Reactive Power Management and Procurement Mechanisms: Lessons for the Power Potential Project

By

Karim L. Anaya and Michael G. Pollitt[1]

Report prepared for National Grid

POWER POTENTIAL PROJECT

SRDC 9.3

Energy Policy Research Group

University of Cambridge

11th June 2018

[1] The authors would like to acknowledge the support from AEMO, CAISO, ISO-NE, NYISO, PJM, SCE, UK Power Networks and National Grid in the provision of relevant information and clarifications. The authors also acknowledge the financial support of National Grid via the Electricity Network Innovation Competition Power Potential Project. The views expressed herein are those of the authors and do not reflect the views of the EPRG or any other organisation that is also involved in the Power Potential project.

Table of Contents

List of Figures

List of Tables

Reactive Power Management and Procurement Mechanisms: Lessons for the Power Potential Project

1. Introduction

The increasing amount of Distributed Energy Resources (DER)[2] is not only challenging the distribution system but also the transmission system by altering traditional grid operation. The transition to a more decentralised and flexible energy system reflected in the adoption of specific national/state policies (e.g. DER Roadmaps in New York, DER Action Plan in California) and the declining cost of DER technologies are contributing to DER expansion. Increasing levels of DER participation in the wholesale market, also imply the need for greater DER visibility by system operators (at the transmission level) and additional coordination between transmission system operators and electricity distribution firms (More than Smart, 2017). DER (aggregated or individual connected) often has dual participation, in wholesale and retail electricity markets, which allow it to deliver greater benefits due to the provision of multiple services, including ancillary services such as reactive power (NYISO, 2017)[3]. Unlike transmission connected generators, DER in general is not necessarily required to provide reactive power support to control local voltage levels[4]. However, it is expected to take a more active role in this in the future. This is reflected by the introduction of new requirements such as those specified in Network Codes, the use of advanced technologies such as smart-inverters in DER, among others[5]. The increase of DER and the decline of centralised generation implies that the use of DER capabilities will be important to support both transmission and distribution system reliability (NERC, 2017, p.12). In addition, in regions with a high level of DER penetration, electricity distribution firms can become a source rather than sink of reactive power (AEMO, 2017c, p.29). Because DER can also introduce additional system complexity, "trials" are required to measure and evaluate the effectiveness of DER in providing reactive power and voltage support (Exelon Companies, 2016, p.12).

The aim of this report is two-fold. First, it sets out the conceptual framework of competitive procurement mechanism design applied to the Power Potential project. Second, it looks at the international experience in the management and procurement of reactive power and related ancillary services to identify specific lessons for the Power Potential project. This project is being implemented by National Grid (the Transmission Electricity System Operator for GB) and UK Power Network (the largest DNO in GB). Power Potential seeks to contract with DER for the provision of reactive and active power services in the southern region of GB using a competitive mechanism (i.e. tenders). We take a closer look at two specific cases studies that relate to the use of competitive

---

[2] DER has been usually associated with facilities connected to the distribution system (NERC, 2017; FERC, 2018). NYISO has proposed a more open definition of DER in its recent DER Market Design Concept Proposal expanding its injection capability to transmission system (usually limited to distribution system) but keeping at the same time the concept of small resource (limited capacity). DER are defined as "*resources qualified to participate in NYISO's Energy, Ancillary Services, and/or Capacity markets that are (1) capable of changing its load, or (ii) capable of injecting 20 MW or less onto the transmission and/or distribution system, at the NYISO's direction*" (NYISO, 2017, p.10).

[3] In contrast with active power.

[4] Some exceptions may apply. For instance in the UK, large-size generators may be subject to the GB Grid Code requirements, which among other things set a specific range of power factors associated with the supply of rated MW (CC.6.3.2). See: https://www.nationalgrid.com/sites/default/files/documents/42550-Issue%205%20Revision%2014%20-%2026%20August%202015.pdf

[5] In GB, greater requirements for new connections of user equipment (e.g. generators, interconnectors) have been set in agreement with the EU Network Codes. Further details are provided in Section 2.1.

mechanisms for the procurement of (1) reactive power in Australia (Business as Usual) and (2) demand response services in California (a pilot project).

The structure of this report is as follows. Section 2 discusses the current methods for managing and procuring reactive power by selected system operators in the USA, Australia and GB. Section 3 describes the Power Potential project. Section 4 discusses the principles of procurement mechanism design and how these apply to Power Potential. Section 5 evaluates the two cases studies from Australia (NSCAS tenders by AEMO) and California (Demand Response Auction Mechanism- DRAM). Section 6 identifies the main lessons for Power Potential from the two case studies with a focus on the auction design. Section 7 concludes.

2. About Reactive Power Management and Procurement

There are two types of power in an AC power supply system, reactive power and active power (real or true power). In contrast with active power (expressed in Watts), reactive power (expressed in Volt-Amperes Reactive) does not involve a transfer of energy. Reactive power is transferred from the source to the load and then returns from the load to the source, then the average power supplied is zero. This means that in contrast with active power, reactive power is positive during one half cycle and negative during another half cycle on the AC waveform (Chapman, 2005). Reactive power (Q) is produced in an AC circuit when the current and voltage waveforms are not in phase. This dephasing reduces the active power (P) output[6]. Then, reactive power compensation is required to keep the system voltage within appropriate limits. These limits can be controlled by devices with leading power factor – PF (increasing system voltage) or lagging PF (lowering system voltage). In the first case reactive power is supplied to the system and in the second one reactive power is consumed by the device[7]. Among the sources that can generate or absorb reactive power are `generators (by operating a range of leading/lagging power factors in order to meet voltage schedules)[8], synchronous condensers (generators that have been disconnected and provide only reactive power using real power from the system), transmission or distribution system equipment (shunt capacitors, inductors, Flexible Alternating Current Transmission System - FACTS[9]), demand response (by regulating the power factor at the delivery point), energy storage (that would depend on its ability to store/hold electric energy and the equipment that connects the storage device with the grid) (FERC, 2014). Network reconfiguration can be also an option.

Depending on the speed and capacity to absorb or produce reactive power, reactive power can be classified as dynamic or static. Dynamic reactive sources such as generators, synchronous condensers, FACTS) are used to adapt to rapidly changing conditions in response to an event or disturbance. Static reactive resources (such as capacitors, reactors) respond to slow and more

[6] $S^2 = P^2 + Q^2$ $(Eq. 1)$, where S: apparent power (MVA). If the dephasing is zero then $P = S$ otherwise, $P < S$.

[7] $PF = \frac{P}{S}$ $(Eq. 2)$, $S = I * V$ $(Eq. 3)$, then from (Eq 1, 2): $Q = \left(\frac{P}{PF}\right) * (1 - PF^2)^{0.5}$, where S: apparent power (MVA), P: real power (MW), Q: reactive power (Mvar), I: current, V: voltage. If $PF = 1$ then I and V are in phase and $Q = 0$. If a generator operates with a PF of 0.95 leading it means that the generator exports 0.3 Mvar (leading reactive power) to the system for every MW of real power produced. On the other hand, if the generator operates with a PF of 0.95 lagging it means that the generator consumes 0.3 Mvar (lagging reactive power) for every MW of real power produced.

[8] The voltage schedule is set by the independent system operator (ISO) or transmission providers in their respective jurisdictions. Synchronous generators are the most common source for reactive power and voltage control (Sauer, 2005).

[9] Static Var Compensators (SVC) and Static Compensator (STATCOM) are specific types of FACTS.

predictable changing system conditions (FERC, 2014). Dynamic reactive power sources provide continuously variable voltage control capability while static can supply only fixed amounts of reactive power (NERC, 2009). The cost of static power sources are usually included in the transmission owners' revenue requirement (static sources are mainly transmission equipment), while dynamic power sources are generally generation equipment that can be owned by independent entities, by distribution firms, or transmission operators (FERC, 2005).

The next section discusses the way how reactive power is managed and procured in organised wholesale markets by system operators and in GB.

2.1 Reactive power as an ancillary service

Reactive power is one kind of ancillary service that system operators need to procure to maintain network stability within the right voltage limits. Traditionally system operators have the primary responsibility to acquire these services mainly from generators (independent or affiliated) using dispatch instructions (voltage schedule), however some exceptions may apply. In Australia, the primary responsibility is given to Transmission Network Service Operators instead, see section 5 for further details. An intermediate approach is observed in PJM where the transmission providers administer the purchases and sales of reactive power supply with PJM as a counterparty (PJM, 2018).

In contrast with other ancillary services such as Regulation or Reserves where market-based mechanisms are used for their acquisition, Reactive Power is less exposed to competitive mechanisms. For instance, ISOs from the USA and Australia procure operating reserves together with energy when clearing either day-ahead market, real-time market or both markets (EPRI, 2016). This practice is called co-optimisation[10]. In GB, where some 'Response and Reserve' products (e.g. Fast Reserve, Firm Frequency Response, and STOR) are acquired by National Grid using tenders, co-optimisation has not been put in practice yet. Appendix 1 compares the different ancillary services procured by ISOs from the USA and GB.

There are limited or non-existent competitive mechanisms for the procurement of reactive power (some exceptions are Australia and GB). Reactive Power services are not incorporated in the dispatch process. Among the reasons for this are the local nature of reactive power ("Vars do not travel well") [11], the limited number of potential providers and technological and modelling issues (IES, 2017). In addition, the procurement of reactive power (along with black start and over frequency reserve) on a half-hour clearing market process could be "uneconomic" to procure (EA, 2016, p.17).

Table 1 shows the different procurement methods and type of remuneration that reactive power providers can get for offering their services in selected system operators' jurisdictions. Mandatory procurement refers to the provision of reactive power services in line with connection agreements. There are also different types of payments associated with the provision of reactive power services. CAISO, the California System Operator, does not compensate for the installation of reactive power

[10] Co-optimisation results in better price formation and also brings important savings, 30-50% of ancillary services costs (Read, 2010). Some initial ideas of co-optimisation are emerging in Europe based on the EU Guideline on electricity balancing (EC, 2017).

[11] Due to high transmission losses, reactive power does not travel far. The local effectiveness of the resource that provides reactive power is directly proportionally to its proximity to the location where it is needed.

capability (even for non-synchronous generators), implying that capability payments do not exist[12]. In addition, those that operate within their power factor ranges are not compensated either[13]. Compensation is only for the opportunity costs of Mvar output outside its mandatory range. In terms of the estimation of payments for capability, there are two methods: a fixed rate (set at US$ 2,747.61/Mvar year by NYISO[14]) and the American Electric Power - AEP method (FERC method) used by the three other system operators.

Table 1: Reactive Power Procuring and Payment Methods: A Comparison

Country	SO	Procurement method		Type of payment						Periodicity
		Compulsory /Mandatory	Tenders	Capability	Availability	Enabling	Utilisation	Opportunity costs	Others	
USA	CAISO	✓						✓		variable
	NYISO	✓		✓				✓	✓	variable
	PJM	✓		✓				✓		variable
	ISONE	✓		✓				✓	✓	variable
Australia	AEMO (GM)		✓		✓			✓	✓	variable
	AEMO (SCM)		✓			✓			✓	variable
GB	NG (ORP)	✓					✓			variable
	NG(ERP)		✓		✓		✓			every six months, with term contract minimun 1 year and then in six-month increments

GM: generation mode, SCM: synchronous condensor mode. Others include: testing charges, cost of energy used to energise equipment that provides voltage support.
Source: AEMO (2017a), ISO Tariffs, NG Reactive Power Service Guides

At the distribution level, there is no currently (May 2018) reported procurement of reactive power services using competitive mechanisms for use locally or by the transmission system. However, this could change in the near future when a more active role for distribution system operators (DSOs) and more coordination between DSOs and transmission system operators (TSOs) are expected for the procurement of non-frequency ancillary services[15]. Reactive power at the distribution level is instead managed via connection agreements by limiting the values of power factors in agreement

[12] This is supported by the fact that in California there are no centralised capacity markets but bilateral contracts for capacity (i.e. Resource Adequacy). This allows generators to reflect in their costs associated with energy, capacity and ancillary services. Then, providing capability payments would result in double payment for reactive power and hence double charging for reactive power to load serving entities (PG&E, 2015).

[13] According to CAISO, Synchronous generators and new renewable resources (i.e. wind, solar) are required to provide reactive power services. However, CAISO currently does not verify and enforce whether renewable resources are providing reactive power services. This is a concern that needs to be addressed by CAISO, however at the moment this is not a reliability issue.

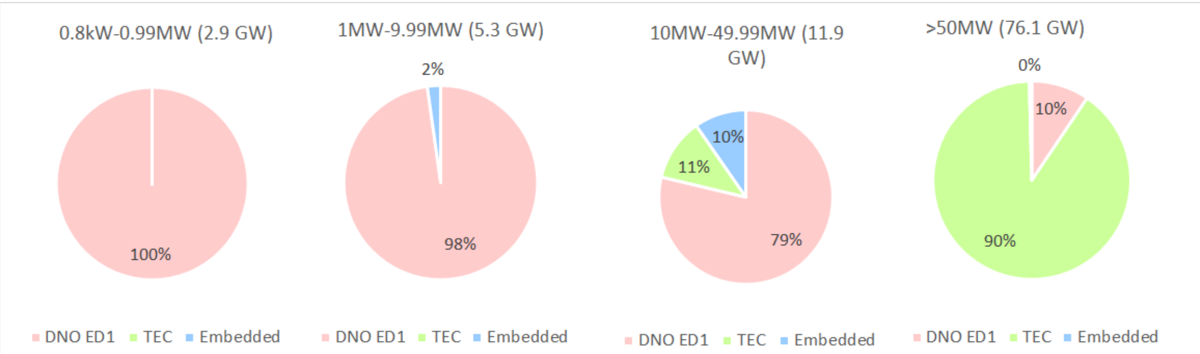
[14] 2018 NYISO Voltage Support Service Rates at http://www.nyiso.com/public/webdocs/markets_operations/market_data/pricing_data/rate_schedule_2/2018/2018_OATT__MST_Schedule%202_%20VSS_Rates_ESTIMATE-POSTING.pdf.

[15] According to the European Draft Energy Directive latest amendment proposal (Feb. 2018), distribution system operators shall **act as a neutral market facilitator** in procuring non-frequency ancillary services, 'based on transparent, non-discriminatory and market-based procedures'. Non-frequency ancillary service refers to 'a service used by a transmission or distribution system operator for steady state voltage control, fast reactive current injections, inertia **for local grid stability**, **short-circuit current**, and black start capability **and island operation capability'** (new text is highlighted). See the new amendments at: www.europarl.europa.eu/sides/getDoc.do?type=REPORT&reference=A8-2018-0044&format=PDF&language=EN

with the national or state regulation on Network Codes (i.e. Distribution Code in GB, Interconnection Handbook in California[16]) and also through financial incentives.

Network Codes for grid connected generators are evolving in line with the integration of more renewable generation in the system and the need to maintain system security and stability. This is the case of the Network Codes that are being updated by different EU member countries as part of the implementation of the Third Package. These codes involve, among other things, the Requirements for Generators (RFG) connection code applicable only for new generating facilities[17]. Under this code generators are subject to specific technical requirements arranged in four bands (Types A-D) based on the connection voltage (up to 110kV from Types A-C and over 110 kV for Type D) [18] and capacity (thresholds are proposed by national TSOs, ratified via industry consultation and approved by the regulatory authority)[19]. Reactive power capabilities are required for Types B-D (NG, 2018b, p.55). In GB this capability is required for generators with at least 1 MW capacity (starting with Type B). Figure 1 illustrates the generator size band (and associated capacity by Nov. 2015) proposed in GB.

Figure 1: Generation by band in Great Britain



TEC: Transmission entry connection. Figures from Nov. 2015. (TEC, Embedded), week 24 2015 (DNO).
Source: NG (2018a, p. 176).

It is noted that the majority of distribution connected capacity in GB is placed in three bands (Types B-D) representing 88% of the total. However, in the future a reduction of this share is expected. By

[16] In line with the standard IEEE 1547 that rules the Interconnection and Interoperability of DER with Associated Electric Power System Interfaces. See: https://standards.ieee.org/findstds/standard/1547-2018.html

[17] Generators classified as "emerging technologies" do not need to comply with the RFG requirements. This is only a temporary exemption and generators need to apply for this. To be eligible generators' technology must comply specific criteria that vary according to the EU member country. In GB generators' technology must be "type A" in GB and be commercially available in GB. In addition, the cumulative sales of generator technology (at the time of application and within GB) must not exceed 25% of the maximum level of cumulative capacity of 58.023 MW, OFGEM (2017, p. 6).

[18] While Type A is the one with basic capabilities with limited automated response and minimal system operator control, Type D is specific for higher voltage connected generation with impact on control and operation of the entire system (EC, 2016).

[19] RFG entered into force as European law on the 17 May 2016. In GB compliance with the code is required by 17 May 2019. The Grid Code will be updated accordingly by 17 May 2018. In the case of distribution, the current Engineering Recommendations (ER) G83 and G59 will be updated and republished as G98 and G99 respectively.

the end of 2021 most of new distribution connected capacity will be categorised as Type A (under 1 MW) representing around 54% of the total, from 12% in Nov. 2015 (NG, 2018a).

In addition to connection codes, excess of reactive power can be also managed by electricity distribution firms using financial incentives. In GB, half-hourly (HH) metered generators (connected at LV or HV) are subject to the Common Distribution Charging Methodology (CDCM) and may be charged if their reactive power excess is 33% of its total active power[20]. However some exceptions apply[21]. Generators connected to Extra High Voltage (EHV) are subject to the EHV Distribution Charging Methodology (EDCM), however it doesn't include a separate charge component for any reactive power flows[22]. In California, the investor owned utilities (IOUs) apply a power factor adjustment charge ($/kvar) – a voltage differentiated charge - to generators that act as load (demand) when not exporting active power[23].

2.2 Reactive power in GB

In GB, the acquisition of reactive power ancillary services by National Grid is based on three mechanisms: Obligatory Reactive Power Service (ORPS), Enhanced Reactive Power Service (ERPS) and through Transmission Constraint Management (TCM).

ORPS relates to the capacity for absorbing or generating reactive power to manage system voltages. This is a mandatory service for transmission connected large generators (over 50 MW) that are subject to the Grid Code (CC 6.3.2). Generators under ORPS receive a default payment for utilisation (£/Mvarh) that is updated monthly in agreement with market indicators (Schedule 3 of the CUSC)[24]. The default payment rate amounts to £3.19/Mvarh[25]. A mandatory service agreement (MSA) is required to be signed by generators for the provision of the ORPS. The ORPS can be provided by synchronous and non-synchronous generators[26]. ORPS is the most common way to acquire reactive power services by National Grid. Over the last ten years, the requirement for reactive power absorption has increased (due to the downward trend in the demand for active power) and this trend is expected to continue (NG, 2018c).

ERPS is procured via tenders and applies to generators whose reactive capability exceeds the minimum technical requirements of ORPS. Tenders are held every six months and the delivery

[20] For further details see Use of System Charging Statement (EPN, 2018).

[21] This is the case when a HH metered generator agrees with the electricity distribution firm to adjust its reactive power (lower power factors) in order to deal with high voltage levels. OFGEM has proposed an additional generation tariff that does not include an excess reactive power charge with an implementation date on 1 April 2018 (OFGEM, 2016).

[22] Instead EDCM charges are site-specific and do reflect the effect on the network of the customer's PF. According to UK Power Networks the charge is based on the outcome of the load flow analysis in the area where generators operate and the impact that their output cause on it (line loss factor). Generators are charged more if their actions increase losses in the network and less if these reduce losses.

[23] According to SCE, one of the main concerns of this charge is that it is applied based on the per Kvar of maximum reactive demand imposed on the utility's system. It does not matter whether there is real power flow (in or out) at the time of the Var peak.

[24] The rate is estimated based on an indexation factor that includes a wholesale power index. The last is a combination of three different power indexes (Heren, Petroleum Argus, Platts), see CUSC Schedule 3, Appendix 1.

[25] Average figure for the period Jan. – Jul. 2017 (NG-UK Power Networks, 2017a).

[26] See: https://www.nationalgrid.com/uk/electricity/balancing-services/reactive-power-services/obligatory-reactive-power-service?overview

period is for a minimum of 12 months and thereafter in 6 month increments. The evaluation criteria for the selection of offers are set in the CUSC and considers economics (market price versus default price), intrinsic capability value (tendered reactive service versus alternative of National Grid reactive assets), among other things. Generators with winning offers receive the following payments: a capability price (£/Mvar/h), and/or a synchronised capability price (£/Mvar/h), and/or a utilisation price (£/Mvarh)[27]. In contrast with ORPS which guarantees a default payment set through a formula, this mechanism has not been successful in the last years. No generator has provided reactive power under a Market contract since 2009. The percentage of total Mvar lagging capability with Market Agreements has been reduced from 70% (highest peak in Oct. 2000) to only 6% in Oct. 2008 (NG, 2017b). According to National Grid, one of the reasons is that ERPS competes with ORPS. The other could be the cap applied to the total funding for reactive power provision (Energy UK, 2017).

National Grid has released the Reactive Power Roadmap (NG, 2018c), and proposes the rationalisation (Stage 1) and simplification (Stage 2) of the current services for procuring reactive power. Based on this, National Grid is planning to submit a proposal (to CUSC) to remove ERPS.

TCM provides an ad-hoc solution. A transmission constraint can arise for different reasons (related to voltage or thermal constraints). A bilateral agreement is usually applied for contracting voltage support from generators using TCM, however constraint management tenders are also a way to procure it if there is sufficient competition[28].

Figure 2 depicts the trend of ancillary services costs in GB. There is an upward trend on total balancing service costs[29]. Reactive power ancillary service costs, represented mainly by those incurred under ORPS, are around £80m per year and represents circa 10% of total balancing service costs (average annual figures, 2013/14 – 2017/18)[30].

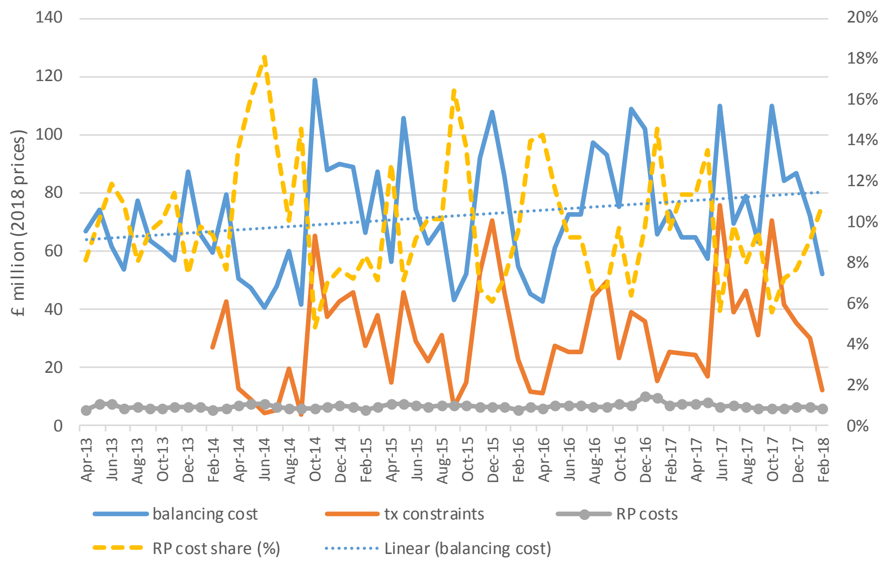
Figure 2: Trend of Ancillary Services Costs in GB

[27] See: https://www.nationalgrid.com/uk/electricity/balancing-services/reactive-power-services/enhanced-reactive-power-service

[28] See: https://www.nationalgrid.com/uk/electricity/balancing-services/system-security-services/transmission-constraint-management

[29] Balancing costs exclude transmission constraint costs, in agreement with the monthly reports from National Grid.

[30] Reactive power costs do not include those for managing voltage constraints, currently grouped in the 'constraints' cost category which covers both: thermal (active power) and voltage constraints. Reactive power costs due to voltage constraints are around £50m per year (NG, 2018c).



Source: National Grid monthly Balancing Services Summary, Office for National Statistics (ONS).

3. About the Power Potential project

3.1 Overview

The Power Potential project (previously known as Transmission and Distribution Interface 2.0 – TDI 2.0) is a customer funded initiative[31] that proposes the creation of a Reactive Power market using DER and additional capacity in the South East Region of the UK.

The transmission network is facing capacity challenges in this region, not only due to resources connected on the transmission system (existing and future interconnectors, large scale conventional and renewable generators), but also due to an excess of distributed generation connections along the southern corridor of Grid Supply Points (GSPs). As a consequence, the transmission network has reached its capacity in this area (limited by dynamic voltage stability and thermal capacity). This makes the connection of additional distributed generation more difficult without important investment in network reinforcement and/or additional reactive compensation systems in this region. The Power Potential project will alleviate the problem by procuring resources reactive power and active power services from different kinds of distributed energy, using a market-based mechanism. Savings to energy customers has been estimated over £412m by 2050 (based on its potential implementation at 59 sites across GB) and up to 3.7 GW of additional connected capacity in this region. The project runs from January 2017 to December 2019 and the auction trial period is due to start in January 2019[32].

[31] The total costs of the project amounts to £10.1m, from which £8.6m were awarded through the Electricity Network Innovation Competition (NIC) funding, £0.75m from National Grid and £0.75m from UK Power Networks (NG-UK Power Networks, 2017b).

[32] It has been agreed that during the trial DER will not be subject to any payment set in the Use of System Charging Statement (CDCM, EDCM).

3.2 About the products

The Power Potential project is soliciting offers from DER to provide reactive power services (dynamic voltage support) and active power support (for constraint management and system balancing)[33] in the South-East of England. DER are expected to be connected ideally at 33 KV or above for most effectiveness (NG-UK Power Networks, 2018a). National Grid has identified four GSPs and their respective served areas where both reactive power and active power services are required. There is no limitation in the size of the resource (synchronous or non-synchronous) that can be offered but it is expected at least 500Kvar for reactive power and/or 500 KW for active power, for both portfolio resources (aggregation) and directly contracted resources[34]. Aggregators are free to aggregate smaller DER and to build the best portfolio of the reactive and active power products.

A capability to provide 0.95 power factor lagging or leading (equivalent to 32% of the maximum export capacity) is required. There are also additional technical specifications that have been set for each type of DER (synchronous and non-synchronous) and service. The following table illustrates this.

Table 2: Power Potential Technical Requirements

Type of service	Technical conditions	Synchronous	Non-synchronous
Reactive Power	Time to sweep from *voltage droop control* to power factor control		10s
	Time to sweep from *voltage control* to power factor control	10s	
	Change in voltage target set-point	within 2s	
Active Power	Minimum running time	30 min	

Source: NG-UK Power Networks (2018b)

According to National Grid, some products can be mutually exclusive. For instance, Active Power and NG's Balancing services cannot be provided simultaneously, or at least active power should be provided outside of any period when the generators have already been contracted for the provision of the balancing service. This is due to the risk of potentially nullifying actions a list of NG's Balancing Services and their compatibility to work simultaneously with reactive power and active power services has been provided (NG-UK Power Networks, 2018c).

3.3 Participation criteria and eligibility

DER participants (including aggregators) are subject to specific pre-qualification and testing before taking part of the trial[35]. After being selected, DER will subject to two different stages (Wave 1 and Wave 2). The aim of Wave 1 is to demonstrate the technical solution, while Wave 2 aims to evaluate

[33] The procurement of active power (AP) is subject to the cost of other options in the same area.
[34] The threshold was set in agreement with the responses from the Flexibility Service Design consultation (UK Power Networks, 2017).
[35] The pre-qualification and testing is only valid for the reactive power service. For the active service, DER go directly to the auction stage (Wave 2).

the financial viability of Power Potential. In Wave 1 DER participate on a non-competitive basis and in Wave 2 DER compete with each other.

Wave 1 involves simulating and measuring DER speed of response to voltage change and measuring effectiveness of DER delivery at each GSP. In order to encourage the participation of DER in the trial, they will receive a fixed fee for fixed number of hours for their participation in this first stage regardless of the size of DER. This would help to reduce the net investment that the DER may be required to do for the acquisition of control and communication equipment, in order to participate in the trial. Some equipment such as Remote Terminal Unit (RTU)[36] installation or upgrade, will be provided by the project, but others such as the DER control system and cable to communicate with the RTU (CAT5 or optical fibre cable) would need to be acquired by the DER. Estimated communication and control capital costs per DER range from £15,000 to £50,000 with average costs of around £25,000.

In Wave 2, DER (with winning offers) will receive two kinds of payments as a result of winning in the procurement auction: a secured availability payment (£/Mvar/h) and a potential utilisation payment (£/Mvarh). There is no cap set for either payments, however an internal cap may be applied to remove offers with very high prices. It has been decided that DER will compete in day-ahead auctions, though they can choose not to alter their offers daily.

Offers from DER can be received from different types of resources (e.g. solar power, wind power, batteries and storage sites, synchronous generators, aggregators) that are able to provide reactive and active power services in the area covered by at least one of the GSP specified by National Grid[37]. Heatmaps are available to inform participants of the location of the GSP that would be more suitable for them[38]. Offers can be made only for one GSP at the same time. Simultaneous offers to different GSPs are not allowed. The submission of offers, will be via a UK Power Networks platform (web portal). The minimum DER size required to participate in the auction is 0.5 MW (aggregators can combine smaller DERs to reach this threshold). The size of reactive and active power services to be procured in each of the GSP (Mvar, MW) has not been estimated yet. The delivery period will not exceed 24 hours. It is expected that there will be windows (probably with 4 hour blocks) at night time and on weekends, when reactive power services would be more valuable for National Grid.

3.4 Evaluation criteria and offer selection

Reactive and active power services will be procured through a market mechanism in day-ahead auctions[39] using the pay-as-bid methodology. According to National Grid, pay-as bid is the method

[36] The RTU, placed at the DER Point of Interconnection (POC) is required to meter the reactive power service provider.

[37] As of April 2018, National Grid and UK Power Networks have already received 13 submissions to provide reactive power services in 18 sites, with reactive power volumes up to 79.3 Mvar (lead) and 69.3 Mvar (lag). The majority of DER are from PV solar, followed by battery storage (NG-UK Power Networks, 2018c). National Grid is expecting around 15 DER for the trial.

[38] NG provides one heatmap per each of the four GSPs: Bolney, Ninfield, Sellindge and Canterbury North. There are three categories that depend on the DER location. Green (high effectiveness), yellow (good effectiveness), and Red (low effectiveness). See Appendix 2.

[39] Each day ahead auction is looking to procure services for the following 24 hour period. Specific windows will be set within this period.

that has always been used and this will keep the trial process as simple as possible[40]. The idea is to select the offers based on a combination of both lowest costs and highest effectiveness but limited to the current budget (around £0.6m for both Wave 1 and Wave 2). NG will forecast the reactive and active power services to be procured for each GSP and will instruct the Distributed Energy Resource Management System (DERMS)[41] about this. The DERMS will evaluate the resources available (free capacity) at the lowest cost based as NG's instructions. DER will then be instructed by the DERMS about the services to be provided at set points[42].

4. Principles of Procurement Mechanism Design Applied to Power Potential

4.1 Background to the current procurement of reactive power in GB

Reactive power is currently procured in Great Britain via either as a mandatory service from incumbent generators set through a formula (ORPS above) or via a bilateral contract to support the grid (as a constraint management product, TCM above). Mandatory service procurement at a fixed price masks the true cost to the system as a whole. The true cost of procurement of voltage support services at a particular grid supply point may be a multiple of the mandatory price due to the low effectiveness of the sources of reactive power procured or (in the future) the additional cost of upgrading the network to reduce voltage problems given the locational availability of mandatory sources. Traditional constraint management solutions which involve bilateral procurement from transmission connected resources may not be least cost because of the uncompetitive nature of the contracting and the failure to utilise available DER.

In principle, a good procurement mechanism would seem to involve an auction to support the voltage at a particular grid supply point because it would reveal the least cost way of supplying the reactive power required. In theory requirements for a given amount of reactive power at a particular GSP can be procured via an auction which includes DER who have high effectiveness in the delivery of reactive power and who compete with transmission connected sources of reactive power. The auction can reveal the availability of local DER and their ability to compete with conventional solutions.

The need for a new process of procurement of reactive power in the Power Potential project is driven by the fact that conventional sources of transmission connected reactive power are declining in quantity and in effectiveness raising their true cost, even in the presence of mandatory fixed price payments. Such a new process might provide incentives for the provision of low cost Mvars, disassociated with the provision of MWs, as has historically been the case. Such 'Wattless' Mvars might be much cheaper to procure than Mvars which also require MWs of capacity. Further total system cost savings might result from joint optimisation of energy, Reactive power and other ancillary services procurement.

---

[40] Power Potential has been designed based on 3 principles: (1) to be simple, (2) to be transparent and (3) in line with the method used in existing balancing services.

[41] The DERMS run by UK Power Networks, is the Power Potential platform that facilitates the communication between National Grid and DER connected to UK Power Networks. It was developed by ZIV Automation.

[42] For instance, for reactive power National Grid may set different periods (from 2 hour to 7 hour windows) over the day. See: https://www.nationalgrid.com/sites/default/files/documents/Power%20Potential%20webinar%20summary_September%202017.pdf.

In this discussion, we focus on the auction design for the particular issue of how to procure reactive power at the four GSPs in the Power Potential trial area. This is a narrower problem than how to procure reactive power across the whole of GB. However, if a novel auction can be designed for the Power Potential trial it has the potential to be scaled up to cover the whole of GB. The evaluation is also easier in the sense that we have some external reference prices - the full costs of the current arrangements - against which the trail auctions can be evaluated.

4.2 The basics of auction design

The intention of a good procurement auction is to reveal the true economic cost of procuring the required quantity of the item in question and to end up paying that price, in conditions when that price cannot be known in advance and where the costs of the auction process itself are going to be covered by the additional economic welfare that the auction creates above the existing arrangements. If we knew what the true cost was in advance we would not need an auction process.

Auctions can take a large number of formats, the simplest of these is an ascending price auction where the highest bidder for an object wins (an English auction). Examples of these are 'auctions' for individual pieces of artwork. Such an auction is for a single unit and is one-sided in the sense that only the demand side bids. Auctions for electrical energy are for multiple units and can be two-sided with both demand side bids and supply side offers which need to be stacked and resolved. Auctions can be for multiple objects, where bidders make package bids on one or more objects, such as we see in national auctions for frequency bands of radio-spectrum involving mobile phone operators.

According to Klemperer (2002) a good auction should attract entry, prevent collusion and prevent predatory behaviour. This is because auctions can be highly transparent and if repeated often they offer opportunities for incumbents to learn how to game the auction. It is important for repeated procurement auctions to be designed in a way that incumbent suppliers do not start by offering predatory (below cost) prices in the early auctions in order to deter entrants and / or then begin coordinating their offers with each other in order to raise outturn prices in the longer run. Klemperer would suggest that if incumbents initially have cost / financial advantages over entrants, that some of quantity of the procurement should be reserved for new entrants to enhance long run competition.

Ausubel and Cramton (2011) further suggest that auctions should aim to enhance substitution if multiple objects are for sale, encourage price discovery and induce truthful bidding. Enhanced substitution is about combining procurement of similar products because although they are differentiated, the number of suppliers will be increased by a combined auction and this will enhance competition. In the Power Potential case, Ausubel and Crampton would suggest that a joint auction to procure reactive power across the four GSPs could be preferable if it enhanced competition between reactive power suppliers, even though a given supplier was more suited to supplying a given GSP. Auctions can encourage price discovery if they are repeated often and / or if the offer stacks in a procurement auction are revealed. This shows the procurer the true supply curve for a product and also reveals information to potential entrants about the likely profitability of entry. Truthful bidding/offering is important because it leads to efficient outcomes in the sense that the least cost suppliers ending up winning in the procurement auction. This is important because if suppliers win who cannot actually supply at the cost they offered in the auction, that may undermine the efficacy of the auction process. Truthful bidding is encouraged by letting the marginal winning or losing bid determine the market price.

In general, auction theory (see Krishna, 2009) suggests that second price auctions are better than pay-as-bid as a way of determining prices. If I know I will only be paid what I bid – pay-as-bid - then there is an incentive to bid (technically 'offer' in a procurement auction) what I think the market price will be rather than my true cost. This can bias the equilibrium prices (up and down) and risk inefficiency in that there is a risk that the offer stack will not be in the true order of cost and hence inefficient offerors might win in the auction. A second price procurement auction is a way of encouraging truthful offers, because suppliers are not paid their own offer but the price of the highest losing offer. All current electricity ancillary service procurement auctions in GB are pay-as-bid for reasons that have been debated in OFGEM (2012). However, the theoretical case for pay-as-clear (which is weak form of a second price auction) is strong and is used in real energy markets.

A final point is that the objective of a procurement auction process should not be to minimize the price paid in the auction, rather it should be to maximize economic welfare where public goods are concerned. This is especially the case where the auctioneer procures products with a quality dimension. Here good auction design should reflect the fact that there is a willingness to pay for higher quality and this should be reflected in the calculation of the winning suppliers. Suppliers that offer higher prices and higher quality might be preferred to suppliers offering lower price and lower quality. In the context of Power Potential, the issue is that effectiveness of reactive power is a quality dimension and that this should be reflected strictly in the procurement process. Less effective reactive power should be consistently valued less within the procurement process and could only win in the auction against more effective reactive power if it was appropriately cheaper. Similarly the willingness to pay for reactive power, on the part of the system operator, should vary significantly in real time according to network condition, so it is important not to over-procure reactive power in conditions when it is known that there is low demand for reactive power. Thus higher frequency auctions (e.g. daily rather than weekly rather than monthly) which allow the auctioneer to vary the quantity they aim to purchase for reactive power would seem to be beneficial if they can be implemented with low additional transaction costs.

4.3 Power Potential trial auction design and fit with wider developments on this in GB

We now highlight the implications of the above discussion of auction design within the wider context of ancillary services procurement in GB.

It is worth having a well-designed auction for reactive power if it is difficult to establish the true cost of supplying it, which would be necessary for a continuation of the current fixed price system in the long run. An auction can solve the problem of how to identify a fair price for reactive power in the face of declining mandatory provision and the rise of alternative sources of reactive power, such as DER. Auctions are more transparent than bilateral constraint management provision. They also encourage a clearer specification of what exactly is the object being procured, which is obscured by a set of bilateral contracts. Power Potential auctions will provide opportunities for new entrants, especially if these entrants are initially higher cost. Klemperer would approve of the fact that all of the DER suppliers in the Power Potential procurement auction will be new to the supply of reactive power. However, in the long term this could only be justified if they are cheaper than sources of reactive power that might connected at the transmission level.

Consideration should also be given to the issues raised by Ausubel and Cramton (2011). They suggest a focus on the question of whether there should be one or four auction processes in the Power Potential trial. One auction process where all suppliers of reactive power could simultaneously bid against each other to supply reactive power to each of the GSPs would enhance competition via substitution. Such an auction would need to be carefully designed. Complex auction designs are difficult to implement in practice because they may not resolve easily. However one could imagine a package auction design where offers to supply different GSPs were entered by the suppliers taking into account their effectiveness factors in supplying reactive power to a given GSP or a design where UKPN stacked the offers in such a way as to minimise total procurement cost at the four GSPs, taking into account the effectiveness factors. This would be a type of co-optimisation process, discussed elsewhere in this report. Either way this would enhance the degree of competition between suppliers relative to a set of four different auctions where a given supplier was pre-assigned to just one GSP, which essentially segments the market, reduces competition and potentially increases local supplier market power.

Truthful bidding is also an issue that Ausubel and Cramton (2011) discuss. Pay-as-bid has the advantage of being in line with current practice in ancillary service procurement in GB. However, it will reduce price discovery in that it will not encourage truthful bidding of true cost. It will encourage suppliers to offer their estimate of what they think the market price is going to be and promote 'bid shaving' (in this case 'offer shaving'). While pay-as-bid can promote generally lower prices in the short run[43], its lack of transparency on true costs may reduce dynamic efficiency relative to pay-as-clear. Thus, on the basis of economic theory, we would commend consideration of a second price auction format (as weakly represented by pay-as-clear), especially as part of the trial.

The objective is the maximisation of welfare and a significant part of that is a better reflection of the demand side in the procurement auction, thus an auction design which allows suppliers and the system operator to adjust their offers and the quantity procured in near real time (day ahead) would be beneficial especially as the demand for reactive power at given GSPs alters considerably, in line with markets for real energy.

National Grid has launched a significant consultation of the 'Future of Balancing Services' in 2016 and published 'System Needs and Product Strategy' (SNAPS) (NG, 2017a) in June 2017. This document acknowledged the need to reduce the number of ancillary services products in order to enhance substitution and improve welfare by a better focus on what consumers actually valued. The SNAPS document identifies four broad classes of ancillary services product: frequency, reserve, voltage and system security. It reports that there are three voltage products (mandatory reactive power, enhanced reactive power and constraint management (voltage)): where one is not procured at all (enhanced reactive power, where no-one comes forward in the 6 monthly auction to offer reactive power). It acknowledges that there were too many products (around 30 were listed in 2016) and that these could be significantly rationalised to enhance competition in the supply of each service. As an example of how this might be done, Greve et al. (2017) discuss how frequency response products might be rationalised. They suggest a single package auction to procure different speeds of frequency response from suppliers who could supply one or more of the possible speeds, against the specification by the system operator of different packages of service that would meet system security constraints. A further suggestion would be the start times/dates of trading periods are aligned with the energy market and with each other to facilitate coordinated offers across multiple electricity product markets for individual electricity suppliers. There is currently a distinct lack of convergence in the periodicity of procurement processes for each electricity service. This would allow a single facility (such as a battery) to coordinate its offers over a given market period.

[43] See Holt (1980).

The SNAPS document ends (p. 36) by suggesting the need to consider all of the elements we have highlighted: fewer products, new auction designs, nearer to real time auctions and pay-as-clear rather than pay-as-bid payments.

4.4 Other issues to be considered in the mechanism design

The efficacy of the new mechanism design for reactive power depends on there being sufficient increased requirements for ancillary services at the GSPs which cannot be met from the provision of reactive power from the transmission system. Power Potential will investigate whether new DER are available to supply reactive power at sufficient quality. Running a mechanism at just these 4 GSPs is costly and whether it is efficacious depends on the relative cost savings of local procurement – relative to the counterfactual of a voltage control transmission or distribution asset investment - outweighing the costs of running a separate procurement mechanism (which includes both the platform and the participation costs – which are significant at £25k per bidder, on average). A key long run question is whether a separate mechanism is necessary if local DER could simply be identified and dispatched by the current central mandatory mechanism run by the TSO, by inter alia lowering the thresholds for participation in the mandatory reactive power mechanism. The identification of DER is separate from the running of a local price determination process. One reason against doing this, could be based on reactive power providers who cannot be incentivised via an extension of the mandatory process, but would need new more competitive mechanisms based on free entry. However, another longer term possibility is that a local procurement mechanism could simply offer fixed prices to DER arising out of reform of the national market for reactive power, which does not currently exist.

Another issue is that the new mechanism is being operated by the DSO (UKPN) on behalf of the TSO (NG). This requires a new contractual relationship between the TSO and the DSO. This will need to be specified without exposing the DSO to significant additional energy product risk, which it typically is not exposed to at all. How reactive power costs are apportioned and regulated may effect incentives for them to be minimised (or optimised to maximise economic welfare). Kim et al. (1917) discuss the TSO-DSO contractual relationship in ancillary services considering a single TSO covering multiple DSOs. What is needed is contract that places incentives on individual DSOs to optimise the need for centrally provided services, when this contract might expose DSO investors to significant risk. Kim et al. (2017) show (for frequency response) that a cost-causality based cost allocation scheme (CC-CAS) is superior to the current area energy-amount based cost allocation scheme. Their scheme fairly allocates DSO system balancing cost among multiple DSOs based on the cost-causality principle. The problem is that such decentralisation is risky as DSO share of total balancing costs may become more variable. The authors propose an optimal balancing payment insurance (BPI) contract sold by the TSO to help DSO hedge the risks associated with uncertain balancing payments.

Another key mechanism design point is what the format of the supplier offer will be: it will likely involve an availability payment (for Mvars) and a utilisation payment (per unit time). This complicates the market clearing as winners in the day-ahead auction can only be decided on the basis of presumed utilisation. That is not so bad as long as all offerors correctly build future profits into the availability offer and charge a marginal cost based utilisation fee. It is by no means clear that under two-part bidding suppliers of reactive power will be able offer to run for longer if cheaper for them to do so and shorter if not. Given that reactive power capacity is not strictly the issue for consumers, while provision of actual reactive power is: why not only pay for utilisation (as in many markets)? This would simplify the bidding process. The issue here being whether utilisation payments alone provide enough incentive to maintain adequate capacity to deliver reactive power.

However, availability payments deep within the distribution grid payable to DERs may be over paying for availability at the whole system level.

So far, our discussion has focussed on the supplier offers. However consideration needs to be given to how the quantity to be procured is being determined. This needs to be a transparent and credible process of determining how much reactive power is being procured for each period. One of the innovations of the project might be improved forecasting accuracy for the modelling team in NG who will have to determine the quantity of reactive power to be procured. Given non-delivery risk, some estimate will have to be made of the extent to which the DSO can over or under procure reactive power (though this is not an issue with the Power Potential trial as this is about use of 'best endeavours' to procure reactive power and there is no requirement to meet the all the reactive power demand at the 4 GSPs). This will be a function of the DSO's incentives and whether it has an incentive to manage the costs in order to maximise societal benefits. There needs to be some penalty if a winning reactive power unit does not deliver as required. It will need to forfeit some part of its availability payment, but how much might determine whether companies are keen to offer reactive power or not. Under Power Potential, if a DER delivers less than 80% of their instructed volume then penalties will be applied to their availability payments. A standard incentive in the US is to only pay utilisation payments (e.g. for frequency response) and to make payments on the basis of the speed of response to an SO request to supply. These are sharper incentives than proposed under Power Potential.

There would seem to be some benefit from co-optimisation (described in more detail below). It is important that reactive power markets are not run in isolation and that in procurement the system operator makes trade-offs between procuring one product more cheaply at the expense of raising the price of another product, especially when certain packages of products from a single facility might be more beneficial than others. Given the existence of the capacity market (which already contracts for reserve capacity 1 and 4 years ahead), working out how to value the provision of reactive power at a given GSP requires more attention to co-optimisation.

Finally, there are a set of competition issues which might arise in the context reactive power markets, given that the reactive power market at each GSP is small. How will anti-competitive behaviour be prevented? There is the potential for a relatively large provider at least one of the GSPs (a pivotal supplier), who could deliberately restrict the quantity in places in the market to raise prices. The trial should look carefully at how the larger suppliers construct their offers to supply. A further competition issue is the nature of the finiteness of the trial itself. The trial auctions will be run until the budget of around £600,000 (£92,000 for mandatory payments and a £500,000 'contingency') is exhausted. This gives rise to incentives to suppliers to raise offer prices in order to exhaust the budget sooner, when they know there is a finite amount of money available. This problem is mitigated by running 4 auctions repeatedly and the high uncertainty about when the last play of the game might be (i.e. the last auction). At the very least the nature of the trial being finite makes it much less likely that collusion we emerge in the trail than if the auction were to become business as usual.

5. Evaluation of Case Studies

5.1 Case Study 1: Network Support and Control Ancillary Services (NSCAS) Tenders by AEMO

5.1.1 Overview

AEMO is responsible for the operation of the largest gas and electricity markets and power systems in Australia including the National Electricity Market (NEM) [44] and the Wholesale Electricity Market and power system in Western Australia. AEMO procures ancillary services to fulfil its obligations in line with the National Electricity Rules. AEMO identifies three major categories of ancillary services: Frequency Control Ancillary Services (FCAS) Markets, Network Support and Control Ancillary Services (NSCAS) and System Restart Ancillary Services (SRAS). Voltage Control Ancillary Services (VCAS) is a sub category of the NSCAS that relates to reactive power services. NSCAS is classified as a "non-market service", which means that these are not acquired by AEMO as part of the spot market (AEMC, 2018, p.167), in contrast with other ancillary services such as FCAS. Table 3 summary the list of Ancillary Services procured by AEMO.

Based on the Rule 2011 No.2 (AEMC, 2011), Transmission Network Service Providers (TNSP)[45] have the primary responsibility for meeting the NSCAS needs in the NEM starting on April 2012.

Table 3: Ancillary Services in Australia – A Summary

Major AS Categories	Sub Categories	Types/Description	Cost Recovery
A. Frequency Control Ancillary Services (FCAS)	FCAS Regulation	(1) Reg. Raise, (2) Reg. Lower	Causer Pays
	FCAS Contingency	(1) Fast Raise (6s raise), (2) Fast Lower (6s lower)	Generators (1, 3, 5)
		(3) Slow Raise (60s raise), (4) Slow Lower (60s lower)	Customers (2, 4, 6)
		(5) Delayed Raise (5m raise), (6) Delayed Lower (5m lower)	
B.Network Support and Control Ancillary Services (NSCAS)	***Voltage Control Ancillary Service (VCAS)***	Use by AEMO to maintain transmission network within the voltage limits and voltage stability.	Market Customers
	Network Loading Control Ancillary Service (NLCAS)	Use by AEMO to help to control the flow (into or out of a transmission network) to within short term limits.	
	Transient and Oscillary Stability Ancillary Service (TOSAS)	Use by AEMO to maintain transmission network within its transient or oscillatory stability limits.	
C. System Restart Ancillary Services (SRAS)		Use by AEMO to restart the power system following a partial or complete black-out.	Customers and Generators (50/50)

Fast Raise/Lower: to arrest a frequency deviation within 6s following a contingency, **Slow Raise/Lower**: to maintain the frequency within the single contingency band over 60s following a contingency. **Regulation Raise/Lower**: to maintain frequency within the normal operating band; **Delayed Raise/Lower**: to return the frequency to the normal operating band within 5m of a contingency.

Source: AEMO (2015).

If this gap[46] remains unmet by the TNSP, AEMO will seek tenders for NSCAS providers under *ancillary services agreements*. AEMO acts as NSCAS procurer of Last-Resort and will acquire NSCAS only to ensure power system security and reliability of supply on the transmission networks. TNSP may acquire NSCAS under *connection agreements* or *network support agreements* (AEMC, 2018), however they aim first to make maximum use of the existing reactive resources. Procurement of

[44] NEM comprises five regional market jurisdictions (Queensland, New South Wales, Victoria, South Australia and Tasmania. The Northern Territory and Western Australia are not interconnected to the NEM due to the long distances between networks.

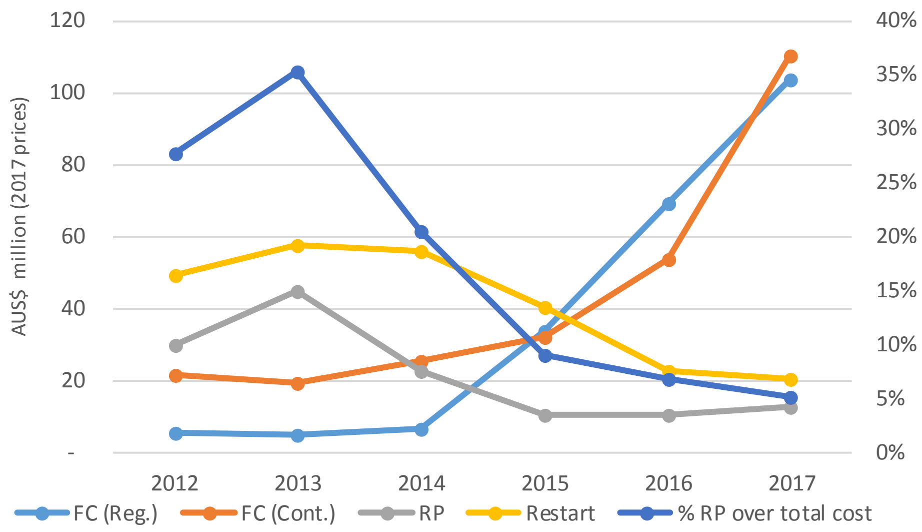
[45] In Australia there are five TNSP in agreement with the NEM region networks: Powerlink (QLD), TransGrid (NSW), Ausnet Services (VIC), Electranet (SA), TasNetworks (TAS). Western Power operates an isolated network in Western Australia. Powerlink and TransGrid are the ones with the largest circuit line length, representing 29% and 25% of the total (51,242 km), including Western Power (AER, 2016; WP, 2015).

[46] The gap is identified by AEMO in its National Transmission Network Development Plan (NTNDP) and is represented by the difference between the NSCAS needs of the NEM power system (arising within a 5-year horizon) and the NSCAS that the TNSPs predict to be procured.

NSCAS under *network support agreements* is an option for reactive support beyond the performance standards (Transgrid, 2017).

The trend costs of ancillary services for the period 2012-2017 is illustrated in Figure 3.

Figure 3: Trend of Ancillary Service costs in Australia



Annual figures: Jan.-Dec., FC: Frequency Control, Reg: Regulation, Cont: Contingency, RP: Reactive Power.

Source: AEMO AS Payments Summary - Annual Reports (2012, 2013, 2014, 2015, 2016, 2017).

A significant reduction of reactive power costs can be observed, in line with the National Electricity Amendment, Rule 2011. By the end of 2017 reactive power costs represented only around 5% of the total ancillary costs.

The following sections discuss the tender mechanism applied by AEMO for the procurement of NSCAS with a focus on reactive power services.

5.1.2 About the products

AEMO distinguishes mainly two kinds of VCAS modes of operation in the tender process for acquiring NSCAS: VCAS Generation Mode and VCAS Synchronous Condensor Mode. In Generation mode, VCAS represents the amount of reactive power capability (generation or absorption) by the NSCAS equipment in excess of the performance standard for reactive power for the NSCAS equipment supplied up to the connection point to the transmission network[47]. In Synchronous Condensor Mode, refers to the reactive power capability (generation or absorption) when the generating unit is not producing active energy.

[47] If there is not a direct connection to the transmission network, the capability of the VCAS equipment must be nominated at the nearest transmission network connection point (AEMO, 2012).

Table 4 describes the performance requirements and minimum technical requirements for both types of operation modes. Figures refer to the latest NSCAS Agreement Proforma for reactive power services (AEMO, 2017a)[48].

Table 4: Concentrated Level of Performance and Minimum Technical Requirements

Mode	Generation Mode	Synchronous Condensor Mode
Performance requirement		
Rated active power - MW	✓	
RP Generation Capability (RPGC) - MVAr	✓	✓
RP Absorption Capability (RPAC) - MVAr	✓	✓
Maximum time that RPGC/RPAC can be sustained - min.	✓	✓
Maximum time to be ready to absorb/generate RP from receipt a communication from AEMO - min.		✓
Minimum technical requirements (NSCAS equipment)		
Be capable of being dispatched	✓	✓
Measurements of AP/RP output to AEMO every **4s**	✓	✓
Absorbing/generating, leading PF or lagging RP **while 0 AP output**		✓
Absorbing/generating, leading PF or lagging RP **in excess of performance standard**	✓	
Sustained contracted levels of RP gen/abs. for at least **15min.**	✓	✓

Source: AEMO (2017a) - NSCAS Agreement Generic Proforma.

The types of product are not limited by the operation modes of unused reactive power capacities of the generating units previously described. Among other types of reactive plants are capacitors and reactors[49], static VAR compensators (SVC), static compensators (STATCOMs), HVDC/HVAC transmission lines, etc. (AEMO, 2012).

5.1.3 Participation criteria and eligibility

AEMO proposes a two-stage approach for participating in the acquisition of reactive power services: Expression of Interest (EOI) followed by Invitation to Tender (ITT). In general and at AEMO discretion, only those that satisfy the assessment criteria requirements set in the request for EOI are the ones that are invited to tender. In the EOI AEMO specifies the type and quantity of reactive power, estimated frequency and duration, the evaluation criteria, timeframes for assessing the EOI, among others. AEMO also requires technical information about the equipment that would provide the required service (description, maintenance records, capability testing results, maintenance records), evidence of connection agreement and relevant experience in the provision of the required service. In the ITT, in addition to the specifications provided in the EOI, AEMO specifies the price structure to be included in the tender and terms and conditions of the services to be contracted (agreement), AEMO (2017b).

The request for reactive power service may be for different term lengths (AEMO, 2012):

[48] The Profroma provides a general indication of the terms and conditions the service provider would expect to enter with AEMO in the acquisition of NSCAS. The specifications (minimum technical requirements) may vary depending on the type of reactive power service that is required by AEMO.

[49] If a TNSP's offer is selected to provide the required reactive power service using reactive equipment (i.e. reactors), after the contracting period this equipment may be included in the TNSP's regulatory asset base (RAB) with a zero capital value in the RAB. This was the case of Transgrid (that provided the lowest cost service) in the provision of NSCAS for voltage control in southern New South Wales (AEMO, 2018a).

a. short term: up to 12 months with the option to extend the service for 12 additional months, usually for existing facilities;
b. long term: for a period of 5 year or longer, installations of new or utilisation of existing reactive plants;
c. a combination of both, short term with existing installations until the construction of long term reactive power equipment.

In addition, there is no preferred type of operation mode or type of reactive plant. Participants are free to offer their best solution. However, some of the tender requirements may be more specific than others. This is the case in one of the latest requests for EOI from AEMO seeking dynamic reactive power services from generating units in synchronous condenser mode only (AEMO, 2018b). Participants are also advised about the locational effectiveness of the VCAS equipment connected at particular points of connection.

Depending on the mode, participants (with winning selected offers) are subject to specific payments, see Table 5. There are two different payment structures based on the type of the generating unit operation mode. A compensation payment applies only when the generating unit is constrained off to generate or absorb reactive power during a trading interval. A Testing charge refers to the cost of specific tests that will be paid by AEMO. For additional details about the type of payments and their calculation see AEMO (2017a).

Table 5: Payment Structure

Mode	Generation Mode	Synchronous Condensor Mode
Price and payments		
Availability charge - RP generation	✓	
Availability charge - RP absorption	✓	
Enabling charge		✓
Compensation payment	✓	
Testing charge	✓	✓

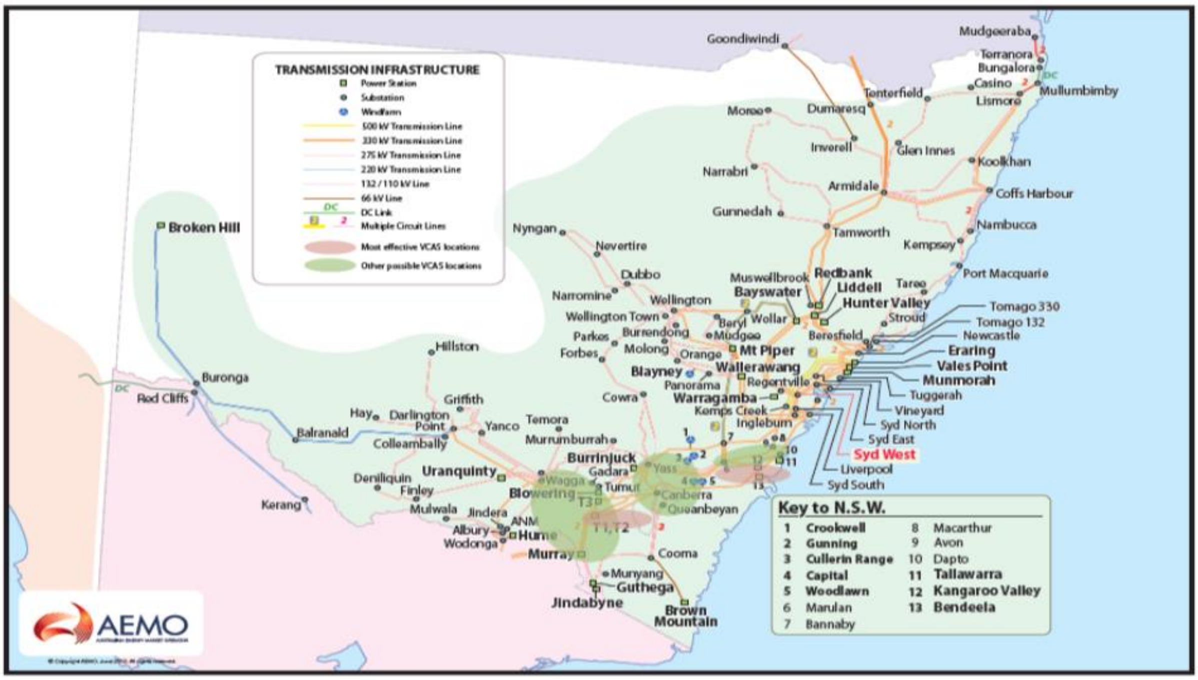
Source: AEMO (2017a) - NSCAS Agreement Generic Proforma.

5.1.4 Evaluation criteria

In the evaluation of EOI, AEMO assess the optimal combination of reactive power services taking into consideration the locational effectiveness of each VCAS equipment at the least cost possible. AEMO does not provide details of the evaluation criteria (quantitative or qualitative) but only a general list of the criteria such as participant registration, compliance of the offered service with the NSCAS description, expected reliability and availability of the offered service, effectiveness to fill the NSCAS gap, compliance with the National Electricity Rule price of the service etc. (AEMO, 2017a).

The locational effectiveness of the VCAS equipment is provided by AEMO in the EOI. A map that shows the transmission infrastructure (such as power stations, substations, transmission lines, others) and the most effective locations for delivery the reactive power services according to the EIO requirements is available for this purpose, See Figure 4. The locational effectiveness is represented by two kinds of areas: red (most effective) and the green (other possible areas).

Figure 4: Example of Locational Effectiveness for Delivery Reactive Power Services



Source: AEMO (2012, p.27)

5.2 Case Study 2: Demand Response Auction Mechanism (DRAM) in California

5.2.1 Overview

As an example of a procurement process for an ancillary service product run by a DSO on behalf on the transmission system operator (more precisely, the independent system operator - ISO) we examine the DRAM case from California in this sub-section. In December 2014, with decision D.14-12-024, the California Public Energy Commission (CPUC) approved the Demand Response Auctions Mechanism (DRAM). This mechanism requires the three Investor Owned Utilities (IOUs) from California (Southern California Edison - SCE, San Diego Gas and Electric – SDG&E, and Pacific Gas and Electric – PG&E) design and implement a two-year DRAM pilot program (DRAM 2016, DRAM 2017) that promotes the participation of third party DR resources in the CAISO market. Under decision D.16-06-029 the program was extended for the period 2018 and 2019. In October 2017, CPUC issued D. 17-10-017 allowing the extension of the DRAM with one more solicitation in 2018 for deliveries in 2019[50]. The main characteristics of the DRAM pilots (from DRAM 2016 to DRAM 2019) and its evolution are shown in Appendix 3. Offers can be for different types of products and subcategories (described in the next section). The delivery period varies from a minimum of 6 months to 24 months. There is a specific budget allocated to each IOU with annual figures between US$1.5m and US$6m. From the total authorised budget a percentage is allocated to administrative costs. In the case of DRAM 2019 those costs represent around 10% of the total (i.e. $600k each for SCE and PG&E). In terms of procurement targets, a minimum (MW) has not been set in the last two DRAM, in contrast with the first two. The maximum target is specially limited by the authorised budget allocated to each IOU. The capacity procured in the three DRAM pilots is over 365 MW.

[50] Among the reasons for these extensions are: (1) limited opportunities for growth in demand response provided by third parties, (2) to support a competitive market for demand response, (3) to provide further evidence about the consolidation or suffering from the DR pilots, (4) and to assess and test the procurement guidelines for demand response auction mechanism (CPUC, 2017a, p.32).

Through DRAM, IOUs make a capacity (also known as resource adequacy - RA) payment to demand response aggregators. IOUs acquire this capacity only and do not dispatch the resources. IOUs have the right to audit this capacity using a “demonstrated capacity” contract provision. The IOUs are not allowed to claim revenues that can be received by the bidders (technically offerors) from the energy market.

In agreement with previous auctions mechanisms performed by IOUs from California (i.e. RAM, others), an independent evaluator (IE)[51] is also required for this programme. According to the evaluation of the Independent Evaluator (Merrimack Energy)[52], there is a downward trend over the last three DRAM pilot solicitations (DRAM 2016, DRAM 2017 and DRAM 2018-2019), in terms of average prices overall and for those from the peak month of August (PG&E, 2017)[53].

The DRAM can be seen as a more cost-effective method to secure DR capacity in contrast with the utility owned and operated DR portfolios. A comprehensive evaluation of the three first DRAMs is expected to be completed by mid-2018 (CPUC, 2017c). A description of the latest DRAM solicitation (DRAM 2019) is provided in what follows.

5.2.2 About the products

In terms of capacity products, there are three types of eligible products: system capacity, local capacity and flexible capacity. A subcategorization applies for flexible capacity[54]. A combination of these products is also possible. The demand response products can be offered either as Proxy Demand Resource - PDR (in the day-ahead or real time market) or Reliability Demand Response Resource - RDRR (in the real-time market especially under emergency conditions) into the CAISO wholesale market. For flexible capacity offers must be bid as PDR. CPUC has established through D.16-06-056 the prohibition of specific resources for load reduction during demand response events[55].

5.2.3 Participation criteria and eligibility

Bidders (technically offerors) are required to submit a set of participation forms, including among others[56], the DR Offer Form (a spreadsheet in excel format). If a bidder is short-listed two additional documents are required to be completed by the bidder: the Signed Shortlisted Letter and Signed Purchase Agreement. The DRAM purchase agreement (PA) has a standard form and is non-negotiable. Offers must be for the products described in the previous paragraph with a minimum of 100 kW per PDR or 500 kW per RDRR per month[57]. The maximum number of offers per bidder is 20. Offers must contain a monthly quantity (capacity kW) and a contract price ($/kW-mo) for each applicable showing month. Bidders are allowed to vary the amount of capacity and price on a monthly basis. The minimum delivery period is one month and bidders are required to include

[51] The role of IE is to ensure a fair, consistent and unbiased solicitation process, in agreement with the solicitation requirements (SDG&E, 2017).

[52] Merrimack Energy has been appointed by all three IOUs as IE for the current solicitation (DRAM 2019). It has also served as IE for previous DRAM solicitations.

[53] See Redacted Appendix D.

[54] Category 1 (base ramping), category 2 (peak ramping) and category 3 (super-peak ramping). For further details see CAISO Fifth Replacement FERC Electric Tariff, Section 40.10.3. See: http://www.caiso.com/Documents/Table_Contents_asof_Dec16_2017.pdf

[55] This refers to distribution generation technologies using diesel, natural gas, gasoline, propane, or liquefied gas, in topping cycle Combined Heat and Power (CHP) or non-CHP configuration. Storage is allowed and encouraged.

[56] Such as Non-Disclosure Agreement, Organisation Chart, Financial reports.

[57] SCE has limited the amount of MW per month to 10 MW.

deliveries in August. Bidders will get paid based on the contract price, product monthly capacity and on the type of service. Offers for non-residential customer product are valued 10% less than those with residential customer products (SCE, 2018).

Offers can include all "peripheral costs" associated with the service in the contract price, including scheduling coordinator costs. Bidders are responsible for all costs related to their participation in DRAM in agreement with the rules that govern the interaction between the utility and third party Demand Response Providers (DRPs)[58].

IOUs make clear that other products (apart from demand response) such as energy and ancillary services, are not part of the products to be offered. In addition, participants are not allowed to be part of DRAM and other IOU's demand response (DR) programmes simultaneously. Participants have the chance to exit their current programme/tariff to participate in the DRAM programme. They are also allowed to switch back to the original DR programme after the completion of DRAM.

Bidders submit offers, and other relevant documentation, via the utility (SCE) or via PowerAdvocate® (PD&E, SDG&E). A *Request to Cure* is applicable if the IOU finds incorrect information or requires further clarification. Bidders should respond before the *Cure Deadline*.

5.2.4 Evaluation Criteria

The IOUs were required to develop a transparent and standard evaluation criteria for selecting the winning offers. A common methodology has been used by the IOUs which involves a combination of quantitative and qualitative assessment. Sample valuations (spreadsheet) are published by PG&E and SDG&E in their respective RFO DRAM website[59]. IOUs evaluate their respective offers separately. The following evaluation mechanisms apply:

<u>Quantitative</u>

a. Offers are ranked based on each offer's net market value (NMV). All cost and benefit figures are adjusted using the utility's average cost of capital and discounted back to the date of evaluation results.

$$NMV = Benefits - Costs$$

b. Benefits are calculated for each offer using its forecast capacity market (Resource Adequacy - RA) and the market value of each type of product (*Product Value*). In DRAM, if different types of RA have different values which also vary in each month, then different weights are allocated[60]. For instance, local capacity is more valuable than system capacity. In addition, offers with flexibility capacity (Cat. 1>Cat. 2>Cat.3) have greater value than those that do not provide flexible capacity SDG&E-PG&E-SCE (2018a). Benefits are multiplied by 1.15 which reflects the Planning Reserve Margin credit given to demand response resources in the RA compliance process[61]. *Offered Volume* (kW) and *Product Value* ($/kW) refer to monthly figures.

---

[58] Such as Electric Rule 24 (SCE, PG&E) and Electric Rule 32 (SDG&E).

[59] For PG&E see Attachment A Offer Form at: https://www.pge.com/en_US/business/save-energy-money/energy-management-programs/demand-response-programs/2019-demand-response/2019-demand-response-auction-mechanism.page?WT.mc_id=Vanity_dram.

[60] However, in terms of DR products, PDRs and RDRRs provide the same value for RA.

[61] 1 MW DR resource is given a 1.15MW credit toward RA compliance, while 1 MW generation resource is given at 1 MW credit toward RA compliance (SDG&E-PG&E-SCE, 2018b).

$$Benefits = \sum_{i=1}^{p} Offered\ Volume\ i * Product\ Value\ i\text{, where } i\text{=each product}$$

c. Costs are computed for each offer by the product of Offered Volume and Offered Pricing per product and per month. All costs are then added.

$$Costs = \sum_{i=1}^{p} Offered\ Volume\ i * Offered\ Pricing\ i\text{, where } i\text{=each product}$$

d. The offers with the highest NMV per unit expressed in $/kW-year are first in the ranking.

$$NMV\ per\ Unit = NMV\ (\$)/NPV\ of\ the\ Average\ Monthly\ Volume\ (kW)$$

Qualitative

e. Qualitative factors affect only the *Costs*. The IOUs may weigh the standard criteria differently (based on IOUs' discretion)[62].The qualitative criteria have evolved over time. The qualitative criteria (and scoring matrix) for the DRAM 2019 (Pilot 4) are shown in Table 6.

f. The offer's cost is adjusted (upward or downward) based on the application of the qualitative factor adjustment (QFA).

$$QFA\ (per\ offer) = 1 + \sum_{j=1}^{7} score\ (j) * weight\ (j)\text{, where } j\text{=criteria}$$

Exclusions

Offers are ranked based on the quantitative and qualitative evaluation, the ones with the highest NMV per unit come first. For instance, if the 20% residential requirement is not met, IOUs may decide to select residential offers out of rank order. This was the case of PG&E in DRAM 2018-2019 (PG&E, 2017). SCE also by-passed few of non-residential offers in rank in DRAM 2018-2019 (SCE, 2017). In addition, there are specific cases when IOUs may not award contracts to high NMV offers. This refers to (1) outlying offers[63], (2) offers with prices greater than the average August price[64], (3) those above the long-term avoided cost of generation[65], or (4) when RDRR offers exceed the Reliability DR cap[66].

[62] For instance, SCE is not considering any weight in DRAM 4.
[63] Relate to non-August capacity prices.
[64] The average August bid price is calculated separately for system, local and flexible capacity by the IOUs by: (1) excluding the top 10% of August bids, (2) totalling all remaining August bid prices and (3) dividing by the number of bids in (2). (CPUC, 2017b).
[65] Offers that exceed the long-term avoided cost of generation (set at US$113.20 kW-yr) may not be procured. For further details see: www.cpuc.ca.gov/General.aspx?id=5267
[66] RDRR Offers can be selected only if there is MW available under the utility's Reliability DR cap. The Reliability DR cap differs across the utilities. For DRAM 4, SCE does have MW available, PG&E is procuring only a limited amount and SDG&E has 15.5 MW left (SDG&E-PG&E-SCE, 2018b).

Table 6: Scoring Matrix Criteria DRAM 2019

	Answer	Score (a)		Weight (b)			Weigthed Score
	Yes/No	Yes	No	SDG&E	SCE	PG&E	(a)*(b)
Technical requirements							
Pending requirements (interconnection agreements, environmental studies, land rights, others) prior to operation.	Yes/No	1	0	3%	0%	0%	
Ongoing/Previous Bidder Experience							
Ongoing investigation (or ocurred) within the last 5 years of any alleged violation of rule, regulation, etc., regarding the DR to be offered.	Yes/No	1	0	30%	0%	0%	
Termination/Default on past DRAM PA, offers with clear evidence of market manipulation/collusion.	Yes/No	1	0	3%	0%	15%	
DRAM PA not signed when extended a shortlisted offer or delivery less than 50% of contracted capacity.	Yes/No	1	0	3%	0%	5%	
Small Business							
Certified small business.	Yes/No	1	0	0%	0%	-1%	
Project Diversity							
Use of Enabling Technology (ET) with at least 90% of the customers comprising PDR customers.	Yes/No	0	1	3%	0%	0%	
Majority of resources/customers to emit GHG emissions.	Yes/No	1	0	3%	0%	0%	

ET: a set of communications, networking and control systems.

Source: IOUs' Offer Forms for DRAM 2019 . Simplified version.

6. Discussion and Lessons for the Power Potential project

6.1 Procurement of reactive power and the need for market-based mechanisms

The use of market-based mechanisms in the procurement of reactive power is practically non-existent. Provision of reactive power by third parties (mainly generators) is generally managed under a mandatory approach and compensated using a fixed methodology without any market determined prices. The proliferation of more DER can help to deal with the poor locational effectiveness that is observed when the resource is placed far from the point where reactive power services are required (Vars do not travel well). DER reactive power capabilities will also improve, in line with the upgrade of Network Codes. Then, DER may constitute an important source of reactive power support for the system grid. Procuring reactive power from DER will also require greater interaction between the DER, electricity distribution utilities and TSOs.

The use of a market-based approach using DER for the provision of reactive power services represents one more channel to procure this type of ancillary service. Power Potential is an opportunity to trial the technical solution, the commercial solution and new roles (UK Power Networks as a facilitator for the procurement of reactive power, National Grid as a contractor of reactive power services from distribution companies). Power Potential could also help to identify any regulatory barrier that may limit the value of the competitively procured reactive power from DER and its large-scale implementation in GB.

6.2 Auction mechanism conceptual framework and the case of Power Potential

Section 4 highlighted a number of issues raised by the study of procurement mechanism design for the Power Potential project. They can be summarised as follows:

a. The centrality in auction design of encouraging new entry and more participants in the auction. Power Potential auction design encourages new entrants (i.e. DER) and more market participants in the supply of reactive power services (DER plus transmission connected resources). However, in the future DER participation should depend on whether it can compete (in terms of prices) with transmission connected resources or other future options.

b. The importance of enhancing competition between DERs across the 4 GSPs via a package auction design. A joint auction allows a higher combination of products enhancing competition via substitution between reactive power suppliers. This would be a more complex auction design than the one proposed by Power Potential, however total procurement cost could be lower by selecting the combinations that maximise social welfare (similar to the use of co-optimisation in the US). Appendix 4 illustrates an example of co-optimisation by performing a joint auction (for GSP1 and GSP2) and 2 individual auctions (where DER can only bid to one GSP at the same time, and the auction at GSP1 comes before the auction at GSP2).

c. Consideration of pay-as-clear price determination format and the incorporation of a quality dimension. Pay-as-bid is an approach that is well-known by National Grid and market participants. However, it can bias the equilibrium price and risk inefficiency. In economic theory, a second-price auction would work better for true price discovery with higher dynamic efficiency in comparison with pay-as-bid. In addition, the objective of a procurement auction is not only to minimise the price paid but to maximise economic welfare. The consideration of quality dimensions in the procurement process (represented by the locational effectiveness of reactive power) should be a part of good auction design.

d. Consideration should be given to non-delivery penalties and the pricing format (availability + utilisation). The proposed-non delivery penalty under Power Potential affects the availability payment only. However due to the new requirements for DER (Grid Code GC0100), reactive capability is going to be compulsory. This implies only a utilisation payment is necessary. This is something that would need to be taken into account when contemplating the large-scale implementation of Power Potential.

e. The frequency and periodicity of the auction and the cost benefit of nearer to real time procurement and co-optimisation. More frequent auctions allow both parties (suppliers and the system operator) to adjust the reactive power offers and demand in nearly real time (day ahead in Power Potential). Shorter trading periods can help to reduce AS costs by allowing similar trading periods for each AS (reactive power in this case) and the energy market. This is the case of other AS such as frequency regulation and reserves which are procured with energy (day ahead and real time) in specific jurisdictions. This practice is referred to as co-optimisation and may result in important system costing savings.

f. The careful specification of the counterfactual against which the auction results are to be evaluated. reactive power can be acquired through auctions but also via transmission or distribution reactive equipment or through other future options (identifying and despatching of a specific DER using a similar approach to the current mandatory mechanism, offering a fixed price to the DER for reactive power). Running a reactive power auction mechanism for a small number of GSPs could be costly.

g. The design of the contract between the DSO and TSO to incentivise optimal risk sharing. Under Power Potential, the DSO assumes a new role that may expose it to a significant energy price risk (unlike now). Proper contractual agreements are required in order to incentivise DSOs to optimise their provision of reactive power (and other ancillary services).

6.3 Lessons to Power Potential from the two case studies

6.3.1 About the products

a. For the Power Potential trial the product is limited to reactive and active power services only. This means that other potential products are not taken into account in the evaluation of the offer (DER compete only for the products specified in Power Potential). Even though the offer of additional products are not part of the evaluation criteria and the selection of the best offers, it is important to know about other products that DER providers are currently offering to National Grid or to other parties. There are products that can be mutually exclusive. This is in line with the clarifications made in DRAM where offerors are not allowed to be part of DRAM and to other IOU's demand response programmes simultaneously.

b. A capability of 0.95 power factor is required in Power Potential. However, the project may benefit more from resources that are also able to operate outside the mandatory range (0.95 PF). Lower power factors means an increase in reactive power export/import but a decrease in active power. Power Potential has ruled out curtailing MWs of DER in order to increase Mvar (on the assumption that the value of Mvarh will be significantly below that of MWh). This would be in agreement with AEMO in the procurement of NSCAS, where reactive power services are required in excess of the performance standard for reactive power.

   Table 7 provides a simple example of co-optimisation (which is practised across some electricity products in the US) applied to reactive and active power services only. There are three scenarios: Scenario 1 (sequential selection), Scenarios 2 and 3 (with co-optimisation). In the first two a 0.95 PF has been assumed and in the third one a 0.80 PF has been assumed. A total of 20 Mvar and 50 MW is required. In Scenario 3, Gen 2 is the only one willing to provide reactive power services beyond their operational range. It is observed that Scenario 3 is the one with the lowest costs based on the assumptions made.

Table 7: Example of Enhanced Co-Optimisation

Generators	Active P (MW)	Price (£/MW)	Reactive P (Mvar)	Price (£/Mvarh)	Enhanced Active P (MW)	Enhanced Reactive P (Mvar)
Generator 1 (Gen1)	20	40	6.6	30		
Generator 2 (Gen2)	40	15	13.1	5	33.7	25.3

Scenarios	Type of service	Active P (£)		Reactive P (£)		Total (£)
Scenario 1	Reactive + Active (seq.)	1,250	(a)	264	(b)	1,514
Scenario 2	Reactive + Active (co-opt.)	1,000	(c)	271	(d)	1,271
Scenario 3	Reactive + Active (enhanced + co-opt.)	1,158	(e)	100	(f)	1,258

For Scenario 1 and 2, PF is 0.95 (Gen 1, Gen 2), for Scenario 3 PF is 0.95 (Gen 1) and 0.8 (Gen 2).

6.3.2 Participation criteria and eligibility

a. DER need to be clear about the extra costs to be incurred (such as control and communication costs) to participate in the Power Potential trial. A way to mitigate the capital costs is by offering an incentive to DER in the form of a fixed rate regardless of the size of the DER (Wave 1), this amounts to £25k (based on the control and communication equipment average costs). Taking into consideration that this is the first pilot project that seeks to procure reactive power services from DER in a limited area (initially 4 GSPs) and that auction theory suggests increasing the number of participants is important, we think this is a reasonable strategy. In the case of DRAM, bidders are allowed to include all "peripheral costs" associated with the service in the contract price they offer, including those relating to scheduling coordinator costs. However, bidders are responsible for all costs related to connection rules (Rule 21) and the same applies in the NSCAS tenders in Australia. This makes sense in these two cases because demand response is a more contestable product[67] than reactive power (from DER) and NSCAS is now a business as usual tender for reactive power services.

b. DER need to know the reactive power capacity to be procured at each GSP to be estimated by National Grid (Mvars and specific service windows). Aggregators and individual DER need to evaluate the best portfolio of offers that would work for them.

c. There are currently (May 2018) some elements of the auction mechanism that are unclear: periodicity (up to 12 months assuming a start in Jan. 2019 or less than 12 months if budget is insufficient); the way in which National Grid will value the two kinds of payments; whether there will be a cap on the maximum offer payable (if applicable and in agreement with the capacity cost cap set in DRAM); the quantity of reactive power services required on different

[67] In the context of this report a contestable product refers to those products that are much easier to be procured using competitive mechanisms. For instance, in contrast with reactive power ancillary services, response and reserves are more mature markets with more market participants ready to provide the services regardless of any locational requirement.

days and in different time windows (reactive power services at night time may be more valuable than at day time on weekdays).

6.3.3 Evaluation criteria

a. The evaluation criteria need to be clear. A good example is observed in the DRAM RFO. The methodology is well explained and is complemented by spreadsheets (with random values) that bidders can download from the IOUs websites. In the NSCAS tenders the methodology is not clear (and it is not clear would happen if there were any ERPS offers in GB).

b. The use of non- cost variables has not been considered in the evaluation of the DER in Power Potential. The scoring matrix from DRAM sets a good reference for the identification of non-variable costs that can minimise the risk of having DER with poor delivery records and can favour particular sources of reactive power (such as residential reactive power).

c. The locational effectiveness of reactive power equipment plays an important role in its evaluation. AEMO provides maps not only with the areas that have the highest locational effectiveness but also with additional information about the transmission network (substations, transmission lines at different voltages, etc.). UK Power Networks is also providing effectiveness heatmaps for each GSP, however DER may benefit by doing a better evaluation of its options if additional information can be provided, drawing on AEMO's experience.

7. Conclusions

Globally, there is a lack of competitive mechanisms in the procurement of reactive power at both the transmission and the distribution level, in comparison with the procurement of other ancillary services. The introduction of more market oriented mechanisms and resources (such as DER) for acquiring reactive and active power services by the system operator opens new opportunities and new ways to deal with voltage stability issues. This also imposes new challenges such as the implementation of new types of agreements (apart from the traditional ones) between DER/system operator/electricity distribution firm and the use new platforms to manage reactive power. Power Potential is a first of its kind in seeking to competitively procure reactive power from DER. It offers the opportunity to trial not only the DER performance in the provision of reactive and active power system but also an innovative procurement mechanism design. This report provides key recommendations for such a design drawing on general lessons from auction theory and practice and the evaluation of two specific case studies from Australia and California that reflect best practice in ancillary service market design.

The Power Potential seeks to be novel and trail new ways of procuring reactive power. Our discussion of the principles of mechanism design would suggest that attention to the following: the frequency of the auction and its price determination mechanism offers significant scope for learning on what sort of price resolution might be necessary/desirable or possible; consideration of the use of pay-as-clear (rather than pay-as-bid) to reveal information about underlying costs and to experiment with a different (and arguably superior) payment rule; and more consideration of how to enhance substitutability of products within the trail area, particularly by integrating the procurement across the 4 GSPs.

References

AEMC (2018), National Electricity Rules. Version 106. Australian Energy Market Commission. https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current

AEMC (2011), Rule Determination. National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011. Australian Energy Market Commission, Apr. 2011. https://www.aemc.gov.au/sites/default/files/content/b3970415-6f8b-4a05-8846-2fc87e7e67cb/Final-Rule-Determination.PDF

AEMO (2012), Request for Expression of Interest Network Support and Control Ancillary Services. Australian Energy Market Operator, July 2012. https://www.aemo.com.au/Datasource/Archives/Archive642

AEMO (2015), Guide to Ancillary Services in the National Electricity Market. Australian Energy Market Operator, Apr. 2015. https://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.ashx

AEMO (2017a), Network Support and Control Ancillary Services Agreement. Generic Proforma. Australian Energy Market Operator, Dec. 2017. www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/NSCAS-Agreement-Proforma-2017-Final.pdf

AEMO (2017b), NSCAS Tender Guidelines. Procurement of Network Support and Control Ancillary Services. Australian Energy Market Operator, Dec. 2017.https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/NSCAS-Tender-Guidelines-2017.pdf

AEMO (2017c), Visibility of Distributed Energy Resources. Future Power System Security Program. Australian Energy Market Operator, Jan. 2017. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/AEMO-FPSS-program----Visibility-of-DER.pdf

AEMO (2018a), TransGrid Transmission Determination 2018-23 Network Support and Control Ancillary Services. Australian Energy Market Operator, Jan. 2018. https://www.aer.gov.au/system/files/AEMO%20-%20Submission%20on%20TransGrid%27s%20revised%20proposal%20-%2018%20January%202018.pdf

AEMO (2018b), Request for Expression of Interest Non-market Ancillary Services – Dynamic reactive power support. Australian Energy Market Operator, Apr. 2018 https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Request-for-Expressions-of-Interest-for-Non-market-Ancillary-Services

AER (2016), AER 2017 transmission partial performance indicators 2012-2016. Australian Energy Regulator, Nov. 2016.

Anaya, K., Pollitt, M. (2017), Regulating the Electricity System Operator: Lessons for Great Britain from around the world. EPRG Working Paper 1718 Cambridge Working Paper in Economics 1755, Dec. 2017. https://www.eprg.group.cam.ac.uk/wp-content/uploads/2018/01/1718-Text.pdf

Ausubel, L. and Cramton, P. (2011). Auction design for wind rights. Report to Bureau of Ocean Energy Management, Regulation and Enforcement. http://www.boem.gov/uploadedFiles/BOEM/Renewable_Energy_Program/Regulatory_Information/AusubelCramtonPaper1.pdf.

Chapman, Stephen, J. (2005), Electric Machinery Fundamentals. Fourth edition, McGraw-Hill, New York.

CPUC (2017a), Decision adopting steps for implementing the competitive neutrality cost causation principle, requiring an auction in 2018 for the demand response auction mechanism, and establishing a working group for the creation of new models of demand response. Decision 17-10-017. California Public Utilities Commission, October 26, 2017.

CPUC (2017b), Research Plan for the Demand Response Auction Mechanism (DRAM) I, II, & III Pilots, 2015-2017. California Public Utilities Commission, Apr. 2017.

CPUC (2017c), Actions to Limit Utility Costs and Rates. Public Utilities Code Section 913.1 Annual Report to the Governor and Legislature. California Public Utilities Commission, May. 2017. http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2017/SB%20695_Master%20Draft_final_5-12-17.pdf

EA (2016), Ancillary Services Procurement Plan. New Zealand Electricity Authority, Dec. 2016. https://www.ea.govt.nz/development/work-programme/operational-efficiencies/so-policy-statement-procurement-plans/development/updated-ancillary-services-procurement-plan/

EC (2016), Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators. European Commission, Apr. 2017. https://publications.europa.eu/en/publication-detail/-/publication/1267e3d1-0c3f-11e6-ba9a-01aa75ed71a1/language-en

EC (2017), Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing. European Commission, Nov. 2017. http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R2195&from=EN

Energy UK (2017), Ancillary services report 2017. Energy UK, Apr. 2017. https://www.energy-uk.org.uk/publication.html?task=file.download&id=6138

EPN (2018), Eastern Power Networks plc Use of System Charging Statement. Effective from 1 April 2018, Feb. 2018. https://www.ukpowernetworks.co.uk/internet/en/about-us/documents/2018/eastern/Eastern%20Power%20Networks%20LC14%20Statement%202018%20V3.1.pdf

EPRI (2016), Wholesale Electricity Market Design Initiatives in the United States: Survey and Research Needs. 2016 Technical Update. Electric Power Research Institute, Nov. 2016. https://www.epri.com/#/pages/product/000000003002009273/

Exelon Companies (2016), Comment and Policy Statement of the Exelon Companies. In the matter of the Value of Distributed Energy Resources. Case No. 15-E-0751. Exelon Companies, Apr. 2016.

FERC (2005), Principles for Efficient and Reliable Power Supply and Consumption. Commission Staff Report Docket No. AD05-1-000. Federal Energy Regulatory Commission, Feb. 2005. https://www.ferc.gov/CalendarFiles/20050310144430-02-04-05-reactive-power.pdf

FERC (2014), Payment for Reactive Power. Commission Staff Report AD14-7. Federal Energy Regulatory Commission, Apr. 2014. https://www.ferc.gov/legal/staff-reports/2014/04-11-14-reactive-power.pdf

FERC (2018), Distributed Energy Resources. Technical Considerations for the Bulk Power System. Staff Report, Docket No. AD18-10-000. Federal Energy Regulatory Commission, Feb. 2018. https://www.ferc.gov/legal/staff-reports/2018/der-report.pdf

Greve, T., Teng, F., Pollitt, M., Strbac, G. (2017), A system operator's utility function for the frequency response market, EPRG Working Paper No.1713. https://www.eprg.group.cam.ac.uk/wp-content/uploads/2017/07/1713-Text.pdf

Holt, C.A. (1980), 'Competitive Bidding for Contracts under Alternative Auction Procedures', Journal of Political Economy, 88 (3): 433-445.

IES (2017), A Package of Improvements for the NEM Auction. A Report prepared by Intelligent Energy Systems for CS Energy. IES Intelligent Energy Systems, Apr. 2017. https://www.aemc.gov.au/sites/default/files/content/e66cb21f-af35-447b-a3b4-3ddfab0f17d5/6-RuleChange-Submission-ERC0201-CS-Energy-170505-consultant-report.PDF

ISO-NE (2018), Reserve Products & Market Overview. Introduction to Wholesale Electricity Markets (WEM 101), March 2018. https://www.iso-ne.com/static-assets/documents/2018/03/20180319-15-wem101-reserve-products-mkt-overview.pdf

Kim, S-W, Pollitt, M, Jin, Y.G., Kim, J. and Yoon, Y.T. (2017). Contractual Framework for the Devolution of System Balancing Responsibility from Transmission System Operator to Distribution System Operators, EPRG Working Paper No.1715. https://www.eprg.group.cam.ac.uk/wp-content/uploads/2017/10/1715-Text.pdf

Klemperer, Paul. (2002). 'What Really Matters in Auction Design', Journal of Economic Perspectives 16(1): 169-189, http://people.hss.caltech.edu/~jkg/what-matters.pdf.

Krishna, V. (2009). Auction Theory, San Diego: Academic Press.

More than Smart (2017), Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid. Prepared by staff from CAISO, PG&E, SCE, SDG&E with support from More Than Smart, Jun. 2017. https://www.caiso.com/Documents/MoreThanSmartReport-CoordinatingTransmission_DistributionGridOperations.pdf

NG (2017a), System Needs and Product Strategy, Warwick: National Grid, Jun. 2017. https://www.nationalgrid.com/sites/default/files/documents/8589940795-System%20Needs%20and%20Product%20Strategy%20-%20Final.pdf

NG (2017b), Reactive Market Report. Thirty Eight Tender Round for Obligatory and Enhanced Reactive Power Services. National Grid, July 2017.

https://www.nationalgrid.com/sites/default/files/documents/39th%20Reactive%20Market%20Report%20Final.pdf

NG (2017c), Product Roadmap for Frequency Response and Reserve. National Grid, Dec. 2017. https://www.nationalgrid.com/sites/default/files/documents/Product%20Roadmap%20for%20Frequency%20Response%20and%20Reserve.pdf

NG (2018a), GC0100 EU Connection Codes GB Implementation – Mod 1. Stage 06: Final Code Modification Report. Grid Code. National Grid, Feb. 2018. https://www.nationalgrid.com/sites/default/files/documents/GC0100%20Final%20Modification%20Report.pdf

NG (2018b), GC0101 EU Connection Codes GB Implementation – Mod 2. Stage 06: Final Code Modification Report. Grid Code. National Grid, Feb. 2018. https://www.nationalgrid.com/sites/default/files/documents/GC0101Final%20Modification%20Report.pdf

NG (2018c), Product Roadmap for Reactive Power. National Grid, May 2018. https://www.nationalgrid.com/sites/default/files/documents/National%20Grid%20SO%20Product%20Roadmap%20for%20Reactive%20Power.pdf

NG – UK Power Networks (2018a), The Power Potential Project. Head of Terms – Subject to contract. National Grid and UK Power Networks, Jan. 2018. https://www.nationalgrid.com/sites/default/files/documents/Power%20Potential%20%20Heads%20of%20Terms.pdf

NG – UK Power Networks (2018b), Technical Characteristics Submission Spreadsheet. National Grid and UK Power Networks. https://www.nationalgrid.com/uk/investment-and-innovation/innovation/system-operator-innovation/power-potential

NG – UK Power Networks (2018c), Power Potential Webinar. National Grid and UK Power Networks, Mar. 2018. https://www.nationalgrid.com/sites/default/files/documents/Webinar%20slides%20final_0.pdf

NG-UK Power Networks (2017a), Power Potential Webinar. Webinar with Power Potential interested parties, Sep. 2017. https://www.nationalgrid.com/sites/default/files/documents/Power%20Potential%20webinar_21%20September%202017.pdf

NG-UK Power Networks (2017b), Power Potential: A New Market for Reactive Power. Presented at LCNI, Low Carbon and Innovation Conference, 6-7 December 2017, Telford. https://www.nationalgrid.com/uk/investment-and-innovation/innovation/system-operator-innovation/power-potential

NERC (2009), Reactive Support and Control Whitepaper. TIS-Reactive Support and Control Subteam. North American Electric Reliability Corporation, NERC, May, 2009. https://www.nerc.com/pa/stand/project%20200801%20voltage%20and%20reactive%20planning%20and%20c/project2008-01_white_paper_2009may18_appendix_1-11_2009aug17.pdf

NERC (2017), Distribution Energy Resources. Connection Modelling and Reliability Considerations. North American Electric Reliability Corporation, NERC, Feb. 2017.

https://www.nerc.com/comm/other/essntlrlbltysrvcstskfrcdl/distributed_energy_resources_report.pdf

NYISO (2017), Distributed Energy Resources Market Design Concept Proposal. A Report by the New York Independent System Operator, Dec. 2017.
http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/DER_Roadmap/DER_Roadmap/Distributed-Energy-Resources-2017-Market-Design-Concept-Proposal.pdf

OFGEM (2012), Electricity Balancing Significant Code Review (SCR) Initial Consultation, Ref.108/12, London: OFGEM. https://www.ofgem.gov.uk/ofgem-publications/40802/electricity-balancing-scr-initial-consultationpdf

OFGEM (2016), Distribution Connection and Use of System Agreement (DCUSA) DCP 222 – Non billing of Excess Reactive Power Charges. Office of Gas and Electricity Markets, Aug. 2016.
https://www.dcusa.co.uk/Documents/DCP%20222%20Authority%20Decision%20Letter.pdf

OFGEM (2017), Requirement for generators – 'emerging technology' decision document. Final decision. Office of Gas and Electricity Markets, May 2017.
https://www.ofgem.gov.uk/system/files/docs/2017/05/requirement_for_generators_-_emerging_technology_decision.pdf

PG&E (2015), Stakeholder Comments. Reactive Power and Financial Compensation. Pacific Gas & Electric, Jun. 2015. https://www.caiso.com/Documents/PG-EComments_ReactivePowerRequirements_FinancialCompensation-IssuePaper.pdf

PG&E (2017), Pacific Gas and Electric Company Advice Letter 5109-E. Advice Letter presented to the California Public Utilities Commission regarding 2018-2019 DRAM, Jun., 2017.

PJM (2018), PJM Open Access Transmission Tariff, PJM. Effective date 23/04/2018-Docket#ER18-893-000. https://www.pjm.com/directory/merged-tariffs/oatt.pdf

Potomac Economics (2017), 2016 State of the Market Report for the ERCOT Electricity Markets. Independent Market Monitor for ERCOT, May 2017. https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf

Read, E. Grant (2010), Co-Optimization of Energy and Ancillary Service Markets. In: Pardalos P., Rebennack, S., Pereira M., Iliadis N. (eds) Handbook of Power Systems I, Energy Systems. Springer, Berlin, Heidelberg. https://link.springer.com/chapter/10.1007/978-3-642-02493-1_13#citeas

Sauer, Peter W. (2005), Reactive Power and Voltage Control Issues in Electric Power Systems. In: Chow J.H., Wu F.F., Momoh J. (eds) Applied Mathematics for Restructured Electric Power Systems. Power Electronics and Power Systems. Springer, Boston, MA. https://doi.org/10.1007/0-387-23471-3_2

SCE (2015), Southern California Edison Company AL 3208-E, Pacific Gas and Electric Company AL 4618-E, San Diego & Electric Company AL 2729-E. Advice Letter presented to the California Public Utilities Commission, Apr. 2015. https://www.sce.com/NR/sc3/tm2/pdf/3208-E.pdf

SCE (2017), Southern California Edison Company Advice Letter 3629-E. Advice Letter presented to the California Public Utilities Commission regarding 2018-2019 DRAM, Jul., 2017.
https://www.sce.com/NR/sc3/tm2/pdf/3629-E.pdf

SCE (2018), 2019 DRAM RFO Pro Forma. Demand Response Auction Mechanism Resource Purchase Agreement. Southern California Edison Company. https://www.sce.com/wps/portal/home/procurement/solicitations/dram/!ut/p/b0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOK9PF0cDd1NjDwNQr2MDRyNDVxMXEJ9DZx9TfSDU4v1C7IdFQHvyhGX/

SDG&E (2017), San Diego Gas and Electric Company Advice Letter 3095-E. Advice Letter presented to the California Public Utilities Commission regarding 2018-2019 DRAM, Jun., 2017.

SDG&E-PG&E-SCE (2018a), 2019 Demand Response Auction Mechanism (DRAM 4). Pre-Bid (bidders) Web Conference, Feb. 2018.https://www.sce.com/wps/wcm/connect/3fefbc02-0678-4ead-810e-98e0a018270d/DRAM4_BiddersConference.pdf?MOD=AJPERES

SDG&E-PG&E-SCE (2018b), 2019 DRAM RFO (DRAM 4) Pre-Bid Conference and Other Questions & Answers, Feb. 2018. https://www.sce.com/wps/wcm/connect/3fefbc02-0678-4ead-810e-98e0a018270d/DRAM4_BiddersConference.pdf?MOD=AJPERES

Transgrid (2017), Transmission Annual Planning Report 2017. TransGrid, Jun. 2017. https://www.transgrid.com.au/news-views/publications/transmission-annual-planning-report/Documents/Transmission%20Annual%20Planning%20Report%202017.pdf

UK Power Networks (2017), Flexibility Services. Design consultation response summary. UK Power Networks, Dec. 2017. https://www.ukpowernetworks.co.uk/internet/en/have-your-say/documents/UKPN_Flex_Consultation_Responses.pdf

WP (2015), Working safely around the Western Power network. Western Power, 2015. https://westernpower.com.au/media/2341/working-safely-around-the-western-power-network-handbook-20170508.pdf

Appendix 1: Ancillary Services Procurement Methods in the USA and GB (selected products)

		USA							GB
	Ancillary service markets and names	CAISO	ISO-NE	MISO	PJM	SPP	NYISO	ERCOT	NG (2)
Regulation/Frequency Response	Regulation		RT	DA,RT	RT (1)		DA,RT		
	Regulation Up	DA,RT				DA,RT		DA	
	Regulation Down	DA,RT				DA,RT		DA	
	Regulation (performance)				RT			NA	
	Regulation Up Mileage	DA,RT				DA,RT			
	Regulation Down Mileage	DA,RT				DA,RT			
	Regulation Service		RT						
	Regulation movement						DA,RT		
	Regulating Mileage			DA,RT					
	Frequency response								
	Mandatory frequency response								
	Firm Frequency Response (dynamic)								monthly tenders
	Firm Frequency Response (static)								monthly tenders
Reserves	Spinning reserve	DA,RT		DA,RT		DA,RT	DA,RT		
	Ten-minute spinning reserve		RT, F						
	Synchronised reserve				RT				
	Responsive reserve							DA	
	Non-spinning reserve	DA,RT					DA,RT	DA	
	Ten-minute non-spinning reserve		RT, F						
	Quick start				RT				
	Thirty-minute operating reserve		RT, F						
	Supplemental reserve (3)			DA,RT	RT (4)	DA,RT			
	Ramp reserves (5)	RT		DA,RT					
	Reserve								
	BM startup								
	Fast reserve								monthly tenders
	Optional Reserve Services								
	Short term operating reserve (Committed)								3 tenders/y
	Short term operating reserve (Flexible)								3 tenders/y
	Short term operating reserve (Premium Flexible)								3 tenders/y
Others	Reactive power (voltage support)								
	Mandatory reactive power service								
	Enhanced reactive power service (6)								semestral tenders
	Black start					NA			

market-based mechanisms (tenders)

other (cost-based, lost opportunity cost, revenue-based, mandatory)

Markets: DA: Day Ahead, RT: Real Time, F: Forward (pre-DA), NA: No available

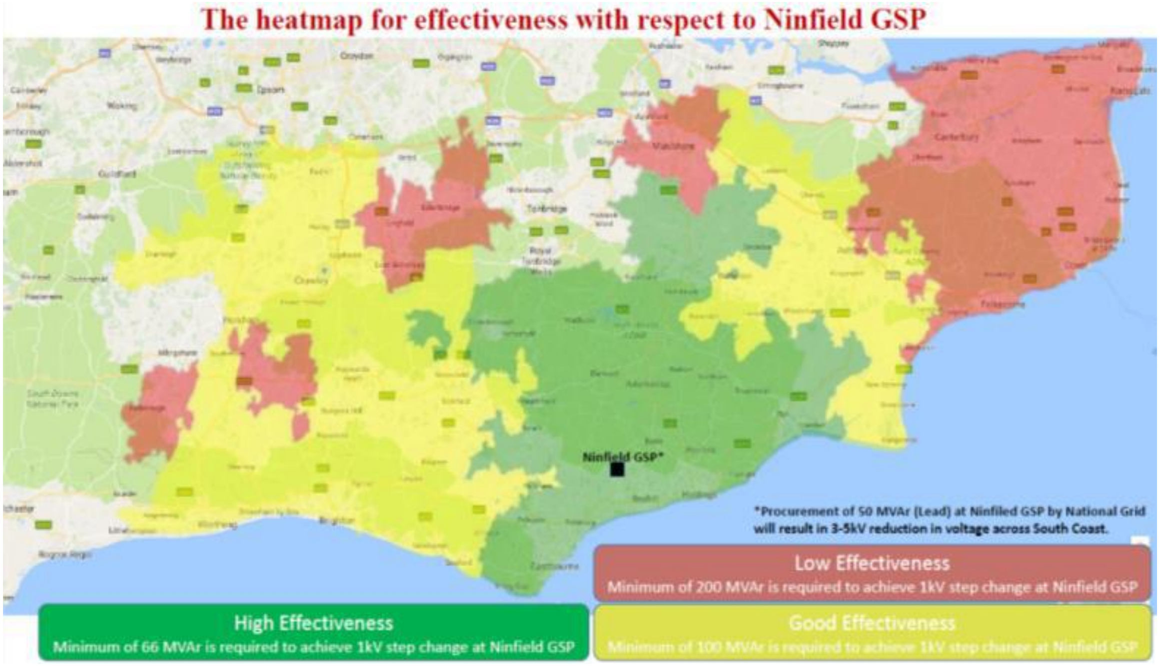
(1): Regulation in PJM is provided by a combination of resources following 2 signals: RegA (slow response) and RegD (quick response).

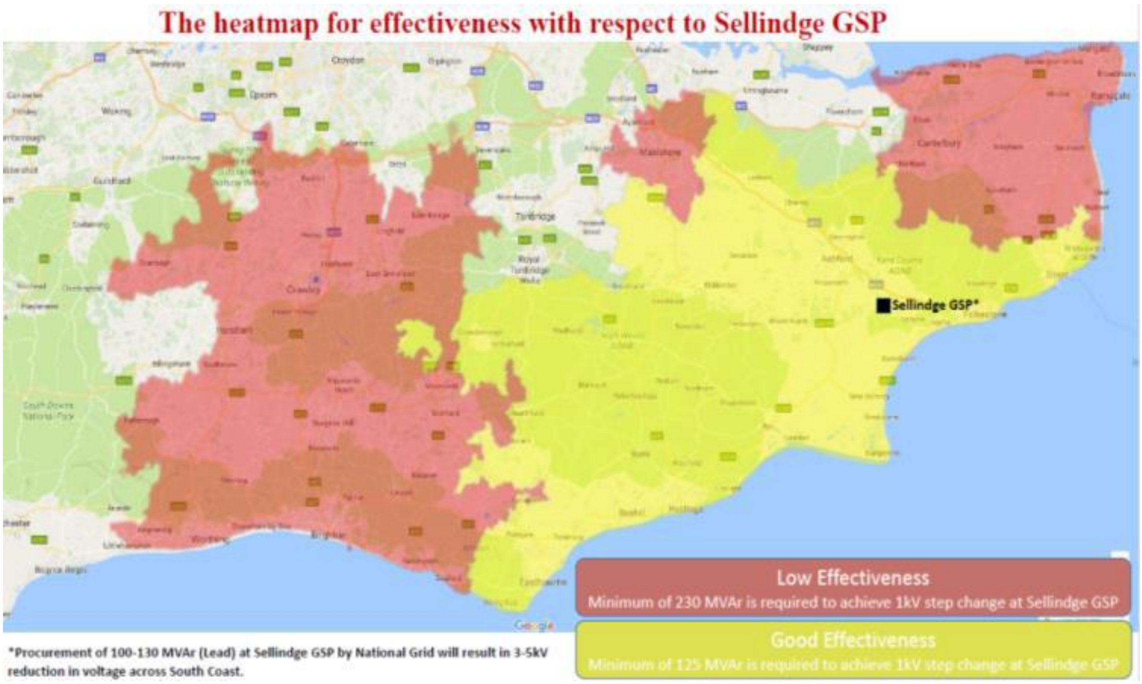
(2): Simplified list of AS as of Dec. 2017, (3): Provided by online or off-line resources in MISO/PJM, (4): PJM uses a day-ahead scheduling reserve in addition to the RT for supplemental reserve (30min), (5): Ramp product: Up and Down Ramp Capability (MISO), Flexible Ramping (CAISO).

(6): Not currently active for procurement. The full list of removed products can be found at NG (2017c) and NG (2018c).

Source: Anaya and Pollitt (2017, p. 31), ISO-NE (2018), NG (2017a), Potomac Economics (2017).

Appendix 2: Reactive Power Effectiveness Heatmaps (Ninfield and Sellindge GSPs)





Appendix 3: Summary of DRAM Pilots

Description	2016 DRAM (Pilot 1)	2017 DRAM (Pilot 2)	2018-2019 DRAM (Pilot 3)	2019 DRAM (Pilot 4)
Type of RA	System	System, local, flexible (cat. 2, 3)	System, local, flexible (cat. 1, 2, 3)	System, local, flexible (cat. 1, 2, 3)
Type of DR product	PDR	PDR, RDRR	PDR, RDRR	PDR, RDRR
Delivery Period	6 months Jun.-Dec. 2016	12 months Jan. – Dec. 2017	2 years (2018-2019) Jan. –Dec.	12 months Jan.-Dec. 2019
Budget	SCE:$6m, PG&E:$6m, SDG&E: $1.5m	SCE:$6m, PG&E:$6m, SDG&E: $1.5m	SCE:$12m, PG&E:$12m, SDG&E: $3m	SCE:$6m, PG&E:$6m, SDG&E: $1.5m
Procurement targets (minimum)	10 MW (SCE), 10 MW (PGE), 2 MW (SDG&E).	10 MW (SCE), 10 MW (PGE), 2 MW (SDG&E)	No minimum (MW).	No minimum (MW).
Procurement targets (maximum)	Based on approved budget limit or available authorised Rule 24 registrations.	Based on approved budget limit or available authorised Rule 24 registrations.	Based on approved budget limit or when there is a clear price outlier.	Based on approved budget limit or when there is a clear price outlier.
Scheduling coordinator costs	separated from the bid cost	separated from the bid cost	included in the bid cost	included in the bid cost
Capacity procured	40.5 MW	124.7 MW	over 200 MW	na (ongoing)
Regulatory framework Decision (CPUC)	D.14-12-024	D.14-12-024	D.16-06-029	D.17-10-017

RA: Resource Adequacy, DR: Demand Response, PDR: Proxy Demand Resource, RDRR: Reliability Demand Response Resource.

Source: CPUC (2017a, b), PG&E(2017), SCE (2015).

Appendix 4: Example of Co-optimisation (individual auction versus joint auction)

In this example it is assumed that the Mvar demand (utilisation) at GSP1 is 8 Mvar and in GSP2 is 5 Mvar. Information regarding the unit cost/Mvar and local effectiveness is provided. The Mvar figures that are shown under each of GSP1 and GSP2 (general assumptions) refer to the maximum Mvars that each DER can provided at their connection points[68] and represent mutually exclusively figures. For ease of exposition, we assume the auction is pay-as-bid, and is taking place for a given hour. We show that in the example the more efficient option would be the joint auction (lowest cost). For instance in Scenario 1, the selection of DER at GSP1 starts with the ones with the lower costs (DER F, D, C and B) and then with the selection of DER at GSP2 using the same approach. For DER B, only a ratio of the total Mvars are selected (until complete the quota of 8 Mvar and 5 Mvar)[69]. In Scenario 2, Mvars at GSP1 and GSP2 are auctioned together. It is observed that the joint auction is the cheapest one.

Table A. Example of co-optimisation (individual auction versus joint auction)

DER	General Assumptions			Scenario 1				Scenario 2			
	GSP1	GSP2	Price	GSP1 (individual)		GSP2 (individual)		GSP1 (joint)		GSP2 (joint)	
	Max. Mvar	Max. Mvar	(£/Mvarh)	Mvar	Tot. price £	Mvar	Tot. price £	Mvar	Tot. price £	Mvar	Tot. price £
DER A	4.34	2.58	10	-	-	2.58	25.8	-		2.11	21.1
DER B	3.34	1.98	9	1.92	17.2	0.85	7.6	2.49	22.4	0.51	4.6
DER C	0.32	1.35	8	0.32	2.6	-	-	-		1.35	10.8
DER D	0.25	1.03	7	0.25	1.7	-	-	-		1.03	7.2
DER E	-	1.76	15	-	-	1.57	23.6	-		-	-
DER F	5.51	3.27	6	5.51	33.1	-	-	5.51	33.1	-	-
Totals				8	**54.6**	5	**57**	8	**55.5**	5	**44**
Total price (GSP1&GSP2), £							**111.7**				**99.2**

Figures in grey represent a ratio of the maximum Mvars provided at each GSP (authors' estimation).
Source: UK Power Networks.

[68] For simplicity we have assumed that these are the Mvars that each DER can deliver at the two GSPs. In addition, the side-benefit to other GSP has not been captured in this example. According to UK Power Networks, when a DER is dispatched in relation to on GSP, there is a side-benefit to nearby GSPs.

[69] In Scenario 1 with DER B: **1.92**=(8-5.51-0.25-0.32), **0.85**=(1.98*(3.34-1.98)/3.34). In Scenario 2 with DER B: **2.49**=(8-5.51), **0.51**=1.98*(3.34-2.49)/3.34.