219	+1239	+2084
	Natural gas	8	–2590	–3755
	Reservoir hydro and pumped storage	8	–1848	–2783
	VRE	241	+1400	+2172
	of which ROR hydro	22	+244	+346
	of which wind	163	+862	+1314
	of which solar	56	+294	+512
Norway	CHP, biomass and nuclear	0.6	0	0
	Natural gas	0.0	+159	+151
	Reservoir hydro and pumped storage	86	–139	–137
	VRE	57	+25	+27
	of which ROR hydro	49	+22	+24
	of which wind	8	+3	+3

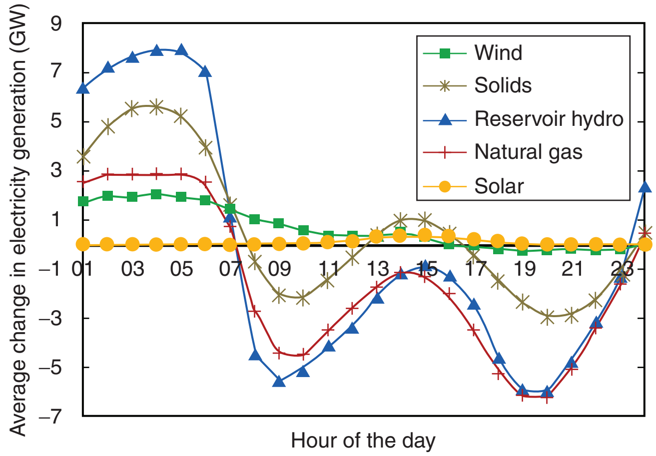

Figure 2: Change in the diurnal Northern European production mix caused by DSF, Full flexibility scenario (all modeled countries, all-year average).

generation (0.7 TWh/year) in peak hours. Due to the general switch in production from mid-merit/peak gas and hydropower to baseload coal power, the reduced VRE curtailment causes only a 1.1 Mtonne reduction in total GHG emissions when comparing the Full flexibility and the *baseline* scenarios, which corresponds to 157 grams reduced GHG emissions per kWh of increased VRE generation.

4.2. Prices and consumers' costs of electricity

Although using the total assumed DSF potential will cause substantial changes in the consumption profiles (Figure 3.1-3), the impact on the average electricity price is found to be low (reported for Germany and Norway in Table 3). The low influence on the average price results in only small changes in consumers' cost of electricity (-0.5-3%) for all countries (Table 4). Summed up for all countries, we find a cost saving of 1.4 G€ for the consumers (Full flexibility scenario), which is only a 1.8% reduction of the consumers' total cost of electricity. Figures 4.1-3 depict the change in average diurnal electricity prices for Norway and Germany for all year (Figure 4.1), winter (weeks 2-6, Figure 4.2) and summer (weeks 34-38 Figure 4.3). Summer prices are generally found to increase with increasing DSF. The price increase during summer is explained by the shape of the supply curve at low load levels. At nighttime, the combination of a high VRE market share and low demand causes hours with low or zero night prices. By increasing the demand in these hours, the market will clear at thermal plants with higher SRMC, causing a considerable price increase. The price increase from DSF during summer is somewhat counter-intuitive, but will likely be a general effect in energy markets with large shares of VRE.

Despite the small influence on the average price level, the intra-day price variation (defined as the standard deviation of the price within a day) is reduced considerably with DSF, by more than 28% and 48% for all countries (*moderate and full* scenario, respectively) (reported for Germany and Norway in Table 3). For Norway, the daily price profile is almost entirely smoothened out (Figure 4.1). In the thermal power dominated countries, the average daily maximum price also decreases substantially by 9-19% (Full response). A more significant reduction in maximum price is observed for the thermal-power-based countries than for the countries with high shares of regulated hydropower and hence less short-term price variation.

4.3 Producers' revenues and VRE market value

The impacts of increased DSF on producers' revenues for the different power technologies are shown in Table 5.

Table 3: Average prices, daily maximum price and price variation in the *baseline* scenario, and changes for the different DSF scenarios, all modeled countries.

		***baseline* scenario**	**DR scenarios**		**Percentage change**
Country	All results in (€/MWh)		Moderate	Full	(Full flexibility)
Germany	Average prices	53.0	+0.2	+0.4	+0.8%
	Consumption weighted price	54.7	–0.5	–0.9	–1.7%
	Daily maximum price	66.8	–3.7	–7.0	–10.4%
	Intra-day price variation	10.6	–3.5	–6.1	–58.1%
Norway	Average prices	55.2	+2.9	+1.7	+3.1%
	Consumption weighted price	56.6	–0.3	–0.5	–0.8%
	Daily maximum price	60.7	–1.0	–3.2	–5.2%
	Intra-day price variation	4.2	–3.0	–3.8	–90.3%

Table 4: Changes in annual consumers' costs, total and for each modeled country.

Country	*baseline* scenario	Change in costs (M€) Moderate	Full	Percentage change (Full flexibility)
Denmark	1.7	–8	–15	–0.9%
Finland	4.6	–30	–37	–0.8%
Germany	30.1	–284	–513	–1.7%
Netherlands	6.6	–65	–119	–1.8%
Norway	7.1	–41	–60	–0.8%
Sweden	7.8	–40	–64	–0.8%
UK	18.7	–293	–554	–3.0%
Total consumers' costs in G€	76.5	–761	–1 360	–1.8%

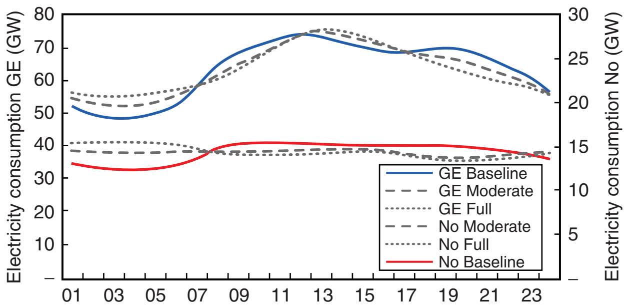

Figure 3.1. GE and No, all year

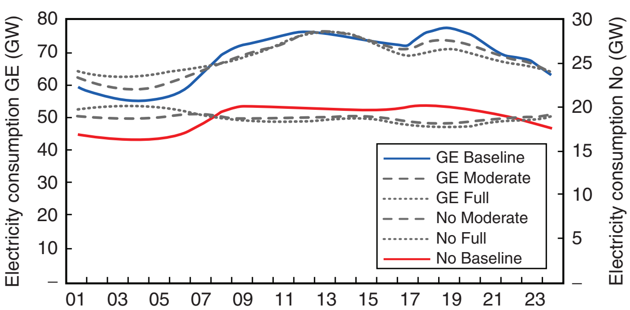

Figure 3.2. GE and No, winter

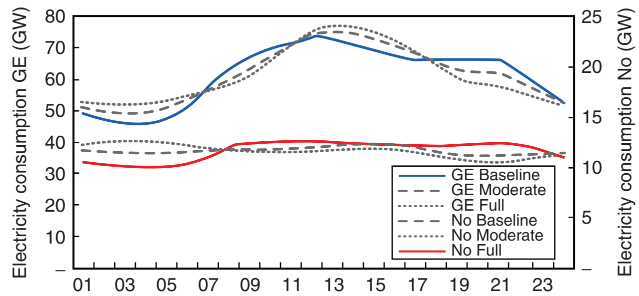

Figure 3.3. GE and No, summer

Figure 3.1-3: Hourly variation of the daily electricity consumption for all DSF scenarios, on an all-year basis (3.1), winter weeks (3.2) and summer weeks (3.3) for Germany and Norway.

Reduced need for peak power production, together with reduced peak-hour prices, causes a significant decrease in total and per-unit revenues for natural gas producers (23 and 9.3%, respectively) and regulated hydropower producers (-3.6 and -1.6%, respectively). Due to increased demand in low-demand nighttime hours, the total revenues for baseload power producers are slightly increased (about 2%) when DSF increases. Since coal and lignite production is moved from high to low demand hours, revenues decrease for these technologies, even though total production increases. Common for all the VRE production technologies is an increase in both total revenues (+1.5 - + 3.6%) and revenues per unit produced power (+1.5-2.2%).

Table 6 presents wind and solar market value relative to the time-average price (hereby denoted "value factor"[‡]) for all modeled countries in the *baseline* scenario, and the percentage point change in value factor for the demand-side flexibility scenarios. Increased DSF is found to increase the wind value factor by between 1-5.9 percentage points in all modeled countries. In thermal regions with high wind deployment levels (a 27-40% market share), the wind value factor increases with increasing DSF level. In hydro regions with lower wind deployment levels (a 5-9% market share), on the other hand, the highest increase in wind value factors is observed in the Medium response scenario. At higher DSF levels, the reduction in revenues caused by reduced peak prices exceeds the increase in revenues in baseload hours.

A similar trend is found for the solar value factor. For Germany, the high solar market share is causing a price drop (i.e. a merit order effect) in high-demand mid-day hours. Increasing DSF reduces this price drop and the solar value factor increases. For the Netherlands and the United Kingdom, on the other hand, the solar market share is too low to cause any significant merit-order effect in peak hours. Instead, increased DSF reduces the price in peak hours with high solar supply, and hence causes a reduced solar value factor.

4.4. System benefits and VRE integration

To investigate further the possible role of DSF for improved VRE integration, the changes in residual

[‡] The value factor is a measure of the market value of a power technology relative to the average market price, defined as the received price for the specific power technology divided by the time-average electricity price. See also, e.g. Hirth (2013)

Table 5: Revenues from power production for the different technologies, measured in total annual revenues and revenues per MWh of produced power

Technology	Change in revenues	*baseline* scenario	DR scenarios Moderate	(change from *baseline*) Full	Percentage change (Full flexibility)
Nuclear	total (G€)	7.2	+0.3	+0.1	+1.9%
	per unit produced (€/MWh)	54.1	+2.1	+1.1	+2.1%
Coal and lignite	total (G€)	19.2	–0.0	–0.0	–0.2%
	per unit produced (€/MWh)	61.5	–0.7	–1.1	–1.8%
Natural gas	total (G€)	6.7	–1.0	–1.5	–22.7%
	per unit produced (€/MWh)	73.7	–4.6	–6.9	–9.3%
Reservoir hydropower	total (G€)	8.4	–0.1	–0.3	–3.6%
	per unit produced (€/MWh)	58.2	+0.1	–0.9	–1.6%
Variable renewable energy sources					
ROR hydropower	total (G€)	5.5	+0.1	+0.1	+1.5%
	per unit produced (€/MWh)	51.3	+1.0	+0.8	+1.5%
Wind	total (G€)	16.0	+0.5	+0.8	+4.8%
	per unit produced (€/MWh)	38.6	+1.2	+1.8	+4.8%
Solar power	total (G€)	3.4	+0.0	+0.1	+2.2%
	per unit produced (€/MWh)	52.1	+0.6	+1.2	+2.2%

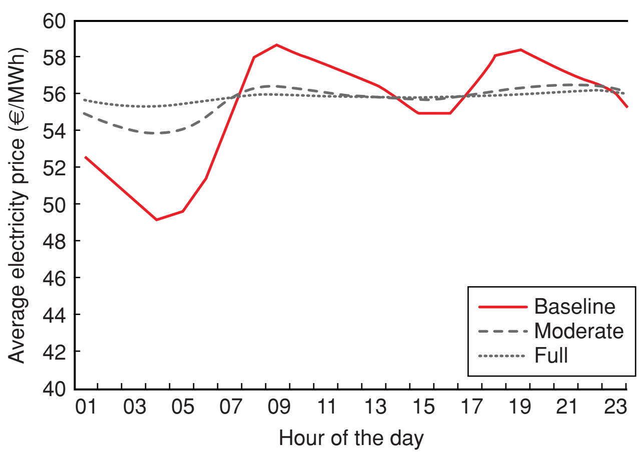

Figure 4.1: Hourly intra-day variation of the electricity price for Norway (in €/MWh) and the influence from increased DSF. (note varying scale on the y-axis).

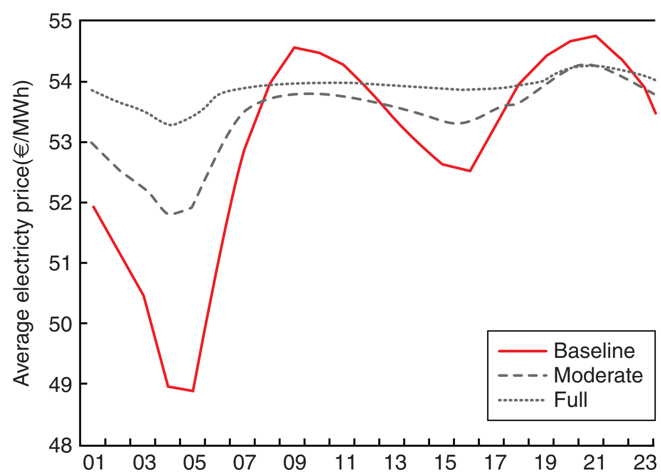

Figure 4.2: Hourly intra-day variation of the electricity price for Norway in summer weeks (in €/MWh) and the influence from increased DSF. (note varying scale on the y-axis).

demand (RD), defined as the total demand minus production from VRE, are analyzed. The daily maximum RD is found to decrease with DSF by almost 19 GW (about 15%), on average (all countries, Full response scenario) (Table 7). The maximum RD level on an annual basis is also reduced by more than 23 GW (all countries). For Germany alone, DSF reduces the annual maximum RD by 4.4 GW, and the average daily maximum by 7.5 GW. The reduced maximum RD implies that the need for peak-load technologies is reduced considerably with DSF.

Hourly illustrations of the dynamics between DSF and VRE are presented in Figures 4.1-4. Figures 4.1-2 show market clearing conditions for a winter week (week 2) in Germany, with varying wind power availability and relatively low solar power production. Figures 4.3-4 show modeling results for a summer week (week 28) in Germany, with high levels of solar power production and low wind power production. For the winter week,

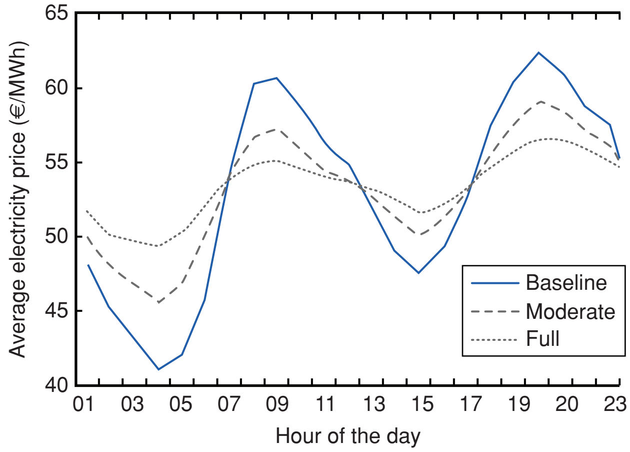

Figure 4.3: Hourly intra-day variation of the electricity price for Germany (in €/MWh) and the influence from increased DSF. (note varying scale on the y-axis).

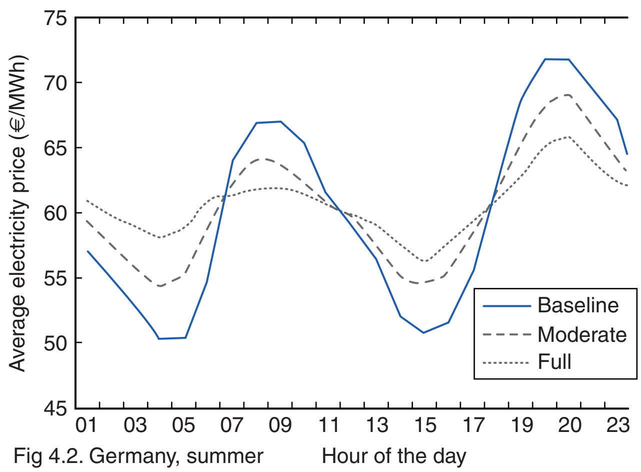

Figure 4.4: Hourly intra-day variation of the electricity price for Germany in summer weeks (in €/MWh) and the influence from increased DSF. (note varying scale on the y-axis).

consumption is generally shifted from high to low demand hours. When wind power supply is high, the consumption could, however, also be shifted from low- to high-demand hours (Figure 5.1), smoothening the short-term price variation and to some extent counteracting the prices from dropping to zero (Figure 5.2). In the summer weeks, when much solar power is available, demand is also shifted to high-demand hours (Figure 5.3), counteracting reductions in the electricity price in solar hours (Figure 5.4).

Table 6: Wind and solar market share and value factors in the *baseline* scenario, and the percentage points change in value factor for the *moderate and full* demand-side flexibility scenarios.

	Market share (%)	Value factor *baseline*	Percentage points change Medium	Full	Percentage change (full flexibility)
Wind value factors					
Denmark	38%	0.90	+1.3	+1.8	+2.0%
Finland	5%	0.98	+5.9	+3.9	+4.0%
Germany	28%	0.77	+1.0	+2.1	+2.7%
Netherlands	27%	0.74	+1.4	+2.7	+3.6%
Norway	5%	1.01	+3.7	+2.7	+2.7%
Sweden	9%	0.98	+4.1	+2.8	+2.9%
UK	40%	0.62	+2.5	+4.3	+6.9%
Solar value factors					
Germany	9.5%	0.97	+1.0	+1.9	+2.0%
Netherlands	0.6%	1.04	–0.5	–1.2	–1.1%
UK	2.0%	1.05	–0.3	–0.4	–0.3%

5. Alternative market assumptions

In this section the benefits of DSF for improved VRE integration are investigated for different assumptions for the future development of the power market: A) consumption level (±20%), B) wind power supply (±50%), C) nuclear power generation level (-100%), D) fuel price level (±50%) and E) carbon price level (±100%). The influence of DSF is analyzed by comparing the *baseline* scenario with the Moderate scenario for three main indicators: i) total wind and solar profit and German wind and solar value factors, ii) total VRE curtailment and iii) total GHG emissions. The results from the sensitivity analysis are summarized in Table 8.

VRE curtailment. DSF is found to reduce VRE curtailment independent of the underlying assumptions. The isolated effect of DSF for reducing VRE curtailment is found to be highest for low RD levels (i.e. for low consumption or high wind supply). In these situations there are more hours with excess VRE, and the benefit from increased DSF for reducing VRE curtailment will hence be higher. A somewhat surprising finding is that there is a higher reduction in VRE curtailment for low than for high carbon prices. One possible explanation is that high carbon prices cause high peak-hour electricity prices, which cause more demand to be shifted according to consumption levels rather than according to VRE production levels. The lowest reduction in curtailment is found for low

Table 7 : Key parameters for the RD level on an annual basis for Norway and Germany and for all countries.

	Residual demand (GW)	*baseline* scenario	DR scenarios (GW change) Moderate	Full	Percentage change (Full flexibility)
All countries	Average residual demand level	95.9	–0.5	–0.8	–0.9%
	Annual maximum	211.8	–15.1	–23.4	–11.0%
	Average daily maximum	128.5	–11.2	–19.0	–14.7%
	Short-term variation	20.7	–7.3	–11.8	–57.2%
Germany	Average residual demand level	35.6	–0.2	–0.2	–0.7%
	Annual maximum	82.7	–3.3	–4.4	–5.3%
	Average daily maximum	51.6	–4.2	–7.5	–14.5%
	Short-term variation	10.1	–2.8	–4.8	–47.4%
Norway	Average residual demand level	7.9	–0.0	–0.0	–0.0%
	Annual maximum	19.6	–0.1	+0.9	+4.4%
	Average daily maximum	9.4	–0.4	+0.2	+1.9%
	Short-term variation	1.2	–0.6	–0.2	–15.2%

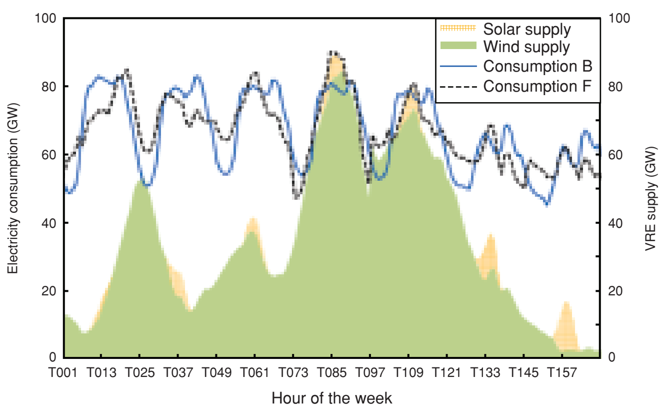

Figure 5.1: Left axis: Hourly power consumption for the *baseline* and Full flexibility scenarios in week 2 of the year. Right axis: solar and wind power production. (note different scales on left and right axes)

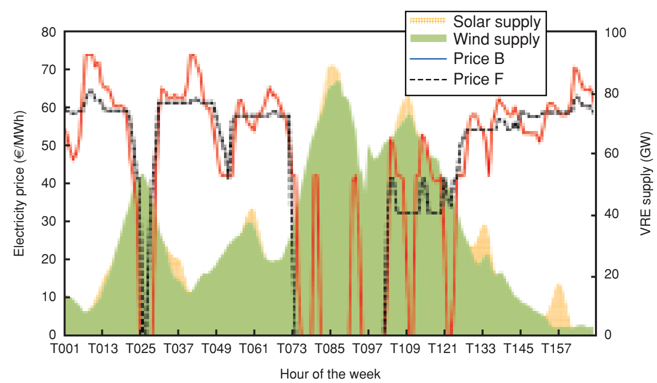

Figure 5.2: Left axis: Hourly power price for the *baseline* and Full flexibility scenarios in week 2. Right axis: solar and wind power production.

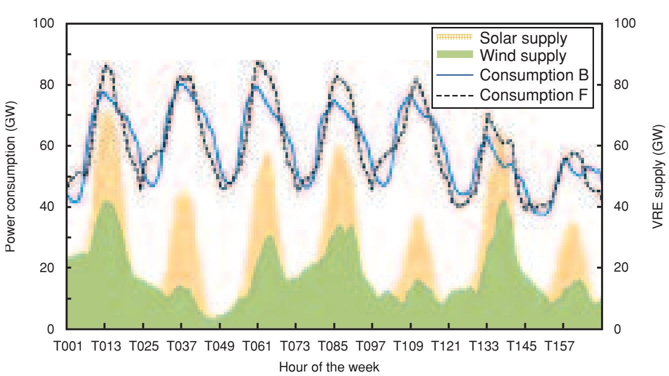

Figure 5.3: Left axis: Hourly power consumption for the *baseline* and Full flexibility scenarios in week 28. Right axis: solar and wind power production. (note different scales on left and right axes).

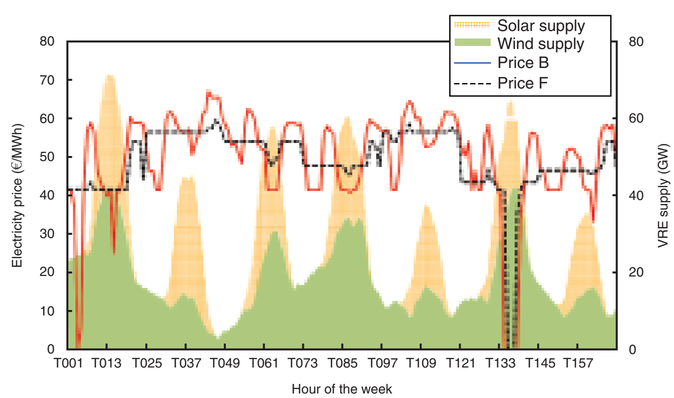

Figure 5.4: Left axis: Hourly power price for the *baseline* and Full flexibility scenarios in week 28. Right axis: solar and wind power production.

Table 8 : Change in VRE curtailment, GHG emissions, wind and solar revenues and value factor, caused by increased DSF (medium flexibility scenario), under the different power market assumptions A) to E).

VRE integration indicator	VRE curtailment (TWh)	GHG emissions (Mtonnes)	Wind revenues (M€)	Wind value factor	Solar revenues (M€)	Solar value factor
baseline, Medium flexibility	–4.1	–0.7	+0.5	+0.9	+0.04	+0.01
Low carbon	–4.9	–1.3	+0.2	+1.4	+0.01	+0.01
High carbon	–3.9	–1.8	+0.6	+1.0	+0.09	+0.01
Low consumption	–6.3	–4.2	+0.2	+1.0	+0.11	+0.05
High consumption	–2.3	–0.8	–0.4	+2.8	-0.16	+0.02
Low fuel price	–3.9	–1.4	+0.3	+1.0	+0.04	+0.01
High fuel price	–4.2	–0.6	+0.4	+1.0	+0.06	+0.01
No nuclear	–3.4	–0.1	+0.0	+0.9	+0.06	+0.02
High wind	–0.6	+1.4	+0.1	+0.8	+0.03	+0.01
Low wind	–7.9	–2.9	+0.3	+1.3	+0.03	+0.01

wind supply levels and for high consumption levels. In these situations, there are less hours of excess VRE, and DSF will hence have lower impact on VRE curtailment.

GHG emissions. The GHG effect of DSF is found to be sensitive to the future development of the parameters A) to E). When consumption is low and wind levels are high, demand will be adjusted more according to VRE supply than according to consumption levels. A consumption pattern that to a less extent shifts demand to off-peak hours will reduce the tendency of increased coal power generation in off-peak hours. An increased carbon price will cause a fuel switch to less carbon-intensive technologies, which will mitigate the increased coal power production in off-peak hours when DSF increases. When wind supply is low, VRE curtailment is also lower, and DSF has less influence on VRE curtailment. Simultaneously, the tendency of higher coal power production in off-peak hours will be stronger, causing increased emissions. Summed up, these results suggest that if wind power growth towards 2030 is low and the carbon price stays at a low to moderate level, increasing the DSF will either increase GHG emissions or have no significant effect on them. If, on the other hand, wind market shares increase significantly towards 2030, energy efficiency measures cause low consumption growth, and carbon prices increase, implementing DSF will likely significantly reduce GHG emissions.

Wind market value. The wind value factor is found to increase for all market assumptions A–E. The most significant increase in the wind value factor is found at high electricity demand levels. When demand levels are high, lower levels of demand shifting will be needed for preventing the prices from dropping to zero. However, an interesting finding is that, while the value factor increases considerably with DSF at high consumption levels, the profit for wind producers decreases. At high consumption levels, high electricity prices cause high profit for wind producers. Since DSF in this situation will reduce peak prices considerably, profit is decreased with DSF for all production technologies, including VRE. A general, and somewhat surprising, finding from the sensitivity analysis is that when the value factor increases considerably with DSF, the total profit is less influenced. A possible explanation is that when the value factor increases significantly from demand shifting to low load hours, the resulting reduction in peak prices will be considerable.

Solar market value. While the wind value factor is found to increase more with DSF for high consumption levels than for low, the solar value factor increases significantly more from DSF for low consumption levels than for high. This difference could be explained by the correlation between solar power and demand: For low consumption levels, the merit-order effect of solar power in mid-day hours causes significantly reduced mid-day prices and hence reduced solar value factor. When increasing DSF in this situation, more consumption is moved to solar hours, which benefits the solar profit and value factor considerably. At high consumption levels, the same is observed for solar profit and value factor as for wind power; without DSF, solar profit is high because of high electricity prices. With DSF, solar value factor is increased, but total solar profit decreases considerably, because of reduced peak prices.

6. Discussion

This study finds a 7.2 TWh reduction in total VRE curtailment from an 8 to 24% increase in DSF. This is somewhat higher than the findings reported by [44], who find a 3 TWh reduction in total European VRE curtailment from increasing the DSF from 5 to 20%. While the current study models optimal DSF considering interaction with both VRE supply and cross-regional trade, [44] model DSF by modifying only the local demand according to available VRE supply. Not considering the interplay between regional VRE supply, regional pricing and cross-regional interconnection could possibly underestimate the potential of DSF for increasing the use of the VRE supply.

While the current study finds a 3.3 GW reduction in maximum German peak power demand (Medium response), Ref. [25] finds a somewhat higher reduction of about 8.5 GW towards 2020. The different results in peak-demand reduction in the two studies could be explained in two ways: First, this study includes costs and limitations related to thermal power plant cycling. Limited flexibility in thermal plants could constrain some of the potential for peak reduction relative to the assumed potential. Second, the current study applies an hourly time resolution, while [25] model representative days with non-consecutive time slices. A low resolution model will be less capable of capturing the multiple time series of the power system. Limiting temporal resolution could hence cause a bias towards overestimating the performance of demand shifting for reducing peak load demand, analogously as reported for the value of VRE in [15]. Nevertheless, both studies conclude that DSF has a significant potential for contributing to improved VRE integration.

Despite considerable potentials, the short-term DSF in electricity markets has so far been limited, for two main reasons. First, most consumers are not exposed to real-time pricing (RTP), and have no economic incentives to move consumption to periods with low prices. Second, technical solutions for automatic adjustment of consumption are today limited, meaning that flexible - or smart - energy usage requires the user's action [20, 45]. There are reasons to expect that these obstacles may become less important in the future [46]. Advanced metering systems (AMS) are currently introduced on a large scale in most European countries, and research and development projects related to their optimal operation and efficient use are currently of high interest [47]. Automation and communication technologies and devices assisting DSF are already becoming available on the market. Consequently, the possibility for electricity consumers to adjust their consumption and contribute to private and system benefits is increasing.

Because of small changes in the average price, the consumers' savings from DSF are found to be very moderate in this study (less than a 3% reduction in consumers' costs). The small price influence supports the argumentation of [48], that introducing DSF will not affect the electricity price level much. A rough estimate of the cost savings for a German household, with a 3500 kWh annual power consumption, corresponding to an annual electricity cost of €198, suggests very small annual savings per household, about €2.7 per year. Furthermore, the model applied in this study does not reflect the capital expenditures associated with implementing DSF. The limited economic benefit for the consumers is supported by [25], who find that, under the existing market regulations, only a very limited share of the technical potential for demand-side management will be realized by 2020. From a thorough cost analysis, they find that the existing technical capacity for demand-side flexibility is only to a limited degree economically feasible by 2020. When modeling DSF under the existing market regulations, the reduction in peak load decreases from 8.5 to 0.8 GW.

Despite the limited consumers' savings, DSF is found to provide considerable system benefits, in terms of reduced short-term variation in residual demand and reduced need for peak capacity.

From a methodological viewpoint, it should, however, be noted that this study investigates the effect of DSF in relation to the variable supply of VRE, while balancing costs, and grid-related costs are outside the study's scope. Previous studies also report significant system benefits from DSF in terms of reduced balancing costs, and grid-related costs (e.g. [25, 34, 44, 45]). The total system benefit of DSF for improved VRE integration is hence likely to be higher than reported in this study. On the other hand, the model implementation assumes no limitations on the duration of the load shift, as long as it occurs within the day. This assumption may give a too optimistic modeling of the demand shifting potential, and may work in the opposite way. The total annual load shift found in this study is, however, well in line with the technical potential found in [25]. They find a total annual demand shift of about 30 TWh in 2020, which is the same level as in the Medium response 2030 scenario in the current study. This implies that the modeling approach in this study gives realistic levels of demand shifting, and provides useful insights into the market effects of the assumed potentials. Nevertheless, implementing a more detailed representation of demand shifting in the model will be an interesting topic for further analysis of market and system effects of DSF.

The present study shows that the system benefits of DSF – in terms of reduced peak residual demand and better VRE integration - is substantially higher than the modest cost reductions for consumers.

However, in light of the limited savings for consumers, policies and market designs that stimulate increased flexibility on the consumer side will likely be needed to fully use the benefits, both for VRE technologies and on system level [9, 49]. RTP combined with automatic control systems would be a first step for realization of the potential. Since the societal benefits are far larger than the private economic ones, additional policy measures should be considered. Adjusting grid tariffs to stimulate system friendly consumption, beyond the modest incentives from the spot price, is one option which has been addressed in previous literature [50-53]. Large commercial consumers such as industries and district heating plants with electric boilers are more likely than households to find provision of DSF interesting from an economic viewpoint, and modification of grid tariffs for such consumers may have a substantial impact. Household consumers may demand not only a slightly lower electricity bill, but also additional services, to install smart devices allowing for a more flexible consumption.

6.1. Conclusion

This study investigates the effects on power markets, and on the market value of VRE, from utilizing the total assumed DSF potential in the future (2030) Northern European power markets in a system-optimal way. DSF is generally found to cause only moderate reductions in the consumers' cost of electricity (less than a 3% cost reduction). Producers' revenues for VRE technologies are, however, found to increase for all types and locations of VRE generation when DSF increases, with the most significant increase in revenues found for wind power. The influence from increased DSF on the solar market value is, however, found to depend highly on the solar market share in the modeled country. The curtailment of VRE caused by excess supply is found to decrease by up to 7.2 TWh. DSF is also found to reduce the need for peak power technologies. However, reduced revenues for peak/midmerit power technologies imply that increased DSF comes at the cost of less supply-side flexibility. Because of increased coal power production in baseload hours, DSF is found to cause only a limited reduction in GHG emissions. The emission effect is, however, sensitive to assumptions regarding the future development in the power market: In a future power market with increasing wind market shares, low consumption growth, and increasing carbon prices, DSF is likely to significantly reduce GHG emissions.

Although DSF should not be regarded as the single solution, we conclude that short-term DSF has the potential of improving integration – and increasing the market value – of VRE technologies. Yet, the results suggest that the benefits on system level, and for VRE technologies, are more important than the modest economic benefits for the consumers. Policies that stimulate increased flexibility on the consumer side will therefore likely be needed to fully use the potential benefits of DSF for VRE integration.

Acknowledgements

The research leading to this study was financed in part by the ERA-NET project, IMPROSUME, and in part by Nordic Energy Research's Flagship project, Flex4RES. The authors thank the editor and two anonymous reviewers for their helpful comments.

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