MIT EL 01-004 WP

Energy Laboratory

Massachusetts Institute
of Technology

Secondary Market for Transmission and Supporting Infrastructures

January 2001

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Energy Laboratory Publication #
MIT EL 01-004 WP

Energy Laboratory
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Cambridge, Massachusetts 02139-4307

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Secondary Market for Transmission and the Supporting Infrastructures

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Abstract

In this paper we discuss two infrastructures important for proficient management of the network, namely the secondary markets for transmission rights and the open access same time information systems (OASIS).

Following the restructuring process the participants in the electric power industry are engaging in complex market activities to meet their electricity needs. Hence, the value of the energy and the transmission portion of electric services are determined by employing the market mechanism. These values once determined, are then communicated among the market participants through the prices specified on various contracts.

Many market participants enter into forward (delivery) contracts for energy. The forward price may be described as the spot market price for delivery of a commodity at a fixed time in the future. As a counterpart to the forward contract marketplace for energy, the secondary market for transmission provides the necessary mechanism for supporting the market activities so that the change in value is readily conveyed to all of the market participants of the forward contracts for transmission portion of electric services in the form of the intermediate term transmission contracts. Here the market participants may be the holders of the physical transmission rights, the holders of the financial transmission rights and/or the bidders in the spot market.

Without the presence of the secondary markets for transmission rights, the ITC relies solely on her expertise gained by observing the transmission charges imposed on the market participants in the spot market when determining the price to be charged for the transmission rights. This creates the open loop computation of the charge. However, with the presence of the secondary market for transmission rights, the ITC can observe the change in prices at the secondary markets for equivalent rights and take this into consideration in determining the price, i.e. in the feedback fashion.

With the introduction of the secondary markets for transmission rights we can compare the workings for the transmission rights in the form of the intermediate term transmission contracts proposed in this paper with the transmission congestion contracts (TCC) and the flowgate rights.

I. Introduction

The secondary markets play a very important role in trading a commodity subject to many uncertainties. These uncertainties are typically related to the high volatility in spot price for the commodity. A spot price is the price at which a commodity is traded for immediate delivery. We refer the marketplace where the spot prices prevail as a spot market.

One of the most common methods used to deal with this spot price uncertainty is the risk hedging through forward (delivery) contracts which are the contracts to buy or sell the commodity at a fixed time in the future at a pre-specified price. We call this pre-specified price, a forward price, and the marketplace where the commodity is traded based on forward contracts, a futures market. A futures market is common form of a secondary market. In a futures market, suppliers can commit some or all of their outputs at the forward price before the actual production. By entering into forward contracts, the risks on profit stemming from the uncertainty in spot prices can be eliminated for the amount of output committed in the contracts.

The purpose of the paper is to investigate the opportunities for risk hedging against network-related uncertainties available to network users. The forward contracts related to such risk hedging method are referred to as the long term or intermediate term transmission contracts depending on the duration of the contracts in this paper and are issued by the transmission provider (TP). We focus on the efficacy of such contracts in the presence of the secondary markets for transmission rights and the necessary infrastructures.

The paper is organized as follows:

In Section II we define the role of the secondary markets for transmission rights. Section III examines the intermediate term transmission contracts in details. We describe briefly one important infrastructure, necessary for well functioning secondary markets for transmission rights, often referred to as open access same time information systems (OASIS) in Section IV. Concluding remarks are made in Section V.

II. Role of the secondary markets for transmission rights

Following the restructuring process the participants in the electric power industry are engaging in complex market activities to meet their electricity needs. Hence, the value of the energy and the transmission portion of electric services are determined employing the market mechanism. These values once determined are then, communicated among the market participants through the prices specified on various contracts. For example, suppose for hour k the value of electric energy at bus g_i is determined to be $\rho_{g_i}[k]$ using the market mechanism. Then, any contract involving a purchase of electricity from bus g_i for hour k carries the price of $\rho_{g_i}[k]$ as valued.

Many market participants enter into the so-called forward (delivery) contracts for energy. This type of contracts serves many useful purposes including hedging against price volatility. A forward contract is an agreement between a buyer and a seller that a commodity (in this case electric power) is to be delivered on a specified date, τ_{dd}, in the future from the present time, t, at a specified fixed price, $\rho_{g_i}(t, \tau_{dd})$ supplied by the generator at bus g_i. The date specified by the contract is called the delivery date, while the price is known as the forward price. The forward price may be described as the spot market price for delivery of a commodity at a fixed time in the future [2], i.e.,[1]

$$\rho_{g_i}(t, \tau_{dd}) = \mathop{\mathcal{E}}_{t} \{\rho_{g_i}[\tau_{dd}]\} \tag{1}$$

where

$$\mathop{\mathcal{E}}_{t} \{(\cdot)\}$$

denotes the expected value of $(\cdot)$ computed given the information available up to the present time t. Thus, at the time of agreement the contract has a value of zero and remains at zero so long as the expected value of the spot market price at the delivery date stays unchanged. As the delivery date approaches, however, new information regarding market conditions emerge and may influence the expected value of the spot market price at the delivery date to move up or down. Suppose at time t_1, where $t < t_1 \leq \tau_{dd}$, the expected value of the spot market price at the delivery date changes from $\rho(t, \tau_{dd})$ to $\rho_{g_i}(t, \tau_{dd}) + \Delta$, i.e.,

$$\rho_{g_i}(t, \tau_{dd}) = \mathop{\mathcal{E}}_{t} \{\rho_{g_i}[\tau_{dd}\} \tag{2}$$

while including the information available now up to the time t_1. Then, the value of the contract also changes from zero to Δ. Here a forward contract *marketplace* plays a significant role in providing the mechanism for supporting the market activities so that the change in

[1] The spot market price needs to be discounted at the rate of risk-free investment in order to reflect the present value of the contract. This fine detail is not included here for the sake of simplicity.

value of the contract is readily conveyed to all of the market participants. For example, with the rise in forward prices the buyer whose demand is elastic may want to reduce consumption and realize a profit on the sale of the original contract. The efficiency of market mechanism depends on how effortlessly such market activities could be carried out.

As a counter part to the forward contract marketplace for energy, the secondary market for transmission provides the necessary mechanism for supporting the market activities so that the change in value is readily conveyed to all of the market participants of the forward contracts for transmission portion of electric services in the form of the intermediate term transmission contracts. Figure 1 shows the information exchange among the market participants, the system operator (SO) and the independent transmission company (ITC) for the intermediate term transmission contracts involving the secondary market. The market

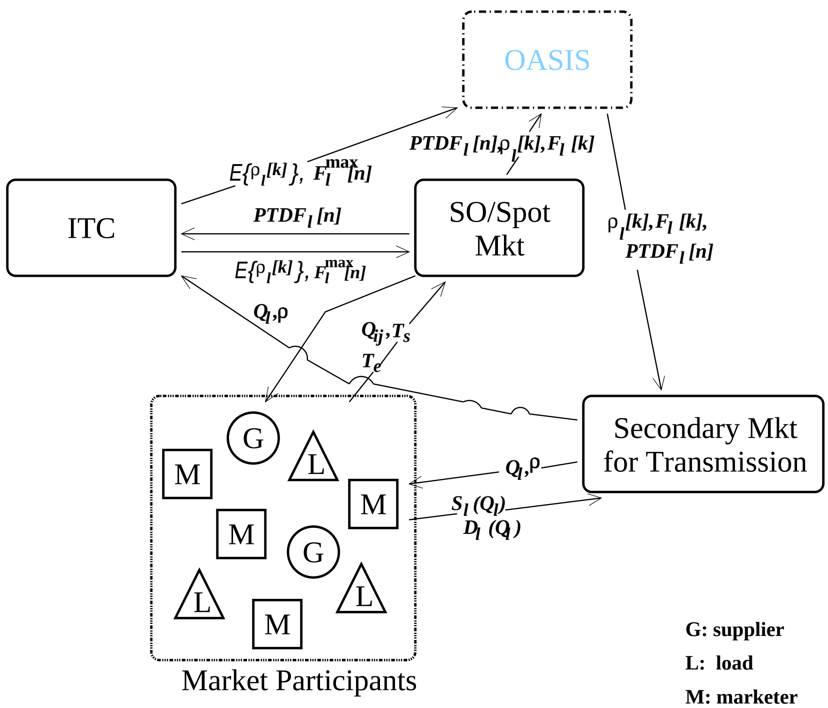

Fig. 1. The information exchange among the market participants, the SO and the ITC for the intermediate term transmission contracts involving the secondary market

participants can purchase intermediate term transmission contracts on each line l in the network from the SO for any desirable duration within the year. First, at the beginning of each year the total capacity available on individual transmission lines within the network is determined by the ITC for the entire year n. When determining the capacity the ITC relies on the expertise of the SO on the operation of the network including the power transfer distribution factors (PTDF). Then, the ITC issues the intermediate term transmission contracts to be offered to the market participants to be used as forward contracts for the transmission portion of the electric services. The price for each of these contracts, $\rho_l(t_s, t_e)$, is determined by the ITC, initially, based on the expected value of the transmission charge,

$$\underset{t=(n-1)T_T+1}{\mathcal{E}} \{\rho_l[k]\}$$

over the interval $[t_s, t_e]$ so that the expected value of the overall transmission revenue is maximized while respecting the network constraints.

Following the issuance of the intermediate term transmission contracts the SO conducts the spot market for energy at each hour k, the actual transmission charge for each line in the network, $\rho_l[k]$ is determined and is made available to the market participants. Here the market participants may be the holders of the physical transmission rights, the holders of the financial transmission rights and/or the bidders in the spot market.

Suppose the market conditions have changed so that the expected value of the transmission charge computed at the beginning of the years needs to be adjusted in order to reflect accurately the current state of the electricity market. Then, the ITC announces the adjusted prices for the transmission contracts and applies the new prices to the contracts in any upcoming sales. The market participants, in turn, may utilize the secondary markets to trade any outstanding contracts issued prior to the price adjustment according to the change in market conditions.

Besides functioning as the marketplace for buying and selling old intermediate term transmission contracts, the secondary market for the transmission rights supports trading of various financial derivatives written on the transmission rights. For examples, a market may issue options for network capacity backed by the intermediate term transmission contracts. Options come in two primary forms, namely calls and puts. One call option gives the holder the right, not the obligation, to buy a specified amount of the underlying commodity (in this case the network capacity) at a specified price and for a specified period of time. A put option gives the holder the right, not the obligation, to sell a specified amount of the underlying commodity at a specified price and over a specified period of time. The trading of various financial derivatives in the secondary markets for transmission rights is done independently from the ITC while the transmission charge determined in the spot market is the major driving force for the trade.

Without the presence of the secondary markets for transmission rights, the ITC relies solely on her expertise gained by observing the transmission charges imposed on the market participants in the spot market when determining the price to be charged for the transmission rights. This creates the open loop computation of the charge. However, with the presence of the secondary market for transmission rights, the ITC can observe the change in prices at the secondary markets for equivalent rights and take this into consideration in determining the price, i.e. in the feedback fashion. The actual mechanism for determining the price while taking the prevailing price in the secondary markets for the transmission rights is beyond the scope of this thesis.

Figure 2 shows the ultimate financial exchanges between the market participants and the secondary markets for transmission rights.

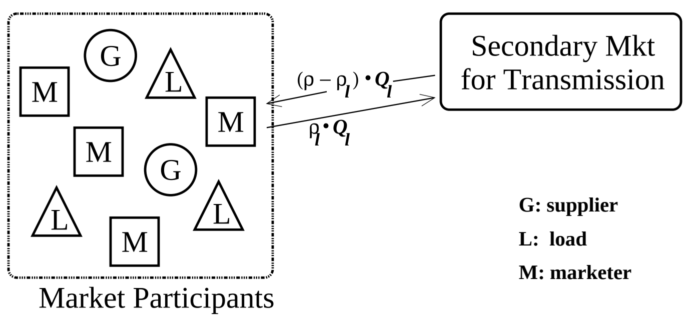

Fig. 2. The financial exchange between the market participants and the secondary markets for transmission rights

III. Closer look at the proposed transmission rights

With the introduction of the secondary markets for transmission rights we can compare the workings for the transmission rights in the form of the intermediate term transmission contracts proposed in this thesis with the transmission congestion contracts (TCC) and the flowgate rights.

In the following sections we first describe the differences between the intermediate term transmission contracts and TCC and between the intermediate term transmission contracts and flowgate rights. Then, the workings of these contracts are compared in terms of the financial exchanges.

A. Point-to-point transmission rights

The transmission congestion contracts (TCC's) proposed in [3] is a representative of the point-to-point transmission rights being widely considered in the electric power industry, at the time of writing, as a possible form of allocating network capacity over the longer term. In order to understand the differences between the TCC's and the intermediate term transmission contracts proposed in this thesis we need to look not only at the actual mechanism for implementing the contracts but also at the underlying market structure.

The underlying market structure assumed for the TCC's is the rate-of-return regulation imposed on the transmission owners and the operational authority given to the non-profit organization called independent system operator (ISO). Under this market structure, the market participants are allowed to submit bids for purchasing the TCC's, once at the beginning of the year (or of the season).[2] The ISO, then determines the price and the amount of TCC's to be made available and allocates network capacity corresponding to the contracts based on the bids. Each of the TCC's issued to the participants specify at least the following three elements: the location of the source bus, the location of the sink bus and the amount of the energy involved in the transaction.

Once the allocation of the TCC is concluded, all of the market participants are required to submit bids to the spot market in the same way whether a participant owns the TCC or not. The ISO, then clears the spot market by solving the optimal power flow (OPF) problem and completes the dispatch schedules without any regards to the allocation of the TCC's. As a result of the market clearing process, the combined price of energy and transmission portions of electric services at each bus are determined by the shadow cost associated with the OPF problem as written in the following:

$$\mathbf{Q_G}^{\star}[k] = \arg \min_{\mathbf{Q_G}[k]} \sum_{g_i} (a_{g_i} Q^2_{g_i}[k] + b_{g_i} Q_{g_i}[k]) \tag{3}$$

$$\sum_{g_i} Q_{g_i}[k] = \sum_{d_j} Q_{d_j}[k] : \qquad \lambda[k] \tag{4}$$

[2]The market participants can determine the amount and the price of the TCC's for the bidding purposes either purely based on the expected value of financial transmission rights of this sort or based on the financial contracts for energy, so-called contract-for-difference (CFD). The CFD is an arrangement made between two or more participants for mimicking bilateral transactions under the TCC scheme. The details on the CFD are referred to [3].

$$Q_{g_i}^{\min}[k] \leq Q_{g_i}[k] \leq Q_{g_i}^{\max}[k] : \qquad \eta_{g_i}[k] \tag{5}$$

$$\sum_{g_i} H_{lg_i} Q_{g_i}[k] - \sum_{d_j} H_{ld_j} Q_{d_j}[k] \leq F_l^{\max}[n] : \qquad \mu_l[k] \tag{6}$$

where

Q_{g_i}: the amount of generation at bus g_i

Q_{d_j}: the amount of consumption at bus d_j

$a_{g_i} Q_{g_i}^2[k] + b_{g_i} Q_{g_i}[k]$: the production cost at bus g_i

$H_{l(\cdot)}$: the PTDF's of network line l with respect to injection at bus $(\cdot)$

$F_l^{\max}$: operational limit on power transfer through line l

The price at each bus is often referred to as the nodal price. The revenue is collected and distributed by the SO as the product of the injection into the bus and the corresponding nodal price. For example, suppose the amount of electric power, $Q_{d_j}[k]$, is taken from the network at the nodal price of $\rho_{d_j}[k]$. Then the load at that bus pays $\rho_{d_j}[k]$ for each unit of power, totaling $\rho_{d_j}[k] \cdot Q_{d_j}[k]$, to the SO. Analogously, if the amount of electric power, $Q_{g_i}[k]$, is injected to the network at the nodal price of $\rho_{d_j}[k]$, the generator at that bus is paid $\rho_{d_j}[k]$ for each unit of power, totaling $\rho_{d_j}[k] \cdot Q_{d_j}[k]$, by the SO. The transmission charge collected by the SO here is often referred to as the congestion charge and is the difference between the amount received from the loads and the amount paid to the generators. Finally, the holders of the TCC's are paid the difference between the nodal price at the location of the sink bus and the nodal price at the location of the source bus specified in the contract. Throughout the process the transmission owners are not involved at all because the revenue received by the transmission owners is a guaranteed return allowed by the regulator and is not related to the TCC's and consequently to the transmission (congestion) charge.

Based on the implementation of TCC scheme described above, it is evident that the TCC's are purely *financial* transmission rights since the holders of the contract are not given the priority for using the network. Indeed, the market clearing process is completely independent of the allocation of TCC's. Considering that the network related risks are two folds, namely the price volatility in transmission capacity and the actual dispatch schedule, the TCC's cover only the former.

When the financial relationship created by the TCC's is examined, it is recognized that there is an apparent disconnect between the reward/penalty mechanism and the entities assuming the financial risks. Because it is the ISO issuing the TCC's to offer the hedging opportunities to the market participants against the volatility in the transmission capacity prices, it appears that the ISO takes on the financial risks. However, the ISO does not assume any financial responsibilities. Thus, this imposes a critical constraint (perhaps auditable by the regulator) on issuing the TCC's, namely the revenue neutrality coming from the simultaneous feasibility criterion. The revenue neutrality refers to the sufficient transmission charge collected by the SO so that all of the payment to the TCC holders can be made from the transmission charge. The simultaneous feasibility criterion limits the ability of the SO in issuing the amount of the contracts so that all of the transactions specified in the contracts appears to take place simultaneously at each hour k while the contracts are valid. That is to say, if the contracts together specify an injection of $Q_{g_i}[k]$ at bus g_i, then at each hour from the beginning of the year to the end, the injection at bus g_i needs to be at least $Q_{g_i}[k]$. Similarly, if the contracts together specify a withdrawal of $Q_{d_j}[k]$ at bus d_j, then at each hour from the beginning of the year to the end, the withdrawal at bus g_i needs to be at least $Q_{d_j}[k]$. In case there is a difference in the transmission charge collected by the SO in the spot market and the TCC payment made to the holders of the contracts, then the difference is handed over to or made up from the market participants through the regulators [5].

In comparison, the underlying market structure assumed for the intermediate term transmission contract is the price-cap regulation (PCR) imposed on the TP composed of the ITC and the SO [7]. Under this market structure, the market participants may purchase the intermediate term transmission contracts at any time directly from the SO at the price determined by the ITC in conjunction with SO for any duration within the year (or the season). The revenue collected by the SO for offering the contracts is given directly to the ITC. The intermediate term transmission contracts specify the following four elements: the designated transmission line, the network capacity offered on the line, the direction of the flow, and the duration of the contract.

Once the market participant makes the purchase of the intermediate term transmission contracts, the holder has the choice of deeming the contract as the physical transmission rights or as the financial transmission rights. For example, suppose the market participant has an energy contract for transporting the amount of electricity $Q_{d_j-g_i}$ between the generation source at bus g_i and the load sink at bus d_j starting at hour t_s and ending at hour t_e. Then, the participant may go to the SO at any time before t_s and purchase the intermediate term transmission contract at each network line l over the entire period $[t_s, t_e]$ for the amount and the direction of the capacity determined by the product of $Q_{d_j - g_i}$ and power transfer distribution factors (PTDF). Then, each day before the SO conducts the spot market, the holder of the energy contract with matching intermediate term transmission contracts can submit the balanced transaction and receive the priority for utilizing the network, so that when the SO clears the spot market, the balanced transaction is scheduled first for dispatch. The holders of the intermediate term transmission contracts do not pay for any transmission charges for using the network other than the payment made to the SO initially to purchase the contracts. Otherwise, the market participants may purchase the intermediate term transmission contracts as purely financial transmission rights. In that case, the SO clears the spot market and the holders of the contracts without the matching energy contracts are paid the transmission charge entitled to them according to the contracts.

When the financial relationship created by the intermediate term transmission contracts is examined, it is apparent that there is a correspondence between reward/penalty mechanism and the entities assuming the financial risks. When the market participants purchase the intermediate term transmission contracts from the SO, the participants' network related risks (whether it is only the price volatility in transmission capacity - the financial transmission rights - or the combined price volatility in transmission capacity and the actual dispatch schedule - the physical transmission rights) are transferred from the holders of the contract to the ITC through the SO. Thus, there is no constraint imposed on issuing the intermediate term transmission contracts. In case there is a difference in the transmission charge collected by the SO in the spot market and the payment made to the holders of contracts as financial transmission rights, the difference is handed over to or made up by the ITC. In case the holders of the intermediate term transmission contracts with the matching energy contracts are denied from utilizing the network, the ITC pays for the damage arising from the breach of contract, which is much higher than the transmission charge.

Plus, the transmission charge imposed under the market structure linked with the TCC's is not relevant to the transmission revenue allowed by the regulator to the transmission owners for expanding and maintaining the network. The transmission charge imposed under the market structure connected to the intermediate term transmission contracts is directly pertinent to the transmission revenue afforded to the ITC.

Based on the comparison between the implementation of TCC scheme and of the intermediate term transmission contracts it is clear that the latter provides the incentive structure necessary for higher efficiency in three folds.

The first is related to the accurate assessment of network status by the TP (ISO under the TCC scheme and SO/ITC under the intermediate term transmission contract scheme). The inaccurate assessment by the ISO on the network capacity available for the TCC penalizes the market participants due to the mechanism used for compensating the difference between the transmission charge collected from the spot market and the payment made to the TCC holders. The regulator plays an important role of verifying the revenue neutrality conditions in order to prevent the efficiency loss. On the other hand, the inaccurate assessment by the SO and the ITC on the network capacity for issuing the intermediate term contract directly results in loss of revenue of the ITC. The accurate assessment of the system status affects not only the short term efficiency related to the operation but also the long term efficiency related to the planning of the transmission network.

The second is related to the active participation by the TP in the process. Under the TCC scheme if the operating conditions vary widely over the year (or over the season), the number of TCC's available needs to be quite conservative in order to satisfy the simultaneous feasibility criterion throughout the year. Whereas under the intermediate term transmission contract scheme the number of contracts available varies depending on network conditions judged by the TP.

Finally, the third is related to the pricing of the contracts. Under the TCC scheme the value of the contract is initially determined by the auction process at the beginning of the year (or of the season) and varies throughout the year depending on the incidence of congestion. The change in the value of the contract needs to be communicated among the participants through the trades. However, it probably is harder to trade point-to-point contracts than the link-based contracts because of the relevance in the physical operation. Only the participant whose bus is designated as one of the points in the point-to-point contract has any interest in the contract from the physical operational sense.

B. Link-based transmission rights

The flowgate rights proposed in [1] is a representative of the link-based transmission rights being widely considered in the industry at the time of writing as another possible form of allocating network capacity over the longer term. Although the flowgate may refer to any transmission line in the system, in general the term refers to only the links associated with the likely network congestion as done here.

Similar to the TCC's case, the underlying market structure assumed for the flowgate rights is the rate-of-return regulation imposed on the transmission owners and the operational authority given to the non-profit organization called independent system operator (ISO). Under this market structure, the market participants are allowed to submit bids for purchasing the flowgate rights, once at the beginning of the year (or of the season).[3] The ISO, then determines the price and the amount of flowgates to be made available and allocates the network capacity corresponding to the flowgate rights based on the bids. Each of the flowgate rights issued to the participants specify at least the following two elements: the designated flowgate (i.e., likely congested line), and the network capacity offered on the flowgate.

Once the allocation of the flowgate rights is concluded, two separate markets, namely the forward market and the spot market, are conducted sequentially. First, the participants in the forward market arrange for transactions and acquire from the current holders the flowgate rights necessary for implementing the arranged transactions. In this process if a participant arranges a transaction that reduces the congestion on the flowgate, then the participant becomes the initial holder of the newly created flowgate rights in the amount by which the congestion is reduced. The process continues until all the transactions arranged are covered by the flowgate rights. The network capacity of unused flowgate rights are then returned to the ISO who conducts the spot market, next.

The market participants who do not want to participate in the forward market can submit bids to the spot market. The ISO, then, clears the spot market by solving the OPF problem subject to the network capacity limits re-defined by the effect of unused flowgate

[3]The market participants can determine the amount and the price of the flowgate rights for the bidding purposes based on the expected value of physical transmission rights of this sort with the matching forward (and/or bilateral) contracts. The explicit bilateral transactions are assumed to be allowed under the flowgate scheme similar to under the proposed scheme.

rights. Again, as a result of the market clearing process, the combined price of energy and transmission portions of electric services at each bus are determined by the nodal prices, and the revenue is collected and distributed by the SO as the product of the injection into the bus and the corresponding nodal price. A part of congestion charge collected by the ISO is used to compensate for the unused flowgate rights that reverted to the ISO.

The flowgate rights scheme is an improvement over the TCC scheme. Unlike the implementation of TCC scheme, the implementation of flowgate rights scheme described above has many desirable features including the physical transmission rights based on the scheduling priority, similar to the intermediate term transmission contracts proposed in the thesis. When the financial relationship created by the flowgate rights is examined, however, it is recognized that there is still apparent disconnect between the reward/penalty mechanism and the entities assuming the financial risks. Similar to the TCC's, because it is the ISO issuing the TCC's to offer hedging opportunities to the market participants against the volatility in the transmission capacity prices, it appears that the ISO takes on the financial risks, but because the particular characteristic of the ISO is such that the ISO as a non-profit entity cannot assume any financial responsibilities. For the flowgate rights to work properly the entity with the operational authority needs to take on the risks associated with the changing capacity limits and the changing PTDF for each flowgate. Otherwise, in case the holders of the flowgate rights are denied from utilizing the network, no compensation scheme may be adequate, or the financial risks are ultimately transferred to the market participants. Therefore, at least a couple of efficiency issues are still problematic including the accurate assessment of network status and the active participation by the TP as discussed earlier in the context of the TCC.

In addition, the transmission charge imposed under the market structure linked with the flowgate rights is not relevant to the transmission revenue allowed by the regulator to the transmission owners for expanding and maintaining the network. The transmission charge imposed under the market structure connected to the intermediate term transmission contracts is directly pertinent to the transmission revenue afford to the ITC.

Finally, there is an implied assumption that the majority of transactions is taken care of at the forward market under the flowgate rights scheme. It is pointed out in [4] that many of the transactions in the current electricity markets still rely heavily on the spot market process. In this case, the complete separation of the forward market from the spot market further reduces the market efficiency.

In comparison, the proposed intermediate term transmission contracts allow the TP to take on the necessary financial risks. For example, the changing capacity limits and the changing PTDF for each link become the responsibility of the ITC by requiring that the maximum flow limits and the PTDF's stay invariant throughout the year (or the season). Moreover, the forward market and the spot market are linked through the TP. All this is possible because of the performance-based regulation scheme, in this case the PCR scheme as proposed in [7], imposed on the TP.

In the following section we compare three methods described above through numerical examples.

C. Numerical example

Consider the 3-bus electric power network introduced earlier as shown in Figure 3. The

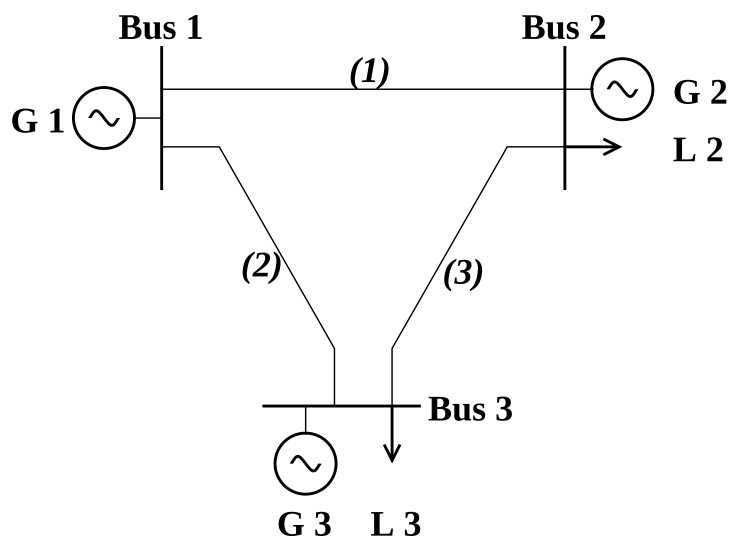

Fig. 3. One-line diagram of 3-bus electric power network

transfer limits on the transmission lines are 150MW for lines 1 and 2 and 80MW for line 3. In the network there are 12 generation units each owned by different suppliers. The marginal operating costs of these units are given in the form of linear functions with respect to their corresponding generations, i.e.,

$$S_{g_i}(Q_{g_i}[k]) = 2a_{g_i}Q_{g_i}[k] + b_{g_i} \tag{7}$$

At bus 1 there are 4 thermal units capable of generating electric power at the cost determined by a_{g_i} given in Table I and $b_{g_i} = 0$ for $i = 1, 2, 3, 4$. At bus 2 there are 7 hydro units with

a_{g_1}	a_{g_2}	a_{g_3}	a_{g_4}
0.300	0.300	1.250	0.613

TABLE I

COEFFICIENTS a_{g_i} AT BUS 1

a_{g_i} given in Table II and again $b_{g_i} = 0$ for $i = 5, 6, \cdots, 11$. At bus 3 there is 1 gas-turbine

a_{g_5}	a_{g_6}	a_{g_7}	a_{g_8}	a_{g_9}	$a_{g_{10}}$	$a_{g_{11}}$
0.125	0.125	0.013	0.350	0.350	0.400	0.400

TABLE II

COEFFICIENTS a_{g_i} AT BUS 2

unit is operating at $a_{g_{12}}$ and $b_{g_{12}}$ given in Table III

$a_{g_{12}}$	$b_{g_{12}}$
5.000	1.000

TABLE III

COEFFICIENTS a_{g_i} AT BUS 3

Assuming the perfect competition condition, the supply functions at each bus is computed by aggregating the marginal operating costs of generators, i.e.,
at bus 1

$$S_{\text{bus }1}(Q_{\text{bus }1}[k]) = 0.2198 Q_{\text{bus }1}[k] \tag{8}$$

at bus 2

$$S_{\text{bus }2}(Q_{\text{bus }2}[k]) = 0.0187 Q_{\text{bus }2}[k] \tag{9}$$

and at bus 3

$$S_{\text{bus }3}(Q_{\text{bus }3}[k]) = 10 Q_{\text{bus }3}[k] + 1 \tag{10}$$

For simplicity, let the entire year be composed of three hours, i.e., $k = 1, 2, 3$, and 4.

Suppose some of the market participants enter into various forward contracts in order to meet their electricity needs at the beginning of the year assuming that the expected demand functions of the load at bus 2 is given by

$$D_{d_2}[k] = -2.5Q_{d_2}[k] + 48.15 \tag{11}$$

and that of the load at bus 3 is given as the following:

$$D_{d_3}[k] = -5.0Q_{d_3}[k] + 817.10 \tag{12}$$

For comparison purposes we consider the following arrangement of forward contracts. First, the marketers at bus 2 and at bus 3 agree on the forward contract for the transfer of 101.25MW covering the entire year, i.e. $k = 1, 2, 3$, and 4. The marketers at bus 1 and at bus 3, then arrange for the transfer of 56.00MW for hours 1, 2 and 3, but *not* 4, i.e., $k = 1, 2$, and 3. Finally, the marketers at bus 1 and bus 2 arrange for the forward contract of 18.50MW this time covering the hours 2, 3, and 4 only, i.e., $k = 2, 3$, and 4. Based on the supply functions given in Eqs. (8) through (10) and the demand functions projected as in Eqs. (11) and (12), the loads at bus 2 and at bus 3 are expected to pay 1.90 ($/MW) and 30.85 ($/MW) respectively. Figure 4 shows the physical exchange among participants only based on the arrangement through forward contracts. Transaction 1 refers to the forward contract for the transfer of 101.25MW from bus 2 to bus 3 for $k = 1, 2, 3$, and 4, Transaction 2 refers to the forward contract for the transfer of 56.00MW from bus 1 to bus 3 also for $k = 1, 2$, and 4, and Transaction 3 refers to the forward contract for the transfer of 18.50MW from bus 1 to bus 2 for $k = 2, 3$, and 4.

Following the arrangement through forward contracts the spot market is conducted at each hour for meeting the residual demand. Suppose following the market clearing process in the spot market the actual demand functions of the loads are revealed as the following:
for the load at bus 2

$$D_{d_2}[k] = -2.5Q_{d_2}[k] + 48.15 \tag{13}$$

where $k = 1, 2, 3$, and 4, and for the load at bus 3

$$D_{d_3}[1] = -5.0Q_{d_3}[1] + 817.10 \tag{14}$$

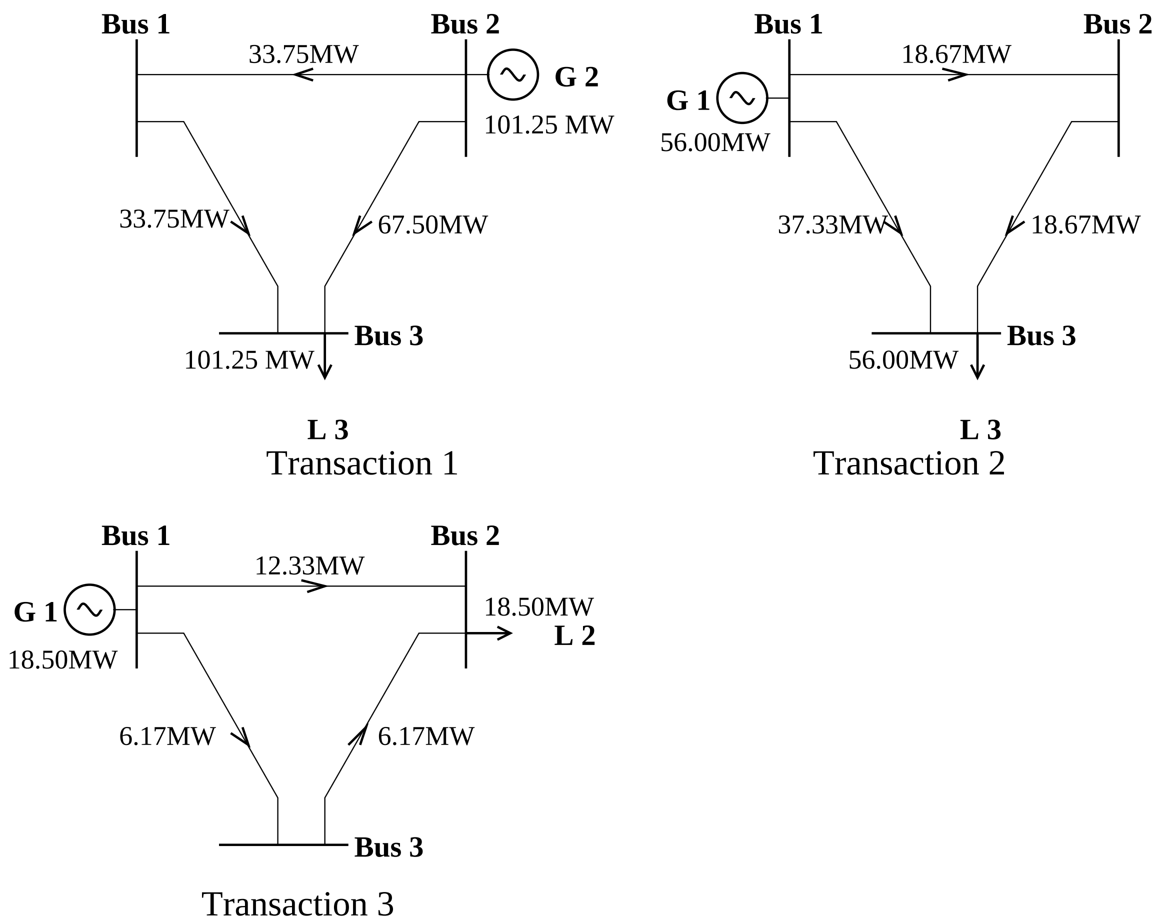

Fig. 4. The physical exchange among participants for each transaction through forward contracts

$$D_{d_3}[2] = -5.0Q_{d_3}[2] + 842.10 \tag{15}$$

$$D_{d_3}[1] = -5.0Q_{d_3}[4] + 817.10 \tag{16}$$

$$D_{d_3}[3] = -5.0Q_{d_3}[3] + 792.10 \tag{17}$$

As evident from Eqs. (13) through (17), the actual demand function for the load at bus 2 stays invariant from the expected throughout the year, but the actual demand function for the load at bus 3 is identical only at hours 1 and 3 and deviates from the expected in hours 2 and 4. This is not surprising since the demand for electric services is uncertain by nature. Nevertheless, if the average is taken for the actual demand function at bus 3, the result is same as the expected as expressed in Eq. (12).

The actual physical exchange among participants is determined as a result of the arrangement through forward contracts and the spot market and is, therefore, highly market structure dependent. Here the presence of transmission rights plays an important role in deciding the final outcome. For simplicity without the loss of generality, assume that the market participants involved in the forward contracts purchase the appropriate transmission rights available in order to hedge against the price volatility in transmission charge whenever possible.

Under the TCC scheme, this assumption implies that the marketers involved in Transaction 1, Transaction 2 and Transaction 3 will purchase the TCC of 101.25MW between bus 2 and bus 3 for $k = 1, 2, 3, 4$, the TCC of 56.00MW between bus 1 and bus 3 for $k = 1, 2, 3$, and the TCC of $18.50MW$ between bus 1 and bus 2 for $k = 2, 3, 4$, respectively. It is assumed that the appropriate arrangements are made between market participants in the form of the contract-for-difference (CFD) in order to mimic the bilateral transfers specified in Transactions 1, 2 and 3. Denote the TCC corresponding to the Transaction i as TCC_i. According to the supply and the projected demand functions in Eqs. (8) through (11), the proper valuation of each TCC leads to 28.95 ($/MW) for $TCC_1[k]$, 14.48 ($/MW) for $TCC_2[k]$, and -14.48 ($/MW) for $TCC_3[k]$. The negative value for TCC_3 arises due to the direction of the flow being opposite to transmission congestion on line 3 caused by the transaction. Then, the expected profit, $\mathcal{E}\left\{\pi_i = \rho_i \cdot Q_i\right\}$ at each bus can be readily computed. For the suppliers at bus 1

$$\mathcal{E}\left\{\pi_1[1]\right\} = 30.85 \cdot 56.00 + 16.37 \cdot 18.50 - \frac{1}{2}(16.37 \cdot 74.50) - 14.48 \cdot 56.00 \tag{18}$$

$$\mathcal{E}\left\{\pi_1[2]\right\} = 30.85 \cdot 56.00 + 1.90 \cdot 18.50 - \frac{1}{2}(16.37 \cdot 74.50) - 14.48 \cdot 56.00 - (-14.48) \cdot 18.50 \tag{19}$$

$$\mathcal{E}\left\{\pi_1[3]\right\} = 30.85 \cdot 56.00 + 1.90 \cdot 18.50 - \frac{1}{2}(16.37 \cdot 74.50) - 14.48 \cdot 56.00 - (-14.48) \cdot 18.50 \tag{20}$$

$$\mathcal{E}\left\{\pi_1[4]\right\} = 1.90 \cdot 18.50 + 16.37 \cdot 56.00 - \frac{1}{2}(16.37 \cdot 74.50) - (-14.48) \cdot 18.50 \tag{21}$$

The first term in Eqs. (18) through (20) is the expected revenue collected from realizing Transaction 2 of 56MW while the first term in Eq. (21) and the second term in Eqs. (19) and (20) are the expected revenue collected from realizing Transaction 3 of 18.50MW all committed through forward contracts ahead of time. The second term in Eqs. (18) and

(21) is the expected revenue from offering 18.50MW and from offering 56.00MW in the spot market, respectively. The third term in Eqs. (18) through (21) is the expected cost for generating 74.5MW. The fourth term in in Eqs. (18) through (20) is the cost of acquiring the TCC to eliminate the risks associated with the volatility in the transmission charge on realizing Transaction 2. Similarly the fifth term in Eqs. (19) and (20) and the fourth term in Eq. (21) is the cost of acquiring the TCC associated with Transaction 3. It is noted that the expected value of the profit at each period is the same \$609.78 even though at $k = 2$, and 3 the entire profit is through the forward contracts with matching transmission rights while at $k = 1$, and 4, the profit includes the hedged forward contracts and spot market activities.

For the suppliers at bus 2

$$\mathcal{E}\left\{\pi_2[k]\right\} = 30.85 \cdot 101.25 - \frac{1}{2}(1.90 \cdot 101.25) - 28.95 \cdot 101.25 \tag{22}$$

for $k = 1, 2, 3$, and 4. The first term in Eq. (22) is the expected revenue collected from realizing Transaction 1 of 101.25MW committed through forward contracts. The second term in Eq. (22) is the expected cost for generating 101.25MW. Finally, the third term is the cost of acquiring the TCC to eliminate the risks associated with the volatility in the transmission charge on realizing Transaction 1. The expected profit of the suppliers at bus 2, \$96.07, only includes the completely hedged forward contracts.

Since the transmission rights under the TCC scheme are purely financial, at each hour k, the market participants are required to submit either their supply or demand bids for energy to the ISO who is responsible for conducting the spot market. Once the spot market is cleared, the collected bids are used for scheduling and for settlement. We assume that the supply bids submitted to ISO are identical to Eqs. (8) through (10) for the entire year, i.e., $k = 1, 2, 3, 4$. On the other hand, the demand bids are submitted according to Eqs. (13) through (17).

For $k = 1$ the result of clearing the spot market yields the prices of 16.37 (\$/MW), 1.90 (\$/MW), and 30.85 (\$/MW) at bus 1, bus 2 and bus 3, respectively. The suppliers are then scheduled for 74.50MW, 101.25MW and 0MW at bus 1, bus 2 and bus 3, respectively. At the end of the hour 1 (and 4), the ISO collects from the loads at bus 2, \$35.12 (= 1.90 (\$/MW) $\times$18.50 (MW)) and from the loads at bus 3, \$4,851.49 (= 30.85 (\$/MW) $\times$157.25 (MW)) for the total of \$4,886.60. The ISO then pays to the suppliers at bus 1, \$1,219.93

(= 16.37 (\$/MW) $\times$74.5 (MW)) and to the suppliers at bus 2, \$192.13 (= 1.90 (\$/MW) $\times$101.25 (MW)) for the total of \$1,412.06. Of the difference between the revenue collected from the loads and the cost paid to the suppliers, \$3474.54, the suppliers at bus 1 receive \$810.73 (= (30.85 – 16.37) (\$/MW) $\times$56 (MW)) and the suppliers at bus 2 receive \$2,931.65 (= (30.85 – 1.90) (\$/MW) $\times$101.25 (MW)) as specified by the corresponding TCC's [3].

For $k = 2$ the result of clearing the spot market yields the prices of 18.24 (\$/MW), 1.82 (\$/MW), and 34.66 (\$/MW) at bus 1, bus 2 and bus 3, respectively. The suppliers are then scheduled for 82.98MW, 97.04MW and 0MW at bus 1, bus 2 and bus 3, respectively. At the end of the hour 2, the ISO collects from the loads at bus 2, \$33.70 (= 1.82 (\$/MW) $\times$18.53 (MW)) and from the loads at bus 3, \$5,596.83 (= 34.66 (\$/MW) $\times$161.49 (MW)) for the total of \$5,630.54. The ISO then pays to the suppliers at bus 1, \$1,513.37 (= 18.24 (\$/MW) $\times$82.98 (MW)) and to the suppliers at bus 2, \$176.50 (= 1.82 (\$/MW) $\times$97.04 (MW)) for the total of \$1,689.87. Of the difference between the revenue collected from the loads and the cost paid to the suppliers, \$3,940.67, the suppliers at bus 1 receive \$615.73 (= (34.66 – 18.24) (\$/MW) $\times$56 (MW) +(1.82 – 18.24) (\$/MW) $\times$18.5 (MW)) and the suppliers at bus 2 receive \$3,324.94 (= (34.66 – 1.82) (\$/MW) $\times$101.25 (MW)) as specified by the corresponding TCC's. In addition, the suppliers at bus 1 receive \$1.46 (= (1.90 – 1.82) $\times$18.5 (MW)) from the loads at bus 2 and pay \$213.11 (= (34.66 – 30.85) $\times$56 (MW)) to the loads at bus 3, and the suppliers at bus 2 pay \$385.31 (= (34.66 – 30.85) $\times$101.25 (MW)) to the loads at bus 3 as specified by the corresponding CFD's.

For $k = 3$ the result of clearing the spot market yields the same prices and same scheduling as given for $k = 1$. Thus, again at the end of the hour 3, the ISO collects from the loads at bus 2, \$35.12 (= 1.90 (\$/MW) $\times$18.50 (MW)) and from the loads at bus 3, \$4,851.49 (= 30.85 (\$/MW) $\times$157.25 (MW)) for the total of \$4,886.60. The ISO then pays to the suppliers at bus 1, \$1,219.93 (= 16.37 (\$/MW) $\times$74.5 (MW)) and to the suppliers at bus 2, \$192.13 (= 1.90 (\$/MW) $\times$101.25 (MW)) for the total of \$1,412.06. Of the difference between the revenue collected from the loads and the cost paid to the suppliers, \$3474.54, the suppliers at bus 1 receive \$542.90 (= (30.85 – 16.37) (\$/MW) $\times$56 (MW) +(1.90 – 16.37) (\$/MW) $\times$18.5 (MW)) and to the suppliers at bus 2 receive \$2,931.65 (= (30.85 – 1.90) (\$/MW) $\times$101.25 (MW)) as specified by the corresponding TCC's.

For $k = 4$ the result of clearing the spot market yields the prices of 14.51 (\$/MW), 1.98

(\$/MW), and 27.05 (\$/MW) at bus 1, bus 2 and bus 3, respectively. The suppliers are then scheduled for 66.02MW, 105.46MW and 0MW at bus 1, bus 2 and bus 3, respectively. At the end of the hour 2, the ISO collects from the loads at bus 2, \$36.50 (= 1.98 (\$/MW) $\times$18.47 (MW)) and from the loads at bus 3, \$4,138.42 (= 27.05 (\$/MW) $\times$153.01 (MW)) for the total of \$4,174.92. The ISO then pays to the suppliers at bus 1, \$958.08 (= 14.51 (\$/MW) $\times$66.02 (MW)) and to the suppliers at bus 2, \$208.43 (= 1.98 (\$/MW) $\times$105.46 (MW)) for the total of \$1,166.51. Of the difference between the revenue collected from the loads and the cost paid to the suppliers, \$3,008.41, the suppliers at bus 1 *return* \$231.90 (= (1.98 − 14.51) (\$/MW) $\times$18.5 (MW)) and the suppliers at bus 2 receive \$2,538.34 (= (27.05−1.98) (\$/MW) $\times$101.25 (MW)) as specified by the corresponding TCC's. Similarly as before, the suppliers at bus 1 pay \$1.46 (= (1.98 − 1.90) $\times$18.5 (MW)) to the loads at bus 2, and the suppliers at bus 2 receives \$385.32 (= (30.85−27.05) $\times$101.25 (MW)) from the loads at bus 3 as specified by the corresponding CFD's.

Tables IV and V summarize the financial as well as physical exchanges among the market participants and the ISO. As evident from the example, the physical exchange among participants maybe different from the arrangement through forward contracts under the TCC scheme depending on the system operating condition. For instance, at hours 2 and 3, all of the transactions are initially committed through the forward contracts on the energy as well as the transmission portion of the electric services. When the bidding into the spot market by the market participants happens to be identical to the expected at the time of entering into forward contracts, the combination of the CFD's and the TCC's results in the actual physical exchanges as is the case with the example at hour 3. However, if the bidding into the spot market deviates from the expected, then the combination of the CFD's and the TCC's may not assure the necessary transmission capacity for carrying out the exchanges according to the contracts as is the case at hour 2. As a matter of fact, at hour 2, the network capacity available to the suppliers at bus 2 is only 97.04MW instead of 101.25MW offered by the ISO through the TCC's. In this case, the ISO needs to buy back the TCC's for the insufficient capacity from the market participants in order to satisfy the simultaneous feasibility criterion, thus satisfying the revenue neutrality of the ISO [3]. The difficulty is in allocating adequate funds to the ISO for carrying out such tasks as buying back the TCC's because of the non-profit nature of the entity.

		$g_{\text{bus 1}}$	$g_{\text{bus 2}}$	$d_{\text{bus 2}}$	$d_{\text{bus 2}}$	ISO
for TCC_1:						
$g_{\text{bus 2}} \to$ ISO	\$11,726.58	-\$11,726.58	·	·	·	\$11,726.58
for TCC_2:						
$g_{\text{bus 1}} \to$ ISO	\$2,432.18	·	-\$2.432.18	·	·	\$2,432.18
for TCC_3:						
$g_{\text{bus 1}} \to$ ISO	-\$803.49	\$803.49	·	·	·	-\$803.49
$k = 1$						
$d_{\text{bus 2}} \to$ ISO	\$35.12	·	·	-\$35.12	·	\$35.12
$d_{\text{bus 3}} \to$ ISO	\$4,886.60	·	·	-\$4,886.60	·	\$4,886.60
ISO $\to g_{\text{bus 1}}$	\$1,219.93	\$1,219.93	·	·	·	-\$1,219.93
ISO $\to g_{\text{bus 2}}$	\$192.13	·	\$192.13	·	·	-\$192.13
for TCC_1						
ISO $\to g_{\text{bus 2}}$	\$2,931.65	·	\$2,931.65	·	·	-\$2,931.65
for TCC_2						
ISO $\to g_{\text{bus 1}}$	\$810.73	\$810.73	·	·	·	-\$810.73
$k = 2$						
$d_{\text{bus 2}} \to$ ISO	\$33.70	·	·	-\$33.70	·	\$33.70
$d_{\text{bus 3}} \to$ ISO	\$5,596.83	·	·	-\$5,596.83	·	\$5,596.83
ISO $\to g_{\text{bus 1}}$	\$1,513.37	\$1,513.37	·	·	·	-\$1,513.37
ISO $\to g_{\text{bus 2}}$	\$176.50	·	\$176.50	·	·	-\$176.50
for TCC_1						
ISO $\to g_{\text{bus 2}}$	\$3,324.94	·	\$3,324.94	·	·	-\$3,324.94
for TCC_2 and TCC_3						
ISO $\to g_{\text{bus 1}}$	\$615.73	\$615.73	·	·	·	-\$615.73
for CDF_1						
$g_{\text{bus 2}} \to d_{\text{bus 3}}$	\$385.31	·	-\$385.31	·	\$385.31	·
for CDF_2						
$g_{\text{bus 1}} \to d_{\text{bus 3}}$	\$213.11	-\$213.11	·	·	\$213.11	·
for CDF_3						
$d_{\text{bus 2}} \to g_{\text{bus 1}}$	\$1.46	\$1.46	·	-\$1.46	·	·

TABLE IV

EXCHANGES AMONG THE MARKET PARTICIPANTS AND THE ISO UNDER THE TCC SCHEME FOR $k = 1, 2$

		$g_{\text{bus 1}}$	$g_{\text{bus 2}}$	$d_{\text{bus 2}}$	$d_{\text{bus 2}}$	ISO
$k = 3$						
$d_{\text{bus 2}} \to$ ISO	\$35.12	·	·	-\$35.12	·	\$35.12
$d_{\text{bus 3}} \to$ ISO	\$4,886.60	·	·	-\$4,886.60	·	\$4,886.60
ISO $\to g_{\text{bus 1}}$	\$1,219.93	\$1,219.93	·	·	·	-\$1,219.93
ISO $\to g_{\text{bus 2}}$	\$192.13	·	\$192.13	·	·	-\$192.13
for TCC_1						
ISO $\to g_{\text{bus 2}}$	\$2,931.65	·	\$2,931.65	·	·	-\$2,931.65
for TCC_2 and TCC_3						
ISO $\to g_{\text{bus 1}}$	\$542.90	\$542.90	·	·	·	-\$542.90
$k = 4$						
$d_{\text{bus 2}} \to$ ISO	\$36.50	·	·	-\$36.50	·	\$36.50
$d_{\text{bus 3}} \to$ ISO	\$4,138.42	·	·	-\$4,138.42	·	\$4,138.42
ISO $\to g_{\text{bus 1}}$	\$958.08	\$958.08	·	·	·	-\$958.08
ISO $\to g_{\text{bus 2}}$	\$208.43	·	\$208.43	·	·	-\$208.43
for TCC_1						
ISO $\to g_{\text{bus 2}}$	\$2,538.34	·	\$2,538.34	·	·	-\$2,538.34
for TCC_2 and TCC_3						
ISO $\to g_{\text{bus 1}}$	-\$231.90	-\$231.90	·	·	·	\$231.90
for CDF_1						
$d_{\text{bus 3}} \to g_{\text{bus 2}}$	\$385.32	·	\$385.32	·	-\$385.32	·
for CDF_3						
$g_{\text{bus 1}} \to d_{\text{bus 3}}$	\$1.46	-\$1.46	·	·	\$1.46	·

TABLE V

EXCHANGES AMONG THE MARKET PARTICIPANTS AND THE ISO UNDER THE TCC SCHEME FOR $k = 3, 4$

Since in the average sense, the amount of the network capacity available throughout the entire year, i.e., $k = 1, 2, 3$, and 4, matches what is offered through the TCC's, the fund used for buying back the capacity which is no longer available may be recovered by offering more TCC's in surplus hours, in this case at hour 4. However, as in this example, the demand for the TCC's are directly related to not only how much exchanges actually take place but also how much of the exchanges are committed through the forward contracts, which implies that in hour 4, there may not be enough participants involved in the forward contracts to create the necessary demand for recovering the fund through the TCC's. Similar problem arises with regards to the TCC's for Transaction 3 in the example. Because the contract starts at hour 2 instead of at hour 1, the participants may be in odds at purchasing the necessary TCC's through the auction process which is only held once at hour 1 for the entire year. Therefore, in order for the TCC scheme to perform at the desired level, the role of marketers involved in trading for the sake of trading (without any actual hedging against physical risks) becomes critical.

Under the flowgate scheme, the ISO offers 80MW of flowgate rights on the transmission line between bus 2 and bus 3 in that direction to be auctioned off at the beginning of the year. For Transaction 1, Transaction 2 and Transaction 3 the PTDF's with respect to the line between bus 2 and bus 3 are 0.6667, 0.3333 and -0.3333 respectively. Based on the forward contracts for each transaction, ideally the suppliers at bus 1 acquire 18.67MW of flowgate rights for hours 1, 2 and 3 (i.e., $k = 1, 2$, and 3) and -6.1667MW of flowgate rights for hours 2, 3, and 4 (i.e., $k = 2, 3$ and 4) while the suppliers at bus 2 acquire 67.5MW of flowgate rights for the entire year (i.e., $k = 1, 2, 3$, and 4). However, the actual bidding process may vary significantly for acquiring the flowgate rights depending on the exact entitlement of the rights and on the market setup. We make the following two assumptions (as also done in the previous section): that the flowgate rights are physical transmission rights with use-it-or-lose-it rule and that once the rights are auctioned off by the ISO, the market participants may utilize the secondary markets for trading these rights at each hour before the spot market is conducted. It is emphasized here again that these assumptions are consistent with the mechanism described in [1]. In the paper, the mechanism is described while treating the power exchange as the only forward market, which is conducted every day before the spot markets are conducted over the same period. In addition the ISO offers the flowgate rights to be auctioned off only once at the beginning of the year. The mechanism is extended here to include the forward contracts over longer periods of various length.

Suppose that since Transaction 3 is not in effect until hour 2, only the suppliers involved in Transaction 1 and Transaction 2 participate in the initial auction process conducted by the ISO. Because Transaction 1 and Transaction 2 are arranged with the loads at bus 3 paying 30.85 ($/MW) while the marginal costs at bus 1 and at bus 2 are 16.37 ($/MW) for generating 56.00MW and 1.90 ($/MW) for generating 101.25MW, the suppliers are willing to pay up to 43.43 ($/MW) for the flowgate rights at each hour, i.e., for suppliers at bus 1

$$43.43 = \frac{1}{0.3333}(30.85 - 16.37) \tag{23}$$

for suppliers at bus 2

$$43.43 = \frac{1}{0.6667}(30.85 - 1.90) \tag{24}$$

where 0.3333 and 0.6667 are the associated PTDF for Transaction 2 (supplier 1) and for Transaction 1 (supplier 2). We impose the restriction that at the initial auction by the ISO the flowgate rights are only offered by the lump sum covering the entire year.[4] Then, given that any flowgate rights purchased by the suppliers at bus 1 is lost at $k = 4$ because of the use-it-or-lose-it rule, the maximum price the suppliers at bus 1 is willing to pay reduces to 32.57 (\$/MW) (= $(3/4) \times 43.43$). This leads to the allocation of 67.5MW (= $0.6667 \cdot 101.25$) flowgate rights to suppliers at bus 2 for the price of 43.43 (\$/MW) while the rest of the flowgate rights, 12.5MW (= $80 - 0.6667 \cdot 101.25$), goes to the suppliers at bus 1 for the price of 32.57 (\$/MW).

Following the initial auction of the flowgate rights by the ISO, the expected profit, $\mathcal{E}\{\pi_i = \rho_i \cdot Q_i\}$ at each bus can be readily computed. For the suppliers at bus 1

$$\mathcal{E}\{\pi_1[k]\} = 30.85 \cdot 56.00 + 16.37 \cdot 18.50 - \frac{1}{2}(16.37 \cdot 74.50) - 32.57 \cdot 12.50 - 43.43(0.3333 \cdot 56.00 - 12.50) \tag{25}$$

where $k = 1, 2$, and 3. The first term and the second term in Eq. (25) are the expected revenue collected from realizing Transaction 2 of 56MW and from offering 18.50MW in the spot market, respectively. The third term is the expected cost for generating 74.5MW. The fourth term is the cost of acquiring the flowgate rights to eliminate the network related risks (both in price volatility and in dispatch scheduling) for 37.50MW of 56.00MW in Transaction 2. The last term is the expected cost to be paid for transmission charge on the rest of 56.00MW in Transaction 2 not covered by the flowgate rights.

$$\mathcal{E}\{\pi_1[4]\} = 16.37 \cdot 74.50 - \frac{1}{2}(16.37 \cdot 74.50) - 32.57 \cdot 12.50 \tag{26}$$

[4]This restriction is not inherent to the flowgate scheme but is added here to address the ambiguity of auctioning the flowgate rights only once at the beginning of the year while covering the entire year. At the time of writing, the author is not aware of any existing literature including [1] spelling out the mechanism necessary for debarring such ambiguity.

The first term and the second term in Eq. (26) are the expected revenue from offering 74.50MW in the spot market and the expected cost for generating 74.50MW. The last term is the payment for the forfeited flowgate rights in the hour. The average of the expected profit for the suppliers at bus 1 is again \$609.78 (compared to under the TCC scheme) of which \$306.94 is assured in hours 1, 2 and 3 through the forward contracts for energy and matching flowgate rights. This is equivalent to saying that 18.50MW of generation committed through the forward contracts for energy is completely exposed to the network related risks.

For the suppliers at bus 2

$$\mathcal{E}\left\{\pi_2[k]\right\} = 30.85 \cdot 101.25 - \frac{1}{2}(1.90 \cdot 101.25) - 43.43 \cdot 67.50 \tag{27}$$

where again $k = 1, 2, 3$ and 4. The first term in Eq. (27) is the expected revenue collected from realizing Transaction 1 of 101.25MW. The second term is the expected cost for generating 101.25MW. The last term is the cost of acquiring the flowgate rights to eliminate the entire network related risks for 101.25MW in Transaction 1. It is recognized that the profit of the suppliers at bus 2 includes no uncertainties and is assured to be \$96.07 throughout the year due to the forward contracts for energy and matching flowgate rights.

Since the transmission rights under the flowgate scheme are physical, at each hour k the functions of only the residual demand and supply are submitted to the ISO who, then, conducts the spot market. Here we assume that any bilateral transactions arising from the forward contracts for energy without the matching flowgate rights are also bid into the spot market as a paired demand and supply [11].

For $k = 1$ the result of clearing the spot market yields the prices of 16.37 (\$/MW), 1.90 (\$/MW), and 30.85 (\$/MW) at bus 1, bus 2 and bus 3, respectively. The suppliers at bus 1 are then scheduled for 56.00MW under the forward contracts of which 37.50MW is already assured before clearing the spot market through the flowgate rights. In addition 18.50MW is also scheduled for the suppliers at bus 1 through the spot market. The suppliers at bus 2 are scheduled for 101.25MW while no dispatch is scheduled at bus 3. At the end of the hour 1, the ISO collects from the loads at bus 2, \$35.12 (= 1.90 (\$/MW) $\times$18.50 (MW)) and pays the suppliers at bus 1, 302.94 (= 16.37 (\$/MW) $\times$18.50 (MW)).

Before the spot market is conducted for the next hour, the secondary market for flowgate rights is conducted. With the presence of Transaction 3 between suppliers at bus 1 and the loads at bus 2, the counterflow of 6.17MW may be created on the transmission line from bus 2 to bus 3. This means that up to an additional 6.17MW of flowgate rights may be created depending on the demand for such transmission rights. Since the suppliers involved in Transaction 2 can use the additional flowgate to insure the transfer, the entire 6.17MW of flowgate rights are created and assigned to the suppliers at bus 1 involved in Transaction 2. Subsequently the suppliers at bus 1 involved in Transaction 3 are paid \$267.83 ($= 0.3333 \cdot 43.43 \cdot 18.5$).

For $k = 2$ Transaction 1, Transaction 2, and Transaction 3 are all covered with appropriate flowgate rights, and thus, reserve the priority for using the network. Therefore, the result of clearing the spot market only with the residual demand and supply functions yields the prices of 17.69 (\$/MW), -5.56 (\$/MW), and 40.93 (\$/MW) at bus 1, bus 2 and bus 3, respectively. The negative price at bus 2 is to lead the loads at that bus to consume more so that more transfer capacity can be created between bus 1 and bus 3. The suppliers are schedules for 61.97MW ($= 56.00 + 5.97$), 101.25MW and 0MW at bus 1, bus 2 and bus 3, respectively. At the end of the hour 2, the ISO pays the loads at bus 2, \$16.60 ($= -5.56$ (\$/MW) $\times 2.98$ (MW)) and collects from the loads at bus 3 \$122.13 ($= 40.93$ (\$/MW) $\times 2.98$ (MW)) for the total of \$105.54 . The ISO then pays to the suppliers at bus 1, \$105.54 ($= 40.93$ (\$/MW) $\times 5.97$ (MW)).

Again before the spot market is conducted for the next hour, the secondary market for flowgate rights is conducted. The arrangement made at this time is same as before with Transaction 1, Transaction 2, and Transaction 3 all having the appropriate flowgate rights to realize according to the forward contracts.

For $k = 3$ the result of clearing the spot market for the residual demand and supply functions yields the same prices and same scheduling as given for $k = 1$. Since all the transactions are done through the forward contracts no financial exchanges take place through the ISO.

With Transaction 2 taken out from the secondary market for transmission rights, there is no longer the demand for the additional flowgate rights created by the Transaction 3. Thus, the only flowgate rights to be exercised belong to the suppliers involved in Transaction 1.

For $k = 4$ the result of clearing the spot market for residual demand and supply functions yields the prices of 14.51 (\$/MW), 1.98 (\$/MW), and 27.05 (\$/MW) at bus 1, bus 2 and bus 3, respectively. The suppliers at bus 1 are then scheduled for 18.50MW under the forward contracts and for additional 47.52MW at the spot market. The suppliers at bus 2 are scheduled for 101.25MW under the forward contracts as well as 4.24MW in the spot market. At the end of the hour 4, the ISO collects from the loads at bus 3, \$1,400.00 (= 27.05 (\$/MW) $\times$51.76 (MW)) and pays to the suppliers at bus 1, \$689.62 (= 14.51 (\$/MW) $\times$47.52 (MW)) and to the suppliers at bus 2, \$8.38 (= 1.98 (\$/MW) $\times$4.24 (MW)) for the total of \$698.00. The difference between the revenue collected and the cost paid, \$53.13, is the transmission revenue collected by the ISO from conducting the spot market.

Table VI summarizes the financial as well as physical exchanges among the market participants and the ISO. As evident from the example, the physical exchange among participants is assured to take place according to the forward contracts if and only if the contracts are covered through the appropriate flowgate rights. For instance, at hours 2 and 3, all of the transactions are intially committed through the forward contracts on the energy as well as the transmission portion of the electric services. Thus, the transactions take place exactly as committed. As in the case at hour 2, when the spot market demand creates a shortage of transmission capacity, the ISO is forced to bring more capacity into the market by paying the loads at bus 3 to consume more.[5] This is due to the *binding* physical commitment made through the flowgate rights. The difficulty is extending the result to the longer term forward contracts rather than just to the power exchange type forward. As shown in hours 1 and 4, if the forward contracts are not synchronized and do not cover all of the transactions (from the expected sense), then there may be inadequacy in flowgate rights to be trade among participants. This is due to the counterflows by various contracts creating more than the mere absolute amount of rights initially offered by the ISO. There is another difficulty associated with the use-it-or-lose-it rule with related to the longer term application. Unlike the power exchange cases, the participants may not be involved in forward contracts over the entire year for which period the initial flowgate rights are auctioned. A clear compensation mechanism needs to be developed in such cases so that the charge mechanism may be viewed as fair from the spot market regardless of several different ways of defining PTDF's.[6]

Under the proposed scheme, the SO offers the intermediate term transmission contracts on

[5]The task is equivalent to utilizing adjustment bids by the suppliers if there are any.

[6]The PTDF's may be defined differently even under the same operating conditions depending on the slack bus assignment.

		$g_{\text{bus 1}}$	$g_{\text{bus 2}}$	$d_{\text{bus 2}}$	$d_{\text{bus 2}}$	ISO
for flowgate rights:						
$g_{\text{bus 2}} \rightarrow$ ISO	\$11,726.58	-\$11,726.58	·	·	·	\$11,726.58
$g_{\text{bus 1}} \rightarrow$ ISO	\$1,628.69	·	-\$1,628.69	·	·	\$1,628.69
$k = 1$						
$d_{\text{bus 2}} \rightarrow$ ISO	\$35.12	·	·	-\$35.12	·	\$35.12
ISO $\rightarrow g_{\text{bus 1}}$	\$302.94	\$302.94	·	·	·	-\$302.94
for flowgate rights:						
$g_{\text{bus 1}}(TR2) \rightarrow g_{\text{bus 1}}(TR3)$	\$267.83	\$0	·	·	·	·
$k = 2$						
ISO $\rightarrow d_{\text{bus 2}}$	\$16.60	·	·	\$16.60	·	-\$16.60
$d_{\text{bus 3}} \rightarrow$ ISO	\$122.13	·	·	-\$122.13	·	\$122.13
ISO $\rightarrow g_{\text{bus 1}}$	\$105.54	\$105.54	·	·	·	-\$105.54
for flowgate rights:						
$g_{\text{bus 1}}(TR2) \rightarrow g_{\text{bus 1}}(TR3)$	\$267.83	\$0	·	·	·	·
$k = 3$						
·	·	·	·	·	·	·
for flowgate rights:						
·	·	·	·	·	·	·
$k = 4$						
$d_{\text{bus 3}} \rightarrow$ ISO	\$1,400.00	·	·	-\$1,400.00	·	\$1,400.00
ISO $\rightarrow g_{\text{bus 1}}$	\$689.62	\$689.62	·	·	·	-\$689.62
ISO $\rightarrow g_{\text{bus 2}}$	\$8.38	·	\$8.38	·	·	-\$8.38

TABLE VI

Exchanges among the market participants and the ISO under the flowgate scheme for $k = 1, 2, 3, 4$

the transmission line between bus 2 and bus 3 at some price. Even though the intermediate term transmission contracts offered by the SO carry not only the congestion cost but also the *ex ante* flow tax, for the purpose of comparison the flow tax portion of the network charge is assumed to be zero. Thus, the network charge on either the transmission line between bus 1 and bus 2 or the transmission line between bus 1 and bus 3 can be ignored since there is no congestion cost associated with the charge on these lines based on Eqs. (8) through (10) and Eqs. (11) and (12). Using these equations the proper valuation of the intermediate term transmission contracts by the ITC leads to \$43.43 in the direction from bus 2 to bus 3 and is -\$43.43 in the opposite direction for the entire year, i.e. $k = 1, 2, 3$, and 4.[7] We assume here that for Transaction 1, Transaction 2 and Transaction 3 the PTDF's with respect to the line between bus 2 and bus 3 are 0.6667, 0.3333 and -0.3333 respectively.

Based on the forward contracts for each transaction, the suppliers at bus 1 acquire 18.67MW of intermediate term transmission contracts from the SO for hours 1, 2 and 3 (i.e., $k = 1, 2$, and 3) and -6.1667MW of flowgate rights for hours 2, 3, and 4 (i.e., $k = 2, 3$ and 4) while the suppliers at bus 2 acquire 67.5MW of flowgate rights for the entire year (i.e., $k = 1, 2, 3$, and 4). The price at which these contracts are offered is \$43.43.

It is noted that by offering the total of 86.1667MW of contracts at hour 1, the SO (in turn the ITC) takes the network related risks, i.e, both price volatility and the dispatch scheduling. What appears to be over-commitment of the network capacity through the intermediate term transmission contracts is actually preferable from the perspective of the ITC. This is because the more capacity committed through the intermediate term transmission contracts, while not violating the transfer limits based on the expected market activities including the forward contracts for energy and the spot market, the more stable the revenue is for the ITC.

The expected profit, $\mathcal{E}\{\pi_i = \rho_i \cdot Q_i\}$ at each bus can be readily computed based on the allocation of the transmission contracts. For the suppliers at bus 1

$$\mathcal{E}\{\pi_1[1]\} = 30.85 \cdot 56.00 + 16.37 \cdot 18.50 - \frac{1}{2}(16.37 \cdot 74.50) - 43.43 \cdot 18.67 \tag{28}$$

$$\mathcal{E}\{\pi_1[2]\} = 30.85 \cdot 56.00 + 1.90 \cdot 18.50 - \frac{1}{2}(16.37 \cdot 74.50) - 43.43 \cdot 18.67 - (-43.43) \cdot 6.17 \tag{29}$$

$$\mathcal{E}\{\pi_1[1]\} = 30.85 \cdot 56.00 + 1.90 \cdot 18.50 - \frac{1}{2}(16.37 \cdot 74.50) - 43.43 \cdot 18.67 - (-43.43) \cdot 6.17 \tag{30}$$

$$\mathcal{E}\{\pi_1[1]\} = 1.90 \cdot 18.50 + 16.37 \cdot 56.00 - \frac{1}{2}(16.37 \cdot 74.50) - (-43.43) \cdot 6.17 \tag{31}$$

The first term in Eqs. (28) through (30) is the expected revenue collected from realizing Transaction 2 of 56MW while the second term in Eqs. (29) and (30) and the first term in Eq. (31) is the expected revenue collected from realizing Transaction 3 of 18.5MW. The

[7]Under the proposed scheme, the price of the intermediate term transmission contracts is determined by the ITC once the SO provides the (operational) transfer limits on each line and the PTDF's even though the allocation of the contracts is conducted by the SO. The reason for this is because of the financial responsibility imposed on the SO. The SO also assists the ITC with the projection of demand and supply functions.

second term in Eqs. (28) and (31) is the expected revenue from the spot market. The third term in Eqs. (28) through (31) is the expected cost for generating 74.5MW. The last term in Eq. (28) and the fourth term in Eqs. (29) and (30) is the cost of acquiring the intermediate term transmission contracts to eliminate the network related risks for Transaction 2, while the last term in Eqs. (29) and (31) is the cost of the transmission contracts for Transaction 3.

For the suppliers at bus 2

$$\mathcal{E}\left\{\pi_2[k]\right\} = 30.85 \cdot 101.25 - \frac{1}{2}(1.90 \cdot 101.25) - 43.43 \cdot 67.50 \tag{32}$$

where $k = 1, 2, 3$ and 4. The first term in Eq. (32) is the expected revenue collected from realizing Transaction 1 of 101.25MW. The second term is the expected cost for generating 101.25MW. The last term is the cost of acquiring the flowgate rights to eliminate the entire network related risks for 101.25MW in Transaction 1. It is recognized here again that the profit of the suppliers at bus 2 includes no uncertainties and is assured to be \$96.07 throughout the year due to the forward contracts for energy and matching intermediate term transmission contracts.

For $k = 1$ the result of clearing the spot market yields the prices of 16.37 (\$/MW), 1.90 (\$/MW), and 30.85 (\$/MW) at bus 1, bus 2 and bus 3, respectively. The suppliers at bus 1 are then scheduled for 74.50MW under the forward contracts and in the spot market. The amount committed through the forward contract is actually scheduled before the spot market is conducted due to the matching intermediate term transmission contracts. The suppliers at bus 2 are scheduled for 101.25MW while no dispatch is scheduled at bus 3. At the end of the hour 1, the SO collects from the loads at bus 2, \$35.12 (= 1.90 (\$/MW) ×18.50 (MW)) and pays the suppliers at bus 1, 302.94 (= 16.37 (\$/MW) ×18.50 (MW)).

Before the spot market is conducted for the next hour, the secondary market for transmission rights is conducted in case any participants with the intermediate term transmission contract wants to trade if the operating condition changes. The price posted for intermediate term transmission contracts may vary as well at this time to reflect more accurate operating conditions according to the ITC's projection. We assume that the expected operating conditions by the market participants and by the ITC remain as given in Eqs. (8) through (10) and Eqs. (11) and (12).

For $k = 2$ Transaction 1, Transaction 2, and Transaction 3 are all covered with appropriate flowgate rights, and thus, reserve the priority for using the network. Therefore, the result of clearing the spot market only with the residual demand and supply functions yields the prices of 17.69 ($/MW), -5.56 ($/MW), and 40.93 ($/MW) at bus 1, bus 2 and bus 3, respectively. The negative price at bus 2 is to lead the loads at that bus to consume more so that more transfer capacity can be created between bus 1 and bus 3. The suppliers are schedules for 61.97MW ($= 56.00 + 5.97$), 101.25MW and 0MW at bus 1, bus 2 and bus 3, respectively. At the end of the hour 2, the ISO pays the loads at bus 2, $16.60 ($= -5.56$ ($/MW) $\times 2.98$ (MW)) and collects from the loads at bus 3 $122.13 (= 40.93 ($/MW) $\times 2.98$ (MW)) for the total of $105.54 . The ISO then pays to the suppliers at bus 1, $105.54 (= 40.93 ($/MW) $\times 5.97$ (MW)). This result is identical to that under the flowgate scheme.

Similarly, for $k = 3$ the result of clearing the spot market for the residual demand and supply functions yields the same prices and same scheduling as given for $k = 1$. Since all the transactions are done through the forward contracts no financial exchanges take place through the ISO. Plus, for $k = 4$ the result of clearing the spot market for residual demand and supply functions yields the prices of 14.51 ($/MW), 1.98 ($/MW), and 27.05 ($/MW) at bus 1, bus 2 and bus 3, respectively, again identical to the result under the flowgate scheme.

Table VII summarizes the financial as well as physical exchanges among the market participants and the ITC through the SO under the proposed scheme. As evident from the example, the physical exchange among participants is assured to take place according to the appropriate intermediate term transmission contracts. Unlike under the flowgate scheme the market participants may not rely on other participants for creating transmission rights because the ITC takes the financial risks of over-committing through the transmission contracts. Thus, the longer term hedging against the network related risks are possible at any time. The change in market conditions (although not shown in the example), may result in the price variation for the transmission rights, thus more accurately reflecting the system status. Finally, the intermediate term transmission contracts may be converted to the financial rights entitling the participant to the transmission charge in case he decides not to commit physically as specified by the contracts.

		$g_{\text{bus } 1}$	$g_{\text{bus } 2}$	$d_{\text{bus } 2}$	$d_{\text{bus } 2}$	ISO
for intermediate term transmission contracts:						
$g_{\text{bus } 2} \to$ ISO	\$11,726.58	-\$11,726.58	·	·	·	\$11,726.58
$g_{\text{bus } 1} \to$ ISO	\$2,432.18	·	-\$2,432.18	·	·	\$2,432.18
ISO $\to g_{\text{bus } 1}$	\$803.49	\$803.49	·	·	·	-\$803.49
$k = 1$						
$d_{\text{bus } 2} \to$ ISO	\$35.12	·	·	-\$35.12	·	\$35.12
ISO $\to g_{\text{bus } 1}$	\$302.94	\$302.94	·	·	·	-\$302.94
$k = 2$						
ISO $\to d_{\text{bus } 2}$	\$16.60	·	·	\$16.60	·	-\$16.60
$d_{\text{bus } 3} \to$ ISO	\$122.13	·	·	-\$122.13	·	\$122.13
ISO $\to g_{\text{bus } 1}$	\$105.54	\$105.54	·	·	·	-\$105.54
$k = 3$						
·	·	·	·	·	·	·
$k = 4$						
$d_{\text{bus } 3} \to$ ISO	\$751.13	·	·	-\$751.13	·	\$751.13
ISO $\to g_{\text{bus } 1}$	\$689.62	\$689.62	·	·	·	-\$689.62
ISO $\to g_{\text{bus } 2}$	\$8.38	·	\$8.38	·	·	-\$8.38

TABLE VII

EXCHANGES AMONG THE MARKET PARTICIPANTS AND THE ISO UNDER THE FLOWGATE SCHEME FOR $k = 1, 2, 3, 4$

IV. ROLE OF OPEN ACCESS SAME TIME INFORMATION SYSTEMS (OASIS)

In order to operate a successful secondary market for transmission rights, a well functioning real time information network is fundamental between the network users and the TP. This is because the amount of transmission rights available at any given time depends on the expected network condition for the period being covered by the rights. For example, suppose there is a significant change in a given network following a contingency such as a major line outage. Then, the electric power flow through the disconnected line is re-routed to other network lines according to Kirchhoff's laws. If there is a transmission line being operated close to its operating limits prior to the contingency, and the flow on the line is affected by a decrease in counterflow following the contingency, then that particular line may experience transmission congestion and has a reduced transfer capacity. Unless this information is readily available to the network users participating in the secondary market for transmission rights, the liquidity of the market can be hardly expected.

Likewise, in order to operate a reliable transmission network, a well functioning real time information network is also essential. The is because the reliable operation of the network depends on how well the transmission capacity is allocated based on the change in market conditions. Suppose a sudden increase in demand for a certain network line is observed based on the market activities in the secondary market for transmission rights. If this surge of demand for that particular line is not communicated properly to the TP, then the price for using the line may remain the same, and the demand may continue to increase beyond the operating limits of the line. This is certain to result in a reduced level of reliability by the time the physical implementation according to the transmission rights takes place.

Based on the Order No. 889 issued by Federal Energy Regulatory Commission (FERC), the open access same-time information system (OASIS) may be operated as the real time information network necessary for supporting the secondary market for transmission rights [10]. First, we describe the minimum contents to be included in the OASIS.

A. Data contents

Based on the intermediate term transmission contracts as proposed in [6] the minimum contents to be included in the OASIS may be determined in the following order. At the beginning of the year (or season) the ITC posts the operational transfer limits on each transmission line within the system and the PTDF's with respect to the injection points. These limits are fixed for the entire year (or season) so that the network users can plan and operate their respective equipment under stable network conditions. This means any sudden change affecting the network is internalized in the ITC and is not visible from the perspective of the network users. Fortunately, the incentive structure based on the proposed framework in [6] assures a higher profit for the ITC that operates the network as closely to the posted operating limits and PTDF's for each transmission line. This information is then used to convert the current year (or season) portion of the point-to-point long term transmission contracts into the link based intermediate term transmission contracts [6].

After the operational limits and the PTDF's determined for the entire year (or season), the ITC is obligated to provide the pricing of intermediate term transmission contracts of each day on the OASIS. The pricing is, of course, based on the expected shadow price of each link in addition to the *ex ante* flow tax. Based on this information, the network users may purchase the intermediate term transmission contracts from the ITC (through SO). Once the purchase, any user holding the rights can trade with other participants in the secondary market for transmission rights as their network need changes. It is important to note that since the network users may always be able to purchase the intermediate term transmission contracts from the ITC at the posted prices, the price in the secondary market is always less than or equal to the posted prices. Furthermore, some users may use the secondary market for transmission rights to purchase many intermediate term transmission contracts and tailor them for their needs. For example, some users may issue various financial derivatives, such as options, on transmission rights in the secondary market for transmission rights and appropriately adjust their exposed risks by purchasing the intermediate term transmission contracts from the ITC at the prices posted on the OASIS for some or all of the options issued.

Finally, because the transmission prices include shadow prices of congestion as well as the *ex ante* flow tax, as the system conditions change, the price posted on the OASIS is updated as many times as required by the ITC. The incentive structure based on the proposed framework in [6], however, prevents the ITC from modifying the prices too often.

Since the price for using the network needs to be kept track of on the individual line basis, the actual amount of information posted on the OASIS may be quite large. However, it is recognized that the prices of most of the network lines are rather stable except for the ones which undergo frequent transmission congestions within a year (or a season), which suggests that some of the data may be posted on the OASIS only as an aggregate average. The one way of accomplishing this is by considering the congestion cluster method [8]. The congestion cluster method identifies the lines which may experience a high volatility in prices and aggregates the rest of lines within regions of infrequent congestions called congestion clusters. With this reduced complexity, much simplification may be achieved as desired by the network users while still conveying the necessary information, which requires carefully designed congestion clusters.

B. Data aggregation

Denote a design of congestion clusters by θ_j and its performance by $\mathcal{E}\left\{L(\theta_i, \xi[k], k)\right\}$ where $\xi[k]$ is the sample uncertainty and $L(\theta_i, \xi[k], k)$ is the sample performance value for design θ_i for given $\xi[k]$. The performance of each design is based on the minimum desired criteria for the method as listed here:

1. the transaction between any buses within the same cluster have little impact of power flows on the congested transmission lines, $L_{D^{(i,j)}}(\theta, \xi[k], k)$
2. the energy cost computed after relieving inter-cluster congestion is small, $L_{Q_{g_i}}(\theta, \xi[k], k)$
3. the additional energy cost necessary for relieving intra-cluster congestion is small, $L_{\Delta Q_{g_i}}(\theta, \xi[k], k)$

where $D^{(i,j)}$ is so-called congestion distribution factor (CDF's) introduced in [9]. Limiting the sample performance to reflect only the measures of the above three criteria, we consider the overall sample performance function to be given as

$$L(\cdot) = \alpha_{D^{(i,j)}} L_{D^{(i,j)}}(\cdot) + \alpha_{Q_{G_i}} L_{Q_{G_i}}(\cdot) + \alpha_{\Delta Q_{G_i}} L_{\Delta Q_{G_i}}(\cdot) \tag{33}$$

where α's denote the relative importance factors of each criterion. Typically, the factors are selected such that $\alpha_{D^{(i,j)}} L_{D^{(i,j)}}(\cdot) \geq \alpha_{\Delta Q_{G_i}} L_{\Delta Q_{G_i}}(\cdot) \geq \alpha_{Q_{G_i}} L_{Q_{G_i}}(\cdot)$.

The CDFs give good measure of the impact of transactions between buses to the congested lines. CDFs are derived from distribution factors. First, distribution factors in usual sense are computed twice with respect to two different slack bus locations within the same system for transmission line of interest, i.e. $\left\{D_m^{(i,j)}\right\}$ and $\left\{D_n^{(i,j)}\right\}$ where bus n is used as the slack bus for the first computation, and bus m is for the second. Then, the difference between these two sets of distribution factors, $\beta_{m,n}^{(i,j)}$, is the result of having two slack buses in different location. Defining the difference as

$$\beta_{m,n}^{(i,j)}\{1\} = \left\{D_m^{(i,j)}\right\} - \left\{D_n^{(i,j)}\right\} \tag{34}$$

where $\{1\}$ is the vector of all ones, $\beta_{m,n}^{(i,j)}$, can be expressed as [9]

$$\beta_{m,n}^{(i,j)} = D_m^{(i,j)}(n) = -D_n^{(i,j)}(m) \tag{35}$$

where $D_m^{(i,j)}(n)$ denotes the nth element of the vector $\left\{D_m^{(i,j)}\right\}$.

Define the shift vector, ϕ as

$$\phi^{i,j} = -\frac{D_m^{(i,j)}(i) + D_m^{(i,j)}(j)}{2} \tag{36}$$

for given distribution factors, $\left\{D_m^{(i,j)}\right\}$ with respect to the slack bus, m. Then, we can subtract out the locational effect of slack bus from distribution factors by adding the sum of shift vector elements to the given distribution factors. The resulting vectors are what is defined as CDF, $\left\{D^{(i,j)}\right\}$:

$$\left\{D^{(i,j)}\right\} = \left\{D_m^{(i,j)}\right\} + \phi^{(i,j)}\{1\} \tag{37}$$

The magnitude of resulting CDF defines the sensitivity of the flow in transmission line of interest on a transaction; this formulation ensures that sensitivity of flows on the line of interest with respect to a bus injection decreases monotonically as the electrical distance between the line and the bus increases. The sign denotes if the transaction will increase or relieve the congestion.

The energy cost after relieving inter-cluster congestion is closely related to the computation of cluster-wide prices step in the implementation of the congestion cluster pricing method. As a matter of fact, the equations used for computing the energy cost and the cluster-wide prices are the same. Suppose the nodes $g_i, g_{i+1}, \cdots, g_{i+k}$ are in the cluster z_j. Then, at some t the new generation cost associated with the cluster z_j is given by

$$C_{z_j}(Q_{z_j}) = f_{z_j}(Q_{g_i}, Q_{g_{i+1}}, \cdots, Q_{g_{i+k}}) \tag{38}$$

where f_{z_j} is the monotonically increasing nonlinear function representing the least cost combination of Q_{g_i}'s in z_j for producing Q_{z_j}. The marginal cost of zone z_j, MC_{z_j}, can be used in order to compute $f_{z_j}(\cdot)$ where

$$MC_{z_j} = \begin{cases} \left(\frac{1}{2a_l} + \frac{1}{2a_{l+1}} + \cdots + \frac{1}{2a_{l+s}}\right)^{-1} Q_{z_j} & Q_{z_j} \in R_{I_1} \\ \left(\frac{1}{2a_m} + \frac{1}{2a_{m+1}} + \cdots + \frac{1}{2a_{m+t}}\right)^{-1} Q_{z_j} & Q_{z_j} \in R_{I_2} \\ \cdot & \\ \cdot & \\ \cdot & \\ \left(\frac{1}{2a_n} + \frac{1}{2a_{n+1}} + \cdots + \frac{1}{2a_{n+u}}\right)^{-1} Q_{z_j} & Q_{z_j} \in R_{I_k} \end{cases} \tag{39}$$

where R_{I_i}'s define the region of operating condition in cluster j with q number of generators are still below the generation limits. a_r's represent the coefficient of associated marginal cost of those generators below their generation limits.

With $C_{z_j}(Q_{z_j})$, the generation costs (and/or cluster-wide prices) are computed by solving the optimization problem given as

$$Q^{\star}_{z_j} = \arg\min_{Q_{z_j}} \sum_{z_j} C_{z_j}(Q_{z_j}) \tag{40}$$

subject to the load flow constraint, i.e., total generation is equal to system load,

$$\sum_{z_j} Q_{z_j} = \sum_{d_j} Q_{d_j} \qquad : \lambda \tag{41}$$

the congestion interface flow limit constraints, i.e., the power flow on any line l *along only the congestion interfaces* is within the maximum rating of the line,

$$|F_l| = \left| \sum_{z_i} H_{lz_i} Q_{z_i} - \sum_{d_j} H_{ld_j} Q_{d_j} \right| \leq F_l^{max} \quad : \mu_l \tag{42}$$

and the generation limit constraints, i.e., the dispatch amount in cluster z_j is within the sum of maximum rating of the corresponding generators within the cluster

$$0 \leq Q_{z_j} \leq \sum_{g_i \in z_j} Q_{g_i}^{max} \qquad : \eta_{z_j} \tag{43}$$

The computation of H_{lz_i} yields

$$H_{lz_i} = \frac{dF_l}{dQ_{g_i}} \frac{\partial Q_{g_i}}{\partial Q_{z_j}} + \frac{dF_l}{dQ_{G_{i+1}}} \frac{\partial Q_{G_{i+1}}}{\partial Q_{z_j}} + \cdots + \frac{dF_l}{dQ_{G_{i+k}}} \frac{\partial Q_{G_{i+k}}}{\partial Q_{z_j}} \tag{44}$$

with

$$\frac{dF_l}{dQ_{g_i}} = H_{lG_i} \tag{45}$$

and with

$$Q_{g_i} = \frac{1}{2a_i} \left(\frac{1}{2a_i} + \frac{1}{2a_{i+1}} + \cdots + \frac{1}{2a_{i+k}} \right)^{-1} Q_{z_j} \tag{46}$$

if $Q_{g_i} \in R_{I_i}$.

The solution to the optimization problem (40) then given by

$$\rho_{z_i} = \lambda + \sum_l \mu_l H_{lz_i} \tag{47}$$

where $\mu_l \neq 0$ if and only if $|F_l| = F_l^{max}$ and

$$Q_{g_i} = \begin{cases} Q_{g_i}^{max} & \rho_{z_i, G_i \in z_i} \geq p_{g_i}^{max} \\ \frac{\rho_{z_i}}{2a_{g_i}} & 0 \leq \rho_{z_i, G_i \in z_i} \leq p_{g_i}^{max} \\ 0 & \text{otherwise} \end{cases} \tag{48}$$

where $p_{g_i}^{max} = 2a_{g_i} Q_{g_i}^{max}$. Graphically, the above derivation has the following interpretation. Without loss of generality we consider a zone consisting only two generators. Given the supply bids at nodes G_i and G_j, the aggregate supply bid for zone z_k can be constructed as shown in Figure 5. For Region I

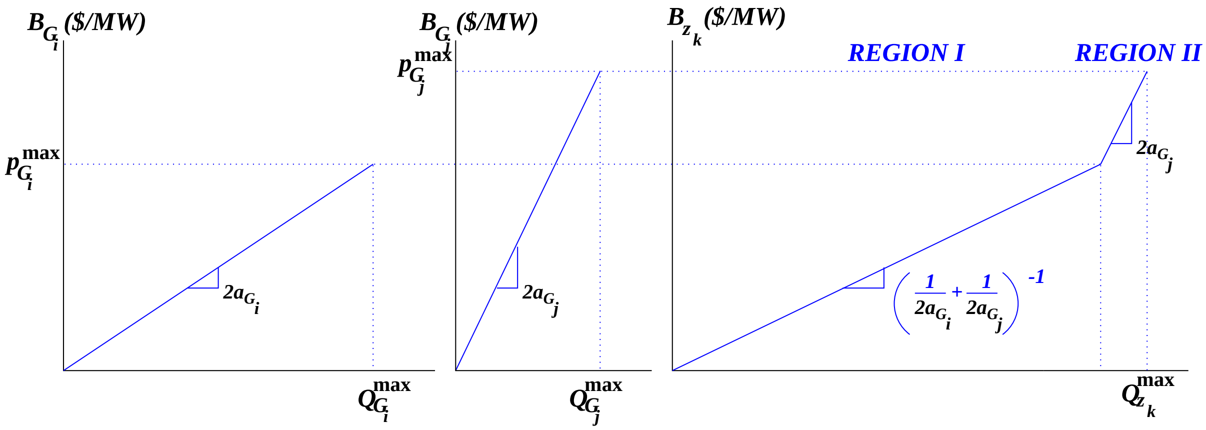

Fig. 5. Aggregation of Marginal Supply Bids in Zone k

$$\begin{aligned}\frac{dF_l}{dQ_{z_k}} = & \frac{1}{2a_{g_i}}\left(\frac{1}{2a_{g_i}} + \frac{1}{2a_{G_j}}\right)^{-1} H_{lG_i} \\ & + \frac{1}{2a_{G_j}}\left(\frac{1}{2a_{g_i}} + \frac{1}{2a_{G_j}}\right)^{-1} H_{lG_j}\end{aligned} \tag{49}$$

and for Region II

$$\frac{dF_l}{dQ_{z_k}} = H_{lG_j} \tag{50}$$

The total energy cost after relieving inter-cluster congestion is then given by

$$TC_{Q_{g_i}} = \sum_{z_i} \rho_{z_i} Q_{z_i} \tag{51}$$

The computation of the energy cost after relieving intra-cluster congestion is similar to that after inter-cluster congestion. The optimization problem to be solved in order to determine the location marginal prices is given by

$$\Delta Q_{g_i} = \arg \min_{\Delta Q_{g_i}, G_i \in \mathcal{Z}} \sum_{g_i} C_{g_i}(\Delta Q_{g_i}) \tag{52}$$

subject to the load flow constraint
where

$$\sum_{G_i \in \mathcal{Z}} \Delta Q_{g_i} = 0 \tag{53}$$

ΔQ_{g_i} : the adjusted generation amount at node G_i

$\mathcal{Z}$: the subset of clusters experiencing intra-cluster congestion

the transmission line flow limit constraints, i.e., the power flow on any line l in the entire system is within the maximum rating of the line,

$$|F_l + \Delta F_l| = |H_{lG_i}\left(Q_{G_i} + \Delta Q_{g_i}\right) + H_{lD_i} Q_{D_i}| \leq F_l^{max} \tag{54}$$

and the generation limit constraints, i.e., the dispatch amount at node $G_i \in \mathcal{Z}$ is within the maximum rating of the corresponding generator

$$0 \leq Q_{g_i} + \Delta Q_{g_i} \leq Q_{Gi}^{max} \tag{55}$$

Here we assume the *ex ante* flow tax to be zero for simplicity.

The additional energy cost necessary for relieving intra-cluster congestion is then given by

$$TC_{\Delta Q_{g_i}} = \sum_{G_i \in \mathcal{Z}} a_{g_i} \Delta Q_{g_i}\left(Q_{g_i} + \Delta Q_{g_i}\right) \tag{56}$$

B.1 Example

We illustrate the approach described in the paper using a simple test case shown in Figure 6. The system consists of 118 buses: 54 generators and 64 loads, and 186 transmission lines interconnecting the entire system; i.e. $N_B = 118$ ($N_G = 54$ and $N_L = 64$), and $N_{TR} = 186$.

The congestion cluster pricing method is to be implemented on the 118 bus system for the cluster boundaries defined at $k = 0$ for a season consisting of 90 days ($T = 2160$ (hours)). The maximum number of clusters allowed is limited to , i.e. $N_z = 20$.

Based on the system parameters it is determined that there are four critical (likely congested) lines in the system, namely the transmission lines between buses 30 and 38, between buses 59 and 63, between buses 70 and 71, and between buses 94 and 100. The critical lines are associated with the lines likely to be congested by reaching the transfer limits. Some of these lines may be congested at the same time or at different times reflecting the stress being applied to the system in more than one possible way at different times throughout the season.

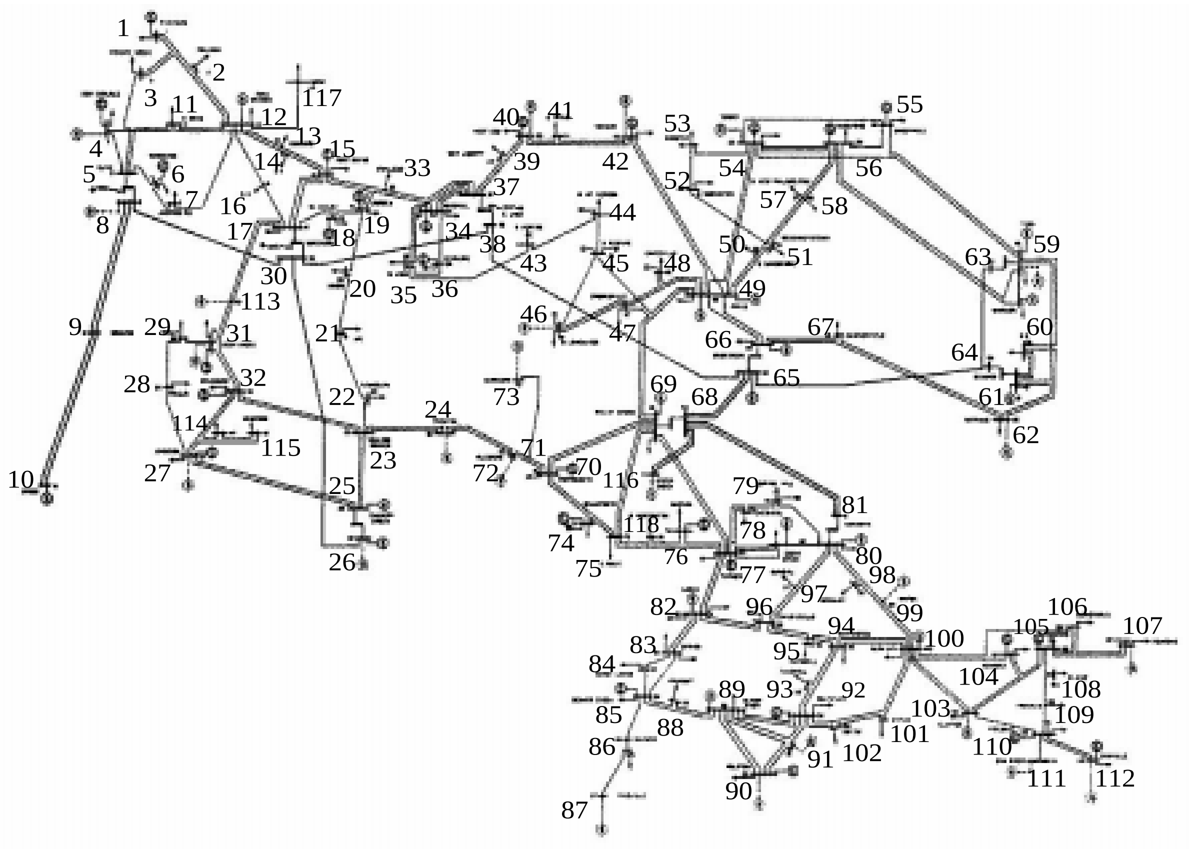

Fig. 6. One line diagram of 118 bus (power flow test case) system

The first cut cluster design is performed for each of these critical lines based on CDFs. For example, Figure 7 shows the cluster boundaries defined based on CDF computed for transmission line between buses 30 and 38. Once the first cut designs are determined, the clusters are superposed on top of each other to create the clusters over the entire season. The resulting number of clusters after the superposition is found to be 18.

V. Conclusion

In this paper we examine the two infrastructures important for proficient management of the network, namely the secondary markets for transmission rights and the open access same time information systems (OASIS).

The secondary markets play a very important role in trading a commodity subject to many uncertainties. Given the forward contracts called intermediate term transmission contracts as

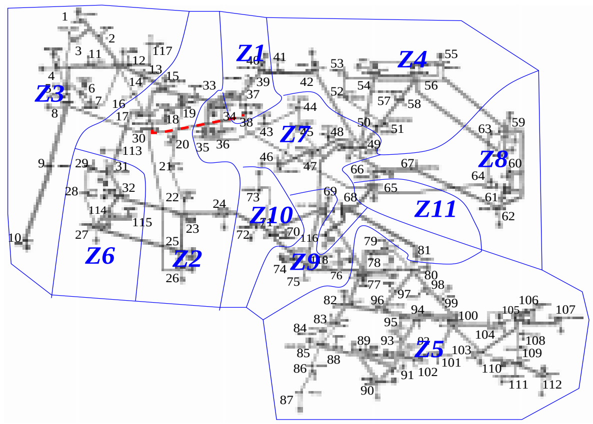

Fig. 7. First cut cluster design for line between buses 30 and 38

proposed in [6], the function of the secondary market for transmission contracts are described in hedging the network related risks, first. The mechanisms given here are then compared to the other proposed methods, namely TCC's and Flowgate rights. It is shown that only the intermediate term transmission contracts allow proper hedging mechanism over a longer period.

Finally, the real time information network called the OASIS is described where the practicality issues are addressed through the data aggregation.

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