COMMENTS ON THE REACTIVE POWER PRICING POLICY IN THE IEGC:
SUBMISSION TO THE CENTRAL ENERGY REGULATORY COMMISSION

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SUMMARY

This paper discusses the key issues underlying the draft IEGC around reactive power planning, management and efficient pricing in India, especially for dynamic reactive power (DVAr) from non-transmission resources which is critical for maintaining voltage stability. This is an emerging area of priority in India considering some of the past events including near misses, one grid collapse event in 2012 and as the system undergoes a major transition with traditional DVAr resources in fossil fuel power plants replaced by variable renewable energy (VRE). The current draft Indian Electricity Grid Code (IEGC) introduces a regional model linked to voltage level at the EHV level and pricing mechanism that explicitly recognizes a compensation to the generators at 5 paise/kVArh (US$0.65/MVArh). There will need to be further refinements to it going forward to recognize the dynamic nature, location, role of DVAr *reserve* to maintain stability. DVAr resources will need a major boost in supply as well as prices to support investment in a wide array of VAr resources. These refinements will need to be articulated through a proper reactive power management policy informed by detailed reactive power planning and pricing studies. The paper concludes with the contours of a methodology and data issues that will be needed to support such policy analysis.

INTRODUCTION: REACTIVE POWER ISSUES IN INDIA

Reactive power is critical for voltage control for both steady-state operation of the system to ensure voltages are maintained within stipulated limits, as well as for managing contingencies arising from a sudden outage of a large generator/line. The role of 'dynamic' reactive power or DVAr for the latter task, typically provided by generators and increasingly from FACTS devices like STACOM, SVC, SYNCONs, and potentially from battery storage, renewable generators and other inverter-based resources, is particularly noteworthy because these require careful planning, more substantial investment and absolutely important from a system security perspective. Since reactive power injection and absorption can be provided through transmission assets owned by the transmission service providers as well as generators, a clear separation among these two sources is essential in the regulatory and commercial frameworks. Yet, there is typically no separate regulatory provision for management of reactive power, nor a well-established economic and commercial framework to remunerate the service providers in India. As the next section discusses, the more advanced electricity markets in the USA, Great Britain and Australia have embedded this separation at the outset of the market reform to create the necessary provision.

Ancillary services in the Indian power system more generally – for both frequency and voltage control – have either been loosely mandated for generators to provide these services for free (embedded bundled) or through some form of pricing. Reactive power management can typically fall in one of the four categories in most of the systems in developing countries:

(a) The service is provided as bundled by embedded resources (or free) by non-transmission resources, and/or
(b) simply left to the system operator to manage their provision through command and control, or
(c) through ad-hoc contracts for very specific cases in critical locations, or
(d) at best, a blanket subsistence level payment that does not recognize the role of dynamic/fast reactive power (DVAr) resources, criticality of the location, timing and the need to hold significant reactive power in 'reserve' mode to cover for contingencies.

Reactive power management in India is no exception and has essentially gone through the entire spectrum of (free) service, mostly as a portfolio rather than the source specific , management by the state load dispatch centers and the central operator (POSOCO), state-specific contracts in some cases, leading up to the current draft IEGC that proposes a compensation/penalization of 5 paise/kVArh. [1] The compensation/penalization scheme as per the Annexure 4 of Indian Electricity Grid Code (IEGC) is more nuanced that in some cases *leave room for clarity/improvements* – for instance:[2]

1. It is set at a regional entity level for an entity to pay, or get paid, depending on whether it is drawing, or injecting, VAr when the voltage is 3% below the nominal level (and vice versa for 3% above the nominal level). *As the pricing policy is set at the extra high voltage (EHV) level, it may imply significantly higher voltage deviations within the region in certain pockets of the network*

[1] Effective from the date of regulation and escalated at 0.5 paise/kVArh/year thereon.

[2] June 7, 2022 version of the Indian Electricity Grid Code is available online on the Central Electricity Regulatory Commission website: https://cercind.gov.in/2022/draft_reg/Draft-IEGC-07062022.pdf

where reactive power consumption is high. There is no compensation (or penalty) for the time when the voltage is within the ±3% range which may lead to perverse incentive to stop VAr injection immediately following a voltage recovery. Such situations may occur under stressed conditions wherein reactive power is provided through adjustments in real power with a high opportunity cost that is not part of the proposed compensation mechanism.

2. The scheme there only indirectly encourages local compensation by each regional entity so that it does not need to pay the penalty for withdrawing reactive power from the EHV grid when the EHV voltage level is low. *As such it does not directly set a compensation mechanism for the service providers or differentiate among their priorities based on location or time when such service is needed or recognize the role of DVAr or reactive power reserve. Put differently, what works for real power balancing that can easily segue from regional to local level, may not work for reactive power due to the intrinsic local nature of it with losses typically an order of magnitude higher than that of real power*.

3. *The pricing mechanism does not recognize the distinction between fixed and variable components. As the most important role of DVAr which comes at a significant premium over capacitor banks is to effectively be a large source or sink of reactive power during a contingency event – it is unlikely to be used for most part of a year and yet its role to bring the system back to safety is critical for those seconds and minutes when it is needed. The function of DVAr devices in reactor mode is also not addressed in the pricing formula.*

4. It encompasses inverter-based resources including storage, solar and wind in addition to conventional synchronous generators (and those that can operate in a synchronous condenser mode). *It probably does imply room for significant flexibility for these non-transmission service providers to decide how much they wish to invest in such resources (e.g., inverter capacity or new/repurposed Syncons) and when they choose to offer these services (e.g., operate a hydro generator in Syncon mode without necessarily being asked by the system operator to do so). However, this is not entirely clear in the regulation as it stands*.

Since reactive power in majority of the circumstances is a relatively low value product, i.e., a small fraction of energy costs[3], and its measurement, monitoring and analysis is more complex, improvements to the IEGC are by no means an easy task. As we also discuss in the next section, although the advanced markets made the right move at an early stage to recognize the need for a separate compensation scheme for non-transmission resources, the state of pricing in these markets too have a few areas where those schemes can improve to provide a more granular and locational signal differentiated by fast and slow acting devices that meet different objectives. While the compensation measures in these markets have continually seen some improvements to ensure power system security, there remains plenty of room to improve the efficacy of pricing. It is probably the case that the cost-benefit of a theoretically optimal pricing mechanism is not favorable, or put simply such measures probably are not worth the

[3] Total ancillary services costs (including frequency and voltage control ancillary services) typically represents ~2% of energy costs in most major markets and VCAS is around 10% of these costs, i.e., only ~0.2% of energy costs.

trouble.[4] That said, adequate provision of reactive power is a critical requirement and this basic task cannot be left unmanaged in India at a time conventional sources of it may dwindle over time while the variability of (net) demand in a VRE-heavy system increases rapidly. A blunt and sub-optimal pricing may also lead to an unmanageable situation by the system operator. The upshot of a largely unmanaged process is that there is either substantial reactive power resource available in the system that cannot be used efficiently, or worse the system is deficit in these resources but there is no incentive for the service providers to create new capacity. Investment in devices like TCSCs, STATCOM, SVCs, VSC of HVDC that are regulated transmission assets can be justified by the transmission system owner, included in its regulated asset based and recovered through regulated return. However, these still in most cases account for a relatively small share of the DVAr needs of the system. Majority of it including the DVAr "reserve" critical for managing contingencies remain in the domain of generators. As Figure 1 below demonstrates 83 GVAr (93%) of absorption capacity and 166 GVAr (96%) of the injection capacity rests with the generation sector majority of which comes from the coal fleet.

Figure 1 Dynamic reactive power resources by category (October 2020 data)

	Absorption	Injection
STATCOM	3300	4100
SVC	1180	1580
RE ISTS	1578	1578
SYNCON hydro	929	1859
Hydro	10895	21791
Thermal	71233	142464

Thermal Hydro SYNCON hydro RE ISTS SVC STATCOM

Source: POSOCO VCAS Report, Table 1.

[4] The Great Britain reactive power service was worth £80 million pounds in 2020 compared to £38.5 billion traded in the wholesale electricity market. Complexity of introducing a granular reactive power market (e.g., spot market) is massively greater with potential efficiency gains in absolute terms far outweighing it. In fact, appeal of simpler market-based schemes from a generator perspective would also be limited for the same reason.

As systems like India go through a transition with a significant part of its coal fleet retiring over the coming 2-3 decades that traditionally filled the need for a substantial part of the DVAr requirements, it is becoming increasingly important that reactive power management and pricing issues are given the attention they merit so that newer form of DVAr supply is put in place. Some of it will no doubt need to be put in place by the transmission service providers in the form of STATCOM/SVC. However, in order to replenish even a part of the 142 GVAr injection capacity currently in place through thermal generators, the system will need to go far beyond transmission resources and be innovative about it. It is, for instance, possible to get DVAr from repurposed SYNCON on a retired coal site using the old generators, and/or from hydro/pumped-storage hydro in SYNCON mode, and/or from modern inverters in BESS, wind and solar generators.[5] However, these "non transmission" resources will have no incentive to provide operational voltage control service or reserve even if they are available, and most certainly not be built to create targeted new capacity. The investment requirements for new DVAr capacity may be a small fraction of new generation capacity. However, in absolute terms the investment requirements are significant. For instance, a blended mix of SVC and STATCOM costs using the numbers from Table 3 of the POSOCO VCAS report yields approximately $80,000/MVAr. Therefore, adding 10 GVAr of such capacity over the next few years would cost $800 million. If we assume a 10% weighted average cost of capital and 30 years of life for these assets, levelized capital cost is approximately $8500/MVAr/year which will need to be recovered by the asset owners. Indeed, the dedicated DVAr devices like STATCOM/SVC would cater for only a fraction of the requirement and the role for repurposed SYNCONs among others will be paramount not only to bring these resources at a much lower cost of $20,000-40,000/MVAr[6] but also replenish much needed inertia that is provided by thermal generators. As demand grows, part of thermal capacity (and hence associated GVArs) gives way for solar/wind generation, even with the best possible mix of repurposed SYNCONs, SVCs, STATCOMs and IBRs – we are possibly looking at a massive investment in the order of $5-6 billion over the next 10-15 years.[7] Non-transmission service

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[5] It should be noted that the Draft Manual on Transmission Planning Criterion clause 5.4.1.2 (p. 25) notes: "*Near to large RE complex(es) synchronous condenser(s) may be planned for dynamic voltage support, in addition to FACTS devices*." Clause 5.4.5.2 further adds: "*The conventional power stations could be refurbished to a synchronous condenser, thereby potentially reducing initial capital cost. A synchronous condenser consumes a small amount of active power from the system to cover losses. As many gas and coal-based synchronous generators approach the end of their life, the retiring of a plant can possibly create a reactive power deficit at the local network, which may impact voltage reliability. The conversion of the existing generator to a synchronous condenser can be potentially economical and effective.*"

[6] General Electric report on SYNCON prepared for the World Bank, 2021.

[7] The transmission plan for the ISTS system prepared by the Central Transmission Utility in March 2022 identifies major reactive power compensation needs *inter alia* rectification of overvoltage issues in North Bengal as well as undervoltage issues in the Norther Region. See https://www.ctuil.in/docs/feeds/1/2022/4/AI_Study_Report_2026_27_Version11_Final.pdf
Giga VAr (GVAr) scale SVC system had already been installed in Punjab by Siemens in 2016/17. (at a cost of Euro 60 million). The National Electricity Plan prepared by CEA in 2018 envisaged massive outlay of bus reactors (19 GVAr) and line reactors (31 GVAr) in addition to SVC and STATCOM. The total investment costs of these projects were estimated at Rs 9,265 crore (US$1.4 billion using 2017 December exchange rate) over 2017-2022. [CEA, National Electricity Plan, vol II, p.343-344].

providers will need to bring most of it to the system and they must have the right structure and level of tariff to do the investment.

The challenge in devising reactive power regulation is therefore to strike a balance so that the pricing regime is not overly complex commensurate with its relatively small monetary value, against not oversimplifying it to a point that it destroys incentives for service providers. There are several steps and associated requirements to ensure that power system in India develops the requisite reactive power capacity in the most efficient way. The first and foremost of it is to create awareness and a sense of urgency on this issue which is lacking so that the necessary regulatory provisions in the draft IEGC can be enhanced over the years. Part of the objective of this paper is to raise the relevant areas of improvement that can be discussed with the regulators, system operators and planning bodies. The second requirement is to establish the analytical foundation for a proper pricing framework to ameliorate on the incumbent ad-hoc static and average cents or paise per kVArh price applied to a specific solution (e.g., SYNCON for one location), or a power factor-based penalty approach. This in turn will provide the requisite incentive to all non-transmission alternatives (including RE generators) that planners can compare against a single dominant solution (e.g., STATCOM) that is routinely used at present. A third requirement is to improve on the availability of data including mandating the need to post hourly voltage profiles and hourly, if not 15-min, MVA and MVArh readings that can help to monitor the supply-demand of reactive power better and also inform analysis of pricing in future. This is important because this area has been neglected for too long and there have been alarming incidents in the past. The role of DVAr in physical terms has been discussed quite extensively around those events. For instance,

1. In 2009, a 'near miss' event was reported. This was a classic case of a heavily loaded 400 kV line carrying 1 GW failing that led to cascaded outages, which in turn led to long distance power transfer between two regions wheeled through a third region. This called for massive reactive power compensation under a contingency which was lacking and led to near voltage collapse event. The system however survived as the system operator was able to elicit generator response in addition to multiple DVAr resources;[8]
2. In 2012, however, there was a major grid failure under a more severe contingency. The Grid Disturbance of 2012 and its report[9] had categorically mentioned the need for Dynamic Reactive resources.
3. A comprehensive case of reactive power management through a voltage control ancillary services (VCAS) has been made in a [submission to the regulator by POSOCO](https://posoco.in/wp-content/uploads/2021/08/Reactive_Power_VCAS_CERC_22Mar2021-002.pdf) in March 2021 (POSOCO, 2021)[10] that *inter alia* argues for a commercial framework, and need to have an analytical foundation.[11]

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[8] M.C Joshi and N.Mishra, "A Near Miss: 28th November 2009 13:26 Event" Published in Transica, Powergrid, 2010. Available online: https://nrldc.in/download/a-near-miss--200911281326-(1)/?wpdmdl=2512

[9] Available online: . https://cercind.gov.in/2012/orders/Final_Report_Grid_Disturbance.pdf

[10] POSOCO, *Reactive Power Management and Voltage Control Ancillary Services in India,* March 2021. New Delhi. https://posoco.in/wp-content/uploads/2021/08/Reactive_Power_VCAS_CERC_22Mar2021-002.pdf

[11] The January 2020 Expert Group report on the Indian Electricity Grid Code pre-empted the critical role of DVAr, e.g., "*NLDC, RLDC and SLDC shall assess the dynamic reactive power reserve available at various substations or*

The POSOCO (2021) report provides a solid foundation that should be used to expand on the need for enhancing the pricing mechanism as there is a growing need for DVAr with over 10 GW of coal that have already retired and many more slated to retire over the next few years. With the right pricing incentive some of these generators can be converted into SYNCONs. The recent Accelerating Coal Transition (ACT) by the Climate Investment Fund also led to discussions on repurposed SYNCONs that in turn raised a question on how these facilities will be remunerated for its service. The same issue applies to wind/solar/hydro generators providing these services and in future battery storages too. The objective of this note is therefore to propose a practical methodology for reactive power pricing that can be implemented to incentivize provision of DVAr from all resources.

The remainder of this note provides a brief overview of reactive power pricing in other countries mainly to provide a comparator for the proposed/draft IEGC price of $0.65/MVArh. The note then continues to provide a commentary on methodology, data and implementation issues to enhance the current IEGC proposal.

SOME OBSERVATIONS ON REACTIVE POWER PROCUREMENT MECHANISMS AND PRICES IN USA, AUSTRALIA AND GREAT BRITAIN

This section skims through three key electricity markets to highlight some of the critical elements of a reactive power compensation framework, namely:

1. How it was necessary to unbundle the provision of reactive power from transmission, e.g., FERC's initiatives dating back to 1996 as part of the initial open access regulations;
2. Procurement mechanisms – both non-market and market based – to get some insights on what eventually prevailed;
3. Structure of tariff, namely, capital and operating costs (including opportunity cost) recovery; and
4. Observed price level (or total cost to the system as the case may) to the extent there is available data.

This is not intended to be by any means an exhaustive survey of the literature, but an attempt to focus it on the most relevant immediate next steps that could enhance reactive power management regulation in India. In particular, we do not delve into the academic literature on spot pricing of reactive power other than touching upon the analytical framework in the next section. Although a spot market for reactive power has been discussed for nearly three decades starting with Bill Hogan's proposition in 1993[12] for a reactive power market, it was quickly contested as a "cheap constraint"[13] that does not merit a market, and to date there has not been a spot market or any market mechanism that may be

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generating stations under any credible contingency on a regular basis based on technical details and data provided by the users" (section 44, p.154 of the IEGC report).

[12] Hogan, W. (1993). "Markets in Real Electric Networks Require Reactive Prices." *The Energy Journal* 14(3): 171-20.

[13] E. Kahn and R. Baldick, "Reactive Power is a Cheap Constraint" *The Energy Journal*, 15(4):191-201.

deemed as significant or competitive.[14] Mandatory provisions and administered contracts with regulated prices are the mainstay for procurement of reactive power and in most cases prices are not published making it hard to do a proper comparison of prices. There is also no uniformity of contract structure or even categories of reactive power services across the systems/countries. However, there are streamlined procurement practices and limited data on prices suggest these are several folds higher (without adjusting for PPP) that are noteworthy.

USA MARKETS

There are variations across the markets within USA on how generators (including non-synchronous) generators are compensated for reactive power. As the FERC Staff Report in 2014 noted: "…*the Commission has not required a uniform approach with respect to compensation for reactive power. As a result, different payment and cost recovery methods have been adopted in each region.* T*ransmission providers in some regions pay a cost-based payment for reactive power capability, while others require reactive power capability as part of good utility practice, i.e., without compensation*." [15] FERC's 1996 decision did recognize that reactive power may be provided by assets that are integral part of the transmission system that are not unbundled as well as generation facilities that are eligible for compensation as part of an unbundled Reactive Power and Voltage Service. Transmission providers that do pay for reactive power capability, mostly follow the American Electric Power (AEP) methodology to compute cost-based reactive power capability payments.[16] The precise implementation of the AEP methodology differs across different markets/systems within USA. However, by and large, the common principles are:

1. All generators are mandated to provide this service within certain power factor range (set at 0.95 lagging and leading for both synchronous and non-synchronous generators). FERC Order 888 did stipulate that the generators will get compensated for operating outside this band but did not specify compensation for operating within this range. Some transmission service providers pay for MVArs within the range while others do not which is one source for variation among the regions;

2. Generators are paid a compensation towards their fixed costs (mainly capital costs) or Annual Revenue Requirement calculated using the AEP allocation factor which of course differs across utilities depending on generator types and other non-generation DVAr resources; and

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[14] K.L. Anaya and M.G.Pollitt, "Reactive Power Procurement: A Review of Current Trends, *Applied Energy*, 2020. https://doi.org/10.1016/j.apenergy.2020.114939.

[15] Commission Staff Report, *Payment for Reactive Power*, AD14-7, Federal Energy Regulatory Commission, Washington DC, April, 2014.

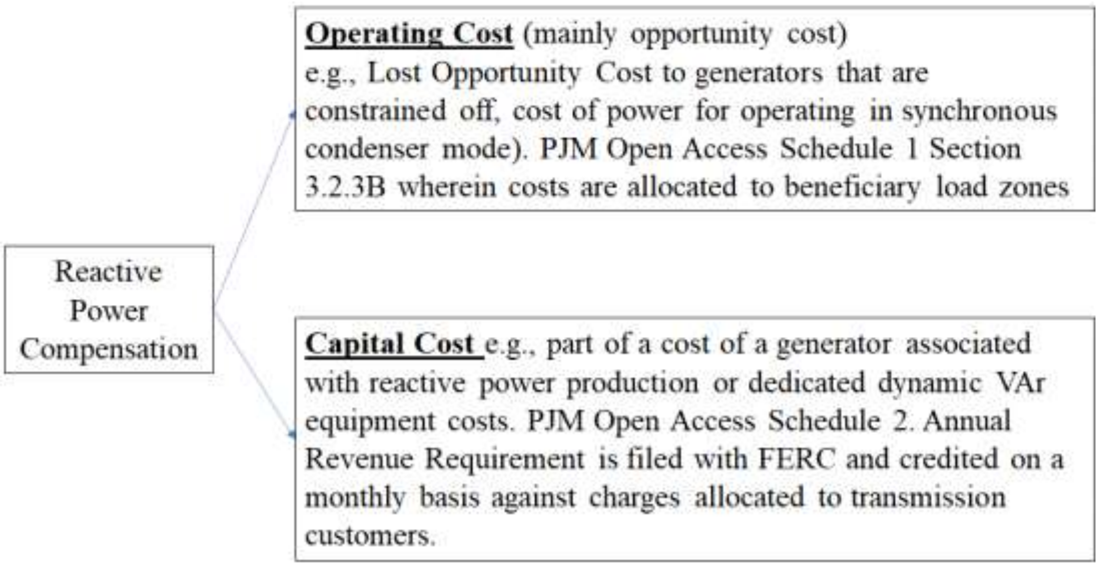
[16] AEP methodology developed originally in 1999 considers three components of a generation plant related to the production of reactive power: "*(1) the generator and its exciter; (2) accessory electric equipment that supports the operation of the generator-exciter; and (3) the remaining total production investment required to provide real power and operate the exciter.*" AEP developed an allocation factor = $MVAr^2/MVA^2$ to calculate the annual revenue requirements of these components between real and reactive power production. [MVA is calculated at unity power factor]

3. A Lost Opportunity Cost (LOC) which represents the 'operating costs' of providing reactive power that may come for some generators operating below or above their optimal dispatch.

Figure 2 shows Pennsylvania-New Jersey – Maryland interconnected system's (PJM) compensation structure which is one of the regions that pay generators for reactive power capability based on the Open Access Transmission Tariff (OATT) Schedule 2 revenue requirement. This is typically allocated to customers based on a load ratio share measured in MWh of real power.

Table 1 reproduces below the OATT Schedule 2 rates as summarized in the Commission Staff Review.

Figure 2 Reactive power compensation components



Source: Adapted from T. de Vita, *Reactive Power Compensation Review*, PJM, Nov 2021.

Table 1 Reactive power compensation schemes in the USA markets/systems

Region	Basis for Transmission customer rate	Capability Rate	Calculation method	Payment for MVArs?	Non generator resources?
ISO-NE	Load ratio	$2.19/kVAR-year	AEP	Yes	Yes
NYISO	Load ratio	$3.919/kVAR-year	Settlement	Yes	Yes
PJM	Load ratio	Varies by individual resource	AEP	Yes (LMP)	No
MISO	Load ratio (varies by zone)	Varies by individual resource	AEP	Yes	No
SPP	Formula in tariff	N/A	Opportunity cost	Yes ($2.26/MVArh)	No
Alabama Power	Fixed rate $1.32/kW-year	N/A	N/A	No	No
Arizona Public Service	N/A	N/A	N/A	No	No
Idaho Power	N/A	N/A	N/A	No	No
Pacificorp	Varies by zone*	N/A	N/A	N/A	No
CAISO	N/A	N/A	N/A	Yes (LMP/RMR)**	No

Source: Adapted from FERC (2014)

* $0 for Pacificorp only; $0.18/MWh for joiPaicificorp and Mid-American ** LPM: Locational marginal based payment calculation RMR: Reliability must run contract price based calculation

Source: FERC Commission Staff Paper, 2014, p.15.

AUSTRALIAN NATIONAL ELECTRICITY MARKET

The Australian market uses a "non market-based" Network Support and Control Ancillary Services (NSCAS) that is managed as a two-tier process between the Transmission Network Service Providers and the Australian Energy Market Operator (AEMO). TNSPs may either install reactive power devices to provide this service with assets built into its regulated asset base to earn a return, or they can also procure it from generators. AEMO can also procure these services as the last resort to control active and reactive power flow into or out of an electricity transmission network. These services that cover both injection and absorption of reactive power, can be purchased by the system operator for both system security purposes, or to enhance "market benefit" which may mean enhancing economic transfer capability in the network. AEMO's purchase through a tender for specific services comes only after TNSPs capacity is exhausted. As such the precise requirement fluctuates over the years including no tender conducted for some years. Reactive power costs usually represent a small fraction of overall ancillary services costs of only a few million dollars out of $200+ million majority of which goes into market-based frequency control ancillary services procurement. The share of reactive power in overall ancillary services cost has been around 5%-10% although in some years back in 2012/13 it has been as high as 35%. However, these costs on a per unit basis has been both highly variable and occasionally very high as Table 2 below shows. For instance, the 800 MVAr contract for the 'Combined Murray and Yass Substation" VCAS contract costs more than AUD 10 million or AUD 13,215/MVAr/year or approximately US$9,500/MVAr/year (using 2019 exchange rate).[17]

Table 2 Australian National Electricity Market Annual VCAS Costs for FY2016-2020 (AUD million)

Facility	Size (MVAr)	2016	2017	2018	2019	2020
Murray & Yass substation	800	10.05	10.16	10.37	10.57	0
Murray and Tumut plant	1650	0.17	0.15	3.84	0	0

Source: AEMO, 2020 Network Support and Control Ancillary Services (NSCAS) Report, December 2020.

Variable requirement of VCAS and high degree of variability in procuring these services may be a reflection of inadequate competition as has been noted in Anaya and Pollitt (2020). However, it should also be noted that the nature of reactive power management is changing rapidly in Australia including a major decline in daytime load because of large scale penetration of rooftop PV which in turn leads to

[17] This will translate into a capital cost of approximately US$100,000/MVAr annualized over a 20 year life at 7% WACC. This would generally represent the high end of a DVAr device. If we were to translate this into a per MVArh cost, it would also require an assumption on utilization hours of the MVAR. For instance, if we assume the MVAr was used for one-third of the time in a year (to cover for daytime low load issues and also evening peaks), it would translate into US$3.27/MVArh, etc. Depending on the usage of the device, namely voltage support vs reactive power reserve to guard against a contingency event, the utilization may vary greatly with the latter application practically requiring the MVAr to be on reserve duty for bulk of the time.

overvoltage. ElectraNet in South Australia where this problem is most prevalent, has been able to tackle the problem at low cost using a series of reactor installations.[18]

AEMO also noted that "…*flexible operation of elements of the system will become very important, including more frequent tapping of transformers, changes to setpoints of generation and SVCs, switching of circuits to reconfigure the system, and possibly investment in new equipment to manage reactive power and voltages on the network*." The difference in requirements and costs over the years may also be a reflection of the extent to which the softer measures may have played a role to curb the need for new contracts. AEMO also noted as parts of its emerging challenges the need to maintain "*adequate reactive power reserves are maintained to ensure the security of the transmission system in the event of a credible contingency*" that may be a critical determinant of DVAr resource requirement and hence costs.[19]

NATIONAL GRID IN GREAT BRITAIN

The National Grid Energy System Operator (NGESO) directly procures all ancillary services using a mix of tenders and ad-hoc bilateral agreements. NGESO distinguishes between an obligatory reactive power service (ORPS) which caters for the bulk of the reactive power requirements and other 2-3 categories of services. ORPS is a non-market mandatory mechanism for all transmission connected generators and accounts 10% of the total ancillary services costs. NGESO also recognizes the contribution from non-synchronous resources albeit the performance criterion is more stringent at 0.95 lagging power factor compared to 0.85 lagging for the synchronous counterparts. Similar to the Australian experience, Great Britain also has significant issues with low real power load hours that accounted for 85% of the reactive power services for absorbing reactive power (over 2013-2018 according to Anaya and Pollitt, 2020). Unlike the Australian contracting mechanism though, ORPS guarantees a default price (BP_U) in £/MVArh set for each month using an indexation formula as described below:[20]

$$BP_U = (46{,}270{,}000 * I_m * X) / 42{,}054{,}693$$

Where,

> I_m = the indexation factor (I) for the calendar month (m) determined as follows:
> $Im = C*[(0.5*FRPI_m/RPI_x)+(0.5*PI_m)]$, where $C = RPI_x/RPI_1$
> RPI_x is the RPI for March 2003 = 179.9
> RPI_1 is the RPI for March 1994 = 142.5
> $FRPI_m$ is the Forecast RPI for the calendar month (m) in question
> PI_m is a wholesale power price index
> X is the utilization factor which is usually set to 1 but for a few exceptions like a failed tests when it is reset to 0.2.

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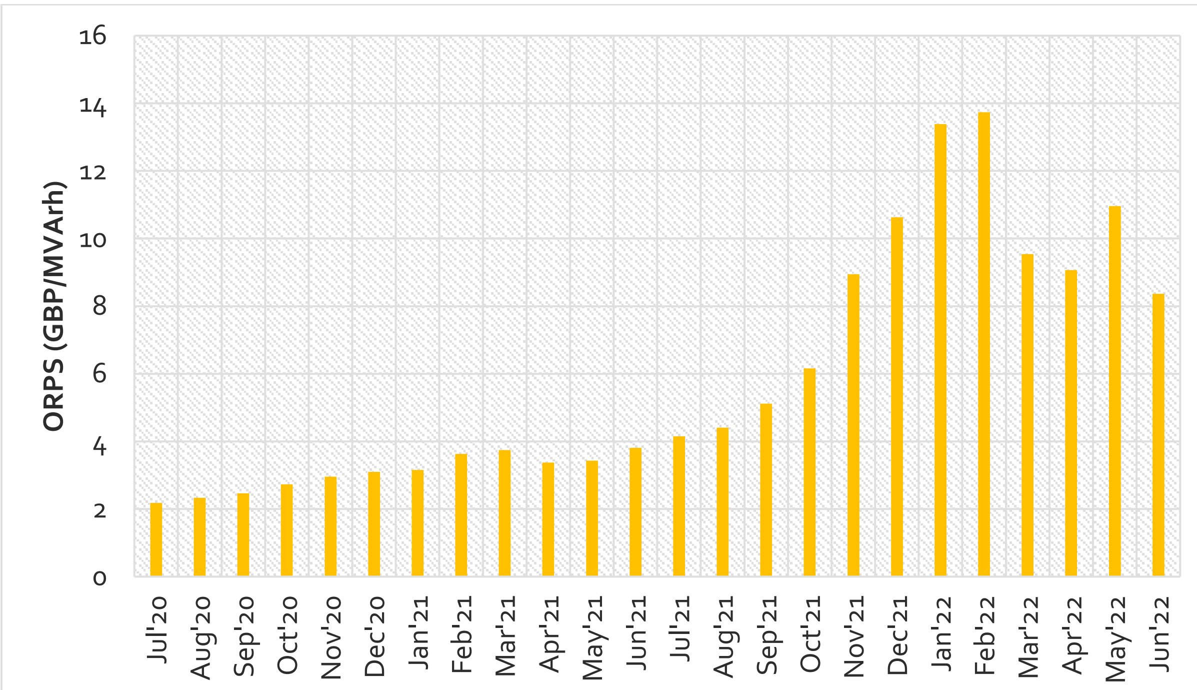
[18] AEMO (2020) report, *ibid.*

[19] AEMO, *Power System Requirements,* July 2020. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf

[20] Refer to: Obligatory Reactive Power Service (nationalgrideso.com) for more detailed explanation and values of ORPS since November 2007.

ORPS default payments started at around £2/MVArh in November 2007 and has been in the range £3-4/MVArh over the past 15 years, albeit it is a function of the wholesale power price index.[21] This index can fluctuate a fair bit in response to gas prices and demand-supply balance, and has in fact been very high since November 2021 with the OPRS climbing as high as £13.73/MVArh in February 2022. Figure 3 shows the ORPS default data over July'20-June'22 period that averages around £5.89/MVArh (US$9.1/MVArh) over this 24-month period, but if the Jan-Jun'22 period is excluded, the average price over the 18-month period prior to it is £3.1/MVArh (US$4.76/MVArh).

Figure 3 Obligatory Reactive Power Service Default Rates for July'20-June'22



Source: https://data.nationalgrideso.com

The obligatory model with default payment is also commonplace in EU countries as well as in North America although prices are not necessarily published in all jurisdictions. In addition to ORPS, there is also an Enhanced RPS mechanism for generators in the NGESO system that exceed the minimum technical standard who may expect a better price. This is procured through a tender but this has not been successful with no generator opting for a market contract since 2009. There is also a Transmission Constraint Management mechanism which is an ad-hoc mechanism to manage specific transmission constraints mostly through bilateral agreements.

[21] It should be noted that the wholesale power price index is calculated based on three different indices (Petroleum Argus, Heren and Platts) with equal weight of 1/3 on them, and is intended to reflect the opportunity cost faced by generators in forgone real power.

REFLECTIONS ON THE DRAFT IEGC REACTIVE POWER REGULATION IN LIGHT OF THE USA, AUSTRALIAN AND GREAT BRITAIN PRACTICES

1. The advanced electricity markets in USA, Australia and Great Britain have not met with great success with market based reactive power/voltage control ancillary services. The non-market mandatory obligation directly managed by the system operator has been the dominant option with market-based options to procure services on the margin playing a secondary role. The draft IEGC provision to add an administered pricing-based compensation is a welcome effort in a similar direction.

2. The mechanism however needs refinements to reflect the international best practices, namely:

    a. It is posed at a regional level for regional reactive power transfers to trigger any penalty/compensation that is expected to incentivize the regional entities to develop concomitant compensation to the local generators to avoid such penalties. The international mechanisms rightly identify VAr to be a local problem first and foremost and devised direct compensation mechanism at a DVAr source level. While the proposed IEGC mechanism might work well for a real power/frequency problem, it may not necessarily be an effective one for reactive power;

    b. As the international practices suggest – a recognition of the reactive power capability range (namely, lagging and leading power factor for injection and absorption of reactive power) for the generators is important that could be considered in the Grid Code. With the introduction of significant roof top solar, daytime overvoltage issue is becoming a critical problem that does require incentives for absorption of reactive power to be in place for some states;

    c. The proposed level of compensation at 5 paise/kVArh or US$0.65/MVArh generally seems to be a fraction of the compensation in all three countries (e.g., Obligatory Reactive Power Services in the Great Britain has been around £3-4/MVArh range i.e. US$3.8-5/MVArh, or around 6 times higher than the proposed price. The proposed price will require careful examination but it is clear that at the proposed price new DVAr investments will not be economic;[22]

    d. Since reactive power provision primarily incurs fixed cost ($/MVAr) and also potentially an opportunity cost for generators, international compensation mechanisms are

[22] There are more country/system specific estimates available some of which are noted in: IEA Hydropower, *Valuing Flexibility in Evolving Electricity Markets: Current status and future outlook for hydropower*, June, 2021. IEA Hydropower estimated a price range of US$1.80-3.54/MVArh with a mean of $2.67/MVArh. ERCOT has used a price of $2.67/MVArh in 2006 estimated off new DVAr capex of $50/kVAr. A study carried out by *Terna* and *Politecnico di Milano* for Italy had estimated the average cost of reactive power procurement at €4.48/MVArh. This is far from a comprehensive review but we find the international prices to be consistently several folds higher than the $0.65/MVArh proposed in the draft IEGC.

structured to recover each of these components separately. The IEGC compensation structure is entirely in variable cost form that *inter alia* also poses a challenge to install DVAr devices that would predominantly be used as large point sources for dynamic reactive power reserve for critical contingencies.

e. The compensation scheme should also include a provision for opportunity cost for generators which is likely to vary across locations but can be significant for critical locations where generators may be constrained off, or on, to inject, or absorb, reactive power. This locational signal is critical for the right set of resources to participate in VCAS.

3. As all three country case histories demonstrate, there are significant analytical underpinnings to support the regulatory development over the last 25 years. The draft IEGC is a good start but it needs to be supported with necessary data and analysis to test the efficacy of alternative forms and levels of reactive power prices.

THOUGHTS ON USEFUL IMMEDIATE NEXT STEPS

As the preceding discussion suggests, there is clearly room to tighten the current draft regulation for it to be more effective in managing reactive power. In this concluding section, we share some of our thoughts that may be useful in chartering a course to achieve this end.

First and foremost, there needs to be a better evidence base for the reactive power policy. Historic data on reactive power production, consumption, flow and voltage level for key areas/zones in the network for different conditions (including contingency states) are essential to understand what the most pressing issues are, what volume of MVAr are we dealing with and hence the size of pool that the system operators will need to work with. Since reactive power is intrinsically a local issue, there will be vastly different representative cases that will need to be stitched together to form a comprehensive view. There may be for instance cases where there are locations in states where reactive power is in short supply either because low power factor load has outstripped supply, or part of the older coal generator fleet has been retired leaving a gap. There may be other cases of significant renewable penetration that leads to the opposite problem of low load during daytime and overvoltage conditions. And there may still be other cases at the EHV level with large MVAr flows necessary across the regions during contingency events. The initial work could be forming a few of these cases to get a holistic view of the salient issues through a stakeholder consultation involving NLDC, SLDCs and the central/state regulators that need to be addressed through a reactive power management framework.

Secondly, there needs to be some analysis done to get a clear understanding of the fixed and variable cost components associated with capital and operating/opportunity cost components, respectively. The former will need an assessment of different options for voltage control ancillary service options (including non-synchronous sources), their capital costs and the best way to apportion these costs. There are alternative ways of allocating the costs and this might be a good opportunity to embed the preferred method in the policy – be it a USA-style AEP methodology or the British ORPS or some other model. The assessment of opportunity cost of reactive power production will require an optimal power flow (OPF) analysis that can be built around the chosen case studies. Although this is a substantial effort, it can also be a very useful way to form insights and evidence needed to set the tariff, give the system operator clearer guidance to manage reactive power more effectively and give an objective assessment of investment needs (both transmission and non-transmission resources). Given the predicaments in the Indian power system in the past with voltage stability issues, it would also be imperative to build in voltage stability margin constraints in the analysis [8]. The dynamic reactive power reserve requirement is an issue that is looming large in several systems that would drive the need for substantial investment in DVAr. Absent an explicit consideration of a voltage stability margin constraint, it is simply not possible to see the necessary DVAr reserve requirement or see the best possible way to price these services.

Finally, once the data and analytical evidence base are in place, a clear roadmap needs to be in place to articulate the steps that may include the following:

1. The process of unbundling the reactive power charges for non-transmission resources needs to commence on a scientific basis with proper metering (15-minute MVA and MVArh). The implementation of Yearly Transmission Charge calculation promulgated in the 2020 CERC Transmission Regulation that collates all reactive power related costs must precede this step. This regulation effectively consolidates all the costs that the Central Transmission Utility has identified as being critical for maintaining system stability, reliability and resilience [9]. The reactive power compensation regime at a regional level in the draft IEGC should be workable with non-transmission service providers paid out of the transmission pool with set threshold for all the entities on reactive power withdrawal and injection linked to EHV level voltage and have reciprocal tariff. But the process needs better clarity on obligations and incentives for individual service providers, measurements, and performance standards.

2. The draft IEGC may be worth revisiting in the following three key areas, namely:
    a. **Tie the regulation more directly with service providers:** including a tighter definition that enables (non-transmission) asset owners' eligibility and relevant range (i.e., lagging and leading power factor range); Presently it is treated mostly as portfolio and embedded , and hence needs complete unbundling
    b. **Tariff structure for the service providers:** specifically a reconsideration of the structure of the tariff so that capital and operating cost components are separated in line with the international practices. The fixed cost of reactive provision can be benchmarked against the (optimal) level and mix of reactive power sources paid through an availability charge linked to performance. The variable cost needs to be paid for both absorption and generation and consider *inter alia* the opportunity cost of reactive power provision for the relevant range of operation; and
    c. **Compensation amount:** i.e.**,** a reconsideration of the compensation level itself as the proposed charge is potentially set at a level well below observed in USA, Australia, Great Britain among others [10] and also deemed levelized costs of dedicated DVAr equipment.

3. Create an evidence base to inform the policy in the first instance and aid with its implementation and subsequent updates. This will need to use both historic data on reactive power contribution from incumbent service providers, flows and voltages, as well as OPF-based planning and pricing studies. As a starting point, there could be an initial set of 3-5 representative cases that can give an indication on ramifications for different lagging/leading power factor ranges, new investment needs for reactive power demand including DVAr reserve (and associated capital costs on the margin), opportunity costs and hence the benchmark fixed and variable costs that should be set in the regulation. These case studies would *inter alia* also provide an indication on whether there is likely to be significant imbalances in the transmission pool.

Reactive power may well be a 'cheap constraint' that may quite justifiably not warrant a sophisticated market-based arrangement much less a spot market. However, the <u>consequences of not meeting this constraint can be very expensive</u> as many systems from New Zealand to North America and everyone in between including India have experienced over the years. Advanced electricity markets took the right approach in recognizing its importance and set out with a framework in the nineties that considered the role of non-transmission resources, even if the compensation arrangements have often relied on mandatory participation and administered prices. These issues are being addressed in India recently with the draft IEGC marking an important step in the right direction. It is expected that the reflections and suggestions in this paper will help to refine it going forward.