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The social efficiency of long-term capacity reserve mechanisms

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Summary : in Public Economics, the simple supply mechanism for a collective good is the centralised provision by government, and paid by all beneficiaries through a small and targeted tax. In the case of capacity adequacy in power supply, which could be considered as a collective good, two solutions of supply by government can be envisaged: a long-term capacity reserve contracting by the system operator (SO), and a direct installation of peaking units by the SO. However, the centralised and direct mechanisms are criticised, because of its potential to distort incentives to invest in peaking units and hence the natural functioning of energy markets. This paper analyses the different characters of a simple capacity mechanism and the safeguards used to limit its potential distortion effects. We discuss its deterrent effects on investment in peaking units. We also demonstrate its advantage in the context of hydro or mixed electricity systems exposed to the risk of exceptionally dry years.

Keywords: Power market, Capacity adequacy, Reliability, Strategic reserve.

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1. Introduction

For a government, a simple way for the supply of a collective good is to provide it directly or by procurement, and collect payment from all beneficiaries through a targeted tax. In our case of capacity adequacy, the collective good is supplied by generation equipment owners. Yet given two characters of the situation - the generation equipments are developed on the basis of anticipated revenues on the energy-only market; and the reserve margin have the fundamental role to insure the system reliability in a random environment - the regulator must act on the development of the reserve margin to ensure adequate capacity for every situation of loads and availability.

If anticipated that the market will under-supply capacity, in a centralized way to proceed, the government or the regulator can program and organise tendering for contracts on capacity. Alternatively, if the system operator (SO) is the owner of the grid and is responsible for long-term supply reliability, then it could be mandated by public authorities to directly install some peaking units or to buy old units that generators aim to close .

The second way has been explored initially by the Nordic countries and The Netherlands (with the « Safety Net » contracts). This approach falls under the generic name “strategic reserves” under which the instrument has been initially named, parallel to the governments’ oil strategic reserves developed for the supply security. The long-term reserve contracting approach has been most recently adopted by some European countries, the same Nordic countries, New Zealand and more recently in France for alleviating congestion costs in a region. Despite contradicting market principles, it is explicitly mentioned as a possible approach in the legislative texts of the European Union - the Directives of 2003[1] and 2006, on the security of the electricity supply (EC, 2003; EC, 2006).

The two variants of this centralised mechanism are indeed criticised because they appear to be intrinsically interventionist and could distort the natural functioning of the energy and operating reserve markets[2]. They appear also to distort the incentives to invest not only in peaking units but also in base load and semi-base load equipments. Market players, as well as potential entrants or investors may consider that the market prices during high load periods will depend too much of the operating decisions of the SO on strategic reserve units and in the longer term, on the reserve capacity decisions of the regulator and the SO (IEA, 2007).

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[1] In its Article 7.1, the 2003 Directive states that “State members shall ensure the possibility, in the interests of the security of supply, of providing a new capacity (or demand side management measures) through a tendering procedure or any procedure equivalent in terms of transparency and non-discrimination, on the basis of published criteria. This procedure can however be launched if on the basis of the authorization procedures the generating capacity being built or the energy efficiency/demand side management measures being taken are not sufficient to ensure security of supply”.

[2] The IEA (2007) report on the “Investment challenges in power generation in IEA countries” considers that the mechanism “does not seem to have contributed positively to investment incentives to private investors. Overall it,is likely that the SO’s ownership confuses the role of the system operator and adds uncertainty to investments particularly in peak load resources” (p.155).

We discuss this critical assessment by pointing out two aspects. The first one points to the definition of the “rules of the game” by the regulator, in particular the definition of the periods when the SO is allowed to have recourse to the “strategic reserves” or contractual reserves in relation to the energy price level or the risk of rationing. Second we discuss the advantage of the mechanism, according to specific characters of some electricity systems. In particular, hydro and mixed systems could benefit usefully from the use of this instrument and minimise costs for consumers. This is due to the facts that reliability in these systems depend less on the capacity criteria of minimal margin reserve than on energy criteria and that private producers’ reserve units dedicated to production during exceptional dry years are difficult to be profitable on an energy-only market.

In our analysis we consider “strategic reserve mechanism” and “long-term reserve contracting” as two variants of the same mechanism with the same regulatory rules to control the recourse to these two types of reserves. We first detail the design principles of each variant. Then we assess the economic efficiency of the instrument from the perspective of different criteria. We then survey the international experience with this mechanism and analyse its particular efficiency in hydro or mixed systems.

2. The reference design of the long term capacity reserve mechanism

A capacity mechanism is based on a clear definition of respective responsibilities of short-term reliability and long-term adequacy between the regulator, the SO, the suppliers and the generators. In systems based on energy-only markets suppliers and producers have a priori no responsibility concerning reliability of the system and its capacity adequacy. Electricity laws do not give direct responsibility for generation capacity adequacy to the SO which only has the responsibility for keeping the balance between production and demand and to continuously check the reliability. Concerning capacity, in a number of national or inter-regional systems, the SO has only the duty to forecast the long-term balance of the system by presenting a multi-year programming of regionalized development of loads and capacities. On one hand, it anticipates the need of transmission grid development that it is supposed to manage itself. On the other, it identifies long-term problem of capacity adequacy, hoping that this identification will influence market players’ investment decision. It has the responsibility to draw alarm on a lack of peak reserves capacity, to define the capacity level that is sufficient to face extreme loads and more generally, to face all the critical situations that may lie ahead. The SO does not, however, have the responsibility for ensuring generation adequacy - this belongs to the regulator and the government. The responsibility of the SO on capacity is exerted, in particular, by identifying where there is insufficient reserve margin in future compared to the criteria of loss of load probability (LOLP).

With this mechanism and its two variants, the government delegates part of responsibility of long-term reliability to the SO. The SO must therefore identify lack of reserve margin in the long-run and then auction long-term contracting on new reserve capacity. In a complementary way, in the countries where the SO owns the transmission system, it may be wallowed to directly buy old units for its strategic reserve or to install peaking units to be run in exceptional periods of very tight supply.

The long-term contractual reserve mechanim

In this institutional framework the main characters of the reference design of this mechanism are the following.

- The level of the contractual or strategic reserves is set by the SO, after agreement of the minister, or the regulator, by a programming procedure as it exists explicitly in a number of national markets in Europe (UK with the Grid's seven-year statement, France with the pluri-annual programming of investment, etc.) and North America.
- A market-based selection procedure by calls for tenders is used, as in New Zealand, France, Sweden and Norway, rather than by mutual agreement.
- Long-term contracts generally are backed to new units to be installed. In some cases such as New Zealand, contracts can also be related to the operation of old units which could be temporarily mothballed.
- The long-term contract provides annual compensation for capacity based on the bid price proposed by the successful candidates, whether or not they produce during the year.
- The SO's right attached to the long-term reserve contract is a right to dispose of the capacity, but not of the energy. In this case, when called up, the contractual reserve units must bid energy on the exchange market, where it is remunerated at the market price. Under this solution, the cost of the reserve mechanism is only the payment for the capital cost of specific units. An alternative solution involves the SO buying directly energy at the hourly market price. The SO has also at its disposal the right to buy the electricity to the contractual reserve equipments when it calls them up to generate, yet dispatches them out of merit at a zero price. It could buy this electricity at the marginal cost of this equipment. However, as it dispatches these units out of merit without no link to the market price, this solution is considered as having a much more distorting effect for energy markets than the former solution. Hence it is more efficient to let the contractual reserve units directly sell on the spot market[1].
- To minimise the market distortions due to recourse to contractual and strategic reserves units, safeguards are added either under the form of a trigger price on the energy market, or a technical criteria (probability of rationing, reserve margin).
- The costs incurred by SO are reimbursed by the payment of an uplift imposed on the transmission price for all kWh transmitted.

The variant of SO's strategic reserve

The constitution of a contractual capacity reserve can be substituted or complemented by two other, much more direct, means. The first which was the most popular following reforms, was to have a reserve of mothballed old plants that can be returned to service under certain conditions in order to face lasting tight supply situation. After regulator's authorisation, a TSO can take over old units that the owners have decided to close. Alternatively, it can sign a leasing contract for a certain volume of capacity in old units. However, due to their slow start up and

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[1] The SO pays a sort of lease to them, and when the contractual reserve units in old equipment are called up on the operating reserve markets, the SO collects the operating profits and transfers them to the owners.

resulting inflexibility in terms of responding to real time balancing needs, these facilities are limited to coping only with inter-annual energy variations in systems that are largely hydroelectric; or in thermal systems in case of forced outages on major equipments. This explains their vocation to be partly mothballed, which increases the time to call up on them in exceptional situations.

The second means consists for the SO in directly investing and operating peaking units. These facilities complement the means provided by long-term reserves contracts. This last approach *a priori* contradicts market principles more than contractual capacity reserve, given the direct role it gives to SO both in capacity investing and in generation. The call-up of these units appears to be more exposed to the discretionary decision of the TSO on the energy and operating reserves markets, because these units are under its full operational control and its decision to invest.

However, in fact the two solutions - long-term reserves contracting and owning peaking units - are equivalent if rules are clearly established on the development and call-up of new units so as to limit the distortion of the energy market functioning. In particular, clarification is required on the energy market price above which it is possible to trigger production of the contracted units or of the TSO’s own or leased peaking units.

A clear distinction must be made between these two variants of the long-term reserve mechanism and the “Standing Reserve Contracting” (see appendix). It is aimed to guarantee the availability of a sufficient amount of operating reserves to the TSO by short-term contracts. In a number of countries (UK, Sweden, Norway in particular), the TSO is allowed to auction short-term option contracts for that purpose. The major differences with the long-term capacity reserve contracting mechanism are the short span of contracts and the absence of relation to specific new equipments to be developed by the contracting party.

Comparison with the design of other contractual capacity mechanisms

The contractual reserve mechanism presents some similarities with the forward capacity mechanism (Cramtom and Stoft, 2006) and the reliability options mechanism (Vasquez et al., 2002; Battle and Perez-Arriaga, 2008) which are considered as the most promising. The long-term reserve mechanism belongs to the same family of quantity instruments (in contrast to price instrument such as the capacity payment): a SO’s centralized coordination of capacity development for guaranteeing a reserve margin; auctioning for long-term contracts which ensure investment in peaking units, and an annual revenue for the capacity at the bid price. In the mechanism of reliability options, the option premium guarantees an annual revenue during a pluri-annual period.

It is noteworthy that a variant of the contractual/strategic reserve mechanism – leasing or purchasing of a certain volume of producers’ existing capacities - falls within the group of price instruments. Indeed, it is a way for the regulator to make prices increase on the energy market by taking a certain volume of old units out of the market, and adding them in the strategic reserve from which they can be only activated to produce during exceptional period of tight supply (De Vries, 2004; 2007). It creates an investment signal by the scarcity rent created on the energy market.

The first difference concerns the interference with the functioning of the markets by the decision of the SO to make owners of reserve units to bid on the operating reserve market or the energy market and in the long-term, the decision to call for tenders for contracts to install reserve capacities. The two" reliability options" mechanisms are based on market-oriented incentives to invest in the long-term, via the revenue of the option premium and in the short-term, to be available in critical periods in the energy and reserve markets[1]. Moreover, the reliability option mechanism does not upset the functioning of the energy market, when options are called by the SO during peak demand or critical periods.

However, precise rules for the use of these strategic reserves above a trigger price or a reserve margin can partly alleviate this difficulty. Moreover, it is noteworthy that this trigger price will act as a price cap during each period of call-up to these equipments, erasing the infra marginal rents for all the other generators that do not occur with the forward reliability contracts mechanisms (see our comparison of instruments in this issue).

The second difference with these reliability and forward capacity mechanisms is that every equipment (the existing and new; the base-load, semi-base load and peak plants) is concerned, and not only those included in the contractual/strategic reserves.

3. Evaluation of the mechanism

We refer to the set of criteria used in comparisons of capacity mechanisms (cf. De Vries, 2007; Cramton & Stoft, 2006; Finon & Pignon, 2006): the efficiency of capacity targeting, the consistency of the mechanism with the energy market (in the sense that it does not create distortion in the electricity price and in investment decision in semi-base and base load equipments); the costs for consumers (which correspond not only to costs supported by the SO in centralised mechanisms and compensated by an uplift, but also the advantage to reduce price volatility on energy markets); the institutional feasibility of the mechanism; and finally the robustness to the exercise of strategic behaviour.

The strategic reserve mechanism shows a high degree of effectiveness with respect to the goal of long-term security of supply. However, it contravenes market principles, unless its use is clearly controlled by safeguards. Moreover, it seems *a priori* to incite to strategic behaviour by underinvestment in peaking units in order to accelerate call for tenders for long-term contracts and to benefit investment security they offer. But we show that it does not displace all the market decision to install peaking units.

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[1] In these two close mechanisms, the payment at the marginal bid price supposedly corresponds to the marginal value of capacity. Besides the long-term issue, the duty of the winners is to provide assigned firm capacity in period of tight supply on the operating reserve market or on the energy market under the thread of a penalty to incite them to compliance. This period is defined economically (when reaching the strike price in the reliability option) or technically (in the capacity forward mechanism when the minimal level of the reserve margin appreciated by the SO or the ISO is reached).

3.1. Short-term and long term compatibility with the energy market

By its very nature, this provision is not the most compatible with the interplay of competitive forces on the energy and operating reserves markets for two reasons. Bringing the energy generated by these facilities to the market directly distorts its functioning unless its provision includes safeguards against discretionary intervention by the SO.

Control of capacity reserves call-up

There are two ways to protect the market functioning. The first way would be the definition of a price ceiling, above which the SO would be authorised to require that the contracted facilities bid on the energy market (and so generate), or to supply operating (or balancing) reserves service on the reserve markets (i.e. to guarantee availability in period of tight supply or shortage). For example, it could be €300/MWh up to the marginal cost of the last peak units which is established around €100/MWh.

This reserve trigger price will have a function of ceiling price on the energy market and this way will be the price paid for the kWh produced by the contractual capacity reserves or the strategic reserve units.

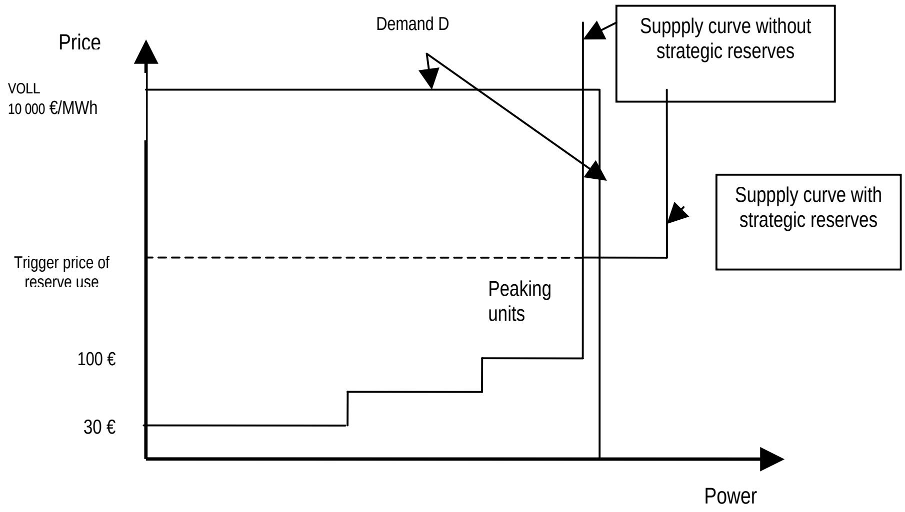
Consequently the contractual/strategic reserve introduces a segment completely elastic in the supply curve at the level of this trigger price for the amount of reserve capacity (see figure 1). After this recourse, the only way for the SO to maintain a real time offer and demand equilibrium is load shedding at a price rising at the level of the VOLL. It is noteworthy that the function of price cap of the trigger price is only partial, i.e. it caps the price on only a limited interval of the demand level.

The second way of controlling the SO intervention is to restrict call-up of strategic reserves to a level below which reserve margins must not decrease without dramatically increasing the probability of black-out without rationing. The regulation should specify the exceptional physical conditions of the system under which these units can be called on for reserve services supply or to bid on the energy market. In principle, this level of reserve margin should entail a price equal to the aforementioned trigger price which acts as a partial price cap.

In other terms, the recourse to a physical criterion would have the same effect as putting a partial price cap, but in fact the energy market remains free and price could go up if market power is exerted.

In the absence of one of these types of protection, the uncertainty created by the SO's possibility of calling on the contractual or strategic reserve facilities may dissuade investment in peak power plants. There is a high risk that the actors will expect the SO to behave “prudently” i.e. to call on available strategic reserve facilities in times of tight capacities in the system (or of congestion) in order to avoid technical imbalance. This intervention will reinforce uncertainty and indirectly affect the market price and the revenue of equipments during peak, and by the way, investment decisions.

Figure 1. Impact of long-term capacity reserve on the energy supply curve



However, even with such protection that curbs intervention of the SO, the mechanism affects revenues of the different equipments by reducing infra-marginal rents during peak periods whereas the price could climb above the price limit of recourse to the strategic reserve. This is the same criticism that is addressed to the general use of price cap. One could argue, that it is supposed to be used in exceptional situations.

Control of long-term capacity adequacy

There is also a risk that the regulator and the SO as adviser behave prudently by anticipating mid-term needs for new peaking units to comfort the reserve margin in a context of uncertainty of the electricity demand growth. A new requisite for the use of this policy is therefore an efficient anticipation of capacity needed to complement the reserve margin the cost of which being balanced by the expected disutility of a loss of load, the VOLL (see Box 1).

The reverse side of using quantity control is that, in acting in a centralised and direct way on quantity, there is a risk of wrong representation of the benefit curve by the SO and regulator's over-precaution, resulting in the overestimation of reserve capacity requirements and hence social inefficiency. There is risk aversion of the regulator and the public authority to power outages due to their high political costs. However, this can be justified from an economic perspective to the extent that the cost associated with an unplanned power outage exceeds the supplementary cost of sporadically excess capacity. In hydroelectric and mixed systems in which reserve units are a response to exceptional dry periods, it will depend on the definition of the exceptional character of the drought and the probability of rationing.

The precautionary choice by the regulator and SO could, however, present a higher cost if the contractual or strategic reserves are mainly made up by existing equipments. If the regulator and the SO attract some existing equipment in the strategic reserve by excess of caution in their anticipation of capacity scarcity, removing this supplement of plants from the market increases the possibility of tight supply and will drive to higher bidding on the energy market by all the other generation units for longer periods. Another option of the design of strategic reserve mechanism exists in which the regulator seeks to attract more investment in peaking units by orienting price upward on the energy market by putting producers' oldest units in the strategic reserves. But the least to say is that this way of proceeding adds market risks by playing with price volatility in tight supply situations.

Box 1

Optimal monitoring of the mechanism: How to jointly choose the trigger price and the level of strategic reserve ?

The regulator with the SO must define three elements to optimise the use of the mechanism in a long-term perspective: the optimal volume of generating capacity C* in relation to extreme situation (load, availability); the optimal level of the energy price Pt to trigger the strategic reserve and then, by anticipating the capacity to be developed by the market Cm with this trigger price Pt acting as a price cap; to deduct the level of the strategic reserve Csr. For this, the regulator follows a decisional sequence. It first defines the trigger price Pt, then allows the market to spontaneously determine the amount of capacity to be present during high load Cm. It then decides the amount of strategic reserve Csr needed to respect the reserve margin ratio in relation to the optimal volume of generating capacity C* that the regulator estimates.

This definition of the optimal instrument presents practical and theoretical problems.

Practical problems arise because the regulator and the SO need prefect information on the probabilistic load growth in the long-run, the future load curves and their stochastic distribution, the availability of the different types of equipment and their vintages, and the VOLL (either simplified using a uniform approach or differentiated by consumers segments) (de Vries, 2004).

Theoretical problems arise because they have to jointly define the optimal levels of two interrelated parameters, the strategic reserve volume Csr for a certain year and the trigger energy price Pt.

1. These parameters are not independent in optimising the system. They are interdependent in the long-term. The lower the trigger price Pt, the lower the installed capacity by the market Cm (because of the lower infra marginal rent during peak resulting in smaller incentive to invest in peak unit), and the larger the share of strategic reserve capacity Csr. Conversely the higher the trigger price Pt, the higher the installed capacity Cm and hence a higher the reserve margin and lower the share of strategic reserve Csr.

From another perspective, the more the market spontaneously develops Cm capacity for meeting high load, the higher will be the optimal trigger price. Conversely, the volume of capacity that the market will spontaneously develop (Cm) depends on the trigger price and infra-marginal rents. This suggests there is no way to define the optimal values of the two endogenous parameters, the trigger price and the level of reserve capacity Csr. The latter depends on the capacity level developed by the market with the trigger price acting as price cap.

2. This begs the theoretical question: Why not to let the market plays completely as if there is no strategic reserve in the absence of risk aversion of competitors? If Pt is set at the level of the value of lost of load (VOLL) (with a supposed uniform VOLL for every consumer), the long-term dynamics of the market and its capacity development are not different from a situation of an energy only market. The market is supposed to develop the capacity necessary to respect a reserve margin. The difference is that a strategic reserve would decrease the probability of load shedding. Yet the additional social benefits of limiting the probability of load shedding beyond the LOLP corresponding to the VOLL are limited because consumers are indifferent about this improvement, given the uniform VOLL. In order to rationale the development of a contractual/strategic reserve in this case, we must consider the uncertainties in the different stages of the temporal process driving to the reliability from the long-term (three years as lead-time for a unit build) to the real time. "The interest to get a reserve of a certain size is linked to the degree to which the market failed to reach the optimal volume of capacity" (de Vries, 2004, p.144). It fails at the stage of the investment decision given the risk aversion of the producers and the resulting higher capital cost from the risk premium, and more generally given capital constraints.

3. However, in most of the cases, given the issue of acceptability of price spikes up to the VOLL, the regulator imposes a price cap below the VOLL. The trigger price must consistently be fixed at the level of the price cap. With a lower price than the VOLL, strategic reserves will be more important than in the previous regulation with no price cap.

Long-term inefficiency by deviation from the optimal mix of equipments

Safeguards exist for limiting calls to contractual/strategic reserves by the SO. In particular, the trigger price limits revenues from the "energy only" market. However, only strategic reserve units receive money to cover capital cost. This allows them to contribute to energy production and reliability during periods of tight supply. All other equipments (base-load and semi-base load equipments) do not receive supplementary revenues despite their contribution to the system capacity during these periods. Moreover, these equipments are deprived of the infra-marginal rents they would obtain in the absence of strategic reserve capacity where market prices spike up to the VOLL.

Consequently, market players will not invest optimally. The administered development of some reserve capacities and their call-up during critical periods affect decentralised decisions to invest in base- and semi-base load equipments, as generation from strategic reserves do limit the prices of energy and operating reserves and reduce infra-marginal rents to them during this period (Joskow and Tirole, 2004; Cramton and Stoft, 2006). Without considering the disutility of electricity shortages, the cost to consumers associated with the sub-optimality of the technology mix (Green, 2007) will be higher, compared to a situation without strategic reserves operating above a trigger price. This loss of welfare is balanced by the least direct costs of the policy which is passed through to the consumers, all things being equal (the level of reserve margin in particular).

3.2. The cost for consumers

In comparison to other mechanisms that give revenue to every equipment (capacity payment, capacity obligation, forward capacity contract/reliability option), this mechanism presents a much lower direct costs for consumers because they only pay the cost of contractual/strategic reserves via the uplift added to transmission prices.

Admittedly, this mechanism does not fit well with principles of economic equity in terms of the treatment of all the contributors to the collective good which in this case consists of the overall capacity of the system. Here, other peaking units do not benefit from revenues, while the revenue itself is handicapped by the price cap created de facto by the trigger price when the strategic reserve units are called up. More generally, all the base load and semi-base load equipments are deprived of part of their infra-marginal rents during periods of recourse to contractual/strategic reserves, without the compensation of a capacity payment. Consequently, there is a risk of deviation of the trajectory of the technology mix from the optimal one, as pointed above, which could also indirectly affect the overall electricity cost for the consumer[1]. It could compensate for the advantage for the consumers just

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[1] Cf. the analysis of the effects of sub-optimality of the technology mix by R. Green (2007)

underlined. The debate remains open on this issue. The net impact of these two opposite effects on the cost for the consumers will depend upon the amount of strategic reserve and the level of the trigger price.

A second advantage in terms of cost for consumers is the contribution of the mechanism to reduce incentives for the generators to restrict their supply on the energy market during period of tight supply and capture more surplus. The trigger price which acts as a partial price cap suppresses part of the incentive to withhold capacity during tight supply on the energy market.

3.3. Institutional feasibility

This mechanism is adaptable to all market designs: non-mandatory markets as in the majority of European markets and (semi) mandatory markets as in the United States and Spain. The fact that it does not require to create new regulatory provisions, and is easy to implement, is doubtlessly its principal benefit. However, the strategic reserve variant will be more consistent with a TSO which owns transmission infrastructures and could directly add reserve units in its assets, compared with the situation of an ISO which does not own any asset. An institutional explanation for the choice of this mechanism relies on the fact that in some liberalized electricity markets, the law has attributed in a broad sense, the responsibility of the system reliability to the SO, while the technical origins of an outage could be shared between producers and the SO. In this institutional context, the TSO will be prone to search simple solutions to respect its mission. Contractual reserve contracts or TSO’s strategic reserves appear to be simple and manageable means for capacity adequacy, provided that stringent rules guarantee the market players that the market will not be distorted.

This aspect of SO responsibility is particularly important in hydro or mixed systems. Indeed, decentralized market players cannot risk investing in thermal units for benefiting from very high prices during exceptional dry years. Moreover, the regulator and the TSO have to arbitrate in a more complex way between marginal cost of “capacity adequacy” and expected cost of rationing in exceptional situations of droughts and limited inflows. This, however, is a seasonal random which is not of the same nature as unforeseen technical failures. There is possibility to inform consumers, to make them aware by higher price signals, in order to adapt to foreseeable outages.[1] The TSO responsible for the long-term supply security would therefore be in a position to arbitrate between the cost of rationing (which is lower than the usual VOLL in the context of these systems) and the cost of developing or inducing the development of a contractual strategic reserve.

In any case, the mechanism needs to embody credible commitment of the regulator to preserve the stability of the rules, in particular those framing the trigger of call-up to contractual/strategic reserves. Criticisms of the strategic reserve mechanism in Nordic countries by analysts - “the SO ownership on the units confuses its role and adds uncertainty to investments particularly in peak load resources” (IEA, 2007) - implicitly challenges this credibility.

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[1] N.H.van der Fehr (2003, chapter 5) develops a theory of optimal rationing in hydro systems in relation to the willingness to pay of the consumers. He mentions in particular a way to use this willingness to pay with the proportional rationing of all the consumers, in which each consumer knows that, above a certain share of its former consumption level, he should have to pay a very high over-price.

3.4. Robustness to prevent exercising of strategic power

A potential problem of strategic behaviour arises with this instrument. Indeed generators may wait for the call for tenders for investing in peaking units when in fact they are able to invest in peaking units on a pure market basis.

The incentives to restrict investment in peak units by the market players

The capacity reserve mechanism aims to compensate the risk adverse behaviour of generators towards investments in peaking units, given the higher degree of revenue uncertainty relative to base-load and semi-base load equipments. Critics of the instrument point out the risk of a moral hazard. The auctioning process for a capacity appears to create an opportunity to a strategic behaviour in increasing the under-investment in peak capacity. Namely, some investors may find it advantageous to wait until the auction is called before investing in peaking unit , amplifying the need for an auction. This mechanism would generate a windfall effect in terms of lower capital cost and risk premium even for the least risk-averse operators. They have an incentive to await these calls for tenders to benefit from the income security that long-term contracts ensure for new capacities. The characters of long-term competition which is initially sought by the market reform even for risky generation investments thus should tend to mutate into competition for public contracts for the supply of capacity and guarantee of reliability during peak periods.

In the variant in which TSO owns strategic reserves, this strategic game could take the form of market players' refusal to invest in peaking units. One possible interpretation could be that the TSO's peaking unit ownerships of strategic reserves could confuse the TSO's role and add uncertainty to investments in peak load resources (cf. IEA, 2007). Behind this alleged hypothesis of opportunism of the producers, however, there is the same theoretical game with moral hazard.

In this game, some generators hide their real risk aversion and implicit risk premium to invest in peak-load units. Knowing that the regulator will have recourse to the auction process as soon as it anticipates that the reserve margin floor will be reached in the near future, they hide their propensity to take higher risks to invest. However, we will see that such a game is not relevant in a competitive environment. Even if such a moral hazard problem from the opportunity created by calls for tenders exists, the windfall effect for the generators that would be willing to invest even without long-term contracts is reduced by the competition of the bidders. Indeed if, despite difference in their risk aversion, every generator prefers to wait for the call for tenders, there will be intensification of competition between bidding candidates, and competition will tend to select candidates that are most prone to propose a moderate capacity price reflecting its moderate risk premium.

From another perspective, an intuitive model helps to show that this instrument does not deter all the producers from spontaneously investing in peaking units (See Box 2 for the demonstration). It simply creates a new equilibrium such that only a share of investments is triggered by auctions, and the other share by the market. In other words, not all decisions to install peaking units will be made with the help of long-term contracts auctioning.

Box 2
The sharing of investment in peaking units between SO's auctioned contracts and the market

In a purely competitive environment, each producer is a price taker. Producers are assumed to be risk averse and their aggregate risk attitude is represented by a utility function U. When producers decide to invest, they choose a total quantity of capacity C_m with an uncertain return r, anticipating that the SO will buy the production of the missing capacity C^*-C_m to their cost price plus a sure return p after auction.

C* is the optimal volume of capacity according to the ISO and Cm is the aggregate capacity spontaneously derived by the market.

The producers have a portfolio-type strategy of developing both units with securitized cash flow by auctioned contracts and units without this securitization. The objective of the producers is to maximize their expected utility EU reflecting their risk aversion:

$$E\,U\,(r.C_m + p.(C^*-C_m)^+)\ \text{ with }\ (C^*-C_m)^+=\max\{C^*- C_m, 0\}$$

The real situation will be set between two extreme cases.

Under one extreme, if and only if p the revenue expected from the auction is superior to E r (the expected revenue by the market), all investments C^* will be realised by auctioning.

Under the other extreme, no investment will result from the auction if the market realises an aggregate investment above C* - this is the case if C* and p are sufficiently small.

Generally, the result is a mix of market investments and investment realised by auctioned contracts. The required capacity C* is superior to the one which will be realised by the market. There is less spontaneous investment by the market if there is the opportunity of gaining long-term contracts that securitize investment in peaking units. It is a common result of the theory that the risk in itself does not deter all the investments in risky assets. The equilibrium between the two types of investment will depend on the parameters of the auction and in particular, the expected price. The SO could commit on a floor price to guarantee the revenue of the contracts, for instance.

The intuitive conclusion is that, in a market environment with different risk averse competitors, the use of this mechanism will not deter the market investment in peaking units, even if it captures part of it.

The correction of strategic behaviour to under-invest in peaking units

In fact the long-term reserve mechanism could alleviate incentive to restrict investment in peaking units in order to benefit larger rents during peaks and extreme peaks. In a more general perspective, the restriction in capacity investment on electricity markets has been shown in two-staged game models with investment (Van der Ferh and Harbord, 1997; Murphy and Smeers 2002). It can be applied specifically to peaking units, given the probability of tight supply in peak periods which gives market power to every generator of any size, in a context of very low price elasticity. In fact, the capacity reserve provision may curb strategies to restrict investment. We can show that indeed, “capacity” procurement by a benevolent SO under the form of auctions for reserve capacity contracts or SO's own reserve unit developments should compensate for the suboptimal investment resulting from the exercise of long-term market power.

In an analysis of mixed oligopoly competition in which the SO behaves as a benevolent public firm within an oligopoly of private firms, we have shown that strategic participants will prefer to invest more compared with a situation without SO contractual/strategic reserve procurement and SO production by these reserves during critical periods (Meunier et Finon, 2006). As detailed in Box 3, the benevolent firm has the mission to invest in order to maximise the social surplus with specific peak-load technology. It is in charge of the supervision of the capacity development and to complement it if sub-optimal.

We demonstrate two points. Firstly, even if there is no investment by the SO, the threat of its intervention by investing is sufficient to incite oligopolistic players to invest more than before. Secondly, the benevolent firms cannot restore the optimum. Since actors are able to foresee the long-term actions of the benevolent firm, the latter cannot completely eliminate the effects of the oligopolistic behaviour and bring about a market optimum. Given that the main source of suboptimal investment and potential high prices during critical periods in the future could result from such exercising of long-term market power, the benefits of this mechanism to alleviate market power provide answers to critics of the underlying strong interventionism.

A similar incentive to the threat of SO investment exists in the variant of reserve contracting based on calls for tenders. Given that this procedure presents the advantage to suppress entry barriers, the oligopolists are under threat of entries by investment in peak units and will prefer to invest rather than to allow more competition to enter during peak periods.

Box 3

A strategic game with a benevolent investor in peaking units

We represent a Cournot game with a price elastic demand and a market equilibria (Meunier and Finon, 2006). In this game, the SO has investment and production strategies, both being anticipated by the oligopolistic players. There is no limit to the capacity intervention of the SO and to the production by its strategic reserve, because it seeks to maximise long-term social surplus and adopts a competitive behaviour in the short-term market.

Hence the game does not represent a situation of discretionary intervention of the SO in relation to the reserve margin preservation in a market with inelastic demand, low elastic supply and consequently a risk of physical imbalance. The SO’s reserve development is intended to alleviate this imbalance, a situation that is more close to the reality of every electricity market. The game represent a situation in which the risk of power outage will indirectly result from the restrictive strategy of investment of the market players to benefit more from their market power during peak and extreme peak periods.

The model uses the methodology of theoretical two-stage oligopoly models including generation investment along several contributions including von der Fehr and Harbord (1997), Murphy and Smeers (2002) and Boom (2002, 2003). They study investments in new generation capacities, after investment has been decided. All future decisions and information are subsumed into one future period representing the decision of production and the short-term market. We extend their dynamic structure by modelling the situation as a three-stage game: firstly the decisions of investment of producers, then decisions of investment by SO and finally decisions of production of firms and SO. We first analyse a three-stage game between a monopolist and a benevolent ISO. We consider only one technology and one state of demand (the situation would be similar if we introduce lower states of demand and corresponding technologies and assume firms’ competitiveness in these states). In usual models, the regulatory authority shapes the incentives of producers or consumers via a price cap on the energy market or conversely by capacity payment, capacity obligation and so on. Here, the SO acts as a generator who can directly sell electricity on the market.

Firms anticipate the SO's intervention. In some cases they can gain strictly positive profit by investing in sufficient capacity to put the SO's in the following dilemma: if it invests in too much capacity the firms restrict their production on the energy market and there is a public loss due to this restriction. As the SO anticipates this reaction, it limits its investment.

The analysis shows that SO's intervention improves the situation. Even in a situation where there is no investment by the SO, the threat of SO investment is sufficient to incite the oligopolistic players to invest. For low elastic demand and concentrated industry, however, it does not restore the long-term optimum. The firms' short-term strategic behaviour prevents the SO from making the system reached the long-term optimum.

The SO's ability to make the system close to the optimal capacity in peaking units will depend on the degree of concentration of the industry, the demand elasticity and the share of variable costs in the production function of technologies.

4. Experiences of contractual/strategic reserve mechanism : specific interest for hydro and mixed systems

The worldwide experience of the strategic reserves shows three ways of designing the mechanism: Long-term contracting for new capacity or existing plants. Purchases of peaking units by the SO; and long-term standing reserves contracts associated to a new generation units in congested areas in order to reduce the congestion cost and incidentally to improve capacity adequacy in these areas, such as in France (see appendix).

4.1. Long-term reserve contracting

This mechanism is used in thermal systems as in the Netherlands where a proposal of contractual strategic reserve of old units is being implemented (Tennet, 2005). The SO leases a certain volume of capacity related to old units, keep them operational and available during critical periods by being managed in seasonal de-mothballing.

However, the mechanism is mainly used in hydroelectric systems or mixed systems (Sweden, Norway, New Zealand) for responding not only to stochastic extreme loads and technical failure, but also to random energy inflow. In hydro and mixed systems, the energy criterion (the ability of the system to cover the yearly energy demand during dry years) dominates the capacity criterion of a reserve margin. In such years, the energy criterion affects the reserve margin or LOLP criterion during high load periods and hence the reliability of the system. This explains why introduction of old thermal equipments with low start-up in a contractual strategic reserve can be operationally useful in these systems, given that the seasonal or annual character of random energy inflow allows time to de-mothball and call up these equipments.

In Sweden, with a hydraulic share of 50%, the reserve contracting is designed to cover up to a maximum of 2 GW on a total capacity of 27 GW. The SO auctions a set of contracts on medium term (four years) for a capacity which does not explicitly correspond to new equipments. The contractual prices are not published. The contractors have the duty to be available during high load periods and to bid on the market after a trigger price of 8000 SKr/ per MWh (around €1100 /MWh) is reached.

In the New Zealand system which is dominantly hydroelectric (65% of the energy in average year), the mechanism is more clearly oriented to overcome the energy constraint during dry years. Strategic reserves include new equipments and producers' old equipments. The contractors are selected by auctioning. The contracted generators must supply energy and capacity, only during dry years. They must be mothballed during wet years. The design of the strategic reserves mechanism integrates a trigger price to control their use. It constitutes a cap on high energy prices during dry years which reflect both energy and capacity scarcities.

4.2. the SO's strategic reserve

This variant of contractual reserves mechanism exists in all the three Nordic countries Sweden, Norway and Finland. It is not an incentive mechanism to make market players invest in reserve units unlike reserve contracting, but a way to complement the reserve margin in countries where the SO has a responsibility extending to long-term reliability. The SO is allowed to order peaking units or buy old thermal equipments which would be closed by competitors, for mothballing them to bring to use under critical situations. It is generally considered as a temporary mechanism given difficulties in transition periods, and used only before the adoption of market procedures of reserves contracting. Yet, countries with hydro systems in fact continue to use it extensively, in particular, responding to the combined problem of hydraulic tight supply and congested areas.

In Sweden, the system operator acquired 640 MW of gas turbines to be used as operational reserves corresponding to 2% of the physical capacity. It remains concerned over adequate investment in capacity.

In Finland, the system operator also currently owns 515 MW of gas turbines, (around 3% of the installed capacity). It has decided to construct 100 MW additional capacity due to reserves associated with the future commissioning of a new nuclear unit of 1600 MW in 2012.

In Norway, following high price in 2002-2003 dry period, the government asked the SO (Stattnet) to develop measures to reduce risk for power rationing in severe dry periods. In response, in 2007 three mobile gas turbines or diesel plants of 50 MW each have been installed in the central regions, while seven 20 MW plants will be installed in other regions over the two next years. Finally, Stattnett has to apply to the regulator to get permission to start the turbines. The criterion is not yet completely decided: permission should be given if the situation is "extremely scarce" and Stattnet is in favour of a criterion of rationing risk of more than 50% probability.

4.3. Why preferential use of this instrument in hydro and hydro-thermal systems with reservoirs

While this mechanism faces general scepticism from market proponents, it is noteworthy that it is mainly used in countries with mixed hydro-thermal system and hydro systems, which were pioneers in market reforms, for example Norway or New Zealand (cf. med-NZ, 2003). Two major reasons explain this preference: social efficiency and institutional consistency.

Social efficieny advantage in context of uncertainty on seasonal inflows

In hydro or mixed systems, directly or indirectly supporting and ordering the development of peaking units for exceptional situation can be more efficient than to rely on decentralized agents' decisions directed by complex capacity instruments.

Firstly, the fact is that in hydro or mixed system including reservoirs, the problem is not exactly a problem of capacity adequacy, but of energy during dry years. The LOLP criterion (or reserve margin criterion) is not the unique criteria of reliability. As said, these systems must also respect the criterion of annual energy availability, i.e. the ability of the system to cover the yearly energy demand during dry years. This also means that the energy criterion determines the LOLP criterion. In such years, the energy criterion affects the reserve margin or LOLP criterion during high load periods and hence the reliability of the system.

Supply variability is particularly prevalent in hydro-based system with reservoirs. Energy availability could vary considerably over time. Storage allows for disentangling water inflows and energy production and adds in fact to supply reliability of the system. The fact is that the reservoirs are dimensioned in order that the system could face up with numerous situations, but not all. Reservoirs capacity is also subject to constraints from being over-dimensioned[1].

Second, investments in peaking units by producers and entrants for critical periods are intrinsically more risky than in thermal systems because it deals only with these situations, given the security offered by hydro reservoirs during all other periods for supply reliability. Moreover, possibilities to import from neighbouring markets in response to exceptional energy scarcity add to the economic risk to invest in thermal capacity for critical dry periods. Expectations on profitability of investment in peak thermal units (gas turbines) built only to face exceptional droughts are therefore poor. The risk premium in the capital cost to invest in gas turbines for this purpose in hydro systems is much higher than for reserve units in a thermal system. The hydro inflow random is such that the associated economic risk suppress all incentives to invest in reserve units.

The problem of energy constrained systems such as hydro or dominantly hydro systems could be generalized to the case of systems with dominant nuclear generation. It could also be the case for small systems that integrate very large generation units, such as the Finnish nuclear reactor EPR of 1650MW to be integrated in a system of 15 000 MW (see above). Contractual and strategic reserves could help to alleviate consequences of technical problem of a large nuclear plant in small systems, shut down of a series of reactors for generic flaws and constraints of refrigeration on the rivers during droughts.

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[1] Let us take an example: if a hydraulic system is dimensioned to have energy storage for half of the year in period of drought. It has to guarantee the reliability of the supply during the peak periods, what would be the energy capacity of reservoirs which will help to meet demand in an exceptional year with only 33% of normal inflows are available? If the average level of annual power demand is 70% of the winter peak , the total power capacity must be 140% times the capacity of the peak demand more than the energy used in normal years.

Institutional simplicity

The second explanation is institutional: other effective capacity instruments for hydraulic or mixed systems are excessively complex and administratively costly.

With the capacity obligation mechanism as with the capacity payment, the regulator or the SO negotiate with hydro producers a coefficient of the firm's capacity, corresponding to a percentage of their total capacity (in the form of firm energy commitment per month). In certain cases as for the Argentinean capacity payment, there have been permanent conflicts to define the firm capacities of hydro plants compared to those of thermal plants (Batlle et al., 2006). There is also no guarantee of effectiveness to secure a minimal reserve margin in dry years with the capacity payment[1]. Mechanisms such as the long-term contractual reserve mechanism (complemented or not by the own strategic reserve of the SO) presents a better guarantee than a complex capacity payment.

In the cases of reliability options mechanism as studied in application to the Colombian mixed system by Battle et al. (2007) and Cramton and Stoft (2007), hydro producers must be able to commit more on their energy production during critical periods than on their available thermal capacities. By default, they must also be able to commit *ex ante* on firm energy (ability to provide energy) during exceptional dry periods i.e. an amount a generator can deliver per month during an exceptional dry period (for instance with an inflow of 35%)[2]. Moreover, the SO commitment to guarantee revenues to producers must be tailored to each type of equipment. In particular, its commitment for new hydro plants must be very long (15 years or more) relative to commitments related to new thermal plants. Hence, simplicity of the long-term reserve mechanism could appear to be an advantage for pragmatic regulators.

5. Conclusion

This centralised and quantity-oriented mechanism allows an effective targeting of the technology mix development toward a reserve capacity target in particular in hydroelectric and mixed systems. It could ensure stability for investment in peaking units by long-term contracts in thermal systems. The mechanism appears to be economically efficient and well adapted to systems with dominant hydroelectric generation which exposes them not only to random loads and equipments unavailability, but also on energy shortage during exceptional dry years.

Critics generally dislike its interventionist characteristic which casts doubts on the neutrality of the system operator and the regulator both in relation to long and short-term perspectives. In the long-term, when the SO decides the amount of the contractual/strategic reserves, the response to this risk takes the form of a close scrutiny of the SO's decisions to issue calls for tenders (or directly construct peak units). Some argue that this mechanism could deter investment in peaking units by the market, but we demonstrated that this argument is weak. A more relevant criticism is that it could distort the technology mix in the long-run by reducing infra-marginal rents up to the trigger price during the period in which strategic reserve units will be called up. However, the consequent costs for consumers may be be

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[1] See Finon and Pignon (2006) on the debate on " Price instrument versus Quantity instrument".

[2] It corresponds to the ability of a thermal unit to commit with 92% of available capacity

compensated by the reduced reserve capacity mechanism costs burden on the consumers. In the short-term market, the main difficulty is to control the utilisation of the reserve units without distorting the market functioning – this gives justification for clear and transparent rules of call up these units to bid on energy and operating reserves market. The regulator must complete the design of the mechanism with such safeguards to guarantee undistorted functioning of the hourly energy market and efficient long-term market decisions.

In any case, it appears that in hydro systems and in mixed hydro, the opportunity to call up the reserve is very limited. Symmetrically investment risks in reserve equipment for exceptional dry periods are much more important than in the case of thermal systems where recourse to this hierarchical mechanism can be justified.

Appendix

Other uses of auctioned long-term and short-term standing reserve contracts

1. Long-term contracts of standing reserves for controlling congestion

A variant to the use of the mechanism is the tendering for solving congestion constraints on a long period by inciting construction of equipments with forward capacity contract inside a constrained area. In some control areas in the USA, public procurement for monthly reserve supply in congested areas helps the system operator to control congestion cost and supply reliability. Yet this procurement is not directly linked to the development of new units. This method has been recently used in France.

- ***Rationale of the mechanism.***

The SO's responsibility is to guarantee the security of the system and to proceed to the transmission under better economic conditions, in particular by limiting the congestion costs. Transmission pricing method could give signals for network investment and for generation development in congested area. However, congestion pricing methods provide *a priori* no incentive to network managers for relieving congestion by investing in network development, given congestion rents.

The administered installation of a new generation unit following a SO tendering (for reducing congested flows by an improvement of local balance between generation and load) is a more effective mechanism. It could be a necessity in the transmission systems without locational pricing, as it is the case of the French transmission pricing (zonal pricing). Tendering must be decided by the SO and the regulator after arbitration between costs-advantages of new grid developments versus new generation development.

Economic value of these units integrates positive side-effects on the regional capacity adequacy in the congested area[1].

- **Main characters of the mechanism**

Refereeing to the French experiment[2], the mechanism has characteristics similar to the long-term capacity reserve mechanism:

- After auctioning a long-term contract guarantee revenue for capacity at the bid price to a new generator for a long period (10 years).
- The duty of the new generator is to be available during the critical periods, i.e. either to bid on the operating reserve market or on the energy market at the demand of the SO. Penalty incites this duty during the critical periods.

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[1] Let us notice that addition of a generation capacity has not the same advantage as the addition of a transmission line which would provide other benefits such as enhanced competitiveness of wholesale markets and opportunity to reduce market power.

[2] For details, see RTE. 2006

- In the reference design, the generator is not dispatched out of merit, but receives direct revenues from sales of balancing services or energy. In the French instrument, these revenues are capped by a ceiling price above which the extra revenues are subtracted from the capacity payment.
- In applications of this mechanism, however, the committed units are called up to be dispatched out of merit, despite anticipated negative economic effects as underlined by Joskow and Tirole's analysis (Joskow & Tirole, 2004).

2. The short-term standing reserve contracting

It presents some similarities with the long-term contracting for standing reserves. In a number of countries (UK, Sweden, Norway, etc), the SO is also allowed to auction short-term option contracts in order to be guaranteed against the risk to have insufficient reserve margin in real time and to have sufficient available capacities. Given the difference of focus with the contractual/strategic reserves, the design is different on several items: short contractual time-span and absence of relation to specific new equipments

The SO defines for each year, a level of operating reserve that it wants to be sure to call up on the operating reserve market with the help of a system of reliability contracts of different terms (one month to one year). If selected, the generator is paid at the marginal bid price for the capacity service it offers, plus the operating reserve price when it will have to bid on this market.

The duty of selected units is to be available for offering operating reserve or balancing service anytime during high loads when called up by the SO. In return, they cannot bid on the day-ahead energy market. In Great Britain in 2005 the tendering process covers annual contracts of standing operating reserve (around 2.2 GW to compare to a peak of 60 GW), plus supplemental reserve contracts (860 MW) for the winter period which will come from the mothballed equipments (JJES report, 2006). One of the main functions of the mechanism has been to incite to de-mothball CCGTs during a period of higher electricity price than period which had provoked their mothballing. In Norway, the centralised market of standing reserves is activated only during a limited number of months corresponding to the high load period. The monthly contracted capacities cover around 2 GW on a peak of 23 GW.

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