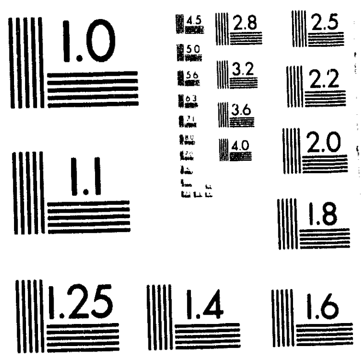
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# MODELING REGIONAL POWER TRANSFERS

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## ABSTRACT

The Spot Market Network (SMN) model was used to estimate spot market transactions and prices between various North American Electric Reliability Council (NERC) regions for summer on-peak situations. A preliminary analysis of new or proposed additions to the transmission network was performed. The effects of alternative exempt wholesale generator (EWG) options on spot market transactions and the transmission system are also studied. This paper presents the SMN regional modeling approach and summarizes simulation results. Although the paper focuses on a regional network representation, a discussion of how the SMN model was used to represent a detailed utility-level network is also presented.

## 1 INTRODUCTION

### 1.1 Background and Motivation

Since the creation of the Public Utility Holding Company Act of 1935 (PUCHA), non-utility generators (NUGs) were effectively prohibited from entering into the electricity generation market. However, the Public Utility Regulatory Policies Act of 1978 (PURPA) allowed cogeneration and small power production technologies based on hydro, wind and biomass to enter the electricity market without being burdened with PUCHA requirements.

While PUCHA primarily focused on electricity generation, the National Energy Policy Act of 1992 (EPAct) further reduced restrictions on electric power supply by creating a new class of wholesale electricity generators, namely, EWGs. Additionally, the EPAct amended the Federal Power Act (FPA) to provide the Federal Energy Regulatory Commission (FERC) with the authority to order transmitting utilities to wheel power produced by EWGs if such wheeling is in the public interest and does not impair the reliability of the transmission system. As a direct result of these legislative policies, NUGs and independent power producers (IPPs), qualified as EWGs, may enter the wholesale electric power market. Because of the increased interest in wheeling alternatives now open to a broader community of IPPs and NUGs, electricity transmission modeling has become an important planning parameter, which essentially determines the feasibility and economic benefit of proposed wheeling, capacity expansion and siting alternatives.



To analyze these alternatives from a transmission perspective, Argonne National Laboratory (ANL) has developed the Spot Market Network model [1] to simulate transactions between regional or individual utility systems. The SMN model is a linear program (LP) that minimizes production costs subject to utility-specific minimum profit margins that trigger spot market transactions. Nodes in the network represent generating resources and load centers. Generating resources are represented as piece-wise linear marginal cost curves while load centers are represented by estimates of hourly electricity demand. Nodes are connected via links that represent transmission lines with capacity limitations and line losses for power flows between nodes. The model also recognizes line rights and includes wheeling, sales-for-resale transactions, and line usage that is reserved for long-term firm (LTF) transactions. Special features for incorporating energy limited and renewable technologies have been incorporated into the model. Adjustments to line capacities in one or both directions are used to compensate for inadvertent power flows.

### 1.2 Spot Market Transactions Overview

Spot market transactions between various regions or utility systems are short-term non-firm agreements that are generally made on an hourly basis. For some systems, spot market transactions comprise a significant portion of the utility's cash flow and significantly influence the operations of generating units. In the case of EWGs, cash flow may be entirely influenced by transmission access and transfer capabilities.

In general, a utility system will sell energy when the spot market price is higher than the utility system's incremental cost of production. On the other hand, a utility system will buy power when it is less expensive to purchase than the cost of producing power from its own resources. Also, there must be sufficient transmission capabilities between the buyer and the seller of power. Line losses for energy transmission must also be considered. These energy exchanges may take place in the form of a wheeling transaction, as a direct sale or purchase, or as a sales-for-resale transaction. The SMN model supports all three energy exchange options.

## 2 SMN MODEL METHODOLOGY

The SMN model estimates spot market activities through the use of a network of nodes and links. Nodes are used to represent generating resources, load centers, and transmission substation points. Generating resources are comprised of piece-wise linear marginal cost curves and load centers are represented by electricity consumption or energy "sinks." Nodes are connected via links that represent transmission limitations, line ownership, and losses. Each node type and link has a set of constraints that are used to describe the physical aspects of an interconnected energy system. The following subsections describe the general characteristics of each node type and the characteristics of a link. Some key SMN model features include:

- Physical transfer limits on transmission lines and within network nodes,
- Line specific transmission loss factors,
- Multiple transmission routes between interconnected systems,
- Line rights and wheeling charges for transmission line usage,
- Generating resources and transmission line usage earmarked for long-term firm (LTF) power commitments,
- Sales-for-resale transactions,
- Minimum "profit" margins,
- Minimum system generation levels, and
- Unit outages.

### 2.1 Variable Supply/Fixed Demand Node Representation

A SMN variable supply/fixed demand node represents electric generating resources with or without an associated fixed local hourly demand. This node type, often called a *supply node*, represents either a single unit or a group of interconnected units (e.g., a utility system) with minimum and maximum generation constraints. Each node contains a marginal cost step function where the function physically represents the additional cost of increasing production by one additional unit (e.g., kWh) of output. The step function can be input directly by the user, or it can be generated by a routine contained within the SMN model. In general, when the generation supply represents one or two units the user enters the curve directly into the SMN model. For a single generating unit or units at the same location with very similar characteristics, marginal production costs are a function of fuel costs, variable O&M costs, and unit heat rate curves. Detailed data are required for each supply node that represents unit-level resources.

When the node represents a utility system or several integrated utility systems (e.g., a power pool or region), the step function is usually constructed by an automated routine that employs the Investigating Cost And Reliability in Utility Systems (ICARUS) model [2]. The limits (i.e., starting and ending steps) and the shape of the marginal cost step function are dependent on the unit-level characteristics of the on-line generators that it represents. These characteristics include maximum operating capacity, a minimum operational level, forced outage rates, variable O&M costs, fuel costs, and heat rate curves. Units that are on-line during a specific time period can be obtained from results produced by the Production And Capacity Expansion (PACE) model [1] developed by ANL. This includes existing, announced, and new units that are projected to be built in order to reliably meet future loads and to replace retired units. Units that have been scheduled for maintenance during a specified week are based on user inputs and a routine contained within ICARUS.

ICARUS is a probabilistic model that implicitly includes the effects of unscheduled outages. Production cost estimates are made for 52 different load levels. A least-squares curve fitting algorithm reduces the number of points in the curve and insures that it is convex upward - a necessary condition for the LP formulation. The maximum number of points used to represent the curve is selected by the user. Slopes between the points represent short-run marginal costs or incremental production costs.

### 2.2 Fixed Supply/Demand Node Representation

SMN fixed supply/demand nodes are used to represent fixed electricity generating resources with fixed local demands. Fixed supply/demand nodes typically represent energy "sinks" or areas of net energy consumption; that is generation is either zero or exceeds local production. In other situations, this node may represent a simple generating resource that operates at a fixed energy output level specified by the user with or without local demand. For example, this node is used to represent run-of-river hydro units or a thermal solar unit where the hourly generation pattern from the unit is determined elsewhere. Most often, this node may be simply referred to as a *demand node* indicating a net local demand. Since the SMN model is typically run on an hourly basis, fixed supply/demand nodes usually require hourly demand data.

### 2.3 Substation Node Representation

A *substation node* is analogous to a substation without generation capabilities or local demand. In an aggregated network model, the substation node may represent an equivalent capability of several underlying substations. The total energy flow entering a substation node must equal the total energy flow exiting the node. The purpose of this node type is to route electricity flow from one or more node input links to one or more output links.

### 2.4 Transmission Representation

Transmission lines in the SMN model are represented as links that connect two nodes. Similarly, a node can be connected to other network nodes with links defining multiple pathways to the node. Individual lines (with an associated line capability) or composite transfer capabilities (CTCs), which consist of groups of power lines serving the same area, can be used when constructing the network. The adjusted transmission line capacity is specified in the SMN model as a maximum net hourly spot market energy transaction (in terms of Megawatts) that can be made between two nodes. Transmission links can connect two similar or two different node types. The model only limits net energy transactions. That is, an energy transaction scheduled in one direction over a line can exceed the line capacity if at the same time there is an energy transaction scheduled in the opposite direction (i.e., back scheduling) that will lower the net flow of energy over the line below its capacity. Only real power flows are considered in the SMN model.

Transmission losses are represented in the SMN model by applying a loss factor to net energy flows over each of the links. The SMN model also recognizes line rights and wheeling charges that are incurred when one utility system uses another system's transmission lines. An individual transmission line that has several utility systems with line rights is represented by the SMN model as several links. The sum of these links equals the total transmission line capacity. Capacities of each individual link are based on the portion of the line that a utility system has rights to use. If a utility system wants to transmit more energy over a line than it has rights to use then energy can be wheeled over another system's link. However, wheeling charges will be incurred.

Limits can also be placed on the amount of power that can be transmitted from one set of links to a second set of links. That is, the aggregate amount of power that flows through a node can be constrained to represent internal utility transmission constraints.

## 3 MODELING GRANULARITY

Although the SMN model was originally designed to analyze economy transactions between utility systems, the model also can be used to perform a detailed analysis of a single utility system. In this mode, each unit or plant is represented by a supply node, and the SMN model provides the capability of estimating unit-level generation for a set of interconnected units. On the other hand, the network representation may have to be configured at a more aggregated level and modeling resolution will be not as granular. An aggregate representation is desirable when only gross transfers between large regions (e.g., power pools or NERC regions) are under investigation, as is the case for the results presented in this paper.

Because there is a strong dependence between data access and modeling resolution, the next two subsections illustrate alternative transmission modeling approaches available so long as necessary data are accessible. The examples are presented to describe how the SMN model has been applied to represent different network descriptions.

### 3.1 Utility Model Formulation

The first application of the SMN model was to support a study conducted among seventeen member utilities of the Western Systems Coordinating Council (WSCC). Various scenarios restricted hydro operations, which had potential impacts on the amounts of seasonal energy and capacity available to load centers in the Western Interconnected region. The SMN model was used to understand what impacts might result for several utilities and wholesale customers by examining the potential effects on network sales and wheeling opportunities under the conditions of the various hydro scenarios.

In order to achieve the modeling goals described above, detailed knowledge of individual utility load curves, load forecasting projections, demand side management programs, generation capabilities, and generation forecasting projections was required. All load data were supplied on an hourly basis to support an hourly spot market transaction analysis. By using a control area representation as the basis of the transmission modeling approach, various utilities were logically grouped around control area centers in the node and link network model. The resulting network representation portrayed major control areas interconnected by various non-simultaneous capacity transfer limits, which are determined by stability, thermal, or reliability limitations. Along with transmission capabilities, specific generation patterns were also provided to further qualify particular transfer patterns and limits.

Because of the important roles associated with control area operations, individual control areas provided a vast knowledge of operational heuristic and operations data needed for proper transmission model development. As a result, transmission modeling at a very detailed level was accomplished by gaining access to control area data and operational expertise. This particular study supported data access at a detailed level through various proprietary agreements in effect between ANL and each cooperating utility. Involved utilities also played a significant role in validating SMN model results, thereby completing the model development design cycle.

### 3.2 Regional Model Formulation

The second alternative network representation considered modeling the entire power system of the United States, Canada, and Mexico at a regional level. Many studies conducted at ANL are centered around serving the needs of various federal agencies and commissions. In a study performed for the U.S. Nuclear Regulatory Commission (NRC) [3], a convenient subregional representation of various U.S. utilities is used to aggregate individual utilities into a NRC subregional representation. This representation consists of twenty-seven areas, which partition the contiguous U.S. As a result, the focus is often on subregional transactions rather than utility-level transactions.

A close examination of publicly available data illustrates necessary data at regional and pool levels. Even though some aspects of unit-level data are publicly available, detailed load data are not typically public domain knowledge. As a result, data limitations tend to restrict model representation at an aggregated level. The privileges of proprietary access to enhanced unit-level and detailed load information by utility is not realistic in this model development effort due to the scope of the study. The same is true of transmission related data.

Argonne is attempting to apply the simulation framework at the NRC subregional level to avoid data overload and to minimize data maintenance efforts. However, obtaining an adequate NRC subregional transmission representation begins with modeling regional transmission characteristics.

The NERC *1993 Summer Assessment* [4] is presently implemented in the SMN model for this study. Obtaining this data was possible by direct request of NERC. Several study years were obtained to support general growth trends and to gain a feel of transmission capability expansion and growth. This representation directly supports region to region transfers. One exception to this view is that SERC is broken down into its four subregions (e.g., VACAR, TVA, Southern, and Florida). The same is true of the NPCC -- NPCC U.S and NPCC Canada are broken into subregions.

In the interest of improving transmission modeling to accommodate the subregional abstraction, ANL has investigated the procurement of various NERC Interregional Reliability Studies (e.g., MAAC-ECAR-NPCC and VACAR-ECAR-MAAC study groups) to grasp lower-level transmission characteristics. Efforts are presently under way at ANL to obtain these studies to achieve a more detailed transmission representation for ANL's subregional network.

## 4 SMN REGIONAL SIMULATIONS

For the purpose of illustrating the SMN model, the authors chose to use the present NERC regional network description. The network description makes use of the First Contingency Incremental Transfer Capabilities (FCITCs) presented in the NERC *1993 Summer Assessment*. Basic generation and load data were taken from the NERC *Electricity Supply and Demand 1993-2002* [5]. Estimates of coincidental hourly loads were determined by applying a diversity factor to seasonal peak load data contained in the NERC report. Supply costs were based on data contained in the *Monthly Cost and Quality of Fuels for Electric Plants* database [6] and typical non-fuel variable O&M costs. Assumptions that apply to the use of information contained in the above data resources, apply to the use of the data in the SMN model.

Because of the interactions that take place between NERC regions it was necessary to simulate the entire contiguous U.S. and interconnections with Canada. A total of 18 supply nodes were used to represent NERC regions and subregions. However, results for only the southeastern portion of the U.S. are presented here, since the main focus of this analysis is on the transmission and production cost implications of alternative generation siting scenarios within the Southeastern Electric Reliability Council (SERC). SERC is one of the nine NERC regions of the continental U.S.

The first scenario analyzed is a base case situation in which no EWGs are present in the network. The base case in Figure 1 shows four numerical values surrounding a particular network supply node name. These numbers represent supply node demands (upper left), generation levels (upper right), spot market prices (lower left), and net sales (lower right). Values representing spot market transactions or energy flows between supply nodes are indicated near adjacent transmission links (in thousands of MWh). Note the large energy flows out of the ECAR

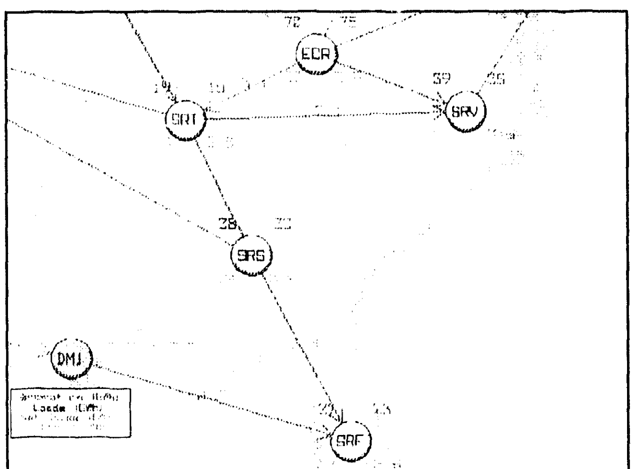


**Figure 1** Energy Flows for the Base Case Scenario.

region (labeled ECR) to surrounding supply nodes; namely SERC TVA (labeled SRT), SERC VACAR (labeled SRV), and MAAC (not shown). This occurs because of the inexpensive costs associated with ECAR electricity production, which is dominated (89%) by base load coal fired units, relative to production costs for neighboring supply regions, which must rely on more expensive oil- and gas-fired units to serve peak loads. Also, note that some of the spot market energy that is received by TVA is transported to VACAR; that is of the 5,223 MWh of energy that TVA receives from surrounding regions, approximately 40% or 2,100 MWh is transported to VACAR. It should be noted that 2,100 MWh is the designated spot market transfer capability between these two supply regions.

Another major flow of energy occurs from the SERC Southern subregion (labeled SRS) to the SERC Florida subregion (labeled SRF). This flow occurs because Southern has a marginal production cost at times of peak load which is significantly less (i.e., roughly 10 to 15 mills/kWh) than SERC Florida. The price difference is expected, because the Florida subregion must rely on its most expensive peaking units to serve peak summer loads. About 58% of Florida's subregional generating mix is comprised of expensive oil- and gas-fired units. If the transmission network would allow greater transfer capabilities, significantly more spot market transactions would occur between most supply nodes shown in Figure 1.

The second scenario that was simulated by the SMN model located several hypothetical EWGs with a combined generating capacity of 500 MW on the eastern seaboard within the VACAR transmission and distribution system. It was assumed that the EWG units burn natural gas and are fully dispatchable. Results of SMN simulations (see Figure 2) for this scenario are identical to the base case scenario except that 500 MWh of generation from EWGs (labeled EWG on Figure 2) serves VACAR loads, and production from VACAR generating resources is reduced by the same amount. A slightly lower production cost of EWGs relative to expensive VACAR peak units and spot market purchases reduced overall production costs in the simulated one hour period in SERC by approximately $1,400. This translates into an incremental savings of 2.8 mills/kWh (i.e., $1,400/500 MWh). Savings could be either higher or lower based on the assumed production costs for EWGs. Although additional generating capacity will lower production costs, additional capital expenditures for constructing EWGs may significantly reduce any savings.

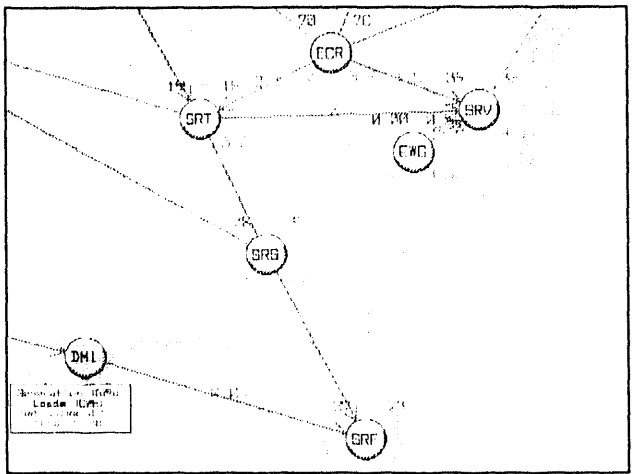


**Figure 2** Energy Flows for the Seaboard EWG Scenario

The third scenario simulated by the SMN is identical to the second scenario except that the EWGs are located in the western portion of VACAR and impact the transmission line between TVA and VACAR. Note in Figure 3 that a substation node labeled ESB was used to connect the EWGs to this transmission line. Under this scenario, EWGs do not generate electricity. This occurs because any energy produced by EWGs would reduce the purchase of energy from TVA. Since the costs for EWG energy production are greater than spot market energy purchases, EWG energy production would, therefore increase overall production costs. Because the EWGs did not generate electricity, production costs for this scenario are identical to the base case.

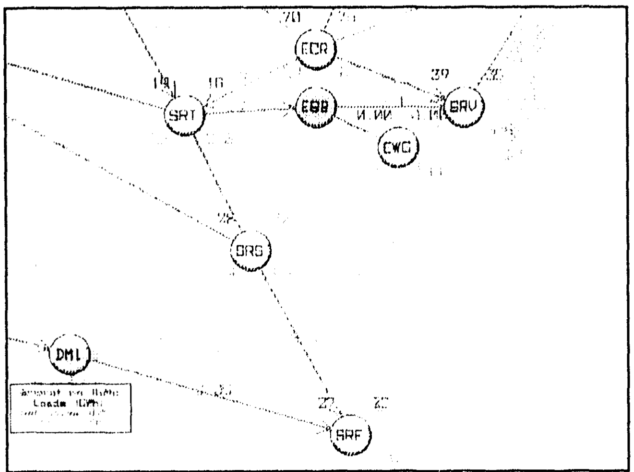


**Figure 3** Energy Flows for the Western EWG Scenario

In order to estimate the effects of non-dispatchable EWGs on overall production costs, it was assumed that the EWGs located in western VACAR operated at a 100% capacity factor for the simulated one hour peak period. As shown on Figure 4, the injection of 500 MWh of energy into the ESB substation node, reduced the amount of energy purchased from TVA. Relative to the previous scenario, purchases are lower by 500 MWh from 2,100 MWh to 1,600 MWh. Because of the assumed 2,100 MWh spot market transaction limit between TVA and VACAR any energy injected into substation node ESB will reduce the spot market transaction capability between these two regions by an identical amount. Costs for the scenario are $3,611 higher than the base case, because marginal energy production costs for EWGs are higher than marginal energy production costs for TVA. As a result, for every kWh that EWGs generate, costs increase by 7.2 mills/kWh.

Under both the third and fourth scenarios, system reliability may not significantly increase above the base case despite the addition of generating resources. This occurs because the transfer capability of the intertie with TVA is decreased. Detailed reliability assessments would need to be performed to confirm this preliminary finding.

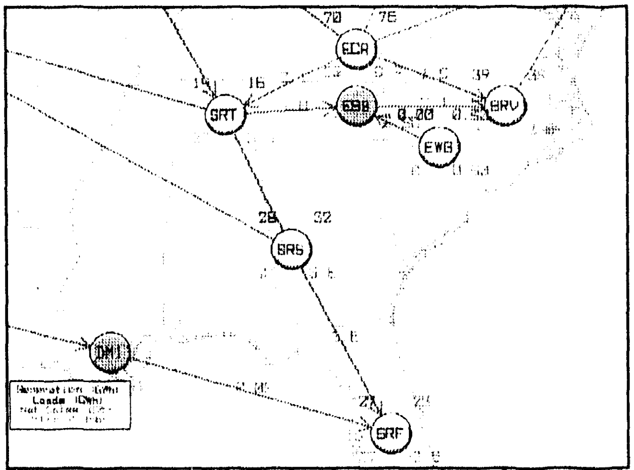

**Figure 4** Energy Flows for the Non-Dispatchable EWG Scenario.

## 5 CONCLUSIONS

The SMN model is designed to represent the transmission network at any appropriate level of abstraction. The results presented in this paper illustrate how gross transfer capabilities may be useful as a first step in evaluating EWG placement without requiring detailed system and network data. Once a general network model is used to identify likely EWG sites, the same network representation can be used as a foundation for a more detailed network representation as new detailed system and network data are added in an incremental fashion. Incremental model development preserves data already entered, while allowing the user to add network detail where appropriate.

This paper described an analysis of various EWG siting situations. As a result of transmission considerations, the siting of EWGs can have a significant impact on production costs. Ideal EWG siting can reduce production costs. On the other hand, poorly sited EWGs that are non-dispatchable can increase production costs and negatively impact the transmission system. Table 1 provides a summary of cost differences (compared with the base case scenario) for the three alternative EWG scenarios analyzed in this study.

The siting of EWGs also can have an impact on system reliability. Additional EWGs can significantly increase system reliability if they do not adversely impact transfer capabilities with other interconnected utilities.

At a time when open transmission access is particularly important, the SMN model offers an approach to begin the analysis of various siting alternatives. However, detailed network and utility data are required to obtain meaningful results. Even so, no model formulation can take the place of direct interactions with surrounding utilities and power pools to finalize siting decisions. The operational expertise and detailed load flow and reliability models available to established utilities are essential for a proper assessment in an interconnected power system.

**Table 1 Change in Production Costs Relative to The Base Case Scenario**

| Scenario | Cost Change ($) |
|---|---|
| Eastern Seaboard EWG | -1,400 |
| Western EWG | 0 |
| Non-Dispatchable EWG | +3,611 |

## 6 ACKNOWLEDGMENTS

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