MAJOR ENERGY USERS INC

THE VOICE OF ENERGY CONSUMERS

Australian Energy Markets Commission

Reliability Panel

Comprehensive Reliability Review

Supplementary comments to the RP Issues Paper 11 May 2006, and the RP Forum of 27 July 2006

by

The Major Energy Users Inc

And

Major Employers Group Tasmania

August 2006

Assistance in preparing this submission by the Major Energy Users Inc and the Major Employers Group Tasmania was provided by Headberry Partners Pty Ltd and Bob Lim & Co Pty Ltd.

Alex Henney and Miles Bidwell provided extremely useful advice with regard to their views on reliability and in particular their development of reliability Options. The authors have used the Henney/Bidwell work extensively in this report and thank them for the information made available for this purpose.

The content and conclusions reached in this submission are entirely the work of the Major Energy Users Inc., MEG Tasmania and its consultants.

"Evidence from the U.S. and some other countries indicates that organized wholesale markets for electrical energy and operating reserves do not provide adequate incentives to stimulate the proper quantity or mix of generating capacity consistent with mandatory reliability criteria."

COMPETITIVE ELECTRICITY MARKETS AND INVESTMENT IN NEW GENERATING CAPACITY

by Paul L. Joskow

April 2006

CONTENTS Page

Executive Summary

This submission expands on the Major Energy User's earlier submission by detailing opinions – such as Reliability Options and Forward Capacity Markets – to ensure adequate investment in generation capacity to meet the future needs of consumers in the National Electricity Market.

The Reliability Panel's attention is drawn to the NEL objective of ensuring "…..the long term interests of consumers….".

Attention is drawn to the Western Australian electricity market, with reserve capacity mechanism.

The US Electricity Energy Market Competition Task Force's recent draft report to the US Congress points to the defects in energy-only and capacity supported markets but clearly demonstrate that a better solution to both extremes is required.

Other academics such as Paul Joskow of MIT points to the failure of energy only markets in the US and to the need for forward capacity markets.

Drawing on Henney and Bidwell, the submission proposes the use of the Reliability Options concept as a possible way forward for the NEM. Details are provided in the submission.

The major benefit of implementing the Reliability Options is that it will result in a dramatic reduction in the level of VoLL, perhaps to the levels used in the US markets. This in turn will reduce the risks and financial exposure faced by generators and retailers operating in the very volatile NEM, leading to a reduction in risk mitigation costs.

1. Introduction

The MEU and MEG (MEU)

Subsequent to the submission made by MEU and MEG (MEU) to the AEMC Reliability Panel (RP) responding to the invitation to respond to the RP Issue Paper as part of the Comprehensive Reliability Review, and to the presentation made to the RP Forum on 27 July 2006, the MEU welcome the opportunity to expand further on its earlier submission, but with particular reference to **options of ensuring adequate investment in generation capacity to meet the future needs of consumers of electricity in the NEM.**

As is required by the National Electricity Law (NEL) objective, the MEU refers the RP to the NEL requirement of the RP must address the issue of reliability in terms of ensuring "…**the long term interests of consumers ..." and that this will be the focus of their deliberations.** As the MEU membership represents exclusively electricity consumers and not consultants, supply side entities or government entities, the views expressed in the earlier submission and again in this supplementary submission are those of consumers.

A specific request was made of MEU that the supplementary submission addresses, in more detail, the concepts of Reliability Options and Forward Capacity Markets raised in the initial submission. In particular, the RP expressed a desire for MEU to identify, in terms of consumer interests, how these concepts might be integrated into the NEM with maximum benefit to consumers.

1.1 Summary of the MEU initial submission

In its initial submission, MEU pointed to the outcomes of the existing reliability approach which has demonstrated a number of negative aspects:-

- ❖ The market shows an excessive degree of volatility, with as much as 25% of the average pool price being caused from a very few (0.2%) half hourly time periods. This degree of volatility provides little on which to rely upon when examining the costs and benefits of investment in new generation.

- ❖ The fact that the reserve trader provisions have been used more frequently in recent times implies that the rise in VoLL in 2002 has not resulted in sufficient new generation.

- Whilst NEMMCo has secured standby for expected short falls in generation capacity, the fact that the reserve trader was not dispatched could be a function of either timing (in that the expected weather driven peak demands were not coincidental with normal work days) or that NEMMCo forecasts were unduly conservative, or a combination of both. Notwithstanding these options, from a consumers viewpoint it is more preferable for NEMMCo to be somewhat conservative, than to force consumers to be load shed unexpectedly.

- That the NEM is in fact a series of regions with modest interconnection, the mix of generation in each of the regions is not necessarily optimal. Thus examination of the NEM as a whole is not appropriate, and analysis of each of the mix of the regions is essential to identify shortcomings. As an example, Tasmania uses hydro to provide base generation, when much of the hydro available is in reality peaking generation. Equally, generation in South Australia is predominantly gas fired and is better used as intermediate generation. In other regions (such as Queensland and Victoria) there is an overabundance of base load generation.

- The degree of interconnection between regions is modest, and as a result causes the regional mix of generation to be less than optimal, and provides generators with excessive market power in each region. Strengthening interconnection is a way of balancing the different regional mixes of generation to provide a more composite view of the NEM. The costs of improving interconnection need to be balanced by the costs of investing in more generation.

- There has been little demand side response, yet the RP and others believe this is essential to optimize the utilization of the NEM assets. In fact, the suggestion that consumers **should be required to** shed load detracts from the NEL objective, and totally misses the point that consumers have made significantly more investment than has the NEM, and has made this investment based on the supposition that there will be power available in the long term. To require consumers to shed load implicitly assumes that the investment made by consumers has less worth than the investment made by those operating in the NEM. For industry to shed load (even if there is some reimbursement for the inconvenience caused) reduces the creation of national wealth.

  From an economic efficiency viewpoint, reimbursing constrained off consumers for the resultant inconvenience is only a transfer of wealth between consumers – with those consumers still taking power paying the costs of the closure of those consumers accepting being constrained off.

- The energy only market is seen as not supplying adequate recompense for generation in the absence of generators using market power to spike prices (as they have done since the NEM commenced). MEU provided the views of Jaskow of MIT and Bidwell (previously of NERA) to support this view. At the recent forum, generators tended to support this view. If this is the case, then it explains why there has been insufficient action to provide more generation except as a physical hedge in response to market spikes.

- There has been little emergence of a secondary market, probably due to the excessive volatility and minimum of coincidence between demand and price. This has resulted in short term forward contracting between consumers and generators, rather than the long term contracts needed to underwrite new generation. Retailers are unwilling to enter into long term contracts as they may have contracted more supply than they have contracted to sell and their ability to on-sell such unused energy is not readily disposed of due to a lack of secondary trading counterparties.

- In the recent stakeholder's forum presentation, MEU introduced the concept of "VoLL on the margin". Consistently consultants and energy market specialists have attempted to quantify at what price consumer's will elect to cease using electricity ie a value of VoLL. The effect of VoLL from a consumer's viewpoint reflects the degree of disruption caused by the loss of power. This varies between consumers and the time at which consumers lose the power. What the various studies have down is identify "VoLL on the margin" – ie at the time when the loss will cause the most disruption to the consumer.

  In fact, even for the same consumer VoLL varies – for the aluminium smelter, loss of power for a short time is more of an inconvenience providing the loss is for a short period. Extend this loss for some hours and the loss is catastrophic.

  For a domestic consumer, loss of power during the night, even for extended periods is no more than an inconvenience, as there is sufficient thermal inertia in the various machine used to tide over. Because this loss to occur at 6pm when the evening meal is being prepared, it is getting colder, and the TV programs cannot be seen, then the loss is considered major.

> **To apply a "one size fits all" approach to VoLL is absurd, and neglects the diversity that applies to all users of electricity and the needs of different consumers.**

The MEU counsels the RP to address its deliberations keeping in mind the way consumers use electricity and their expectations

1.2 Other concepts on reliability

The WA Electricity market

In its summary of the how the WA electricity market is to operate, the WA Office of Energy states[1]

> "The Reserve Capacity mechanism is intended to ensure that the SWIS[2] has adequate installed capacity available from generators and demand-side management options at all times so as to:
>
> - Cover expected system peak demand plus adequate additional capacity to ensure demand can be meet in the event of the failure of the largest generator while maintaining some capability to respond to frequency variations.
> - **Remove the need for high and volatile energy prices that are required in markets like the NEM to provide adequate revenue for peaking facilities and to trigger new investment.** Instead, energy prices will be capped to low levels (relative to the NEM) with the Reserve Capacity mechanism contributing to generator capital costs. While the Reserve Capacity mechanism may fully fund the capital costs for peaking facilities, it may only cover some of a baseload unit's capital costs." (emphasis added)

That the WA Government, despite its exposure (perhaps even because of it) to the NEM, has elected to have a capacity mechanism to ensure reliability in the SWIS implies that there are concerns in this country about the efficacy of the energy only market to deliver adequate generation reserves.

The WA Government has attempted to minimize the ability of generators to "game" the capacity market by holding auctions for supply periods of three years ahead, and capping the capacity market price at the cost of an open cycle gas turbine generator of a specific size. Whilst the approach designed is to minimize the ability of the generators to "game" the capacity market, it does not

---

[1] Section 7.1

[2] The SWIS is the South Western Integrated System and is the electricity system that provides electricity to the south west of WA, including Perth.

include some of the features inherent in more recent developments to resolve the detriments of the approach.

Electric Energy Market Competition Task Force

It is interesting to note that whilst MEU (and in the Bardak report referenced in the MEU initial submission) have identified these shortcomings in the NEM (even to the extent of being called "the Cassandra" of the NEM), the recent draft report to the US congress by the specially established Electric Energy Market Competition Task Force report[3] tends to support a number of these defects identified in the NEM by the MEU. In particular, the draft report highlights the need for better interconnection and a lack of investment in generation. That the US has both energy-only markets and capacity supported markets in different regions, and yet both approaches suffer a similar lack of investment, clearly shows that a better solution to both extremes is needed.

The proponents of the energy-only market point to the signals that such a market provides, and to the detriments of the capacity market approach. Likewise, the capacity market proponents point to the certainty of needed investment as being the prime advantage and the disincentive provided by the highly volatile prices in the energy-only market.

Both approaches allow generators to exercise market power and the draft report points this out. Their concern with the energy-only markets is that there is no clear construct as to when the signals point to scarcity of energy or to market power exercise. The report goes onto highlight that the capacity market can be cornered by incumbent generators and so prevent new entrants, and there is no certainty that the capacity payment made is equitable and driven by competition factors.

On page 63 of the report, it states:

> "Financing was more readily accessed for projects like combined cycle gas and particularly gas turbines that can be built relatively quickly and were viewed at the time to have a cost advantage compared with existing generation already in operation, including less efficient gas-fueled generators.[4] In 1996, the Energy Information Administration projected that 80% of electric generators between 1995 and 2015 would be combined cycle or combustion turbines.[5] Base-load units, such as coal

[3] see excerpts in the appendix

[4] ENERGY INFO. ADMIN., DOE/EIA-0562(96), THE CHANGING STRUCTURE OF THE ELECTRIC POWER INDUSTRY: AN UPDATE 38 (1996).

[5] Id.

plants, with construction and payout periods that would put capital at risk for a much longer period of time, were harder to finance.[6]"

Box 3-3
The Use of Capacity Credits in Organized Wholesale Markets:

In theory, capacity credits could support new investment because suppliers and their investors would be assured a certain level of return even on a marginal plant that ran only in times of high demand. Capacity credits might allow merchant plants to be sufficiently profitable to survive even in competition with the generation of formerly-integrated local utilities that may have already recovered their fixed costs.

The report goes on to say (page 68) that:

> "Unfortunately, it is difficult to distinguish high prices due to the exercise of market power from those due to genuine scarcity. High prices due to scarcity are consistent with the existence of a competitive market, and therefore perhaps suggest less need for regulatory intervention. High prices stemming from the exercise of market power in the form of withholding capacity may justify regulatory intervention. Being able to distinguish between the two situations is therefore important in markets with market-based pricing.[7]"

In regard to capacity payments the reports cite some cautions (pages 68 and 69):

> "Like any regulatory construct, however, capacity payments have limitations. It is difficult to determine the appropriate level of capacity payments to spur entry without over-taxing market participants and consumers.
>
> To the extent that capacity rules change, this creates a perception of risk about capacity payments that may limit their effectiveness in promoting investment and ultimately new generation. When rules change, builders and investors may also take advantage of short-term capacity payment spikes in a manner that is inefficient from a longer-term perspective.
>
> If capacity payments are provided for generation, they may prompt generation entry when transmission or demand response would be more

---

[6] Hearing on Nuclear Power, Before the Subcomm. on Energy of the S. Comm. on Energy & Nat'l Res., Mar. 4, 2004 (statement of Mr. James Asselstine, Managing Director, Lehman Brothers); see also NUCLEAR ENERGY INSTITUTE, INVESTMENT STIMULUS FOR NEW NUCLEAR POWER PLANT CONSTRUCTION: FREQUENTLY ASKED QUESTIONS, available at http://www.nei.org/documents/New_Plant_Investment_Stimulus.pdf.

[7] See generally Edison Mission Energy, Inc. v. FERC, 394 F.3d 964 (D.C. Cir. 2005).

affordable and equally effective. Capacity payments also may disproportionately reward traditional utilities and their affiliates by providing significant revenues for units that are fully depreciated. Capacity payments also may discourage entry by paying uneconomical units to keep running instead of exiting the market. These concerns can be addressed somewhat by appropriate rules – e.g., NYISO's rules giving capacity payment preference to newly-entered units – but in general, it is difficult to tell whether capacity payments alone would spur economically efficient entry.

One issue that has arisen is whether capacity prices should be locational, similar to locational electric power prices. PJM, ISO-NE and NYISO have either proposed or implemented locational capacity markets that may increase incentives for building in transmission-constrained, high-demand areas. The combination of high electric power prices and high capacity prices in these areas may combine to create an adequate incentive to build generation in load pockets.[8]

Several options may be used to elicit adequate supply in wholesale markets:

1. One possible, but controversial, way to spur entry is to allow wholesale price spikes to occur when supply is short. The profits realized during these price spikes can provide incentives for generators to invest in new capacity. However, if wholesale customers have not hedged (or cannot hedge) against price spikes, then these spikes can lead to adverse customer reactions. Unfortunately, it can be difficult to distinguish high prices due to the exercise of market power from those due to genuine scarcity. Customers exposed to a price spike often assume that the spike is evidence of market abuse. Past price spikes have caused regulators and various wholesale market operators to adopt price caps in certain markets. Although price caps may limit price spikes and some forms of market manipulation, they can also limit legitimate scarcity pricing and impede incentives to build generation in the face of scarcity. Not all the caps in place may be necessary or set at appropriate levels.

2. "Capacity payments" also can help elicit new supply. Wholesale customers make these payments to suppliers to assure the availability of generation when needed. However, where there are capacity payments in organized wholesale markets, it is difficult for regulators to determine the appropriate level of capacity payments to spur entry without over-taxing market participants and customers. Also, capacity payments may elicit new generation when transmission or other

[8] Siting in these areas can be difficult or impossible as a result of land prices, environmental restrictions, aesthetic considerations, and other factors.

responses to price changes might be more affordable and equally effective. Depending on their format, capacity payments also may discourage entry by paying uneconomical generation to continue running when market conditions otherwise would have led to the closure of that generation.

3. Building appropriate transmission facilities may encourage entry of new generation or more efficient use of existing generation. But, transmission owners may resist building transmission facilities if they also own generation and if the proposed upgrades would increase competition in their sheltered markets. Another challenge with transmission construction is that it is often difficult to assess the beneficiaries of transmission upgrades and, thus, it is difficult to identify who should pay for the upgrades. This challenge may cause uncertainty both for new generators and for transmission owners. There can also be difficulties associated with uncertain revenue recovery due to unpredictable regulatory allowances for rate recovery."

Paul Jaskow of MIT

In his paper "Competitive electricity markets and investment in new generating capacity" (April 2006) Paul L. Joskow concludes that:

> "Evidence from the U.S. and some other countries indicates that organized wholesale markets for electrical energy and operating reserves do not provide adequate incentives to stimulate the proper quantity or mix of generating capacity consistent with mandatory reliability criteria. Based on U.S. experience, a large part of the problem can be associated with the failure of wholesale spot markets for energy and operating reserves to produce prices for energy during periods when capacity is constrained that are high enough to support investment in an efficient (least cost) mix of generating capacity. A joint program of reforms applied to wholesale energy markets, the introduction of well design forward capacity markets, and symmetrical treatment of demand response and generating capacity resources is proposed to solve this problem. This policy reform program is compatible with improving the efficiency of spot wholesale markets, the continued evolution of competitive retail markets, and restores incentives for efficient investment in generating capacity consistent with operating reliability criteria applied by system operators. This reform package also responds to investment disincentives that have been associated with volatility in wholesale energy prices by hedging energy prices during peak periods as well as responding partially to concerns about regulatory opportunism by establishing forward prices for capacity for a period of up to five years.

> These hedging arrangements also reduce the incentives of suppliers to exercise market power."

1.3 The desired outcome

Consumers have consistently sought longer term contracts at prices which replicate the average cost of producing electricity. Few consumers take the risk of the spot market as foreknowledge of what prices will be is identified as a key need and is related to budgeting. This need for simplicity is clearly seen by the decision of most consumers to reject the multiple part tariffs offered in the early days of the NEM (some of these had up to 48 separate tariffs referencing different seasons, peak, shoulder and off peak times, with work days and non work days) and reverting to two or three part tariffs.

What confounds consumers in their attempts to understand the market is the variation between the pool price and those prices offered by retailers. Consumers find difficulty in understanding the extent of the risks faced by retailers and the risk premiums that have to be included in the contract prices to provide for the excessive volatility in prices.

Of major concern to consumers is that the signals for new generation must be clear and allow sufficient time for the new generation to be constructed and ready for dispatch before load must be shed to ensure integrity of the system. At the same time, consumers do not want to pay excessively for risk management tools that are designed to protect from the excess of volatility inherent in the energy-only market.

In an emergency consumers are prepared to reduce demand, as evidenced by the widespread (if reluctantly facing cold showers) given to the Victorian gas market after the fire at Longford. What they do not want is for these events to be frequent. Consistently being requested to cut back in demand for electricity does not sit well with consumers as they want simplicity and the freedom to proceed with their normal activities.

The NEL requires the RP to address the issues in light of the long term interests of consumers. Thus the basis of the RP deliberations must be assessed in these terms.

Consumers want in their electricity supply:-

- simplicity – there is enough complexity in their own business
- prices to reflect the cost of the provision of the commodity – getting value for money

- prices to be consistent and stable – to allow sensible budgeting
- sufficient electricity to be available to match their own growth and to be reliable – to allow them to get a return on their investment

When these desires are reduced to elements being addressed by the RP, these convert to:-

- not wanting to have built into the demand supply balance a consistent amount of demand reduction
- needing there to be adequate signals for new generation to be available in sufficient time to meet the expected demand
- less volatility in market prices and
- predictability in prices over the longer term.

2. Analysis of the NEM and approaches to address the needs

In its presentation to the Reliability Panel, Newgen provided an analysis of the NEM highlighting the need for peak generation overall. It provided a view that baseload generation is oversupplied and intermediate ranked generation is near balanced. **In fact, because of the regional basis of the NEM, the global approach taken by NewGen does not properly address the needs of the regions.**

When the regional structure of the NEM is analysed, there is clearly an oversupply of peak power in Snowy and Tasmanian regions, an under supply of base load in Tasmania and SA (most of the generation in SA is intermediate ranking) and an over supply of baseload in Victoria and Queensland and a lesser over supply of baseload in NSW.

The excess of peaking supply in Snowy and Tasmania is constrained in availability due to restrictions in the inter-regional interconnections. Increased interconnection between Victoria and SA, and Victoria and Tasmania would allow the over supply of baseload in Victoria into the undersupplied baseload in SA and Tasmania, with Tasmania providing adequate peaking for both Victoria and SA. Strengthening interconnection between Snowy and Victoria would also ease the shortage of peaking into the southern states.

2.1 Adequate reimbursement for generation

Incumbent generators advise that they are not receiving adequate compensation from the NEM as it currently operates. As discussed in our earlier submission, Henney and Bidwell have calculated that this is to be expected under an energy only market – that an energy only market theoretically is unable to provide adequate compensation and as a result generators use market power to enhance returns. This is achieved by spiking the price and creating excessive volatility (and risks).

That this approach has been successful can be seen from the work by Bardak referred to in our earlier submission. Subsequent research supports the Bardak conclusions.

The WEPI[9] (wholesale electricity price index) is intended to provide an indication of the prices provided by generators as contract prices to retailers.

---

[9] For more detail about WEPI refer to

Retailers add their own risk margins to the contracts offered by generators to manage their own exposure. In 2005, the WEPI indicates that generators did achieve a return which provided adequate compensation.

In 2005, figures in $/MWh	Qld	NSW	Vic	SA
Av Spot (NEM Review)	25.2	35.9	26.3	33.6
Av WEPI (AER weekly reports)	37.5	40.2	32.2	40.6
Average Generator Premium	12.3	4.3	5.9	7
Typical base SRMC (ACIL)	11	15	3	30
New entrant LRMC (ACIL)	31	32.7	35	45.6

The table shows that certainly generators in Queensland and NSW exceeded the long run marginal cost that a new entrant generator would need and considering that the generators in Victoria and SA would have significantly depreciated their assets (and therefore not need the same return on assets that a new entrant would need) the WEPIs that were observed in Victoria and SA generators would indicate that they too have achieved an adequate return.

This view is further reinforced by identifying the increase in WEPI over time – this being a randomly selected week (the 3rd week in August) being examined.

August Week 3	Qld		NSW		Vic		SA	
	WEPI	Spot	WEPI	Spot	WEPI	Spot	WEPI	Spot
2006	38.2	22	44.1	27	33.7	30	47.8	35
2005	37.6	18	37.2	28	32	31	41.3	34
2004	29.7	18	28.2	18	27.8	18	36.7	22
2003	none	16	none	19	none	21	none	23

Overall, generators are achieving returns much higher than indicated by spot prices, and probably more than adequate for a more than reasonable return on investment.

2.2 A drawback of the NEM

When all generation was centrally dispatched in each of the regions, the mechanism used was to dispatch generation in merit order. This had two significant benefits.

---

www.d-cyphatrade.com.au/products/wholesale_electricity_price_i This index was developed in conjunction with DITR.

- The lowest cost generation was dispatched first
- As the lowest cost plant was usually the most efficient, the thermal efficiency of the regional generation was higher, resulting in lower greenhouse gas emissions. The overall thermal efficiency of the NEM has fallen significantly since the NEM commenced[10]

The downsides of increased competition have been that:-

- Deregulation has led to generators seeking to maximize their individual profitability, and actively encouraging generators to bid above LRMC and reserving capacity for high price regimes
- In maximizing profitability, generators seek to game the market by withdrawing capacity when it is needed, to spike the regional price.

The price spikes observed in the NSW market are mostly caused by constraints between NSW and Victoria, and NSW and Queensland allowing the NSW baseload generators to withdraw supply, driving high priced Snowy supplies into NSW. They are in most cases not the result of a shortage of generation as such. Eliminating the ability of the NSW generators to reduce supply from its baseload plants would allow Snowy to provide the peaking power needed in NSW, as was always intended under the pre-deregulation environment when ECNSW dispatched its baseload plants in merit order.

Thus the market structure of the NEM itself is driving more thermal inefficiency, and creating the need for more peaking plant in a number of regions. At the same time baseload plant is needed in other regions, creating a NEM wide imbalance.

Market proponents point to the need and availability in the NEM of market signals to provide investment signals to generators and to the demand side to minimize demand at critical times. There is now a large body of work which points to the fact that as time between the signal for investment or DSR and the identified need gets shorter, the less the supply/demand arrangements are able to react[11].

Given time (say 2-3 years for building new generation) and forewarning of a demand spike (say 24+ hours) there is adequate time for the supply side and demand side to respond. However, in the energy only market the price spikes

[10] See the Bardak report
[11] See for instance, Reliability and competitive electricity markets by Paul Joskow and Jean Tirole, December 5, 2005

exist for a short a time as 5 minutes and seldom (if ever) last for more than 2-3 hours. These signals do not provide adequate time for a response to be achieved by demand side or supply side.

Thus to ensure reliability there is a need to provide signals well outside the observed times provided by an energy only market.

2.3 The New England ISO approach - Forward Capacity Market

The New England (US) electricity market has some unique problems. Not only does it have a shortage of generation overall, but there are regions within the market which have intra regional capacity constraints causing a severe shortfall of gene ration in specific areas within the overall market.

In some ways the New England market could be likened to the Australian NEM, which is a connection of regional markets, some with specific generation needs.

The New England approach is to identify the generation needs in each region within the market and to call for new generation to be constructed. They have identified the needs into the future, where it is needed, and the type of plant required to meet those needs.

As noted in section 1, the widespread use of capacity payments has a number of drawbacks, not least being that plant which is paid to be available often is not available when needed, and that the bidding approach does not engender the lowest price for being available.

The approach used by NE-ISO (and approved by FERC is that the ISO identifies the needs for the future, and calls tenders for supply of generation in 4-5 years hence. The key elements of the new approach are that:-

- the ISO starts bidding at twice the standard capacity price
- calling for supply a number of years hence allows for bids to come from new entrants on the same basis as incumbents
- there is a penalty for non-availability when capacity is called whether the capacity is called as reserve or under conventional bids
- offers are for an extended period (5+ years) which allows amortization of the capital cost
- the bidding descends in price with offers of capacity reducing (a “descending clock” auction)
- when the capacity offered by the bids equals the forecast future capacity identified, this sets the price for the capacity payment.

The benefits of this approach are that it can be for reserve capacity only or for total capacity with competitive bidding for dispatch. The price for the capacity sits at between 10-20% of capacity cost associated with an open cycle gas turbine, as it is amortized over the period of supply sought.

3. Reliability Options

Henney and Bidwell collaborated to develop the Reliability Options approach to seeking new generation investment. They had identified that the energy only market can theoretically only deliver some 80-90% of the funds needed to cover the long run marginal costs incurred by an ideal mix of base, intermediate and peaking generation.

They identified that the existing approach to capacity markets showed some distinct disadvantages in that:-

- They do not allow potential new entrants to compete with existing generation
- They value capacity uniformly across time regardless of system stress, when in fact the economic value of capacity is greater when a system is tight
- They do not penalize generators that are not available at times of system stress
- They may pay generators twice for capacity, once from the capacity market and again from price spikes
- They do not mitigate market power

They also identified that in a pure (and unrealistic) perfectly competitive electricity market where price equaled the short-run marginal cost of the marginal unit, there would be a revenue shortfall in an optimal system for all types of generator, and for all types of generator the shortfall would equal the cost of a new peaker. They further pointed out that due to the infra-marginal rents that are a source of revenue in real-world electricity systems, the actual shortfall to generators would probably not be as much as a new peaker.

3.1 The RO concept

Henney and Bidwell observed in their communication with the authors that:-

> "The concept of using options as a way to pay generators for providing reserve capacity has occurred to a number of people. In Europe, it is associated with Professor Ignacio Perez-Arriaga and his colleagues who developed the concept at the Instituto de Investigacion Tecnologica and published a description of it in the IEEE[12], and the Norwegian consultant SKM has proposed an arrangement that could be regarded as a type of

[12] See Vazquez, C., Rivier, M. and Perez-Arriaga, I.J. 2002. "A market approach to long-term security of supply", IEEE Transactions on Power Systems 17(2): 349-357.

> option[13]. In New Zealand, the Wholesale Electricity Market Development Group proposed a form of option in the mid-1990s. In the United States, Miles Bidwell was involved in the restructuring of the electricity markets and when capacity markets were proposed for New York State in the mid-1990s he argued that options on electricity, which could be tied to a specific physical plant, would provide a better approach. Although his proposal was not adopted then, he and his colleagues at Power Economics, Inc. further developed the concept in 2002 on behalf of the California Independent System Operator."

The form of the Reliability Options (RO) concept that is presented is the result of extensive examination over recent years combined with an intensive attempt to design an RO-based electricity market as part of the restructuring of the New England electricity market that took place in the winter of 2004-2005 under the auspices of the FERC and continued as a market settlement conference until April of 2006. The RO method that is described is designed to function either in a mandatory centrally dispatched pool or in a decentralized bilateral market. This implies that the RO concept can either be used in the NEM, or it can be used by NEMMCo in its role as reserve trader.

As Henney and Bidwell advised, using the RO approach has the core function of stabilizing an electricity market in that it provides for future generation as it is needed without the excessive volatility experienced in the NEM which has been seen as essential to provide both adequate returns to incumbent generators and to provide signals for future investment. Although incumbent generators are receiving adequate compensation as seen above, the signals for new investment are not seen as performing the needed function, and this has occasioned the implementation of reserve trader in the past two years of the NEM.

Henney and Bidwell described their approach to RO as follows:

> "An RO is a call option that is both physical and financial. It is physical in that it is associated with a specific plant that will be penalized if it is either not generating or not available as a reserve when the option is called at a time of system stress, which is defined as when the spot price exceeds the "strike price" and reserves are deficient. The strike price is set to be slightly higher (*e.g.* 10-15%) than the marginal cost of the most expensive unit on the system. The RO is financial in that a generator that has sold an RO must pay the purchaser the difference between the spot price and the strike price whenever the spot price exceeds the strike price.

[13] SKM in 2003 made a proposal for a concept that retailers should offer their customers a negotiable compensation (similar to a strike price) for non-delivered energy. Retailers were supposed to hedge these obligations with contracts – and producers were considered as those who could offer such hedges at the most favorable prices. The government did not pursue the idea.

Exhibit 1

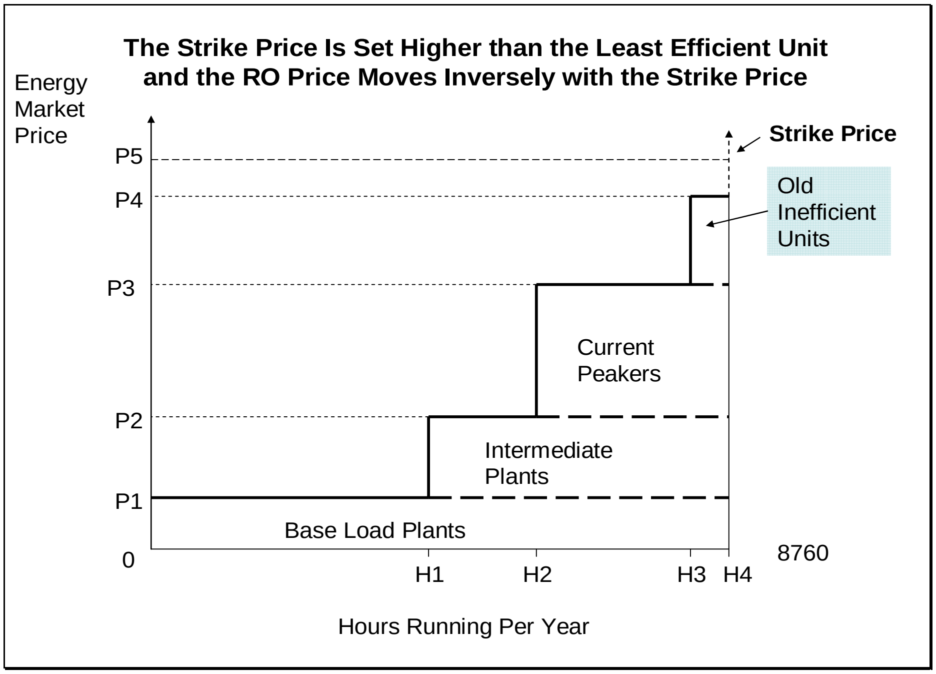


Exhibit 1 shows the strike price in a simplified system. In non scarcity situations, the maximum market price will be set by the old inefficient units. The RO strike price is set at an amount somewhat higher than the marginal running cost of the old units so that it does not come into effect until all units are running and the price is either being set by demand response or is unlimited due to the absence of a demand elasticity and a zero supply elasticity and presumably is at some predetermined price cap. Note that the strike price sets a cap on the revenue that generators can receive in times of stress—something that the generators are being compensated for by having sold the ROs. It does not place a cap on the price that can clear the market. In such extreme scarcity conditions the market can clear at a higher price that is set by demand responses, by plants that have chosen to not participate in the RO market, and by plants producing more energy than the plants' normal maximum output[14].

The strike price and the RO price move inversely. Since the RO price is determined in the competitive auction that we describe below, the strike price is included in bidders' estimates of the future total returns on which the bidders base their decision of how much they will be willing to accept in return for selling an RO. The greater the expected energy-related revenues, the smaller the acceptable price for selling an RO. This means that the

[14] Each plant will usually offer a number of ROs equal to the plant's normal maximum output. In a time of stress in which the market energy price may be much higher than the RO strike price, these units will be able to produce an emergency amount of additional output and will be compensated for this output at the market price.

exact strike price is not important so long as it is greater than the running cost of any plant on the system.

To see why this is so, consider the following: in an expanding or stable system generators must receive, or expect to receive, net revenues equal to the marginal cost of capacity which in an optimal system is the cost of a new peaker. For less than this amount, investment in new generation would not take place. At a greater amount, an excess supply would be forthcoming. In the RO descending-clock auction the RO price is such that the marginal new entrant just covers its expected costs which means receiving the marginal cost of capacity. If the strike price is set much higher than shown in the graph, the generator will make much of its marginal capacity revenues in the energy market by selling into the price spikes, and generators will therefore be willing to accept a smaller RO price and a smaller RO price will have to be the outcome in the competitive auction. On the other hand, if the strike price is set lower, say at P3, the old inefficient plants would exit and the RO price would have to be approximately equal to the price of a new peaker to induce entry.

The RO may be conceptualized as a contractual commitment to provide future electricity from installed capacity, but the RO is *not* capacity and an RO market is *not* a capacity market[15]. *Fundamentally consumers are not interested in buying capacity per se – they want to buy reliable electricity.* An RO market is an options market based on the energy market. If the energy market is a single-pool centralized market, the RO market will also be centralized; if, however, the energy market is not centralized, then the RO market may be either a centralized or a decentralized bilateral market or both. We discuss the different aspects and benefits of these approaches below in Section VI.

In summary:

- The RO method involves creating an RO product and a “reliability market” administered by an RO Administrator, which may be the TSO if it is unbundled or some independent agency.
- An RO is a call option that requires a plant to be generating or to be supplying reserves (*i.e.*, to be available to generate) when the system is stressed by setting a strike price that is higher than the most expensive unit on the system and, thus, is higher than the maximum price that would normally be seen in a competitive market in non-shortage conditions.

[15] Although an RO has the similar effect as a capacity product in paying for capacity, it has many different characteristics.

- Existing and potential new plants may offer (*but do not have to offer*[16]) ROs in an annual auction after the RO Administrator has announced the strike price and any non-performance penalty.
- The annual contract does not go into effect until three years after the auction. This allows potential new generators to compete with existing generators[17].
- The RO Administrator determines the desired amount of capacity for each location and then holds a descending clock auction (discussed below) to obtain exactly this amount at the lowest possible competitive price.
- If the spot price equals or exceeds the strike price and a plant is selling into the spot market at more than the strike price, the plant pays back the difference to the RO Administrator[18].
- If the plant is neither running nor providing reserves, it pays the RO Administrator the difference between the spot price and the strike price for the amount of contracted electricity that it did not produce, and it may in addition pay a penalty based on some physical measure of system stress such as deficient operating reserves.
- ROs would be paid for by the RO Administrator. The RO Administrator would then pass the net costs (RO purchase price less penalties) through to retailers and, ultimately, to consumers."

3.2 The critical elements involved in the RO process

- Determining the critical few hours when the system is under stress
- Setting the strike price which is higher than the marginal cost of the most expensive plant in the constraint or price zone
- Setting the planning period – this is the period between calling the auction and when the generator has to deliver the RO product. This should be at least 3 years to enable new entrants to participate
- Setting the commitment period – this should be a minimum of one year but may be longer to allow new entrants to amortise capital over a longer period. This allowance could be provided only for new entrants and on a one-off basis to the new entrant. There after

[16] Participation in the RO market is voluntary. We expect, however, that all or most generators will choose to participate because the RO price will compensate them for the price spike revenues they are forgoing and these should never be very high and prolonged as the RO approach will prevent generation inadequacy.

[17] Even for plants that take longer than three years to build, this lag and the four-year fixed RO price that we discuss below will significantly reduce the uncertainty that investors now face.

[18] This effectively caps the price generators receive. It does not place a cap on the market price which can clear at a higher demand-response price if there is excess demand at the strike price level and if the spot price has a demand-responsive component.

a successful bidder would be allowed to bid for only one year like all other incumbent generators

- Integrating DSR – the RO auction can accommodate DSR but special consideration for DSR might to be considered
- An essential element of the RO is structuring a penalty for non-provision of the RO when called. Generators would be required to pay the difference between the spot price and the strike price for the amount of electricity offered in the RO contract but not delivered. This means the greater the need for the RO delivery, the greater the penalty. Further generators are only paid the capacity payment when they are called and deliver to the contract.

3.3 How the RO auction works

- Determine the desired amount of capacity. Getting this quantity as accurate as possible is essential. The current approaches used by NEMMCo are seen as appropriate for this purpose, particularly as these replicate the approaches used by regional governments when electricity supply arrangements were vertically integrated
- A descending clock auction is commenced, using the strike price (eg 15% above the highest cost generator in the system as a starting point. At each price bids for RO options are received (1 RO equals 1 MW of capacity). If the amount of options exceeds the estimated future needs for capacity, then a lower strike price is offered. There are subsequent rounds of bidding each with a lower strike price, until the offered bids equals the capacity desired. This becomes the contract price for the provision of supply.
- Separate auctions can be held in separate regions and different strike prices used to start the process and different contract prices set in each constrained regions.
- Generators can not increase the amount of RO options offered at any stage, but they can be permitted to move options from one region to another providing they are able to offer capacity in that region.

There are three fundamental different scenarios.

- System has less than optimal capacity. In this case the start price for the auction should be higher than the entry price for a new entrant
- System has more capacity than optimal. In this case the start price will be set lower than new entry price but higher than existing generator prices
- System has optimal capacity but demand is increasing. In this case the auction will use a start price higher than new entry costs.

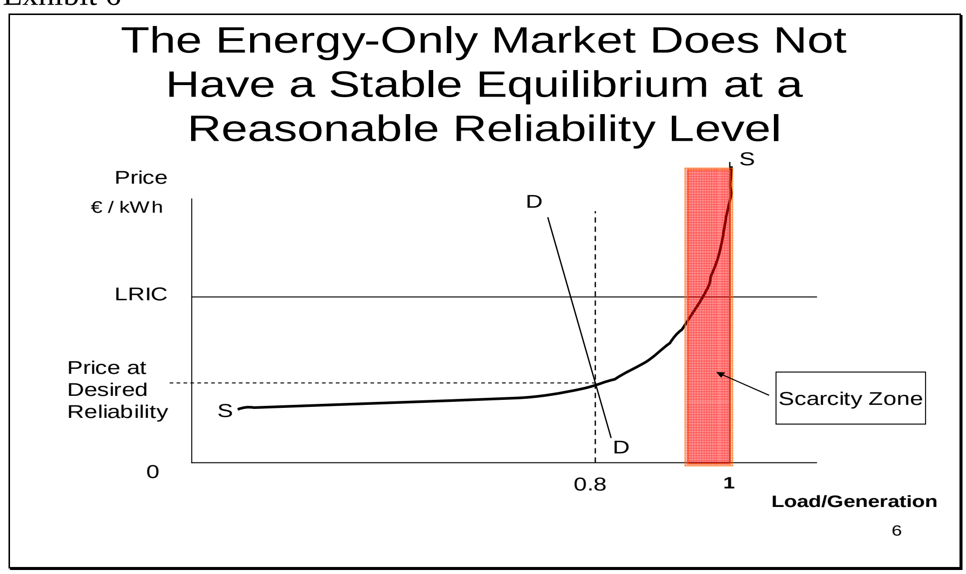
The process is designed to ensure that there is no surplus capacity incorporated into the forecast program as to do so will result in very (unsustainable?) prices. The time frames incorporated allow for an adjustment of excess capacity through moth-balling or retirement.

Auctions are held annually. Where there appears to be a lack of competition in any region, the auction would be cancelled and alternative approaches taken to relieve the constraint, identify other options or eliminate barriers to entry. Once these steps are taken, a new auction can be initiated.

3.4 RO in an energy only market (eg NEM) provides stability

Henney and Bidwell provide the following explanations of the stability benefit of ROs in a energy only market.

> "One of these problems was the lack of a long-term equilibrium caused by the market price being unremunerative at the desired level of reliability. [This is] illustrated … with … Exhibit 6. The problem, shown in the exhibit, is that an investor will not want to build a plant unless he can expect the price[19] to be at or above the LRIC which is the cost of building a new plant.
>
> Exhibit 6



> Exhibit 7 … shows the effect of adding ROs. The upper curve in Exhibit 7 is the supply curve with ROs. With ROs the price and quantity shown constitute a stable long-run equilibrium in which the long-run price will be equal to LRIC.

[19] Price is taken to be the average revenue from all sources.

Exhibit 7

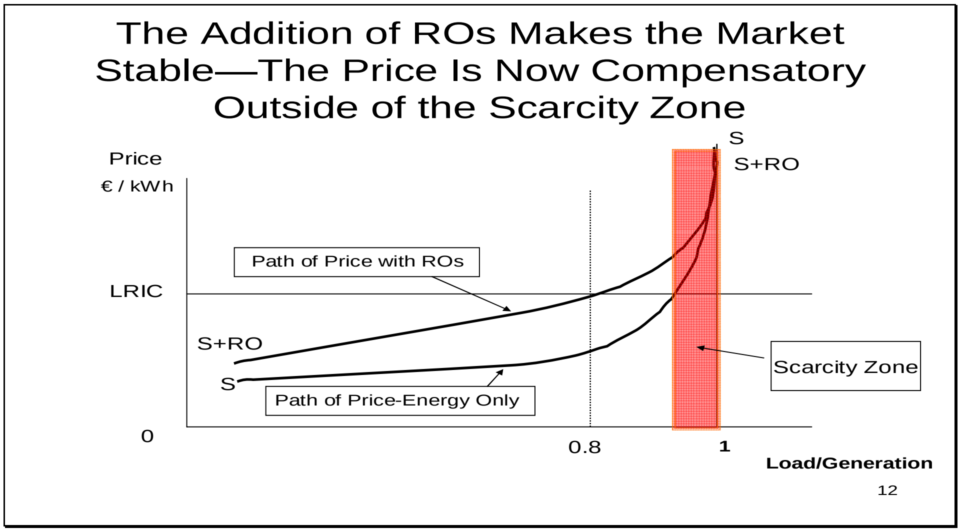


Exhibit 7 shows both the energy-only supply curve from Exhibit 6 and the new supply curve that includes the ROs. Both of the supply curves are assumed to be competitive supply curves but they include different components in that the supply curve with the ROs includes all the now internalized external costs and benefits … discussed in Report 2. The two supply curves represent the two different paths that price will follow as reserve margins (and hence reliability) change. With the addition of the ROs, market forces will lead generators to maintain the desirable level of reliability.

Exhibit 8

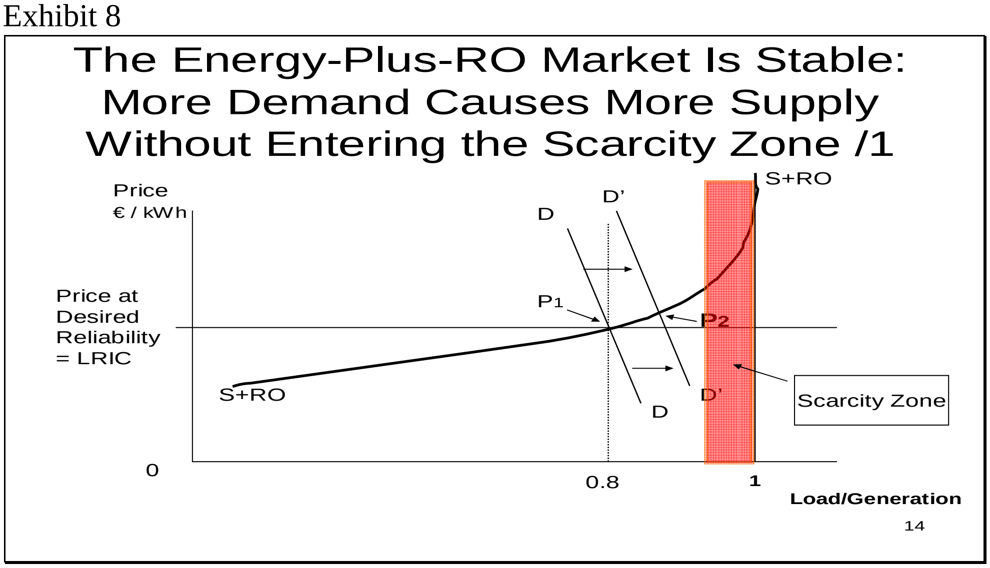
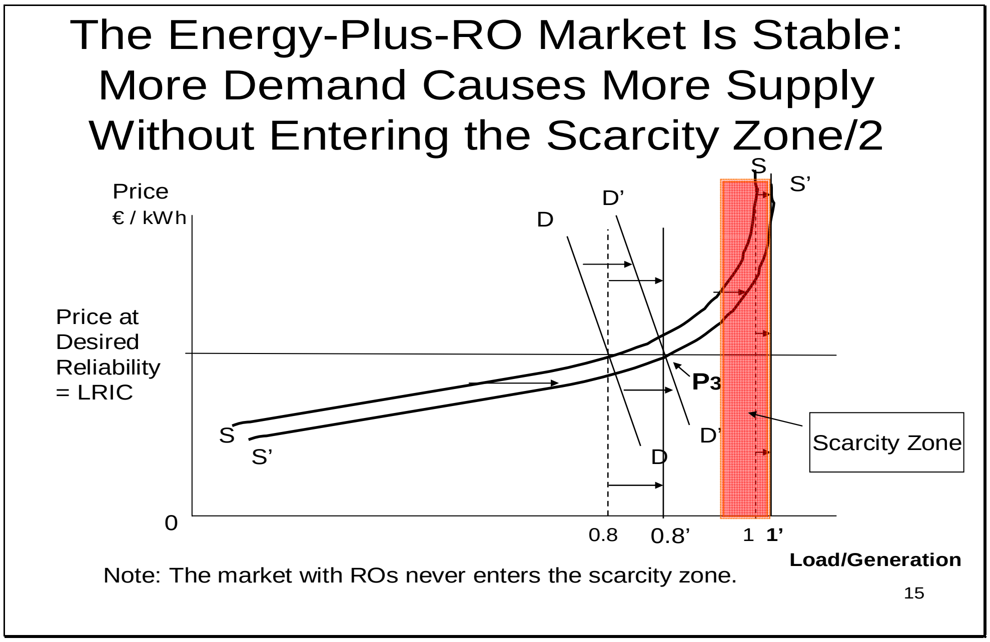


Exhibit 8 illustrates the new market's inherent stability around a price equal to the LRIC and a quantity that corresponds to the desired reserve margin. With the ROs, the electricity market now is a self-adjusting well-behaved market. If demand increases more than expected, the market response is to first produce a slight increase in price, which is represented by the shift of the demand curve DD to D'D'. The new price is now somewhat above LRIC and this will induce more entry, which is represented by the new supply curve S'S' shown in Exhibit 9.

Exhibit 9



The old supply curve SS represented the amount of capacity before the price increase. The new supply curve S'S' is the old supply curve plus the new capacity. The increased amount of capacity also moves the scarcity zone further out and increases the reserve margin at any given level of load.

The final part of the story is that the increased supply and reserve margins cause the price to decrease back toward the LRIC. The final price, P3, is the same as the price was before the demand increase. The difference is that now the amount of generation has increased by as much as the demand increased, and it has done so through market forces, not by command-and-control intervention or by the balancing market operator buying plants on contracts, and without the extreme price fluctuations that are characteristic of an energy-only market.

The structure of the RO market and auction is such that the additional capacity will be supplied as a result of an expectation that demand is going to increase. The market price paid by consumers does not increase until after they have the benefit of the new capacity.

3.5 Benefits of ROs

The major benefit of implementing the Reliability Options is that it will result in a dramatic reduction in the level of VoLL, perhaps to the levels used in the US markets. This in turn will reduce the risks and financial exposure faced by generators and retailers operating in the very volatile NEM, leading to a reduction in risk mitigation costs.

In addition:-

- They improve long term adequacy and short term reliability
- They mitigate market power abuse in the energy market. This is achieved without distorting the spot energy market as the RO only comes into effect at a point above the strike price set. Making market power abuse unprofitable is better than imposing sanctions!
- They do not increase the average prices consumers pay, but with the reduction in volatility, the costs for risk mitigation are removed. When it is considered that in the NEM the cost of the price spikes adds ~$8/MWh or 25% to the average pool price already, plus the risk premiums added by generators and retailers to manage the risks of these spikes, it is quite probable that costs of electricity supply might well fall.
- It is anticipated that the revenue earned from the price spikes in the energy only market will be equal to the cost of the RO
- Reduced volatility makes new entrant generators have more faith in the market pricing, thus encouraging investment in new generation.
- The approach is dynamically efficient as the approach provides clear future signals as to where, what and when to build new generation
- Bilateral contracting can co-exist with ROs, and due to the lower volatility, long term contracting is encouraged, providing further opportunities for new entrant generation.
- A generator can coincidently offer long term contracting and ROs, as an RO is only a contract for the generator to run or providing reserves when called – supplying under a long term contract fulfils this obligation.
- One of the drawbacks of a capacity market is the volatility exhibited, but the RO eliminates this volatility.

Appendix 1

Extract from the draft report to congress on competition in the wholesale and retail markets for electric energy, June 5, 2006, by the Electric Energy Market Competition Task Force

Chapter 3
Section D
Factors that Affect Investment Decisions in Wholesale Electric Power Markets

The Task Force examined comments on how competition policy choices have affected the investment decisions of both buyers and sellers in wholesale markets. A number of issues emerged including the difficulty of raising capital to build facilities that have revenue streams that are affected by changing fuel prices, demand fluctuations and regulatory intervention and a perceived lack of long term contracting options. Some comments to the Task Force assert that significant problems still exist in these markets, particularly steep price increases in some locations without the moderating effect of long-term contracting and new construction.[20] In some markets, the problem is that prices are so low as to discourage entry by new suppliers, despite growing need.[21] Experience over the last 10 years shows three different regional competition models emerging. Each has its own set of benefits and drawbacks.

1. Long-Term Purchase Contracts – Wholesale Buyer Issues

Many wholesale buyers suggested that they had sought to enter into long-term contracts but found few or no offers.[22] The Task Force attempted to determine whether the facts supported these allegations by examining 2004-05 data collected by FERC through its Electric Quarterly Reports for three regions – New York, the Midwest, and the Southeast. Appendix E contains this analysis. Although not conclusive because of data limitations described in Appendix E, the analysis showed that contracts of less than one-year dominated each of the three regional markets examined and that in two of the markets, longer contract terms are associated with lower contract prices on a per MWh basis.

Three reasons may exist to explain the perceived lack of ability to enter long-term purchase power contracts.[23] First, some comments argued that organized exchange markets based on uniform price auctions (*e.g.*, PJM and NYISO) have made it difficult to arrange contracts with base-load and mid-merit generators at prices near their production costs.[24] These generators would rather sell in the exchange markets and obtain the market-clearing price, which may be higher than their production costs at various times.

[20] ELCON; NRECA; APPA.
[21] E.g., PJM; EPSA.
[22] ELCON.
[23] In competitive markets, customers also have the ability to build their own generation facility if they are unable to obtain the long-term purchase contracts that they seek.
[24] APPA, NRECA.

Base-load and mid-merit generators may see relatively high profits when gas-fueled generators are the marginal units, particularly when natural gas prices rise. Box 3-2 describes how prices are set in organized exchange markets. Natural gas-fueled generators in a uniform price auction may see lower profits as their fuel costs rise, to the extent other generation becomes relatively more economical.[25] Stated another way, when natural gas units set the market price, these units may recover only a small margin over their operating costs, while nuclear and coal units recover larger margins. Under traditional regulation, by contrast, all of an owner's generation units generally are allowed the same return, which may be less than marginal units, and more than infra-marginal units, in competitive markets.

In addition, the very competitiveness of these markets cannot be assumed. For example, over ten years ago, FERC requested comments on a wholesale "PoolCo" proposal, which was the predecessor entity to today's organized electricity market with open transmission access.[26] At the time, the Department of Justice generally supported the emerging market form but warned: "The existence of a PoolCo cannot guarantee competitive pricing, since there may be only a small number of significant sellers into or buyers from the pool. The Commission should not approve a PoolCo unless it finds that the level of competition in the relevant geographic markets would be sufficient to reasonably assure that the benefits of eliminating traditional rate regulation exceed the costs."[27]

The fact that the market-clearing price in organized exchange markets may be established by a subset of generators depending upon demand and transmission congestion heightens the competitiveness concern in the organized markets. At one end, generators with high costs do not have much impact on the market prices when there is low demand and low transmission congestion, and conversely, generators with low costs do not have much impact on the market-clearing prices when there is high demand and high transmission congestion. There is a wide-range of market-clearing prices between these two end points based on the diversity of generator costs available in each region.[28] Indeed, some commenters specifically cited to recent studies of the electric industry that argue that a larger number of suppliers are needed to sustain competitive pricing in electricity markets than are needed for effective competition in other commodities.[29]

Second, the perceived lack of long-term purchase contracts may be due to a lack of trading opportunities to hedge these long-term commitments. Long-term contracts in

---

[25] See, e.g., Public Advocate's Office of Maine, National Association of State Utility Consumer Advocates.
[26] Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-000.
[27] Comments of the U.S. Department of Justice, Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-00 filed March 2, 1995 at p. 6. See also Reply Comments of the U.S. Department of Justice, Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-00 filed April 3, 1995.
[28] See Comment of the Federal Trade Commission. Docket No. RM-04-7-000 (Jul. 16, 2004) at 7-8, available at http://www.ftc.gov/os/comments/ferc/v040021.pdf.
[29] APPA, Carnegie Mellon.

other commodities are often priced with reference to a “forward price curve.” A forward price curve graphs the price of contracts with different maturities. The forward prices graphed are instruments that can be used to hedge (or limit) the risk that market prices at the time of delivery may differ from the price in a long-term contract. In a market with liquid forward or futures contracts, parties to a long-term contract can buy or sell products of various types and durations to limit their risk due to such price differences. Currently, liquid electricity forward or futures markets often do not extend beyond two to three years.[30] In some markets, one-year contracts are the longest products generally available; in markets where retail load is being served by contracts of fixed durations, such as the three-year obligations in New Jersey and Maryland, contracts for the duration of that period are slowly growing in number. But the relative lack of liquidity may discourage parties from signing long-term contracts, because they lack the ability to "hedge" these longer-term obligations.

Third, the availability of long-term purchase contracts depends on the availability and certainty of long-term delivery options. Particularly in organized markets, transmission customers have argued that the inability to secure firm transmission rights for multiple years at a known price introduces an unacceptable degree of uncertainty into resource planning, investment and contracting.[31] They report that this financial uncertainty has hurt their ability to obtain financing for new generation projects, especially new base-load generation.

Congress addressed this issue of insufficient long-term contracting in the context of RTOs and ISOs in EPACT05. In particular, section 1233 of EPACT05 provides that:

> [FERC] shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, <u>and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs</u>.[32]

To implement this provision in RTOs and ISOs, FERC proposed new rules regarding FTRs in February 2006. The rules would require RTOs and ISOs to offer long-term firm transmission rights. FERC did not specify a particular type of long-term firm transmission right, but instead proposed to establish guidelines for the design and administration of these rights. The proposed guidelines cover basic design and availability issues, including the length of terms the rights should have and the allocation

---

[30] Nodir Adilov, <u>Forward Markets, Market Power, and Capacity Investment</u> (Cornell Univ. Dep’t of Econ. Job Mkt. Papers, 2005), <u>available at</u> http://www.arts.cornell.edu/econ/na47/JMP.pdf.
[31] APPA, TAPS.
[32] Pub. L. No. 109-58, § 1233, 119 Stat. 594, 958 (2005) (emphasis added).

of those rights to transmission customers. FERC has received comments on its proposal but has not yet adopted final rules.

2. Long-Term Supply Contracts – Generation Investment Issues

Commenters cited the certainty of long-term contracts as a critical requirement for obtaining financing for new generators.[33] These contracts, however, are vulnerable to certain regulatory risks. First, contracts are subject to regulation by FERC, and a party to a contract can ask FERC to change contract prices and terms, even if the specific contract has been approved previously.[34] For example, in 2001-2002 several wholesale purchasers of electric power requested that FERC modify certain contracts entered into during the California energy crisis. The customers alleged that problems in the California electricity exchange markets had caused their contracts to be unreasonable. The sellers argued that if FERC overrides valid contracts, market participants will not be able to rely on contracts when transacting for power and managing price risk. FERC declined to change the contracts.[35] FERC cited its obligation to respect contracts except when other action is necessary to protect the public interest.[36]

A second type of regulatory uncertainty involving bankruptcy may limit future market opportunities for merchant generators and, thus, reduce their ability to raise capital. In recent years, several merchant generators (NRG, Mirant and Calpine) have sought to use the bankruptcy process to break long-term power contracts.[37] These efforts, when successful, leave counterparties facing circumstances that they did not anticipate when they entered into their contracts. This risk may give state regulators an incentive to favor construction of generation by their regulated utilities over wholesale purchases from merchant generators. These disputes have spawned conflicting rulings in the courts. In particular, these cases have centered on separate, but intertwined, issues: first, where jurisdiction over efforts to end power contracts properly lies, as between FERC and the bankruptcy courts and to what extent courts may enjoin FERC from acting to enforce power contracts; and second, what standard applies to such efforts (that is, what showing must a party make to rid itself of a contract). As FERC and the courts have only recently

[33] Constellation, Mirant.

[34] In December 2005, FERC proposed to adopt a general rule on the standard of review that must be met to justify proposed modifications to contracts under the Federal Power Act and the Natural Gas Act. Standard of Review for Modifications to Filed Agreements, 113 FERC ¶ 61,317 (2005) (Proposed Rule). Specifically, FERC proposed that, in the absence of specified contractual language, a party seeking to change a contract must show that the change is necessary to protect the public interest. FERC explained that its proposal recognized the importance of providing certainty and stability in energy markets, and helped promote the sanctity of contracts. A final rule is pending.

[35] Nevada Power Company v. Enron, 103 FERC ¶ 61,353, order on reh'g, 105 FERC ¶ 61,185 (2003); Public Utilities Commission of California v. Sellers of Long Term Contracts, 103 FERC ¶ 61,354, order on reh'g, 105 FERC ¶ 61,182 (2003); PacifiCorp v. Reliant Energy Services, Inc., 103 FERC ¶ 61,355, order on reh'g, 105 FERC ¶ 61,184 (2003).

[36] See Northeast Utilities Service Co., *v FERC*, 55 F.3d 686, 689 (1st Cir. 1995).

[37] See Howard L. Siegel, The Bankruptcy Court vs. FERC- The Jurisdictional Battle, 144 PUB. UTIL. FORTNIGHTLY 34 (2006).

begun to consider these questions, the law remains unsettled, as do parties' expectations.[38]

A third type of regulatory uncertainty concerns the regulated retail service offerings in states with retail competition.[39] The uncertainty of how much supply a distribution utility will need to satisfy its customers due to customer switching that can occur in retail markets can prevent or discourage those utilities from signing long-term contracts.[40] The extent of this disincentive is unclear if competitive options are available for distribution utilities to purchase needed supply or sell excess supply.

3. Risk and Reward in the Face of Price and Cost Volatility – Capital Requirements

Building new generation in wholesale markets also is based on the ability of a company to acquire capital, either from internal sources or external capital markets. If a company can acquire the necessary capital it can build. There is no federal regulation of entry, and most states that have permitted retail competition have eliminated any "need-based" showing to build a generation plant.

Private capital has generally funded the electric power transmission network in the United States. Under traditional cost-base rate regulation, utility investment decisions were based in part on the promise of a regulated revenue stream with little associated risk to the utility. The ratepayers often bore the risk. Money from the capital markets was generally available when utilities needed to fund new infrastructure. One significant problem, however, was that regulators had limited ability to ensure that utilities spent their money wisely.[41] Regulatory disallowances of imprudent expenditures are viewed by investors as regulatory risk. This risk can be mitigated somewhat by Integrated Resource Planning, to the extent it limits or avoids after-the-fact regulatory reviews of investment decisions.[42]

In competitive markets, projects obtain funding based on anticipated market-based projections of costs, revenues and relevant risks factors. The ability to obtain funding is impacted by the degree to which these projections compare with projected risks and returns for other investment opportunities.[43] Therefore, potential entrants to generation markets have to be able to convince the capital markets that new generation is a viable profitable undertaking. In the late 1990s investors appeared to prefer market investments

[38] At least one rating agency treats a utility's self-built generation as an asset while treating long-term purchase contracts as imputed debt, thus making it less attractive for utilities to choose the contract option.
[39] See infra Chapter 4 for a discussion of regulated service offerings in states with retail competition.
[40] Mirant, Constellation.
[41] CONG. BUDGET OFFICE, FINANCIAL CONDITION OF THE U.S. ELECTRIC UTILITY INDUSTRY (1986), available at http://www.cbo.gov/showdoc.cfm?index=5964&sequence=0.
[42] Southern, Duke.
[43] COMMODITY FUTURES TRADING COMM'N, THE ECONOMIC PURPOSE OF FUTURES MARKETS, available at http://www.cftc.gov/opa/brochures/opaeconpurp.htm.

over cost-based rate-regulated investments, as merchant generators were able to finance numerous generation projects, even without a contractual commitment from a customer to buy the power.[44]

In recent years, however, investors have generally favored traditional utilities over merchant generators when it comes to providing capital for large investments.[45] In part, this preference reflects the reduced profitability of many merchant generators in recent years, and the relative financial strength of many traditional utilities. It also may reflect a disproportionate impact of the collapse of credit and thus trading capability of non-utilities after Enron's financial collapse.[46] As shown in the Table in Appendix G, for example, virtually all of the companies rated A- or higher are traditional utilities, not merchant generators.

Investor preference for traditional utilities also may be affected by increasing volatility in electric power markets. As wholesale markets have opened to competition, investors recognized that income streams from the newly-built plants would not be as predictable as they had been in the past.[47] Under cost-based regulation, vertically integrated utilities' monopoly franchise service territories significantly limited the risk that they would not recover the costs of investments. Once generators had to compete for sales, generation plant investors were no longer guaranteed
that construction costs would be repaid or that the output from plants could be sold at a profit.[48] Financing was more readily accessed for projects like combined cycle gas and particularly gas turbines that can be built relatively quickly and were viewed at the time to have a cost advantage compared with existing generation already in operation, including less efficient gas-fueled generators.[49] In 1996, the Energy Information Administration projected that 80% of electric generators between 1995 and 2015 would be combined cycle or combustion turbines.[50] Base-load units, such as coal plants, with construction and payout periods that would put capital at risk for a much longer period of time, were harder to finance.[51]

[44] APPA.
[45] Task Force Meetings with Credit Agencies, see Appendix B.
[46] U.S. GEN. ACCOUNTING OFFICE, GAO-02-427, Restructured Electricity Markets, Three States' Experiences in Adding Generating Capacity 13 (2002).
[47] Connecticut DPUC.
[48] U.S. GEN. ACCOUNTING OFFICE, GAO-02-427, Restructured Electricity Markets, Three States' Experiences in Adding Generating Capacity 13 (2002).
[49] ENERGY INFO. ADMIN., DOE/EIA-0562(96), THE CHANGING STRUCTURE OF THE ELECTRIC POWER INDUSTRY: AN UPDATE 38 (1996).
[50] Id.
[51] Hearing on Nuclear Power, Before the Subcomm. on Energy of the S. Comm. on Energy & Nat'l Res., Mar. 4, 2004 (statement of Mr. James Asselstine, Managing Director, Lehman Brothers); see also NUCLEAR ENERGY INSTITUTE, INVESTMENT STIMULUS FOR NEW NUCLEAR POWER PLANT CONSTRUCTION: FREQUENTLY ASKED QUESTIONS, available at http://www.nei.org/documents/New_Plant_Investment_Stimulus.pdf.

Box 3-3
The Use of Capacity Credits in Organized Wholesale Markets:

In theory, capacity credits could support new investment because suppliers and their investors would be assured a certain level of return even on a marginal plant that ran only in times of high demand. Capacity credits might allow merchant plants to be sufficiently profitable to survive even in competition with the generation of formerly-integrated local

The increasing amount of new generation fueled by natural gas, however, has caused electricity prices to vary more frequently with natural gas prices, a commodity subject to wide swings in
price.[52] With input costs varying widely, but merchant revenues often limited by contract or by regulatory price mitigation, investors may worry that merchant generators may not recover their costs and provide an attractive rate of return.

4. Regulatory Intervention May Affect Investment Returns

Generation investors must expect to recover not only their variable costs but also an adequate return on their investment to maintain long-term financial viability. One way for suppliers to recover their investment is to charge high prices during periods of high demand. However, regulators may limit recovery of high prices during these periods, and thus may deter suppliers from making needed investments in new capacity that would be economical absent these price caps.

This dynamic leads to a chicken-and-egg conundrum: if there were efficient investment, there might not be a need for wholesale price or bid caps. More investment in capacity would lead to less scarcity, and thus fewer or shorter episodes of high prices that may require mitigation. By contrast, it may be that price regulation during high-priced hours diminishes the confidence of investors that they can rely on market forces (rather than regulation) to set prices. That diminished confidence in their ability to earn sufficient investment returns thus deters entry of new generation supply.

Price mitigation through the use of price or bid caps has become an integral component of most organized markets. The use of mitigation has led generators to seek a supplemental revenue stream (capacity credits) to encourage entry of new supply. See Box 3-3 for a discussion of capacity credits.

In practice, however, the presence or absence of capacity credits has not always resulted in the predicted outcomes. California did not have capacity credits and did not experience much new generation, but two of the regions (the Southeast and Midwest) experienced significant new generation entry without capacity credits. Northeast RTOs

[52] Natural Gas, Factors Affecting Prices and Potential Impacts on Consumers, Testimony Before the Permanent Subcommittee on Investigations, Committee on Homeland Security and Governmental Affairs, United States Senate; GA)-06-420T (February 13, 2006) at 7.

with capacity credits continue to have some difficulty attracting entry, especially in major metropolitan areas.

As noted above, much of the new generation in the Southeast was non-utility merchant generation, and relied on the region's proximity to natural gas supplies. In the Midwest, in the late 1990s, largely uncapped prices were allowed to send price signals for investment. In California, price caps of various kinds have been used for a number of years, limiting price signals for new entry. In the Northeast, organized markets have offered capacity payments for long term investments in addition to electric power prices that are sometimes capped in the short term. Unfortunately, there is no conclusive result from any of these approaches – no one model appears to be the perfect solution to the problem of how to spur efficient investment with acceptable levels of price volatility.

Net revenue analyses for the centralized markets with price mitigation suggest that price levels are inadequate for new generation projects to recover their full costs. For example, in the last several years, net revenues in the PJM markets have been, for the most part, too low to cover the full costs of new generation in the region.[53] Based on 2004 data, net revenues in New England, PJM and California would have allowed a new combined-cycle plant to recover no more than 70% of its fixed costs.

Regulation also may interfere with efficient exit of generation plants due to the use of reliability-must-run requirements. In some load pockets in organized markets, plant owners are paid above-market prices to run plants that are no longer economical at the market-clearing price. For example, in its Reliability Pricing Model filing with FERC, PJM states, "PJM also has been forced to invoke its recently approved generation retirement rules to retain in service units needed for reliability that had announced their retirement. As the Commission often has held, this is a temporary and sub-optimal solution. Such compensation, like the reliability must run ("RMR") contracts allowed elsewhere, is outside the market, and permits no competition from, and sends no price signals to, other prospective solutions (such as new generation or demand resources) that might be more cost-effective."[54] To the extent that market rules allocate the cost of keeping these plants running to customers outside of the load pocket, such payments may distort price signals that, in the long run, could elicit entry. Graduated capacity payments that favor new entry of efficient plants may be a partial solution to retirement of inefficient old plants.

5. Investment in Transmission: A Necessary Adjunct to Generation Entry

Transmission access can be vital to the competitive options available to market participants. For example, merchant generators depend on the availability of

[53] Occasionally in the past few years net revenues have been sufficient to cover the costs of new peaking units, and in 2005 they were enough to cover the costs of a new coal plant. MARKET MONITORING UNIT, PJM INTERCONNECTION, LLC, 2005 STATE OF THE MARKET REPORT, at 118 (2006) [hereinafter PJM STATE OF THE MARKET REPORT 2005], available at http://www.pjm.com/markets/market-monitor/som.html.
[54] Intial Order on Reliability Pricing Model, 115 FERC ¶ 61,079, *3 (2006)

transmission to sell power, and transmission constraints can limit their range of potential customers. Small utilities, such as many municipal and cooperative utilities, depend on the availability of transmission to buy wholesale power, and transmission constraints can limit their range of potential suppliers. Much of the transmission grid is owned by vertically-integrated, investor-owned utilities and, traditionally, these utilities have an incentive to limit the use by others of the grid, to the extent such use conflicts with sales by their own generation. In short, the availability of transmission is often the keystone in determining whether a generating facility is likely to be profitable and, thus, to elicit investment in the first instance.

Since FERC issued Order No. 888 in 1996, questions have arisen concerning the efficacy of various terms and conditions governing the availability of transmission. For example, transmission customers have raised concerns regarding the calculation of Available Transfer Capacity (ATC). Another area of concern is the lack of coordinated transmission planning between transmission providers and their customers. Finally, customers have raised concerns about aspects of transmission pricing. Based on these concerns, FERC in May 2006 proposed modifications to public utility tariffs to prevent undue discrimination in the provision of transmission services. FERC is soliciting public comments on its proposed modifications.

As discussed above, generation that is built where fuel supplies are readily available, but not necessarily near demand, and construction costs are low, rely heavily on readily available transmission. The Connecticut DPUC noted that while generation growth may have been sufficient for some regions such as New England as a whole, some localized areas had demand growth without increases in supply, raising prices in load pockets. If transmission access to the load pocket were available, a large base-load plant outside the load pocket might become an attractive investment proposition.

Less regulatory intervention in wholesale markets for generation may be necessary if transmission upgrades, rather than unrestricted high prices or capacity credits, are used to address the concerns about future generation adequacy. Although capacity credits may spur generators within a load pocket to add additional capacity, capacity credits may not be required for base-load plants outside the load pocket. Those base-load plants would not have the problem of average revenues falling below average costs because they would have access to more load, and be able to run profitably during more hours of the day. Similarly, price caps may be unnecessary if improved transmission brought power from more base-load units into the congested areas. Prices would be lower because there would be less scarcity, and high cost units would be needed to run during fewer hours.

Section E.
Observations on Wholesale Market Competition

One of the most contentious issues currently facing federal regulators is whether the different forms of competition in wholesale markets have resulted in an efficient allocation of resources. The various approaches used by the different regions show the range of available options.

1. Open Access Transmission without an Organized Exchange Market

One option is to rely upon the OATT to make generation options available to wholesale customers. No central exchange market for electric power operates in regions taking this option (the Northwest and Southeast) Instead, wholesale customers shop for alternatives through bilateral contracts with suppliers and separately arrange for transmission via the OATT. With a range of supply options to choose from, long-term bilateral contracts for physical supply can provide price stability that wholesale customers seek and a rough price signal to determine whether to build new generation or buy generation in wholesale markets. However, prices and terms can be unique to each transaction and may not be publicly available. Furthermore, the lack of centralized information about trades leaves transmission operators with system security risks that necessitate constrained transmission capacity.. The lack of price transparency can also add to the difficulty of pricing long-term contracts in these markets.

This model is extremely dependent on the availability of transmission capacity that is sufficient to allow buyers and sellers to connect. Thus, it also is dependent upon the accurate calculation and reporting of transmission capacity available to market participants. Short-term availability is not sufficient, even if accurately reported, to form a basis for long term decisions such as contracting for supply or building new generation. Not only must transmission be available, but it must be seen to be available on a nondiscriminatory basis. As the FERC noted in Order 2000, persistent allegations of discrimination can discourage investment even if they are not proven. Without the assurance of long term transmission rights, wholesale customers may remain dependent on local generation owned by one or only a few sellers and be denied the competitive options supplied by more distant generation. Similarly, new suppliers may have no means of competing with incumbent generators located close to traditional load.

2. Policy Options in Organized Wholesale Markets

In organized markets, market participants have access to an exchange market where prices for electric power are set in reference to supply offers by generators and demand by wholesale customers (including Load Serving Entities or LSEs). Such an exchange market could have prices set by a number of mechanisms. All existing U.S. exchange markets have a uniform price auction to determine the price of electric power. Uniform price auctions theoretically provide suppliers an incentive to bid their marginal costs, to maximize their chance of getting dispatched. The principal alternative to uniform price auctions is a pay-as-bid market.

The academic research on whether pay-as-bid auctions can actually result in lower prices has been evolving, and the results are at best mixed. Theoretically, pay-as-bid auctions do not result in lower market-clearing prices and may even raise prices, as suppliers base their bids on forecasts of market-clearing prices instead of their marginal costs. More recent research suggests that pay-as-bid can sometimes result in lower costs for customers. [55] But, the pay-as-bid approach may reduce dispatch efficiency, to the extent generator bids deviate from their marginal costs.[56]

A uniform price auction may allow some generators (*e.g.*, coal- or nuclear-fueled units) to earn a return above those typically allowed under cost-based regulation, but it also may limit the return of other generators (*e.g.*, natural gas-fueled units) to a return below those typically allowed under cost-based regulation. In a competitive market, a unit's profitability in a uniform price auction will depend on whether, and by how much, its production costs are below the market clearing price. A uniform price auction may thus produce prices that are very high compared with the costs of some generators and yet not high enough to give investors an incentive to build new generation that could moderate prices going forward. The uniform price auction creates strong incentives for entry by low-cost generators that will be able to displace high cost generators in the merit dispatch order. Three policy options have been suggested to address the tension between market-clearing prices with uniform auction and entry.

a. Unmitigated Exchange Market Pricing

One possible, but controversial, way to spur entry is to let wholesale market prices rise. As discussed in Chapter 2, the market will likely respond in two ways. First, the resulting price spikes will attract capital and investment. To assure that the price signals elicit appropriate investment and consumption decisions, they must reflect the differences in prices of electricity available to serve particular locations. Where transmission capacity limits the availability of electric power from some generators within a regional market, the cost of supplying customers within the region may vary. Without locational prices, investors may not make wise choices about where to invest in new generation.

Unfortunately, it is difficult to distinguish high prices due to the exercise of market power from those due to genuine scarcity. High prices due to scarcity are consistent with the existence of a competitive market, and therefore perhaps suggest less need for regulatory intervention. High prices stemming from the exercise of market power in the form of withholding capacity may justify regulatory intervention. Being able to distinguish between the two situations is therefore important in markets with market-based pricing.[57]

Second, higher prices will likely signal to customers that they should change their decisions about how much and when to consume. Price increases signal to customers to reduce the amount they consume. Indeed, during the Midwest wholesale price spikes in the summer of 1998, demand fell during the period in which prices rose and customers

---

[55] Par Holmberg, Comparing Supply Function Equilibria of Pay-as-Bid and Uniform Price Auctions (Uppsala University, Sweden Working Paper 2005:17, 2005); G. Federico & D. Rahman, Bidding in an Electricity Pay-As-Bid Auction (Nuffield College Discussion Paper No 2001-W5, 2001); Joskow, Difficult Transition at 6-7.

[56] Alfred E. Kahn, et al., Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond (Blue Ribbon Panel Report, study commissioned by the California Power Exchange, 2001).

[57] See generally Edison Mission Energy, Inc. v. FERC, 394 F.3d 964 (D.C. Cir. 2005).

purchased little supply during those periods.[58] For an efficient reduction in consumption to occur, however, retail customers must have the ability to react to accurate price signals. As discussed in Chapter 4, customers often have limited incentive, even in markets with retail competition, to reduce their consumption when the marginal cost of electricity is high. This is because retail rates in the short-term do not vary to account for the costs of providing the electricity at the actual time it was consumed.

b. Moderation of Price Volatility with Caps and Capacity Payments

To date, the alternative to unmitigated exchange market pricing has been price and bid caps in wholesale exchange markets. Although price and bid caps may moderate wide swings in market-clearing prices, not all the caps in place may be necessary to prevent exercise of market power or set at appropriate levels. Higher caps may strike a balance between the desire of policy makers to smooth out the peaks of the highest price spikes and the need to demonstrate where capital is required and can recover its full investment. Some argue, however, that high price caps may burden consumers with high prices and yet not allow prices to rise to the level that will actually insure that investors will recover the cost of new investment. Thus prices can rise significantly and yet not elicit entry by additional supply that could moderate price in later periods.

Capacity payments are one way to ensure that investors recover their fixed costs. Capacity payments can provide a regular payment stream that, when added to electric power market income, can make a project more economically viable than it might be otherwise. Like any regulatory construct, however, capacity payments have limitations. It is difficult to determine the appropriate level of capacity payments to spur entry without over-taxing market participants and consumers.

To the extent that capacity rules change, this creates a perception of risk about capacity payments that may limit their effectiveness in promoting investment and ultimately new generation. When rules change, builders and investors may also take advantage of short-term capacity payment spikes in a manner that is inefficient from a longer-term perspective.

If capacity payments are provided for generation, they may prompt generation entry when transmission or demand response would be more affordable and equally effective. Capacity payments also may disproportionately reward traditional utilities and their affiliates by providing significant revenues for units that are fully depreciated. Capacity payments also may discourage entry by paying uneconomical units to keep running instead of exiting the market. These concerns can be addressed somewhat by appropriate rules – e.g., NYISO's rules giving capacity payment preference to newly-entered units –

[58] Robert J. Michaels and Jerry Ellig, Price Spike Redux: A Market Emerged, Remarkably Rational, 137 PUB. UTIL. FORTNIGHTLY 40 (1999). Wholesale customers with supply contracts for which the prices were tied to the market price paid higher prices for electric power during those hours.

but in general, it is difficult to tell whether capacity payments alone would spur economically efficient entry.

One issue that has arisen is whether capacity prices should be locational, similar to locational electric power prices. PJM, ISO-NE and NYISO have either proposed or implemented locational capacity markets that may increase incentives for building in transmission-constrained, high-demand areas. The combination of high electric power prices and high capacity prices in these areas may combine to create an adequate incentive to build generation in load pockets.[59]

c. Encouraging Additional Transmission Investment

Building the right transmission facilities may encourage entry of new generation or more efficient use of existing generation. But transmission expansion to serve increased or new load raises the difficulty of tying the economic and reliability benefits of transmission to particular consumers. In other words, because transmission investments can benefit multiple market participants, it is difficult to assess who should pay for the upgrade. This challenge may cause uncertainty about the price for transmission and about return on investment both for new generators and for transmission providers.

If transmission entry can connect low-cost resources to high-demand areas, it is closely linked to the issues of generation entry. Transmission entry, however, can in theory remove the kinds of transmission congestion that results in higher prices in load pockets. Transmission entry may be a double-edged sword: if it is expected to occur, it would reduce the incentive of companies to consider generation entry, by eliminating the high prices they hope to capture.

Both generation and transmission builders face the issue of dealing with an existing transmission owner or an RTO/ISO to obtain permission to build. Moreover, there are substantial difficulties to site new transmission lines. It is difficult to assess whether these risks are higher for transmission builders than for generation builders.

d. Governmental Control of Generation Planning and Entry

The final alternative is a regulatory rather than a market mechanism to assure that adequate generation is available to wholesale customers. As a method to spur investment, regulatory oversight of planning has some positive aspects, but it also has costs. Using regulation through governmentally determined resource planning to encourage entry could result in more entry than market-based solutions, but that entry may not occur where, when or in a way that most benefits customers. Regulatory oversight of investment also means regulators can bar entry for reasons other than efficiency. The stable rate of return on invested capital offered under rate-regulation can encourage investment. On the other hand, rate-regulation can lead to overinvestment,

[59] Siting in these areas can be difficult or impossible as a result of land prices, environmental restrictions, aesthetic considerations, and other factors.

excessive spending and unnecessarily high costs. Regulation also lacks the accountability that competition provides. Mistakes as to where and how investments should be made may be borne by ratepayers. In competitive markets, the penalties for such mistakes would fall on management and shareholders. The specter of future accountability for investment decisions can lead to better decision-making at the outset.[60]

It is possible that regulatory oversight of planning would result in greater fuel diversity, and thus less exposure to risks associated with changes in fuel prices or availability. It could also lessen potential boom-bust cycles where investors overreact to market signals and too many parties invest in one region. That reaction creates overcapacity, which in turn leads to lower prices. One large drawback to regulation, however, is the regulator's lack of knowledge about the correct price to set. It is difficult to set the correct price unless frequent experimentation with price changes is possible, and yet consumers generally do not favor significant price variation.

[60] Regulatory solutions, more so than market-based outcomes, may outlive the circumstances that made them seem reasonable.