MIT EL 01-011 WP

Energy Laboratory

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POSSIBLE DECISION TOOLS FOR TRANSMISSION SERVICE AND PRICING IN THE EVOLVING ELECTRICITY MARKETS

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Energy Laboratory Publication #
MIT EL 01-011WP

Energy Laboratory
Massachusetts Institute of Technology
Cambridge, Massachusetts 02139-4307

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POSSIBLE DECISION TOOLS FOR TRANSMISSION SERVICE AND PRICING IN THE EVOLVING ELECTRICITY MARKETS

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Abstract: This paper considers two methods for transmission service to the electric grid users. First, the service in which a transmission system provider is the main decision maker, and the second in which the system users indirectly control flows on the grid by deciding how much demand to exert for system use. In this paper the emphasis is on the process characterization, the assessment of the computational tools for solving the underlying stochastic optimization problems and their interpretation in light of market rules for transmission service in the electric power industry under restructuring.

Keywords: Power Transmission, Complex Systems, Reliability Analysis, Dynamic Programming, Stochastic Modeling, Optimization Problems, Decentralized Systems.

1. INTRODUCTION

In this paper the problem of transmission service in the electric power industry under restructuring is considered. This industry is generally characterized by having an electricity market in which electricity is supplied to the load demand competitively (Ilic and Liu 1996). In order for the supply/demand transactions to be implemented, arrangements must be made for their delivery from the supplier to the consumer. In this paper we assume existence of an electricity daily spot market as well as the longer-term bilateral contracts between suppliers and consumers. The problem of electricity delivery then becomes a new problem, often referred to as the congestion control problem in electric transmission grids (); conceptually, this problem is very similar to the congestion control problem in Internet (Kelly 1997), and communications networks (Kelly 1997).

In this paper transmission service and its pricing to the electricity market participants are posed as the stochastic optimization problems. The uncertainties are created by both market activities of other users and by the uncertain equipment status. The decision making must be done by modeling these uncertainties carefully. This paper models the process seen by the service provider, and poses the decision making problem first as a complex dynamic problem which generally needs to be solved by a service provider, and, next, as a distributed dynamic programming problem which supports decisions by the system users. These two formulations form the basis for two qualitatively different ways of transmission service and pricing in the evolving energy markets. The first is the one in which a Transmission Service Provider (TSP) is the main decision maker and he determines the priorities at which long term users and spot market users are served. The problem is posed as a dynamic programming problem whose objective is the revenue optimization. This will be referred as a top-down approach. The coordinating decision maker (TSP) accepts the demand and supply requests for transmission service from the system users (electricity market participants) and run it through its optimization and system reliability test functions. It is this technical detail concerning the reliability tests that must be considered carefully as it has major implications on the use of electric grid at present. The currently practiced (N-1) reliability test requires that the grid be used under normal conditions (prior to any equipment outages) somewhat conservatively; the reliability test requires sufficient generation and transmission reserve capacity in a stand-by mode in order to supply the consumer in an uninterrupted way in case any single equipment outage (contingency) takes place. An equipment outage could be viewed as a high impact, low probability uncertain event and cannot be ignored as a TSP develops his decision tools for serving electricity market participants.

In this paper, we pose the decision making problem by TSP by carefully characterizing both the uncertain process of demand for transmission service created by the electricity market participants over time, as well as the effect of transmission line outages. The modeling of the process created by the spot and bilateral demands for transmission is described in dynamic programming formulations and the cases that are defined. And the transmission line outages as a discrete event dynamic system process is described in the case description with reliability related uncertainties. This is what distinguishes the problem formulation in this paper from many other existing references.

The majority of the literature for transmission provision assumes this type of centralization but treats the problem as a deterministic, non-linear static optimization, as does the optimal power flow analysis. (Yu and Ilic 1999) There also have been some ideas which allow the transmission system users to be the main decision makers concerning the grid capacity to be used in response to a technical constraint, (Varaiya and Wu, 1997) or in response to a price signal (Ilic and Liu 1996). This basic decentralization idea will be referred as the bottom-up approach. The increasing research about decentralized control of large information systems like the Internet has provided literature on reaching system stability and optimal control for such complex networks. Defining operational bounds, priority servicing for congestion relief, sub-optimal operating points that lead to long-term stability are the challenges facing the issue of large networks. Motivated by this, the bottom up approach, the problem of transmission provision is posed as a decentralized decision making problem under uncertainty. The uncertainties influencing the technical constraints and thus the related prices for using the grid will be signaled to the users by the TSP to assure stable operation.

It is asserted that a centralized control by the transmission operation is likely to lead to reliable and stable system operation at the cost of a very intensive dynamic optimization. The second method of decentralized control ranks lower in performance as it raises questions about possibility of system instability. However, it promises a low complexity problem, ease of use and decision making which will make open access a reality. This introductory work aims to provide background for bringing these two solutions together.

The long-term objective is to analyze these two different approaches and establish conditions where the two may give a similar solution. These conditions are important for the following reasons. The first approach is a computationally complex method where the system is analyzed with its dynamic behavior and uncertainties. It leads to an optimal solution depending on the objective function, maximum social welfare or revenue maximization. However, the dynamic programming poses many computational hardships that get even more burdensome with the addition of system uncertainties such as equipment and line outages. However, the second approach is much simpler where each user does an internal optimization. The complexity of the system is done away with except for the partial complexity faced by the TSP to provide the price signals. Even though this method is much more simpler and extendable, there is a chance that it may lead the system to instability if the coordination is not accomplished. That is why, the goal is to define conditions that will allow us use simpler methods, such as the second approach, but reach same level of optimization and operational reliability as robust solutions like the first approach. It is often agreed that the two approaches result in the same decision, which is true only at equilibrium. Reliability-related risk management is qualitatively different in these two methods, as well as the impact of this risk management on individual players. The structures have different implications on how will be the risk manager and will need to absorb the damages from a hazardous situation. In the top-down approach, it is relatively straightforward to assign the transmission provider as the reliability gatekeeper and this way it can charge for this service and plan accordingly. But this becomes a challenge in the decentralized setup where the end users will not necessarily be aware of reliability issues facing the grid. While the price signals should include such information for planning ahead, will that be enough to recover operation once system fails in a decentralized system? This deviation from equilibrium conditions is very crucial to handle. (It should also be noted that the concept of reliability in the deregulated industry is different that the conservative tools used before since now the TSP has incentive to optimally use its lines' capacity and extract the highest level of utility.)

In both approaches, top-down and bottom-up, TSP needs to model its system accurately to insure system reliability and incorporate risk from its system. In the centralized scheme, as the decision maker TSP has to know the uncertainties inherent to the system like equipment outages in order to make long-term decisions. Similarly, in the partially decentralized set-up TSP is responsible for sending the right price signals, which have the incorporated information about the system conditions. Uncertainties inherent in the grid are numerous, but this paper will focus on line outages as a subset of equipment uncertainties. Methods developed in this issue can be extended to substation, generation outages and their likes. We consider the line outage problem to be the most complex because the effect of any outage event depends on the system topology, ie., how well the system can absorb and cover up for that problem.

1.1 Market Setup

The optimization suggested under both schemes will be described in a market setup in which the TSP offer long-term bilateral contracts at a premium to enable the load and the supply to hedge against the volatility of the spot prices. (Yoon and Ilic 2001) Two types of transactions will be available to the market players: (For simplicity, only three players will be analyzed, the supply, the load and the TSP. The roles of the marketer and secondary markets are excluded for this analysis.)

1.Long Term Bilateral Contracts: These will be contracts between a supply-load pair that will designate the obligation of supply to produce a certain amount of power at a negotiated price for a defined time period in the future. The failure to provide this service will incur a penalty. For this study, the agreements can be established only between nodes that are physical connected with a single line, and agreements between three or more parties are not permitted.

2.Real Time Spot Market: This is the traditional regulated spot market where demand meets supply and market clears at a spot price determine by demand and supply curves. The price depends on the cost functions as well as demand elasticity functions of the loads. Therefore, the nature of the price is probabilistic with a variance.

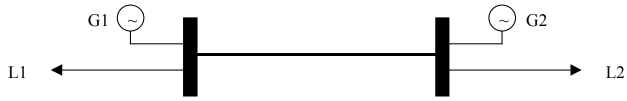
The three players in the market can choose which type of transactions they would like to participate in, the deterministic risk-free bilateral agreements at a premium or the risky spot market at a clearing price. The supply and the load are likely to operate in both of these spaces. In other words, the generators will produce for both the spot market and the agreements and the loads will buy their electricity through both types of setups. They will do this in a fashion to maximize their individual welfare functions. The TSP will also make decisions to determine whether to allocate its resources, line capacity, to bilateral agreement requests or the spot market again to maximize its revenues. TSP's accept or reject decision will be the determining factor in the first approach and the price signals will be its input for such decisions in the second approach.

1.2 Time Frames

The decisions can be classified into two, season-ahead and near real-time. Season ahead decisions describe the decisions made by the players to participate in bilateral agreements within the season coming up, and how much they would like to allocate for spot market transactions. Near real-time decisions are modifications made to long-term decisions as more current information becomes available. With more information, load and supply may decide to call off a bilateral agreement or establish one, similarly the TSP can decide to curtail an agreement it had accepted before or respond near real-time to near real-time decisions made by the other players. This duality is a result of the volatility of the spot market and certain correlations the players may believe in. For example, if a load believes that spot prices will be high in the next time frame, it may choose to strike a bilateral agreement and the supply side might find this acceptable, as it will itself hedge against the risk of elastic load. In another setting, the TSP can decide to curtail a bilateral agreement with the expectation of making higher profits in the spot market even after paying a penalty.

1.3 2-Bus Example

The concepts introduced above will be formalized in a 2-Bus example to enable the initial problem formulation to be simple and tractable. The generating units are G1 and G2 with generation cost functions $C_1(Q_{G1})$ and $C_2(Q_{G2})$, the loads are L1 and L2. The two buses are connected with a single line of capacity K operated by TSP. This section will pose the season ahead decision-making problem where the season will be analyzed at discrete



time periods. The arrival of bilateral requests and the ending times for implemented requests can only happen

Figure 1: Sample Two Bus System

at these discrete time periods. Similarly, the continuously changing spot market will be sampled at discrete times.

2. TOP-DOWN APPROACH: TSP IS AT THE CENTER

This scheme is a natural extension to the role of the TSP as the market maker under the regulated market setup. The only thing added is the operation of bilateral agreements that will allow the TSP to collect a profit other than market based transmission price. Bilateral and spot markets both influence the quantity of power transmitted on the lines, which have a certain carrying capacity. Higher the congestion on one line, the higher the price due to high demand. Even though, it may seem that the TSP would like to use as much of its lines as possible thus accept any incoming bilateral and spot market request that is not the case. Bilateral agreements that are accepted in one period of time, e.g. a day, might impact the line congestion levels of the next. While maximizing revenue for one period, they may decrease it for the next compared to the case where the agreement had not been accepted. Or an agreement may take up capacity that would be more profitable to sell later to another party.

After the supply and demand units make their own allocation decisions, among them they can find the matching price and quantities that will determine the properties of the bilateral agreements they would like to get involved in, if any. Note that the optimization problem solved by the end users here is not very complicated since they trust the TSP to make sure the system reliability levels are met. After these decisions, the parties must submit their requests to the TSP who will actually see that the service is delivered. Should the TSP find it more profitable and safe to curtail the bilateral agreement he may choose to do so at any point in time? Cancellations at the beginning of the season will not incur a cost to the TSP but curtailment in real time will be a penalty. Note that in this case, the flow distribution will be much different than that was used by the end users to calculate their initial willingness to take part in bilateral agreements season-ahead.

The goal is to a build a tool and a framework where the system revenue is maximized, season-ahead, by the TSP who chooses the optimal combination of the incoming bilateral agreements, implements them in addition to the spot market in consideration of limited transmission resources. Using dynamic programming tools, this near real time resource allocation problem can be solved effectively.

2.1 Top-Down: Dynamic Programming Formulation

The proposed dynamic programming (DP) modeling calls for some design considerations that will allow the model to be computationally feasible. The design considerations and assumptions will be listed; however, the motivation will become clearer as the dynamic programming algorithm for finite horizon unit allocation is introduced:

1) Using the information from the generation and supply sides, the TSP can determine its own estimates of what part of a unit is participating in the bilateral market and what part in the spot market. It can then use these estimates as a way to create the following setup for ease of computation. TSP then can treat a single generation unit as two, one that only operated in the bilateral market and one that operates in the spot market. These two can be kept separate until the TSP decides to curtail a bilateral agreement at which point it would have to account for that in the spot market. So the new setup looks like:

a.The generators that will only inject power for a bilateral agreement (P_{B1} and P_{B2}) and loads (L_{B1} and L_{B2}) that will only take place in a bilateral agreement. These generators and loads and their associated parameters are not included in the spot market considerations. In other words, the value of load for each bus under the spot market value will not include the power supplied by the bilateral agreement. We assume the generator always has enough power for the agreement.

b.Spot market where Bus1 and Bus2 will be associated with some aggregate load and generation bid curves that are dispatched only in the real time market. (Generators P_{S1} and P_{S2} and loads L_{S1} and L_{S2}.)

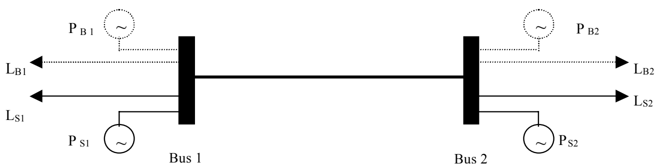


Figure 2: Modified Two-Bus Setup for calculations.

2) In a system, node pairs that are connected by a single line will be eligible to being pairs that can implement a bilateral agreement. So the number of lines will indicate how many agreements can be made. The actual possible number of agreements is twice the number of lines since the lines are bi-directional. So in our system of 2 buses, we can have 2 bilateral agreements: inject from P_{B1} to L_{B2} or from P_{B2} to load L_{B1} . (A worst-case scenario is when all buses are connected.)

3) Although the number of pairs of buses is fixed in a system, if multiple agreements can be established between the same pair and the same direction, then the number of cases that will have to be analyzed in order to find the optimal solution will be very big and will grow exponentially due to the combinatorial characteristics. In addition, building a tool which can handle variable number of cases is even harder, therefore, a simplifying assumption is made: At any time, between a pair, in one direction, only one agreement can be implemented or can be operating. In other words, if there is a bilateral agreement in place from bus1 to bus2, no new ones can be made. If there are no agreements, then one will be accepted given it leads to optimal resource allocation. A second issues arises here. What if multiple requests for the same pair and same direction come at once? This also would lead to variability and indefinite computation size in the system. Therefore, this is avoided by limiting the number of incoming requests per time, per node-pair per direction to one request. As the tool is made more efficient and rigorous, this can be relaxed.

4) While running the model initially on the TSP side we assume the following inputs and characteristics:

Bilateral Requests: each request with the necessary data about quantity its requesting, price of implementation and time duration. This information for all incoming requests through out the season will be available to the operator at time 0, ex ante. For the spot market, this following formulation will assume the use of deterministic data, and the subsection will discuss the use of probabilistic load and supply curves.

5) Since we are using deterministic inputs for the optimal power flow analysis, the resulting values will be static without any correlation between daily prices. This is again a simplifying assumption, where we treat each day as independent.

6) The following formulation will omit the uncertainties in the physical system, but the subsection will consider physical reliability concepts as well.

The whole time of simulation can be thought of a season and the each time increment can be a day. Each day is associated with a state X_k. The state carries information about the bilateral agreements that have been implemented prior to day k but are those that are going on. And this information is available for each possible bilateral agreement pair. In other words, in our 2-bus system the state can be defined as X_k = [State 1-2 ; State 2-1]. Each state will tell us the quantity of power that the agreement uses, the price it pays for the whole power and how many more time periods it will continue for. This information about the current state will describe the admissible control space. As we mentioned before, between any pair and direction of there is an implemented bilateral agreement, we cannot execute a new one. So unless a state i-j is not [0 0 0] we cannot accept another agreement. These control parameters will be used to choose from the incoming agreement request W.

The performance to be maximized is the revenue collected by the system, This revenue will have two flows. One is from the execution of the agreements, and this is simply stated in the state description. The second part comes from the spot market at that time period. The need to couple these two elements comes from the fact that the transmission capacity used up by the bilateral agreements has an influence on the spot prices and therefore the revenue. So an optimal power flow calculation is done using the new line capacity altered by the bilateral agreement, deterministic generation bids of the generators only involved in spot market and deterministic system load which does not include any bilateral components.

The seasonal revenue is maximized over the decision space U, where the first line in the expression defines the revenue collected from the agreements that are accepted at time = k. The second line defines the revenue collected from agreements already being implemented and last line defines the revenue collected from the spot market as a product of nodal price differences between the injection and the withdrawal bus and the quantity carried between them:

$$R^{season} = \sum_k \left(R^{BA}[k] + R^S[k] \right)$$

$$\max_U R^{season} = \sum_k \left[\begin{array}{l} \sum_{ij} u_{ij}[k] P_{ij}^W[k] Q_{ij}^W[k] + \\ \sum_{ij} P_{ij}^X[k] Q_{ij}^X[k] + \\ \sum_{ij} \left(P_i^S[k] - P_j^S[k] \right) Q_{ij}^S \end{array} \right]$$

Once the dynamic programming tree is completed, the backward walk down the tree determines the maximum accumulated revenue. The branch that results in this outcome is the decision made for the coming season.

2.2 Top-Down: Detailed Formulation

This section first presents the detailed formulation of dynamic programming approach under the deterministic setup. The following sections relax the assumptions about the nature of the inputs and points out the computational problems that are faced in their application.

Deterministic Case

The following formulation defines the skeleton of the optimization function ignoring the stochastic nature of our problem. Please note that in this section, market related uncertainties, the changing load, the changing supply bids and the stochastic arrival of bilateral requests are not considered.

State description at time k of the bilateral agreements that are being implemented is the matrix X_k defining all possible agreements in the system, ie. *ij* would be the agreement with injection at *i* and withdrawal at *j*. Each agreement described by the quantity and price of agreement as well as time periods remaining at time k. Similarly, the matrix W_k will define the incoming bilateral requests at time k having the same form as X_k.

Given $X_{ij,k} = \lfloor Q_{ij,k} P_{ij,k} tr_{ij,k} \rfloor$,

the state evolution function *f* is defined as

$$f_k(X_k, u_k, W_k) = T(X_k) + T(u_k * W_k) = X_{k+1}$$

where

$$T(X_k) = \left\{ \begin{array}{l} tr_{ij} \le 1 \rightarrow Q_{ij,k} = P_{ij,k} = tr_{ij,k} = 0 \\ tr_{ij,k} > 1 \rightarrow tr_{ij,k+1} = tr_{ij,k} - 1 \end{array} \right\}.$$

The single time period revenue calculation is

$$g_k(X_k, u_k, W_k) = \left\{ \begin{array}{l} \sum_{ij} u_{ij,k} P_{ij,k}^W Q_{ij,k}^W + \sum_{ij} P_{ij,k}^X Q_{ij,k}^X + \\ + \sum_{ij} \left(P_{i.k}^S - P_{j.k}^S \right) Q_{ij,k}^S \end{array} \right\}$$

.

Putting these terms together, the complete dynamic programming objective function is derived.

$$J_N(X_N) = g_N(X_N)$$

$$J_k(X_k) = \max_{u_k} E\{ g_k(X_k, u_k, W_k) + J_{k+1}(f_k(X_k, u_k, W_k)) \}$$

(Formulation format can be studied in Bertsekas 1995.)

While this formulation does not include any probabilistic calculations, even with a deterministic setup, we experience computational complexity. The size of the dynamic programming tree grows exponentially with the number of nodes in a system and linearly with the number of time periods, it is computed at. Each revenue calculation requires optimal power flow analysis which involves iterations of a non-linear optimization problem. Solutions such as ordinal optimization, approximate dynamic programming and perturbation analysis are being considered as a remedy.

DP With Market Related Uncertainties:

Three market inputs go into the DP formulation. One set is the bilateral agreement information which has been taken as ex ante deterministic in the previous formulation, but relaxing this assumption will lead to developing a tool that can help the TSP make decisions ahead of time about possible incoming bilateral agreements, and as they get realized, then the TSP accepts or rejects depending on the solution it got from the DP. This would fit with the definition of stochastic dynamic programming where the disturbance W, the incoming requests, would be modeled stochastically. However, please note that the arrival process of the bilateral agreement cannot be simplified to a known process but should rather be derived from historical data. (?) The second set is composed of the other two inputs, the spot market load curve and the supply bids. In the above formulation, these two inputs have been taken as deterministic, well-anticipated. However, using probabilistic distributions for these inputs would emulate the real decision making better. Again, with the incorporation of probabilistic behavior, we suffer from computational complexity where these distributions will make the spot market formulation harder. A probabilistic spot market behavior, will translate into a distribution of revenue related to each decision branch, which makes the decision making harder.

DP With Reliability Related Uncertainties

The formulation presented in the above section does not include uncertainties about the operation and the availability of the physical system. As stated in the introduction, this paper will consider line outages to be the only form of equipment outages causing reliability issues. These outages are low probability events with high impact on the operation of the system deviating it from normal conditions. Even if the isolation of nodes might not be an issue, the transmission provider suffers from congestion when one of his lines fail as he had to serve that node still. This may increase congestion on certain lines driving the demand and thus the service price high. Worse case would be when the line reaches its transmission limit and the nodes are not delivered the power they need. This has severe implications on the reliability of the system. That is why, it is crucial for the TSP to model these events, plan and commit accordingly. Figure 3 shows a timeline for seasonal operation and shows the arrival of a line outage which disturbs the planned system operation.

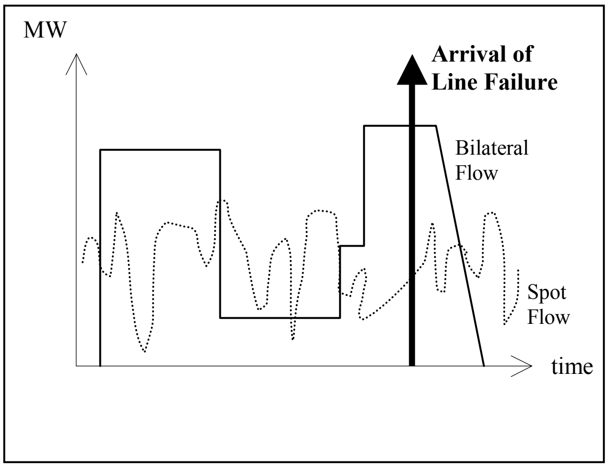


Figure 3: Description of Possible Events

The simplest case will be considered: All line failures are independent with known failure rates, such that each line operation can be modeled as a Markov chain with two discrete states and transition rates shown in Figure 4. From here, it can be seen that the steady state probability of being in the operating state is $\mu_n/(\mu_n+\lambda_n)$ and the probability of being in the non-operating state is $\lambda_n/(\mu_n+\lambda_n)$. Since it was assumed that all lines are independent, these values can be used to determine the probability of having any combination of lines out at the same time. These combinations will be referred as topologies.

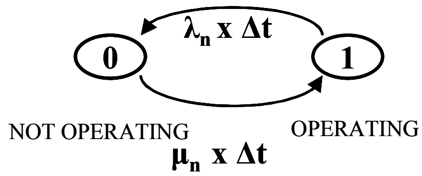


Figure 4: Markov Chain modeling of a single line status.

If the set of alert states are defined for a system, the associated probability of each topology in the set can be calculated. Since each topology will yield a different transmission system and different optimal operating conditions, the TSP will need to consider all these cases while making decisions. But, there is a flip side to using this valuable information. Each of these cases will have low probabilities. And in cases where the TSP may be operating a high number of lines, the number of topologies making up the alert set can be a in the tens of thousands. This is a lot of cases to consider to make decisions for the TSP. Solutions like ordinal optimization are looked into to ease the burden of calculation. Incorporating this information into the DP formulation poses significant computational problems leading to an exponentially increased number of calculations. Considering this approach unfeasible, but also recognizing the need to incorporate system risk into the financial planning, conservative (N-1) reliability criterion seems more useful.

There is also work done around a time scale simulation of the status of the lines in a transmission system. The idea was developed based in relation to the Markov Chain modeling of the system. Further assumptions can yield an effective simulation mechanism. (Note that this work is still in progress and is just an assertion by the first author.) Assumptions: If the current state of the lines are known, their state in terms of operation, and if it is assumed that memoryless property holds, ie. if Δt between observation points are small compared to the rate of transitions between states then it can be said that only one event happens in Δt, and non-overlapping time

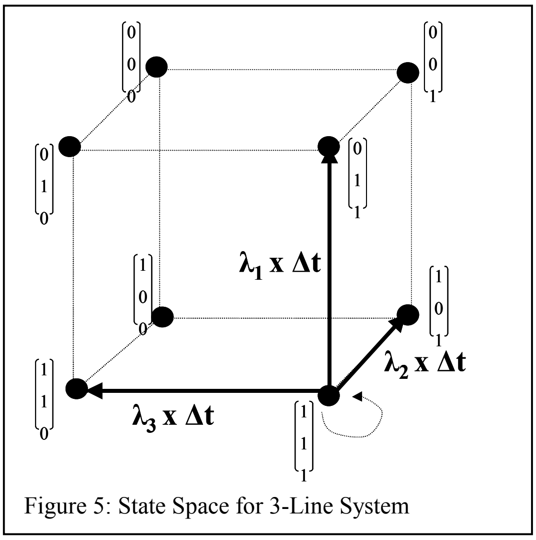


Figure 5: State Space for 3-Line System

periods are independent; then instead of considering all possible states defined under the alert condition, a simplification can be made as follows: For each time period in the DP calculation, these assumptions will limit the number of states to be considered to the immediate neighbors of the current state, neighbors that are only one event away, see figure 5 for a 3-line system. This does away with the exponential problem at hand and replaces it with a linear problem. If this solution proves to be effective, it immensely eases the reliability calculations needed to be carried out by the TSP to evaluate system-wide risk.

2.3 Top-Down: Near Real Time Feedback

In the top-down approach, the TSP can alter its decision near real time by correcting its revenue predictions with feedback from real operations. Expectation by the TSP of the demand, supply and prices of the spot market can change with what he observed in real time. In order to maximize its earnings, he can then choose to curtail a bilateral agreement paying a penalty but earning more operating in the spot market.

3. BOTTOM-UP APPROACH: SMART END-USER

3.1 Formulation

Bottom-Up approach is the complement of the top-down approach, which had put the intelligence in a central controller, the TSP. In this scheme, the intelligence of the network is shared among the end users all of which are expected to make optimal decisions for their utility function in a decentralized manner, but the main challenge is the transfer limits on the transmission system. In a decentralized manner, each party can make sure about injecting its generation or withdrawing its needed power though agreements and contracts. But who will make sure that all these decisions will adhere to the transmission limits? We believe with the right kind of market signaling, this can be achieved. Please note that most technical issues such as transmission losses and frequency, voltage regulation under decentralized control is not studied in this paper.

The Generators: As mentioned above in the top-down approach in order to maximize profits and decrease volatility, the generating units will project season ahead how much of their capacity they would like to allocate to which type of agreement at what price. Let $\beta_{ij}[k]$ be the fraction of production, $Q_{Gi}[k]$, at bus i at time=k that will be sold in the spot market to node j if denoted by S, or the bilateral market if denoted by BA. Let P^S_i [k] be the spot market price at bus I and let P^{BA}_{ij} [k] be the bilateral agreement price for the injection from supply at bus i to load at bus j including the premium charge. So the objective function will be to maximize over the whole season, the expected revenue collected by G1 with an estimate for transmission cost:

$$\max E\left\{\sum_k \begin{bmatrix} \beta^{BA}_{1,1}[k]\cdot Q_{G1}[k]\cdot P^{BA}_{1,1}[k]+\beta^{S}_{1,1}[k]\cdot Q_{G1}[k]\cdot P^{S}_{1}[k]+ \\ \beta^{BA}_{1,2}[k]\cdot Q_{G1}[k]\cdot P^{BA}_{1,2}[k]+\beta^{S}_{1,2}[k]\cdot Q_{G1}[k]\cdot P^{S}_{2}[k]+ \\ -C_1(Q_{G1}[k]) - Tran\hat{s}Cost[k,Q,\beta] \end{bmatrix}\right\}$$

subject to $Q_{G1}[k] < Q^{max}_1$ and $\beta^{BA}_{1,1}[k] + \beta^{BA}_{1,2}[k] + \beta^{S}_{1,1}[k] + \beta^{S}_{1,2}[k] = 1$.

Each generator will run this optimization problem and get β values for all time periods. The inputs that the generator needs is the cost function of its own production, which it knows, the estimate of the demand and the rest of the supplies in the system to determine the spot market prices. One crucial information is about the loading factors in the transmission network for the generator to accurately calculate its costs incurred by using the grid. For each time period, the optimization function will be run with separate set of inputs that will eventually determine the optimal allocation by the generators.

The Loads: The scenario is similar for each individual load, they have their optimization functions as well. They would like to maximize their utility, which will be defined as minimizing cost for a desired level of service. In the case of the load, the elasticity of demand is excluded from the below expression but can be added. Also in both the generator and load optimization functions the risk adversity of the entities are ignored which will be explored later. The optimization function for a single load: Let $\alpha_{ij}[k]$ be the fraction of demand analogous to the β used for the generation case:

$$\min E\left\{\sum_k \begin{bmatrix} \alpha^{BA}_{1,1}[k]\cdot Q_{L1}[k]\cdot P^{BA}_{1,1}[k]+\alpha^{S}_{1,1}[k]\cdot Q_{L1}[k]\cdot P^{S}_{1}[k]+ \\ \alpha^{BA}_{1,2}[k]\cdot Q_{L1}[k]\cdot P^{BA}_{1,2}[k]+\alpha^{S}_{1,2}[k]\cdot Q_{L1}[k]\cdot P^{S}_{2}[k]+ \\ -Tran\hat{s}Cost[k,Q,\alpha] \end{bmatrix}\right\}$$

where $\alpha^{BA}_{1,1}[k] + \alpha^{BA}_{1,2}[k] + \alpha^{S}_{1,1}[k] + \alpha^{S}_{1,2}[k] = 1$.

From the requirements of demand equaling supply, more constraints can be written as well as matching the desires to participate in bilateral agreements assuming that there is only one load and generator at each bus. Once the end users determine their optimal operation factors, they can then go and look for units to engage in bilateral contracts. Each unit will run iterations of its optimization function with different bids and requests from the other parties. Extra trades can be added to balance flows and engage third parties.

The challenge of the decentralized approach is the formation of price signals that will keep the system stable. Ensuring real-time simultaneous feasibility in the presence of uncertainties involving the physical system becomes the main problem.

3.2 Bottom-Up: Near Real Time Feedback

Similar to the top-down real time feedback, in the decentralized scheme, the end users can feedback recent market data in order to change their predictions and therefore decisions for the operations in the future. In order to give the right incentives and not let the market balance get lost, penalty methods should be used.

3.3 Priority Pricing

Priority pricing method approaches decentralization from a different perspective where the smart end users define the maximum price they would pay for the service, which will automatically rank their preference for reliable service with respect to the other users. Here the risk around reliability related uncertainties would be decentralized as well. This is a very new idea that lies between the centralized and partially decentralized model and needs to be elaborated more.

4. CONCLUSION

We have identified two different approaches to Transmission Service Provision in the restructuring market. One is a centralized approach where the decision making depends on a complex optimization under stochastic inputs. The other one bypasses the intelligence in the center provided by TSP and puts the decision making on the end users. The information the end users need are obtained from the TSP. TSP faces a major challenge under both schemes to anticipate system reliability levels and in the decentralized scheme translate it into price signals. Much work is needed under both areas both to develop the theory and introduce feasible tools that will handle the computational complexities. However, the authors strongly believe the need for a more active TSP in the restructured market.

Acknowledgments
The authors would like to thank EPRI for funding the research related to development of probabilistic tools and competitive software for the changing electricity industry. The first author would also like to thank Yong T. Yoon, Petter Skantze and Jose Arce for their time, input and expertise during these discussions that formed the ideas for this work.

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