Our Ref: DMS#3459149

23 November 2011

Attention of Assistant Director Markets
Economic Regulation Authority
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SUBMISSION RELATED TO DISCUSSION PAPER: ANNUAL WHOLESALE ELECTRICITY MARKET REPORT TO THE MINISTER FOR ENERGY

Synergy is please to offer the following submission in response to the Authority's request for stakeholder feedback on strategic, policy or other high-level issues that impact on the effectiveness of the Western Australia's Wholesale Electricity Market (WEM) in meeting the Wholesale Electricity Market Objectives.

Synergy, in its feedback, has raised a number of points categorised under the Authority's questions. The more important points raised relate to the areas of:

- Market governance, in particular, the dual roles of the IMO as rule administrator and rule maker, and;
- The inefficiencies as a result of the Reserve Capacity Mechanism creating both high capacity prices with an increasing volume of excess capacity.

Synergy is happy to discuss any or all of the attached feedback with the Authority by contacting either Stephen MacLean: phone 6212 1498, email: stephen.maclean@synergy.net.au or John Rhodes: phone 6212 1138, email john.rhodes@synergy.net.au.

Yours sincerely

STEPHEN MACLEAN
MANAGER MARKET DEVELOPMENT

Submission to the Annual Wholesale Electricity Report to the Minister for Energy

23 November 2011

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1.0 Comments related to climate change

Does the design of the Wholesale Electricity Market provide the most efficient outcomes with meeting climate change policies?

1.1 Impact of climate change policies

The Authority has made the comment "*that a significant factor causing an increase in the cost of supplying electricity to retail customers is the impact of climate change policies*".

Components of the cost increases referred to by the Authority are due to the federal REC legislation bringing on additional cost as a result of both having to purchase and surrendering a Renewable Energy Certificate (REC) and as a result of energy production being provided from higher cost renewable generator such as a wind farms.

The added federal legislative requirement of carbon should not impact upon the operation of the market directly nor should the market design be impacted by this instrument. Carbon should be translated into a price and so become another component of the variable cost reflected in bilateral arrangements and also in the STEM and balancing prices.

It is worth noting that with the introduction of carbon, the electricity market will have two different climate change policies and obligations in operation. Although carbon will operate as a broad emission reduction mechanism this will not reduce or impact the legal requirement for the market to source RECs. Therefore both will operate almost independently. The introduction of a carbon price may reduce the REC price, but given electricity retailers retain a REC liability, it will not reduce the need for a growth in REC production until 2020, when the current cap is reached. The existence of carbon should therefore not dampen the incentives to continue to invest in renewable generation, particularly wind facilities, to satisfy the 41,000 GWh target.

1.2 Impact of intermittent generation production at times of low demand

An area where climate change policy (RECs) and the WEM may not work well together relates to intermittent renewable generation and system security. The most mature renewable technology currently available is wind which is both intermittent and has a tendency to produce at low demand times. An increase in wind production volume[1] brings a number of market concerns which have not been adequately resolved, including:

[1] It is noted that the Western Power submission relating to the Mid West line enhancement cites wind farm investment, resulting from this investment, in the southern section of the Mid West at 230 MW. It is also noted that other large wind farm projects are currently being considered in the eastern section of the mid west with potential expansions at Collgar's

1. It could threaten the economic dispatch of base load generation;
2. It may increase the use of low efficiency gas turbines, increasing variable costs; and
3. It may increase the cost of load following service above that required for loads.

1. Currently, wind operates according to the wind resource and if wind is producing in volume during low demand times the result necessitates base load generation being forced to less efficient minimum generation (mingen) positions or being turned off. The introduction of competitive balancing will moderate this situation by allowing generators including wind to choose their output based upon incremental bids/offers. Expectation is that, at times of low demand but high intermittent production, the market price for energy will drop below zero representing the shutdown and start-up costs of base load facilities. The reality may be that the negative price needed to reduce wind farm facilities production is lower than that required to turn-off base load facilities. If this is the case and base load generators are turned off leaving an excessive volume of intermittent production and load following plant then the result could be an unreliable mix of synchronised capacity.

Some have suggested this is unlikely given wind can only price down to a negative of the REC price, currently at less than $50. This view assumes that the REC payment is the only payment that a wind facility gets if producing and so it becomes the price at which it is economic for it to turn off. The more likely situation is that wind will have a bilateral agreement with a Market Customer which includes REC, energy and capacity. In this circumstance, what is more likely to happen, for a generator with virtually zero variable costs, such as a wind turbine, is that the dispatch price needs to further reduce to the equivalent of the negative full contract price before a wind generator is incentivised to turn down. Given the full cost for a new wind farm is above $120 per MWh this would require the balancing price to be less than negative $120 to turn wind off and maintain base load generation production. This price may be too low for a base load generator to sustain and so could force them to shut down in response i.e. the cost of staying on exceeds the cost of turning off.

2. System Management has speculated, irrespective of pricing considerations and generator merit order, that to maintain frequency control at low demand times could require a mix of wind and fast response gas turbines, given that base load facilities are too slow to respond if required to turn on/off. If base load facilities are replaced with this mix to maintain system reliability then it will impact upon the cost of supply.

3. The IMO through the Renewable Energy Generation Working Group (REG WG) used Roam Consulting to price the extra cost of the ancillary service of load following to the market as a result of an increase in wind penetration. Load following has been provided to meet variations in aggregate load demand, but more recently has been increased to cover the incremental need resulting from variations in a higher level of wind production. At current levels of wind investment there has been a marginal increase in the cost of this ancillary service but with the sustained increase in wind capacity likely to be necessary to meet legislated renewable energy targets this will quickly become the prime cause of increases in load following costs. Given the continuation of the REC liability for Market Customers and that wind is the mature renewable technology, an increase of load following due to wind production variation may be unavoidable unless the market elects to cap this cost.

Merredin site and in the northern section of the Mid West with Mumbida already under construction and potential expansions at Walkaway.

2.0 Demand Side Management

What impact does Demand Side Management have on the achievement of the efficiency, Reliability and security objectives of the Wholesale Electricity Market?

2.1 Issues with payments to DSM

Though DSM can be a lower cost alternative to peaking generation the Reserve Capacity Mechanism (RCM) fails to deliver this to the market by providing the same Reserve Capacity Price (RCP) to all capacity solutions. Given the RCM pays both a peaking generator and DSM the same even though the performance of DSM has restricted operating hours and requires up to four hours notification before being committed suggests a “value-for-money” argument should apply. The facility that delivers the more valuable product, being generation, should therefore get a higher payment than DSM. If both are paid the same then the market would always prefer to credit a real generator than pay the same amount for DSM.

Given the RCP is not differentiated by capacity type; the RCM should therefore only credit DSM if it could not attract sufficient peaking generation and DSM was all that was left.

It should also be noted that under the current arrangements, when DSM is called to operate the cost to the market is always higher than if a peaking generator were used instead. This is the consequence of the market making a second payment to DSM when it is dispatched which results in a total cost being higher than the full cost of dispatching a peaking generator, even if it is operating on distillate. The IMO has modelled this situation and presented this conclusion to the February 2011 MAC meeting.

The conclusion one would draw from the above comments is that DSM provides to the market a different value product than that provided by a peaking generator, but costs the market more if used. While the one price applies to all capacity types it is difficult to accept how such an arrangement can be considered efficient or can deliver the lowest cost.

2.2 Issue of double capacity payment to DSM

The current market rules allow a cross subsidy to be arise on account of a different approach being used to determine a load’s capacity liability,, being its Individual Reserve Capacity Requirement (IRCR),, from that being used to determine its creditable capacity, being its Relevant Demand (RD).

The IRCR is determined on the medium of the 12 peak intervals, being the 3 highest demand trading intervals over the 4 highest demand days. On the other hand, the RD is determined on the medium of the 32 peak demand trading intervals, being the 8 highest trading intervals for each month for the 4 summer months December to

March. Effectively, using two different sets of data to determine IRCR and RD allows a load to reduce its IRCR, whilst maintaining a high RD.

The IMO's view regarding this has been that a load can either reduce its IRCR by turning off during the 12 peak values but get no capacity credits; or apply for capacity credits but not both[2]. Doing both creates an effective double capacity payment: one being the actual capacity payment and the second being the reduction in capacity liability. This behaviour also means that the avoided capacity liability does not disappear from the market in the relevant Capacity Year but is passed onto other loads.

The IMO attempted to correct this situation under RC _2010_29 but in the Final Rule Change Report removed its initially proposed change providing the reason that the market may, in the future, adopt a dynamic baseline approach to determining RD which would require a further change in IMO systems. So to avoid a second system change the IMO decided to continue to allow behaviour that is considered inappropriate and an inequitable transfer of wealth between loads.

The IMO's final decision is interesting in that no rule change proposing a dynamic baseline was in the formal Rule Change Process at the time the IMO Board decided about RC_2010_29, and even if such a rule change had been in the formal process there would have been no guarantee that it would have been accepted. What appears to have happened is that the classic proverb of "one in the hand is worth two in the bush" has been suspended if not reversed here. Clearly, decisions should be made on current issues and not on what may be in the future. As a result, this situation remains unresolved.

It can further be argued that by allowing a load to reduce its demand for the 12 peak Trading Intervals, effectively reducing its IRCR when the IMO has already secured sufficient capacity to cover the load in question, is an inherent cross subsidy and so a market weakness. The broader point is that the method by which IRCR is determined allows behaviours which can reduce a load's capacity cost but passes this cost onto other loads. Clearly, formulating an annual IRCR based upon a very small number of Trading Intervals creates this weakness. It may therefore be appropriate for the market to reconsider the method of IRCR determination and by either increasing the number of Trading Intervals, used to determine IRCR, sufficient to discourage this type of IRCR reduction behaviour or determine IRCR based upon a usage, equivalent to an energy consumption value.

2.3 Issue with early capacity payment:

This only happens for a few months each year but has already cost the market $2.6 million this calendar year. The inefficiency here relates to payments made to capacity that arrives earlier than the start of the Capacity Year.

The first inefficiency happens when the market has excess capacity for the coming Capacity Year, meaning that any early capacity payments will not improve market reliability and so delivers little, if any, benefit for the payment being made. The second inefficiency is that such payments when made to DSM facilities are a windfall as such payments are available for up to four months, from next year, and are not needed by DSM facilities.

[2] This view is reinforced in the Lantau Group Review on RCM: Issues and Recommendation paper (section 2.2.3).

The purpose of an early capacity payment is to avoid post-commissioning problems for generators causing them to miss or be unavailable for the summer peak period. By providing an incentive for these generators to arrive early any post commissioning problems should be well sorted before the start of the summer peak period. However, DSM facilities do not have these issues and so do not require such incentives given they already exist as loads in the market and so only require the simple adjustment of being able to be turned off on request. Any early capacity payments made to DSM results in market inefficiency, being a payment without commensurate benefit.

It should be noted that with the increase in DSM credited for the 2012/13 Capacity Year and an two month extension for early capacity payments over the two months already provided in the Market Rules, the expected cost to the market for making this paying to DSM will be in the order of $8 million.

2.4 Aligning DSM with peaking generators – increases cost

Rather than use and reward DSM in a way which suits its operation and cost structure, there appears to be preference to make DSM perform as if it were a peaking generator. It is therefore being suggesting that DSM increase its hours of operation closer to the 2% capacity factor expected of a peaking generator in the Maximum Reserve Capacity Price determination procedure.

The potential benefit of DSM to the market comes from the case that it is a lower cost capacity solution compared to a generator, if infrequently used. The suggestion[3] that DSM has to increase its available hours to compete with peaking generation creates inefficiency in the market because it removes, from the market, a lower cost capacity solution from the potential mix. DSM has a function in an electricity market not because it can operate like a peaking generator but because it can provide a cheaper source of capacity to meet the top few hours of peak demand.

Clearly, the current “one RCP applies to all capacity types” approach equates DSM with a peaking generator although it cannot be available to the same extent as a peaking generator. Therefore, rather than equate the two types of capacity, another approach would be for the market to recognise the unique role of DSM and construct pricing and expectations which allow DSM to operate in a limited way which delivers those market efficiencies.

A simple way to achieve this would be to provide DSM capacity with a lower fixed payment recognising its lower fixed cost compared to that of a peaking generator. If dispatched then the dispatch payment should reflect the DSM’s forgone production revenue with the sum of the lower capacity cost and total dispatch costs being constrained to the standard RCP. Using this payment structure could improve the chances of the market getting value for money from a capacity type that in reality has limited availability and high dispatch costs.

2.5 Sufficient generation – DSM optional

Since inception the market has been characterised by a volume of excess capacity and that volume of excess capacity is as high if not higher than the volume of DSM credited. Given that there is sufficient generation capacity to meet the IMO’s

[3] Implied in the Lantau Group Review of RCM: Issues and Recommendation paper.

expected need for capacity from generators, and that DSM if used costs more than the equivalently sized generator, indicates the market does not benefit from extra capacity provided by DSM.

The RCM review[4] calculated the benefit of excess capacity to be less than $1,000 per MW. It could therefore be argued that the value of DSM to the market when sufficient capacity from generation sources exists to meet the Reserve Capacity Requirement, meaning DSM, is also less than $1,000 per MW.

2.6 Capacity Refunds

Regarding capacity refunds, the current arrangements applicable to DSM are different to those used for generators. The magnitude of the refund for DSM is related to the number of hours of offered service. Therefore, if DSM is credited to be available for 24 hours failure to supply one hour, if called upon, creates a refund of 1/24th of the annual capacity payment.

This arrangement was put in place given the understanding that the capacity refund applicable to generators being up to six times would not provide sufficient incentive to make DSM perform when needed. Given that the market has excess capacity, this reduces the probability that DSM will need to be called and so makes even the current penalty arrangement less effective. Therefore, one could question whether the current performance incentive is sufficient given the odd chance that DSM is likely to be called - a load may be willing to fail a one hour dispatch once, suffering the single refund but still retain the remaining 23/24 of the annual payment.

Use of the suggested payment arrangement, given in section 2.4, may be a better solution to achieving DSM performance than the current refund mechanism.

2.7 Practical volume of DSM

The volume of DSM that the SWIS would efficiently use cannot be a value simply transplanted from another market. For example, in the Pennsylvania New Jersey Maryland Interconnector (PJM) market with over 1,300 generators, meaning failure of one or two generators has limited impact on reliability; DSM is limited to 7%. In view of this level of restriction in the PJM, one may consider that the percentage of acceptable DSM for the SWIS, which has far fewer generators than the PJM, would need to be a lower percentage. It is noted that the amount of DSM credited for Capacity Year 2013/14 is already in excess of the PJM value.

3.0 Outage Planning

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[4] The Lantau Group Review of RCM: Issues and Recommendation paper.

What impact does the outage planning process have on the achievement of the efficiency, reliability and security objective of the Wholesale Electricity Market?

Generator outage planning is a balance between the cost of avoiding plant failures and suffering plant failure. This is a balance between incurring maintenance costs and capacity refunds against the cost of supply commitment replacement to contracted Market Customers. More planned outages reduce for Market Generators the exposure to the cost and inconvenience of forced outages but can result in a greater exposure to the market price of electricity to meet supply obligations.

The above is a self regulating mechanism given that if generators plan their outage at the same time that other generators are undertaking maintenance, particularly if this is on a high demand time, they suffer the possibility of facing high STEM/Balancing prices. Such high prices should of themselves discourage a concentration of outages.

Given that generators do not know what other generators are planning, only System Management has this information, so avoiding coincident outages and high replacement energy costs is not easy for Market Generators. This is more likely the case if those Market Generators are coal fired facilities which can place an extra burden on the limited market gas supply leading to distillate firing. This could be better avoided if each generator were aware of other generator's plans as notified to System Management.

This situation becomes a larger issue for generators when planning a major outage, often arranged several years ahead, given the lack of visibility of short term planned outages. This though could be resolved if Market Generators decided to hedge their STEM exposure through short-term bilateral arrangements.

The question here is whether the market in its current form, bearing in mind the number of generating companies and ownership structures, is able to successfully develop such hedging products or arrangements between the affected parties. It may be that the current size and structure of the market does not easily allow for such arrangements between the generators to be either organised or provided cheaply enough. It may be that given the small number of Market Generators that limiting such hedging to Market Generators alone is inefficient and that the market should increase the number of potential bilateral providers by allowing Market Customers to participate. Synergy, having the largest supply portfolio, is limited in its ability to offer such hedging arrangements given the current Market Rules disallow it from nominating bilateral supply into the market; only Market Generators can do this.

4.0 Rule governance

How effective is the rule change process, and its governance structure, in promoting the efficiency, reliability and security objective of the Wholesale Electricity Market?

4.1 The ability to propose changes to Market Procedures

As result of the market changing to a competitive balancing arrangement Market Rules will no longer detail the transactions instead provide an overview of the underlying principles allowing the detail to be addressed through the Market Procedures. The Market Procedures will therefore take on a broader and more important function and so will be more subject to change than is currently the case.

Unlike Rule Change Proposals, which can be proposed by anybody, changes to Market Procedures may be requested by Rule Participants under clause 2.10.2 but can only be initiated by the IMO or System Management. If Market Procedures are to play a larger defining role in competitive balancing, and later in other parts of the rules, then the ability for others, besides the IMO and System Management, to initiate a procedure change needs to be considered.

4.2 Rule administrator and rule maker roles – should be separated

There has always been a lingering concern regarding the dual IMO role as rule administrator and rule maker. The IMO both administers the operation of the rules but it is also the body that either accepts or rejects proposed rule and procedure changes.

In principle, this dual role is weak governance allowing accusations of capture and bias to be laid on the IMO. In practice, the IMO prepares rule change assessments for its board that has the final say to accept or reject rule changes. This subtle difference may be considered a separation of powers within the IMO and so sufficient to satisfy governance concerns, but it is hard to argue that an organisation and its board are really separate entities with different agendas, more often they share a common view and direction.

So, although the IMO and its board are expected to be independent; such impartial behaviour may be difficult to consistently and unambiguously achieve given completing agendas from Rule Participants, including the IMO and its board's own agendas; the IMO roles and function in the market operation; and the reality that the IMO has to live with any changes to the rules. It is therefore timely and appropriate to revisit the rule making governance arrangement with a clear intention of divesting the final approval from the IMO board to an unbiased external group.

4.3 Authority to approve minor changes to the market rule

For proposed rule changes of a minor or purely procedural nature the fast track process is currently available. It is worth considering a variant approach for some of these minor proposed rule changes which could include: typographical errors, clear calculation errors and missing items. Rather than these requiring external approval, as recommended in point 4.2 above or even IMO board approval, they could instead be directly approved by the IMO CEO. Given their minor nature, no involved consultation or independent review is required, and so these could proceed requiring only IMO management agreement. Appropriate governance arrangements would need to be developed around the definition of minor to ensure appropriate the efficiency outcome was not achieved at the cost of loss of transparency.

4.4 Progress of competitive balancing

It has been noted that the IMO has expectations which are beyond their usual duty of operating the market and administering the rule/procedure change processes. The IMO and its board were disappointed when in June 2010 that the MAC recommended against pursuing a more sophisticated market redesign agenda and instead preferred to progress incrementally fixing up the identified weaknesses with the current market design. What has resulted since is almost a reversal of the MAC's recommendation with the IMO delivering the programme for competitive balancing being something akin to a gross pool design largely rejected by the MAC 12 months earlier. Although later the MAC gave the tick to the IMO to proceed, to the rule drafting phase, concerns still remained with a number of Rule Participants that the more aggressive approach was not the timeliest solution and that a series of smaller step changes would have been more consistent with the MAC's June 2010 decision.

As an example of a step change, the market could have improved with the introducing of a clean balancing price curve alone, which could have delivered considerable benefit without the cost of the current proposal. Instead, the market has been corralled to accept a radical change moving to a 24/7 operation requiring sophisticated systems based on a multiple gate closure delivering price based merit order dispatch.

The above raises questions regarding how should the market progress; who is or should be doing the guiding; and whether what is happening is a good fit for the WEM or is it happen too quickly?

4.5 Not providing full details to the market

The RCM review consultant's report[5] has finally been presented to the market, but this report lacks the detailed assessment of this critically important element of the market expected for the time it took. The IMO Board's scope, related to this review, required detailed assessments and proposals which is lacking in the 18 page report. Clearly, consultants of the standing of the Lantau Group would have proposed considerably more details, options and analysis to the IMO Board, but such review details have not been made available to the MAC.

This is not the first time the MAC has not seen the full details of reviews or assessments undertaken by the IMO's consultants. There have been other occasions when a consultant has been commissioned by the IMO, but the IMO has either not fully released the report to the market, or has delayed the report offering only a revised version.

Although there may be valid reasons for such behaviour of not revealing all the details to Market Participants, who effectively pay for this work through market fees, such behaviour lacks accountability and comes across as a governance weakness.

As required by Market Rule 2.3.16, arrangements that ensure the market has access to the same information available to the IMO, unless confidential, will improve market decision making.

[5] The Lantau Group's report on the "*Review of RCM: Issues and Recommendations*".

4.6 Working group work load

Regarding the current rule change and working group work load, there is clearly evidence that resources have been stretched. Some of this has not been completely necessary, and the non-changeable commencement of competitive balancing has placed pressure on the market's resources particularly given that a full year's delay in the competitive balancing project would not have impacted the market's efficiency in any material way.

A more pressing concern besides the IMO resources is the ability of Rule Participants to review, assess and adequately comment upon rule changes during a period of significant development. It has been well noted that the market as a whole has a limited number of knowledgeable and suitably qualified individuals who can make themselves available to participate in rule changes and this limited number cope during times of normal operation but are less capable of performing during time of great change. Perhaps for large market changes, a staged approach would ensure the wider market was afforded sufficient opportunity to undertake the necessary scrutiny such change deserves to reduce the potential for design inefficiencies to slip through.

5.0 The Reserve Capacity Mechanism

Does the recent increase in capacity traded through the Independent Market Operator have implications for the effectiveness of the Wholesale Electricity Market?

5.1 Efficient pricing and volume

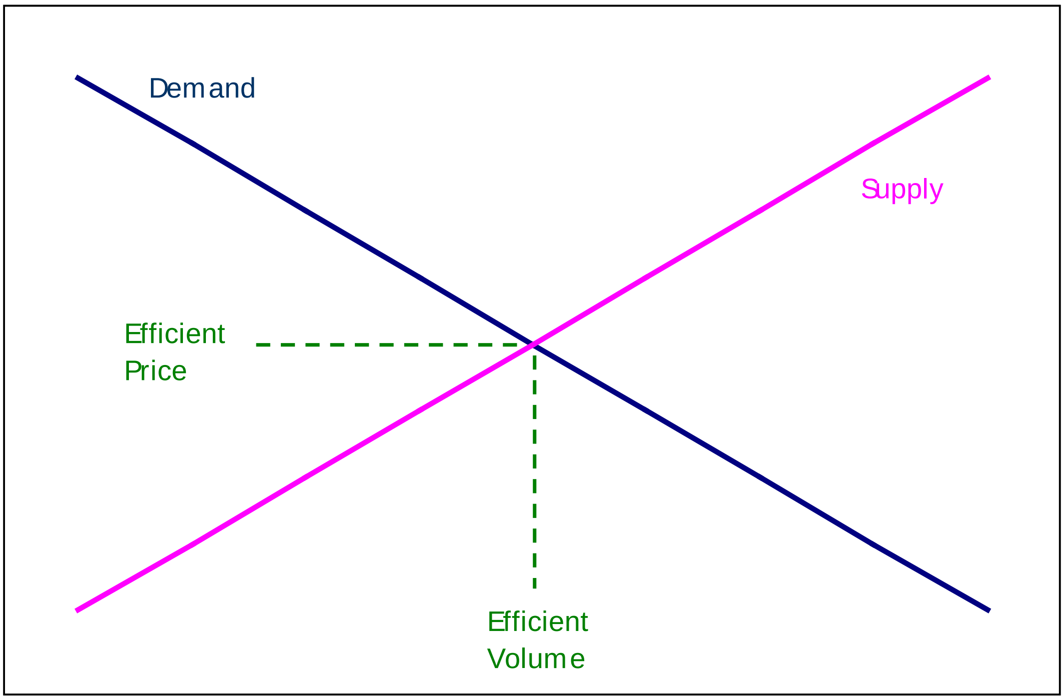
A Capacity Credit is a notional representation of a MW of production capability, or in the case of DSM, a reduction of demand. The credit and the resulting Reserve Capacity Price (RCP) is not connected to the fixed cost of either a generator or DSM, it is an administered pricing arrangement disconnected from the real costs.

Given this disconnection with real costs, an administered price such as the RCP finds it difficult to prove it is efficient, and the increasing volume of excess capacity requesting capacity crediting strongly suggests that the price setting is not efficient.

An efficient market determined price naturally caps the volume to that which is required. If supply exceeds demand then the price drops to remake the match. This basic economic behaviour of demand and supply matching with the intersection of the supply/demand curves which deliver the efficient price is lacking in the RCM. The ability of the IMO to unilaterally credit all capacity presented can be viewed as creating an artificial increase in demand which delivers higher prices than would otherwise be the case if a market based, as opposed to a an administrative, pricing mechanism applied. As a result the market bears two increases in cost: the first being the higher than efficient price and the second being this higher price applied to a greater volume of capacity. Charts 1 and 2 below show this simple relationship which can produce these price volume distortions.

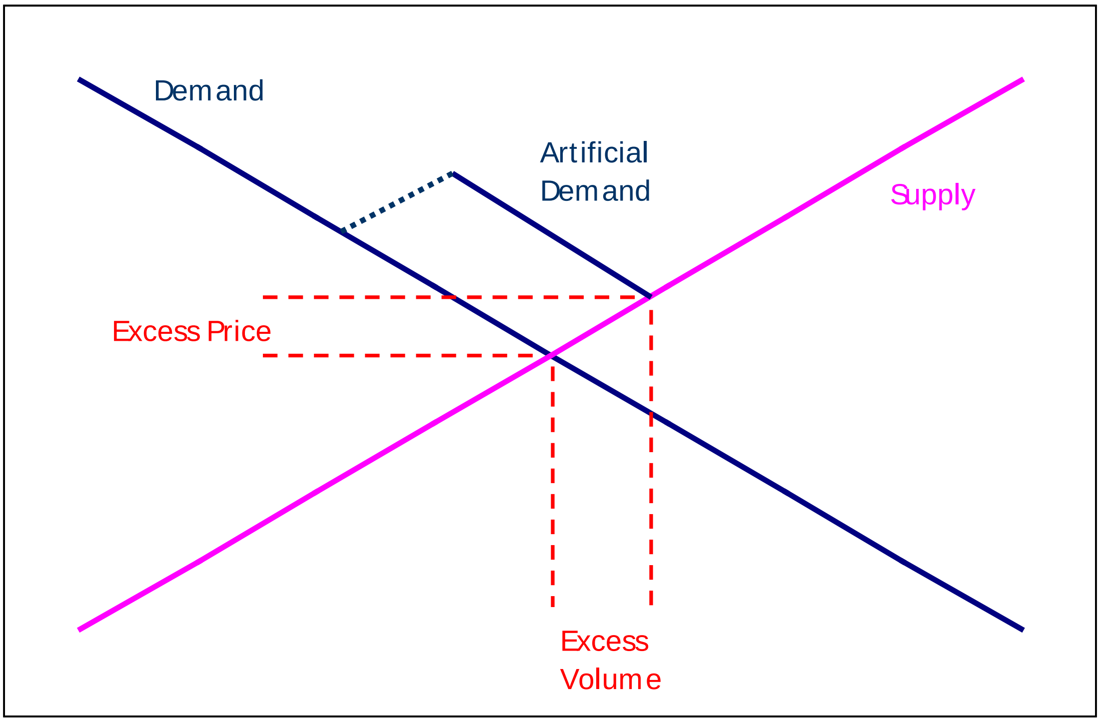
Note: Although capacity can be procured by Market Customers directly with the capacity provider, the volume of credit capacity above the IMO’s forecast as published in the Statement of Opportunities (SOO) can only be purchased from the IMO at the RCP.

Chart 1: Efficient Pricing Volume Relationship



Note - For Charts 1 and 2 the more classical sloping demand curve has been used simply for visual ease rather than represent the full nuances of the price setting mechanism.

Chart 2: Inefficient Pricing Volume Relationship

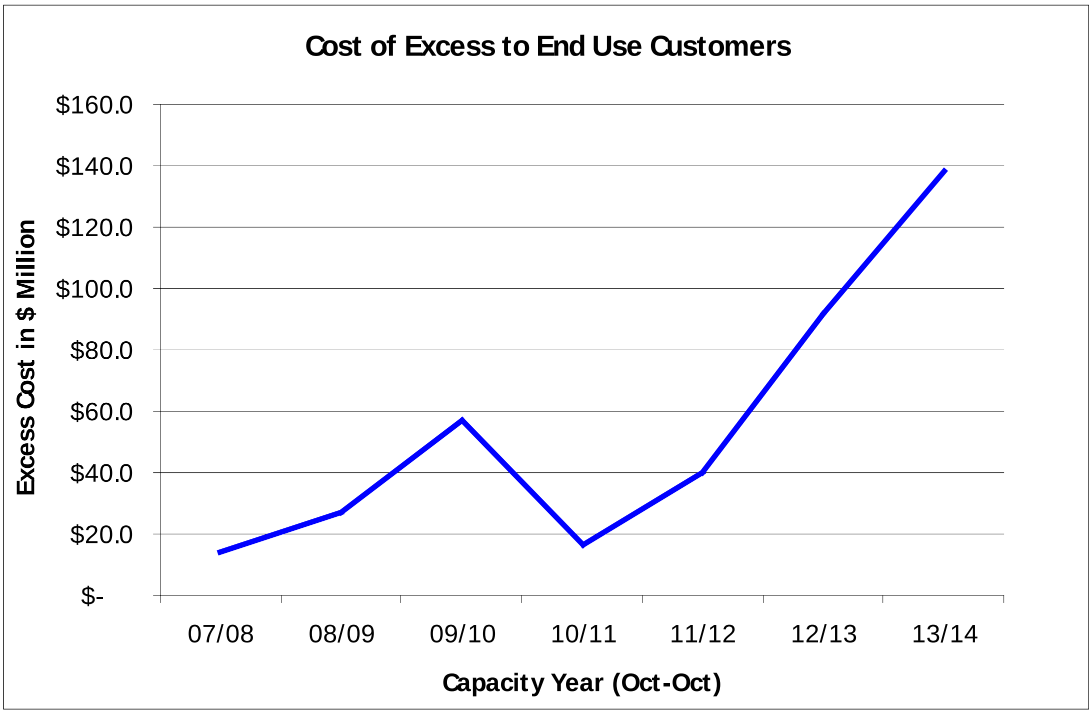


Given the RCM's administered pricing structure does not create a market based solution (an efficient price) it is difficult to know the full extra cost retail customers have been paying for capacity. The market does not know the cost of the '*Excess*

Price', given in Chart 2, because of the absence of the true or efficient market price which could be compared to the RCP. The market knows what the '*Excess Volume*' cost is given the volume of excess capacity and the RCP are both known.

Chart 3 shows the cost to the retail customers of the '*Excess Volume*' part only for each Capacity Year[6]. Since market commencement up to 2013/14 the market will have paid $400 million in '*Excess Volume*' costs. This cost, through the tariff formulation process, is transferred as an extra cost to retail customers. Given that the '*Excess Price*' is not included here, the full extra cost to retail customers, than if set efficiently, is greater than expressed in Chart 3.

Chart 3: Impact of Excess Volume alone on Retail customers



5.2 Reduced RCP given volume of excess capacity

The RCM uses a scale of price related to the volume of excess capacity as a way to moderate excess capacity and its cost impact. Unfortunately this scale of price appears to be too sluggish, as has been suggested by the Lantau Group[7].

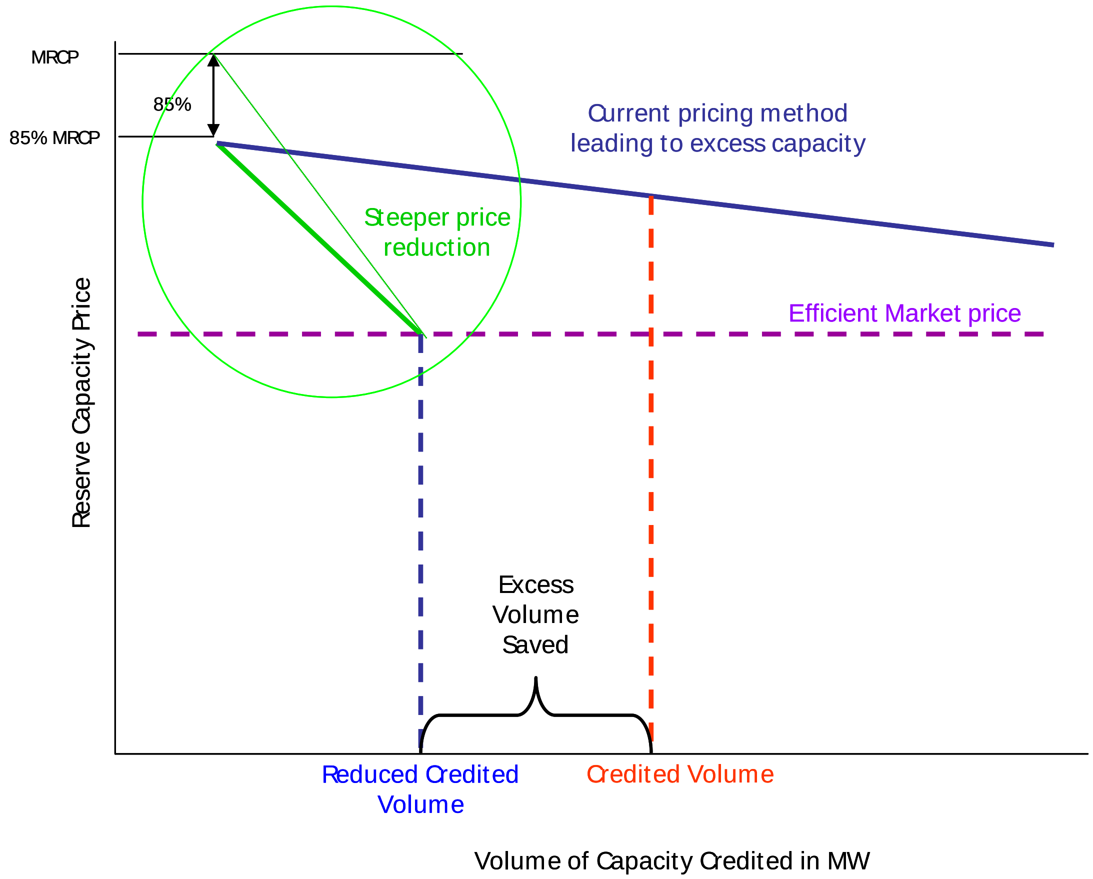
The Lantau Group has recommended a steeper price reduction scale apply as represented in Chart 4 below. Their suggestion is to increase the negative slope of the price scale by a factor to reduce the incentive for excess capacity to be offered. If such a suggestion were to be pursued by the market as the only control on excess

[6] The Excess Volume is calculated by multiplying the excess volume for a Capacity Year with the RCP.
[7] The IMO Board's consultants undertaking the RCM review in their paper "Review of RCM: Issues and Recommendations

capacity and high capacity prices then the increased slope chosen would need to be such that it restricted the volume of excess capacity to an acceptable level. Given the auction mechanism under the RCM allows for only 100 MW above the Reserve Capacity Requirement, this could be considered a reasonable tolerance value for the factor to achieve.

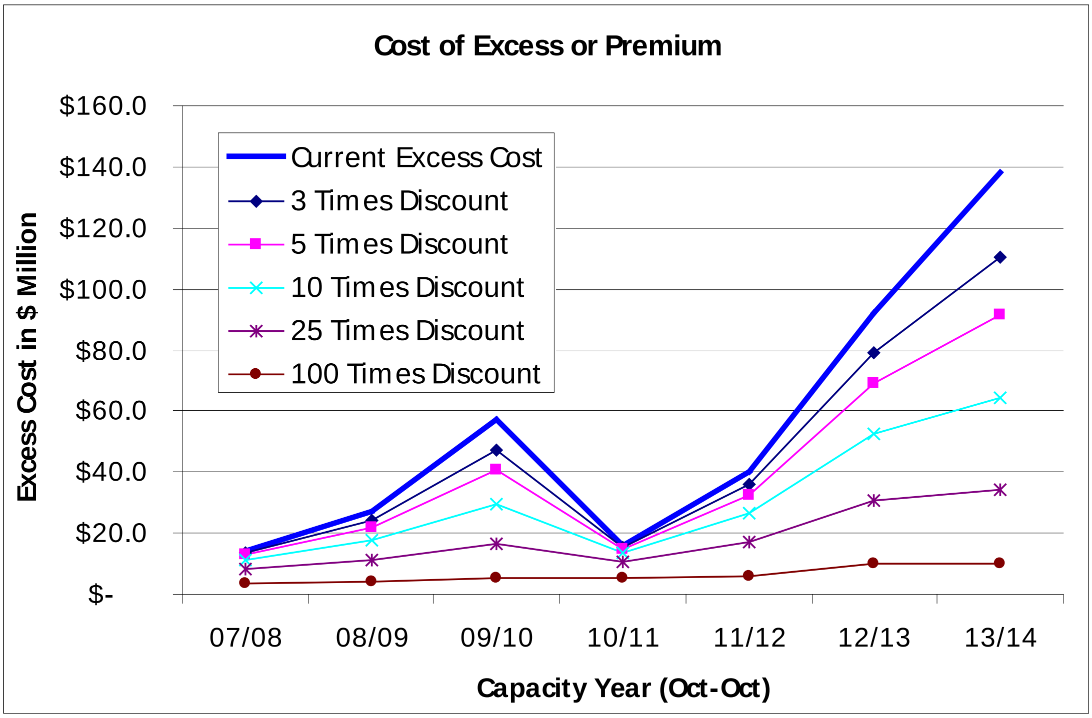
It should be noted that a large volume of excess capacity credited already exists for 2013/14 Capacity Year and to reduce this in future years may require a more aggressive reduction incentive to rapidly bring this excess to a reasonable level by using a larger price reduction factor. Chart 5 below shows the resulting "Excess Volume" cost, previously shown in Chart 3, with increasing levels of scaling factor referred to as a '*Times Discount*'.

Chart 4: Rate of Price Reduction with Excess Capacity Volume



Although Chart 5 appears to suggest that a high discount factor approaching 100 reduces the "Excess Volume" cost it is more likely a lower value, something less than 10 times, would be sufficient given the reduction in RCP. Using the 2013/14 situation, if a scaling factor of 5 were used given the current volume credited the resulting RCP would be 49% of the MRCP or $92,000 per MW. Therefore the sharp reduction in price, even using a scaling factor of 5 **may discourage** sufficient excess capacity to achieve only a modest over volume. This assumption will need to be tested.

Chart 5: Excess Volume cost with increasing RCP discounting



5.3 Alternative approaches

An increased negative slope, as discussed above, by itself may be insufficient to minimise excess capacity or achieve a reasonable cost of capacity. Given the range of possible capacity technologies, including DSM, the market is currently using and could potentially use in the future to provide capacity a single price based upon a theoretical 160 MW open cycle gas turbine may not deliver the desired results. Also deciding the size of the price reduction slope for each year could become a torturous practice leading to errors or unforeseen consequences. The market, if it is going to address the issues of excess capacity and inefficient capacity prices, should consider alternatives to the Lantau Group's proposal to determine whether these provide better, a more sustainable, outcome.

Several ideas worth considering are:

- Limiting the total volume of DSM given this can be cheap capacity and so using a scaled price approach, as suggested by the Lantau Group, only may not limit its volume but continue to add further DSM to the excess capacity category.

- Consider changing the pricing arrangements for DSM such that it is given a small fixed payment with a larger variable payment. Although this may not limit the volume of DSM it should reduce the total cost if an excess of DSM is credited.

- Disallow the IMO from making capacity payment to capacity that it is bilaterally traded. If capacity is declared as bilaterally traded but in fact is not then it cannot receive a capacity payment from the IMO. This is a more complex idea and would need to be seriously considered by the market, but has the potential to eliminate excess capacity whilst creating a competitively formed price via the auction mechanism. It delivers a neat solution that would most likely reverse the currently observed trend of more and more capacity being traded through the IMO rather than bilaterally through retailers.

- The market may also consider moving away from the centralised capacity mechanism to a market based approach where Market Customers are completely responsible for procuring their own capacity mix with suitable sanctions applying if Market Customers elected not to cover their demand. The IMO's role here would be limited to a facility crediting process and using its step in rights if total capacity was going to be short of that required. This would be a radical change from the current (comfortable) approach removing the standard capacity product and the security (comfort) of the IMO determining the price. It is though worth the market considering this as a possible alternative given it delivers better efficiencies for individual Market Participants than the current administered approach.

5.4 Increasing volume of capacity traded by IMO

At the IMO's MRCP workshop it was indicated that the MRCP was not intended as an investment signal. Clearly, the administered price (RCP) which results from the MRCP is also not an investment signal and so should be set on the basis of a fair value to discourage extra capacity volume. In the last few years it appears that the RCP has become an investment signal bringing in considerable capacity, largely of the non-energy producing type. At the same time the volume of capacity contracted by those with the capacity liability has declined to the point were more than half of the capacity credited is allocated to the IMO and not bilateral contracted. There therefore appears to be a linkage between the increasing capacity price, the increasing volume of excess capacity and the reluctance for Market Customers to contract for capacity.

Exploring this linkage further, it is understood that Market Customers operate their business by providing electricity at the lowest possible cost. This is clearly competitive behaviour aimed at improving a Market Customer's market share or profit margin. Capacity in the Wholesale Electricity Market can form part of that competitive response if it can be purchased at less than an administered price. If a Market Customer can procure capacity at reasonable rate, something approximating historical costs, then they will underwrite that capacity. If a loss of market share happens the Market Customer could sell the surplus capacity back to the IMO without loss. If capacity appears to be expensive (being the current case), as represented by too high a RCP, then there is a natural reluctance to procure capacity. Market Customers therefore avoid the higher prices and associated risks of paying too much, but remain protected by passing the IMO charges through to retail customers. Therefore the increasing volume of capacity traded through the IMO is a clear indication that the RCP is set too high and not reflecting the longer term value of that capacity.