Gone with the wind? An empirical analysis of the renewable energy rent transfer

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October 30, 2015

Abstract

Subsidies to renewable energy are costly and contentious. But what is their impact on the electricity prices? We estimate the reduction in prices that follows from the subsidized entry of wind power in the Nordic electricity market. A relatively small-scale entry of renewables leads to a large-scale transfer of surplus from the incumbent producers to the consumers: 10 % market share for wind generation eliminates more than 60 % of the electricity market expenditures, making the subsidies cost-neutral to consumers. We develop a novel empirical approach to the quantitative assessment, building on the Nordic climatic and hydrological variation.

JEL Classification: L51, L94, Q28, Q42, Q48

Keywords: Electricity, renewables, stranded assets, climate policies

1 Introduction

This paper estimates the reduction in electricity prices that follows from the subsidized entry of wind power in the Nordic electricity market. The wind generation has a small market share, less than 5 per cent of annual consumption. Yet, its is extracting 3-4 billion euros annually from the incumbents, that is, close to 20 per cent of the total incumbent revenue in the wholesale electricity market. The estimate increases to 11-13 billion euros under the Nordic renewable energy expansion path for the coming 5-10 years, extracting two-thirds of the hydro technology rents, and one-third of the nuclear revenues; the traditional thermal power technologies become fully stranded. On the flip side, consumers are expected to save two-thirds in electricity market expenditures, compared to the situation without wind. The wealth transfer implies that a subsidy of 70-80 euros per MWh for the new technologies would be cost-neutral to the consumers, exceeding the average subsidies in the region by a wide margin.

The empirical evaluation in this paper is among the first quantitative assessments of the wealth reallocation that follows from the renewable energy expansion taking place globally. The results for the Nordic market show that a relatively small-scale entry of renewables leads to a large-scale transfer of surplus from the incumbent producers to the consumers — the scale of the impacts seem to have gone unnoticed.[1] The controversial green energy subsidies are not, in effect, paid by the consumers but the incidence of the policies falls on the rents of the incumbent producers, through the output price reduction. Ideally, the rents are justified as rewards for market-driven investments in the productive assets.

The Nordic electricity market with close to 15 million electricity customers offers an ideal case for quantifying the stranded assets problem: On average, 50 per cent of incumbent production comes from hydroelectricity. This creates several notable features relevant for the empirical assessment. First, the hydro technology significantly mitigates or even eliminates the problems that arise because wind generators only produce when it is windy. In most markets, scaling up the share of such intermittent technologies

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[1]The transfers have not gone unnoticed by the industry. According to Caldecott and McDaniels (2014), the policy-induced total asset write-down of major EU utilities in 2010-2012, amounts to €22 billion. Accenture "Accenture Digitally Enabled Grid Research 2014" released on Dec 8, 2014, states: "Continued growth of distributed energy resources and energy efficiency measures could cause significant demand disruption and drive down utilities' revenues by up to $48 billion a year in the United States and €61 billion a year in Europe by 2025". In Europe, 11 major energy companies have formed "Margritte Group", fighting the subsidies eroding their asset values.

presents a serious challenge to the current ways of organizing transmission, distribution, and production of electricity (Gowrisankaran, Reynolds and Samano, 2015).[2] Since the hydro generators provide a natural source of balancing power for the renewables, the market can reasonably well accommodate intermittent entry.[3] As a result, we can shift the focus from the short-term problems to the longer-term implications for price levels, and to the question that has not been quantitatively addressed: How do consumers and producers share the cost of the policies?

Second, the implications of subsidized entry can become convoluted if the supply mix changes dramatically. In the Nordic context, the pressure on the existing assets can be stated as an almost pure rent-transfer problem since the bulk of inframarginal production remains in the market. In particular, the hydro technology earns significant scarcity rents; the supply price is determined by the high marginal cost of the alternative technologies such as thermal power. Since the subsidies are targeted at alternative technologies that have low or even zero running costs, their entry to the market lowers the opportunity cost of hydro and thus subsidies to entrants become indirect taxes on hydro rents. The main incumbent technologies, most notably hydro and nuclear, are trapped to bear the cost of entry, so that estimating the subsidy-induced fall in prices identifies the rent transfer from producers to consumers.[4] The quantified pressure on the assets is informative of the renewable energy wealth destruction reshaping electricity markets in general – in other contexts, the pressure leads to immediate and potentially large changes in the structure of supply and thus to immediate efficiency ramifications.

Third, the exogenous variation in the availability of the hydro resource together with the conspicuous Nordic climatic variation allows using a novel empirical identification strategy for the equilibrium division of labor between the technologies in this market. It turns out that the equilibrium generation patterns for different technologies depend on

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[2]Gowrisankaran et al. (2015) evaluate quantitatively the intermittency cost for southeastern Arizona. For example, Ambec and Crampes (2012) study the optimal energy mix with reliable and intermittent energy sources.

[3]For the Nordic region, there is no clear evidence that renewable energy generation has increased the volatility of electricity prices (Rintamäki et al., 2014).

[4]Hydro is a fixed factor and can evade the policy only if there is a political decision to restructure the market area. Nuclear, the second-largest source of power and a carbon-free technology, can respond to policies by the timing of phase downs. That nuclear is not strictly a fixed factor shapes the long-term interpretations of the estimates but it is not a problem for the gist of the analysis: we quantify the immediate and medium term pressure on the assets. The wealth transfer estimates are not sensitive to the timing of shut-downs of traditional thermal plants since, in any case, they no longer accrue surplus from the market when wind generation exceeds 10 % of the total supply.

natural fundamentals such as temperatures, wind, and rainfalls that are similar to those that determine the availability of renewables in general. In the counterfactual analysis, we scale up the observed wind generation patterns to recover a new invariant seasonal equilibrium, and the implications for surpluses across technologies and consumers in the Nordic countries.

Hydropower provides 16 per cent of the world's electricity, which is less than the supply coming from carbon technologies in total but more than from any other single fuel source; it is the dominant technology in more than 30 countries (IEA, 2012). We contribute to the literature on electricity markets by developing an empirical approach to estimating supply in a hydro-dominated market. We are unaware of previous attempts to estimate empirically the dynamic hydro policies; the previous literature relies on simulation methods to evaluate the supply price of the hydro resource (for example, Bushnell, 2003; Kauppi and Liski, 2008; Kopsakangas-Savolainen and Svento, 2014).[5] Our approach does not address the issue of market power, which is a key concern in electricity markets (for example, Borenstein, Bushnell, and Wolak, 2002; Fabra and Toro, 2005; Hortaçsu and Puller, 2009; Puller, 2007; Reguant, 2014). The dynamics of hydro use has been a major obstacle to market power assessments in markets dominated by hydro resources; the empirical policy functions estimated here could open the door for a structural approach to evaluating hydro producer's market power, for example, building on Bajari, Benkard and Levin (2007).[6]

The empirical strategy in this paper could be applied in other storable-good markets as well but the data on storage levels is not typically available with the same precision. In fact, the competitive storage model (Deaton and Laroque, 1992) has been designed to deliver implications for the price dynamics, without data on the underlying quantities.[7] In contrast with other major commodities, the electricity market setting produces information on prices and productions, as well as "harvest" (inflow of water) and storage levels, with a precision not feasible for commodities in general. This allows estimating the policy rules directly as a function of the relevant state. We estimate a relationship between the amount on hand and the current price, which is the key concept for understanding pricing in storable good markets (see Wright (2014) for an overview). We believe that this concept has not been previously empirically identified. In contrast with Roberts

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[5]Fridolfsson and Tangerås (2009) review also the simulation models used by the industry for evaluating the "water values".

[6]Wolak (2009) provides a quantitative assessment of the New Zealand market where the hydropower is important, but the hydro producers policies are not estimated. See also Fehr (2009).

[7]See Williams and Wright (1989) for an extensive treatment.

and Schlenkler (2013), who consider an instrumentation strategy for a storable good, our identification is based on the observed stocks, not on variables that are correlated with the stocks.

The roadmap is the following. In Section 2, we shortly overview the policy incidence problem, with analysis in the Appendix. In Section 3, we describe the institutional setting. In the empirical analysis, Section 4, we first explicate the identification strategy used in the paper. Then, in Section 4.1, we state the theory arguments for the policies to be estimated. This section also provides the basis for identifying the variation that can be used to recover the equilibrium prices. The prices, in Section 4.3, are estimated for the historical market where the installed capacities remained stable. In Section 5, the capacities change; the rent transfer results follow directly from estimated surplus generating process that we have estimated. Section 6 concludes and discusses the wider policy implications.

2 The policy cost incidence: a brief look

Who bears the financial burden of the climate policies? The electricity sector produces the bulk of the carbon emissions and is among the first sectors facing policy-determined carbon prices, further passed on to the users of electricity (Fabra and Reguant, 2014). By familiar tax incidence arguments, when the demand is inelastic, it is the buyer side that bears the lion's share of the carbon input costs if carbon pricing is used as a policy instrument. It has been noted before that policies encouraging the adoption of new technologies through subsidies can lower the final consumer price (Fischer, 2010), reversing the policy cost incidence. However, the policies that deviate from straight carbon pricing are generally distortive (Böhringer and Rosendahl, 2010).

Yet, the empirical results of the current paper presents puzzles, not solved by the previous literature. First, why is it that such a large price reduction follows from a small-scale entry to the market? Second, what is it that protects the rents of the incumbents under carbon pricing but not under subsidies? The answer to the first question is essentially static and can be explained with the help of Fig. 1, where there are two basic sources of supply: a low cost base-load and higher-cost carbon-intensive capacity. The carbon price increases the supply cost and thus the consumer price; the implication for the consumer price is reversed under policies that shift the residual demand for the incumbent capacity to the left. The renewable energy entry, subsidized or not, achieves exactly this. The larger the share of the highest quality base-load, such as the hydro

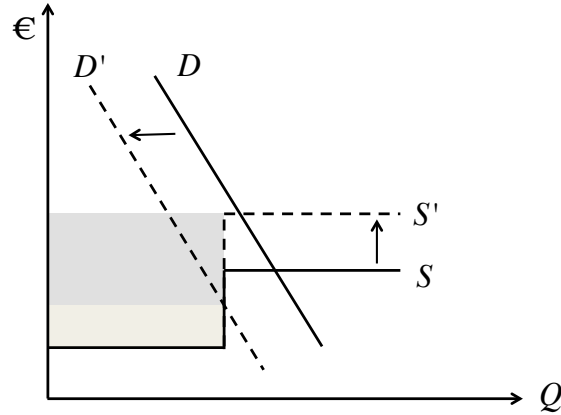generation in the Nordic market, the larger is the rent extraction that follows from a given price drop.

Figure 1: A schematic illustration of the policy cost incidence, with low and high cost of portions in supply. Carbon pricing increases the cost differentials in supply and the rent (in grey) to the existing low cost suppliers. In contrast, subsidies to new entrants shift the overall demand for the incumbent capacity to the left, and extract the rent.

For the second question, in Appendix D, we develop a simple model were the entry and the gradual eroding of rents is explicit. The model identifies a source of entry friction that protects the incumbents' rents; it also idenfities a limiting case where the subsidized entry to the market has only distributional but not efficiency implications.[8]

Assume that the new carbon-free technology faces an initial cost that is too high for an immediate entry, even after the introduction of the carbon price. The cost of the new technology declines over time: the rate of decline determines the rate of old technology replacement in equilibrium. It is socially optimal to postpone large scale entry in anticipation of lower future technology costs: this increases the social value of the incumbents' assets and is the source of the incumbent rents.[9]

In the model, subsidising entry brings new technologies to the market too early: the

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[8]We were led to work out the basic mechanisms since the literature on distortive policy instruments has not looked at the dynamics of rent protection (see, for example, Böhringer and Rosendahl (2010)).

[9]In the general equilibrium context, Nordhaus (e.g., 2008) has made the argument that climate policies should be gradually tightening for reasons related to income growth and consumption smoothing. Our model captures a different reason for gradualism, exogenous technical change, but the implications for the existing capital structure a similar: it should be phased out gradually. With endogenous technical change, a crash start could be optimal (Gerlagh, Kverndokk and Rosendahl 2009; and Acemoglu, Aghion, Bursztyn, and Hemous, 2012).

society pays too much for the new capacity. In addition, the total consumption path becomes front-loaded, although there is no long-run consumption distortion. Yet, the model also shows that the distortions vanish for a consumer demand that is inelastic enough: when consumption is not price sensitive, subsidies have no effect on the total allocation of consumption over time. Thus, with inelastic demand, subsidies become a distributional issue: relatively small increments of new capacity lead to large price changes, and thereby the quantitative distortions from the rent-extracting subsidies are small.

Since the consumer demand is inelastic and the new technology costs are trended downwards in electricity markets, this stylized model may capture part of the rent extraction dynamics in our setting. Indeed, we do find evidence for large rent transfers from relatively small quantitative entry.

3   Institutional context

The core of the Nordic market is a spot market for wholesale power, Nord Pool Spot (NPS), owned jointly by the national transmission system operators in Denmark, Finland, Norway and Sweden.[10] NPS runs as a day-ahead hourly market where aggregated supply and demand bids from the Nordic countries lead to an hourly price, the system price, for the region.[11] The operators have their units geographically dispersed, and the transmission capacity has been sufficient to avoid persistent segmentation of the market into separate pricing zones. The system price prevails if all trades are physically implementable; if this is not feasible, regional (or zonal) prices established. For example, Finland has at most one price region, and Sweden has at most four regions; the differences in the number of price zones reflects differential pressures on the physical transmission grid.

There is pressure for future segmentation but this does not remove the fact there is a natural division of labor between capacities in the participating regions. Norway's capacity is close to 100 per cent hydropower; Sweden has more equal shares of hydro and nuclear power; Finland has diversified between nuclear, thermal, and hydro power;

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[10]These countries have been NPS members since 1999; Estonia, Lithuania, and Latvia joined NPS in 2010, 2012 and 2013, respectively. However, the system price, in focus in our analysis, is only calculated from the prices of Denmark, Finland, Norway, and Sweden.

[11]According to NPS, there are 370 producers, and about 70-80 per cent of all electricity consumed is circulated through NPS.

Denmark has no hydropower but the largest share of wind.[12] In years of abundant hydro availability, the direction of exports is from the west to east; the reverse holds in dry years. The winners and losers from trade take turns over the years, which may explain the stability of the trading institution. Moreover, the pressure on transmission links varies accordingly so that the system price is arguably the relevant longer-run reference price in the Nordic region (see also Juselius and Stenbacka, 2011). In our analysis, we focus on the system price.

The market structure is conducive to competition; the market power concerns have not been as pressing as in many other early deregulated markets. Rather, the question has been, as in the title of Amundsen and Bergman (2006), "Why Has the Nordic Electricity Market Worked So Well?" (see also Fehr, 2009).[13]

Figure 2: The Nordic market area. The detailed interconnection map available from here.

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[12]Appendix A provides the descriptive statistics for productions by capacity over the years 2001-2013.

[13]Yet, it must be noted that the market performance of the Nordic market has not been as systemically evaluated as in other major electricity markets. One complication is the dynamic nature of hydro supply; another is that NPS does not release the firm-level bid curves.

4 Empirical analysis

Our data covers years 2001-2013.[14] All data is aggregated over regions to monthly observations; the seasonal variation is relevant for the identification strategy in this paper. Spot prices come from Nord Pool (the system price); productions by technologies are obtained from the national grid operators, as well as all the hydrological variables. The Appendix A lists the sources of data, with a detailed description of the data construction.

$$\underbrace{TOTAL.DEMAND}_{=D_t} = \underbrace{HYDRO + THERMAL}_{=d_t} + \underbrace{WIND + CHP + NUCLEAR}_{\text{price insensitive}} \tag{1}$$

Equation 1 provides a breakdown of the technologies that are used to generate the output that meets TOTAL.DEMAND.[15] We argue that TOTAL.DEMAND is exogenous, that is, defined by seasons and climatic conditions. We also argue that supply from WIND, combined heat and power (CHP), and NUCLEAR are exogenous.[16] Thus, by equation (1), the total output from HYDRO and THERMAL is also exogenous.[17] Then, the allocation problem that the market is solving is effectively the sharing of exogenously realized joint demand d_t for the two technologies, HYDRO and THERMAL.

To illustrate the empirical strategy, consider a market with linear demand (q^d) and supply (q^s):

$$q^d = \alpha_0 + \alpha_1 p + u$$
$$q^s = \beta_0 + \beta_1 p + v$$
$$q^d = q^s$$

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[14]The definition of the market and the available capacity have been relative stable in this period. Extending to 1990's would change the market definition; the eastern interconnections (Baltics, Russia) have influenced the market but only in the recent past. The capacity expansion has been mostly WIND generation that has followed a stable trend until 2013, which is included in the analysis.

[15]Term "load" is often used, instead of demand, to indicate that the quantity is given and needs to be procured from the suppliers in the market. We use the concepts interchangeably.

[16]NUCLEAR is a must-run capacity. CHP units sell power to the market but the main obligation is to produce heat. Yet, fraction of CHP can respond to prices. We separate out the temperature-dependent CHP from the price sensitive CHP (see the Appendix A). The latter part of CHP is allocated to the price sensitive thermal power. WIND power output depends climatic conditions.

[17]THERMAL includes traditional coal, gas, and oil fired power generation but also the price sensitive CHP (see the previous footnote). In addition, trade with other than Nordic countries is added to THERMAL. The quantitative volumes, partners, and the organization of trade are in the Appendix A.

with constants $(\alpha_0, \alpha_1, \beta_0, \beta_1)$, shocks (u, v), and price p. If it can be argued that demand q^d is exogenous, $\alpha_1 = 0$, then q^d can be directly used to as an instrument to identify the supply curve.[18] Translated to our setting, $q^s = THERMAL$; we are interested in identifying the price-quantity relationship for this technology. However, in our setting, the exogenously realized demand, d_t in eq. (1) above, is not for THERMAL but for the joint output from HYDRO and THERMAL. Now, suppose that HYDRO is some function of the state of the market, HYDRO$= a(\mathbf{s}_t)$, where state $\mathbf{s_t}$ is a collection of exogenous drivers such as temperatures, seasons, and hydrological conditions. Then, with the exogenously realized d_t from equation (1), the total demand for THERMAL reads $q^d = d_t - a(\mathbf{s}_t)$, which is exogenous.[19]

The next step is to show the theory arguments why HYDRO should be a function of the state (Section 4.1). Then, we estimate policy function $a(\mathbf{s}_t)$ (Section 4.2). Finally, we use the estimated policy to generate exogenous demand variation for THERMAL to recover THERMAL supply prices (Section 4.3).

Before taking these steps, let us confirm that TOTAL.DEMAND is exogenous in equation (1), for the above identification argument to hold. Table 1 shows TOTAL DEMAND regressed on: seasons (column 1); seasons and the temperature deviation from the average (column 2). Figure 3 illustrates the fit from the two regressions: with $R^2 = .98$, the Nordic demand is almost solely a function of the exogenously changing Nordic conditions.[20] Note that the seasonal quantities are directly informative about the mean aggregate demand per month in TWh.

4.1 Allocation policies: theory

To show that observing the state is a sufficient statistics for determining HYDRO output, we formalize the underlying dynamic planning problem (by standard arguments, the planning outcome can be decentralized so that the argument holds for the market

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[18] This is the approach, for example, in Bushnell et al. (2008).

[19] One could still use d_t as an instrument for THERMAL; demand realizations are correlated with THERMAL, as long as HYDRO does not fully insulate THERMAL from the shocks. However, such an instrument would be problematic: demand shock implications across periods are correlated since HYDRO responses to shocks by storage so that one period shock to demand affect THERMAL over several periods.

[20] However, looking at the Nord Pool spot market bid curves, the short-run demand can response to price differentials across hours, for example, through industrial demand and pumped-hydro technology. At monthly level such adjustments are not feasible.

	(1)	(2)
Jan	39.55***	28.93***
Feb	39.53***	28.71***
Mar	36.49***	27.51***
Apr	31.79***	26.28***
May	28.18***	26.60***
Jun	26.06***	25.92***
Jul	24.48***	24.48***
Aug	26.17***	26.08***
Sep	28.26***	26.71***
Oct	31.86***	26.56***
Nov	35.55***	27.84***
Dec	37.81***	27.90***
Temperature		17.97***
Observations	156	156
R^2	.95	.979
Adjusted R^2	.95	.977

Note: *p<0.1; **p<0.05; ***p<0.01

Table 1: TOTAL DEMAND regressed on: seasons (column 1); seasons and temperature (column 2). Temperature measured in heating degree days (HDD). Demand is measured in TeraWatthours.

interpretation as well).[21]

Time $t = 0, 1, 2, ...$ is discrete and extends to infinity. State is a vector denoted by

$$\mathbf{s_t} = (s_t, r_t, d_t, \omega_t, \theta_t),$$

where s_t is the amount of the good in storage, r_t is inflow ("harvest"), d_t is demand realization, ω_t is the recurring season of the year, and θ_t allows for including processes capturing, for example, technological change or input prices. State transition is a Markov process, affected by "action", denoted by a_t:

$$P(\mathbf{s}_{t+1}|\mathbf{s}_t, a_t)$$

where transition is stationary and bounded. Action $a_t \in A(\mathbf{s}_t)$ measures the drawdown from the stock where the choices are constrained by the set $A(s_t)$, capturing, for example, storage and other capacity constraints. The payoff at period t from action $a_t \in A(\mathbf{s}_t)$ is

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[21]To extend the argument to the case of imperfect competition, we would need to introduce a Markov structure for the strategic interactions as, for example, in Bajari et al (2007). Market power on the side of dynamic HYDRO producers is not a challenge to the empirical strategy in this paper, given that our focus is to identify a relationship between prices and quantities to be used in counterfactual analysis. But, without having an explicit model of imperfect competition, we cannot address if the observed allocations deviate from the first best allocations.
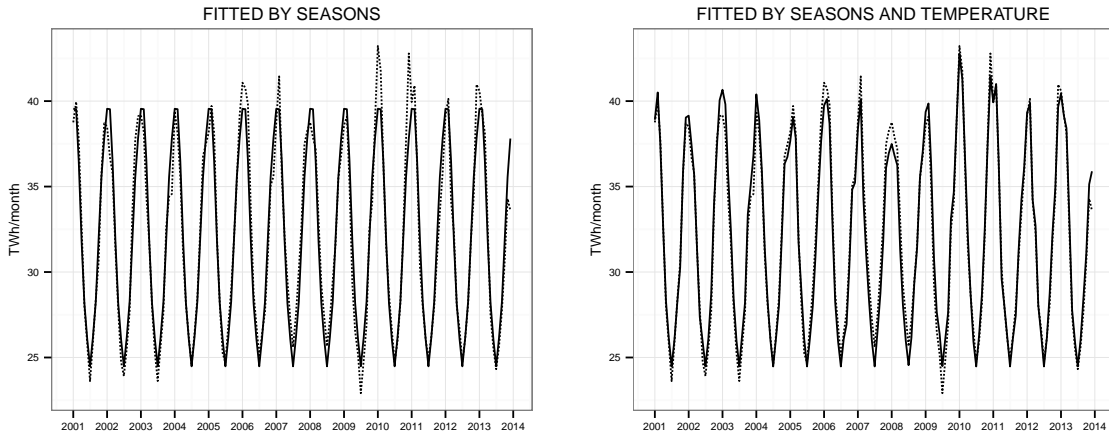
Figure 3: Actual (dotted lines)and the estimated TOTAL DEMAND (solid lines) (TWh/month) in years 2001-2013. Left: actual and fitted values from TOTAL DEMAND regressed on seasons (column 1 of Table 1). Right: actual and fitted values from TOTAL DEMAND regressed on seasons and temperature (column 2 of Table 1).

$$\pi(\mathbf{s}_t, a_t) = -C(d_t - a_t, \omega_t, \theta_t),$$

where $C(d_t - a_t, \omega_t, \theta_t)$ is the cost of meeting demand with the alternative technology. The cost is increasing in the first argument, bounded, and positive. Under relatively mild assumptions, it follows that there exists a stationary policy function to the planning problem.[22] With discount factor $\delta < 1$, the optimal policy maximises the discounted sum of gains:

$$V_t = V(\mathbf{s}_t) = \max_{\{a_\tau\}} \mathbb{E}[\sum_{\tau=t}^{\infty} \delta^{t-\tau} \pi(\mathbf{s}_\tau, a_\tau) | \mathbf{s}_t],$$

where the value of the program satisfies the Bellman equation

$$V(\mathbf{s}_t) = \max_{a_t \in A(\mathbf{s}_t)} \{\pi(\mathbf{s}_\tau, a_\tau) + \delta \mathbb{E}[V(\mathbf{s}_{t+1}) | \mathbf{s}_t, a_t]\}.$$

PROPERTIES:

1. The optimal policy is a function of the state: $a_t = a(\mathbf{s}_t)$

2. Policy generates invariant distributions for state elements through $P(\mathbf{s}_{t+1} | \mathbf{s}_t, a(\mathbf{s}_t)) = P(\mathbf{s}_{t+1} | \mathbf{s}_t)$.

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[22] In particular, we need to assume (i) stationary rewards and transitions, (ii) bounded rewards, (iii) discounting, and (iv) discrete state space. See Puterman (1994), Chapter 6. Of course, item (iv) can be relaxed (Stokey and Lucas, 1993); for conceptual clarity, we make assumptions (i)-(iv).

In our application, the storable good is hydroelectricity and the alternative technology is thermal electricity such as condensing power. The cost structure of the alternative has seasonal variation as captured by ω_t in $C(d_t - a_t, \omega_t, \theta_t)$. It also captures technical change or input prices through θ_t. [23]

The key observation is that the optimal policy compresses information about cost $C(\cdot)$ into a functional dependence on the state, $\mathbf{s_t} = (s_t, r_t, d_t, \omega_t, \theta_t)$. Thus, if the analyst observes the state, HYDRO policies can be estimated without knowing the cost structure of the alternative technology. In our application, the elements of the state are observable so that we can estimate the policy directly. We proceed to this estimation next.

4.2 Allocation policies: estimation

The next step is to estimate policy HYDRO$= a(s_t, r_t, d_t, \omega_t, \theta_t)$: we regress the monthly output of hydroelectricity on the monthly storage level, inflow, residual demand, and seasonal dummies. We have noted above that demand is strongly dependent on seasons and temperatures (Table 1 and Figure 3); for convenient interpretation and consistency with the theory arguments above, we use d_t in the regression but it should be kept in mind that this variable mostly captures temperature variation. We measure both storage and demand as deviations from the historical monthly average. Finally, to capture θ_t in the policy, we include, in addition to seasonal time, a distinct time trend.

In Table 2, we report the estimation results by adding four sets of covariates successively. Alongside with the Table goes Figure 4 showing the actual HYDRO and the fitted values for each respective regression. Column (1) demonstrates the strong seasonality of the output: 60 per cent of the variation in policies can be explained by seasons only; see also panel I in the Figure. The values are in TWh. The sum of the monthly dummies is the total mean annual availability of the resource, close to 200 TWh, which is ca. 50 per cent of the total mean annual demand in this market.

Column (2) adds the most important natural variation for the policies, inflows and reservoirs: R^2 increases to .85. Figure 4 (panel II) confirms that "availability" is a source large deviations from the seasonal average outputs. For interpretation of the reservoir

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[23]Input prices are relevant if one believes that, for example, oil or emission allowance prices processes are important for the hydro allocations. However, the input prices turn out be quantitatively insignificant when estimating HYDRO policies. Intuitively, while a level shift in input prices for THERMAL increase the output prices and thus the value of HYDRO output, there is no change in the relative value of HYDRO output across periods. In the next Section we show the variation in policies explained by different sets of covariates.

coefficient, one standard deviation in the variable "reservoir" is approximately 10 TWh per month; monthly production increases by 1.3 TWh per one standard deviation increase in availability.

	(1)	(2)	(3)	(4)
inflow		−0.01	−0.02	0.05**
reservoir		0.15***	0.15***	0.13***
demand				0.55***
trend			.009***	.008***
Jan	20.93***	20.87***	20.23***	20.30***
Feb	20.93***	20.98***	20.33***	20.40***
Mar	18.33***	18.45***	17.79***	17.84***
Apr	15.71***	15.73***	15.06***	15.12***
May	15.44***	15.19***	14.51***	14.61***
Jun	14.77***	14.77***	14.08***	14.15***
Jul	13.71***	13.93***	13.23***	13.28***
Aug	14.67***	14.89***	14.19***	14.23***
Sep	15.51***	15.64***	14.93***	14.98***
Oct	17.14***	17.29***	16.57***	16.63***
Nov	18.72***	18.90***	18.17***	18.23***
Dec	19.93***	20.04***	19.31***	19.37***
Observations	156	156	156	156
R^2	0.62	.86	.88	.998
Adjusted R^2	0.6	.85	.86	.997

*p<0.1; **p<0.05; ***p<0.01

Table 2: Hydro policy regressed on different sets of parameters. Column (1): seasonal dummies. Column (2): seasonal dummies + inflow + reservoir. Column (3): Column (2): seasonal dummies + inflow + reservoir + trend. Column (4): seasonal dummies + inflow + reservoir+trend+temperature. Units: inflow, reservoir, demand, and production is measured Terawatt hours. Variables "demand" and "reservoir" expressed as deviations from seasonal mean values. Standard errors for estimates in column 4: inflow .02, reservoir .01, demand .05, trend .0015, and the month dummies approximately .2.

Column (3) adds only the trend which is precisely estimated but quantitatively small; over the 150 months, production has increased about 1.25 TWh (.3 per cent of the market size).[24] The final column incorporates the residual demand realization, as a deviation from the seasonal mean (≈ temperature deviation from the seasonal mean, see Table 1). Prodigious 99 per cent of the variation in HYDRO outputs is explained by natural variation only: seasons, inflows, reservoirs, and temperatures (through the

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[24]The most likely explanation is the development or upgrades of the turbine technology.
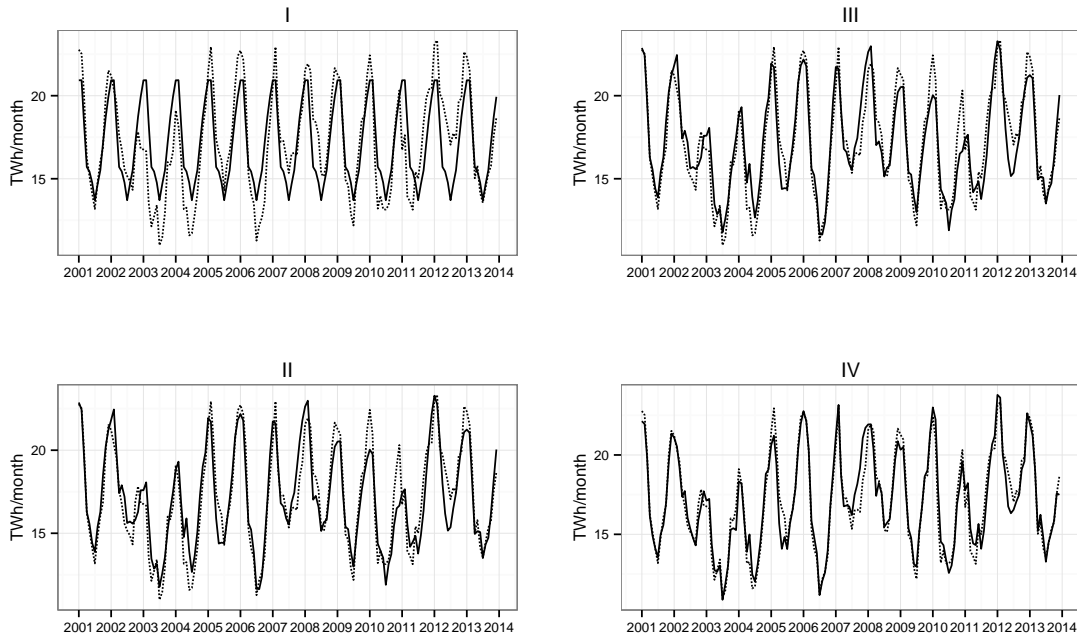
demand variation).[25] [26]

Figure 4: Solid lines = fitted values, dotted lines=actual. Hydro policies estimated on four sets of explanatory variables (TWh/month) in years 2001-2013. I: seasons. II: seasons+inflow+reservoir. III: seasons+inflow+reservoir+trend. IV: seasons+inflow+reservoir+trend+demand.

We can now come back to you hypothesis that THERMAL=$d_t - a(\mathbf{s}_t)$, that is, THERMAL is exogenously obtained from the realized residual demand d_t and HYDRO policy $a(\mathbf{s}_t)$ that we have just estimated. We show the resulting predicted THERMAL in Fig. 5.

For comparison, Fig. 5 plots HYDRO and the implied THERMAL in parallel over the sample years. This allows discussing events that the policy estimates are not capturing, for example, in years 2007-2008. The large deviation of the thermal estimate from the observed, and the corresponding deviation on the hydro side, can be explained by the European Emission Trading System (ETS) that created temporary incentives for saving ETS allowances through hydro storage: the ETS allowances where not storable between

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[25]The table reports the main effects; interaction terms such as $reservoir \times month$ seem economically meaningful. The inclusion of interactions does not change the main effects. Overall, there is little variation left to be explained by interactions.

[26]We also included a larger set of controls, for example, the input prices and indicators for the state of the economy; they have no practical impact on the policy, once the natural state covariates are included. Excluding other than the natural state covariates preserves conceptual clarity: the invariant prices, discussed shortly, can be obtained directly, after the price regression below.

the ETS Phase I (2005-2007) and Phase II (2008-2012). Temporarily, this created incentives to expand THERMAL above the level predicted in Fall 2007 to use Phase I surplus allowances. Effectively, the emissions allowances were saved through hydro storage.

Note that the thermal power quantities in this market are not large; the mean annual output is 30 TWh, clearly less than 10 per cent of the total load. This is the target capacity (or generation) to be replaced by the renewable energy.
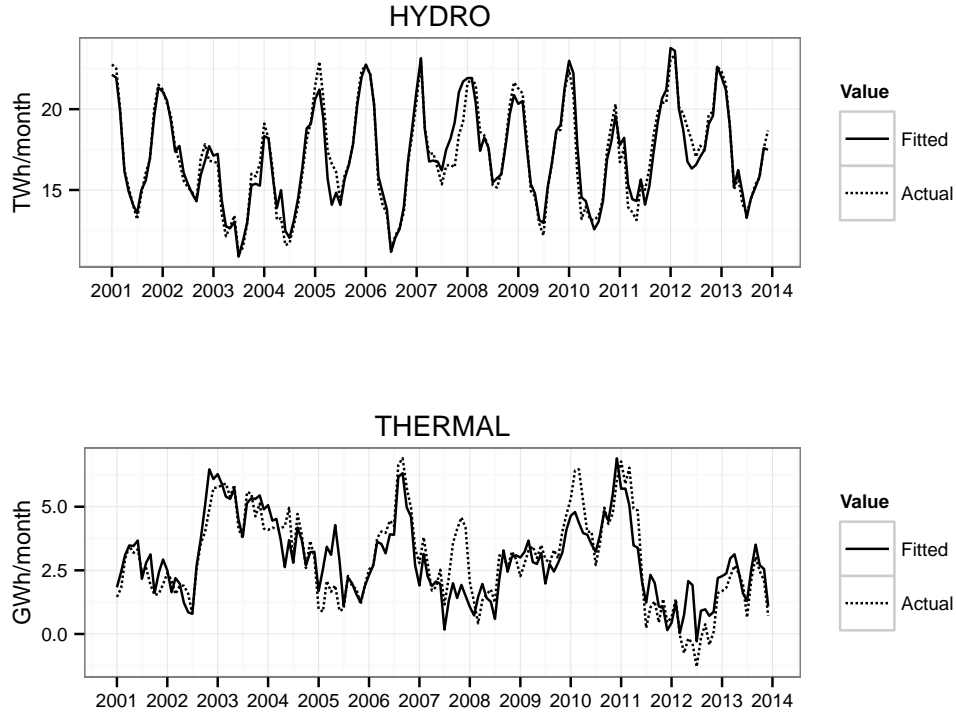

Figure 5: Actual and the estimated HYDRO and THERMAL polices (TWh/month) in years 2001-2013.

4.3 Recovering prices

Ideally, the market outcome is a solution to a problem where the objective is to allocate the hydro resource to minimize the expected cost of production with the alternative technologies — the observed market outcome reveals how exactly the allocation rule depends on the state. The estimation above captures the dependence on the state but is yet silent about the costs that underly the policy. Next we recover the costs, that is, prices by estimating the price-supply relationship for THERMAL.

As seen above, THERMAL is also a function of the state, denoted by $q^{TH}(\mathbf{s}_t) =$

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$d_t - a(s_t, r_t, d_t, \omega_t, \theta_t)$. Our price regression should be seen as a second stage regression where policy $q^{TH}(\mathbf{s}_t)$ comes from the first stage regression explicated in the previous Section. As, for example in Bushnell et al (2008), we regress (the log of) the spot price on (log of) of the index of marginal costs, denoted by mc_t, and on the policy $q^{TH}(\mathbf{s}_t)$:[27]

$$\ln p_t = \alpha_0 + \alpha_1 \ln mc_t + \alpha_2 q^{TH}(\mathbf{s}_t) + \epsilon_t. \tag{2}$$

The marginal cost index depends on input prices, average rates for efficiency in using the inputs, and emissions rates.[28] To recap the identification idea, the dynamic policies that determine $a(\mathbf{s}_t)$ and thus $q^{TH}(\mathbf{s}_t)$ take into account the general cost structure of the alternative supply, as explained through the dynamic programming arguments in Section 4.1. Hence, in principle, $a(\mathbf{s}_t)$ can depend on the cost of alternative supply also through persistent processes such as those determining the level of the oil price (θ in the natural state). Even if fuel prices entered $a(\mathbf{s}_t)$, sufficient exogenous variation in $\mathbf{s}_t$ that is unrelated to the costs of THERMAL can be used to instrument THERMAL quantities. However, we have seen in Section 4.2 that $a(\mathbf{s}_t)$ depends solely on variation in inflows, reservoirs, temperatures and seasons of the year – these variation has nothing to do with the cost of generating THERMAL. As a result, when we regress (2) directly as presented, or via 2SLS, the efficiency of the estimates remains the same.

In Table 3, we report the estimated relationship between the output price and the production of thermal power. For this specification, 1000 MWh increase in output, that is, a change corresponding to a nuclear power unit, leads to a 16 per cent increase in the price.

The linear regression presented is useful for conceptual clarity: obtaining the estimates is a matter of matrix algebra. Yet, electricity supply is featured by sharp short-run capacity constrains, and also by must-run units with willingness to supply even with negative prices. While the linear model (or, the semi-log specification) ignores such complexities, it captures the monthly supply behavior, first, consistently (we can test its consistency) and, second, without significant deviations from more structured supply representations.[29] We show the fitted price and actual price in Fig. 6. What explains

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[27]Some may find it more natural to explain the output by the price. In particular, if one uses in a 2SLS regression demand shifters correlated with the price but not with THERMAL generation costs, this order of presenting variables seems natural. Obviously, reversing the order of variables would not affect the results. For presentation, given that we first estimate the stand-alone policy rules, it is convenient to use equation (2).

[28]See Appendix A for the detailed numbers and the sources of data.

[29]When the supply approaches the maximum installed capacity, the reservation prices for supply

	Dependent variable:
	log(spot)
log(mc)	0.61*** (0.038)
thermal	0.158*** (0.011)
Constant	1.08*** (0.145)
Observations	156
R^2	0.68
Adjusted R^2	0.68

Note: *p<0.1; **p<0.05; ***p<0.01

Table 3: Results on regression of equation (5). Marginal cost measure mc is a function of the input prices (Appendix). The coefficient on Thermal reported per MWh of output. Thermal output is a function of the natural state from the hydro policy estimation. All data: monthly observations.

the performance of the linear model? The aggregation to monthly observations. The monthly supply is not the same concept as the spot bid curves but an aggregate measure suitable for long-term analysis.

4.4 Invariant prices

By the dynamic programming arguments, the hydro policy generates invariant distributions for the state elements through $P(\mathbf{s}_{t+1}|\mathbf{s}_t, a(\mathbf{s}_t)) = P(\mathbf{s}_{t+1}|\mathbf{s}_t)$. Output allocations and thereby prices are given by the invariant distribution. In addition, the price distribution depends on the cost shifters, entering through mc_t, with contribution estimated

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are rising steeply. On the hand, even negative reservation prices are possible when temporary plant shutdowns are costly. We can put more structure on the estimated reservation prices for supply by bringing in information on the maximum available capacity in each month. We took this constraint from data as the historical observed maximum output in a month, denoted as Q_t^{max}. We then took a Gaussian form for the bid price fitting of condensing power:

$$q^{TH}(\mathbf{s}_t) = \Phi(p_t, \mu_t, \sigma_t)Q_t^{max}$$

$$q^{TH}(\mathbf{s}_t) = \frac{1}{2}\Big[1 + \frac{1}{\sigma_t\sqrt{2\pi}}\int_{-\infty}^{p_t} \exp\big(\frac{x - \mu_t^j}{\sqrt{2}\sigma_t^j}\big)dx\Big]Q_t^{max} \Rightarrow p_t = \mu_t + \sqrt{2}\sigma_t\,\mathrm{erf}^{-1}\Big(\frac{2q^{cond}}{Q_t^{max}} - 1\Big)$$

The mean price is taken to be linear in the measure of condensing marginal costs:

$$\mu_t = \alpha_0 + \alpha_1 mc_t.$$

We then estimated parameters $(\alpha_0, \alpha_1, \sigma_t)$ yielding the best maximum likelihood fit. The resulting fit is almost identical to the one produced by the simpler semi-log form. For the results that follow, the differences between the specifications are not material.
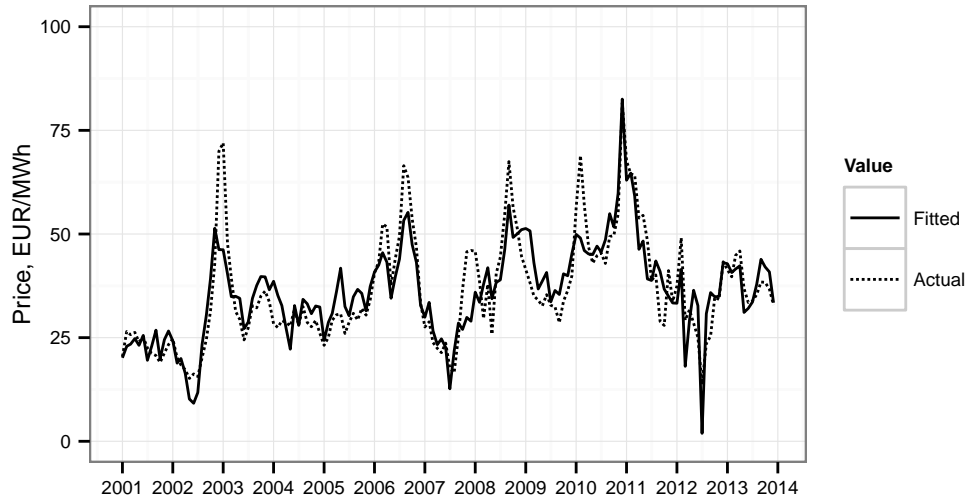
Figure 6: Actual and the fitted price from equation (**??**).

above. Given the marginal costs (and the input prices), the invariant prices follow from the primitives for the elements in the natural state (seasons, hydrological conditions, and temperature). The price distribution is the basis for the quantitative assessment of the impact of renewable energy entry. Before this analysis, we look at the seasonal pattern of invariant output prices.
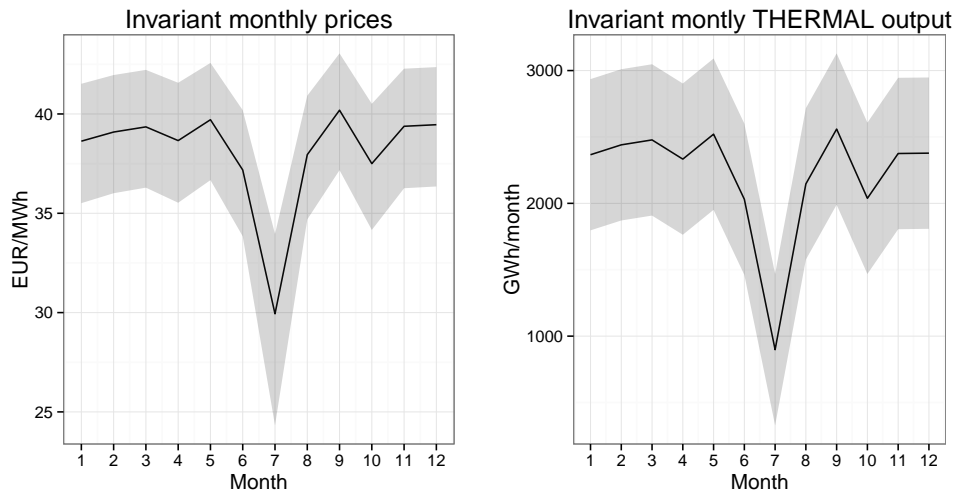

Figure 7: The invariant monthly mean prices (2010 EUR/MWh) and monthly meanTHER-
MAL outputs (GWh/month), and their respective 95 confidence intervals.

In Fig. 7, the right hand panel depicts the monthly invariant outputs of the price sensitive capacity THERMAL (mean values and the 95 per cent confidence intervals); the

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left hand panel shows the corresponding monthly output prices.[30] As expected, prices and quantities are images of each other. The precise price level depends on the marginal costs and thus on the input prices assumed; here, we set the fuel price and carbon emission allowance prices to their Feb. 2015 level.

To road-test the expected seasonal price as captured by the invariant distribution, we can evaluate if they match well the price expectations in the market as captured by the long-run term financial contracts for seasonal prices. The model prices capture well the seasonal pattern in the contract data; see Appendix B for the analysis. The seasonality of prices is strongly shaped by the storage dynamics, and also by storage constraints: in the absence of capacity constraints in storing the commodity, the invariant prices should not fall during periods of expected storage. In Appendix C, we find evidence for seasonal storage constraints from the estimated price-storage curve (Deaton and Laroque, 1992; Williams and Wright, 1989). The seasonal pattern has implications for WIND. The WIND profile implies larger generation in the Fall and Winter where THERMAL reaches its annual peaks (see Fig. 7). Thus, WIND enters proportionally more in the seasons where it has the greatest potential for replacing the marginal (price-setting) capacity. However, WIND in the Summer exacerbates the hydro power storage capacity constraints in states of high availability: WIND in contrast with THERMAL, is not responsive in states with over-supply.

5   Analysis of the rent transfer

With the invariant distribution of prices and outputs, the impact of scaling WIND on producers' surpluses by technology and consumers' surpluses by region can be quantified. The analysis builds on the following premises:

I. Installed capacity, other than WIND, remains stable. This is what has been implicitly assumed by the empirical strategy for recovering the policies and prices.[31] The analysis measures the pressure on the existing assets. The measured consumers'

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[30]We obtain THERMAL output from the policy regression explained in Section 4.2, using historical mean values for the explanatory variables. The confidence interval for outputs follows from that regression directly. The mean invariant price is the price implied by the output from the THERMAL policy, using the estimated supply curve from Section 4.3. The confidence interval for prices is obtained by applying the supply estimates at the confidence bounds for the policy estimates.

[31]The assumption is more or less correct for hydro, nuclear, and condensing power. WIND has a historical rate of increase equal to one per cent per month (Table 9 in Appendix A.3); however, the wind capacity added during the data period for empirical analysis has been still small in comparison with the

surplus change will be smaller if inframarginal productive assets exit because of WIND expansion.[32]

II. THERMAL output must respond, on average, one-to-one to *permanent* increases in WIND. This premise captures the long-run nature of the analysis. If there is short-run temporary reduction in demand for all existing capacity units, the response is shared between HYDRO and THERMAL as captured by the estimated policies. If there is a permanent reduction in demand for these capacities, HYDRO cannot response by permanently saving inflows.[33] By equation (1), all the other technologies are non-responsive.

III. WIND generation in all scenarios follows the estimated monthly pattern (see Table 9 Appendix A and Fig. 8 below). The pattern seems stable; in the counterfactual analysis, we allocate any given increase of WIND over the year according to the estimated monthly profile. Note that the entry profile of WIND over the year is important for the evaluation because of the strong seasonality of prices; see Section 4.4.

IV. WIND scenarios 0-50TWh of annual generation. The benchmark is the current capacity that implies 20 TWh of WIND generation per year.[34] In the experiments, we adjust the annual WIND to reflect the change in capacity underway. TEM (2012) has compiled, from various sources, the estimated increase for the total WIND in the Nordic countries: 29 TWh in 2015 and 48 TWh in 2020. Thus, we take 50 TWh as the upper bound for the WIND increase. We vary the level of the annual WIND between 0-50 TWh to capture six scenarios. The permanent price reduction implied by the current 20 TWh is the main case; considering 0 TWh provides a benchmark for evaluating the change in the market that has already taken place. Scenarios 30-50 TWh are related to the forthcoming projects in the pipeline. While the Nordic market is conducive to intermittent renewable energy, a sufficient increase in its share can make the counterfactual analysis unsound if the

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total capacity, currently ca. 20 TWh of the total 400 TWh. See also Fig. 8 for the historical WIND generation pattern.

[32]The assets that become stranded since output price falls below marginal costs have no effect on the surplus evaluation, provided the assets have no other social value.

[33]If WIND leads to spilling of water, the total availability of hydro over time is reduced. Spilling is regulated activity in the Nordic countries; see Kauppi (2009).

[34]The average annual output has been 17 TWh over the years 2010-2013.

current price-setting capacity is fully replaced. 50 TWh increase comes close that limit.
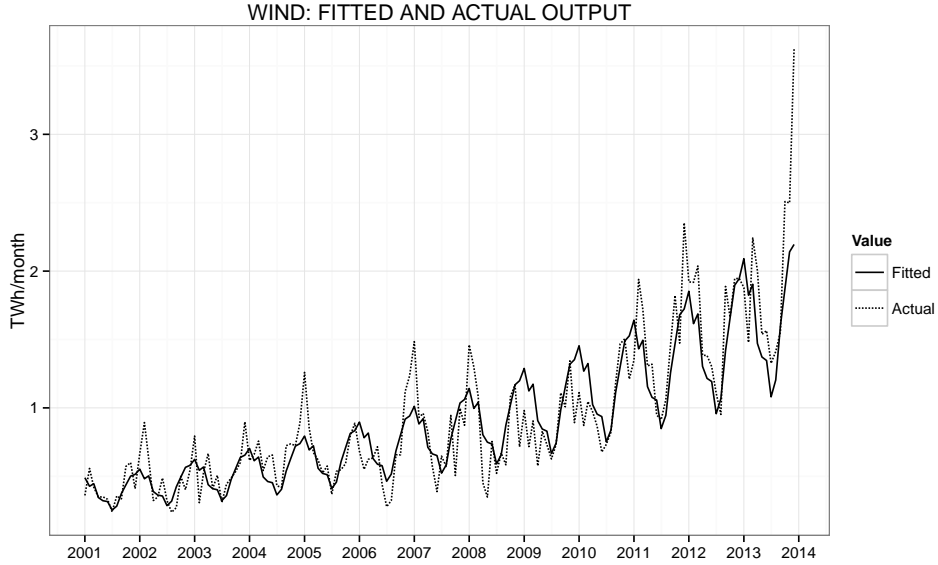

Figure 8: Mean monthly WIND output and the output fitted from the regression on month dummies and growth trend.

5.1 Consumer surplus

Considering the current 20 TWh addition of WIND, we evaluate that consumers in the Nordic countries spend 14.8 billion euros annually on the wholesale electricity (Table 4). This estimate is obtained from the annual consumption profile and the invariant price estimate for 20 TWh; the confidence interval $[13517, 15941]$ reflects the monthly price as depicted in Fig 7. The annual consumptions are relatively stable so that the variation in the consumptions contributes little to the range of expenditures (see Figs. 11 and 12 in Appendix A).

The current WIND has reduced the invariant expenditures by 3.4 billion euros per year: the counterfactual without WIND increases the electricity market expenditures to 18.18 billion euros. For magnitudes, the Nordic region spends ca. one per cent of the GDP on procuring wholesale electricity.[35] The total cost estimate falls for the first 10 TWh increments by less than 2 billion euros but the last increment takes the cost down by more than 3 billion. However, the numbers in this extreme case should be interpreted

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[35] The GDP share of electricity cost is considerably lower Denmark but higher in Finland.

with caution. As shown below, 50 TWh increase in WIND replaces THERMAL close to fully; such an increase in WIND is expected to happen but this may change the supply reservation prices from the estimated.

TWh WIND	low estimate	mean	high estimate
0	16,906	18,180	19,330
10	15,223	16,497	17,647
20	13,517	14,791	15,941
30	11,562	12,836	13,986
40	8,682	9,956	11,106
50	4,530	5,804	6,954

Table 4: Total annual invariant electricity market expenditures in the Nordic countries in millions of 2010 euros for Terawatt-hours WIND generated. Low and high estimates from the 95 per cent confidence interval (invariant distribution).

The savings in expenditures are shared between the countries in proportion to consumptions.[36] Majority of the new WIND locates in Sweden which, as the largest economy, is the biggest consumer. Consumers in Norway are large beneficiaries as well, but the loss in HYDRO asset values is by factor two larger, as is demonstrated shortly. The regional expenditures are in Table 5.

TWh WIND	0	10	20	30	40	50
DEN	1,654	1,501	1,346	1,168	906	528
FIN	3,956	3,590	3,218	2,793	2,166	1,263
NOR	5,787	5,251	4,708	4,086	3,169	1,847
SWE	6,783	6,155	5,518	4,789	3,714	2,165
Total	18,180	16,497	14,790	12,836	9,955	5,803

Table 5: Annual invariant electricity market expenditures by country in millions of 2010 euros for Terawatt-hours WIND generated. Mean values reported.

To obtain a measure for the consumers' willingness to pay, we take the expenditure reduction and divide it by the cumulative addition of WIND (Table 6). This number measures how much consumers could subsidize every MWh generated by the new technologies without net budgetary implications. Given the existing rents in the system and the rent extraction property of the entry, the willingness to pay exceeds the price of the output generated. Yet, it is surprising by how much: the Nordic consumers should be willing to pay close to 170 euros per MWh of new generation for the first 10 TWh

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[36]Consumptions by country are shown in Fig. 12, Appendix A.

increment; at the current WIND generation levels, the willingness to pay exceeds the market prices by factor of two. How large are the gains in comparison with the actual subsidies paid? The subsidies vary by country and over time. Sweden implements a subsidy scheme based on "green certificates"; each MWh renewable energy generated produces a certificate that can be sold to non-green producers. The cost is thus not collected directly from consumers. In 2003-2013, the certificate price has fluctuated between 20 and 30 €/MWh (Fridolfsson and Tangerås, 2013). In Finland, the feed-in tariff price is currently at 83 €/MWh but scheduled to decline. For comparison, in Finland, the levelized-cost estimates for a new nuclear power plant is estimated at 50 €/MWh (TEM 2012).[37] The total consumer side gains per MWh WIND entry in each country are obtained by sharing the gains in proportion to consumptions in Table 6.

TWh WIND	10	20	30	40	50
DEN	15	8	6	7	8
FIN	37	19	14	16	18
NOR	54	27	21	23	26
SWE	63	32	24	27	31
Total	168	85	65	72	83

Table 6: Consumer-side willingness to pay for MWh of wind generation: annual expenditure reduction (in 2010 euros) divided by the cumulative addition of wind generation (MWh), start from zero. Mean values reported.

5.2 Producer surplus by technology

We look next at the technologies whose losses present a mirror image of the consumer side gains.[38] HYDRO presents about 50 per cent of output on average, with ca. 10 billion of annual invariant revenue. The current WIND has lowered prices by about 20 per cent, leading to a direct HYDRO loss of the same magnitude (Table 7). The near-term WIND projects in the pipeline imply 6-7 billion annual loss of HYDRO rents. Interestingly, the assets that suffer most have the lowest risk of exit. NUCLEAR is a must-run capacity, which is also likely to lose at least half of its revenue. THERMAL units become idle after 50 TWh of annual WIND generation. Given the focus on the long-run price level

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[37]This number is perhaps more than an estimate: the new plant under consideration is a cooperative that has pledged to deliver electricity at cost, 50 €/MWh, to the members.

[38]There is a slight difference in the producer and consumer side numbers due to trade with other regions.

and surplus-sharing implications, our analysis cannot shed light on the potential reserve capacity value of THERMAL units – the analysis shows that THERMAL units cannot receive a compensation in the wholesale market.

	0	10	20	30	40	50
HYDRO	10,081	9,151	8,207	7,125	5,527	3,246
NUCLEAR	4,005	3,637	3,262	2,833	2,197	1,299
CHP	2,334	2,110	1,885	1,628	1,248	678
THERMAL	2,200	1,569	1,025	561	191	0
WIND	0	429	768	999	1,031	742
Total	18,620	16,896	15,147	13,146	10,194	5,944

Table 7: Annual invariant electricity market revenues losses by technology in millions of 2010 euros for Terawatt-hours WIND generated. Mean values reported.

Similarly as for the consumer side, we can consider the producers' willingness to pay for not having WIND: divide the loss of revenue by the cumulative addition of WIND generation (Table 8). Alternative interpretation of the number is that it gives the euros of rent extracted from producers per MWh of additional WIND. The number is particularly insightful if we look at it by technology. For example, for the first increment of WIND (10 TWh), HYDRO producers lose 93 euros for each WIND MWh.

	10	20	30	40	50
Hydro	93	47	36	40	46
Nuclear	37	19	14	16	18
CHP	22	11	9	10	11
Condense	63	27	15	9	4
Wind	-43	-17	-8	-1	6
Total	172	87	67	74	85

Table 8: Rent extraction per MWh of wind generation by technology: annual reduction in revenues (2010 euros) divided by the cumulative addition of wind generation (MWh), start from zero. Mean values reported.

6 Conclusions

Why should we subsidize the renewable generation technologies, instead of placing an appropriate price on carbon? The primary argument has been that such carbon prices are not in place, and that, due to learning and other spillover effects, the price instruments

may not provide enough incentives for entry (Joskow, 2011). In this paper, we considered the "forced" renewable entry from a new perspective: what is the effect of renewables on the final incidence of the climate policy costs? The emerging literature not looked at this issue but, rather, focused on identifying the social cost of renewables, paying due attention to the property that renewables generate intermittent output that can vary widely from hour to hour (Joskow, 2011; Gowrisankaran et al., 2015). We know of no empirical study looking at the longer-term surplus sharing, after the renewable energy entry, although there is a heated popular debate on the cost of the energy transition.

The cost incidence matters for the overall climate policy architecture. If carbon costs are passed on to consumers (including industries), the optimal policy should differentiate the tax across sectors that are differently exposed to competition from regions without climate policies (Hoel, 1996). In a similar vein, subsidies vs. carbon prices as climate policy instruments differentiate the cost of carbon emissions. Under subsidies the incidence falls on incumbent electricity producers, if there are pre-existing rents in the market; with prices on carbon, the cost is passed on to the consumer side (Fabra and Reguant, 2014). Since electricity production is does not face global competition, the carbon cost differentiation argument favors subsidies.[39]

We have quantified the incidence problem in the Nordic market where (i) there is a large current share for renewable energy, (ii) the shorter-term intermittency costs are arguably low relative to other electricity markets, and (iii) there are large pre-existing rents enjoyed by owners of assest with superior qualities. The core assets in the market cannot easily exit or relocate, and thereby evade the tax on their rents.[40] These features allow us to quantify the renewable energy rent transfer using on empirical strategy that exploits renewable energy variation and other natural variation in the past; the results are based on real past generation decisions, rather than on simulations. The main result is that a relatively modest expansion of generation in renewable energy generation, still less than 10-12 per cent of the total load, lowers the gross consumer expenditure by 15-20 per cent. The cost-savings justify a cost-neutral subsidy of 50 €per MWh of new generation, a number not far fro the current Nordic subsidy levels.

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[39]Note that sufficiently high carbon prices should induce entry of renewables so that the final market outcome is the same as with subsidies. However, in markets, entrants can be compensated only through market prices that consumers pay so that the transitory consumer cost is very different under the two regimes.

[40]Of course, the trading institution can fall apart, or the trading areas can be reorganized to protect the assets that are under pressure — a natural follow-up of our analysis is to elaborate how enhanced linkages to other market areas might change the results.

The purpose of the current study is not to argue that climate policies should be primarily used to appropriate the existing asset values in the electricity markets. Yet, by definition, assets must become stranded, for the policy to have an impact. As shown in this paper, the pressure can also be on carbon free units, which can lead to unwanted consequences for the ultimate climate policy objectives. Informed policy choices are predicated on a solid quantification of impacts.

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APPENDICES

A   Appendix: data

Data used together with the code for replicating the results can be uploaded from: `https://www.dropbox.com/sh/bel0c8pe14wq5fq/AABWSG-pjj_iMDd5EmaXdGIca?dl=0`

A.1   Data sources

We have used the following sources of data:

1. DENMARK: Energinet.dk, the Danish Transmission System Operator (TSO)
   `http://www.energinet.dk/en/el/engrosmarked/udtraek-af-markedsdata/Sider/default.aspx`

2. FINLAND: The Finnish Energy Industries
   `http://energia.fi/tilastot/sahkon-kuukausitilastot-2014-2015`

3. NORWAY: Statistics Norway
   `https://www.ssb.no/en/energi-og-industri/statistikker/elektrisitet/maaned/`

4. SWEDEN: Statistics Sweden
   `http://www.scb.se/sv_/Hitta-statistik/Statistik-efter-amne/Energi/Tillforsel-och-Manatlig-elstatistik/`

5. NORD POOL: Nord Pool Spot AS, the Power Exchange
   `https://www.nordpoolspot.com/globalassets/download-center/power-data-services/outline-nord-pool-spot-ftp-server.pdf`

6. EUROPEAN CLIMATE ASSESSMENT & DATASET (ECA&D)
   file created on 13-01-2015. Klein Tank, A.M.G. and Coauthors, 2002. Daily dataset of 20th-century surface air temperature and precipitation series for the European Climate Assessment. Int. J. of Climatol., 22, 1441-1453. Data and metadata available: `http://www.ecad.eu`

7. THE FINNISH METEOROLOGICAL INSTITUTE
   `http://ilmatieteenlaitos.fi/c/document_library/get_file?uuid=827685fa-942d-4727-a` `groupId=30106`

8. European Energy Exchange AG

DATA PERIOD: 2001-2013

The maximum time period for which the full data is available at the time of writing.

A.2 Data quality

All output data in the analysis is at the monthly level, and all data has been corrected to 30 day months to remove the variations caused by shorter (e.g. February) and longer months. We also correct for the number of working days within a month. Electricity demand is higher during the working days (Mon-Fri) than during weekends and public holidays.

A.3 Supply

Equation 1 in the text provides the breakdown of output by technology, reproduced here

$$TOTAL.DEMAND = HYDRO + THERMAL + WIND + CHP + NUCLEAR.$$

HYDRO, WIND, and NUCLEAR is complied from data sources 1-4. Combined Heat and Power (CHP) reported in statistics 1-4 is divided into two categories: CHP for district heating and CHP for industrial processes. CHP generation is run against heat load, but in some CHP systems there is a possibility to adjust the amount of power generated to some extent. In industrial CHP plants these possibilities are more limited. However, in district heating, there are typically several plants available for heat generation and a few CHP plants. This allows the district heating system operators to adjust, to some extent, the amount of power generated on the basis of electricity prices. While the exact capabilities are distributed to tens of individual networks, we can separate the heat load or temperature-driven CHP (CHP TEMP) and market-driven CHP (CHP PRICE). The former category constitutes CHP; the latter is classified as THERMAL that can respond to market prices. We run the following regression:

$$ln(CHP.TOTAL) = ln(CONS.WEIGHT.HDD) + TREND$$

where the log of total CHP production is regressed on CONS.WEIGHT.HDD that is defined as the weighted average of HEATING DEGREE DAYS (HDD) for the capital cities in the Nordic countries, where weights are given by electricity use for residential and service customers (average 2003-2012). HDDs are calculated according to the guidelines in the data source number 7. The fitted values of the regression are shown in Fig. 9: this

temperature-driven portion of the total CHP is defined as CHP. The remainder is added to THERMAL.
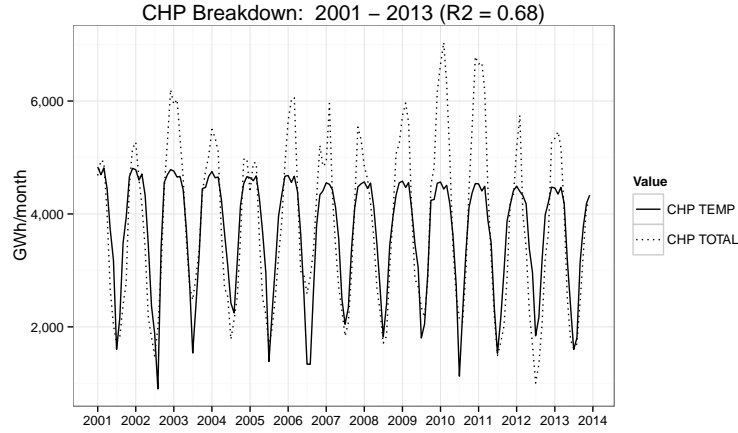

Figure 9: Total CHP and temperature driven CHP outputs in 2001-2013.

Panel in Fig. 10 shows the monthly production data by technology. CONDENSING is the power produced with condensing plants; TOTAL CONDENSING includes CHP PRICE. Thus, total THERMAL is CONDENSING+CHP PRICE+TRADE.

WIND output has a predictable seasonal pattern. We regress WIND on seasonal dummies and a exponential trend:

$$ln(WIND) = MONTH.DUMMIES + TREND \qquad (3)$$

Table 9 shows that that the growth rate of wind output has been one per cent per month. Fig 8 depicts the fitted values in absolute scale.

A.4 Residual demand and total demands by country

RESIDUAL.DEMAND is the sum of total load that the HYDRO and WIND must produce:

$$RESIDUAL.DEMAND = TOTAL.DEMAND$$
$$-WIND - NUCLEAR - CHP.TEMP$$

In Fig. 11, we show TOTAL DEMAND and RESIDUAL DEMAND means per month.
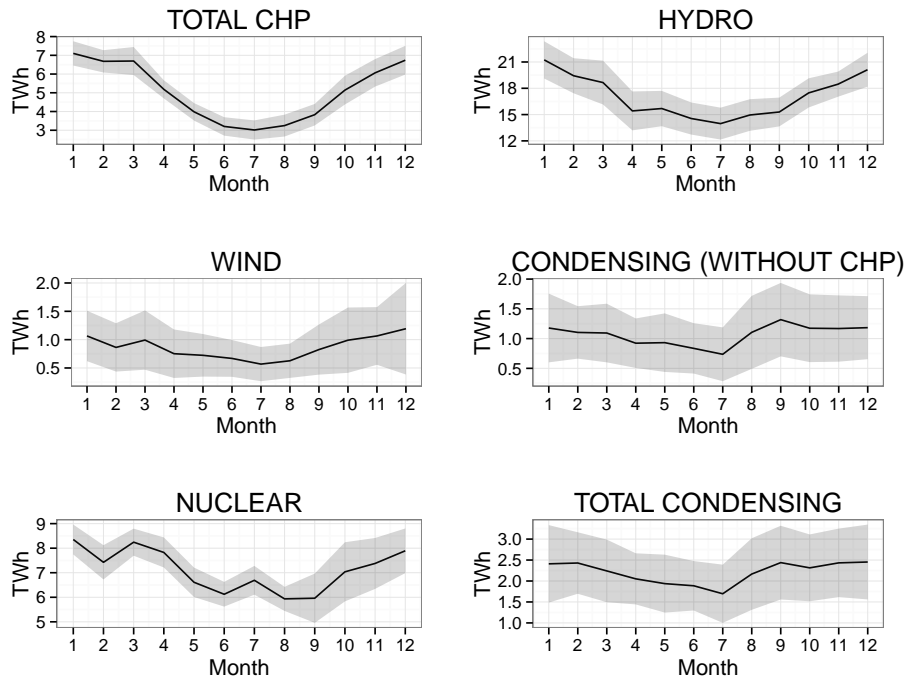
Figure 10: Mean monthly supplies by source and +/- st. dev. bands in 2001-2013. TOTAL CHP= CHP TEMP+CHP PRICE. TOTAL CONDENSING includes CHP PRICE.

	Dependent variable:
	Wind production
trend	0.0095***
Jan	0.0061***
Feb	0.0060***
Mar	0.0060***
Apr	0.0058***
May	0.0057***
Jun	0.0057***
Jul	0.0054***
Aug	0.0055***
Sep	0.0058***
Oct	0.0059***
Nov	0.0061***
Dec	0.0061***
Observations	156
R^2	0.9985
Adjusted R^2	0.9984
Residual Std. Error	0.2687 (df = 143)
F Statistic	7,262.6550*** (df = 13; 143)

Note: *p<0.1; **p<0.05; ***p<0.01

Table 9: WIND regressed on month dummies and trend. Values logs of TWh.

A.5   Costs

Short-run marginal cost (SRMC) depends calculated as follows:
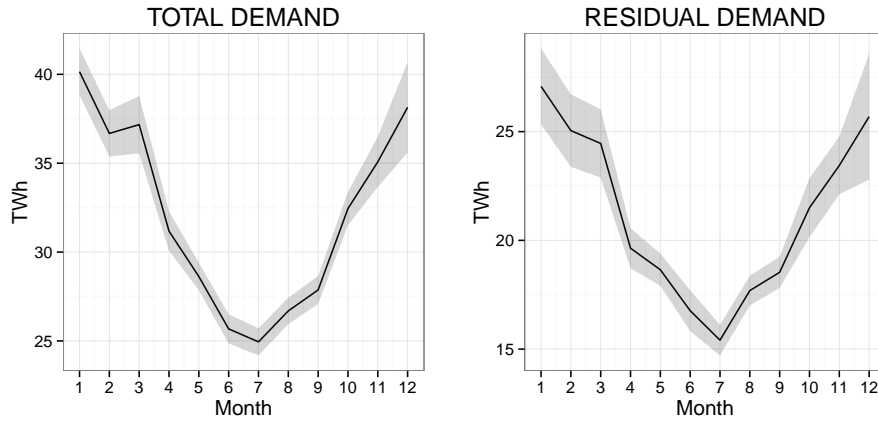
Figure 11: Mean monthly TOTAL and RESIDUAL DEMANDS and +/- st. dev. bands in 2001-2013.
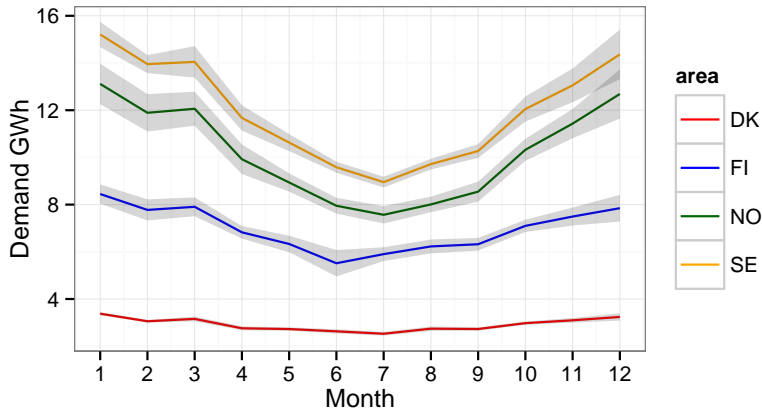

Figure 12: Annual consumption means and st. deviations by month in years 2001-2013.

$$SRMC = \frac{COAL.PRICE + EUETS \times .341}{.36}$$

where EUETS is the emissions trading price (European Energy Exchange AG). Coal emission rate is 0.341 $gCO2/kWh$ (Statistics Finland), and the average power efficiency of condensing power plants is assumed to be 36 % (Statistics Finland). COAL.PRICE is "Consumer Prices of Hard Coal and Natural Gas in Heat Production", monthly average in Finland (Statistics Finland).

B Appendix: Invariant prices vs. seasonal contract prices

We perform a simple road-test of the estimated current invariant prices; we test if the invariant prices match the price expectations in the market. Financial contracts provide one measure of the expectations. Ideally, one would need monthly future prices well-beyond the immediate future so that the current realization of the natural state does not, through storage, strongly correlate with the observed future contract prices.[41] For this purpose, we look at electricity price contracts for quarterly seasons that are traded up to two years from the current date. We look at the contracts for the latter year only, and thereby we leave one "hydrological year" between the pricing of the contract and the date of the contract. These second-year – long-run seasonal contracts – are the best available measure of how the market sees the seasonal pricing in this market.

In Fig. 13, we report the observed quarterly forward prices in year 2017 as of February 2015. The model fit comes from the invariant monthly price distribution, aggregated to four seasons. As before, the natural state elements supporting the prices have their monthly mean values as in historical data; the fuel price costs are assumed to remain at the current the level.[42] The model prices capture well the seasonal pattern in the data. For the quantitative analysis that follows, it is useful to discuss the determinants of the observed seasonal prices – large scale entry of WIND may have implications for seasonal logic of the market.
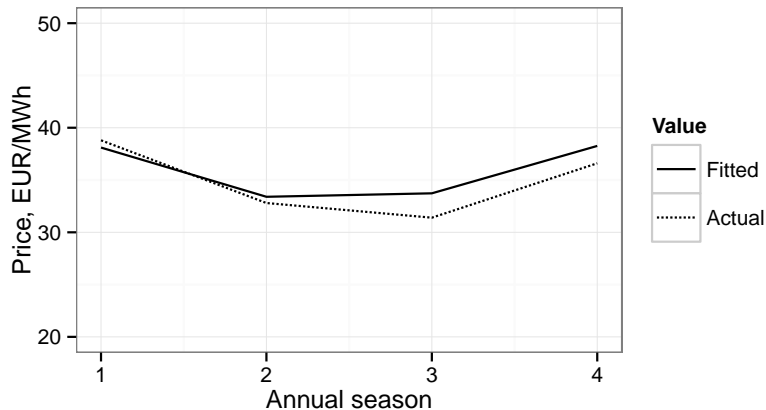

Figure 13: The invariant prices predicted by the estimated model and the quarterly forward prices in 2017 (as of Feb 2015).

The seasonality of prices is strongly shaped by the storage dynamics. The Spring

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[41]The dependence on past shocks is elaborated in Roberts and Schlenkler (2013), in a different context.

[42]The fuel costs merely alter the level of the prices, not the seasonal pattern.

(season 2) is the time for the peak inflow, with reservoirs filling up. Supposing that the Spring is the period of inflow, the producers should allocate the water endowment over the year such that prices increase at the rate of interest towards the next Spring. The price increase is the only source of return for savings as in the Hotelling's resource-use model (1931). But, as seen from Fig. 13, the neither the market or estimated prices are not expected to increase from season 2 to 3. Looking at the inflow data, the market expects significant inflows not only in the Spring but also later: the reservoir capacity can bind during the Fall, preventing storage in some states, which rules out price arbitrage over the seasons. Yet, towards the Winter, the prices are expected to increase between seasons 3 and 4.

C   Appendix: Storage constraints

We can obtain more information on whether storage capacity constraints (reservoir capacity) distort savings in some states of the market. The price-storage curve is a core concept in the theory of competitive storage (Deaton and Laroque, 1992; Williams and Wright, 1989). According to the concept, for low storage levels, the current availability is used for current consumption so that prices follow the static demand curve. For sufficiently large availability, prices and consumed quantities depart from the static demand because speculators or producers demand the good for storage; otherwise, the current price would drop below the expected future price, given discounting and the potential loss if the good is not perfectly storable.

Fig. 14 depicts the estimated relationship between the availability (deviation from the historical mean for the current availability) and the market price, after controlling for the other price shifters (marginal costs of the alternative production). The overall shape of the curve is roughly consistent with the theoretical price-strorage curve, except in states with high availability: the price collapses for high storage levels. We take this as evidence for storage constraints – such a drop in prices should not happen in the absence of constrains.
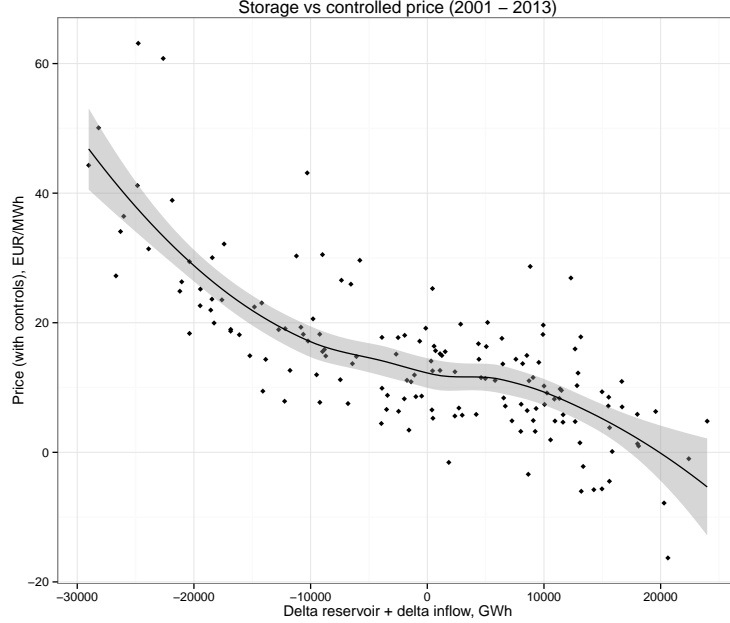
Figure 14: The estimate price-storage curve.

D   Appendix: A model for the policy cost incidence

Here we outline a dynamic model of renewable energy entry to identify the distortions from subsidizing the entry. Time $t \in [0, \infty)$ is a continuous variable but it is first suppressed to describe the demand and supply before entry (Section D.1).

For a sharp case, we consider a very stylized entry model that, however, captures how the entry subsidies distort the first best and also reallocate rents.

D.1   Demand and supply before entry

Consider a market where the quantity demanded is given by a downward sloping and continuously differentiable demand function $D(p)$ where p denotes the price. Let $S(Q)$ denote the inverse supply. It has two distinct segments:

$$S(Q) = \begin{cases} c, & Q \leqslant K \\ c + x, & Q > K. \end{cases}$$

Parameter $c > 0$ denotes the supply reservation price (marginal cost) for the low cost capacity of size K. Parameter $x > 0$ measures the cost disadvantage of the higher cost capacity. We think that capacity K is carbon free while any production $Q - K$ releases one unit of carbon per output. We denote $F = Q - K$ (where F stands for 'fossil'). Also,

$$D(c + x) > K \Rightarrow p = x + c, F > 0.$$

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Further, x includes not only the private cost of the carbon technology but also the social cost of carbon: x is the carbon price. Rent to the carbon free capacity is $(p - c)K = xK$. This rent attracts new entry to the market.

D.2   entry of non-carbon technologies

We assume unlimited mass of potential entrants. Each marginal entrant faces an entry cost I_t at time t per unit of installed capacity. We denote the installed capacity at time t by R_t (where 'R' stands for renewables). Specifically, investment cost evolves according to

$$I_t = I^\infty + \Delta \exp(-\theta t)$$

where $I^\infty > 0$ is the final long-run entry cost and Δ is the cost mark-up over the long-run cost. The cost mark-up declines at rate $\theta > 0$.[43] Once installed the new unit can produce energy for free for unlimited time interval of time. Time discount rate is $\delta > 0$. We assume further assume that

$$\delta I^\infty > c \tag{4}$$

The equality ensures that the new technology cannot replace capacity K in the long-run: the price needed to cover the lowest possible investment cost, $p^\infty = I^\infty / \delta$, assuming that this price prevails forever, exceeds the reservation price for production with capacity K. Below, we make further assumptions to make sure that entry takes place.

D.3   Equilibrium: the first-best allocation

The equilibrium is a path $(p_t, R_t)_{t \geqslant 0}$ such that for all t:

(i) $I_t \geqslant V_t \equiv \int_t^\infty p_\tau \exp(-\delta(\tau - t)) d\tau$

(ii) $D(p_t) = K + R_t + F_t$.

With entry, $dR_t/dt > 0$, condition (i) must hold as equality. For characterization, we first assume a continuous entry path so that $dR_t/dt > 0$ over some interval $[0, T)$ with possibly $T = +\infty$ and then show that the assumption is correct. From (i), $I_t = V_t$ which, when differentiating both sides w.r.t. time, gives

$$-\theta \Delta \exp(-\theta t) = -p_t + \delta V_t.$$

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[43]This is stylized approach to modelling a source of entry friction – it could be extended to include an endogenously development of the technology as a function of the carbon policy. Yet, the partial equilibrium setting here gives some justification for the abstraction.

Differentiating for the second time gives, after substitutions and rearranging,

$$dp_t/dt = \gamma \exp(-\theta t)$$

where $\gamma \equiv -\Delta\theta(\delta + \theta) < 0$. We obtain the price path, conditional on $dR_t/dt > 0$, as

$$p_t = p_0 + \frac{\gamma}{\theta}(1 - \exp(-\theta t)). \tag{5}$$

We assumed $dR_t/dt > 0$ for $[0, T)$ and derived the above price equation from the equilibrium zero-profit condition for entrants. Considering the limit $T \to \infty$, it must be the case that $\lim_{T\to\infty} p_T = \delta I^\infty$: the last entrant must cover its costs. This boundary condition pins down the initial price,

$$p_0 = \Delta(\delta + \theta) + \delta I^\infty$$

and the full price path,

$$p_t = \delta I^\infty + \Delta(\delta + \theta)\exp(-\theta t). \tag{6}$$

It proves useful to define carbon price x as high, moderate, or low relative to the investment costs, respectively:

$$\delta I^\infty - c + \Delta(\delta + \theta) < x \tag{7}$$

$$\delta I^\infty - c < x < \delta I^\infty - c + \Delta(\delta + \theta) \tag{8}$$

$$x < \delta I^\infty - c. \tag{9}$$

Proposition 1 *Let τ measure the time passed since the first entry. For all $\tau > 0$, the equilibrium entry path is continuous with $dR_\tau/d\tau > 0$ and $(p_\tau, R_\tau)_{\tau>0}$ given by*

$$p_\tau = \delta I^\infty + \Delta(\delta + \theta)\exp(-\theta\tau) \tag{10}$$

$$R_\tau = D(p_\tau) - K. \tag{11}$$

The entry is immediate for a high carbon price (7), follows after a waiting period if carbon price is moderate (8), and never takes place for a low carbon price (9).

Proof. Let first entry take place at $t = 0$ (case (7)). There is mass entry: conditions (10)-(11) determine (p_0, R_0) with $p_0 < c + x$ (price drop) and $R_0 > F_0$ (fossil-fuel capacity replaced). The same initial condition determination follows for any other first entry time (case (8). By construction, the last investor at any given t who foresees the equilibrium price path is indifferent between entering or staying out. Since all investors have the same constant returns to scale investment technology, the same conclusion applies to the mass entrants that make the quantity R_t. Again, by construction, all entrants are indifferent at all times. ∎

Remark 1 *The equilibrium path* $(p_t, R_t)_{t \geqslant 0}$ *in Proposition 1 is socially optimal.*

The value V_t measures the marginal social surplus attributable to one marginal unit of capital. Since all entrants receive this surplus as compensation, they invest resources to marginally equate costs and the social value of the investments.

D.4 The rent-extraction path

From now on, we assume that entry starts at $t = 0$, so $\tau = t$, without loss of generality. We consider subsidies to entry, and how they reallocate rents and if they distort the allocation from the first-best. Subsidies can be designed in multiple payoff-equivalent ways; we consider subsidies paid at the investment time:

$$S_t = s\Delta \exp(-\theta t)$$

with $s \in [0, 1]$. This subsidy can be thought of as compensating the investor for accepting a less than mature technology. Thus, the investment cost, net of the subsidy payment, evolves as

$$I(S_t) = I^\infty + \Delta(1 - s)\exp(-\theta t).$$

Proposition 2 *The rent extracted by subsidy policy* S_t *from the installed carbon free capacity* K *at time* t *is*

$$Ks\Delta \exp(-\theta t). \tag{12}$$

Proof. For the impact of the subsidy on the equilibrium path, let $\hat{p}_t$ denote the price path induced by the subsidy policy. By the equilibrium condition $I_t = V_t$ that must hold with and without subsidies, we have a closed form expression for the price impact:

$$\int_t^\infty p_\tau \exp(-\delta(\tau - t))d\tau - \int_t^\infty \hat{p}_\tau \exp(-\delta(\tau - t))d\tau \tag{13}$$

$$= I_t - I(S_t) \tag{14}$$

$$= s\Delta \exp(-\theta t). \tag{15}$$

This gives the amount of rent extracted from the installed carbon free capacity. ∎

What is then the effect on the consumer side, taking into account the subsidy costs?

Proposition 3 *For demand elasticity sufficiently small, the consumer side net gain (=consumption cost gain - subsidy costs) from unit subsidy s is approaches the producer side loss (12).*

Proof. Let $\epsilon_{dp} = \frac{D'(p)p}{D(p)}$ denote the price elasticity of demand. It follows

$$\frac{dR_t}{dt} = D'(p_t)\frac{dp_t}{dt} \Rightarrow \frac{dR_t}{dt} = \epsilon_{dp}\frac{dp_t}{dt}\frac{D(p_t)}{p_t}. \tag{16}$$

Note that (p_t) follows from Proposition 1 and is independent of ϵ_{dp}. Also, since (D, p) are strictly positive and bounded, $\epsilon_{dp} \to 0 \Rightarrow \frac{dR_t}{dt} \to 0$. The total consumer expenditure is

$$W_t = \int_t^\infty D(p_\tau)p_\tau \exp(-\delta(\tau - t))d\tau \tag{17}$$

$$= K\int_t^\infty p_\tau \exp(-\delta(\tau - t))d\tau + \int_t^\infty R_\tau p_\tau \exp(-\delta(\tau - t))d\tau. \tag{18}$$

Let $W(S_t)$ denote the subsidy induced consumer costs. Then, for $\epsilon_{dp} \to 0$,

$$W_t - W(S_t) \tag{19}$$

$$\approx K\int_t^\infty p_\tau \exp(-\delta(\tau - t))d\tau - K\int_t^\infty \hat{p}_\tau \exp(-\delta(\tau - t))d\tau \tag{20}$$

$$= K[I_t - I(S_t)] \tag{21}$$

$$= Ks\Delta \exp(-\theta t). \tag{22}$$

Finally, we need to consider the the subsidy payment flow:

$$S_t\frac{dR_t}{dt} = s\Delta \exp(-\theta t)D'(p_t)\frac{dp_t}{dt} = \epsilon_{dp}\frac{dp_t}{dt}\frac{D(p_t)}{p_t}. \tag{23}$$

Again, $\epsilon_{dp} \to 0$ implies that the subsidy costs vanish.

∎

The result identifies a limit that, by continuity, shows that there is room for rent extraction even with more reasonable descriptions of the demand: the lower is the demand elasticity, the smaller is the quantitative change in R_t that is associated with the equilibrium price path p_t, thereby lowering the subsidy payment. The limiting result also abstracts from adjusting margins that create inefficiencies. First, the allocative inefficiency arises. The expedited investment path distorts cost minimization: the total producer surplus from producing a given demand is strictly larger without subsidies. Second, the subsidies bring the entrants online too early. The expedited investment path distorts consumption if demand is price responsive: consumption path is too front-loaded from the social point of view.