Optimal location of renewable power*

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Abstract

A decarbonization of the energy sector calls for large new investments in renewable energy production, and several countries stimulate renewable energy production through economic instruments, such as feed-in premiums or other kinds of subsidies. When choosing the location for increased production capacity, the producer has typically limited incentives to take fully into account the investments costs of the subsequent need for increased grid capacity. This may lead to inefficient choices of location. We explore analytically the design of feed-in premiums that secure an optimal coordinated development of the entire electricity system. We show that with binding electricity transmission constraints, feed-in premiums should differ across locations. By the use of a numerical energy system model (TIMES), we investigate the potential welfare cost of a non-coordinated development of grids and wind power production capacity in the Norwegian energy system. Our result indicates that grid investment costs can be substantially higher when the location decision is based on uniform feed-in premiums compared with geographically differentiated premiums However, the difference in the sum of grid investment cost and production cost is much more modest, as location based on uniform feed-in premiums leads to capacity increase in areas with better wind conditions.

Key words: Energy policy, renewable targets, wind power, location of renewable energy production, feed-in premiums

JEL classification: Q42, Q48, Q58

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1 Introduction.

A starting point for our analysis is that increased renewable energy production is one important pillar for reaching a low-carbon society. Increased renewable electricity production demands investments in grid infrastructure, especially because sources for renewable energy, like wind power and hydro power, may be located far from consumer sites. The necessary investment in infrastructure does not only depend on the amount of new production capacity, but also on the geographical location of this capacity. Within a market based system it is to a large extent up to the electricity producers to determine which generation projects they believe may be profitable. The regulatory authorities typically decide whether to grant a license for a specific project, but they have a limited role in determining which areas market participants choose to locate their projects. In this paper we analyze analytically the conditions for an optimal geographical distribution of renewable production capacity, and we discuss how this can be implemented in a market economy with a support scheme for renewable energy production. Furthermore, we conduct a numerical analysis of the Norwegian energy system to illustrate the social cost of ignoring the investments in the grid infrastructure when designing policy instruments to induce more renewable energy production.

Several countries have specific targets for renewable energy production, including all EU Member States (EU, 2009). The European Union seeks to establish an Energy Union with an ambitious climate policy and an integrated EU electricity market open to cross-border trade.[1] Moreover, environmental acts such as the Renewables Directive 2009/28/EC are of large

[1] Legislation at both primary Treaty level (Treaty on the Functioning of the European Union (TFEU)) and secondary legislation level are key instruments to achieve these goals. This EU *energy acquis* is also, as a point of departure, EEA (European Economic Area) relevant, and is or will become part of the EEA Agreement. The energy specific secondary legislation includes a comprehensive set of substantive and institutional requirements aimed at promoting a sustainable, secure and competitive EU Internal Electricity Market. These provisions are included, inter alia, in the Third Energy Package comprising (for electricity) the Electricity Directive 2009/72/EC, the Electricity Regulation (EC) No. 714/2009 and the Regulation (EC) No. 713/2009 establishing the Agency for the Cooperation of Energy Regulators (ACER).

significance for the electricity market, requiring new renewables investments through the setting of binding national renewables targets. However, the choice of instruments to achieve the binding national targets have not been harmonised at EU level. Moreover, EU law does not at present include harmonised rules for the setting of connection tariffs for new electricity generation plants. Member States are therefore free to choose different kinds of renewables incentives – such as feed-in premiums, green certificates, tax- or tariff schemes – provided the schemes are designed in accordance with the more general EU legislation. The designated policy instrument varies across countries, see, among others, Kitzing et al. (2012).

Furthermore, according to Kitzing et al. (2012), the support for new renewable energy production among EU member states is, in general, not site specific (but does vary across technologies and size). Capacity location may matter significantly for the social cost of the transformation of the energy sector. Location matters for both emission reductions, impact on landscape and transmission congestions, see Hitaj (2015) and Zografos and Martinez-Alier (2009). In this paper we concentrate attention on the impact on grid costs. A radical increase in renewable energy production may demand substantial investments in increased transmission and distribution capacity. Whether the market system leads to a socially efficient geographical distribution of production capacity depends inter alia on the design of grid connection charges. The literature distinguishes between so-called deep and shallow connection charges, see, i.e., Turvey (2006). Deep connection charges reflect all of the estimated cost of accommodating additional generation. With shallow connection charges the producers only pay for the local investment required to connect capacity to the grid, and not the incremental investment that has to be made in the wider transportation system. Shallow connection charges lead to inefficient location. Although deep connection charges can ensure optimal location of energy production capacity, it raises new question concerning how the cost of reinforcement of the wider energy system is to be shared among new and existing users. This is especially relevant for lumpy connection investments; see discussion in Turvey (2006). Although the discussion on shallow versus deep connection charges is not new, the problem of inefficient location may become increasingly severe due to the greening of the energy sector and the subsequent need for grid enforcements.

In the next section, we present an analytical model to derive the conditions for an optimal geographical distribution of new renewable energy production, taking into account the warranted grid investments. The model is very simple, but rich enough to capture some of the main characteristics of an electricity market with price zones (bidding areas).[2] We show how a market-based solution with shallow connection charges and uniform feed-in premiums (subsidies) to green energy production leads to socially inefficient location and grid investments. Furthermore, we show how differentiated (non-uniform) feed-in premiums can yield socially optimal location.

Several authors have analyzed the effect of different renewable subsides schemes on spatial distribution of wind power (Grothe and Müsgens, 2013; Schmidt et al., 2013; Hitaj et al., 2014; Pechan, 2017), but none of these studies analyze the impact on grid investment costs. Grimm et al. (2016) studies how private suboptimal locational decisions for generation capacity may imply excessive network expansion. However, they do not derive how an optimal design of subsidies alleviates the inefficiencies.

We restrict our analysis to the potential inefficiency following from the geographical distribution of new production capacity, ignoring any potential inefficiencies following from the behavior of the regulated grid owners; see discussion in Brunekreeft (2004). For analyses of merchant transmission investment as an alternative to investment by regulated transmission

[2] Zonal pricing has a uniform market price inside a price zone and is adopted by most European countries. See Bjørndal and Jørnsten (2001) for a critical analysis of zonal pricing.

system operators, see, i.e., Chao and Peck (1996), Bushnell and Stoft (1997) and Joskow and Tirole (2005).

In Section 3 we present results from a numerical model for the Norwegian energy system to illustrate the potential social cost of a socially non-optimal location of wind power capacities. Our starting point for the numerical exercise is a political goal to increase the production of wind power (a renewable target). We compare the outcome of market based incentive system with uniform feed-in premiums (subsidies) with a first-best outcome, that is, a geographical distribution of wind production capacities that minimizes the energy system cost (given the renewable target). Our result indicate that the total energy system cost of a 5 TWh increase in wind power production following from uniform feed in premiums was modestly (6%) more costly than a first-best outcome. However, the location of capacities deviates substantially between the two regimes, leading to around 50 % higher grid investment costs under a market-based incentive mechanism with uniform feed-in premiums compared with the socially optimal distribution.

2 Analytical model

The purpose of the analytical model is to highlight some important characteristics of an optimal spatial distribution of wind power, and show how feed-in premiums can be designed to achieve that solution in a competitive electricity market. We therefore have constructed an analytical model which is very simple, but still rich enough to capture some of the main characteristics of an electricity market with price zones. For the sake of simplicity, we make several assumptions. All of them are presented successively below, and the implications of the simplifying assumptions are briefly discussed in section 2.4. The assumptions are also listed in Table 2. From the model, we derive some general qualitative results, which, due to their generality, will also hold for more sophisticated models. In section 3.2, we present our numerical model which has a detailed description of the entire energy system, and without the simplifying assumption made in the analytical model. We use this model to derive quantitative results regarding the social cost of an inefficient geographical distribution wind power in Norway.

We consider a simple electric power network with two price zones, A and B. There are three production nodes and two consumption nodes, as shown in Figure 1. Nodes 1, 2 and 3 are potential supply nodes for new wind parks, whereas nodes 4 and 5 are consumption nodes. A notation list is provided in Table 1.

Table 1. Notation

q_i	Wind production capacity installed (MW) at node *i*.
q^{Ck}	Consumption (MW) in price zone *k*.
$c_i\ (q_i)$	Cost of wind production capacity installed (MW) at node *i*.
$T_{ij}\,(T_{AB})$	Physical power flow capacity (MW) between nodes *i* and *j* (price zones A and B).
$T_{ij}^0\,(T_{AB}^0)$	Initial physical power flow capacity (MW) between nodes *i* and *j* (price zones A and B).
$I_{ij}\ (I_{AB})$	New physical power flow capacity (MW) between nodes *i* and *j* (price zones A and B).
$k(I_{12})$	The cost function of new transmission capacity between node 1 and 2

$d(\mathrm{I}_{35})$	The cost function of new transmission capacity between node 3 and 5
$z(I_{AB})$	The cost function of new transmission capacity between price zone A and B.
$U_k(q^{Ck})$	Utility functions. Benefit from consuming electricity (MW) in prize zone *k*
W	Social welfare
F_i	Feed-in premium for renewables (per unit MW) at production node *i*.
Π^G	TSO's profit
p^k	Energy price (per unit MW) in zone *k*.

Table 2. List of assumptions

- Profit maximizing price taking producers and utility maximizing consumers
- TSO invests in new transmission capacities whenever that is profitable
- Cost functions of wind power capacity are increasing and non-concave.
- It is less costly to install capacity at node 1 than at node 2 for all levels of capacity.
- The flow on the high voltage transmission capacity between price zone A and B goes in the direction from B to A.
- The physical transmission constraints between node 1 and 4 and 2 and 4 will always be nonbinding.
- New transmission capacities are divisible investment project with continuous increasing cost functions.
- No losses in the network.

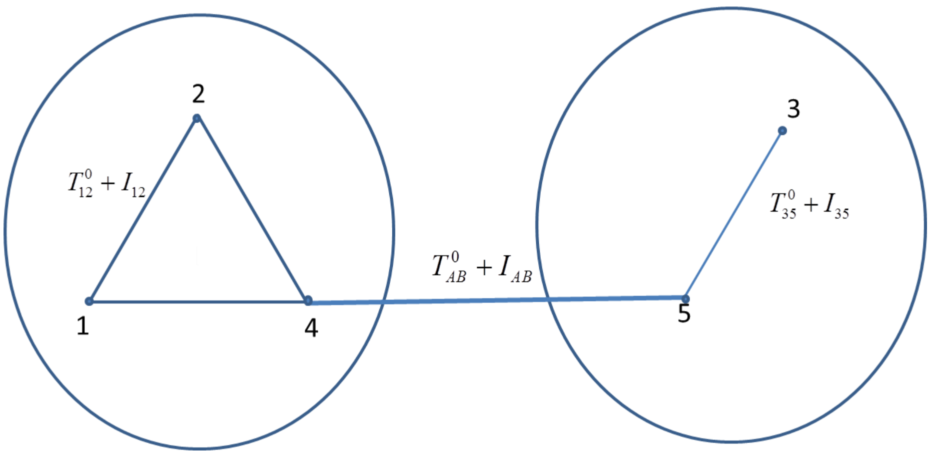

Figure 1. Electric power network

Let q_1, q_2 and q_3 denote the wind production capacity installed, measured in MWs, at nodes 1, 2 and 3, respectively. The locations differ regarding investment cost. Let $c_1(q_1)$ and $c_2(q_2)$ and $c_3(q_3)$ denote the cost functions, which are all assumed to be increasing and non-concave; in particular, $c_i'(q_i) > 0$ and $c_i''(q_i) \geq 0$ for all i =1,2,3.[3] Furthermore, for the sake of simplicity, we assume that it is less costly to install capacity at node 1 than at node 2 for all levels of capacity, that is, $c_1(q_1) < c_2(q_2)$ for all $q_1 = q_2$. The capacity costs include inter alia the producer's annualized cost of providing for grid infrastructure from the production facility to the grid connection point (radial grids), see the discussion in section 3.1 on investment contributions.

We denote by T_{ij} the physical power flow capacity between the two connected nodes i and j. We follow the modeling of a simple transmission network in Chao and Peck (1996) and Bushnell and Soft (1997), and assume that there are no losses in the network, and that the only significant constraints are the thermal limits on each line. The grid capacity can be expanded

[3] We use one apostrophe to denote the first derivative and two apostrophes to denote the second derivative.

by investments; either in new transmission and/or distribution infrastructure or upgrading the existing network (see Joskow, 2005 for list of projects to enhance transmission networks):

$$T_{ij} = T_{ij}^{0} + I_{ij} \quad , \tag{1}$$

where T_{ij}^{0} is the initial transmission capacity and I_{ij} denotes new transmission capacity in line (*ij*), all measured in MW. Although all investment projects are typically lumpy, we simplify the model by treating new transmission capacity as a divisible investment project, and there are increasing costs attached to adjusting the transmission capacities. (The lumpy characteristics of grid investments are taken into account in the numerical model, see section 3.2).

As it is less costly to increase the capacity at node 1 than at node 2, the pressure on the transmission capacity typically comes from the production at node 1. According to Kirchoff's law, we have the following constraint for the power flow on the line between node 1 and 2:[4]

$$\frac{1}{3}q_1 - \frac{1}{3}q_2 \leq T_{12}^{0} + I_{12}. \tag{2}$$

To simplify, we ignore the other physical transmission constraints within zone A by assuming that they will always be nonbinding, also in the absence of new investments. The cost of new transmission capacity between node 1 and 2 is given by $k(I_{12})$, where $k' > 0$.

The transmission capacity between node 3 and 5 can also be expanded by investments, either in new transmission lines or upgrading the existing network.

$$q_3 \leq T_{35}^{0} + I_{35}. \tag{3}$$

[4] Electricity moves according to Kirchoff's law, following the path of least resistance. The constraint follows from the symmetric structure of our network model (identical characteristics of the transmission lines).

The cost of building new transmission capacity in prize zone B is an increasing function of the new transmission capacity between node 3 and 5, given by $d(\mathrm{I}_{35})$, where $d' > 0$.

We assume, again for the sake of simplicity, that the flow on the high voltage transmission capacity between price zone A and B goes in the direction from B to A, such that the relevant transmission constraint is

$$q^{CA} - (q_1 + q_2) \leq T_{AB}^0 + I_{AB}, \tag{4}$$

where q^{Ck}, $k = A, B$ denote consumption in price zone *k*. The cost of building new transmission capacity between A and B is an increasing function of the new transmission capacity between A and B, given by $z(I_{AB})$, where $z' > 0$.

Consumption equals production:

$$q^{CA} + q^{CB} = q_1 + q_2 + q_3 \tag{5}$$

2.1 Socially optimal capacity localization

The social welfare generated from electricity consumption (W) is the benefit from consuming electricity, expressed by the utility functions $U_A(q^{CA})$ and $U_B(q^{CB})$

$(U_k' > 0, U_k'' < 0, k = A, B)$, less of the production and transmission cost. We assume that the regulator wants to stimulate production of new renewable energy. The regulator's objective function is to maximize social welfare, given q^R units of new wind energy.

$$q^R = q_1 + q_2 + q_3 \tag{6}$$

This leads to the following objective function:

$$\text{Max } W = U_A(\mathrm{q}^{CA}) + U_B(q^{CB}) - \left[c_1(q_1) + c_2(q_2) + c_3(q_3) + k(I_{12}) + d(I_{35}) + z(I_{AB})\right] \tag{7}$$

subject to (2)-(5).

See Appendix A for the derivation of the first order conditions. The solution depends on whether the transmission constraints are binding or not.

2.1.1 Non-binding transmission constraints

When the transmission constraints are non-binding we find the following optimality conditions (see Appendix A):

$$\begin{aligned}&U'_A = U'_B\\&c'_1 = c'_2 = c'_3\\&c'_1 - U'_A (= c'_2 - U'_A = c'_3 - U'_B) = \lambda_R > 0,\end{aligned} \tag{8}$$

where λ_R is the shadow cost of the renewable constraint.

Proposition 1. *In the case of non-binding transmission constraints:*

- *The optimal distribution of consumption is such that the marginal benefit of consumption is equalized across prize zones*
- *The optimal distribution of renewable production capacities is such that the marginal cost of production capacities should be equalized across all production nodes.*
- *Due to the renewable constraint, marginal cost of production exceeds the marginal benefit from consumption. The difference is equalized across all production zones.*

Proof: Proposition 1 follows from the first-order conditions and a binding renewable target ($\lambda_R > 0$).

2.1.2 Binding transmission constraints

When the transmission constraints are binding in optimum, we find the following optimality conditions for the distribution of production capacities and investments in transmission lines (see Appendix A):

$$\begin{aligned}&c'_1 + \frac{1}{3}k' = c'_2 - \frac{1}{3}k' = c'_3 + d' + z'\\&U'_A = U'_B + z'\end{aligned} \tag{9}$$

This leads to the following proposition:

Proposition 2: *With binding transmission constraints:*

- *The marginal cost of production capacities including the marginal cost of the (optimal) investments that have to be made to accommodate the new generation capacity, should be equalized across production nodes.*
- *The marginal utility of consumption less the marginal cost of transmission between price zones, should be equalized across price zones.*

Proof: Proposition 2 follows from the first-order conditions (see Appendix A).

From proposition 2, we can immediately derive the following corollary:

Corollary 1. *With binding transmission constraints:*

- *The marginal cost of optimal production capacity will differ within price zones and across price zones.*
- *The marginal utility of optimal consumption will differ across price zones.*

2.2 Profit maximizing behavior

We now consider a system with shallow connection charges; that is, energy producers do not face the full transmission costs of accommodating their additional generation capacity, (I_{12}, I_{35}, I_{AB}). Let p^A and p^B denote energy prices in zone A and B, respectively. We assume that the producers and the TSO are price-takers. Furthermore let F_i denote the feed-in premium for renewables at production node *i*. The profits of the producers at node 1, node 2 and node 3 are given by, respectively, $(p^A + F_1)\cdot q_1 - c_1(q_1)$, $(p^A + F_2)\cdot q_2 - c_2(q_2)$ and $(p^B + F_3)\cdot q_3 - c_3(q_3)$.

Profit-maximizing behavior leads to the following first order conditions:

$$\begin{aligned} c_1'(q_1) &= p^A + F_1 \\ c_2'(q_2) &= p^A + F_2 \\ c_3'(q_3) &= p^B + F_3 \end{aligned} \qquad (10)$$

The consumers maximize their welfare, given by $U^i(q^{Ci}) - p^i, \quad i = A, B$, leading to the following first order conditions:

$$\begin{aligned} U_A'(q^{CA}) &= p^A \\ U_B'(q^{CB}) &= p^B \end{aligned} \tag{11}$$

Throughout the analysis we assume that the transmission system operator (TSO) and/or distribution system operators (DSOs) invest in the local grid to accommodate new generation capacities within each price zone, and optimize profit when it comes to investments in the high voltage grid between price zones.

The TSO's profit (Π^G) from the high voltage grid is the income from selling in the high price zone and buying in the low price zone, less of the investment costs. The amount of trade is restricted by the transmission capacity, $T_{AB}^0 + I_{AB}$:

$$\Pi^G = (p^A - p^B) \cdot (T_{AB}^0 + I_{AB}) - z(I_{AB}) \tag{12}$$

Maximizing Π^G with respect to I_{AB} gives the following first-order condition:

$$p^A - p^B = z' \tag{13}$$

From (10), (11) and (13), we can write the capacities and trade between A and B as functions of the prices and feed-in premium. The equilibrium prices, as functions of the feed-in premium, are found from the market equilibrium conditions:

$$\begin{aligned} q_1(p^A + F_1) + q_2(p^A + F_2) + I^{AB}(p^A - p^B) &= q^{CA}(p^A) \\ q_3(p^B + F_3) - I^{AB}(p^A - p^B) &= q^{CB}(p^B) \end{aligned} \tag{14}$$

2.2.1 Optimal feed-in premiums

We define optimal feed-in premiums as the premiums that ensure that producers locate their production according to the socially optimal location. In the case of a non-binding transmission constraints, this is characterized by (5), (6) and (8), and $I_{12} = I_{35} = I_{AB} = 0$. We see from (10) and (11) that the following feed-in premiums gives the optimal production capacities identified in (8):

$$F_i = c_1'(q_1^*) - U_A'(q^{CA*}) = c_2'(q_2^*) - U_A'(q^{CA*}) = c_3'(q_3^*) - U_B'(q^{CB*}) = \lambda_R^* \quad i = 1,2,3 \qquad (15)$$

Proposition 3: *With no binding transmission constraints, the optimal feed-in premium should be equalized across all production nodes and set equal to the shadow cost of the renewable constraint (in optimum).*

For binding transmission constraints, the optimal localization is characterized by (5), (6) and (9). We see from (10) and (11) that the following feed-in premiums give the optimal production capacities identified in (9):

$$\begin{aligned} F_1^{**} &= c_1'(q_1^{**}) - U_A'(q^{CA**}) \\ F_2^{**} &= c_2'(q_2^{**}) - U_A'(q^{CA**}) \\ F_3^{**} &= c_3'(q_3^{**}) - U_B'(q^{CB**}) \end{aligned} \qquad (16)$$

Furthermore, we see from the first order conditions (Appendix A) that:

$$\begin{aligned} c_1'(q_1^{**}) - U_A'(q^{CA**}) &= \lambda_R^{**} - \frac{1}{3}k'(I_{12}^{**}) \\ c_2'(q_2^{**}) - U_A'(q^{CA**}) &= \lambda_R^{**} + \frac{1}{3}k'(I_{12}^{**}) \\ c_3'(q_3^{**}) - U_B'(q^{CB**}) &= \lambda_R^{**} - d'(I_{35}^{**}) \end{aligned} \qquad (16)$$

Proposition 4: *With binding transmission constraints, the feed-in premiums should differ across production nodes.*

We see from the right hand side of (16) that the optimal feed-in premiums can be expressed by shadow costs of the optimizing problem. The first term represents the shadow cost of the renewable constraint and is identical for all locations.

The second term represents the transmission costs associated with increased capacity. The second term will in general differ across production nodes, and correspond to optimal deep connections charges. (See discussion in the introduction).

The following proposition follows directly from the right hand side of (16):

Proposition 5: *Let the production nodes be ranked according to their marginal transmission costs associated with increased capacity. The higher transmission costs, the lower feed-in premiums.*

Note that the feed-in premiums should not be adjusted for the marginal transmission cost between zone A and B. The reason is that this transmission cost is reflected in the price difference between the zones, when the TSO optimizes the investment, see (13). However, within a price zone, the transmission cost is not properly internalized by the producers, as they all face the same price for their production capacity, regardless of their impact on the need for new grid capacities. If there is only one node within a price zone, this problem obviously disappears:

Proposition 6: *With optimal nodal pricing, the feed in-premiums should be equalized across nodes, also in the case of binding transmission constraints.*

Proof: Let p_1, p_2 and p_3 denote the producer prices in the production nodes. Taking into account the transmission costs associated with increased production capacities, and transmission costs from node 4 to node 5, we get the following optimal differences in prices:

$p_1 = p^A - \frac{1}{3}k', p_2 = p^A + \frac{1}{3}k', p_3 = p^B - d', p^A = p^B + z'$. Given these price differences, an identical feed-in premium (equal to λ_R^{**}) for all profit maximizing producers will yield an outcome which satisfies (9).

2.3 Optimal versus suboptimal feed-in premiums

In the case of binding transmission constraints and socially optimal ("opt") feed-in premiums, (16), the social welfare is given by

$$\begin{aligned} W^{opt} &= U_A(\mathrm{q}^{CA**}) + U_B(q^{CB**}) \\ &-\left[c_1(q_1^{**}) + c_3(q_2^{**}) + c_3(q_3^{**}) + k(I_{12}^{**}(q_1^{**}, q_2^{**})) + d(I_{35}^{**}(q_3^{**})) + z(I_{AB}^{**}(\mathrm{q}^{CA**}, q^{CB**}))\right] \end{aligned} \tag{17}$$

Consider the case where all producers get the same feed-in premium, sufficiently large to fulfill the same renewable outcome as in (17), given that the TSO and/or DSOs accommodate new generation capacities within each price zone, and optimize profit when it comes to investments in the high voltage grid between price zones, see (13). Hence, the equilibrium outcome satisfies (10) ,(11) and (13) for $F_1 = F_2 = F_3$. Let the outcomes be denoted with bars. The social welfare of this profit maximizing ("PM") system is

$$\begin{aligned} W^{PM} &= U^A(\bar{\mathrm{q}}^{CA}) + U^B(\bar{q}^{CB}) \\ &-\left[c_1(\bar{q}_1) + c_3(\bar{q}_3) + c_3(\bar{q}_3) + k(\bar{I}_{12}(\bar{q}_1, \bar{q}_2)) + d(\bar{I}_{35}(\bar{q}_3)) + z(\bar{I}_{AB}(\bar{q}^{CA}, \bar{q}^{CB}))\right] \end{aligned} \tag{18}$$

Note that in the case of non-binding transmission constraints, $W^{opt} = W^{PM}$. However, when it is optimal to differentiate the feed-in premiums, due to the transmission constraints, the location of production capacities and the investment in the grid will differ between (17) and (18), and $W^{opt} > W^{PM}$. Identical feed-in premiums across locations will in that case lead to too large production capacities in nodes where the accommodating investment costs are large (relatively to the profit from electricity production).

In the next section we illustrate numerically how uniform versus non-uniform feed-in premiums can affect the location of new wind-power plants, grid investments and social welfare (measured in energy system cost of meeting an exogenous demand for energy services).

2.4 Implications of the simplifying assumptions

In order to highlight our main points, we have made several simplifying assumptions about the electric power network. Some of these are quite standard and reasonable characteristics of the economy, like increasing, and non-concave generation capacity cost and profit (utility) maximizing behavior. Furthermore, we have made some assumptions on transmission capacities, production cost differences and direction of flows (bullet point 4, 5 and 6 in Table 2). These assumptions are merely done for the purpose of simplifications and have no impact on the propositions. We have assumed that transmission capacities are divisible investment project with continuous increasing cost functions. If we instead had presented the investment projects as lumpy investments options, we could not derive the first order conditions as we have done. It that case we had to find the investment option with cost closest to the optimality conditions derived in our model. This specification would, in our view, not add much to the illustrative purpose of our analytical model. The lumpy characteristics of grid investments are taken into account in the numerical model, presented in the section 3.2. We have ignored transmission losses. If we had taken that into account, things become more complicated as new production may affect the distribution of transmission losses throughout the network (see Chao and Peck, 1996). That issue is beyond the illustrative purpose of our analytical model. However, in the numerical model presented below, transmission losses are included.

3 Numerical illustration

Norway has implemented EUs Renewables Directive and has, together with Sweden, a joint target for new renewable energy by 2020. Norway and Sweden have a joint green certificate market (GCM) for new renewable energy, see The Swedish Energy Agency and the Norwegian Water Resources and Energy Directorate (2013). As shown in Aune et al. (2012), in the case of no uncertainty and market power, cf. von der Fehr and Ropenus (2017), a green certificate system can be designed to yield the same outcome as feed-in tariffs or feed-in premiums. In the following we use a numerical model to illustrate the potential social cost of uniform versus non-uniform feed-in premiums, given a target of 5TWh increased wind production. An increase of 5TWh is in line with the literature on expected new wind power production in Norway, given the Norwegian-Swedish renewable target. Lind and Rosenberg (2014) obtained a production increase of around 4.5 TWh from wind power when analyzing how various risk factors could influence the green certificate market of Norway and Sweden. In a work by Bøeng (2010), a production increase of 6 TWh from wind power is assumed when analyzing the consequences of the renewable energy directive. By October 2016, only 0.4 TWh of new wind power production in Norway contributes to the joint target of 28.4 TWh of new renewable energy production by the end 2020. However, wind-power facilities expected to produce approximately 3.3 TWh is currently under construction in Norway (NVE, 2016a). In 2016, the annual Norwegian wind-power production was 2.1 TWh (Weid, 2017), with an installed capacity of 873 MW. This corresponded roughly to 1.4% of the total national power production that year.

For both Norway and Sweden, the expected renewable production increase can lead to challenges for the electricity transmission grid. For several of the price areas in the Nordic spot market, the existing transmission grid has limited capacity for new power projects. Both countries have extensive plans for expanding and strengthening grids, but the relevant projects will depend on various investment decisions related to renewable power technologies. Furthermore, the investments must be within the grid regulations.

3.1 Grid regulations

In Norway, the connection of new electricity generation plants to the grid must follow Norwegian requirements governed by the Energy Act with appurtenant regulations. Section 3-4 of the Energy Act requires grid companies to connect to new electricity production and consumption units and to carry out the necessary investments in their grid. This provision was introduced with effect from 1 January 2010 as a tool to facilitate better coordination between grid, production and consumption behaviour (Ot. prp. nr. 62 (2008-2009), p. 25).[5]

The connection requirement applies for all grid companies, including the TSO Statnett, and for all the necessary grid investments from the connection point and up to and including the transmission grid. It is, however, still the electricity producer's responsibility to provide for grid infrastructure from the production facility to the grid connection point identified by the grid company (Ot. prp. nr. 62 (2008-2009), p. 34).

The grid company may be granted an exemption from the connection and investment obligation if the production and grid investments taken together are not considered so-called "socio-economic profitable". The assessment of socio-economic profitability will primarily be made by comparing the total income from both the production and grid facilities with the total cost from the same facilities.[6]

Neither Section 3-4 of the Energy Act nor Section 3-4 of the Energy Regulation set forth any rules governing the distribution of costs for grid investments carried out by the grid company as part of the connection obligation. Section 17-5 of the Control Regulation sets forth that the

[5] The provision is supplemented by the Energy Regulation 7 December 1990 No. 959 Section 3-4.
[6] In cases where several production or grid facilities must be established, all facilities must be assessed together (Ot. prp. nr. 62 (2008-2009), pp. 3-4). The right of exemption is analysed in detail by Bjerke (2013), pp. 69-115.

grid companies may stipulate an investment contribution ("anleggsbidrag") in order to cover investment costs for new grid connections, or cover the costs for grid reinforcements to existing customers where the customers require increased capacity.[7] Investment contributions for new grid connections may, however, at the outset only be required for radial grids, as these grids will have a specific customer group, for example a new electricity producer. For meshed grids, investment contributions may only be required in extraordinary cases.

In cases where investment contributions may be required, the grid company shall determine the amount irrespective of the customer's estimated energy off take and the maximum cost may be set to investment cost less connection charge. The latter right to a connection charge is further regulated in Section 17-4 of the Control Regulation. The investment contribution shall be estimated based on the costs arising due to the customer's connection to the grid. If the connection requires reinforcement of a joint radial grid with several users, a proportionate share of the cost may be comprised by the investment contribution. The grid company may also distribute the investment contribution between customers connected to the grid at the time of completion and customers that will be connected to the grid at a later stage within the next 10 years after completion.

When the new grid facilities become operational, the question arises how the costs for running the grid shall be distributed between the grid company's customers. If the new grid is defined as an ordinary grid facility, i.e. distribution or transmission grid, the grid income will fall under the grid company's income frame and tariff costs will be distributed among all grid users. However, if the new grid has as its main function to transport electricity from the connected electricity production facility to the closest exchange point in the grid, it qualifies as a production related grid facility. The tariff costs for such production related grid facilities shall be covered by the electricity producer in question, and not be distributed among all grid

[7] Regulation 11 March 1999 No. 302.

company customers.[8] The relevant costs for new grid facilities are also included in the numerical illustration presented below. If the new grid's main function is to transport electricity to the closest exchange point in the grid, the cost are covered by each individual wind power plant (i.e. power producers). Otherwise, the cost are covered by the local grid company, as indicated by the various transmission lines in figure 3.

3.2 Modelling Framework

TIMES (The Integrated MARKAL-EFOM System) is a model generator developed as a part of the IEA-ETSAP (Energy Technology Systems Analysis Program) (ETSAP, 2017). The TIMES model generator combines two different systematic approaches to energy system modelling, including a technical engineering approach and an economic approach. A TIMES model gives a detailed description of the entire energy system including all resources, energy production technologies, energy carriers, demand devices, and sectorial demand for energy services. A two-step methodology is used where the demand of energy services is calculated first. This is used as input to the energy system model that again calculates the energy consumption. The development in useful energy demand is calculated as an activity (e.g. m2) multiplied by an indicator (e.g. kWh/m2). The development in both the activity and the indicator is based on national studies. Assumptions of economic growth, business development, demographics etc. and development of energy indicators are considered, as well as normative measures (e.g. building regulations). The energy demand is divided into four main sectors (with underlying sub-groups); industry, households, service & other, and transport. For the household sector, number of persons per dwelling (ppl/dwelling), area per dwelling (m2/dwelling), and energy service demand per area (kWh/m2) are the main energy indicators. Similarly, energy service demand per area or energy service demand per capita

[8] See Section 17-1 of the Control Regulation. See also Section 17-1 second paragraph on the distribution of costs in cases of other offtake directly from the production related grid facility.

(kWh/capita) were used for the primary, tertiary and the construction sector. Both the development in the activity (A), for instance floor area, and the development of the energy indicators (I) must be considered.

A modified version of TIMES-Norway (Lind et al., 2013; Rosenberg and Lind, 2014) is used to analyze the optimal location of new wind power plants based on various transmission grid assumptions (see below). The potential for new onshore wind facilities in the TIMES model is based on information from the Norwegian Water Resources and Energy Directorate (NVE). NVE reports information on all wind power plants that have either applied for a license or been approved. In order to ensure socio-economic profitability, we have only included wind power plants with a license in our numerical simulations, see discussion in section 3.1.[9] Based on the information in the licensing database (NVE, 2016b), each plants' respective investment and operating costs are included, along with associated capacity factors. Investment costs also include the investment contribution to new radial grids ("anleggsbidrag"), as discussed in section 3.1. [10] As a part of the transmission network tariffs a locational charge for marginal losses to all users of the system is applied. This term is calculated individually for each separate input point and determined based on marginal network losses in the network system as a whole. Note that this location charge only takes into account marginal losses in the transportation of electricity and not the investment costs associated with expansions of the meshed grids.

Geographically, the TIMES model covers Norway, Sweden and Denmark, and is divided into 11 model regions (see Figure 2) based on the pricing areas in the Nordic spot market for electricity (Nord Pool Spot, 2015; Statnett, 2017). As seen in the figure below, Norway is divided into five market areas for electricity. This is based on the regulations of the Energy

[9] Only projects which are considered socio-economic profitable will be granted a construction license pursuant to Section 3-1 of the Energy Act, see further the objectives set out in Section 1-2 of the Act.
[10] See Section 17-5 of the Control Regulation.

Act, where it is stated that the system operating grid companies are responsible for dividing the various countries into elspot areas in order to handle large and prolonged bottlenecks in the regional and central grid. In addition, the power and market situation of each of these areas will determine the direction of the power flows between the elspot areas.

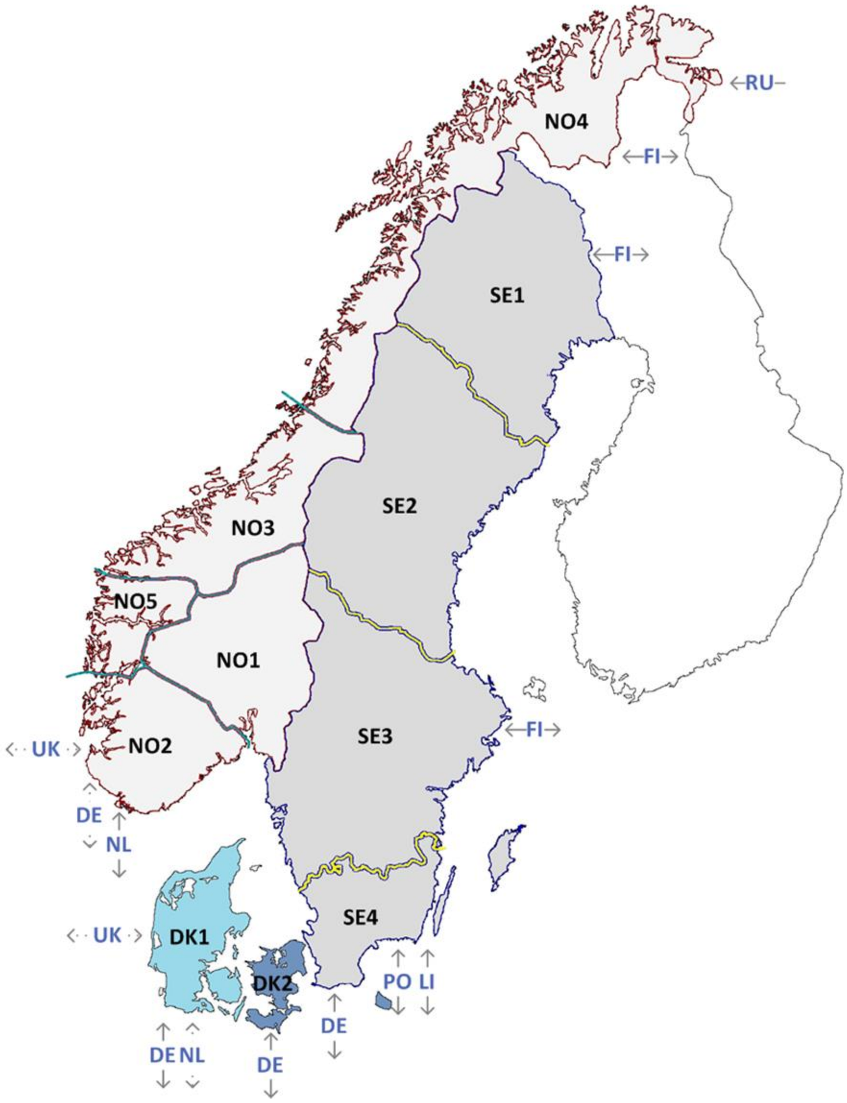

Figure 2: Illustration of the Scandinavian Nord Pool price areas with external trade to Europe.

Transmission grid modelling

As described in section 2, investments in new wind power production capacity may necessitate grid reinforcements. Indeed, several of the potential new power projects in Norway will require investments in the transmission grid. In order to incorporate this feature in the TIMES model, integer variables are included to describe whether or not a grid investment is made. As indicated in Figure 3, several wind power projects can use the same transmission line if built, whereas none of the projects can be completed if the opposite happens. If e.g. transmission line A is constructed in a social optimal scenario, it is most likely that the majority of the wind power projects connected to this line will be built before another transmission line is constructed. The same applies to transmission line B and C. Additionally, some projects are not in need of a new transmission line, and can be connected directly to the existing HV-grid.

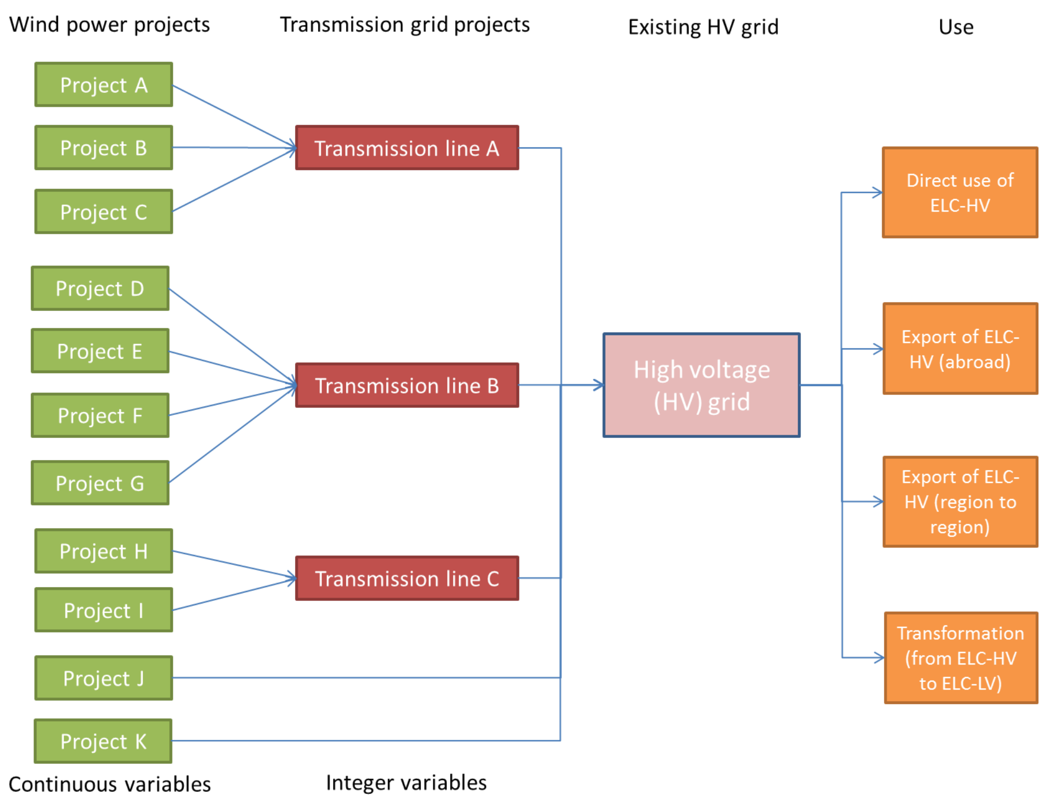

Figure 3: Intersection between wind power and transmission grid projects

Energy End Use Demand

The demand for various energy services are supplied exogenously to the model. The TIMES model is used to analyse the consumption of energy carriers and to investigate the substitution effect with technology shifts. In this work, the same methodology as in Rosenberg et al. (2013) is used for calculating the energy end use demand, where the calculations are based on the development of drivers and indicators of each demand sector. More specific details regarding the demand projection can be found in Rosenberg et al. (2015). It should be noted that flexible demand could be an economical and technical alternative in preference to grid investments. However, this work focuses solely on optimal location of renewable power, and any measures on the supply side of the energy system is not covered here.

3.3 Scenario Assumptions

Unless otherwise noted, the analyses in this paper take account of all active national policy measures with direct relevance to the electricity market. However, instead of the joint green certificate market with Sweden, we consider a domestic feed-in premium scheme for new renewables. The energy taxes are kept constant at the 2014 level until 2050, including value added tax (VAT), nonrecurring charge for new vehicles, fuel tax for road transport, tax on electricity consumption, and various CO2 taxes.

Energy Prices

Energy prices for imported energy carriers are taken from Energinet.dk (2015). The prices of electricity import/export to and from Scandinavia are given exogenously and kept constant at the 2014 level throughout the analyses. In addition, the various price profiles for each of the time-slices are calculated based on historical prices. It should be noted that electricity prices in the Scandinavian regions are endogenous, represented by the dual values of the electricity balance equation.

Scenarios

Socially optimal scenario (*opt*): As a starting point, we added a restriction to the TIMES model requiring 5 TWh of new wind power production in Norway by 2020. As discussed above, this assumption is motivated by a likely production increase in Norway due to the green certificate market. For the *opt* scenario, we find the welfare optimizing combination of locations of new capacities and grid investments by minimizing energy system cost, including the costs of necessary investments in the transmission grid. The outcome of this scenario corresponds to (17) in the analytical model.

Profit max scenario (*PM*): The same restriction regarding production increase is added in this case as well. In the *PM* scenario, the wind power producers act as if they received a uniform feed-in premium, sufficiently high to incentivize 5 TWh of new wind power. The producers find the locations for their wind farms that maximize their profit, given that the TSO invests in grids to accommodate their capacity into the energy system, as described in 2.2. Technically this is modeled in TIMES by first finding the least cost locations of wind farms, ignoring the costs of necessary transmission upgrades within each price zone. Thereafter, we find the necessary investments in transmission grids within each price zones to accommodate the new capacities. Upgrades of the high-voltage inter zones transmission lines are assumed to be implemented if profitable, given the new capacities and zonal transmission grids. The welfare of this scenario corresponds to (20) in the analytical model.

For all of the scenarios, TIMES finds the total cost of providing the electricity demanded. We compare the system cost of the Profit max scenario with the system cost of the socially optimal scenario, where the difference is the social cost of an inefficient geographical distribution of wind parks. Additionally, we identify the cost of transmission network investments for each location.

We also present a Business as usual scenario (*bau*). The purpose of this scenario is to demonstrate the effects of the policies analyzed in the other scenarios.

Sensitivity analyses of the three main scenarios were also conducted. Here, Kirchhoff's laws are incorporated by including a DC power flow linearization of an AC power flow, as well as simplified N-1 security constraints. Clearly, the actual grid is much more detailed than the aggregated network included in the TIMES model. It is therefore too strict to assume that the grid behaves as according to Kirchhoff's voltage law. However, it is also imprecise to assume that the law does not apply. Results from the sensitivity analysis are presented in the appendix.

3.4 Results

Figure 4 illustrates the new wind power production in 2020 for the three main scenarios. As shown, the model results vary considerably for three of the price areas depending on how the transmission grid investment costs are included. For the Profit max scenario, it is optimal that the production increase is largest in NO3. Currently, this region is a net importer of energy, so increasing the local production will decrease the dependency of imports from other regions. The production increase is second largest in NO2, which is the southernmost price area in Norway. This area is strongly connected to Europe through cables. There is also a considerable production increase in the northernmost price area (NO4). This is largely due to the high capacity factors (i.e. better wind conditions) experienced in this area.

The Socially optimal scenario illustrates the optimal location of new wind farms when all necessary investments related to grid expansion are taken into consideration. Compared to *PM*, the production increase is now even larger in NO3. This is mainly due to the fact that the

PM scenario will not be optimal when adding the costs of network development. It will require significant grid investments to export the additional electricity out of NO4, which means that it is more cost effective to take both power and grid investments in NO3. As a consequence, the production increase is now lowest in NO4.

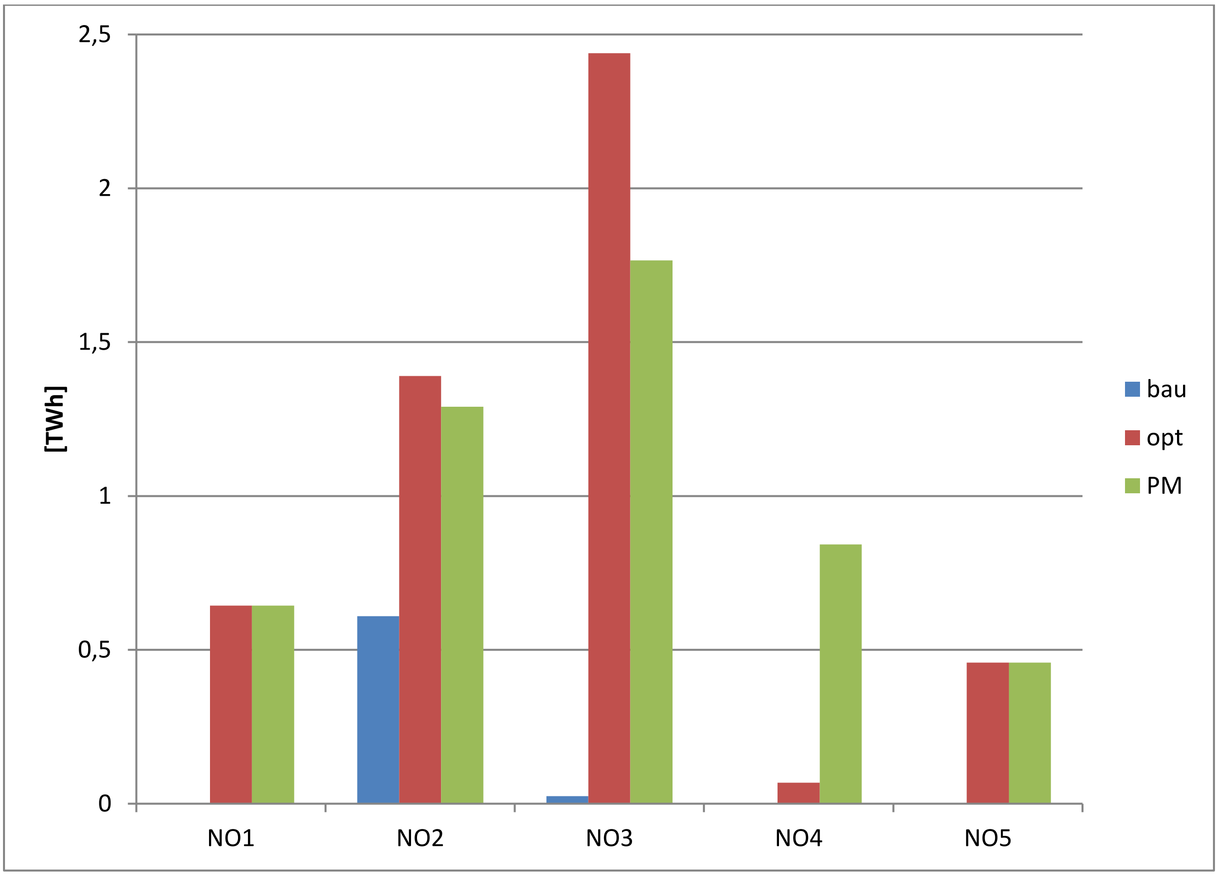

Figure 4: New wind power production in 2020

Figure 5 illustrates total power production costs for the new wind farms and the total costs related to the grid expansion (related to both transmission and distribution). The grid costs are around 55 % higher for the Profit max scenario, primarily due to higher necessary investments in transmission grids within each price zone to accommodate the new capacities. However, power production costs are roughly 8% lower. In total, achieving the target of 5 TWh of new wind power is only 6% more costly under a system with uniform feed-in premiums (Profit max) than under a system with optimal localization of new wind farms (as would follow from optimally differentiated feed-in-premiums, the Social optimal scenario). [11] Hence, policies to minimize the system costs of new wind power have significant impact on the geographical distribution of wind farms, but significantly less impact on the total energy system cost.

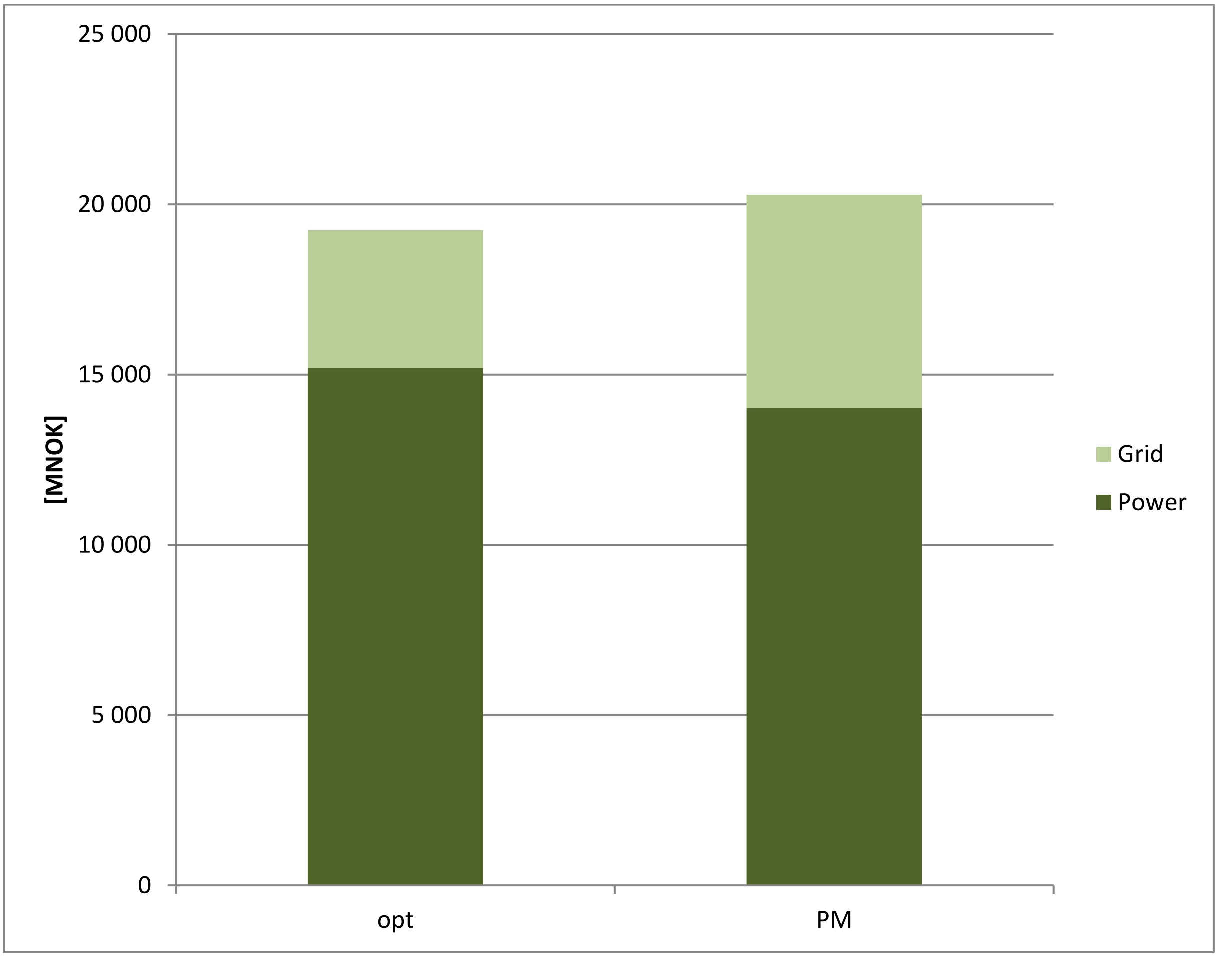

Figure 5: Power and transmission grid costs

[11] Note that we have limited the analysis to include only those wind power plants with a license. In a model-run where we expanded the feasible region by also including wind power projects that have applied for a license, the difference was much larger.

Figure 6 illustrates the investment costs for transmission grid upgrades per region for the two main scenarios. As seen, the investments vary considerably for NO4 depending on the wind power production in this region. A positive change in production of 0.7 TWh in NO3 (going from *PM* to *opt*) gives an increased transmission cost of around 200 MNOK, whereas a decreased production of 0.8 TWh in NO4 results in cost savings of around 2 400 MNOK for this model region. Otherwise, the necessary grid investments do not vary significantly for the other three model regions. It is interesting to note that the grid investment costs are almost similar for the Social optimal and the Profit max scenarios for region NO3, although there is a difference in power production of around 0.7 TWh. This clearly demonstrates that the same grid connection(s) can be used for several wind power projects, just as described in Figure 3.

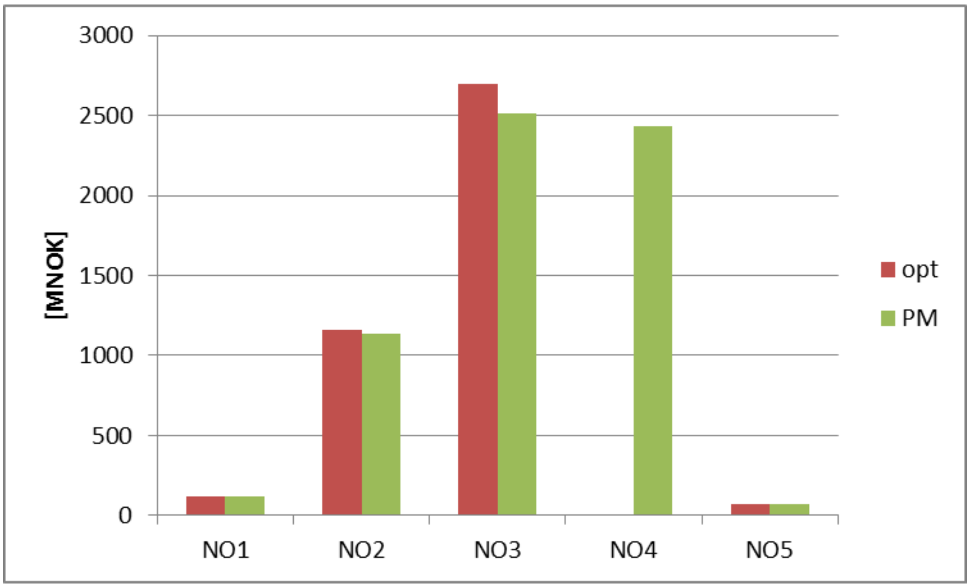

Figure 6: Investment costs per region

3.5 Other case studies

The text below describes briefly seven other papers dealing with adjacent problems, however none of them consider long-term investments in both grids and generation capacity simultaneously. Delarue and D'haeseleer (2007) analysed expansion of the net transfer capacity (NTC) on Belgian-French and Belgian-German borders. A simulation tool called E-Simulate was used to simulate electricity generation in a set of interconnected zones. It is an 8-zone model, where each zone represents a country. Here, each zone has its own set of electricity generation technologies. The main conclusion is that when imposing expansion on the NTC, the optimal distribution of power generation changes.

Schroeder *et al.* (2013) analysed electricity capacity investments in 2030 for Germany. The analysed scenarios varied in the location of power resources and line expansion projects. However, all this information was supplied exogenously. The results indicated that the proposed grid expansions were not sufficient to avoid high line congestion, and therefore not able to fully integrate the amount of renewable energy.

Steinke *et al.* (2013) focused on the interplay between storage and grid expansion. They analysed a 100% renewable power system based on wind and solar power (supplied exogenously) on the European level. However, there were no continuous development from today's situation. In a work by Lumbreras *et al.* (2017), optimal transmission expansion planning in a stochastic optimization context were presented. The model determines new investments in lines, transformers and circuits in a medium and long-term perspective. Generation expansion are handled in scenarios (exogenously). The study focused on Portugal, Spain and France, with a simplified grid for the rest of Europe (one node per country).

Gils *et al.* (2017) assessed capacity expansion and dispatch at various levels of photovoltaic and wind power penetration. A linear cost minimizing energy system model (REMix) was used to optimize capacity expansion of power generation, storage and transmission. The time horizon is one year, whereas the model divides Europe into 15 model regions. The results from the scenarios indicated that transmission expansion becomes important at high wind shares. Schlachtberger *et al.* (2017) analysed how to balance large shares of wind and solar PV at continental level with transmission grids and locally with storage. They performed a techno-economic cost optimization for the capacity investments and dispatch of wind and other generation technologies. The load and generation were aggregated at the country level. The model used has limited spatial detail, one-year horizon and focuses only on the power sector.

Hess *et al.* (2017) focused on node-internal grid calculation representing the electricity grid in cost values. The study used 491 nodes for describing Germany, and analysed a 100% renewable energy system in 2050 with maximum grid expansion with the optimisation model REMix. However, the optimization of generation technologies and grid expansions are performed sequentially.

4 Conclusions and discussion

Increased renewable energy production requires new investments in the grid. However, the magnitude of the necessary investments depends, inter alia, on where the new production plants are located. In this paper we have analyzed how a subsidy scheme (feed-in premiums) can be designed to induce a socially optimal location of new wind power capacities, given the subsequent investments in grids to accommodate the new capacities to the energy system. The optimal non-uniform feed-in premiums are differentiated across locations. The optimal feed-in premiums correspond to a system with optimal connection charges combined with a uniform subsidy to wind power. Hence, implementing a system with differentiated feed-in premiums faces some of the same challenges as implementing a system with geographically differentiated deep connection charges. A large increase in renewables, and thereby grid investments, calls for an investigation of the current regulations to see whether it might be reasonable to allow for some kind of differentiated feed-in premiums or connection charges which reflects the grid investments costs. Such solutions must be assessed further under EU/EEA law, in particular State aid law, as well as from the perspective of regulatory design, where the question arises how such scheme may be drafted with sufficient precision.

Our numerical illustration indicates that for an increase in new wind power of 5 TWh, the total cost of an uncoordinated location (the Profit max) was modestly (5%) higher than a coordinated development (social optimum). However, the location of new capacities and thereby grid investments differed substantially. The Profit max scenario demanded 55% more grid investments. In this paper we have not considered any of the environmental costs associated with wind parks and new grids. Including environmental cost may lead to another optimal geographical distribution of new wind power parks. This will be the topic of further research.

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Appendix A

In this appendix we find the first order conditions for the optimizing problem given by

(7) and (2)-(5).

We solve the optimizing problem by first forming the Lagrangian:

$$\begin{aligned}
&L(q_1, q_2, q_3, q^{CA}, q^{CB} I_{12}, I_{35}, I_{AB}) = \\
&U_A(q^{CA}) + U_B(q^{CB}) - \left[c_1(q_1) + c_2(q_2) + c_3(q_3) + k(I_{12}) + d(I_{35}) + z(I_{AB})\right] \\
&+\lambda_R(q_1 + q_2 + q_3 - \bar{q}^R) - \lambda_{TA}(\frac{1}{3}q_1 - \frac{1}{3}q_2 - I_{12}) + \lambda_M(q_1 + q_2 + q_3 - q^{CA} - q^{CB}) \\
&-\lambda_{TAB}(q^{CA} - (q_1 + q_2) - I_{AB}) - \lambda_{TB}(q_3 - I_{35}).
\end{aligned} \tag{18}$$

where λ_R is the shadow cost of the renewable constraint, λ_{TA} is the shadow cost of the transmission constraint within price zone A, λ_M is the shadow cost of the market equilibrium constraint, λ_{TAB} is the shadow cost of the transmission constraint between prize zone A and B and λ_{TB} is the shadow cost of the transmission constraint in price zone B.

We find the following first order conditions (The Kuhn-Tucker conditions), after some rearrangements:

$$
\begin{aligned}
&U'_A = U'_B + \lambda_{TAB} \\
&c'_3 = U'_B + \lambda_R - \lambda_{TB} \\
&c'_1 = U'_A + \lambda_R - \lambda_{TA}\frac{1}{3} \\
&c'_2 = U'_A + \lambda_R + \lambda_{TA}\frac{1}{3} \\
&k'(I_{12}) = \lambda_{TA} \\
&d'(I_{35}) = \lambda_{TB} \\
&z'(I_{AB}) = \lambda_{TAB} \\
&\lambda_{TA} \geq 0 \quad (= 0 \; if \; \frac{1}{3}q_1 - \frac{1}{3}q_2 - I_{12} < T_{12}^0) \\
&\lambda_{TAB} \geq 0 \quad (= 0 \; if \; q^{CA} - (q_1 + q_2) - I_{AB} < T_{AB}^0) \\
&\lambda_{TB} \geq 0 \quad (= 0 \; if \; q_3 - I_{35} < T_{35}^0) \\
&q_1 + q_2 + q_3 = \overline{q}^R \\
&q_1 + q_2 + q_3 = q^{CA} + q^{CB}
\end{aligned} \tag{18}
$$

Non-binding transmission constraints implies that $\frac{1}{3}q_1 - \frac{1}{3}q_2 < T_{12}^0$, $q^{CA} - (q_1 + q_2) < T_{AB}^0$,and $q_3 < T_{35}^0$ such that $\lambda_{TA} = \lambda_{TB} = \lambda_{TAB} = 0$ and $I_{12} = I_{35} = I_{AB} = 0$.

Let $q_i^* \; (i = 1, 2, 3)$, q^{CA*}, q^{CB*}, $\lambda_g^* \; (g = R, TA, TB, TAB, M)$, I_{12}^* , I_{35}^* and I_{AB}^* denote the solution to (18) when the transmission constraints are non-binding.

Let $q_i^{**} \; (i = 1, 2, 3)$, $\lambda_g^{**} \; (g = R, TA, TB, TAB, M)$, q^{CA**}, q^{CB**}, I_{12}^{**} , I_{35}^{**} and I_{AB}^{**} denote the solution to (18) when the transmission constraints are binding.

Appendix B

This section presents some of the results from the sensitivity analysis described in section 3.3. Figure 7 illustrates the new wind power production per region in 2020 for the *opt* and *PM* scenarios, respectively. The results are presented with and without the Kirchhoff's voltage law imposed on the grid. Generally, when the voltage law is imposed, the geographical location in the grid becomes more important. This can to some extent be seen in figure 7. It is now harder to transmit electricity from the two northernmost regions (NO3 and NO4). Instead, more projects are developed in NO2, which is highly connected to Europe.

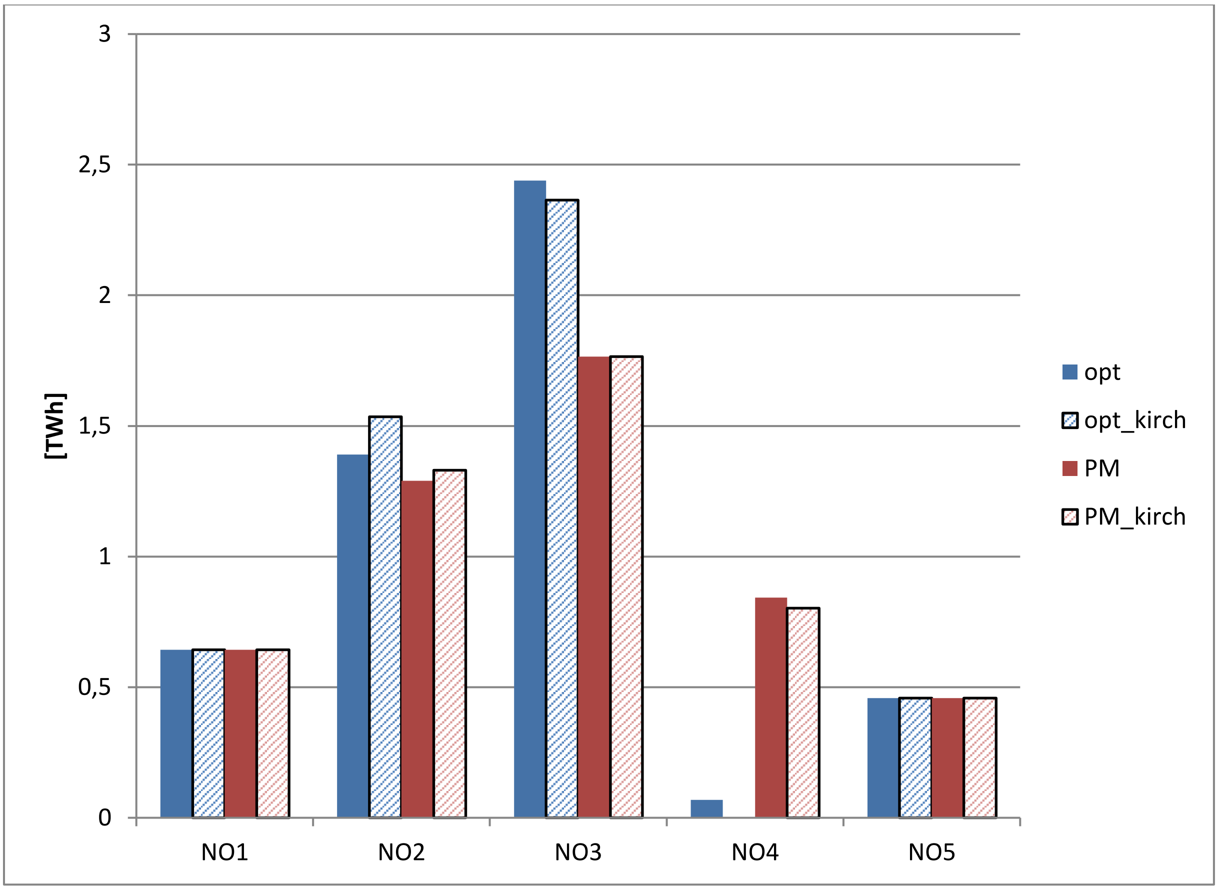

Figure 7: New wind power production in 2020

As seen in figure 8, much of the production increase is exported from Norway. Export volumes are also increased when the Kirchhoff's voltage law is imposed on the grid. The reason is that the grid becomes less flexible and network capacities are therefore more difficult to use. Another consequence is that more expensive wind power projects are built.

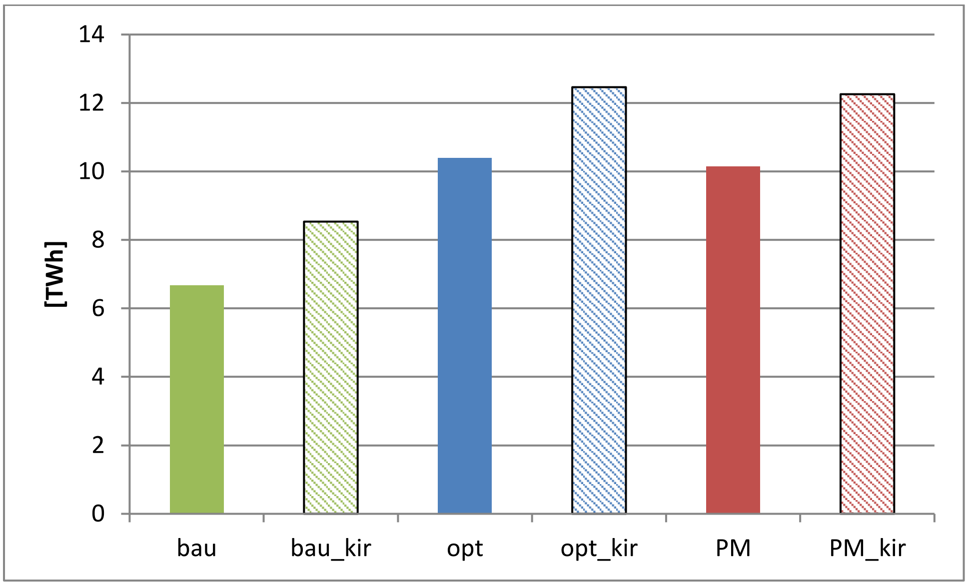

Figure 8: Net power export in 2020 per scenario.