10 December 2015

Mr John Pierce
Chairman, Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000

Submitted at www.aemc.gov.au

Dear Mr Pierce,

Demand Response Mechanism and Ancillary Services Unbundling - ERC0186

GDF SUEZ Australian Energy (GDFSAE) appreciates the opportunity to respond to the Australian Energy Market Commission (AEMC) demand-side response rule change consultation.

GDFSAE continues to support the competitive electricity market and market based approaches to energy production and consumption which includes demand side participation. This principled support is based on an appreciation of the theory underpinning energy only markets and observed outcomes since National Energy Market (NEM) start.

It is important to recall, that consistent with the economic theory behind energy-only markets, the original design principles of the NEM included active supply and demand, thus a "two sided" market, where a clearing price is established by the intersection of generator offers and customer bids. In this way the specific clearing price may be set by customers at some time and generators at other times, as demand is not, and was not, intended to be considered inelastic.

For a variety of reasons, as the NEM has evolved, the demand side has not been incorporated as intended. GDFSAE notes that this issue is being considered elsewhere by the AEMC in a separate rule change on demand side obligations for bidding into central dispatch. While it is important that these rules are treated separately, the shared timing of these two rule changes raises a useful point about demand response and the nature of load.

Specifically, if load rejects calls to be scheduled but supports demand response interventions in the NEM it shows a significant conflict in intentions. This is because scheduled load has a greater ability to demonstrate its firmness in the market and enter into contracts with other market participants at known price points. If a load participant rejects the proposed scheduling arrangements there can be little confidence in that load's actual ability to provide demand response and thus it should be no surprise that their non-firm demand response is not highly valued in the market.

In other words, the market currently allows for demand response. Loads taking steps to firm up their ability to respond is the key requirement to increasing the value of demand response products, not the introduction of contrived arrangements. The demand side bidding rule change has the potential to signal and deliver real demand side value in the NEM and is superior to any artificial mechanisms.

This is important to note, as GDFSAE considers that the arrangements that were originally articulated at a high-level in the *Power of Choice* review, remain artificial, against the intent and design of the NEM, and are based on misguided beliefs about demand management as opposed to any failures to value non-firm demand response.

In summary, there is no evidence of a market failure and, in fact, demand response is occurring and certainly isn't being prevented from occurring.

In the retail market, consumers have reacted strongly to price increases and there has been a surprising, but with hindsight obvious, reaction to retail price outcomes through curtailment in consumption. Leaving aside the notable and important hardship issues and drivers of price rises, this shows that retail level demand response, even if for reasons of price shock, is happening.

In terms of large commercial and industrial demand response with existing retailers, Simply Energy, the retail subsidiary of GDFSAE, actively works in the market to meet the needs and interests of its commercial and industrial customers. Should any of these customers show an interest in developing demand response products or capabilities Simply Energy is always eager to assist. This applies to existing and potential new customers.

At a network level, network service providers have the ability to consider demand response and other creative projects in delivering on network service and investment requirements to best meet consumer needs in accordance with the current regulatory arrangements.

At a wholesale level, market participants have an ability to sign wholesale contracts and take pool price exposure, work with specialist demand response providers, or be dispatched by a second party. Some large industrial loads already do this as is evident by market outcomes. Demand response that is firm has significant value to third parties and in its own right to reduce consumption costs. This is especially likely to be the case in an environment of rising gas prices, increased pressure on thermal generation, and growing penetration by intermittent generation.

Thus, as it stands, proponents have failed to show that disrupting the NEM settlement arrangements and introducing a distortion that creates further inconsistencies between the NEM and the economic principles which underpin successful energy-only wholesale markets would provide net benefits to consumers in the long term.

Rather, information provided by industry participants has demonstrated clearly that the system costs that will be incurred by industry if required to enable settlement against baselines will be considerable and certain, whereas the benefits from enabling settlement against baselines are doubtful and at best marginal.

This is the reason that the rule change has been framed as a voluntary arrangement: a voluntary arrangement seeks to obtain some of the benefits of the compulsory model, but without incurring the costs. Nevertheless, it has still not been demonstrated that the voluntary model as proposed has incremental net benefits compared to the current market rules which already permit participants to freely enter the contractual arrangements that meet their business needs on both the supply and the demand side.

We consider that the voluntary model as proposed is highly unlikely to have incremental net benefits over the current arrangements, because the model adds complexity and costs in an attempt to 'facilitate' something that can and does already occur. Furthermore, the model is flawed in concept as it confuses physical demand and settlement of contracts (financial instruments).

On this basis, GDFSAE remains firmly of the view the rule change should not proceed. The remainder of this submission provides further information relevant to the AEMC's deliberations.

Market Conditions

It is important to observe actual market conditions when assessing the validity of comments by participants who believe the non-firm product they are offering is not being sufficiently valued or an aggregator who wishes to avoid becoming a licensed retailer or Australian Financial Services License holder.

Granted, GDFSAE believes the regulatory and license obligations on retailers and wholesale markets participants require attention but even leaving that aside, existing barriers to entry are low and there is little justification for favourably treating one class of participant differently to another.

In considering the low barriers to entry, many new retailers have emerged over time and continue to emerge. Some new entrant retailers have successfully started with just a few customers. In such an environment, a retailer's willingness to provide all possible benefits to customers, especially large customers likely to provide demand response, is acute. This is the environment that GDFSAE actively compete in.

In fact, supply to large customers is hotly contested as evidenced by the very low retail margins in this market segment. Large customers are able to choose pool exposure for some of their load, or demand side response, and some already elect to do so. It is common for large customers to tender out their electricity supply decision making process, frequently using third-party brokers.

There is no barrier, with the exception of low pool price, to prevent these customers from stipulating demand side response elements in their tenders. However, only a few large customers appear interested in such products. This is possibly also exacerbated by their short term contracting strategies. For example, large customers commonly seek 12 month or 24 month contracts. In some cases they seek shorter periods, such as six months to maximise competitive tension.

Further, were customers interested in developing such arrangements, retailers currently have access to the necessary information required to offer and settle demand side response contracts. Retailers are in a prime position to negotiate positions, even baselines with customers, and to measure actual demand for settlement purposes. There is no need for additional settlement or prudential requirements to be imposed on retailers for baselines under this approach.

With the installation of smart meters and development of batteries, retailers are likely to be well placed to extend the service to smaller customers and to include network services as part of their energy services when it becomes economic. The AEMC should be assured that market participants are actively working on, as they always have, energy services that can deliver customer benefits and returns. It is illogical to assume that retailers would exclude demand response on occasions where real value exists.

Interestingly, several specialist retailers have either previously facilitated, or currently have demand side responsive customers. A recent example of a new entrant in the demand response space is PG Energy (see attached). Customers are kept informed of price events and remote load management is facilitated. This

includes both demand management and coordination of onsite generation at times of high wholesale prices.

On the wholesale side, it is important to examine the supply demand balance. While declining demand has already been touched upon, it is also important to note that the wholesale electricity market is chronically oversupplied, mainly due to forced subsidised renewable generation in the mix, which has resulted in multiple generator exits and moth balling of thermal plant.

The recently sustained low wholesale prices have not encouraged demand response, especially non-firm demand response which cannot easily be called upon. More recently as conventional generation has withdrawn from the market, price increases will provide more incentive for demand response.

How does the proposed demand response mechanism actually work?

There appears to be some degree of misunderstanding regarding the outworking of the proposed DR mechanism. One way of clarifying the mechanism is to follow the money flows between entities in two timeframes, one during a demand response event and the other at times outside the event.

It should be reiterated that there is no "new money" under the proposed arrangement. The mechanism provides a signal to assist customers in reducing load (or increasing on-site generation) during high price events. As part of this signal customers receive a payment for the volume of demand response, which is priced at the wholesale market price. During a demand response event customers receive back some of the money they effectively already paid the retailer through their risk adjusted tariff (essentially a hedge) at times outside of the demand response event.

Thus, a customer cannot be better off under the proposed demand side response arrangement than if they were simply exposed to the spot market, and responding to price signals to optimise their opportunity cost. Such a customer would simply avoid pool purchase costs for the amount of load curtailed. If the risk management products are fairly priced, a demand response mechanism customer would be worse off than a spot exposed customer by at least a risk premium.

GDFSAE has developed a worked example of the demand response mechanism, which it would be happy to discuss with the AEMC, that illustrates the cash flows. The conclusions of this analysis are consistent with the points raised above. There is no incremental benefit to the market or consumers.

First, the money paid to the customer during a demand response event is collected from the same customer at times outside of the demand response event. There is no magic pudding but in fact a merry-go-round of finances that can only serve to increase transaction costs in an inefficient manner.

Importantly, the mispricing of risk is a driver of any differences to the retailer or the customer and will quickly be corrected, likely through an additional risk premium which would cover the transaction costs. The net effect would be increased expenditure on transactions. This additional cost is due to risk management instruments (hedging) the retailer would need to put in place and a service charge for the demand response infrastructure.

Superficially it may appear that a customer has an incentive to take steps that increase its baseline, in order to increase the value of any demand response. However, as baseline increase, so does the cost of contracting with a retailer through their tariff (or hedge). Nonetheless, under the proposed arrangement there may be limited opportunity to increase the baseline as it would be determined by an AEMO developed process.

In the absence of the rule a customer could negotiate a baseline with a retailer. Under such an arrangement, if the customer were to overestimate/over contract their load, they would not be "gaming" the arrangement. They would simply take a view that the product was mispriced and that the payoff will be in excess of the additional hedging costs.

It should be noted that a retailer has various options to manage their price and volume risks relating to the demand response load. These include options to self-hedge the load, or to lay off the risks to a third party, such as a financial institution or a generator. However, the risk management option does not change the net economic position of the customer, generator or the retailer.

It should be noted that the risk management element of a demand response load often gets confused with the lost opportunity cost to a generator during the demand response event. The lost opportunity for a generator represents an efficient market outcome in a competitive electricity market, where the generator has essentially priced its product out of the market (i.e. customer isn't willing to pay the asking price and curtails consumption).

It also does not mean that the same generator must underwrite the demand response load hedge (tariff); however, if a given generator chooses to do so, its position will be no different to any other party hedging arrangement. In principle, these hedges need to be assessed independently of the physical generation.

Network benefits

The current rule change does not specifically address network benefits and services. There may be significant benefits from demand side response in specific network locations. These could range from demand management to defer network augmentation, to provide local voltage and reactive control, or to reduce export of embedded generation at certain times (e.g. from rooftop photovoltaics) by implementing battery storage.

These benefits were originally a driver of the mechanism on the basis they may be much greater than benefits from large customers in the spot market alone. Leaving aside the view that network demand response benefits should not be derived from artificially contriving wholesale market outcomes, as it will undermine total system costs and the long term costs of delivered energy to consumers, the proposed rule change would not capture any network benefits, because it omits a locational price signal that applies at times of peak loading of the relevant network elements.

Again, retailers are in a good position to offer these products to customers and networks as part of their suite of energy services. The existing competitive arrangements can already provide these benefits where economic, and rule changes are not needed.

Technological neutrality and level playing field issues

The proposed rule change seeks to treat different technologies selectively in the NEM. This creates an uneven playing field between retailers and demand response aggregators in relation to retail license obligations. Such an arrangement would serve to undermine the existing retailers that are already offering demand side management products under the current arrangements. The rule change may perversely curtail existing demand side response in the hope of stimulating new responses under the modified rules.

Settlement

The proposed rules would move away from the settlement of physical energy and introduce the settlement of financial instruments by AEMO. AEMO should not be expanding into the settlement of financial products

and this should be left to the competitive market, which has successfully managed these products to date. A regulated solution should only be imposed when the market has been demonstrated to have failed. After multiple assessments over a number of years it remains the case that no failure has been demonstrated.

In summary, GDSFAE continues to support market based solutions, including demand side response, as intended in the NEM design, and is opposed to artificial mechanisms which undermine the principles on which the NEM was founded.

GDFSAE maintains that demand side response is already occurring under the current arrangements and there is no market failure. The proposed arrangement offers no additional value to customers or retailers and stands to create a distorted playing field. Demand side response is a form of energy service offering that should be led by the customers and retailers.

The proposed rule fails the National Electricity Objective test as it introduces additional costs with no additional benefits beyond what the existing market is already delivering and therefore should be abandoned.

GDFSAE trusts that the comments provided in this response are of assistance to the Review Panel in its deliberations. Should you wish to discuss any aspects of this submission, please do not hesitate to contact me on, telephone, 03 9617 8415 or Mr David Hoch on 0417 343 537.

Yours sincerely,

Jamie Lowe
Head of Regulation

Appendix --Specific responses to questions raised in the consultation paper.

Question 1 Assessment Framework

- Would the proposed framework allow the Commission to appropriately assess whether the rule change request can meet the rule making test?
- What changes to the proposed assessment framework would stakeholders' consider appropriate, if any?

Demand side response can and does occur under the existing regulatory arrangements. The rule change will introduce a different mechanism which relies on fundamental changes to the role of AEMO and the settlement process.

Software changes to participant systems will be expensive, as was previously established and articulated by independent consultants.

Therefore the proposed rule change introduces significant additional costs without additional benefits and thus fails to meet the National Electricity Objective criteria.

As a matter of market design principle, AEMO should not be expanding into the settlement of financial products and this should be left to the competitive market. This reliance on market based mechanisms has worked well to date and no change to the standing principles and arrangements is necessary.

While we understand that it is challenging to develop a robust cost-benefit assessment to determine that a regulatory change is justified in terms of improved net benefits compared with current arrangements, we consider that this is the standard the AEMC should strive to achieve. The proposed assessment framework is overly qualitative and this leads to a significant risk that costly regulatory changes will be made on the basis that they are considered to have a theoretical justification.

A robust cost-benefit analysis is needed, as this will enable stakeholders to provide further information that can help avoid a poor decision. Under the proposed assessment framework, in contrast, we cannot see how a stakeholder could provide information that would overturn a view that the proposed changes would 'send better signals to market participants', for example. Whether or not a signal is 'better' is overly subjective.

Additionally, tests such as 'whether the costs and benefits are allocated to parties that are best able to manage them' does not help decide whether a change to regulations will give better outcomes than the current arrangements. For example, costs may be increased by more than benefits, meaning that in overall terms outcomes are worse, but the change may still pass this test if the worse outcomes are appropriately allocated.

In conclusion, we consider that the proposed assessment framework should be replaced with a robust cost benefit analysis of the proposed changes in comparison to the current arrangements, following a clear determination that a market failure exists.

Question 2 Potential barriers to demand side participation relevant to this rule change request

- What are stakeholders' views on the potential barriers to demand side participation that have been set out in this consultation document? How relevant might they be? Should they be considered in the Commission's assessment?
- Have stakeholders identified other barriers to DSP that should be considered in the Commission's assessment? Please, explain and provide evidence where possible
- What are the costs and benefits of removing the barriers that are identified as significant to this rule change request? Which barriers are the most problematic and/or more cost-effective to remove?
- Are there any current or upcoming changes in the market that would mitigate or address any of the identified barriers?
- Might there be any unintended consequences from addressing such barriers?

The proposed rule change fails to establish a case of market failure and also ignores existing demand side participation and demand side service providers.

The biggest obstacle to demand side participation currently is the chronically low wholesale pool price. However, this does not represent a market failure, but is the correct and economically efficient response of a competitive electricity market.

Large customers already generally face cost reflective (capacity based) network tariffs, and the introduction of cost reflective small customer tariffs should encourage further demand side response. Coincident network demand in a distribution infrastructure maybe costly to build out and demand response could be the least cost solution.

Customers would decide based on the value they place on electricity consumption (either they consume and pay, or reduce demand and avoid energy and network costs).

For smaller consumers networks charges are more costly to consumers than energy charges, and high energy prices don’t necessarily occur at the time of high distribution demand (ie the energy market and distribution system dynamics are different).

The unintended consequences may well be that the changed arrangements harm existing DR response retailers by creating an un-level playing field for existing retailers by allowing non-retail entities to compete for some services but under “softer” set of regulatory arrangements.

Questions on the overall DRM design proposal

- Would the proposed DRM generate useful demand-side information in relation to improving wholesale pre-dispatch and dispatch prices? How significant would this improvement be?
- Would the proposed DRM generate useful demand-side information in relation to improving the management of transmission constraints through the dispatch process? How significant would this improvement be?
- Would the proposed DRM generate useful demand-side information in relation to improving the provision or procurement of ancillary services? How significant would this improvement be?
- Would the proposed DRM operation result in a technology neutral approach between demand response and generation resources?

- Do stakeholders think that there exist and relevant gaming risks or unintended consequences from implementing the overall proposed DRM operation? If so, how could they be mitigated in a cost-effective way?
- Would the DRM result in system-wide benefits and/or costs that might impact the operation and investment in electricity transmission and distribution networks? What aspects of the design would contribute to this?
- Would the DRM result in improved ability for AEMO to manage system security and reliability? What aspects of the design would contribute to this??

The proposed DRM is unlikely to generate useful demand-side information that could not be more easily obtained by other means.

The proposed DRM allows the customer or demand response aggregator to call a demand response interval at any time before the end of a trading interval. There is no incentive for the call to be made before the trading interval, because the DR provider will benefit from high generator bids that are responding to a high level of expected demand. Early notice of DR would, in contrast, be expected to reduce generator bids as generators compete to service a lower level of expected demand. As a result, a DR event is unlikely to provide useful information about upcoming trading intervals.

Similarly, demand response events provide minimal additional information about trading intervals that have already happened, which can usefully inform forecasts about future trading intervals. If information about demand response is to inform future trading intervals, then it is necessary to forecast it. AEMO does not need demand response event information to forecast future demand response impacts. Instead it can forecast based on observation of how load changed as prices changed (similar to how it forecasts load changes in response to weather and the time of day). For these reasons it is unlikely that the proposed demand response mechanism will provide system-wide benefits or improvements to system security and reliability management.

As a technology neutral alternative to the proposed DRM, there are several potential ways of improving the pre-dispatch and dispatch processes and these include:

- Mandatory bidding of large loads into the market (would require a rule change)
- Estimation of price sensitive load by AEMO to inform the market (doesn't require a rule change but a change to AEMO procedures (similar to wind and PV generation estimation))

The proposed DRM should not hinder the pre-dispatch and dispatch processes subject to reasonable accuracy of baseline and DR response estimation.

However the proposed DR approach is redundant if either one or both of the abovementioned improvements are introduced.

Question 4 Accredited baseline consumption methodologies

- In stakeholders' views, are there any alternative demand response mechanism options that would not require the use of baseline consumption methodologies?
- What might be the costs, benefits, and consequences from having an administrative baseline developed and then managed by AEMO?
- What are stakeholders' views on the proposed baseline methodologies, and the proposed assessment criteria to be applied when assessing baseline consumption methods?

The principle behind the baseline is that settlement is based on real and notional consumption. The notional consumption is essentially a hedge which is a financial instrument.

One pragmatic option is for the baseline to be negotiated between the customer and retailer; “a customer choice”. This negotiation sets the level of hedging (tariff) the customer wishes to arrange in relation to their expected load and DR response. For a customer this will ultimately be a trade-off between higher ongoing cost (tariff/hedge quantity) and higher potential payoff during DR events, and lower ongoing tariff/hedge and lower payoff during DR events.

This is a commercial decision which the customer and retailer are best placed to address. AEMO has no commercial expertise in this area and isn’t in the business of developing and settling financial products. As a result, we do not support AEMO calculating baselines.

Limiting the baseline to a physical supply arrangement is unlikely to deliver an optimal solution for a customer as it ignores the commercial drivers for the DR load.

Question 5 Restrictions on the provision of demand response

- In stakeholders' views, how effective would the proposed DRM design be in preventing the exercise of potential gaming opportunities?
- Are there alternative options to improve upon the current design to manage gaming risks?

Gaming opportunities under this arrangement are overstated, most likely as a result of a misunderstanding of the proposed DR mechanism. A customer would pay more for a higher baseline (which the retailer needs to hedge) which would offset the potential increased payoff during DR events.

Consequently there is a negative feedback once the baseline quantity is increased beyond the expected physical demand and DR response. Beyond the actual response, the customers is essentially taking a view that the retail product is mispriced, in the hope of receiving a larger payoff during the high priced DR events to offset the higher purchase costs of the hedge (tariff).

Customers may wish to have a larger or smaller margin on their load. This would be inconsistent with the AEMO arrangement as they don’t have visibility of the commercial drivers of customers.

Question 6 Interactions with demand side participation mechanism

- Does the proposed DRM design appropriately capture and address all potential interactions between the DRM and other demand side participations options in the NEM?

The paper states that a customer has multiple ways that it can offer its demand response to those who can benefit from it: its retailer, its distributor, and the ancillary services market (scheduled DR only).

Where DR can provide multiple benefits at the same time, it is appropriate that the DR provider can access multiple markets. However, it has not been demonstrated that the proposed DRM is needed to address a deficiency in the current options that prevents potential DR providers from accessing any relevant market.

Question 7 Prudential requirement

- Are the proposed prudential requirements on DRAs and retailers appropriate?

The DRM proposes that retailer prudentials would be based on baseline energy rather than actual energy. This is yet another example of how the model distorts well-established and well-performing market mechanisms that are based on actual consumption, and replaces them with mechanisms based on notional values.

Additionally, as identified in the paper the DRA, while expected to normally be a creditor, can become a debtor under some circumstances. This creates a risk for the market that will require DRAs to provide a risk-based instrument that will cover a DRA's potential debit position if it should occur.

Question 8 Settlement charge

- Do stakeholders have any observations over the proposed changes to the way the costs of ancillary services would be recovered from DRAs and/or retailers?
- Do stakeholders have any observations regarding the proposed changes to the compensation cost recovery from retailers?
- Do stakeholders have any observations regarding the proposed changes to the way the operating costs would be recovered from DRAs and/or retailers?

These arrangements are likely to be quite costly and are arguably unnecessary. Any costs associated with these changes must be confined to the DR loads under this arrangement.

Cross subsidisation from other customers must be specifically prohibited. Otherwise customers with DR arrangements with retailers not using the AEMO settlement process would be disadvantaged by having to pay for settlements they use with retailers as well as a cost of settlements with AEMO they do not use.

Customers without DR would also be disadvantaged if the AEMO settlement costs are allowed to be smeared across loads.

Question 9 Implementation issues in relation to the DRM

- The Council proposes a voluntary approach for retailers to enable their customers to participate in the DRM. How effective do stakeholders think this voluntary approach will be in encouraging retailers to enable their customers to opt-in into the DRM?
- What are stakeholders' views on allowing manual billing as a viable short term solution to encourage retailers to enable their customers to opt-in the DRM?

In the event that the AEMC decides to proceed with this unnecessary rule change, it is imperative that choice is maintained. This is important because analysis has shown that a compulsory mechanism has expected net costs, due to the certainty of high implementation costs and the low and uncertain potential benefits.

There must be freedom for customers to use other market arrangements (already in place as well as potential schemes) without being constrained to the AEMC proposed scheme.

The proposed manual billing is strongly supported to minimise costs to customers and the industry.

Question 10 Voluntary and staged approach

- The Council proposes a voluntary approach for retailers to enable their customers to participate in the DRM. How effective do stakeholders think this voluntary approach will be in encouraging retailers to enable their customers to opt-in into the DRM?
- What are stakeholders' views on allowing manual billing as a viable short term solution to encourage retailers to enable their customers to opt-in the DRM?

Replicated questions, see response to Q9

Question 11 Potential barriers to demand side participation in FCAS markets

- Do stakeholders agree that current market arrangements where only market participants that purchase or sell electricity on the wholesale spot market can participate in FCAS markets are a barrier to entry that restrict DSP in the FCAS markets?
- Do stakeholders agree that facilitating entry via greater DSP, either as individual or aggregated loads, can result in lower cost and higher quality provision of FCAS services while minimizing the scope to exercising market power in these markets? Do stakeholders have any particular evidence to support their views?
- In which category ancillary service provision do stakeholders believe that entry will be more likely? Are there any foreseeable future changes that might broaden the scope of entry in markets where demand response has generally not been able to provide ancillary services?

GDFSAE does not agree that the current market arrangements represent an unreasonable barrier to entry that restricts DSP in the FCAS markets. Loads that wish to provide FCAS are able to either register directly with AEMO as a market load, or enter into a commercial arrangement with an existing market customer. This is not substantially any more difficult that the DRM proposal for Demand Response Loads (DRLs) to enter into commercial arrangements with DRAs.

The more substantial hurdle for FCAS service providers to meet is that they are able to comply with the market ancillary service specification (MASS), which imposes a number of stringent obligations. This is important as when FCAS services are called upon, the security of the power system is dependent on these services functioning promptly and effectively. The MASS obligations are unchanged by the DRM proposal.

Question 12 Questions on the overall ancillary services unbundling (ASU) proposal

- In stakeholder's view, how would the ASU proposal impact on the cost of balancing supply and demand in the NEM?
- Would the ASU proposal result in improved ability for AEMO to manage system security and reliability? What aspect of the rule change would contribute to this?
- Would the ASU proposal result in reduced ability for AEMO to manage system security and reliability? What aspect of the rule change would contribute to this?

GDFSAE believes that the ASU proposal, which relies on complex interactions between a DRA and a DRL, will even more complex than the current framework, which allow a load to offer FCAS more directly through a market customer. GDFSAE therefore does not believe that the ASU will have any positive impact on FCAS liquidity or cost.

Question 13 Interactions with the DRM

- Does the ASU proposal appropriately capture and address all potential interactions with the proposed DRM?

As noted in response to question 12, GDFSAE believes that the complexity ASU proposal in terms of the required interactions between the DRA and the DRL, and the need to manage when and how FCAS response impacts on offered DR, will result in the proposed DRM/ASU arrangements being deemed as too complex, and unlikely to be taken up in any substantial volume.

Attachment – Progressive Electricity advertisement

PROGRESSIVE ELECTRICITY RETAILER PROVIDES BIG SAVINGS TO BUSINESSES

- DO YOU SPEND MORE THAN $50K PER ANNUM ON ELECTRICITY?
- DO YOU OPERATE PUMPS OR HAVE A COLD STORAGE FACILITY?
- DO YOU HAVE A STAND-BY GENERATOR?
- WOULD YOU LIKE TO REDUCE ELECTRICITY COSTS?

For many businesses, electricity represents a major operating cost where machinery, pumps and refrigeration plant consume significant amounts of electricity. Short of reducing production, most businesses would appear to have little control over the cost of their electricity. One innovative company has taken advantage of a new way of purchasing electricity, allowing businesses to control energy costs, and significantly reduce the energy component of their electricity bills up to 25%!

According to Business Development Manager, Antony Denahy, PG Energy is a specialised electricity retailer, offering wholesale market access to large electricity users within the National Electricity Market (NEM).

"Traditionally, most businesses purchase their electricity from an energy retailer via a standard retail contract. The retail contract usually contains standard peak, off-peak and shoulder rates. In order for retailers to supply their retail customers with electricity, retailers purchase the electricity from the variable price wholesale electricity market. The cost is at the prevailing spot rate and then is charged on to the customer at fixed retail contract rate," Anthony said.

With the dramatic rise in fixed rate offers many customers are now seeing, the wholesale market is something that should be considered...many large Australian businesses purchase wholesale, now your business can as well.

"PG Energy has recognised the opportunity to save customers money by providing direct access to the wholesale market via its Managed Pool Purchasing product. Our sophisticated management tools and tailored energy contracts provide innovative solutions with realistic returns," explains Anthony.

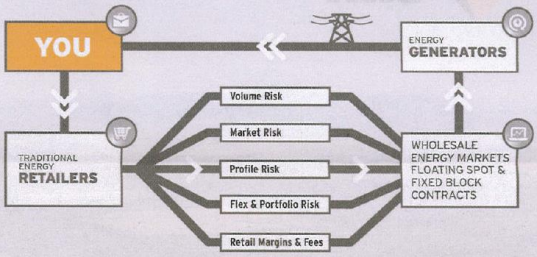
The company offers a unique end-to-end management solution that includes a comprehensive 2-way notification and automated remotely controlled load management system.

"The solution keeps sites informed of market price events, this allows load to be managed at the right time, i.e. to shed load and or the best time to use load (low prices) - an essential element for purchasing from the wholesale market or starting up any onsite generation," he said.

PG Energy provides energy agreements for both fixed and direct wholesale pool purchasing consumers. Options include benefits tailored to suit the operation of the particular site, for example, load shedding capability and/or partially fixing load at prevailing prices.

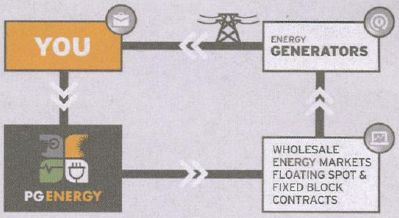
To see if we can help you, please contact Anthony direct on 0417 080 535 or email your enquiry through direct at Anthony.denahy@pgenergy.com.au

How you currently purchase power.



Save between 5% and 25%

PG Energy's simple power purchasing solution.



For more information contact PG Energy on 1300 08 06 08 or by emailing
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PG ENERGY