CERC Discussion Paper
Market-based Economic Dispatch of Electricity – Redesigning Day-ahead Market (DAM) in India

Comments and Suggestions

Summary of comments

i. 87% energy is currently supplied through long-term PPAs. Apart from a few competitively awarded contracts, the rest are all cost-plus PPAs wherein full fixed or capacity charges are payable including return on notional equity already recovered by the generator in cash as depreciation. The paper proposes not to disturb the recovery of fixed and variable charges (7.1, 7.2) of such generators through Bilateral Contract Settlement (BCS) mechanism and payment of fixed charges outside the market. Since 87% energy comes from long-term PPAs, the gain from change in market design may be limited to marginally additional sale of power viz. un-requisitioned surplus (URS) of long-term PPAs.

ii. A more comprehensive study may be undertaken with realistic assumptions to assess the benefits of national merit order dispatch, without disturbing the existing PPAs and coal linkage policy.

iii. The paper does not recommend changes in existing policy of not providing coal linkage to power plants selling through competitive bidding in the day-ahead power exchange (7.2). As such many private sector thermal generators who have to buy expensive coal from e-auctions by Coal India Ltd will not be facilitated to effectively compete with plants having long-term PPAs under the new market mechanism and replace the energy supplied from inefficient plants. Hence the proposed market design may not provide sufficient signal to the old and inefficient plants to close down/ improve performance.

iv. Many new and efficient plants have not been able to tie up long-term PPAs due to sluggish demand and are suffering losses. Investment in private coal based generating capacity has come down to a trickle. The Discussion Paper has not attempted to mainstream the idle capacity for greater competition in the national market.

v. Even as the Government of India has permitted cross-border entities to trade on India's day-ahead power exchange[1], the potential of a national power exchange to harness significant hydropower of neighbouring countries and India's ability now to scale up resource optimisation through cross-border electricity trade has not been discussed. Cross-border trade will provide India with clean hydro energy having high inertia for grid stability. It will be a win-win situation for the entire South Asian region. The proposed concept of national power exchange must be aligned with the Government of India Guidelines for Import/Export (Cross Border) of Electricity- 2018, issued in December 2018.

[1] Guidelines for Import/Export (Cross Border) of Electricity- 2018, issued in December 2018

vi. If the idling generating units of new and efficient plants located in the eastern and western regions were to be provided with sufficient coal, they would offer real competition in the proposed national power exchange. This would result in massive changes in power flow pattern in the country, which needs to be extensively studied with power system simulation software to identify the grid security constraints.

vii. Merit order dispatch through a national power exchange should not impair the ability of the grid to quickly respond to emergency. The islanding schemes for critical load centres should not be compromised.

viii. The paper has limited the analysis to broader commercial design. However, policy as well as technical issues are equally important.

ix. It is not clear whether open access consumers would be permitted to buy power from the national pool. Figure 14 in the paper gives the impression that open access consumers and cross-border generators are excluded in the proposed market design.

x. The retirement of (cost-plus tariff based) old capacity (5,926.5MW) and environmentally non-compliant plant old capacity (16,789MW) up to the year 2022 and another 25,572MW by the year 2027 is recommended by CEA in the National Electricity Plan 2017-22 (13th Plan) notified on 28 March 2018 would significantly reduce the fixed charge burden. This would enable discoms to buy more renewable energy. It may be highlighted that such vintage plants are not capable providing flexible output required in high RE scenario for maintaining load-generation balance and may be closed as per the recommendation of CEA.

xi. The principal loan amount of cost plus thermal plants is recovered by the generator in about 12 years as per regulatory norms in vogue since 2009. In order to reduce the burden of fixed charges, it is suggested for consideration to invite capacity bids from cost-plus thermal plants after 15 years of the date of commissioning in suitable batches, other than those listed by CEA for closure.

xii. It would be worthwhile to allow financial trade of electricity in the commodity market for the purpose of hedging. The paper has mentioned the need of discom for hedging against price volatility. However, hedging is equally important for financing new generation projects and this can only be provided by a robust financial market for electricity. The paper has not made any concrete proposal on the subject as well as with regard to developing a capacity market to replace the cost-plus regime of fixed charges.

xiii. Currently, a state/discom can adjust its load -generation balance by reducing its requisition from a long-term PPA or by arranging more power. In the proposed market design the state/discom cannot schedule power from resources within the state since all power has to be scheduled through the day-ahead power exchange where there is no flexibility to revise the schedules. So, any adjustment would have to be done through the real time market. States will have to gear up to operate in the new operational environment so that ancillary services are not over-stretched. Liquidity would be required in the real-time market for balancing power.

.

xiv. The untied/merchant renewable generators may have to be allowed to bid their charges as variable charges on the national exchange and may be issued Renewable Energy Certificates as per the current practice. As and when they are selected in capacity auction by SECI or other such agency, they will be required to quote zero capacity charges.

xv. The congestion revenue is neither for profit nor for compensation. It should be exclusively used for removing the cause of congestion in electricity market to achieve uniformity in prices. The money could be given to CTU as interest free loan through the Power System Development Fund for quickly removing transmission bottlenecks reported in the operational feedback reports of POSOCO.

xvi. A full-fledged surveillance mechanism would be required monitor market abuses such as withholding capacity during peak season, under declaring availability in the day-ahead market for selling higher in real-time market, deliberately quoting high in the day-ahead market with a view to tapping pricy real-time market, colluding for rigging market clearing price manipulation in day-ahead and ancillary market etc.

Detailed Comments

2.0 Main Issues in the current day-ahead market design as highlighted by the paper

i. Self-scheduling by discoms results in sub-optimal dispatch (with regard to variable cost) because they *'may not have the opportunity to identify cheaper generation outside their portfolio due to the lack of visibility of such available capacity'.* This *'scheduling in individual silos by each discom can lead to sub-optimal utilization of lower cost generation while relatively expensive generation is used.'(2.2)*

ii. *'The system marginal cost in the actual dispatch scenario is much higher than that of the pooled dispatch.....Available URS[2] from cheaper variable cost plants is not utilised, whereas the plants with higher variable costs are being dispatched.'* While this can partly be attributed to technical constraints, *'the results of the constrained optimization still show definitive scope for optimization of generation resources' (2.4, 2.5)*

iii. *'The other challenges emanating from the practice of self-scheduling includelack of flexibility to meet variation in demand……..The availability of un-requisitioned surplus (URS) from low cost generating stations also implies a potential for optimizing scheduling and dispatch in order to lower cost of power procurement for discoms'. (2.6)*

iv. *'The extant practice followed to provide day-ahead schedule (of the generation contracted under long-term agreements)often weakens the physical and financial sanctity of transactions, as both generator and the discoms can revise schedules 4 time blocks ahead of dispatch without any financial liability. This makes system operation prone to a lot of uncertainties.' (2.7)*

v. *'Given that Discoms are not obligated to reveal the variable cost of the generation they are scheduling, true system marginal cost is not known.'(2.8(iii))*

vi. *'Self-scheduling often constraints optimum utilisation of renewable sources of energy.As the visibility of a discom is limited to its own territory; surplus renewable energy in the State is curtailed. Further, with increase in penetration of Distributed Energy Resources (DER) at Distribution Network (which SLDC and RLDC are not able to observe), DISCOMs would need to take into account generation from such sources, to ensure flexibility in the system while catering to 'net load (demand minus the generation from embedded RE resources)'. This is critical because such embedded sources of renewable generation need to be taken explicit cognizance of while scheduling other conventional sources.' (2.8 (iv))*

2.1 Comments: Introductory Remarks

i. The Indian Power Sector has made great strides after the enactment of Electricity Act, 2003. In the last 70 years, the Indian electricity grid has evolved from the local grids, state grids, inter-state regional grids, inter-connected regional grids to the present 'one grid one nation' system since 2014. The Indian grid is also interconnected with Bhutan, Bangladesh and Nepal for cross border electricity trade.

[2]Un-requisitioned surplus power of plants contracted under long term PPA

ii. India is one of the few countries to institute open access in electricity transmission. The de-licensing of generation sector; permitting trading, and the creation of an electricity market; institution of a regulatory structure; allowing of choice to big consumers; strict compliance with grid code; and trade settlement code[3] and the creation of a robust national grid – all these have changed the outlook of the power sector. India now has a well-established day ahead spot market organised through a power exchange which commenced operations in 2007. The power exchange in India is a voluntary trading platform with single closed auctions on day-ahead basis. The exchanges are accessible to discoms, generators, traders, and open-access consumers. In 2018, they also became accessible to neighbouring countries under the new cross-border electricity trade policy of India, in line with Article 2 and 13 of the *SAARC Framework Agreement for Energy Cooperation (Electricity) signed at the 18th SAARC Summit on 26 November 2014*.

iii. Electronic reverse auctions for short-term bilateral contracts by discoms were started in 2016. However, the discoms are not able to take full advantage of the spot market as they are locked up in several long-term PPAs. They also have to bear the entire fixed or capacity charges computed on cost-plus norms. The discoms are accountable to the state electricity regulator for all power procurement contracts. Discoms are putting in place power procurement optimization systems which include software tools for weather forecasting, demand assessment as well as external support for information regarding availability of cheaper electricity outside the state. The bilateral power market including electricity traders and day-ahead voluntary power exchange provides opportunity for resource optimisation as well for meeting additional/contingency demand. Liquidity in the power exchange having improved, the discoms even back down their own contracted plants and buy power from the open market.

iv. Between 2007 and Dec’2018, the All-India generation capacity grew from 132GW to 349GW[4], including 74GW from renewable energy sources (RES).The table at **Appendix-1** depicts the growth of generation and voluntary power market in India.

v. The aggregate volume of the various segments of the short-term voluntary market is currently of the order of 9%-10% of the gross all-India generation. The objectives of the power exchange were to harness surplus power with any discom/generator, additional sources of power like merchant, captive and co-generation plants, and the free hydro power share of Himalayan states. The price signal of the power exchange was expected to serve as an investment trigger for the private sector for the setting up of new generating capacity. This was necessary because public resources were not enough to meet the investment requirements for new generation.

vi. India has been working on expanding and augmenting its inter-regional transmission network for more than two decades now. This is an ongoing process with newer sources of generation and newer load centres coming on-stream. All the regional grids have now been integrated to form one national grid. States are also working towards augmenting intra-state transmission capacity. The development of high-capacity transmission corridors, including 765kV AC and HVDC, is resulting in increasing power transfer capability of the grid. With generation adequacy having been achieved by the liberalisation of generation sector, the possibility is now

[3]Deviation Settlement Mechanism (DSM)
[4]Excluding captive generation capacity

emerging for stepping up competition in generation and for cross-border trade. The transition to greater competition needs to be smooth and done in a phased manner. However, the grid security constraints should first be critically analyzed.

vii. In view of the above chronology of events, it is abundantly clear that the present market design of CERC, refined from time to time, has been serving the intended objective. It is only now that we see the possibility of creating a system of national scheduling and dispatch for resource optimisation on a national and cross-border scale. The Discussion Paper has proposed switching over to a mandatory national pool but does not propose to provide relief to the discoms from paying full fixed charges determined on cost plus norms. The possibility of harnessing enormous hydropower of neighbouring countries and larger resource optimisation through cross-border electricity trade has not been discussed.

viii. If the idling generating units of new and efficient plants located in the eastern and western regions were to be provided with fuel, they could become very competitive in the proposed national power exchange. This could result in significant change in power flow pattern in the country. This and other impacts of a national power exchange on power flow patterns need to be extensively studied with power system simulation software to identify the grid security constraints. For instances, it will not be desirable to back down entire local generating capacity near critical load centres – even if it is not selected in merit order – in order to immediately cater to a grid contingency or change over to islanding mode of operation. The paper has limited the analysis to broader commercial design. However, policy as well as technical issues are equally important.

2.2 Comments on specific issues

i. The Indian electricity grid is divided into state-wise autonomous control areas managed by the SLDC, which in turn is supervised by RLDC and NLDC. Each control area is responsible in real time for balancing its demand with generation resources. The Discussion Paper proposes to put in place a central market operator to dispatch the inter-state as well as intra-state generation plants (para 4.4, 5.12),while the responsibility of balancing the load and generation will continue to be retained with SLDC.

ii. At present, the generators and discoms, having a long-term PPA, have the flexibility to revise their day-ahead schedules on the day of implementation at short time notice. However, on the day-ahead power exchange this cannot be permitted because there is no one to one matching of trades on a collective platform. Currently, a state/discom can adjust its load -generation balance by reducing its requisition from a long-term PPA or by arranging more power. In the proposed market design the state/discom cannot schedule power from resources within the state since all power has to be scheduled through the day-ahead power exchange where there is no flexibility to revise the schedules. So, any adjustment would have to be done through the real time market. States will have to gear up to operate in the new operational environment.

iii. In order to realistically estimate the quantity of URS which ought to have been scheduled, one must take into account the transmission constraints, fuel constraints, scheduled plant outages, prevailing market price, and consider a large number of states and scenarios.

iv. The RE sources are must run as per IEGC and state grid codes. The inter-state RE generating farms are not dependent for sale on the host discom. RE farms having PPA within the state are governed by the applicable PPA and are curtailed only in the event of transmission constraints during very high RE scenario or transmission outages or such technical issues. Such issues would continue to occur in real-time. SLDC has ample visibility of their generation sources including those causing reduction in net demand.

v. From Table 1 at page 32, it is illustrated that renewable generators would be treated at a must-run plant having zero variable cost. This is true for renewable generators including hydro, wind and solar, provided fixed charges are recoverable outside the market. However, the untied renewable generators may have to be allowed to bid their charges as variable charges on the national exchange and may be issued Renewable Energy Certificates as per the current practice.

vi. It is not clear whether open access consumers would be permitted to buy power from the national pool. Figure 14 in the paper gives the impression that open access consumers and cross-border generators are excluded in the proposed market design.

3.0 Proposed MBED Framework for Day Ahead Market (DAM) - Scheduling, Dispatch and Settlement

i. *In the MBED model, the sellers (central generators, IPPs, traders and discoms would be required to submit offers for all the time blocks for the following day.(4.4)*

ii. *All discoms would declare their day-ahead requirement (Fig. 17))*

iii. *The existing bilateral contract holders will be paid the fixed cost separately outside the market and as such would also be induced to bid ... based on their variable/ marginal cost of generation....(4.6)*

iv. *The buyers will be supplied electricity as per their load and the generators will get dispatched in merit order up to the point where the total system load is met; and the contracts would be settled bilaterally...(4.6)*

v. *The market operator would discover the market clearing price (MCP) after the bid process closes. MCP in each time-block would be the bid value of the last generator/seller matched to meet the demand offers which would reflect the marginal value of electricity ....(4.7)*

vi. *The day-ahead market follows uniform pricing principle. However, in case the discom and generator tied in long term PPA were to participate, both would face the volatility of day-ahead market prices but because they are tied up … there would be hedging arrangement of refunding the difference between the market clearing price and contracted price… the fixed cost would be paid separately based on (plant) availability as per current practice /outside of market …(4.8, Figure 17)*

vii. *The proposed mechanism ensures that the financial obligations of the existing contracts remain intact.... (4.12)*

3.1 Comments:

i. **Legal Implications:** It is apparent that the proposed mechanism requires a review of existing laws and regulations unless all the states agree voluntarily for centralised dispatch and decentralised balancing mechanism.

ii. **Equitable allocation of fuel:** In order to foster competition and incentivising more efficient technologies, one needs to create a level playing field in the allocation of fuel such as coal so that there are substantial savings to the discoms. Coal linkages are provided to projects having long- or /medium-term PPAs. The power plants whose power is not contracted bilaterally on a long- or /medium-term PPA have to buy expensive coal through e-auctions, which has limited availability. A number of new fuel-efficient, environmentally compliant and grid-friendly power plants of unit size 600/660MW are starved of coal and are incurring losses. Providing fuel linkages to all power plants competing in the proposed mandatory national pool is desirable for ensuring a substantive replacement of costly power with cheaper power in line with the objective of the Act, "... *for taking measures conducive to development of electricity industry, promoting competition therein, protecting interest of consumers and supply of electricity to all areas, rationalisation of electricity tariff, ensuring transparent policies regarding subsidies, promotion of efficient and environmentally benign policies*.."

Action as per CEA plan to close vintage and environmentally non-compliant coal based power plants: The National Electricity Plan for the period 2017-22 (13th Plan) has recommended retirement of 59 units of aggregate capacity 5,926.5MW on account of aging and 16,789MW capacity due to inability to meet new environmental norms as listed in the Tables below extracted at **Appendix-2** from the National Electricity Plan (Vol. I) notified on 28 March 2018. The retirement of the notified thermal power plants would have significant impact on CO_2 emissions and more coal would become available for the new and efficient power plants, apart from reducing the burden of fixed charges of power plants operating at low plant load factor. CEA has also notified future retirement plan for 2022-27 of about 25.5GW. By reducing the fixed charge burden, the retirement of above listed cost-plus plants would enable discoms to buy more renewable energy. It may be noted that such vintage plants are not capable providing flexible output required in high RE scenario for maintaining load-generation balance.

4. Other important issues

4.1 Revenue recovery of untied capacity through the proposed national pool: The majority of base load capacity in India is tied up in cost plus long term PPAs with two-part tariff, a significant new private generating capacity (IPPs) has to sell power in the short-term market at a composite price and has no way to recover fixed charges separately. In such a complex scenario, it will be difficult to monitor the bidding pattern of private generators, particularly when they have accumulated losses[5]. Such IPPs cannot be expected to quote at their variable cost alone. Normally, these IPPs quote according to market conditions and try to recover fixed charges during peak hours and sometimes sell at a loss during off-peak hours just to keep the plant running. Hence, effective market surveillance in such conditions would be a challenging task.

4.2 Capacity market and financial markets: Along with the new market design, need for developing a capacity market would arise. The principal loan amount of cost plus thermal plants is recovered by the generator in about 12 years as per regulatory norms in vogue since

[5] https://www.thehindubusinessline.com/economy/thermal-power-projects-with-investments-worth-rs-25-lakh-cr-facing-stress-report/article26230174.ece

2009. In order to reduce the burden of fixed charges, it is for consideration to invite capacity bids from cost-plus thermal plants after 15 years of the date of commissioning in suitable batches, other than for those listed by CEA for closure.

It would be worthwhile to allow financial trade of electricity in the commodity market for the purpose of hedging. The paper has mentioned the need of discom for hedging against price volatility. However, hedging is equally important for financing new generation projects and this can only be provided by a robust financial market for electricity.

4.3 Danger of arbitrage between day-ahead national pool and real-time market: The Discussion Paper has briefly touched upon the subject as reproduced below:

"7.11 Market monitoring needs to be enforced under the following broad heads:
a) Market surveillance to identify and address wrong doing
b) Market performance assessment to examine and improve the economically efficient functioning of the market, including the efficient formation of prices..."

In the present market design, there are multiple options to buy/sell in the open market. However, the new design proposes to reorganise the market to three successive segments – day-ahead, ancillary and real-time. The proposed market design requires safeguards from the dangers of gaming. Ancillary and real-time markets would provide opportunity to generators and surplus discoms to try make super profit. There is also a possibility that generators may not declare their true availability in the day-ahead market but they may declare additional availability in the real-time market. A suitable mechanism to prevent gaming by withholding capacity in the day-ahead market would have to be devised to prevent profiteering by generators and discoms. Discoms can create artificial shortage by buying more than required power from the national pool, and profiteer by selling their surplus in the real-time market. Suitable market monitoring rules and tools diagnostic tools would need to be developed, for instance:

- Declared Capability (DC) of a generator at any time of the day cannot be more than the peak hour DC.
- In the real-time market, a generator cannot deploy capacity exceeding the maximum DC declared in the day-ahead market.
- In case the entire capacity of a generator is contracted on long-term PPA, no mark up may be allowed on the regulated variable charge or bid out energy charge.
- A generator with full or part merchant capacity including a renewable plant may be allowed to freely bid in the National Pool.
- The DC declaration pattern of an untied generation capacity of a plant shall be monitored during peak season.
- A conventional generator must quote for ancillary service to be eligible for selling in the real-time market.
- Monitoring the buy quantum of discom with respect to its demand forecast for the forthcoming day.
- Monitoring sell pattern of a surplus discom.

4.4 Impact on planning for power: At present, planning is done for the development of power resources at central and state levels. Under the proposed mechanism of a national pool , there is little motivation for the state planning agency to play a proactive role in harnessing their power resources. This is because if a state or private entity sets up an intra-state generating plant, it cannot be scheduled through SLDC and has to compulsorily bid in national pool.. On the other hand, the discoms of the state would be free to bid their daily demand in the national pool irrespective of their own generating resources and as a result, the onus of adequacy of generation resources to meet the demand would shift from the state to the national pool operated by the central government. This would tend to make state planning agency complacent.

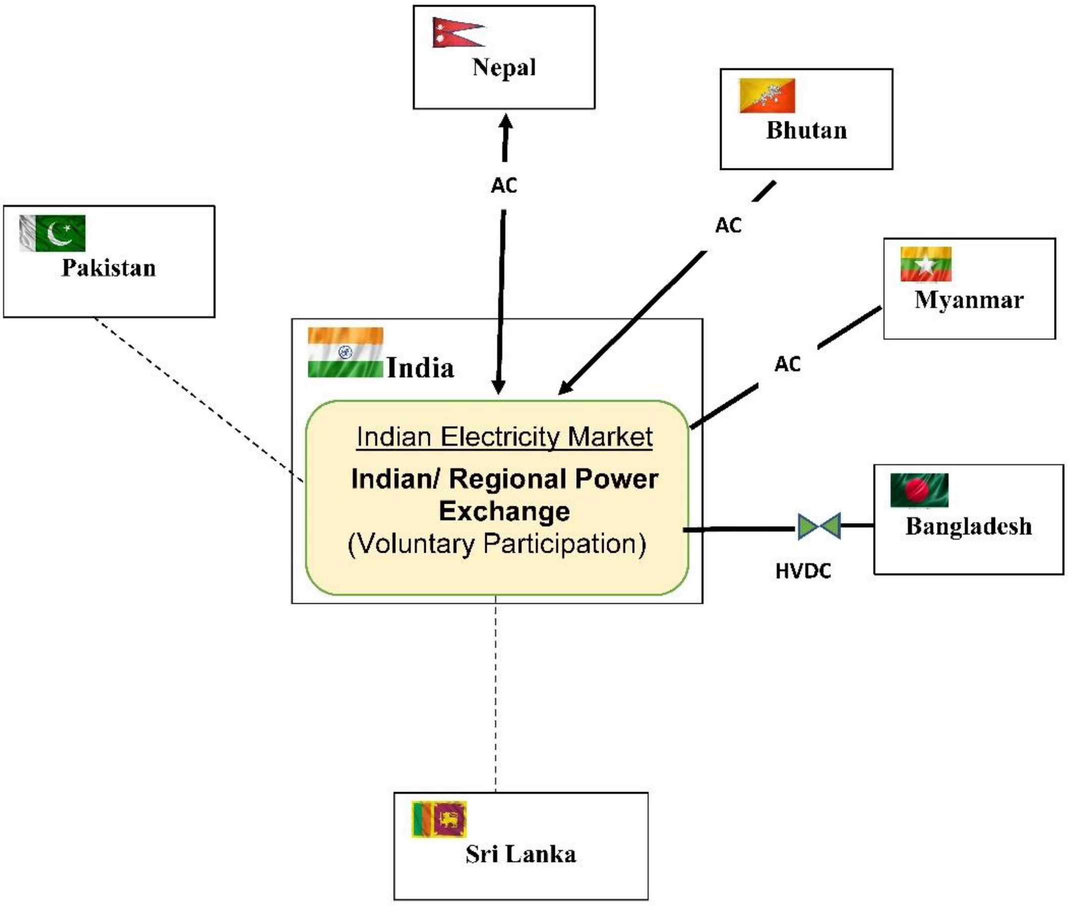
4.5 Increase in working capital requirement of discoms: The standard long-term PPAs provide a monthly billing cycle with a payment period of 30 days during which the buyer is entitled to 2% discount on the invoice price. Under the new mechanism, the payment cycle has not been discussed. In the existing power exchange, the buyer/member is responsible for maintaining the margin money, and the power exchange has the right to block the funds in the buyer's bank account. There is a daily settlement cycle and the sellers are paid on the 3rd day. If the same system were to be adopted in the proposed national pool, it would be a financial challenge for the discoms. Therefore, lending agencies like PFC and REC may have to step in and the SERCs would have to allow more margin money for working capital.

4.6 Development of cross-border Power Exchange: India has significantly liberalised its policy on cross-border trade of electricity in 2018 by way of the **Guidelines for Import / Export (Cross Border) of Electricity- 2018**in December 2018 ("**Cross-Border Guidelines"**). For the first time, since the inception of day-ahead power exchange in India and after many years of debate, the Indian Power Exchange has been opened up for cross border trade - a longstanding demand of the neighbouring countries. Relevant extract from the guidelines is reproduced herein below:

> *5.3 Any Indian power trader may, after obtaining approval from the Designated Authority, trade in Indian Power Exchanges on behalf of any Entity of neighbouring country, for specified quantum as provided in the Approval and complying with CERC Regulations*

This is a welcome step for hydro power projects/investors in Nepal and Bhutan. It will provide India with clean hydro energy having high inertia for grid stability. The proposed concept of national power exchange must be aligned with the Cross-Border Guidelines. Please refer **Appendix-3** for existing cross-border trade. The optimisation of electricity resources at the level of South Asia would yield far greater advantages besides improving political relations through electricity trade. Looking forward, this aspect ought not to be ignored in any market design for India. As permitted under the Cross-Border Guidelines, architecture for a voluntary cross-border power exchange, as a composite part of Indian power exchanges, has been depicted below:

Journey of Indian Power Exchange evolving as Regional Power Exchange has begun with the new Cross Border Power Policy of India, issued in December 2018



In view of above it is suggested that:

- All existing and future long-or medium-term cross-border PPAs may be scheduled through the proposed mechanism for national power exchange.
- All existing and future long-or medium-term cross-border PPAs may be settled through the proposed mechanism for national power exchange and BCS..
- Cross-border merchant generators may be allowed to participate in the national power exchange through Indian electricity traders as per the **Cross-Border Guidelines**.

5.0 MBED Implementation and Operational Aspects:

a. *All such bilateral contract holders participating and getting cleared in the day-ahead market will then receive the "Congestion Amount" if the congestion occurs in the "direction" of the contract and will have an obligation to pay for congestion if the congestion occurs in the direction "opposite" to the direction of the contract (5.4)*

b. *Participation would be initially voluntarily (5.12)*

c. *The existing arrangement of self-scheduling of the long-term PPAs to continue during the transition period of one year (5.12)*

d. *After one year, MBED would become a mandatory national pool. (5.12)*

5.1 Comments:

The Discussion Paper makes a significant departure from the accepted principle to channelize congestion revenue to remove the cause of congestion. Congestion revenue arises from a price differential between areas with restricted supply and those with surplus supply. This revenue is not supposed to be distributed as a profit to discoms located in surplus regions and having long-term PPAs. It has to be channelized for the strengthening of transmission system and for removing constraints in the transfer of power to congested areas, with a view to achieving uniform market clearing price for the whole of India. Even during periods of transmission adequacy, transmission congestion can arise due to power system outages or generation failure, but congestion revenue accrued to the Exchange should go to the agency responsible for transmission development. At present, the congestion revenue goes to Power System Development Fund. The recommendation for the distribution of congestion revenue to selected discoms may lead to difference of opinion in planning of transmission for future. The existing system should continue, and it may be ensured that the funds go as interest free loan to the CTU to remove system bottlenecks reported in the operational feedback reports of POSOCO.

6.0 Recommendations

1. A more comprehensive study may be undertaken with realistic assumptions to assess the benefits of a national merit order dispatch, with and without disturbing the existing PPAs and coal linkage policy.
2. Idling thermal capacity of modern plants should be provided with fuel so that it can provide competition to old and inefficient plants.
3. Open access consumers may be allowed to buy power from the national power exchange.
4. All existing and future long-or medium-term cross-border PPAs may be scheduled through the proposed mechanism for national power exchange.
5. All existing and future long-or medium-term cross-border PPAs may be settled through the proposed mechanism for national power exchange and BCS.
6. Cross-border merchant generators may be allowed to participate in the national power exchange through Indian electricity traders as per the Cross-Border Guidelines.
7. Carry out extensive studies with power system simulation software to identify the grid security constraints in all possible skewed scenarios.
8. Merit order dispatch through a national power exchange should not impair the ability of the grid to quickly respond to emergency. The islanding schemes for critical load centres should not be compromised.
9. As recommended by CEA in the National Electricity Plan 2017-22 cost-plus tariff based old capacity (5,926.5MW) and environmentally non-compliant plant old capacity (16,789MW) may be retired by 2022 and another 25,572MW by 2027 to reduce the fixed charge burden of discoms and to reduce average rate of CO_2 emission.
10. The capacity market may be put in place simultaneously with the implementation of national pool.
11. The financial trade of electricity may be commenced as soon as possible.

12. The untied/ merchant wind, solar and hydro generators may be allowed to bid their price on the proposed day-ahead exchange as variable charge since there is no other way for a merchant plant to recover fixed charges.
13. The congestion revenue is neither for profit nor for compensation. It should be exclusively used for removing the cause of congestion in electricity market to achieve uniformity in prices. The money could be given to CTU as interest free loan through the Power System Development Fund for quickly removing transmission bottlenecks.
14. A full-fledged surveillance mechanism would be required monitor market abuses.

Appendix-1

Volume and prices in India's short-term market

Year	All India Generation*	Total Short-term market volume**	Total no. of market transact-ions***	Price through traders**	Price on IEX power exchange**	Volume of IEX power exchange**	Trade as %age total power generated
	BU	BU	-	Rs/kWh	Rs/kWh	BU	%
2004-05	587.4	17	778	2.32	-	-	2.89
2005-06	592	23	3,938	3.23	-	-	3.88
2006-07	639	24	5,933	4.51	-	-	3.75
2007-08	689	30	9,560	4.52	-	-	4.35
2008-09	713	31	15,414	7.29	7.31	2.77	4.34
2009-10	764	40	18,128	5.32	5.19	6.17	5.23
2010-11	812	53.47	19,883	4.74	3.56	11.8	6.58
2011-12	874	67	24,111	4.23	3.54	13.79	7.66
2012-13	907	74	32,139	4.35	3.49	22.35	8.15
2013-14	963	83	33,917	4.27	2.81	28.92	8.61
2014-15	1,045	79.5	37,046	4.3	3.65	28.12	7.60
2015-16	1,103	94.47	44,634	4.13	2.71	33.96	8.56
2016-17	1,157	96.01	34,892	3.53	2.41	40.52	8.29
2017-18	1,209	103.4	32,335	3.61	3.35	44.84	8.55
2018-19	839^	86.4^	24,475^^	4.18^	4.08^^	40.63^^	10.29

^ Data from April-November 2018
^^ Datafrom April-Dec 2018
**Total Generation in FY 2005 from MoP Annual ReportforFY2005-06; Total net energy supply data for FY2006 to FY2009 from Ministry of Statistics and Program Implementation's Energy Statistics2015; Total generation data forFY2009 to FY2019 from CERC Monthly Market Monitoring report; Total generation April-Dec as per CEA Report is 945.2 BUs*
***CERC Market Monitoring Report*
****NLDC Monthly report*

Appendix-2

List of Projects considered for retirement by March 2022 (as on August 2017)

SN	Name of the Utility	Name of the Station	Unit No.	Capacity (MW)	Year of Commissioning*
1	DPL	DPL TPS	3	70	---
2	DPL	DPL TPS	4	75	1964
3	DPL	DPL TPS	5	75	1964
4	ASEB	Chandrapur TPS	1	30	1973
5	ASEB	Chandrapur TPS	2	30	1989
6	GSECL	Sikka TPS	1	120	1988
7	GSECL	Ukai TPS	1	120	1976
8	GSECL	Ukai TPS	2	120	1976
9	IPGCL	Rajghat TPS	1	67.5	1989
10	IPGCL	Rajghat TPS	2	67.5	1990
11	MPPGCL	Satpura TPS	6	200	1979
12	MPPGCL	Satpura TPS	7	210	1980
13	UPRVUNL	Harduaganj	5	60	1977
14	UPRVUNL	Obra TPS	8	94	1974
15	NLC	NevyeliLigniteTPS-I	1	50	1962
16	NLC	NevyeliLigniteTPS-I	2	50	1963
17	NLC	NevyeliLigniteTPS-I	3	50	1963
18	NLC	NevyeliLigniteTPS-I	4	50	1963
19	NLC	NevyeliLigniteTPS-I	5	50	1964
20	NLC	NevyeliLigniteTPS-I	6	50	1965
21	NLC	NevyeliLigniteTPS-I	7	100	1967
22	NLC	NevyeliLigniteTPS-I	8	100	1969
23	NLC	NevyeliLigniteTPS-I	9	100	1970
24	TSPGCL	Kothagudem TPS	1	60	1966
25	TSPGCL	Kothadudem TPS	2	60	1966
26	TSPGCL	Kothadudem TPS	3	60	1967
27	TSPGCL	Kothadudem TPS	4	60	1967
28	PSPCL	GND (Bathinda) TPS	1	110	1974
29	PSPCL	GND (Bathinda) TPS	2	110	1975
30	CSPGCL	DSPM Korba TPS	1	50	1966
31	CSPGCL	DSPM Korba TPS	2	50	1967
32	CSPGCL	DSPM Korba TPS	3	50	1968
33	CSPGCL	DSPM Korba TPS	4	50	1968
34	MPPGCL	Satpura TPS	8	210	1983
35	MPPGCL	Satpura TPS	9	210	1984
36	UPRVUNL	Obra TPS	1	40	1967
37	UPRVUNL	Obra TPS	2	50	1967
38	UPRVUNL	Panki TPS	3	105	1976
39	UPRVUNL	Panki TPS	4	105	1977
40	TSPGCL	Kothagudem TPS	5	120	1974
41	TSPGCL	Kothagudem TPS	6	120	1974
42	TSPGCL	Kothagudem TPS	7	120	1977
43	TSPGCL	Kothagudem TPS	8	120	1978

44	TSPGCL	Ramagundem-B TPS	1	62.5	1971
45	PSPCL	Ropar TPS	1	210	1984
46	PSPCL	Ropar TPS	2	210	1985
47	PSPCL	Ropar TPS	3	210	1988
48	PSPCL	Ropar TPS	4	210	1989
49	MSPGCL	Koradi TPS	5	200	1978
50	PVUNL	Patratu TPS	4	50	1970
51	PVUNL	Patratu TPS	6	100	1972
52	PVUNL	Patratu TPS	9	110	1984
53	PVUNL	Patratu TPS	10	110	1986
54	PVUNL	Patratu TPS	7	110	1977
55	NTPC LTD.	Badarpur TPS	1	95	1973
56	NTPC LTD.	Badarpur TPS	2	95	1974
57	NTPC LTD.	Badarpur TPS	3	95	1975
58	DVC	Chandrapur TPS	2	130	1965
59	DVC	Chandrapur TPS	3	130	1968
	TOTAL			**5,926.5**	

*CEA data

LIST OF PROJECTS CONSIDERED FOR RETIREMENT AS PER NEW ENVIRONMENTAL NORMS

(Thermal station units without space for FGD installation and shall attain age of=>25years on 1/1/2022) (as on August,2017)

	Developer	Name of project	Sector	State	Region	Unit No.	Total Capacity	Yearof Commg.*
1	BSEB	BarauniTPS	State	Bihar	ER	6	105	1983
2	BSEB	BarauniTPS	State	Bihar	ER	7	105	1985
3	NTPC & BIHAR	Muzaffarpur TPS	Central	Bihar	ER	1	110	1985
4	NTPC & BIHAR	Muzaffarpur TPS	Central	Bihar	ER	2	110	1986
5	D.V.C	Bokaro `b` TPS	Central	Jharkhand	ER	1	210	1986
6	D.V.C	Bokaro `b` TPS	Central	Jharkhand	ER	2	210	1990
7	D.V.C	Bokaro `b` TPS	Central	Jharkhand	ER	3	210	1993
8	TENUGHAT VN	TenughatTPS	State	Jharkhand	ER	1	210	1994
9	TENUGHAT VN	TenughatTPS	State	Jharkhand	ER	2	210	1996
10	INDBARATH	IndbarathTPP	Private	Odisha	ER	1	350	2016
11	NTPC	Talcher (Old) TPS	Central	Odisha	ER	1	60	1967
12	NTPC	Talcher (Old) TPS	Central	Odisha	ER	2	60	1968

13	NTPC	Talcher (Old) TPS	Central	Odisha	ER	3	60	1968
14	NTPC	Talcher (Old) TPS	Central	Odisha	ER	4	60	1969
15	NTPC	Talcher (Old) TPS	Central	Odisha	ER	5	110	1982
16	NTPC	Talcher (Old) TPS	Central	Odisha	ER	6	110	1983
17	C.E.S.C. PVT.	TitagarhTPS	Private	West Bengal	ER	1	60	1985
18	C.E.S.C. PVT.	TitagarhTPS	Private	West Bengal	ER	2	60	1982
19	C.E.S.C. PVT.	TitagarhTPS	Private	West Bengal	ER	3	60	1983
20	C.E.S.C. PVT.	TitagarhTPS	Private	West Bengal	ER	4	60	1984
21	D.V.C	Durgapur TPS	Central	West Bengal	ER	4	210	1982
22	WBPDC	Bakreswar TPS	State	West Bengal	ER	1	210	2009
23	WBPDC	Bakreswar TPS	State	West Bengal	ER	2	210	1999
24	WBPDC	Bakreswar TPS	State	West Bengal	ER	3	210	2000
25	WBPDC	Bakreswar TPS	State	West Bengal	ER	4	210	2001
26	WBPDC	Bakreswar TPS	State	West Bengal	ER	5	210	2007
27	WBPDC	BandelTPS	State	West Bengal	ER	1	60	1982
28	WBPDC	BandelTPS	State	West Bengal	ER	2	60	1965
29	WBPDC	BandelTPS	State	West Bengal	ER	3	60	1965
30	WBPDC	BandelTPS	State	West Bengal	ER	4	60	1966
31	WBPDC	BandelTPS	State	West Bengal	ER	5	210	1966
32	NTPC	BadarpurTPS	Central	Delhi	NR	4	210	1978
33	NTPC	BadarpurTPS	Central	Delhi	NR	5	210	1981
34	HGP CORPN	Panipat TPS	State	Haryana	NR	5	210	---
35	PSEB	GND TPS(bhatinda	State	Punjab	NR	3	110	1978
36	PSEB	GND TPS(bhatinda	State	Punjab	NR	4	110	1979
37	PSEB	Ropar TPS	State	Punjab	NR	5	210	1992
38	PSEB	Ropar TPS	State	Punjab	NR	6	210	1993
39	RRVUNL	Kota TPS	State	Rajasthan	NR	1	110	1983
40	RRVUNL	Kota TPS	State	Rajasthan	NR	2	110	1983
41	RRVUNL	Kota TPS	State	Rajasthan	NR	3	210	1988
42	RRVUNL	Kota TPS	State	Rajasthan	NR	4	210	1989

43	RRVUNL	Kota TPS	State	Rajasthan	NR	5	210	1994
44	NTPC	TandaTPS	Central	Uttar Pardesh	NR	1	110	1988
45	NTPC	TandaTPS	Central	Uttar Pardesh	NR	2	110	1989
46	NTPC	TandaTPS	Central	Uttar Pardesh	NR	3	110	1990
47	NTPC	TandaTPS	Central	Uttar Pardesh	NR	4	110	1998
48	UPRVUNL	Harduaganj TPS	State	Uttar Pardesh	NR	7	105	1978
49	UPRVUNL	ObraTPS	State	Uttar Pardesh	NR	7	94	1974
50	UPRVUNL	ParichhaTPS	State	Uttar Pardesh	NR	1	110	1984
51	UPRVUNL	ParichhaTPS	State	Uttar Pardesh	NR	2	110	1985
52	APGENCO	Tata Rao TPS	State	A.P	SR	1	210	1979
53	APGENCO	Tata Rao TPS	State	A.P	SR	2	210	1980
54	APGENCO	Tata Rao TPS	State	A.P	SR	3	210	1989
55	APGENCO	Tata Rao TPS	State	A.P	SR	4	210	1990
56	APGENCO	Tata Rao TPS	State	A.P	SR	5	210	1994
57	APGENCO	Tata Rao TPS	State	A.P	SR	6	210	1995
58	KPCL	Raichur TPS	State	Karnataka	SR	1	210	1985
59	KPCL	Raichur TPS	State	Karnataka	SR	2	210	1986
60	KPCL	Raichur TPS	State	Karnataka	SR	3	210	1991
61	KPCL	Raichur TPS	State	Karnataka	SR	4	210	1994
62	KPCL	Raichur TPS	State	Karnataka	SR	5	210	1999
63	KPCL	Raichur TPS	State	Karnataka	SR	6	210	1999
64	KPCL	Raichur TPS	State	Karnataka	SR	7	210	2002
65	KPCL	Raichur TPS	State	Karnataka	SR	8	250	2010
66	IND BARATH	Tuticorin (p) TPP	Private	Tamil Nadu	SR	1	150	2013
67	IND BARATH	Tuticorin (p) TPP	Private	Tamil Nadu	SR	2	150	2013
68	NEYVELI LIGNITE	Neyveli (Ext) TPS	Central	Tamil Nadu	SR	1	210	2003
69	NEYVELI LIGNITE	Neyveli (Ext) TPS	Central	Tamil Nadu	SR	2	210	2002

70	NEYVELI LIGNITE	NeyveliTPS-II	Central	Tamil Nadu	SR	1	210	1988
71	NEYVELI LIGNITE	NeyveliTPS-II	Central	Tamil Nadu	SR	2	210	1987
72	NEYVELI LIGNITE	NeyveliTPS-II	Central	Tamil Nadu	SR	3	210	1987
73	NEYVELI LIGNITE	NeyveliTPS-II	Central	Tamil Nadu	SR	4	210	1991
74	NEYVELI LIGNITE	NeyveliTPS-II	Central	Tamil Nadu	SR	5	210	1991
75	NEYVELI LIGNITE	NeyveliTPS-II	Central	Tamil Nadu	SR	6	210	1992
76	NEYVELI LIGNITE	NeyveliTPS-II	Central	Tamil Nadu	SR	7	210	1993
77	TNEB	MetturTPS	State	Tamil Nadu	SR	1	210	1987
78	TNEB	MetturTPS	State	Tamil Nadu	SR	2	210	1987
79	TNEB	MetturTPS	State	Tamil Nadu	SR	3	210	1989
80	TNEB	MetturTPS	State	Tamil Nadu	SR	4	210	1990
67	IND BARATH	Tuticorin (P) TPP	Private	Tamil Nadu	SR	2	150	2013
81	TNEB	North Chennai TPS	State	Tamil Nadu	SR	1	210	1994
82	TNEB	North Chennai TPS	State	Tamil Nadu	SR	2	210	1995
83	TNEB	North Chennai TPS	State	Tamil Nadu	SR	3	210	1996
84	TNEB	Tuticorin TPS	State	Tamil Nadu	SR	1	210	1979
85	TNEB	Tuticorin TPS	State	Tamil Nadu	SR	2	210	1980
86	TNEB	Tuticorin TPS	State	Tamil Nadu	SR	3	210	1982
87	TNEB	Tuticorin TPS	State	Tamil Nadu	SR	4	210	1992
88	TNEB	Tuticorin TPS	State	Tamil Nadu	SR	5	210	1991

89	TSGENCO	Kothagudem TPS (New)	State	Telangana	SR	9	250	1997
90	TSGENCO	Kothagudem TPS (New)	State	Telangana	SR	10	250	1998
91	CSPGCL	Korba-III	State	Chhattisgarh	WR	1	120	1976
92	CSPGCL	Korba-III	State	Chhattisgarh	WR	2	120	1981
93	CSPGCL	Korba-West TPS	State	Chhattisgarh	WR	1	210	1984
94	CSPGCL	Korba-West TPS	State	Chhattisgarh	WR	2	210	1983
95	CSPGCL	Korba-West TPS	State	Chhattisgarh	WR	3	210	1985
96	CSPGCL	Korba-West TPS	State	Chhattisgarh	WR	4	210	1986
97	GSECL	Sikka Rep. TPS	State	Gujarat	WR	2	120	1993
98	TORRENT POWER GENERATION LTD,.	Sabarmati	Private	Gujarat	WR	15	30	1962
99	TORRENT POWER GENERATION LTD,.	Sabarmati	Private	Gujarat	WR	16	30	1963
100	GUPTA ENERGY P L	GEPL TPP Ph-I	Private	Maharashtra	WR	1	60	2012
101	GUPTA ENERGY P L	GEPL TPP Ph-I	Private	Maharashtra	WR	2	60	2012
	Total						**16,789**	

*CEA data

Appendix-3

Cross Border Transactions between India and South Asian countries (MUs)				
Year	**Export from Bhutan to India**	**Export from India to Nepal**	**Export from India to Bangladesh**	**Export from India to Myanmar**
2013-14	5,555	702	1,448	
2014-15	5,109	997	3,272	
2015-16	5,557	1,470	3,654	
2016-17	5,863	2,022	4,420	3
2017-18	5,611	2,388	4,808	5
2018-19 (Till Dec '18)	4,559	1,597	4,139	5