Evaluation of Optimal Transfer Capability in the Haenam-Jeju HVDC System Based on Cost Optimization

Hyun-Il Son*, Jin-O Kim†, Hyo-Sang Lee and Dong-Joon Shin*****

Abstract - The restructure of the electrical power industry is accompanied by the extension of the electrical power exchange. One of the key pieces of information used to determine how much power can be transferred through the network is known as available transfer capability (ATC). The traditional ATC deterministic approach is based on the severest case and it involves a complex procedure. Therefore, a novel approach for ATC calculation is proposed using cost optimization in this paper. The Jeju Island interconnected HVDC system has inland KEPCO (Korean Electric Power Corporation) systems, and its demand is increasing at the rate of about 10 [%] annually. To supply this increasing demand, the capability of the HVDC system must be enlarged. This paper proposes the optimal transfer capability of the HVDC system between Haenam in the inland and Jeju in Cheju Island through cost optimization. The cost optimization is based on generating cost in Jeju Island, transfer cost through Jeju-Haenam HVDC system and outage cost with one depth (N-1 contingency).

Keywords: ATC, Cost Optimization, HVDC System, Outage Cost

1. Introduction

The successful implementations of electric power deregulation require the efficient methods to calculate Available Transfer Capability (ATC) of power systems. In the operation of bilateral markets, ATC is used to allocate the reservations of transmission rights, and in the pooled markets, transfer capability combined with bid information can be used to allocate the financial transmission rights or the transmission congestion contracts. ATC values in the competitive electricity markets are the indices that determine whether the proposed particular transactions of electric power between participants can be approved or not.

By the NERC definition [1], ATC determination involves several parameters, namely, Total Transfer Capability (TTC), Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM). Among these three parameters, TRM is the reserved capacity that accounts for the uncertainties of network conditions as well as calculation error. And it is desirable to properly quantify the uncertainty in the ATC calculation as a safety margin so that the power system will remain secure despite the uncertainties such as generator/transmission line outages, load deviation and line impedance changes. CBM is the transfer capability reserved by Load Serving Entities (LSE) to ensure access to generation of the interconnected systems to meet generation reliability requirements.

The areas utilizing the High Voltage DC (HVDC) transmission system have been magnified to accomplish the optimization of electric power supply through electric power link between separated areas. Commercial driving of the HVDC transmission system was initiated between Haenam and Jeju in March of 1998. It charged about 50 [%] of the entire demand of electric power in Jeju. Now, all electric power companies in Korea are progressing toward being a part of the restructured power industry and are taking part in the electric power transactions to maintain economic performance and efficiency. Accordingly, the operation of transmission systems is being altered to seek the most suitable economical operation among the operation modes of the past. Therefore, under the existing capacity the concept of usable, but expensive, transmission capacity requires the expansion of the commercial utilization of transmission lines and the assurance of security.

Instead of the existing TTC method in N-1 contingency, this paper proposes a new ATC calculation method to minimize the expenditures that consist of the System Marginal Price (SMP) and the generating cost and the outage cost of N-1 contingency in Jeju including the transfer capability of the HVDC system. The data used in this paper are SMP, generation and demand of Jeju KPX (Korea Power Exchange) in June 2003.

2. ATC AND PARAMETERS

2.1 Interconnected mainland

Jeju is the largest island in Korea, and 50% of its present

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demand is supplied from the mainland, because the generating cost on Jeju is higher than the market price on the mainland. On the contrary, if the SMP on the mainland was more expensive than the generating cost of Jeju and the generating capability was sufficient, it would mean that Jeju could supply electric power to the mainland. In Jeju, demand increases about 10 [%] every year, and generating cost is usually about 3~4 times of SMP on the mainland.

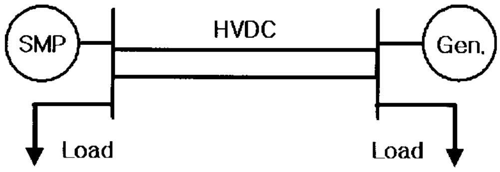

Fig. 1 A concept of the HVDC system at KEPCO

2.2 Determination of ATC

According to the NERC definition, ATC is determined as a function of increase in power transfers between different systems through prescribed interfaces. ATC determination involves several parameters; TTC, CBM and TRM (see Fig. 2).

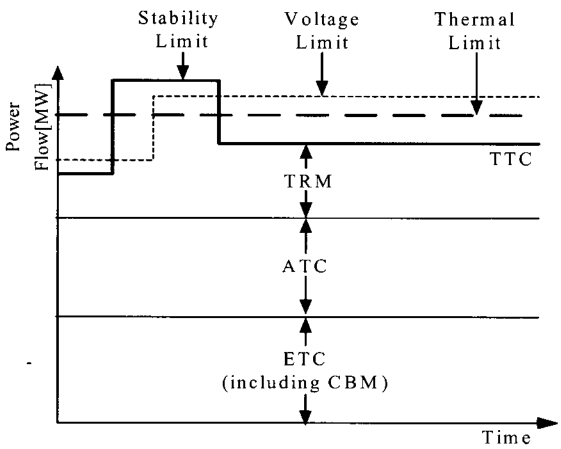

Fig. 2 Available Transfer Capability

The definitions of these three parameters are given as follows. TTC is the largest flow through the selected interface, which does not cause any thermal overloads, voltage limit violations, voltage collapse and/or any other system security problems such as transient stability. TRM is the reserved capability that accounts for uncertainties related to the transmission system conditions, contingentcies and parameter values. The TRM is the amount of transmission capability required to ensure that the interconnected network is secure under a reasonable range of uncertainties in system conditions. CBM is the amount of transmission transfer capability reserved by LSE to ensure access to generation of the interconnected systems. The CBM is set aside to meet the generation reliability requirements of LSE. Among these parameters, TRM and CBM are the factors that account for the uncertainty and reliability in the power system. TTC and ATC can be expressed as (1) and (2).

$$TTC = Mim\{Thermal, Voltage, Stability\ Limits\} \quad (1)$$

$$ATC = TTC - TRM - ETC - CBM \quad (2)$$

where, ETC is Existing Transmission Commitment.

2.3 Determination of ATC using Cost Commitment

Unlike the ATC calculation through contingency, the ATC computation through cost calculation can be expressed as (3) [2, 3].

$$\min[TCC] = C_G + C_T + C_O \quad (3)$$

where, TCC : Total customer cost [₩]

C_G : Generating cost [₩/MW]

C_T : Transfer cost through HVDC [₩/MW]

C_O : Outage cost [₩/MW]

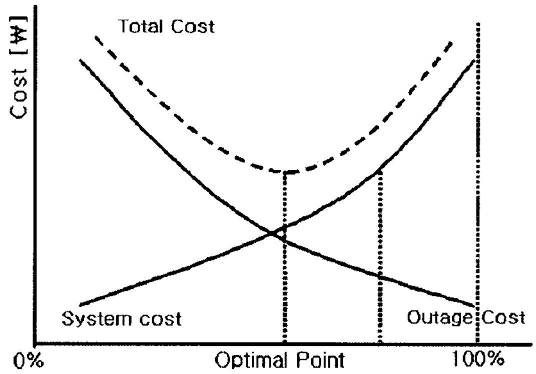

Fig. 3 Determination of optimal cost point

We will obtain the objective function to be minimized, which is optimal transfer capability and generating capability.

2.4 Calculation of Outage Cost

Outage cost accounts for two sides. First, it covers the damage of customers who are not supplied electric power by contingency. Second, it covers the restoration expenditure and the amount of money involved when electric utilities do not sell power by contingency [4].

Various methods have been used to evaluate the outage cost but they can primarily be classified into two kinds. The first type is the macro method, which evaluates the outage costs in relation to national economy. The second type is the micro method, which calculates the outage cost by customer type based on the survey of individual customers.

The former, the macro method is conceived on the point that economic loss occurs after power interruption as economic activities are halted. The simple method is to divide GNP by total power consumption to macro-scopically calculate the outage cost. A more detailed method can also be used. By using tables related to economic activities, this method estimates the outage cost of each economic sector by dividing the value obtained in the sector by the power input of the sector. These methods are rough but have merits also. With these methods, it is possible to determine the outage cost of a country as a whole or by sector. However, evaluating the outage cost of individual customers with the value obtained by these methods has some problems.

$$\text{Interruption cost by economic activity} = \frac{\text{Value added by economic activity}}{\text{Power input by economic activity}} \tag{4}$$

Alternatively, by way of the micro method it is possible to calculate the outage costs of customer groups but not individual customers, and the results can be problematic from the objectivity standpoint. As a result, it is necessary to carry out large-scale surveys. The actual outage costs are calculated based on large-scale surveys in Sweden, Britain, France, the U.S., Canada and Japan.

The outage cost can be calculated from (4).

$$C_O = \sum_t \left(ESE_t \times p_{ESE} \right) \tag{5}$$

where, ESE_t : Expected not supplied energy in post-contingency [MW]

p_{ESE} : Consumed electric energy by GNP [₩/MW]

2.5 Calculation of Transfer Cost

The HVDC system consists of 2 lines, and the maximum transfer capability is 300 [MW].

The transfer cost through the HVDC system is decided using SMP and transfer capability as equation (6).

$$C_T = \sum_t \left(SMP_t \times T_t \right) \tag{6}$$

where, SMP_t : SMP in mainland at time t

T_t : Transfer capability in HVDC system at time t

2.6 Calculation of Generating Cost

Generating cost consists of the fixed cost and the changeable cost. But, the fixed cost is relatively less than the changeable cost. Fuel cost, one of the changeable costs and the greatest part of the expense composition, can be alternated with generating cost.

Equation (7) indicates generating cost in a selected time.

$$C_G = \sum_{i=1}^{n-1} \left(G_i \times p_{Gi} \right) + \left(P - \left(T + \sum_{i=1}^{n-1} G_i \right) \right) \times p_{Gn} \tag{7}$$

where, n : The number of generating units at time t

G_i : i th generating capability in Jeju [MW]

p_{Gi} : i th generating unit cost in Jeju [₩/MW]

P_t : Demand in Jeju at time t [MW]

T_t : Transfer capability in HVDC system at time t [MW]

Jeju has 3 power plants and 7 generators. The generating costs and capabilities of selected Jeju generators are shown in Fig. 4.

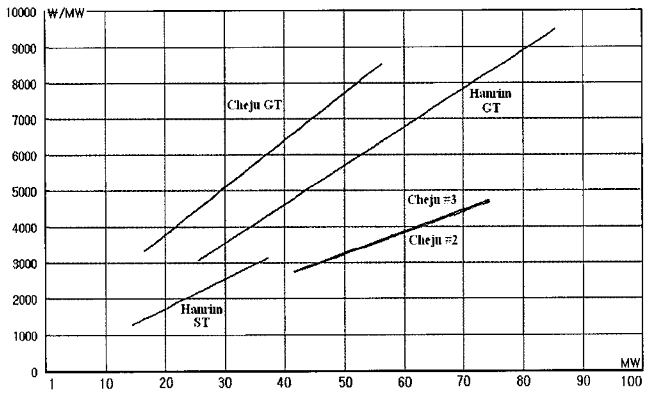

Fig. 4 Generating Capabilities and Costs of Jeju Generators

In Fig. 4, the fuel cost of Hanrim Steam Turbine (Hanrim ST) is the lowest, but electric power is available after the generation of Hanrim Gas Turbine (Hanrim GT). Therefore, Jeju #2, which has the lowest generating cost next to Hanrim ST, operates firstly. Jeju Gas Turbine (Jeju GT), which has the highest generating cost, remains as a spare generator.

3. CASE STUDIES

In June 2003, the demand of Jeju was low in daybreak, peak load happened at 22 hours, and average demand was 217 ~ 320 [MW]. 50 [%] of the total demand was received from the HVDC system.

Now, suppose that the HVDC system was used by 0 [%], 50 [%] and 100 [%], and each cost was calculated as below.

In cost calculation, two constraints were supposed. Firstly, the transfer capability through HVDC system can be changed freely, but generators have to be started before generator starting time. Secondly, the generating cost is calculated by added 15% of the reserve rate in demand. Such constraints are the items that are applied in the actual demand plan as well as the convenience of calculation.

3.1 Case Ⅰ : 0 [%] usage of HVDC system

Without transfer capability through HVDC system, the 7 generators of Jeju will supply its total demand. Jeju #2, #3, and Hanrim GT will always supply power, Hanrim ST, Jeju GT #1, and #2 are operated timely according to demand, and Jeju GT #3 are reserved.

The calculation of generating cost considers generator operating hours, minimal generating capability, starting cost, start-up time, and generating unit cost.

Outage cost considers starting time and was calculated using equation (5). It supposes a contingency of Hanrim GT, which has the biggest generating capability.

In Fig. 5, the upper line is the generating cost, and the lower line is the outage cost. As compared with the next cases (Case Ⅱ and Case Ⅲ), the generating cost is more expensive, and the result of outage cost is similar to the result of generating cost, because the same generating unit cost is applied to the results.

3.2 Case Ⅱ : 50 [%] usage of HVDC system

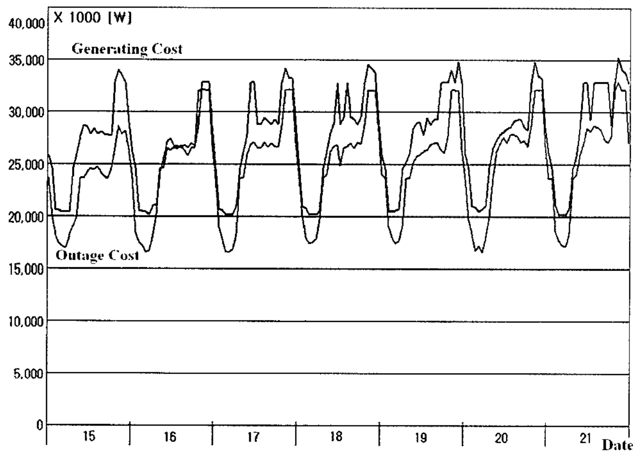

Fig. 5 Generating Cost and Outage Cost of Case I

The transfer capability through HVDC system is 150 [MW], which is 50% of maximum transfer capability, and the chief generators supply the lack of electric power.

Outage cost is measured under two events.

- *Event A*: Contingency occurs in one line of HVDC system,
- *Event B*: Contingency occurs in Hanrim GT and Hanrim ST.

In *Event A*, if the repair cost of the HVDC system is ignored, then the outage cost does not occur except during repair time. In *Event B*, the outage cost is similar to that of Case I, which uses the generating unit cost and the outage cost at outage time in (5).

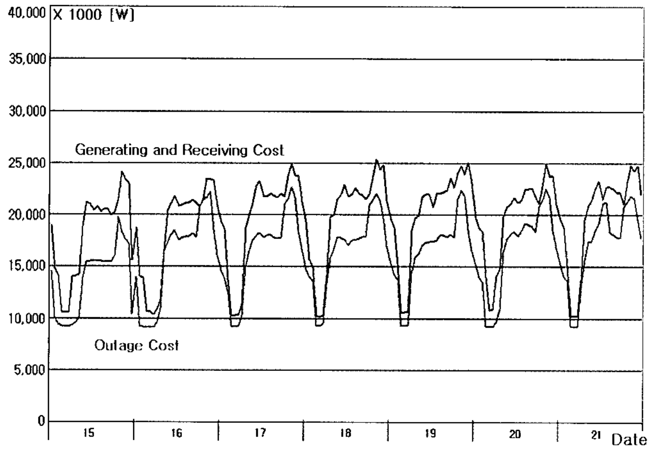

Fig. 6 Generating Cost, Receiving Cost and Outage Cost of Case II

Computation outcomes are presented in Fig. 6. As before, the upper line is the sum of the generating cost and transfer cost, and the lower line is the outage cost. As compared with the others (Case Ⅰ and Case Ⅲ), generating and transfer costs are lower than that of Case Ⅰ, but are more expensive than Case Ⅲ.

Remarkably, the outage cost is the lowest among three cases because of the shortest outage duration of this case.

3.3 Case Ⅲ: 100 [%] or full-load supply by HVDC

This case shows that the HVDC system is fully used. In June 2003, the demand of Jeju was 217 ~ 320 [MW]. When the demand exceeded 300 [MW], Jeju #2 having the lowest generating unit cost, was put in operation.

Outage cost is measured under two events.

- *Event A:* Contingency occurs in one line of HVDC system,
- *Event B* : Contingency occurs in both lines of HVDC system.

In *Event A*, the outage cost is similar to the *Event B* of Case Ⅱ. In *Event B*, all generators in Jeju must operate.

Fig. 7 shows, as same as before, the sum of generating cost and transfer cost and the outage cost. As compared with the others (Case Ⅰ and Case Ⅱ), the sum of generating and transfer cost is the lowest among three cases, because

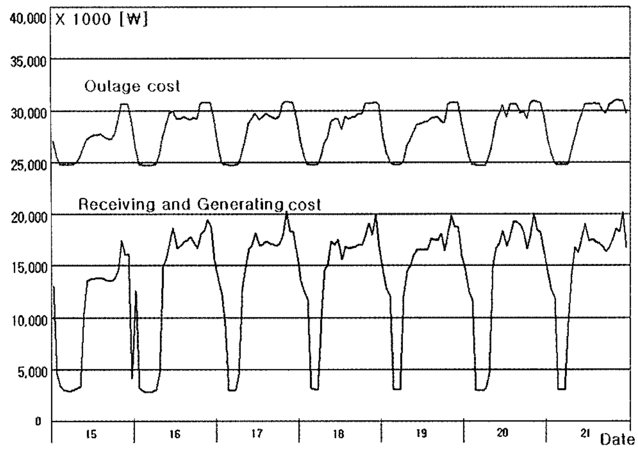

Fig. 7 Generating Cost, Receiving Cost and Outage Cost of Case III

the SMP in mainland is lower than the generating unit cost of Jeju. The outage cost, however, is the most expensive among the others. It is the reason that the outage duration is the longest among three cases, and the starting time of Jeju #3 is 47 minutes. Remarkably, when the outage cost is ignored, the increase of transfer capability is better.

3.4 Computation of optimal transfer capability

After the selection of the lowest point using least square curve fitting to the total cost calculated in case Ⅰ, Ⅱ and Ⅲ, we can solve the approximated optimal transfer capability.

In Fig. 8, the actual transfer capability is 50 [%] of the demand of Jeju, and it is 25~50 [%] of the maximum transfer capability of the HVDC system. The optimal transfer capability by the cost calculation is 60~95 [%] of demand, and 55~75 [%] of the HVDC system rating.

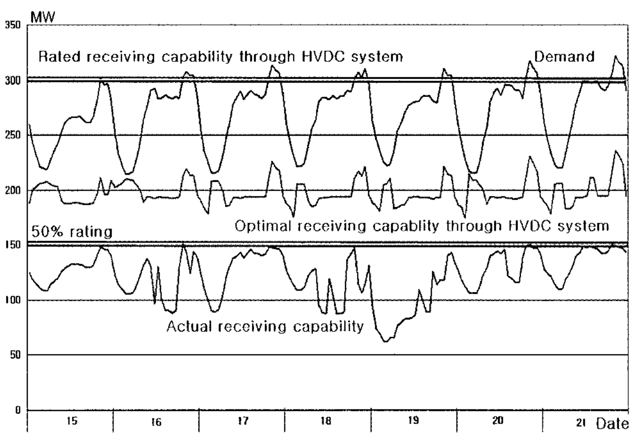

Fig. 8 Actual and proposed transfer capability

In Fig. 8, the elements that influence the transfer capability are the demand of Jeju and the SMP on the mainland. So, the receiving capability through the HVDC system can be considered as a function of SMP and demand as in (8).

$$\text{Receiving Capability through HVDC system} = f(\text{SMP}, \text{demand}) \tag{8}$$

The demand simulation of Jeju is 200~400 [MW], supposing that SMP is 10~70 [₩/kWh]. The results of equation (8) are expressed as (9) and Fig. 9.

$$T = 0.003SMP^2 - 0.703SMP - 0.001P^2 + 0.128P + 54.063 \tag{9}$$

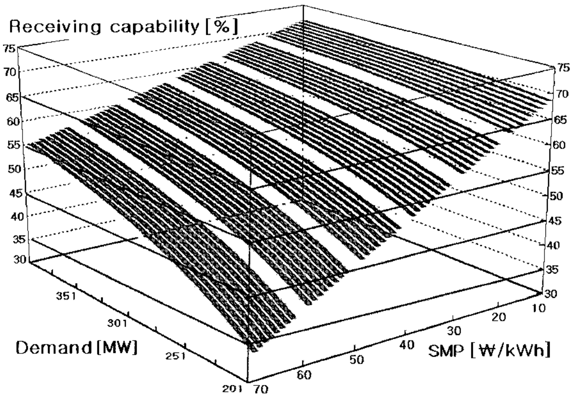

Fig. 9 Simulation of optimal transfer capability

In the simulation result, the relation between demand and transfer capability and the relation between SMP and transfer capability are expressed as the quadratic function, and the transfer capability changes according to that function. Remarkably, the transfer capability function draws a slow curve in accordance with the increase of demand, but the SMP influence is significant enough to be near fan shape, because the SMP is lower than the generating unit cost and there is the limitation of transfer capability through the HVDC system.

4. Conclusion

Now, 50 [%] of demand in Jeju is supplied through the HVDC system. In other words, the demand is supplied first of all by generators in Jeju, and the remainder of demand is supplied through the HVDC system. This means the supply strategy of non-economic concepts takes a serious view of reliability to customers. However, the generating unit cost of generators in Jeju is higher than the SMP of the mainland.

This paper presents that electric power in Jeju should be supplied through the HVDC system, and shows its profits in an economical aspect. Contrarily, if the SMP of the mainland is more expensive than the generating cost per MW in Jeju, and the generating capability is sufficient, then the mainland must purchase electric power from Jeju.

Hereafter, with the advancement towards the power industry restructuring of Korea, the customers and suppliers in Jeju can assume the advantages offered by acquiring the use of the HVDC system.

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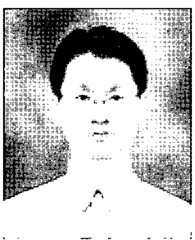

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