Annexure A

KE's Evaluation & Integration Plan for Competitive Trading Bilateral Contracts Market (CTBCM)

Contents

1. Purpose of the Plan

The Competitive Trading Bilateral Contracts Market (**"CTBCM"**) model envisions setting up of a competitive wholesale electricity market and the design was proposed by CPPA as per ECC directives dated April 30, 2015. On December 05, 2019, National Electric Power Regulatory Authority (**"NEPRA"**) approved the high-level design with directions to CPPA for submission of detailed design with certain modifications, which was submitted by CPPA in February 2020 and thereafter in July 2020 with subsequent changes.

NEPRA through its determination dated November 12, 2020 approved the detailed design submitted by CPPA, however, within NEPRA's determination, KE's integration under centralized economic despatch as proposed by CPPA was not approved and NEPRA directed KE to evaluate and come up with a comprehensive plan covering all financial, technical, legal, and market-related aspects of the matter with recommendations in consultation with CPPA, NTDC and NPCC for submission to NEPRA.

1.1 Structure of the Plan

KE's plan for evaluation and integration into CTBCM (**"Plan"**) is divided into different sections which include detailed assessment of the proposed CTBCM Detailed Design, evaluation of CTBCM Detailed Design in context of the existing power sector along with recommendations for a sustainable transition from the current regime to competitive markets envisioned pursuant to CTBCM.

Further, the plan details evaluation of the CPPA proposed central economic despatch and KE's proposed plan for integration into CTBCM based on the consultation process carried out with CPPA, NTDC and NPCC in accordance with NEPRA directives, entails key considerations for KE including with respect to the centralized economic despatch, tariff structure and also sets out the implementation action items for a sustainable roll out and an orderly transition towards open markets pursuant to CTBCM model.

2. KE's Overview and Current Market Structure

As a private vertically integrated utility operating in the power sector, in addition to stakeholder consultation, a holistic assessment of each of KE's Generation, Transmission and Distribution businesses along with KE's rights and obligations under licenses granted to KE, its tariff structure as well as other considerations including supply of power from the National Grid is critical for KE to prepare its plan for a sustainable roll out of CTBCM.

2.1 KE's Overview

Incorporated in 1913, KE being a Vertically Integrated Power Utility (VIU) is responsible for end-to-end planning and execution of generation, transmission, and distribution of power to its consumers within its service area which includes Karachi, Gharo in Sindh and Hub, Uthal, Vinder and Bela in Balochistan region.

Being an integrated utility, KE is involved in Generation, Transmission and Distribution businesses, details of which are provided below:

Generation

The installed capacity of KE's generation fleet will increase to 2,817 MW[1] upon commercial operations of KE's 900 MW BQPS III RLNG power plant. Through investment of over USD 1.8 Billion since privatization, KE has enhanced its generation capacity by 1,057 MW and improved overall fleet efficiency by 25%. In addition to its own generation fleet, to meet the power demand in its service area, KE also has arrangements with IPPs and National Grid. Here, it is important to highlight that unlike state-owned entities or IPPs, all the generation additions made within KE's fleet since privatization and all of KE's existing PPAs / EPAs have been executed without any sovereign guarantee.

Considering the projected increase in power demand in its service area, KE is adding a 900 MW RLNG power plant. KE is pursuing the 900 MW project in an expedient manner, and Licensee Proposed Modification (LPM) has also been approved by NEPRA in December 2020. Further, GSA for supply of 150 MMCFD RLNG has been executed with Pakistan LNG Limited (PLL) and construction works for a dedicated pipeline to KE's Bin Qasim complex have been completed.

In addition, keeping in view surplus capacity in the National Grid and shortfall within KE's service territory due to delays in KE's planned projects including the 700 MW coal project on account of pending tariff notification by the GoP which was beyond KE's control, KE is being asked to pursue off-take of additional power from the National Grid. In this regard, KE was given principle approval from GoP in June 2020 and the Power Purchase Agency Agreement (PPAA) and Interconnection Agreement (ICA) will be executed after necessary approvals from the Competent forum.

Further, the Company has planned additions of 350 MW renewable projects by 2023 / 2024 which will help diversify its fuel mix. This includes 150 MW of solar projects in Hub, Uthal, Vinder and Bela (HUVB) region, RFP of which is currently under approval from NEPRA.

Transmission

As System Operator for its service area under the Transmission License granted to KE, the Company owns and manages its transmission network, which as of June 30, 2021 comprised of 71 grid stations, 172 power trafos having transmission capacity of 6,536 MVAs, and 1,350 km of 220 kV, 132 kV and 66 kV Transmission lines.

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[1] Post decommissioning of Units 3 & 4 of BQPS – I (as per License)

To meet its service obligations and improve reliability of its transmission network, since privatization, KE has invested over USD 900 Million in its Transmission segment which has resulted in addition of 19 new grid stations and transmission capacity enhancement by around 88%, thus resulting in significantly improved transmission network reliability.

Going forward, KE's planned additions in the Transmission segment are focused on capacity enhancement and further improving network reliability and stability through addition of new grid stations, which also include grid at 500 kV level for off-take of additional supply from the National Grid, along with addition of power trafos which would increase capability to serve the growing power demand in its service area.

Distribution

Similar to other distribution companies in the country, KE operates under an exclusive distribution license for its service territory. As of June 30, 2021, KE's distribution network comprised of 1,937 feeders, and over 29,700 PMTs having distribution capacity of 8,153 MVAs.

Since privatization, cognizant of its role as the sole electricity provider within its service area, KE has invested over USD 1.2 Billion in its distribution network with a focus on capacity enhancement, improving reliability of the network and loss reduction. As a result, KE has reduced its Transmission and Distribution (T&D) losses from 34.2% in FY 2005 to 17.5% in FY 2021, doubled the distribution capacity and, over 75% of the service area is exempt from load-shed, which also includes conversion of high loss areas such as Gharo.

Initiatives undertaken by KE in its distribution segment include conversion of around 11,000 PMTs to Aerial Bundled Cable (ABC) and community engagement efforts to curb power theft and improve recovery levels, along with technological advancements including installation of Automated Meter Readers (AMRs) at PMT level and implementation of Meter Data Management System (MDMS) Project, providing greater visibility into network performance.

As the sole power distributor for its service area, KE remains committed to further improve network safety and reliability through planned additions of around 150 feeders and 2,500 PMTs till 2023, installation and replacement of protection equipment and conversion of all high loss PMTs to ABC, in line with its commitment to meet its service obligation of providing safe and reliable supply of power to its consumers.

2.2 Current Market Structure of KE Area

As a private vertically integrated power utility and exclusive supplier of power within its service area, KE is responsible for end-to-end planning of its value chain. KE's unique structure also has a bearing on its licenses and tariff determination as unlike other entities operating in the power sector, the utility operates under an integrated Multi-Year Tariff (**"MYT"**) regime.

Moreover, as mentioned above, to meet the power demand for its service area, KE has agreements with external power producers and also off-takes power from the National Grid. With regard to off-take from National Grid, discussions around additional supply from the National Grid are being finalized, as detailed in later sections.

2.2.1 KE's Licenses

KE has three separate licenses for each of its business functions. Further, it is submitted that Section 25 of the NEPRA Act, 1997 as amended through the NEPRA Amendment Act, 2018 specifically allows for grant of licenses to one or more licensees within KE's service area.

Section 25 of the NEPRA Amendment Act, 2018

Licenses of Territory Served by KESC. — (1) Notwithstanding anything contained in this Act and subject to the provisions of this section, the Authority may grant licenses [or registration under this Act] to one or more licensees [or registered persons] for the territory served by KESC at the time of commencement of this Act.

Generation License

KE was granted Generation License (GL/04/2002) on November 18, 2002 and has been modified from time to time to account for additions / deletions of power plants to / from KE's generation fleet. With respect to KE's generation license, the latest modification was issued by NEPRA in February 2021.

Details of plants within KE's generation license are given below:

Plant	BQPS-I	KCCP	KGTPS	SGTPS	BQPS-II	BQPS-III
Installed Capacity (MW)	840	247	107	107	573	942
COD	1983-97	2008-15	2009-15	2009-15	2012	2021
End of Useful Life[2]	2023-32	2039-40	2039-40	2039-40	2042	2051

Transmission License

KE's Transmission license (TL/02/2010) was granted to KE on June 11, 2010. Under this license, KE is the Transmission Network Operator and System Operator for its Service Territory. Accordingly, KE owns and manages its own transmission network and also performs the functions of System Operator for its service area through its Load Despatch Centre (LDC).

KE's state-of-the-art online LDC is operational for over 10 years. At present, the entire KE network including all grid stations and generation plants are adopted and are being monitored / controlled through SCADA. Further, SCADA is being utilized for Grid Code compliance like power quality monitoring, optimal power flows etc., and its archives are also used for routine switching operations, planned outage management, RCA and for the generation of performance-based reports. Further, as part of its TP-1000 project, KE has upgraded the SCADA SINUAT spectrum from 4.5 to 4.7.

In addition to being the System Operator for its service area, KE's Transmission License also obliges KE to perform the functions of a Planner, preparing short-and long-term plans, which is also supplemented by KE's vertically integrated structure responsible for all three functions.

Distribution License

KE was granted an exclusive Distribution license (09/DL/2003) on July 21, 2003, which allows KE to exclusively carry out distribution service and make sales of electric power within its service territory. Under KE's existing distribution license, there is no separation of distribution network and supply business, and therefore, KE under its distribution license performs both these functions.

2.2.2 KE's Integrated Multi-Year (MYT) Tariff Regime

KE's current tariff is an integrated MYT which was finalized on July 05, 2018 and is for a 7-year period, valid till June 30, 2023. This is a cost-plus tariff, premised upon KE's distribution exclusivity and allowed returns are linked with certain KPIs such as sent-out growth, T&D loss targets etc. The tariff setting is based

[2] Useful life as per Generation License Modification-X (dated February 19, 2021)

on the principles of cross-subsidization where high-end consumer categories (mainly industrial and commercial) cross-subsidize the low-end consumer categories.

Given that the current tariff is based on KE's distribution exclusivity for the tariff control period, the sent-out targets and T&D loss projections do not take into account Bulk Power Consumers (**"BPC"**) *(eligible consumers as per the CTBCM Detailed Design)* within KE's service area moving into bilateral contracts. In this regard, it is also submitted that NEPRA while assessing the risk profile of KE and allowing returns for KE's T&D segment within the MYT, has considered that the T&D licenses granted to KE provides exclusivity to KE. Accordingly, KE's planned and committed investments going forward, also submitted as part of KE's MYT Mid-term review request, are premised on the same, and include planned investments keeping in view the projected demand growth and capacity enhancement required to meet projected demand from BPCs as well.

Para 14.16 of MYT Review Decision dated October 09, 2017

*"...the **Authority considers that the transmission and distribution license granted to K-Electric provides exclusivity for its operations,** whereby, laying down any distribution or transmission lines is the sole responsibility as well as opportunity for K-Electric..."*

It is further submitted that under KE's tariff capacity payment for generation in the form of return on asset base and depreciation is allowed without any link to dispatch, i.e. similar to 'Take or Pay' arrangement with IPPs, while overall sent out units remain a KPI for KE. Moreover, under the existing tariff, there is no separate component for variable O&M for KE's Generation business and the same will also be evaluated during the implementation phase for KE's integration into the CTBCM as further detailed in Section 5.3 of this Plan.

Here, it is important to highlight that under the existing tariff regime, DISCOs and KE are obligated to charge consumers based on GoP's Uniform Tariff Policy, whereas, Generators / Competitive Suppliers supplying to BPCs *(eligible consumers under CTBCM)* will have an undue advantage as they will be able to avoid cross-subsidy charges imposed by GoP as per its Uniform Tariff Policy. Accordingly, required revisions in this respect shall remain a key consideration for KE's tariff post 2023 as well as KE's participation in CTBCM.

(Evaluation of KE's tariff post 2023 and under CTBCM is detailed in Section 5.3 of this Plan).

2.2.3 Supply of Power from External Sources including the National Grid

As mentioned in the previous section, in addition to its own generation, KE has arrangements with IPPs and the National Grid. Unlike in the case of state-owned DISCOs where GoP plans and procures power on behalf of state-owned DISCOs and the PPAs / EPAs entered into by CPPA are backed by sovereign guarantee, KE performs the function of planning and capacity procurement on its own and enters into long-term PPAs / EPAs bilaterally, without any sovereign support.

As an integrated utility responsible for end-to-end planning of its value chain, to meet the projected growth in power demand in its service area, KE had planned generation additions including 700 MW coal project. However, keeping in view the surplus capacity in the National Grid, based on discussions with relevant stakeholders including GoP and NEPRA, KE is now pursuing additional supply of upto 1,400 MW[3] from the National Grid to bridge the projected shortfall, instead of planned 700 MW coal and other projects.

[3] With completion of required rehabilitation and upgradation works on the 220kV KDA-Jamshoro line, off-take from National Grid has increased by 450 MW i.e. total upto 1,100 MW from existing interconnections. Additional supply of 1,400 MW from National Grid includes additional off-take of upto 450 MW from existing interconnections.

As detailed above, finalization of contractual arrangements for off-take of additional supply from the National Grid is in advanced stages and will be executed after necessary approvals from the Competent Forum. Here, it is also pertinent to mention that the current arrangement for supply from National Grid provides for a security mechanism and accordingly, KE understands that the requirement of escrow account for off-take of power from the central pool, as mentioned in the CTBCM Detailed Design does not apply to KE.

Further, it is also important to consider that under the existing regime, KE manages despatch for its service area based on Economic Merit Order (**"EMO"**) of KE plants, IPPs with which KE has bilateral arrangement and supply from National Grid. Moreover, under the current structure, energy charges for off-take from the National Grid are invoiced based on average basket rate, whereas capacity charges are billed on monthly Maximum Demand Indicator (**"MDI"**) basis.

(Detailed evaluation of mechanism for centralized despatch as proposed under CTBCM, and capacity and energy invoicing mechanism is detailed in Section 5 of this Plan).

3. Key Features of CTBCM, Areas to be Firmed Up & Other Design Considerations

The CTBCM model envisages a shift from the existing single buyer model to a competitive wholesale electricity market, allowing eligible consumers to enter into bilateral contracts for their demand (energy and capacity) requirements, along with certain other initiatives aimed at bringing structural shifts at sector level as well as capacity building of state-owned entities. The CTBCM model is a major change to Pakistan's power sector landscape, aimed at bringing efficiency in the power sector and structural changes directed towards development of an efficient liquid power market. KE appreciates market reforms for an efficient competitive power market and is confident that appropriate policy decisions for implementation as envisaged under the National Electricity Policy 2021 would help shape a resilient Pakistan power market for the future.

As further detailed in Section 3.2 of the Plan, various aspects of the CTBCM Detailed Design have been approved on an indicative basis and are to be firmed up during the implementation phase of CTBCM. In view of this, KE requests that a firmed up CTBCM design is provided to enable a thorough evaluation and sustainable transition.

3.1 Key Features of CTBCM

As summarized above, the CTBCM model envisages a shift from the existing single buyer regime to a competitive wholesale electricity market, thus introducing new market players along with capacity building of institutions and structural shifts including a single country-wide central economic despatch.

With regard to execution of bilateral contracts as envisioned in the CTBCM, the model introduces the concept of 'eligibility' used to designate the consumers which are granted the choice to change their supplier (other than DISCOs and KE) by entering into bilateral contracts. It also makes reference to the NEPRA Act in respect of eligibility being granted only to BPC. This framework implies that after the introduction of the CTBCM model, two parallel markets will co-exist, namely (i) a competitive market for eligible consumers, and (ii) a regulated market for consumers who are not eligible to enter into bilateral contracts until the time the eligibility threshold is modified to include such consumers as well.

In this context, it is also important to distinguish between the different components of last resort supply which can be done using the separate constructs of a Base Supplier (supplier mandated to ensure universal service obligation) and a Last Resort Supplier (reserve supplier in case a competitive supplier becomes unable to discharge its obligations). The convention typically used in other markets is as follows:

- A **Base Supplier** operates on the regulated market and sells energy to end consumers at regulated tariffs. In many cases, the regulators establish a market structure which enables the Base Supplier to also procure energy and capacity at regulated prices, especially where end tariffs are not on cost of service basis and/or are subject to cross subsidies. The function of the Base Supplier is typically linked with the universal service obligation which is aimed to provide protection for small enterprises and residential customers.
- A **Last Resort Supplier** operates on the competitive market and sells energy (and/or capacity) to eligible consumers in case the latter have not entered into bilateral contract with a Competitive Supplier or the Competitive Supplier fails to discharge its obligations towards such eligible consumers (for example, when a supplier goes bankrupt or the license of a competitive supplier is revoked). Given that such a role is imposed by the regulatory framework, there also needs to be a framework to govern the cost recovery for performing such a role by the DISCOs/KE. In other markets, the tariffs charged by Last Resort Suppliers are typically material inferior (higher) to those

of Competitive Suppliers in order to discourage the use of such suppliers on ordinary basis where such motivation can be additionally enhanced by restrictions on the time period during which an eligible consumer can be served by a Last Resort Supplier. For example, the Market Monitoring Report for 2018 by the Agency for the Cooperation of Energy Regulators in Europe (ACER) concluded that most member states intervene in the price setting of the Last Resort Supplier in some fashion as well as that Last Resort Supplier prices tend, on average, to be higher than the prices paid by consumers served by competitive suppliers in the majority of member states. Also, there was no single member state where energy sold by a Last Resort Supplier was generally cheaper than a comparable standard product. An example was provided for Sweden where the Last Resort Supplier price was estimated to be 20-30% higher than comparable contracts. A similar concept of Provider of Last Resort also exists in US markets, for example in Texas, where the Public Utility Commission of Texas has designated Providers of Last Resort (POLR) as a backup electric service provider in each area of Texas open to competition. POLR service is relatively high-priced due to the costs associated with planning and the risk of serving an uncertain number of consumers with uncertain electricity loads. POLR service is a safety net for consumers whose chosen Competitive Supplier is unable to continue or ensure provision of service as per their bilateral contracts. A review of the POLRs appointed for 2021-2022 and their Service Area Rates indicates that for the different consumer segments, the energy charge component of the rate is 20-25% higher than the respective real-time settlement point prices for the consumer's load zone. There is also a floor rate for the energy charge component which is intended to prevent POLRs being exposed to fluctuations on the real time market resulting in very low or negative prices because the POLR rate is not intended to be a competitive offering. In addition to the energy charge, the POLR service rates also include non-bypassable charges and a customer charge.

In view of the above, it is recommended that the CTBCM Detailed Design and related rules and regulations clearly distinguish between a Base Supplier and a Last Resort Supplier, defining mechanism / instances allowing for use of such Last Resort Suppliers. Further, in line with international practices as mentioned above, tariffs charged by Last Resort Suppliers should be higher than that charged by Competitive Suppliers and a time period should be set with respect to facilitation by DISCOs or KE in their role of Last Resort Suppliers, to limit the use of such suppliers, which otherwise can have material implications from planning perspective for DISCOs and KE, ultimately having an impact on security of supply.

3.1.1 Structural Shifts under CTBCM

The CTBCM model seeks to bring the following key structural reforms:

- **Security Constrained Economic Despatch (SCED)**

With a single country-wide central economic despatch, CTBCM envisages to bring in efficiency in the generation segment, which will be subject to network security constraints and despatch commitments under respective Fuel Supply contracts. The underlying idea behind a single country-wide central economic despatch is to phase out the inefficient generators from the system and benefit from cost optimization at national level along with greater transparency.

The CTBCM model and in particular the SCED makes reference to using variable cost of generation as a basis for determination of the merit order and setting of the market clearing prices in the Balancing Mechanism for energy. However, further clarity is required on how other cost components of the "make-whole / uplift" type will be reflected in potential uplift payments, for example start-up costs and no-load costs. Further, with regard to operating cost and decision making for despatch purposes under central despatch, key considerations have been highlighted in Section 4.2.2 of the Plan.

Moreover, while the integration of captives has not been approved by NEPRA within its determination dated November 12, 2020, and a framework in this regard is to be provided by NEPRA during the implementation phase of CTBCM, considering the challenge of low grid utilization and that the basic premise of having a single country-wide central despatch under CTBCM is to phase out inefficient generators from the system, therefore, captive generators shall also be integrated as part of the central despatch, as also stated in Section 4.5.1 of the Detailed Design.

Section 4.5.1 of Detailed Design

"Captive Generators intending to wheel power for self-consumption or selling to third parties through the grid shall register as market participants and will be subject to all requirements of market participants."

Further, the CTBCM Detailed Design also proposes KE's integration into CTBCM based on central economic despatch, and NEPRA in its decision dated November 12, 2020 directed KE and other stakeholders to evaluate the same as part of KE's Evaluation and Integration Plan for CTBCM. Accordingly, detailed evaluation of KE's integration under central economic despatch is given in Section 5.1 of the Plan.

- **Commercial Allocation of Existing PPAs / EPAs**

Under CTBCM Detailed Design, the existing PPAs / EPAs at the time of commercial operations of CTBCM are to be allocated to DISCOs and KE. In this regard, as per discussions, it has been proposed by CPPA that the existing PPAs / EPAs will be allocated to DISCOs based on their share in the system peak demand on co-incidental basis, whereas KE will be allocated to the extent of contracted capacity for supply from National Grid / central pool (for example, with the additional off-take of 1,400 MW from the National Grid taking the total to 2,050 MW from 2023 onwards, KE's share from the existing PPAs will gradually increase to upto 2,050 MW from 2023 onwards). However, mechanism for commercial allocation of existing PPAs / EPAs is to be firmed up and finalized during the implementation phase of CTBCM.

Further, during the regulatory proceedings in relation to CTBCM, as submitted by CPPA, while the existing PPAs / EPAs are to be commercially allocated to DISCOs and KE and treated as bilateral contracts once CTBCM is operational, provisions of the existing PPAs / EPAs will remain unchanged.

In addition to commercial allocation of existing PPAs / EPAs, considerable deliberation was done between KE and CPPA in terms of the capacity invoicing mechanism under CTBCM. Initially, it was proposed by CPPA that DISCOs and KE will be billed capacity charges based on their share of allocated capacity from the National Grid regardless of their off-take, and as such it was proposed to shift from the existing MDI basis to a 'Take or Pay' regime for the purpose of capacity invoicing for off-take from the National Grid.

However, subsequently, based on discussions, CPPA has revised the proposed mechanism for capacity invoicing and during the consultation process, CPPA has proposed that the existing mechanism of capacity invoicing on monthly MDI on co-incidental basis shall continue for both DISCOs and KE under CTBCM. Moreover, based on discussions with CPPA, KE understands that for any change in capacity invoicing mechanism in the future, similar treatment shall be applied to KE and DISCOs and any revisions to the capacity invoicing mechanism shall be finalized in consultation with all stakeholders.

- **Balancing Mechanism**

Under CTBCM, any imbalances between contracted and actual quantity will be settled in the balancing mechanism, centrally administered by the Market Operator, wherein market participants will be required to provide credit cover to Market Operator for settlement of any imbalances.

Since the market will have contracts for energy as well as capacity, the design proposes separate balancing mechanism for energy and capacity, wherein imbalances will be settled on a monthly and yearly basis, respectively. Initially, at the time of commercial operations of CTBCM, Balancing Mechanism for Energy (BME) is set to become functional, whereas, the design proposes that Balancing Mechanism for Capacity (BMC) will become operational after two years of market COD.

- **Types of Contracts under CTBCM**

As detailed above, CTBCM envisages a shift from a single buyer model to a competitive wholesale electricity market, wherein BPCs, Suppliers, Traders and Generators can directly enter into bilateral contracts for energy and capacity.

In this respect, the different types of contract designs under CTBCM are summarized below:

– **Generation Following Supply Contract:** Under this type of contract, the contract quantity of the buyer follows the actual generation of the generator, and not the buyer's actual demand or peak demand. Accordingly, seller's energy payment is based on what the seller has generated, and the contract price agreed under the bilateral contract and there is no risk of imbalance for the generator. This design is appropriate for non-controllable generation such as renewables.

Illustration of a Generation Following Supply Contract & Settlement under Balancing Mechanism

Suppose a Generator enters into bilateral contracts with $Demand_1$ and $Demand_2$ as follows:

- 60% of generation contracted with $Demand_1$
- 40% of generation contracted with $Demand_2$

During a particular hour, the Generator injects 200MWh of energy into the system, accordingly, the share of D_1 and D_2 would be as follows:

- $Demand_1$ share: 200 MWh x 60% = 120 MWh
- $Demand_2$ share: 200 MWh x 40% = 80 MWh

However, as the despatch is on central economic basis, energy injected by the Generator may be despatched to meet demand of other demand participants which may not necessarily be in a bilateral contract with the particular Generator. Therefore, suppose during this particular hour, the actual drawl of demand participants was as follows:

- $Demand_1$ draws 100 MWh
- $Demand_2$ draws 90MWh
- $Demand_3$ draws 10 MWh

As a result, $Demand_1$ has a positive imbalance of 20MWh (120 – 100) which will be sold in the Balancing Mechanism. This will be purchased by $Demand_2$ having a negative imbalance of 10MWh (80 – 90) and another 10 MWh will be purchased by $Demand_3$ in the Balancing Mechanism at the prevailing marginal price of the system.

Within the Detailed Design, it was proposed that the existing PPAs / EPAs at the time of commercial operations of CTBCM will take the form of Generation Following Supply Contract. However, based on evaluation, the same exposed DISCOs and KE to the risk of imbalance between DISCOs and KE despite DISCOs and KE ensuring that their demand remains within the allocated capacity.

Subsequently, based on discussions with CPPA, and after review of contract designs, CPPA has proposed that the existing PPAs / EPAs will be converted into a separate contract design whereby DISCOs and KE will not be exposed to the risk of imbalances to the extent of their contracted / allocated legacy PPAs / EPAs capacity, as further detailed in Section 4.2.1 of the Plan, (i.e. in KE's case, power drawn upto 2,050 MW will be charged at basket rate, and any power drawn beyond 2,050 MW shall be charged at the prevailing marginal rate of the system).

– **Load Following Supply Contract:** In this type of contract, the contract quantity is quantified as a percentage of buyer's actual consumption or peak demand, and therefore, if 100% contracted, the buyer does not face any risk of imbalance.

  Accordingly, seller's energy payment is based on what the buyer actually consumes / actually demands and the contract price.

Illustration of a Load Following Supply Contract & Settlement under Balancing Mechanism

Under a Load Following Supply Contract, if 100% contracted, demand participant does not face any imbalance. As CTBCM proposes a central economic despatch, the System Operator manages total despatch in the system such that the overall cost is optimized.

Suppose Demand_1 enters into a Load Following Supply Contract with Generator_1 for 100% of its demand.

Generator_1 injects less than 100% of the contracted energy

Suppose during a particular hour, the demand profile and power injected by the Generator_1 were as follows:

- Demand_1 consumes 100MWh
- Generator_1 injects 80MWh

In such a scenario, the remaining 20 MWh demand will be met through the balancing mechanism by another generator (Generator_2). Accordingly, Generator_1 has a negative imbalance of 20 MWh.

Settlement shall be carried out as follows:

- Demand_1 will pay Generator_1 for 100 MWh as per the price agreed in the bilateral contract
- Generator_1 will pay for 20 MWh in the balancing market as per the prevailing marginal rate for that hour

As a result, in case where the marginal rate for the particular hour (rate at which the settlement is done in the balancing mechanism) is lower than contract price, Generator_1 will benefit, and vice-versa.

Generator_1 injects more than 100% of the contracted energy

Suppose during a particular hour, demand profile and energy injected by the Generator_1 were as follows:

- Demand_1 consumes 100MWh
- Generator_1 produces 120MWh

In this particular scenario, Generator_1 will have a positive imbalance of 20MWh, which will be sold in the balancing market at the prevailing marginal rate for that hour. As the despatch will be on centralized economic basis, therefore despatch by Generator_1 beyond the contracted 100%

(100 MWh) would only be in case where the operating cost of $Generator_1$ is lower than the marginal cost of the system.

Settlement shall be carried out as follows:

- $Demand_1$ will pay $Generator_1$ for 100 MWh as per the price agreed in the bilateral contract
- $Generator_1$ will sell 20 MWh in the balancing market as per the prevailing marginal rate for that hour which will be higher than the operating cost of the $Generator_1$, thus $Generator_1$ will benefit in this scenario.

– **Fixed Quantity Supply Contract:** Under a Fixed Quantity Supply Contract, fixed quantities are agreed in advance between the buyer and the seller. This contract is financial in nature, where the buyer has an obligation to pay but not to consume, and the seller has an obligation to supply but not to generate.

Illustration of a Fixed Quantity Supply Contract & Settlement under Balancing Mechanism

$Demand_1$ and $Generator_1$ enter into a Fixed Quantity Supply Contract for 100MWh of energy. $Generator_1$ takes the view that the marginal price of the system will be lower than the price agreed in the bilateral contract. Therefore, $Generator_1$ may not generate and instead purchase 100 MWh of energy from the balancing market to meet its contractual obligations.

Similarly, in a scenario where $Demand_1$ speculates that the marginal price would be higher than the contracted price, $Demand_1$ can sell the 100MWh in the Balancing Mechanism.

Considering the implications of contract types on market participants and overall functioning of the market, detailed assessment / evaluation of these contract designs has been done in Section 4.2.1 of the Plan.

- **Market Participants & Service Providers**

The market structure under CTBCM is defined by types and functions of Service Providers and Market Participants as detailed below.

Market Participants

Market Participants are entities that buy and / or sell electricity in the market. The market design includes the following types of Market Participants:

- **Generators:** Generators can enter into bilateral contracts with demand participants and sell directly to BPCs and Traders, based on a Competitive Supplier license. Further, under the CTBCM, it is proposed that generators without having bilateral contracts can also participate in the market as merchant plants, and their cost recovery shall depend on despatch on centralized economic basis. Accordingly, in case of such merchant plants, the risk of cost recovery is with the generator.

KE's Participation:

Similar to existing and committed IPPs, KE's existing generation fleet as well as the upcoming 900 MW RLNG power plant along with bilateral contracts that KE has entered into with IPPs / National Grid will be considered towards KE's contracted capacity to meet KE's capacity obligations.

- **Suppliers:** Licensed entities as per the NEPRA Amendment Act 2018, involved in procurement of electricity (energy and capacity) and selling it to end consumers, either eligible consumers (BPCs as per CTBCM design) or other consumers. The CTBCM model envisages two types of suppliers (i) Base Supplier / Last Resort Supplier which will be the existing DISCOs and KE, and (ii) Competitive Suppliers.

  KE understands that DISCOs and KE in their role of Base Supplier / Last Resort Supplier will be responsible to meet the demand of regulated consumers (i.e. those who do not move into bilateral contracts) or eligible consumers who entered into a bilateral contract, however, their Competitive Suppliers failed to discharge their obligations towards such eligible consumers and they fall back on DISCOs and KE. Whereas, Competitive Suppliers will only be able to sell to BPCs / eligible consumers having bilateral contracts.

  In this regard, NEPRA has also initiated consultation process for Suppliers Regulations, wherein as per the draft regulations, Competitive Suppliers can provide supply of electric power services to all consumers, whereas as per CTBCM, eligible consumers who can move into bilateral contracts are only BPCs. KE through its letter dated April 19, 2021 and June 22, 2021 has submitted its comments as part of proceedings on Suppliers Regulations and humbly requests NEPRA to take the same into consideration.

KE's Participation:
KE, under its distribution license, will continue to perform the functions of supplier within its service area and will engage in sales to end consumers, either BPCs or the regulated consumers.
Moreover, for participation as competitive supplier, KE understands that KE may have to form a separate legal entity.

- **Traders:** Licensed entities allowed to buy and sell electricity to other market participants at wholesale level and can be involved in import and export activities.

KE's Participation:
As a Trader, KE may engage in buying and selling of electricity to other market participants by entering into agreement(s) with one or more generators (as a generation aggregator) and sell the aggregated generation in the market through bilateral contracts.
However, similar to Suppliers, eligibility criteria for traders is awaited and KE requests that the same be finalized after required deliberation with stakeholders.

- **Bulk Power Consumers (BPCs):** Eligible consumers as per CTBCM Detailed Design who can purchase power directly from the market or enter into bilateral contracts with Generators / Suppliers.

- **Special Purpose Trader (SPT):** As per the CTBCM Detailed Design, it is proposed that SPT will be a government-owned entity which will be a spinoff from the existing CPPA and will be responsible for commercial allocation as well as management of existing PPAs / EPAs.

Service Providers

Service Providers are entities that will provide non-discriminatory services to all Market Participants, but do not buy or sell electricity in the market. Different types of Service Providers under CTBCM are as follows:

- **Market Operator:** Market Operator will be responsible for admission and registration of market participants and contracts, administration of the Balancing Mechanism, and management of imbalances including calculation of security / credit cover, settlement and payment system etc. Within the Detailed Design, it is proposed that Market Operator will be a carve out from the existing CPPA.

- **Independent Auction Administrator (IAA):** A state-owned entity responsible for new capacity procurement for DISCOs, to facilitate DISCOs in meeting their capacity obligations. IAA will not sign contracts on behalf of DISCOs but will only be a facilitator and DISCOs will be responsible for bilateral execution of contracts to meet their capacity obligations.

  Further, IAA will also facilitate in arranging credit cover for financially weak DISCOs, for their participation in the balancing mechanism, and as per the Detailed Design, initially, PPIB and AEDB will be functioning as IAA.

  Responsible for power planning of its service area, KE, without any sovereign guarantee, has added efficient generation through additions in its own generation fleet as well as by executing bilateral contracts with IPPs, and will continue to perform this function in accordance with relevant rules and regulations as prescribed by NEPRA from time to time.

- **System Operator:** The System Operator under CTBCM is responsible to administer transmission system operations including generation scheduling, commitment and administration of open access to the transmission grid.

KE's Participation:
Under its Transmission License, KE is the System Operator for its service territory and will continue to perform the functions of System Operator for its service area under CTBCM, as also evaluated in detail in Section 5.1 of this Plan.

- **Transmission Network Operator:** As per the CTBCM Detailed Design, Transmission Network Operator will look after transmission wire business and will be responsible for providing reliable transmission network infrastructure / services.

KE's Participation:
Under its Transmission License, KE is the Transmission Network Operator for its service area and owns and manages its own transmission network. Therefore, under the CTBCM, KE will continue to perform the functions of Transmission Network Operator in its service area in accordance with its Transmission License.

- **Distribution Network Service Operator:** Distribution licensees will be responsible for developing adequate and reliable distribution network in their respective service territories.

KE's Participation:
As is the case in role of Supplier, KE will continue to perform its role of Distribution Network Service Operator. Further, in its role as Distribution Network Service Operator, KE will continue to prepare and submit its investment plan as part of MYT for NEPRA's approval, subject to periodic review / adjustment mechanism.

- **Planner:** The Planner function will be responsible for preparation of an Indicative Generation Capacity Expansion Plan (**"IGCEP"**) and development of least cost Transmission System

Expansion Plan (**"TSEP"**), after due consideration of power plants under construction as well as demand information.

KE's Participation:

Transmission License granted to KE obliges KE to be the Planner for its system. Moreover, under Section 23G of the NEPRA Amendment Act, 2018, the functions of Planner are to be performed by the licensed System Operator, which is KE for its service area, and accordingly, KE will continue to perform the role of Planner for its service area.

However, to facilitate integrated planning at national level, KE as Planner for its service area shall collaborate with NTDC / NPCC for provision of required information including projected demand growth, planned capacity additions, etc., to enable development of a long-term least cost based IGCEP and a least cost-based TSEP, subject to NEPRA's approval.

In addition, operating under an integrated MYT regime, KE, as part of its tariff petition will also submit its investment plan for the tariff control period having details of KE's planned projects across the power value chain.

- **Metering Service Provider:** The Metering Service Provider will be responsible to collect all metering information required by the Market Operator to perform the settlement functions, to assess their completeness and consistency and to transfer them to the Market Operator, with established periodicity.

KE's Participation:

KE being the network service provider, is responsible for the metering services of Generation plants, IPPs, captive power plants and consumers connected to its network and KE is equipped with State-of-the-art AMR metering system.

Accordingly, KE shall continue to perform the functions of Metering Service Provider for its service area and is in discussions with CPPA *(proposed Market Operator under CTBCM)* for formulation of a joint SOP for the purpose of data exchange and other modalities required to execute the settlement function in the market.

3.1.2 Introduction of a Competitive Wholesale Electricity Market

The envisaged competitive electricity market under the CTBCM allows BPCs *(eligible consumers under CTBCM)*, which account for around 16% of the overall sales at national level, to enter into bilateral contracts with generators / competitive suppliers or procure power from the market.

As per the NEPRA Amendment Act, 2018, a BPC is defined as follows:

Definition of Bulk Power Consumer as per NEPRA Amendment Act, 2018

Bulk-power consumer means a consumer who purchases or receives electric power, at one premises, in an amount of one megawatt or more or in such other amount and voltage level and with such other characteristics as the Authority may [specify] and the Authority may [specify] different amounts and voltage levels and with such other characteristics for different areas.

As per the draft Suppliers Regulations, a competitive supplier can provide supply of electric power services to all consumers, and therefore does not specify any threshold for consumers eligible to move into bilateral contracts. Considering the possible implications that the same may have on enabling a sustainable roll out of CTBCM as well as from planning perspective for DISCOs and KE in the absence of clearly defined thresholds for consumers who are eligible to participate in competitive markets / move into bilateral contracts, KE requests that the same is finalized including mechanism and periodicity for review / any adjustments to the thresholds in the future, after detailed consultation with all stakeholders.

Further, as stated above, KE has submitted its comments on the draft Suppliers Regulations through its letter dated April 19, 2021 and June 22, 2021, and humbly requests NEPRA's consideration of the same. *(For the purpose of this Plan, evaluation has been made considering BPCs as eligible consumers who can move into bilateral contracts in line with the approved Detailed Design).*

Moreover, detailed assessment in context of the existing power sector and its associated challenges is done in Section 4.1 of the Plan.

3.1.3 Capacity Building of State Entities

One of the key challenges faced by the power sector today is the significantly over contracted capacity. Identified in the Detailed Design as well, a structural weakness in the overall planning process has been ineffective demand forecasting at national level, resulting in significant over contracting of capacity.

Accordingly, the CTBCM model envisages capacity building of state entities by:

- Reducing their dependence on the GoP for financial sustainability as well as planning future capacity procurement by DISCOs which will be through execution of bilateral contracts under CTBCM
- Conducting Financial Health Assessment (FHA) of DISCOs to assess their credit cover requirement which is a pre-requisite for their participation in the balancing mechanism
- Restructuring within state entities to align with CTBCM framework

3.2 Areas to be firmed up within CTBCM Framework & Other Design Considerations

Within the CTBCM Detailed Design approved by NEPRA, there are areas which have been approved by NEPRA on an indicative basis and are still to be firmed up by stakeholders including CPPA, and subsequently approved by NEPRA.

Considering that CTBCM model is a major change to Pakistan's power sector landscape, to ensure a sustainable transition, it is imperative that areas pending finalization and other design considerations, as detailed below, are firmed up in consultation with all stakeholders which is imperative for a healthy competitive power market and to ensure reliable power supply at least cost for all consumers.

In view of the above, it is humbly submitted that since the following areas have been approved on an indicative basis by NEPRA, therefore, once finalized, in case any change is required in KE's Plan, the same shall be submitted for NEPRA's approval accordingly.

i. Contracts & Capacity

The approved Detailed Design of CTBCM includes various aspects related to contracts and capacity of generators that have been approved on an indicative basis and are to be firmed up during the implementation phase, as summarized below:

a. Firm Capacity of Generators

With the increasing share of variable renewable generation and their intermittent nature in terms of despatchability, CTBCM has proposed the concept of 'Firm Capacity' with the objective of providing security to the system. As detailed in Section 5.3 of the Detailed Design, firm capacity will be a certified product and procedures will be established to calculate firm capacity of different types of generation technologies to assign them a firm capacity certificate which will also determine the maximum capacity which generators can contract upto.

As a result, firm capacity certificate will be particularly important with regard to capacity contracts / capacity obligations under CTBCM. However, details of methodology for calculating firm capacities are to be prepared by CPPA for NEPRA's approval during the implementation phase.

Action Item:

CPPA to prepare detailed methodology for calculation of firm capacity, to be approved by NEPRA after consultation with stakeholders.

b. Types of Contracts under CTBCM

With regard to design of the contracts, the proposed contract types / models have been deemed indicative in the approved design, as future contracts will still be subject to NEPRA's approval. Given the indicative state in which future contract designs have been approved, market players will need clarity / confirmation on the same so that contracts may be entered into / executed accordingly.

Here, it is also submitted that based on the details shared within the Detailed Design and the consultation process, types of contracts under CTBCM and their possible implications have been evaluated in Section 4.2.1 of the Plan.

Action Item:

Confirmation is requested from NEPRA on the design of future contracts enabling an efficient and liquid power market as envisaged under CTBCM.

c. Allocation of Existing PPAs & EPAs

As detailed above, during the consultation process, CPPA proposed that for the purpose of allocation of existing PPAs / EPAs, KE shall be allocated a fixed share based on its contract with CPPA / National Grid, whereas DISCOs will be allocated their share based on their contribution to system peak on co-incidental basis. Further, it has been proposed by CPPA that capacity invoicing for supply from National Grid shall continue to be on monthly MDI basis for KE and DISCOs.

However, the allocation mechanism for existing PPAs / EPAs as well as capacity invoicing mechanism is to be firmed up as part of the CTBCM implementation phase, for which CPPA is required to prepare methodology in consultation with Power Division, DISCOs and KE.

Given the commercial and financial significance of this for KE and DISCOs as also detailed in Section 5.2 of the Plan, it is critical that as part of the process to firm up the mechanism for allocation of existing PPAs / EPAs and capacity invoicing mechanism, detailed consultation is carried out with all stakeholders.

KE's evaluation and recommendation with respect to allocation of existing PPAs / EPAs and capacity invoicing mechanism is given in Section 5.2 of the Plan.

ii. Pricing in Balancing Mechanism

As briefed in Section 3.1.1 of the Plan, under the CTBCM model, the contracts market is complemented with Balancing Mechanisms, both for Energy and Capacity, to settle imbalances related to energy and capacity. This is a necessary feature of the market to ensure that the cost of imbalances is not socialized but is allocated to respective market participants. However, within NEPRA's determination, balancing mechanism has been approved on an indicative basis and the formula / mechanism including pricing of energy and capacity for the purposes of settlement of imbalances will be subject to changes during the development of codes and other applicable documents.

a. Pricing in Balancing Mechanism for Energy (BME)

As per the CTBCM Detailed Design, energy balancing price will be based on marginal cost principle, to be calculated on an hourly basis. However, as mentioned in Section 11.2 of the Detailed Design, detailed methodology for calculating the BME price on hourly basis is to be developed by the Market Operator, which will then be approved by NEPRA.

It is submitted that since there is always a tendency for deviation between the actual and committed quantities of energy, it is critical that the pricing methodology for settlement of such imbalances is finalized in consultation with all stakeholders and keeping in view the best international practices, prior to commercial operations of CTBCM.

In this regard, an important consideration would be technological interventions / capacity required to gather the underlying data for determination of price to settle imbalances. Given the commercial implications of balancing market, prior to commercialization of CTBCM, it is recommended that rigorous testing of the data should be done and made accessible to all market participants to ensure transparency and efficient functioning of the market.

Action Item:

Market Operator to develop a detailed methodology for calculation of pricing in BME in consultation with all stakeholders for NEPRA's approval.

Upon completion of NTDC's SMS metering project, prior to commercialization of CTBCM, underlying data gathered should be shared with all stakeholders to ensure correctness and bring transparency in the process.

b. Pricing in Balancing Mechanism for Capacity (BMC)

The purpose of balancing mechanism for capacity is to settle differences between the capacity obligations of demand participants and available capacity of generators during critical hours, with the capacity contracted (bought or sold in contracts). As per the CTBCM Detailed Design, critical hours are presumed to be those hours of the previous year in which the power system is at maximum stress. Accordingly, in principle, these hours are those in which the amount of reserves in the system are minimal.

However, with regard to pricing in BMC, it is submitted that the following areas are to be finalized during the implementation phase:

- Detailed methodology for determining the critical hours to be developed by System Operator.
- Minimum Planning Reserve (**"MPR"**) which will be minimum reserve required to assure secure operation of the system and the minimum amount of reserves required to comply with the limits established in the Grid Code. Under CTBCM, Planner is responsible for calculation of MPR.
- Reference technology to be considered for the purpose of determining the capacity cost in balancing mechanism, to be provided by the Planner.

With respect to the proposed methodology for pricing of capacity in the balancing market, it is further submitted that detailed explanation and elaboration is required for the proposed methodology and given the material implications that the same may have on market efficiency as well as security of supply, detailed deliberation in consultation with all stakeholders is recommended in this respect.

Action Item:
NPCC to develop detailed methodology for critical hours, MPR and reference technology to be used in calculation of capacity pricing for BMC in consultation with stakeholders for NEPRA's approval.

c. Contracts Register

All contracts under the CTBCM are required to be registered with the Market Operator through a Contract Register, which will serve as a database for calculation and settlement of imbalances. For this purpose, information for Contract Register will be obtained through Market Participation Agreement (MPA), however, the template for this agreement is yet to be shared by Market Operator for NEPRA's approval.

Further, as mentioned in Section 8.2 of the Detailed Design, only those contracts which have valid registration in the Contract Register will be considered in the calculation and settlement of imbalances. Accordingly, clarity is required with respect to participation of merchant plants in the balancing market, as KE understands that these plants will not be entering into bilateral contracts and would participate directly in the market through the balancing mechanism.

Action Item:
Market Operator to undertake a consultative process for development and finalization of template for Market Participation Agreement, to be approved by NEPRA. Framework to address the inclusion and settlement of merchant plants in the balancing mechanism.

iii. Allocation of Transmission Losses & NTDC Wheeling Charges in KE Service Area

For allocation of transmission losses under CTBCM, a 'postage stamp methodology' has been proposed in the CTBCM Detailed Design, wherein transmission losses to the extent allowed under the tariff of Transmission Network Service Provider will be paid by the demand and no charges will be applied to generation, regardless of their location. Moreover, there will be no difference based on geographical location of the demand (i.e. no nodal prices), however, this mechanism is indicative and subject to change during the implementation phase (once Commercial Code and Grid Code are finalized).

As also highlighted in the CTBCM Detailed Design, the selected approach for transmission losses will affect the administration of the balancing mechanism for energy and resultantly, the calculation of cost and payment of transmission losses. Accordingly, required modalities with regard to determination and allocation of transmission losses under the CTBCM must be finalized and firmed up as part of the relevant codes / documents, at the earliest, in consultation with all stakeholders.

Moreover, under the CTBCM Detailed Design, it is proposed that wheeling charges for NTDC system will be allocated to all demand participants (BPCs as well as regulated consumers) within the respective service area of a particular DISCO / KE. However, considering that KE manages its own Transmission Network having wheeling charges determined at Transmission voltage levels as well, clarity is requested in terms of applicability of NTDC wheeling charges for bilateral contracts where the demand as well as generation is physically located within KE's service area, and as such there is no involvement of NTDC network.

Action Item:

Formula / mechanism for allocation of transmission losses aligned with codes / relevant documents under the CTBCM, subject to NEPRA's approval.

Clarity from NEPRA whether wheeling charges of NTDC would be applicable on consumers within KE service area where, as such, there is no involvement of NTDC network.

iv. Legal, Policy & Regulatory Framework

The Detailed Design of CTBCM identifies a set of changes / modifications required to the existing legal and regulatory framework which includes introduction of new regulations such as Suppliers' Regulations, Distribution Regulations, as well as the eligibility criteria for Traders, Suppliers, Transmission Licensee, framework for integration of Captives and Housing Colonies, etc.

Further, as per Section 14A of the NEPRA Amendment Act 2018, KE understands that National Electricity Policy will be the governing document including for policy and regulatory matters to ensure a sustainable transition towards competitive markets, and therefore, it is important that the regulatory framework is aligned with the CCI approved National Electricity Policy 2021 as well as the principles approved by the CCoE for establishing wholesale competitive power markets and the National Electricity Plan which is currently under deliberation, to avoid any bottlenecks during the rollout of CTBCM.

In addition, as per Section 14B of the NEPRA Amendment Act, 2018, a mechanism is to be provided by the Federal Government for the gradual cessation of the generation licenses for various classes of generation license holders within five years from coming into effect of the NEPRA Amendment Act, 2018 and thereafter any generation facility may be established, operated and maintained without obtaining a license under the NEPRA Amendment Act, 2018 provided that it complies with technical standards relating to connectivity with grid as specified. Accordingly, keeping in view the current surplus capacity and for future functioning of the power market based on bilateral contracts as envisaged under CTBCM, it is important that a proper framework and mechanism is provided in this respect, after thorough assessment and consultation with stakeholders.

Action Item:

Finalize required amendments in Legal, Policy and Regulatory framework in consultation with all stakeholders.

Alignment of regulatory framework for open markets with the recently approved National Electricity Policy 2021 as well as principles approved by CCoE for establishing competitive wholesale markets and the National Electricity Plan, to ensure a sustainable framework and orderly transition towards competitive markets.

Mechanism for cessation of requirement for Generation License to be provided by the Federal Government in accordance with Section 14B of the NEPRA Amendment Act, 2018.

v. Ancillary Services

Under CTBCM, System Operator is responsible for organizing and managing all ancillary services such as frequency control, operational reserves, voltage control and black start services with the associated costs to be recovered through charges to all Load Serving Entities (LSEs) participating in the market, irrespective of their contracts registered with the Market Operator.

However, no details with regard to methodology for calculation and allocation mechanism of the same has been provided in the Detailed Design. Since the same will have commercial implications for DISCOs and

KE, as well as their regulated consumers, a proper framework is required for determination of cost of these services and their allocation / recovery in consultation with stakeholders.

Here, it is important to highlight that the determination and allocation / recovery of cost of ancillary services should be made with a view to allocate as much as possible of these ancillary services cost to the Market Participants responsible for them rather than socializing them to all consumers.

Moreover, the design of the Ancillary Services market needs to be detailed further especially with a view to the target of increasing the share of renewables in the country's generation mix in accordance with GoP Policies. The successful integration of renewables will depend on a market design which provides a value to flexibility and properly reward Market Participants which provide backup to intermittent renewable generation.

Therefore, a market with simultaneous and co-optimized clearing of the energy and reserve markets may be considered as well to take advantage of synergies between the two complementary products, as also done in other international markets in order to ensure efficient market outcomes.

Action Item:

CPPA to develop a concept paper on ancillary services detailing procedures and ensuring their alignment with Grid Code and Market Commercial Code, as mentioned in Section 15.1 of the Detailed Design.

vi. Security Package: Market Contracts for Regulated Consumers

One of the action items during the implementation phase is the assessment of Security Package: Market Contracts for Regulated Consumers, to be undertaken by PPIB and AEDB. However, no details have been provided in the Detailed Design with regard to such security packages including their purpose, mechanism and implications on the functioning of the market.

Given that this relates to regulated consumers who shall be served by DISCOs and KE in their role of Base Supplier, KE requests that thorough consultation should be done with DISCOs and KE in this respect.

Action Item:

Concept paper on Security Package: Market Contracts for Regulated Consumers to be shared by PPIB and AEDB and finalized in consultation with DISCOs and KE.

Other Design Considerations

i. Day Ahead Market / Binding Despatch

A financially binding day ahead market is not considered in the CTBCM Detailed Design, and only day ahead operational planning is considered, hence energy imbalances are defined as the difference between energy quantities agreed in contracts (bilateral) and the physical results of the generation scheduling and economic despatch.

The existence of a binding day ahead market in the form of binding despatch cleared using the SCED will allow for the capacity committed in the despatch to be remunerated regardless of later modifications to the commitment. A binding despatch will allow for efficiently allocating further costs of re-despatches to the market participants causing them rather than socializing them to all consumers. The day ahead binding despatch will also provide economic signals for the value of flexibility especially in the context of increasing share of renewables in the system.

ii. Concept of a Balancing Group

Possibility to transfer explicitly the balancing responsibility to another party, should be explicitly provided for Market Participants in general, especially for BPCs. Under the CTBCM Detailed Design, transfer of balancing responsibility is implicitly embedded in some of the contract designs – namely, the Load Following Supply Contract – under which demand participant will not be exposed to imbalances. This concept should be further detailed also in respect of the remuneration for such transfer of balancing responsibility where it is recommended that CPPA should design general principles to be approved by NEPRA for the allocation of overall imbalance costs of a Balancing Group to the members of the Balancing Group. This will be especially beneficial going forward as the eligibility threshold will be reduced and smaller consumers enter the competitive market which may be less equipped to manage the complexities of the market and such an arrangement will mitigate some of the risks for them.

iii. Single System Marginal Price

The Detailed Design provides for a single system marginal price which will be calculated based on the generation merit order subject to network security constraints and fuel commitments. Moreover, within the Detailed Design, CPPA also proposed that for the generators which will be required to reduce generation, a lost opportunity compensation will be paid equal to the difference between the marginal price and the variable cost of such generator, multiplied by the amount of reduction required; respectively, for the generators which will be required to increase generation (or being requested to synchronize) the compensation will be equal to the difference between the variable cost of the generator and the marginal price multiplied by the amount of the generation increase required, which will also be in line with developed markets, and therefore it is recommended that the same be considered as a market design feature.

iv. Overall Electricity Sector Boundary Conditions for Efficient Deployment of CTBCM related to Financial Health of the Sector

Experience from introduction of competitive wholesale markets in emerging economies indicates that there is a set of boundary conditions which need to be met to ensure the successful implementation of the competitive markets. These boundary conditions fall into two main groups – structural (related to structure of generation and demand) and financial health (overall sustainability of the sector and the elimination of any embedded distortions).

Successful competitive market implementation requires that such boundary conditions are clearly identified as well as transitional measures deployed to mitigate them in a way that they will not be exacerbated by the competitive market implementation.

The most critical such boundary conditions for Pakistan's power sector are the following:

- Level of tariff cost-reflectiveness overall and by customer segments (cross-subsidies)
- Circular debt related to revenue recovery from different consumer segments

Pakistan's end-user tariff levels are not on cost of service basis, as indicated by GoP's Uniform Tariff Policy wherein the consumer-end tariff is adjusted for GoP's socio-economic policy objectives. Moreover, the degree of such cost non-reflectiveness differs between consumer segments. Taking into consideration that the CTBCM will be applied sequentially to different consumer segments, there needs to be developed a detailed simulation on the impact on the tariffs that will be paid by the different consumer segments – both the ones transitioning to the CTBCM but equally so for the ones remaining on the regulated market. This embedded distortion is further exacerbated by the different degree of cost reflectiveness, generally higher for industrial consumers and lower for small business and residential consumers. Therefore, to address the likely indirect outcome of opening up of the markets in the form of further external subsidies required for the remaining regulated consumers once the BPCs *(i.e. eligible consumers under CTBCM)* transit to the open markets, the National Electricity Policy 2021 as well as the principles approved by CCoE for establishing competitive wholesale market recommend uniform application of cross-subsidy charges on consumers of all suppliers; DISCOs, KE and Competitive Suppliers, and therefore it is humbly requested that prior to roll out of CTBCM, regulatory framework is aligned with the aforementioned policy directives.

Therefore, it is recommended that in addition to pursuing the goal of an efficient liquid competitive power market, a long-term mitigation plan be developed in parallel with the CTBCM to mitigate the risks and ensure a sustainable financial state for the overall electricity sector.

These are further elaborated in Sections 4.2.5 and 4.2.6 and recommendations are summarized in Section 4.3 of this Plan.

4. Evaluation of CTBCM & Need for a Sustainable Framework

Keeping in view the critical juncture and the fragile state of the power sector today and considering the significant opportunities that the CTBCM model presents to make decisive changes to Pakistan power sector and transform it into a resilient, dynamic and efficient sector, it is imperative that a holistic assessment is made prior to its implementation and all the key areas are aligned keeping in view the best practices.

As directed by NEPRA, KE has made an evaluation along with possible implications keeping in view the current state of power sector, as detailed below and has given its recommendations in Section 4.3 of the Plan.

4.1 Power Sector Challenges & Potential Risks

The CTBCM model envisages to allow BPCs *(i.e. eligible consumers under CTBCM)* to move into bilateral contracts along with capacity building of state-owned entities with a focus to enable DISCOs to improve demand forecasting / planning and enter into bilateral contracts, as well as seeks to bring technological infrastructure initiatives and interventions for improved market monitoring.

While the capacity building initiatives are appreciated, for a sustainable transition towards open markets pursuant to CTBCM, it is important that initiatives / reforms are undertaken to address the critical issues faced by Pakistan's power sector where circular debt stands at around PKR 2.3 Trillion mainly due to surplus capacity, high AT&C losses, increasing tariffs for regulated consumers, network reliability and access to power, and accumulation of receivables from government entities.

Further, considering the significant changes to the power sector, detailed implication analysis should also be done prior to implementation of CTBCM, and in this respect, KE has made an evaluation in context of key power sector challenges, as summarized below:

Power Sector Challenges	Potential Risks
Surplus Capacity	• BPCs / eligible consumers move into bilateral contracts resulting in addition of new generation capacity, thus exacerbating the issue of underutilization and surplus capacity
High AT&C Losses	• Risk parked with DISCOs and KE, responsible for supply of power to the regulated consumers along with having to bear the risks and associated challenges of T&D business • Allowing BPCs to move into bilateral contracts would result in adverse sales mix for DISCOs and KE, hence, institutional reforms to turnaround DISCOs are imperative
Increasing Tariffs for regulated consumers	• Will lead to further increase in consumer-end tariff for regulated consumers with increase in benchmark T&D losses *(due to exclusion of BPCs from consumer mix)*, higher per unit capacity charges due to increased surplus capacity, etc.
Network Reliability, Access to Power & Load-shed Reduction	• Network business will continue to remain with DISCOs and KE, however, financial viability and investment capability of DISCOs and KE will be severely compromised if the regulatory framework for open markets is not aligned with policy directives, thus would not result in improvement in network reliability

Power Sector Challenges	Potential Risks
	• As a result, DISCOs and KE will not be able to invest on network improvement and conversion of high loss areas into low loss
Accumulation of Government Receivables	• Focuses on improving payment discipline in DISCOs and does not provide any mechanism for improving payment discipline / address the issue of government receivables

As summarized above, with majority of the risk still parked with DISCOs and KE, and with financial viability and investment capability of DISCOs and KE compromised, they will not be able to undertake the requisite investment for network improvements, whereas the CCoE approved principles for establishing competitive wholesale markets specifically state that there should be fair allocation of risks among market participants.

As part of the regulatory proceedings, issues such as further exacerbation of surplus capacity as well as cross-subsidy were highlighted, and in this regard, National Electricity Policy 2021 as well as the CCoE approved principles for establishing competitive wholesale markets have been issued, aimed at providing for a sustainable transition towards open markets. Therefore, it is imperative and KE humbly requests that the overall regulatory framework is aligned with these policy directives enabling a sustainable transition as well as a healthy and efficient competitive power market.

In addition, KE understands that while reforms to address sector challenges such as structural changes including privatization of state-owned DISCOs as also suggested by NEPRA, are not within the scope of CTBCM, GoP is committed to these reforms and is working on it separately.

Further, based on the documents available including areas that have been approved indicatively within the Detailed Design and the consultation process, KE has conducted a detailed evaluation of impact of CTBCM design to assess if the model achieves the regulatory objective of providing reliable supply of electricity at least possible cost for all consumers. In addition, considering the need for a sustainable framework, based on its evaluation, KE has also provided certain recommendations, as detailed in subsequent sections and requests that the same be taken into consideration prior to roll out of CTBCM.

Here, we would also like to humbly submit that the evaluation in respect of the subject matter is without prejudice to KE's exclusive rights of distribution in its service territory till July 2023, as granted through KE's Distribution License dated July 21, 2003 and duly protected in light of Section 50 of the NEPRA Amendment Act, 2018 and further, without prejudice to existing litigation on this matter.

4.2 Evaluation of CTBCM

KE's evaluation of key areas of the CTBCM Detailed Design is given in subsequent sections.

4.2.1 Types of Contracts under CTBCM

Under the current Single buyer model, all the power is purchased through PPA / EPAs, wherein generators are guaranteed a certain level of return on their investment and do not face any risk on their revenue stream. As market transitions from the current single buyer model towards a competitive wholesale electricity market, the existing PPAs / EPAs will be replaced by market contracts with different payment structures. However, to have a sustainable market where market participants do not have any undue advantage over one another and there is fair allocation of risk, a holistic assessment of different types of contracts under CTBCM is important.

a) Generation Following Supply Contract

As briefed in Section 3.1.1 of the Plan, under a Generation Following Supply Contract, the contract quantity and payment of the seller / generator follows the actual generation of the generator, where all price-quantity risk lies with the buyer / demand participant.

Assessment with respect to Commercial Allocation of Existing PPAs / EPAs

Within the current CTBCM Detailed Design, existing PPAs / EPAs are presumed to be Generation Following Supply Contracts to be commercially allocated among DISCOs and KE. Regarding commercial allocation of existing PPAs / EPAs, Section 5.4 of the Detailed Design states:

> *"Pre-existing PPAs and EPAs will be commercially allocated to DISCOs* ***proportionally to its share of the aggregated demand of DISCOs and KE*** *(the share that it is supplied under PPA with CPPA)."*

As the existing PPAs / EPAs are referred to as Generation Following Supply Contracts, it is submitted that based on the commercial allocation criteria for the existing PPAs / EPAs under deliberation initially, drawl of energy during a particular hour from the pool is also to be allocated to DISCOs and KE as illustrated below.

Illustration – Generation Following Supply Contracts for Existing PPAs / EPAs

Assume that DISCO A is allocated a 5% share out of the existing PPAs / EPAs having total capacity of 41,000 MW as given below.

Fuel Type	Capacity (MW)	PKR / MW
Nuclear (A)	8,200	1.5
Hydel (B)	8,200	1.5
Coal (C)	8,200	4.0
Gas (D)	8,200	5.0
Furnace Oil (E)	8,200	10.0

During a particular hour, the system demand is 18,000 MW and since electricity cannot be stored, therefore the generation will equal the demand (i.e. 18,000 MW). To meet the system demand of 18,000 MW, based on centralized economic despatch as per EMO, the average basket price shall be PKR 1.7/MW, and since the last plant despatched to meet the system demand will be the coal plant (Plant C), the marginal price at this hour will be PKR 4.0/MW.

Based on 5% allocation out of the existing PPA / EPAs, DISCO A's share will be 900 MW (18,000 x 5%). However, in case DISCO A utilizes 1,500 MW during such an hour, under the Generation Following Supply Contract for the existing PPA / EPAs as deemed in the Detailed Design, would result in a negative imbalance of 600 MW for DISCO A, which shall be procured from the system / market at the prevailing marginal price of that hour (i.e. PKR 4/MW). This is due to the fact that based on the proposed design, the SCED will operate on the full available generation in the system and not only on the residual generation outside of physical bilateral contracts, i.e. imbalances and redispatches.

As a result, DISCO A's effective cost will increase from PKR 1.7/MW to PKR 2.6/MW.

As illustrated above, despite being within the contractual limit, legacy contracts proposed to take the form of Generation Following Supply Contracts under CTBCM **unduly expose DISCOs and KE to the risk of imbalance ultimately resulting in increased cost for regulated consumers of DISCOs and KE,** as power purchase cost is a pass-through in tariff, thus having significant financial implications.

Here, it is also important to note that this will also be contrary to the provisions of existing PPAs / EPAs as they require KE and DISCOs to be billed on basket rate. Further, CPPA during regulatory proceedings also submitted that there will be no modification to the existing PPAs/EPAs and the same will remain intact.

In addition, such a mechanism would also be in contradiction with one of the core objectives of CTBCM which is to improve planning discipline among DISCOs, as it exposes DISCOs and KE to the risk of imbalance between DISCOs and KE despite being within their contractual limits, as illustrated above, and therefore, simply results in one DISCO benefiting at the cost of another without making any contribution to system efficiency.

Implications

DISCOs and KE unduly exposed to the risk of energy imbalance where one DISCO benefits at the cost of another, resulting in increased cost for regulated consumers of DISCOs and KE.

Based on detailed evaluation, during the consultation process, KE highlighted the above issues / inherent limitations of a Generation Following Supply Contract to CPPA in relation to legacy PPAs / EPAs, subsequent to which CPPA has proposed that the **existing PPAs / EPAs at the time of commercial operations of CTBCM will be converted into a separate contract design whereby DISCOs and KE will not be exposed to the risk of imbalance to the extent of their contracted / allocated capacity from the legacy PPAs / EPAs.**

Assessment of Generation Following Supply Contracts for Non-Controllable Generation

The CTBCM Detailed Design suggests that Generation Following Supply Contracts are particularly suited to non-controllable generation such as renewables (solar, wind, small hydro run of river) and sell only energy that they generate (without prior fixed commitments). In this regard, to ensure security of supply in the system, CTBCM introduces the concept of Firm Capacity of Generators, wherein the generators including renewables will be allowed to sign bilateral contracts to the extent of the capacity as per their firm capacity certificate. However, detailed methodology for calculation of firm capacity is to be firmed up during the implementation phase of CTBCM, as also detailed in Section 3.2 of the Plan.

KE also understands that in addition to the proposed methodology within the Detailed Design, alternatively, eligible consumers (BPCs) having bilateral contracts with renewable generators, should have arrangements with DISCOs and KE for their demand beyond the capacity contracted with renewables, and a separate tariff category be determined for such hybrid BPCs which allows DISCOs and KE to recover their fixed costs.

b) Load Following Supply Contract

As explained in Section 3.1.1 of the Plan, under a Load Following Supply Contract, the contract quantity is quantified as a percentage of buyer's actual consumption or peak demand, and therefore, if 100% contracted, the buyer does not face any risk of imbalance.

Illustration – Load Following Supply Contract

Assuming that D1 enters into a bilateral contract with G1 for 100% of its demand at PKR 15/MW[4], and therefore G1 is obligated for 100% of D1's demand.

Subsequently, demand of D1 during a particular hour is 100 MW and since it is a Load Following Supply Contract, G1 will be obligated to supply 100 MW to D1. However, as CTBCM envisages central despatch, actual despatch would be on the basis of operating cost of all plants available in the system.

[4] For simplicity purposes, it is assumed that the contract price of PKR 15/MW is also the operating cost of G1.

G1 is not despatched and marginal cost is lower than price agreed under bilateral contract

Assuming that during the same hour, the marginal price of the system is PKR 12/MW, this would mean that G1 will not get despatch and instead the demand of D1 will be served through the system.

In the above scenario, settlement shall be as follows:

Transaction	**PKR**
D1 pays G1 for 100 MW @ PKR 15/MW as per bilateral contract	1,500
G1 buys 100 MW @ PKR 12/MW from the balancing market to meet its obligation towards D1	(1,200)
Net Gain to G1	**300**

In the above scenario, G1 will benefit by not generating the entire 100 MW as contracted, and instead meeting its contractual obligation through the balancing mechanism.

G1 is not despatched and marginal cost is higher than price agreed under bilateral contract

Suppose that during this particular hour, the marginal price of the system is PKR 18/MW and G1 is unable to generate and instead the demand of D1 is served through the system.

In this scenario, settlement shall be as follows:

Transaction	**PKR**
D1 pays G1 for 100 MW @ PKR 15/MW as per bilateral contract	1,500
G1 buys 100 MW @ PKR 18/MW from the balancing market to meet its obligation towards D1	(1,800)
Net Loss to G1	**(300)**

In this scenario, G1 will lose PKR 300 if the entire 100 MW is met through the balancing mechanism.

As explained in the first scenario above and considering the current market dynamics as well as market maturity where participants may not have access to requisite level of information / details, Load Following Supply Contract presents arbitrage opportunities particularly considering today's surplus capacity scenario, allowing generators to make higher returns by meeting their contractual obligations through the balancing mechanism at marginal price.

In this regard, Section 5.12 of the Detailed Design also recognizes the need for a mechanism to monitor such practices stating that *"along with evolution of the market, it might be needed to issue specific regulations and operational procedure could be implemented to counteract threats of manipulations."* Accordingly, while the design itself acknowledges that such manipulation may be practiced in the market, no regulation or mechanism for market intervention is provided at this stage, and CPPA is of the view that as market matures, market forces would cater to the issue and demand participants would have sufficient knowledge / price signals to avoid such contracts. However, as detailed above, given the market dynamics, it may take considerable time for the market to mature, and therefore a holistic assessment should be made along with a monitoring mechanism to minimize the chances of any arbitrage gains / opportunities in the market, which would also be in line with CCoE approved principles for competitive wholesale electricity markets to ensure that there is fair allocation of risk and there are no anomalies that may allow some participants to take undue advantage.

Moreover, Section 5.12 of the Detailed Design also makes reference to thorough analyses which have been done to assess the level of risk of market manipulations and those concluded that the risks of manipulations having detrimental impact for some in benefit of others are negligible and therefore as per CPPA, for the start of the CTBCM, no special provisions are required in terms of market interventions. Given the importance of such assessments in any competitive wholesale market design, in KE's view further transparency in the form of making such analysis available to stakeholders would benefit the credibility of the proposed Detailed Design.

Implications

Possible opportunities to make arbitrage gains for generators which may result in market manipulation impacting overall market efficiency as well as security of supply.

c) Fixed Quantity Supply Contract

In this type of contract, fixed quantities are agreed in advance between the buyer and the seller and under the Fixed Quantity Supply Contract, the obligation on the generator is to supply the contracted quantity and not necessarily generate, whereas the obligation on the demand participant is to purchase but not necessarily consume.

Illustration – Fixed Quantity Supply Contract

Assuming that D1 enters into a bilateral contract with G1 for 100 MW at PKR 12/MW. Under a Fixed Quantity Supply Contract, there is no obligation on G1 to generate 100 MW for D1 to meet its contractual obligations and instead G1 can procure 100 MW from the market (balancing mechanism) and supply 100 MW to D1.

Marginal price less than price agreed under bilateral contract

Assuming that in a particular hour D1's demand is 100 MW and the marginal price of the system is PKR 10/MW. Under a Fixed Quantity Supply Contract, G1 has the option to procure 100 MW from the market to fulfill its contractual obligation towards D1. Settlement under this contract shall be as follows.

Transaction	PKR
D1 pays G1 for 100 MW @ PKR 12/MW as per the bilateral contract	1,200
G1 buys 100 MW from the balancing mechanism @ PKR 10/MW	(1,000)
Net Gain to G1	**200**

In the above scenario, **G1 benefits by purchasing the 100 MW from the market and meeting its contractual obligation towards D1, without taking any risk.**

Marginal price higher than price agreed under bilateral contract

Assuming that D1's demand is 100 MW and the marginal price of the system is PKR 15/MW. In case G1 is not able to supply the contracted 100 MW to D1, in such a scenario D1's demand will be served through the market, and settlement shall be as follows:

Transaction	PKR
D1 pays G1 for 100 MW @ PKR 12/MW as per the bilateral contract	1,200
G1 buys 100 MW from the balancing mechanism @ PKR 15/MW	(1,500)
Net Loss to G1	**(300)**

Accordingly, similar to a Load Following Supply Contract, there are arbitrage opportunities under Fixed Quantity Supply Contracts, wherein the generator without having the obligation to generate (i.e. without taking any risk), can meet its contractual obligations through the balancing mechanism at a price lower than the bilaterally agreed price, hence resulting in arbitrage gains for the generator, and due consideration must be given to such practices, especially in view of the current market dynamics and maturity.

A key consideration in this respect should be that retiring plants which have recovered their fixed costs and operate at low efficiency may get into such bilateral contracts while having no obligation to generate and can meet their contractual obligation through the balancing mechanism at the prevailing marginal price.

In addition, as there is no obligation to generate under such contracts, competitive suppliers may also look to benefit from such arbitrage opportunities by entering into Fixed Quantity Supply Contracts.

Moreover, it is also important to consider that currently there are no caps on the maximum procurement that a generator / competitive supplier can make from the balancing mechanism, which as a result, may incentivize such transactions in the market.

Here, it is also pertinent to highlight that the Detailed Design does not provide any in-depth assessment of the potential benefits of a Fixed Quantity Supply Contract and given the material implications that it may have on market functioning and efficiency, in particular speculative practices in the market for participants, KE humbly requests that a detailed assessment and review of Fixed Quantity Supply Contracts must be carried out and shared with all stakeholders.

Implications
Possible arbitrage opportunities for generators and competitive suppliers which may result in market manipulation without resulting in any system efficiency improvement.

In view of the above, for a sustainable roll out of CTBCM, holistic assessment of contract types / designs and their implications need to be made and KE's proposed recommendations in this regard are detailed in Section 4.3 of the Plan.

4.2.2 Security Constrained Economic Despatch

As detailed in Section 3.1.1 of the Plan, CTBCM envisages a single country-wide central economic despatch subject to network security constraints and despatch commitments under respective Fuel Supply contracts. Energy as a result of centralized despatch is not controllable by contracts, and therefore, there will always be imbalances to be settled in the Balancing Mechanism as per the prevailing marginal price of the system.

With regard to Security Constrained Economic Despatch, following are key considerations:

- **Operating Cost for decision making under Central Despatch:** The CTBCM design envisages a cost-based pool and proposes central despatch wherein the despatch decision is to be made based on the operating cost of the respective generators. As per the envisaged mechanism, each generator will be submitting their operating cost to the System Operator for the purpose of making despatch decision. However, considering that the central despatch will also be serving the demand of regulated consumers, further clarity is required in terms of whether NEPRA will be issuing tariff determinations for all generators including captive generators, and otherwise, how will the authenticity of operating costs submitted by the generators be ensured.

- **Contract Design and Balancing Mechanism:** Despatch will be subject to respective operating cost of the plants, and therefore, under Load Following Supply Contract and Fixed Quantity Supply Contract, generators may benefit in case the marginal cost of the system is lower than the price agreed within the bilateral contract. In addition, allocation of costs related to ancillary services also needs to be reviewed with a view that most of it should be allocated to market participants responsible for it, instead of socializing the cost to all consumers.

- **Settlement of Imbalances:** For settlement of imbalances, data from each of the Common Delivery Points (CDP) equipped with Secured Metering System (SMS) will be required on real time basis. As per the Implementation Roadmap, the deployment of SMS by NTDC is expected to complete by September 2021, and the data recorded and transmitted through the same will require subsequent rigorous testing / validation to ensure correctness and reliability prior to implementation of the CTBCM. Moreover, the balancing mechanism may need to be further developed to incorporate the explicit creation and operation of balancing groups of Market Participants in order to minimize the overall financial consequences of imbalances as also noted in Section 3 of the Plan, especially for Market Participants on the demand side which may have less expertise / ability to manage risk if fully exposed to the potential volatility of the market.

Moreover, metering SOPs will also need to be established by relevant stakeholders including KE, NTDC and CPPA, to cater to any disruption caused due to technical constraints (e.g. non-availability of communication signals to transmit data on real time basis).

- **Out of Merit Despatch:** As per the Detailed Design, out of merit despatch for system security purposes will not form part of the marginal cost of the system and such cost will be separately determined and allocated to the total demand (both regulated and non-regulated consumers) of the respective zone. Based on discussions with CPPA, KE understands that initially under CTBCM, there will be two zones: (i) KE zone, and (ii) NTDC zone. Further, with regard to out of merit despatch, based on discussions with CPPA during the consultation process, interconnection limits will also form part of the SCED, and therefore despatch decisions based on interconnection limits shall not be construed as out of merit despatch.

  However, further clarity with respect to mechanism / methodology for determination or allocation of cost related to such out of merit despatch is required and given the complexities involved including contractual arrangements such as 'Take or Pay' contracts and fuel commitments, it is imperative that the mechanism for determination and allocation of such costs is diligently designed in consultation with all stakeholders.

In addition to the above considerations with respect to SCED, the Detailed Design makes reference to the use of variable cost as a basis for the SCED. In order for this cost-based mechanism to be effective, it needs to be further detailed in terms of not only the composition of the variable cost but any other associated costs that will need to be considered, for example start-up costs and no-load costs, and mechanism by which generators will be compensated for those. If we refer to other markets which utilize versions of SCED, e.g. the US markets, they require generators to bid and/or provide cost information not only for the incremental energy cost ($/MWh) but also for start-up cost ($/start) and no-load cost ($/hour). The despatch engines of those market ensure that generators' total costs are recovered via uplift payments (make-whole and/or lost opportunity cost) in cases where physical constraints of units may result in locational marginal prices which do not cover the total costs of despatched units. Accordingly, it is recommended that such additional market features may also be considered in line with international markets, while firming up the CTBCM design.

Implications
As the above considerations with respect to central despatch are to be firmed up as part of the implementation phase of CTBCM, therefore detailed evaluation / impact analysis will be made post their finalization.

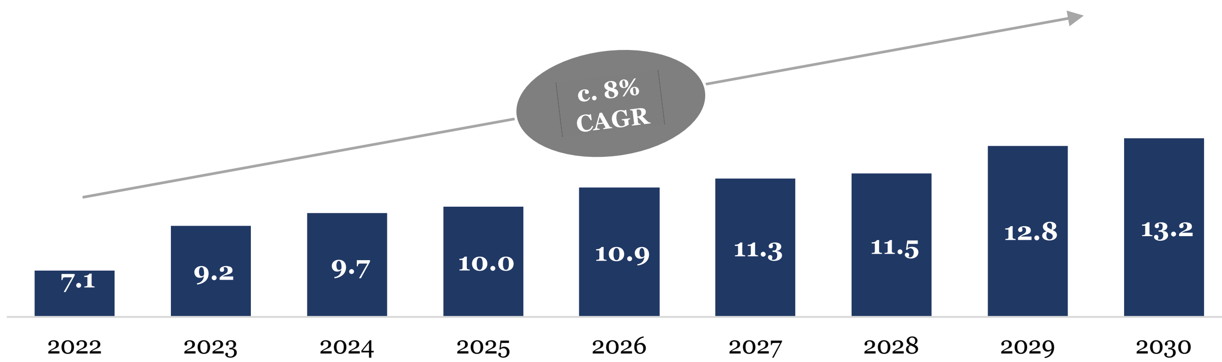
4.2.3 Over Contracted Capacity & Stranded Costs

Over the last two decades, the generation segment has experienced accelerated investments, resulting in more than 14,000 MW of generation capacity added in the last 6 to 7 years. Today, Pakistan operates in a surplus capacity scenario with peak demand of around 26,000 MW recorded in FY 2020 against dependable generation capacity of around 34,000 MW.

Further, based on IGCEP, another 22,000 MW of projects have already been committed, which include 14,000 MW of Nuclear and Hydel projects that are strategic in nature, along with 3,000 MW of candidate projects, mainly solar and wind based, which if pursued, would further increase the power surplus scenario.

With the significantly over contracted capacity and even if committed projects are taken into consideration, based on CPPA estimates, the per unit capacity rate is expected to increase from around PKR 7/kWh to PKR 13/kWh by 2030[5] (an increase of 74%), assuming sales growth of around 4% under a normal GDP growth rate scenario of 4.7%.

Exhibit 1: Projected Capacity Purchase Price (PKR/kWh)



In such a scenario, allowing eligible consumers / BPCs to procure power through bilateral contracts or directly from the market without any recovery of costs arising due to advent of open access, would exacerbate the issue of idle capacity and further increase the cost for regulated consumers, as long-term capacity commitments and infrastructure investment have already been made/planned.

Based on the existing generation capacity and the committed generation projects, as BPCs which currently account for 16% of the total sales at national level (excluding KE) move into bilateral contracts under CTBCM, it is estimated that the same would have an **impact of around PKR 1.3/kWh[6] in the form of additional capacity charges for the remaining regulated consumers** on account of advent of open access**.**

Similarly, the impact of BPCs in KE area moving into bilateral contracts is estimated to be **PKR 1.3/kWh**[7] on the remaining regulated consumers. Here, it is important to highlight that in case the threshold for consumers eligible to participate in the market / move into bilateral contracts is lowered from the current proposed of 1MW (BPCs) under CTBCM, the impact of costs due to advent of open access would increase further.

Further, it is pertinent to highlight that considering the significant financial impact of costs arising as a result of BPCs procuring power directly, CCoE while approving the principles for establishing competitive wholesale market approved the following:

CCoE Approved Principles for establishing Competitive Wholesale Market (vi)
The Regulator should account for stranded fixed costs that arise due to advent of the competition. The Federal Government should decide whether such costs will be paid through Government subsidy or otherwise charged to consumers through regulatory process (Accounting for fixed costs that become stranded)

[5] CPPA Presentation – Hearing on IGCEP 2021 – 2030 (June, 2021)
[6] Impacts have been calculated based on high level assumptions and estimates
[7] Impacts have been calculated based on high level assumptions and estimates

Moreover, the recently approved National Electricity Policy 2021 also states that the regulator will provide for recovery of costs arising due to advent of competition, as decided by the Government, and therefore, KE understands that a mechanism needs to be devised and finalized in consultation with all stakeholders to ensure recovery of such stranded costs, which would be critical for a sustainable transition towards open markets.

National Electricity Policy 2021 (5.6.7)

The Regulator will provide for recovery of costs arising on account of distributed generation and open access in the consumer-end tariff, as decided by the Government. Further, the Government may announce, from time to time, various concessional packages to incentivize additional consumption to minimize such costs.

In view of the above, KE humbly requests that the regulatory framework for open markets is aligned with the National Electricity Policy 2021 and CCoE approved principles for competitive wholesale market for a sustainable roll out of CTBCM.

Implications:

- Stranded costs to result in an increase in tariff for regulated consumers. Estimated per unit impact of stranded costs on regulated consumers would be around **PKR 1.3/kWh** (excluding KE area), whereas the impact of stranded costs for remaining regulated consumers in KE's service area is estimated to be around **PKR 1.3/kWh.**

Considering the significant implications of non-recovery of stranded costs arising as a result of open markets for DISCOs and KE as well as their regulated consumers, it is critical that a framework for recovery of stranded costs is provided prior to transition towards open markets or implementation of CTBCM which would also be in line with the National Electricity Policy 2021 and CCoE approved principles for establishing a wholesale competitive power market. Further, KE's recommendation with respect to stranded costs under an open market regime is given in Section 4.3 of this Plan.

4.2.4 Mechanism for T&D Loss Adjustment

Under the existing tariff regime, DISCOs and KE are allowed a loss percentage, based on a certain consumer mix assumed for the purpose of tariff determination which is also used to determine the fuel and power purchase cost variation to be allowed in tariff. It is estimated that as eligible consumers *(BPCs under CTBCM)* move into bilateral contracts, there would be an adverse mix impact on T&D losses at national level (excluding KE) by around **2.1% points**[8], whereas the impact for KE's area is estimated to be around **2.0% points;** representing the T&D loss of the remaining regulated segment**.** Therefore, revisions to the tariff framework as illustrated in Section 4.3 are required, which otherwise would result in under recovery of costs for DISCOs and KE.

Implications:

Under recovery of costs, since as per the current tariff framework, costs are to be passed onto the regulated consumers based on company-wide average T&D losses which would be required to be re-adjusted to reflect T&D loss of the remaining regulated segment.

In view of the above, it is recommended that necessary revisions be made to the tariff framework as recommended in Section 4.3 of the Plan, to ensure that there are no adverse implications on DISCOs and KE and their regulated consumers.

[8] Calculated based on BPCs share of 16% of the total sales at national level and high level assumption of T&D losses of c. 5% for these consumers.

4.2.5 Tariff Setting & Cross Subsidization

Under the existing regime, tariff setting is not on Cost-of-Service basis and instead high-end consumers which also include BPCs *(eligible consumers under CTBCM)* cross-subsidize low-end consumers. In this regard, CPPA in its response to comments on the Detailed Design of CTBCM also highlighted that cross-subsidies are social costs paid by large / high-end consumers for relatively small / low-end consumers to compensate the high cost of service of the latter group, and therefore, there should be uniform application of cross subsidies to all BPCs whether supplied from DISCOs (Base Supplier) or Competitive Supplier.

Similar to the issue of stranded costs discussed in Section 4.2.3, CCoE has also recognized the issue of cross-subsidy surcharge and approved the following as part of the principles for establishing competitive wholesale market.

CCoE Approved Principles for establishing Competitive Wholesale Market (v) *Providing a level playing field to all market participants; it includes inter-alia, equal application of "cross subsidies & other grid charges" to all suppliers in the market; either DISCOs or Competitive Suppliers supplying power to consumers (Level playing field for all market participants in the market to compete)*

Moreover, the National Electricity Policy 2021 also provides that there shall be uniform application of cross-subsidy and other grid charges to consumers of all suppliers, i.e. DISCOs, KE as well as Competitive Suppliers, as the same is a pre-requisite to ensure level playing field.

National Electricity Policy 2021 (5.5.2) (f) *Providing a level playing field to all market participants through uniform application of cross-subsidization and other grid charges to consumers of all suppliers*

Accordingly, KE humbly requests that the issue of cross-subsidy in context of open markets be appropriately addressed, and the regulatory framework is aligned with the National Electricity Policy 2021 and CCoE approved principles for competitive wholesale market, thus providing a level playing field which is critical for an efficient future competitive power market.

Further, experience from other markets (e.g. Eastern Europe) which experienced similar cross-subsidy issues both in terms of cross-subsidies between consumer segments as well as an overall cross-subsidy effective differential between the overall market price on the competitive market as compared on the overall tariff level in the regulated market, indicates that robust mechanism needs to be deployed with respect to cross-subsidy in context of competitive markets with a focus on gradual elimination of cross-subsidies and tariff setting on Cost of Service basis as further detailed in Section 4.3 of the Plan. In addition, it will also help alleviate any potential volatility which may result from immediate exposure to the competitive market, respectively the flexibility embedded in the end tariffs to timely and full recovery of incurred costs on the competitive market.

In terms of the impact of cross-subsidy, it is estimated that the annual impact of lost cross-subsidy surcharge as a result of BPCs *(eligible consumers under CTBCM)* moving into bilateral contracts will be around **PKR 1.5/kWh**[9] on the remaining regulated consumers at national level (excluding KE area)[10], whereas for KE's regulated consumers, the estimated impact is around **PKR 1.2/kWh**[11]**.** Here, it is also important to understand that the cross subsidy is a social obligation imposed on DISCOs and KE as per GoP policy and has no nexus to the efficiency or performance of DISCOs and KE, and therefore, it is critical

[9] Impacts have been calculated based on high level assumptions and estimates
[10] CPPA Presentation – Hearing on Additional Issues of XWDISCOs Tariff Petition for FY 2018-2019 & 2019-20 (September, 2020)
[11] Impacts have been calculated based on high level assumptions and estimates

that a sustainable framework to address the issue of lost cross-subsidy surcharge under CTBCM or open markets is provided prior to the transition in line with the National Electricity Policy 2021 and the CCoE approved principles for establishing a competitive wholesale market.

KE's recommendation with regard to tariff setting and cross-subsidy surcharge pursuant to an open market regime is given in Section 4.3 of the Plan.

Implications
• Estimated per unit impact of lost cross-subsidy surcharge on regulated consumers as a result of BPCs *(eligible consumers under CTBCM)* moving into bilateral contracts is estimated to be around **PKR 1.5/kWh** at national level (excluding KE area), whereas the impact for KE's regulated consumers is estimated to be around **PKR 1.2/kWh.**

4.2.6 Accumulation of Government Receivables

With regard to improving payment discipline, CTBCM primarily focuses on DISCOs through the requirements of escrow account and credit cover for the purpose of participation in the market including balancing mechanism. However, mechanism to improve payment discipline of government entities is critical, as the same has remained one of the main factors driving circular debt.

As part of the regulatory proceedings in the matter of CTBCM, current issues of the sector which include accumulation of government receivables have been recognized, however, the scope of CTBCM is introduction of a competitive wholesale electricity market in Pakistan. Here, it is important to highlight that unless a sustainable framework for resolution of accumulation of government receivables is provided, the objective of an efficient and liquid power market as envisaged under CTBCM may not be achieved.

KE's recommendation in this regard is given in Section 4.3 of the Plan.

Implications
No mechanism is provided to avoid accumulation of government receivables which would continue to impact liquidity of DISCOs and KE, and ultimately the overall circular debt.

4.2.7 Type of Suppliers

As per the draft Suppliers Regulations, a licensee which includes Competitive Supplier as well, is to provide electric power services to all consumers on a non-discriminatory basis within the licensed area, and the Competitive Supplier shall not charge higher than the regulated tariff as charged by the Base Supplier (DISCOs and KE). As a result, Competitive Suppliers would focus on areas skewed towards high-end consumers only, whereas DISCOs and KE in their role of Base Suppliers will be obligated to serve the remaining regulated consumers.

Here, it is also important to note that under the existing framework, in case of default in obligation by a Competitive Supplier, DISCOs and KE in their role of Last Resort Supplier will be obligated to meet any such unmet demand / obligation, which will have material implications in terms of planning for DISCOs and KE as well as for overall supply security.

Further, as detailed in Section 3.1.1 of the Plan, as per the CTBCM framework, eligible consumers allowed to move into bilateral contracts are only BPCs (i.e. Competitive Supplier can only sell to such eligible consumers), whereas the draft Suppliers Regulations allow Competitive Suppliers to provide electric power services to all consumers, which is therefore inconsistent with the CTBCM design, and KE through its letter dated April 19, 2021 and June 22, 2021 has submitted its comments on the draft Suppliers Regulations for NEPRA's consideration.

Implications

DISCOs and KE in their role as Last Resort Supplier will be exposed to additional risks and hence appropriate compensation in tariff for Last Resort Supplier be provided and Suppliers eligibility criteria should require thorough evaluation of Competitive Suppliers ability to perform and meet their obligations.

4.3 Recommendations

For a sustainable transition towards a competitive electricity market, it is important to develop a framework which provides for an orderly transition. As detailed in Section 4.1 of the Plan, while CTBCM seeks to bring various key interventions in terms of capacity building and technological interventions, it is critical to address the pressing issues in the power sector today which are required to be addressed separately as a pre-requisite to healthy functioning power market. Further, various key aspects of the CTBCM design including contract designs, allocation mechanism of existing PPAs / EPAs have been approved indicatively, and mechanism for key policy and regulatory matters such as stranded costs and cross-subsidy surcharge in line with National Electricity Policy 2021 and CCoE approved principles for establishing competitive wholesale markets are to be finalized.

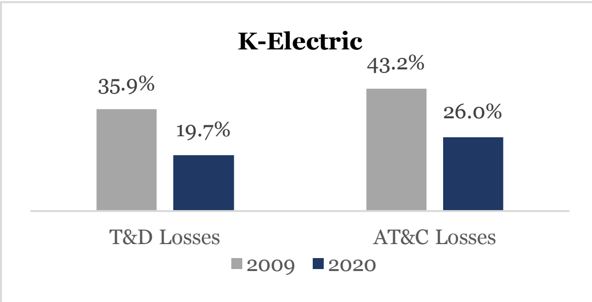
In view of the above, availability of surplus power and the current state of the sector, prior to roll out of open markets pursuant to CTBCM, following reforms / interventions are recommended for a sustainable transition:

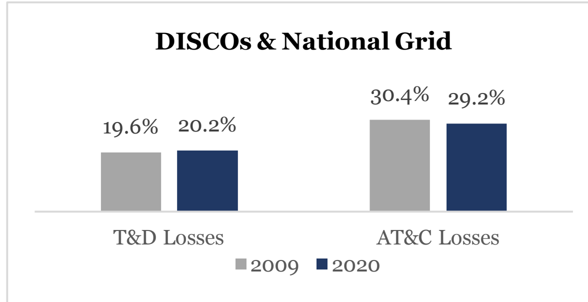
a) Restructuring / Privatizing State-Owned Distribution Companies

Despite operating in surplus capacity, consumers continue to experience load-shed and network reliability issues along with high and increasing tariffs. One of the key contributing factors in this regard has been high system losses and sectoral inefficiencies, as state-owned DISCOs have continued to rely on GoP for their financing, planning as well as investment requirements. Further, under an open market regime, DISCOs would still be exposed to risk and associated challenges of T&D business, along with the obligation to ensure smooth wheeling of power. Hence, it is imperative that DISCOs' performance is improved to not only ensure reduction in circular debt but for a healthy and efficient functioning future competitive electricity market.

Here, it is pertinent to highlight KE's post privatization turnaround which resulted in significant operational improvements, as also acknowledged by NEPRA in the State of Industry Report, 2018. Since privatization, KE has invested over USD 3.8 Billion across the power value chain, and more importantly, all these investments have been made without any sovereign guarantee or GoP's financial support. In comparison, as per NEPRA's State of Industry Report 2018, investments made by DISCOs during 2014 to 2018 have been lower than NEPRA allowed levels. Further, KE is the only entity in the distribution segment having no contribution in the circular debt and is in a net receivables position from government entities.

Below is a comparison of historic T&D and AT&C loss improvement of KE compared with state-owned DISCOs.





In view of the above and considering KE's post privatization turnaround resulting in improved operational performance, it is recommended to restructure / privatize state-owned distribution companies with considerations including improvement in losses based on a loss reduction trajectory as done in other international markets (e.g. yearly thresholds for reduction in AT&C losses) as well as inclusion of technical and strategic partners, which will help improve DISCOs' operational performance and capabilities. This is also in line with the recommendation given by NEPRA in the State of Industry Report 2019.

NEPRA State of Industry Report 2019 (page 2)

NEPRA in its earlier reports has kept on stressing that the prevailing governance model has totally failed to deliver, and it would not be out of place to mention here that the present problems have emanated from centralized control. Persisting with this model would only reinforce the failure. Therefore, for any recovery of the sector, DISCOs have to be made independent, while total or partial privatization of DISCOs must be undertaken forthwith.

Important to note that privatization of state-owned DISCOs will not only result in operational improvements but will also allow for wealth creation to pay off circular debt. However, considering the current state of financial affairs where most of the state-owned DISCOs are in losses, assets of these DISCOs are currently undervalued and therefore full potential value may not be realized. Accordingly, the Government may initially consider transferring control to a private investor with gradual sale of ownership stake. As an example, initially a 10%-20% equity stake with management control may be offered with an offer to further increase in shareholding at the end of five years after reviewing performance. This would enable the Government to sell more equity stake as entities become more profitable, allowing for wealth creation, while also helping the Government to avoid any further issuance of sovereign guarantees as DISCOs will be responsible for making their own investment plan and new capacity procurement, as done by KE.

b) Addition of New Generation only through competitive bidding and focus on increasing the share of renewables

As detailed in Section 4.2.3 of the Detailed Design, one of the major challenges faced by Pakistan's power sector today is the significantly over contracted capacity, a consequence of generation capacity added to the central pool without integrated planning including ineffective demand forecasting at national level.

In this regard, it is recommended:

Allocation of Existing and Committed Capacity & Cut-off Date for Future Additions

Considering the surplus capacity in the National Grid, it is important that the existing and committed generation capacity be allocated in accordance with a mechanism finalized in consultation with all stakeholders, and no further generation capacity addition is made for the central pool after projects which have already been committed for.

Moreover, a cut-off date be agreed for addition of new capacity in the National pool with appropriate consultation after which any generation capacity addition shall be for the purpose of bilateral contracts of identified DISCOs only, keeping in view their demand projections and capacity obligations, and such capacity addition should be allocated to the identified DISCO only and not form part of the central pool. Further, with respect to addition of hydel and nuclear projects, given the strategic nature of these projects, framework with regard to addition of these projects as well as their allocation in the future (i.e. post commercialization of CTBCM) needs to be provided.

While CTBCM provides for the concept of commercial allocation of existing PPAs / EPAs, the methodology for allocation is to be firmed up during the implementation phase. As detailed in Section 5.2 of the Plan, allocation of existing PPAs / EPAs and capacity invoicing for supply from National Grid is a key aspect of CTBCM and may have material implications, and hence it is important that the same be deliberated upon thoroughly and firmed up accordingly.

Grid Integration of Renewables & Reassessment of Policies

To benefit from renewables' low cost of generation, it is humbly submitted that policies and regulations in respect of Distributed Generation, Net Metering and Wheeling should be reviewed with a focus on maximum integration of renewables at grid level. This would also allow regulated consumers to benefit from lower cost of electricity, instead of high end consumers only who opt for open markets by entering into bilateral contracts with renewable generators.

Further, tariff structure for hybrid BPCs and net metering consumers which use grid as a back-up arrangement/intermittently, also need to be reassessed, and a separate tariff category for such consumers be introduced to ensure recovery of fixed costs incurred by DISCOs and KE in respect of these consumers.

c) Mechanism for timely payments of government dues including energy dues from Government entities and release of TDC

One of the major contributing factors towards the issue of circular debt, which is a roadblock for successful privatization effort and attraction of technical and strategic partners is the continuous accumulation of government receivables. Delays in release of dues result in significant cashflow constraints for DISCOs and KE, which ultimately impact their ability to meet their financial obligations and investment plans.

In this respect, following is recommended:

- Timely determination and subsequent notification, verification and release of TDC in line with the defined SOP / timelines.
- Cost of time taken in determination of tariff adjustments and processing and release of TDC beyond SOP defined / statutory timelines should be allowed to DISCOs and KE in their tariff or compensated by GoP.
- Significant portion of DISCOs' and KE's receivables are on account of energy dues of provincial entities and departments, adversely impacting the cashflows of DISCOs and KE and

consequentially their ability to undertake the required investments. In this regard, it is recommended that a mechanism may be devised wherein the GoP clears the outstanding dues of provincial entities towards DISCOs and KE, and the same may be adjusted against the budgetary allocation. Further, a compensation mechanism be provided to compensate DISCOs and KE for cost of delays in payment of energy dues by government entities.

d) A Sustainable Framework for Transition to Open Markets

Considering the above challenges faced by the power sector today, a sustainable transition framework should be designed and implemented including key policy decisions required to ensure a level playing field, having no tariff impact on regulated consumers as well as promotes competitive markets.

To achieve the objectives of an efficient power market providing level playing field and no tariff impact on regulated consumers while also encouraging competition, specific recommendations in relation to CTBCM and open market regime for a sustainable framework are given below:

i. Alignment of Regulatory Framework for Open Markets with National Electricity Policy and Finalization of National Electricity Plan

For a sustainable transition towards open markets, it is imperative that a holistic review of the regulatory framework is undertaken to ensure a sustainable transition towards open markets as well as that the intended objectives are achieved, which is only possible if a level playing field is provided to all market participants and regulatory and policy matters are decided in a way that safeguards the interest of all stakeholders.

In this regard, KE understands that National Electricity Policy will be the governing document, and as recognized in Section 14A of the NEPRA Amendment Act, 2018, transition towards competitive markets should be in line with the National Electricity Policy and Plan. Therefore, required interventions in line with the National Electricity Policy 2021 and CCoE approved principles for establishing competitive power markets should be undertaken in consultation with all stakeholders to ensure a sustainable transition towards open markets.

ii. Treatment of Cost arising due to advent of Open Access

As explained above, with BPCs *(eligible consumers under CTBCM)* moving into bilateral contracts, in the absence of a mechanism for treatment of stranded costs, regulated consumers of DISCOs and KE will be burdened. Here, it is important to highlight that keeping in view the implications of costs arising as a result of advent of competition, framework providing for treatment of such stranded costs is considered a critical part of the market liberalization process across international markets and has also been recognized by the National Electricity Policy 2021 and the CCoE approved principles for establishing a competitive wholesale power market.

Lessons from Market Liberalization in United States

The process of deregulation in California's electricity market started in 1998. However, absence of a sustainable mechanism for transition towards open markets resulted in existing utilities to face severe financial implications and exorbitant increase in cost of electricity, eventually resulting in the 2000 / 2001 energy crisis, calling for immediate reforms and measures including elimination of mandatory sell / buy requirement through the CalPX; approval of an interim surcharge to raise retail rates to provide relief to utilities; and suspension of retail choices in California under 2001 Interim opinion with only existing contracts allowed to continue until their expiration[12].

Considering the initial implications of roll out of open market regime in California and the consequential implications of not having a sustainable framework for recovery of stranded costs arising as a result of opening up of markets, a Competition Transition Charge (CTC) was applied under a staggered approach across various states in the US market for recovery of stranded costs.

As an example, in Maryland state of the US, stranded costs were recovered through a CTC over different lengths of time for each distribution utility, usually ranging from 4 to 9 years and a staggered approach was adopted with decreasing per unit rates[13].

Lessons from Market Liberalization in India

In 2008, the Maharashtra Electricity Regulatory Commission (MERC) vide its Order allowed consumers to shift/changeover from one Distribution Licensee to another, with the long-term objective of introducing competition and availability of cheaper electricity supply to consumers[14].

However, lack of a sustainable framework posed several challenges including network development, cross-subsidization and stranded costs for DISCOMs. Subsequently, in 2016, MERC issued its Order imposing a separate charge on consumers opting for open access for recovery of stranded costs over a period of four years[15].

Based on the above and considering that as per IGCEP 2030, Pakistan's power sector is still expected to operate in a power surplus scenario till 2030, as a result, when BPCs *(eligible consumers under CTBCM)* move into bilateral contracts, this may lead to further surplus capacity, and therefore exacerbate the issue of stranded costs in the form of idle capacity.

In view of the above, it is recommended that for treatment of stranded costs arising from consumers opting for open access, a mechanism in consultation with all stakeholders and keeping in view international precedents be devised with the following considerations:

a) **Gradual Opening up of the Market to the extent of Forecasted Power Shortfall:** Taking into account the planned generation capacity additions in the central pool that have already been committed and the projected growth in power demand, no further additions (beyond the ones already committed) should be pursued for the central pool as also detailed in Section 4.3(b) of the

[12] Subsequent Events California's Energy Crisis, US Energy Information Administration (EIA) https://www.eia.gov/electricity/policies/legislation/california/subsequentevents.html

[13] Competition and Consumer Protection Perspectives on Electric Power Regulatory Reform: Focus on Retail Competition, US Federal Trade Commission (FTC) https://www.ftc.gov/sites/default/files/documents/reports/competition-and-consumer-protection-perspectives-electric-power-regulatory-reform-focus-retail/appa.pdf

[14] Evolution of retail supply competition in distribution of electricity: A choice to Mumbai consumers https://www.researchgate.net/publication/315116824_Evolution_of_retail_supply_competition_in_distribution_of_electricity_A_choice_to_Mumbai_consumers

[15] Retail Tariffs for Electricity Consumers in Maharashtra, Council on Energy, Environment and Water (CEEW) https://www.ceew.in/sites/default/files/CEEW-Retail-Tariffs-for-Electricty-Consumers-in-Mumbai-10Jun18.pdf

Plan. Based on the assessment, BPCs *(eligible consumers as per CTBCM)* may be allowed to opt for open access / enter into bilateral contracts only to the extent of power shortfall, with prior intimation atleast three to four years in advance so that DISCOs / KE may plan accordingly. This will ensure that no stranded cost is created because of opening up of markets.

Separately, CPPA should work with GoP and NEPRA to identify capacity committed which can be forgone and any possibility of capacity buy back by GoP which can be early retired to identify potential for market opening. Further, the visibility to consumers about the potential of opening up of market be made available on transparent basis well in advance to facilitate healthy competition.

b) **Mechanism for Stranded Costs Recovery from Consumers Opting for Open Access prior to opening up of market as a) above:** Option should be provided to BPC *(eligible consumers as per CTBCM)* to opt early for open markets by paying necessary stranded cost arising due to advent of open access.

Eligibility Criteria for Consumers Allowed to opt for Open Access

With respect to treatment of stranded costs, it is imperative that eligibility criteria for consumers eligible to participate in the market is clearly defined so that DISCOs and KE are able to plan accordingly. In addition to increase in costs due to excess capacity that DISCOs and KE may commit to in the absence of clearly defined thresholds for eligibility of consumers to participate in open markets, security of supply may also be put at risk in case of short planning and will therefore be against the interests of regulated consumers as well as market as a whole.

Further, defining thresholds for eligibility of consumers to participate in open markets would also provide required clarity to BPCs / eligible consumers on the quantum and time period of stranded costs that they are required to pay which would be a key consideration for them to opt for open markets.

In view of the above, KE humbly requests NEPRA to provide detailed definitions of the following:

a) Bulk Power Consumers *(eligible consumers under CTBCM)* specifically in the context of possibility of several consumers (of a smaller scale) possibly accumulating their demand and forming "procurement alliances or cooperatives" in order to achieve certain thresholds, and

b) The transition timelines / milestones for the eligible consumers and all other types of consumers to transition to competitive markets (e.g. periods allowed for transition in context – at every year-end, etc.)

The above are critical for incumbent DISCOs/KE to manage the transition as well as provide clarity to consumers moving towards open markets to plan their capacity obligations well in advance – ensuring a sustainable and efficient power market, enabling proper planning and bilateral contracting by competitive suppliers.

iii. Cost of Service Based Tariff Setting & Uniform Tariff Policy

As detailed in Section 4.2.5 of the Plan, currently, there is a Uniform Tariff Policy across the country which is also adjusted for cross-subsidy in line with GoP's socio-economic policy objectives. Here, it is important to highlight that cross subsidy is a social obligation imposed on DISCOs and KE as per GoP policy and has no nexus to the efficiency or performance of DISCOs and KE.

Hence, in order to provide a level playing field, a holistic review of the existing tariff regime including application of GoP's Uniform Tariff Policy and cross-subsidization is required, and in this regard, it is recommended:

Cost of Service Based Tariff Setting & Application of GoP's Uniform Tariff Policy

Tariff should be cost reflective and set on 'Cost of Service' basis for all consumers of DISCOs and KE. As stated above, currently, there is a Uniform Tariff Policy, which is not on Cost of Service basis, but is adjusted for socio-economic policy objectives of the GoP, and DISCOs and KE are obligated to charge the Uniform Tariff so determined, as a result of which, Generators / Competitive Suppliers supplying to BPCs *(eligible consumers under CTBCM)* will have an undue advantage as they will be able to benefit by avoiding cross-subsidy charges imposed by GoP, as per GoP's Uniform Tariff Policy. Recognizing the issue of cross-subsidy charges and its impact on ensuring a level playing field for all market participants, for alignment with National Electricity Policy 2021 and CCoE approved principles for establishing competitive wholesale markets while also encouraging competition, it is recommended that for:

- Categories of consumers who are eligible to participate in open market / enter into bilateral contracts

  GoP's Uniform Tariff Policy should not be applied, and DISCOs and KE should be allowed to charge these consumers based on their cost of service, which will enable them to compete commercially with competitive suppliers based on their efficiency. In the absence of such a framework, Generators / Competitive Suppliers will not compete on efficiency basis, rather will be able to benefit by avoiding cross-subsidy charges imposed by the GoP, as per GoP's Uniform Tariff Policy.

  Further, if any cross subsidy is required to be charged, it should be separately identified for such consumers and a uniform per unit cross subsidy surcharge be charged to each consumer category which cross subsidizes, whether being served by DISCOs, KE or any competitive supplier.

- Categories of consumers not eligible to participate in open markets/enter into bilateral contracts

  GoP's Uniform Tariff Policy may be continued for such category of consumers in line with socio-economic policy objectives of the Government.

Separate Tariff Category for Hybrid BPCs and Net Metering Consumers

BPCs having bilateral contracts with renewables which have an intermittent supply as well as consumers opting for net metering, stay connected to DISCOs and KE network as backup, as a result of which DISCOs and KE have to incur fixed costs to ensure sufficient capacity to meet demand of these consumers as well as maintenance of the network. Therefore, a separate tariff category for such hybrid BPCs and net metering consumers be introduced allowing DISCOs and KE to recover their fixed costs.

Revision in Tariff Adjustment Mechanism

Under the current framework, tariff setting is done on the basis of company-wide average T&D losses which also includes BPCs *(eligible consumers under CTBCM)*. As discussed in Section 4.2.4 of the Plan, as BPCs move into bilateral contracts, this will require re-setting of benchmark T&D losses of DISCOs and KE based on the remaining regulated consumers' T&D loss. In this regard, it is important to note that BPCs opting for open markets under the wheeling charges will be paying for their technical losses only, whereas, tariff setting for regulated consumers will be on the basis of company-wide average T&D losses. As a result, with no mechanism available to adjust T&D losses to reflect cost of service for regulated consumers, DISCOs / KE will have negative implications in the form of under recovery of costs.

Accordingly, KE recommends that the tariff setting / adjustment framework be reviewed and a mechanism to allow recovery of costs based on T&D losses of the regulated consumer segment be provided, to ensure recovery of prudent costs in tariff of DISCOs / KE.

Illustration for Revision in Tariff Adjustment Mechanism

Particulars	Sent-out Units	Units Billed	T&D Loss	Comments
Existing Scenario				
Company-wide	90.0	74.1	17.7%	Tariff setting on company-wide T&D loss allowed in tariff
Revised Scenario				
BPCs *(eligible consumers)*	10.0	9.4	6.2%	BPCs pay for their respective technical losses allowed in tariff
Regulated Consumers	80.0	65.8	17.7%	No mechanism to adjust allowed T&D loss for adverse mix due to departure of BPCs
Company-wide	**90.0**	**75.2**	**16.4%**	**T&D Loss level allowed for tariff setting reduces from 17.7% to 16.4%**
Proposed Mechanism				
BPCs *(eligible consumers)*	10.0	9.4	6.2%	BPCs pay for their respective technical losses allowed in tariff
Regulated Consumers	80.0	64.7	19.1%	Regulated consumers pay for their cost-reflective T&D loss levels
Company-wide	**90.0**	**74.1**	**17.7%**	**Overall T&D loss target for tariff purposes remains the same for DISCO**

iv. Operating Cost for Central Despatch

As mentioned in Section 3.1 of the Plan, the envisaged CTBCM framework implies that after the introduction of the CTBCM model, two parallel markets will co-exist, namely (i) a competitive market for eligible consumers, and (ii) a regulated market for consumers who are not eligible to enter into bilateral contracts until the time the eligibility threshold is modified to include such consumers as well. Considering the proposed central despatch model where the despatch decision is to be made on operating cost shared by the respective generators, clarity should be provided for the process of determination of operating cost while keeping in view the distinction between the regulated market and competitive market as done in other international markets.

In this regard, as done in other international markets, for the purpose of competitive markets and SCED, predefined conditions should be set and may be monitored by the System Operator including audits of the submitted generation parameters such as heat rates, minimum loads, ramping limits and others, as well as financial parameters such as fuel costs and variable O&M costs, no-load costs, start-up costs, etc. to ensure market transparency and efficiency.

v. Review of Contract Designs

As detailed in Section 4.2.1 of the Plan, within the existing contract designs proposed under CTBCM, there are possible arbitrage opportunities, which may impact the overall sustainability of the market. In this regard, a holistic assessment of the contract designs including devising a mechanism in consultation with stakeholders for greater monitoring to avoid any arbitrage gains or undue advantages to any market participant is critical for an efficient future competitive power market.

Here, it is pertinent to highlight that tacit collusion in open electricity markets has precedents even in developed markets, such as California, UK, Spain, where generators / suppliers have managed to get away with collusion for years after deregulation. Such collusion was also observed in Germany where energy giants (c. 80% share of the total electricity market) operated like a cartel for years; which 'substantially influenced' electricity prices, hence defeating the very purpose of bringing competition through open electricity markets.

Moreover, specifically with regard to Fixed Quantity Supply Contracts proposed under CTBCM, as detailed in Section 4.2.1 of the Plan, the contract design may encourage speculative practices in the market, and therefore, it is recommended that thorough evaluation is done and till such time that the market matures, Fixed Quantity Supply Contracts design may not be made functional.

vi. Types of Suppliers

To have a sustainable competitive market and in line with Section 23E of the NEPRA Amendment Act, 2018, it is critical that criteria for eligibility and participation of competitive suppliers be formulated and finalized in consultation with stakeholders. The eligibility criteria for Competitive Suppliers should include specific thresholds for their participation as it may otherwise have significant implications including from planning perspective for DISCOs and KE, and may as well put supply security at risk.

Here, it is important to highlight learnings from the UK market where in an attempt to encourage competition, 'Supplier in a Box' (SIAB) model was introduced to ease out entry barriers in the market. However, as a fallout, in 2018, 30% of suppliers entered through SIAB in the UK market failed due to inadequate checks on entry of suppliers to boost competition in the market[16]. More importantly, with respect to DISCOs and KE who are deemed Last Resort Suppliers and will therefore be responsible to meet the demand obligations that competitive suppliers may have defaulted upon, this will have serious planning implications for DISCOs and KE.

Accordingly, it is critical that eligibility criteria for suppliers and thresholds for consumers eligible to move into bilateral contracts / opt for open markets be decided and finalized after thorough consultation with stakeholders.

In addition to eligibility criteria, in relation to the context of the co-existence of the regulated market and the competitive market, the different types of suppliers (Base Supplier, Competitive Supplier, Last Resort Supplier) need to be clearly delineated in terms of the types of consumers they are mandated / obligated to serve (eligible on competitive market or regulated market – but not both) as well as the prices at which such suppliers contract with consumers (regulated tariffs for base suppliers, freely negotiated tariffs for competitive suppliers, tariff linked to competitive market prices with a punitive add-on element for Last

[16] Rahmatallah Poudineh, "Liberalized retail electricity markets: What we have learned after two decades of experience?". The Oxford University for Energy Studies, 2019. Retrieved from: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/12/Liberalized-retail-electricity-markets-EL-38.pdf

Resort Suppliers). This is of fundamental importance to create clarity and predictability for consumers and to prevent any distortions between the two markets.

vii. Dry Run of CTBCM

For an efficient roll out of CTBCM, subsequent to addressing the existing challenges faced by the power sector and considering the material changes envisaged under CTBCM, initially a dry run be considered without having any commercial implications as also done in various international markets that have transitioned towards open markets.

In this regard, learnings from international markets may also be drawn where prior to commercialization of open market regime, a dry run period is provided to assess the implications of the proposed reforms as observed in Georgia where Day-ahead Market Dry run was initiated in July, 2020, including trainings, simulative trading and tests / exams to develop trading skills of potential Day-ahead market participants before launch of market targeted for July 2022.[17]

Given the current state of the power sector as well as significant changes that CTBCM seeks to bring including capacity building of state-owned DISCOs to enter into bilateral contracts, it is recommended that a study be conducted to assess the impact on consumers as well as do a dry run for a period of at least 12 months to assess the possible implications and any subsequent revisions that may be required to the market design or any other reforms to ensure a sustainable and efficient competitive power market.

[17] Georgian Energy Exchange: The First Year
https://genex.ge/files/ShowFiles?id=f76a92be-3bbd-4a57-8d00-7ba21c359fbf

5. KE's Integration into CTBCM

As part of the CTBCM Detailed Design, CPPA proposed KE's integration into the CTBCM based on central economic despatch with one System Operator for the entire country (NPCC). However, considering KE's uniqueness as a VIU having a tariff structure different from other entities operating in the sector, NEPRA, within its determination dated November 12, 2020 did not approve KE's integration as proposed by CPPA and directed KE, CPPA, NTDC / NPCC to deliberate upon and develop a plan for KE's integration into the CTBCM, evaluating financial, technical, legal, and market-related aspects.

Here, it is humbly submitted that KE's current distribution license which is valid till July 2023 provides for exclusive rights of distribution within its service area, and therefore, implementation of CTBCM in KE's service area shall be implemented post expiry of KE's exclusive Distribution license in 2023.

5.1 Evaluation of Centralized Economic Despatch

Based on the available documents and concepts within the Detailed Design which have been approved indicatively and are yet to be firmed up as also detailed in Section 3.2 of the Plan, KE in consultation with other stakeholders including CPPA, NTDC / NPCC conducted its evaluation of the proposed option for integration under centralized economic despatch.

Key considerations with regard to having a single country-wide centralized economic despatch as highlighted during the consultation process are summarized below:

- Interconnection Capacity of NTDC and KE network is planned to increase to 2,050 MW by 2023 and considering projected growth in peak power demand, in addition to drawl from the National Grid / central pool, to meet its demand, KE will have its own generation fleet as well as IPPs supplying power to KE.
- Currently, KE and NTDC systems are managed independently wherein KE as System Operator optimizes despatch for its service area based on EMO of KE plants, IPPs supplying power to KE and the National Grid, whereas, NTDC system is managed independently by NPCC. Accordingly, as both systems integrate under central despatch, opportunity exists where generators within KE's fleet (KE own & IPPs having bilateral arrangements with KE) may be despatched to meet demand in NTDC system for cost optimization at national level.
- Further, under the existing autonomous despatch mechanism, despatch decision for off-take from National Grid is based on the average basket rate. As a result, supply from National Grid is high on KE's EMO and is despatched regardless of the marginal cost of NTDC system. Accordingly, opportunity exists that KE's generation or other IPPs may be despatched which would cost lower than off-take from the National Grid.

Keeping in view the above considerations, commercial and technical evaluation for KE's integration under centralized economic despatch was done in consultation with stakeholders as directed by NEPRA:

a) Commercial Evaluation through study carried out by CPPA with support from KE

b) Technical evaluation through joint consultation carried out by KE and NTDC / NPCC

a) Commercial Evaluation

To evaluate the benefit of central despatch as envisaged under CTBCM, a study was conducted by CPPA with support from KE. This study was DC based and primarily focused on cost optimization.

The study covered the following scenarios:

- **Autonomous Despatch Scenario:** KE's system is not part of country wide central despatch and KE is its own System Operator with interconnection capacity enhanced to 2,050 MW by 2023 as per KE's planned interconnection capacity enhancement projects.

  For despatch decision, supply from National Grid is considered on average basket rate as per the current practice. This was the base case scenario depicting the existing operations and used to compare the results of a central despatch scenario.

- **Central Despatch Scenario:** KE's generation and IPPs having contracts with KE become part of central despatch and interconnection capacity enhanced to 2,050 MW by 2023 as per KE's planned interconnection capacity enhancement projects, and both the systems (KE & NTDC System) are operated in an integrated manner.

The study was conducted by CPPA over a 5-year horizon through SDDP tool. Results of the study conducted are presented below and detailed report including assumptions, methodology and procedures performed as part of the study is enclosed as **Annexure A.1**.

PKR Billion

Year	Central Despatch			Autonomous Despatch			Savings
	KE	NTDC	Total	KE	NTDC	Total	
	(a)	(b)	(c = a + b)	(d)	(e)	(f = d + e)	(g = f – c)
2021	101.5	542.7	**644.2**	98.5	545.9	**644.4**	**0.2**
2022	78.5	394.2	**472.7**	78.2	394.4	**472.6**	**(0.1)**
2023	61.7	369.1	**430.8**	61.2	370.6	**431.7**	**0.9**
2024	59.0	355.6	**414.6**	55.8	359.7	**415.5**	**0.9**
2025	62.1	333.8	**395.9**	58.0	338.6	**396.7**	**0.8**

As summarized in the table above, with the addition of cheaper generation sources in the National Grid and KE and enhanced interconnection capacity between KE and National Grid, integrated operations of the two system under a centralized economic despatch model is expected to result in cost optimization and annual savings of upto c. PKR 900 Million at national level.

Here, it is important to note that in certain cases, KE generation (i.e. KE own plants & IPPs having contracts with KE) is higher on the EMO and despatched to meet the demand in the NTDC system. As a result, generation in KE system under central despatch is higher as compared to autonomous despatch which would result in increased fuel and power purchase cost for consumers of KE. However, on overall national level, central despatch would result in cost optimization and savings of upto c. PKR 900 Million on annual basis, which may increase as cheaper generation is added to the system.

Limitations of the Study

- Fuel constraints including gas supply and pressure issues have not been accounted for in the study and the same have an impact on the actual system operations. As an example, within the study, it is assumed that 100% gas will be available for gas-based power plants.

- No indexations on account of fuel prices or inflation for variable O&M have been accounted for.
- A 5% tolerance level is assigned to the simulation model, and therefore, actual operations may differ from the study results.
- Timelines for planned projects may differ from their actual COD which will have an impact on the least cost operations and accordingly the results of the study over the study period.
- Study is DC based and primarily focuses on cost optimization and therefore actual operations may differ due to technical and administrative considerations, thus impacting the results / projected savings at national level.

b) Technical Evaluation

Technical evaluation for KE's integration under central despatch was jointly conducted by KE and NTDC / NPCC. As mentioned above, the study conducted by CPPA was DC based and as part of technical evaluation, KE also held discussions with NTDC / NPCC on the requirement for an AC load flow study to assess system stability and reliability under central despatch scenario.

In this regard, a joint meeting was held on March 10, 2021, having representatives from KE, NTDC / NPCC and CPPA, wherein, it was agreed that the technical study for drawl of upto 2,050 MW by KE from the National Grid will suffice the requirement for AC load flow study for KE's integration into CTBCM under central despatch, and therefore a separate study for AC load flow analysis is not required at this stage.

5.1.1 Implementation of Central Economic Despatch

Keeping in view the above technical and commercial evaluation and KE's continuation as System Operator for its service area, the parties agreed on formulation of Standard Operating Procedures (**"SOP"**) between KE and NPCC to implement central economic despatch.

In addition to technical and commercial evaluation, a key consideration highlighted during evaluation of central despatch was the impact on KE's IPPs having 'Take and Pay' arrangements. Under the current autonomous despatch scenario, despatch from National Grid in KE area is on the basis of average basket rate which falls high on the EMO, and the generation cost in the National Grid is expected to further reduce as planned projects come online. Given that under central economic despatch, National Grid plants will be despatched based on marginal cost, therefore, there is a greater possibility for these 'Take and Pay' IPPs to get despatched which under the existing scenario fall lower on EMO due to consideration of National Grid on average basket rate for despatch purposes.

Accordingly, in KE's view, post implementation of central economic despatch, all IPPs including those under 'Take and Pay' arrangement would also be despatched in accordance with central economic despatch. However, with regard to 'Take and Pay' Contracts and their functioning under central despatch, the CTBCM Detailed Design proposes that the capacity payments in case of despatch of such a 'Take and Pay' IPP will have to be made as per the bilateral contract. As an example, in case an IPP having 'Take and Pay' arrangement with KE is despatched to meet any non-KE demand, regulated consumers of KE would still have to bear the related capacity costs, thus burdening them for costs related to despatch even for such non-KE demand. During the consultation process, KE highlighted this concern to CPPA and requested for a review of treatment of 'Take and Pay' contracts and the recovery of capacity charges therein. However, in CPPA's view, this is a bilateral issue between the counterparties and needs to be settled contractually.

In view of the above, KE humbly requests NEPRA to review KE's submissions in the matter to develop a principle understanding for treatment of existing as well as future 'Take and Pay' contracts, and also issue necessary directions for consultation between the parties for revisions, if any, to the already executed 'Take and Pay' contracts to avoid any adverse implications or bottlenecks in roll out of CTBCM.

In addition, as the despatch decision under central despatch will be made on the basis of variable costs only, there is a possibility that while a particular 'Take and Pay' IPP may get despatched on the basis of lower variable cost, such a 'Take and Pay' IPP may have a high capacity component and thus the overall marginal cost including capacity component may be higher. Therefore, a holistic assessment should be made in this respect in line with international practices.

Evaluation of KE's Continuation as System Operator for its Service Area

As per Section 2 of KE's Transmission License, KE is the System Operator for its service area and the planning function for KE's service area is also mandated to KE. Further, as mentioned in Section 2.2.1 of the Plan, Section 25 of the NEPRA Amendment Act, 2018 also specifically allows for grant of licenses to one or more licensees within KE's service area.

Considering KE's unique status as a VIU having ownership and managing its own Transmission Network as well as rights and obligations under KE's license, during joint discussions with CPPA and NTDC/NPCC, it was discussed that NTDC / NPCC as per its license is not obligated to manage operations within KE's network and neither does it have the required understanding of KE's owned system / network. Further, it was highlighted that to ensure implementation of central economic despatch, the parties agreed that the same can be done through an agreed upon SOP with NPCC which will include operational topology as well as mechanism for exchange of information / data between KE and NTDC / NPCC to enable both entities to plan for future generation additions in an integrated manner, as well as make fuel commitments, maintenance plan, etc.

Formulation of SOP with NPCC for Central Despatch

With respect to formulation of SOP for central despatch, a joint meeting of KE and NPCC teams was held on April 01, 2021, wherein both KE and NPCC have agreed to formulate and finalize the protocols / SOP for centralized economic despatch with KE being the System Operator for its service area and the same will be submitted to NEPRA by January 2022, as further discussed in Section 6 of the Plan.

Action Item
KE and NPCC to formulate and finalize SOP for central despatch and submit for NEPRA's approval by January 2022.

In view of the above, KE's integration into CTBCM is proposed as follows:

KE's Integration into CTBCM
• *KE integrates into CTBCM under central economic despatch.* • *For implementation of central economic despatch, KE and NPCC will agree upon SOP / protocols.* ***However, it is humbly submitted that KE's Plan for integration into CTBCM is subject to finalization of pending matters / areas to be firmed up and other design considerations, as highlighted in Section 3.2 of the Plan, tariff considerations as detailed in Section 5.3 of the Plan as well as policy and regulatory matters providing framework for a sustainable transition.***

5.2. Mechanism for allocation of Existing PPAs / EPAs and Capacity Invoicing for Supply from National Grid

With regard to KE's integration into CTBCM, a key consideration is the mechanism for commercial allocation of existing PPAs / EPAs and invoicing of energy and capacity charges for off-take from the National Grid / central pool.

In this respect, energy and capacity invoicing mechanism under the existing regime and as proposed under CTBCM is summarized below:

Current Mechanism	Proposed under CTBCM
• Energy charges for supply from National Gird are billed on average basket rate	• Within the Detailed Design, it is proposed that existing PPAs / EPAs will take the form of Generation Following Supply Contracts. However, as detailed in Section 4.2.1 of the Plan, the same exposed KE and DISCOs to the risk of imbalance between KE and DISCOs despite KE and DISCOs being within their contractual limits. As a result, DISCOs and KE for the energy drawn from the National Grid beyond the allocated energy were to be charged at marginal rate of the system. Accordingly, KE proposed that a separate contract design shall be applied for existing PPAs / EPAs (National Grid / central pool) whereby imbalances are only charged when drawl is beyond the contractual limits of DISCOs and KE. • Following detailed evaluation and deliberations during the consultation process, CPPA has agreed to propose separate contract design for legacy PPAs / EPAs, where imbalances will apply to DISCOs and KE only if their drawl is beyond their contracted capacity (i.e. energy drawn within the contractual limits will be billed on average basket rate).
• Capacity charges are billed on MDI basis to DISCOs and KE (to the extent of drawl from National Grid)	• Within the detailed design, it is proposed that KE be allocated a fixed share to the extent of contracted capacity out of the total generation capacity at national level and will be invoiced capacity charges based on its allocated share. • During the consultation process, CPPA proposed to revise the mechanism for allocation of capacity and invoicing of capacity charges. In this regard, following two options were under deliberation:

Current Mechanism	Proposed under CTBCM
	i. Capacity be allocated to KE to the extent of its contracted capacity out of the total capacity in National Grid as proposed initially; or ii. Capacity be allocated to KE and DISCOs based on their share in system peak demand on coincidental basis • However, subsequently, during the consultation process, CPPA has proposed that KE shall be allocated a fixed a share based on its contracted capacity with CPPA / National Grid, whereas DISCOs will be allocated capacity from the existing PPAs / EPAs based on their share in the system peak on co-incidental basis. Further, CPPA has proposed that the capacity invoicing mechanism shall continue to remain as per the existing practice of monthly MDI basis for KE and DISCOs. Moreover, for any changes to capacity invoicing mechanism in the future, similar treatment shall be applied to KE and DISCOs and revisions to the mechanism, if any, shall be finalized in consultation with all stakeholders.

Moreover, KE would also like to highlight that with continued generation capacity additions in the central pool resulting in increase in capacity charges, a cut-off date be agreed for addition of new capacity in the National pool with appropriate consultation after which any generation capacity addition shall be for the purpose of bilateral contracts of identified DISCOs only, and such capacity addition should be allocated to the identified DISCO and not form part of the central pool. Till the cut off date, the capacity allocated shall be subject to periodic review and on the cut-off date, each DISCO and KE will be allocated a firm capacity from the National Pool which should also take into account planned decommissioning of plants in the National Pool so that required visibility is provided for their future planning and capacity obligations.

Action Items

- Cut-off date for new generation capacity addition in the National pool following which any new generation addition will not form part of the central pool, but will be allocated to the identified DISCO only.
- On the cut-off date, each DISCO and KE to be allocated firm capacity from the national pool taking into account planned decommissioning of plants in the national pool.

Keeping in view the material implications of commercial allocation of existing PPAs / EPAs, it is humbly submitted that **Plan for KE's integration is subject to finalization of commercial allocation of existing PPAs/ EPAs and mechanism for capacity invoicing for supply from National Grid, at the time of commencement of CTBCM,** as well as other areas which need to be firmed up as part of CTBCM implementation phase, detailed in Section 3.2 of the Plan.

5.3 Tariff Structure

As detailed in Section 2.2.2 of the Plan, KE operates under an integrated MYT regime. The following key features of KE's tariff along with their evaluation with respect to CTBCM is given below:

KE's Current MYT	KE's MYT Post 2023
• Based on KE's distribution exclusivity and having certain KPIs such as sent-out growth and T&D losses locked for the tariff control period	• For a shift towards open market, sent-out as a KPI under KE's MYT for the period post 2023 would need to be reviewed. • Similar to current tariff structure, recovery of capacity payment of KE plants i.e. depreciation and return on asset base should not be linked with despatch of KE plants • As detailed in Section 4.2.4, if BPCs are allowed to move into bilateral contracts as envisaged under CTBCM, this will have an adverse mix impact on T&D losses by around 2.0% points. Accordingly, tariff framework needs to be on cost reflective tariff setting basis, as illustrated in Section 4.3 of the Plan.
• No separate tariff component of variable O&M for Generation	• Instead of variable O&M currently allowed based on an assumed generation mix, separate variable O&M component be determined for each of KE's generation plants to be allowed on actual basis.
• No separate tariff for Distribution (Network) and Distribution (Supply) business	• For the period post 2023, separate tariff component for Distribution (Network) and Distribution (Supply) business should be determined and allowed on Cost of Service basis along with an appropriate retail margin given the asset light nature of supply business
• Tariff based on Cross-subsidy model	• Tariff setting should be on cost reflective basis and any cross-subsidy provided should be separately identified for each consumer category • Per unit cross-subsidy charged for each consumer category that cross-subsidizes shall be uniform whether the consumer is served by DISCOs, KE or any competitive supplier
• Uniform Tariff Policy adjusted for GoP socio-economic policy objectives	• Currently, DISCOs and KE are obligated to charge consumers in accordance with GoP's Uniform Tariff Policy, whereas Generators / Competitive Suppliers will be able to benefit by

KE's Current MYT	KE's MYT Post 2023
	avoiding cross-subsidy surcharges imposed by GoP as per GoP's Uniform Tariff Policy. Therefore, for consumers who are eligible to participate in open market / enter into bilateral contracts, Uniform Tariff Policy should not be applied so that DISCOs and KE can also compete based on their Cost of Service.

It is imperative that the above issues are addressed completely to ensure viability and sustainability of DISCOs and KE while providing for a level playing field. In addition, wheeling charges for KE will have to be determined along with an escalation / adjustment mechanism to ensure full recovery of costs. KE as part of the implementation action items for CTBCM will evaluate the appropriate tariff structure including separate tariff components for each business segment, incorporating key considerations for tariff post 2023 as highlighted above, and will accordingly file its tariff petition for the period post June 2023 with NEPRA.

5.4 Company Structure

As detailed above, KE currently operates as an integrated utility which provides the following advantages:

- Natural hedge between KE's different business units which improves KE's ability to raise and service debt considering that being a private entity, KE does not benefit from any sovereign guarantees – a critical component of delivering the necessary investment in all parts of the business and to maintain and enhance service to customers.

- Holistic investment approach supporting KE's ability to optimize investments and operation of the end-to-end energy system.

Further, under a legally separated scenario, the following will remain key considerations for KE:

- Raising finance in the absence of cross-business security structures and with limited assets, especially for its Distribution business. The current integrated structure provides for a natural hedge, and therefore, debts that have been secured on one part of KE's business are used to underwrite risks in another part of its business.

- Allocation of centralized support services, contractual obligations etc.

- Management of transmission and distribution as two stand-alone businesses given their high operational dependency (for example, transmission business needs to undertake operational actions to implement distribution business operation decisions)

- Reassessment of tariff, allocation of assets / facilities, financial and legal considerations

Keeping in view global trends and evolving market / service dynamics, KE will separately evaluate the feasibility of legal separation of different business segments and will submit its evaluation to NEPRA. However, with regard to company structure under CTBCM, it is submitted that with virtual separation through separate tariff components for each business segment and its financial reporting, KE would provide the necessary transparency for participation in CTBCM.

Here, it is pertinent to mention that under the proposed option for KE's integration into the CTBCM, CPPA in Section 18 of the Detailed Design also proposed that KE may remain as an integrated utility, and therefore the current integrated structure of KE may not have any bearing with respect to KE's participation in CTBCM.

Accordingly, subject to other considerations as detailed in earlier sections, KE may participate / integrate in CTBCM as an integrated utility and the evaluation of legal separation will be a separate exercise wherein any actions required will be separately submitted to NEPRA.

6. Implementation Roadmap

For a smooth transition and KE's integration into CTBCM as well as a sustainable roll out of the CTBCM model for a resilient future power sector, decision on key policy and regulatory matters along with a firm up CTBCM design will remain critical. Action items for a sustainable roll out of CTBCM and for KE's integration into CTBCM are detailed below:

i. Firming up of CTBCM Design and Key Policy & Regulatory Matters

As detailed in Section 4.1 and 4.2 of the Plan, the CTBCM model presents opportunities for transformation of Pakistan power sector into a resilient and efficient sector. In addition to detailed implication analysis, there are various aspects within the proposed CTBCM model as well as key policy and regulatory matters which need to be firmed up / finalized, as also identified within the Detailed Design. Therefore, prior to implementation of CTBCM, it is imperative that a firm CTBCM model along with an appropriate transition framework is provided to ensure a sustainable roll out.

In this regard, it is humbly submitted that KE understands that the National Electricity Policy 2021 will be the governing document for transition towards competitive markets as also identified in Section 14 of the NEPRA Amendment Act, 2018 and therefore, policy guidelines as provided within the recently approved National Electricity Policy 2021 including mechanism to ensure recovery of stranded costs, lost cross-subsidy surcharge arising as a result of transition towards competitive markets as well as a holistic review of the tariff regime needs to be undertaken prior to implementation of the CTBCM. Further, for a sustainable roll out of CTBCM based on a holistic assessment, it is requested that the National Electricity Plan should also be finalized in consultation with all stakeholders.

In addition, as detailed in Section 3.2 of the Plan, within the current CTBCM Detailed Design, there are various aspects which have been approved on an indicative basis by NEPRA, and the same are to be finalized during the implementation phase of CTBCM. Given the material implications of these issues for a sustainable roll out of CTBCM as well as KE's evaluation and Plan for integration into CTBCM, it is requested that the same be finalized at the earliest after thorough consultation.

Key areas include:

- Alignment of the regulatory framework with the National Electricity Policy 2021, National Electricity Plan and CCoE approved principles for establishing competitive wholesale power market, including mechanism for treatment / recovery of stranded costs due to advent of open access and cross-subsidy as detailed in Section 4.3 of the Plan.
- Review of tariff framework with a shift towards Cost of Service based tariff setting as well as revision in tariff adjustment mechanism as recommended in Section 4.3 and 5.2 of the Plan.
- Mechanism for Commercial Allocation of existing PPAs / EPAs on firm basis and capacity invoicing for supply from National Grid as detailed in Section 4.3 and 5.2 of the Plan.

In addition, as detailed in Section 3.2 of the Plan, following areas are to be firmed up:

- Types of contract designs including detailed review and implication analysis for each type
- Methodology for determination of Firm Capacity of Generators
- Pricing methodology in Balancing Mechanism including a detailed analysis for optimal economic consequences

- Mechanism for allocation of Transmission Losses
- Determination and allocation of costs related to Ancillary Services
- Changes to regulatory framework including revisions in codes, finalization of Regulations, etc.

Here, it is humbly submitted that KE's evaluation and Plan for integration into CTBCM is also subject to any revisions which may be required, once the policy and regulatory matters are finalized along with a firmed up CTBCM design.

Moreover, as recommended in Section 4.3 of the Plan, once a firmed-up design along with required interventions have been made to enable a sustainable transition towards open markets pursuant to CTBCM, a dry run for a period of at least 12 months be done to assess the possible implications and any subsequent revisions that may be required to the market design or any other reforms to ensure a sustainable and efficient competitive power market.

After having completed the dry run for at least 12 months and detailed implication analysis along with revisions required, if any, to the market design in consultation with all stakeholders, formal integration into the CTBCM framework may be considered.

In view of the above, KE humbly submits that a careful assessment should be made in consultation with all stakeholders, and a mechanism for an orderly transition taking the above factors into consideration should be provided.

In addition to the above pre-requisites for a sustainable transition, action items relevant to KE for integration into / participation in CTBCM are summarized below:

ii. Formulation of Standard Operating Procedures (SOP) between KE and NPCC for Central Despatch

As detailed in Section 3.1 and 5.1 of the Plan, to benefit from cost optimization at national level, it is proposed that KE may integrate into CTBCM on the basis of centralized economic despatch. However, as concluded in discussions with CPPA and NTDC / NPCC, evaluation of SCED will be done centrally by NPCC for despatch purposes, whereas KE shall continue to perform the functions of System Operator for its service area in coordination with NPCC.

For efficient execution of central despatch, KE and NPCC have agreed to formulate a joint SOP, wherein modalities for central despatch, including despatch instructions, outage schedules, exchange of data for future planning as well as calculation of hourly marginal rates, etc. will be agreed upon, and the agreed upon SOP for centralized economic despatch will be submitted to NEPRA as part of the implementation phase.

In this regard, KE and NPCC teams are in deliberations and an initial draft of the SOP is targeted to be developed by November 2021, following detailed consultation / discussions between KE and NPCC teams to finalize the required modalities and SOP for central despatch including KE area and the same is targeted to be submitted to NEPRA for approval by January 2022.

KE and NPCC to formulate and finalize SOP for central despatch and submit it for NEPRA's approval by January 2022.

iii. Formulation of Standard Operating Procedures (SOP) between KE and CPPA for Metering Service Provider

As detailed in Section 3.1 of the Plan, KE will perform the role of Metering Service Provider in its service area and is in discussions with CPPA for formulation of a joint SOP detailing modalities including exchange and verification of data required by the Market Operator to carry out the market settlement functions. Based on initial discussions between KE and CPPA teams, KE's system is equipped with the basic technical requirements to fulfill the role of Metering Service Provider in KE's service area.

In addition, as part of the exercise, KE shall also evaluate any requirements for revisions / additions to the existing metering infrastructure or any other technological intervention required in this respect in consultation with NTDC and CPPA.

For formulation of a joint SOP for KE's participation as Metering Service Provider, CPPA and KE teams are in deliberations to assess the requirements including technical and data related and it is targeted that an initial draft of the SOP is developed by October 2021, and the same is finalized by December 2021 based on detailed deliberations between KE and CPPA teams, which will then be submitted to NEPRA for approval.

KE and CPPA to formulate and finalize SOP for Metering Service Provider by December 2021.

iv. KE's Participation in Revision in Grid Code

As part of the implementation items for roll out of CTBCM, revisions in Grid Code are being made. In this regard, KE has representation on the working group for revision in Grid Code. As deliberated during the consultation process, the initial draft of Grid Code was not in alignment with the open market regime pursuant to CTBCM and a revised draft of Grid Code was shared with KE in July 2021.

KE is in discussions with CPPA and NTDC with respect to the revised draft of Grid Code and the amendments required for alignment with an open market regime, and targets to submit its comments to the working group / Grid Code Review Panel by October 2021.

With regard to adoption of Grid Code, it is submitted that as detailed in Section 3.1.1, KE shall be responsible for planning and undertaking required investments, subject to NEPRA's approval, to ensure reliability of its network, and therefore KE shall continue to function as Planner for its service area. Further, as directed by NEPRA, KE shall also collaborate with NTDC / NPCC and provide all relevant information to enable development of a long-term least cost based IGCEP and a least cost-based TSEP, subject to NEPRA's approval.

Moreover, with regard to Scheduling, Despatch and Metering, relevant details and modalities shall be included within the SOPs for KE's participation as System Operator and Metering Service Provider for its service area as detailed above, which will be submitted to NEPRA for approval.

Submission of KE's comments to Grid Code Review Panel for revision in Grid Code by October 2021.

v. KE's Participation in Revision in Distribution Code

Similar to revision in Grid Code, as part of the CTBCM implementation roadmap, revisions are also being made to the Distribution Code to align the same with CTBCM. With respect to revision in Distribution Code, KE has representations on the working group and remains in continuous engagement with all stakeholders including CPPA.

KE targets to share its comments for revision in Distribution Code by October 2021.

Submission of KE's comments to the working group for revision in Distribution Code by October 2021.

vi. Connection Agreements

KE is engaged with all relevant stakeholders and has participation on working groups for preparing of standardized templates for Connection Agreements. In this regard, it is submitted that for Connection Agreement with NTDC, KE is already engaged in its finalization with NTDC as part of discussions for contractual arrangements for off-take of additional supply from National Grid, and based on discussions, KE understands that the same shall be adopted as the standard template for Connection Agreement with NTDC.

Further, for template of Connection Agreement with BPCs *(eligible consumers under CTBCM)* and Generators, it is submitted that the initial draft was not aligned with the open market regime pursuant to CTBCM, and KE's working group is working in close coordination with other DISCOs and CPPA in this respect.

Here, it is submitted that after the initial review, a revised draft of template for Connection Agreement between Generators and DISCOs was shared in July 2021 for stakeholder comments, whereas template for Connection Agreement between BPC and DISCOs is awaited. As submitted above, KE remains in continuous engagement with relevant stakeholders with regard to preparation of standardized templates for Connection Agreements.

Based on discussions with stakeholders including CPPA, draft standardized templates for Connection Agreements are targeted to be submitted to NEPRA for approval by October 2021.

Submission of KE's comments to the working group for preparing standardized templates of Connection Agreements, which based on stakeholder discussions is expected to be finalized by October 2021.

vii. Formation of DISCOs Association

KE is in continuous engagement with relevant stakeholders on formation of DISCOs Association and will provide input on defining the role, responsibilities and obligations, incorporation requirements, Board composition & criteria for Board members, and other key considerations / aspects relevant to formation and functionality of DISCOs' Association. In this regard, KE through letter dated August 09, 2021 has also nominated its representative for promotors for DISCOs Association.

Upon incorporation of DISCOs' Association, KE will become a member of the same which based on discussions, KE understands is expected by September / October 2021.

KE to file for membership of Association of DISCOs upon incorporation of the Association which is expected by September / October 2021.

viii. Tariff Structure post 2023

As detailed in Section 2.2.2 of the Plan, KE's Current MYT is for a 7-year tariff control period, expiring on June 30, 2023.

As per the CTBCM Detailed Design and also detailed in Plan, KE shall participate in CTBCM in various capacities of Service Provider as well as Market Participants. In order to align with the CTBCM framework which proposes central despatch, KE, as part of the implementation phase shall evaluate appropriate tariff structure, agree on key principles with NEPRA and will accordingly file its tariff petition with NEPRA by July 2022.

KE to file the tariff petition for the next tariff control period by July 2022.