Financial Transmission Rights Viability Study

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Philippine Electricity Market Corporation –
Market Surveillance Committee for the
Department of Energy

The information contained in this document is based on data that are subject to continuous verification by the Philippine Electricity Market Corporation (PEMC). The same information is subject to change as updated figures come in.

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1.0 INTRODUCTION

The sale of electricity has long been negotiated through long-term contracts called as “bilateral contracts”, which is an avenue provided for generators and Distribution Utilities (DU) to secure cost-efficient supply of electricity. In 2001, the Electricity Power Industry Reform Act of 2001 or EPIRA paved the way for the deregulation of the electric power industry in a number of sectors, which introduced the Wholesale Electricity Spot Market (WESM) that played a critical role in providing transparency, fairness, and efficiency ultimately promoting competition.

Currently, the country’s WESM is employing a real-time gross pool market model with a must-offer rule (MOR) that ensures all available capacities are accounted for in the dispatch scheduling. The WESM likewise utilizes a Locational Marginal Pricing (LMP) mechanism wherein prices per interval are determined in consideration of the losses and congestions present in the delivery of electricity via a transmission system. An inevitable component, the cost of losses is a natural occurrence in the energy transfer between the connection points or nodes of generators to the DUs and/or End-Users. LMPs also include congestion cost which refers to the additional financial value associated with the re-dispatch of more expensive generators to address limitations in the transmission capabilities. Equation 1 below presents the mathematical representation on how the LMP may be broken down to its three (3) components as follows:

$$LMP = System\ Marginal\ Price + Marginal\ Cost\ of\ Losses + Marginal\ Cost\ of\ Congestion$$

Equation 1. Locational Marginal Pricing

Since LMPs are greatly influenced by the real-time interaction among the demand, supply and the grid situation, LMPs naturally experience volatility and, at times, may reach unusually high levels unduly exposing market participants. In many jurisdictions, this risk is addressed by way of market participants acquiring hedging instruments that would allow them to minimize or even eliminate this exposure. Financial Transmission Rights (FTR) is among these mechanisms.

According to a report by the National Economic Research Associates (NERA) Economic Consulting, “the common denominator of the markets that have adopted FTRs is that they all use a nodal pricing system for energy”. Nodal pricing is synonymous with the LMP feature which the WESM employs since its commencement back in 2006.

Majority of jurisdictions implementing FTR markets only hedge for marginal cost of congestion (MCC) although an exception would be the Electricity Authority of New Zealand who operates an FTR market based on the full LMP difference of two nodes covering the marginal cost of losses (MCL) on top of the MCC.

MCL is generally constant due to a relative static physical characteristics of the transmission system referred to as the technical loss. These losses are usually comprised of the conductor loss, transformer core loss, and technical errors in meters, all of which do not possess high variance and do not significantly affect the resulting LMPs. For this purpose, this paper will only focus on the FTR as a form of insurance in the event of congestion.

As a brief overview, FTR is a type of financial derivative vastly used in jurisdictions with electricity markets. The price/value for these rights is based on the cost of power at two different nodes involved in the transaction. In general, FTR is defined by the following characteristics:

- it is a financial instrument;
- the value is based on MW reservation and the transmission congestion prices at the designated point of delivery and the point of receipt;
- FTR holders are entitled to receive compensation from transmission congestion costs paid to the market per interval over the term of the FTR; and
- Generally settled based on prices in a day-ahead market.

2.0 OBJECTIVES

This paper, first and foremost, aims to set a baseline understanding on the concept of FTR by surveying similar mechanisms in other jurisdictions. Likewise, this study also aims to determine the viability in terms of prerequisite/s for the introduction of the FTR Market in the Philippines, in terms of fulfillment of the WESM rules, market design, FTR regulation and ERC's role for the implementation procedure and identification of the next steps and ways forward for further consideration of the Technical Working Group (TWG) for the establishment or commencement of the FTR market in the WESM.

3.0 RELATED LITERATURE

3.1 Background

3.1.1 Financial Transmission Rights (FTR) in Other Jurisdictions

Based on a survey undertaken for this study, FTRs are currently implemented in the following jurisdictions:

- California ISO (CAISO)
- Midwest ISO (MISO)
- New York ISO (NYISO)
- PJM Interconnection (PJM)

- ISO New England (ISO-NE)
- Electric Reliability Council of Texas (ERCOT)
- New Zealand's Electricity Market (NZEM)

Several definitions have likewise been used to describe this mechanism as elaborated in **Table** below.

Table 1. FTR Definition

ISO/RTO	Definition
ISO New England (ISO-NE)	"a financial instrument that entitles the holder to receive compensation for Congestion Costs that arise when the transmission grid is congested in the Day-Ahead Energy Market and differences in Day-Ahead_Locational Marginal Prices (LMPs) result from the dispatch of generators to relieve the congestion"[1]
Midwest ISO (MISO)	"financial instruments whose values are determined by the transmission congestion charges that arise in the Day-Ahead Energy and Operating Reserve Market, leading to differences in the Marginal Congestion Components (MCCs) of Ex-Post Day-Ahead Locational Marginal Prices (LMPs) at different locations. FTRs may be used to provide a financial hedge to manage the risk of congestion cost in the Day-Ahead Energy and Operating Reserve Market."[2]
PJM Interconnection (PJM)	"a financial instrument that entitles the holder to receive compensation for Transmission Congestion Charges that arise when the transmission grid is congested in the Day-ahead Market and differences in Day-ahead Congestion Prices result from the dispatch of generators out of merit order to relieve the congestion"[3].
New Zealand Electricity	"hedge product designed to help parties manage the risk they face from large, unpredictable differences in wholesale electricity prices":[4]

[1] ISO New England Manual for Financial Transmission Rights
[2] Business Practices Manual: Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR)
[3] PJM Manual 06: Financial Transmission Rights
[4] New Zealand Electricity Authority Te Mana Hiko - Overview of the FTR Market

FTRs are also referred to as congestion revenue rights (CRR)[5], transmission congestion contracts (TCC)[6] or transmission congestion rights (TCR)[7].

3.1.2 FTR – WESM Rules Provision

As of writing, FTR is yet to be implemented in the Philippines as the WESM Rules Clause 3.12 requires the approval of the PEM Board upon its determination that FTR is necessary or reasonably feasible[8]. Apart from this approval, the Rules likewise sets a number of activities to be undertaken and considered prior and during the FTR operation:

1) MO's regular publication of line rental information[9];
2) Potential issuance of further transmission rights[10];
3) Matters to be considered in the assessment of FTR[11]:
    a. Demand for transmission rights
    b. Uncommitted physical capacity and
    c. Economic feasibility of supporting further transmission rights;
4) Issuance of transmission rights[12];
5) Accounting of accounting for net income[13]; and
6) Development of the price substitution methodology for congestion[14].

The DOE's creation of a technical working group[15] (TWG) to ensure the smooth transition and operation of spot market is likewise among the necessary requirements by the Rules and this TWG shall be composed of government and industry participants from:

1) Philippine Independent Power Producers' Association (PIPPA);
2) Private Electric Plant Owners Association (PEPOA);
3) Philippine Rural Electric Cooperative Association (PHILRECA);
4) Manila Electric Company (MERALCO);
5) National Power Corporation (NPC);
6) National Transmission Company (TRANSCO); and
7) Power Sector Assets and Liabilities Management Corp. (PSALM).

[5] CAISO and Texas (ERCOT)
[6] New York ISO (NYISO)
[7] Southwest Power Pool (SPP)
[8] WESM Rules Clause 3.12.1
[9] WESM Rules Clause 3.12.2
[10] WESM Rules Clause 3.12.3
[11] WESM Rules Clause 3.12.4
[12] WESM Rules Clause 3.12.5
[13] WESM Rules Clause 3.12.6
[14] WESM Rules Clause 3.12.7
[15] WESM Rules Clause 10.4.19

As part of their responsibility, the TWG shall recommend to the DOE, for its appropriate action, supplemental modification and other amendments or additional provisions to WESM Rules which among other for the FTRs. The first TWG[16] was created in accordance with the which tenure had already lapses upon the operation of the WESM.

3.1.3 Overview of Financial Transmission Rights

3.1.3.1 Definition and Purpose of FTRs

An FTR is a financial instrument that permits the holder to receive compensation from congestion rents arising when the transmission grid is constrained in a day-ahead market (DAM) or real-time balancing market. To relieve the transmission constraints, generators which are out-of-merit will be dispatched and shall incur higher cost in the form of the transmission congestion charges.

Based on the definition of congestion in the Philippine Grid Code (PGC), congestion is a situation where cheaper power from a generating unit cannot be dispatched and is replaced by more expensive power to supply the demand because (i) the transmission limit of a transmission line or the capacity of a transformer is reached and no more additional power may be transmitted through that line or transformer; and/or (ii) the grid operating criteria limits the transmission capabilities in some portions of the network[17].

FTR, CRR, TCC, and TCR are mechanism designed by William Hogan to allow transmission service customers hedge their transmission congestion cost for the delivery of electricity to their long-term contracts[18]. FTR is financial instrument that give the holder the right to receive reimbursement for congestion tolls paid by the market trading participants which may be purchased as liabilities or options. Since FTR is only a financial instrument, they do not stand for a right to actual physical exercise of power.

Primarily, FTR have two major goals: 1) to mitigate the volatility of congestion cost allowing the FTR holder to hedge their congestion cost; and 2) for transmission owners and/or transmission investors to have an avenue for review of the transmission expansion.

3.1.3.2 Allocation

[16] Department of Energy Department Oder No. 2004-05-005
[17] Philippine Grid Code 2016 – GC 1.7. Definition
[18] Transmission Capacity Rights for the Congested Highway: A Contract Network Proposal, FERC PL91-1-000; William W. Hogan, June 8, 1991

Acquisition of FTR is most commonly done through allocation and/or auction. Based on survey, FTR is primarily allocated to market participants as their initial allocation depending on their prior usage of the transmission system. Another type for consideration in the initial allocation of FTR are investments made in the transmission system of participants in their jurisdictions – this is possible since the transmission operator in other jurisdictions are private corporations. This initial allocation of FTR may further be auctioned or traded in the secondary markets and the price of the FTR will be dependent on the holder of the rights.

Since congestion and its cost are dynamically changing, FTR holders are allowed to modify their FTR allocations. This is done simultaneously with the scheduled auction which may be held on a monthly, seasonal, quarterly, or annual bases depending on the design and implementation of the operator.

According to NERA, FTR entitlement is vastly acquired through an auction market[19]. Some jurisdictions conduct annual auctions performed in three (3) rounds with increasing percentage of the total transmission capacity offered in each succeeding rounds. On the other hand, multi-round auctions allow trading participants to adjust their bidding strategy based on the results of the earlier rounds. Given that FTR auction seldom occurs within a year, a multi-round auction provides trading participants the opportunity (i.e., by changing their bidding strategy) to address any under- or over-estimation of the value of FTRs that they are trying to acquire.

FTR markets in other jurisdictions generally implement multi-round auctions for long auction periods (i.e., annual, quarterly). On the other hand, monthly auctions are usually implemented as a single-round auction. One major difference of an multi round to a single round auction is that multi-round auction is only applicable for semi-long term contraction periods (i.e., annual, quarterly). This is to allow the holders to modify their contracts. This avenue for modification will not be available for FTR contracts on a monthly scale which is the minimum contract period and categorized under a single round auction.

3.1.3.3 Value of FTRs

Apart from mitigating the risks involved for the end-users upon contracting FTRs, acquisition of an FTR also provides its holder with possible revenues based on the nodal prices of the electricity market. On an interval basis, the settlement amount of an FTR can be calculated as follows:

[19] Review of Financial Transmission Rights and Comparison with the Proposed OFA Model – NERA Economic Consulting

$$FTR\ SA_i = FTR\ Q_i \times (MCC_{R,i} - MCC_{S,i})$$

Equation 2. FTR Settlement Amount if FTR is Allocated

Where,

FTR SAi	–	settlement amount of FTR for interval i
FTR Qi	–	FTR quantity for interval i
MCCR,i	–	Marginal Congestion Cost at receiving node for interval i
$MCCS_{,i}$	–	Marginal Congestion Cost at sending node for interval i

Based on the above equation, the value of an FTR to its holder is a receivable if the marginal congestion cost at the receiving node (MCC_{Ri}) is higher than the marginal congestion cost at the sending node (MCC_{Si}). In the event that the condition or the direction for congestion is opposite (i.e., the marginal congestion cost at the receiving node is less than the marginal congestion cost at the sending node), the value of an FTR becomes payable to its holder; hence, it will become a liability or an FTR obligation.

For the FTR options, a trading participant would be entitled to any revenue associated with the FTR but would never be charged during intervals when the marginal congestion cost at the receiving node is less than the marginal congestion cost at the sending node; hence, an FTR option is never a liability.

Due to its revenue adequacy and nature, the FTR type (obligation/option) for most jurisdiction implements the obligation type. The FTR type shall automatically of the allocation/purchased and not a choice for market participants.

3.1.3.3.1 Example

To further illustrate the hedging property of an FTR, an example scenario below is provided.

- Load A consumed 200 MWh for a 1-hour interval
- Load A has a 200 MWh bilateral contract with Generator A
- The LMP at Load A's node is PhP 15,000 / MWh while the LMP at Generator A's node is PhP 10,000 / MWh

For this scenario, the Load A do not have a FTR for its bilateral contract. Below is the resulting settlement in the market for with the assumption of imbalances and technical losses, are as follows:

Load A charged for its consumption:

200 MWh x PhP 15,000 / MWh = **PhP 3,000,000.00**

Bilateral Contract:
200 MWh x PhP 6,000 / MWh = **PhP 1,200,000.00**

Net-Settlement Amount:
Load charged for its consumption - Bilateral Contract
PhP 3,000,000 - PhP 1,200,000 = **PhP 1,800,000.00**

For this example, Load A will have a net settlement amount of PhP 1,800,00.00 payable to the market. While the remaining net settlement amount is a result of the re-dispatch of a more expensive generator in Load A's region due to a congested line between Load A's node and the node of Generator A counterparty for the bilateral contract. The FTR will allow the Load A to addressed the LMP difference of Load A and Generator A counterparty .

Similar assumption to previous example, that no imbalances and technical losses (lossless system) and considering the MCL is not part in FTR calculations. LMP components for each node will be as follows:

Load A : MEC = PhP 6,000 / MWh, MCC_R = PhP 9,000 / MWh
Generator A : MEC = PhP 6,000 / MWh, MCC_S = PhP 0 / MWh

This will result Load A would be provided entitlement receive the cost of congestion between their node to Generator A. The settlement amount (assuming a lossless system) for the 200 MW FTR will be as follows:

$$FTR\ SA_i = FTR\ Q_i\left(MCC_{R,i} - MCC_{S,i}\right)$$

= 200 × (9,000 – 0)

FTR SAi = **PhP 1,800,000.00**

With the FTR entitlement of Load A it will have a receivable of PhP 1,800,000.00. The total settlement amount of Load A would be net to zero (0). Therefore, Load A hedged against the volatility for both energy cost and congestion cost by entering into bilateral contracts and acquiring FTR. Subsequently, Load A's energy costs would is not affected by the demand and supply condition in the market as well as the presence of congestion between its node and its generator counterparty's node.

It should be noted that the acquisition of FTRs could entail costs as part of its hedging mechanism. In the event that Customer A purchased its FTR from an FTR market, it would essentially be fixing its congestion costs at the cost of the FTR purchase which can be calculated as follows:

$$FTR\ SA_i = FTR\ Q_i \times [\ (MCC_{R,i} - MCC_{S,i}) - FTR\ AP\ ]$$

Equation 3. FTR Settlement Amount if FTR is Purchased

Where,

FTR SAi	–	settlement amount of FTR for interval i
FTR Qi	–	FTR quantity for interval i
MCCR,i	–	Marginal Congestion Cost at receiving node for interval i
MCCS,i	–	Marginal Congestion Cost at sending node for interval i
FTR AP	–	FTR awarded price

Since the FTR is a type of hedging mechanism, it is also worthy to note that the FTR awarded price or the hedge price, meaning, the FTR holder will only be benefited with its hedging when the difference of congestion cost at the receiving node (MCC_{Ri}) and congestion cost at the sending node (MCC_{Si}) is higher than the awarded price for FTR. Hence, if the cost of congestion is lesser than the hedge amount/FTR awarded price, it will be an additional charge its holder.

3.1.3.4 Revenue Adequacy

FTR provide its holders revenue based on congestion costs. Since a new revenue stream will be introduced in the market, it must be sourced or recovered from a certain area in the market where no additional cost is incurred by the end-users and that which would benefit them when receiving such additional revenue. In other jurisdictions, FTR revenues are funded by the so-called “congestion rent” which is an hourly credit/charge to FTR holders in the Day-Ahead Market (DAM). These have already been paid by the market participants from difference in the delivery and receipt nodes. In the Philippine WESM, this congestion rent is currently considered as the surplus or deficit in the market’s settlement process and is currently allocated to the trading participants based on the methodology approved by the ERC[20] – surplus are flowed-back to those who actually paid for the losses and congestion costs. Since FTR will be funded by the congestion rent, it is important that FTRs would be awarded to market participants such that the congestion rent would be adequate to fund the FTR revenues. This concept is called revenue adequacy. In order to achieve this, a Simultaneous Feasibility Test (SFT) must be performed to ensure that the transmission system can support the subscribed FTRs during normal and transmission constraints condition. The SFT is also used to determine the maximum capacity which can be offered of FTR ensuring the revenue adequacy.

[20] ERC Resolution No. 7, Series of 2019

3.1.4 Type of Market

A cursory review of available literatures provides that most of jurisdictions implementing FTR receive compensation based on transaction/settlement for congestion during the DAM. Since FTR is a financially binding, it is much better to transact the congestion in the electricity market, ahead of time. William Hogan, as the developer of the FTR, also suggest the "FTR must be settled at the day-ahead price"[21].

DAM is used by organized electricity markets to include customers' bid loads and generation offers. A reliability assurance is also included in the DAM to guarantee that enough capacity will be made available in real-time to handle the actual load[22].

Based on survey, it was also recognized that the introduction of a DAM would allow generators and loads to lock-in energy prices in a less volatile day-ahead time frame and allow forward bilateral contracts to be paid during the same period when the commitment was established.

In general, DAM may also be defined by the following characteristics:

- it is a forward financial market;
- allows buyers and sellers to hedge against price volatility prior to the actual operating day; and
- similar to the forward market which allows the future contracts (i.e., FTRs) for hedging and speculation.

In the course of the undertaken survey, jurisdictions implementing FTR defined DAM, as follows:

- ISO New England (ISO-NE) – "is a financial market where market participants purchase and sell electric energy at financially binding day-ahead prices for the following day."

- Midwest ISO (MISO) – "serves as a "planning phase" for the next operating day. The outcome is an optimal set of unit commitment and hourly operating schedules for the following day. The Day-Ahead Market also calculates costs and allows buyers and sellers to lock in pricing prior to real time."[23]

- PJM Interconnection (PJM) – "is a forward market in which hourly locational marginal prices are calculated for the next day based on the amount of energy generators offered to produce, the amount of energy needed by consumers and scheduled transactions between buyers and sellers of energy."

[21] Electricity Market Design – The Value of FTRs; William W. Hogan, 26 October 2018
[22] ELECTRICITY MARKET DESIGN – The Value of FTRs by William W. Hogan, 26 October 2018
[23] Business Practices Manual: Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR)

Considering this, it has been noted that majority of jurisdictions implementing FTR complements their operation with the DAM. Since DAM is scheduled one day in advance, it allows slow ramping generators to meet their scheduled demand providing self-scheduled and bilateral quantities to manage their congestion cost and further strategize their FTR allocations. ***Currently, the WESM does not have a DAM but only utilizes a day-ahead projection (DAP) which does not provide financial commitment. This is another essential component which shall be in place prior to FTR adoption in the WESM***.

4.0 DISCUSSION OF MARKET INFORMATION

Forward contracting (including self-supply and bilateral trading) should account for most trades in the LMP market, so that the spot trading (including the Day-Ahead and Real-Time Markets) may provide a viable, competitive option for market participants to cover their residual requirements. Investopedia defined forward contracts to be: "*A forward contract is a customized contract between two parties to buy or sell an asset at a specified price on a future date. A forward contract can be used for hedging or speculation, although its non-standardized nature makes it particularly apt for hedging*". FTR, as a financial hedging mechanism, is an example of a forward contract as a risk management for LMP difference between to nodes.

In the WESM, only the bilateral trading is currently available. Bilateral trading is significant because it is the most efficient way for market players to manage the risk of volatile prices in the spot market and as discussed in the introductory part that it has been a staple in the electricity industry for so long. With the recent transition of the WESM to a 5-minute market, it has become more volatile as it may now be able to react on a real-time manner on the changes in the conditions of the market, preventing slow ramping generators to cope with the per interval demand. This would provide more risk for market participants to use the WESM as their principal source of electricity transactions. Because of bilateral trading, involved participants rely on – and must specify – the location of the transaction or the supply resource. The property right represented by the point-to-point definition of congestion rights allows market participants to hedge their exposure to locational price differences between their bilaterally contracted supply and the location of their demand. Electricity market players' capacity to manage the risk associated with the delivery of their physical supply resources to their physical load commitments must be considered when decoupling congestion charges by eliminating the point-to-point aspect of congestion-hedging rights in an LMP market.

Table 2. Historical Wholesale Trading Supply

	BCQ Qty	Spot Qty
2014	90%	10%
2015	89%	11%
2016	84%	16%
2017	82%	18%

	BCQ Qty	Spot Qty
2018	80%	20%
2019	86%	14%
2020	85%	15%
2021	89%	11%
Average	**86%**	**14%**

Table 2 shows the historical wholesale trading supply in the WESM. It eminently shows that majority of the traded supply in the WESM is under bilateral transactions. This concludes that the flow of electricity traded in the market has already been established and that the point-to-point mechanism of FTR can further support bilateral transactions to mitigate the congestion risks.

4.1 Overview of WESM Congestion

4.1.1 Price Substitution Methodology

Currently, the WESM has a mechanism to address undesirable market pricing situations that arise from the effects of network congestion caused by non-spring washer effect[24] in the power system, particularly during the occurrence of extreme nodal separation which is called the Price Substitution Methodology (PSM). Initially, the PSM is established as in the absence of FTR to mitigate extreme nodal separation. The PSM will only be applied to dispatch interval exceeding the trigger factor threshold of 0.2 it shall be computed using the equation 2 below:

$$Trigger\ Factor_i = ABS\left(\frac{\sqrt{\frac{\sum_{j\in J}\left[EDS_{j,i} * (EDP_{j,i} - NWAP_i)^2\right]}{\sum_{j\in J}(EDS_{j,i})}}}{NWAP_i}\right)$$

Equation 4. Price Substitution Methodology – Trigger Factor

Where:

J	refers to the set of all resources
$EDS_{j,i}$	refers to the energy dispatch schedule of resource j at dispatch interval i
$EDP_{j,i}$	refers to the nodal energy dispatch price of resource j at dispatch interval i

[24] EMC Energy Market Company Study: Occurs when there is a constrained circuit in the transmission loop. The nodal price at the sending end of the binding line is depressed, while the price at the receiving end is pushed up. This is a natural result of economic forces striving to achieve optimal dispatch within a constrained transmission system.

$NWAP_i$ refers to the weighted average price of all resources and computed as:

$$NWAP_i = \frac{\sum_{j \in J} \left(EDP_{j,i} * \ EDS_{j,i} \right)}{\sum_{j \in J} \left(\ EDS_{j,i} \right)}$$

Equation 3. Price Substitution Methodology – Average Weighted Price

Once the trigger factor has been breached, the PSM shall be imposed which would necessarily pro-rate the congestion cost among all the load participants which benefitted from the mechanism. Generators will be settled at the unconstrained market outcomes and the constrained-on generators, or those which that were dispatched due to the congestion, shall be allowed to recover costs for the actual delivery of electricity.

Nevertheless, the PSM is not applicable for the following causes of network constrains:

a. Constraint indicated in the market run is caused by erroneous input data;
b. Localized constraint, such as but not limited to, constraint on a load-end transformer, which is the source of the load connected to it or of the step-up transformer in a generating plant; and
c. Constraint on a radially-connected line.

Table 3. Historical Line Constraint With and Without PSM Imposition

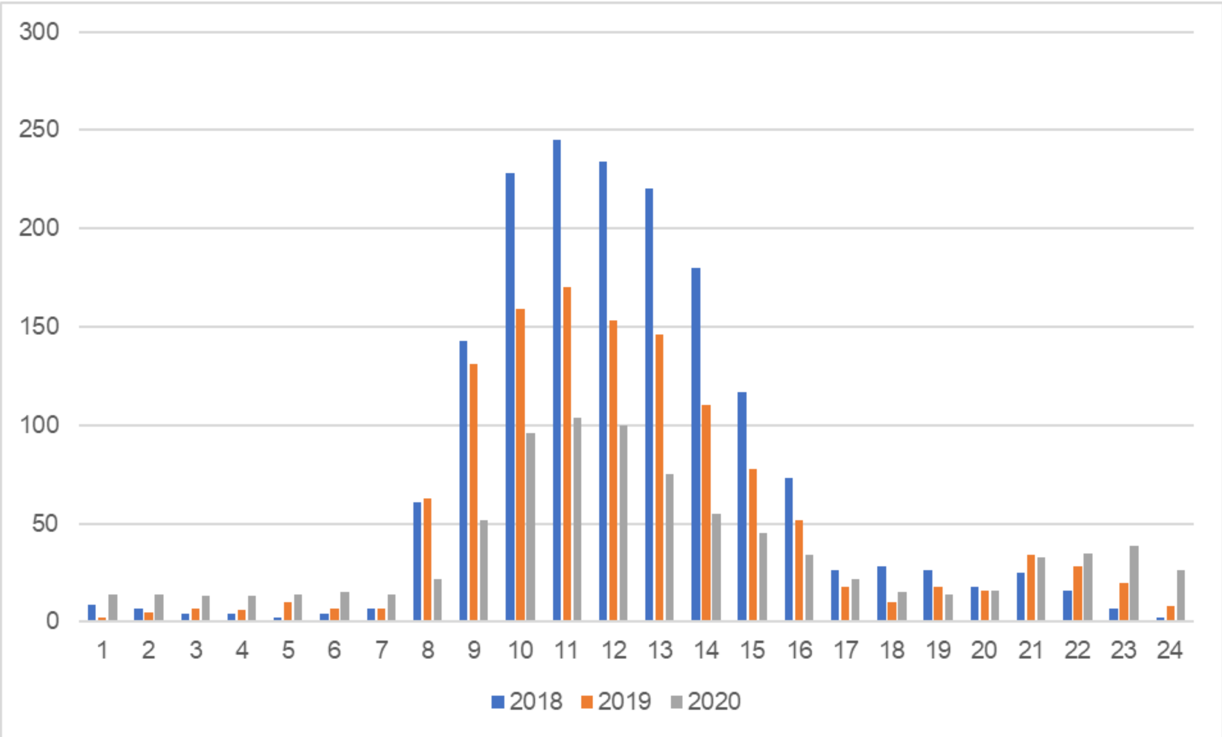
Lines	2018		2019		2020	
	Without*	With*	Without*	With*	Without*	With*
Samboan-Amlan	58	1,543	288	713	128	412
Bacolod- Barotac	110	32	45	-	19	44
Sucat-Binan	-	-	-	-	1	11
Leyte-Cebu	250	250	209	38	102	25
Quezon-Dona Imelda	-	-	1	2	-	-
Amadeo-Calaca	-	-	-	-	-	1
New Naga-Quiot	-	-	131	296	16	51
Maasin-Ubay	69	64	338	12	31	-
Bauang-BPPC	7	7	-	-	8	16
Araneta-Balintawak	-	-	-	-	1	2
Balingueo-Kadampat	-	-	4	47	4	65
Sta. Rita-Batangas 2	-	-	3	1	23	143
Bacolod-Cadiz	-	-	-	-	-	1
Mexico-Hermosa	-	-	-	-	-	4
Mabinay-Amlan 2	24	2	-	-	5	-
Kabankalan-Mabini	-	-	-	-	1	-

Lines	2018		2019		2020	
	Without*	With*	Without*	With*	Without*	With*
Bauang-Payocpoc	-	195	64	149	-	-
Bauang-Balingueo	-	-	2	-	-	-
Bauang-La Trinidad	-	-	-	8	-	-
Toledo-Calung calung	-	-	-	1	-	-
Quezon-San Jose	208	103	-	-	-	-

***** *No of Intervals – per hour*

Based on historical data, the table shows that for the past 3-years, the line constraints with and without imposition PSM imposition are not regularly prevalent. It should be noted that in a one-day trading day it will have 24 counts of interval and, in a year, it may have a total of 8,760 interval. Moreover, the below graph for the hourly interval of line constraints.

Figure 1. Hourly Historical Line Constraint

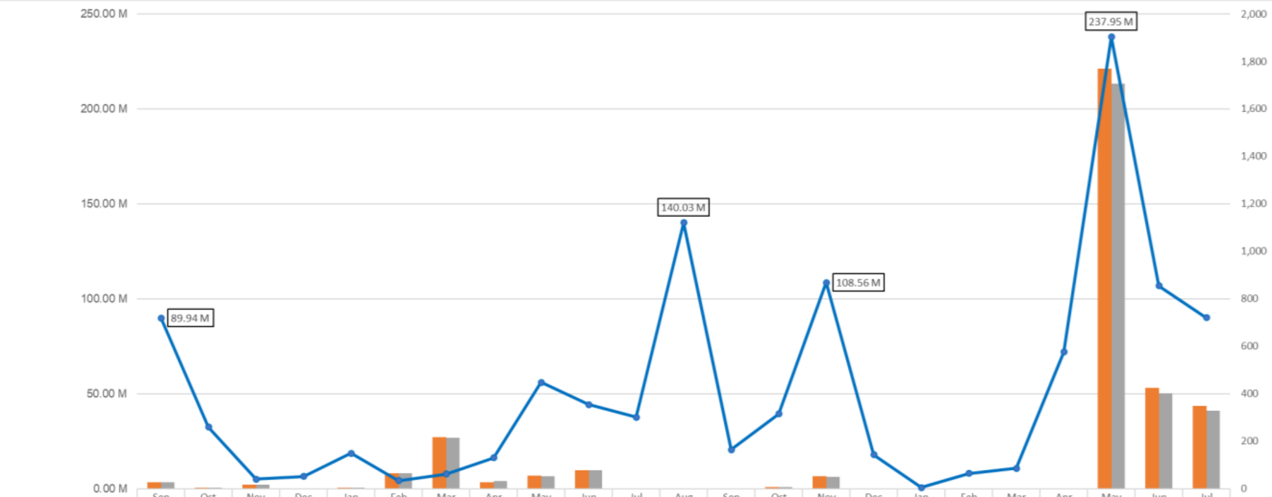


The graph denotes that for the past 3-years, the line constraint appears to transpire at any hour of the day. Meanwhile, it is expected to have continuous constraint during peak hours (0800H – 2000H) due to higher demand during these hours which would mean requiring more supply from various areas in the Luzon and Visayas grid.

4.1.2 Congestion Net-Settlement Surplus

Since FTR will be funded by the congestion rent, it is also worthy to understand the resulting net-settlement surplus with respect to the PSM.

Figure 2. Historical Net-Settlement Surplus and PSM Data



	2020 Sep	2020 Oct	2020 Nov	2020 Dec	2021 Jan	2021 Feb	2021 Mar	2021 Apr	2021 May	2021 Jun	2021 Jul	2021 Aug	2021 Sep	2021 Oct	2021 Nov	2021 Dec	2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul
PSM- Luzon	27	5	18	2	4	64	216	27	54	77	0	0	0	7	53	0	0	0	0	0	1,769	424	350
PSM- Visayas	28	5	18	2	4	64	215	32	53	78	0	0	0	7	49	0	0	0	0	0	1,707	402	328
Congestion Surplus	89.94 M	32.41 M	5.05 M	6.55 M	18.64 M	4.34 M	7.79 M	16.30 M	55.99 M	44.32 M	37.65 M	140.03 M	20.54 M	39.44 M	108.56 M	17.86 M	0.70 M	8.14 M	10.70 M	71.96 M	237.95 M	106.84 M	90.05 M

The figure above shows that even with PSM impositions, net-settlement surplus for congestion is still high which signify that there is enough congestion rents to properly fund the FTR market. Currently, the net-settlement surplus for congestion will be flowed-back to each market participants which shall be dependent on the participant's actual payment for total costs of congestion and loss[25]. The flowback amount shall correspondingly be re-distributed to end-users as part of the monthly generation power supply agreements. This allows market participants to receive refunds in congestion amount which translates to lesser payment of congestion charges.

4.1.3 Markets Design of Other Jurisdictions Implementing Financial Transmission Rights

Table 4. Market Structure Comparison

		
Market		

[25] Allocation based on methodology of ERC Resolution No. 7 Series of 2019

				
Wholesale Electricity Spot Market (WESM)	Midwest ISO (MISO)	PJM	ISO New England	New Zealand
Market and System Operator				
Two (2) different entity	Single entity	Single entity	Single entity	Single entity
Day-ahead Market				
Not Yet Implemented only Day-ahead Projections (no financial commitment)	Implemented	Implemented	Implemented	Implemented
Congestion Management				
Price substitution methodology is a mitigation congestion caused by non-spring washer effect with trigger factor of 0.2 With net-settlement surplus for congestion flowback	FTR implementation	FTR implementation	FTR implementation	FTR implementation

Basing on the comparisons undertaken with regard to the operations of other jurisdictions with operational FTRs, it may be concluded that LMP markets will benefit more due to the inherent differences in prices for various nodes of market participants. However, all these jurisdictions which have successfully implemented FTRs also utilizes the DAM which allows market participants to hedge volatility of market outcomes, in general, including congestion prices. This may be a major consideration in the implementation of FTR as it would require new policies and regulations, not to mention, further enhancements to the NMMS of the operator.

5.0 PREREQUISITE FOR FTR INTRODUCTION IN WESM

There is no one-size-fits-all model for FTRs. It has been allocated in several different ways to several different entities including market participants and financial speculators. This is to be expected, though, given the diversity that exists in electricity markets across the globe. But no matter how different FTRs may be from one another, they are still very useful tools in electricity markets with locational pricing as other jurisdictions have already demonstrated their success in their respective implementation of FTR.

However, market structure plays a big part in the decision-making whether an FTR will be suitable or not to the Philippine market. With the foregoing, the pre-requisites in terms of market design and rules need to be established prior the implementation of the FTR in the WESM, have been identified in this portion of the viability study.

In the succeeding sections, the review of other jurisdictions shall form part of the considerations for determining the viability of the FTR market operation in the WESM.

5.1 Market Operator and System Operator Relationship for the FTR Market

FTR's introduction necessitates a very close cooperation between the transmission System Operator (SO) and the Market Operator (MO) due to these various factors[26]:

a. Coordination on the allocation of FTR will require information of transmission system capacity and development for the simultaneous feasibility test;
b. Determination of monetary values for FTRs will require transparent, reliable, and precise market pricing methodology; and
c. Scheduling process must be done on a power exchange (not through self-scheduling).

Given that there are two (2) independent entities responsible for the operation of the electricity market and transmission system in the Philippines, it shall be emphasized that the determination of the operator of the FTR market should be an important consideration that would require a shift in policies and regulations. Similarly, an established and robust protocol between the operators shall be put in place in order for the operation of the FTR to be effective and efficient.

5.2 Energy Regulatory Commission Role

The Energy Regulatory Commission (ERC) plays an important role in the FTR implementation. Similar to the implementation of PSM, the FTR will also undergo a rule-making process for the review and approval of the Commission. As discussed in Section 4.1.2, the modification of NSS flowback which will be utilized for funding the FTR is under the jurisdiction of the ERC. Currently, the NSS for congestion flowback to market participants is dependent on the participant's actual payment to the total cost of congestion. With FTR, the holders shall be the recipients congestion flowback and thus would entail amendments on existing rules that would need modifications for utilization of the NSS to fund the FTR revenues.

[26] Financial Transmission Rights in Europe's Electricity Market – Christof Duthaler (EPFL)1 and Matthias Finger (EPFL) November 2008

Similar to the NSS for congestion, the NSS for Loss is also present in the market as part of LMP component. While the NSS for congestion will be utilized for funding of the FTR, the NSS loss and the excess for FTR congestion will also need to evaluate the flowback. Other market would have term this as the Auction Revenue Rights (ARR). This ARR will serves as the engine on the allocation for the FTR revenue to its holder.

Another consideration in the operation of the FTR is the possible removal of the PSM. Since PSM is a mitigating measure for congestion resulting from extreme nodal separation due to network congestion with a triggering factor mechanism, it will essentially limit the market for FTR holders if to be retained in the operations of the WESM – this may result to discouragement of participants from joining the competition.

Furthermore, considering that FTR is a financial instrument, this means that financial risk will still be present depending on the forecasted LMP differences between two points. With this in consideration, it is inevitable that opening the FTR market will affect the regulatory powers of the ERC with regard the management of congestion costs in the system. As aptly discussed above and in Section 4.1.2 of this study, the ERC had full control over the collection of congestion costs that it may, in its own volition, order the halting of activities which would drastically affect end-users. With the operation of the FTR, while there will still be certain regulatory framework to be implemented to ensure fair, efficient, and transparent competition, ERC's control over the FTR market may be diminished.

5.3 Regulation for FTR

The regulation on the implementation of FTR will have to be determined whether the Security and Exchange Committee (SEC) or the ERC shall exercise the oversight function on the regulation of FTR considering that the same is a financial instrument. The SEC which is the government regulatory agency mandated for the development of capital markets[27], while the ERC is also a government agency tasked to promote competition, encourage market development, ensure customer choice, and penalize abuse of market power in the electricity industry[28]. Since the current Laws, Rules, and guidelines do not explicitly convey who shall regulate the FTR market, it is also included as a pre-requisite for consideration its establishment.

In accordance with the review of best practices, in the US, the Federal Energy Regulatory Commission (FERC) regulate only the energy portion for FTRs/CRRs. Unlike any other futures markets, FTRs and CRRs are not governed by US Commodities Futures Trading Commission (CFTC) or Commission for Securities and Exchange (SEC).

[27] Capital markets are used to sell different financial instruments, including equities and debt securities. - Investopedia
[28] Section 43 of R.A No. 9136 – Electric Power Industry Reform Act of. 2001 (EPIRA)

According to William Hogan[29] "*Because FTRs would be purely financial instruments, they would impose no constrains on the actual dispatch. Thus, unlike must-take power contracts, must-run generation or strict physical transmission rights, FTR ownership alone would not affect either line availability or transmission scheduling.*" With this, it should be noted that FTRs may be exempted from financial regulation of Philippines. This viewpoint is supported by the fact that the physical capacity of the transmission grid and the actual dispatch of generation and loads are the only factors that affect the price and volume of FTRs. As a result, the only way to manipulate FTRs is to manipulate the physical market, which is governed by conventional energy regulations and measures which are in place to avoid the same. Additionally, FTRs are mostly utilized for physical hedging and are very seldom for financial speculating. However, the government is still not precluded from undertaking a final determination on the regulation of the market once the market has been established.

As discussed in Section 3.1.3.2 on FTR allocation, similar to market share limitation, another thing that needs to be considered for FTR regulation is the percent share of FTR ownership. This is to promote competition in the FTR auction and avoid market concentration by allowing monopoly in the market.

5.4 Market Design

Section 4 discussed that the majority of WESM energy traded is under bilateral contract indicating the energy traded in the market has already been established. This implies that the flow of electricity in the market had also been established making for the prospect paths/lines for FTR.

As provided in Section 3.1.5 of this paper, since FTR is a type of forward contracting, DAM has an important role to play for the hedging mechanism of FTR supporting the determination of prices and financial bidding schedules which is set in a similar timescale of commitment. With the DAM, generators and loads commit themselves to energy trades and prices that may lessen the volatility of prices and enabling forward contract to be settled at the same time.

In comparison to the DAM, the WESM having a real-time balancing market, forward financial contract such as bilateral contract is settled outside the market since they have separate financial obligation commitment.

5.5 Fulfillment of the WESM Rules

[29] Report on PJM Market Structure and Pricing Rules (1996), pg. 55

As provided in Section 2.1.2 of this paper, the primary consideration in the implementation of the FTR market is the PEM Board approval as required by the WESM Rules, upon its determination of readiness.

In addition to the PEM Board approval, the WESM Rules also provides for the creation of a technical working group (TWG) which would recommend to DOE, supplemental, modification and other amendments or additional provision to WESM Rules ensuring smooth transition implementation of FTR, among others. The said TWG shall be composed of WESM stakeholders which shall also serve as an avenue to consider the market participants' capability and demand for FTR.

However, what is not clear in the WESM Rules is the entity who shall request from the PEM Board the approval on the implementation of FTR, on whether it should be the TWG or the MO. Similar to other WESM enhancements, the DOE, as the policy-making body issued pertinent Circulars and Orders declaring the framework and commencement of enhancements.

6.0 CONCLUSION

In summary and after an exhaustive review of the FTR markets in other jurisdictions, the merits of establishing an FTR Market has been highly considered in this study. However, in order to comply with the requirements of the WESM Rules, the primordial step in order to keep the establishment rolling is the creation of the TWG for the body to recommend to the DOE the supplemental, modificatory, clarificatory and other amendments or additional provisions to the WESM Rules which should cover the readiness and appetite of the stakeholders for this huge change in the market, and discusses and agree on certain concerns which should be determined prior to the introduction of enhancements. Based on available issuances of the DOE, a TWG was already formed under DOE's Department Order No. 2004-05-005 but the tenure of the members had already lapsed. With this, there is a need to form another set of TWG to already discuss, among others, the possible operation of the FTR in the WESM.

While this paper discusses the issues on the implementation FTR, which the TWG may consider, this paper also includes technical considerations that need to be considered before introducing FTR in the WESM. First is the establishment of DAM. It is true that majority of energy traded in the WESM is with bilateral contract, however, without future commitment in the energy dispatch, volatility in terms of congestion is more prevalent as evidenced in Section 4.1 presenting the statistics on the numerous congestions that occurs in a particular day. Another matter which needs to be considered is the net-settlement surplus for congestion flowback system in the WESM which is already a robust and efficient implementation for managing the costs for congestions – where all the surplus for congestion is flowed back to market participants depending on their actual payment/share. In this scenario another best solution is the identification and upgrading of lines always congested.

Furthermore, other identified prerequisites for the FTR implementation, based on the operations in other jurisdictions are as follows:

- MO and SO relationship;
- Energy Regulatory Commission Role;
- Regulation for FTR;
- Market Design; and
- Fulfillment of the WESM Rules.

Finally, this paper concludes that further research on congestion is needed to be conducted to determine the efficiency of the market which may will lead to the remodeling the NSS flowback mechanism set and approved by ERC.

This viability study on the implementation of the FTR in the WESM is hereby respectfully submitted to the DOE and the ERC for consideration.

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