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Excellence Through Innovation

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Australia

Stuart Johnston
General Manager Network Transformation
Energy Networks Australia
385 Bourke Street
Melbourne
Victoria 3000

Our Ref: JC 2018-074

10 August 2018

Dear Stuart,

S&C Electric Company response to the ENA Open Energy Networks Consultation

S&C Electric Company welcomes the opportunity to provide a response to the Consultation Paper covering the transition of Network Service Providers to System Operators to best support the increasing role of Distributed Energy Resources.

S&C Electric Company has been supporting the operation of electricity utilities in Australia for over 60 years, while S&C Electric Company in the USA has been supporting the delivery of secure electricity systems for over 100 years. S&C Electric Company not only supports the “wires and poles” activities of the networks, but has delivered over 8 GW wind, over 1 GW of solar and over 45 MW of electricity storage globally, including batteries in Australia and New Zealand. We have also deployed over 30 microgrids combining renewable generation, storage and conventional generation to deliver improved reliability to customers.

S&C Electric are particularly interested in facilitating the development of markets and standards that deliver secure, low carbon and low cost networks and would be very happy to provide further support to the Energy Networks Australia on the treatment and potential of emerging technologies and approaches.

Yours Sincerely

Jill Cainey

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General Comments

We a are very pleased that the Australian Energy Market Operator (AEMO) and Energy Networks Australia (ENA) are working together on the important issue of developing approaches and architectures for the delivery of the future electricity system.

AEMO does not need to control ("Total TSO") everything to beyond the front door of customers' homes and businesses. We would favour options that are either "Total DSO" or more towards the "Total DSO" model. While Distributed Energy Resources (DERs) present system problems for AEMO, DERs are tightly focused on the distribution network and also cause technical issues for Distribution Network Service Providers (DNSPs) that have to be managed. If the DNSPs have to take actions to manage their networks, why does AEMO also need visibility and control? Essentially DERs are a local small-scale problem and need to be resolved at that scale.

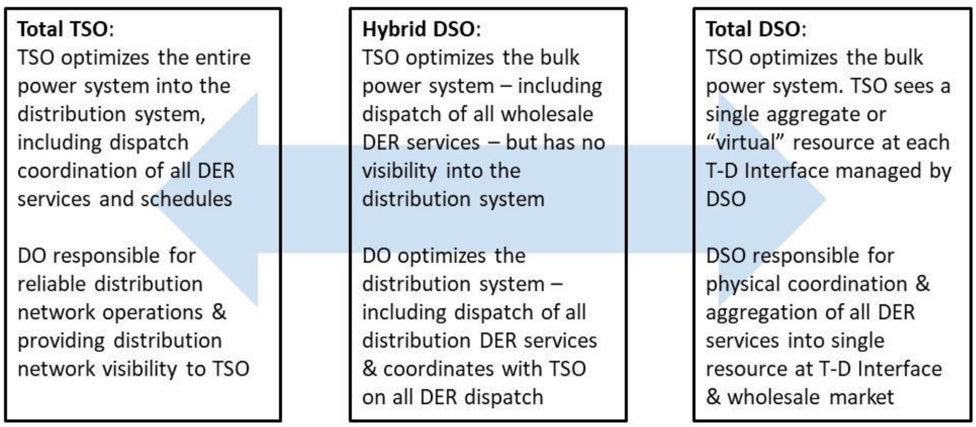

Figure 1: Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design, Newport Consortium

UK Process

Australia is not so unique. Many other countries are exploring how best to manage the impact of DERs and the potential for DERs to support the system, both distribution and transmission. In particular the UK have been exploring the issue of DERs for several years and are very actively exploring this now, with a current consultation, "Open Networks Future Worlds", due to close on 25 September 2018 (http://www.energynetworks.org/electricity/futures/open-networks-project/future-worlds/future-worlds-consultation.html).

The role of DERs, including the important role of demand-side response, has also been the focus of a number UK Ofgem-funded innovation projects over the last several years (pre-RIIO-ED1 and T1) and the results of these projects are available on the innovation websites of the various GB Distribution Network Operators (DNOs).

Active Network Management

Active Network Management (ANM) was trialed in the UK in the Scottish and Southern Electricity Networks (then Scottish Hydro Electric Power Distribution, SHEPD) in 2009, using the developments from

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the University of Strathclyde and Smarter Grid Solutions (https://www.smartergridsolutions.com/). ANM is used to manage connections (https://www.ninessmartgrid.co.uk/our-trials/active-network-management/what-is-active-network-management/) and provide Dynamic Line Ratings (e.g. https://www.ssepd.co.uk/WorkArea/DownloadAsset.aspx?id=995). Note that ANM cost GBP500K versus GBP30M for reinforcement. Since the completion of the project, many other GB DNOs have been using ANM to manage their networks (business as usual approach) and it is a useful tool in avoiding reinforcement.

Use of System Charges

The consultation paper is completely devoid of any discussion of Use of System (UoS) charging and it is difficult to see how any progress on equitably using DERs can be made without adequately addressing this issue.

It is obvious that the use of the network is changing. No longer does electricity only flow to customers from large centralised generators. Electricity is now exported from customers to the wider system. The use of the network is now bi-directional, but we only charge UoS in a single direction – import (demand led). However, export or reverse power flow has a technical impact on the secure and reliable operation of the networks. This technical impact has a cost, which currently the DNSPs cannot cover through UoS.

This means that those that can afford to and desire to can deploy DERs. Often this results in a reduction in demand (import) at that customer, reducing the ability to collect the necessary income to fund the operation of the network. The network still has to be funded, meaning that those customers that are financially unable or unwilling to deploy DERs end up bearing the costs of running the network. That is, the cost of operating the network falls on fewer customers, resulting in an increase in the UoS portion of their energy costs, and often these customers are the most vulnerable.

Essentially the owners of DERs can export for free and are getting a "free ride" at the expense of non-owners of DERs. This is not equitable. Further, the premise of the CSIRO-ENA Electricity Networks Transformation Roadmap and this consultation paper is that the owners of DERs should have an increased benefit through being paid to deliver services.

The delivery of those services, in particular a (fast) frequency response, will have a technical impact on the operation of the network, which may be negative and may need remediation. This is an additional cost that will again mainly be borne wholly by those who import and those being remunerated for providing a service with their DER (which may be either an import (footroom) or an export) are unlikely to be exposed to the cost of delivering that service.

Import and export both ***use*** the system and therefore UoS should be levied on both import and export. Until UoS is levied on both import and export it is difficult to see how DNSPs can signal locations for investment, connection or support cost effective and efficient operation of networks.

In some locations tariffs are used to incentivise appropriate network use, such as the Hawaiian Electric tariffs that encourage import at the time of peak solar generation (and an Electric Vehicles (EVs) tariff that favours charging at midday) and a tariff that encourages export at evening peak (or on hot days).

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In Victoria, Feed-in-Tariffs are time-based, so that export is less valuable at midday (to curtail the export of Solar PV).

Carefully designed UoS charges may help manage the operation of the distribution network, without the need to pay for services.

Additionally, significant investment is needed in networks. The current Regulatory Investment Test (RIT) process is cumbersome and longwinded, particularly given the speed of transformation the electricity system is currently experiencing. Without the ability to provide a locational signal and without an overhaul of charging and investment arrangements it is difficult to see how we can deliver the low carbon, secure and lowest cost electricity system Australia needs.

Behind-the-Meter Solar + Storage

All DERs present a major challenge to the operation of the distribution network and the wider system. We need to better understand that challenge before trying to utilise the same assets to provide network and system support.

Forecasting the impact of DERs is critical and while rooftop solar PV may be broadly dependent on the weather, behind-the-meter solar PV combined with storage is independent of the weather, since the export (negative demand) is highly dependent on the State of Charge (SoC) of the battery, which is not known to the DNSPs or AEMO.

Europe is considering requiring the SoC of any battery, particularly behind-the-meter, to be fully transparent to system operators.

Frequency Control

Maintaining stable system frequency is a current system issue (e.g. AEMC Frequency Control Framework Review). The location of a source of primary frequency control is critical to ensure the stability of a given region and the wider National Electricity Market (NEM). All generators, including incumbent thermal synchronous plant, should provide mandatory frequency support. Synchronous generators still represent the bulk of the generation fleet (>70 %) but are not providing primary control. By having a mandated, but remunerated service (mandated providers bid into market), the options for having a source of primary frequency control in the required location is maximised.

While we will need other sources of frequency control in the future, synchronous generation still dominates the fleet in 2030. This means that while we do need to explore other options, there is not a pressing need (except in specific regions).

DERs, if orchestrated simultaneously, could deliver frequency control, but typically it is easier to secure reliable frequency response from single large (~1 MW) assets or a single large load, via demand response, rather than distributed assets (see later comments under question 2.2).

Utility-scale batteries can provide frequency control. We do need to gain more experience on how batteries (as a load and as an export) can impact on the wider system, but we do not yet need to rapidly expand the utility-scale battery fleet. Such utility-scale batteries could be deployed on distribution

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network, where services could be provided to both the DNSPs and AEMO (see later comments on "sharing" under question 4.3).

Understanding Customers

A number of studies in the UK, particularly the Ofgem-funded network innovation projects (some detailed below at Question 2.2) have shown that domestic customers can be particularly hard to engage and retain for the provision of system support services. That while in aggregate the value of DER service may significant (many millions), when this value is split over the providers and the facilitators it becomes small (a few of tens). If the value that the customer sees is not sufficient to provide motivation to participate or fairly remunerate for the use of an asset, then customers are unlikely to participate.

Even in trials, with incentives to participate beyond that of the reward of providing a service, customers were limited in their response, with only 24% of participants in one trial delivering a service when required. This can be mitigated by holding sufficient capacity to ensuring that a 24% response rate delivers the capacity required, but it complicates the use of domestic customer demand side response (further assessment at Question 2.2).

Additionally, domestic customers are largely disengaged with energy costs and described as "sticky". If customers aren't interested in importing electricity it is hard to see why they would be interested in exporting/importing electricity to help the wider system.

Responses to Questions

Chapter 2 – Pathways for DER to provide value

2.1 Are these sources of value comprehensive and do they represent a suitable set of key use-cases to test potential value release mechanisms?

Demand Side Management (both turn up and turn down) is likely to be more critical than direct services from DERs, but both are difficult to secure from domestic-scale customers.

National Grid, the GB Transmission System Operator (TSO), has had a major focus on securing demand-side response to provide ancillary services, through its "Power Responsive" programme (http://powerresponsive.com/). National Grid have estimated that 50-60 % of its balancing services will be provided by demand response in 2020. However, the programme seeks to encourage Commercial and Industry (C&I) scale demand response, rather than domestic-scale demand response.

While C&I demand response is seen as critical, domestic-scale is seen as being too small (load) and represent too small a value (to the provider) on household-by-household basis. This may change once domestic loads increase, e.g. EVs are widespread.

Managing air conditioning loads in summer is an important issue, but this could be addressed by thermal energy storage and/or building design and standards (noting that a suitable building will act as a thermal store of cold and heat). Once thermal storage is available, demand management then becomes an option, since customer comfort can be assured. Air conditioning load will not

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be addressed by behind-the-meter batteries (battery capacity is too small), but a similar "time shifting" problem exists between maximum solar PV generation and the need for cool on a summers day during the evening peak, as applies to all evening loads.

2.2 Are stakeholders willing to share work they have undertaken, and may not yet be in the public domain, which would help to quantify and prioritise these value streams now and into the future?

As stated in the General Comments section, there are numerous trials of customer-led approaches to managing networks. While most of the UK trials have been on domestic demand side response, the issues of customer engagement and value are applicable to accessing services from DERs.

Pacific Gas and Electric (PG&E) have been running a "Smart Inverter" trial in California and have recently published a report (https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.03a.pdf?WT.mc_id=Vanity_epicinterimreport-SmartInverters).

While PG&E say that "smart inverters" could provide the following services:

- Anti-islanding
- Voltage and frequency disturbance ride-through
- "Soft-start" after an outage to help maintain grid safety
- Power quality
- Reliability
- Autonomous reactive (volt/VAR)
- Active (volt/watt) power output control

There have been some significant challenges during the trial:

Communications between PG&E and the inverters was poor and insecure

DER uptime was greater than 99% only 5% of the time and there was a 15% probability of uptime being less than 95%. Utilities require much better standards and protocols if DERs (via smart inverters) are going to offer reliable services that can securely replace traditional network assets.

Customers weren't interested in being involved

Even with the offer of free Energy Storage and a $300 incentive, it was hard to secure engagement from customers. PG&E said this was a "...significant project risk for grid investment deferral..."

Customers aren't thrilled at the potential of curtailment

Every unit of reactive power=unit of real power lost to the system. So handing over control of your asset (used to minimise your energy costs) to a utility, may mean curtailment.

Difficult to determine benefits and cost of Non-Wires Alternatives (NWAs)

PG&E said it difficult to determine "whether the [non-wires alternative] and the market benefits outweigh the integration costs, including storage, communications and grid infrastructure upgrades, that may be required to capture all of the potential DER benefits."

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This latter point is one that is emerging in various approaches in the UK, along with issue of how to impact of purchasing of services on the Regulated Asset Base (RAB). Additionally, many networks are rightly concerned about whether NWAs will deliver regulated security requirements.

National Grid assessed the assessed the potential for EVs and Heat Pumps (HP) to provide rapid frequency response under a Network Innovation Allowance (http://nationalgridconnecting.com/fresh-thinking-on-frequency-response/). HP were found to be too low to respond and impacted adversely on the comfort of home-owners. Controlling the charging of EVs was found to provide a reliable fast frequency response. However, while the aggregated value for the service was GBP100M, by the time this value was dispersed it represented GBP25 per year per EV (4 % of the average annual UK electricity bill or 2 % of annual energy costs). This was deemed in an industry “straw poll” to not offer sufficient motivation. Additionally, National Grid ignored the impact and potential costs of delivering this fast frequency service on the distribution network.

Northern Power Grid (NPG) explored domestic demand side response in Customer-Led Network Revolution (CLNR: http://www.networkrevolution.co.uk/). The trial deployed “smart” appliances in customer households and used these appliances to support network operation. Customers were paid GBP24 per year for up to 15 events requiring the support of their assets or up to GBP38 per year if a HP was available in their home. These are relatively low financial rewards, particularly given the cost of “smart” appliances (which were provided by NPG to customers during the trial). UK Power Networks (UKPN) ran the innovation trial Low Carbon London (LCL: http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Low-Carbon-London-(LCL)/) to assess the role of demand side response in supporting the network, the impact of HP and EVs on network operation and explored how a future Distribution System Operator (DSO) might function.

UKPN’s ‘Low Carbon London’ project found that engaging and retaining domestic customers was difficult and costly. For each customer the costs were GBP207/customer (GBP103 one-off cost, GBP104 annual cost), suggesting that for the average load per household (relatively small currently) the cost of DDSR was more than GBP4,000/kW in the first year and thereafter more than GBP2,000/kW.

UKPN also found that to avoid reinforcement on a given network 1MW of response was required, which would require the mandatory involvement of all 19,200 households on a low-voltage network, since response rates were 24%. That is, only 24% of participants responded by delivering a demand response when requested. This is similar to the issues encountered by PG&E in their Smart Inverter trial.

UKPN determined that only two or three C&I providers would be needed to deliver the same 1MW response. And C&I customers were likely to have an energy manager and be more motivated to manage their energy costs (particularly if directly exposed to time varying UoS charges, which is dependent on customer size and typical in the UK).

http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Low-Carbon-London-(LCL)/Project-Documents/LCL%20Learning%20Report%20-%20A1%20-%20Residential%20Demand%20Side%20Response%20for%20outage%20management%20and%20as%20an%20alternative%20to%20network%20reinforcement.pdf for the most relevant report on LCL.

Let's explore the option of behind-the-meter batteries as a DER that can support the system with a 1 MW frequency service.

Domestic Battery Aggregation	***Utility-scale Battery***
24% response rate	100% response rate
4.2 MW required to be held	1 MW required
840 batteries needed	1 battery needed
Aggregated cost = $13.5M	Cost = $2M
Slow to respond (Trigger from AEMO to aggregator, signal to assets, management of response/no response to ensure delivery of 1 MW)	Sub-second response (Trigger from AEMO)
Located in the home	Located at a sub-station
Inexperienced operators (managing state of charge, maintenance and safety)	Experienced operators

Aside from the fact that regulations make it difficult for a NSP to own and operate a battery (generation), the 1 MW service can be delivered by an NSP at lower cost, more rapidly and via assets that are maintained and operated by experts, sited in locations that are secure and safe (along side other hazards, so easier for emergency services to manage in the event of a problem).

If we can ignore the fact that domestic-scale batteries are not an economic investment for domestic customers, then the 1 MW frequency service can be delivered at lowest cost to the customer if the asset is owned and operated by the DNSP. Additionally, the DNSP is likely to be able to use the battery for other network requirements, making an efficient investment. A trial in the UK (https://www.westernpower.co.uk/Innovation/Projects/Current-Projects/Solar-Storage.aspx) demonstrated that of the 9 income streams available to the battery operator, 7 of them accrued only to the DNSP. The only way to deliver electricity storage cost effectively to all is to maximise the income opportunities. The most economic location for a battery is as close to the end customer as possible, but not behind-the-meter (https://www.sciencedirect.com/science/article/pii/S2352152X17300889). In Australia the Alkimos Beach community battery project (https://www.synergy.net.au/Our-energy/Alkimos-Beach-energy-trial) represents an approach that gives customers the benefit of access to a battery (for solar PV) and would allow the larger capacity battery to provide wider system services. But without the partnership with the DNSP, this battery may not be maximizing opportunities to earn income and reduce the costs to all.

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Care is needed to ensure that a focus on monopolies (vertical separation) doesn't actually mean higher costs for customers, since the full efficiencies of an approach cannot be accessed.

Chapter 3 – Maximising passive DER potential

3.1 Are there additional key challenges presented by passive DER beyond those identified here?

Some of the issues, particularly around forecasting and management of batteries (SoC) have been covered above in "Behind-the-Meter Solar+Storage".

3.2 Is this an appropriate list of new capabilities and actions required to maximise network hosting potential for passive DER?

Broadly appropriate

3.3 What other actions might need to be taken to maximise passive DER potential?

The potential for DER to support the operation of networks or the wider system cannot be considered without addressing the issue of UoS charging and/or the role of tariffs.

Chapter 4 – Maximising active DER potential

4.1 Are these the key challenges presented by active DER?

As for 3.1.

4.2 Would resolution of the key impediments listed be sufficient to release the additional value available from active DER?

Potentially, within the limits covered in Question 2.2, such as how can NWAs meet security of supply and /or reliability standards? Unwillingness of customers to engage, either because remuneration is too low or because of apathy etc. It will be incredibly challenging to deliver whole system support from DERs and this should not be under-estimated.

4.3 What other actions might need to be taken to maximise active DER potential?

Appropriate standards and protocols are needed for communication and interoperability between NSPs, AEMO and customer assets (see comments on PG&E trial).

Customer protection in terms of contracts to provide services, relationships with delivering entities, such as the aggregator.

Much more work is needed on understanding domestic customer behaviour and what motivates customers, before any reliance can be placed on domestic-scale DERs.

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Ensure competition in the market for smart appliances/assets and integration (e.g. not locked in to Google appliances, with Google apps and contracts).

Who has priority access over to an asset that can provide a service to both AEMO and the DNSP? Work by the UK ENA on Shared Services (http://www.energynetworks.org/assets/files/news/consultation-responses/Consultation%20responses%202016/Demand%20Side%20Response%20Concept%20Paper_revised.pdf) determined that because DNSPs required highly location specific services, they should have priority over the needs of the TSO, who is more likely to be able to access other services.

4.4 What are the challenges in managing the new and emerging markets for DER?

In order for DERs to reliably provide services to AEMO (or the wider distribution network), the distribution network needs to be highly reliable. Outages, even momentaries, will disconnect inverter connected DERs, with a delay in their reconnection and subsequent availability for system support. This same issue (outages, momentaries, voltage sags) may mean that there is a mismatch between generation and demand locally, creating technical issues on the distribution network.

Where are the services needed by the DNSP specified?

If DNSP/TNSP has a role in securing the system (TNSP already obligated), then how much of a role does AEMO have or how much more work does AEMO need to do?

AEMO is currently a monopsony and this may make it difficult for DNSPs to purchase services.

Care is needed in contracts for service, to ensure that neither the DSO or AEMO would have “exclusivity” to a service or asset.

4.5 At what point is coordination of the Wholesale, FCAS and new markets for DER required?

May not be needed. No need to coordinate, if DSO balancing their system up to the Bulk Supply Point. In the UK there are range of views from DNOs on their role in balancing. Some DNOs see DERs as providing services to manage network constraints, while other DNOs are keen to have a balancing role.

If AEMO and DNSPs are just purchasers of services from DER, then other than the issues of sharing and prioritisation (who has first call on a single asset), coordination is not needed.

Chapter 5 – Frameworks for DER optimization within distribution network limits

5.1 How do aggregators best see themselves interfacing with the market?

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We are not aggregators, so leave them to comment. However, in the C&I sector in other countries (e.g. UK and Europe), Aggregators are the interface between the customer (with DSR or generation) and the service market.

See: https://www.ofgem.gov.uk/publications-and-updates/independent-aggregators-and-access-energy-market-ofgem-s-view

They are unregulated entities in the market, but as a result may not be able to access all the value (e.g. retailer, DNSP).

5.2 Have the advantages and disadvantages of each model been appropriately described?

It's all about location: AEMO minimum demand is a system issue, but cause is located deep in the DN. The solutions should therefore also be local and managed locally, that is DNSP-DSO based, because the DNSP-DSO has the sight and ability to manage the issue. This means that the roles and functions of any model should more towards the "Total DSO" approach (Figure 1).

For instance, clouds reduce generation form solar PV. At the system level (AEMO), this has less impact since there is diversity at that level (clouds in one location offset by clear skies elsewhere). However, clouds over a LV feeder, will have a greater impact on the management of the distribution network, since there is also diversity on a LV feeder (geographically limited).

The Single Integrated Platform is a top of the system approach and it is unlikely that it will efficiently optimise customer level actions.

The Two Step Tiered Platform cold be described as the worst of both worlds and have many duplications and overlapping functions that are not desirable (see some of the discussion under "Architecture Principles" in the Newport Consortium paper on page 6).

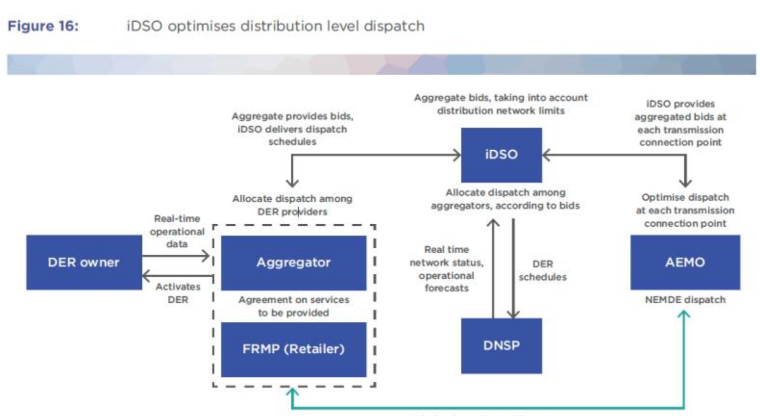

Figure 2: iDSO model

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The iDSO approach is probably closest to the most efficient and effective model. However, the creation of an iDSO (which is very "Helm-esque" in approach: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/654902/Cost_of_Energy_Review.pdf) inserts an unnecessary additional layer into the architecture, which is more about vertical separation than minimising costs for customers. Any new entities are likely to increase the costs of the operating to the system to the end customer. A change in the role of DNSPs will also have a cost, but is likely to be more efficient than creating a new operational layer in the wider system.

It is not entirely clear why Retailers have any sort of role in the delivery of DER services, other than arbitrary and restrictive ring-fencing (Power of Choice).

5.3 Are there other reasons why any of these (or alternative) models should be preferred?

It could be argued that Retailers will become increasingly redundant. Peer-to-Peer (P2P) approaches that allow customers to trade excess generation with their neighbours (e.g. https://www.energy-storage.news/news/blockchain-enables-australias-peer-to-peer-power-trading-kick-off/) may become the normal supply model.

It is necessary to have an entity that links customers with DER who want to provide a service to those wanting a service, such as DNSPs, TNSPs, AEMO and other electricity customers. That entity doesn't have to be a retailer and in Europe and the UK that entity is an Aggregator.

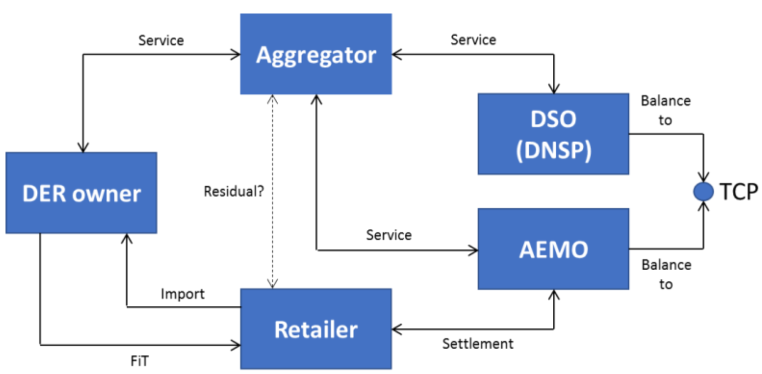

Figure 3: Table 2 Melbourne Workshop Model

The model in Figure 3 was developed during the Melbourne Workshop and still has a role for Retailers for providing import to the DER owner, while the Aggregator acts as the conduit for the provision of services to both the DSO (an expanded role for the current DNSPs) and AEMO. Note that services can be both a demand (footroom) or export.

The roles in Figure 3 are broadly similar to those proposed by the European Distribution System Operators (EDSO), with DER owners able to contract directly with the DSO (and this would be reasonable for larger capacity plant, such as that owned by C&I customers).

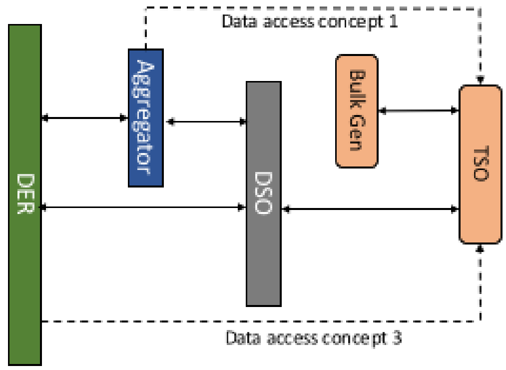

Figure 4: E.U. DNO Associations Proposed Future Architecture (Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design, Figure 8, Newport Consortium)

The current work by the UK ENA proposes a number of models, with "DSO Coordinates" most desirable:

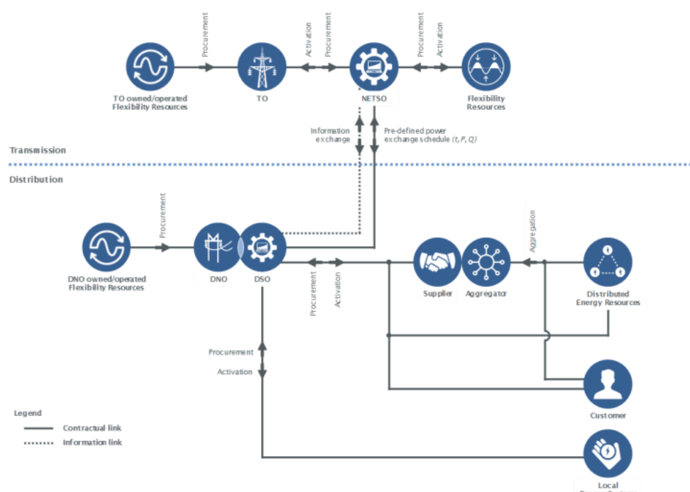

Figure 5: ENA UK (Open Networks Project – Overview & Update, Randolph Brazier)

Although in Figure 5 the DSO/DNO relationship is not clear. It could be the same entity (as in Figure 3). Also the DNO/DSO delivers energy services directly to the TSO, which is not currently permissible for GB DNOs.

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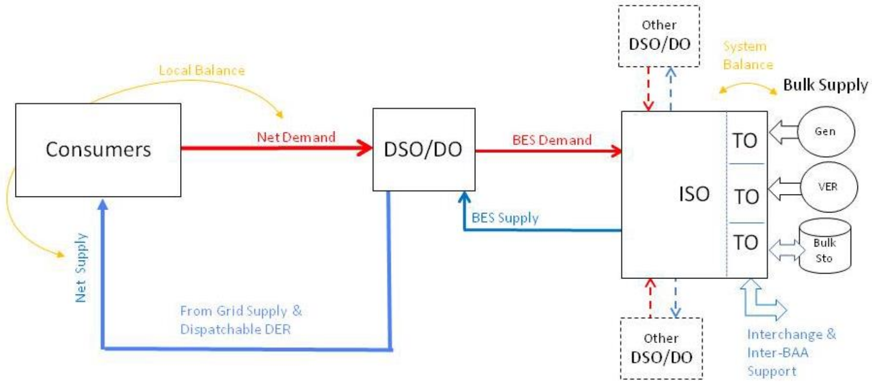

Figure 6: Simplified DSO model (PNNL, Grid Architecture 2, 2016 "PNL-24044 2")

Figure 6 is taken from a PNNL report (January 2016) and covers local balancing versus system balancing, but has a significant central role for the DSO.

It should be noted that there is considerable tension between TSO and DNOs/DSOs in the GB system, particularly where the model has the DSO balancing their system up to the Grid Supply Point (GSP, equivalent to the Transmission Connection Point), since this diminishes the role of the TSO to that of "residual" balancing. While the ENA and AEMO should be rightly lauded for working in partnership on the roles needed to deliver transformation, care is needed, since in the future they may be competitors or encroach on market share. The situation is subtly different in the UK, with National Grid the TSO going through major restructuring as requirement of Ofgem and the Department of Business, Energy and Industrial Strategy.

Another issue is that the distribution network has to be technically capable of delivering services to AEMO, such as a fast frequency service, without the need for reinforcement (e.g. National Grid project covered in 2.2).

Chapter 6 – Immediate actions to improve DER coordination

6.1 Are these the right actions for the AEMO and Energy Networks Australia to consider to improve the coordination of DER?

Yes

6.2 Are there other immediate actions that could be undertaken to aid the coordination of DER?

As well as understanding network constraints some thought should be given to the specification of the services that might be required and the potential value, to both the DNSP/DSO and the customer. Cost and benefits must be determined, not in aggregate, but for each customer to determine if the value is likely to be a driver (value may be too low to prompt engagement).