

What can we learn from international comparators about how we should structure an incentives framework for the future GB electricity system operator to help maximise consumer welfare?¹

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1. Introduction

Changes are happening across different elements of the electricity supply chain - generation, transmission, distribution and retail businesses - and also across different emerging markets such as distributed electric energy storage (EES). These changes are driven by the integration of more renewables into the electricity system, the need to have more flexible networks, the identification of new market participants and emerging technologies (including smart solutions). These changes may also capture value from existing infrastructure and customers (i.e. demand response).

In the generation sector, we are moving from centralised to more decentralised electricity production, where renewable distributed generation (i.e. solar PV, wind) is playing a key role in decarbonisation of the electricity sector. This contributes to the connection of more generation closer to the end customer (generators are connected to the distribution network instead of transmission). This is cheaper (specific transmission charges and network reinforcement can be avoided, with lower operation and connection costs) and quicker (i.e. it takes less time to get connected at a lower cost when offering flexible capacity).

However, we are also aware of the large-scale generation projects that are being recently implemented at the transmission level but using renewable and/or storage solutions instead of conventional generation technologies. Some good examples are observed in Australia², Chile³ and California. Prosuming end customers (residential/commercial/business) may benefit for additional revenue streams or savings due to demand response, net metering,

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² In July 2017 Tesla won the tender to provide 100MW/129 MWh battery storage paired with the biggest wind farm in South Australia to back up the state in case of potential blackouts. This would be the world's largest battery storage. Price information has not been provided. See: <http://reneweconomy.com.au/sa-100mw-battery-storage-tender-won-by-tesla-and-neoen-65874/>

³ In March 2017, SolarReserve received the Chilean approval for building a 450 MW Concentrated Solar Power (CSP) with integrated thermal storage capacity of 5.8 GWh at the record price of US\$ 63/MWh (without subsidies). The integrated system will provide non-intermittent electricity from solar energy 24-hours a day. See: <http://www.power-eng.com/articles/2017/03/solarreserve-to-build-450-mw-solar-facility-with-storage-in-chile.html>

aggregated services or other initiatives that promote the use of specific technologies. Distribution network operators (DNOs) are also exploring the adoption of new roles such as providing ancillary services within their distribution system rather than relying on transmission level provided frequency regulation and voltage support (Kim et al, 2017). The deployment of smart metering increases the range of services that might be provided by prosumers, which represent an integral part of the power system and the market.

System operators are adapting to these changes in load patterns and their need to balance the system using different mechanisms (wholesale, capacity and ancillary services markets) in order to operate the transmission system efficiently (in terms of reliability, planning, load dispatch).

This study explores the international experience in system operation with respect to the incentives that system operators face to operate the network efficiently (from the point of view of society). It does so in the light of the emerging challenge of distributed renewable generation. We look for lessons that we can learn from this experience for the future regulation of the GB System Operator (National Grid Electricity Transmission). These incentives can take different forms (from regulatory mandates to non-monetised incentives such as performance metrics). This study also analyses stakeholder-governance arrangements and the role that stakeholders have in decision-making around proposed new initiatives, such as the introduction of new participants and resources into the wholesale market, changes related to the real time market (e.g. length of the settlement period) etc. We look at seven ISO/RTOs from the USA, where the model seems to be successful but with some cost issues within the system operator itself (Pollitt, 2012). We also examine system operators from Australia (AEMO), Chile (SIC/SING)⁴ and Peru (COES). Our findings are supported by a short survey (Annex 1) that was sent directly to our contacts in the system operators from our sample of ISOs/RTOs.

The structure of this study is as follows. Section 2 provides a description of the current and future incentive regulation of the GB electricity system operator. Section 3 describes briefly the ISOs that are part of this study. Section 4 discusses the international experience of ISOs with respect to their incentives to: maximise social welfare; manage the increasing amount of renewables and new participants; manage their overall actions for customers; engage in stakeholder participation and transparency. Section 5 identifies lessons for the regulation of the GB System Operator.

2. National Grid Transmission System Operator

2.1 Overview

⁴ Based on Law No 20.936 (2016), SIC and SING from Chile have joint to create the new System Operator (Coordinador Electrico Nacional- CEN). CEN started its operation in Oct. 2017.

National Grid Electricity Transmission (NGET), a subsidiary of National Grid plc (National Grid), is currently the system operator⁵ (electricity and gas) in Great Britain⁶. It also owns and manages the transmission system in England and Wales (NETS) and the gas transmission system (NTS) in Great Britain. The NETS consists of circa 7,200 km (4,474 miles) of overhead lines and 1,500 km (932 miles) of underground cable and 342 substations. The NTS involves 7,660 km (4,760 miles) of high-pressure pipes and 618 km of above-ground installations⁷. National Grid also owns part of the existing interconnectors with France (IFA, 70 km, 2 GW) and the Netherlands (BritNed, 260 km, 1 GW) (see NG, 2016). Interconnectors in partnership with others are under construction⁸. The main price control framework that relates to both, the electricity transmission network and the system operation is given by RIIO-T1⁹. There are also other incentive mechanisms that are not part of RIIO-T1 and that relate to the incentives on balancing costs. Some of these are discussed in the next section. In the case of the existing interconnectors¹⁰, NG earns its revenue by selling three services: interconnection capacity (representing 80-90% of revenues), and ancillary services (frequency response and capacity markets), NG (2016).

2.2 NGET System Operation (SO) Incentives

NGET in its role as a SO, is responsible for balancing the system and managing generation output in order to match it with demand, keeping frequency and voltage levels within the operational limits. In order to achieve this, NGET needs to buy and sell electricity and procure specific services (i.e. ancillary services). These costs (i.e. external costs) are recovered from users of the system via Balancing Services Use of System (BSUoS) charges. Other payments made by the users of the grid (i.e. Transmission Network Use of System - TNUoS charges) are linked to the allowances given to NGET in its role as Transmission Operator (TO). Those payments allow the users to use the transmission system to transport their electricity and cover the capital (capex) and operating (opex) costs of its lines and transformers¹¹. In 2016/17 around 4.4% of the total domestic electricity bill (or 20% of the network costs) was attributed to the NGET costs (TO and SO)¹², NGET (2017). The charging methodology for TNUoS and BSUoS is enforced through licence conditions and contained in the Connection and Use of System Code (CUSC) industry code.

Other costs that NGET incurs due to its role as a SO and associated outputs, are related to administrative costs (i.e. internal costs). These costs are regulated through the RIIO-ET1 price

⁵ This will cease to be the case from April 2019 when the ESO (electricity system operator) will be legally separated from NGET, and made into a new National Grid company

⁶ Until March 2017, National Grid owned and operated four gas distribution networks in the UK. National Grid has retained 39% share of the regulated asset value (RAV) of the disposed UK Gas Distribution business. National Grid plc has also other businesses in the US (electricity transmission, electricity distribution, gas distribution), NG (2017).

⁷ <https://www.nationalgrid.com/uk/about-grid/our-networks-and-assets>

⁸ Among them are interconnectors to Belgium – Nemo Link (140 km, 1 GW, c.d. 2019), Norway – NSL (720 km, 1.4GW, c.d. 2021), France – IFA2 (1 GW, 240 km, c.d. 2020), Denmark-Viking Link (760 km, 1.4 GW, c.d. 2023).

⁹ RIIO (Revenue = incentives + innovation + outputs) lasts for the eight-year period from 1 April 2013 to 31 March 2021. This framework defines specific outputs that need to be delivered efficiently and that are linked to the allowed revenue set by the regulator. There are six output categories, each one is associated with a number of primary and secondary deliverables.

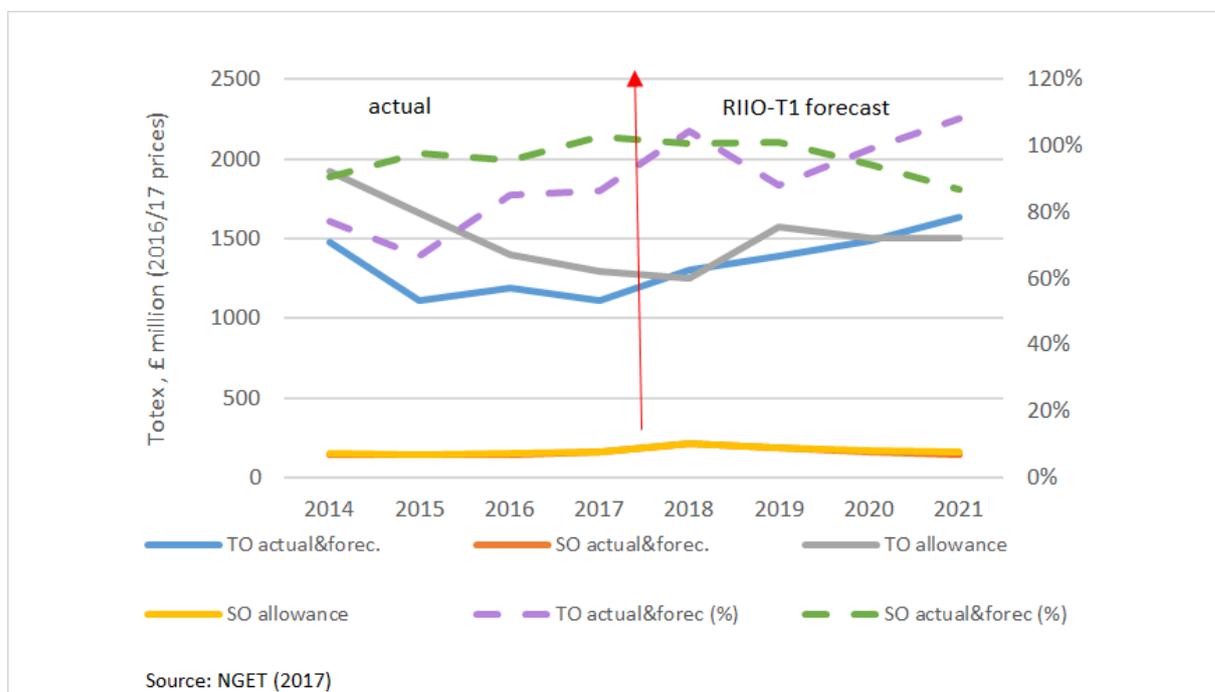
¹⁰ For the new Belgian and Norwegian interconnectors a new cap and floor regulatory model has been approved by OFGEM.

¹¹ For further details about the system charges see: <https://www.ofgem.gov.uk/electricity/transmission-networks/charging>

¹² From this percentage only 0.173% of the total electricity bill corresponds to SO and the rest (4.1%) to TO.

control for NGET SO which includes allowance for capex (i.e. investment in IT systems) and opex (i.e. ongoing costs of running the business, including support for IT systems) (OFGEM, 2017a, p. 80). The total expenditure (totex) on the SO internal costs are around £140 million a year. Both external and internal costs are levied on market participants through the BSUoS charges which are ultimately passed through to customers. The costs associated with the Transmission Operator (TO) are also regulated through the RIIO-T1 price control for NGET TO. Then specific annual allowances for Totex are set for both the SO and TO functions. Figure 1 depicts the expected trends of those costs for the period (2014-2021). Figure 1 suggests that the difference between the actual costs and the total allowance (period 2014-2017) is much higher for the TO than for the SO, representing 79% (£344 million average annual) and 97% (£5 million average annual) of the total allowance for TO and SO respectively. Based on the RIIO-T1 price control, NGET SO faces a share of 50% share of any over or underspend against the total SO allowance (OFGEM, 2017b).

Figure 1: NGET Actual Totex (TO and SO) versus allowances (2014-2021)



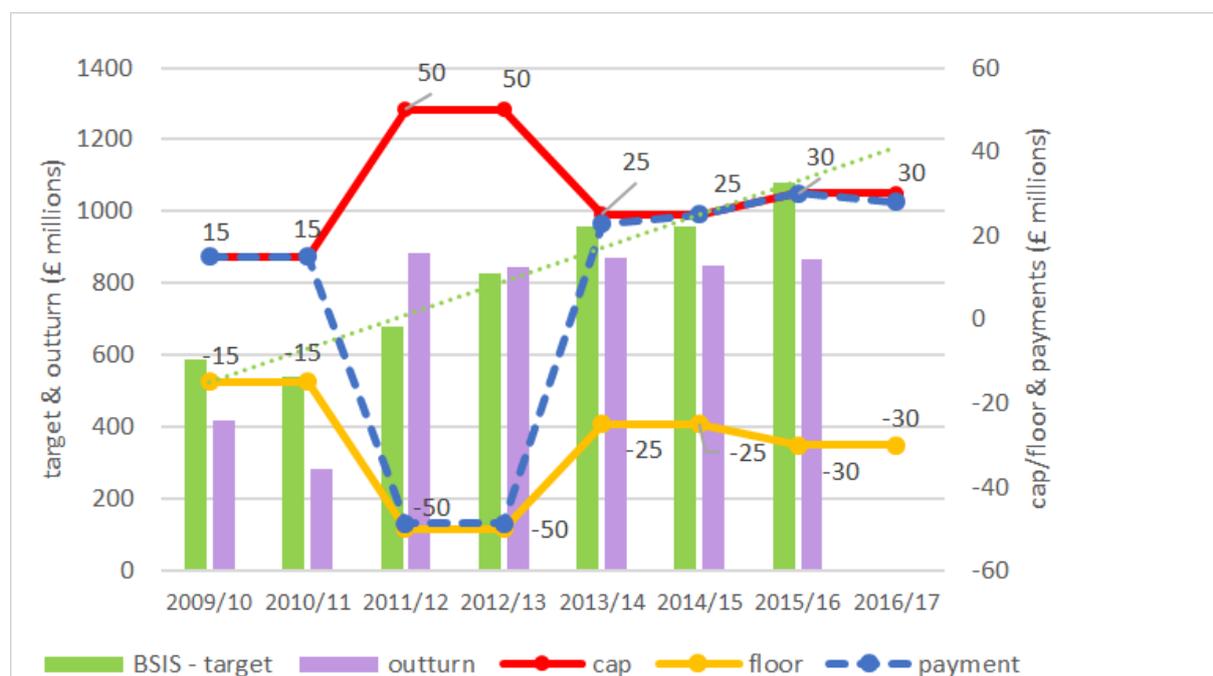
Among other financial SO incentives through RIIO-ET1 are those related to stakeholder engagement and satisfaction, innovation schemes composed of the Network Innovation Adjustment (NIA) and Network Innovation Competition (NIC); and the Environmental Discretionary reward (EDR).

In contrast with the NGET SO internal costs (opex and capex cost allowance), the NGET SO cost allowances for system balancing are set via a distinct process, outside the RIIO-T1 framework. This process relates to a list of specific SO incentives (financial and reputational). The main (and largest) financial incentive is the Balancing Service Incentive Scheme (BSIS) which sets incentives towards the c. £850 million of annual balancing costs. In fact, a target-based approach to set incentives on SO balancing costs has been used since 2001, however the methodology for its estimation has changed over time. The aim of the BSIS is to minimise the cost of balancing the system (including energy and constraint costs) by comparing the

outturn costs versus a target cost. The BSIS 2015-2017 was composed of three key cost components: energy costs, constraint costs and Black Start costs. These costs combined are compared against a modelled target cost¹³ which is used to determine NGET performance. In case of over/underspend compared with the target costs, NGET has to share this amount with the industry (via reductions in future charges). In the last BSIS (2015-2017), the share was set at 30/70 respectively and a cap of £100 million was applied to over/under spend. This means that the maximum value that NGET was allowed to gain/loss was £30 million. The size of the share has also changed over time. A new sharing regime (with NGET's share reduced from 30% to 10%) is now in place for a one-year interim scheme during 2017/18, which means that the cap/floor has moved from £30 million to £10 million. Other changes are related to the recovery of Black Start costs, the introduction of output based incentives (focused on accurate demand and wind generation forecasting, as well coordination with other TO companies, with a total value of +/-£5 million) and the introduction of clearer requirements for being more transparent, among other things (OFGEM, 2017c).

Figure 2 illustrates the trends in the BSIS target versus the outturn incentivised balancing costs. We observe that SO has usually incurred less costs than the BSIS target (except for the period 2011-2013 where a single target was set for this period). In general, incentivised costs have been below the maximum value allowed. On the other hand, an upward trend is observed on the BSIS targets over time.

Figure 2: Target vs Outturn system balancing costs



For the period 2011-2013 BSIS performance refers to a two-year scheme

Source: OFGEM (2017b, p.43), OFGEM (2016, p.20). Adapted.

¹³ For further details about the methodology applied for estimating the BSIS cost target see: <http://www2.nationalgrid.com/UK/Industry-information/Electricity-system-operator-incentives/bsis/>

The BSIS models are managed and maintained by the SO and validated by OFGEM at the beginning of the scheme (which lasts 2 years). In agreement with OFGEM, we observe that BSIS targets have been on average higher than the actual outturn. This suggests that the methodology should not be fixed for a longer period but instead revised and improved over time by the SO. The involvement of stakeholders and a good understanding of the methodology by them, can help to towards a more transparent and accurate BSIS model. According to OFGEM, the participation of stakeholders is quite limited. One of the reasons is that wider stakeholders do not have much understanding of SO incentives models. This reduces the options for collaborative work with stakeholders.

2.3 SO Future Regulation and Challenges

OFGEM is looking for a new regulatory framework for the SO that supports the greater independence of the SO function and involves a new SO incentives scheme (OFGEM, 2017d). This initiative is based on the need to have a more independent SO that helps with the transition towards a smarter, competitive and more flexible electricity system (BEIS, 2017). This requires a set of step-changes over the coming years. One of the first steps was to propose and implement an interim SO incentive scheme in the period from 01 April 2017 to 31 March 2018. Currently OFGEM is exploring new and innovative approaches to the regulatory framework, including SO incentives to be applied between 01 April 2018 and 31 March 2021 and when the current RIIO-T1 expires. OFGEM is looking for a consolidated arrangement from 2021. National Grid's proposed separation package (i.e. around the separation of the SO within National Grid) is the one being followed by OFGEM to create a more independent system operator in GB.¹⁴ However OFGEM is proposing a number of measures in order to mitigate the risks of continuing to have the SO within National Grid (e.g. independent directors, incentives for SO staff based on SO performance, regulation of shared services, among others). OFGEM is proposing a high level re-design of the regulatory framework from 1 April 2018. The design involves: (1) a set of principles (to apply to the SO roles); (2) effective SO engagement with existing and potential future stakeholders; (3) publication of key performance indicators; (4) a greater role for external parties (e.g. introduction of new panel to oversee the SO performance); and (5) more transparent and well governed financial incentives.

The regulation of the electricity SO function is non-trivial. This is because of the multiplier effect of SO actions. The internal SO opex and capex costs are of the order of £140 million per year. The external costs of balancing, induced by the system operator's actions are £850 million per year. However, the total wholesale costs in Great Britain are around £17,000 million¹⁵ per year. In addition, SO decisions significantly influence transmission system costs. Traditional regulation might focus on the internal costs of the monopoly system operator, but external costs are almost an order of magnitude more significant and total system costs are more than an order of magnitude greater again. Hence SO regulation needs to focus substantially on these external and whole system costs.

¹⁴ OFGEM proposed this separation (SO and TO functions) by 1 April 2019. The estimated costs (NPV, 30-year period) of the separation are between £216.67 million (OFGEM estimation) and £249.14 million (National Grid estimation) (OFGEM, 2017e, p.34).

¹⁵ For 2016, see DUKES (2017, p.33).

3. About the International ISOs/RTOs Sample

System operators can take different forms based on the functions that they perform, the type of area served (local, regional) and on the type of assets that they operate (i.e. transmission assets). For a discussion of the different types of system operators see Chawla and Pollitt (2014). This study involves only Independent System Operators (ISOs) and Regional Transmission Organisations (RTOs) that operate in the USA¹⁶ and ISOs from Australia, Chile and Peru and that do not have any transmission assets and that usually operate only the electricity sector. The Australian Energy Market Operator (AEMO) also acts as the gas system operator. System operators have different functions that relate mainly to the operation of the transmission system (dispatching, reliability, planning), to the system operation itself that involves different markets (energy, capacity, ancillary, transmission rights, etc.) and to customer services and accounts (i.e. meter reading, customer records and collection, etc.). The ISOs/RTOs that are part of this study are categorised as not-for-profit organisations. The list of the current functions performed by the ISOs/RTOs that are part of this study is illustrated in Annex 2. Table 1 summarises the main characteristics of the ISO/RTO sample.

Table 1: ISOs/RTOs main characteristics

| Country | ISO/RTO | Year of creation | Type of SO | States (USA, AUS) | Tx. Lines (miles) | Area (sq. miles) | Pop. served (millions inh.) | Elec. Gen. (TWh) |
|-----------|------------|------------------|------------|-------------------|-------------------|------------------|-----------------------------|------------------|
| USA | CAISO | 1998 | ISO | 2 | 26,000 | 132,000 | 30 | 229 |
| | PJM | 1996 | RTO | 13 | 82,546 | 243,417 | 65 | 792 |
| | NYISO | 1999 | ISO | 1 | 11,130 | 47,000 | 19.3 | 161 |
| | ERCOT | 1996 | ISO | 1 | 46,500 | 200,000 | 24 | 352 |
| | MISO | 2001 | RTO | 15 | 65,800 | 900,000 | 48 | 622 |
| | ISO-NE | 1997 | RTO | 6 | 9,000 | 72,000 | 14.7 | 124 |
| | SPP | 2004 | RTO | 14 | 65,755 | 546,000 | 17.5 | 249 |
| Australia | AEMO (WEM) | 2009 | ISO | 1 | 4,847 | 976,000 | 1 | 39 |
| | AEMO (NEM) | 2009 | ISO | 5 | 27,200 | 1,465,000 | 9 | 216 |
| Chile | SIC | 1999 | ISO | | 13,714 | 220,447 | 17.6 | 54 |
| | SING | 1999 | ISO | | 5,892 | 71,485 | 1.1 | 19 |
| Peru | COES | 1994 | ISO | | 16,627 | 124,050 | 28.2 | 48 |

Figures as of Dec. 2016. WEM: Wholesale electricity market, NEM: National Electricity market.

Source: AEMO (website), CAISO (Company Brochure, Oct. 2017), CNE (2016), COES (2017), FERC (Electric Power Markets),

MISO (Corporate Information, Mar. 2017), MISO (2016a), PJM (2016b), SPP (Fast Facts, 2017), WorldBank (Chilean population)

The trend of peak demand (MW) from our sample is depicted in Figure 3. A big difference in peak demand is observed across ISOs/RTOs. Some of them, such as PJM and MISO have increased their peak demand in recent years (partly due to geographic expansion) and a slight increase is also observed in ERCOT and SPP. A few of them show a downward trend, namely CAISO and NYISO. The rest remain nearly the same.

¹⁶ Independent System Operators in the US have their origin based on FERC Orders 888/889 which mandated the existing power pools to provide non-discriminatory access to transmission. Later on, based on FERC Order 2000, the Commission encouraged the creation of Regional Transmission Organisations (on voluntary basis). This Order promoted the administration of the transmission grid on a regional basis throughout North America (including Canada). PJM, ISO-NE, MISO and SPP are the ones that operate at regional level.

Figure 3: Trend of Peak Demand period 2012-2016

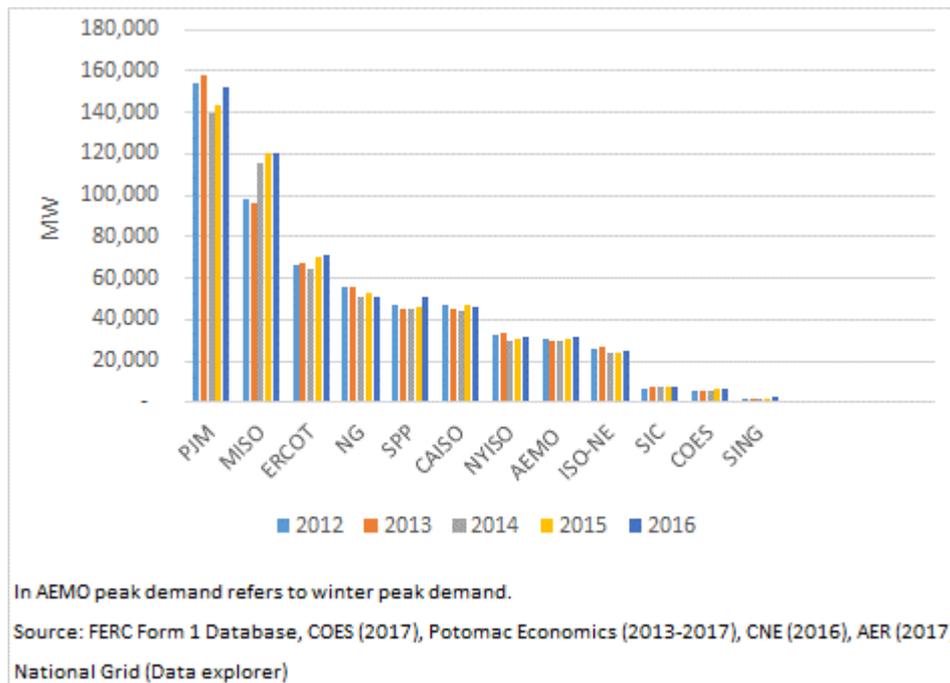
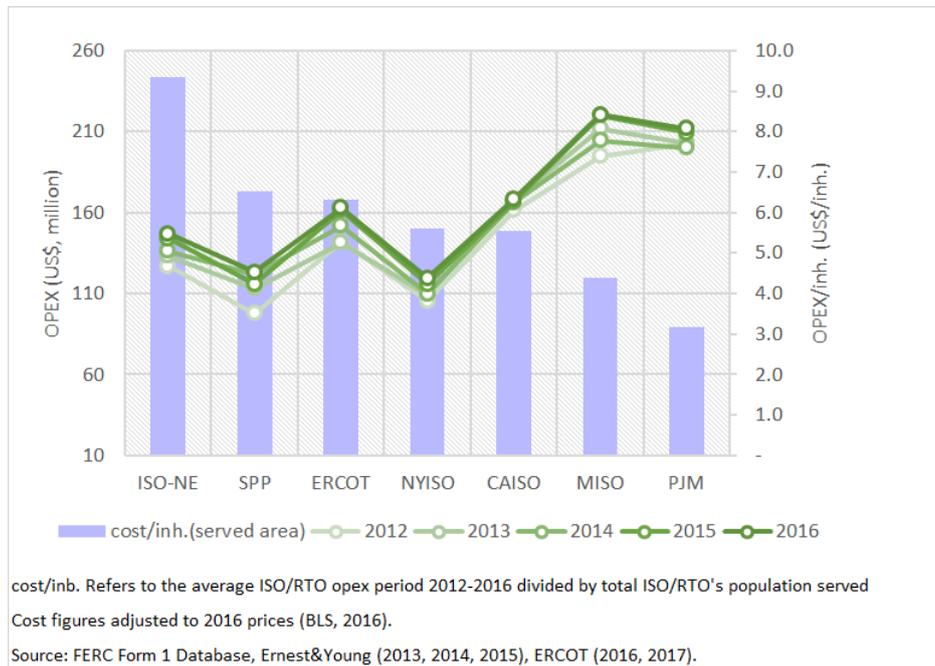


Figure 4 depicts the trend of operational expenses¹⁷ among the ISOs/RTOs from the USA for the period 2012-2016. PJM and MISO are the ones with the highest opex, however they have the lowest ratio of opex per population served (US\$/inh.). This clearly suggests some scale economies.

This group of ISOs / RTOs is interesting because they exist in similar jurisdictions to Great Britain in terms of the structure of the electricity industry (vertically disintegrated / privately owned / market based) and in terms of policy ambition towards decarbonisation and the promotion of renewable electricity. Relative to other system operators which are integrated into other parts of the electricity supply chain, ISOs / RTOs also provide much more transparent information on the way they are governed, the products they offer and their costs.

¹⁷ Operational expenses (opex) acquired from Form 1 (FERC), Electric Operation and Maintenance Expenses (pp. 320-323). Opex figures exclude: Regulatory Commission Fees, Depreciation and Amortisation.

Figure 4: ISO/RTO OPEX and OPEX per inh. period 2012-2016



4. Discussion and comparison of incentives and the role of stakeholder governance across ISOs/RTOs

4.1 The way in which the ISO/RTO is incentivised to maximise system welfare and how this is manifested in its incentives to control both external market costs (i.e. for balancing the system) and internal costs (i.e. system operator).

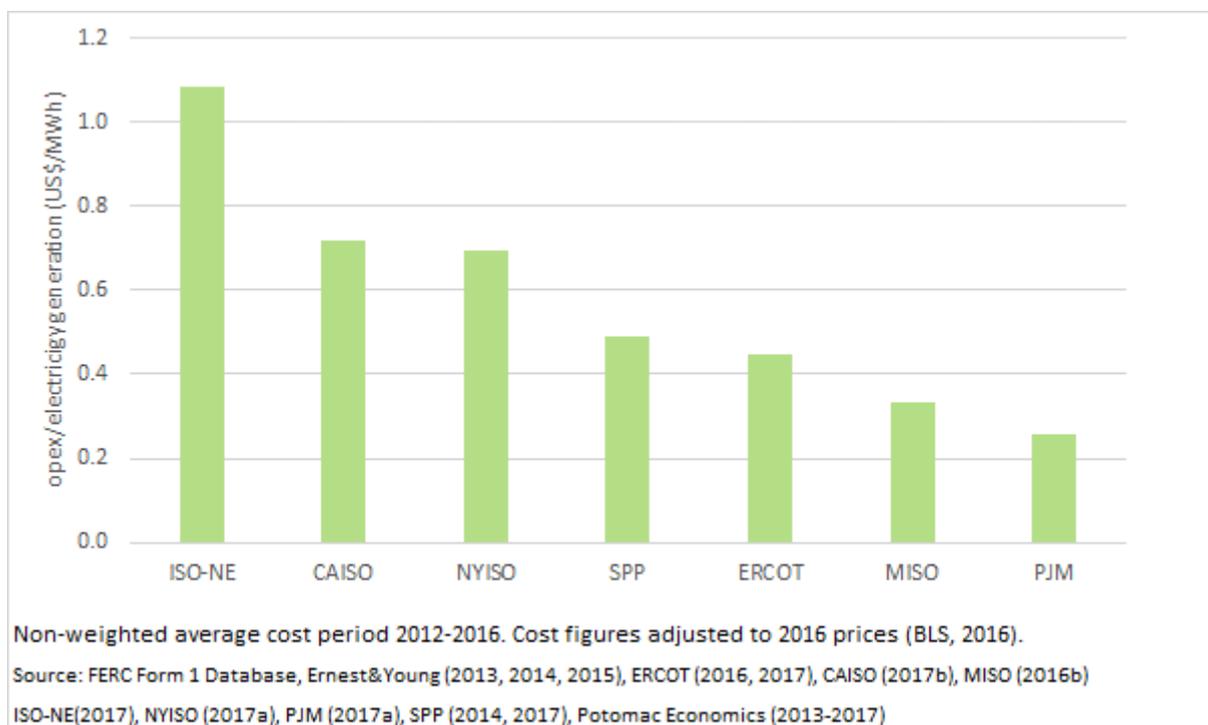
ISOs/RTOs are associated with two different kinds of costs, internal and external costs. Internal costs are related to the expenses incurred by the ISOs/RTOs themselves for operating the system (these largely relate to their own staff costs and system operation capital). On the other hand, we refer to external costs as those incurred by the ISOs/RTOs for balancing the system, managing constraints etc. These costs are incurred in paying third parties to provide services and then recharging the costs to market participants. In the USA, internal and external costs are reflected in the ISO Tariff that is approved by FERC in agreement with its annual budget requirement (see Section 4.3 for further details about the annual budget process to get approval). The process that the ISO/RTO is subject to for the approval of its respective budget (which involves a diversity of stakeholders, from transmission owners to public state authorities) could help to mitigate the risk of underperformance. In addition, and based on FERC Order 888/888-A*¹⁸, the ISOs/RTOs are required to operate the wholesale market and grid based on specific principles. For the regulatory point of view, the ISOs/RTOs are required explicitly to operate efficiently the system too. For instance, COES (the Peruvian system operator) has confirmed that this happens in Peru as well. There are no specific incentives (i.e. monetised incentives) that encourage COES to maximise customer (or total)

¹⁸ <https://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp>

welfare. This has been one of the main concerns expressed by FERC some years ago¹⁹. For this reason FERC established a set of common metrics²⁰ for ISOs/RTOs and for non-RTO/ISO markets in order to track the performance and benefits of these markets²¹. The relevant data collection is made under Information Collection order FERC-922 (Docket No. AD14-15-00). The report includes 30 common metrics related to reliability (day-to-day operations and long term) and system operation (operational efficiency). Additional metrics are also submitted only by ISO/RTOs, such as those related to coordinated wholesale power markets and to organisational effectiveness.

Figure 5 depicts the opex (internal costs) per MWh (electricity generation) for the period 2012-2016. We observe that ISO-NE has the highest opex per MWh (of US ISOs) with a five-year average opex of US\$ 1 / MWh, while PJM is the one with the lowest opex, US\$ 0.26 / MWh.

Figure 5: ISO/RTO OPEX per MWh, 2012-2016 average



These results are in line with those from Figure 4. As we mentioned above, internal costs are only one component of the amount billed by ISOs/RTOs. ISOs/RTOs bill for energy, capacity and other costs, as well as for internal costs. For instance, energy and capacity market costs

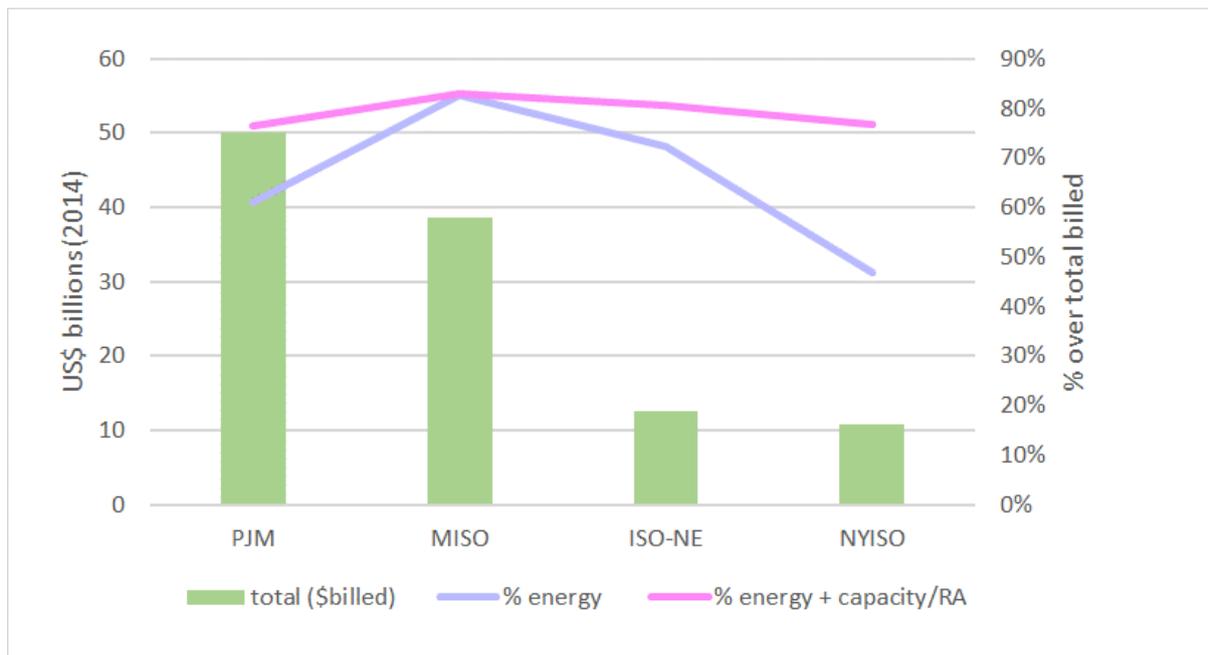
¹⁹ This initiative is based on the 2008 Government Accountability Office (GAO) recommendation. GAO found that there was a lack of standardised measures for tracking the RTO performance which did not help to identify the benefits and their magnitude. <http://www.gao.gov/new.items/d08987.pdf>

²⁰ The FERC RTO/ISO performance metrics reports can be found at: <https://www.ferc.gov/industries/electric/industryact/rto/rto-iso-performance.asp>

²¹ These metrics are purely reputational and do not constitute any financial incentive for the ISOs/RTOs. Even though these metrics compare standardised metrics (operational, reliability, and others) across the ISOs/RTOs. Some ISOs/RTOs have indicated that while these metrics are good for a best practice exercise, relevant factors such as ISO/RTO efficiency and successful market design, cannot easily be measured.

represented around 75% of the total amount billed²² in 2014. Figure 6 depicts the size of annual US\$ billed (internal + external costs) by specific ISOs/RTOs. PJM has the highest annual US\$ billed while MISO has the highest share on energy markets (83%) and NYISO has the highest share on capacity markets (30%) over the total billed.

Figure 6: Total costs (billed) by ISOs/RTOs and share on energy and capacity (2014)



Source: FERC (2017b)

Other markets that are also exposed to competition are ancillary services (i.e. regulation and reserves). In the USA, the majority of these services operate in the Day Ahead Market (DAM) and Real Time Market (RTM) and 5 minute settlement intervals have been applied by some ISOs/RTOs (NYISO, SPP, CAISO, see EPRI (2016))²³. PJM expect to implement 5 minute settlement in Feb. 2018²⁴. Co-optimisation of energy and ancillary services in real time operation is also applied by different ISOs/RTOs²⁵. Effective designs for market-mechanisms (including auction mechanisms) can also help to mitigate the risk of underperformance associated with the operation of the system. Other types of ancillary services such as voltage support (reactive power) and black start are not usually procured in the market due their local dispatch nature. However, due to the proliferation of more distributed generation in general, competition for procuring reactive power could also be possible. In the USA, FERC does not require a standard approach to payment for reactive power. As a consequence, different cost recovery mechanisms have been adopted (e.g. cost-based, part of good quality with no compensation, American Electric Power methodology, see FERC (2014)). Annex 3 shows the list of ancillary services provided in the ISOs/RTOs from the USA and in the UK.

²² Own calculations based on FERC (2017b, pp. 51-52). Average value.

²³ FERC Order 825 mandates all the ISOs/RTOs to align settlement and dispatch intervals.

²⁴ <http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/5-minute-settlements.aspx>

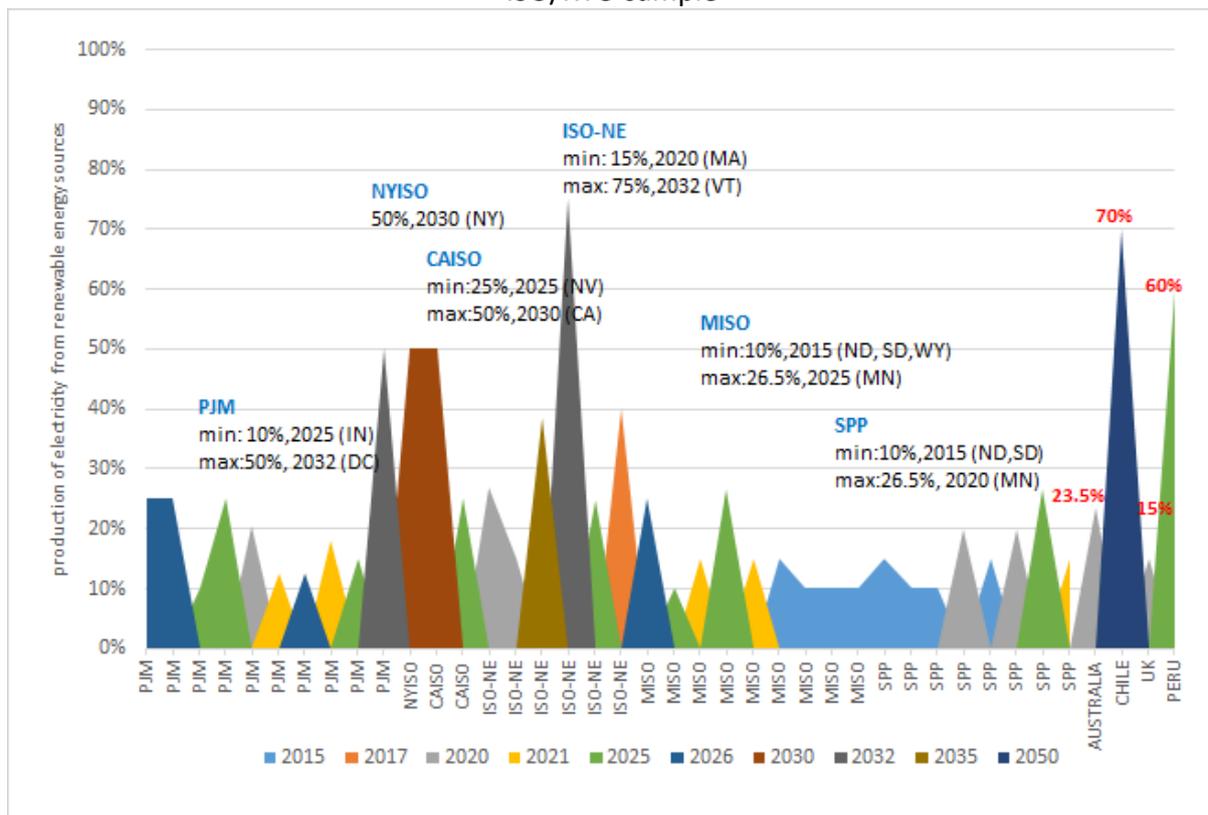
²⁵ The requirement of co-optimisation is based on FERC Order 719.

4.2 The way in which ISO/RTOs are incentivised to deal with increasing amounts of renewables and the entry of new participants and resources (i.e. storage, demand side response) on its network and increased demand for analysis of potential new market designs

One of the main drivers that have influenced the integration and increase of more renewables into the system are the specific incentives that different jurisdictions have designed. In the USA one of the most popular is the Renewable Portfolio Standard (RPS) mechanism.²⁶ In the European context, the Renewable Energy Directive has set an EU renewable target of 20% by 2020. National member states of the EU have been given specific targets for meeting their 2020 renewable obligations²⁷.

Figure 7 illustrates the different RPS and renewable targets that have been set in relation to the ISOs/RTOs that are part of this study. Figure 7 shows different groups of ISOs/RTOs. Every group is composed of the number of states the ISOs/RTOs served. Annex 4 lists the ISOs/RTOs and the states where they operate along with their respective RPS²⁸. In the USA context, NYISO and CAISO are the ones with the highest renewables targets by 2030: 50% in both cases.

Figure 7: State level Renewable Portfolio Standard (RPS) and renewable targets in the ISO/RTO sample



Source: DSIRE (U.S. Department of Energy), ISOs/RTOs websites. Adapted.

²⁶ <https://energy.gov/savings/renewable-energy-portfolio-standard>

²⁷ <https://ec.europa.eu/energy/en/topics/renewable-energy>

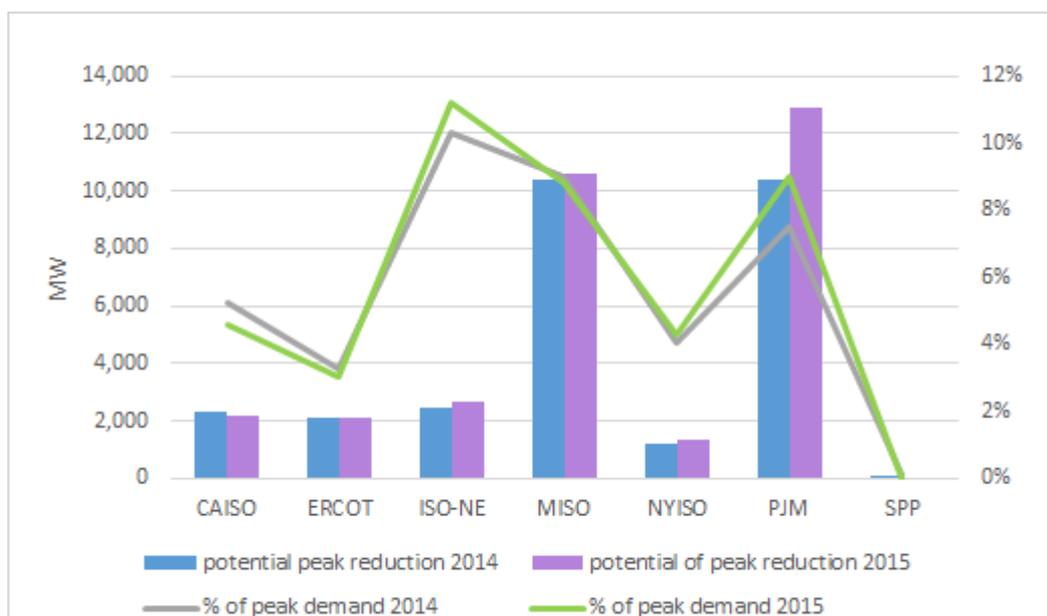
²⁸ Not all the states have implemented RPS. Figure 7 shows only those states with mandatory or voluntary RPS.

Other initiatives can be observed that are related to the participation of non-conventional technologies or resources in the wholesale market such as Distributed Energy Resources (DERs) which include distribution level demand response and energy storage. FERC has been working on more appropriate cost recovery mechanisms. Based on these initiatives, electric storage resources have the ability to recover their costs for certain services through cost-based rates (i.e. transmission/grid support) and market-based rates for providing separate market-based services (FERC, 2017a).

At the state level there are also some good initiatives related to energy storage and DERs, from ISOs such as CAISO under the stakeholder initiative supported by this ISO (e.g. ESDER, phase 1 and 2). As a result of ESDER phase 1, FERC proposed CAISO two enhanced amendments: (1) to allow energy storage resources (classified as Non-Generator Resources) to reflect their state of charge and energy limits as part of the their bids; and (2) to implement the metering generator output methodology (developed by the North American Energy Standards Board-NAESB) to acquire accurate meter data on demand response performance (CAISO, 2016a). In ESDER phase 2, CAISO is working on three topics: (1) three new types of demand response performance evaluation methods that reflect the performance of different types and configurations of demand response; (2) the distinction between wholesale charging energy and power; and (3) the use of an additional gas index in the estimation of demand response net benefits test (CAISO, 2017c).

Figure 8 shows the contribution of demand response programs in potential peak reduction for 2014 and 2015 in the seven ISO/RTOs from the USA. ISO-NE is the one with the largest share of demand response in potential peak reduction (over 10%). New York is amongst the ones with the lowest share.

Figure 8: Potential peak reduction from ISOs/RTOs Demand Response Programs



Source: FERC (2016, p.17), FERC Form 1 Database (years 2014, 2015; p. 400a), Potomac Economics (2015, 2016)

4.3 The way in which the ISO/RTO manages the best overall actions for its customers in a dynamic setting where trade-offs need to be made between current and future costs.

We observe that the stakeholder community in the ISOs/RTOs is very involved in the proposal of new initiatives. However initiatives can also come from the ISO/RTO staff. Some of the initiatives may affect the ISO/RTO budget (internal or administrative costs). If this is the case and if the initiative (i.e. project) gets the respective approval (based on the methodology determined by the stakeholder governance, see next section for further details), the cost of this should be reflected in the ISO/RTO annual budget. For instance, in California one of the criteria (Feasibility) established by CAISO (that allows it to rank the proposed initiative) is related to the impact of its implementation (\$ and resources) on the market participants and the ISO. If the initiative does not have any impact this gets the maximum score (10) but if the impact is significant the score is zero (CAISO, 2017a, p.3).

In order to fund the services the ISOs/RTOs provide, they need to collect fees from participants in the wholesale markets that operate in their jurisdiction and from those that use the regional transmission services (RTOs only). In the USA, the ISO tariff is composed of a different set of tariffs/charges approved by FERC. This tariff relates to external and internal costs. For instance in the case of CAISO, the administrative or internal costs incurred by CAISO as a SO, are funded by the Grid Management Charges (GMC), set in the CAISO Tariff. GMC is linked to the annual CAISO budget which covers their internal costs. CAISO recovers its internal costs through three volumetric charges and five transaction fees. There are specific percentages of the total revenue requirement allocated to each volumetric charge: market services (27%), system operation (70%) and Congestion Revenue Rights – CRR services (3%)²⁹ (CAISO, 2016b). Any under or overspend is reflected in the budget in line with the percentage allocated to market services, system operation and CRR services. Finally, an annual revenue cap is applied. This cap has been set at US\$ 202 million for CAISO. This cap was determined by CAISO and its stakeholders and approved by FERC. There is not any other cap related to other costs (i.e. external costs).

The ISOs/RTOs funding and budget process may differ. For instance, ISO-NE's process involves five steps. In the **first one** the *Business Plan* is created by the Board of Directors and senior managers. In the **second one** the *operating budget* and *capital budget* are created. The capital budget covers projects that add or improve services to the stakeholders, IT software, or any other activity that is beyond the typical day to day services. Then the service rate is calculated and also the way this is allocated among the RTO's customers. In the **third step** the stakeholder review process takes place which involves presentations, symposia, consultations etc. In the **fourth one**, the ISO Board and FERC make their own review of the proposal, in parallel with the external stakeholders review (from previous step). The Board votes after receiving the respective feedback (internal from specific Committees and external from state agencies and the local power exchange, NEPOOL). Then the Board votes on whether to approve the budget; if approved it is filed with FERC. Then FERC evaluates the proposal and if the budget is fine for them, the proposed service rates become part of the ISO-NE tariff (ISO

²⁹ According to CAISO a cost of service study is performed every three years. Activity base costing is used to allocate costs to each charge. The result of this study sets the percentages which are used for the next three years.

Tariff). The **last step** corresponds to the implementation and ongoing budget review process. It is important to note that if the ISO/RTO collects more than is needed, the market participants get a refund. If the ISO/RTO collects less than needed to serve its respective jurisdiction, this is added to the future operating expenses³⁰.

NYISO uses a similar process that involves 5 steps (Identification, Prioritisation, Evaluation, Recommendation, Review and Approval). It is in the second one where NYISO and stakeholders score the projects using specific criteria. A survey mechanism is used in order to capture the stakeholder's valuation of the projects.³¹

The ISO Tariff differs among ISOs/RTOs. For instance, ISO-NE charges a residential electricity consumer around US\$1.2 per month (based on 750 kwh month usage)³². On the other hand, NYISO charges less than 50 cents (with an average residential monthly utility bill of US\$113)³³ for the services and benefits the ISO provides in order to keep the power flowing.

An interesting case of a stakeholder initiative associated with future costs (and benefits) for the grid users is observed in Australia. This initiative involves an important change not only in the way in which AEMO operates (in terms of impact in \$ and resources) but also affects different participants of the electricity market. The initiative was raised by Sun Metals Corporation Pty Ltd (Sun Metals) in December 2015. The firm proposed to have 5 minutes settlement period pricing instead of 30 minute average settlement pricing. According to the Australian Energy Market Commission (AEMC, 2017, pp. 14-15), this option would provide the following benefits:

- a. Improved price signals for more efficient generation and use of electricity,
- b. Improved price signals for more efficient investments in capacity and demand response technologies to balance supply and demand,
- c. Improved bidding incentives.

In terms of the implementation costs of 5 minute settlement, AEMC concluded that the present value over 15 years of implementation would exceed AUS\$250 million (£145 million)³⁴. Table 2 shows the cost breakdown.

Table 2: Cost Breakdown (AUS\$ million) for the implementation of five minute settlement in Australia³⁵

³⁰ <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

³¹ http://www.nyiso.com/public/markets_operations/services/financial_services/budget/index.jsp

³² <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

³³ <https://home.nyiso.com/frequently-asked-questions/>

³⁴ The cost evaluation was made by Russ Skelton & Associates (2017), who were commissioned by AEMC. The estimated costs do not include the cost of metering changes.

³⁵ According to AEMC, the cost of implementing the 5 minute settlement represents mainly one-off costs which is relatively small compared with the ongoing annual NEM transactions (AUS\$ 16.6 billion in 2016/17) and with an expected medium term generation investment of up to AUS\$ 90 billion. The AEMC suggests that the benefits of this implementation would outweigh the costs. According to them a reduction of AUS\$ 0.50/MWh in average wholesale price would represent savings of around AUS\$100 million per year in energy costs which is translated in lower retail prices to consumers (AEMC 2017, p. vi).

| Contracts | Standard | Be-spoke | Large | <i>Sub total</i> |
|---|-------------------|---------------------|-----------------|------------------|
| Number | 97 | 54 | 15 | |
| Cost per negotiation | 0.005 | 0.050 | 0.300 | |
| Cost of collective negotiation with AFMA | 0.600 | | | |
| <i>sub total</i> | 1.085 | 2.700 | 4.500 | 8.29 |
| Change to business systems | Wholesale trading | Retail | Risk management | |
| <i>sub total</i> | 54 | 73 | 23 | 150.00 |
| other annual costs (increase ongoing costs of operating business systems) | 7 | (15 years, 5% rate) | | 72.66 |
| AEMO costs | | | | |
| <i>sub total</i> | | 10 | | 10.00 |

Source: Russ Skelton & Associates (2017, p.22,23). Cost figures in millions AU\$. AFMA: Australian Financial Markets Association.

AEMC suggested a transition period of three years and seven months for its implementation (with a proposed start day of Thursday, 1 July 2021). This date would provide participants and the AEMO enough time to manage the implementation issues (i.e. large IT system changes). AEMC has released its final Rule on 27 November supporting the implementation of the 5 minute settlement period for all wholesale market participants³⁶.

4.4 The way in which an ISO/RTO builds trust with its stakeholder community via appropriate levels of engagement and transparency of decision making and information

In the USA, stakeholders³⁷ play a key role in planning, operation and the proposal of new initiatives that allow a more efficient operation of the system. Depending on the type of stakeholder, these can be grouped in different categories such as transmission owners, generation owners, suppliers, end user consumers, public power and environmental parties. Members of the stakeholder community select their preferred sector in the application process. At the same time, depending on the type of ISO/RTO, they can be part of specific committees that, along with the ISO/RTO Board of Directors, constitute the base for stakeholder governance. James et al. (2017) identify three types of stakeholder governance: advisory-only, shared-governance, and governor-appointed boards³⁸. MISO, ISO-NE and SPP are placed in the first category, NYISO and PJM in the second one and CAISO in the third category. Annex 5 describes the different types of stakeholder governance and additional relevant information about the FERC Section 205 filing and voting system. The current stakeholder governance in the USA allows stakeholders to have a voice in different processes which determine tariffs, the ISO/RTO's annual budget, market design etc. A specific percentage of votes is required to approve a proposal. Not all the members have the right to vote, there are non-voting entities too. In NYISO around 30% (52) of the members do not vote (NYISO, 2017b). In ISO-NE only 57% (277) of the members can vote (NEPOOL, 2017). In many cases a weighted voting system is applied. Different weights are allocated depending on the type of sector. The number of sectors (and affiliations) also differs across the ISOs/RTOs. For

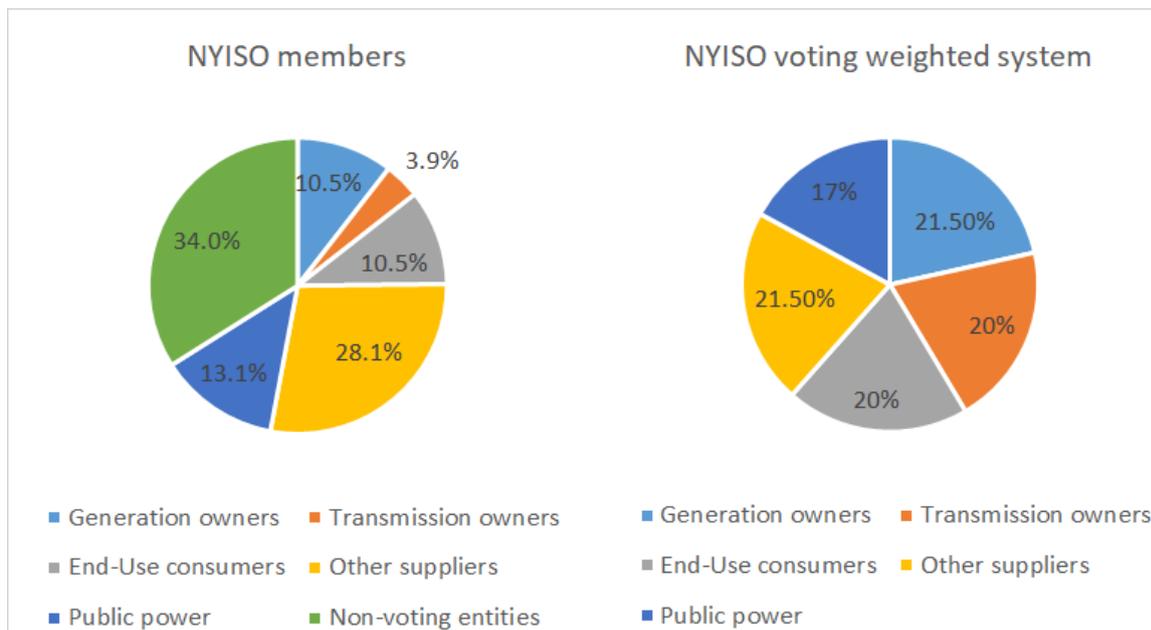
³⁶ The final decision can be found at: <http://www.aemc.gov.au/getattachment/97d09813-a07c-49c3-9c55-288baf8936af/Final-determination.aspx>

³⁷ The term stakeholder involves members and non-members of the ISO/RTO. For instance according to the PJM Stakeholder Process Manual the term involves PJM members, Organisation of PJM States (OPSI) and its members, state consumer advocates who are not PJM members, the Independent Market Monitor, PJM staff and PJM's Board (PJM, 2016a, p. 16).

³⁸ In shared-governance systems such as in NYISO, the board of directors need the approval of the stakeholders (via a Management Committee) before submitting any filing to FERC (Section 205 filing). The right to make or not a section 205 filing depends on the type of governance process.

instance in New York stakeholders are organised in five sectors (two of them with specific subsectors) with their respective weights in the voting system. In MISO the number of sectors is ten³⁹ and it is observed that weights are also more dispersed among sectors (MISO, 2017)⁴⁰. Some System Operators, such as PJM, have implemented an online voting system that facilitates voting at the Markets and Reliability Committee and Members Committee meetings. The participant needs an account with voting read/write access and must be designated as a voter for that committee⁴¹. WebEx is also an online tool used by PJM for committee meetings and training courses⁴². Figure 9 depicts the type of sectors and weighted system used in NYISO.

Figure 9: Type of members and system voting in NYISO



Source: NYISO (2017b). Adapted.

CAISO has a less complex approach in terms of stakeholder governance. There is no formal voting process or ranking structure among stakeholders (Nelson, 2016). However this is only partially true in reality. According to CAISO (2017a), CAISO works with its stakeholders to rank discretionary initiatives that have a strong potential to be included in the Policy Initiatives Roadmap. A simplified ranking process is applied for this purpose by the identification of benefits (3 criteria) and feasibility (2 criteria)⁴³. The score allocated to each criterion varies between 0 and 10, then the maximum score that an initiative can get is 50 points (CAISO,

³⁹ The sectors are: independent power producers, transmission owners, TDU (municipals, cooperatives, transmission dependent utilities), power marketers, public consumer advocates, state regulatory authorities, environmental/other stakeholder groups, eligible end-use customers, coordinating members, and transmission developers.

⁴⁰ In MISO, transmission owners have a weight of 12% in the voting system while in New York the weight is 20%.

⁴¹ <http://www.pjm.com/markets-and-operations/etools/committee-voting.aspx>

⁴² <http://www.pjm.com/committees-and-groups/webex.aspx>

⁴³ Among the benefit criteria are: (1) Grid Reliability, (2) Improving Overall Market Efficiency and (3) Desired by Stakeholders. The criteria for Feasibility are: (1) Market Participant Implementation Impact (\$ and resources) and (2) ISO Implementation Impact (\$ and resources). There are four scales: High (10 points), Medium (7 points), Low (3 points) and None (0 points).

2017a, p.3).⁴⁴ However this mechanism is currently being evaluated by CAISO due to some concerns raised by stakeholders⁴⁵. Figure 10 illustrates an example of the Stakeholder Initiative Process in CAISO.

Figure 10: Stakeholder Initiative Process in CAISO



Source: CAISO⁴⁶

A good flow of information is observed from all the ISOs/RTOs from the USA. Apart from the conventional annual reports (including annual reviews and technical material), the ISOs/RTOs upload to their respective websites *State of Market Reports* produced by external partners and/or internally (e.g. their Market Monitoring Unit). The aim of these reports is to evaluate market performance (outputs, competitiveness of the wholesale electricity markets) and to provide recommendations for improving the market design. These reports are published periodically (quarterly, annually). Some ISOs/RTOs publish both external and internal State of Market Reports (NYISO, ISO-NE), others only internal (CAISO, SPP) and others only external (PJM, MISO, ERCOT)⁴⁷. In Australia, the effectiveness of the market is monitored by the Economic Regulatory Authority (ERA).

Finally, RTOs/ISOs in the USA provide training courses and materials to their market participants in order to update them on new products, processes, and operational aspects. Courses offered by PJM can be delivered online, either in person or virtually⁴⁸. Courses are free of charge for PJM members and Governmental entities. There is a fee for non-members, except for online courses that are free of charge. MISO provides training for market participant and operators. A set of online pre-reading material is also available at three different levels (100, 200 and 300 Level)⁴⁹. Both RTOs offer specific courses that are accredited by the North American Electric Reliability Corporation. CAISO offers courses free of charge and paid courses categorised as follows: market initiatives, markets, settlements and ISO systems⁵⁰.

⁴⁴ There are four scales: High (10 points), Medium (7 points), Low (3 points) and None (0 points).

⁴⁵ According to the stakeholders the practice of ranking the discretionary initiatives has been time-consuming, subjective and ineffective. For further details see:

https://www.caiso.com/Documents/DraftFinalProposal_AnnualPolicyInitiativesRoadmapProcess.pdf

⁴⁶ <http://www.caiso.com/informed/Pages/StakeholderProcesses/Default.aspx>

⁴⁷ Potomac Economics is the External Market Monitor for ERCOT, ISO-NE, MISO and NYISO. Monitoring Analysis is the Independent Market Monitor for PJM.

⁴⁸ The course catalog can be found at: <http://www.pjm.com/training/course-catalog.aspx>

⁴⁹ <https://www.misoenergy.org/Training/MarketParticipantTraining/Pages/MarketParticipantTraining.aspx>

⁵⁰ <http://www.caiso.com/participate/Pages/Training/default.aspx>

5. Discussion and Lessons for GB

Regulation of the SO is not primarily about assessing the efficient amount of revenue the SO requires but about the efficiency of its ancillary service procurement process, its system optimisation (to set procurement levels) and its stakeholder governance process.

GB is currently in the process of creating a much more independent SO business within National Grid. This immediately suggests that close attention to the experience of ISOs is required and that we seem likely to move away from the presumption that the SO can be incentivised in ways that are more appropriate for distribution and transmission asset based utilities. More flexible and transparent regulation processes are likely to be more suitable to the emerging role of the SO. Strong profit incentives relative to the actual asset base of the SO will be less acceptable/relevant. This is already the case for ELEXON, which manages the balancing market and settlement system at arms-length within National Grid, on an economic cost recovery basis. Hence, we have reviewed the evidence under four headings and here we summarise some of the lessons for GB.

5.1 Maximisation of Social Welfare

The aim of this paper was to conduct an international review of how independent system operators were regulated in order to ensure that they are maximising social welfare. This is an important question because system operators impose both internal and external costs, as well as indirectly influencing the efficiency of whole system energy markets and network costs. It is not simply a question of monitoring their internal costs. For a typical ISO in the US the ISO internal cost is around 50 cents per MWh and hence very small in relation to the total customer bill.

Conventional UK network regulation based on comparing costs across groups of similar entities seems particularly ill suited to properly assessing ISO performance. This is because ISOs are inherently difficult to compare between jurisdictions: there are significant scale and scope effects; many of the external costs are energy price related; and the demands on ISOs are location specific and changing. ISOs are themselves regulatory bodies responsible for real time system operation and for taking a view about the future development of the system and hence must be sufficiently resourced. They must be subject to regulatory oversight but they also have to provide appropriate levels of voice, accountability and training to their stakeholder community which may be expensive in themselves.

5.2 Coping increasing amounts of renewables and new market participants

ISOs around the world are responding to the same sorts of renewable targets and technological possibilities that are appearing on the GB system. They provide good examples of initiatives to widen market participation and procure new services.

ISOs/RTOs in the US tend to be subject to annual budget approval processes for internal costs. This would seem to have advantages in terms of flexibility to respond to new demands on the system in contrast to longer term RIIO-type incentives in GB. Price control periods in GB were designed for capital intensive sectors, not for responsive system operators, facing uncertain

demands. Reducing the ex-ante nature of internal cost regulation and moving to shorter term, possibly even ex post budgetary approval would seem to merit consideration.

By contrast, US ISOs/RTOs, have relatively little oversight of their external costs, and leave these to be monitored by wider stakeholders rather than the regulator. This may be a weakness of US regulation, but given the lack of stability in the regulation of external costs in GB, moving the monitoring of external costs to wider stakeholders might also have some merits against the current mechanism.

5.3 Managing the best overall actions for present and future customers

We have documented the ways in which ISOs/RTOs are subject to regulatory oversight and how proposed changes to their activities need to be approved, both via ISOs' own stakeholder management process and by the regulatory authority responsible for overseeing them (e.g. FERC in the US). They are usually explicitly required to operate the system efficiently.

In the face of long-term trends in renewable penetration, some jurisdictions such as Australia and PJM have responded with proposals for radical market redesign of price resolution in order to sharpen signals in the energy market. It is important that the GB SO is incentivised to the benefit of present and future consumers and this may involve a combination of radical market redesign to reduce external and overall system costs, as well as incremental changes.

5.4 Stakeholder Role, Governance Models and Transparency

Stakeholders play a key role in the proposal of and design of detailed implementation rules for new initiatives for the best ISOs. Complex voting rules are observed which attempt to balance out competing interests. These rules are worthy of study for the lessons they might have for GB. It is important to stress that these rules may be complex but they may give rise to good processes for representing stakeholder interests in a way that both takes them seriously but also prevents them being over-weighted. Participation incentives are important, as well as participation costs. There are some examples of good practice in training of stakeholders, encouragement to participate and the use of remote electronic voting.

High levels of internal and external oversight of ISO decision making are associated with impressive amounts of publicly available information on ISO performance. Decisions around the SO are becoming more complex and subject to high levels of uncertainty. This suggests that high levels of monitoring and attention to the capacity to learn quickly from new information would seem to be important as we move towards a system with high shares of intermittent distributed renewables. State of the Market Reports provide excellent examples of regular updates on key recommendations for future market design.

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Annex 1: About the Survey

Invited Participants:

| Country | Name of ISO/RTO |
|-----------|--|
| USA | California Independent System Operator (CAISO) |
| | PJM Interconnection |
| | New York Independent System Operator (NYISO) |
| | Electric Reliability Council of Texas (ERCOT) |
| | Midcontinent Independent System Operator (MISO) |
| | ISO New England (ISO-NE) |
| | Southern Power Pool (SPP) |
| Australia | Australian Energy Market Operator (AEMO) |
| Chile (*) | Central Interconnected System (SIC) |
| | Northern Interconnected System (SING) |
| Peru | National Interconnected System Operation Committee (COES) |

(*): SIC and SING have recently joint in October 2017 to create the single Interconnected System (Coordinador Electrico Nacional)

Questionnaire:

1. How **XXXX** is incentivised to maximise system welfare and how this is manifested in its incentives to control both external market costs (i.e. for balancing the system) and internal costs (i.e. system operator own costs)?
2. How **XXXX** is incentivised to adapt to increasing amounts of renewables on its network and increased demand for analysis of potential new market designs?
3. How **XXXX** can manage the best overall actions for its customers in a dynamic setting where trade-offs need to be made between current and future costs?
We want to know about the process to get regulatory approval in specific situations (i.e. anticipatory work, introduction of new markets, specific trials, among others).
4. How **XXXX** builds trust with its stakeholder community via appropriate levels of engagement and transparency of decision making and information?
Please provide a good example of successful stakeholder engagement process.

Annex 2: ISO/RTOs Main Functions

| ISO/RTO | USA | | | | | | | AUSTRALIA | GB | CHILE | PERU | |
|--|-------|-------|--------|------|-------|-----|-----|-----------|------------------|----------|------|---|
| | CAISO | ERCOT | ISO-NE | MISO | NYISO | PJM | SPP | AEMO | NATIONAL GRID | CEN | COES | |
| FUNCTION | | | | | | | | | | | | |
| A. SYSTEM OPERATION | | | | | | | | | | | | |
| Load Dispatching - Scheduling, System | | | | | | | | | | | | |
| 1 Control, Monitor and Dispatch | Y | Y | Y | Y | Y | Y | Y | Y | Y | Y | Y | Y |
| Reliability, Planning and Standards | | | | | | | | | | | | |
| 2 Development | Y | Y | Y | Y | Y | Y | Y | Y | Y | Y | Y | Y |
| 3 Transmission Service Studies | N | N | Y | Y | Y | Y | Y | Y | Y | Y | Y | Y |
| 4 Generation Interconnection Studies | Y | Y | Y | Y | Y | Y | Y | Y | Y | Y | N | Y |
| B. MARKET OPERATION | | | | | | | | | | | | |
| Day-ahead and Real-time Market | | | | | | | | | | | | |
| 5 Facilitation | Y | Y | Y | Y | Y | Y | Y | Y | Y | Y | N | N |
| 6 Transmission Rights Market Facilitation (*) | Y | Y | Y | Y | Y | Y | Y | P | N | N | N | N |
| 7 Capacity Market Facilitation (**) | N | N | Y | Y | Y | Y | N | Y | Y | N | N | N |
| 8 Ancillary Services Market Facilitation | Y | Y | Y | Y | Y | Y | Y | Y | Y | Y (2018) | N | N |
| Market Monitoring and Administer | | | | | | | | | | | | |
| 9 Compliance with Market Rules (***) | Y | Y | Y | Y | Y | Y | Y | P | N | Y (2020) | Y | Y |
| C. CUSTOMER ACCOUNTS AND SERVICES | | | | | | | | | | | | |
| Meter Reading, Customer Records and | | | | | | | | | | | | |
| 10 Collection | P | Y | P | N | N | N | P | Y | Y | P | N | N |
| Informational and Instructional Advertising | | | | | | | | | | | | |
| 11 to encourage safe use of electric equipment | N | N | N | Y | N | N | N | N | N | N | N | N |

(*) Transmission Rights can take different names (i.e. Transmission Congestion Rights - SPP, Congestion Revenue Rights - CAISO, ERCOT, Transmission Congestion Contracts - NYISO).

(**) Capacity market facilitation refers to centralised capacity markets in the USA, with mandatory auctions (ISO-NE, NYISO, PJM) and voluntary auctions (MISO).

(***) In some cases the market monitoring functions are also made by third parties on behalf of the ISO/RTO.

Source: FERC FORM 1 (2016), ISOs/RTOs' websites, personal communication (AEMO, CEN). Y:Yes, N:No, P:partial.

Annex 3: Comparison of Ancillary Services between USA and GB

| | Type of ancillary service and names | USA | | | | | | GB |
|---|---|-------|--------|-------|---------|-------|-----------------|-------------------|
| | | CAISO | ISO-NE | MISO | PJM (*) | SPP | NYISO | ERCOT |
| Regulation/Frequency Response | Regulation | | RT | DA,RT | RT | | DA,RT | |
| | Regulation Service | | | | | | | DA |
| | Regulation Up | DA,RT | | | | DA,RT | | |
| | Regulation Down | DA,RT | | | | DA,RT | | |
| | 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 | | | | | | | |
| | Dynamic FFR | | | | | | | monthly tenders |
| Static FFR | | | | | | | monthly tenders | |
| Reserves | Spinning reserve | DA,RT | | DA,RT | | DA,RT | DA,RT | |
| | Ten-minute synchronised reserve | | | | | | | |
| | 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 | | | | | |
| | Thirty-minute operating reserve | | RT, F | | | | | |
| | Non-synchronised reserve | | | | RT | | | |
| | Supplemental reserve | | | DA,RT | | DA,RT | | |
| | Ramp reserves (***) | | | 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 | | | | | | | semestral tenders |
| | Black start | | | | | NA | | |

market-based mechanisms (tenders) Markets: DA: Day Ahead, RT: Real Time, FM: Forward, NA: No available
 other (cost-based, lost opportunity cost, revenue-based, mandatory)

(*) PJM uses a day-ahead scheduling reserve in addition to the RT one, (**): Simplified list of AS, updated list (Dec. 2017) based on information provided by NG, (**): Ramp product in MISO since 2016.

Source: CAISO (2017b), ISO-NE (2017), MISO (2016a), PJM (2017b), SPP (2017), Potomac Economics (2017), EPRI (2016), National Grid web site.

Annex 4: Renewable Targets in the USA (RPS, voluntary renewables goals) and non-USA (mandated renewable targets)

| COUNTRY | ISO/RTO | States | 2015 | 2017 | 2020 | 2021 | 2025 | 2026 | 2030 | 2032 | 2035 | 2050 | |
|-----------|----------|---------|---------|------------|--------|--------|--------|--------|--------|------|------|--------|--|
| USA | PJM | DE | | | | | | 25% | | | | | |
| | | IL | | | | | | 25% | | | | | |
| | | IN (*) | | | | | 10% | | | | | | |
| | | KY (**) | | | | | | | | | | | |
| | | MI | | | | 15% | | | | | | | |
| | | MD | | | | | | 25% | | | | | |
| | | NJ | | | 20.38% | | | | | | | | |
| | | NC | | | | 12.50% | | | | | | | |
| | | OH | | | | | | | 12.50% | | | | |
| | | PA | | | | | 18% | | | | | | |
| | | TN (**) | | | | | | | | | | | |
| | | VA (*) | | | | | | 15% | | | | | |
| | | DC | | | | | | | | | | 50% | |
| | NYISO | NY | | | | | | | | 50% | | | |
| | CAISO | CA | | | | | | | | 50% | | | |
| | | NV | | | | | | 25% | | | | | |
| | ERCOT | TX | 5880 MW | | | | | | | | | | |
| | ISO-NE | CT | | | | 27% | | | | | | | |
| | | MA | | | | 15% | | | | | | | |
| | | RI | | | | | | | | | | 38.50% | |
| | | VT | | | | | | | | | 75% | | |
| | | NH | | | | | | 24.80% | | | | | |
| | | ME | | | 40% | | | | | | | | |
| | MISO | AR (**) | | | | | | | | | | | |
| | | IA | 105MW | | | | | | | | | | |
| | | IL | | | | | | | 25% | | | | |
| | | IN | | | | | | 10% | | | | | |
| | | KY (**) | | | | | | | | | | | |
| | | LA (**) | | | | | | | | | | | |
| | | MI | | | | 15% | | | | | | | |
| | | MN | | | | | | 26.50% | | | | | |
| | | MO | | | | 15% | | | | | | | |
| | | MS (**) | | | | | | | | | | | |
| MT | | 15% | | | | | | | | | | | |
| ND (*) | | 10% | | | | | | | | | | | |
| SD (*) | | 10% | | | | | | | | | | | |
| TX | | 5880 MW | | | | | | | | | | | |
| WI | 10% | | | | | | | | | | | | |
| SPP | MT | 15% | | | | | | | | | | | |
| | ND (*) | 10% | | | | | | | | | | | |
| | SD (*) | 10% | | | | | | | | | | | |
| | WY (**) | | | | | | | | | | | | |
| | NE (**) | | | | | | | | | | | | |
| | IA (**) | 105MW | | | | | | | | | | | |
| | KS (*) | | | | 20% | | | | | | | | |
| | OK (*) | 15% | | | | | | | | | | | |
| | TX | 5880 MW | | | | | | | | | | | |
| | NM | | | | 20% | | | | | | | | |
| | MN | | | | | | 26.50% | | | | | | |
| | AR (**) | | | | | | | | | | | | |
| MO | | | | | 15% | | | | | | | | |
| LA (**) | | | | | | | | | | | | | |
| AUSTRALIA | AEMO | | | 33,000 GWh | | | | | | | | | |
| CHILE | SIC/SING | | | | | | 20% | | | | 70% | | |
| PERU | COES | | | | | | 60% | | | | | | |
| UK | NG | | | 15% | | | | | | | | | |

(*) Renewable portfolio goal, (**) without RPS or Renewable portfolio goal

Source: DSIRE (U.S. Department of Energy), ISOs/RTOs websites.

Annex 5: Characteristics of the Stakeholder Governance in ISOs/RTOs

| ISO/RTO | Type of Stakeholder - Governance | | | Market Monitoring | | Board of Directors | # members | | | Filling rights (Section 205) (only in the USA) | Relevant parties or committees or initiatives | Voting (% for approval) |
|---------|----------------------------------|----|-----|-------------------|------------------|--------------------|-----------|-----|-------|--|--|--|
| | AD | SG | GAB | Internal Reports | External Reports | | TO | NTO | total | | | |
| CAISO | | | X | X | | 5 | | | 150+ | CAISO Board (Tariff) | Stakeholder initiative process, Board of Governors | By majority (Governors) |
| PJM | | X | | | X | 10 | | | 990+ | PJM rights over Tariff and Reliability Assurance Agreement. Members Committee rights over Operating Agreement. | 5 Committees (Members, markets and reliability, market implementation, operating and planning) | 66% (members, markets and reliability) |
| NYISO | | X | | X | X | 10 | 6 | 147 | 153 | NYISO Board of Directors, no rights over governing documents | 3 Committees (management, operating, business issues) | 58% |
| ERCOT | | | | | X | 16 | | | 162 | NA | 4 Committees (Finance and Audit, HR and Governance, Nominating, Technical Advisory) | NA |
| MISO | X | | | | X | 10 | 48 | 127 | 175 | MISO (rights over governing documents) | OMS, Advisory Committee | 66% |
| ISO-NE | X | | | X | X | 10 | 35 | 447 | 482 | ISO-NE (rights over governing documents) | Committee participants (NEPOOL) | 60% |
| SPP | X | | | X | | 10 | 10 | 85 | 95 | SPP (rights over Tariff) | Organisational groups, Markets and Operations Policy Committee (MOPC) | 66% |
| AEMO | X | | | | | 11 | | | 110 | | | |
| CEN | X | | | | | 5 | | | 377 | | | |
| COES | X | | | | | 5 | 15 | 117 | 132 | | Asamblea (composed of four sub committees: generators, transmission, distribution and large users) | |

AD: Advisory-only, SG: Shared-governance, GAB: Governor-appointed boards, TO: transmission owners, NTO: non-transmission owners, NA: no applicable.

Source: MISO (Corporate Information, Mar. 2017), CAISO (Company Brochure, Oct. 2017), SPP (Fast Facts, 2017), James et al. (2017), COES (2017), NYISO (2017b), NYISO (FAQ's), PJM (2016a), SPP (2010), SPP(2017), Potomac Economics (website)