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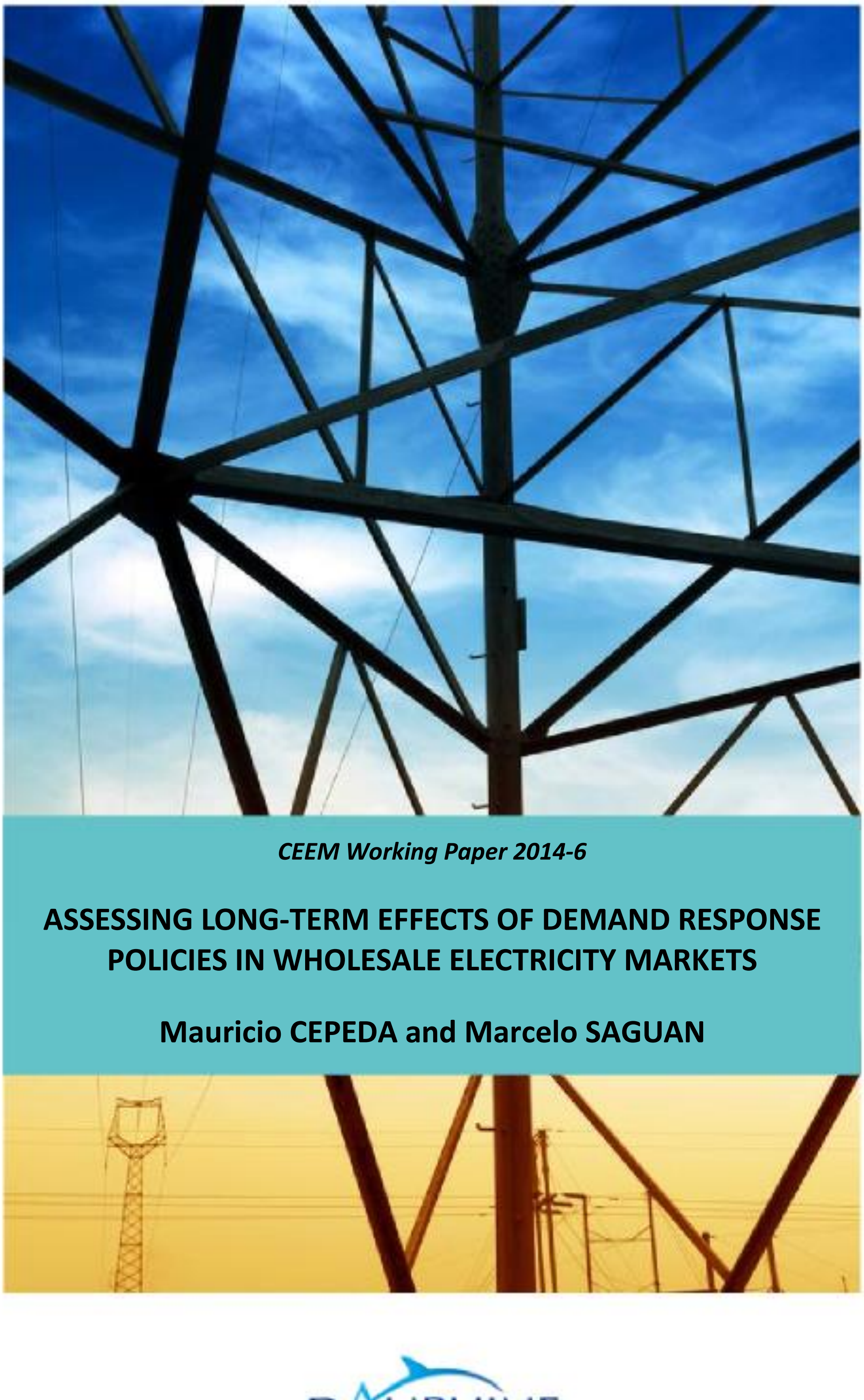

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ASSESSING LONG-TERM EFFECTS OF DEMAND RESPONSE POLICIES IN WHOLESALE ELECTRICITY MARKETS

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Abstract

This paper deals with the practical problems related to long-term issues in electricity markets in the presence of demand response development. Different policies have been implemented around the world aiming to develop demand response potential. Externalities, in particular the CO_2 externality, have been one of the key elements in the debate on the effectiveness of different policies regarding demand response development. Policy makers have several options to deal with this externality. The most direct one is to correct the externality by setting a CO_2 price at a level that corresponds to the cost to society of the corresponding CO_2 emissions. One alternative solution could be to subsidize carbon-free technologies as demand response. In this paper we examine potential long-term impacts of these two policies. We rely on a long-term market simulation model that characterizes expansion decisions in a competitive regime. We test for each policy two different scenarios regarding the possibility of internalization of the CO_2 externality. The results show that differences in development policies affect both investments and social costs in the wholesale electricity market and confirm previous findings that a market-driven development of demand response with the internalization of the CO_2 externality is the most efficient approach.

Key words: demand response, generation investment, market design, wholesale electricity markets.

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1. INTRODUCTION

The energy sector faces unprecedented challenges on environmental sustainability, security of supply and competition. In this context, demand side management presents a large potential which, however, has remained insufficiently addressed (IEA, 2008). Demand Response (DR) refers to the provision of incentives to consumers for optimally managing their electrical consumption (Braithwait et al., 2002). DR has been gaining interest recently, as power systems become more congested and as renewable energy penetration increases. DR deployment may result in significant benefits for power systems by allowing a large participation of final consumers in wholesale electricity markets (Stoft, 2002).

In this context, different programs and policies have been implemented around the world to develop DR potential (Torriti et al., 2009, Pfeifenberger and Hajos, 2011, Conchado and Linares, 2012). These programs have taken different forms depending on the type of approach used to induce DR development, ranging from wholesale market participation and capacity mechanisms to technology-oriented programs and promotion subsidies prioritizing DR among others.

In recent years hot debates about the efficient way to incentivize DR in wholesale markets have taken place in different parts of the world (Chao, 2010, Crampes and Léautier, 2012). For example, in the US, these debates have focused on two options to remunerate in the wholesale market the DR actions provided by retail customers: i) paying DR the same wholesale price that generation when demand is reduced or, ii) paying less than the wholesale price to DR, concretely, the wholesale price minus the (generation) rate at which retail customer would have purchased the electricity, had he consumed (LMP-G rule). In March 2011, after two years of strong disputes, FERC (the energy regulator) issued an order (order 745) in favor of the first option (Pierce, 2012). Parties opposed to FERC's action have taken the issue to court (Borlick et al 2012). The debates among energy economist start again.

There is an almost general consensus among energy economists about the inefficiency of the rule chosen by FERC analyzed in a context of a "perfect" world, i.e., in a world without externalities. Indeed, it is economically justified that the retail consumer should receive less than the wholesale price when remunerated for its DR action: retail customer has to buy the energy before selling it back to the market (the term G is indeed the cost of this purchase). If DR is remunerated at the wholesale price, the incentive for its deployment will be too high and, the outcome will consequently be inefficient.

However, energy economists do not agree on the efficiency of the FERC decision in the presence of externalities. The externality that is often mentioned in the debates to justify asymmetrical treatment of DR is the lack of internalization of the social cost of CO_2 emissions[3]. On the one hand, some economists argue that the option chosen by FERC is an inefficient subsidy to DR, distorting markets and investments (Bushnell et al. 2011, Hogan, 2009). For them other measures to tackle CO_2 externalities exist, such as pricing CO_2 emissions. On the other hand, other economists perceived the option selected by FERC as a second-best solution to compensate DR for externalities (Falk, 2010).

The purpose of this paper is to assess the long-term dynamic effects of alternative DR development policies. For this, we rely on a long-term dynamic model of an electricity market which simulates expansion decisions in a market regime and incorporates several DR development policies under different scenarios.

[3] Reducing consumption at peak-load hours may reduce CO_2 emissions by replacing CO_2 emitting generation technologies as gas or coal power plants.

The model is based on Cepeda and Finon (2011) and is expanded to incorporate DR programs and policies. The model has been developed using concepts and tools from system dynamics, which is a branch of control theory applied to economic and management problems. This methodology has been extensively used in electricity market modeling to represent capacity expansion planning in wholesale markets (Forrester, 1961; Bunn and Larsen, 1992; Ford, 1997, 1999; de Vries and Heijen, 2008).

In this paper, we study three different cases of DR development: (1) one driven by the market in presence of the CO_2 externality (reference case); (2) a second driven by specific subsidies for DR in presence of the CO_2 externality; and (3) the third driven by the market and with internalization of the CO_2 externality. The purpose here is to compare over time the dynamic evolutions in an electricity market for these different cases, assessing the economic performances of different policies (e.g. the evolution of generation technology mix, the amount of CO_2 emissions associated with electricity generation and the overall social cost).

The paper is organized as follow. In section II, the question about the CO_2 externality and the DR development policy in a long-term perspective is examined. In section III the long-term dynamic model is presented and in section IV preliminary results are discussed. In section V, concluding remarks and policy implications close the paper, highlighting pros and cons of different policy options and discussing possible further work.

2. DR DEVELOPMENT POLICIES, CO2 EXTERNALITY AND LONG-TERM IIMPACTS ON ELECTRICITY MARKETS

Long-term impacts of DR policies and the CO_2 externality on electricity markets can be analyzed using screening curves. This section introduces the question discussed in the paper and gives economic intuitions using this standard method commonly used in electricity generation investment analysis.

2.1. Analysing generation long-term equilibrium using screening curves

The screening curve of a thermal power plant is defined as the average cost of using the plant's capacity. The mathematical formulation is given by:

$$ACC = FC + \alpha VC \tag{1}$$

where *ACC* is the *Average Capacity Cost* (€/MWh), *FC* is the fixed cost (€/MWh), α is the capacity factor of the plant ($0<\alpha<1$) and *VC* is the variable cost of the plant. The fixed cost may be expressed as:

$$FC = \frac{r\,.OC}{1-(1+r)^{-T}}\, 8760 \tag{2}$$

where *OC* is the overnight cost of the plant, in (€/MW), *r* the discount rate (in per unit per year), *T* is the life of the plant (in years). The variable costs are mainly the fuel cost (fc, in €/MWh) of the thermal plant, corrected by the CO_2 emission rate (er, in tons of CO_2/MWh) and the CO_2 externality value (V_{CO2}, in €/tons of CO_2) if the externality is priced:

$$VC = fc + er.V_{CO2} \tag{3}$$

According to its screening curves, a power plant may be classified as peak-, middle- or base-load. Base-load units have the highest fixed costs, and the lowest variable costs, while peak-load units have usually the lowest fixed costs and the highest variable costs. Load rationing could be also included in the screening curve, with no fixed costs and with very high variable costs, which would be the value of lost load (VOLL).

Examples of screening curves for base-load units (yellow line), peak-load units (blue line) and load rationing (red line) are shown in Figure 1. The horizontal axis measures the (annual) capacity factor and is normalized to 1. The fixed cost is represented by the interception with the vertical axis whereas the variable cost gives the slope of each curve.

By comparing the different screening curves it is possible to determine capacity factor segments (or a number of hours that at technology should generate) where a technology is cheaper than other. From the Figure 1, interception of screening curves indicates where peak capacity is cheaper than base-load capacity (yellow and blue lines) and where rationing is costs less than building peak units (blue and red lines). Combining these results with load-duration curve data (black line), it is possible to determine the optimal capacity for each technology, i.e., the capacity that ensures minimal total cost. Load duration curves indicate the amount of time that the load has been higher than a given value. In Figure 1 the duration has been normalized to 1 (horizontal axis). Optimal capacities determined using this graphical method corresponds to generation capacities that would result in the long-run in a perfectly competitive power system, i.e., a long-term equilibrium under perfect competition.

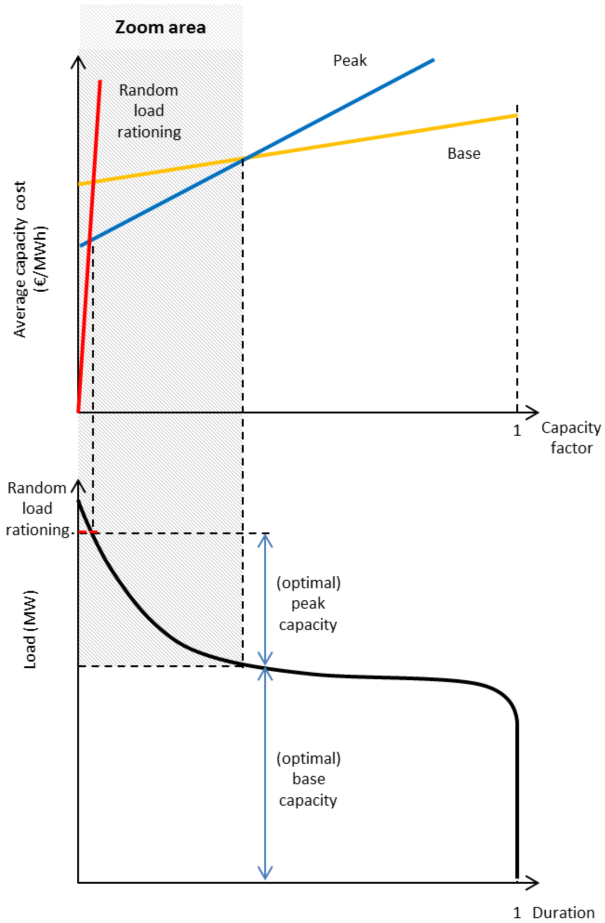

Figure 1. Screening curves and long-term equilibrium

We will now analyze the impact of DR on the long-term equilibrium, using this method. For clarity, we truncate at the "peak area" of the screening curves (grey zoom area) and we do not consider the base-load capacity in the following analysis.

2.2. The impact of DR on long-term equilibrium in a perfect world (without CO2 externality)

Demand response can be seen as a new technology in the screening curve diagram. Figure 2 shows an example of what could be the impact on the long-term equilibrium considering this new technology, i.e., what would be the new equilibrium and how optimal capacities would be modified.

We plot the screening curve of DR (green line) considering that demand response has a lower fixed cost than peak technology but a higher variable cost. Why do we introduce a linear cost function for the DR with this highest variable cost and lower fixed cost? We consider that the DR would run as if fictitious DR aggregators act for the sake of a benevolent planner. For that, they agree to act in a converse sense than the sense of a normal trade-off. They arbitrate between the very high prices during peak and extreme peak periods, and the lower price during middle-load periods to which some hourly consumption of the former periods are shifted by the DR load shaving. DR aggregators buy a number of MWh to some consumers at the spike prices, which are higher than the marginal cost of combustion turbines which are the last generators called by the market, to re-sell the same quantity (or less) at a much lower price. They contribute by this way to the long term social efficiency of the electricity market after having invested in DR programs.

From the figure 2, it can be seen that DR can reduce total cost because it is cheaper than peak technology for a certain segment of capacity factors (efficiency gains are represented by the dark grey area). As a result, the new long-term equilibrium includes DR capacity and less peak capacity. These are optimal capacities and they ensure in theory that the social cost (including the cost of loss of load) is minimized[4].

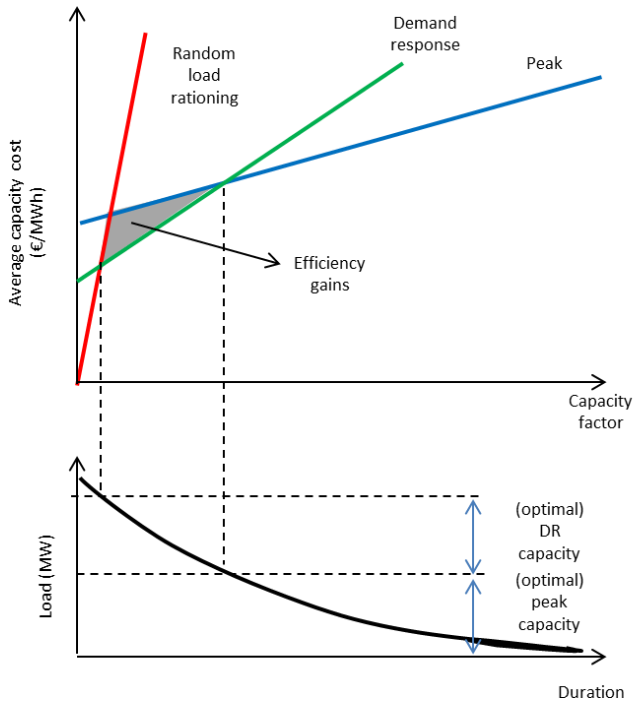

Figure 2. DR impact on long-term equilibrium without CO_2 externality

[4] It is important to emphasize that consumers can be eventually equipped with back-up systems (for safety reasons) which are often poorly efficient and high emitters of CO_2.In this case, it would not be social efficiently to set an incentive on DR including an *ex ante* "CO_2 free" remuneration which would be in fact a CO_2 emitter reward. We will not consider this case in this paper.

2.3. The impact of DR development on long-term equilibrium in an imperfect world (with CO2 externality)

Now, let us consider the same case as before but including the CO_2 externality. By the CO_2 externality we mean that the emissions of CO_2 are not priced (or are not correctly priced). In other terms the cost for the society of emitting one ton of CO_2 is not (or not fully) internalized by private operators (i.e., fossil fuel producers). We adjust the screening curve of peak technology to analyze this situation. We make the assumption that demand response programs have a combined effectiveness on both power and energy reduction, in the sense that there is no report of consumption from stressed system hours to off-extreme peak-load periods. That means that we suppose that every load shifting would mean demand and CO_2 emissions reductions. Indeed, DR to face peak periods cannot be the only issue when a market player is looking for flexibility. To stimulate the load rather than to shed it during off peak periods, when wind is blowing and / or sun is shining, is also an important issue. It will be more and more the case, quite different from the situations 10 or 20 years ago when we had developed DR approaches.

In fact in an electricity market with a CO_2 externality, the private operator will decide investments with respect to its own cost and not relatively to the overall social cost. Thus, the screening curve for peak technology only considers fuel costs (and no CO_2 cost) as shown in

Figure **3** (dark blue line). The long-term equilibrium in the presence of CO_2 externality leads to lower level of DR capacity than in the optimal situation (Figure 2), and consequently there are economic inefficiencies.

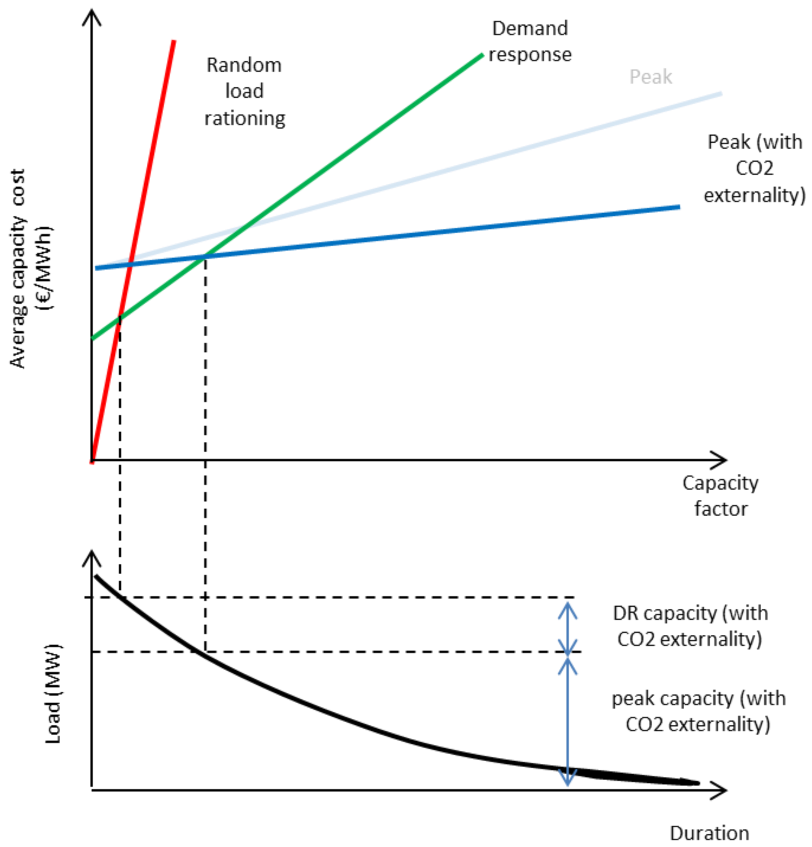

Figure 3. Impact of CO_2 externality on DR development

From this analysis, it could be concluded that subsidizing DR makes sense because in a world with CO_2 externality, DR technology will not develop as much as necessary. Thus, the fact of providing a subsidy to induce incentives for DR development could correct for economic inefficiency. However, this approach could not be the best solution to correct for this inefficiency. Let us assume a situation where a subsidy to DR has been accepted by the public authorities. To determine the optimal level of the subsidy, public authorities should undertake complex computations and have very detailed data (e.g., cost of peak, cost of DR, etc.). In addition, the policy making process can be influenced by lobbies affecting final decision which could result in an oversubsidy. In this case new inefficiencies could appear. Figure 4 illustrates an example in which we represent the impact of a too high capacity subsidy as a reduction on the fixed cost of DR. It can be seen that the resulting level of DR capacity is not optimal, compared with the situation of optimal capacity without CO_2 externality (Figure 2)[5].

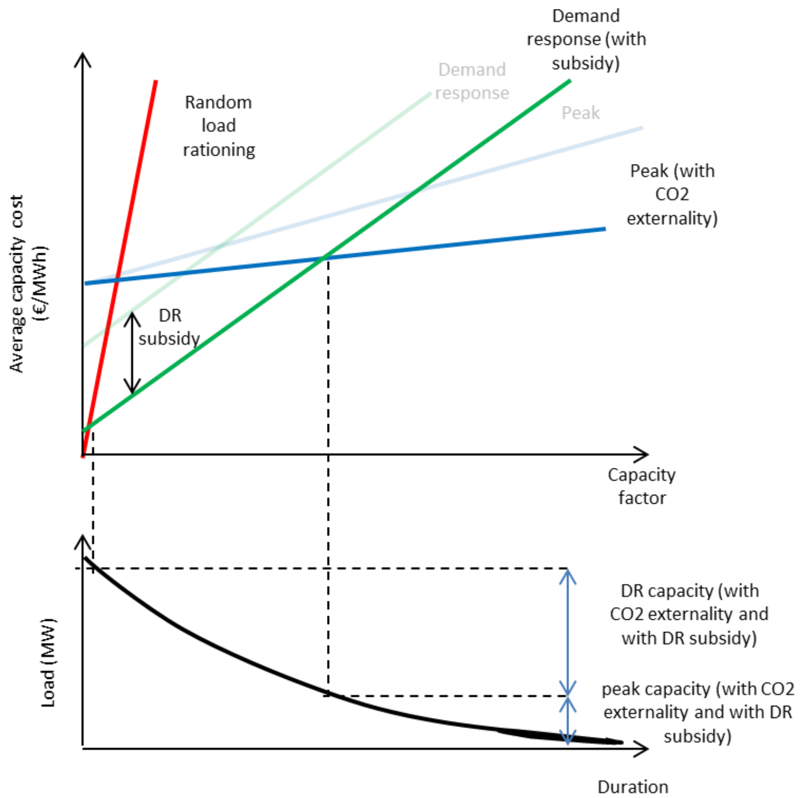

Figure 4. Impact of DR subsidy on the long-term equilibrium

In conclusion, in an imperfect world (with CO_2 externality) policy makers have several options to deal with market failures. The most direct one is to try to correct the externality by attacking its root causes i.e., setting a CO_2 price at a level that corresponds to the cost to society of the corresponding CO_2 emissions. The second solution could be to subsidize carbon-free technologies, in this case, demand response. The long-term impacts of these two kinds of policies are not the same. The rest of the paper is focused on the examination of this question, using a long-term dynamic model that integrates actual complexities of the investment decision process in generation capacity, and analyzing quantitatively through an actual size case study.

[5] A more complex case but resulting in the same kind of inefficiencies would be one where the subsidy is set at the optimal level but is imposed to electricity generators. As generators see their costs increase (by the level of the subsidy) inefficiency would appear anyway because DR will be over incentivized with respect to generation.

3. THE STRUCTURE OF THE MODEL

This section presents the system dynamics model used to simulate the long-term evolution of electricity markets in the presence of DR development. The input variables of the model and the causal relations among them are explained. The different assumptions of the sub-model regarding investment decisions are also detailed. We then proceed to develop the different versions of the model with the purpose of representing different DR development policies.

3.1. Model Overview

The model is based on Cepeda and Finon (2011) and is expanded to incorporate DR development, while preserving the essential elements of the model: thermal generation modelling and its long- and short-term uncertainties (i.e. demand growth rate uncertainty, generation unit outages and load thermo-sensitivity), reliability modelling, anticipation on demand growth and supply in the investment decision process. What is new here concerns the representation of DR as well as its integration into the mechanism of price formation and into the investment decision process. In addition, the representation of the investment decision process is adapted to include DR programs, in particular those with technology-oriented or subsidized design options.

The main relationships included in our modelling of investments in new generation capacity follow the structure of the causal loop diagram depicted in Figure 5. These relationships reflect the way operating and investment decisions are made in the power industry. In the causal loop diagram, causal relationships between two variables, x and y, are identified by arrows. The positive (negative) sign at the end of each arrow can be understood as a small positive change in variable x that provokes a positive (negative) variation on variable y. The double bar crossing an arrow implies a time lag in that relationship. A circle arrow with a sign indicates a positive feedback loop (reinforcement) or a negative feedback loop (balancing).

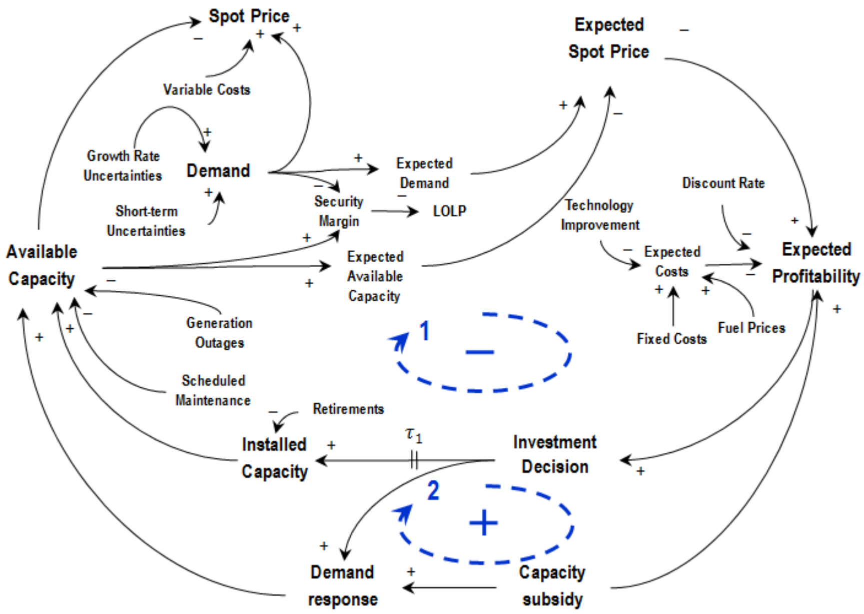

Figure 5. Causal-loop diagram of the electricity market

Two major feedback loops may be observed (showed by the dashed line). The first one is a negative loop, linking installed generation capacity and expected spot prices. It states that as long as installed and available generation capacity increase, expectations regarding future electricity prices go down. As a result, the economic attractiveness of new generation investments is reduced. This feedback loop is considered as a balancing loop that limits the investments in new generation units.

The delay τ_1 refers to the time needed to secure permits and to build generation power plants. The second feedback loop,[6] a positive one, is caused by the interaction between the energy market and technology-oriented subsidy for DR. Expected profitability is determined by expectations of future prices and the level of subsidy for DR. As subsidy increases, expected profitability and generation capacity rise, thus electricity spot prices decrease.

3.2 The representation of the electricity market

The system dynamics model used to simulate the long-term evolution of an electricity market closely follows the formulation in Cepeda and Finon (2011). In this subsection, we provide details of the representation of DR and its integration into the investment decision process. The modelling of the thermal generation, demand curtailment, electricity price formation and reliability are explained thoroughly in Cepeda and Finon (2011).

We model a single type of DR which is assumed to represent the DR aggregated over different customers' categories such as residential, commercial and industrial. The participation of these different classes is not accounted for in this paper, but will be dealt with in future work. In addition, DR is seen in the model as a generation technology[7] with both variable[8] and fixed costs[9]. Under this symmetric treatment[10] where consumption and generation participate directly on the wholesale market, DR resources that clear in the energy market should receive its default price (i.e. marginal cost) for services provided as generation technologies do.

To calculate the electricity price, we assume perfect competition; hence the price is generally settled by the marginal cost of generation, i.e. the variable cost of the marginal technology. If demand exceeds the available generation capacity, the electricity price is equal to the marginal cost of DR. Finally, the electricity price is set at the value of loss of load (VOLL) when the volume of DR is exhausted.

Demand response and investor's behaviour

In the model, investment decisions in new generation capacity and DR technology mainly depend on the expected prices which reflect expected market conditions, which in turn are a function of expected demand and expected generation availability. We model a ''forward merit-order dispatch'' in order to calculate the future electricity prices. We implement a second-order smoothing process to forecast the expected growth rate of demand and the available generation for each technology, using a variant of the procedure adopted by Cepeda and Finon (2011). We calculate these expectations from the built-in function forecasting in MATLAB. It is worth noting that we do not

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[6] Note that in the case of an energy-only market without technology-oriented subsidy for DR the second feedback loop in the causal-loop diagram in Figure 5 does not exist, as DR resources are only driven by electricity prices.

[7] In contrast to the modelling of thermal generation units, we assume that unplanned outages and planned downtime for maintenance activities of DR technology are negligible.

[8] Variable cost of DR represents the cost for the consumer of stopping or modifying its consumption (e.g., comfort or utility losses, overcosts due to changes in industrial process, opportunity cost of activating DR later if frequency is limited, cost of alternative sources of energy, etc.).

[9] Fixed cost of DR represent the cost of installing the necessary equipment in order to activate and measure DR (e.g., special meters and relays, boxes, command controls, software and control rooms, work force, etc.).

[10] Since we consider one type of DR that corresponds to the definition of load shedding, which means a CO_2 free technology with fixed costs, this approach do not differ fundamentally from another hypothetical peak generation technology that would have the same characteristics.

represent strategic behaviours in the model, hence excluding potential market power effects, even though this may be an important issue for the electricity market.

In this paper we abstract from the choice between an energy-only market and one which includes a capacity mechanism, implicitly assuming that the latter (if adopted) would produce the revenues that the idealized energy-only market was supposed to. In an energy-only market, firms' revenues are provided by their sales in the spot market and investment decisions are driven purely by electricity prices. In the theoretical long-run equilibrium, fixed costs of generation capacity are perfectly covered by infra-marginal rent. They are covered by scarcity rent during hours of peak demand, when prices are above the highest marginal cost of generation resource.

Two versions were created to represent different investment behaviours in an energy-only market with two specific cases of DR development: one driven by technology-oriented subsidy, and another by the market.

In the case of a market-driven development of DR, firms invest in DR when the expected profitability is high enough to recover their total costs during the life cycle of this technology. We use a net present value (NPV) analysis to calculate the profitability of a new DR technology standard unit. Since several technologies are available, there could be more than one technology with a positive NPV. A further condition is therefore added in order to select the technology with higher profitability during each specific time-duration. The economic assessment at period τ of a DR capacity investment K_{DR} is formulated as follows:

$$NPV_{DR}^{\tau} = \sum_{\tau'=\tau+T_{DR}^{c}}^{\tau'=\tau+T_{DR}^{c}+T_{DR}^{v}} \left[\left[\sum_{t=1}^{t=T} \left(\hat{p}^{t,\tau'} - VC_{DR} \right) \hat{q}_{DR}^{t,\tau'} \right] (1+r)^{-\tau'} - I_{DR} K_{DR} \right] \ \forall\, \hat{p}^{t,\tau'} > VC_{DR} \qquad (4)$$

where T_{DR}^{c} and T_{DR}^{v} are respectively the construction period and the economic life cycle of the DR technology. $\hat{p}^{t,\tau'}$ is the expected future price for each time step t for the period τ. $\hat{q}_{DR}^{t,\tau'}$ is the expected DR reduction in consumption for the period $\tau + T_{DR}^{c}$. VC_{DR} is the variable cost, r is the discount rate and I_{DR}, the annualised fixed cost of DR in the first year.

In the case of a subsidised development of DR, we assume that DR is subsidized with a payment which amounts to x_{DR}% of the fixed cost of a new standard unit of DR in the model. This subsidy is set exogenously and is supposed to be determined by the regulator and supported by a tariff policy. In this case the economic assessment is formulated as follows:

$$NPV_{DR}^{\tau} = \sum_{\tau'=\tau+T_{DR}^{c}}^{\tau'=\tau+T_{DR}^{c}+T_{DR}^{v}} \left[\left[\sum_{t=1}^{t=T} \left(\hat{p}^{t,\tau'} - VC_{DR} \right) \hat{q}_{DR}^{t,\tau'} \right] (1+r)^{-\tau'} - I_{DR} K_{DR} (1 - x_{DR}) \right] \ \forall\, \hat{p}^{t,\tau'} > VC_{DR} \qquad (5)$$

The economic assessment for the thermal generation technologies, which is strictly conventional is identical to that formulated in Cepeda and Finon (2011).

In addition, two cases were created to represent different situations concerning the CO_2 externality: a case with externality and a case without (i.e., where the externality is completely internalized). In the case in which the CO_2 externality is internalized, we assume for simplicity that the social marginal cost of CO_2 emissions abatement, set exogenously in the model, is equal to the

CO_2 allowance price in a general equilibrium price[11]. In the model this price is fixed and is integrated in the marginal cost of generation technologies.

4. RESULTS

4.1. Simulation data

The model represents a market which holds DR and thermal-generating units with four different technologies including nuclear (N), hard-coal (HC), combined cycle gas turbine (CCGT) and oil-fired combustion turbine (CT). These thermal technologies are characterised by outages and schedule maintenance. The key figures used in our simulations for each power plant and DR resource type are shown in Table 1. Values used here are based on available public data and try to mimic real system characteristics, in particular French ones. The purpose of their use is to illustrate simulations results for real size cases. However, other sets of values can be tested and sensitivity analyses should be realized in the future.

Table 1. Generation data used in simulations

Description \ Technology		**Nuclear**	**Coal**	**Combined cycle**	**Combustion turbine**	**DR**
Generation capacity per unit [MW]		1 630	900	450	175	40
Annualised fixed cost[12] [€ /MW-year]		305 000	205 000	120 000	60 000	30 000
Variable cost [€/MWh]		11	40	75	200	300
CO2 emission factor [tCO2/MWh]		---	0.96	0.36	0.80	---
Variable cost including CO2 externality [€/MWh]		11	74	107	244	300
Amortisation time [year]		40	35	25	25	10
Lead time [year]		6	4	3	2	1
Forced outage Rate		0,042	0,036	0,051	0,041	----
Schedule maintenance [% of installed capacity]	Winter	6%	10%	2%	6%	----
	Spring	29%	33%	12%	23%	----
	Summer	23%	24%	10%	17%	----
	Autumn	16%	19%	7%	13%	----

The level of CO_2 externality is set exogenously at 50 €/t over the simulation period (this level is modified later under the sensitivity analysis).

[11] To model future generation technologies CO_2 emissions costs a CO_2 price model would be necessary, quantifying the relationship between the CO_2 price and the CO_2 emission cap over time (cap-and-trade systems generally reduce the emission cap over time).This approach is out of scope for this paper.

[12] The discount rate is set at 8%.

Electricity demand is characterised by a load-duration curve, which illustrates a cumulative distribution of demand levels over each year during the simulation period, and is derived from data on the French electricity consumption in 2012.[13] We split the load-duration curve (Figure 6) in 40 segments of extreme peak hours, and 40 segments of 218 hours each for the remaining hours (peak, intermediate and off-peak hours). As previously mentioned, we consider two uncertain components affecting demand: its growth rate and thermo-sensitivity.[14] The VOLL is set at 20 000 €/MWh.

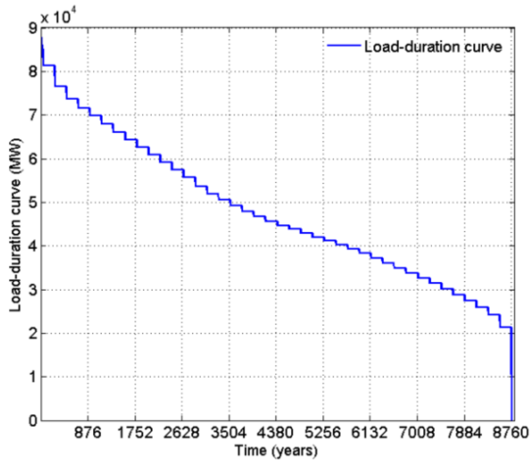


Figure 6. Load-duration curve of the model at the beginning of the simulation period

The resolution time-step of the model is one year, using the simplifying assumption that investment decisions can only be made at the beginning of each year. To test the level of uncertainty, 400 random scenarios, on 30-year period each, are generated through a Monte Carlo simulation method. The presented results correspond to the average results over these 400 random scenarios. The initial generation mix is set corresponding to the theoretically optimal generation (i.e., minimizing total cost using screening curves, only considering variable and fixed costs and load curve). The model has been developed as a set of programmes using MATLAB.

4.2. Results analysis

This section aims to evaluate the investment dynamics in an electricity market in the presence of different drivers of DR development with or without the internalization of the CO_2 externality. The most suitable combination is the one that ensures efficiency in terms of overall social costs. We analyse three different cases:

- ***Case 1(reference case) :*** **Energy-only market with DR development in presence of CO_2 externality.**
- ***Case 2 :*** **Energy-only market with DR development supported by technology-oriented subsidy in presence of CO_2 externality.**
- ***Case 3 :*** **Energy-only market with DR development and with internalization of CO_2 externality.**

Beside the first case that will be used as a reference, two rather extreme cases are tested. Case 2 considers an extreme case in terms of the level of capacity subsidy (75% of the fixed cost of DR). Case 3 considers a complete internalization of CO_2 externalities set at 50€/tCO_2. Considering extremes

[13] See http://www.rte-france.com/
[14] These components are modeled and parameterized as in Cepeda and Finon (2011).

cases is useful to get a first idea of the dynamic effects using two different kinds of policies. In the sensitivity analysis presented in section 4, some intermediary cases are studied.

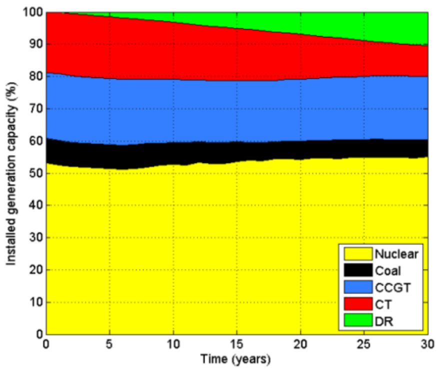
The model provides several types of performance indicators over the 30-year time horizon: installed generation capacity, annual generation investment, generated energy, capacity factors, prices, CO_2 emissions, hours of shortage, security margin and social costs (variable, capacity, CO_2 and shortage). All these indicators give a complete view of the dynamic behavior of the electricity market and of its economic performances. We focus here on three types of indicators. The first one concerns the dynamics of the installed generation capacity mix (in % of total installed capacity).The second one captures the CO_2 emissions over the entire simulation period. The last indicator is related to the social costs for each case.

1) **Installed generation capacity**

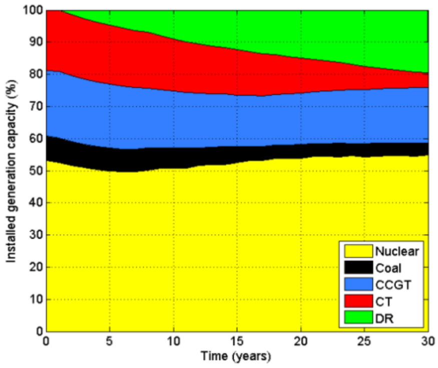
Figure 7 shows installed generation capacity evolution (in terms of % of total installed capacity) for the 30-year time horizon and for the three cases. At first glance, several observations can be made. Naturally, the DR capacity share is twice higher in the DR subsidy case than in the other two cases. The starting point is an optimised mix of generation technologies with no DR technology, which starts to be developed from the first years for all three cases. It shows that this technology is competitive (in all the cases) and that its introduction could contribute to improve the efficiency of the system (i.e., reducing total cost).

We note that after the high DR introduction in the subsidy case (case 2) the fossil generation technologies (CT, CCGT and Coal) decrease their shares in the generation capacity mix. This result seems counterintuitive, but it should be recalled that in the screening curve analyses previously done (cf. section 2), DR only replaces peak technology (CT in this case) without affecting the optimal capacity volume of other generation technologies.

Case 1(reference case) : Energy-only market with DR development in presence of CO_2 externality



5. ***Case 2 :*** **Energy-only market with DR development supported by technology-oriented subsidy in presence of CO_2 externality**



6. ***Case 3 :*** **Energy-only market with DR development and with internalization of CO_2 externality**

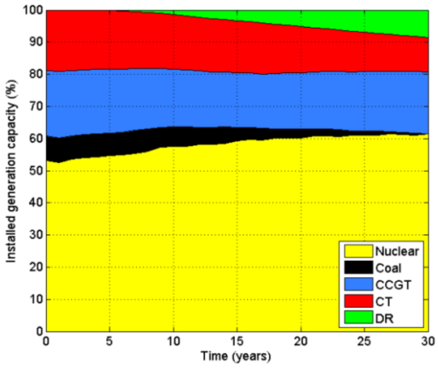


Figure 7. Dynamics of shares in the installed generation mix

These differences result from dynamic cyclical investment fluctuations with long periodicity, instead of a relatively smooth rapid to an equilibrium investment in the screening curves methodology. In the subsidy case (case 2), the high increase of DR resource in the generation capacity mix act as price cap when it clear the price in the electricity market due to its high marginal cost. This leads to a reduction in inframarginal rents for thermal generation technologies, particularly for CT, CCGT and coal which are closer to the non-competiveness area than nuclear, given the cost data of this study. To put it another way, this "virtual price cap effect" prevents electricity price spikes during peak hours and amplifies investment cycles which, in turn, deviate optimal investment paths from the one that could be obtained from the screening curves methodology. However, it is worth noting that the reduction in the generation capacity mix is much greater for the share of CT than for other technologies (see Table 2), as anticipated from theoretical static results.

With regards to the case in which the CO_2 externality is internalized (case 3), the share of coal generation capacity declines significantly whilst the share of nuclear generation capacity increases with respect to the reference case. This results from the increase in the marginal cost of carbon-emitting technologies making less profitable the investment in these technologies. Surprisingly, the DR capacity share decreases and the CT capacity share increases with respect to the reference case. As previously mentioned this result is related to the internal dynamics of the generation mix evolution and cost data. Indeed, in contrast with the nuclear generation capacity, which becomes clearly more competitive with the internalization of the CO_2 externality, the coal and CCGT generation capacities are less competitive, even not competitive at all (for the coal case). Regarding the CT generation capacity, the total capacity cost remains lower than that of DR resource (despite the increase in variable cost after internalization of the CO_2 externality for CT) for a greater capacity factor.

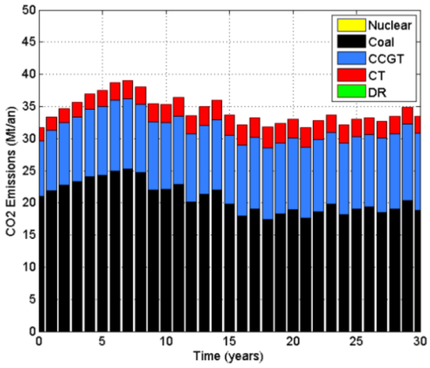
Table 2. Installed generation capacities in year 30

Case / Technology	Case 1 [reference in MW]	Case 2 [variation relatively to reference in %]	Case 3 [variation relatively to reference in %]
Nuclear	79 740	+1%	+11%
Coal	7 704	-32%	-100%
CCGT	28 647	-12%	-3%
CT	13 699	-53%	+11%
DR	15 116	+90%	-17%

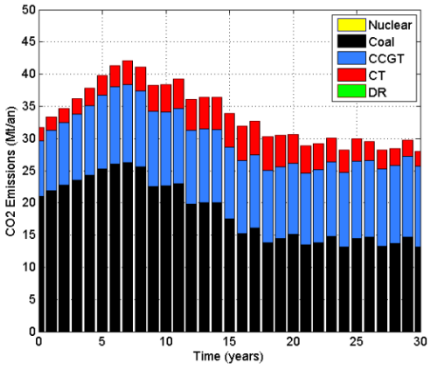
2) **CO_2 emissions**

Figure 8 displays the annual CO2 emissions for the 30-year time horizon and for the three cases. In the reference case as well as in the DR subsidy case, coal technology is the one that is responsible for most the CO_2 emissions. Naturally, the third case, in which the CO_2 externality is internalized, presents significantly reduced CO_2 emissions, in particular those incurred by the coal technology. The emissions for the DR subsidy case (case 2) are interesting to observe. Whereas the coal-incurred CO_2 emissions decrease (as a consequence of the lower installed capacity), CCGT and CT CO_2 emissions increase with respect to the reference case. In fact, coal generation should be replaced by other technologies. The nuclear generation capacity increase is not sufficient to fully replace the coal generation capacity, resulting in an increase in CCGT and CT production and consequently in their respective CO_2 emissions.

***Case 1(reference case) :* Energy-only market with DR development in presence of CO_2 externality**



7. ***Case 2 :* Energy-only market with DR development supported by technology-oriented subsidy in presence of CO_2 externality**



Case 3 : Energy-only market with DR development and with internalization of CO_2 externality

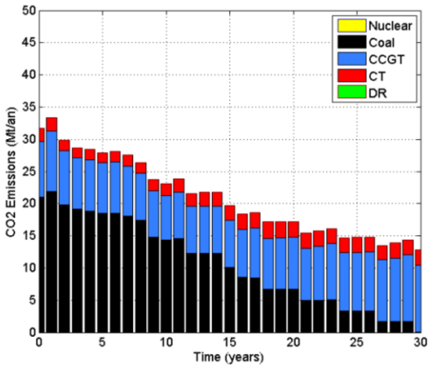


Figure 8. Dynamics of CO_2 emissions

3) **Costs analysis**

Total operating costs are greater in case of a subsidised development (case 2) in which DR resources, despite higher variable cost than others, present a greater development than cases with market-driven development (with or without internalization of CO_2 externality). By comparing market-driven development cases (cases 1 and 3), we also find that total operating costs are less important in the internalization case. As previously mentioned, the internalization of the CO_2

externality (case 3) leads to a sharp increase in nuclear generation capacity due to the replacement of fossil generation technologies with higher marginal costs (coal and CCGT).

Given that the generation mix can change significantly if some amounts of DR resources are introduced in the system, we can compare the cost impacts associated with this change in the portfolio mix. In this subsection, we address this question by comparing the total cost over the simulation period for the three cases previously studied. The total social cost is calculated as the sum of four different components: the capital expenditures (referred to here as the fixed costs), the CO_2 emission costs (estimated by the emission volume multiplied by the value of the externality), the operating costs (only including fuel cost and not CO_2 cost to avoid double counting) and the shortage costs (corresponding to random load shedding). Results of the estimation of total social costs for each case are summarised in Table 3.

Table 3.Comparison of the social costs of different types of DR development for the 30-year simulation period

Costs / Case	Total operating costs + shortage costs	Total emissions costs	Total fixed costs	Total social costs
Case 1 [in M€/year]	9 851	1 775	27 380	39 007
Case 2 [variation relatively to case 1 in %]	+4,5%	-2,0%	-1,4%	+0,0%
Case 3 [variation relatively to case 1 in %]	-9,8%	-38,7%	+3,8%	-1,5%

In line with expectations, the results show that CO_2 emission costs are lower in the internalization case (case 3). When comparing the reference and subsidy cases (cases 1 and 2), the CO_2 emissions costs are lower in the subsidy case, DR is more developed.

To explain these differences of social cost results, CO_2 emissions reduction is the main driver of the total social cost reduction. In the Case 2, the increase of subsidised DR reduces only CO_2 emissions during peak periods by replacing the fossil fuel peaking capacities development, while a CO_2 tax influences the overall technology mix and not only the mix for the supply during the peak load.

Regarding the total fixed costs, since the increase of DR development (being the less capital-intensive technology) is higher in the subsidy case, fixed costs are lower in this case. The internalization case (case 3) presents the highest total fixed costs as technologies with high capital costs (nuclear) replace technologies with lower capital costs (coal and CCGT).

In terms of total cost, we find that the internalization of the CO_2 externality is the most efficient approach to develop DR resources. In other words, the costs incurred by the implementation of this approach (i.e. the difference of the sum of the total fixed and total operating costs between case 3 and case 1, and between case 3 and case 2) are lower than the savings in terms of CO_2 emission costs (i.e. the difference of the total emission costs between case 3 and case 1, and between case 3 and case 1).

4) **Sensitivity analysis**

In this section we analyse the sensitivity of results, notably the total cost, with respect to two parameters: the level of the CO_2 externality (which is also the carbon tax in the case 3) and the level of DR subsidy. To understand the following results, we should have in mind that the two instruments to be compared have not the same field of actions to help to the reduction of carbon emissions: the DR subsidy only acts on peaking resources and the recourse to fossil fuel peaking units, while the CO_2 tax acts on the whole of the technology mix in the balancing between fossil fuel technologies and non-carbon technologies.

First we deal with only one of the major parameters, the CO_2 externality which is also the tax level in the case 3. Figure 9 shows results in terms of total cost of cases 2 (DR subsidy) and 3 (CO_2 internalization) with respect to the reference case 1 for different levels of CO_2 externality (from 25 €/ton to 100 €/ton). These results illustrate that the superiority of the CO_2 internalization over the 75% DR subsidy policy increases for higher levels of the CO_2 externality increases.

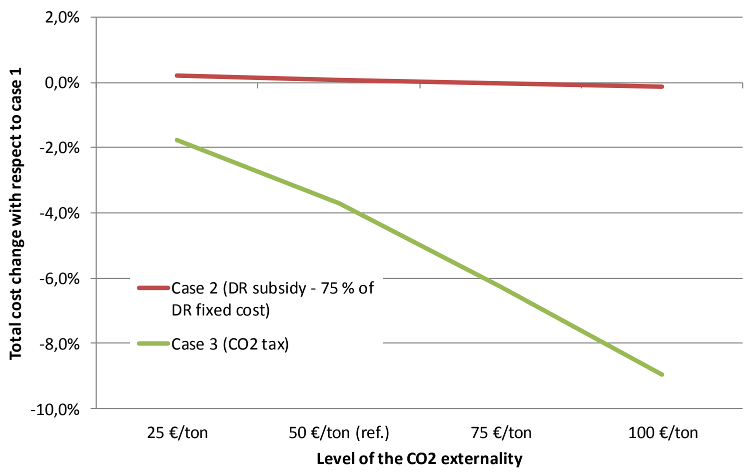


Figure 9. Total cost change for different levels of the CO_2 externality/tax

Figure 10 shows results in terms of total cost of cases 2 (DR subsidy) and 3 (CO2 internalization) with respect to the reference case 1 for different levels of DR subsidy (from 25% of fixed cost to 100% of fixed cost). These results illustrate how the increase of the subsidy level affects the efficiency of DR subsidy policy in terms of total cost with respect to the reference case. Indeed DR subsidy has no or negative impact on efficiency (low levels of DR subsidy have no impact on total cost whereas higher levels result on total cost increase with respect to reference case) whereas alternative policy (CO2 internalization) allows for cost reduction.

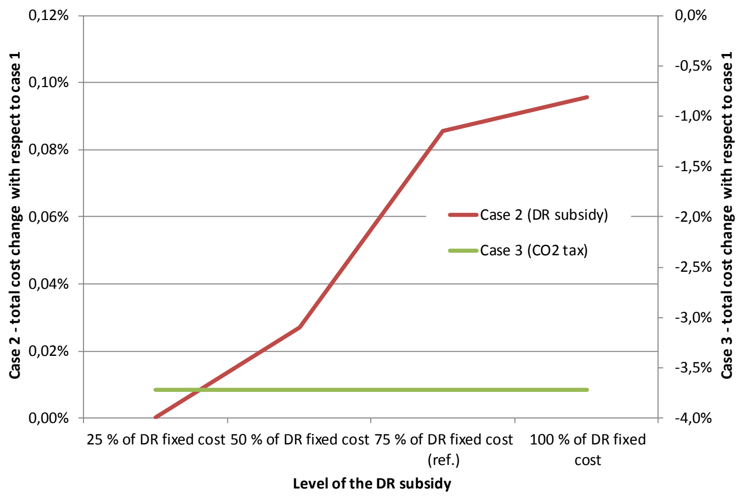


Figure 10. Total cost change for different levels of the DR subsidy

CONCLUSION AND FURTHER WORK

The model developed in this paper allows to analyse long-term effects of different DR policies and to identify pros and cons of different policy options.

Preliminary results illustrate the potential effects and inefficiencies that can appear due to an oversized subsidy for DR with respect to alternative ways to deal with externalities (i.e., internalizing CO_2 externality). They confirm previous findings that market-driven development of demand response with internalization of the CO_2 externality is the most efficient approach to develop DR resources.

These results however show the possible outcome of different policies for one specific case. Much more analysis should be done to understand more accurately the long-term effects of less extreme DR policies. For instance, different types of subsidies could be compared with incomplete or imperfect internalization ofCO_2 externality. Other externalities can also be considered.

Our modeling set-up and simulations are based on several simplifying assumptions and present therefore some limits. Further research will be oriented to relax these assumptions in order to minimize the limits. For instance, a sensitivity analysis will be carried out in order to generalize results to other sets of parameters. Different types of initial systems will be tested to evaluate the impact of the initial conditions on results. Finally, as the current model only considers one type of DR that corresponds to the definition of load shedding, a completion of the model with the consideration of other situations will be done (for instance, load shifting with a load duration curve that has an evolution over the time horizon).

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