Probabilistic Transfer Capability Assessment in a Deregulated Environment

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Abstract
A methodology for available (simultaneous) transfer capability (ATC) analysis based on a probabilistic approach is presented. It is postulated that the system is operated by an ISO. The traditional concept of “area” is extended to include a utility, an individual IPP, a large customer, etc. All areas are divided into three groups: (a) study area or area under the ISO control, (b) transfer participating areas, and (c) external areas which have no direct transactions or they have fixed transactions with the study area. A performance index based contingency selection procedure is applied within the study and transfer participating areas to rank those contingencies that will affect simultaneous transfer capability. The contingency ranking order is utilized by a variation of the Wind Chime diagram to select contingencies that are then evaluated by an optimal power flow algorithm. Subsequently, the probability distribution of simultaneous transfer capability is computed based on the electric load, circuit and unit outage Markov models. The 24x3 bus IEEE RTS is utilized to evaluate the proposed method. The performance of the proposed method is also demonstrated on an actual large scale system (2182 bus, 8 area system).

Keywords: Simultaneous transfer capability, transfer interface, contingency ranking, optimal power flow, Wind Chime scheme, expected transfer capability.

1. Introduction

Modern power systems are interconnected to share their resources and assist in emergencies. The major objectives of interconnections are (a) economics and (b) security/reliability. The beneficial economic effects of interconnections as well as their favorable impact on system security/reliability have been long recognized. Recent trends such as competition, non-utility generation, and transmission access resulted in increased power transfers among utilities. In addition, power markets impose new constraints and uncertainties on the available transfer capability. As interchanges and power markets increase, interconnections may be used at their capacity. This reality has brought into focus the practical limitations of interconnections and the associated problem of transfer capability. Transfer capability which refers to the capacity and ability of a transmission network to allow for the reliable movement of electric power from the areas of supply to the areas of need is an issue of concern to both system planners as well as system operators.

In a deregulated environment, the interconnected power system may comprise many areas corresponding to owners/utilities. The operation of the system is entrusted to an Independent System Operator (ISO). The ISO may receive bids for generation in real time. Bids may be accepted as long as the transfer capability of each one of the areas is not exceeded. Therefore it is important that the ISO computes in real time the available transfer capability of all the areas under its jurisdiction. At the same time it is important to evaluate the risk of violating the transfer capability, because of random events, such as random failures of equipment. In other words, it is important to compute the probability that the transfer capability will not exceed the required. Another issue is created by the existence of interruptible loads. In a competitive market it is conceivable to accept a generation bid and at the same time to interrupt load to meet transfer constraints, if such action is economically justified. Recent events have made this scenario plausible. In general, in a deregulated environment, there is increased uncertainty because of: (a) uncertainty in bid acceptance procedures, (b) customer response to prices, (c) control of interruptible loads, and other. This uncertainty must be assessed in real time and the effects of uncertainty must be quantified for the next few hours.

There are many proposed approaches to determining the available transfer capability. Most of the approaches are deterministic. Specifically, they determine the available transfer capability using power distribution factors to project the amount of power that can be transmitted before the capacity of a transmission corridor or line will be exceeded. A semi-probabilistic approach
extends this concept to include a number of contingencies.

This paper presents a flexible and rigorous formulation of the probabilistic transfer capability problem that accounts for operating practices of utilities/areas, the typical variation of the electric load, the new uncertainties under a deregulated environment and the operating practices of an ISO.

2. Model Description

Figure 1 illustrates a general structure of a multi-area interconnected power system, operated by an ISO. Here the concept of an area is used in its general term: an area can be a specific utility, a single IPP, a load center, etc. Consider area S. Tie lines connecting area S with other areas provide the means for power transactions between the area S and outside areas. Real power meters are placed on tie lines. A set of power meters determines the transfer interface over which the transfer is to be evaluated. The purpose of simultaneous transfer capability analysis is to determine the maximum simultaneous power transfer through this interface, i.e. to or from the area S under a certain set of postulated system load and contingency conditions.

Mathematically, the simultaneous transfer capability (STC) problem is represented as an optimization problem that determines the maximum simultaneous power transfer through a transfer interface TI (TI may represent power transfer to or from the area S).

Maximize

\[ STC = \sum_{ij \in TI} P_{ij} \]

Subject to:

Network constraints
Generation real and reactive power constraints
Transmission circuit loading constraints
Bus voltage constraints
Security constraints, and
Committed unilateral power transfers, bid offers, etc.

Where \( P_{ij} \) is the real power flow on the line ij of the transfer interface TI.

The network constraints are formulated in a way as to fit the problem of the transfer capability. Specifically, Figure 2 illustrates some of the innovations for formulating the network constraints. Specifically, the generating unit output of area k is defined with a variable \( z_k \) that represents the total change of generation in area k. The total generation change in the area is allocated to the various units of the area via participation factors \( p_i \) that are computed with a usual economic dispatch procedure within the area. In this way, the need to have a slack bus and all the complications of a slack bus are avoided. It should be also apparent that in the case of a single generating unit (IPP, etc.), the variable \( z \) becomes the output of that single unit.

The variation of the electric load at a bus, \( m \), is assumed to be a linear function of a small number of variables that can vary randomly. Figure 2 illustrates the load at bus m to be a linear function of two random variables, \( v_1 \) and \( v_2 \). In general the vector of bus loads is given by:

\[ P = P^0 + a v_1 + b v_2 + .. \]

(2)

Note that the variables \( v_1, v_2 \), control the loads at all buses of area k. In case that the number of variables is
only one, then we have what is known as conforming load, i.e. the load at the buses varies proportionally to a single variable. Obviously, two or more variable can simulate the randomness of load variation and the correlation that exists in these variations.

In addition, some of the load may be interruptible. This generation and load model is embedded in the network constraints.

The figure also illustrates a number of market variables, \( P_b, u_b, P_w, u_w, \) price, etc. The variables \( P_b, u_b, \) represent an accepted bid for power generation, \( P_b \) is the power delivered and \( u_b \) is a 0 or 1 variable representing the availability of the transaction. The variable \( u_b \) is a random variable with a certain probability of being 1 and the complimentary probability of being 0. Similarly, the variables \( P_w, u_w, \) represent a committed bilateral wheeling transaction.

The control variables in above problem are (1) net real power generation in each area, (2) generation bus voltage magnitudes, (3) transformer phase shift adjustments, (4) switchable capacitor or reactors, (5) accepted bids, (6) committed bilateral transactions, etc. The above formulation represents a complex optimization problem that can be solved by two approaches, i.e. deterministic approach and probabilistic approach. The two approaches are vastly different and the computational requirements of the probabilistic approach are much higher.

Deterministic approach: In this approach a security constrained optimal power flow model is utilized. The results of the OPF can be presented in two different ways: (a) maximum transfer capability through a user selected transfer interface, and (b) sensitivity of the power flow on a user specified transfer interface versus net generation of each area and electric load of each entity (customer groups). Figure 3 illustrates typical results of this computational procedure. The results are useful for determining the ability of the system to transfer load under the present operating conditions. This approach can be also extended to include a number of user selected contingencies.

<table>
<thead>
<tr>
<th>System State: Base Case</th>
<th>Xfer Generation</th>
<th>Load</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Area 1</td>
<td>Area 2</td>
</tr>
<tr>
<td>Interf</td>
<td>0.0012</td>
<td>0.0013</td>
</tr>
<tr>
<td>1</td>
<td>0.0020</td>
<td>0.0015</td>
</tr>
<tr>
<td>…</td>
<td>…</td>
<td>…</td>
</tr>
</tbody>
</table>

**Figure 3. Typical Transfer Capability Sensitivity Results**

**Probabilistic approach:** In this approach the problem is decomposed into three manageable sub-problems: (a) contingency selection, (b) effects analysis (contingency simulation), and (c) probabilistic index computations. The purpose of contingency selection is to select the contingencies that will adversely affect STC. Contingency simulation is performed with an optimal power flow (OPF) which yields the maximum STC for a specific contingency and load. Finally, the probabilistic index computation provides expectation, frequency and duration indices of ATC. Figure 4 illustrates the overall procedure. First, a loading condition is selected. For this loading condition, initially the base case transfer capability is determined by using an optimal power flow model and assuming all circuits and units are available. Subsequently, contingencies are selected which will adversely affect simultaneous transfer capability using a contingency selection model (see section 4). The selected contingencies are simulated with an optimal power flow to determine the simultaneous transfer capability yielding a value of STC for each contingency. The procedure is repeated for all loading conditions. Finally, the results are assembled into a probabilistic distribution function of simultaneous transfer capability. A concise description of the three major modules, contingency selection, contingency simulation, and index computations is provided next.

**Figure 4. Flow Chart of Probabilistic Simultaneous Transfer Capability Analysis**

3. Contingency Selection Model

A comprehensive presentation of contingency selection models can be found in [13]. Here we present a performance index (PI) based method for ranking contingencies in terms of their effects on simultaneous transfer capability. The proposed method is based on four concepts: (1) selection of proper performance indices, (2) component outage models, (3) computation of
Performance index changes, and (4) Wind Chime diagram. These are discussed next.

Performance indices: To effectively select contingencies with adverse effects on STC, two types of performance indices are proposed.

(1) \( J_{tc} \) is defined as the absolute value of the real power export of the study area, expressed with:

\[
J_{tc} = \left| \sum_{j \in TJ} P_{ij} \right| \tag{3}
\]

A negative change in the performance index \( J_{tc} \) due to a contingency indicates an adverse effect on transfer capability.

(2) In this category, two performance indices are proposed: (a) circuit MVA loading performance index, \( J_P \), and (b) bus voltage performance index, \( J_V \). These indices are expressed in equations (4) and (5). More details of these indices can be found in [13].

\[
J_P = \sum_{\ell \in S,P} W_{\ell} \left( \frac{S_{\ell}}{S_{\ell, \text{max}}} \right)^{2n} \tag{4}
\]

where:

- \( S_{\ell} \) is the circuit MVA power flow of circuit \( \ell \)
- \( S_{\ell, \text{max}} \) is the circuit MVA capacity rating
- \( W_{\ell} \) is a weighting factor of circuit \( \ell \)
- \( n \) is a selected integer

\[
J_V = \sum_{i \in S,P} W_i \left( \frac{V_i - V_{i, \text{av}}}{V_{i, \text{st}}} \right)^{2n} \tag{5}
\]

where:

- \( V_i \) is the voltage magnitude at bus \( i \)
- \( V_{i, \text{av}} = \frac{1}{2} (V_{i, \text{max}} + V_{i, \text{min}}) \)
- \( V_{i, \text{st}} = \frac{1}{2} (V_{i, \text{max}} - V_{i, \text{min}}) \)
- \( V_{i, \text{max}} \) is the maximum allowable magnitude at bus \( i \)
- \( V_{i, \text{min}} \) is the minimum allowable magnitude at bus \( i \)
- \( W_i \) is a weighting factor of bus \( i \)

A large positive change in the two performance indices \( J_P \) and \( J_V \) may indicate violation of operating constraints that in turn may cause reduction of simultaneous transfer capability.

Component outage model: The outage model used in the proposed contingency ranking method has been presented in [13]. Specifically, the outage is represented with one control variable, the *outage control variable* \( u_c \) which has the following property:

\[
u_c \begin{cases} 1, & \text{if the component is in operation} \\ 0, & \text{if the component is outaged} \end{cases}
\]

Figures 5(a) and 5(b) illustrate the use of outage control variables to represent circuit and unit outages respectively. Note that the variable \( u_c \) enables a rigorous representation of a contingency. For example, consider the outage of circuit \( ij \). The power flow is expressed in terms of the control variable, \( u_c \):

\[
P_{ij} = \begin{cases} (g_{ij} V_{i}^2 - V_j V_i g_{ij} \cos(\delta_i - \delta_j) + b_{ij} \sin(\delta_i - \delta_j) ) u_c & \text{if the component is in operation} \\ 0 & \text{if the component is outaged} \end{cases}
\]

\[
Q_{ij} = \begin{cases} (b_{ij} V_i V_j - [V_i (g_{ij} \cos(\delta_i - \delta_j) - b_{ij} g_{ij} \sin(\delta_i - \delta_j))] u_c & \text{if the component is in operation} \\ 0 & \text{if the component is outaged} \end{cases}
\]

Similar expressions can be applied to transmission lines, transformers, phase shifters, etc.

![Figure 5. Illustration of Component Outage Modeling with Outage Control variable \( u_c \)
  (a) Circuit Outage, (b) Unit Outage in Area I](image-url)

The outage of a generating unit, \( i \), in area \( I \), will cause the loss of generation, \( P_{gi}^0 \), which is absorbed by other units.
in the same area according to their participation factors, yielding (see Figure 5b):

\[
P_{gi} = u_c \cdot P_{gi} \quad i \in I \quad (7a)
\]
\[
P_{gk} = P_{gk} + (1 - u_c) \cdot P_{ik} \cdot P_{gi} \quad k \in I, k \neq i \quad (7b)
\]

where \( u_c \) is the participation factor for unit \( k \). This outage model can also represent a multi-component outage with only one outage control variable \( u_c \).

Performance index changes: Contingency ranking is now performed by simply computing the derivative of the performance index with respect to \( u_c \):

\[
\frac{dJ}{du} = - \frac{\partial J}{\partial u} - x^T \frac{\partial g}{\partial u}
\]

where: \( J \) is the performance index (\( J_{tc}, J_P, \) or \( J_V \))
\( g \) is the set of power flow equations
\( x \) is the state vector (voltage magnitudes and phase angles)
\( \dot{x} \) is the costate vector.

Since the outage control variable \( u_c \) is normalized, the above derivative expresses the first order change of the performance index due to the contingency. The ranking order is based on the values of the derivative \( dJ/du_c \). More details of the PI approach can be found in [13].

Wind Chime diagram: The Wind Chime diagram is used to select contingencies (single independent outages or multiple (common mode) outages). This method has been extensively used for reliability analysis [18]. However, the Wind Chime diagram used in the simultaneous transfer capability analysis is different from that applied in reliability analysis in two respects. First, in reliability analysis if a contingency is identified causing system problems, then all its combinative contingencies are immediately assumed to cause system problems and detailed simulation of the contingency is not required. However, for the simultaneous transfer capability problem, if a contingency is identified to have adverse effects on STC, then all its combinative contingencies must be evaluated in order to compute the actual STC. This procedure makes the required simulation set very large. Second, for on-line applications, one is concerned with the operation of the system for the next few hours. In this case the probability of contingencies is relatively small and multiple contingencies need not be considered. This reduces the required simulation set. The required simulation set is further reduced using a variation of the Wind Chime scheme: Specifically, first we compute the ATC for the base case and specified loading condition. Subsequently, all contingencies are ranked using the three performance indices. The basic idea here is to adaptively select only those contingencies that have adverse effects on base case STC. All other contingencies are assumed to have the same ATC as the starting base case. This procedure drastically reduces the total number of required simulation cases.

4. ATC Effects Analysis Model

Each contingency is analyzed with an OPF method to determine the available transfer capability over a specified interface. The proposed OPF must have the following properties: (a) provide a solution under any conditions (non-divergent) and (b) efficiency. An OPF with these properties has been developed and described in this section. The non-divergent property of the OPF is achieved with the introduction of the mismatch variables. They are defined as follows. Let vector \( x \) represent system states and let vector \( u \) represent the available controls. Assume a given operating state \( x^0 \) and setting of controls \( u^0 \). Further, consider bus \( k \) as is illustrated in Figure 6. Unless \( x^0 \) and \( u^0 \) represent a power flow solution, there will be a power mismatch at bus \( k \) equal to \( P_{mk}^0 + jQ_{mk}^0 \). Now assume that a fictitious generating unit is placed at bus \( k \) as in Figure 6. Let the output of the fictitious unit at bus \( k \) be \( P_{mk}^0 + jQ_{mk}^0 \). In this case \( x^0 \) and \( u^0 \) represent the present operating condition of the system which includes the fictitious units. The actual operating condition of the system can be obtained by gradually reducing the output of the fictitious generating units to zero while at the same time computing the changes in the system variables \( x \) and \( u \). The solution trajectory maintains feasibility and optimality. Mathematically, this procedure is formulated as an optimization problem with the objective of maximizing the simultaneous transfer capability:

\[
\begin{align*}
\text{Minimize:} & \quad P_{gk} + jQ_{gk} \\
\text{subject to:} & \quad P_{mk} + jQ_{mk} \\
& \quad \text{Electric Load} \\
& \quad \text{Other circuits}
\end{align*}
\]

Figure 6. Illustration of a General Bus \( k \) of an Electric Power System

Minimize:
\[
\mu \sum_k (|\Delta P_{mk}| + |\Delta Q_{mk}|) + \sum_{i \in S, j \notin S} P_{ij} \quad (10a)
\]

or Maximize:
\[
-\mu \sum_k (|\Delta P_{mk}| + |\Delta Q_{mk}|) + \sum_{i \in S, j \notin S} P_{ij} \quad (10b)
\]

Subject to:
\[
\text{(11)}
\]

Power balance equation
Voltage constraints
Circuit flow constraints (MVA, MW or A)
Unit real and reactive power constraints
Other pertinent constraints, and:
\[
\text{(12)}
\]

Constraints (12) are added to guarantee that two successive solutions will be characterized with non-increasing mismatches. Thus, these constraints guarantee non-divergence. The first term of the objective function (10a or 10b) is a penalty function that tend to reduce the fictitious mismatches to zero. The solution is obtained in two steps. In the first step, the objective is to minimize the penalty expressed in terms of the fictitious mismatch variables. If a solution to this problem does not exist, it means that the system cannot support the present loads and generation schedules without violating operating limits. In this case the available transfer capability is zero. If a solution exists, it means that there is some available transfer capability. The second step of the solution determines the available transfer capability for this condition.

5. Probabilistic Description of Simultaneous Transfer Capability

The results of the enumeration approach are in the form of a set of simulated contingencies. For each contingency and load level a value for the simultaneous transfer capability has been computed. These data are combined with the Markov model of electric load, circuits and units to yield a probabilistic description of the simultaneous transfer capability.

Each component (circuit or unit) is modeled with a two state Markov model. Load levels are modeled with a multi-state Markov model. For example, Figure 7 illustrates transitions from one load level to another \((\lambda_{ij})\) and transitions from one contingency to another \((\lambda_{jk})\). More details on the load model can be found in [15]. Utilizing these models, a contingency at certain load level (which is referred to as a Markov state) is characterized with a certain probability and transition rates to other Markov states as it is shown in Figure 7. Utilizing this information the following probabilistic descriptions of STC can be derived:

(a) Cumulative probability distribution of STC,
(b) Expected STC,
(c) Probability of STC being at a selected range (i.e. 1000 MW to 1200 MW),
(d) Frequency and duration of STC being at a selected range.

The computation of above descriptions will be explained with the aid of Figure 7. Specifically, each Markov state in Figure 7 represents a contingency at a certain load level which may have been evaluated or not evaluated. Each evaluated state is described with a certain transfer capability in MW, a certain probability and transition rates to any other state. To each not evaluated contingency, a STC value is assigned equal to the STC value of the parent contingency with the same load level. The not evaluated contingencies are also characterized with a certain probability and transition rates. The cumulative probability distribution is constructed by first constructing a histogram of probability versus STC for all states in Figure 7. Subsequent integration of the histogram provides the cumulative probability distribution, denoted with \(F_{TC}(t)\). By definition:

\[
F_{TC}(t) = \Pr[TC \leq t]
\]

i.e. \(Pr[TC \leq t]\) is the probability that the transfer capability, \(TC\), is less or equal to the value \(t\). The expected transfer capability, \(\overline{TC}\), is computed by evaluating the integral:
\[
\bar{TC} = \int_{t=0}^{\infty} dF_{TC}(t) = \sum_j p_j TC_j \quad (13)
\]

where:
- \(p_j\) is the probability of Markov state \(j\)
- \(TC_j\) is the transfer capability of Markov state \(j\) (for a non-evaluated state \(j\), the transfer capability is assumed to be equal to the base case with the same load level as state \(j\)).

The probability, frequency and duration indices being at a user-selected range are computed as follows. First, all states in Figure 7 that have a STC in the specified range are identified. The process yields a set, \(S_r\), as it is illustrated in Figure 7. The probability \(P_r\), frequency, \(f_r\), and duration, \(T_r\), of STC being at the selected range are given by:

\[
P_r = \sum_{j \in S_r} p_j \quad (14)
\]

\[
f_r = \sum_{j \in S_r} p_j \sum_{k \in S_r} \lambda_{jk} \quad (15)
\]

\[
T_r = \frac{P_r}{f_r} \quad (16)
\]

6. Method Evaluation

This section presents example applications of the method to two test systems. The first test system is the 24x3 bus, three areas system which is proposed as a new IEEE RTS and the second system is a 2182 bus, 8 area system. The first system is illustrated in Figure 8. It consists of three identical IEEE 24 bus RTS [19] interconnected with five tie lines. The data for each RTS can be found in [19]. The overall system consists of 72 buses, 96 generation units and 119 circuits. Area 10 is defined as the study area and areas 20 and 30 are transfer participating areas. The power transfer to the study area is of concern.

The base case STC yielded a maximum net import of 1404.88 MW to the study area 10. The OPF convergence performance to compute the base case STC is listed in Table 1 and the final binding operating constraints are listed in Table 2. From Table 1, we can observe that as the OPF algorithm progressed, the mismatches were gradually reduced, the binding operating constraints were gradually introduced, and the power transfer gradually increased. At the optimal solution, the mismatches were reduced to below the convergence criteria (0.01 p.u.) and the simultaneous power transfer to the study area was limited by the tie line capacity as shown in Table 2.

Typical results of the proposed contingency ranking procedure are shown in Table 3. The table lists the top 15 ranked first level contingencies using \(J_{TC}\) as PI. For comparison, the OPF results are also listed in columns 6, 7, and 8. The table shows that the proposed power transfer performance index, \(J_{TC}\), can effectively select the contingencies that may cause reduction of STC from the base case. Note that the derivative of \(J_{TC}\) provides a rather accurate prediction of the STC reduction. Table 3 also lists the number of OPF iterations to convergence. Note also that, in general, the contingency OPF requires less iterations than the base case OPF.
Table 1. Convergence Performance of the Proposed OPF Model to Compute the Base Case STC

<table>
<thead>
<tr>
<th>Iter No</th>
<th>Total Const. In LP</th>
<th>Maximum P Mismatch (p.u)</th>
<th>Maximum Q Mismatch (p.u)</th>
<th>Transfer Power (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0</td>
<td>5.8657</td>
<td>5.4313</td>
<td>-13.92</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>5.2793</td>
<td>4.8886</td>
<td>132.70</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>4.2265</td>
<td>3.9181</td>
<td>387.95</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>2.9571</td>
<td>2.7392</td>
<td>684.98</td>
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<td>4</td>
<td>1</td>
<td>1.7758</td>
<td>1.6456</td>
<td>964.35</td>
</tr>
<tr>
<td>5</td>
<td>1</td>
<td>0.8905</td>
<td>0.8263</td>
<td>1195.24</td>
</tr>
<tr>
<td>6</td>
<td>2</td>
<td>0.3587</td>
<td>0.3336</td>
<td>1363.98</td>
</tr>
<tr>
<td>7</td>
<td>4</td>
<td>0.1428</td>
<td>0.1337</td>
<td>1456.76</td>
</tr>
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<td>1406.11</td>
</tr>
<tr>
<td>9</td>
<td>7</td>
<td>0.0230</td>
<td>0.0202</td>
<td>1406.44</td>
</tr>
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<td>10</td>
<td>7</td>
<td>0.0100</td>
<td>0.0110</td>
<td>1405.46</td>
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<tr>
<td>11</td>
<td>7</td>
<td>0.0040</td>
<td>0.0064</td>
<td>1404.88</td>
</tr>
</tbody>
</table>

Table 2. Binding Operating Constraints (Base Case OPF)

<table>
<thead>
<tr>
<th>Constr No.</th>
<th>Circuit From Bus</th>
<th>Circuit To Bus</th>
<th>Circuit Rating (MVA)</th>
<th>Circuit Flow (MVA)</th>
<th>Circuit Overload (MVA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>108</td>
<td>203</td>
<td>175.00</td>
<td>175.30</td>
<td>0.30</td>
</tr>
<tr>
<td>2</td>
<td>121</td>
<td>323</td>
<td>500.00</td>
<td>499.81</td>
<td>-0.19</td>
</tr>
<tr>
<td>3</td>
<td>113</td>
<td>215</td>
<td>400.00</td>
<td>400.15</td>
<td>0.15</td>
</tr>
<tr>
<td>4</td>
<td>123</td>
<td>217</td>
<td>400.00</td>
<td>399.94</td>
<td>-0.06</td>
</tr>
<tr>
<td>5</td>
<td>207</td>
<td>208</td>
<td>175.00</td>
<td>175.17</td>
<td>0.17</td>
</tr>
</tbody>
</table>

Table 3. Top 15 Ranked Contingencies Using Jtc as Performance Index

<table>
<thead>
<tr>
<th>Rank Order</th>
<th>Comp Type</th>
<th>From Bus</th>
<th>To Bus</th>
<th>ID</th>
<th>OPF Iter</th>
<th>Computed STC (MW)</th>
<th>Change of STC (MW)</th>
<th>Derivative of Jtc (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>CIR</td>
<td>121</td>
<td>323</td>
<td>1</td>
<td>7</td>
<td>925.74</td>
<td>-479.13</td>
<td>-498.52</td>
</tr>
<tr>
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<td>CIR</td>
<td>123</td>
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Table 4. Top 15 Ranked Contingency Using Jp as Performance Index

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<th>Rank Order</th>
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<th>From Bus</th>
<th>To Bus</th>
<th>ID</th>
<th>OPF Iter</th>
<th>Computed STC (MW)</th>
<th>Change of STC (MW)</th>
<th>Derivative of Jp (MW)</th>
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The load model consisted of three load levels at 100%, 80% and 60% of peak load respectively. Combining the Markov models of circuits, units and load levels and the results of the OPF analysis, the probability distribution of STC for area 10 was computed and illustrated in Figure 9. For all evaluated contingencies, the STC ranged from 204 MW to 1405 MW. The expected STC is 1239.39 MW. The simulation results can be utilized to compute many other quantities of interest. As an example, The probability, frequency and duration of simultaneous transfer capability being greater than or equal to 1200 MW and 1300 MW are computed to be:

\[
\begin{align*}
\text{STC} \geq 1200 \text{ MW} & \quad \text{Probability} \quad 0.89804 \\
\text{STC} \geq 1300 \text{ MW} & \quad \text{Frequency} \quad 5.3515 \text{ yrs}^{-1} \\
\text{Duration} & \quad 0.1678 \text{ yrs} \\
\end{align*}
\]

The proposed method was also tested on an actual large-scale system, a 2182 bus, eight-area system that represents the Southern Company System and its neighbor utilities. The total system peak load is 143535.9 MW. This system consists of 280 generation plants with 570 units. There are 3791 circuits in the system. Among them 358 are transformers. The study system (Southern Company system) consists of 1607 buses and has total summer peak load of 30537.1 MW. For the given data, the peak area export of the Southern Company system was 2751.3 MW and the normal scheduled net area export was 1725.1 MW. The base case STC was computed by the proposed OPF to be 3071.44 MW (exported from the Southern Company system to the other 7 areas). The maximum STC was limited by the generation capacity of the Southern Company system while the tie line capacity was sufficient.
The proposed method was implemented to compute the probabilistic description of STC for this system. A contingency depth of two was used (any combinations of two units or one unit and one circuit outages). The cut-off probability was set to 0.00000001 and the summer peak load level was used (one load level). The cumulative probability distribution of STC was computed and it is illustrated in Figure 10. The probability, frequency and duration of STC being greater than or equal to the normal net export (1725 MW) and peak net export (2751 MW) were computed to be:

\[ \text{STC} \geq 1725 \text{ MW} \]

Probability 0.95422 0.48004

Frequency (yrs\(^{-1}\)) 3.1228 6.8060

Duration (yrs) 0.3055 0.0705

7. Conclusions

This paper presented a formulation of the available transfer capability in a deregulated environment. A rigorous formulation has been presented that determines the ATC through a user specified transfer interface by modeling all pertinent aspects of power system operation under an ISO. A deterministic as well as a probabilistic approach is proposed. The deterministic approach provides the ATC for a specific operating condition of the system. The probabilistic approach is based on a Markov model of system components and provides the expected value of ATC as well as frequency and duration of specific ATC values. The Markov states (contingencies) are selected via multiple performance indices. Selected contingencies are simulated via an optimal power flow that determines the maximum simultaneous transfer capability for a given contingency and load level. Both procedures, contingency selection and OPF are computationally efficient. Results on two nontrivial test systems are given in the paper. The implementation of the proposed method to an actual large-scale power system has demonstrated that the proposed probabilistic simultaneous transfer capability analysis method is practical and suitable for practical systems.

8. References


9. Biographies

A. P. Sakis Meliopoulos (M '76, SM '83, F '93) was born in Katerini, Greece, in 1949. He received the M.E. and E.E. diploma from the National Technical University of Athens, Greece, in 1972; the M.S.E.E. and Ph.D. degrees from the Georgia Institute of Technology in 1974 and 1976, respectively. In 1971, he worked for Western Electric in Atlanta, Georgia. In 1976, he joined the Faculty of Electrical Engineering, Georgia Institute of Technology, where he is presently a professor. He is active in teaching and research in the general areas of modeling, analysis, and control of power systems. He has made significant contributions to power system grounding, harmonics, and reliability assessment of power systems. He is the author of the books, Power Systems Grounding and Transients, Marcel Dekker, June 1988, Lightning and Overvoltage Protection, Section 27, Standard Handbook for Electrical Engineers, McGraw Hill, 1993, and the monograph, Numerical Solution Methods of Algebraic Equations, EPRI monograph series. Dr. Meliopoulos is a member of the Hellenic Society of Professional Engineering and the Sigma Xi.

George Cokkinides (M '85) was born in Athens, Greece, in 1955. He obtained the B.S., M.S., and Ph.D. degrees at the Georgia Institute of Technology in 1978, 1980, and 1985, respectively. From 1983 to 1985, he was a research engineering at the Georgia Tech Research Institute. Since 1985, he has been with the University of South Carolina where he is presently an Associate Professor of Electrical Engineering. His research interests include power system modeling and simulation, power electronics applications, power system harmonics, and measurement instrumentation. Dr. Cokkinides is a member of the IEEE/PES and the Sigma Xi.