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Different Approaches to Supply Adequacy in Electricity Markets

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ABSTRACT

This paper studies the electricity market design long run problem of ensuring enough generation capacity to meet future demand (*resource adequacy*). Reform processes worldwide have shown that it is difficult for the market alone to provide incentives to attract enough investment in capacity reserves due to technical and institutional features. We study several measures that have been proposed internationally to cope with this problem including strategic reserves, capacity payments, capacity requirements, and call options. The analytical and practical strengths and weaknesses of each approach are discussed.

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INTRODUCTION

The electricity power crises in California, New York, Italy, Norway, Sweden, Brazil, Argentina, Chile and New Zealand in the past few years have dramatically showed the importance of a reliable electricity supply.[1] As of 2000, generation reserves had declined in most markets since liberalization.[2] Average reserves have also decreased in most IEA markets except for the UK. An extreme case is Australia where there was significant initial overcapacity but reserves drop significantly after the reform. In the cases of UK, Sweden and in Pennsylvania, New Jersey, Maryland (PJM), reserves in 2000 stayed similar to those observed at the time of the original reform, but in Norway there was a decrease of 2% from 1991 to 2000, and in California a decrease of 7.5% from 1990 to 1998.

The change in reserve margins has occurred, in most cases, from a starting point of large reserves so that current reserves generally remain above 16%, which seems acceptable for reliability purposes. Likewise, several of the examples of electricity crises have been in systems that depend heavily upon hydropower. However, there is a growing concern on whether liberalized markets will be able to provide adequate incentives for sufficient investment in generation capacity. This is particularly problematic due to some intrinsic characteristics of electricity markets such as: a) a short-term inelastic demand that implies that the (long-term) supply-demand balance cannot be achieved through a market-clearing price; b) a lack of forward electricity markets beyond one or two years; c) the favorable arena for strategic behavior due to the difficulty to get market clearing prices in tight situations, and d) final consumers do not feel the need to engage in long-term contracts because they are usually isolated from spot prices by regulated tariffs.[3] Likewise, markets with particular regulatory policies –implying, for example, price caps and

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[1] Reliability in electricity markets is usually understood as the sum of adequacy and security standards. Adequacy (security) is generally associated with the long run (short run). Security describes the ability of the system to deal with contingencies, while adequacy refers to the ability of the system to meet the aggregate consumer energy requirements at all times. Security includes the so called ancillary services (voltage support, regulation capacity, spinning reserves, black start capability, etc.). See Singh (2002), and Oren (2003).

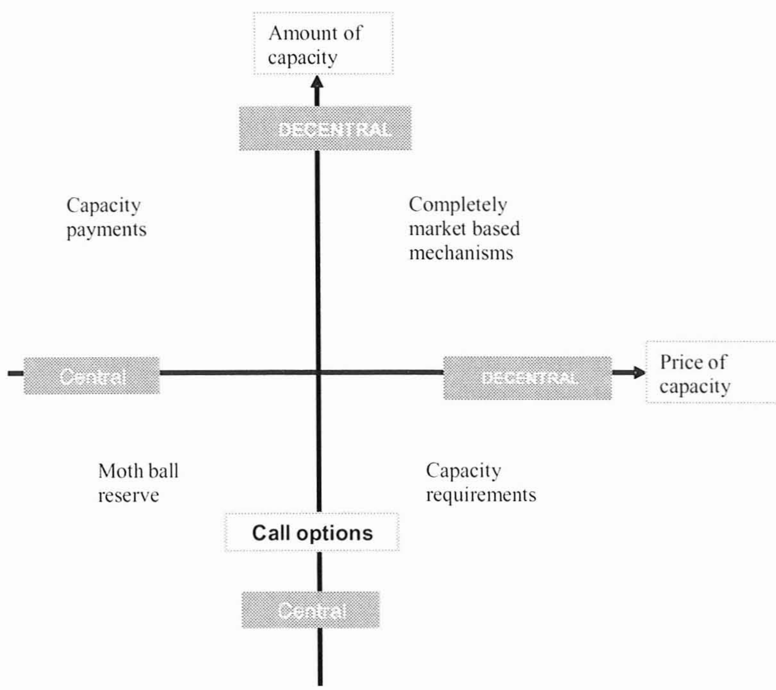
[2] The annex presents data on generating reserves for IEA countries

[3] See Bouttes (2004), and Vázquez et al (2002). De Vries and Neuhoff (2003) carry out an extensive analysis of the market and institutional failures in the electricity industry that impede the development of long-term contracts including: lack of generators' counter-parties to sign long-term contracts, producers' imperfect information of the demand function, regulatory uncertainty on whether the regulator will impose price caps in periods of price spikes, investment cycles due to long-lead times for new generation facilities, generators' market power, and so forth.

artificially elastic consumers-- might require resource adequacy mechanisms to return capital to investors in electricity plants.[4]

Several measures have been proposed to ensure a sufficient amount of generation capacity reserves. As shown in figure 1, such measures might be analyzed in terms of their degree of centralization or decentralization with regards to the *amount* of capacity and the *price* of capacity (see Knops, 2002, and De Vries, 2004). In this paper, we carry out an analysis of each one of these measures both studying their theoretical fundaments as well as their international application and assessment.

Figure 1



[4] Therefore, a market with high price caps would typically not need supply requirements. The question of course is with regards to the price cap level that would not cause resource adequacy problems. As discussed below, simulations for the PJM market show that price spikes that might occur in an energy only market are way above the $1,000 price cap set for PJM, even when combined with an interruptible service policy (see Bushnell, 2005).

1. TOTALLY CENTRALIZED VS. TOTALLY ECENTRALIZED RESOURCE ADEQUACY

We start analyzing two extreme approaches to resource adequacy and investment in capacity reserves. One extreme is a fully centralized solution where a vertically integrated utility centrally deals with imbalances and manages congestion and ancillary services using its own generation resources. This is the "wheeling" model that is utilized in the United States in areas that have not gone into a competitive structure and that have no spot market (Hunt, 2002). The Mexican model is another example of centralized supply adequacy where private independent power producers (IPPs) sell their energy to the state monopsony CFE under long-term power purchase agreements that are supported by government funds.[5]

Another centralized alternative is the creation of a "moth ball" (or strategic) reserve with government subsidy, and centralized decisions regarding both amount and price of capacity (see figure 1). The moth ball reserve would imply a strategic reserve of generation capacity,[6] with an operation centrally controlled by the government that would only be used during emergencies. There is of course a social cost to this procedure since subsidies would be financed through public funds at large. Supply of capacity reserves would then be categorized as a public service obligation (Knops, 2002).[7]

An opposite extreme approach to resource adequacy is a fully decentralized solution where the market determines the amount and price of capacity resource that will grant resource adequacy. Under such a solution, the different energy markets would be separated and a sequential equilibrium would theoretically be reached in the spot market, the forward energy market, the market for capacity reserves, and the forward transmission market through the voluntary participation of agents and a minimal supervision of an Independent System Operator (ISO) (Wilson, 2002).

Different decentralized models have been tried internationally as in Texas, California, Australian Victoria pool, and NETA in the United

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[5] See Carreón-Rodríguez, et al (2006), and Madrigal and de Rosenzweig (2003).

[6] In Norway and Sweden there is direct ownership of some peaking plants (Güllen, 2000).

[7] In Mexico, most generation units operate at low factor plants. This could be interpreted as a sort of moth-ball strategy so that some spare capacity is strategically reserved in the general system. However, the low factor plants could also be interpreted as part of CFE's monopolistic behaviour. In any case, low factor plants does not necessarily have a direct relationship with incentives within the private generation scheme based on IPP projects that are bid by the CFE, and that must compulsory sell all their energy to such a public monopoly.

Kingdom.[8] The aim has been in some cases (NETA) to get the system operator out of the spot markets, so that traders manage the spot market as well as manage congestion, and separate arrangements are set up for ancillary services. Typically, the primary income for recovery of capacity costs is the difference between the market clearing price and the generators' marginal cost (scarcity payments).

A basic problem of a decentralized model is precisely that it ends up creating private markets not only for spot energy, but also markets for congestion energy, markets for imbalance energy, and markets for ancillary services (Hunt, 2002). All these markets deal with the same energy product, and in an efficient market all these products would end up being traded at the same price.[9] In reality, these prices do not converge, and alternatively higher prices, shortages, bureaucracy and new transaction costs are created.

In fact, wholesale market designs that separate energy and individual ancillary service markets have performed poorly and have made electricity markets subject to unilateral behavior that leads to price increases (Joskow, 2003). California did an actual separation of five electricity markets (Hunt, 2002). Some theoretical studies try to find the optimality conditions for such an approach (Wilson, 2002, and Chao and Wilson, 2002). However elegant in theory, [10] the electricity industry practice has clearly shown the inconvenience of separating the different markets.

Electricity markets do not fulfill the conditions for full competition to work, so that decentralized sequential and efficient equilibrium of the different electricity markets is practically impossible (Borenstein, 2002). Market power and volatility are really inherent to electricity markets since demand is difficult to forecast and inelastic. Likewise, electricity supply faces

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[8] In England and Wales the existing integrated system was substituted with an extreme version of a decentralized model that discourages the use of imbalances and trading in markets remote from the system operator (New Electricity Trading Arrangements or NETA). According to Hunt (2002), this implies a reduction in the transparency of energy markets because imbalance prices do not reflect efficient contract prices.

[9] This is theoretically confirmed by Carreón-Rodríguez and Rosellón (2005) which show that prices in the capacity reserves, peak capacity and non-peak capacity markets converge to the same price in a model that separates these three markets.

[10] For example, Chao and Wilson (2002) analyze the two-part Californian procurement auction for the market of spinning reserves. One part of the auction was designed for making capacity available, while the other part was for supplying incremental energy. A scoring rule is meant for comparing bids, while a settlement rule is used for paying accepted bids. The revelation principle applied to this model makes each supplier's optimal-energy bid reveal his true marginal cost. Additionally, the ISO and the generators are not required to agree on the probability distribution of dispatched energy

binding constraints at peak times, and it is inelastic and very costly to store.[11] This implies that short-term prices are extremely volatile so that small changes in demand or supply conditions lead to price bursts, and even small-share generators can exercise market power. Borenstein then claims that the best way that regulators can handle market power is through long-term forward contracts between power buyers and sellers together with *real-time* pricing. Forward contracts help to lower the average price paid in both spot and forward markets, while real-time pricing also makes the demand curve flatter.[12]

Another market-based mechanism for resource adequacy could be based on subscription of capacity (Knops, 2002). The desired generation capacity would be decentrally determined (see figure 1). When demand approaches supply, every consumer is restricted to the peak capacity contracted in advance from generators. Peak capacity can be sold by each generator in any amount, and the price for this capacity is left to the market. With this solution both the price and the quantity of peak capacity would also be decentrally determined.[13] However, at this moment, such a solution is not technically feasible.

In the context of an integrated ISO that reaches a centralized equilibrium in all the electricity markets, De Vries and Neuhoff (2003) analyze the "energy-only" market solution. Such a solution relies on the spot market run by the ISO to take care of resource adequacy so that price spikes signal the need of investment in generation capacity. De Vries and Neuhoff

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11 This non storable nature of electricity is what mainly differentiates electricity markets from other energy markets (such as natural gas and oil). Such a peculiar characteristic of electricity implies a complex system of dependent markets (the spot market, the forward energy market, the forward transmission market, and offcourse the market for capacity reserves) whose sequential equilibrium is very hard to achieve in practice without a centralized ISO. However, the need to regulate electricity markets might as well be driven by reluctance from the jurisdiction to pass through wholesale prices into retail rates that are not "politically acceptable".

12 Most of the recent electricity reform proposals also promote the use of demand side bidding measures (see, for example, Commonwealth of Australia, 2002)

13 Carreón-Rodríguez and Rosellón (2005) develop a two-stage oligopolistic model where generators decide first if they should enter to the long-term reserves market or the spot market. If they go into the spot market, they decide in the second stage to supply either peak or non-peak capacity. Therefore, both amount and price of long-run capacity reserves and peak capacity are set in the market. Also in a theoretical framework, Murphy and Smeers (2002) build a closed-loop Cournot two stage game that describes a situation where investments in capacity reserves are decided in a first stage while sales in the spot market occur in a second stage. Both stages take place in oligopolistic markets. Their framework does not include forward contracting. They find non-convexities in the first stage of the problem (a fact common of bi-level programs) but are able to conclude that a model with a spot market has lower prices and higher quantities than a model without a spot market.

argue that there are insufficient incentives for generators in an energy-only market to invest in capacity whenever there exist economic uncertainty or fluctuations in demand. Moreover, they show that when generators and consumers are risk averse, the optimal level of investment from the perspective of generators is below the level consumers wish to finance with long-term contracts. The main reason is that market designs do not have the *institutions* that permit long-term contracts to develop sufficiently, and generators are restricted in the amount of risk that they can transfer to consumers. Likewise, complete reliance on price spikes is not advisable because they are usually not "politically acceptable," and they can also be manipulated by generation companies. For example, if the probability of lost load in the PJM market is 1 day in 10 years, price spikes in the range of $12,000-$30,000 per Mwh are needed in an energy-only market. The political acceptance of this price range might be analyzed when compared with a $1,000 regulatory price cap.[14] Even more, electricity markets that rely on short-term energy revenues might lead to shortfalls in capacity over time that might originate investment cycles where investment lags demand in the market. This is a characteristic mainly true of electricity markets only, due to the sequential equilibrium of such markets and to the non-storable nature of the electricity good.

Regulators worldwide are then very concerned that energy prices are not enough to cover generators' capacity costs, due to both theoretical and practical reasons. Most markets have implemented some type of resource adequacy measure. Texas has recently changed to generation adequacy assurances, and FERC's Standard Market Design (SMD) also recognized the adequate contracted provision of capacity reserves (FERC, 2002).[15] California in 2001 also changed its market approach to capacity supply and prompted a proposal for an available capacity requirement (ACAP) to be imposed on load serving entities (LSEs).

It is therefore not surprising that several methods have been formally studied in the literature on incentives for investment in reserve capacity such as capacity payments, capacity requirements, and capacity options. The literature on resource adequacy analyzes these mechanisms in the context of an integrated ISO. We next study such mechanisms.

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[14] Likewise, energy-only markets work in Australia and New Zealand with maximum prices between $2,500 and $5,000 (Gülen, 2002).

[15] However FERC has recently backed of and recognized the State's jurisdiction over resource adequacy measures.

2. CAPACITY PAYMENTS

Capacity payments provide remuneration to generators for making available their generation capacity (whether they get dispatched or not). The price of capacity is set while the market determines the amount of capacity available. That is, prices are centrally determined while capacity decisions are decentralized (see figure 1). Capacity payments are collected from consumers through an uplift charge and determine the cost behavior of the firm but leave the amount of reserves uncertain. Capacity payments are rooted in the theory of peak-load pricing so that energy is priced at marginal cost, and a capacity payment is used to recover the fixed capacity cost imposed on peak-period energy users (Oren, 2003). The optimality condition is such that the shadow price of the capacity constraint is equal to the incremental cost of capacity.

Capacity payments have been used in Argentina,[16] Chile, Colombia, Peru, Spain (together with bilateral capacity contracts), and the United Kingdom.[17] Two different kinds of capacity payments have been applied in the international practice: fixed payments and fluctuating payments. Fixed per MW payments have been implemented in Spain, where the compensation depends on the availability and the technology of the power plant, and in Argentina, where the *Secretaría de Energía* set a $10 MWH ($5 for base capacity and $5 for reliability) payment paid during peak demand blocks (6am-11pm during workdays).

Fluctuating payments vary with the need for reserved capacity. Although later rescinded under NETA, they were implemented in the early UK (England and Wales) electricity market. The market merit-order pricing rule was modified during periods of high demand when reserve capacity margins were low. In such circumstance, the market price was defined as the weighted average of two factors: the price of the last accepted offer to generate (*LAO*) and the value of lost load (*VOLL*). The weight is the *LOLP*. The formula for the market price is then *market price* = *LAO* * *(1-LOLP)* + *VOLL* * *LOLP*, where: $0 \leq LOLP \leq 1$. The greater (lower) the surplus reserve capacity the smaller (higher) is *LOLP*. Generators would ideally add capacity when the expected sum of all these payments over all hours of the year is greater than the cost of installing new capacity. This formula also implies a price cap for VOLL when the system is short of power.

A general assessment of capacity payments is that they do not always favor competition because they tend to create artificial rents that might lead to increased market power in generation. In a simple Cournot model, Carreón-Rodríguez and Rosellón (2005) find the conditions under which a fluctuating

[16] Argentina changed to a capacity market in 2000.

[17] With the adoption of "NETA" in October 2000, the UK abandoned capacity payments based on the loss of load probability (LOLP) method along with the pool system.

capacity payment (as the one put in practice in the UK) might lead to worse results in terms of consumer surplus, profits and net social benefits compared to a system where the market price is not artificially increased and excess demand is satisfied in a regulated reserve (or standby) market.[18] They show that implementation of a bypass reserve market makes social sense in terms of prices only if there is a large efficiency gap between old and new generation plants. In such a case, the implementation of the capacity-payment solution would only create artificially high rents that could provide incentives for a development of oligopolistic generation markets.[19]

In a similar effort, Joskow and Tirole (2004) analyze the effects of an uplift charge of an ISO to recover the costs of resources. They do so in the context of a general model that studies the effects on the theorems of welfare economics of market failures as those existing in electricity markets. They find that capacity payments grant inefficient results:

- When the uplift charge is applied both to peak and off-peak periods, large ISO purchases discourage the build up of base load capacity and push down the peak price.
- For small purchases, off-peak capacity decreases when the uplift is applied in both peak and off peak periods, and the peak capacity decreases when the uplift is only applied during the peak period.

In a model of imperfect information, Oren and Sioshansi (2003) analyze payments for reserve capacity in a joint day-ahead energy and reserves auction. Reserves are procured through the energy market using energy only bids, and capacity payments are made based on the generator's opportunity cost. The revelation principle is applied to show that generators have an incentive to understate their costs so as to capture higher capacity rents.[20]

Such theoretical assessments are confirmed in practice by the case of Argentina that substituted its fixed capacity payment mechanism for a hybrid system of payments and contracts because fixed payments were found to distort the merit order dispatch, and negatively affected the long-term financial situation of thermal generators. In the UK, the LOLP system was manipulated by large players at the end of the pre-NETA period.[21] In several other countries, capacity payments have also led to construction of inefficient

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[18] A similar approach to a standby market was applied in Victoria, Australia, with obligations to ensure capacity in an energy-only market.

[19] The mathematical derivation of these results is presented in the annex. See also Barzalobre (2000).

[20] See also Newbery (1995).

[21] See Green (2004).

peaking units, promote the use of one fuel over others, and eliminated the incentive for availability during crisis of deficit supply.

Likewise, as in any price-cap procedure, setting the optimal level of capacity payments is very difficult (Singh, 2002). In Great Britain, during the pre-NETA period, the calculation of the LOLP suffered several flaws that overestimated the probability of losing load,[22] and underestimated the VOLL. This was a political strategic choice to provide generators with a constant flow of revenues so that capacity payments made investments in power plants easier. In Australia, VOLL was substantially increased to make peaking capacity commercial.

A practical problem of fluctuating capacity payments is that variations in such mechanism happen in the short run, whereas the relevant time for investment in capacity reserves is the long term (Knops, 2002). Additionally, the LOLP method is not adequate for largely hydro-based systems (as Brazil) as the LOLP would be very small during wet seasons, which would lead to disproportionate low revenues for thermal generators (Gülen, 2002). Therefore, any capacity adder should be designed to reflect the value of the plant to the system, which is in turn affected by the technology plant composition in such a system (Hunt, 2002).

Capacity payments might be combined with price caps to protect consumers because when capacity is paid separately, there is no need that price spikes remunerate reserve capacity (IEA, 2002). The result of such combination could be a reduction in price volatility without affecting average prices and reserves (Hobbs et al, 2002). However, price caps can also have a locational influence on generators that would seek high price-cap areas.

Notwithstanding its inconveniences, many sources believe that a capacity payment system --together with an ISO pool design-- is superior to the new NETA system for the UK at least with regards to resource adequacy. Such a combination "...is close to the Standard Market Design (SMD) recommendations of the FERC, which Hunt (2002) considers as the 'clear market design winner'" (Roques et al, 2004). Likewise, a comparative study carried out by the Council of Australian Governments in order to evaluate the Australian national electricity market concluded that their capacity payment system fares well when compared to market designs in PJM, Nordpool, and (especially) NETA (Commonwealth of Australia, 2002).

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[22] Capacity actually available and dispatched at peak times was therefore underestimated, which in turn facilitated gaming behaviour by generators. Other flaws included: the calculation of LOLP used average availability (ignoring that plants are typically fully available at peak times but less available off peak), and the LOLP software looked at absolute (rather than relative) differences between generation and demand even during the summer and as on a winter peak. VOLL was underestimated in part because a generic VOLL was used for all consumers (Roques et al, 2004).

3. CAPACITY REQUIREMENTS

Capacity requirements are set as an obligation to maintain a certain amount of reserve capacity. Such an amount is centrally determined through an administratively forecast of demand, and is usually imposed by the ISO (or the regulator) to LSEs. Conversely to capacity payments, the price is decentrally determined by the market once the amount of reserve capacity is set (see figure 1). LSEs must buy enough "capacity tickets" to meet the expected peak load of their customers multiplied by (1+X), where X is the expected reserve margin that will cover an estimated level of reliability to cope with random outages. The tickets are sold by generators who are usually allowed to export their reserve capacity to other markets. With a capacity requirement, the regulator is able to control the reserve level but the cost remains uncertain (IEA, 2002)

Capacity requirements are used in PJM, New York and New England markets where an obligation is imposed on LSEs to arrange for Installed Capacity (ICAP). In particular, PJM put into practice a bid-based, day-ahead and month-ahead ICAP markets.[23] LSEs are required to buy ICAP in order to be able to serve loads, and they can trade their ICAP with other LSEs. The ICAP requirements can be met by LSEs through self supply, bilateral transactions with suppliers, capability period auctions (several–month strip), monthly auctions, deficiency-spot market auctions, and so forth. Capacity resources can be exported from (or imported to) the PJM area. Generators sell a recall right that enables PJM to recall energy exports from capacity resources when required. When capacity is recalled, the supplier is paid the market price for energy. The system operator determines demand through the choice of obligations of LSEs, which must own or purchase capacity resources greater than or equal to their expected peak-load plus a reserve margin. If an LSE is short of capacity, it pays a penalty that equals the daily amount of deficiency in capacity times the number of days. When the system itself is short of capacity, the deficiency charge is the double of the capacity deficiency rate (equal to USD 174.73 per MW-day in 2003).[24]

Long-term reserves can also be viewed as price insurance and be treated as a private good but within the framework of a centralized provision of the ISO that imposes mandatory levels of such insurance on LSEs (Oren, 2003). These mandatory rules would compensate for several obstacles that consumers face when choosing an adequate level of protection, such as

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[23] On October 1, 1998, PJM initiated monthly and multi-monthly capacity markets, while daily capacity markets initiated their operation in 1999.

[24] The capacity deficiency rate indicates the annual fixed cost of a combustion turbine in PJM plus transmission costs (PJM, 2003).

technological barriers on metering control, political barriers to set electricity tariffs efficiently, and so forth.

For a market base on operating reserves backed by high prices, Stoft (2002) shows that optimal investment in generation capacity depends on the inverse relationship between capacity requirements and the purchase price limit on the system operator: the higher the reserve requirement the lower the optimal price limit.[25]

A theoretical analysis of the PJM-ICAP market is provided in Creti and Fabra (2004). They build a two-stage game theory model. In the first stage, prior to the realization of demand, generators compete in the capacity market and receive their payments for the capacity amounts they commit. In the second stage, once demand is realized, generators compete in the domestic and foreign markets. When there is excess demand, the regulator recalls the suppliers' committed capacity resources, which are paid at market prices. Finally, suppliers get their payments for the energy sold.

Creti and Fabra analyze this game for the monopoly and the perfect competition cases, and also study the role of the regulator in choosing the capacity requirement as well as in setting a capacity price cap. Creti and Fabra derive several results from their model on:

- The opportunity costs of committing capacity resources.
- The firm's optimal behavior in the capacity market.
- The regulator optimal decisions regarding capacity price caps and the optimal reserve requirement.

In a first result, they show the trade-off that a generator faces between committing more resources to the capacity market against the foregone revenues from exports (in the case of being recalled). The difference between the foreign and domestic prices then determines the opportunity cost of committing capacity resources.[26] The second result shows that two types of equilibria are possible for the firm's optimal behavior given the value of the capacity price cap, and the reserve requirement set by the regulator. When the price cap is too "low", the generator's opportunity costs will not be covered and a capacity deficit would arise (*capacity deficit equilibrium*). When the price cap is "high" enough capacity resources are able to cover the needed

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25 Stoft (2002) also shows that in a perfectly competitive market a price cap equal to the average value of lost load results in an optimal level of investment in generation capacity. Ford (1999), and Hobbs et al. (2001) also discuss the need for price caps when markets do not clear.

26 More specifically, the opportunity cost is also a function of the probability of recall, the amount of resources needed by the system to assure resource adequacy, and the intensity of price competition in the energy market.

capacity requirement (*market clearing equilibrium*).[27] Finally, Creti and Fabra show that the regulator should always set the capacity requirement equal to peak demand so as to fully avoid the risk of shortage, and to set the capacity price cap equal to the firm's opportunity costs of providing full capacity commitment.

Creti and Fabra's results show the fragility of the ICAP system, which crucially depends on the capacity price cap, and the capacity requirement. The administrative calculation of the latter variable is a subjective one,[28] while the optimality of the former variable depends on the market structure of financial transmission rights (FTRs) since the opportunity cost of the generator is given by the price difference between the domestic and foreign markets: if the FTR is subject to market power that will be reflected in the ICAP market.

In practice, ICAP mechanisms have generally failed to provide investment signals when they are most needed. ICAP markets were subject to market manipulation[29] that caused price spikes in 2000 in PJM. The pool was deficient some days in June, July and August 2000 since owners of capacity increased their exports for periods when external prices surpassed the PJM market price. In January 2001, there were price spikes of more than $300 MW-day with a deficiency in system capacity. Furthermore, high market concentration in capacity ownership has also been observed.

For New England, Joskow (2003) showed that the scarcity rents generated were far below from what would be necessary to attract reserve "peaking" capacity to invest (or continue operation) so as to supply the needed operating reserves and energy during scarcity conditions. The average scarcity rents in New England of $10,000 Mw-Year are very low compared to

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[27] Joskow and Tirole (2004) also build a model that shows how a combination of capacity requirements with capacity price caps might potentially restore investment incentives. Even in the presence of market power, a (Ramsey) optimum can be achieved when: (i) LSE capacity requirements can be met both by peak and base load generators, (ii) capacity requirements are determined using the demand from *all* consumers, and the capacity prices reflect the prices paid by *all* retail consumers, and (iii) the market for peaking capacity is contestable. However, this result is not true when there are more than three states of nature (where two state of nature are "off-peak" and "peak"). In such a case, strict price-cap regulation might be used to alleviate market power off-peak and allow peakers to recover their investment (Joskow and Tirole, 2004, pp. 45-46).

[28] There have been efforts to improve the calculation of the capacity requirement. For example, in the New York ISO a demand curve was proposed to be constructed as an alternative to an ICAP market. The intention was to increase resource reliability by valuing additional ICAP above the fixed capacity requirement (Harvard Electricity Policy Group, 2003).

[29] ICAP gives incentives in the short run for manipulating the availability of plants to increase revenue. Anticompetitive behavior is potentially higher when capacity and system constraints are binding. Such effects are magnified by the typical high inelasticity of both the supply and demand curves of electricity markets. Another practical problem of ICAP is the interaction among systems with and without capacity requirements, which might lead to inefficient distortions (IEA, 2002).

the fixed cost of a new combustion turbine built to provide reserve capacity estimated in between $60,000-$80,000 Mw-year. This means that the combination of an ISO spot market with ICAP markets has not been capable to provide enough incentives to attract generating capacity to maintain adequate reliability levels. Similar results have been obtained for the New York ISO (Patton, 2002).

The ICAP system is usually flawed in part because it derives from short-term adequacy concerns rather than long-term, and since it depends on a subjective estimation of a "right" capacity level which depends on generation stocks, fuel prices, load shapes, and elasticity of demand for reserves. Also, since ICAP is combined with the possibility of exportation of capacity, the value of the ICAP depends on the price differences across the adjacent markets. Furthermore, ICAPs have not provided incentives to build new generation facilities and, conversely, have contributed to keep old inefficient plants in place (Harvard Electricity Policy Group, 2003).[30]

FERC's original SMD also criticized ICAP requirements and proposed instead the use of resource adequacy requirements with targeted curtailments, penalties for undercontracting, and long-term contracting mandatory measures (FERC, 2002). This is a further flawed policy because there is no objective way to solve the resource-adequacy problem in accordance with SMD without incurring the many difficult issues faced in ICAP design (Chandley and Hogan, 2002). A preferred solution would be to allow prices to clear the energy and reserve markets (so that scarcity costs are properly signaled)[31] while allowing financial hedging contracts and demand-side measures. According to Chandley and Hogan, FERC should not mandate the replacement of ICAP mechanism while totally discourage a market-clearing alternative for reserve capacity markets.

PJM has then been looking to modify its ICAP system by developing a new methodology for peak load obligation, and by changing the month-ahead and day-ahead markets to a price-taker auction while retaining mandatory participation in the day-ahead market. Likewise, the ISO New England proposed a new locational installed capacity (LICAP) market since the capacity markets in New England were registering at certain times prices of zero while generation in constrained areas needed to be valued more highly

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30 Joskow and Tirole (2004) theoretically show that the inefficient dispatch of resources procured by the ISO in order to be used during reserve scarcity conditions will lead in the long run to substitution of base load units by peak units.

31 This is of course confronted with the political motivation to keep prices low. However, from a strictly economic point of view, the experience in industries different from the electricity industry is that "the best cure for high prices is high prices" (Harvard Electricity Policy Group, 2003, p.18).

(Davis, 2004).[32] The initial plan was to extend the day-ahead and real-time markets to include reserve availability bids. However, a primary difficulty was that the marginal cost of providing reserves in such markets was negligible (Cramton et al, 2005). The LICAP proposal included basing prices in demand curves for Maine, Connecticut, metropolitan Boston, and the rest of New England. New prices are to be phased-in through capped increments in a five-year period. These proposals were initially opposed by LSEs and other consumers since –in their opinion-- they would only produce huge transfers from LSEs to generators, without providing long-term incentives to increase new generation (Davis, 2004). However, the New England ISO abandoned the original idea of extending the day-ahead and real-time markets to include reserves, and proposed instead to price reserves in real time during shortages (shortage pricing) together with enhancing the forward reserve market for offline reserves.[33] The LICAP market and the forward reserve market then work as complements. LICAP rewards flexible resources, while the forward market provides compensations (based on locational prices) to reserve resources so that price reflects the economics costs of reserving supply.

4. CALL OPTIONS

As seen in the previous section, capacity requirements have the problem of artificially setting a capacity level and the value of maintaining such a capacity. Call options are proposed as an alternative system that would represent a more real value of capacity, and that bundles generation adequacy with price insurance (Vázquez et al, 2002). The desired capacity is centrally determined, while price is decentrally determined but consumers are hedged against huge price spikes (see figure 1). Typically, the system operator would purchase call options from the generators in a competitive bidding process that would cover the desired capacity.[34] The buyer exercises the option if the spot price is greater than the strike price (and receives a premium equal to the

[32] Creti and Fabra (2004) deduce from their theoretical model the possibility that capacity markets clear at zero prices if there is no spread between national and foreign prices.

[33] Real time shortage prices are determined for each type of reserves according to a penalty factor. A bonus is paid for most reserves for being available when most needed. Meanwhile, the forward reserve market works according to auctions of offline reserves.

[34] Alternatively, LSEs could be the buyers of options through self-provision from their own controlled resources, or through bilateral contracts with generators.

difference between the spot price and the strike price).[35] The strike price of options is used as a price-cap in case of emergencies, and high penalties are imposed for failure to deliver when the option is called. This assures that the promised capacity is really made available, especially during the peak periods.

The price cap of a call options system works as a protection to consumers, which will assure that prices stay within a socially acceptable range so that the regulatory intervention becomes a form of insurance against price volatility. Compared to the ICAP system, the risk is now changed to the system operator (or the LSE) that now bears the uncertainty of whether the options are used or not. Risk is removed from generators that now face a more stable revenue horizon compared to an uncertain and volatile income for peak generation. The expected generators income for prices above the strike price equals the price of the call options, and generators now receive a fixed payment for the option. Prices and corresponding capacity payments are then derived as market based premia from the market players' strategies for risk management.

The provision of supply adequacy through LSE's hedging obligations captures several important features (Oren, 2003). If the LSE obligations are adjusted (say) monthly to reflect fluctuations in forecasted peak demand, a secondary market for call options should emerge that would permit the trading of options among LSEs. However, while secondary markets permit the LSEs to adjust their positions each month, price volatility in such markets increases the LSEs risk. Hedging should then be treated as another ancillary service, allowing LSEs self provision through bilateral contracts with the ISO act as a provider of last resort. The danger is of course that this may interfere with incentives in the contract market, and be perceived by LSEs as an alternative to prudent risk management.

In countries lacking well-developed financial markets, LSEs or generators may assume more risk than they can handle reliably.[36] In particular, LSEs might not be able to manage risk in a socially optimal way,

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[35] The strike price of a call option is the contractual price at which the underlier (i.e. the value(s) from which a derivative derives its value) will be purchased in the event that the option is exercised. The buyers of the call option may choose the strike price that suits their risk aversion: high (low) strike prices have small (high) premiums. Option premiums also work as substitute efficient signals compared to price signals generated by ICAPs (Singh, 2002).

[36] Likewise, the capital market might not be able to provide the long term financing for generation investments commensurate to the associated risk. This combined with inexperience with commodity trading in the electricity industry --and the perceived regulatory risk-- might raise the cost of capital so much that the investment level will be far below than the needed for an efficient resource adequacy level (Oren, 2003).

so that the regulator should need to set a minimum contracting or hedging level on LSEs. Then again, this would lead to non-market arbitrariness.

A call-option mechanism has been designed for the electricity market in Colombia (Vázquez et al, 2002). The regulator requires the system operator to buy a prescribed volume of reliability contracts that allow consumers to get a market compatible price cap in exchange for a fixed capacity remuneration for generators. This entitles consumers to enough available generation capacity. Reliability contracts then consist of a combination of a financial call option with a high strike price, and an explicit penalty for generators in case of non-delivery.[37] The regulator carries out a yearly auction of option contracts and sets the strike price (at least 25% above the variable cost of the most expensive generator) and the volume of capacity to be auctioned (in terms of the expected peak demand and the available installed capacity). However, generators decide how to divide their total capacity into different blocks (firm, less-firm, new entrants, and least-firm) and how to price each block, so that capacity assigned to each generator is a market result and not the outcome of an administrative process. This proposal is very sensitive to market power. Therefore, its implementation requires that the maximum amount that a generator can bid is limited to its nominal capacity, that portfolio bidding is not allowed, and that the winning bids cannot transfer their obligations of physical delivery to other generators.

CONCLUSIONS

This paper has surveyed the contributions to the literature on supply adequacy in electricity markets. We studied the different existing approaches, and described their analytical properties and implementation characteristics. In assessing the different alternatives, the trend in the literature is to look for some kind of transitory regulatory intervention that grants resource adequacy. Capacity obligations or capacity payments can mainly be useful if hourly metering, hourly pricing, and demand bidding are inadequate, and cannot be implemented expeditiously. Otherwise, many believe that the energy and the reserve markets should not be separated (Hunt, 2002). The ideal would then be an ISO (which runs day-ahead and spot markets) that takes care of imbalances and reaches equilibrium of all electricity markets in an integrated way. Market players would meet their long run expectations for the demand-supply balance in well-developed forward and futures markets. Energy and reserve pricing would take care of supply adequacy. This last approach relies

[37] When the market price p is greater than the strike price s, and the generator is unable to honor its obligation to produce, the generator will have to pay an additional penalty *pen* (apart from the difference $p-s$). The additional penalty is intended to discourage even more bids not backed by reliable capacity.

on the view that capacity mechanisms are designed for electricity markets that miss a fundamental central issue: if regulators set the type, level and location of capacity levels and payments there will not be much left for markets to do. All that would be left is competitive procurement, very much like what is done through traditional regulation.

In practice, however, electricity markets are usually implemented together with transitory resource-adequacy measures, but capacity payments and requirements alone have been found to present several inconveniences both in theory and practice. In the case of capacity payments, Argentina abandoned them because they negatively affected the financial situation of generators, while they were manipulated by large players in the UK. In several other countries, they led to create inefficient peaking plants, artificially promoted the use of a certain fuel, and distorted the structure of production incentives during crisis of deficit supply. Additionally, experience has shown that the calculation of the level of capacity payments does not follow the long run logic needed for investments in capacity reserves. Likewise, it is a subjective task that could be susceptible to political manipulation, and that very much depends on the technological plant composition. Notwithstanding its inconveniences, the capacity payment system combined with a pool design has shown to provide better incentives in the UK and Australia for investments in generation reserves compared to NETA, PJM and Nordpool.

With regards to capacity requirement mechanisms, practice has shown that they do not provide adequate investment signals, and that they have been subject to market manipulation, have not promoted the building of new generation facilities, and have led to inefficient distortions when they interact with systems without capacity requirements. In PJM, for example, they led to several price spikes when owners of capacity increased their exports as external prices surpassed the PJM market prices. In New York, the ICAP system was not able to generate incentives to attract generating capacity that guaranteed resource adequacy because scarcity rents were too low compared to the cost of building peaking capacity. The LICAP proposal for New England was originally opposed for its lack of long-term incentives to increase capacity reserves, and because it represented a rent transfer from LSEs to generators. Even FERC proposed resource adequacy requirements based on long-term contracting measures. Similar to capacity payments, capacity requirement mechanisms are usually derived from short-term adequacy concerns rather than long-term, and the calculation of an optimal capacity level is subjective as well.

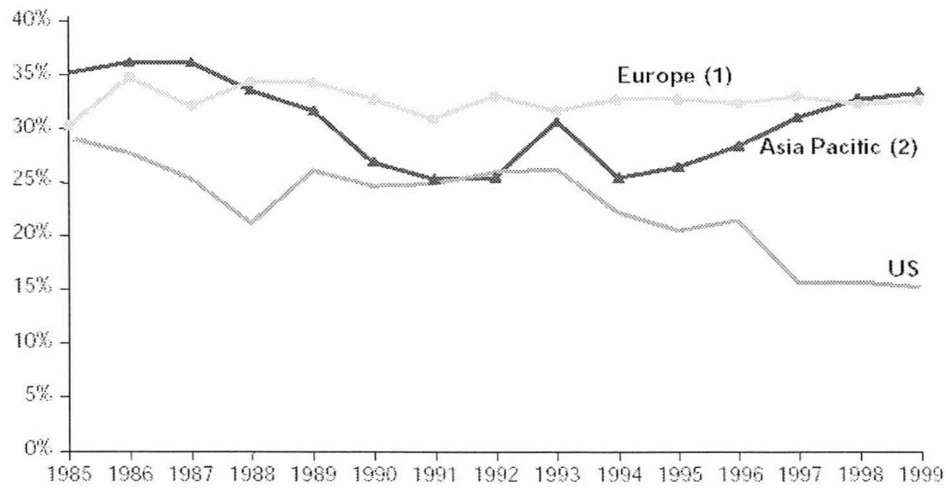
However, the ISO New England has recently proposed capacity reserve market that more or less combines capacity requirements and payments, as well as forward markets. The original proposal of extending the day-ahead and real-time markets to include reserves was abandoned. The new proposal is to price reserves in real time during shortages together with developing a forward reserve market for offline reserves. The LICAP market and the forward reserve are then combined in such a way that LICAP rewards flexible resources, while the forward market remunerates offline reserve resources. This is an interesting proposal that seems to extract the virtues of both the capacity requirement and capacity payment methods.

The most advanced developments in the literature point to the use of an alternative system based on some type of hedging instruments such as call options. Capacity payments or requirements would work efficiently when combined with risk management approaches and hedging instruments that promote demand side participation. Regulatory intervention would then be focused on promoting rules that facilitate liquid markets for energy futures and risk management. In any case, even tough some see resource adequacy requirements as artificial policies that suppress market signals and retard market development, they could also be understood as positive measures that, if effective, could prevent governments from severely costly policy reversals (as the costly policy reversals in California and Ontario) that could occur in the absence of any supply requirement.

Annex

Reserve Margins in IEA Countries

Figure 2. Reserve Margin in IEA Countries 1985-1999



(1) Portugal, Italy, Denmark and the Netherlands not included.

(2) Australia not included.

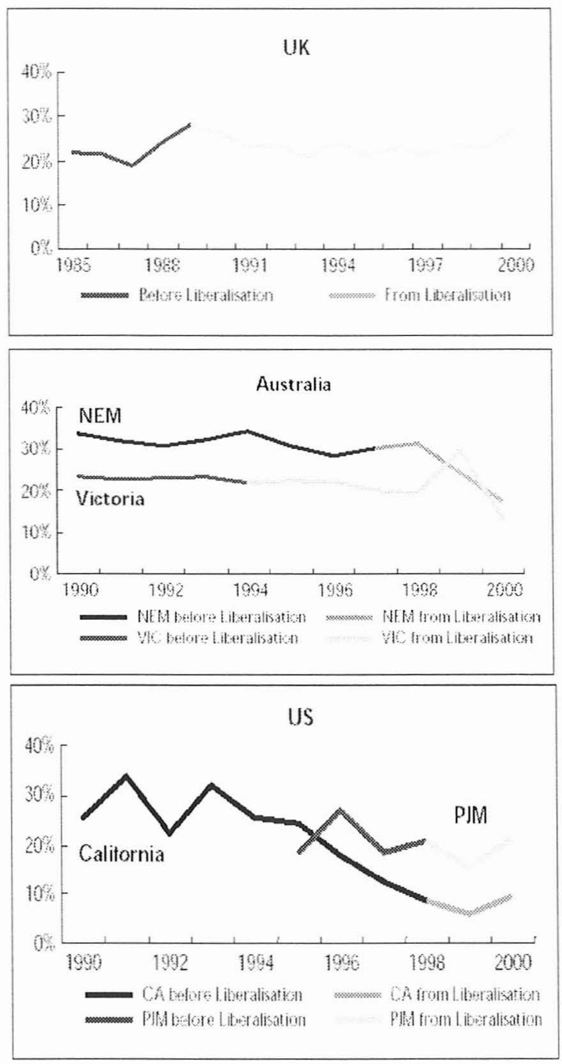
Source: IEA

Table 1
Reserve Margins in IEA Countries (%)

	1985	1990	1995	1999
Australia	36	28	...	21*
Austria	...	61(2)	60	54(3)
Belgium	38	26	21	18
Canada	26	19	24	...
Denmark	36	36	46	49
Finland	22	23	22	23
France	31	39	38	37
Germany	27	25	28	29
Greece	42	42	32	31
Hungary	6	9	23	26
Ireland	34	32	24	14
Italy	45(1)	36	40	42
Japan	35	27	26	33
Luxembourg	54	...	...	...
Netherlands	43	39	41	26(3)
New Zealand	37	29	34	29
Norway	27	37	28	27
Portugal	...	...	52	57
Spain	46	39	44	39
Sweden	27	36	27	23
Switzerland	47	42	42	33
Turkey	40	46	36	34
United Kingdom	21	26	21	23
United States	30	26	20	16

(1) 1986 data.,(2) 1991 data, (3) 1998 data, (*) Missing data.
Source: IEA

Figure 3 Reserve Margins in Selected Power Markets



Notes:

- In PJM, there is approximately 5 per cent interruptible demand which has been included in the reserve margin calculation, for comparative purposes.
- VIC means Victoria, Australia.

Source: IEA

Table 2. Change in Reserve Margins in the Reformed Markets

	UK	Norway	Sweden	Australia Victoria	Australia N.S. Wales	US: California	US: PJM
Change in reserve margin since year of liberalization until year 2000	0	-2	0	-24	-13	1	0
Change in average reserve margin (1)	5	-3	-5	-16(2)	-7	7,5	-3(3)
Year of liberalization	1990	1991	1996	1994	1997	1998	1998

Notes:

(1) Difference between average reserves in the five years before liberalization and average reserves from year of liberalization to year 2000.

(2) Average four years before liberalization in 1994.

(3) Average three years before liberalization in 1998.

Source IEA

The Capacity Payment Model

Let us first study a simple stylized version a capacity-payment model. Assume that the inverse demand function at a peak period has the form:

$$P(Q)+\Delta P(Q)=a(1+k)-bQ(1+k) \tag{1}$$

where $P(Q)$ is the inverse demand function, Q is the amount of electricity generated, $a>0$ and $b>0$ are positive constants, and $k>0$ is a factor added to the price of electricity during peak periods.[38]

[38] k would therefore contain terms such as "*cfalla*" and "*k factor*" of the 1999 Mexican reform proposal (see Carreón-Rodríguez and Rosellón, 2002).

We assume there are only two firms, firm 1 and firm 2. We then have $Q = q_1 + q_2$ (where q_1 and q_2 are the amounts of electricity generated by firm 1 and firm 2, respectively).
The cost functions are

$$c_i(q_i) = c_i q_i \qquad \text{for } i = 1,2 \tag{2}$$

where c_i is the marginal cost of power generation for firm $i = 1,2$. Suppose that $c_1 < c_2$. The profit maximization problem for firm $i = 1,2$ is then

$$\max_{q_i}\{\Pi_i\} = \max_{q_i}\{[a(1+k) - b(1+k)(q_i + q_j)]q_i - c_i q_i\} \tag{3}$$

The optimal quantities of a Cournot duopoly, and the market price that solve problem (3) are

$$q_i^* = \frac{a(1+k) + c_j - 2c_i}{3b(1+k)} \qquad \text{for } i = 1,2 \tag{4}$$

$$P^*(Q) + \Delta P^*(Q) = \frac{a(1+k) + (c_1 + c_2)}{3} \tag{5}$$

Given these optimal values, profits for firm $i = 1,2$ are

$$\Pi_i = \frac{[a(1+k) + c_j - 2c_i]^2}{9b(1+k)} \tag{6}$$

Therefore, the net social benefit (equal to the sum of total profits plus total consumer surplus) is

$$NSB = \Pi_1 + \Pi_2 + EC$$
$$= \frac{\{8a^2(1+k)^2 - (c_1 + c_2)[8a(1+k) + (c_1 + c_2)] - 36c_1c_2\}}{18b(1+k)} \tag{7}$$

Note that that this expression is mainly determined by the value of k (the term that artificially increases the price of electricity), and the marginal costs of each firm.

The Regulated Standby Model

Let us now formally analyze the regulated standby model in which excess demand is satisfied in a reserve (or standby) market. Now firm 1 is a monopoly in the pool market, while firm 2 is also a monopoly operating in the reserve market. Firm 2 only takes care of excess demand.

Firm 1's inverse demand function is given by

$$\hat{p}(\hat{q}_1) = \hat{a} - \hat{b}\hat{q}_1 \tag{8}$$

and its cost function is

$$c(\hat{q}_1) = \hat{c}_1\hat{q}_1 \tag{9}$$

The profit maximization problem of firm 1 is then:

$$\max_{\hat{q}_1} \left\{\hat{\Pi}_1\right\} = \max_{\hat{q}_1}\left\{(\hat{a} - \hat{b}\hat{q}_1)\hat{q}_1 - \hat{c}_1\hat{q}_1\right\} \tag{10}$$

In this case, the equilibrium quantity and price are

$$\hat{q}_1 = \frac{\hat{a} - \hat{c}_1}{2\hat{b}} \tag{11}$$

$$\hat{p}^*(\hat{q}_1) = \frac{\hat{a} + \hat{c}_1}{2} \tag{12}$$

Then, profits are

$$\Pi_1 = \frac{(a - c_1)^2}{4b} \tag{13}$$

Firm 2 only operates to satisfy excess demand at peak periods. This firm faces an inverse demand function of the form:

$$\hat{p}(\hat{q}_2) + \Delta\hat{p}(\hat{q}_2) = \hat{a}(1 + \hat{k}) - \hat{b}\hat{q}(1 + k) \tag{14}$$

and its cost function is

$$\hat{c}(\hat{q}_2) = \hat{c}_2\hat{q}_2 \tag{15}$$

Firm 2's profit maximization problem is

$$\max_{q_2}\{\hat{\Pi}_2\} = \max_{q_2}\{[\hat{p}(\hat{q}_2) + \Delta\hat{p}(\hat{q}_2)]\hat{q}_2 - \hat{c}_2\hat{q}_2\} \tag{16}$$

In this case, the equilibrium quantity and the equilibrium price are

$$\hat{q}_2^* = \frac{\hat{a}(1+\hat{k}) - \hat{c}_2}{2\hat{b}(1+\hat{k})} \tag{17}$$

$$\hat{p}^*(\hat{q}_2) + \Delta\hat{p}^*(\hat{q}_2) = \frac{\hat{a}(1+\hat{k}) + \hat{c}_2}{2} \tag{18}$$

Then, profits are

$$\Pi_2 = \frac{[a(1+k) - c_2]^2}{4b(1+k)} \tag{19}$$

Hence, the net social benefit in the standby model is

$$NSB = \frac{3(1+k)(a-c_1)^2 + 3[a(1+k) - c_2]^2}{8b(1+k)} \tag{20}$$

Now, assuming $c_1 \langle c_2$ (firms in the pool are more efficient than the firms in the reserve market), we get

$$\hat{q}_1^* = \frac{\hat{a} - \hat{c}_1}{2\hat{b}} \quad \rangle \quad \hat{q}_2^* = \frac{\hat{a}(1+\hat{k}) - \hat{c}_2}{2\hat{b}(1+\hat{k})} \tag{21}$$

$$\frac{\hat{a}(1+\hat{k}) - \hat{c}_2}{2\hat{b}(1+\hat{k})} = \frac{\hat{a}}{2\hat{b}} - \frac{\hat{c}_2}{2\hat{b}(1+\hat{k})}$$

and

$$\hat{p}^*(\hat{q}_1) = \frac{\hat{a} - \hat{c}_1}{2} \quad \langle \quad \hat{p}^*(\hat{q}_2) + \Delta\hat{p}^*(\hat{q}_2) = \frac{1}{2}\hat{a}(1+\hat{k}) + \frac{\hat{c}_2}{2} \tag{22}$$

Comparison of the Capacity Payment and Standby Models

Once we have obtained the equilibrium values for quantities, prices, profits, consumer surplus and net social benefits in both models, it is possible to compare under what conditions one policy is superior to the other. For this purpose, we will assume that generators in the capacity-payment and the standby models face the same cost and demand functions, that is

$$\hat{a} = a$$
$$\hat{b} = b$$
$$\hat{q}_i = q_i, i = 1,2$$
$$\hat{c}_i = ci, i = 1,2$$

We carry out the comparison both at the firm level, and at the social level. Total profits under the standby model are greater than total profits under the capacity-payment model if

$$\frac{5}{18}c_1\left(\frac{a}{b}\right) - \frac{5}{18}c_2\left(\frac{a}{b}\right) + \frac{5}{9}\frac{c_1^2}{b(1+k)} - \frac{8}{9}\frac{c_1 c_2}{b(1+k)} - \frac{11}{36}\frac{c_2^2}{b(1+k)} \rangle \frac{1}{4}\frac{a^2}{b} - \frac{5}{18}\frac{a^2(1+k)}{b} \tag{23}$$

while consumer surplus in the standby model is greater than consumer surplus under the capacity-payment model if

$$\frac{5}{18}\left(\frac{a}{b}\right)c_1 - \frac{5}{18}\frac{c_2}{(1+k)} + \frac{1}{(1+k)}\left[\frac{5}{9}c_1^2 - \frac{11}{36}c_2^2 + \frac{c_1}{4} - \frac{8}{9}c_2\right] \rangle \frac{1}{36}\frac{a^2(1+k)}{b} + \frac{a^2}{b} \tag{24}$$

Given that $c_1 \langle c_2$, it is evident from these equations that profits, consumer surplus and net social benefits are greater under the standby model than under the "capacity payment" model the greater is the value of $(c_2 - c_1)$. That is, the standby model provides better social and private outcomes for economies where the marginal cost difference between modern and old plants is large enough.

Moreover, both models can also be compared in terms of implied electricity prices. According to (22), the equilibrium reserve-market price in the standby model is greater than the corresponding spot price. However, what is the relation between the former price and the equilibrium price of the capacity-payment model?

It can be shown that

$$p^*(q_1+q_2)+\Delta p^*(q_1+q_2) > \hat{p}^*(\hat{q}_2)+\Delta\hat{p}^*(\hat{q}_2) \tag{25}$$

whenever the difference (c_2-c_1) is sufficiently large. That is, implementation of a bypass reserve market makes social sense in terms of prices only if there is a large efficiency gap between old and new generation plants. In such a case, the implementation of the capacity-payment solution would only create an artificially high rent that could provide incentives for development of oligopoly generation markets.

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