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Technical Challenges of Computing Available Transfer Capability (ATC) in Electric Power Systems

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Abstract

A key concept in the restructuring of the electric power industry is the ability to accurately and rapidly quantify the capabilities of the transmission system. Transmission transfer capability is limited by a number of different mechanisms, including thermal, voltage, and stability constraints. This paper discusses the ATC definitions and determination guidelines approved by the North American Electric Reliability Council (NERC) and presents several concepts for dealing with the technical challenges of computation.

1. Introduction

There has been interest in quantifying the transmission transfer capabilities of power systems for many years. When systems were isolated and largely radial, these capabilities were fairly easy to determine and consisted mainly of a combination of thermal ratings and voltage drop limitations. In most cases, these two limitations were easily combined into a single power limitation (either MW, MVA, or SIL). As such, ATC for a given transmission line at a given time could be interpreted as the difference between the power limitation and the existing power flow. NERC has been careful to distinguish the word "capacity" from the word "capability". Capacity is normally a specific device rating (i.e. thermal), whereas capability refers to a limitation which is highly dependent on system conditions. Another interpretation is that capacity refers to the ability of a system to serve native load and engage in transfers while capability is solely the ability to engage in transfers.

As isolated systems became interconnected for economic and reliability reasons, looped networks introduced technical issues with the definition and calculation of ATC. In addition, the differences between contract path and actual power-flow path introduced additional complexity to the quantification of ATC. System stability became an important constraint for some areas of the interconnected network and this required the consideration of a third limiting phenomena. The introduction of St. Clair curves were one of the first attempts to include thermal, voltage, and stability constraints into a single transmission line loading limitation [1]. These results were later verified and extended from a more theoretical basis in [2]. This "single rating" concept is extremely valuable from a computational point of view. Linear load flow and linear programming solutions made transmission transfer capability determination relatively fast and easy [3-7]. They focused on both the "Simultaneous Interchange Capability (SIC)" and the Non-Simultaneous Interchange Capability (NSIC)". Many extensions to this work have appeared including economic dispatch and nonlinear considerations such as VAR limits and transient stability constraints [8-12].

2. 1995 documentation

In May 1995, NERC revised its earlier reference documents on transfer capability to provide additional clarifications and examples [13]. This 1995 document recommends two NERC transfer capability measures: "First Contingency Incremental Transfer Capability (FCITC)" and "First Contingency Total Transfer Capability (FCTTC)". The FCITC was defined to be the amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected transmission systems so that:

(1) From a given system configuration with pre-contingency operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

(2) The given system remains stable following a disturbance that results in the loss of any single element (line, transformer, generating unit, etc.).

(3) The post-contingency system (after operation of any automatic operating systems, but before any post-contingency operator-initiated adjustments) has all facility loadings within emergency ratings and all voltages within emergency limits.

The concept of voltage collapse can be considered to be included either in the voltage limit or the stability limit. The concept of bifurcation can be considered to be included in the stability limit. The time frame for stability is considered to be between milliseconds and several minutes. The FCTTC was defined to be the total amount of electric power (normal base power transfers plus FCITC) that can be transferred between two areas satisfying the above criteria.

The issue of "before any post-contingency operator-initiated adjustments" in (3) above attempts to define the range of contingency cases and specific scenarios which must be considered. Unfortunately, this does not specifically address the many "operator guidelines" which can potentially change the necessary contingency scenario and case outcome.

The terminologies of "Simultaneous Interchange Capability (SIC)" and "Non-Simultaneous Interchange Capability (NSIC)" originally referred primarily to the ability of an area to import from more than one other area. If this import capability was from only one other area, it was the NSIC for that area. If the import capability was from two or more areas simultaneously, it was the SIC for those areas. Today the term "Simultaneous" refers primarily to the notion of more than one transaction and "Non-simultaneous" refers to a single transaction.

3. 1996 documentation

The movement towards open-access transmission and associated recent rulings of the Federal Energy Regulatory Commission (FERC) have added considerable emphasis to the interest in quantifying electric power system transmission capabilities. This interest has led to new definitions and recommended methods of determination by NERC [14]. Through this document, virtually all players in the U.S. interconnected electric power system agree on the six ATC principles which are paraphrased as follows.

ATC calculations must:

(1) give a reasonable and dependable indication of transfer capabilities.
(2) recognize time-variant conditions, simultaneous transfers, and parallel flows.
(3) recognize the dependence on points of injection/extraction.
(4) reflect regional coordination to include the interconnected network.
(5) conform to NERC and other organizational system reliability criteria and guides.
(6) accommodate reasonable uncertainties in system conditions and provide flexibility.

This 1996 document introduces several new terms which refine the concepts of the 1995 documents and specifically identify quantities associated with uncertainty in modeling and system conditions. The "Total Transfer Capability (TTC)" is essentially the same as the FCTTC discussed above with the following clarification. If the maximum transfer capability of the pre-contingency system using normal limits is less than that of all first-contingency cases considering emergency limits, the TTC is the more restrictive number. If an area considers multiple contingencies to ensure reliability, and these transfer capabilities are more restrictive, then the TTC is this more restrictive number. As such, the word "Contingency" does not explicitly appear in the new term. The "Transmission Reliability Margin (TRM)" is the amount of transmission capability necessary to ensure that the interconnected network is secure under a reasonable range of uncertainties in system conditions. The "Capacity Benefit Margin (CBM)" is the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. With these two terms added, "Available Transfer Capability (ATC)" is equal to:

$$ATC = TTC - TRM - ETC - CBM$$

where ETC is the sum of "Existing Transmission Commitments (which includes retail customers)". This ETC term essentially includes all normal (pre-transfer) transmission flows included in the given case. The ETC and CBM quantities can be further described in terms of their contractual firmness using terminology such as "Recallable", "Non-recallable" (or "Firm" and "Non-Firm"), "Scheduled", and "Reserved" transfers. The contractual nature of the transaction could influence the level of assurance needed to ensure a transfer can take place. This means that more contingencies may be studied for the more firm transactions. Since the full impact of these terms on the computational burden of ATC calculations is not clear at this time, they are not discussed further. Instead, this paper focuses on the TTC and TRM calculations.

4. Dealing with the technical challenges

A possible scenario for the computation of TTC proceeds as follows:

a. Definition of a base case. This may be a current or forecasted condition, existing or planned configuration and must specify what is meant by areas. An "area" may include one or more generators. If it is one generator, the increase or decrease of power out is easily specified. If it is more than one generator, the appropriate unit allocation (dispatch) must be specified both for the increase and decrease in outputs.

b. Specification of contingencies. The exact list of contingencies could vary from single outages such as a loss of a line or generator, to complex fault/switching scenarios. The number of contingencies to be considered could vary from a very small number to thousands.

c. Determination of network response. A computer simulation is done to determine how the specified generation changes impact transmission line flows, system voltages, and stability margins. This must be done for the base case with normal limits enforced plus all specified contingencies with emergency limits enforced.

d. Finding the maximum transfer. It is possible that the base case condition and configuration does not satisfy the normal constraints on line flows, voltage and stability. In this case, the TTC could be considered zero or perhaps negative. In either event, it should be considered degenerate and some modification of parameters or conditions should be obtained to make the base case secure as a starting point. From this point, a systematic procedure to increase the specified transfer must be used to determine the maximum transfer that satisfies the above criteria. While repeated incremental analysis could be used, the concept of sensitivities gives a fast estimate of this maximum. For example, power transfer distribution factors give a linear prediction of power flow distribution in response to change in generation changes. These linear factors can be used to predict the maximum generation change which can be allowed. Similar distribution factors for voltage levels and stability margins are less reliable, but may be a useful alternative to repeated full nonlinear simulation.

e. Interpretation of results. In the Network Response (NR) method of TTC computation, the transfer capability from area A to area B is the maximum amount of real power that can be transferred from area A to area B by all physical paths. In the Rated System Path (RSP) method of TTC computation, the transfer capability from area A to area B is the amount of real power which flows over the physical paths directly connecting areas A and B under system-wide limiting conditions. As such, the computational requirements in both cases are similar, and mathematical solutions may even be the same, but the designation of capabilities is different. The RSP method includes a further allocation of capability to each physical line connecting areas A and B.

f. Repeat for alternate cases. Steps a.-e. above must be repeated for all possible cases which may be in affect at the time the TTC number will be used. Since the TRM is designed to account for uncertainty in the model configuration and operating conditions, the alternate cases could be used to compute the TRM. The available capability for a given transfer can become smaller as more alternate (but not necessarily likely) cases are considered. If appropriately weighted by the likelihood of occurrence, this could be used to determine the TRM for this base case. This is illustrated in Figure 1. below for the most likely base case and four less likely alternate cases. The TRM associated with the base case is determined from the most limiting TTC of the alternate cases (in this case alternate 4.

```
     TTC
      |   *
      |   *     TTC1
      |   *        *
 TRM  *     *    TTC2
      |   *        *        *
      |   *        *        *
      |   *        *        *    TTC3
      |   *        *        *        *
     ATC-----------------------------------------TTC4
          -        -        -        -           -
          -        -        -        -           -
          -        -        -        -           -
          -        -        -        -           -
          -        -        -        -           -
          -        -        -        -           -
 Base Case     Alt.1    Alt.2    Alt.3     Alt.4
```

Figure 1. Determining TRM from alternate cases

Alternatives to this systematic approach to TRM calculation could include fixed MW amounts (50MW), or fixed percentages (5%). A reduction of line ratings by some fixed percentage (2%) will normally lower the TTC. This reduction in TTC from a reduction of individual element ratings could also be used to specify the TRM.

From an engineering perspective, the challenges of ATC computation lie in the need to consider all likely base cases, all likely contingencies, and systematically compute the maximum transfer capability. In an operations environment where ATC numbers are posted on a short-term (several hours) basis, the number of base cases needed should be smaller than for a planning environment. However, when a given transaction is made, this transaction must be considered in the base case for future ATC calculations. This means that the ATC numbers must be updated after every transaction. A systematic method to rapidly update the ATC number after a transaction is needed. Current computation times for full ATC calculations of large systems (15,000 buses) considering up to 7,000 contingencies for 500 different transaction directions could take up to 24 hours even when linear methods are used. This means that considerable reduction in computation time is still needed. The new TRACE program which is being tested by EPRI may provide a significant new tool for these computations. This program was originally developed to compute SIC numbers [15].

Sensitivity analysis may provide a useful solution to this challenge. Since the system is very likely to be in a very nonlinear region at each maximum, it is important that these sensitivities be of the "large-change" type. For example, we now have large-change sensitivities to predict the impact of line outages (Line Outage Distribution Factors). A similar large-change sensitivity may be computable from the information obtained in the repeated alternate cases. If sensitivities of ATC to likely transactions could be computed at the same time that the ATC number itself is computed, rapid estimates could be obtained and utilized in a real-time basis. For example, when repeated alternate cases are computed to ensure all possible conditions are considered, their information could be used to estimate changes in the TTC when similar transactions actually occur.

The use of probabilistic methods to consider the impact of uncertainty has been used extensively in power systems [16,17]. These concepts may prove useful in quantifying TRM from a probabilistic approach. Expected values of ATC numbers could be used for TTC with variances used to compute TRM.

The concept of "most limiting phenomenon" may offer another approach to the reduction in computation time. Depending on the properties of the given system, it may be clear that the most limiting constraints are found in only one of the three - thermal, voltage and stability. In this case, there may be no need to consider constraints which will never be enforced. The results by Dobson [18] and Chiang [19] offer potentially useful tools to rapidly quantify distances to instability and thereby constraints for TTC calculations.

Traditional load flow and stability programs must be revised to properly enforce system limits. For example, the reactive power limit of a generator should be variable and dependent on the real power output. This should reflect the limitations of the unit capability curve.

5. Summary and conclusions

The computation of TTC and TRM presents a major challenge for power system engineers. While the NERC definitions and methods for determination provide considerable guidance for these calculations, there are still many major issues associated with their practical implementation. One of the main issues is related to the question of what to study. The concept of Available Transfer Capability requires the determination of what is available from a particular condition. If the exact condition were known in advance and a specific transaction was in question, the burden would be significantly less than that encountered in the attempt to predict what will be available at a future time. This paper has presented several of the issues associated with these computations and offered possible concepts for dealing with the challenges of the ATC calculation.

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